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RELIABLE GENERATOR ISLANDING DETECTION FOR INDUSTRIAL POWER CONSUMERS WITH ON-SITE GENERATION

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Abstract—Large power consumers often have on-site generation. If the utility tie opens, it is essential to isolate the on-site generators to prevent generator equipment damage before the utility attempts to reclose in a possible out-of-synchronism condition. Typically, islanding detection schemes are used to detect this condition and disconnect on-site generation quickly, thereby allowing successful utility reclose.

This paper introduces a reliable islanding detection solution that was proposed, implemented, and tested at a refinery in Texas. The facility houses two on-site generators and is interconnected to the utility via a looped system. A topology-based islanding detection scheme was originally installed at this facility but was later decommissioned because of difficulties in adapting to evolving topology changes. Following an undesirable event in the utility system that could have resulted in damage to the refinery on-site generator equipment, the refinery decided to implement an islanding detection scheme that is independent of system topology changes and only relies on local-area measurements. However, the dependability of a traditional local measurement-based scheme is vulnerable to the dynamic generation-load mismatch, making it possibly unreliable. This paper describes a solution using a redundant high-speed multiprinciple islanding detection scheme that incorporates a unique voting supervision logic to achieve security.

Index Terms—Generator islanding detection, rate of change of frequency, refinery generators, wide-area islanding detection, local-area islanding detection.

I. INTRODUCTION

Large industrial power consumers, especially those in continuous process industries, often have on-site generation capabilities in order to meet their essential power requirements. Islanding is defined as a condition where a portion of the power system that contains loads and on-site generation remains energized but is electrically isolated from the rest of the utility system [1]. Typically, islanding is caused by a disturbance in the utility system due to faults or wide fluctuations in frequency and/or voltage caused by real and reactive power mismatch. Fig. 1 shows a simplified one-line diagram of an industrial plant interconnected to a utility. Under normal operating conditions, the on-site generators operate in parallel with the utility to feed the total plant load. The local generation (P_G) plus the imported power (P_I) together meet the entire plant load (P_L). For a fault on the line supplying power to the plant, line protective relaying will detect the fault and open Breakers 2 and 3, thus resulting in a loss of utility supply to the plant and leaving it islanded.

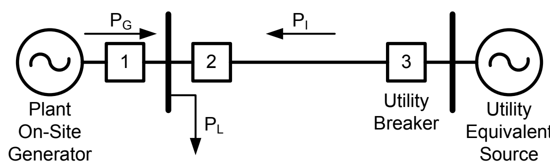

Fig. 1 Simplified One-Line Diagram of Interconnection

After being disconnected from the utility, the islanded network can experience active and reactive power mismatch, depending on the power exchange between the plant and utility prior to islanding. This results in one of the following three possible scenarios [1]:

1. If the plant load is significantly higher than the local generation capacity, the electrical energy demand will be much higher than the mechanical input of the generator, causing a reduction of generator speed and frequency.
2. If the local load is less than the generation, the generator speed will momentarily increase, resulting in a frequency rise above nominal.
3. If the plant load and generation match, the speed and frequency of the generators will hardly change.

For Scenarios 1 and 2, the frequency and voltage of the plant may fall outside acceptable levels, resulting in power quality concerns with the connected loads.

When the utility source is lost due to a disturbance, whether or not to keep the local generation online will be determined by the power quality for the loads served, the criticality of the plant process, the hours of lost operation, and the time it takes for the entire process to be restarted. If the process is critical and power continuity is a necessity, then the local generation can be kept online, but the industrial facility may require a load-shedding scheme to only supply critical loads. In short, the industrial facility will be intentionally islanded and still be operational [2] [3].

An alternative for facilities where the processes are not as critical and where there is no load-shedding scheme is to disconnect the local generators from the system faster than the utility breaker automatic reclosing time. If synchronism check is not present and the generators do not disconnect fast enough, the utility breaker will attempt to reclose out of synchronism. When an out-of-synchronism close is initiated, the high electrical torque translates to stress on the mechanical shaft of the rotating equipment, reducing the life of the equipment and even leading to equipment damage in the worst cases [4]. On the other hand, if synchronism check is present, a reclose attempt will fail and the plant will run on poor-quality power until it goes offline completely instead of being restored quickly from the utility by the first reclose. For these reasons, the islanded generators should be isolated as fast as possible to minimize abnormal operating conditions. Typical generator protection schemes used to protect the generator during abnormal and fault conditions that rely on frequency and voltage magnitude may not be able to detect the islanding condition when the power exchange with the utility is minimal. Fig. 2 shows typical operating times for the generator protection to detect the opening of Breaker 2 or 3 (shown in Fig. 1) for different power exchange conditions.

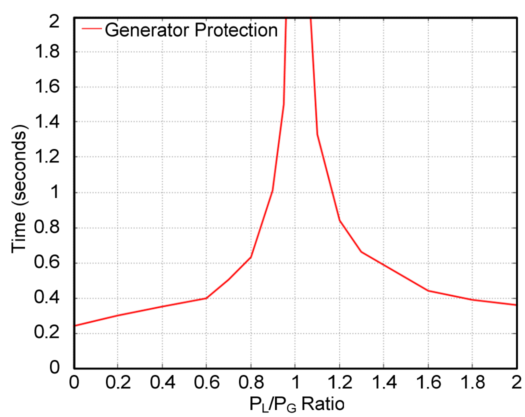

Fig. 2 Typical Generator Protection Response Time for Varying P_L/P_G Ratios

Islanding detection schemes are used to reliably detect a loss of interconnection with the utility, even during minimal power exchange conditions, and to securely disconnect the on-site generators without causing any false or nuisance trips. Several islanding detection techniques have been developed and are discussed in detail in Section III of this paper. This paper presents a fast and reliable islanding detection and separation (IDS) scheme based on local-area measurements that was implemented at a North American refinery.

II. BACKGROUND

Fig. 3 shows a simplified one-line diagram of the refinery plant (Plant A), which houses two on-site steam turbine generators with a total generation capacity (P_G) of 50 MW and a total plant load (P_L) of approximately 115 MW. The plant is served by two utility-owned ring-bus substations (Substations B and C shown in Fig. 3). Four 69/12.5 kV distribution transformers (T1, T2, T3, and T4) are used to interconnect the Plant A system with the utility grid. The total connected load at Plant A remains relatively stable under normal operating conditions. Variances in load characteristics typically only occur during scheduled process unit outages once every four to five years.

Originally, Plant A was a corn processing facility dating back to the 1940s. The plant load was served via one 69/12.5 kV transformer (T1) and a small 10 MW on-site generator. The generator was able to support load even if separated from the utility. Therefore, no automatic reclosing feature was implemented on the utility source breaker. In 1983, the site was converted to a refinery, and two additional steam turbine generators were added to the system. The additional plant load surpassed the on-site generation, so a utility automatic reclosing scheme was implemented. A protection scheme was developed to trip the generators offline in the event that Plant A lost its tie with the utility to allow the plant load to be restored quickly from the utility source by the automatic reclosing function. Without this protection, the Plant A generation equipment would have been subjected to mechanical damage if a reclose attempt was made during an out-of-synchronism condition. During the early 1990s, several expansions at Plant A required the addition of two

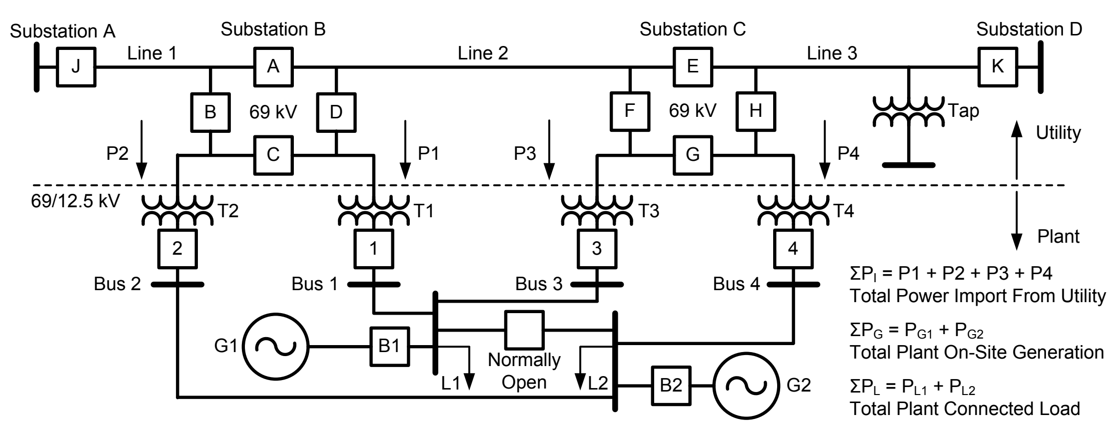

Fig. 3 Simplified One-Line Diagram of the Refinery Plant A System

69/12.5 kV transformers (T2 and T3) to serve additional loads. Also, the local utility constructed two 69 kV four-breaker ring-bus substations (B and C) to serve these loads. Plant A continued to operate with the on-site generation tied to the utility via T1, while loads on T2 and T3 were radially fed from Substations B and C. The islanding detection technology available at that time was an audio tone transfer trip system that used dedicated telephone lines between the utility and the Plant A generator. The system required a network of breaker contacts wired from the remote and local utility substations. Breaker statuses were transmitted over telephone lines to receivers located at the plant, making it a topology-based islanding detection scheme. The audio tone transfer trip system functioned properly for many years and was updated as the utility topology evolved.

In the following years, both the utility and Plant A underwent further upgrades, including the addition of another transformer (T4). However, audio tone system upgrades were not performed on a regular basis by either the utility or the refinery. Printed circuit boards were beyond their life expectancy, and there were difficulties with the integrity of the telephone cable system. An evaluation was performed to determine the likelihood of on-site generators being damaged if exposed to a utility out-of-synchronism reclose event. Because Plant A is normally served from two 69 kV sources, the chance of it losing its tie with the utility was determined to be less likely. A decision was made to decommission the audio tone system.

However, in March 2011, the utility experienced a fault on Line 2 from Substation B to Substation C caused by a failed lightning arrestor at Substation B. The Line 2 protection correctly isolated the fault. However, Breaker B incorrectly opened due to a failed timing relay. At the same time, the Line 3 protective relays at Substation D overtripped for this out-of-zone fault due to a miscoordination problem, opening Breaker K. This series of events left the plant islanded from both 69 kV sources. The oscillography of the event data retrieved from the Line 3 relay at Substation D showed a 40 kV line voltage, indicating that Plant A was exporting poor-quality power back to the tapped loads on Line 3. Fortunately, the utility did not have automatic reclosing installed on Breaker K; otherwise, a reclose attempt would have damaged the Plant A generators. Following this event, the refinery decided to implement an islanding detection scheme that only relies on local-area measurements and that is independent of utility and refinery electrical system topology changes.

III. ISLANDING DETECTION SCHEMES

Before the actual islanding detection solution implemented at the refinery is introduced, this section reviews the concepts behind various islanding detection techniques to provide a basis for the subsequent discussion.

A. Topology-Based Schemes

A topology-based scheme requires communicating breaker and disconnect statuses to detect an islanding condition. The statuses can be transmitted by means of hard-wired signals or a reliable communications channel. This is a simple scheme and has been deployed by many industrial facilities over the past decade. Predefined logic can be programmed in the intelligent electronic devices (IEDs) protecting the generator, which then use the breaker and disconnect status information to appropriately detect an islanding condition and trip the unit offline prior to the utility reclosing. This scheme is a cost-effective and simple solution if the topology of the power system is relatively simple and remains fixed.

However, if the topology changes and the complexity of the system increases (e.g., a breaker-and-a-half or ring-bus arrangement as opposed to a simple straight bus arrangement at the utility end), the relative simplicity of the scheme is impacted. Topology changes can require a significant amount of wiring to communicate the necessary statuses of breakers and disconnects to all the generator IEDs. Limited IED inputs would necessitate a central communications processor to monitor every breaker and disconnect status in the area. The predefined logic can become more involved as the system topology becomes more complex.

In the example topology-based scheme shown in Fig. 4, the logic for detecting an islanding condition and tripping the generating units resides in the logic processor. The security of the scheme can be compromised if the breaker and disconnect auxiliary contacts do not reflect the actual status of the device. Another factor that can affect the scheme performance is the loss of a communications channel, because such a channel is the backbone of any transfer tripping that takes place. Cost is not a consideration if there is an existing communications channel, such as radio or telephone. If not, new installation costs should be taken into account.

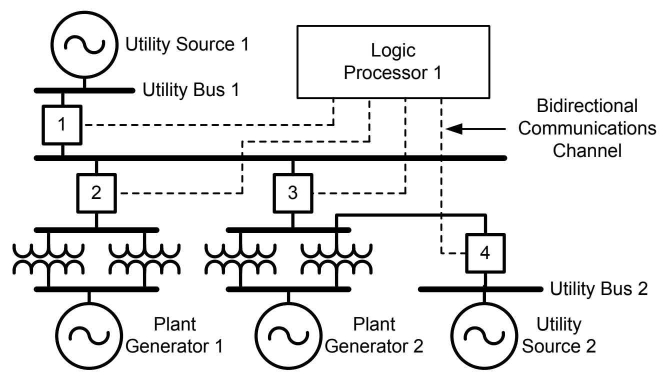

Fig. 4 Topology-Based Scheme

For the system shown in Fig. 4, Plant Generator 2 can be tied to Utility Source 1 or 2 depending on the status of Breakers 3 and 4. The scheme has to take into account different system topologies causing different islanding conditions. For a given system with a fixed topology, the scheme is very simple because there is no need to account for different network configurations. On the other hand, for larger systems with more complex configurations or more breakers, it becomes challenging to account for every scenario.

B. Local-Area Measurement-Based Schemes

Islanding detection schemes using local-area measurements rely on voltage, frequency, and/or rate of change of frequency to detect an islanding condition [5].

1) Voltage-Based Schemes

When an industrial facility with a synchronous generator becomes islanded from a utility system, there will be a change in the terminal voltage of the machine depending on the extent of generation-load mismatch. If the generation is less than the load, the voltage starts dropping after islanding and might recover temporarily, depending on the machine excitation characteristic. Continued mismatch will result in a permanent voltage drop. An undervoltage relay set sensitively will be able to detect such a condition. However, the relay can also pick up for a system fault condition, which is accompanied by a drop in faulted phase voltage. One way to counter this problem is to add a security time delay to ride through such fault conditions, which then can prevent the use of high-speed reclosing on the interconnecting tie lines. Conversely, when an industrial facility with local generation becomes islanded with generation much greater than the available load, it results in an overexcitation condition, which leads to voltage above the nominal value. An overvoltage relay set accordingly is able to detect this condition. The greater the reactive power mismatch, the easier it is to detect the islanding condition and the better the performance of the element.

2) Frequency-Based Schemes

If local generation cannot support the connected load during an islanding condition, the frequency of the islanded system will decay, resulting in an unstable operating condition. The amount of the frequency deviation depends on the local generation and power import from the utility system prior to islanding. An underfrequency relay (81U) set below the nominal frequency will be able to detect this condition.

During an islanding condition with the load less than the generation, the machine will temporarily accelerate until the governor on the synchronous machine can reduce the mechanical energy into the generator, resulting in an overfrequency condition. An overfrequency relay (81O) set to operate above nominal frequency will be able to detect this condition.

However, if the generation-load mismatch is minimal, it becomes a challenge to detect an islanding condition by measuring the deviation of frequency from nominal. Setting the elements too sensitively can result in operation for other system events. Settings choices for frequency pickup and time delays have to be chosen in such a way that they prevent element operation during such conditions. The greater the real power mismatch between generation and load, the easier it is to detect the islanding condition and the better the performance of these elements.

An islanded system operating in an unstable operating region will experience a greater rate of change of frequency variation than that expected during power system faults in the utility and local systems [1]. Therefore, a relay measuring a rate of change of frequency can distinguish between frequency variations resulting from islanding conditions and other power system events [1]. Relays measuring rate of change of frequency (81R) are commonly used for islanding detection and have a relatively faster response time compared with conventional 81U and 81O elements. 81R elements operate faster because there is no need to add a security timer to ride through disturbance conditions.

One other variation of this element is the fast rate of change of frequency element (81RF), which is discussed in detail in Section IV, Subsection A.

3) Impedance-Based Schemes

Typically, the equivalent impedance of the utility that the plant ties into is relatively smaller than the impedance of the plant, which consists of the plant generator unit impedance, the transformer impedance, and the impedance of the interconnecting cables. When the utility bus-tie breaker is closed, the impedance of the total network is a smaller value. But with the bus-tie breaker open, the impedance increases to a relatively high value. Any increase in system impedance that is greater than the normal operating condition when the industrial facility is synchronized with the utility can be attributed to an islanding condition [6]. This variation in system impedance between synchronized and islanding conditions can be used to detect the islanded operation.

As shown in Fig. 5, when the generator is tied to the utility and is in synchronism, the effective impedance of the network is the parallel combination of Z_{plant} and $Z_{utility}$. When the utility is the stronger source—which most likely is the case—the effective impedance is reduced to just $Z_{utility}$, which is an order of magnitude smaller than when the utility bus-tie breaker opens (i.e., the plant generator is running in an islanding condition). The effective impedance in this case is the series-parallel combination of transformer (Z_{TRn}), cable (Z_{Linen}), and generator (Z_G) impedance.

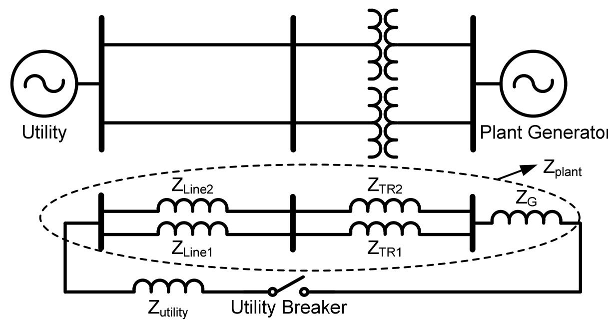

Fig. 5 Impedance-Based Scheme

As shown in Fig. 6, this scheme also requires a high-frequency signal generator whose output will be embedded into the generator signal. The final output is obtained after the voltage signal passes the high-pass filter. Because the scheme requires additional hardware as well as the generator protection relays, the cost factor might be a limitation.

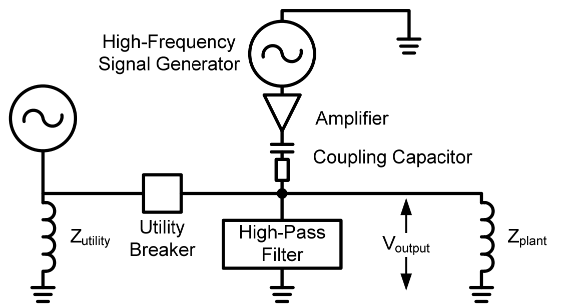

Fig. 6 Comprehensive Impedance-Based Scheme With Signal Generator

C. Wide-Area Measurement-Based Schemes

Fig. 7 shows a characteristic based on slip frequency and acceleration. The slip is calculated by measuring positive-sequence voltage at the utility and at the intertie point. The rate of change of phase angle difference gives an estimate of slip in hertz. Because this angle comparison occurs at the same instant of time and at periodic intervals, the data used for slip and acceleration calculations have to be time-synchronized with a Global Positioning System (GPS) clock.

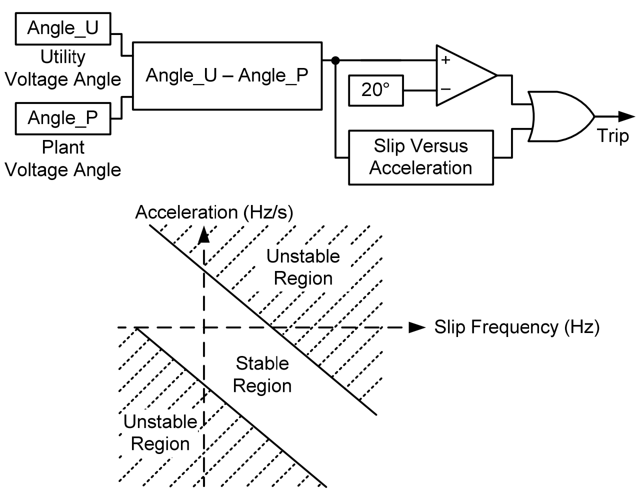

Fig. 7 Wide-Area Measurement-Based Scheme

This scheme also requires the installation of phasor measurement units (PMUs) at the desired measurement points, although many modern microprocessor-based relays have an integrated PMU within the unit. One of the advantages of this scheme is that there is no intentional delay because the measurements are performed in real time and transmitted to a phasor data concentrator (PDC), which computes the slip and acceleration values with data transfer rates up to 60 messages per second [4].

The PDC receives time-synchronized positive-sequence voltage angle measurements from the utility and the intertie point. The processor calculates the angle difference and then uses that information to calculate the slip and acceleration. As shown in Fig. 7, the top half of the logic simply looks for an angle difference, and if it is greater than the threshold, a trip signal is issued to trip the plant generators. The bottom half of the logic plots the slip versus acceleration, and if the operating point lies within the stable region, then there is no operation. During an islanded operation, the operating point will diverge from the stable region to the unstable region, thus resulting in the tripping of plant generators.

One advantage of the scheme is that it operates for all power transfer conditions, provided the generator is operating in an islanded mode. The slip in hertz between two systems is a function of generation-load real power mismatch. When one system is slipping slowly with respect to the other, it takes a longer time to detect the islanding condition; however, it is eventually detected as the angular difference increases. Conversely, if the generation-load mismatch is higher, the slip rate will be higher and the response time will be faster for the overall scheme. This scheme is not dependent on topology and therefore can be easily applied to different intertie configurations. Gaining access to the remote utility voltage angle measurement may, however, not always be feasible.

IV. IMPLEMENTED SOLUTION

Different islanding detection methods using local-area measurements and wide-area measurements were discussed in detail in the previous section of this paper. This section discusses the innovative IDS scheme that was successfully implemented and tested, and is in service at a North American refinery (see Fig. 3). The implemented solution uses a redundant multiprinciple islanding detection technique.

Fig. 8 shows the communications architecture of the scheme. The scheme employs multifunctional protective relays, referred to as IEDs throughout this paper. The primary islanding detection element is based on frequency measurements and is implemented in the four transformer low-side IEDs (IED 1) and the two generator IEDs (IED 2). The secondary islanding detection element is based on directional power flow measurements and is implemented only in the transformer IEDs (IED 1) shown in Fig. 8.

All six IEDs are connected to two logic processors (Logic Processors 1 and 2) using a high-speed peer-to-peer serial communications protocol through separate communications links. The IEDs communicate the output status of the islanding detection elements to the logic processors. A unique voting supervision logic is programmed in the logic processors and is explained later in this section. The purpose of the voting supervision logic is to enhance both security and dependability to make a reliable islanding decision. The primary and secondary islanding detection schemes, along with the voting supervision logic, provide a fast and reliable IDS scheme for this application.

A. Fast Rate of Change of Frequency Element

The primary IDS scheme uses a special characteristic as shown in Fig. 9, referred to as a fast rate of change of frequency (81RF) element. It detects an islanding condition based on frequency change (ΔF) from the nominal frequency and rate of change of frequency (df/dt) calculated over a predefined period. Under steady-state operating conditions, real power generation on the local network plus the real power import from the utility matches the real power connected plant

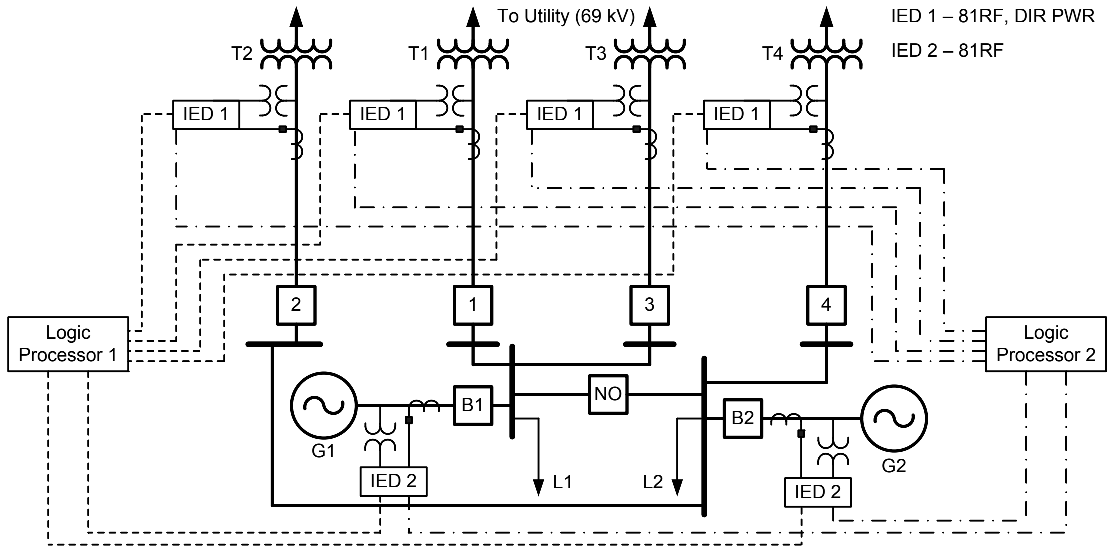

Fig. 8 Communications Architecture

load. Hence, frequency is close to nominal frequency (60 Hz) and the operating point is close to the origin of the ΔF versus df/dt plane, as shown in Fig. 9. The power exchange between the local network and the utility system affects the response time of the scheme. After islanding, if the load demand is greater than the generation ($P_L/P_G > 1$), the frequency decelerates and the operating point of the 81RF element falls in Trip Region 2. If the generation is higher than the load ($P_L/P_G < 1$), the frequency accelerates and the operating point moves to Trip Region 1. The time it takes for the 81RF element to move to either of the trip regions depends on the degree of mismatch. A higher degree of mismatch means the rate at which the frequency slips from nominal is also higher, resulting in a faster response. The reverse is also true. However, the overall response of this element is faster relative to the conventional elements when $0.8 > P_L/P_G > 1.3$ [5].

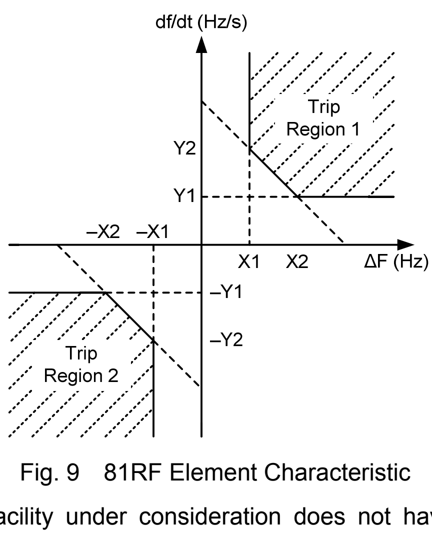

Fig. 9 81RF Element Characteristic

If the facility under consideration does not have a load-shedding scheme in place, then the odds of having a minimal generation-load mismatch between the generation and load are much less. For a system without a load-shedding scheme, the 81RF element provides the fastest response time among all the local-area measurement-based techniques discussed in Section III. The faster operation makes the 81RF element more attractive, especially with short open intervals for reclosing shots at the utility-side breakers. The other advantage of applying the 81RF element is that it is independent of system topology changes.

The IDS scheme must be designed to be tolerant of transients during power system faults. Therefore, the scheme operation must be blocked under fault conditions. The primary IDS logic, which uses an 81RF element, is shown in Fig. 10. The V_BLK and I_BLK settings can be used to block the operation of the 81RF element during fault conditions. In this application, the security of the primary IDS logic has been improved to selectively block the operation of the scheme for internal faults of significant magnitude that might occur within the plant and to not block the operation for external faults in the utility system. For a fault within the 12.5 kV system of the plant, the fault current contribution from the utility is higher than the plant contribution for faults on the 69 kV utility system. As such, the I_BLK setting in each of the transformer relays (IED 1) is set higher than the current seen by each relay for the 69 kV faults.

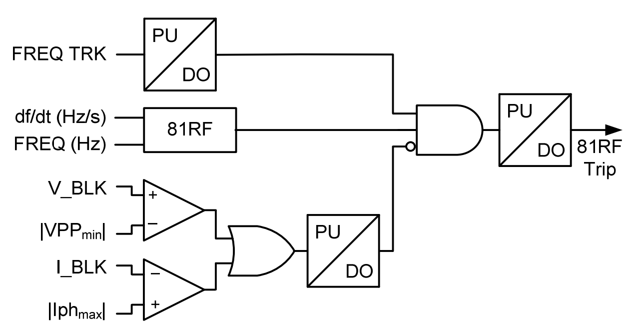

Fig. 10 Primary IDS Logic

For a fault on the utility system, the 81RF element is set to anticipate an islanding condition, and if an islanding condition does occur, the 81RF trip will assert if the operating point falls in either Trip Region 1 or 2. The I_BLK setting is turned off in each of the generator relays (IED 2) because the generators will contribute to the fault and the generator relays may not be able to differentiate between the 12.5 kV plant and the 69 kV system faults. The FREQ TRK binary input shown in Fig. 10 ensures that the IED is tracking and measuring the system frequency. The 81RF element is supervised with the FREQ TRK bit, and the primary IDS scheme will be blocked if the frequency falls outside the tracking band.

B. Directional Power Element

The secondary IDS scheme uses directional power elements to detect an islanding condition. Directional power relays rely on measured current and voltage magnitudes along with the angular relationships between them and are commonly used to determine the magnitude and direction of power flow [7]. The secondary IDS scheme shown in Fig. 11(a) was implemented only in the four transformer low-side IEDs (the IED 1 relays shown in Fig. 8) to detect underpower or reverse power conditions resulting from an islanding condition. The direction of active power in the generator IEDs will be forward into the refinery for all conditions except motoring conditions; therefore, this element cannot be implemented in the generator IEDs (IED 2).

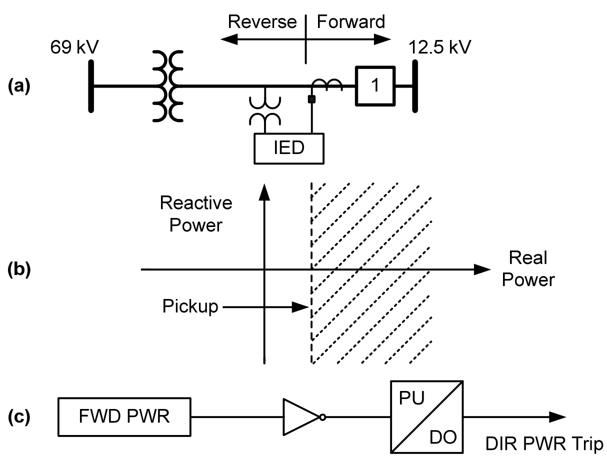

Fig. 11 Secondary IDS Logic

Under steady-state operating conditions, the total connected load is around 115 MW and the local generation is around 50 MW. The plant imports around 65 MW of real power from the utility in order to meet the required plant load. Thus, under normal operating conditions, the measured real power is forward and above the pickup in the characteristic shown in Fig. 11(b); hence, the operating point lies in the shaded region.

An islanding event results in no net power import from the utility. Therefore, the transformer IEDs only measure the magnetizing losses fed by the local generators. The pickup of the directional power element in each transformer IED is set to account for the corresponding transformer magnetizing loss. However, with a looped system configuration, it is possible for power to flow in the reverse direction in three transformers and to loop back in the forward direction in one transformer in a worst case. This scenario is accounted for in the secondary IDS voting supervision logic.

The output of the secondary IDS scheme, shown in Fig. 11(c), is intentionally delayed in order to let the primary IDS scheme detect and attempt to trip the generator breakers during an islanding condition. In the event that a generator breaker fails, the secondary IDS voting logic detects the failure and trips the G1 and G2 buses shown in Fig. 8. The pickup timer is set to coordinate with the response time of the primary IDS scheme with a margin and to be faster than the utility automatic reclose timer.

C. Voting Supervision Logic

The voting supervision logic is a probabilistic algorithm developed to allow for secure operation of the schemes without compromising dependability by taking into account various possible contingencies, such as equipment failure, maintenance outages, and communications channel failures. As mentioned previously, the outputs of the primary and secondary IDS schemes (81RF Trip and DIR PWR Trip, respectively) are transmitted from the four transformer relays (IED 1), and only 81RF Trip is transmitted from the two generator relays (IED 2) to the dual logic processors.

From a security standpoint, the following considerations are taken into account. First, it is essential that the islanding detection scheme does not make a false decision due to a corrupted data bit received from the IEDs through an unhealthy communications channel. Second, a minimum number of votes has to be registered from participating IEDs in the logic processors to make an islanding decision. Therefore, the voting algorithm is designed to ensure that at least a minimum number of IEDs send the 81RF output for the primary IDS scheme and the DIR PWR output for secondary IDS scheme to the two logic processors in order for them to declare that the system is islanded. This prevents false tripping of the generators due to the spurious assertion of an IED output (81RF or DIR PWR) caused by system transient conditions other than islanding.

From a dependability standpoint, physical failures (such as communications channel failures or IED failures) and system operating conditions preventing an IED from registering its vote (such as a single transformer out or a generator offline) are taken into account.

The two types of voting supervision logic explained in the following subsections takes into account these considerations to achieve a good balance between dependability and security.

1) Primary IDS Voting Supervision Logic

Primary IDS voting supervision logic, as shown in Fig. 12, is programmed to make a trip decision for the two generator breakers (B1 and B2 in Fig. 8) via the two generator relays (IED 2). This voting supervision logic takes into account combinations of the possible contingencies, such as one equipment failure (e.g., a transformer out of service or an IED failure), one communications channel failure, and any one generator offline prior to islanding. Therefore, for the primary

IDS trip to occur, the primary IDS scheme must be enabled, at least three of the four transformer communications channels must be working, and any two of the four transformers and any one of the two generators must detect an islanding condition. The three-out-of-four transformer communications voting accounts for one channel failure, the two-out-of-four transformer 81RF trip accounts for one transformer outage with a simultaneous communications channel or IED failure at another transformer, and the one-out-of-two generator voting accounts for either a communications failure or a generator offline.

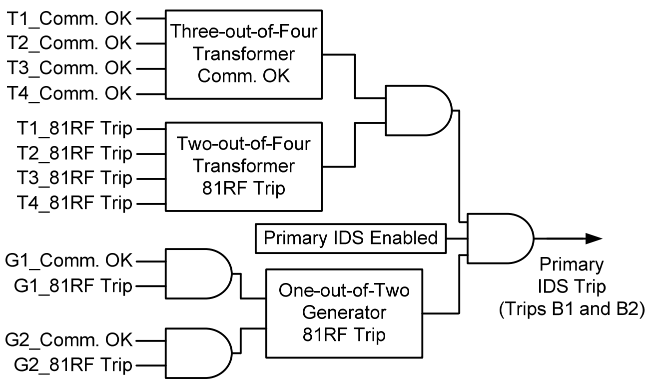

Fig. 12 Primary IDS Voting Supervision Logic

2) *Secondary IDS Voting Supervision Logic*

Secondary IDS voting supervision logic, as shown in Fig. 13, is programmed to make a trip decision for the two generator breakers (B1 and B2 in Fig. 8) via the two generator relays (IED 2). The secondary IDS trip signal is also transmitted to all the IEDs (not shown in Fig. 8) associated with the feeders connected to the G1 and G2 buses in order to account for a generator breaker failure scenario. In the event that one or both generator breakers fail to trip as a result of the primary IDS scheme, all the breakers associated with the feeders connected to the G1 and G2 buses are tripped. This voting supervision logic takes into account combinations of the possible contingencies, such as one equipment failure (e.g., a transformer out of service or an IED failure) and one communications channel failure.

For the secondary IDS trip to occur, the secondary IDS scheme must be enabled, at least one of the generators must be online with the associated generator breaker closed, and at least three of the four transformers must detect the islanding condition (directional power-based decision) or all four transformer low-side breakers must be open (topology-based decision). The three-out-of-four transformer decision voting was based on the following. If at least one source is present, then the plant is paralleled; otherwise, it is islanded. If the plant is paralleled, then at least two transformers will see forward power because one 69 kV source is feeding the plant. However, for the third and fourth transformers, one transformer will see reverse power, one may see forward power if the tie on the high side is closed, or both may see reverse power. Also, when the system is islanded, the scheme needs to account for the case where at least one transformer has power from the generator in the forward direction because of the looped arrangement. Therefore, at least three transformers need to see reverse power to conclude that the system is islanded.

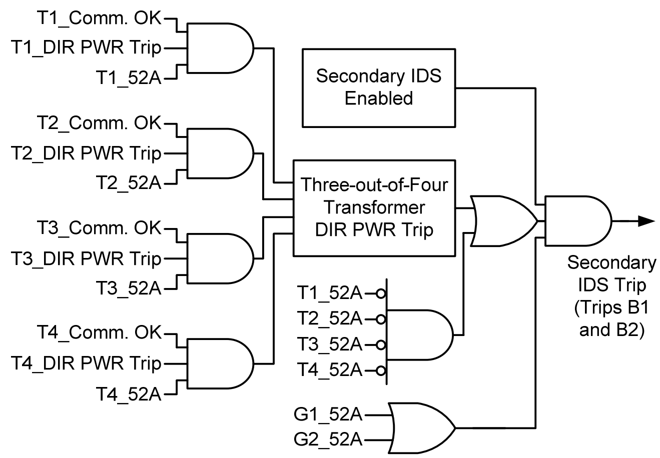

Fig. 13 Secondary IDS Voting Supervision Logic

Even though each of the local-area measurement-based islanding detection schemes described in Section III and Section IV functions as a standalone protection element to properly detect an islanding condition, the response for each element is different and also highly dependent on the generation-load mismatch, as shown in Fig. 14. A combination of two or more elements will make the scheme more comprehensive and still be able to achieve fast response times. This is referred to as a multiprinciple islanding detection scheme. Which combination gives a better response depends on the system. This paper presents one such practical implementation that uses multiple elements to detect an islanding condition for all P_L/P_G ratios, as shown in Fig. 14.

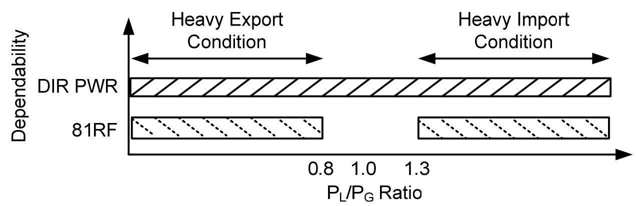

Fig. 14 81RF and DIR PWR Element Response Versus P_L/P_G Ratio

V. CONCLUSIONS

This paper discusses various islanding detection techniques and the importance of islanding detection schemes. The system implemented at the North American refinery required a scheme that relies only on local-area measurements. The primary IDS scheme using the 81RF element is fast. However, it can be vulnerable to the generation-load real power mismatch. To account for this, a directional power element is used to detect an islanding condition based on the power flow scenario in the transformer while the system is islanded. Thus, a scheme was developed that ensures dependable operation regardless of the generation-load mismatch and that trips the generators while the plant is islanded. The integration of these multiprinciple local-area measurement-based detection techniques with voting supervision logic ensures the security of the scheme, thereby making the entire scheme reliable. This paper serves as a practical example of how a reliable islanding detection system was developed by combining multiple local-area measurement-based detection elements.

An alternative solution for detecting an islanding condition regardless of the generation-load mismatch is to use wide-area measurement-based schemes that use time-stamped phasor data to make decisions.

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VII. VITAE

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