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IEC 61850-based islanding detection and load shedding in substation automation systems

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Abstract: Distributed generation (DG) systems are common within industrial plants and allow continuity of supply to critical loads. In cases when DG cannot support the entire system load, islanding detection (ID) and load shedding (LS) schemes are required. Such an automation scheme serves to monitor the connection to the grid and generation-load imbalance, and it controls the load shedding process. The design of such schemes has undergone significant revolution from electromechanical relays and PLC systems to the use of communications-enabled intelligent electronic devices. This paper discusses the design of an IEC 61850-based smart ID and LS scheme using a complete system design approach. Novel control algorithms are presented for the ID and initiation processes as well as the LS process. The study proposes an innovative system, which incorporates the generator governor gain factor in LS decisions, and assists in avoiding unnecessary amounts of LS.

Key words: Load shedding, load shedding controller, IEC 61850, islanding detection, GOOSE messaging, governor gain factor

1. Introduction

Distributed generation (DG) systems are often installed at industrial plants where the quality and reliability of supply is a major concern. On-site DG offers solutions to many challenging problems, including blackouts and brownouts, and aids in reducing the plant costs. This ensures an uninterrupted supply of power, often large enough for the critical processes in the case of disruptions. Islanding (also known as 'loss of mains') is a condition where a part of the network gets disconnected from the grid and continues to operate in a stand-alone mode. The size of on-site generation is often not large enough to run all the normal processes when islanding occurs. In such cases, load shedding (LS) is needed to disconnect the noncritical load, ensuring the continuity and quality of supply to the critical plant loads.

IEC 61850 [1] is an international standard developed for substation automation and is likely to impact how electrical power systems are designed and built for many years to come. The model-driven approach of the IEC 61850 standard describes the communication between substation devices and the related system requirements [2]. Simply speaking, IEC 61850 defines how processes in a substation are to be modeled and what/how data are to be communicated between substation equipment [3–5].

Figure 1 shows an industrial substation single-line diagram (SLD). A new nitric acid plant/ammonium nitrate solution plant (NAP4/ANS3) will be built as well as an ammonium nitrate prill plant (ANP3). Higher

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reliability of NAP4/ANS3 is required and ANP3 may operate at 85% or less availability. A new 12.18 MVA synchronous generator is also being installed. The plant has previously experienced undervoltage (UV) dips below 80% and frequency disturbances of 1–2 Hz. The protection equipment operates under disturbances and trips after 300 ms, resulting in uncontrolled islanding. In the case of grid distortions, a P418 circuit breaker (CB) opens and substation 3 gets islanded. P418 is the incomer CB connecting substation 3 to the utility system. The plant has previously experienced trips from the utility supply. Therefore, it is vital to detect grid separations and have mechanisms in place to shed the noncritical loads, ensuring a healthy supply to the high priority loads. In the case of power disturbances greater than 300 ms, supply should switch to islanded-mode. The plant currently trips under undervoltage conditions (less than 85%) lasting 0.5 s or longer.

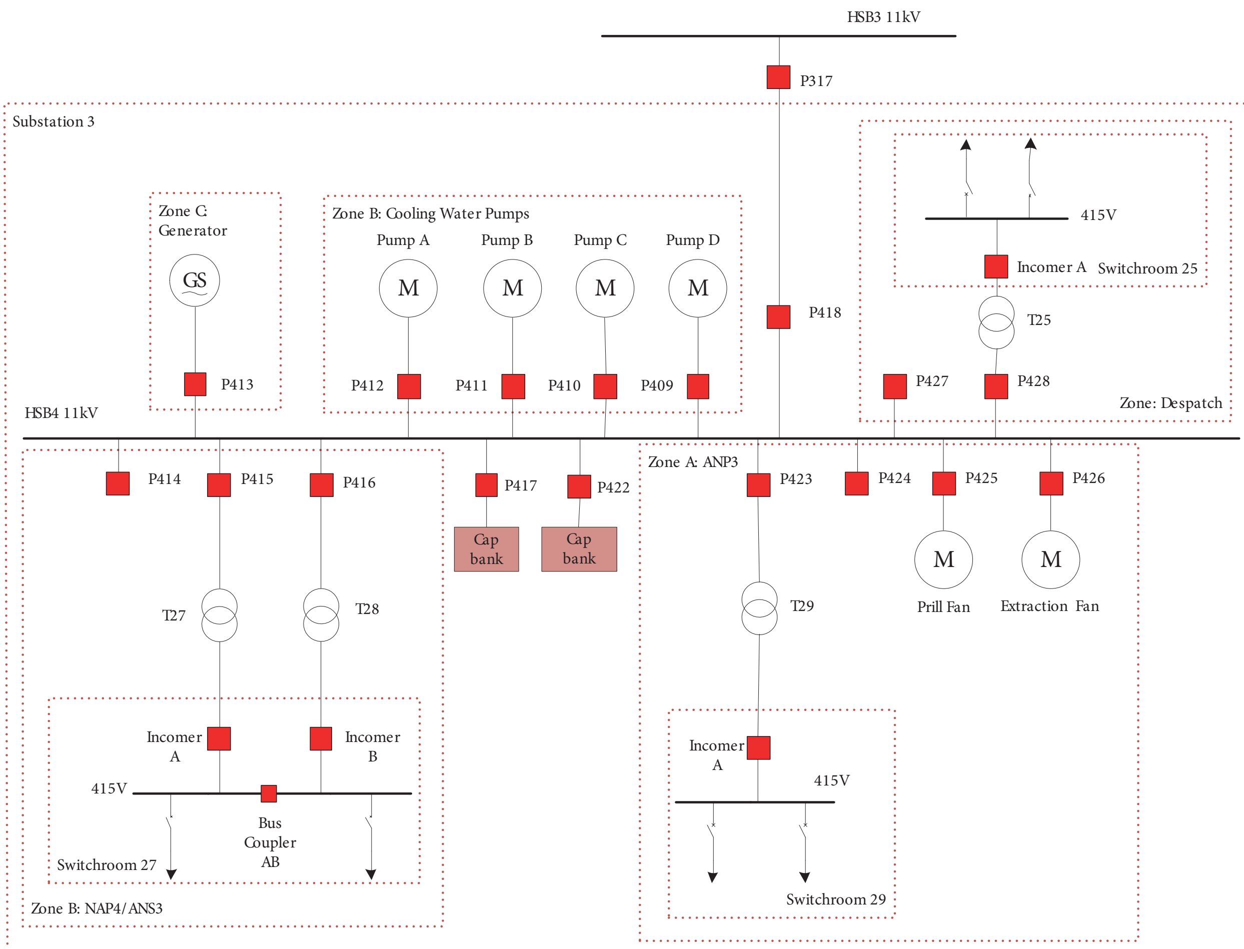


Figure 1. Substation 3 single-line diagram.

In this paper, a detailed literature review is presented on the previously reported IEC 61850-based islanding detection and load shedding (IDLS) schemes. The design of the IEC 61850-based IDLS scheme is discussed from a range of aspects including the design of the communication network, Generic Object Oriented Substation Event (GOOSE) messaging, and the development of 2 discrete ‘islanding detection’ and ‘load shedding’ control schemes. The study proposes the incorporation of the generator governor gain factor (K) in LS decisions, the most significant novel attribute of this paper against other published works in this field.

2. A review of IEC 61850-based IDLS

In [6–8], the authors discussed the need for a fast and reliable LS scheme capable of detecting underfrequency (UF) or UV events that may be present during dangerous system overloading conditions. A GOOSE messaging-based LS scheme is proposed for radial feeders on a main-tie-main line-bus configuration when the tie breaker is open. GOOSE messaging is used between the feeder and main source relays to exchange load flow, voltage, and frequency values and to initiate commands for opening/closing feeder breakers. The scheme proposed in [6–8] suggests using the source relay to detect UV or UF conditions and initiating LS on preselected configuration and priority levels.

The study by Kulkami [9] discusses the practical aspects of "Integrating SCADA, load shedding and high-speed controls on an Ethernet network at a North American refinery". The system determines the amount and combination of load to be shed based on predetermined contingency events and priorities. In a contingency event, the LS signals are generated and distributed throughout the network. The work discussed was carried out for an old substation with non-IEC 61850-compliant intelligent electronic devices (IEDs). Hence, various processors were used to collect IED data and provide the translation from serial to Ethernet [9], which resulted in a complex architecture. A table on "Load shedding event delay times" and another on "Total load shedding trip times" were provided to allow the reader a good understanding of delays throughout the system.

In [10], Wester and Adamiak gave an overview of practical applications of peer-to-peer messaging in industrial facilities. The paper discusses an IEC 61850 GOOSE messaging-based fast LS scheme, where a fast load shedding controller (LSC) makes the final LS decisions in real-time. Shedding loads based on contingencies and predetermined priorities was also the approach followed in [10]. The work discussed in [11–13] gives an overview of the fundamental aspects of an IEC 61850-based load shedding (LS) system. A number of useful suggestions are given including the need to initiate islanding for unstable conditions on the utility grid, and debouncing the breaker status signals for 8 ms before they become valid to use in the logic.

3. Substation network architecture

In designing an IEC 61850 application, a key task is choosing a communication network topology. Figure 2 shows the communication network as laid on top of the SLD of Substation 3. The entire network has been shown to enable the reader to view and comprehend the overall structure of the communication architecture from a holistic perspective. Although this approach has complicated the diagram, the authors think that this representation is useful for a better understanding, since it shows how the communication/automation system blends in with the power system devices.

Several works [10,14] discussed and compared different network topologies in detail. The topology of the local area network (LAN) is critical due to the fact that most protection and control applications rely on the reliability of this network. The architecture shown in Figure 2 was based on the **Star** topology. In the **Star** topology, each station (i.e. each 4–6-port switch) will be connected to a common central node (i.e. a 24-port switch), which results in redundancy concerns due to a single point of failure. Explicitly, if the 24-port switch fails, then there will be an entire loss of communication in the substation. Designing for redundancy is often a critical task when designing such engineering applications. The discussion on redundancy is not a main topic of discussion in this paper as redundancy was not a required feature by the research partner. Thus, no redundancy measures are shown in Figure 2. However, redundancy is important and can be achieved with the duplication of system components, especially the 24-port switch. This will increase the complexity of the system as well as the costs of design and implementation, but it makes the communication network more redundant.

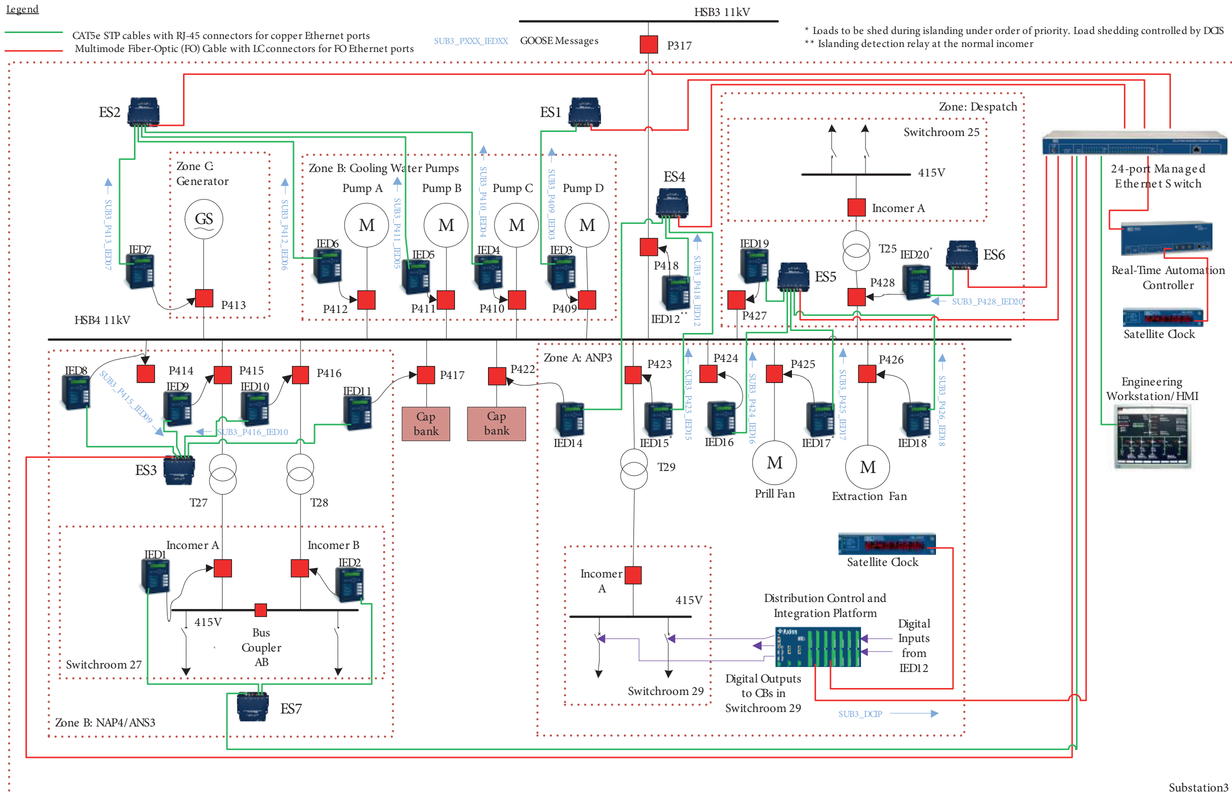


Figure 2. Single-line diagram and communication network for substation 3.

Figure 2 identifies some of the IEDs playing a key role in the IDLS scheme. IED 12 monitors the mains and executes islanding detection or initiation. IED 7 is the generator protection relay and IEDs 15, 17, 18, and 20 control the least critical loads, which may be shed during a grid separation. All devices communicate via the 24-port switch, and hence it must be a managed switch, which gives more control over the LAN traffic and offers advanced features such as the high priority routing of selected messages. The origin of GOOSE messages throughout the network is also shown in Figure 2.

4. Dynamic network studies

Dynamic network studies carried out using the CYME PSAF software investigated the performance of the generator and its governor in cases of grid separation and sought to determine a suitable LS approach. Figure 3 shows the developed simulation network model. The type 7 prime mover governor model, shown in Figure 4, was used for modeling the governor behavior in CYME as it was a close match to the actual governor model. The governor model shown in Figure 4 is the "IEEE Type 1 General Purpose Steam Turbine" speed-governing model (also referred to as the 1981 IEEE type 1 WSIEG1). The governor and the governor gain factor (K-factor) setting in effect control the mechanical power input control rate and the rate of change in the mechanical active power input the generator, as shown in Figure 5. The K-factor is a set constant value and cannot be dynamically adjusted during plant operation. The associated governor control block parameters were set in accordance with the data received from the research partner.

The simulation methodology followed included the disconnection of the industrial plant from the grid and an observation of the plant frequency, the rate of change of frequency under different generation conditions

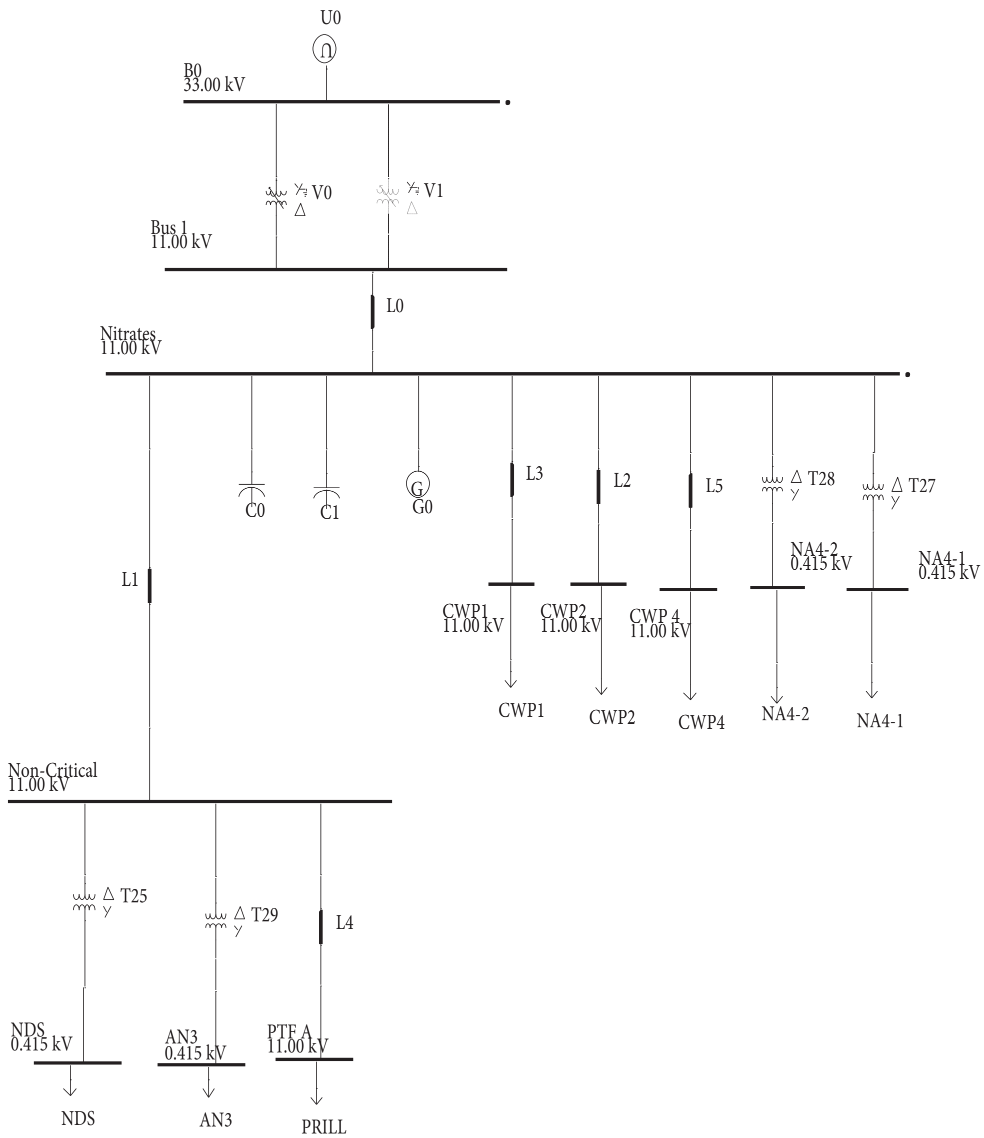


Figure 3. Network model developed for dynamic simulations.

and for different governor gain factor (K) settings. The plant's frequency has to be kept between 48 Hz and 52 Hz, as the plant can withstand variations in this range.

The analysis carried out demonstrates that K has a significant effect on the operation of the governor and dictates how quickly it can respond to changes in the network. Figure 5a shows and compares how the mechanical active power of the generator varies for different K values. The simulated case is "minimum generation" and shedding of the entire noncritical load is carried out. As shown, the generator is able to respond much more effectively when a large value for K is used. Figure 5b shows how the frequency varies for different values of K. For all values of K, the frequency is dropping due to the fact that there is an imbalance between generation and demand and the latter is larger. This is causing the generator to slow down and hence the frequency is dropping. When $K = 5$, the generator is able to respond very quickly and increase/decrease (as appropriate) the energy admitted to the prime mover as shown in Figure 5a before frequency falls too much. Once a balance

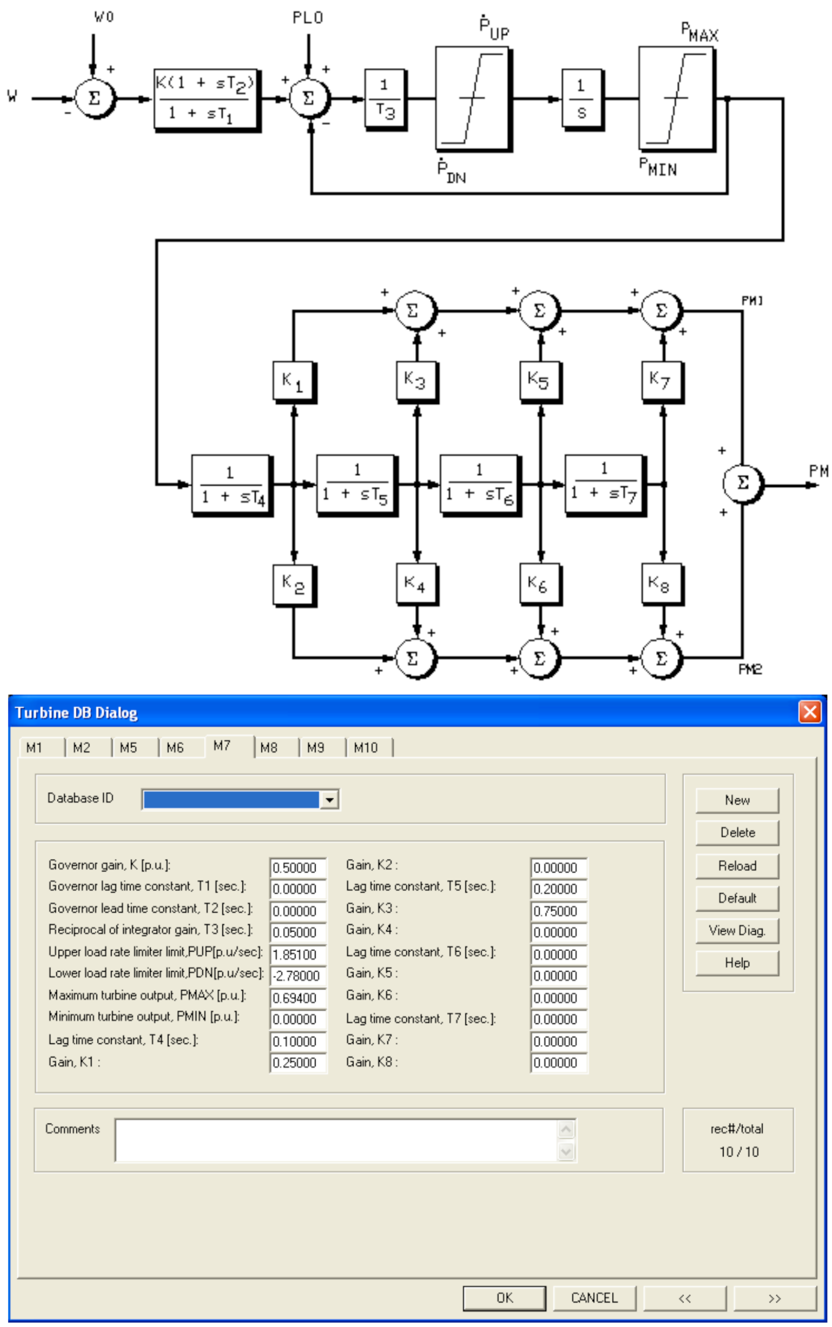


Figure 4. Governor model and parameters.

between generation and demand is reached, the speed where this equilibrium is reached becomes the operating speed. When $K = 0.5$, the frequency falls a lot further until the governor can increase the energy input to the prime mover to balance its real power output with demand.

Dynamic studies were carried out for two main scenarios and a number of possible K values were considered. The first scenario investigated normal generation when embedded generation provides 5.7 MW and the import from the grid is 1.2 MW. The second scenario looked at minimum generation when embedded generation provides 3.85 MW and the grid import is 3.05 MW. Load shedding initiation was assumed to take

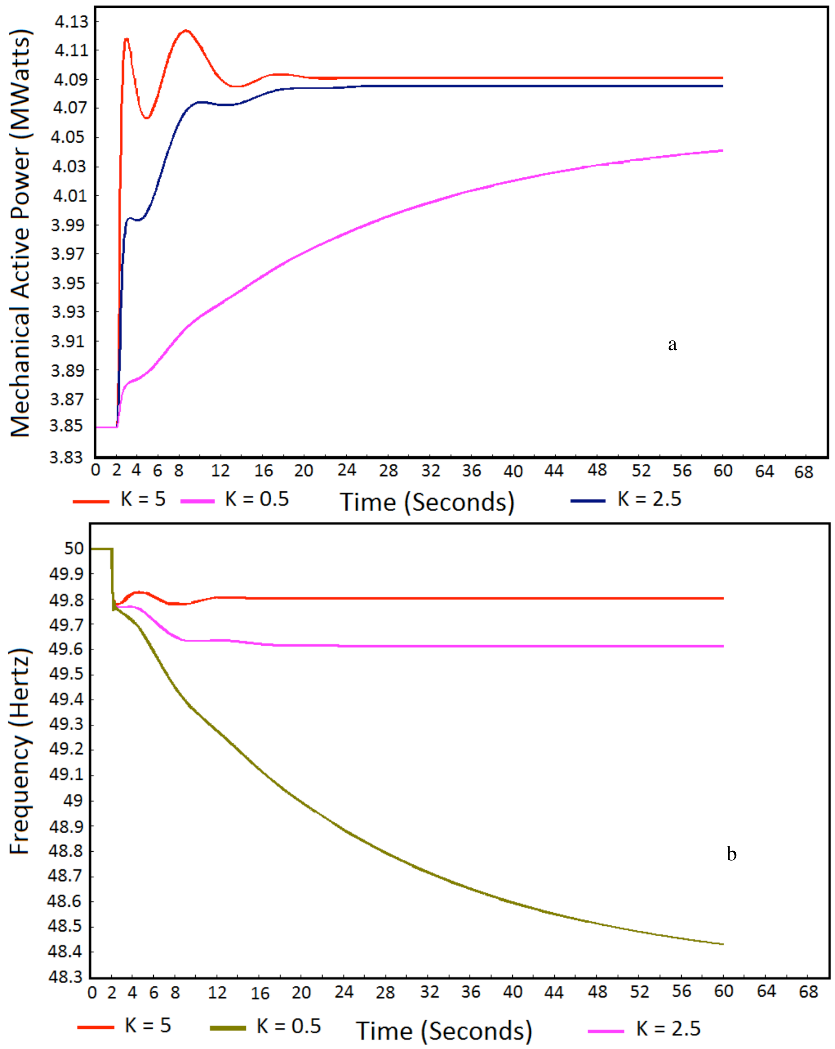


Figure 5. a) Mechanical active power. b) Frequency variation for different values of K.

place 0.3 s after islanding, which was chosen based on the need to initiate islanding as quickly as possible while giving sufficient time to the protection system to clear faults occurring internal and external to the plant. With reference to Figure 1, the electrical loads on the plant and their properties were as follows:

- The 4.5 MW load in zone B includes the NAP4/ANS3 and cooling water pumps and is the high priority load that must be supplied at all times regardless of power failures and disconnections from the grid.
- The 2.8 MW load in zone A and zone dispatch can be used for LS. The entire load in switchroom 29 (ANP3) is 1.52 MW, that in zone dispatch is 0.57 MW, and the load of the prill fan is 0.75 MW.

The key finding of the network studies was that K must be tuned to a relatively high value to implement a LS strategy that would work for both generation conditions. The impact of K is likely to be generic and of interest to a wide audience. Therefore, the incorporation of the *K-factor* in LS decisions can be applied irrespective of the generator type and governor model. This incorporation of the K-*factor* in LS decisions is further discussed in Section 7. The results are summarized in Table 1, which shows that the initial rate of change of frequency right after separation depends on the generation conditions prior to islanding and is unrelated to K. The interpretation of results has further shown that the amount of load to be shed depends on K and the generation conditions prior to islanding.

Table 1. Summary of results.

Mode	$K = 0.5$	$K = 2.5$	$K = 5$
Normal generation			
df/dt (Hz/s)	–0.184	–0.184	–0.184
Frequency without load shedding (Hz)	42	48.2	49.1
Frequency after shedding 2.8 MW (Hz)	>> 52	52.4	51.3
Frequency after shedding 1.28 MW (Hz)	50.6	50.15	50.07
Minimum generation			
df/dt (Hz/s)	–0.82	–0.82	–0.82
Frequency without load shedding (Hz)	<< 48	45.5	47.6
Frequency after shedding 2.8 MW (Hz)	48.3	49.6	49.8
Frequency after shedding 1.28 MW (Hz)	<< 48	47.2	48.6

As shown in Table 1, when $K = 5$, frequency will be over 49 Hz without LS under normal generation, but partial LS is required under minimum generation. Figure 6 shows that when $K = 5$ and without any load shedding after separation, the frequency drops to about 49 Hz and the governor is able to keep the frequency at that level. The rate of change of frequency in the first 0.3 s is –0.184 Hz/s. Figure 7 demonstrates the minimum generation case and shows how the partial shedding (1.28 MW) of noncritical load after separation is sufficient to keep the frequency around 48.6 Hz.

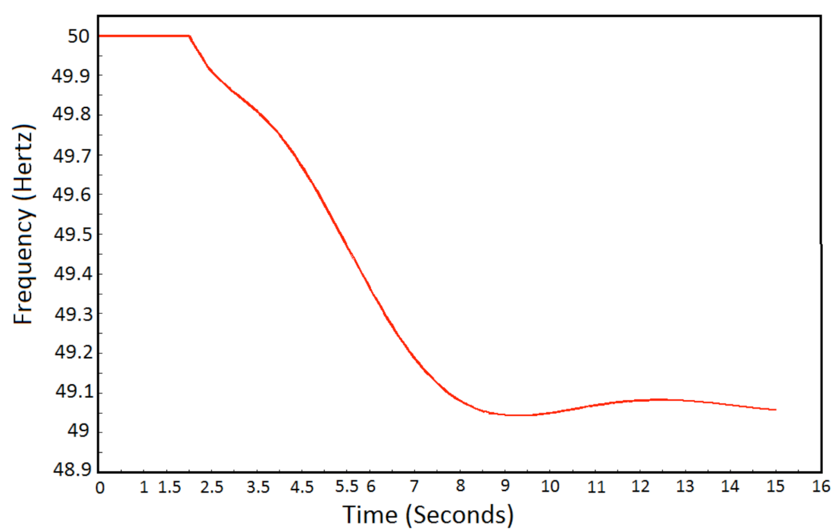


Figure 6. Frequency response without any load shedding (normal generation; $K = 5$).

A "load shedding MWs versus frequency" curve was also plotted for the $K = 5$ case as shown in Figure 8, assuming a linear response. As shown, under the minimum generation condition, at least 0.5 MW of load must be shed to keep frequency above 48 Hz, whereas the plant frequency can be maintained slightly over 49 Hz without any LS under the normal generation condition. Alternatively, a LS strategy common to both generation conditions can be developed, which will require a medium level of LS (ANP3 + zone dispatch = 2.09

MW). This LS approach will result in a plant frequency below 49 Hz and 51 Hz for the minimum and normal generation cases respectively.

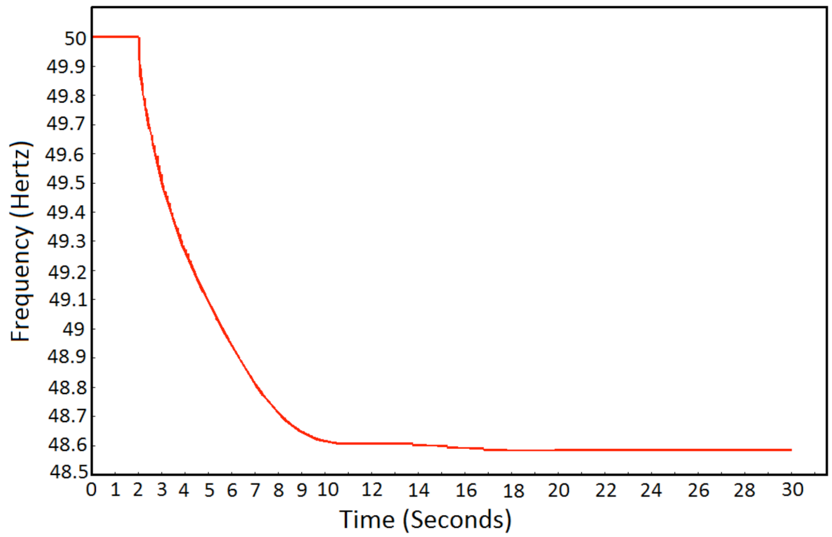


Figure 7. Frequency response with partial load shedding (minimum generation; $K = 5$).

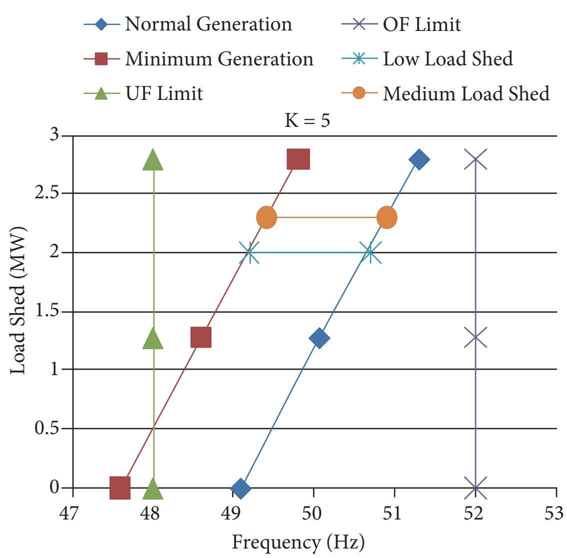


Figure 8. Load shedding MW vs. plant frequency for $K = 5$.

5. Islanding detection and initiation

It is imperative that grid disconnection events be detected in a timely manner to enable a timely response to grid separation and to decide whether or not to shed any plant load. It is also vital that the external quality of supply be monitored and islanding be initiated when the quality of supply is out of the norms. Hence, 2 distinct control processes (islanding initiation and detection) for monitoring the mains connection are recommended. In the network shown in Figure 2, these 3 processes were implemented in IED 12, which controls the CB at the incomer feeder.

5.1. Islanding initiation

The importance of forcing islanding under UF and/or UV conditions was highlighted in [12,13]. It is not sufficient just to detect islanding; it is also imperative to have a means of forcing islanding when necessary. In this section, the authors present an IEC 61850-compliant control logic, as shown in Figure 9, to assist in the initiation of islanding and LS. The OUT101 is connected to the trip coil of the P418 CB and its status is also included in the GOOSE message published by IED 12. Table 2 shows the various protection elements used in the control logic, their pick-up values, and time delays. The control logic initiates islanding if frequency is under 0.5 Hz under or over 50 Hz, or voltage is 10% under or over 1 p.u. The 0.9 p.u. and 1.1 p.u. settings for the UV and OV thresholds were chosen based on the traditionally accepted voltage tolerance levels, +10% to –10%, and in accordance with the Australian grid codes [15]. According to the "Power System Frequency and Time Deviation Monitoring" report [16] released by the Australian Energy Market Operator (AEMO), in the month of February 2011, frequency was within ± 0.029 Hz, one standard deviation (49.971–50.029 Hz) of the mean value (50 Hz) for about 68% of the time assuming a normal (bell-shaped) distribution. The 49.5 Hz and 50.5 Hz values chosen for the underfrequency and overfrequency thresholds equate to 17 standard deviations (± 0.5 Hz) and it is likely that frequency will stay within the 49.5–50.5 Hz range for more than 99.999% of the time in the absence of serious frequency network events.

Table 2. Islanding initiation threshold values.

Element	Description	Pick-up value	Pick-up timer
81D1T	Underfrequency (UF)	49.50	300 ms
81D2T	Overfrequency (OF)	50.50	300 ms
27P1	Undervoltage (UV)	0.9 p.u.	300 ms
59P1	Overvoltage (OV)	1.1 p.u.	300 ms

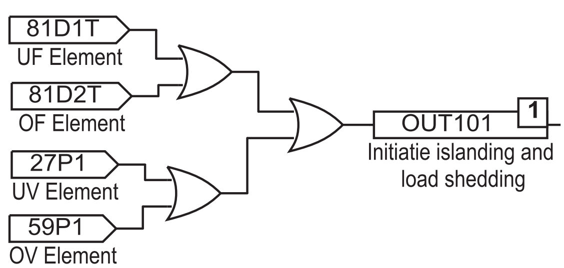
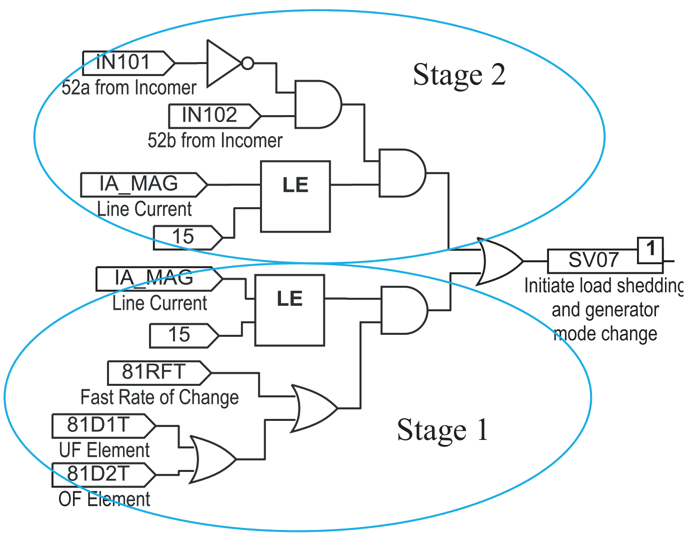


Figure 9. Islanding and load shedding logic initiation.

The 0.3 s delay was chosen based on the information that the overall trip time for faults occurring internal or external to the plant is about 0.2 s including the relay and CB contact delays. Hence, the delay was assigned ensuring that faults can be cleared within 0.3 s and the proposed scheme will ride through faults without initiating islanding, thus eliminating needless islanding conditions. The goal was to give the protection system enough time to detect and clear faults before islanding and LS gets initiated as the last resort action. The 0.3 s timing also ensures that islanding operates ahead of the process plant UV protection scheme. The proposed islanding initiation and LS scheme is therefore superior to the uncontrolled shutdown of the plant, which occurs in the case of UV conditions (less than 85%) lasting 0.5 s or longer.

5.2. Islanding detection

The smart IDLS scheme must be able to quickly and reliably determine a grid separation event. The use of CB status signals, or line current measurement, or a combination of both was recommended in [9,12,13] for the detection of a line outage. The authors do not recommend a solution that primarily relies on CB status signals on their own as it may not always be the source CB (P418) that opens in the case of a disturbance. Any CB in the upper stream of P418 might open during network disturbances and it might be impossible to acquire the status data of every single CB in the vicinity. In [6], the authors proposed the use of a source relay (such as IED 12) that continuously monitors voltage and frequency of the incoming line and issues a load shed trigger when the line voltage or frequency falls to the preset thresholds. The scheme shown in Figure 10 combines fast and slow LS initiation mechanisms. The proposed control involves monitoring and processing of the line current, frequency, and the incomer CB status for the detection of islanding quickly and reliably. There are 2 stages worthy of discussion in the developed control logic.



52a = CB auxiliary contact (open when breaker contacts are open, closed when breaker contacts are closed)
52b = CB auxiliary contact (closed when breaker contacts are open, open when breaker contacts are closed)
LE = Less than or equal (≤)
81RFT = Fast-rate-of change element. Picks up when the df/dt ≥ df/df threshold (0.18 Hz/s)
81D1T = Under-Frequency (UF) element. Picks up when f < 49.50
81D2T = Over-Frequency (OF) element. Picks up when f > 50.50

Figure 10. Islanding detection and load shedding initiation.

Stage 1 implements the slow LS initiation, where LS is activated based on frequency events. Stage 1 utilizes fast-rate-of-change, UF and OF elements, and determines the line current to be less than or equal to a preset threshold. Table 3 shows the various pick-up values for the frequency elements. The same reasoning as in Table 2 was used in the choice of the 49.5 Hz and 50.5 Hz values for the underfrequency and overfrequency pick-up thresholds. The rate of change of frequency in the first 0.3 s was determined from the dynamic studies to be –0.184 Hz/s for the normal generation and –0.82 Hz/s for the minimum generation cases. The initial rate of change of frequency right after separation was not affected by the K constant. The 0.18 Hz/s fast-rate-of-change pick-up threshold was therefore chosen as the smaller of the 2 cases so as to cover both generation scenarios.

The 15-A threshold for the line current has been set considering the inaccuracy of the current transformer (CT) and the possibility of a reverse power flow during islanding. Substation 3 can be exporting power to the rest of the network specifically if disconnection occurs at a higher level than substation 3 and this must be taken into consideration when setting the line current threshold. Stage 1 asserts a local variable (SV07) when one of the frequency conditions is correct AND the line current signifies islanding. One of the frequency conditions AND the line current condition must be true before LS initiation can be given to avoid LS under circumstances when an unintentional balance between generation and local demand could result in zero or near-zero power import from the grid.

Table 3. Islanding detection threshold values and delays.

Element	Description	Pick-up value	Pick-up timer
81D1T	Underfrequency (UF)	49.50	300 ms
81D2T	Overfrequency (OF)	50.50	300 ms
81RFT	Fast-rate-of-change	0.18 Hz/s	100 ms
Item	Description	Delay	
IA_MAG	Line current	0.625 ms	
IN101	Hard-wired 51a contact from circuit breaker	Input debounce	8 ms
IN102	Hard-wired 51b contact from circuit breaker	Input debounce	8 ms
IED logic processing execution delay			5–25 ms

As shown in Table 3, when the rate of change of frequency (ROCOF) is higher than the set threshold, it takes 100 ms before the LS trigger can be issued. If the ROCOF is small, then LS will be initiated after 300 ms when the frequency is below the UF threshold for 300 ms. This slow response time can be acceptable in networks where the mismatch after islanding is not expected to be very large. Stage 1 provides a reliable scheme that can be used in isolation to avoid nuisance tripping. However, in applications where a much faster LS trigger will be needed due to an expected large mismatch, then stage 2 also needs to be used in the overall control logic.

Stage 2 implements the fast LS activation in response to a device trip. A double-point CB status checking is used as recommend in [12,13], which provides added reliability and a means of detecting failures in the CB monitoring and/or racking system. Stage 2 asserts the local variable SV07, when the ‘a’ contact is open, the ‘b’ contact is closed, and the current is less than the set threshold. As demonstrated in Table 3, 8 ms of debounce timing delay is applied to provide added security that the open condition was not due to a voltage transient event in a paralleled conductor. In the worst case, SV07 asserts after 25 ms given the IED processing delay of the Maths functions. If a faster LS trigger is required, then line outage must be detected through the CB status signals, in which case the delay will be about 13 ms before the logic triggers the GOOSE transmission.

6. GOOSE messaging

Figure 11 shows the network without the SLD mapping and highlights the distribution of GOOSE messages in the network. The motor, generator, and feeder protection IEDs publish GOOSE messages. Binary and analog GOOSE data get mapped to the various variables of the distribution control and integration platform (DCIP). Table 4 shows the publishers of data, the various data (e.g., the CB status and instantaneous real-power magnitude) they publish, and how these data get mapped to the DCIP (the only subscriber) variables on their arrival in messages received by the DCIP. The mappings of signals to DCIP variables is provided in Table 4 such that the reader can refer to Table 4 when interpreting the LS-related control schemes given in Section 7.

The standard IEC 61850-7-420 [17] was developed by the IEC in 2009 to address the interoperability concerns related to the monitoring and control of DER devices. IEC 61850-7-420 defines logical nodes (LNs) applicable to DER systems such as diesel generators, solar cells, and fuel cells. There is no information modeling in IEC 61850-7-420 related to governor settings, which is a serious shortcoming in the first edition of IEC 61850-

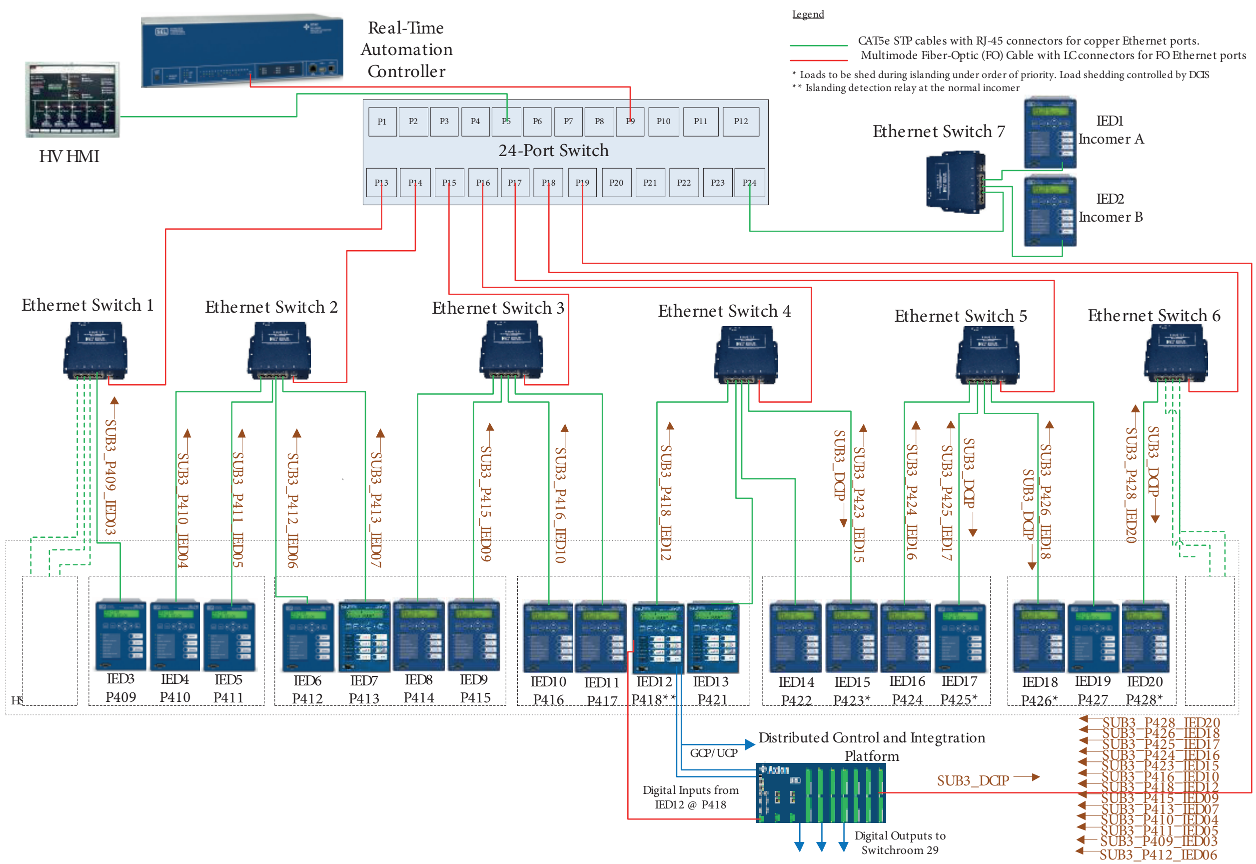


Figure 11. Communication network architecture.

7-420. Therefore, the current IEC 61850 and its more recent extension (IEC 61850-7-420) on DER devices do not allow the transmission of the K-factor information of a governor across the network. Thus, in this paper, it is assumed that the K-factor detail is manually entered into the DCIP system by the system operator. It is expected that information modeling regarding the governor parameters will be included in future editions of IEC 61850-7-420 as more researchers highlight the need.

7. Load shedding controller

The DCIP acts as the LSC hardwired to noncritical load CBs in switchroom 29. The DCIP can initiate the tripping of noncritical load CBs through either hardwired connections to switchroom 29 or GOOSE messages to smart IEDs (IEDs 20, 18, 17, and 15) that control the CBs of noncritical loads in the substation. The relays in switchroom 29 are not IEC 61850-enabled, which necessitates the use of the DCIP. The amount of load to be shed upon the detection of islanding is often calculated from the measurement of the dynamic load-generation imbalance. The plant load can be calculated by summing the power flows into the feeders as in Eq. (1). The mismatch can then be calculated from Eq. (2). According to most work in this field [12–14], the LS approach must depend on shedding enough load (sometimes priority-based) to counteract the mismatch.

$$Load = RA01 + RA02 + RA03 + RA04 + RA06 + RA07 + RA09 + RA10 + RA11 + RA12 \tag{1}$$

$$Mismatch = Load - RA5 \tag{2}$$

Table 4. GOOSE messaging table.

Pub	DataSet	Map
IED 3	Data[0] = PRO. BK1XCBR.Pos.stVal (circuit breaker Status)	VB1-2
	Data[1] = MET.METMMXU1.TotW.InstMag.f (3-phase P mag)	RA01
IED 4	Data [0] = PRO. BK1XCBR.Pos.stVal	VB3-4
	Data[1] = MET.METMMXU1.TotW.InstMag.f	RA02
IED 5	Data [0] = PRO. BK1XCBR.Pos.stVal	VB5-6
	Data[1] = MET.METMMXU1.TotW.InstMag.f	RA03
IED 6	Data [0] = PRO. BK1XCBR.Pos.stVal	VB7-8
	Data[1] = MET.METMMXU1.TotW.InstMag.f	RA04
IED 7	Data [0] = PRO. BK1XCBR.Pos.stVal	VB9-10
	Data[1] = MET.METMMXU1.TotW.InstMag.f	RA05
IED 9	Data [0] = PRO. BK1XCBR.Pos.stVal	VB11-12
	Data[1] = MET.METMMXU1.TotW.InstMag.f	RA06
IED 10	Data [0] = PRO. BK1XCBR.Pos.stVal	VB13-14
	Data[1] = MET.METMMXU1.TotW.InstMag.f	RA07
IED 12	Data[0] = ANN.OUTAGGIO2.Ind01.stVal (OUT101 Status)	VB15
	Data[1] = ANN.SVGGIO3.Ind07.stVAl (Local variable SV07)	VB16
	Data[2] = MET.METMMXU1.TotW.InstMag.f (3-phase P mag)	RA08
IED 15	Data [0] = PRO. BK1XCBR.Pos.stVal	VB17-18
	Data[1] = MET.METMMXU1.TotW.InstMag.f	RA09
IED 17	Data [0] = PRO. BK1XCBR.Pos.stVal	VB19-20
	Data[1] = MET.METMMXU1.TotW.InstMag.f	RA10
IED 18	Data [0] = PRO. BK1XCBR.Pos.stVal	VB21-22
	Data[1] = MET.METMMXU1.TotW.InstMag.f	RA11
IED 20	Data [0] = PRO. BK1XCBR.Pos.stVal	VB23-24
	Data[1] = MET.METMMXU1.TotW.InstMag.f	RA12

where **RA01** to **RA12** are local DCIP variables that contain the received instantaneous 3-phase real power measurements throughout the network.

RA05 is the generator real power export received from IED 7.

None of the previously published work [12–14] considered the impact of the governor gain factor (K) in LS decisions. As a novelty, in this paper, the concept of the K factor was introduced in Section 4 and it was demonstrated that:

- When $K = 5$, no LS is required under the normal generation conditions although the mismatch is 1.2 MW. Frequency could be maintained at 49.1 Hz without LS. A scheme purely dependent on the mismatch analysis would have necessitated at least 1.2 MW LS.
- When $K = 5$, 0.5 MW of LS is sufficient to keep the plant frequency above 48 Hz under the minimum generation condition although the mismatch is 3.05 MW. A mismatch-dependent scheme would have required 3 MW LS.

Therefore, the work presented in this paper suggests a novel approach that will contribute to minimizing the amount of load to be shed in substations. This novel approach, even though not significantly complex, has not been detailed and considered in any other comparable work [12–14] in this field and hence is the main attribute that separates this work from other comparable work in the literature.

Finally, Figure 12 shows the DCIP LS selection logic. Stage 1 performs the preevent calculations and determines the load-generation imbalance. Stage 1 also assesses if the mismatch is greater than 3.0 MW, signaling the minimum generation condition. Stage 2 checks for the arrival of LS triggers from IED 12 and assesses if the plant has islanded from the grid. If both the minimum-generation condition and the loss of mains are TRUE, then the logic proceeds into stage 3, where the governor gain factor is verified. If the governor gain factor is verified as 5, then a GOOSE-based initiation of LS in zone dispatch is carried out. The control logic given in Figure 12 can be easily expanded to cover the other governor gain possibilities.

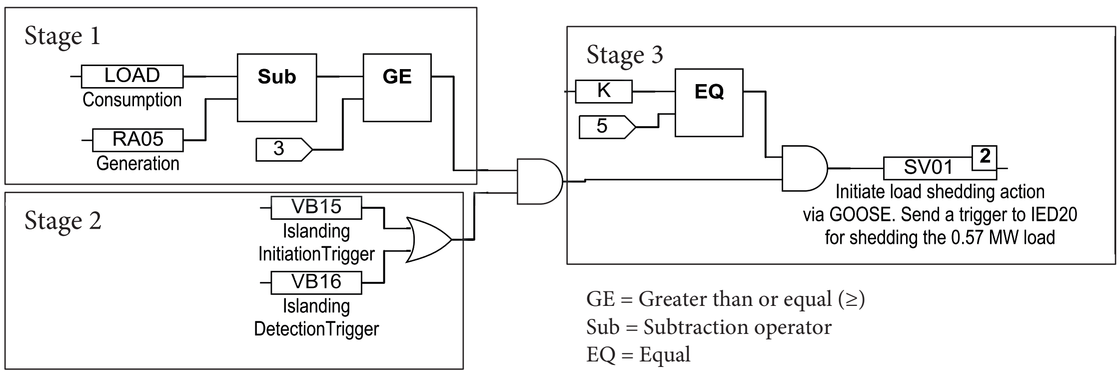


Figure 12. Load shedding selection logic in the DCIP.

The scheme outlined in this paper will be built and tested in real life. However, currently, the implementation phase of the project is on hold by the research partner. Further publications will follow to report on test results once the proposed system and the novel approach of LS based on K is tested and verified. The real-life implementation of the proposed scheme detailed in this paper is expected to run smoothly. Substation 3 will be a new substation to be built from scratch and all provisions (such as the use of IEC 61850-compliant IEDs and a fiber-optic network) have been made during the design phase to enable the smooth implementation of the proposed Ethernet-based methodology for the IDLS scheme. The incorporation of the governor gain factor (*K-factor)* in LS decisions can be applied with ease as it will be a known preset quantity. The high-speed capabilities of GOOSE messaging over Ethernet networks have been previously tested and confirmed in numerous studies; therefore, the project team has no concerns regarding achieving the desired timely responses. Researchers are looking forward to comparing the real-world results with actual results after the implementation phase and reporting on any unmatched findings.

8. Conclusion

This paper has presented an IEC 61850-based IDLS scheme as an integral element of industrial systems. The paper makes a key contribution by providing insight into all aspects of designing such a system, a main attribute of this paper separating it from previously published works. Design of the communication network, development of the islanding detection and initiation algorithms, and configuration of GOOSE messaging have all been explicitly elaborated. Control algorithms have been presented for the islanding detection and initiation processes as well as the LS process. The proposed ID logic is simple and does not require obtaining any status signals from the utility grid such as the transformer, line protection trip signals, or isolators. This is a key feature of the proposed method against previously published works in the literature and is likely to lead to a reduction in the implementation costs of such a system. The work presented can be applied in any industry where DG systems are likely to be used and continuity of critical plant loads is a concern. The most significant innovation in this paper has been the proposal of a governor gain factor-based LS scheme, which is expected to save costs in industrial substations by avoiding unnecessary amounts of LS in the likelihood of islanding (loss of mains) situations. This is the most critical contribution of this research in comparison with existing IEC 61850-based methods detailed in the literature.

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