Complete Power Management System for an Industrial Refinery

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COMPLETE POWER MANAGEMENT SYSTEM FOR AN INDUSTRIAL REFINERY

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Abstract—Islanded power systems for critical facilities require a robust, secure, and reliable power management system that can respond to system disturbances and avoid blackouts to ensure process survivability. A facility in Saudi Arabia with four gas-oil separation plants and one natural gas liquids recovery facility operates with a total installed generation capacity of approximately two gigawatts and no utility interconnections. This paper discusses power management system components, such as automatic generation control (power and frequency), volt/VAR control systems (reactive power and voltage), intertie power factor control, high-speed generation shedding and runback, and high-speed load shedding, along with an overview of the overall system architecture and the state-of-the-art dual-ring time-division multiplexing synchronous optical network communications networks at this facility. High-speed generation-shedding and load-shedding systems are designed with overfrequency- and underfrequency-based secondary backup protection schemes to provide additional system reliability. This paper also introduces a transient-level computer model of the facility power system, which is used for functional testing of the power management system components.

Index Terms—Power management, generation shedding, runback, load shedding, frequency and voltage stability, autosynchronization, blackout prevention, microgrids.

I. INTRODUCTION

One of the key requirements of an islanded (isolated) power system (also known as a microgrid) is a complete power management system (PMS) to avoid system outages and ensure load availability and reliability. This paper discusses a fully redundant PMS for a major oil field in Saudi Arabia with a production capacity of 750,000 barrels of oil per day. This facility is composed of five plants: a natural gas liquid plant (Plant 1, 230 kV) and four gas-oil separation plants (Plant 2 [115 kV and 230 kV], Plant 3 [69 kV], Plant 4 [230 kV], and Plant 5 [230 kV]). The original plant consisted of Plant 3, Plant 4, and Plant 5; Plant 1 and Plant 2 are the latest additions. Thirteen tie lines connect the five stations using overhead and underground cables. Plant 1 contains eight combustion-gas turbine generators (CGTGs), Plant 2 contains six CGTGs, and Plant 3 contains four CGTGs. The total generation capacity of all the on-site generation is approximately two gigawatts. Fig. 1 shows a simplified diagram of the plant without the load represented.

This facility, with no utility connections, can split into ten viable islands. The PMS was designed and tested to track any combination of islands and is equipped with thirteen autosynchronization schemes to synchronize the islands as required.

II. POWER MANAGEMENT SYSTEMS

Similar to the utility grid, an islanded power system needs control systems to maintain system frequency and voltage within allowable limits. A PMS for an islanded power system is similar to utility energy management systems and remedial action schemes. A PMS combines low-speed functions, such as automatic generation control (AGC), volt/VAR control systems (VCSs), and tie line control, with high-speed functions, such as load shedding and generation shedding. A PMS also requires autosynchronization systems that can synchronize generators and system islands. All of these systems operate in a coherent fashion to control the system during all manner of low-speed and high-speed disturbances.

Islanded industrial systems have much less inertia than utility systems. Disturbances such as short-circuit conditions therefore cause larger changes to rotor angles and system frequency. These islanded power systems therefore require faster load- and generation-shedding systems to preserve system stability. Fig. 2 shows a simplified architecture of the PMS used to protect and control the power system shown in Fig. 1.

III. COMMUNICATIONS ARCHITECTURE

Modern PMSs are a complete integration of protection, control, and automation devices. These include devices such as protective relays, embedded computers, logic controllers, I/O modules, and communications and engineering tool sets.

The capability and determinism of such PMSs are heavily dependent on the communications networks and devices involved. Multiplexer technology was used to improve the reliability and determinism of the facility wide-area

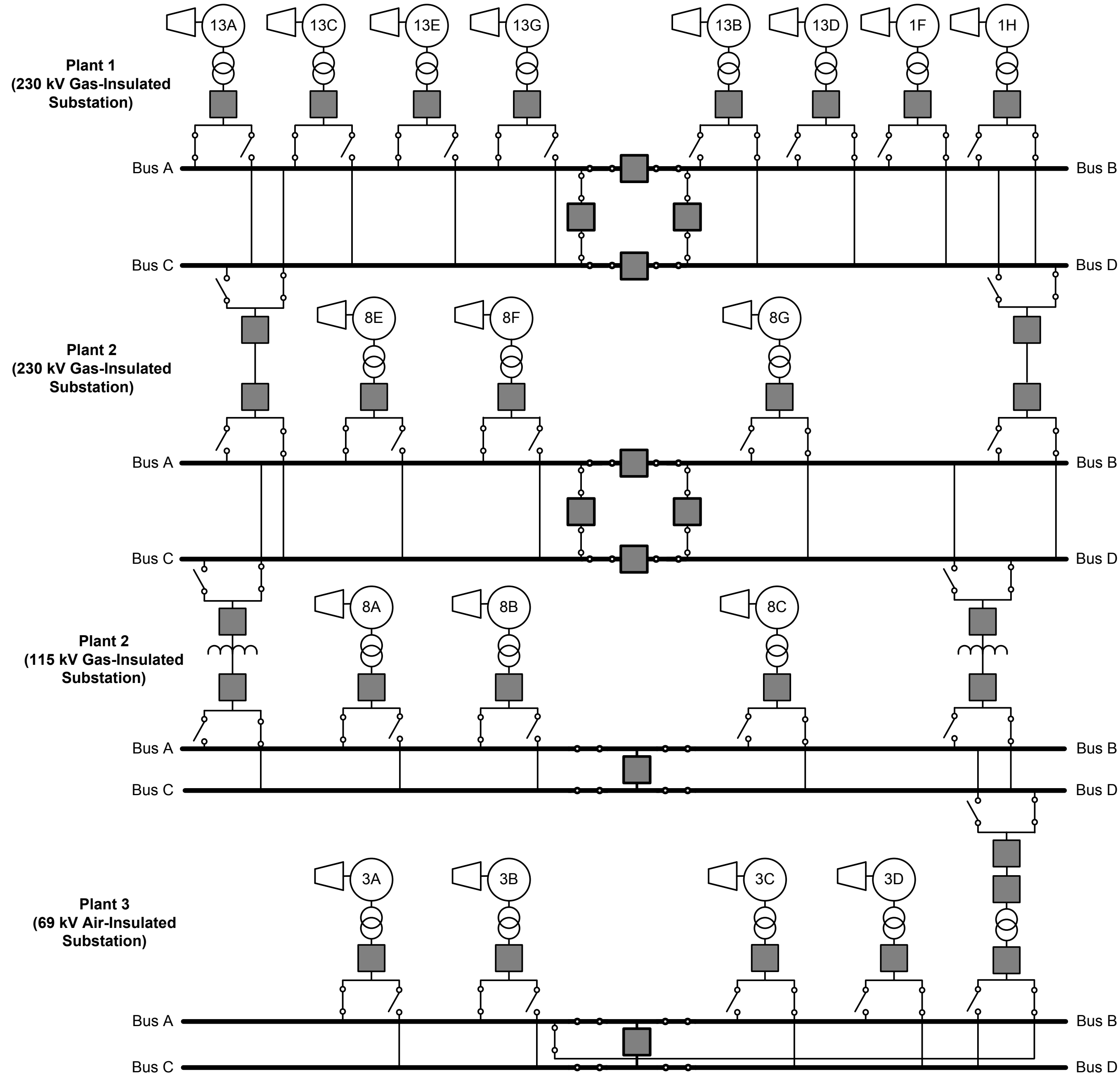

Fig. 1 Simplified One-Line Diagram of Power Generation and Transmission Systems

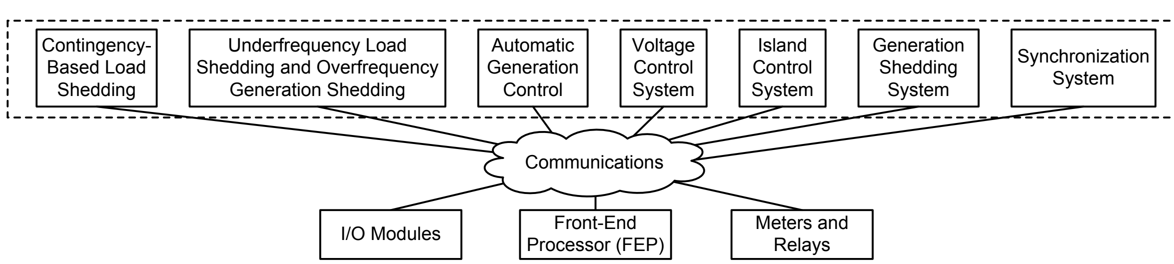

Fig. 2 Simplified PMS Architecture

network (WAN). This was crucial for high-speed applications, such as load and generation shedding, that protect the overall integrity of the system.

As shown in Fig. 3, the communications architecture at the facility uses a fully redundant time-division multiplexing-based network connecting all five plants. The multiplexers and the fiber connections between them represent the WAN. The WAN links the local-area networks (LANs) of the plants together. The WAN network provides the advantages of determinism, reliability, and data segregation via time-division multiplexing pipes [1]. Reliability is improved through fast network healing times; WAN traffic is interrupted for less than 5 milliseconds for a fiber break in the system. Table I shows the typical protocols used in such PMSs.

TABLE I
PMS PROTOCOLS

Application	Protocols
High-speed controls (load shedding, generation shedding)	IEC 61850 Generic Object-Oriented Substation Event (GOOSE), IEEE C37.118 synchrophasors, proprietary peer-to-peer protocols
Low-speed controls (supervisory control and data acquisition [SCADA], data monitoring)	DNP3, Modbus® TCP/IP, IEC 61850 Manufacturing Message Specification (MMS)

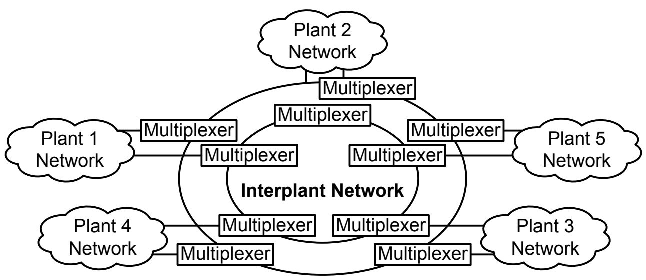

Fig. 3 Simplified Communications Architecture

IV. SLOW-ACTING REBALANCING CONTROL SYSTEMS

The generation control system (GCS) described in this section operates in seconds or minutes to slowly correct the system frequency, voltage, active and reactive power flows, power factor, and more.

A GCS controls the active and reactive power flow from generators. This is done to maintain generator bus voltage and system frequency by controlling the exciter and governor of the CGTG. A GCS also participates in system synchronization efforts because it has control of every governor and exciter.

A typical GCS includes functions such as AGC, a VCS, and an island control system (ICS). Such control systems are connected to the generator unit controller using an interface device that sends and receives control and status signals.

A. Automatic Generation Control

AGC dispatches turbine governor set points for equal-percentage real power load sharing, while simultaneously maintaining the system frequency and the real power flow across tie lines. Tie line control follows user-defined set points for maintaining the real power flow.

Fig. 4 shows the overall control strategy of the AGC algorithm. The algorithm is basically a four-stage cascaded advanced control system. The controls are all feed-forward and use observer-based strategies based on decades of power system experience.

Inside the AGC system a unit megawatt controller keeps the CGTG real power output to a desired megawatt set point. The megawatt set point for each generator is determined by the optimal load-sharing controller. The optimal load-sharing controller receives bias commands from either the frequency or tie flow controller algorithms. The island detection logic in the ICS determines which of these algorithms is activated.

Of the 24 different possible power-wheeling buses at the facility, only 16 can have generators attached. As such, there are 16 unit megawatt control subsystems, 16 frequency control systems, and 5 tie flow control subsystems. The AGC can simultaneously control 16 different islands and 5 different tie lines or any combination of these, as required.

In the system, 5 intertie lines are controlled for active power flow by the PMS: 2 tie lines between Plant 1 and Plant 2 (230 kV), 2 tie lines between Plant 2 (230 kV) and Plant 2 (115 kV), and 1 tie line between Plant 2 (115 kV) and Plant 3.

The PMS simultaneously controls the island frequency and voltage and maintains the real power flow across the tie lines. As soon as the tie control is enabled, the ICS designates the swing and power buses based on the system topology and islanding scenarios in the system. The swing bus controls the island frequency, and the power bus controls the real power flow across tie lines. As the system separates into multiple islands, these swing and power buses are dynamically reconfigured to maintain the tie flow.

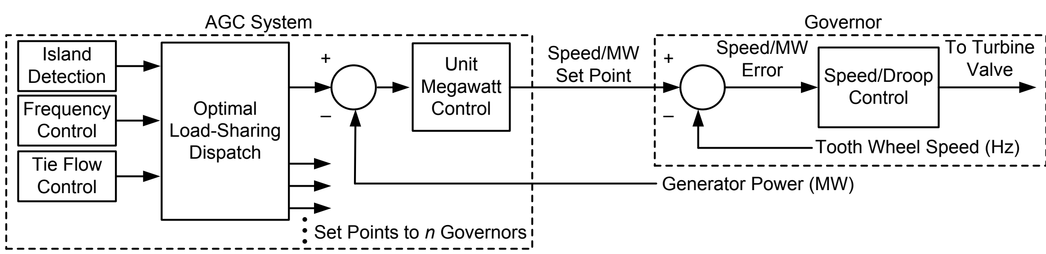

Fig. 4 AGC System

B. Volt/VAR Control System

The VCS dispatches exciter set points for equal-percentage reactive power load sharing and maintains the generator terminal voltages within acceptable limits. Fig. 5 shows the overall control strategy of the VCS algorithm.

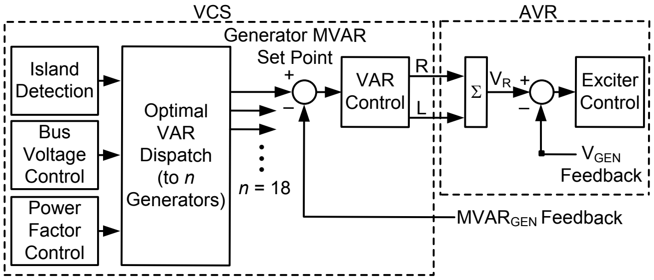

Fig. 5 VCS Strategy

As shown in Fig. 5, the VAR control sends voltage set points to each of the exciters through raise/lower (R/L) commands. The VAR control keeps the generator MVAR output at a desired set point. The optimal VAR dispatch (load-sharing controller) sends the set points to the unit VAR controls and performs equal-percentage sharing between the collocated generators. The optimal VAR dispatch receives bias commands from the bus voltage control or power factor control algorithms. The island detection logic in the ICS determines which of these algorithms is activated for each island and bus configuration.

The VCS contains 16 unit VAR controls and 16 optimal VAR dispatch subsystems. If the entire system is connected as a single grid, then 3 different voltage control subsystems are active for 3 different voltage levels (230 kV, 115 kV, and 69 kV). The VCS can simultaneously control 16 different islands and 5 different tie lines or any combination of these, as required.

C. Island Control System

The ICS controls the modes (droop and isochronous [ISO]) of the governors and the modes of the exciters (volt/VAR), and selects the AGC and VCS dispatch algorithm modes. The ICS also tracks the number of electrical islands within the system and all of the CGTGs connected to those islands. Using this information, the ICS dynamically creates individual AGC and VCS control loops for each island, thereby allowing the control systems to adapt to all electrical grid conditions.

D. Allowable Operation Region

The GCS uses a continuously adapting allowable operational region algorithm to track the CGTG real and reactive power limits. The controllers are not allowed to dispatch a generator outside the boundaries of this region. This region is used to calculate real and reactive power spinning reserves for use in the AGC and VCS.

Fig. 6 shows two different operational scenarios for the allowable operational region algorithm. Fig. 6a shows an example where the operator-entered regulation limits are within the generator capability curve but outside the turbine capability. The allowable operational region is indicated by the shaded region.

Fig. 6b shows an example where the regulation limits are outside the generator capability curve, the turbine capability, and the underexcitation limit of the turbine (10 percent reduced capability). As shown by the shaded region, the turbine line is used for part of the allowable operational region. The generator capability curve is used for the upper-right corner of the operational region boundary, whereas the underexcitation limit is used for the lower excitation boundary.

Because the generator capability curves can change during system operation, the allowable operational region needs to be dynamically adjusted depending on the curve and the fixed operator-entered regulation limits.

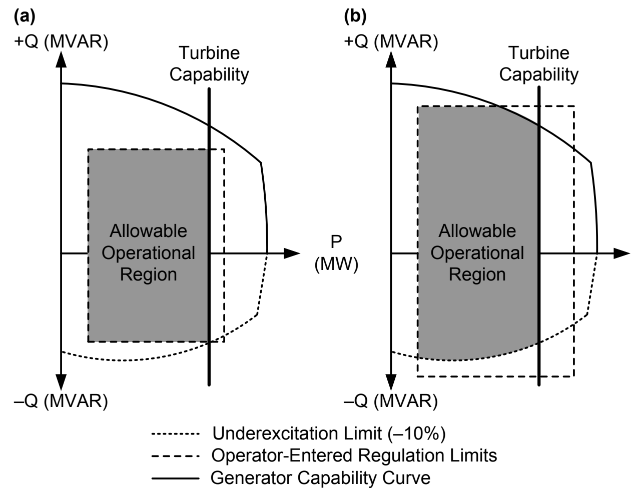

Fig. 6 Regulation Limits Within and Outside the Generator Capability Curve

E. Megawatt and MVAR Equal-Percentage Load-Sharing Algorithm

AGC turbine load sharing is critical to prevent turbine operation at or near turbine and generator capability limits. The VCS exciter load sharing is critical to prevent generator operation at or near exciter and generator capability limits. By keeping all of the machines in the same quadrant, no single machine can become underexcited.

The philosophy of an equal-percentage load-sharing method is to load the turbines equally so that the turbine governors have maximum flexibility to move turbine control valves during disturbances. Having one turbine operating near its upper limit while other units are less loaded means that the most loaded unit will not be able to actively participate in rejecting a disturbance. This technique is also commonly referred to as optimal stability dispatch. The system also adapts to all forms of steam control and provides optimal steam dispatch, if required [2].

The AGC and VCS calculations take into consideration boundaries such as dynamic real-time turbine derating, dynamic real-time synchronous generator curve derating, the underexcitation limit of the exciter, an operator-entered boundary condition, and an operator-entered preferred operating point.

The operator-entered preferred operating point allows experienced users to set a CGTG at the best-known or normal operating point. The AGC and VCS algorithms then adjust the real and reactive dispatch as close as possible to this value. The units cannot typically be sent to the exact operator-entered operational point because the active and reactive power from the units must be adjusted by the AGC and VCS to meet bus voltage, frequency, and tie line power and power factor control set points.

Operator-entered upper and lower regulation limits on real- and reactive- power allow an experienced user to prevent a unit from operating in a known region of dangerous operation. For example, a governor region of operation known to be unstable can be avoided with these upper and lower limits. Also, the limits can be used to keep the unit within a low-nitrous oxide (low-NOX) emission level. The AGC and VCS will not dispatch a CGTG outside of the operator-entered boundaries (upper and lower limits on active and reactive power output).

F. Autosynchronization System (A25A)

A25A systems are required at generators, tie lines, and bus couplers. Unit-autosynchronization systems are used to synchronize individual generators to power grids. Island-autosynchronization systems are used to synchronize and reconnect power system islands. These systems are required to function automatically with minimal human supervision because they must dispatch multiple generators simultaneously to reduce slip and voltage differences at the interconnection point [3].

A25A systems replace analog synchroscopes and manual breaker closing. This creates less damage on generator windings and provides better reporting features, such as sequence of event (SOE) reports and oscillography. These systems adapt to changing bus topologies without external switching of voltage transformer signals. They also feature protection-class equipment and high-speed (subcycle) communications over long distances.

At the facility, the autosynchronization systems measure the voltage and frequency on both sides of several breakers (bus couplers, bus ties, and tie line breakers) to send proportional correction pulses for adjusting the governor and exciter as necessary to automatically close the breaker. This process enables safe, secure, unattended synchronization of the generators connected to one bus and the generators on the opposing bus.

V. FAST-ACTING REBALANCING CONTROL SYSTEMS

Disparities between turbine power output and electric power consumption occur as the power system becomes slightly unbalanced. The unbalance causes the power system frequency to change as kinetic energy is extracted from (or inserted into) the rotating inertia of the turbines, generators, motors, and loads. The control schemes described in this section attempt to balance the mechanical power input with the electric power consumption.

A. Contingency-Based Load-Shedding System

A contingency-based load-shedding system (CLS) is a protection algorithm that sheds load to maintain the power balance between the prime movers and the electric power system loads. This is done by reducing the total plant electrical load to less than the calculated available turbine and generator capacity after a contingency occurs. Because of the power system net rotating inertia, the CLS operates fast enough that loads are shed prior to any significant decay in frequency.

A contingency is any event that results in the loss of power to a grid section (island). Contingencies can occur when a tie line, bus coupler, sectionalizer, or generator breaker opens under load. A contingency can also be the overload of a transformer, cable section, or generator. The CLS operates by making load-shedding decisions based on topology statuses (breaker 52A [close status], 52B [open status], and disconnect switch 89A and 89B statuses), contingency statuses and metering (breaker 52A and 52B statuses and active power values measured on contingency breakers), and load statuses and metering (breaker 52A or 52B statuses and the megawatt values measured on sheddable load).

When an event occurs that would cause a contingency situation, the 52A and 52B contacts of the contingency breaker change state. This state change is detected by I/O modules. These modules transmit the 52A and 52B status signals to the CLS controller. The CLS controller then determines the loads to shed based on the contingency statuses and metering, user-defined load-shedding priorities, user-defined incremental reserve margin values, topology statuses, and load statuses and metering. The CLS sends the load trip signals to I/O modules, and output contacts on these modules trip breakers.

The CLS algorithm is depicted in Fig. 7. For further details regarding load-shedding systems, refer to [4], [5], and [6].

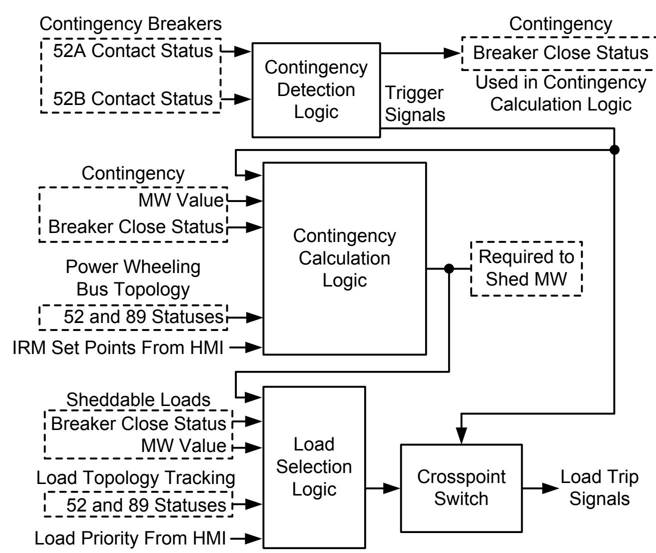

Fig. 7 CLS Algorithm

B. Generation-Shedding and Runback System

A generation-shedding system (GSS) keeps the steady-state frequency of the power system at nominal during a major loss of load. By keeping the frequency at nominal, the turbine revolutions per minute (rpm) are also stabilized, thus keeping turbine generators online and preventing system power outages (blackouts). A secondary goal of the system is to minimize disturbances to generation during these shedding and runback events. This generation-shedding and runback system is the primary protection for excess generation, which tends toward overfrequency.

The GSS is a fast, contingency-based algorithm that sheds and runs back generators to maintain the power balance between the loads and the generation. This is done by reducing the total island generation to make it approximately equal to the running load of the island after a contingency occurs. Because of the power system net rotating inertia, the GSS operates fast enough that generation sheds prior to any significant overshoot in frequency.

A GSS contingency is any event that results in excess generation on an island. Contingencies can occur when a tie line or bus coupler breaker opens under load.

Similar to CLS, the GSS operates by making generation-shedding and/or runback decisions based on three basic categories of information: contingency statuses and metering, topology statuses, and generator statuses and metering.

When the GSS controller detects a contingency breaker open condition, it determines the generation to shed or run back based on the contingency status and metering, user-defined generator-shedding and runback priorities, user-defined decremental reserve margin (DRM) values, topology statuses, and generator statuses and metering. Then the GSS sends the generator trip and runback signals to I/O modules. Output contacts on these modules trip breakers, send digital signals to enable runback control mode, and send an analog megawatt set point (runback level) to the turbine generator controller.

The system performs pre-event calculations to dynamically determine which generator to shed or run back and to build a generation-shedding and runback table. The system monitors contingency trigger signals and generates generation-shedding and runback signals based on the generation-shedding and runback table when a trigger is detected.

1) Generation Runback Philosophy

Generation runback is used to quickly reduce CGTG output and avoid having to trip a CGTG. The governor regulates the speed and active power output of a CGTG, but it is inherently limited in its ability to quickly reduce output. This limit in reducing output is caused by a number of factors, including PID tuning constants, measurement time lags, filtering, and ramp rates. In a generator runback scheme, the governor PID is bypassed and runback set points are directly injected into valve control set points, as shown in Fig. 8. This runs the CGTG output directly to the real power required within the response time of the valve and associated valve controls.

Runback schemes like the one in Fig. 8 can respond in less than one second, whereas governor PID speed controls typically respond in one to five seconds. The runback is coordinated with the GSS based on the plant load, total generation runback capacity, and the amount of excess power on the system. Governor runback responses in a CGTG are limited by flame-out restrictions on fuel valve movement, while runback in steam generation has no such limit.

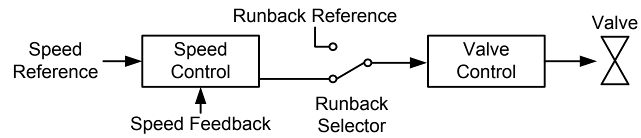

Fig. 8 Runback in a CGTG Speed Governor

Generation runback at the facility works as follows. First, the GSS calculates the runback target load set point for each generator. The runback target load set point indicates the desired megawatt operating set point of the CGTGs. When a contingency is detected, the runback target load set point and runback control mode enable signals are sent to the CGTG governor controller. The CGTG governor controller, on receipt of the runback signals, processes these signals as follows:

1. Change the control fuel valve position to the output real power (in megawatts) to match the runback target load set point from the GSS.
2. Change the mode of operation of the CGTG, if required, based on the runback target load set point.
3. Maintain the generator megawatt set point at the runback target load set point.

Fig. 9 explains the runback target load set point and how this set point should be treated by the CGTG governor controller.

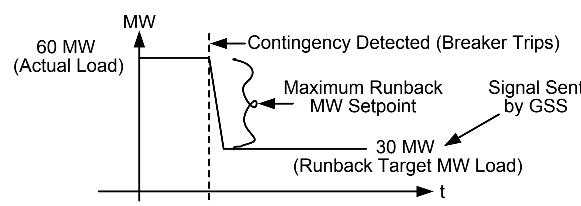

Fig. 9 Generator Runback Target Load Set Point

2) System DRM

The GSS and runback algorithm uses the DRM in the calculation of the excess generation (in megawatts). Unit DRM is the amount of step decrease in generation a turbine can provide within the tuning time response of the governor (typically one second). The same effect can be described as the load rejection capability within frequency stability margins. There is no recognized industry standard for this characteristic. DRM is the reverse of the incremental reserve margin described in [6].

System DRM is the accumulated total of the DRM of all online generators. Island DRM is the accumulated total of the DRM of all online generators connected to a given island. The user-defined DRM is limited by the lower regulation limit set for the AGC.

DRM values must be coordinated with overfrequency GSS tripping levels. The GSS reduces the amount of generation selected for shedding or runback by accounting for DRM in its calculation. This limits the impact of GSS on the user's process. Another effect of incorporating the DRM into the

GSS calculation is that the frequency commonly increases following a GSS generator-shedding event. The level of this frequency increase is a function of the tuning in the governor, the user-defined DRM, system inertia, and generation composition. The larger the DRM the user enters, the more the frequency increases for a GSS generator-shedding event. This is because the DRM calculation forces the governors to tap into power decay to keep the frequency at nominal. It is for this reason that DRM values must be coordinated with overfrequency GSS tripping levels.

DRM is also commonly used to compensate for poor governor tuning. Reducing the DRM set point can limit large frequency swings (overshoot) to drop generation resulting from improper tuning.

Following events such as short circuits or breaker openings, control systems receive measurements with oscillatory and or aliased data. For the first event, the controllers can use steady-state pre-event data. To avoid reacting to poor quality data, GSS, runback, and CLS algorithms must have several safeguards. Common safeguards (such as modal detection, data filtering, data freeze, and state estimation) are used to prevent misoperation.

C. Underfrequency Load-Shedding and Overfrequency Generation-Shedding Systems

The overall reliability of the load- and generation-shedding systems is improved with redundant controllers using different algorithms. These different algorithms are the underfrequency load-shedding (UFLS) and overfrequency generation-shedding (OFGS) systems.

The UFLS algorithm is designed to be a load-shedding protection system secondary to the CLS controller. Because the UFLS requires the frequency to decrease, underfrequency triggers happen later than a CLS contingency trigger. The CLS scheme minimizes process, frequency, and power disturbances. UFLS events are therefore commonly associated with power swings and process disturbances.

The time difference between a power disparity event and the UFLS trigger is dominated by the physics of a power system. Net power system inertia and power deficits predicate the rate-of-change of frequency via (1).

$$2H\omega \bullet \frac{d\omega}{dt} = P_m - P_{elec} = P_{acc} \tag{1}$$

where:

ω is the generator speed (in per unit [pu] of the rated speed).

H is the inertia constant in MW/MVA.

P_m is the mechanical power output of a turbine (in pu).

P_{elec} is the electric power output of a generator (in pu).

P_{acc} is the acceleration power of the combined turbine and generator system.

In the event of a sudden loss of load, the CGTGs must reduce their output to prevent the frequency from rising unacceptably. Excessive system frequency causes protection equipment to trip off generators and other sensitive power apparatus. Once protection equipment starts to trip on frequency, power systems commonly deteriorate into a power outage (blackout).

Similar to UFLS, the OFGS algorithm is designed to be a generation-shedding and runback protection system secondary to the GSS and runback algorithm

VI. TRANSIENT-LEVEL SYSTEM MODEL FOR CLOSED LOOP SIMULATIONS

A simulation tool for system modeling allows engineers to model the dynamics of the power system with a time step sufficiently fast to test relay protection schemes, fast-acting control algorithms, and slow-acting control algorithms. The simulation tool derives dynamic power system information, such as current and voltage, by solving multiple simultaneous differential and algebraic equations. A completed simulation model incorporates real-time inputs and outputs with the control or protection system under test. For example, a load-shedding trip command should be able to go directly into the model running on the simulation hardware.

Testing requires an accurate, dynamic model of the power system under test, including both mechanical and electrical subsystems such as governors, turbines, exciters, motors, busbars, generator parameters, power system stabilizers, inertia of loads, nonlinear load mechanical characteristics, electrical component impedances, magnetic saturation of electrical components, transient and subtransient reactance, and more. This level of modeling provides an accurate depiction of frequency, voltage, current, turbine speed, generator rotor angle measurements, and governor response characteristics. Model development includes the collection of data required for modeling different power system components, such as generators, transformers, transmission lines, distribution lines, and loads. After model development is complete, validation ensures that the model is sufficiently accurate for live testing of the PMS. Details of how the models are built and the response characteristics of the power distribution system, governor, loads, and exciters are discussed in the remainder of this section.

A. Simulation Model

For the facility under discussion, the full power system model was used to successfully predict events that could cause voltage and frequency collapse. The model consisted of 18 synchronous generators, generator exciters and associated power system stabilizers, turbine governor controls, 50 sheddable synchronous and induction motor loads, 41 on-load tap changer controls, 5 high-voltage overhead transmission lines, 4 underground cables, and 33 nonsheddable loads represented as lumped induction motors.

This model, running on real-time simulation hardware, was connected in a closed loop with the PMS algorithms for testing and validation. The model communicates with the controllers via industry standard protocols, such as IEC 61850 GOOSE and DNP3. The model also has hard-wired connections to the PMS to send and receive analog signals.

Due to the real-time nature of the simulation hardware and communications involved, the control systems under test cannot tell whether they are connected to a simulator in the lab or to the actual electrical system in the field.

B. Validation and Full Model Tests

The first step before creating a full model is individual component validation. This involves individually validating components, such as generators, loads, transformers, and so on. Generator validation involves performing load rejection, load acceptance, and step tests on generator controllers. Transformer validation includes validating the on-load tap changer controls for step tests. Load validation includes synchronous motor power factor correction and voltage control tests.

Once the individual validations are complete, the full model is tested for load flow convergence, short-circuit comparison, and dynamic stability comparison. Typically, the comparison is done against any available field data or the user software model. Short-circuit comparison involves comparing fault currents for several single-phase and three-phase faults. Dynamic stability comparison involves comparing critical fault-clearing times, frequency excursion limits, and so on.

C. Closed Loop Simulations

For performing closed loop simulations, several Ethernet-based, hard-wired communications are set up between the simulation model (running on real-time hardware) and the PMS. This enables the testing of the PMS for round trip times, critical fault-clearing times, and so on.

Such closed loop testing also allows the user to perform point-to-point testing of several PMS input and output signals before the start of field commissioning.

After full model validation, closed loop simulations are primarily divided into two categories. The first category is functional testing of individual PMS functions (unit testing). Functions such as load shedding, generation shedding, autosynchronization, and so on are individually tested to validate their performance according to system requirements.

Once unit testing is successful, the functional testing proceeds to the integrated system phase. Integrated testing involves evaluating all PMS functions simultaneously for several system scenarios. During this testing, all of the functions are enabled, and the interactions between various functions are evaluated for system-wide performance. For example, integrated system testing shows how a CLS trips load to keep frequency within bounds after a generator trip, which is followed by the slow redispatch of governors by the AGC.

VII. CONCLUSIONS

The full suite of PMS functions is critical for the safe and reliable operation of the entire facility. Such PMSs play a critical role in ensuring process survivability when it comes to islanded power systems. Low-speed controls assist in everyday operations to preserve stability margins. High-speed controls, such as load-shedding systems and GSSs, operate during disturbances to preserve system stability.

Some of the key points to take away from this paper include the following:

1. The complexity of the power system required the AGC, VCS, and ICS to simultaneously control 16 different islands and 5 different tie lines or any combination of these.
2. The AGC and VCS control the swing bus to a constant frequency and the inter-tie lines to real power and power factor set points.
3. The ICS controls the modes (droop and ISO) of the governors and the modes of the exciters (volt/VAR), and selects the AGC and VCS dispatch algorithm modes.
4. A25A schemes are required at generators, tie lines, and bus couplers.
5. CLS algorithms shed load to maintain the power balance between the prime movers and the electric power system loads.
6. GSS algorithms shed generators to maintain the power balance between the prime movers and the electric power system loads.
7. Runback algorithms quickly redispatch turbine governors to prevent overfrequency events.
8. DRM values must be coordinated with overfrequency GSS tripping levels. Incremental reserve margin values must be coordinated with UFLS levels.
9. Common safeguards (such as modal detection, data filtering, data freeze, and state estimation) are used to prevent misoperation of the CLS, runback, and GSS algorithms.
10. The power system must be modeled with a time step sufficiently fast to test relay protection schemes and fast acting control algorithms.
11. The real-time simulation model and closed loop testing of the system allowed the plant operators and engineers to effectively test the PMS for various operating conditions.

As of the writing of this paper, the system is operating in Plant 2 and Plant 3, while systems for Plant 1, Plant 4, and Plant 5 are still being commissioned. Plant 2 and Plant 3 have had several power management system operations, and all of these operations resulted in correct decisions by the system to optimize plant processes and ensure load survivability. When fully commissioned, the system will be one of the largest microgrids ever built, with a state-of-the-art PMS monitoring and controlling the entire plant.

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