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DESIGN AND IMPLEMENTATION OF GENERATION CONTROL SYSTEM FOR AN OFFSHORE PLATFORM

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Abstract—An offshore complex with five production platforms is powered by two gas turbine generators, three gas engine generators, and one diesel engine generator operating in parallel. An automatic generation control system (GCS) controls the six generators and maintains system voltage, frequency, and generator kW/kVAR load sharing. System development and commissioning was complicated because of the multiple inertia models imposed by dissimilar generators. The primary controls (governor and automatic voltage regulators) are set to frequency-droop and voltage-droop modes under normal operating conditions. However, isochronous load sharing lines are also present between the turbine- and engine-driven generators as a manufacturer backup control strategy in the event of GCS control loss. The GCS needed to be adaptive to operate in parallel with a second control system for the turbine-driven generator. Another challenge was simultaneous regulation of bus voltage and kVAR load sharing between the generators. This paper presents a tested GCS that was designed and implemented to adapt to a generation system with multiple inertias, islands, control modes, and voltage levels that will tolerate system contingencies.

Index Terms—Control systems, industry applications, power engineering, reliability, power generation and systems engineering and theory.

I. INTRODUCTION

A generation control system (GCS) was developed to control six generators at an offshore complex in West Africa. The complex comprises five platforms and the electrical power system comprises six generators. The offshore system comprises Platforms A, C, B, B2, and B3. LAN-1600, LAN-1610, and LAN-1620 are gas engine generators, LAN-1750 is an emergency diesel engine generator, and LAN-5200 and LAN-5220 are gas turbine generators. Platforms B, B2, and B3 are connected by tie cables. Platforms A and C do not include power generation and are connected to Platform B2 via subsea cables. There is a power transformer between Platforms B2 and B3. The voltage on the B3 main bus is 4.16 kV, whereas the main bus voltage of Platforms B and B2 is 0.48 kV. The three gas engine generators on Platform B2 are rated at 0.48 kV/750 kW/938 kVA at 0.8 PF, whereas the diesel engine generator on Platform B is rated at 0.48 kV/500 kW/625 kVA at 0.8 PF. The gas turbine generators in Platform B3 are rated at 4.16 kV/3.2 MW/4 MVA at 0.8 PF. Fig. 1 provides an overview of the GCS architecture.

The six generators have a wide range of inertia, voltage, and MW/MVA ratings. Consequently, a GCS solution was proposed to perform the following functions:

1. Manage and maintain load (kW/kVAR) sharing between the generators (considering generator capability curves). The operator can impose operating limits on each generator by entering kW and kVAR upper and lower regulation limits.
2. Provide operators capability to manage generator load and skew load distribution between the generators when required.
3. Allow operators to baseload the generators and maintain them at a constant power output.
4. Identify system frequency excursions and restore system frequency to 60 Hz. Similarly, identify bus voltage excursions and restore the bus voltage to the normal bus voltage.
5. Track system topology and identify multiple island formation. If multiple islands are created, perform generation control calculations for each island. Maintain load sharing, voltage, and frequency control for each island.

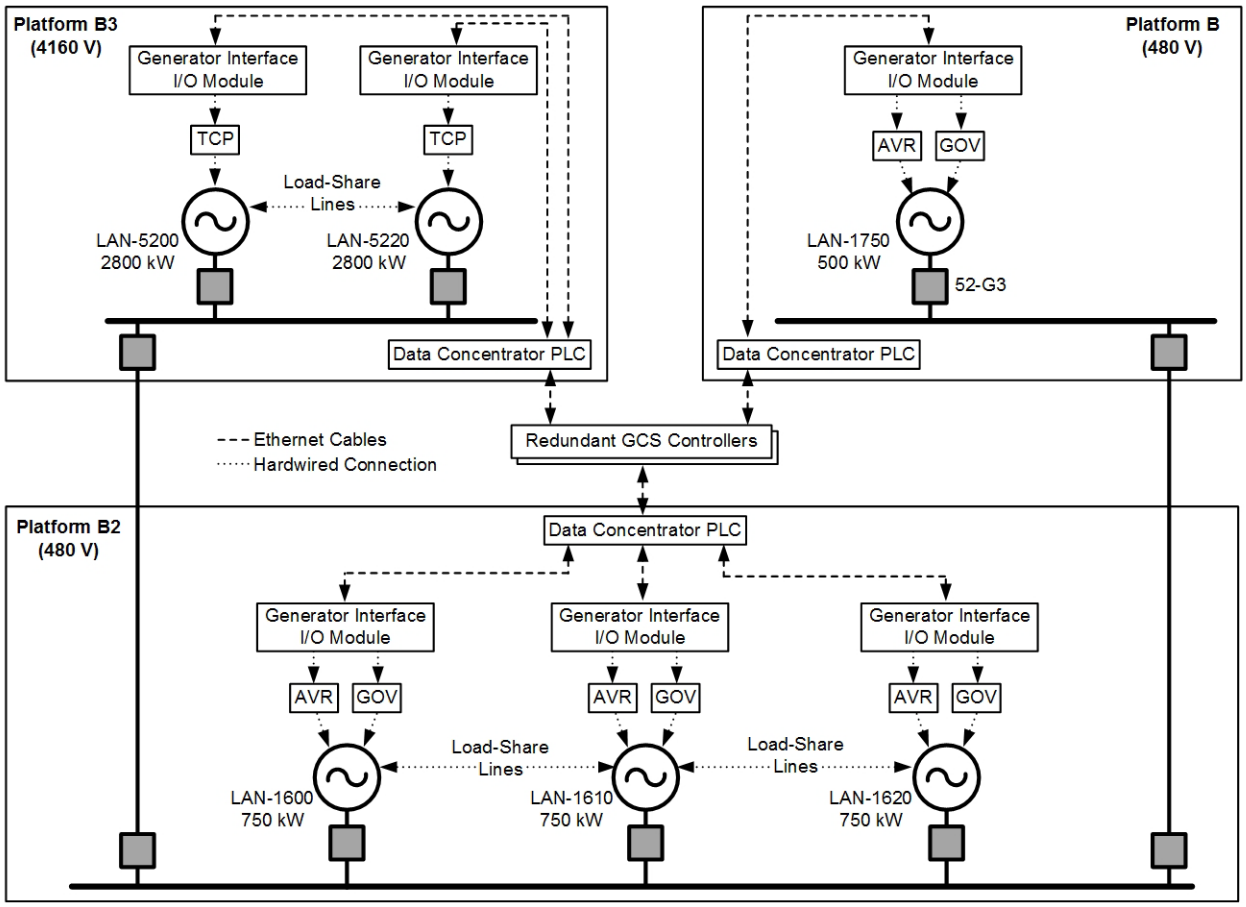


Fig. 1 GCS Architecture

6. Track automatic voltage regulation and governor control modes for all generators. Identify the potential to create conflicting controls due to operator error or system topology changes and prevent occurrence. The GCS has built-in interlocks that block operators from creating certain conflicting controls by annunciating alarms on the GCS human-machine interface (HMI).
7. Perform operator-initiated remote start for the generator turbine and engines. Calculate spinning reserves and perform generator unload permissive calculations. Provide operator-initiated automatic generator unload capability.
8. Control multiple generators to synchronize and connect two separate islands.
9. Respond to high-speed events (such as generator trip) that cannot be controlled through droop. The GCS is supplemented by a high-speed load-shedding system that dynamically sheds load based on the system topology and user-entered load priorities.
10. Allow users to start, unload, and set operating limits as well as disable control for all the generators via a GCS HMI. Alarms annunciated on the HMI alert users to manually intervene when required. The GCS HMI also displays all metering values and generator breaker statuses as well as the state of the generator and the dynamically calculated spinning reserve.

The automatic voltage regulator (AVR) and governor controls provide the primary controls for each generator, whereas the GCS provides the secondary level of control. The primary controls are fast-acting in the order of a few seconds and largely control the generator response following step-load changes and system events [1]. The secondary GCS is a slow-acting system (operates in 30- to 60-second intervals) and generally regulates the steady-state system performance [2]. The requirements for the secondary generation system are comprehensive, so a standalone redundant pair of controllers was included in the GCS.

II. GENERATOR CONTROL MODES

This section presents common control modes for the governor and AVR. The GCS should constantly track the control modes of all AVR and governor controls in the system and adjust operation accordingly. Changes in control modes have the potential to create conflicting controls and lead to system stability issues.

A. Governor Speed Control

Governor speed control methods are broadly classified into two categories: droop and isochronous. In droop mode, the governor causes the generator to follow the droop curve to calculate the generator's power output based on the machine speed. In isochronous mode, the governor tries to maintain the generator speed and system frequency at a constant value [1].

When a generator operates in droop mode, the speed decreases proportional to the generator load by a certain percentage, called the droop percentage. The relationship between generator load, speed, and droop percentage is given in [1], [3], and [4].

In isochronous mode, the governor attempts to maintain constant generator speed. Multiple generators can operate in isochronous mode by using load sharing lines between them. Reference [3] provides a detailed overview of isochronous load sharing principles.

B. Automatic Voltage Control

Excitation voltage control (performed by the AVR) can be broadly classified into two categories: constant voltage control (CVC) and reactive droop control (volt-ampere reactive [VAR] control or power factor control is included). In a CVC strategy, the generator tries to control the terminal voltage or the bus voltage to the rated value. In a reactive droop control strategy, the AVR decreases the generator terminal voltage based on the reactive load the generator supplies. There are other forms of voltage control, such as cross-current compensation and load compensation. Reference [4] provides more details about voltage control modes.

III. MODELING AND SIMULATION

To verify and validate GCS performance, a real-time dynamic hardware simulator was used. The power system model was developed in the simulator, and the actual GCS controllers were connected to the simulator to perform hardware-in-the-loop (HIL) testing. The controller performance, actions, and system response were tested in this dynamic simulation environment. These simulations also helped tune various control parameters within the GCS, such as dead bands, speed/voltage raise and lower parameters, and proportional-integral loop constants. Tuning the GCS parameters during simulation helped with onsite commissioning by providing a better starting point.

The following power system components were included in the model:

1. Manufacturer-provided governor-turbine/governor-engine model for each generator.
2. Manufacturer-provided AVR and excitation system model for each generator.
3. Generator model.
4. Large transformers (>1 MVA).
5. Cables and breakers.
6. Large loads modeled as dynamic power quantity loads (remaining smaller loads in each bus were lumped together).
7. Thyristor-controlled heaters (largest load in the power system), which formed a large nonlinear load and produced continuous kW step changes to the power system.

Validation of the power system model was performed by taking the following actions:

1. The generator model was validated by comparing the generator open-circuit characteristics and short-circuit characteristics with the manufacturer-provided open-circuit and short-circuit characteristics.
2. The governor-prime mover model was validated by comparing the manufacturer-provided field generator step-load response with the generator model response for the same step-load change.
3. The simulation model load flow study results were compared with the power system load flow study results. The power system model was developed in an alternate software.
4. The short-circuit values for several three-line-to-ground bus faults were compared with the power system model short-circuit study results.

Fig. 2 and Fig. 3 show the step-load response of the B3 generators (LAN-5200 and LAN-5220) used to validate the generator/governor-turbine model as an example.

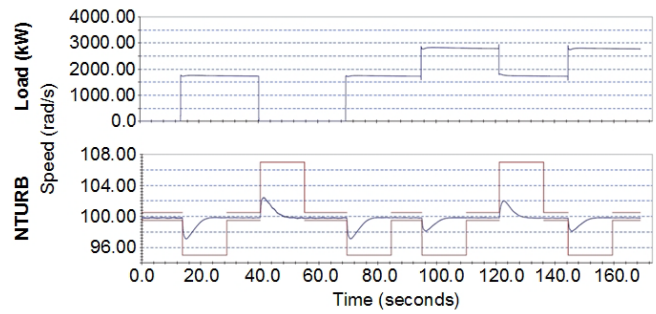


Fig. 2 LAN-5200 Generator Field Step-Load Response Test

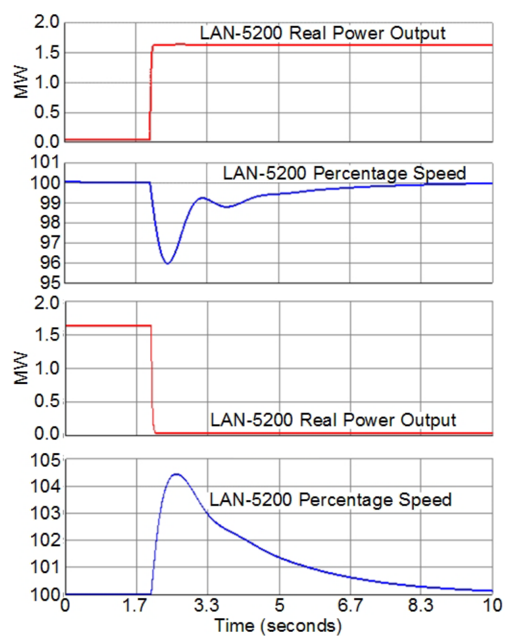


Fig. 3 LAN-5200 Generator Step-Load Response Using Power System Model

Other model validation checks are not included in the paper. Fig. 2 shows the generator step-load response for several step-load additions and rejections based on field measurements provided by the manufacturer. Fig. 3 shows the simulation response of the generator for similar step-load additions and rejections. For dynamic simulation model validation, the generator field response should be similar to the simulation model response. The transient peak and settling time between the model and the field response should match. The transient peak difference is 2 percent between the model and the actual generator and the settling time is 6-8 seconds in both cases for a 1.6 MW step-load change.

IV. GCS DESIGN CONSIDERATIONS

The existing power system comprised only the B and B2 platforms. The four generators in these platforms have load sharing lines between them. Per the existing control system, the four generators shared kW using load sharing lines. They operated under CVC, and the operators adjusted kVARs on the generators periodically. The new B3 platform installed has two larger, gas turbine-driven generators that also have load-share lines between them. Load sharing lines, however, are not present between the B3 and B2-B generators because of differences in manufacturer control, physical distance, and other factors.

Dedicated data concentrators are in each platform to gather data required for the GCS algorithms. The GCS controllers control the generators on the B3, B2, and B platforms via dedicated generator interface modules. Each generator interface module is hardwired to the turbine control panel in B3 and governor and voltage regulator in B and B2 to control the frequency and voltage. The GCS controllers communicate with the data concentrators on an Ethernet network.

A. KW Load Sharing and Frequency Control Considerations

The new GCS operates all six generators under droop mode for kW and kVAR load sharing. Droop mode is the default mode of kW/kVAR load control for all six generators. However, the GCS design also provides operators flexibility to operate one or more generators in isochronous mode and use load-share lines. Operators can switch the generators to isochronous mode and use load-share lines when the GCS controllers have failed or are disabled.

An island system operating with all generators in droop mode can have frequency excursions. This is because of the low system stiffness. One of the most popular control modes is to operate a single large generator or group of generators in isochronous load sharing mode and the remaining generators in droop mode. However, this system is designed to operate all six generators in droop mode. Advantages of operating all generators in droop mode are described in [1].

Unlike grid-connected power systems, the stiffness of island power systems is low, and events such as step changes in load, generator trips, and faults tend to produce transient and steady-state frequency excursions in the island. The GCS control uses the formulas in (1) and (2) to determine generator loading and regulate steady-state system frequency. The governors correct transient system frequency excursions according to their droop characteristic [2].

$$\%GL = TIL \cdot 100\% / TIC + \%FB + GkWSP \cdot 100\% / GkW \quad (1)$$

$$\%FB = (60 - MF) \cdot 100\% / (60 \cdot D\% \cdot 0.01) \quad (2)$$

where:

%GL = determined target percentage loading on each generator.

TIL = total kW load on the entire island.

TIC = total kW generation capacity across the island.

%FB = change in operating frequency relative to nominal frequency.

GkWSP = operator-entered base set point.

GkW = generator kW Available for load sharing.

MF = measured frequency.

D% = percentage of droop.

Using this formula, the GCS calculates the target load of each generator in terms of generator capacity percentage. The error between target load and current generator load is calculated as the kW error. The kW error is compared with certain dead band thresholds, and if the error is outside the dead bands, the GCS sends a speed reference raise or lower signal to the generator. These dead bands and speed control signals were calibrated onsite. To avoid constant set-point changes, frequency bias is forced to zero when the system frequency is within the dead band of the nominal frequency. Even small frequency differences can cause large differences to the kW error, which may produce excessive hunting in the system. The governors and AVRs in this application required pulse signals for the speed and voltage reference raise and lower command. The percentage change in speed reference signals in the governor was proportional to the pulse width.

Table I shows the final calibration of speed reference raise and lower signals, the pulse width of the speed reference change signals, the percentage change in reference speed, and the change in kW power output for the droop percentage configured for a stiff power system. The values were determined onsite during commissioning.

B. Island Capacity and Generator Available kW Calculation

The generator operating capability (derate rating) is different than the generator nameplate prime rating because of the operating temperature, altitude, fuel quality, and for other mechanical reasons. For example, in this application, the gas engine generators have a nameplate rating of 750 kW, but under certain physical conditions they are derated to 400 kW. Loading these generators above this rating increases the chance of failure or shutdown. Similarly, the B3 gas turbine generators are also derated based on ambient temperature. Typical load sharing schemes in islands operate based on generator nameplate ratings [1] [3]. This GCS application uses dynamically calculated generator operating capability and operator-entered limits to determine generator available capacity and to implement proportional load sharing. Doing this maximizes effective spinning reserves available in the system [2].

Simulation was performed to check the performance of the system under two scenarios. In Case 1, load sharing was implemented using generator nameplate ratings. In Case 2, load sharing was implemented based on generator operating capability. Table II, Table III, and Table IV summarize the steady-state load results before and after the event based on simulation results.

In Case 1, where the generator nameplate rating was used for both load sharing and spinning reserve calculations, the available spinning reserve is 4160 kW. When operating capability is used for GCS calculations (load sharing and spinning reserves), the available operating capacity is 2740 kW. Generator operating capability, or derate values, provide a more realistic estimate of available operating capacity than the nameplate rating. Also, in an all-droop system, an event that causes a step change in load (or loss of generation) results in the additional load being proportionally shared (based on nameplate rating) between all generators by governor control action [2].

TABLE I
SPEED REFERENCE RAISE/LOWER SIGNAL CONFIGURATION

Generator	Pulse Width (s)	Speed Reference Change (%)	Power Output Change (kW)
LAN-5200 (G1) and LAN-5220 (G2) (droop setting = 3.5%)	0.18 (small)	0.090	72
	0.23 (medium)	0.115	92
	0.35 (large)	0.175	140
LAN-1600 (G3), LAN-1610 (G4) and LAN-1620 (G5) (droop setting = 5%)	1.1 (small)	0.185	27.8
	1.4 (medium)	0.236	35.4
	2.4 (large)	0.405	60.7
LAN-1750 (G6) (droop setting = 5%)	7.5 (small)	0.275	27.5
	9 (medium)	0.330	33
	13 (large)	0.477	47.7

TABLE II
GENERATOR NAMEPLATE RATINGS / OPERATING CAPACITY

Generator	Nameplate Rating (kW)	Generator Operating Capability (kW)
LAN-5200 (G1)	2800	2800
LAN-5220 (G2)	2800	2800
LAN-1600 (G3)	750	400
LAN-1610 (G4)	750	400
LAN-1620 (G5)	750	400
LAN-1750 (G6)	500	500
Total capacity (kW)	**8350**	**6900**

TABLE III
GENERATOR LOADING FOLLOWING CASE 1 TRIP

Generator	Load Sharing	Loading After Trip
LAN-5200 (G1)	935 kW	1536 kW
LAN-5220 (G2)	934 kW	0 kW
LAN-1600 (G3)	270 kW	433 kW
LAN-1610 (G4)	287 kW	455 kW
LAN-1620 (G5)	Offline	Offline
LAN-1750 (G6)	Offline	Offline
Total	**2426 kW**	**2424 kW**

TABLE IV
GENERATOR LOADING FOLLOWING CASE 2 TRIP

Generator	Load Sharing	Loading After Trip
LAN-5200 (G1)	1076 kW	1747 kW
LAN-5220 (G2)	1076 kW	0 kW
LAN-1600 (G3)	137 kW	339 kW
LAN-1610 (G4)	137 kW	340 kW
LAN-1620 (G5)	Offline	Offline
LAN-1750 (G6)	Offline	Offline
Total	**2426 kW**	**2426 kW**

Following the loss of G2 Generator LAN-5220 because of an unintentional trip in Case 1, Generators LAN-1600 and LAN-1610 operate beyond their operating capability and are likely to trip shortly. The plant has experienced such trips in the past when a generator was loaded beyond the derated operating limits. However, when load sharing is implemented based on operating capability rather than the nameplate rating (Case 2), all generators still operate within capacity, and the system is likely to survive the event. The GCS determines the operating capability of the generator as follows:

1. The GCS constantly tracks the turbine ambient temperature and kW/kVAR outputs. The GCS has the generator capability curves built-in for each generator. The GCS uses the capability curves in conjunction with the current operating values to dynamically calculate the operating capability and additional kW/kVAR margins.
2. Operators can enter kW and kVAR operating limits. There is a check and balance algorithm in the GCS HMI that requires the operators to enter realistic limits. The GCS uses the minimum of the dynamically calculated operating limits and the operator-entered limits to determine the kW/kVAR available capacity.

The GCS adjusts the generator loading proportional to the operating capability [5]. This maximizes true available spinning reserves and minimizes potential for cascading trips or shutdown. Even though adequate spinning reserves are available in both instances, Case 1 would result in cascading trips or possible shutdown.

C. kVAR Load Sharing and Voltage Control Considerations

Voltage and kVAR load sharing calculations are also implemented similar to frequency control and kW load sharing. The GCS performs calculations for kVAR load sharing and voltage control per (3) and (4).

$$\%GL = TIL \cdot 100\% / TIC + \%VB + GkVARSP / GkVAR \quad (3)$$

$$\%VB = (RBV - MV) \cdot 100\% / (RBV \cdot D\% \cdot 0.01) \quad (4)$$

where:

%GL = determined target percentage of kVAR loading on each generator.

TIL = total kVAR load on the entire island.

TIC = total kVAR generation capacity across the island.

%VB = change in operating voltage relative to nominal generator terminal voltage.

GkVARSP = operator-entered base set point.

GkVAR = generator kVAR available for load sharing.

RBV = the rated bus voltage.

MV = the measured voltage.

While the formulas for droop VAR sharing and droop kW sharing appear to be the same, there are several differences between the two control modes. In an island power system, the terminal voltage of each generator and the bus voltages across the island are different depending on load flow. While kW load sharing can be implemented between generators without major considerations for load flow, kVAR load sharing and voltage control need to consider reactive power flow, especially if there are large impedances between the generators [5].

In this application, the larger B3 generators are connected to the 4.16 kV bus, and the smaller B2 and B generators are connected to the 0.48 kV bus. To maintain the system voltage feeding the motors and the loads downstream, it is desirable to maintain the voltage on the three main buses within ±5% of the nominal voltage. The main buses are 0.48 kV switchgear in Platform B, 0.48 kV switchgear in Platform B2, and 4.16 kV switchgear in Platform B3. Because of the system configuration, proportional kVAR sharing and voltage control across the buses cannot be achieved simultaneously. The GCS should attempt to regulate bus voltage on the main buses by distributing the kVAR load between the generators. While proportional load sharing and system frequency control are achievable for kW load sharing, the same may not be achieved for kVAR load sharing [6].

Per the system load configuration, the normal operating load for Platform B3 is more resistive because of the presence of thyristor-controlled resistive heater loads. Incidentally, these are the largest loads on the system. Loads on the B2 and B platforms include several large motors and, hence, are more reactive. When proportional kVAR load sharing is implemented across the platform, the B2 and B bus voltages are depressed and operate at close to or less than 95 percent of the nominal voltage, even though Platform B3 operates at the rated voltage. This is not desirable, and there is an increased risk of voltage stability issues, degraded power quality, and increased risk from inadvertent generation loss [6]. Alternately, reactive power (kVAR) can be disproportionately distributed between the generators (e.g., B2 generators produce more kVARs relative to capacity than B3 generators and operate at a lower power factor).

1) Case 1: Proportional kVAR Sharing or Power Factor Control

In Case 1, simulation tests were performed by implementing a proportional kVAR control, or power factor control, strategy for each generator under normal operating conditions. The simulation plots in Fig. 4 show the generator kVAR and bus voltage under this control strategy and the system response following a G4 (LAN-1610) generator trip.

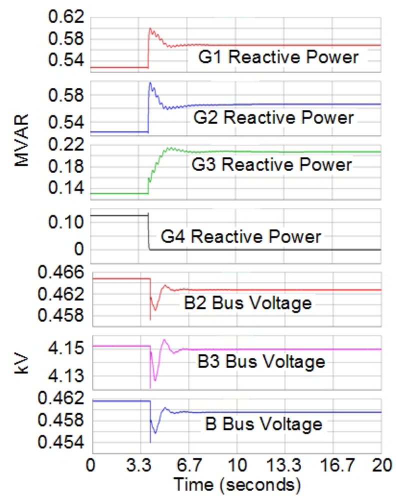


Fig. 4 Case 1 Power Factor Control, or Proportional kVAR Sharing, and LAN-1620 Trip

This was the worst-case event, and following this event, the steady-state voltage decreased to less than 95 percent of nominal voltage on the B2 and B platform bus. The plant operations traditionally used power factor as the basis for manual voltage control. However, under the new design, the simulation showed this was no longer the optimal control strategy. Note that the B2 bus voltage was only 466 V before the event and not 480 V. This is due to the nature of power flows in the system when equal reactive kVAR sharing is implemented. The GCS maintains Bus B3 voltage at 4160 V.

2) Case 2: Voltage Regulation on B2 Bus and Disproportionate Load Sharing

In Case 2, the GCS implemented independent voltage control on all three buses by calculating the voltage bias on each generator using the generator terminal voltage. Maintaining all three bus voltages close to their rating required B2 generators to supply more kVAR as a percentage of their rating than B3 generators. Consequently, B2 generators operated at a low power factor (less than 0.6) to maintain bus voltage on B2 and B. Simulations were performed with this control strategy, and a LAN-1620 generator trip event was again simulated. For this case, the voltage on the B2 and B bus held up well (475 V and 472 V, respectively), but the kVAR on LAN-1600 increased to 700 (it was operating at 460 kVAR) before the event. Further, the GCS attempted to increase excitation on LAN-1600 to increase bus voltage on B2 and B to 480 V. Consequently, LAN-1600 (rated at 937 kVA) operated close to limits, and there was an increased risk of cascading trips even with this strategy. Fig. 5 shows the plots for Case 2.

Both Case 1 and Case 2 show a system that has drawbacks, and they are not suitable voltage/kVAR control strategies in this system.

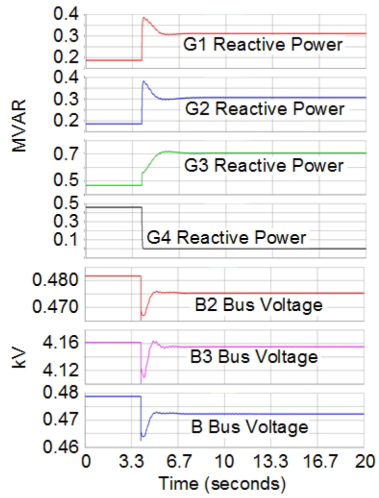


Fig. 5 Case 2 kVAR Load Sharing Implemented Based on Voltage Control Across All Three Buses

It can be concluded based on the previous observations and waveforms that the power system dynamic performance can be improved by optimizing voltage control and kVAR load sharing between the generators. Simulation results were used to implement certain system design requirements. These are summarized below. To maintain bus voltage within acceptable tolerance and optimize kVAR reactive power flows, the following actions were taken.

1. The GCS selects a single bus voltage reference to calculate voltage bias in each island. The GCS then selects the bus with the largest generation for voltage control since this provides flexibility to generate greater VARs when required. If all platforms operate as a single electrical island, the GCS selects B3 bus voltage as a reference for voltage bias calculation.
2. Operators can adjust VAR flows and modify bus voltage by changing the generation kVAR set point on the GCS HMI. This can distribute kVAR load disproportionately and help regulate voltage during certain abnormal operating conditions.
3. To balance kVAR load on the generators and maintain bus voltage, the tap of the B2-B3 tie transformer can be set to 2.5 percent. By setting a tap on this transformer, it is possible to maintain the voltage on all three buses and at the same time kVAR flows under normal operating conditions.

The kVAR reactive power flow and bus voltage were simulated under normal operating conditions. The GCS performed proportional load sharing and maintained voltage on all three buses within ±2% of the nominal voltage under this arrangement.

A B3 generator trip was simulated in this configuration. The power system response following loss of the B3 generator is shown in Fig. 6. The loss of the B3 generator was the worst-case event under the arrangement in Case 3. This is also the final configuration used for voltage control.

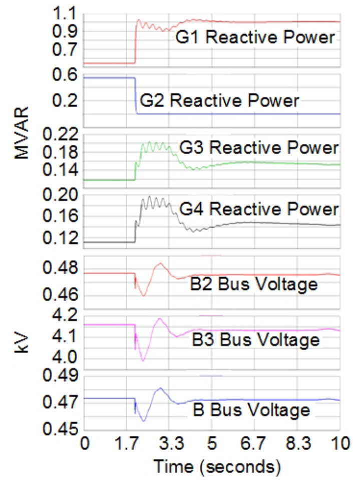


Fig. 6 kVAR Flow and Voltage Waveforms Following B3 Generator Trip Under Designed Load Sharing Conditions

D. Compatibility With Existing Controls and Potential for Conflicting Controls

In addition to GCS control, the generators also have load sharing lines and provide operators the option to switch the system to isochronous load sharing mode when required. This is a fallback option for operations in the event of GCS failure. However, this arrangement also creates potential for conflicting controls. Some of the potential issues that conflicting controls create and the interlocks designed to avoid them are summarized as follows.

1. If the B3 generators are in isochronous load sharing mode, they attempt to regulate the island frequency. Under this condition, the GCS automatically sets the B2 and B generators to droop mode and blocks isochronous load sharing. This ensures that two sets of generation with no load-share lines between them do not operate in isochronous mode simultaneously. Similarly, when the B3 generators are in isochronous mode, the GCS does not attempt to control the bus frequency and sets the frequency bias to 0. The GCS only attempts to load the generators running in droop mode proportionally while the generators in isochronous mode attempt to maintain constant system frequency.
2. Since the B3 generation is much larger than the B and B2 generator, the B2 generators cannot operate in isochronous mode while B3 generators operate in droop mode. During step-load changes and while regulating frequency or voltage, the risk of the B2 generators overloading and tripping is high. The GCS blocks B2 generators from being placed in isochronous mode when they are operating in parallel with B3 generators.

3. Conflicting voltage controls are another major concern. If a B3 generator AVR operates in CVC mode, the generator attempts to control the bus voltages to their set point. Meanwhile, the GCS may also attempt to regulate B3 bus voltage to a different set point by controlling the remaining generators, which are operating in kVAR droop mode. This can cause the GCS to attempt to load more kVARs on the generators that it controls or operate them in the underexcited region, thereby increasing the trip risk and causing voltage issues [6].

E. Island Detection and Synchronization

The GCS constantly tracks and monitors the formation of islands based on the breaker contact status. The following combination of islands are possible in the system.

1. B, B2, and B3 platform operate as a single island.
2. B2 and B3 operate as a single island while B operates as a separate island.
3. B and B2 operate as a single island and B3 operates as a separate island.
4. B, B2, and B3 each operate as a separate island.

The GCS can implement all functions in any of the listed island combinations and can simultaneously implement its listed functions in multiple islands.

To synchronize and connect two separate islands, operations need to modify the voltage and frequency on one or both islands to bring them in sync and close the tie breaker. There are several challenges to performing this function manually. Operators must either control multiple generators or a single generator in an island to modify the voltage/frequency. Since these generators are operating in droop mode, raising speed or voltage on a single generator disrupts load sharing. Per the droop characteristics, to raise frequency and voltage on a bus without disrupting generator loading, speed/voltage raise and lower signals should be applied to all generators in the island simultaneously. Hence, the automatic island synchronization function was implemented in the GCS. When the operator initiates a tie breaker close command, the GCS can control voltage and frequency on either side of the tie breaker (both islands). The GCS issues simultaneous raise and lower signals and suspends any changes to kW/kVAR power sharing until the synchronization process is complete. The tie breaker is closed by a synchronism-check relay (25A) when voltages on both islands are in sync [7].

F. Generator Start and Black Start

The GCS provides operators the ability to remote start the engine or turbine. It uses several inputs from the generator control panel to supervise generator start commands, and it issues an alarm if the engine or turbine fails to start and reach its rated speed within a set time. If the B, B2, and B3 bus voltages are dead and the diesel generator is not running, the controller automatically starts the diesel generator and provides a guided restoration sequence.

G. Generator Unload and Trip

The GCS performs operator-initiated automatic generator unload functionality. When the operator initiates automatic unload to the GCS, the controller checks if sufficient spinning reserve margins are available in the system. Once all unload permissions are satisfied, it sends a kW/kVAR lower command to the selected generator. Once the generator load reduces to less than 50 kW, the GCS issues a breaker trip. The gas turbine and the gas/diesel engine generators in this application have overspeed and load rejection capabilities. Therefore, the generator breaker can be opened without shutting down the engine or turbine first. The advantages of using the GCS to perform automatic unload are summarized as follows.

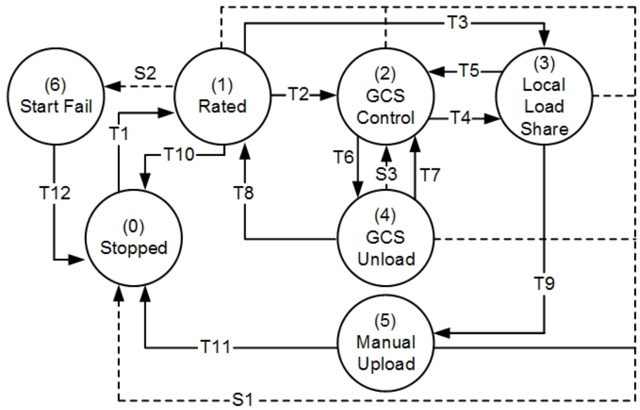
1. The GCS constantly tracks island spinning reserves (kW and kVAR). It can use this information to supervise and block unload when adequate spinning reserves are not available.
2. During unload, the GCS continues to control the remaining generators and ensures load sharing and system voltage and frequency control. By gradually unloading the generator (lower speed and voltage reference), it avoids system disturbance and load shed triggers.

H. Generator State Sequencer

To accommodate different control modes, the GCS controller is programmed so that each generator is a state machine. The GCS uses digital inputs from the generator governor, exciter, control panel, and analog measurements from intelligent electronic devices (IEDs) to assign a state to each generator. Fig. 7 shows the state diagram programmed in the GCS for each generator. The state sequencer-based model enables the GCS to track different control modes and perform the appropriate control and monitoring actions for each generator.

V. CONCLUSIONS

This application shows the considerations involved in the design of a GCS. All generators operate in kW and kVAR droop mode under GCS supervision (quasi-isochronous mode). All the generators operate in droop mode while the GCS regulates system voltage and frequency and manages generator load sharing. The GCS performs several functions apart from voltage and frequency control and serves to optimize plant generation. Through the implementation of the GCS described in this paper, the power systems of all three platforms were integrated into a single island, which is the normal mode of operation. The authors identified the difficulty with manually regulating the power system of this multiple platform arrangement and designed the GCS to operate autonomously without manual intervention, except under rare circumstances. The GCS is also a control system and enables remote control of several other functions, such as generator start, synchronize, unload, and shutdown. The interlocks provided in the scheme help enhance safety and minimize potential unintended operations resulting from operator errors. The paper also presents design details derived from simulation results, demonstrating the value of real-time dynamic simulations. These simulations were used to perform controller validation and test the system response for several power system events and operating scenarios. The system was successfully commissioned and has been in service for over two years now.



Transitions

T1 – Starting
T2 – Automatic Synchronization in Progress
T3 – Manual Synchronization in Progress
T4 – Local Load Share / Isochronous Mode Transfer
T5 – GCS Control Transfer
T6 – GCS Unload Command
T7 – GCS Unload Fail
T8 – GCS Unload Successful
T9 – Manual Unload
T10 – Engine Cooldown or Turbine Shutdown in Progress
T11 – Manual Unload Successful and Engine Cooldown or Turbine Shutdown in Progress
T12 – Manual Stop or GCS Stop
S1 – Protection Trip
S2 – Start Fail
S3 – Unload Fail

Fig. 7 State Diagram of Control Logic

VI. REFERENCES

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VII. VITAE

Srinath Raghavan received his B.S. in 2009 from Anna University in India and his M.S. in electrical engineering from Missouri University of Science and Technology in 2013. His research encompassed power system modeling and analysis. Srinath worked as a protection engineer in Areva T&D in Chennai, India, where he was involved in the commissioning of protection systems. In 2013, he joined Schweitzer Engineering Laboratories, Inc. as a protection engineer. He is a registered professional engineer in the state of Texas.

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