

POWERMAX[®] Solutions

Industrial Power Management Systems

Microgrid Control Systems

Remedial Action Schemes



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For more than 20 years, SEL POWERMAX Power Management and Control Systems have provided a reliable, resilient, and secure solution for maintaining uninterrupted energy delivery. POWERMAX is an all-inclusive ecosystem of SEL hardware and software working to stabilize, automate, and simplify the operation of any power system.

POWERMAX systems serve utilities; industries; municipalities; college campuses; and facilities, such as hospitals, data centers, and research labs—anywhere that requires a continuous and dependable power supply. Because every microgrid is unique, we design and customize each solution to match your specific application and economic goals.

This booklet provides an overview of the capabilities, features, and benefits of SEL POWERMAX solutions. Following introductory material about SEL and the core features common to all POWERMAX applications, three main sections describe POWERMAX as it applies to industrial power management, microgrid control systems, and remedial actions schemes. Each section outlines key benefits and includes a typical communications infrastructure diagram for a deeper look into the solution. You will also find more than two dozen detailed case studies of actual POWERMAX applications.

Through technical information and real-world examples, this booklet illustrates how POWERMAX solutions provide the grid stability and flexibility required to meet your system needs.

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About SEL

Who We Are

Schweitzer revolutionizes power industry protection.

Based on his research as a Washington State University graduate student, Dr. Edmund O. Schweitzer, III, invented the microprocessor-based digital protective relay and started Schweitzer Engineering Laboratories, Inc. (SEL) in 1982. Two years later, SEL sold the first microprocessor-based relay, which offered fault locating and other protective features for a fraction of the cost of systems based on traditional electromechanical relays. SEL now invents, designs, and manufactures digital products and systems that protect, automate, and control critical infrastructure around the world.

SEL offers global expertise at a local level.

Headquartered in Pullman, Washington, SEL is a 100 percent employee-owned company with over 8,500 employees. SEL serves customers worldwide, with products in over 170 countries. Our application engineers are based in over 100 locations throughout the United States and at strategic global field offices to provide expert support locally.

We put our values to work.

Quality, integrity, customer focus, community—our values drive everything we do. We design and build our high-quality products in the United States and back them with a ten-year warranty. As customers share their needs, we listen and exchange knowledge that allows us to create solutions purposely engineered to address their project goals, no matter the scale or scope.



What We Do

SEL has a comprehensive understanding of power systems.

SEL makes electric power safer, more reliable, and more economical. We manufacture high-quality and dependable products to address the needs of our customers. Our products provide the foundation of power management and control technologies that strengthen stability and reliability across industrial, microgrid, and transmission sectors. In the United States and around the world, SEL supports projects of every size—from replacing a single digital relay to commissioning a new substation.

We offer complete service.

SEL Engineering Services (ES) teams provide a broad range of expertise and support to customers in the utility, industrial, commercial, and government sectors.

SEL ES offerings include:

- **Microgrids and power management solutions**—microgrid control systems, industrial power management, remedial action schemes (RASs), and mobile microgrids.
- **Protection and control solutions**—SCADA and HMIs, distribution automation, and compliance services.
- **Transmission, distribution, and substation engineering**—development, modernization, and maintenance.
- **Project and program management**—comprehensive substation solutions, owner's engineering, planning, procurement, and risk management.
- **Cyber services**—system assessments for security vulnerabilities; cyber defenses; and compliance with NERC CIP and other regulatory requirements.
- **System modeling and studies**—offline power system modeling and studies, Real-Time Digital Simulator (RTDS) protection testing, and RTDS automation and control testing.
- **Panels and enclosures**—custom protection, automation, control, and metering panels, control cabinets, direct-replacement assemblies, and retrofit solutions.
- **Field services**—site investigation and surveying; demolition and site development; construction management; installation services; testing and commissioning; and life cycle support.
- **Government services**—digital products and systems that protect, automate, monitor, and control electric power systems in demanding environments.

SEL POWERMAX® Solutions

POWERMAX Offerings

The SEL POWERMAX Power Management and Control System is an integrated, vendor-agnostic control system that supports the resiliency and reliability of grid-connected and islanded power systems. POWERMAX is robust, fast, and scalable with applications that support microgrid control systems, industrial power management, and remedial action schemes (RASs).

SEL POWERMAX solutions help protect valuable fixed assets and increase safety for personnel. SEL has developed POWERMAX systems to meet the needs of utilities, industries, and commercial customers, including government entities, hospitals, educational campuses, mobile microgrids, disaster relief efforts, and forward military operating bases.

The POWERMAX solution includes:

- SEL hardware, including Real-Time Automation Controllers (RTACs), computing platforms, relays, Ethernet switches, and HMLs.
- SEL software, such as proprietary control algorithms, from our POWERMAX library.
- Other technologies, such as communications and precise timing devices.
- Modules that focus on visualization, protection, load management, generation control, point of common coupling (PCC) management, and cybersecurity.

Microgrid control systems, industrial power management, and RAS solutions include control logic that maximizes uptime for critical loads. Solutions provide seamless islanding from grid-connected mode and also provide the flexibility to prioritize loads and generation sources. These functions reduce operating expenses, increase stability, and keep industrial, microgrid, and transmission systems operational even under extreme conditions.

SEL Engineering Services (ES) power system engineers work closely with owners and integrators to design, engineer, and implement the best possible POWERMAX solution for specific operational requirements.



POWERMAX Hardware-in-the-Loop (HIL) Factory Acceptance Testing

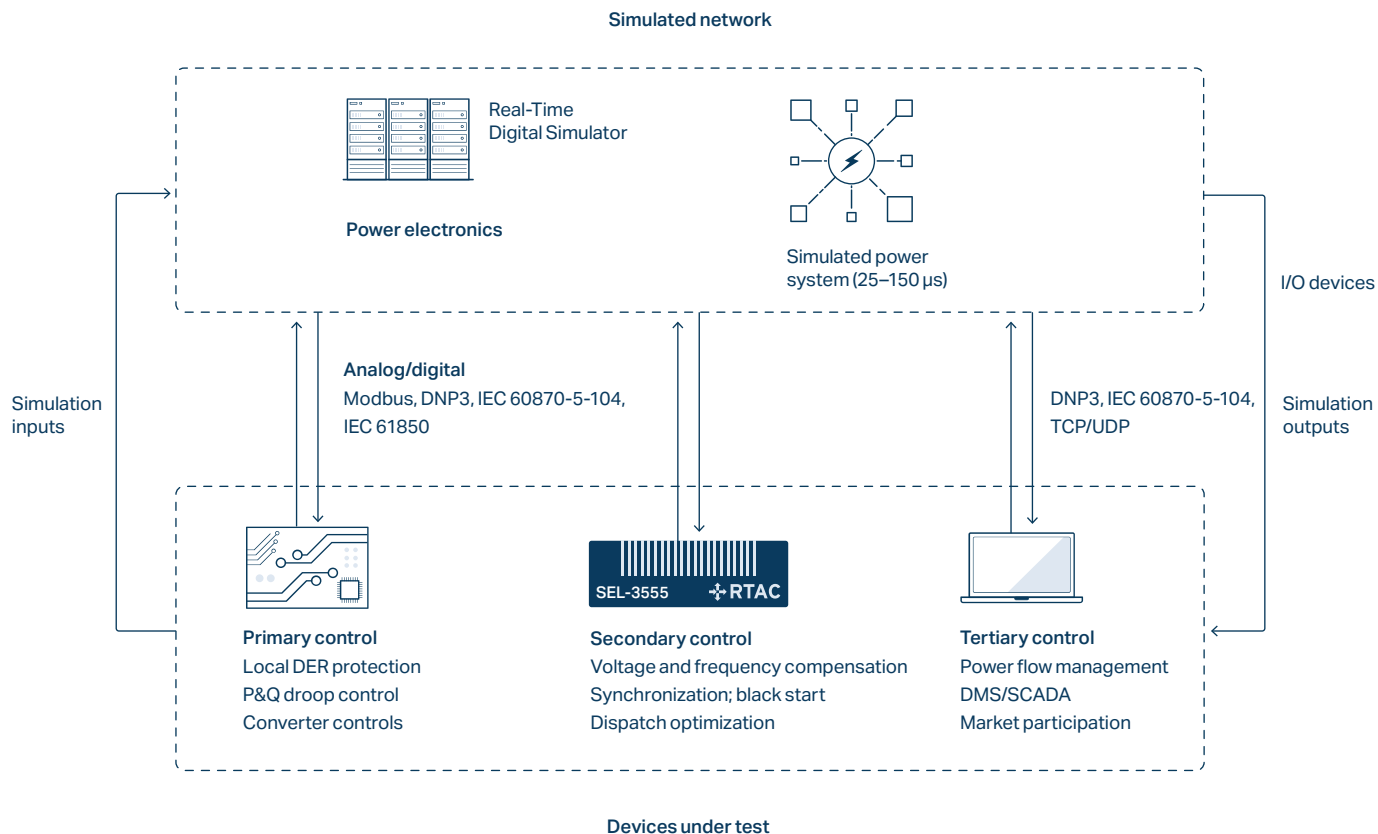
Our extensive factory acceptance test (FAT) procedures and comprehensive library of validated software models confirm that a POWERMAX system performs as designed before it is deployed in the field. During an FAT, we connect your POWERMAX solution, using HIL, to our Real-Time Digital Simulator (RTDS), which mimics the behavior of your power system. Using our extensive library of validated power system models, we systematically test the system against a multitude of fault conditions and operating scenarios. In only a few days, this process provides data equivalent to years of operational history.

SEL tests and validates the following:

- Microgrid control systems
- Industrial power management
- RASs
- Load-shedding and restoration schemes
- Generation-shedding and runback schemes
- Fast motor bus transfer schemes
- Autosynchronization schemes
- Phase-shifting transformer control systems

HIL testing that follows the IEEE 2030.8 standard demonstrates both the performance of the control scheme and its effect on the power system. HIL testing simulates scenarios that would be too risky or impossible to field-test. With this type of evaluation, there is no worry about damaging power system assets or affecting customers. The results provide the necessary proof and confidence that the solution will maintain system stability.





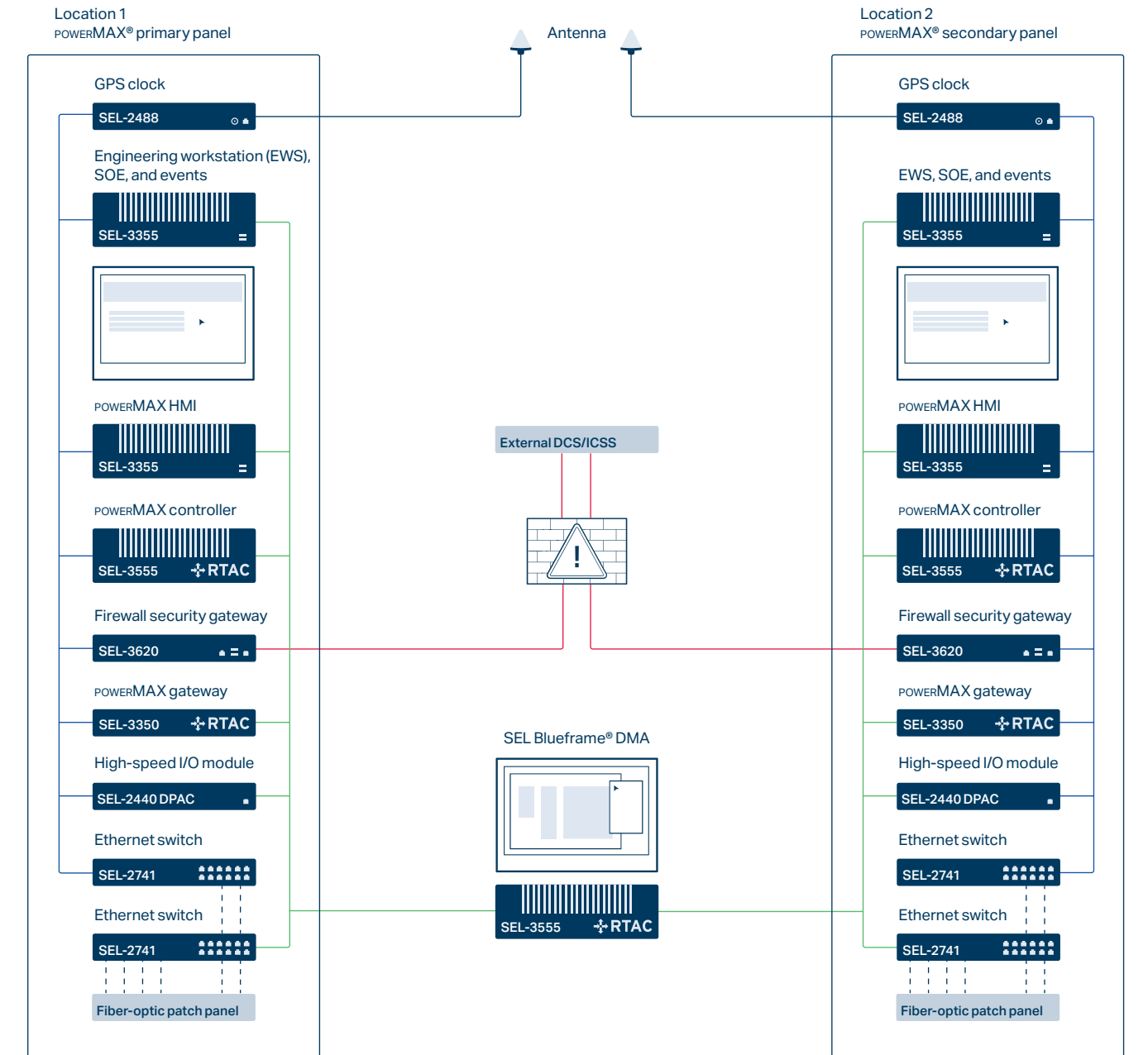
Test loop setup for RTDS-based HIL testing



POWERMAX Panels

- SEL protective relays monitor line conditions, protect against faults, and provide the data that POWERMAX uses to manage the system.
- HMI provides a visual interface to monitor the system status and control the equipment.
- The SEL-2488 Satellite-Synchronized Clock offers precise timing to coordinate all devices in the POWERMAX system.
- The SEL-3555 RTAC manages communications between devices and coordinates wide-area decisions.
- Software-defined networking (SDN) mitigates cybersecurity vulnerabilities.
- Redundant POWERMAX control panels can be located several miles apart from each other, provided they are on the same high-speed network.





POWERMAX Site Acceptance Testing

A site acceptance test (SAT) is the final validation step for a POWERMAX system test after successfully completing the FAT. During commissioning, SEL installs the POWERMAX system and verifies that it meets all project objectives and performs correctly in the real-world operating environment.

SEL works closely with all project stakeholders to develop comprehensive SAT and commissioning procedures. These procedures clearly define the scope of precommissioning and final commissioning activities and undergo extensive technical review prior to execution. Based on our Qualified Electrical Worker (QEW) program, SEL assigns appropriately qualified engineers to perform the required tasks safely and efficiently on site.

During precommissioning, SEL focuses on verifying system readiness and installation integrity before enabling closed-loop control and system

automation. Final commissioning activities validate overall system performance under real-world operating conditions.

Qualified SEL engineers and specialists offer the following services for the deployment of any POWERMAX system:

- Supervision of proper installation and powering of POWERMAX panels, I/O modules, networking devices, electronic devices, and related equipment
- Evaluation of existing firmware, settings, software, and basic functionality of POWERMAX devices prior to executing commissioning activities
- Updates to all devices within scope to implement the latest firmware, site-specific settings, and proper network, time synchronization, and monitoring configurations
- Precommissioning tasks, including point-to-point checks; signal and data verification from sensors and PT/CT inputs through POWERMAX controllers to the HMI; power cycling and redundancy validation; and verification of relay logic and protection settings
- Customer education on proper isolation and restoration plans prior to executing scenario-based and closed-loop tests
- Functional tests based on approved SAT procedures, such as islanding detection and decoupling schemes, load shedding and restoration, black start, automatic synchronization, open- and closed-loop generator testing and tuning, active and reactive power sharing between generation sources, power export and import control, and utility-tie management



SEL POWERMAX Life Cycle Support (LCS) Program

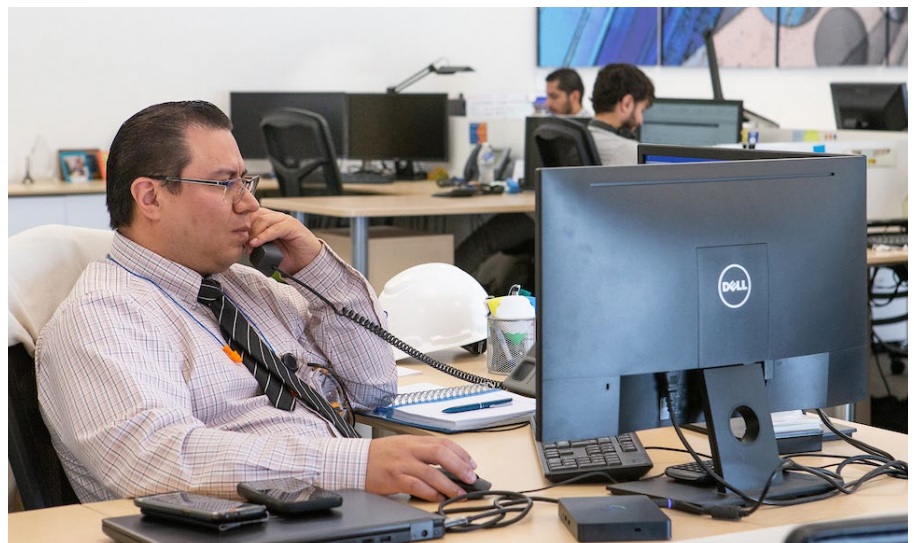
Protect against misoperations and promote the continued health of your power management system with SEL POWERMAX life cycle support. Our engineers partner with you to implement safeguards against potential blackouts, carry out proactive inspections, recommend measures for preventative maintenance, deliver actionable post-event analysis and reports, and provide comprehensive technical support.

Customer Benefits

- Access to expert power system engineers
- Guaranteed service response by a technical expert
- Customizable service plans that support business and operational requirements
- System awareness with periodic health reports and data analysis
- On-call event analysis and risk assessment
- Comprehensive technical review and compatibility testing prior to implementing system changes
- A simulator configured to mimic your POWERMAX application to enable root cause analysis and system diagnostics
- System upgrade recommendations
- System training for site personnel

Support Services Tailored to Your Needs

SEL understands that different factors drive each organization, such as risk profile, system location, environmental considerations, and safety margins. We offer customizable support plans, including a mix of remote, onsite, and office support to match your system and operational needs.

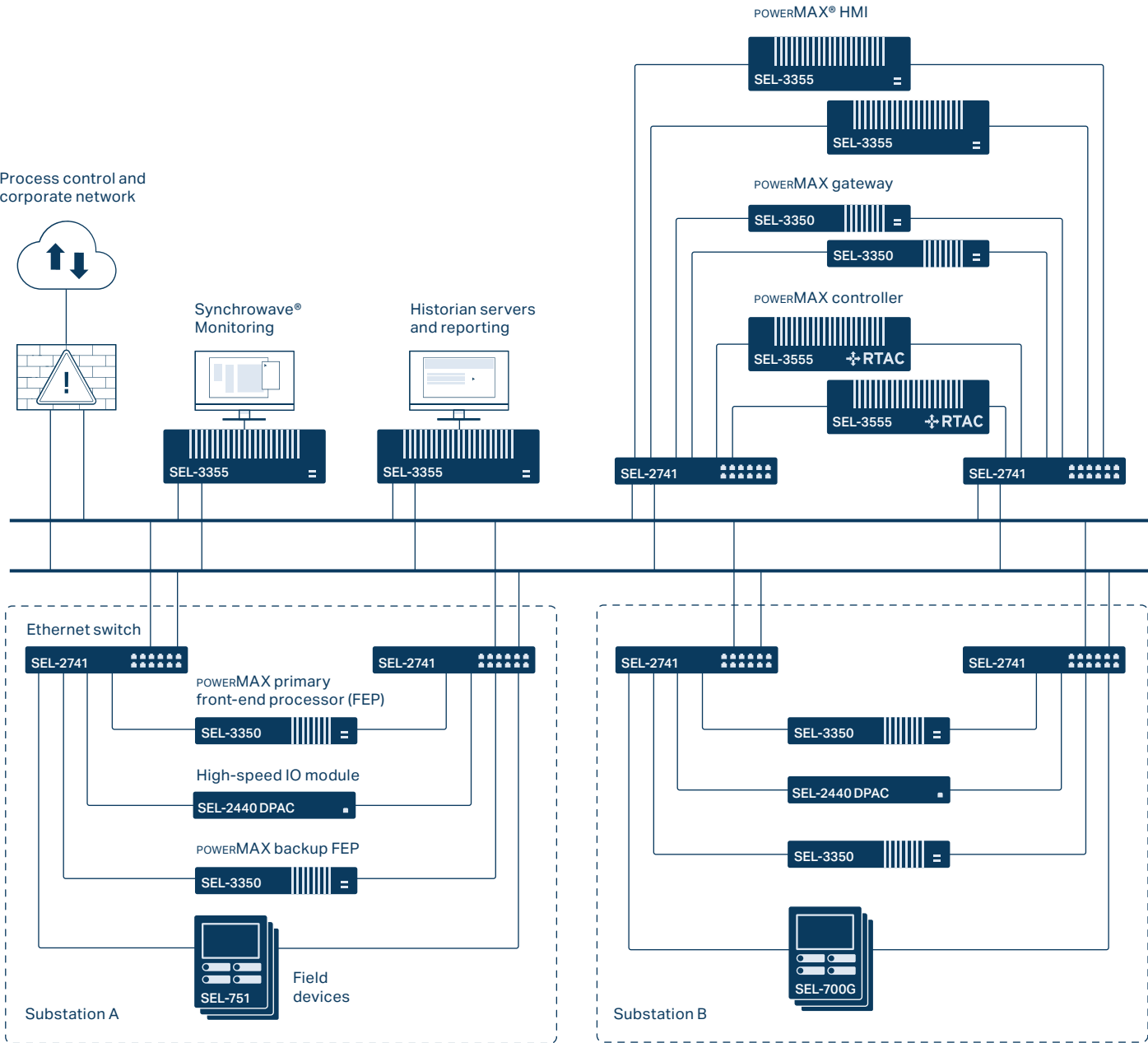


POWERMAX for Industrial Power Management

Work with SEL ES to deploy a POWERMAX power management and control solution that protects and stabilizes your industrial system. POWERMAX solutions seamlessly integrate with motor protection and management systems to protect your entire facility, from bulk power systems to end devices.

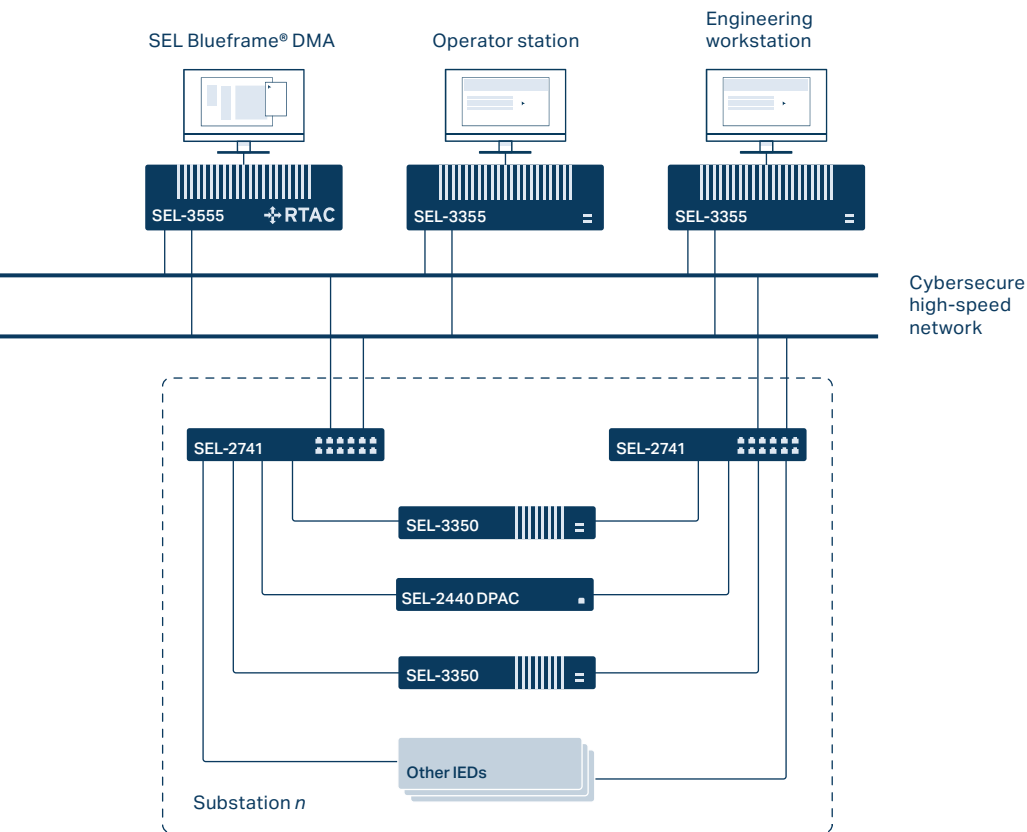
Other POWERMAX benefits for industry include:

- Reducing the risk of widespread blackouts and keeping your critical processes running with advanced high-speed protection and control technology.
- Achieving total system awareness with time-synchronized condition-monitoring systems that track equipment status, electrical metering, cyber attacks, and network traffic.
- Improving human safety and reducing equipment damage by using adaptive protection, advanced protection systems, and arc-flash mitigation.



Before deploying POWERMAX for industrial power management solutions, SEL offers various studies and system tests according to your specific project needs, including the following.

- System studies:
 - Under- and over-frequency coordination studies
 - Increment reserve margin calculations
 - Voltage stability studies
 - Motor starting studies
 - Transformer inrush analysis
 - Transient stability studies
- High-speed islanding detection and decoupling schemes testing
- Automatic island synchronization system (25A) testing
- Black starting and load restoration system testing
- Load-shedding and generation-shedding testing:
 - High-speed, contingency-based load shedding and generation shedding
 - Underfrequency-based load shedding and overfrequency-based generation shedding
 - Asset overload (progressive) load shedding
 - High-speed generator runback
 - Reactive power-based load shedding
- Generation control system (GCS) testing:
 - Frequency and voltage regulation in island mode
 - Active and reactive power sharing in grid connected mode
 - Power factor control across utility tie
 - Power export/import control across utility tie
 - Island control system
 - Generator start and stop management
 - Dynamic capability curve tracking
- Power system simulations:
 - Static simulation
 - Nontransient dynamic simulation
 - Transient simulation





POWERMAX® for Industrial Power Management

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CASE STUDY: INTEGRATING THE POWER MANAGEMENT SYSTEM OF AN EXISTING OIL PRODUCTION FIELD

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Kei Hao
Member, IEEE
Schweitzer Engineering
Laboratories, Inc.
2350 NE Hopkins Court
Pullman, WA 99163, USA

Abdel Rahman Khatib
Senior Member, IEEE
Schweitzer Engineering
Laboratories, Inc.
2350 NE Hopkins Court
Pullman, WA 99163, USA

Nevil Herbert
Member, IEEE
Chevron
6001 Bollinger Canyon,
San Ramon, CA 94583, USA

Niraj Shah
Schweitzer Engineering
Laboratories, Inc.
2350 NE Hopkins Court
Pullman, WA 99163, USA

Abstract—The power management system at a brownfield oil production facility must minimize production interruption while ensuring power system reliability, stability, and scalability. This paper describes the implementation of a power management system for a mature oil field. The new system optimizes the use of sources that allow the facility to separate from the utility during system events and reconnect back to the utility when the power system is stable. To counteract an unbalance between the power supply and demand, the system includes three independent, redundant load-shedding schemes. Additionally, an added generation control system allows control of frequency, voltage, power, and power factor through the utility tie line. The system includes automatic synchronization schemes and islanding controls that allow the generators to operate in the optimized mode. To validate the system, the load-shedding and generation control functionalities were tested using a real-time, closed-loop environment. Additionally, the paper describes the networking and its redundancy strategies for the system and the integration of the supervisory control and data acquisition and human-machine interface system in the facility. The implemented system manages and operates the power management system and offers synchrophasor data collection that allows archiving and analysis of higher-resolution data.

Index Terms—Power management, load shedding, generation control, automatic synchronization, tie flow control, frequency and voltage stability, islanding control.

I. INTRODUCTION

Adding a power management system (PMS) and integrating it with a brownfield oil production facility faces some unique challenges and requirements. A key requirement is to design a PMS that minimizes production interruption by providing a continuous power supply and increased reliability for the brownfield electric power system. The oil field facility described in this paper uses both the utility source and its own generation to feed its loads. The goal is to design a PMS that optimizes the correct source(s) in events when only the utility is available, when both the utility and local generation are available, or when only the local generation is available. The PMS has to manage the field to operate in these three modes of operation seamlessly. The PMS includes control

functionality that allows the field to separate from the utility, operating in islanded mode when the utility suffers temporary major disturbances or outages. The PMS supports automatic synchronization mechanisms that allow the field to reconnect back to the utility. To counteract a power deficit or an unbalance between the power supply and demand of the field, the PMS includes three independent redundant load-shedding schemes. The generation control system (GCS) not only has full control of the generators but also the system frequency, voltages, and tie line control for the export and import of power. The tie line control allows users to control the amount of import and export at any given time, giving the facility operators an option to decide between onsite generation and purchasing power from the utility.

To further increase the reliability of the power system, a redundant communications network is implemented to support the load shedding schemes and full system-wide generation control. The integration of the supervisory control and data acquisition (SCADA) and human-machine interface (HMI) provides complete visualization and control of the facility. Finally, a synchrophasor system is included to provide higher-resolution data, monitor the dynamics of the power system in real-time, and archive data for post-event analysis.

II. OIL FIELD ELECTRIC POWER SYSTEM

Fig. 1 shows a simplified one-line diagram of the brownfield facility power system. The field receives power from one 115 kV overhead utility tie line and generates power from its two onsite cogeneration plants (cogens). The total power consumption of the field is about 40 MW. Cogen B has two generators, and Cogen E has one generator. All three generators have the same rating. The utility tie line enters the field, splits into two 115 kV branches, and forms a loop connecting substations and cogens. The top branch feeds Substation F and the bottom branch feeds Substation A. During normal operation, the two 115 kV branches feed the entire oil field with the Tie Breaker CB17 normally open. Tie Breaker CB23 also remains normally open in normal operation. A single branch is capable of powering the 115 kV loop with either CB1 or CB40 closed and CB17 closed. The 115 kV loop is stepped down to 12 kV at the substations and then distributed to the entire field. The 12 kV distribution lines and other low-voltage lines are not part of this project.



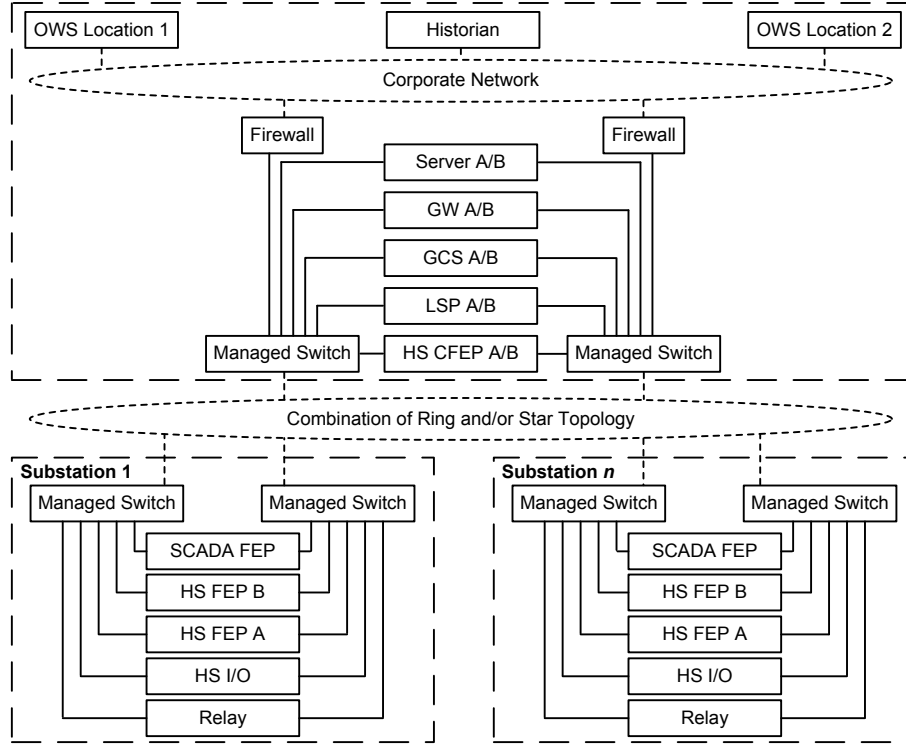


Fig. 2 Communications Architecture of the Oil Field

In summary, the implemented CLSP has the following characteristics:

1. Dynamically calculates the quantity of load to shed for each predefined primary contingency before the occurrence of an event.
2. Dynamically selects individual loads to shed based on settable priorities, measured power consumption, and the present topology of the power distribution system (each load has its own unique priority).
3. Responds to a contingency trigger in less than 40 milliseconds, excluding circuit breaker opening time.

B. Underfrequency LSP

The underfrequency LSP (UFLSP) serves as a backup for the contingency-based system in the scenario that a loss of generation or sudden addition of load occurs without sending the contingency-based system a trigger input. The underfrequency load-shedding system can handle two islands simultaneously and can select varying amounts of load to shed for different-sized islands. This scheme sheds load based on two underfrequency thresholds. It dynamically selects from a list of action tables, similar to the contingency CLSP, that are necessary to shed and equalizes the generation to load. These load-shedding decisions are independent from the contingency-based load-shedding system.

The underfrequency levels are detected by the relays located at Cogens B and E. Power system simulations are

used to fine-tune the underfrequency pickup and time-delay settings.

C. Progressive Overload Shedding

The progressive overload shedding is treated as a contingency within the system, similar to a contingency breaker being tripped. However, instead of monitoring the breaker state, this contingency is executed when the integrator value exceeds a user-settable value. This scheme is active when either the facility is islanded or tie flow control is enabled. The integration starts when the power produced by a generator is above a user-settable percentage of the individual generator capacity, thereby referred to as “excess load threshold.” It integrates proportionally to the difference between this user-settable threshold (percent of rated capacity) through the HMI and the present output of the unit. The integrator uses the same proportionality to integrate backwards so that a brief power output lower than the user-defined set point will not cause the integrator to reset immediately. The amount of field load to shed is the overload amount plus a simple set point that the user sets to trip off enough loads to return the generation to well below the integration threshold and begin the integrator counting down. Fig. 3 depicts the logic used within the controller.

The user-settable integrator pickup (in percent of actual MW capacity) and the user-settable threshold (in power [pu] • seconds) are determined from a thermal-loading model of the generators. These parameters must ensure that the system sheds load before the thermal limits of the governor cause the turbine to throttle back and suddenly drop load.

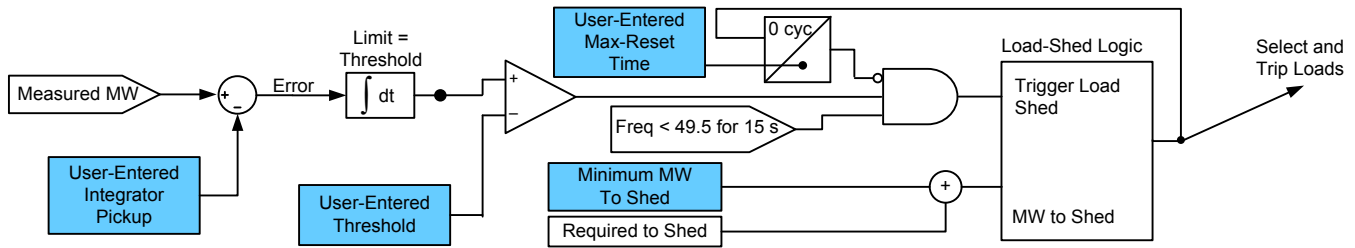


Fig. 3 Progressive Overload-Shedding Logic

D. Automatic Transfer Scheme

In Substation C, the power system has an ATS in place for both 115 kV and 12 kV lines. Substation C's loads are split between the two branches of 115 kV. The goal of the ATS is to automatically transfer the loads from one branch to another when one branch experiences a power outage or has a fault and one of the 115 kV breakers opens. Because the ATS is independent of the PMS implementation, its operations create racing conditions between them. The ATS uses a bus differential protection relay with multiple independent check zones and the breaker relays. The bus differential protection relay senses the voltages and currents of the buses and receives analog and discrete data from the breaker relays. The relay uses this information to perform the automatic transfer in high speed so that the transferred loads do not experience any interruption. The principle logic of the ATS is summarized in Table I.

TABLE I
ATS LOGIC FOR 115 KV AND 12 KV LINES

Case	Initial Conditions	Trigger	Transfer Action
1	CB18 close; CB16 close; CB17 open	CB18 or CB16 opens	ATS senses dead bus on B1 or B2, live voltages on B2 or B1, and no pending trips; ATS closes CB17
2	CB18 open; CB16 close; CB17 close	CB16 opens	ATS senses dead buses on B1 and B2, live voltages on B3, and no pending trips; ATS closes CB18
3	CB18 close; CB16 open; CB17 close	CB18 opens	ATS senses dead buses on B1 and B2, live voltages on B4, and no pending trips; ATS closes CB16
4	CB19 and CB20 close; CB21 and CB22 close; CB17 and CB23 open; CB16 and CB18 close	CB19 or CB20 or CB21 or CB22 opens	ATS senses 12 kV dead bus and no pending trips; ATS closes CB23

The following two approaches were considered to resolve the racing conditions:

1. Modify the ATS and PMS logic so that both can coordinate their operations to avoid racing conditions.
2. Block some PMS operations under certain conditions, giving the ATS the precedence to operate.

In the end, Approach 2 was selected. After analyzing all the racing conditions between the ATS and PMS in all possible scenarios, a complete blocking logic was implemented in the PMS. Basically, when a contingency arises and creates a racing condition, the PMS blocks load-shedding schemes from triggering and lets the ATS do the transfer. If it is a contingency and does not create a racing condition, the PMS handles the contingency.

V. GENERATION CONTROL, TIE FLOW CONTROL, AND AUTOSYNCHRONIZATION

A. Generation Control System

The functionality of the GCS includes an automatic generation control (AGC) system, voltage control system (VCS), and island control system (ICS) software functions. The system uses the controllers to gather data from the relays installed throughout the oil field.

The GCS supervises all data signals with communications quality indicators. Because of this, the controller is robust and will not act inappropriately during communications outages or faults.

The solution properly controls generation in response to all contingencies (such as a loss of generator, or bus-tie breaker) with its adaptive algorithm [2].

The following are three functions of the GCS:

1. The AGC system controls the active power set point of the turbine governors to keep units at an equal percentage of load, simultaneously maintaining long-term bus frequency at nominal. It is also integrated into an automatic synchronization (25A) system.
2. The VCS controls the terminal voltage set point and/or MVAR output of the generator as necessary to control system voltage. It is also integrated into the 25A system.
3. The ICS tracks the generator connections and creates the individual AGC and VCS controls for each island formed.

The implemented functionality of the control systems are as follows:

1. AGC functions share the power contribution from all generators.
2. AGC functions continuously regulate the busbar frequency to 60 Hz in case the system is islanded and no isochronous (ISO) unit is in the system.
3. VCS functions manage the reactive load sharing between generators.

4. VCS functions continuously regulate the 115 kV busbar voltage in case the system is islanded.
5. GCS detects islands automatically.
6. GCS participates in automatic synchronization.
7. GCS switches the generators' modes to the proper modes of operation.

B. Modes of Operation

In normal operations, all three generators are running close to their rated capacity. Excess power is exported to the utility. With CB17 normally open, the top branch has fewer loads than the bottom branch; therefore, the top branch exports about 40 percent of its generation and the bottom branch exports about 20 percent.

1) Old Modes of Operation

In normal operations, all three generators are running in droop mode with a unity power factor (PF). The Cogen E generator runs in MW control mode while Cogen B generators run in temperature control mode. The temperature control mode limits the generators' output to the maximum allowable temperature set point. If the generators reach the temperature

set point before reaching the output power set point, the generators stop raising their output power.

When the field is islanded, the two generators in Cogen B run in ISO sharing operation mode and are controlled by a load sharing control system balancing the load equally between the generators. The generator in Cogen E also runs in ISO mode independently from Cogen B because the two cogens are on two different islands. Table II summarizes the old modes of operation.

2) New Implemented Modes of Operation

As part of the new operation requirements, the new GCS must be integrated with the old generation control and the existing load sharing control systems. Each cogen has a remote/local switch. The switch determines whether old modes of operation or the GCS controls the generators. The old synchronization system remains responsible for synchronizing the generators to the 12 kV bus in the cogens. The new control system is responsible for synchronizing three breakers on the 115 kV line. The two control systems monitor the states of the generators and exchange information to avoid a bump transfer when switching controls between them. Table III summarizes the new modes of operation.

TABLE II
OLD MODES OF OPERATION

	Utility Connected; CB1 and CB40 Closed	Utility Connected; CB1 or CB40 Open; CB17 Closed	No Utility; CB1 and CB40 Open; CB17 Open (2 Islands)	No Utility; CB1 and CB40 Open; CB17 Closed (1 Island)
Cogen E G3	Droop; MW → MW control; MVAR → PF control	Droop; MW → MW control; MVAR → PF control	ISO; MW → Frequency control; MVAR → Voltage control	Droop; MW → MW control; MVAR → Voltage control
Cogen B G1 and G2	Droop; MW → Temperature control; MVAR → PF control	Droop; MW → Temperature control; MVAR → PF control	ISO; MW → MW load sharing; MVAR → Voltage control and MVAR sharing; AVR allows change to voltage set point	ISO; MW → MW load sharing; MVAR → Voltage control and MVAR sharing; AVR allows change to voltage set point

TABLE III
NEW MODES OF OPERATION

	Utility Connected; CB1 and CB40 Closed	Utility Connected; CB1 or CB40 Open; CB17 Closed	No Utility; CB1 and CB40 Open; CB17 Open (2 Islands)	No Utility; CB1 and CB40 Open; CB17 Closed (1 Island)
Cogen E G3	Droop; MW → Maintained or regulation; MVAR → PF control; GCS → Voltage control (of PF tie control is enabled)	Droop; MW → Maintained or regulation; MVAR → PF control; GCS → Voltage control (of PF tie control is enabled)	ISO; MW → Frequency control; GCS → Voltage set point	Droop; MW → Maintained or regulation and MW sharing; GCS → Voltage set point
Cogen B G1 and G2	Droop; MW → Maintained (temperature control) or regulation; MVAR → PF control; GCS → Voltage control (of PF tie control is enabled)	Droop; MW → Maintained (temperature control) or regulation; MVAR → PF control; GCS → Voltage control (of PF tie control is enabled)	ISO; MW → MW sharing; GCS sets frequency set point; MVAR → Voltage control and MVAR sharing; GCS sets voltage set point	ISO; MW → MW sharing; GCS sets frequency set point; GCS sets voltage set point and MVAR sharing

a) Two separate islands connected to the utility – normal operations

In normal operation, CB17 is normally open and all generators are running in droop mode with a PF set point enabled. The PF set point can be adjusted based on operation needs. The two generators in Cogen B can be running in maintained mode with temperature control or in regulation mode. In either mode, once a generator's temperature reaches the maximum limit, the GCS will stop raising the generator's output. In maintained mode, the GCS sends raise or lower pulses to the generator controller to maintain a user-set MW set point. The generators do not participate in load sharing, automatic synchronization, or utility tie line power control. In regulation mode, the GCS increases or decreases the outputs of the generators to maintain the amount of import or export within the upper and lower regulation limits.

The generator in Cogen E can run in either maintain or regulation mode, as described previously.

b) One island connected to the utility

When either CB1 or CB40 is open and another one is closed, the utility is available, and the requirement is to close CB17 so that the oil field electric system is connected to the utility. Under this requirement, the following cases are implemented.

If CB40 opens, the top branch forms an island, and the Cogen E generator switches from droop to ISO. The GCS raises or lowers the generator voltage and frequency to synchronize with the utility and closes CB17. As soon as CB17 is closed, the generator switches from ISO to droop (connected to the utility). The generator can run in either maintain or regulation mode to control the tie flow control across CB1.

If CB1 opens, the bottom branch forms an island. Both generators switch from droop to ISO and the load sharing controller is in charge of the sharing. The GCS raises or lowers the generators' voltage and frequency to synchronize the breaker with the utility and closes CB17. As soon as CB17 is closed, both generators switch from ISO to droop.

If CB9 opens and CB1 is closed, Substation A is not affected and Cogen B and Substation C form an island. The operations of the generators are the same, as explained previously.

c) Islanded operations

When the oil field is initially islanded, CB1, CB40, and CB17 are open; the two generators in Cogen B run in ISO mode and are controlled by the load sharing controller. The generator in Cogen E also runs in ISO mode independently from Cogen B's generators. The goal is to form one single island by closing CB17.

If the user decides to keep CB17 open when the electric power system is islanded, then all three generators run in ISO mode. In Cogen B, the load sharing controller is in control and responsible for real and reactive load sharing. The GCS does not control the real and reactive power output. The GCS is able to control the frequency and voltage set points of the two generators. The GCS can be responsible for MVAR sharing

by disabling the load sharing controller's MVAR sharing. In this case, the GCS is responsible for the MVAR sharing and voltage set point while the load sharing controller is responsible for MW sharing. When Cogen E is running islanded, MVAR maintain mode should not be used to keep the voltage stability. In Cogen E, the generator is running in ISO mode, and the GCS is responsible for controlling the voltage and ensuring that the voltage is within the limits.

As soon as CB17 is closed, the two generators in Cogen B remain in ISO, and the generator in Cogen E switches from ISO to droop. The GCS is responsible for MW and MVAR sharing for the entire system. Because the load sharing controller is responsible for the MW sharing of Cogen B's generators, the GCS raises or lowers the MW of the generator of Cogen E (if it is in regulation mode) so that the generator is responsible for one-third of the total MW load. If the Cogen E generator is in maintained mode, the GCS will not do any MW sharing and will maintain the set point of Cogen E. Similarly, for the MVAR sharing, the GCS raises or lowers the MVAR of the generator in Cogen E (if it is in regulation mode). If for some reason the MVAR sharing between the GCS and load sharing controller cannot be achieved, then the GCS disables the load sharing controller MVAR sharing scheme and is responsible for the MVAR of the three generators.

C. Autosynchronization System

The oil field electric power system has three locations where synchronization mechanisms are required. The two interconnections with the utility in Substations A and F require synchronization when either one has disconnected from the grid. The third location is the normally open circuit breaker CB17. Once a breaker is selected from the HMI, the synchronization process is automatic. CB17 has two additional modes of operation: manual and automatic. In manual mode, an operator first selects the breaker, and then the synchronization process starts automatically, similar to the other two breakers. In automatic mode, the synchronization process does not require operator intervention. This mode of operation only applies when the oil field power system is islanded from the utility. As soon as the field is islanded, the synchronization process initiates automatically and a five-minute timer starts. If the synchronization process fails after the timer expiration, the PMS generates an alarm.

Once a breaker is selected or initiated automatically (CB17 only), the PMS sends a close permissive to the selected breaker relay and starts sending speed and voltage raise or lower commands to the generators. The generators start adjusting the voltages and frequencies of the oil field power system and try to synchronize with the utility or between the two islands when the field is islanded. The breaker relays are programmed to continuously compare the voltages and frequencies on both sides of the breaker. The relay then automatically closes the selected breaker if it detects that the voltages, slips, and angles meet the following criteria [4]:

1. Slip frequency is less than 0.1 Hz.
2. Voltage difference is less than 0.1 pu (103.5 V and 126.5 V with reference to $V_{Snom} = 115.23$ V).
3. Angle difference is ± 10 degrees.

In each location, a local/remote switch is installed. The switch status enables or disables the HMI's synchronization functionality.

D. Tie Flow Control

The tie flow control allows the field to import and export real and reactive power through the two tie line connections, CB1 and CB40. Tie flow control allows the operator to determine the most economical dispatch according to the utility price for MWs. If the utility price per MW is higher than the local MW generating price, then it is economical to reduce importation and use more local generation. On the other hand, if the price from the utility is low, reducing the local generation is an option. In this oil field project, several different zones are assigned per day, depending on the MW price and the day of the year, and the PMS tie flow control adjusts the flow accordingly.

In the oil field, the two tie lines can be controlled for active and reactive power flows. To enable the tie flow MW, the generators in each branch should be running in regulation mode, which enables control of the MW flow from the utility. When the generators are connected to the utility and tie flow MW control is disabled from the HMI, the AGC will only do MW percent load sharing between the generators; frequency is controlled by the utility. When tie flow MW control is enabled from the HMI, the AGC maintains the tie flow MW according to a scheduler based on user-entered parameters.

The AGC simultaneously ensures percent MW load sharing among the utility-connected generators. If all generators reach their capacity while maintaining the set point, then the tie flow MW set point may not be achieved and a generator maximum capacity alarm is triggered. If both tie lines are connected in parallel and set points are different for the two tie lines, then the average of the set points is maintained across each tie line. If the tie lines are not in parallel, then an individual tie line set point is maintained.

VI. SCADA, HMI, AND SYNCHROPHASOR SYSTEM

A. SCADA and HMI

PMSs cannot be completed unless operators can visualize, and are able to take corrective actions based on, real-time data. This important feature is accomplished with help from a dedicated SCADA data communications channel using a SCADA FEP and I/O servers. Wherever possible, DNP3 IP with a time stamp from the original IED is used. IEDs that do not support DNP3 IP are integrated using Modbus TCP. Very careful coordination and communications design are implemented for all protective IEDs already in operation. Refer to Fig. 2 under Section II, which demonstrates dedicated SCADA FEP and I/O servers.

The SCADA system for this application is not just for traditional visualization and alarming but also designed with the following major subcomponents to help oil field electrical engineers and operators identify the root cause of any major electrical event and/or take quick action to fix problems related to the system. Table IV summarizes the SCADA and HMI features.

B. Synchrophasor System and Data

The synchrophasor system provides real-time phasor measurements of the electrical quantities of the field electric power system. The system allows users to monitor and archive system dynamics in real-time and perform post-event analysis with finer time resolution compared with the SCADA system. The synchrophasor messages can be as fast as 60 messages per second. At this speed, the synchrophasor system is capable of performing controls to preserve the stability of the system. The synchrophasor system consists of time sources; phasor measurement units (PMUs); phasor data concentrators (PDCs); a synchrophasor processor/controller; and visualization, archiving, and analysis software.

TABLE IV
SCADA AND HMI FEATURE DESCRIPTIONS

SCADA System Feature	Description
Real-time data monitoring	Helps operator understand the real-time status of entire system at a glance. It also displays protective relay front-panel LEDs and harmonic data without going to a remote substation.
Alarming and trending	Clearly categorize critical-, high-, medium-, and low-priority alarms. It also records all operator-initiated events and long-term trending using a dedicated historian.
SOE reporting	Displays and filters SOE from various protective relays under a common time reference to determine root cause of any major event. This includes SOE logs from the load-shedding system as well.
Oscillography of events	Centralized oscillography event monitoring, including phasor diagrams, is a very important feature that helps electrical engineers make crucial decisions.
Synchrophasor data	Displays real-time phasor measurements, historical data, status, and alarms and allows users to compare measurements. Provides a map that indicates the phases of the phasors at different locations.
Billing data analysis and GCS scheduler	Analyzing 24- and 48-hour monthly sales and purchase data versus active power generated helps operators adjust export/import set points across the utility tie.
Communications network monitoring	At-a-glance monitoring of the entire system's Ethernet network using Simple Network Management Protocol (SNMP) helps plant operators quickly address any issue to reduce downtime if a failure happens.

1) Time Sources

The time sources include Global Positioning System (GPS) satellite-synchronized clocks and network time servers. The GPS clocks usually provide IRIG-B outputs or network-based time protocols, such as Precision Time Protocol (PTP) (IEEE Standard 1588). A unique feature of the synchrophasor system is that all components must be connected to a time source to provide synchronized data measurements.

2) Phasor Measurement Units

The PMUs are devices that use external power system instruments, such as current transformers (CTs) and potential transformers (PTs), to measure three-phase electrical quantities. The sampled data, also known as synchrophasor data, are measured quantities with an associated precise time stamp. Once the PMUs acquire synchronized data, the PMUs send the data to other components of the system for further processing. Some protective relay manufacturers include built-in PMU functionality as a standard feature in their relays. Activating the PMU functionality in these relays minimizes the need for additional instruments and wiring.

3) Phasor Data Concentrators

The PDCs usually collect synchronized data from PMUs, other PDCs, or controllers; time-align them; and then process them as a coherent data set. The PDCs serve as an aggregation point for the PMUs and provide synchronized data to other components of the system. The PDCs can be a piece of hardware or software.

4) Monitoring, Archiving, and Analysis Software

The software consists of three main components: a graphical user interface (GUI), a configuration interface, and a database. The software uses the data coming from PDCs to display real-time measured quantities; archive these quantities in the database; or process them and generate statuses, events, and alarms. The interface displays various graphics that include real-time and historical data, statuses, events, alarms, and a phasor scope. The interface additionally includes a map display that shows the wide-area view of the system. The map displays synchrophasor quantities based on their geographic locations and displays phasor shifts among the locations.

5) Synchrophasor Processor and Controller

The processor allows users to program custom logic and algorithms for wide-area and control applications or determine events and system dynamic conditions. The processor communicates directly with PMUs or PDCs, or a combination of both, for incoming data. The processor aligns the collected synchrophasor data, processes the data with its internal logic engine according to the custom logics and algorithms, and sends control commands to external devices to perform user-defined actions. Moreover, it can generate events or conditions that can be sent to the analysis software.

6) Synchrophasor System Implementation in the Field

A total of seven PMUs are strategically located in the 115 kV loop. Two are located in the intertie with the utility, one is located in Substation A, and the other one is located in

Substation F. They allow the synchrophasor system to monitor grid conditions and the interconnection conditions between the oil field electric power system and the utility grid. Three PMUs are located in the cogen sites, one on each generator. These PMUs allow the system to monitor generator dynamics and interconnection dynamics between the generators and 115 kV line. The other two PMUs are located on both sides of circuit breaker CB17. Because this circuit breaker separates the 115 kV loop into two pieces, it is important for the synchrophasor system to monitor the dynamic behaviors of the oil field electric system when the field forms two islands.

In the first phase of the project, the synchrophasor controller is disabled. The users want to monitor and archive the system dynamic behaviors for two years to analyze and separate critical from noncritical events. Once the critical events are identified, the synchrophasor controller can be programmed and optimized to perform controls to preserve the stability and reliability of the electric power system.

VII. CLOSED-LOOP SIMULATIONS

Hardware in the loop (HIL) is a perfect tool for thorough design, study, and testing of PMS schemes. For this oil field project, a simplified power system model was created and interfaced with the PMS. The closed-loop interacts with different components of the PMS. HIL testing of the PMS was performed to validate the CLSP, GCS, and UFLSP functionality. The HIL was connected to the PMS control system to allow for closed-loop validation of the PMS and to achieve the following:

1. Test all possible contingencies that are hard to test in the brownfield facility.
2. Test all the I/O points between the PMS and FEP.
3. Verify that all the generators' modes of operation perform as designed.
4. Verify autosynchronization functionalities for different generator modes.
5. Run the system for different topology and different operating scenarios.
6. Prove that the PMS control works for all pre-identified scenarios.

VIII. CONCLUSIONS

The implementation and integration of the PMS is critical to minimize production interruption of the brownfield facility and provide increased reliability of the oil field's electric power system. Triple independent load-shedding schemes provide for the survivability of the oil field, avoiding outages during an unbalance of supply and demand.

This brownfield facility required a series of customizations of the PMS implementation. Simulations have shown that the blocking scheme implemented in the PMS to integrate with ATS works quite well, resolving the racing conditions. The GCS was customized to work with the existing generator controllers and load sharing controller. The integration of the control systems allows the field to operate with either the GCS or old control system and switch between them seamlessly, giving the field a dual redundant control system. The GCS

allows the field to operate using either a utility-only source, a utility source and its own generation, or generation only when islanded, which is important to provide a continuous power supply. The modes of operation of the generators, either droop or ISO, are implemented to meet the load characteristics of the oil field when the field is connected to the utility or islanded. The autosynchronization system was also adjusted in order to be integrated with existing equipment and has proved to work quite well. Tie flow control gives the field total control of the export and import of power at any given time.

Due to user requirements, the redundancy of critical devices in the communications network was essential for the reliable operation of the PMS. The integration of the SCADA and HMI was crucial to have complete monitoring and control of the brownfield electric system. Although SCADA is widely used in the oil field to monitor and control oil production and power systems, synchrophasors provide an additional tool that allow users to monitor and analyze system dynamics that would not be possible using SCADA alone.

The real-time simulations are essential to test PMS before commissioning because it is not possible to perform some tests in a production brownfield facility. The closed-loop simulation provides firsthand proof of the working PMS.

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X. VITAE

Kei Hao, P.E. (M 2011), received his Ph.D. in electrical engineering from the University of Wisconsin–Madison, his M.S.E.E. from the University of Wisconsin–Milwaukee, and his B.S.E.E. from La Universidad de la Republica, Uruguay. He joined Schweitzer Engineering Laboratories, Inc. in 2010 as an automation and protection engineer. He is presently a lead product engineer in research and development. He has

experience in control and automation systems, wireless communications systems, and power system automation and protection. He is a member of IEEE and a registered professional engineer in the state of California. He can be contacted at kei_hao@selinc.com.

Abdel Rahman Khatib, P.E. (M 1999, SM 2016), received his B.S. and M.S. in electrical power engineering from Military Technical College, Egypt. He received his Ph.D. in electrical engineering from Virginia Tech in 2002. Abdel Rahman has worked as a protection engineer at Schweitzer Engineering Laboratories, Inc. since 2010. His current research interests are power system modeling, power system load flow and dynamic stability, and power system protection. He has 12 years of university teaching experience in Egypt, the United States, and Saudi Arabia. Abdel Rahman is a registered professional engineer in Washington, California, and Texas. His email is abdel_rahman_khatib@selinc.com.

Nevil Herbert received his B.E. in electrical power engineering from Madurai Kamraj University in India, and he is a registered Chartered Engineer with The Institution of Engineers (India). He has worked as a lead electrical engineer at Chevron North America Exploration and Production since 2012. His current interest is in reliability focused power project development for brownfield oil fields. He has a total of 12 years of experience in India, Kuwait, and the United States. He can be contacted at nevilherbert@chevron.com.

Niraj Shah is a branch manager for the engineering services division of Schweitzer Engineering Laboratories, Inc. (SEL). He received his bachelor of engineering degree in instrumentation & control from Gujarat University (India). He is a member of the International Society of Automation (ISA). He joined SEL in 2007. He has more than 18 years of experience in process control, substation automation, electrical power distribution automation (DA), applications engineering, configuration, and onsite commissioning. His expertise includes PMSs, SCADA, HMIs, energy monitoring systems (EMSs), DA control and simulation, programmable logic controller (PLC) and distributed control system (DCS) programming. His email is niraj_shah@selinc.com.

POWER MANAGEMENT SYSTEM FOR A 4 GW INTEGRATED GASIFICATION COMBINED-CYCLE GENERATION FACILITY

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Dr. Abdel Rahman Khatib, P.E.
Senior Member, IEEE
Schweitzer Engineering Laboratories, Inc.
2350 NE Hopkins Court
Pullman, WA 99163, USA
akhatib@selinc.com

Abstract—This paper presents the design of a power management system (PMS) for a 4 gigawatt (GW) integrated gasification combined-cycle power plant and refinery. The facility is comprised of 5 combined-cycle power blocks, 800 MW each. The combined-cycle block consists of two gas turbines and one steam turbine. The gas turbine is one of the largest in the world that runs on synthesis gas (syngas). The facility is designed to export 2.4 GW to support the local utility, with the remaining power feeding the refinery and internal loads.

The paper discusses the islanding impact on the refinery and how the fast generation-shedding and runback solution maintains power system stability after islanding. Automatic synchronization for the facility to connect back to the local utility at a 380 kV level is also covered in the paper. It also discusses a tie-flow control scheme for active and reactive power at the point of common coupling, dispatched by the local utility or plant operation. This scheme allows utility operators to control demand output at the power block level.

The paper covers the automatic black start and load restoration sequence for the facility, a critical requirement and automated within the capabilities of the PMS. Contingency-based load shedding and underfrequency-based load shedding are implemented for the black start substation to ensure the reliability of the black start sequence.

The electrical power system, including the syngas turbine challenging modeling, has been tested and validated using hardware-in-the-loop (HIL) simulation.

Index Terms—power management system (PMS), synthesis gas generator, voltage control, frequency control, hardware-in-the-loop.

NOMENCLATURE

AGC	automatic generation control
AO	analog output
ASU	air separation unit
AutoSynch	automatic synchronization
BPD	barrels per day
CGT	combustion gas turbine
CIT	compressor inlet temperature
CLS	contingency-based load shedding
DCS	distributed control system

EDG	essential diesel generator
GIS	gas insulated substation
GSS	generation-shedding system
GPF	global power failure
GW	gigawatt
HIL	hardware-in-the-loop
ICS	island and tie line control system
IGCC	integrated gasification combined-cycle
ISO	isochronous
LRS	load restoration system
LTC	load tap changer
MMm ³ /hr	million cubic meters per hour
OHTL	overhead transmission lines
PB	power blocks
PF	power factor
PMS	power management system
SLD	single-line diagram
STG	steam turbine generator
Syngas	synthesis gas
TPD	tons per day
UFLS	underfrequency-based load shedding
UT	utility
VCS	voltage control system

I. INTRODUCTION

This paper describes the power management system (PMS) of the largest integrated gasification combined-cycle (IGCC) system in the world and capable of producing up to 4 GW of power. This is enough to exceed the energy demands of the plant itself, and also to support power to nearby communities.

The main aspects of the IGCC refinery design and operation are reducing carbon emissions and increasing efficiency and sustainability, while also transforming waste leftover products into valuable end-products [1]. For instance, the dry ash produced will be processed through a special operation to separate the metal residue (nickel and vanadium). About 7,200 tons per year of nickel and vanadium are estimated to be extracted from the refinery ash. Nickel can be used for batteries, coins, and steel strengthener. Vanadium can be used for jet engines, machine components, and automotive parts.

The vacuum residue is the heaviest of the distillation cuts. It is cut from the vacuum distillation tower. Vacuum residue from the refinery is supplied to the IGCC complex for gasification.

The gasification unit is supplied with oxygen generated by the air separation unit (ASU) to produce hydrogen and syngas. Vacuum residue is the substance which is obtained by vacuum distillation. The vacuum residue elements' composition is carbon (88.7 to 90 percent), oxygen (5.7 to 15.80 percent), sulfur (1.4 to 3.5 percent), and aluminum (0.1 to 0.3 percent) [2].

The gasification unit is designed to deliver up to 2.11 million cubic meters per hour (MMm³/hr) of syngas (which consists of 30 percent hydrogen), which will be used for power generation by the combined-cycle facility. The entire facility is estimated to produce about 585,000 tons of steam and 184,000 cubic meters of hydrogen per hour [3].

In this process, syngas is produced, then treated to remove impurities, to create hydrogen gas. This pure hydrogen product is then utilized in the desulfurization of refinery products, resulting in the creation of lower-sulfur fuels, such as ultra-low-sulfur diesel and gasoline. Fig. 1 shows a simplified block diagram of the IGCC plant.

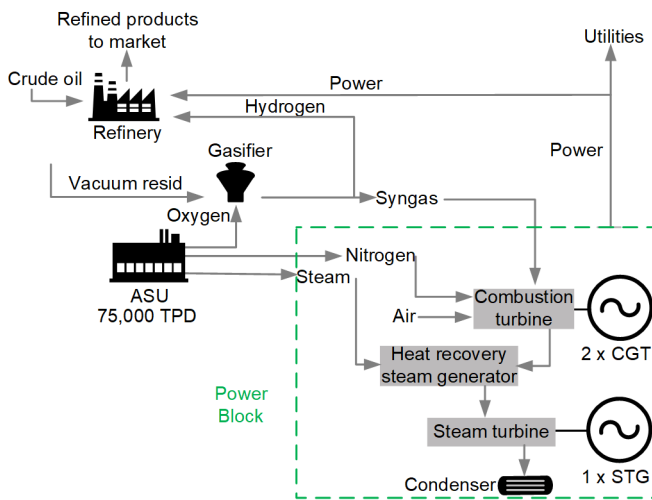


Fig. 1 A simplified block diagram of the IGCC power plant.

The PMS covered in this paper contains the main algorithms:

- Automatic generation control (AGC)
- Voltage control system (VCS)
- Generation shedding and runback
- Island and Tie Line Control System (ICS)
- Automatic synchronization between utility and IGCC system
- Load shedding for the Essential Substation
- Black start and load restoration for the Essential Substation
- Main challenges required to model syngas combustion gas turbine (CGT)
- Hardware-in-the-loop (HIL) [4] for individual CGTs and system performance during islanding with a large export

II. OVERVIEW OF THE ELECTRICAL SYSTEM NETWORK

A simplified single-line diagram of the system under study is shown in Fig. 2. Utility Substation 1 Gas Insulated Substation (GIS) connects with five other 380 kV utility substations. Substation 2 GIS connects with the five power blocks (PBs), the Refinery Substation, the 132 kV Main Substation, and the 230 kV ASU Substation.

Furthermore, each PB is consists of

- Two gas turbines 288 MVA, 18 kV, inertia 5.28 MWs/MVA
- One steam turbine 382 MVA, 23 kV, inertia 6.76 MWs/MVA

The 132 kV Main Substation is feeding the Essential Substation at 13.8 kV. The Essential Substation has essential feeders that can be used to feed the essential load in case of blackout.

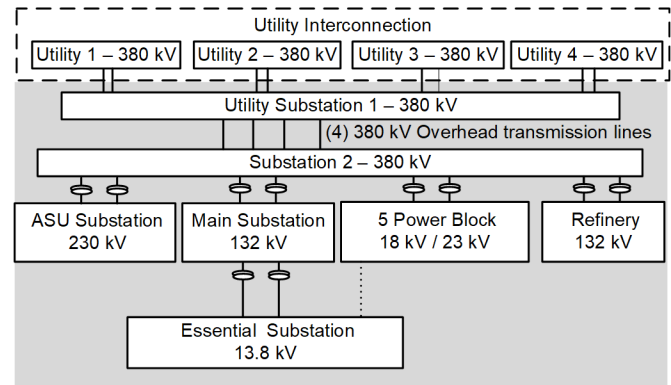


Fig. 2 Overall single-line diagram.

A. Utility Substation 1 and Substation 2

Utility Substation 1 GIS connects with four other 380 kV utility substations through double circuit (one future) overhead transmission lines (OHTLs). The length of these lines varies from short to long, with an average length of 150 km. Substation 2 GIS is connected to Substation 1 through four short OHTLs, each with line capacity of 1,200 MVA, for total capacity of 4,800 MVA that can support export of up to 4 GW.

B. Refinery Substation

The 400 MW refinery with capacity of up to 400,000 barrels per day (BPD), is intended to create a varied range of products, which includes benzene, paraxylene, gasoline, and ultra-light sulfur diesel. It is expected to provide vacuum residue feedstock for the IGCC plant, which generates power and industrial gases [5].

C. Power Generation Block

Each of the five 800 MW blocks includes two dual-fuel gas turbines and their generators, two dual-pressure, duct-fired heat recovery steam generators, and one steam turbine and its generator. Syngas from gasification is the primary and high-sulfur fuel oil is the secondary fuel. The PB rating is 958 MVA /

800 MW. A gasification facility using vacuum residue from the refinery is the main source of syngas for CGTs.

D. ASU Substation

The ASU Substation is built of six air separation units [6] that are estimated to supply approximately 75,000 tons per day (TPD) of oxygen and nitrogen to the IGCC power station and the refinery.

E. Main Substation

The Main Substation is built to distribute power to many substations that are outside the scope of the work of this paper, except for Essential / Black Start. Other substations include Gasification Units, Acid Gas Removal, Sulfur Recovery Units, Essential / Black Start Power Systems, Utility Wastewater Treatment, Sea Water Systems, Tank Farm, and Administration Buildings.

F. Essential / Black Start Substation

This substation is mainly connected to the Main Substation and feeds essential loads. Each essential load has double feed sources: one is from the Essential Substation that is normally fed from the Main Substation. The second source, in case of blackout, are essential diesel generators that energize this substation and feed all essential loads. The load-shedding system and black start have been implemented for this substation as part of the PMS and will be explained in Section VIII.

III. TYPICAL POWER FLOW OF IGCC POWER SYSTEM

The IGCC power system typically generates 3.3 GW and total loads of 1.46 GW that includes 100 MW PB auxiliaries. The system typically exports 1,840 MW to the utility through four OHTLs with each line carrying 460 MW. Two OHTLs, out of four lines, can carry the full export capability of the system. At normal operation, the essential diesel generators do not run and only start if there is a global power failure (GPF) blackout. Fig. 3 shows the typical power flow for the IGCC power system.

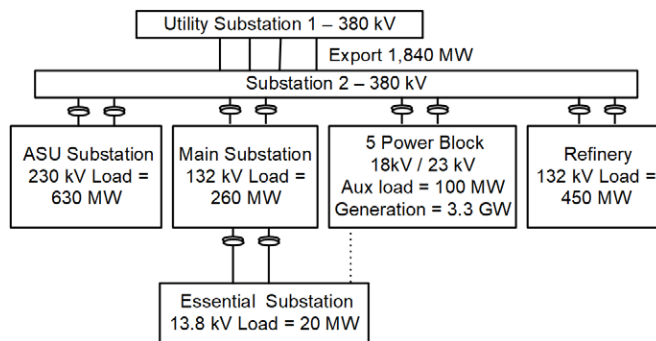


Fig. 3 A typical power flow for an IGCC power system.

IV. AGC/VCS MAIN FUNCTIONALITY SCOPE

In an IGCC system, when generators are connected to the utility, the PMS sends the MW demand set point analog output (AO) for each PB to the respective distributed control system (DCS) interface. The DCS dispatches the set point among individual generators. All generators operate in droop mode when connected to the utility. If a generator is found in isochronous (ISO) mode, the PMS sends a droop-enable command to switch the generator to droop mode.

When generators are islanded from the utility, the PMS sends the MW demand set point AO for each combustion gas turbine (CGT) to the respective CGT controller. The same signal is also used for the island/runback set point if runback is enabled and is overwritten by the runback set point for the duration of runback enabled.

Runback might not be a common term among generator manufacturers. Runback is fast load rejection to the governor. It is designed to bypass some rate limiters and to be immune against flaming out and generator tripping. The governor needs to be equipped with runback capability. The PMS feeds the analog MW for generator target runback and digital signal for enabling runback.

In a normal scenario, the MW dispatch required by the PMS, based on frequency control and equal-percentage MW sharing, is sent to the CGTs. There is no MW control for steam turbine generators (STGs) through the PMS. If the generator is in ISO mode and autosynchronization is initiated, the PMS can send speed raise and lower pulses to the CGT operating in ISO mode.

When generators are connected or islanded from the utility, the PMS can send volt/VAR raise and lower pulses to the CGT and STG exciter. The same signal is also used during autosynchronization. In addition, based on the user selection, the PMS can send power factor (PF) or MVAR analog set points to the generator exciter.

A. PMS AGC/VCS Common Functionalities

The PMS AGC/VCS performs the following common functions:

- Tracks all system islands and assigned generators and loads to each island.
- Designates buses based on system topology to AGC and VCS control loops so that utility-connected generators will be controlled for maintaining utility MW and MVAR/voltage and islanded generators are controlled for island frequency and voltage control.
- Allocates the available spinning reserves (MVAR and MW) of generators to islands and tie lines.
- Displays voltage and frequency measurements for all system islands.
- Dispatches droop and ISO control mode enable signals to the governor based on the operating scenario.
- Dispatches volt, VAR, or PF control mode enable signals to the exciter based on the operating scenario.
- Includes time-stamped PMS Sequential Events Recorder records for all alarm conditions.

- Generates a voltage alarm, frequency alarm, or MVAR/MW maximum capacity alarm when the measurements go outside the defined limits.

B. PMS AGC Main Functionalities

The PMS AGC performs the following functions:

- Dispatches turbine generator governor set points for equal-percentage MW load sharing in an islanded scenario.
- Controls the system frequency of each islanded section of the plant.
- Dispatches MW set points for each power block when connected to the UT.
- Controls the MW flow across the tie lines according to user-entered set points.

C. PMS VCS Main Functionalities

The PMS VCS performs the following functions:

- Dispatches exciter set points for equal-percentage reactive power load sharing within plant generators.
- Controls the generators terminal voltage to maintain the bus voltage at nominal on each plant.
- Controls transformer load tap changer (LTC) in parallel with generator excitation to maintain the generator terminal voltage.

D. AGC and VCS Control Modes

The PMS AGC and VCS operate in either of the following three modes, one at a time, whichever mode is selected.

- Under PMS control
- Under DCS control
- Under utility (UT) control

The PMS uses the set point selected by the system operator (PMS / DCS / UT) to dispatch the generators. The default mode is PMS. When in PMS mode, the operator has complete control of the generator dispatch.

If the DCS wants to take control of the utility export set point, the operator must enable DCS mode control from the DCS. The DCS can set the following set points:

- MVAR export/import from the UT.
- MW export from the UT.
- 380 kV bus voltage set point from the UT.

If the UT wants to take control of the IGCC export or generator set points, the UT operator must send the request for UT Mode Enable control. The PMS operator is then prompted to give control to the UT. The UT can set the following set points and controls:

- MVAR and PF dispatch set points for each generator, including the STGs.
- MW dispatch set points for each CGT.
- MW, MVAR, and PF set points for each power block.
- MW, MVAR, and PF dispatch set points for overall utility export/import between the IGCC and the UT.
- Voltage set point for the 380 kV bus.
- MW mode selection:
 - Utility Plant Export Set Point (overall export)

- Individual CGT MW Set Point
- PB MW Set Point
- MVAR/Exciter mode selection:
 - Utility/IGCC Bus Voltage Set Point
 - Overall export/import MVAR Utility
 - Individual Generator PF Set Point
 - Individual Generator MVAR Set Point
 - Power Block PF Set Point
 - Power Block MVAR Set Point

E. AGC and VCS Control Strategy

CGTs can operate on two different fuel types, syngas and liquid (oil) fuel. The PMS AGC is designed to operate efficiently considering the type of fuel. Based on the fuel type status received by the AGC from the DCS interface, the AGC dynamically calculates the capability and spinning reserve of the machine and dispatches the MW demand output accordingly.

However, the spinning reserve is interlocked with the MW load capability analog input to the PMS from the turbine. The PMS uses this value all the time except when it is not available (communication alarm, etc.). The dynamic capability calculation is based on a manufacturer-provided capability curve.

The VCS sends voltage raise and lower commands to each of the generation units so that each unit shares an equal portion of the MVAR, as a percent of available capacity for each generator. The voltage raise and lower signals, which are sent from the VCS, will raise the terminal voltage on the generator and push more MVARs through the generator step-up transformer. Simultaneously if the generator terminal voltage exceeds +/- 5 percent, the PMS controls the transformer LTC by sending tap raise or lower commands to the LTC to bring the voltage between ± 5 percent.

V. UTILITY TIE LINE CONTROL

In the IGCC system, four utility tie lines can be controlled for active power flow by the PMS. The PMS sends the PB MW dispatch set point to DCS interfaces, and the DCS dispatches it among generators within PBs. The PMS calculates the PB MW dispatch set point based on the tie MW set point by the operator (IGCC/UT) and, accordingly, demands the PB to produce MW based on the set point, ensuring the MW percent load sharing between the PB connected to the utility.

In this case, if one or two transmission lines trip, the overall set point remains applicable since the two lines are capable of handling the complete export flow. If only one line remains, the generation-shedding system (GSS) needs to take an action and tie flow will be disabled.

Tie line control is for active power MW and reactive power MVAR/PF/voltage set point; therefore, all the alarms, including voltage high/low limits and MVAR maximum capacity, are considered for system stability. The thermal stability limit alarm is also considered. The thermal stability limit MW alarm is triggered when the tie MW flow reaches a certain MW on a single line; the tie control is stopped automatically on all the alarms. After the stopped tie flow on alarm initiation, the PMS

waits for the user to enter a different MW set point before disabling tie control.

Tie-flow control for reactive power is only enabled when the VCS is in Voltage/MVAR mode. If the VCS is utility-connected, it can run in six different modes as shown in Table I. In the first two modes, volt mode and volt/MVAR mode, the PMS controls all generators to maintain the voltage/MVAR. Any time the terminal voltage goes outside that five percent range, the PMS is controlling the transformer LTC to keep the generator terminal voltage within five percent. The four other modes are passthrough modes to either PB or an individual generator; in these four modes, the PMS is not controlling the voltage nor the LTC.

TABLE I
VCS UTILITY-CONNECTED CONTROL MODE SUMMARY

VCS mode	Exciter mode	VCS control summary
Volt mode	Voltage	Maintains UT dispatch voltage. Uses transformer LTC to maintain generator voltage.
MVAR mode	Voltage	Maintains UT dispatch MVAR. Uses transformer LTC to maintain generator voltage.
PB PF mode	PF	Distributes PB PF to each generator. No voltage / transformer control.
Gen PF mode	PF	Sends individually entered PF set point to each generator. No voltage / transformer control.
PB MVAR mode	VAR	Distributes PB MVAR set point to each generator. No voltage/ transformer control.
Gen VAR mode	VAR	Sends individually entered VAR set point to each generator. No voltage/ transformer control.

VI. AUTOSYNCHRONIZATION SYSTEM

This section describes the redundant automatic synchronization (AutoSynch) system, which is part of the PMS. This AutoSynch system is used to synchronize eight breakers (in a breaker-and-a-half scheme substation), connecting four transmission lines between UT Substation 1 and Substation 2. Two dedicated autosynchronization system relays are installed on all eight breakers. AutoSynch has been placed only in Substation 2, not Substation 1.

When the IGCC is islanded from the UT and synchronization is initiated on any of the eight breakers, the PMS sends an analog set point to all connected generators to match the UT frequency and voltage raise/lower pulses to all generators to match the UT voltage. Once all the synchronization parameters are within the breaker closing window, a relay will close the breaker.

The AutoSynch [7] [8] uses advanced angle technology that considers the slip rate and the breaker closing mechanism delay setting to cause closure to occur at zero degrees.

VII. GENERATION-SHEDDING AND RUNBACK SYSTEM

The primary goal of this system is to keep the frequency of the IGCC power system in a stable range during major disturbances since the system is exporting up to 2.4 GW and

the CGT runs on syngas, which has lower energy content compared to natural gas. Major disturbances can be utility lines tripping or losing the major load substations. By keeping the frequency in a stable range after major disturbances, the generation control system corrects the frequency and brings it back to steady-state normal frequency.

There are 15 generators (STGs and CGTs) on the IGCC system that can be shed and 10 CGTs that can be run back, if required. These generators shed or run back based on the priorities set by the operator on the PMS. Different interlocks can be set up for setting priorities in the PMS based on operational requirements. CGT runback is used to quickly reduce the generator output to bring the system frequency back to nominal. The generation runback characteristics are typically faster than the generator load-rejection characteristics. If a CGT is selected for shedding and the STG of the same PB is still running, the coupling effect of the tripped CGT on STG output has an effect in about ten minutes. During this time, the AGC MW set point to the other CGTs can be increased more quickly to compensate for the STG load drop. The CGT can raise 13 to 14 MW per minute.

A. Islanding and Runback Scenarios

There are three different types of contingency events in terms of how the PMS uses islanding digital (latch), runback digital, runback set point, AGC generator set point, and AGC PB set point. There are multiple scenarios within each type, as explained next.

1) Utility-Connected GSS Contingency Trigger

In this scenario, two or three utility lines trip or the refinery trips while the IGCC is still utility-connected. Generation shedding is the only option in this case and no runback is allowed since the generators are still connected to the utility (per the CGT manufacturer), the GSS sends a PB set point to the DCS interface. The PMS will perform generation shedding only, based on excess generation if required.

2) Islanded Runback Utility Disconnected

In this scenario, the IGCC is islanded from the utility. An islanded latch signal and analog runback set point are sent to the turbine interface. An analog runback set point is sent for a certain duration, and the AGC analog set point takes over once the generator settles down to runback set point.

3) Islanded Runback Already Utility Disconnected

In this scenario, the IGCC is already islanded from the utility and then an additional contingency is triggered, such as a refinery trip, and excess generation occurs on an island. An islanded latch signal is already high since the IGCC is already islanded. Another runback digital output and analog runback set point will now be sent to the CGTs for a certain duration. The AGC analog set point will take over once the generator settles down to runback set point.

VIII. ESSENTIAL SUBSTATION LOAD SHEDDING AND LOAD RESTORATION

A. Simplified Single-Line Diagram (SLD) for Essential Substation

Fig. 4 shows an SLD simplified for the Essential Substation. The substation consists of eight essential diesel generators (EDGs), two incomers, and one bus intertie. The Essential Substation back feeds PB-1 for black start. The two incomers are fed from the Main Substation.

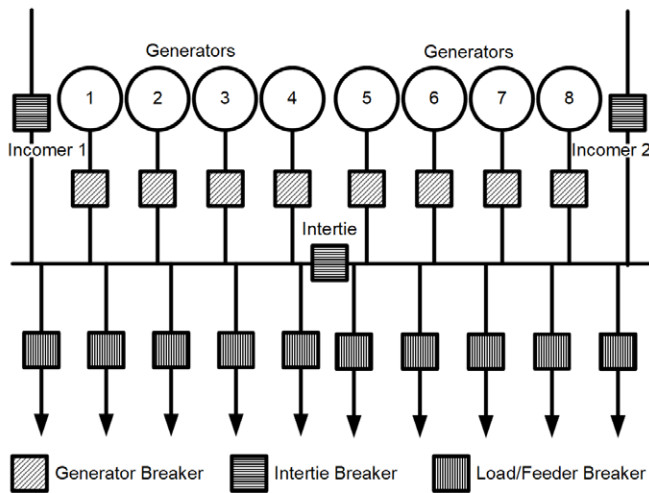


Fig. 4 SLD of the Essential Substation.

B. GPF and Load Shedding Enable

GPF is defined as the IGCC being isolated from the utility with ten CGTs in the IGCC facility tripped. The logic diagram to determine a blackout and assert GPF signal is shown in Fig. 5.

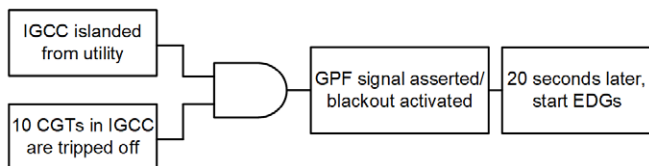


Fig. 5 Logic diagram to assert GPF and start EDGs.

The load shedding is enabled only when the following condition is satisfied, as shown in Fig. 6.

- Two incomer breakers are opened.
- IGCC has GPF.
- Essential Substation is not back feeding PB 1.

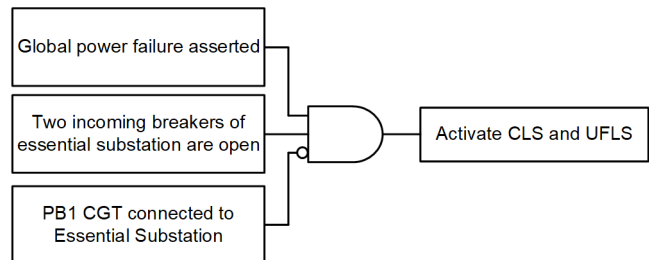


Fig. 6 Logic diagram to activate CLS and UFLS.

Contingency-based load shedding (CLS) and underfrequency-based load shedding (UFLS) are implemented to protect the system if any of the generators or the intertie trip during a black start. For detailed information for CLS and UFLS refer to [9] [10] [11].

C. Black Start and Load Restoration System (LRS)

A black start and load restoration sequence can be summarized as shown in Fig. 7 as follows.

- Once a GPF is detected, open all outgoing feeders and the incomer breakers.
- The PMS sends a close command to the intertie breaker dead bus closing.
- The PMS sends a start command to the EDG controller.
- The EDG controller starts all eight EDGs after receiving the command from the PMS controller.
- The PMS opens all the incomer PBs.
- The PMS begins closing the outgoing load feeders one by one, according to operator priority.
- For the load breakers feeding PBs, the PMS sends the close command to the load feeder and to the corresponding incomer breaker and tiebreaker PBs to energize PB auxiliaries.
- Outgoing feeders are restored based on two parameters: restoration priority and available generation.
 - Priorities for load restoration are separate from those used for load shedding.
 - Available generation is calculated based on the number of generators that have started and connected to the essential switchgear and the loads that have been restored.
- The power value for outgoing feeders is the expected power consumption entered by operators. If the actual load is more than the operator-entered value, then the PMS will consider the actual load when calculating the spinning reserve.

IX. POWER SYSTEM MODELING CHALLENGING

The main challenge of this power system model is the government mode of the syngas CGT. Since the energy content of syngas is less than natural gas, a standard governor model cannot be used because it is based on high-energy content fuel. A modified version of the GGOV1 governor has been used and validated with the governor manufacturer. The details of the syngas governor model are out of the scope of this paper. The summary of these modifications as follows.

- When the gas turbine generator (CGT) is switched to ISO mode, the output of the governor proportional integral derivative controller will be reset to the value corresponding to ISO target MW.
- The fuel control to the governor passes through a rate limiter that is able to provide an 8 percent instantaneous increase, followed by an 8.4 percent per minute ramp-up rate. This fuel control is due to the energy content of the syngas for pickup load. The

simulation results in the next section will demonstrate that limitation.

- Modified droop function logic allows 10 percent instantaneous droop MW increase followed by a 30 MW per minute increase rate. For the same reason explained previously.
- The governor model is equipped with underfrequency protection logic. The logic is based on CIT. When the speed drops below the limit, an underfrequency trigger is activated. The loading above maximum MW is reduced if the underfrequency trigger signal is active. The maximum MW of gas turbine loading is related to CIT. More details will be explained next.

A. Governor Underfrequency Protection Logic

The chemical composition of syngas varies based on the raw materials and processes used to make it; however, in general it has less energy density than natural gas.

Due to that fact, when operating in syngas, if the system frequency decays, the maximum capability limit of CGT will be reduced.

- The underfrequency protection trigger (Hz) is a function of the compressor inlet temperature (CIT).
- The maximum capability protection limit (measured in MW) is a function of the CIT as well.

For example:

- For CIT 48 degrees C → underfrequency protection is 59.61 Hz.
- For CIT 48 degrees C → CGT rejects any loads above 164.3 MW.

A realistic example for this scenario is when the IGCC is islanded from the utility and operating with ISO and Droop machines in the system. If only the ISO machine reaches the MW turbine limit (maxed-out) and is unable to correct the frequency to nominal 60 Hz, CGT underfrequency is triggered. If the droop generators still have MW reserve, the PMS will update the turbine maximum limit of all machines in the island. Accordingly, the PMS demands that the droop machines increase MW out, which will eventually reduce MW on the ISO machine and help in correcting the frequency.

For example, one ISO machine is operating at 230 MW. Three droop machines are operating at 100 MW. The maximum MW limit of all the machines is 250 MW. A load of 117.5 MW is increased on the system. The ISO can only pick up 20 MW, so the remaining 97.5 MW is picked up by three droop units. ISO is unable to correct the frequency so underfrequency is triggered at 59.61 MW at 48 degrees C, which reduces the maximum MW limit to 164.3 MW for all the generators.

ISO machine MW rejection = $250 - 164.3 = 85.7$ MW

Total Droop MW pick = $97.5 + 85.7 = 183.2$ MW

MW Droop units reserve = $3 \cdot (164.3 - 100) = 192.9$ MW

Because droop units have enough MW reserve, the PMS will be able to increase the droop machines' MW output and correct the frequency.

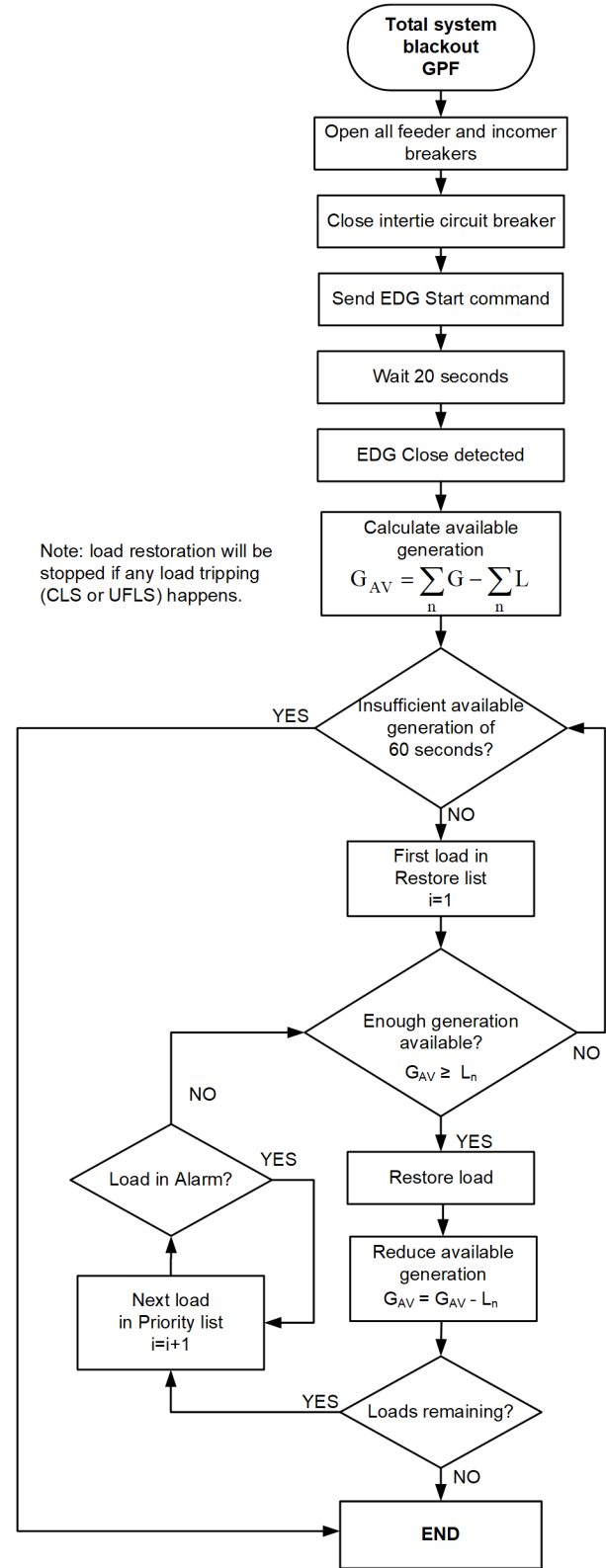


Fig. 7 Simplified LRS logic diagram.

X. HIL SIMULATED CASES

A. Load Acceptance of CGT

The first test is performed by adding loads to the single islanded CGT when the CGT is running in droop and ISO mode, respectively. Fig. 8 shows the frequency response for different load acceptance with different governor modes.

The response of a single CGT with the GGOV1 governor was analyzed. For the load acceptance test when the CGT was in droop/ISO mode, one load is always connected to the CGT and absorbs 180 MW. The load acceptance for Load 2 is switched in after one second for the following four scenarios:

- Droop mode 15 MW
- Droop mode 18 MW
- ISO mode 18 MW
- ISO mode 30 MW

The bus-frequency response of the test is shown in Fig. 8. Note that the CGT in Droop mode cannot accept much load.

- For CGT in Droop mode, 18 MW load acceptance in a single CGT test brings the frequency down to 56.7 Hz.
- For CGT in ISO mode, 30 MW load acceptance in a single CGT test brings the frequency down to 57.9 Hz.

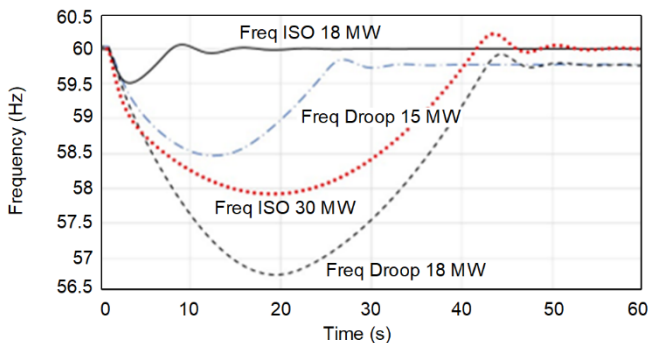


Fig. 8 Load acceptance for CGT ISO/Droop.

B. Test 2: Load Rejection of CGT With Runback

This test of individual CGT 120 MW load rejection with runback is enabled. The test is performed with ISO and Droop modes of CGT. Fig. 9 shows the frequency response of load rejection with runback.

- Maximum and minimum frequency of droop mode is 62.5 Hz and 59.9 Hz.
- Maximum and minimum frequency of ISO mode is 62.3 Hz and 58.8 Hz.

Maximum frequencies for both ISO and Droop are close to each other for the runback test, and ISO mode has under damped response and frequency reach to 58.8 Hz, which might not be a perfect scenario considering the underfrequency protection logic explained previously. The final mode of operation will be decided during system commissioning.

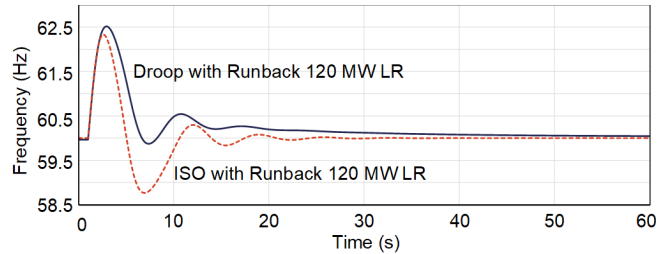


Fig. 9 Frequency response for 120 MW load rejection with runback.

C. Test 3: Load Rejection of CGT Without Runback

Performing load rejection without runback has an unacceptable behavior for the CGT frequency response. Fig. 10 shows a frequency response for 60 MW load rejection.

As explained from the previous test, ISO mode has under damped behavior and, for this test, it has a frequency collapse. For the droop mode, the frequency behavior is also not acceptable and the minimum frequency is 52.9 Hz.

Enabling runback is a critical function for the PMS, and without it the islanding will fail.

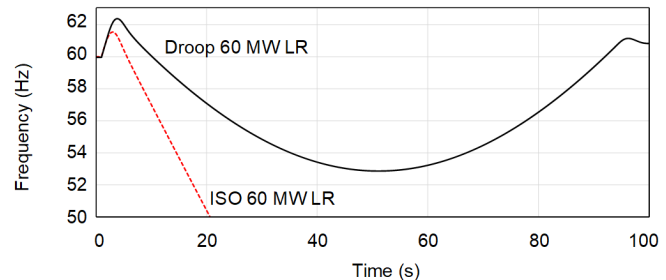


Fig. 10 Frequency response for 60 MW load rejection without runback.

D. Test 4: IGCC Island With Export 2,335 MW

This test demonstrates an islanded scenario with export of 2,335 MW to the UT. The island load is 841 MW, as shown in Fig. 11.

- Four PBs with eight CGTs and four STGs.
- Each CGT producing 240 MW and each STG producing 314 MW.
- Total generation is 3.176 GW.

After the island PMS performs the following actions, shown in Fig. 12.

- Two full PBs consisting of four CGTs and two STGs (1.588 GW) are tripped after a 200 ms delay (worst expected delay).
- The other four CGTs are running back to 53.3 MW after a 200 ms delay.
- Two remaining STGs assumed are constant MW.
- One CGT is switched to ISO mode after islanding.
- Island load is 841 MW.

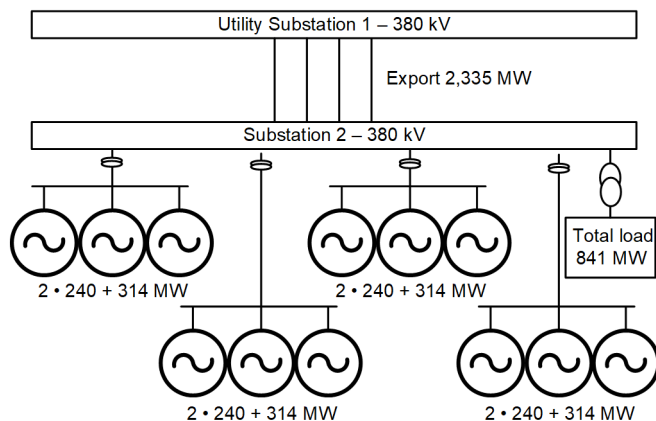


Fig. 11 Loading for Test 4 precontingency.

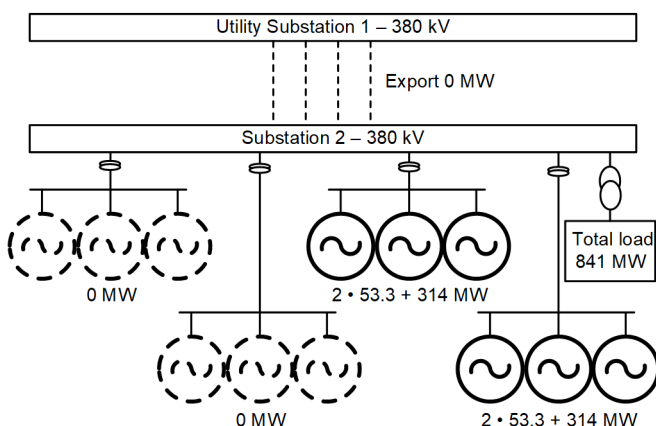


Fig. 12 Loading for Test 4 postcontingency.

The same test has been repeated with the unlocked STG. Since the STG is coupled with the CGT, the output of the STG is reduced over time with runback; the STG and the ISO CGT will compensate for that. The frequency response of lock and unlocked STG is shown in Fig. 13.

The maximum frequency that the island hits is 62.6 Hz with a locked STG and 62.2 with an unlocked STG. These frequencies are within the acceptable range with over 2 GW export level.

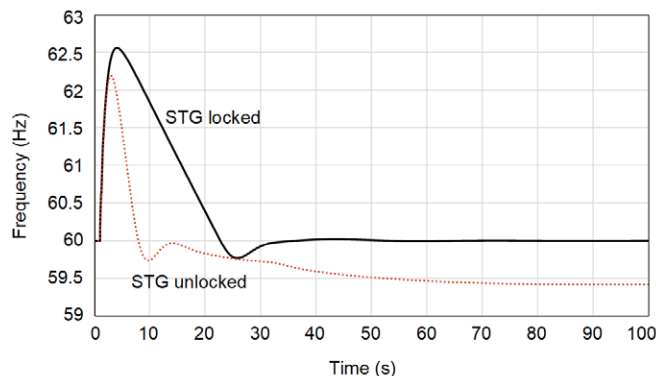


Fig. 13 Frequency response for Test 4.

XI. CONCLUSIONS

This paper presents a PMS that has been designed for an IGCC system that can export up to 2.5 GW. The main objective of the PMS is maintaining the stability of the refinery after islanding, which is a great challenge particularly because syngas is the main fuel of the CGTs. While the IGCC is utility-connected, the PMS maintains the tie-flow active and reactive power and voltage across the utility. The PMS has multi-agent tie-flow control that can be controlled from the utility, DCS, and local operators in multiple different mode of operations, such as PB level, individual generator level, or IGCC level.

The PMS leads the black start and load restoration in the essential substations with a load-shedding system running in the background to prevent the Essential Substation from blackout again during a black start operation.

Optimal selecting for shedding and/or runback generators has been achieved using HIL modeling and testing. The best combination of shedding and runback has been tested and evaluated with an HIL test environment.

The paper highlights the main challenge of modeling syngas CGTs and shows some key generator and system tests that explain the special behavior of syngas CGTs.

XII. ACKNOWLEDGMENTS

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XIV. VITAE

Abdel Rahman Khatib, PE (M 1999, SM 2007), is a principal engineer at SEL Engineering Services, Inc. (SEL ES), a subsidiary of Schweitzer Engineering Laboratories, Inc. (SEL). He joined SEL in 2010. He received his BS and MS in electrical power engineering from Military Technical College in Cairo, Egypt. He received his PhD in electrical engineering from Virginia Tech in 2002. He executes and consults on projects that focus on power management system design, testing, and commissioning for the petrochemical and oil industries, data centers, microgrids, and remedial action schemes. His current research interests are power system modeling, power system load flow and dynamic stability, smart grid control systems, and power system protection. He has 12 years of university teaching experience in Egypt, the United States, and Saudi Arabia. He is a senior member of the IEEE Power Engineering Society, and is a registered professional engineer in Washington, California, Indiana, Montana, and Texas.

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CASE STUDY: TURBINE LOAD-SHARING AND LOAD-SHEDDING SYSTEM FOR AN AUSTRALIAN LNG FACILITY

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Abdel Rahman Khatib
Senior Member, IEEE
Schweitzer Engineering
Laboratories, Inc.
2350 NE Hopkins Court
Pullman, WA 99163, USA

Anshuman Mallya
IEEE Member
Chevron
1400 Smith Street
Houston, TX 77002,
USA

Bowen Dai
Schweitzer Engineering
Laboratories, Inc.
420 Exchange, Suite 100
Irvine, CA 92602, USA

Roberto Costa
IEEE Member
Schweitzer Engineering
Laboratories, Inc.
420 Exchange, Suite 100
Irvine, CA 92602, USA

Abstract—This paper presents a turbine load-sharing and load-shedding system for an islanded liquefied natural gas facility in Australia. The system includes three independent and redundant load-shedding schemes: process-based contingency load shedding with predefined load group and load pairs, high-speed underfrequency-based load shedding, and progressive overload shedding with system frequency supervision. In addition to the load-shedding schemes, the site includes a generation control system with frequency control, voltage control, automatic synchronization, and turbine load-sharing schemes. A breaker-and-a-half configuration complicates the fast load-shedding scheme. Results from hardware-in-the-loop testing are shared.

Index Terms—Power management, generation control, fast load shedding, autosynchronization, power system modeling.

I. INTRODUCTION

A power management system (PMS) is a collection of hardware and software components configured to provide intelligent automatic load reduction in response to predetermined contingencies, in addition to maintaining frequency and voltage within an island [1] [2]. This paper describes a PMS implemented at an islanded liquefied natural gas (LNG) facility in Australia, including system design and hardware-in-the-loop testing results.

The PMS at the LNG facility automatically adjusts the system loading and generator set points to account for operational changes made within the electrical grid. The PMS also provides load shedding to recover after a major instability develops, such as a sudden loss of generation. The load-shedding system (LSS) includes three schemes for determining the amount of load to shed. The primary scheme is contingency-based, while the secondary (backup) scheme is underfrequency-based [3]. Both schemes run on independent, dual redundant processors supplied from redundant direct current (dc) supplies. The third load-shedding scheme is progressive overload shedding (PLS), which is an overload scheme that protects generators from overload.

The LSS at the LNG facility is deployed on two pairs of dual modular redundant (DMR) LSS controllers. A DMR design is a

reliability engineering technique in which both appliances in a pair receive data, run logic, and operate simultaneously. This technique is proven to be vastly more reliable than hot- or warm-standby redundancy configurations used elsewhere. In a DMR system, a pair of controllers is used for fast and proactive load shedding, while another pair is used for underfrequency load shedding.

The PMS generation control system (GCS) includes an automatic generation control (AGC) system, a voltage control system (VCS), and an island control system (ICS). The hardware uses PMS controllers that gather data from the relays installed throughout the LNG facility.

The PMS GCS controls both active and reactive power dispatch and sharing of generators. More challenges can be introduced to the system if the PMS is required to coordinate with steam production, which can impact the generator production [4]. In this project, two steam expander turbines are running in the system; however, they are not controlled by the PMS. The PMS is only controlling the gas turbines. In addition, the GCS actively controls system voltage and frequency. Also, any number of system islands can be simultaneously handled. The hardware for this hot-standby redundant system is loaded with the GCS image. At all times, the GCS maintains the voltage and frequency at normal values [5] [6].

Generation control at the LNG facility is accomplished with two GCS controllers. The two GCS controllers operate in a hot-standby mode. Hot-standby redundancy occurs when one controller is constantly operating as the master controller. The second controller will take over if the master fails or is not in perfect operating condition. This strategy is well suited for the slow control behavior of the GCS.

II. LNG FACILITY POWER SYSTEM OVERVIEW

The Australian LNG facility downstream power system is sourced by four 36 MW gas turbine generators (GTGs) connected to a main substation (see Fig. 1), and two 9 MW steam expander cogenerators. The LNG facility is not connected to the utility; therefore, onsite generation is the only power source. The power system typically operates as a single island. The main gas-insulated switchgear incorporates a breaker-and-a-half scheme.

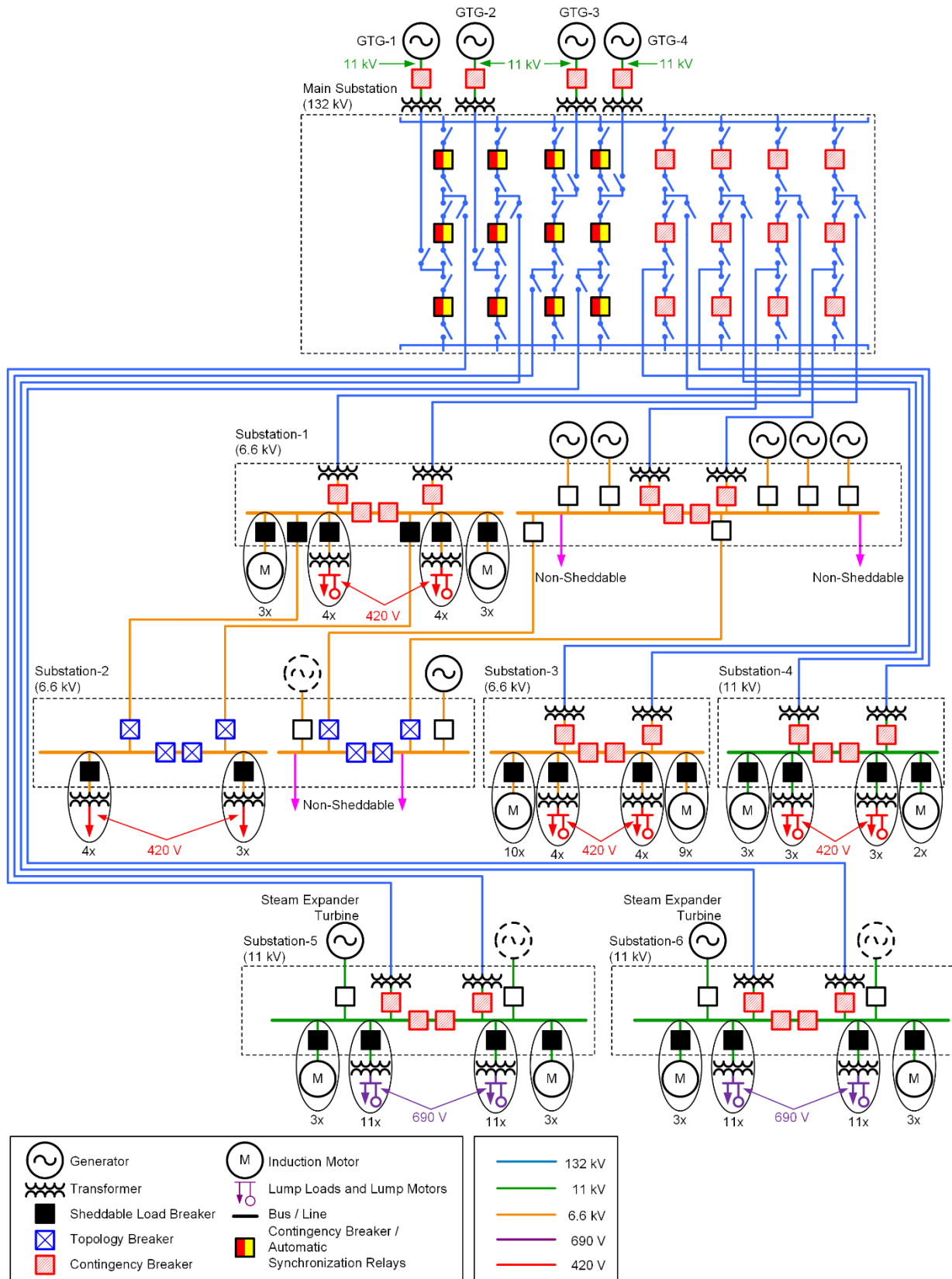


Fig. 1 Simplified One-Line Diagram

The main substation provides power to six other substations. The main feeders at the substations employ a main-tie-tie-main scheme with the ties in a normally closed position, as shown in Fig. 1. The LNG facility has over 100 loads that can be shed.

III. GENERATION CONTROL SYSTEM

This section provides a functional description of the GCS applied at the LNG facility. Generators are controlled by the GCS to maintain system frequency and voltage at the 132 kV buses. Both bus voltage and frequency are critical data to the GCS, especially in an islanded system. Active and reactive power flows throughout the primary buses are monitored to facilitate properly executed controls. Voltage and frequency are maintained across the primary generation substations. Fig. 2 shows a simplified one-line diagram related to the GCS control.

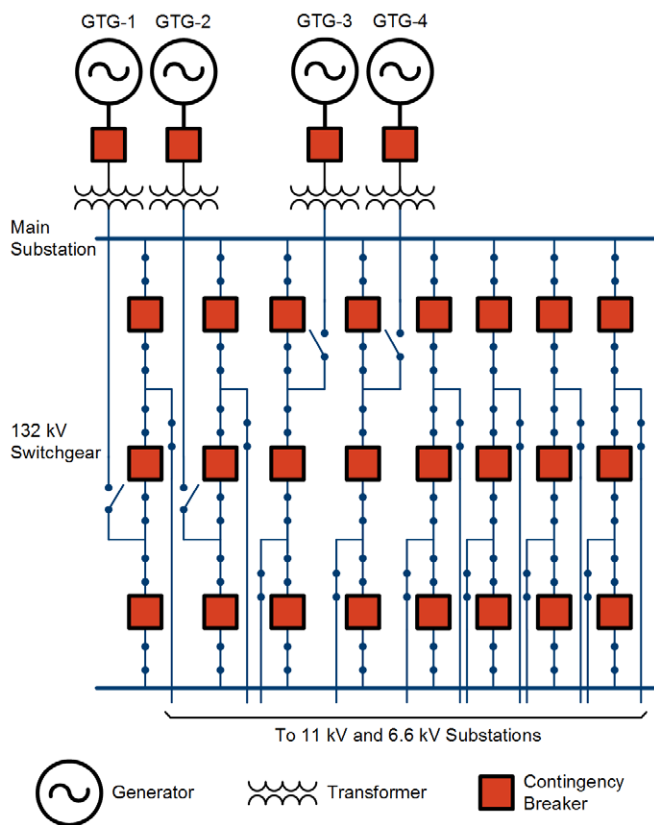


Fig. 2 GCS Simplified One-Line Diagram

A. Generation Control System Control Philosophy

The general requirements of the AGC system and VCS are as follows:

1. Share the MW/MVAR contribution between GTGs; this function is also commonly called load sharing.
2. Continuously regulate the busbar frequency to 50 Hz for single- and multiple-island operations; this is an AGC system function.

3. Continuously regulate the busbar voltage at the generation bus for single- and multiple-island operations; this is a VCS function.
4. Participate in automatic synchronization.

1) Bringing a Generator Online

Each generator at the LNG facility can be brought online manually by the operator at the generator control panel or initiated from the PMS human-machine interface (HMI). In both scenarios, the generator manufacturer is responsible for matching the actual frequency and voltage to the system.

To initiate automatic synchronization from the PMS HMI, the operator must put the governor in external load control mode and the exciter in remote mode. While in remote mode, the PMS will not issue lower and raise pulses until the generator breaker is closed.

If the unit is not in external load mode, the GCS will not include this generator in its MW and MVAR sharing algorithms and will simply keep the remaining generators equally sharing the load.

2) Generator Loading Modes

Three modes of operation are used by the AGC system and VCS to facilitate commissioning in this project, as well as the different types of generator operating constraints. These modes will generally be entered into the system before the generator is brought online (although, they can be changed afterward). The modes are:

1. Disabled
2. Maintained MW/MVAR
3. Maintained MW/MVAR with regulation

a) Disabled mode

The disabled mode removes the GTG from all control routines within the PMS and prevents noncommissioned GTGs from affecting the portion of the system that has already been commissioned.

The AGC system and VCS do not send any up or down controls to the generator governor. The GTG is treated by the AGC system and VCS as though it is still in local mode. With the generator in local mode, the PMS should not control the generator; instead, it must be controlled by the operator.

b) Maintained MW/MVAR mode

This mode is used primarily for commissioning. The unit output is controlled to the load set point, which is only displayed on the GTG dialog box; whereas, the AGC system and VCS maintain the generator at a constant power output.

The maintained MW mode can be used to maintain the units at a constant power output only when the governors are in droop mode. The generator still reacts to any sudden load change in the system. Similar to the other generators, it will still throttle up or down quickly in response to the step-load change, based on its droop characteristic. However, this mode will not be operational if the GTG is in isochronous (ISOC) mode.

c) Maintained MW/MVAR with regulation

In normal operation, this is the recommended mode for all generators. The unit output is biased toward the base set point; however, it is not constrained to it. Rather than attempting to

maintain each generator at a specific set point, the bias point is used to weigh the relative load sharing of each generator as a percentage of generator capacity. If all generators are set with the same percentage of rated power, all generators will be biased equally and will share the load equally.

When all generators have the same capacity, upper limit, lower limit, and MW/MVAR bias point, the result of the MW/MVAR sharing algorithm is intuitive. For example, if two 100 MW/MVAR capacity generators are online, their bias points will be 50 MW/MVAR. Additionally, if there is a requirement of 100 MW/MVAR, each generator will run at its bias point of 50 MW/MVAR and each generator will be exactly at its MW/MVAR set point. If the load increases to 125 MW/MVAR, then both generators will pick up an equal share (12.5 MW/MVAR) and run at 62.5 MW/MVAR each. The calculation for this load-sharing bias allows for differentiated loading, actual generator capacity considerations, and artificial loading boundaries.

Maintained MW with regulation mode will not be operational if the GTG is in ISOC mode.

3) Capability Curve and Regulation Limits

The capability of generators is important information for the GCS. Reserve margins (RMs) for real and reactive power are calculated based on the present operating temperature and power output. Given the real and reactive power and the operating temperature, the actual operating point along with a dynamic capability curve can be determined. The capability of the GTG is usually limited more strictly by other factors or bounds, such as the operator-entered limits or the manufacturer's control system.

The bounds set by the capability curve and the operator-entered regulation limits determine the ultimate margins used within the GCS. These margins are aggregated for each bus and analyzed for any electrical island that is created to facilitate calculating the percentage of real (P) and reactive (Q) power on each island, which can be used in generation control. The margins bound by both the capability curve and the regulation limits are visually represented in Fig. 3.

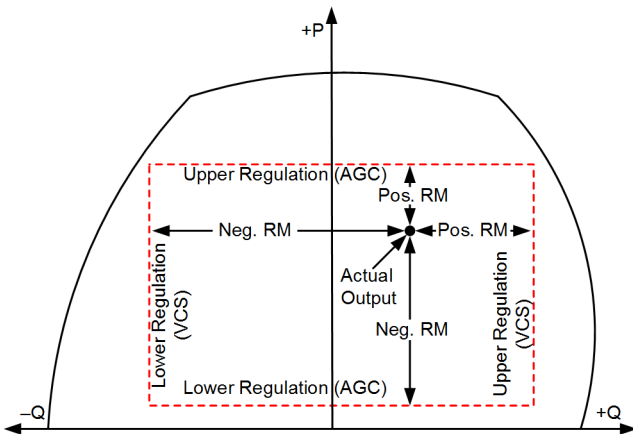


Fig. 3 Final Reserve Margins in the GCS

Calculated and selected RMs, shown in Fig. 3, are used internally during the aggregation and allocation process for island control. Regulation limits create a box, as shown in the

figure; however, the limits may be entered such that the box exceeds the capability curve. In this case, the RMs would be bound by the capability curve. A selection process is executed in the logic to use a specific boundary for the calculated reserves to represent reality.

The generator spinning reserve measurement is available to the GCS as an input from the turbine manufacturer. The GCS will calculate the turbine limit as the sum of the present active power and the spinning reserve. The GCS will then calculate the maximum capacity of each generator as the minimum between the operator-entered upper regulation limit and the turbine limit.

4) Load-Sharing Calculations

The equal percentage loading for the AGC system and VCS is calculated using the following equations:

$$\text{Total_Capacity} = \sum_{i=1}^n \text{Generator_Capacity}_{\text{GEN}_i} \quad (1)$$

Total capacity, as shown in (1), is equal to the summation of all generator capacity, where the generator capacity is the least of the following factors:

1. Operator-entered upper regulation limit
2. Generator capability curve
3. Turbine capability in MW sharing only

$$\% \text{Deviation} = \frac{\text{System_Load} - \sum_{i=1}^n \text{Bias_Point}_{\text{GEN}_i}}{\text{Total_Capacity} - \sum_{i=1}^n \text{Bias_Point}_{\text{GEN}_i}} \quad (2)$$

$$\text{Deviation}_{\text{GEN}_i} = \% \text{Deviation} \cdot (\text{Generator_Capacity}_{\text{GEN}_i} - \text{Bias_Point}_{\text{GEN}_i}) \quad (3)$$

$$\text{Power_Request}_{\text{GEN}_i} = \text{Bias_Point}_{\text{GEN}_i} + \text{Deviation}_{\text{GEN}_i} \quad (4)$$

where:

System_Load is the total MW load of the facility.

Bias_Point is the HMI operator-defined MW/MVAR set point.

From the previous equations, it is clear that the percentage of load sharing depends on the generator capacity and the MW/MVAR set point entered by the operator on the PMS HMI.

The AGC system and VCS automatically create new control arrangements for multiple-islanded systems. For example, if two islands exist, two completely autonomous solutions are required for active AGC/VCS control.

5) Generation Control System Functional Overview

The PMS GCS performs the following functions:

1. Supervises all signals with communications-quality indications.
2. Regulates the active and reactive power output of the generators to maintain the system frequency at nominal.
3. Remains operational and dynamically recalculates control set points under all system bus configurations.

4. Reselects the data source dynamically. The system will automatically select the most reliable data source for control.
5. Controls generation with an adaptive algorithm in response to all topologies related to its control.
6. Allows the control mode of each generator to be operator-selectable between disabled, maintained, and regulated.

B. Frequency Control Philosophy

Depending on the combination of breakers and switches, the system in the LNG facility can form individual islands. The frequency control philosophy depends on the number of generators in an electrical island. The governor will set the GTG units to droop mode before putting them in external load mode. The AGC system can control the frequency by keeping all generators in droop mode, or one of the generators can be manually placed in ISOC mode and the AGC system will control the remaining droop units to load-share with the ISOC unit.

The AGC system performs active power sharing among the droop units, taking into consideration the ISOC unit loading, to provide enough headroom to the ISOC unit for maximum disturbance rejection. This is accomplished by sending raise and lower power set-point commands to the GTGs in droop mode. Because the power output of the ISOC unit cannot be controlled directly, the AGC system will directly control the droop units, which indirectly maintains the output of the ISOC unit at an equal percentage loading or a lower percentage with the droop units. Keeping the ISOC unit near its optimal maintained set point maximizes the disturbance rejection abilities. This allows the governor of one unit to control the system frequency at exactly 50 Hz. Simultaneously, the droop units will share the remaining load as close as possible to the bias points set by the HMI. This is realistic because the droop units are not responsible for the final frequency control.

If all units are running in droop, the algorithm will monitor the frequency of the system. An increase in load causes a slight drop in frequency. This frequency decline will be arrested by the droop characteristic of the individual turbine governor, which dictates that the lower the frequency, the higher the power output. This causes the system to settle at a slightly lower frequency than nominal. As soon as the frequency declines, the PMS will begin to send raise signals to each generator; therefore, the droop line is biased to a higher power output for a given frequency and the system operates again at nominal frequency.

C. Voltage Control System Philosophy

The normal operating mode for the system is to set all generator exciters in the system to voltage control mode. The PMS HMI is set with each generator in regulated mode. This configuration allows the generation bus voltage to be completely controlled by the VCS. The VCS sends voltage raise and lower commands to each of the generation units, allowing each unit to maintain the 132 kV bus voltage while sharing an equal portion of the MVAR as a percent of available capacity for each generator. The voltage raise and lower signals, which are sent from the VCS, change the terminal

voltage on the generator and change MVARs through the generator step-up transformer. Therefore, what is interpreted by the exciter as a terminal voltage command to maintain the 132 kV will also share the MVAR output of the generator. The equitable sharing of MVARs is accomplished by setting each of the units with the same MVAR set points in the HMI. If one generator has a higher unit set point, it will share a larger percentage of the MVAR support than it would at a lower set point.

The VCS automatically creates new control arrangements for multiple-island systems. For example, if two islands exist, two completely autonomous solutions are required for active VCS control.

D. Island Control System Functional Overview

The PMS ICS performs the following functions:

1. Supervises all signals with communications-quality indications.
2. Detects electrical islands created by breaker and/or switch openings. The ICS successfully operates with any combination of generators connected to all combinations of the generation bus connections.
3. Shows in the HMI the total percent loading of all generators on that island.
4. Sends control operation messages that include information redundancy and shifting to provide data security and prevent false operations.

E. Generation Control System Error Handling

Several different types of failures are accounted for within the GCS. It is important to note that the GCS is designed so that it does not need to control every generator in the system to function. If a generator is unresponsive or has a loss of communication, the PMS GCS is limited in its capability to maintain the system. However, the GCS will continue to manage all remaining units under its control while maintaining the system integrity at the set parameters. The details of the different error compensation methods used by the GCS are outlined in the following subsections.

1) Communications

The PMS GCS dynamically tracks the health and communications status of all front-end processors, as well as the enabled status of the individual intelligent electronic devices (IEDs) to which they are connected. The GCS immediately recognizes a communications or equipment failure and sends an alarm to the HMI screen. The adaptive algorithm monitors the health of the IEDs used for data acquisition and control and reconfigures its solutions to account for the failure.

2) Unresponsive Generator

Expected system responses are monitored by the GCS. If the GCS does not detect the expected results or if the mode for the governor or exciter is not the expected mode, the system will flag that generator as unresponsive and display an error alarm. The alarm will also be automatically raised if the governor or exciter is in a different mode than expected. Once a generator has been flagged as unresponsive, it is removed

from the load-balancing algorithms by disabling either the AGC system or the VCS.

3) Data Acquisition Device Failure

Redundant gateways send the voltage and frequencies. If either gateway experiences a communications failure, or any other failure, the alarm signal will cause the GCS to automatically switch to the alternate gateway for both its frequency and its voltage source. A similar redundancy is used to receive the 52A and 52B contacts from the relays. A communications failure will cause the binary inputs of the other device to be used. If no frequency (AGC system) or voltage (VCS) from the generation busbar is present, the respective control will turn off.

4) Insufficient Capacity Warning

The ICS screen shows the total percent loading of all generators on an island. This must be monitored to ensure that the loading of the island does not become excessive and that an adequate margin is maintained. The ICS will generate an alarm if there is insufficient power to maintain frequency or insufficient MVARs to support voltage. If a generator has run out of capacity in either direction, the At Max Capacity alarm on the AGC system and VCS will illuminate.

5) Frequency and Voltage Warning

The frequency warning indicates when the steady-state frequency of the system falls below 49 Hz or rises above 51 Hz for a certain time. The voltage warning indicates when the steady-state voltage of the system falls below 0.9 per unit or goes above 1.1 per unit for a certain time. This alarm occurs when the MW/MVAR reserve margin for the island is completely used up and as a result, the frequency and voltage begin to fall.

6) Generation Control System Failure Indication

The input/output (I/O) modules at the generators each have an A-type contact (open in the quiescent state) that is held closed under normal operations. The health of the GCS is monitored, and the contact is opened if it detects a GCS failure. These contacts, which are wired in parallel between the redundant GTG interface, function such that if both I/O modules fail or communication from the GCS to both I/O modules fails, it will cause the contacts to open. Then, an input monitoring these contacts in parallel detects a control system failure to that specific GTG when both contacts open (the input wired to these contacts will be normally high and will alarm when low). These contacts are wired in parallel because the loss of a single I/O module GTG interface does not constitute a loss of control.

F. Automatic Synchronization

This section describes the automatic synchronizer that was developed to synchronize islands formed in the LNG facility system. A total of 12 relays were used for automatic synchronization as shown in Fig. 1. The relay used for this application was programmed to perform the automatic synchronization via the synchronization logic (synchronizing/synchronism-check device [25A]) elements in the relay. The controls included local and remote initialization

of the automatic synchronization process and monitoring for alarms.

The automatic synchronization relay was used to track phase rotation, phase angle, frequency, and the voltage of one power system and to compare them to the frequency and voltage of another power system before allowing the circuit breaker to be closed.

The automatic synchronization relay system can also perform the following functions:

1. Inform the GCS about the status of the 25A (i.e., initiated, paused, aborted, or failed).
2. Display frequency angle margin, voltage magnitude difference, and frequency magnitude difference acceptance criteria for automatic close.
3. Provide a close fail alarm and indication if the controlled circuit breaker fails to close within an operator-settable time.
4. Provide a close lockout alarm and indication if the controlled circuit breaker opens within a specified time after a close.
5. Allow either bus to be the controlling unit depending on which units are in service. All voltage and frequency matching controls originate from the GCS.
6. Use two series relays for sync-check (25A) to increase the security of automatic synchronization. The automatic synchronization relay and supervisory relay are shown in Fig. 4.

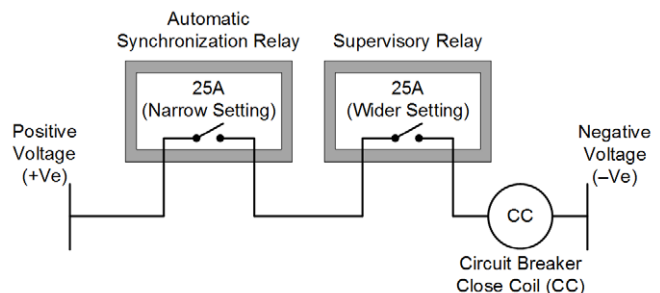


Fig. 4 Two Sync-Check Relays in Series

IV. POWER MANAGEMENT SYSTEM LOAD-SHEDDING SYSTEM

After industrial systems are islanded from the utility, they will have a small inertia. Based on the system inertia and the response by the governor to arrest the frequency, the frequency decay might be very high and the protection for the generators might trip the generators before any underfrequency causes the necessary loads to shed.

The typical scenarios that might lead to underfrequency in the system include opening a generator, utility lines, or power-wheeling circuit breakers. Opening any of these breakers will create a power mismatch between the electrical power and the mechanical power. If the system loses its source of power, the frequency will start to go down and loads must be shed to balance the system again. The faster the load is shed, the faster the system will regain its balance [5].

The following subsections explain the different methods of load shedding that have been used in the LNG facility to rebalance the mismatch between the electrical and mechanical power within the system after disturbances. The section concludes with a summary of the technical and economic benefits of the load-shedding system.

A. Contingency Load-Shedding (CLS) System

CLS is the primary scheme that sheds load based on a predicted power deficit when a contingency occurs. Contingencies are defined as the opening of breakers that cause the loss of one or more power sources. This scheme sheds the total facility load to less than the calculated available capacity, based on the measured capacity. The calculation is done before a contingency occurs and includes the sum of the incremental RM (IRM) of the power sources in the remaining generators. This scheme only operates when a contingency breaker is opened under load.

The amount of load selected to shed is based on the system IRM. The IRM factor, in units of MW/Hz, is the amount of step-change in load required to result in a specific frequency change in the system.

For every scenario, the system predetermines the amount of load to shed. Calculations take into account the bus topology and available power that can be supplied from various sources. When the amount of load to shed is determined, loads (or load groups) are automatically selected for shedding based on bus connection and an operator-defined priority list. If the system detects an event requiring load shedding, load is shed according to the preselection logic. Load is shed via high-speed outputs from I/O modules wired directly to breaker trip coils. After a system event, logic will dictate how the system responds to subsequent contingency triggers.

B. Underfrequency Load Shedding

This scheme sheds load based on underfrequency thresholds. It sheds the amount of load predicted to correspond with levels of frequency excursion. This scheme backs up the primary load-shedding scheme by detecting frequency decay that would be caused by a contingency breaker opening and the CLS system failing to operate.

The underfrequency scheme is considered to be a centralized underfrequency LSS. This centralized style of load shedding serves to correct all known weak points of traditional underfrequency systems. These centralized schemes still shed load based on several underfrequency thresholds; however, the signals are sent from remote devices to a centralized processor.

Generator protection relays use the frequency relay (81) elements to advise the underfrequency-based load-shedding (UFLS) controllers when underfrequency thresholds have been crossed. The UFLS controller then declares an underfrequency event and selects an amount of load to shed based on the frequency response characteristic of the system. Each underfrequency level progressively sheds more load. If the system fails to recover and the next level is triggered via threshold detection, more loads are shed based on the set point.

This application runs on its own dedicated hardware. It serves as a backup for the contingency-based system in scenarios that involve a breaker opening without sending the system a trigger input (such as equipment failures, broken wiring, or shorted current transformer windings). There are many failure modes that might not be detected by the CLS system, such as a contingency in alarm, a GTG beginning to lose its output power due to bad quality natural gas, or a generator cool shutdown initiated.

Based on these issues, to protect the system it is recommended to always have another scheme that is based on the power system behavior (frequency based) as a backup scheme.

The UFLS accesses the same operator-defined priority list as the CLS system to dynamically select loads or generators that must be shed to equalize the generation to load balance. The UFLS also tracks the bus configuration to select loads associated with the underfrequency bus in advance of the contingency. If loads are triggered to be shed on the CLS system, an indication that these loads are already being shed will be sent to the UFLS; therefore, they are masked from selection in both controllers.

Power system real-time simulations are used to find the Level-1 and Level-2 pickup setting values to determine the underfrequency pickup and time-delay values used to initiate underfrequency contingencies. Power system simulations indicate the amount of load reduction required for each underfrequency contingency.

C. Progressive Overload Shedding

The PLS portion of the LSS code is treated as an overload contingency within the LNG facility system, similar to a contingency breaker being tripped [2]. However, instead of monitoring the breaker state, this contingency is asserted when the PLS integrator value exceeds an operator-settable value.

The PLS pickup starts when the power produced by a generator is higher than an operator-settable percentage of the individual generator capacity, which is referred to as excess load threshold. The PLS pickup time is proportional to the difference between this operator-settable threshold and the present output of the unit. The PLS also has a drop-down timer, so that a brief power output lower than the operator-defined set point will not cause the integrator to reset immediately. For example, a single generator rated at 36.4 MW at 27.3°C from the factory may be slightly derated because of ambient temperature; therefore, the actual capacity might be 34.00 MW. If the operator enters a value of 95 percent, the integrator will begin integrating when this single generator exceeds 32.3 MW of load. The lowest PLS setting will be coordinated with the GCS upper-limit setting. The PLS is supervised with underfrequency.

D. Load Priorities Group and Load Pairs

Priorities are set for each load by entering it into a specific load-shedding group. The operator can also assign priorities to the load-shedding groups. Once all loads within a load-shedding group have been selected to be shed for a specific contingency, the loads listed for the next sequential group will

be selected until the calculated power deficit is satisfied. In this case, loads can be grouped by priority such that the loads on the first action table will be the first to be shed. When no more loads can be selected from that list, the system begins selecting loads from the second list, and so on. These action tables allow the operator to have complete flexibility in defining the priority and grouping of loads to be shed; yet, provide optimal levels for selection of load shedding. The system at the LNG facility has a maximum of ten configurable action tables. Within the group, the operator can assign the same priority to different loads; therefore, loads with the same priority will be shed together.

An example load priority table is shown in Fig. 5. Note that the group load-shedding option priorities are limited to Numbers 1 through 10. Hence, each load-shedding option must have a unique, non-zero priority ranging from 1 through 10. The LSS sheds load with the smallest priority first. For example, a load set to Priority 1 will be shed first when compared to a load set to Priority 2, if both are available for shedding. If a load-shedding priority is set to zero, the load will be inhibited from being shed. Fig. 6 shows the flowchart for the LSS used in the LNG facility project.

Low-voltage switchgear is sourced from transformers that are connected to outgoing feeders in the medium-voltage switchgear. Low-voltage switchgear include a main-tie-main circuit arrangement with an automatic transfer scheme (ATS) functionality. The LSS is configured to always shed both medium-voltage breakers that are feeding a low-voltage switchboard. This ensures that the ATS does not cancel out the LSS action by bringing the shed loads back online.

Load-Shedding Group		Load	Load-Shedding Priority	Load 1	Load 2	Load 3	Load 4	Load 5	Load 6	Load 7	Load 8	Load 9	Load 10
LS 1	Load Group 1	1				1	1						
LS 2	Load Group 2	2		1	2								
LS 3	Load Group 3	3						1	2	2			
LS 4	Load Group 4	4											
LS 5	Load Group 5	5											
LS 6	Load Group 6	6											
LS 7	Load Group 7	7											
LS 8	Load Group 8	8											
LS 9	Load Group 9	9									1	2	
LS 10	Load Group 10	10											1

Fig. 5 Example of a Load Priority Table

E. Variable-Frequency Drive Starting Inhibit

At the LNG facility, starting inhibit logic was implemented for the variable-frequency drive (VFD) feeders at Substation-4 (see Fig. 1). The LSS calculates the effects of the export compressor VFDs that are added to the system. This is accomplished by comparing the rated MW value of these loads to the total spinning reserve available on the island to which they connect. If a load is rated higher than the total spinning reserve of the island that it will be connected to, the load inhibit signal is sent to the process controls system.

An override control button is provided on the HMI to override the inhibit signal from the PMS. If the motor does not start after 15 minutes, the override command automatically resets.

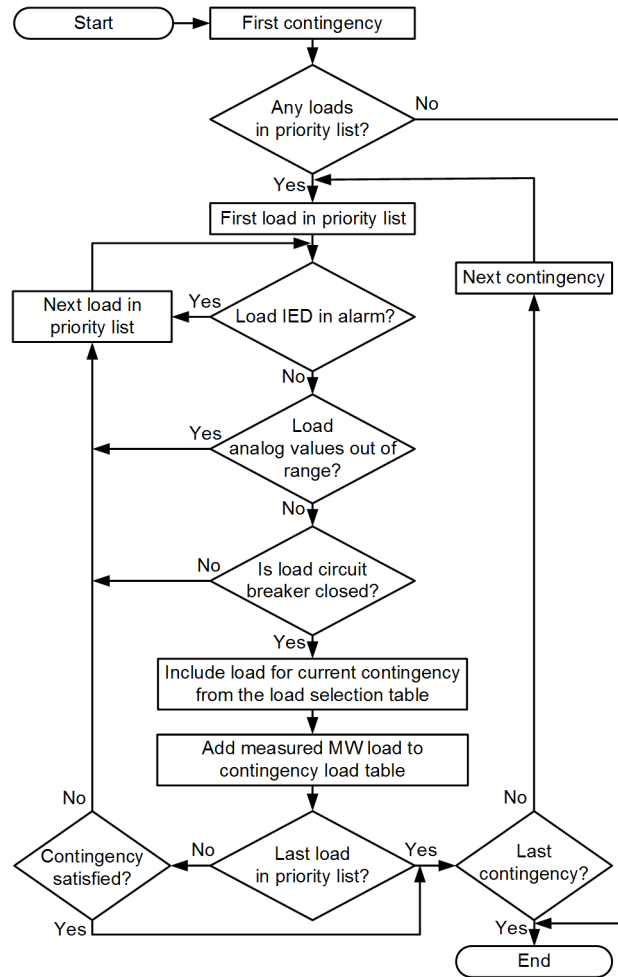


Fig. 6 LSS Selection Algorithm

F. Summary of Technical and Economic Benefits

Load-shedding schemes were incorporated in this LNG facility because they possess the following technical and economic benefits:

1. Maintain the island stability during any contingency event by fast CLS and with the backup UFLS scheme.
2. Prevent generators from overloading by using a PLS scheme, which also protects the assets by shedding loads.
3. Execute process-based priority shedding by load-shedding groups, in addition to different load pairs.
4. Track the topology of the system in real time to provide the correct load shedding in multiple islands.
5. Handle simultaneous or closely timed contingency events to reduce system blackouts.
6. Provide more reliability to the system by using a redundant controller.
7. Provide event reports for post-event analysis.

V. REAL-TIME SYSTEM MODELING AND VALIDATION

Hardware-in-the-loop testing, using a real-time power system simulator [7], was adapted to test the PMS for the LNG facility. The real-time simulator was connected to the PMS controllers to form the hardware in the loop. The closed-loop validation of the PMS was accomplished during factory acceptance testing for the LNG facility project.

Fig. 7 shows two different scenarios for a GTG response to one expander generator tripping and the Underfrequency Level-1 being triggered. In both cases, two GTGs are running at 30 MW and the expander generator is running at 9 MW. The expander generator is tripped and the frequency response of the GTG is shown in Fig. 7. The first scenario occurred when one GTG was running in ISOC mode and the other was running in droop mode. The second scenario occurred when both GTGs were running in droop mode.

Underfrequency Level-1 was triggered at 47.5 Hz after 100 milliseconds. Approximately 20 MW was shed, and the ISOC unit controlled the frequency back to 50 Hz. There was no significant difference in either overshoot or undershoot for both curves.

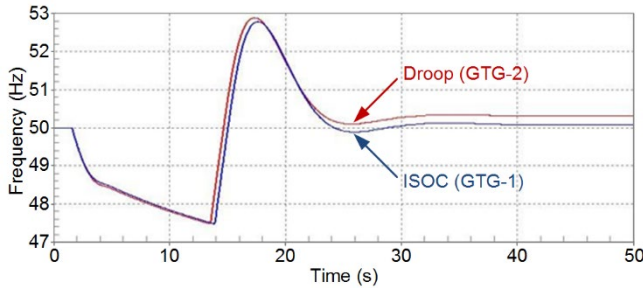


Fig. 7 Comparison of Droop Versus ISOC Response for Loss of 9 MW Expander Generator

Fig. 8 shows the electrical power response of the ISOC GTG-1 unit compared to the droop GTG-2 unit when a 9 MW expander generator was tripped and Underfrequency Level-1 was triggered.

The dynamic electrical power responses for both units are very similar. However, the steady-state settling power to the units is different. The droop unit returned to the original power set point, while the ISOC unit backed off to maintain the frequency.

An important note is that the expander generator was not part of the CLS system; therefore, the CLS system did not take any action for the event. The GCS redispached the droop unit to an equal share with the ISOC unit, and after a few minutes, both units were sharing equally.

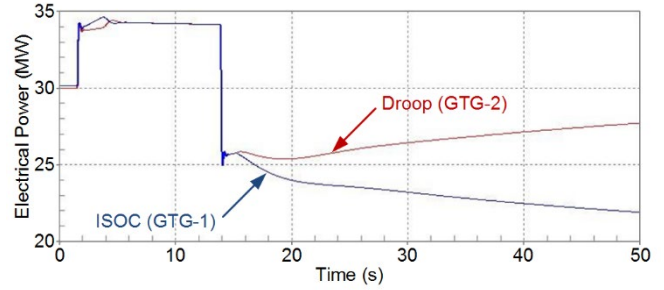


Fig. 8 Electrical Power Comparison of GTG-1 Unit Versus GTG-2 Unit for Loss of 9 MW Expander Generator and Level-1 Underfrequency

VI. CONCLUSIONS

The PMS of an islanded system has many critical functions that protect the system and increase the reliability of the electric power system.

This project required a series of customizations of the CLS load group implementation and low-voltage ATS pair load shedding in addition to VFD start inhibit.

The GCS must maintain the voltage and frequency at all times at normal values. The GCS allows the LNG facility to operate using one ISOC unit or all droop units, based on the operator's selection. The modes of operation for the GTGs are implemented to provide flexibility to meet the characteristics of the LNG facility loads. The automatic synchronization system was also designed to synchronize all generators across the breaker-and-a-half scheme.

Hardware-in-the-loop simulation and testing were crucial methods to assess the PMS functionalities because the facility was a greenfield; therefore, it was impossible to perform any testing in the greenfield. The results of the hardware-in-the-loop simulation provided great confidence to the operators and engineers of the working PMS.

VII. NOMENCLATURE

25A	Synchronizing/synchronism-check device.
81	Frequency relay.
P	Real power.
Q	Reactive power.
-Ve	Negative voltage.
+Ve	Positive voltage.

VIII. ACKNOWLEDGEMENT

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X. VITAE

Abdel Rahman Khatib, P.E. (M 1999, SM 2016), received his B.S. and M.S. in electrical power engineering from Military Technical College, Egypt. He received his Ph.D. from Virginia Tech in 2002. A senior power system engineer, Abdel has nine years of industrial experience focusing on power management system design, testing, and commissioning for the petrochemical industry. His research interests are power system modeling, load flow and dynamic stability, and power system protection. He has 12 years of university teaching experience and holds P.E. licenses in Washington, California, Texas, and Indiana. He can be contacted at abdel_rahman_khatib@selinc.com.

Anshuman Mallia is currently a senior electrical power systems engineer with the Chevron Energy Technology Company. His responsibilities include design, development, and testing of power management, fast load-shedding, generation control, and closed-loop simulation systems. In addition, he maintains the associated Chevron Engineering Standards. He received his B.S. in electrical engineering in 2001. He can be contacted at amallia@chevron.com.

Bowen Dai received his B.S. in electrical power engineering from Huazhong University of Science and Technology, Wuhan, China. He received his M.S. in electrical engineering with a power system focus from the University of Southern California in 2011. He has over seven years of experience in substation automation, from engineering design to procurement and commissioning. His technical expertise includes programming of logic for country-wide remedial action schemes, power management systems, microgrids, SCADA systems, and networking applications. He can be contacted at peter_dai@selinc.com.

Roberto Costa is a regional director for SEL Engineering Services, Inc. at Schweitzer Engineering Laboratories, Inc. (SEL). He received a Master of Science degree in electrical engineering from Università degli studi di Genova, Italy. He has over 19 years of experience in substation automation, from engineering design to procurement and commissioning. He can be contacted at roberto_costa@selinc.com.

HOW TO SAFELY ISLAND A CHEMICAL FACILITY

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Asad Mohammad
IEEE Member
Schweitzer Engineering
Laboratories, Inc.
2350 NE Hopkins Court
Pullman, WA 99163, USA
asad_mohammad@
selinc.com

Aaron Fontenot
IEEE Member
The Dow Chemical
Company
21255 Louisiana Hwy 1
Building 4301, Office 13
Plaquemine, LA 70764, USA
adfontenot@dow.com

Nigel Jordan
The Dow Chemical
Company
21255 Louisiana Hwy 1
Building 2801, Office 1
Plaquemine, LA 70764, USA
nrjordan@dow.com

Hariharan Subramanian
Senior Member, IEEE
Schweitzer Engineering
Laboratories, Inc.
2350 NE Hopkins Court
Pullman, WA 99163, USA
hariharan_subramanian@
selinc.com

Abstract—In a chemical plant facility with excess generation, it is not only beneficial to export excess power, but essential to support the utility's load by maintaining a certain minimum power export. A chemical plant's electrical stability is of highest importance because downtime and unplanned events pose potential risks to the plant, personnel, and environment.

This paper describes how rate-of-change of frequency (ROCOF) detection is used to safely island a chemical plant from a utility. This is followed by runback and generation shedding. Decoupling protection design, benefits, and limitations are explored with results from hardware-in-the-loop (HIL) testing. The ping-pong effect between sheddable loads and generators is discussed and underfrequency-based load shedding as back up is also introduced.

Index Terms—Decoupling, generation shedding, generator runback, inertia, HIL testing, rate-of-change of frequency (DFDT) (ROCOF), load shedding.

I. INTRODUCTION

A. System Overview

The chemical facility power system is a combined heat and power facility that has steam and power generation sources

across the facility at different voltage levels separated into three main areas as illustrated in Fig. 1. Area 1 has four gas turbine generators (GTGs) and one steam turbine generator (STG) connected to the 230 kV breaker-and-a-half substation. This is the largest power generation area where power is distributed to the remainder of the chemical production facility and the utility. The facility is almost always exporting power, which is about half the total generation capacity, to the utility during normal operation through three utility tie lines. The power export to the utility is nearly the same across the three utility tie lines, and each has the capacity to carry the entire power export from the facility. The facility *can* decouple if the frequency-based protections on the line operate and trip all tie lines together. The three lines serve as redundant connections where one or more lines could be isolated for maintenance routinely.

Area 2 has two GTGs and two synchronous condensers (SCs) to provide VAR support to the 15 kV bus. This area imports additional power from a 230 kV system through step-down Transformers T1, T2, and T3 (230/15 kV) as illustrated in Fig. 1. Area 2 also sends power to Area 3 through two interconnecting tie lines. Area 3 has four GTGs that provide power to the loads connected at this area of the facility.

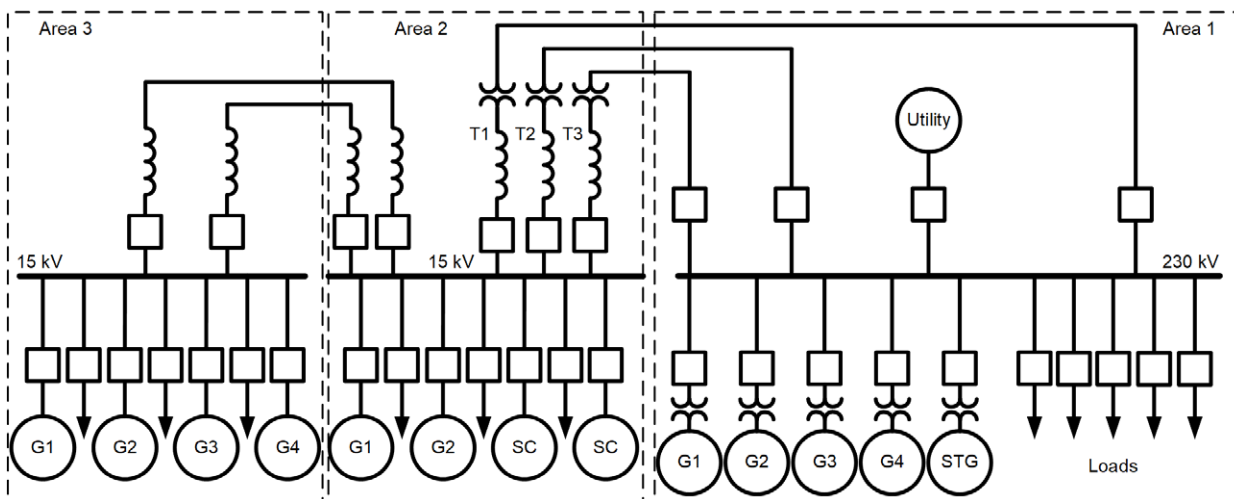


Fig. 1 Simplified One-Line Diagram of the Facility

The major loads for the plant are connected at the generator supported buses in Area 2 and Area 3. The 15 kV power distribution switchgear has many series reactors that are used to limit the short-circuit current and regulate power flow.

B. Problem Statement

This power system can produce more power than the required load within its plant. This excess power is exported by the facility to the utility for distribution to its customers. The facility is primarily in export mode, where a portion of its generation capacity is exported under normal conditions. In a situation where the system is suddenly disconnected from the utility due to an undesirable condition, the excess generation needs to be reduced and balanced with the system load to maintain system stability.

This paper discusses solutions implemented in the facility using protection and microgrid control systems for the detection of unstable conditions, isolation from the utility, and resolution for system instability.

C. Power Swing Equation and Critical Clearing Time (CCT)

The CCT is the maximum time interval by which the fault must be cleared to preserve the system stability [1]. The CCT is essential to evaluate the system performance but is impacted by many factors. The CCT in the plant, recorded through simulation studies, is the maximum time a three-phase fault at the intertie needs to clear before the generators in the plant lose complete synchronism. The CCT was used as a reference in performing transient stability tests on the system and in the design of the decoupling protection system.

Fig. 2 depicts an example equal area criteria illustration. The most critical fault for system stability is the three-phase fault. In general, fault types involving more phase conductors are more critical for stability.

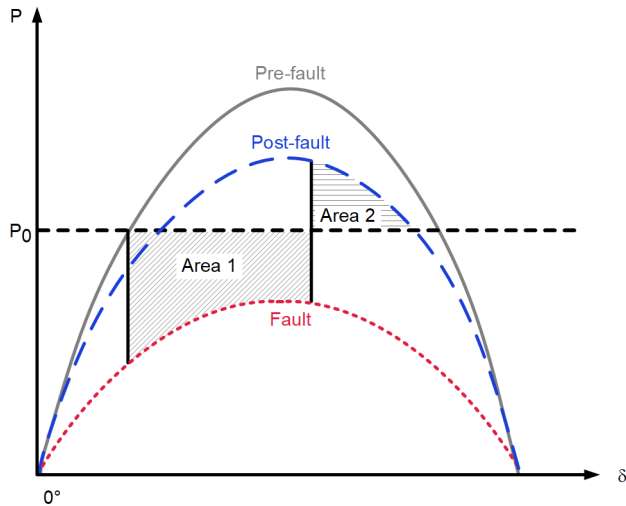


Fig. 2 Equal Area Criteria

When a fault occurs on the transmission system, the power flow is predominantly reactive due to the dominant inductive impedances of the transformers and lines. During the fault, the voltage at the fault is zero, and the voltage at the terminals of

the generators is significantly reduced. The low voltage restricts the real power flow from the generators. Since the prime movers driving the generators are continuing to produce real power, the generator accelerates due to the law of conservation of energy. This acceleration continues until the faulted transmission line is disconnected from the system. With the fault removed, the real power starts moving from the generators to the load, and the generators decelerate. With the removal of the faulted transmission line from the power system, the transmission path impedance is increased.

Fig. 2 shows Area 1 as the accelerating area and Area 2 as the decelerating area. This figure depicts an unstable system. Slow fault clearing causes a large accelerating area, which cannot be compensated by a corresponding decelerating area. The equal area criteria method helps determine stability of a system without the need to solve the swing equation. This method is applicable for one machine connected to an infinite bus or for two machines. Using this method, the CCT is determined for the facility.

II. DECOUPLING PROTECTION DESIGN

A decoupling scheme detects disturbances in the utility power system and intentionally islands the microgrid. Disturbance detection settings for such intentional decoupling systems should be carefully set to avoid being too sensitive and to prevent nuisance tripping [2].

Decoupling protection is essential for safely islanding the facility and triggering other important actions within the facility, such as generator shedding, load shedding, and generation control. This section introduces the decoupling characteristics and how the sensitivity of the decoupling protection is set.

Equation (1) is from [3]:

$$\Delta f_{PU} = \frac{\Delta P_{PU}}{2H} \quad (1)$$

where:

Δf_{PU} is change in frequency in pu.

ΔP_{PU} is change in frequency in pu • seconds.

H is inertia in seconds.

During a transient in the system, the deviation in frequency without the interference of any control system (which is usually the first few cycles after an event) is a consequence of the power exchange and system inertia.

The decoupling design is based on two factors:

1. The power exchange with the utility
2. The total system inertia

The worst-case scenario is when the breakers upstream on the utility side are opened unintentionally and the system responds to the sudden mismatch of the overall generation and load within the facility. This condition is considered to be the worst case since any connection to the utility would just add more inertia. This test condition is set up for all further discussions regarding decoupling in this section. Since the facility is always exporting power, a positive DFDT condition is the focus of the adverse frequency condition.

A. The 81RF Element Characteristics

The 81RF element provides a faster response compared with the frequency (81O and 81U) and ROCOF (81R) elements. The faster response times make the 81RF element suitable for detecting islanding and system disturbance conditions with critical time requirements.

Fig. 3 shows the 81RF characteristic. This element uses frequency deviation from nominal frequency ($DF = \text{FREQ} - \text{FNOM}$) and ROCOF to detect islanding conditions.

Under steady-state conditions, the operating point is close to the origin. During separation from the utility, depending on the frequency difference and the ROCOF, the operating point enters the operating region of the characteristic. If the system is accelerating, the operating point enters Trip Region 1, and if the system is decelerating, the operating point enters Trip Region 2.

Fault-blocking logic is used to restrain the element under fault conditions or other conditions where the frequency measurements are not reliable. At the same time, if the fault is not cleared within the CCT, the decoupling should not be blocked, and a trip signal must be issued. The logic unblocks and arms the decoupling if the fault persists for more than eight cycles. The timing is determined based on the CCT of the facility.

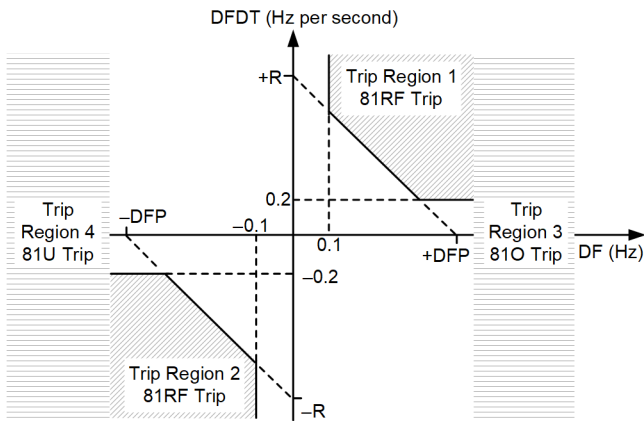


Fig. 3 Decoupling Scheme Characteristics

The 81RF element should be secure so it does not operate in conditions of faults and other spurious switching events. The slope of the 81RF characteristic is the equation of a line, as shown in (2).

$$y = m \cdot x + c \quad (2)$$

where:

y is DFDT.

m is the slope of the line.

x is df (slip frequency).

c is the y intercept.

If the DFDT of a frequency swing is known, it is easy to calculate the frequency at which the decoupling protection triggers when the slope and y intercept are known. The same applies if the DFDT of the event is calculated based on the slip frequency (df) where decoupling happens. A faster DFDT can

result in quick detection for 81RF protection and a slower DFDT picks up the 81RF event slower, as demonstrated in the following sections.

B. Power Export and 81RF

This system usually exports 50 percent of its total generation capacity, which is also about 75 percent of its total export capability. In a high-export condition, the ΔP is high enough to create a fast DFDT. In a condition when the upstream breaker is opened, a DFDT of about 4.13 Hz/second is observed.

Similarly, a low-export condition is at 20 percent of the total generation capacity, which is also about 30 percent of its total export capacity. In a condition when the upstream breaker is opened, a DFDT of about 2.36 Hz/second is observed.

Fig. 4 shows a comparison of the frequency response of the system in a high-export and a low-export condition, respectively. It can be noted here that the decoupling protection isolates the system faster in a high-export case with a faster DFDT than the low-export condition.

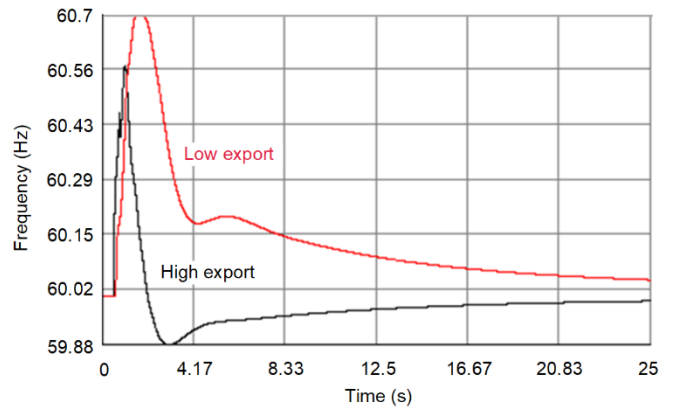


Fig. 4 Impact of Power Exchange on Decoupling

C. System Inertia and 81RF

The inertia of a machine is calculated as the combination of the rotating masses that store kinetic energy. It is represented as inertia constant (H) with the units MWs/MVA or just seconds. In practical terms, it represents the time in seconds a machine takes to respond to one pu change in speed in terms of acceleration or deceleration [3].

In a system like this one, the combination of multiple machines connected directly online (generators or loads) provides cumulative system inertia. To find the cumulative H of the system, the inertia of each machine is measured against a common base and summed. For a conservative design of the system, the inertia contribution from any load machines is ignored. In many cases, inertia contributions from loads are insignificant in comparison to big generators.

The decoupling protection is as sensitive to inertia as it is to the power exchange with the utility. With a higher inertia, a DFDT recorded by the decoupling relay is smaller than the DFDT recorded with a lower inertia in the facility. The combined inertia of the machines online store kinetic energy during a transient, thereby dictating the DFDT of the facility.

Fig. 5 shows the frequency response of the system in a high-inertia and a low-inertia condition, respectively. In both cases, the amount of power exported is the same, at 30 percent export of the total plant capacity. It is seen from the plot that decoupling is not triggered in a high-inertia condition. It is more beneficial to run fewer machines in a lower export condition for a successful decoupling.

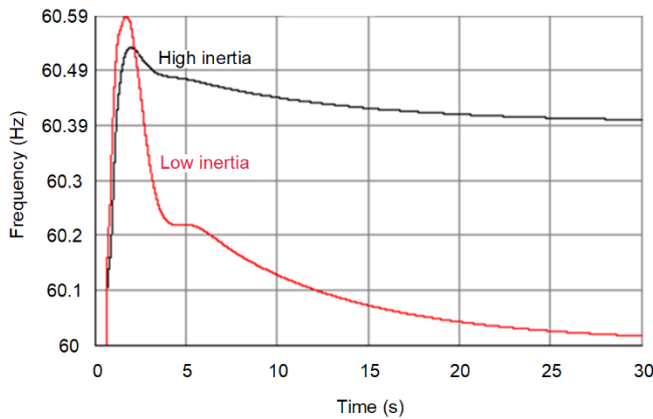


Fig. 5 Impact of Inertia on Decoupling Protection

III. MICROGRID CONTROLLER SOLUTIONS

After a safe decoupling event, facilities with significant exports and imports with a utility need a controller that is able to detect the event as a contingency and take action to maintain their system's stability. This system requires a controller that can act on a generation-shedding system (GSS) contingency as well as a load-shedding system (LSS) contingency, depending on whether the system is connected to a utility or islanded. Decoupling from the utility triggers a GSS contingency, and the controller takes action by shedding some generators and issuing runback to other generators. Once in an islanded system, the same controller now monitors the system for LSS contingencies, such as loss of generation or tie lines and bus couplers within the facility through which power transfer is occurring. The microgrid controller's primary goal is to always monitor the system for power imbalance between the source and load and take appropriate action by shedding generators or loads to maintain the stability of the system.

A. GSS Introduction

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, making 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 defined as any event that results in excess generation on an islanded system. Contingencies can occur when a tie line or bus coupler breaker opens under load. The GSS algorithm then determines the generation to shed and run back based on the contingency status and metering

information, user-settable generator-shedding and runback priorities, user-settable decremental reserve margin (DRM) values, topology status, and generator status. The GSS sends the generator trip signals to corresponding generator breakers and runback signals to respective generator controllers with analog MW set point (runback level).

B. Generator DRM

DRM is defined as the capacity of a generator to reject load without affecting its frequency and stability. Unit DRM is the amount of step decrease in generation that a generator can provide within the tuning time response of the governor (typically one second). Manufacturers describe this as the "load rejection capability within system stability margins."

System DRM is the accumulated total of the DRM of all online generators available in a system. Island DRM is the accumulated total of the DRM of all online generators connected to a given island.

When the system is islanded from the utility, one of the generators goes to isochronous (Isoc) mode to maintain the frequency that reduces the overall system DRM to the difference between the present power of a generator before islanding and the minimum MW level of this Isoc unit. The Isoc unit at a steady state rejects the total excess load after islanding, and the droop machine's steady-state loading is back to its original loading. Hence, the maximum system DRM equals the Isoc machine's MW power output just before islanding—the minimum MW limit of the Isoc machine.

The system DRM should be capped well above the Isoc unit's minimum MW limit to avoid stability issues with the Isoc machine. Some manufacturers of turbine controllers do not allow the governor to instantaneously respond to deviation in load rejection at a user-settable DRM value. The DRM used by the GSS is the lesser of two values: the minimum MW limit set in the controller (five MW) and a user-enterable maximum DRM. The GSS uses DRM only when the DRM on an island is greater than the excess generation. If the excess generation in an island is greater than DRM on an island, then DRM is not considered in the calculations.

C. Generator Runback

Generator shedding works in coordination with the generator runback. Upon detection of a contingency (loss of tie line or loss of a large load), the controller calculates the excess generation value on the exporting island and selects the generator to shed to ensure that the frequency of the system quickly recovers to the rated 60 Hz. Because generator shedding and runback must work together, both functions are part of the GSS. The decision to shed generators and to run back generators depends on the plant load, the amount of excess generation on the system, and the generator runback capacity.

Generator runback is used to quickly reduce the generators' output to bring the system frequency back to nominal. The generator runback characteristics (frequency versus time) are typically similar to the generator load rejection characteristics.

The GSS calculates the runback target load set point for each generator. The runback target load set point indicates the

desired MW operating set point of the generators. Refer to Fig. 6.

The GTG governor controllers, on receipt of the runback signals, process these signals the following way:

1. Change the control fuel valve position to the output MW power to match the runback target load set point from the GSS.
2. Change the mode of operation of the GTGs, if required, based on target runback set point.
3. Maintain the generator MW set point at the runback target load set point.

The operational philosophy described previously is also shown in Fig. 6.

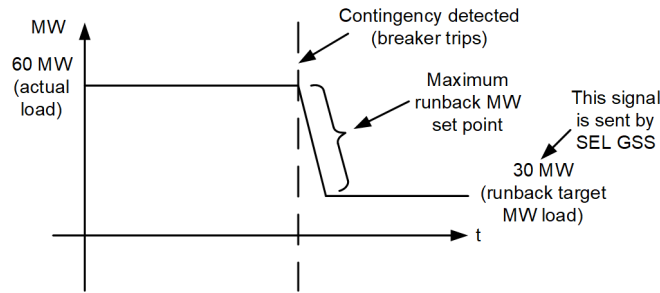


Fig. 6 Generator Runback Target Load Set Point

The GSS algorithm and logic, as shown in Fig. 7, explains how the generation-shedding and runback logic works and

E_g (excess generation) =
island source – island load

IDRM (island decremental reserve margin)
= $\sum$ island generation DRM

TRB (total runback capacity)
= $\sum$ runback capacity of generation

RB cap (runback capacity)

%P (threshold above which a
generator is selected in
percentage)

While loop for shedding is based
on generation availability and
priority. If not available, then this
loop inhibits that generator and
checks the next priority
generator for shedding.

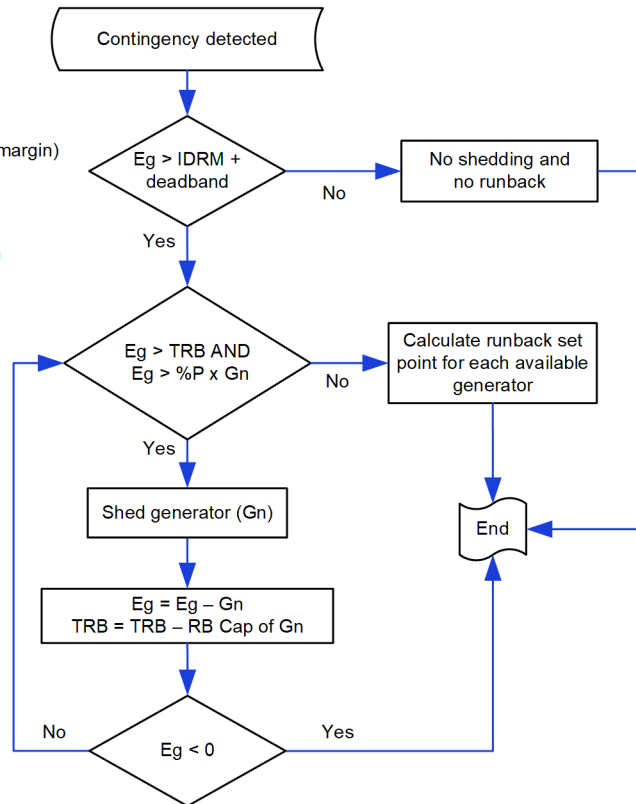


Fig. 7 GSS Control Logic

takes action based on a contingency. It is important that GSS does not overshoot generation so that the runback is used to balance the shedding and keep it to a minimum. Generator runback and shedding together create a robust response to stabilize the system in case of a utility line outage contingency when the facility is exporting power.

D. HIL Test Setup

HIL testing is an excellent tool for validation of a control system or protection and helps in validating design, troubleshooting errors, and preparing for all scenarios without the need to test in the field, thereby avoiding downtime and potential hazards. IEEE 2030.8 [4] recommends testing the microgrid controller system (MGCS) with control HIL (cHIL) and the protection relays with protective HIL (pHIL).

Fig. 8 shows the testbed considered for evaluating the decoupling protection and the microgrid control system. In HIL setup, voltage and current signals from the real-time digital simulator (RTDS) are hardwired to decoupling relays through an I/O cube. The microgrid controller receives all the data from the RTDS through the front-end processor using communication protocols like DNP3 and GOOSE. The RTDS provides real-time data to the microgrid controller and decoupling relays similar to the field data; hence, this setup helps to test the system in a close-to-field conditions. This sort of HIL testing and validation improves the confidence in the algorithm and logic of the microgrid controller.

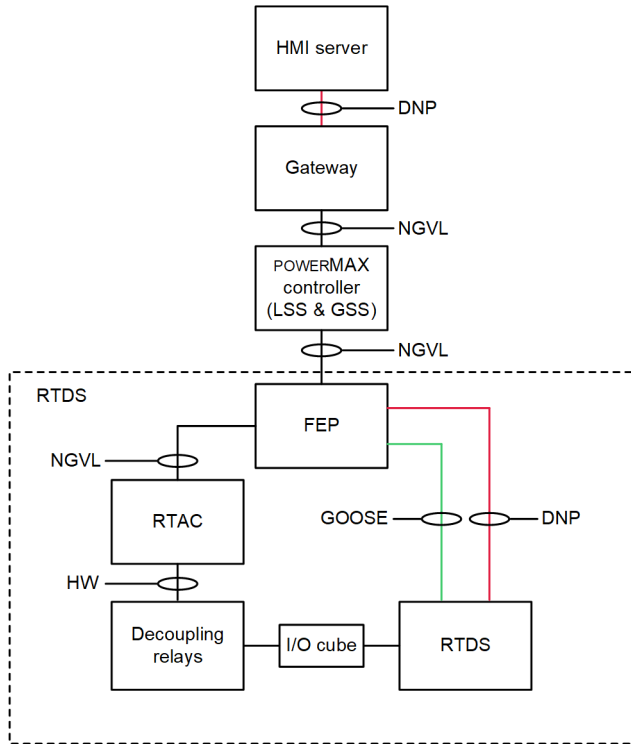


Fig. 8 HIL Simulation Test Bed

E. Simulation Results for Decoupling and GSS

Various scenarios with different power export conditions, different generators online, and different plant load conditions were tested using RTDS to validate the decoupling settings and microgrid controller response for several permutations of system conditions.

The result discussed here is from the high-export case shown in Fig. 4. Fig. 9 is an expanded view of that high-export case. T1 shows the time at which the decoupling relays detected and tripped the tie line breakers, followed by subsequent generator-shedding action within two to three processing cycles (10–15 milliseconds) of detecting the decoupling event. T2 shows the time at which generator runback signals were sent. The delay between T1 and T2 is due to the generator interface device converting the set point from the microgrid controller into an actual 4 to 20 mA signal to send it out through one of its analog outputs to the generator. A command to change one of the generators to Isoc mode is

also sent out at Time T2. After these actions are taken, the system frequency stabilizes and recovers to a nominal value over the next 25 seconds, as seen in Fig. 4. From the moment of utility disconnection, it takes less than 200 milliseconds for the microgrid controller to safely decouple and take control action by shedding generators and issuing a runback signal. The speed of operation of the microgrid controller after detecting is key in quickly stabilizing the system after such an event.

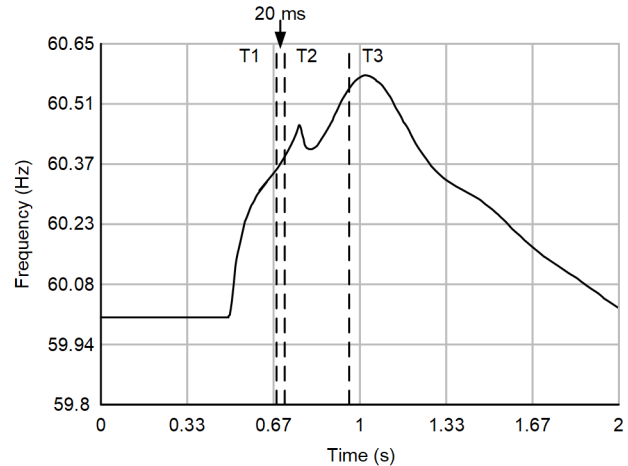


Fig. 9 Generator Runback Simulation Results for Decoupling and GSS

In the microgrid controller with GSS and LSS algorithms, it becomes critical to make sure that one algorithm does not trigger the other, as the action taken by one of them becomes a contingency trigger for the other. For example, as a result of GSS action, if generators are shed it can trigger a contingency for the LSS, and similarly, when the contingency-based load-shedding (CLS) system sheds a load, it could become a GSS contingency. Hence, to avoid such ping-pong-style action, both the GSS and CLS systems are logically coordinated such that the algorithms can monitor and detect each other's actions and contingencies, and they act only in cases of individual triggers and not based on each other's action. This is crucial, as incorrect algorithm supervision can result in back-and-forth shedding of generators and loads leading to a blackout.

F. CLS and Coordination

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

The primary goal of this LSS is to keep the steady-state frequency of the power system at nominal during a major loss of generation. 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). The secondary goal of the system is to minimize disturbances to loads during load-shedding events.

The conceptual architecture and the underlying algorithm for LSSs have been discussed in multiple papers for further reading [5] [6] [7] [8].

The CLS reduces the amount of load selected for shedding by accounting for incremental reserve margin (IRM) in its calculation. This limits the impact of the CLS. Another effect of incorporating IRM into the calculation is that the frequency commonly decays following a load-shedding event. This frequency decay level is a function of tuning in the governor, user-entered IRM, system inertia, and load composition. The larger the IRM the user enters, the greater the frequency decay for an LSS load-shedding event. This is because the IRM calculation forces the governors to tap into power reserves to keep the frequency at nominal.

G. Underfrequency Load Shedding (UFLS) and Coordination With Other Frequency-Based Protection

The UFLS is a backup protection system for the CLS that relies on the measurement of the system frequency from protection relays. This backup protection serves situations such as an out-of-service CLS, gradual decay of frequency, tripping of an alarmed breaker, load-shedding failure due to wiring or trip coil issues, and incorrect load metering values [9]. Fig. 10 shows the frequency line diagram used for coordination with other protections in the facility.

The UF Level 1 and Level 2 protections are derived after detailed underfrequency coordination and IRM study of the system. This study examined capabilities of the facility to accept step change in load, due to loss of some generation and coordination with other protections. Boundary operating conditions, normal operating conditions, detailed models of each generator governor, generator inertia, load inertia, and frequency protection settings are required to evaluate the most optimal solution for such protection.

Equation (3) shows a simple conversion of a machine's inertia constant to a common base.

$$H_{NEW} = H_{OLD} \cdot \frac{MVA_{base_{NEW}}}{MVA_{base_{OLD}}} \quad (3)$$

Using a boundary condition, the total inertia of the islanded system is calculated using (3) and the DFDT is estimated for a change in power (ΔP) using (1). Using these equations, several combinations of generators online are considered to estimate the lowest DFDT within the system. The following steps can be followed for estimating frequency deviation after loss of generation.

1. Calculate total inertia at common base MVA (excluding the generator that is simulated to be lost).
2. Record ΔP as loss of generation.
3. Calculate DFDT in Hz/second using (3).
4. Calculate Δf in one second.
5. Coordinate with other protection settings as in Fig. 10.
6. Repeat steps for other generation combinations and find boundary operating conditions for successful underfrequency protection.

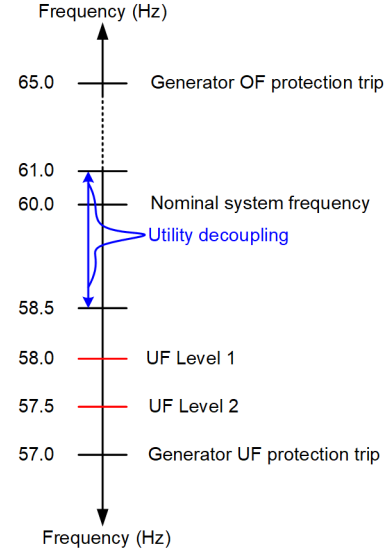


Fig. 10 Sample Frequency Line Diagram for Coordination

IV. CONCLUSION

This project design illustrates a complete solution for detecting unintended isolation of a utility, islanding the facility from the utility, and stabilizing the facility's frequency by balancing the generation and load. Using protection relays and microgrid controllers, this facility can be safely islanded and protected in its own islanded operation from adverse frequency instabilities due to sudden loss of generation or load.

It has also been demonstrated how HIL testing is helpful in validating the microgrid controller algorithms and decoupling protection design before any live testing on field. Simulation results showing a decoupling and GSS action have been discussed and illustrate how the fast-acting microgrid controller stabilizes the system within 200 milliseconds (including detecting of decoupling and taking GSS action).

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VI. VITAE

Asad Mohammad received his BE in electrical engineering from Andhra University, India, in 2011 and MS in electrical engineering in 2017. He previously worked as a substation design engineer and currently works as a power system studies engineer in Schweitzer Engineering Laboratories, Inc. (SEL) since 2017. He is a member of IEEE since 2015.

Aaron D. Fontenot, PE, received his BS from Louisiana State University in 2009. He worked at Dow Chemical for the first three years as an instrumentation, electrical, and analyzer maintenance and reliability engineer. In 2013, he began his career in Dow's Power and Utilities group as a support engineer and later managing the daily operations. He presently holds the title of senior technology manager in Dow's Energy Technology Center, providing support to Dow's Power and Utility organizations globally. He is a member of IEEE and a registered professional engineer in the state of Louisiana.

Nigel Jordan received his BS from the University of Mississippi in 2007 and MS from Louisiana State University in 2007. He worked at Southern Company for the first five years as a substation engineer in maintenance, design, and field services. In 2012, he joined Dow Chemical and has worked in site electrical support, as well as projects for Dow's Power and Utilities group. He presently holds the title of project manager in Dow's Feedstocks and Energy group executing projects in the Louisiana region.

Hariharan Subramanian received his BE from the College of Engineering, Guindy (Anna University) in 2005 and an ME from Texas A&M University in 2009. He worked at Schweitzer Engineering Laboratories, Inc. (SEL) as an automation engineer for three years, starting in 2009. He rejoined SEL in 2018 and is presently a senior engineer. He has experience in power system design, power system automation, power system protection and studies, and power management systems. He is experienced in the design, development, testing, and commissioning of projects with various customers in the oil, gas, and utility industries. He is a senior member of IEEE and a registered PE in Texas.

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Integrated Power Management and Protection System for a Remotely Located Islanded Facility

Mehul Joshi and Greg Smith, *Teck Resources Limited*Pradeep Varma Sangaraju, Ashish Upreti, and Maaz Kazmi, *Schweitzer Engineering Laboratories, Inc.*

Abstract—In the modern world, ensuring power system reliability and management is imperative for safety of human lives and to minimize production interruption. This is especially paramount for a facility such as Red Dog mine, which is situated above the Arctic Circle in Alaska, USA, with no available utility connection. This paper describes the design philosophy, system architecture, implemented solutions, and testing methodologies used for the power management system (PMS) provided for Red Dog. The entire electricity at the mine is supported by eight onsite generators, 5.5 MW each, distributed among three buses. Two of these buses are connected using a current limited reactor. The primary loads are personnel accommodation, ball mills, sag mills, stir mills, pumps, compressors, conveyors, and some variable-frequency drive (VFD) loads that have active front end (AFE) providing reactive power support.

The solution includes high-speed load-shedding, automatic generation control for frequency management, unique reactor control for limiting current (amperes), and VFD control for voltage stability, reactive load-sharing, and automatic synchronization of different electrical islands. The high-speed load-shedding system includes three algorithms that are contingency, underfrequency (UF), and overload-based schemes.

This paper also discusses control hardware-in-the-loop (cHIL) testing using a real-time transient-level computer model of the power system. This was used for functional testing of the PMS including protection and automation prior to field deployment.

I. INTRODUCTION

Red Dog, owned and operated by Teck Resources Limited, is an open pit zinc and lead mine, located about 170 kilometers (106 miles) north of the Arctic Circle in northwestern Alaska, USA. It has the world's largest zinc reserves and accounts for ten percent of the world's zinc production. Once the ore is processed, the lead and zinc concentrates are transported via a 84-kilometer (52-mile) road to a port facility on the Chukchi

Sea, which can only operate in the summer months due to the harsh winters.

Since Red Dog is a remote location with no connection to the grid, it is important to have an advanced power management system (PMS) that can not only protect the frequency and voltage stability under regular conditions but also prevent blackouts by taking high-speed load-shedding actions, when required.

The electrical power requirement at the mine is met by eight onsite generators, each one rated at 5.5 MW and fed into three different buses. The eight diesel generators are split on either side of a current limiting reactor, and all the loads are distributed between these three buses as illustrated in the simplified one-line diagram (see Fig. 1).

II. POWER MANAGEMENT SYSTEM (PMS) OVERVIEW

PMSs are being installed in a wide range of applications ranging from microgrids, universities and various industrial facilities, to country wide macro-grid schemes [1]. The primary goal of any PMS is to maintain the frequency and voltage stability of the power system. The PMS achieves this goal reliably using intelligent algorithms that run in the generation control system (GCS) and load-shedding processor (LSP) controllers. While the GCS maintains the frequency and voltage by dispatching set points to the governor and exciter, the LSP performs high-speed load shedding in response to a loss of generation and quickly restores the load-generation balance to achieve system stability [2]. These real-time automation controllers (RTACs) run continuously at subcycle speeds, constantly monitoring data and taking vital requisite actions as necessary. The following section will discuss in detail the communication architecture governing these systems.

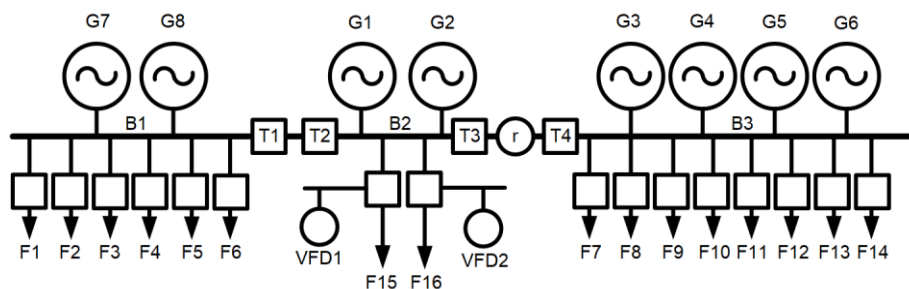


Fig. 1. Simplified electrical one-line diagram from Red Dog mine

III. COMMUNICATIONS OVERVIEW

The controllers make load shedding and generation control decisions based on data they receive from relays in the field. The relays typically transmit high-speed data via protocols such as IEC 61850 GOOSE or MIRRORED BITS® communications while slow-speed data are transmitted via IEC 61850 MMS, Modbus or DNP3 protocols. The judicious application of protocols is key to ensuring both power system stability and management of network burden [3].

At Red Dog the data from all the relays in the field are sent to two redundant data concentrators (A and B). The relays send the high-speed data via IEC 61850 GOOSE protocol; whereas, the slow-speed data are transmitted via IEC 61850 MMS protocol. The data concentrators (A and B) then communicate with the LSP and GCS controllers via NGVL protocol. The controllers provide a visual indication to the human-machine interface (HMI) by first transmitting to the Gateway (GW) via NGVL protocol, and the GW acts as a protocol converter by passing tags to the HMI via DNP3 protocol. Fig. 2 illustrates this communication.

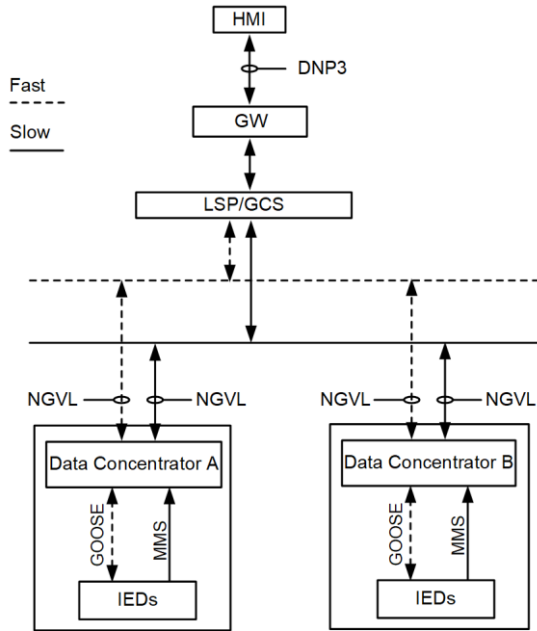


Fig. 2. Communication architecture

IV. LOAD-SHEDDING PROCESSOR (LSP)

Load shedding systems come in different configurations, depending on the requirements of the power system application, but the common goal is to preserve the stability of the power system by performing high-speed load-generation rebalancing. The LSP does this effectively via three algorithms that run concurrently and use different inputs as contingency triggers for load shedding. These algorithms are discussed in the following section.

A. Contingency-Based Load Shedding (CLS)

The CLS defines a contingency as the opening of a breaker that causes a power deficit in the system. For example, generator breakers would classify as contingency breakers. The LSP is constantly monitoring the system, and when it detects this contingency, it intelligently sheds load (priority-wise) on the same electrical island where the deficit occurred within milliseconds to maintain the load-generation balance. The typical round-trip time, excluding the breaker operation, is expected to be between 30 and 50 milliseconds. To enable such high-speed shedding, the controller constantly tracks the system topology and arms itself ahead of the actual event. By shedding load according to available capacity, the system can minimize the negative effects of frequency in the system, thereby restoring the power balance. There are 13 contingencies that have been identified for the CLS in this project and are listed in Table I. Typically a load feeder does not constitute a contingency, but F9 is set up as a contingency here since it can act as a power source when required, via an emergency generator.

TABLE I
LIST OF CLS CONTINGENCIES

Contingency	Asset
1	G1
2	G2
3	G3
4	G4
5	G5
6	G6
7	G7
8	G8
9	T1
10	T2
11	T3
12	T4
13	F9

B. Underfrequency-Based Load Shedding (UFLS)

This scheme sheds load based on underfrequency (UF) triggers from protection relays by detecting frequency decay in the system. Despite the contingency-based scheme, a frequency decay could still occur due to the opening of an alarmed breaker, load-shedding failure due to wiring/trip coil issues, and incorrect load metering values. When this happens, the UFLS sheds load and helps recover the system frequency.

The different UF thresholds selected for this project are indicated in the frequency line diagram in Fig. 3.

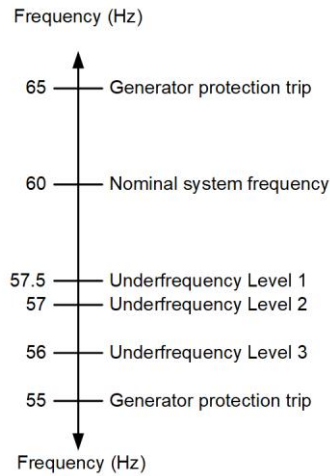


Fig. 3. Frequency line diagram

Once the controller sheds load based on the Level 1 trigger, the system frequency is expected to recover, but if it does not recover and Level 2 UF is subsequently triggered, additional load is shed based on the set point for that level. Table II lists the UF contingencies that identify the buses where the UF level triggers are monitored for this project.

TABLE II
LIST OF UFLS CONTINGENCIES

Contingency	Bus
1	B1
2	B2
3	B3

A voting scheme is set up to process the raw UF triggers from the field. The controller looks at all the relays on the island and only responds to a UF contingency if there are at least two relays from that island that have detected a UF trigger. This ensures that the controller does not inadvertently act on one trigger that could have been generated due to incorrect settings on that relay, wiring issues, mapping errors, and more.

The amount of load to shed for a UFLS contingency is calculated as a percentage of the total load and is done for every island independently. Using percentages instead of fixed real power values allows for scalability between differently sized islands and is critical for a remote power system that could have different island configurations. The percentages in Table III are operator settable through the HMI and are recommended based on closed loop testing in the laboratory.

TABLE III
UF SHED TABLE

Level 1	Level 2	Required to Shed
10%	10%	X % of total system load on that island

For Level 3, instead of further shedding any load, a bus separation scheme is implemented, where the bus couplers associated with the UF contingency are opened, and the rest of the electrical system is isolated from the affected buses.

C. Progressive-Based Load Shedding (PLS)

This scheme sheds load based on monitoring the output power values of a source, such as a generator or a utility tie line, and once the output exceeds the threshold for an operator defined time, the controller sheds load to bring the power values within the threshold [4]. This scheme is based on an integration function that is akin to an inverse overprotection curve with time-to-shed load that is inversely proportional to the overload. The greater the overload, the less time it takes to shed load, and vice versa.

For this remote facility, along with monitoring the instantaneous overload, an hourly rolling average overload scheme was provided. The controller captures snapshots of the real-time power values every minute and calculates the average for the last 60 values. This scheme is set up to meet EPA requirements, which mandates a limit on the hourly average output of the generators. Once load shedding occurs, the contingency locks out for a predefined time with an automatic reset after the load-shedding action. If the assets continue to be overloaded after the lockout time, the controller will perform load shedding again until the asset is under the threshold.

D. Overall Load Selection and Processing

The controller is programmed with a list of sheddable loads that are provided by the mine. Several factors such as load priority, present power, breaker status, binary/analog alarm, etc. go into the selection of a sheddable load for a contingency. The flowchart in Fig. 4 illustrates the way the controller goes through every load until it has selected enough load to satisfy the required shed demand for every contingency [5].

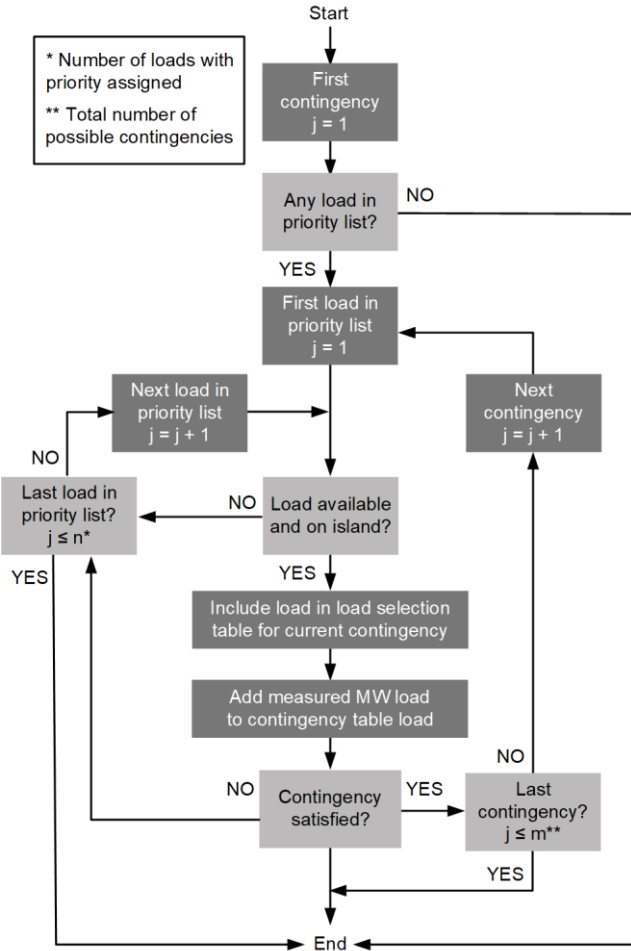


Fig. 4. Load selection flowchart

1) Multiple Priority Lists

Typically, load shedding controllers select loads to shed based on a priority list. The loads are sorted dynamically based on operator changes to that priority list, and then the controller selects loads based on priority that are on the same electrical island as that contingency.

For this mine, however, two separate priority lists (Group A and Group B) were developed to accommodate the unique requirement of minimizing the current flow across the reactor, post load-shedding. For all CLS and PLS contingencies on the left side of the reactor, the Group A priority list is used. For all CLS and PLS contingencies on the right side of the reactor, Group B priority is used. For UFLS contingencies, which are not tied to any particular asset but the overall system frequency, there is a third priority list, which is derived from the two priority lists (A and B). The priorities are derived in this

manner: Priority 1 from Group A is assigned Priority 1, Priority 1 from Group B is assigned Priority 2; and Priority 2 from Group A is assigned Priority 3, and Priority 2 from Group B is assigned Priority 4. This continues, until all loads are assigned priorities. This ensures that the third priority list for UFLS picks equally from the two priority lists (A and B). This also confirms that loads from both sides of the reactor are selected for a UF event.

2) Sheddable Load Feeding Another Sheddable Load

In this system, there were some cases when one sheddable upstream load was feeding into another sheddable load downstream. In those cases, special calculations regarding power flow and priorities are implemented in the algorithm for the upstream loads. Consider the example in Fig. 5.

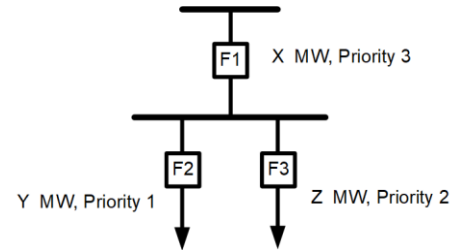


Fig. 5. Sheddable load feeding another sheddable load

Feeder 2 (Priority 1) and Feeder 3 (Priority 2) each consume Y and Z MWs, whereas, Feeder 1 (Priority 3) feeds both of these loads and is metering X MW. When the load selection algorithm traverses through the priority lists and selects F1 after F2 and F3, it results in an incorrect calculation, since the real time metering value of F1 will already include F2 and F3 values. Hence, the power of F1 is modified to subtract the power of downstream loads (F2 and F3). This real power modification ensures system stability.

Similarly, when priorities are concerned, if an upstream load has a higher priority than a downstream load, it will be inhibited. This is to ensure that the controller first selects and trips the downstream loads before going upstream. This means that if the priority of F1 was set to 1, then the controller would automatically inhibit that load for selection; at this point, the operator can change the priority to a number that is greater than the priorities of the downstream loads (greater than 2).

V. GENERATION CONTROL SYSTEM (GCS)

In an islanded facility, a GCS provides flexibility of operation and control of different power system parameters, such as frequency, voltage, active power, reactive power, and current flow across reactor. It also participates in system synchronization by controlling the governor and exciter of synchronizing island generators. There are different components in a GCS as discussed in the following section.

A. Automatic Generation Control (AGC)

The AGC dispatches set points to the governor for percentage load sharing while simultaneously controlling the system frequency (F) and limiting ampere (I) flow across reactor breaker.

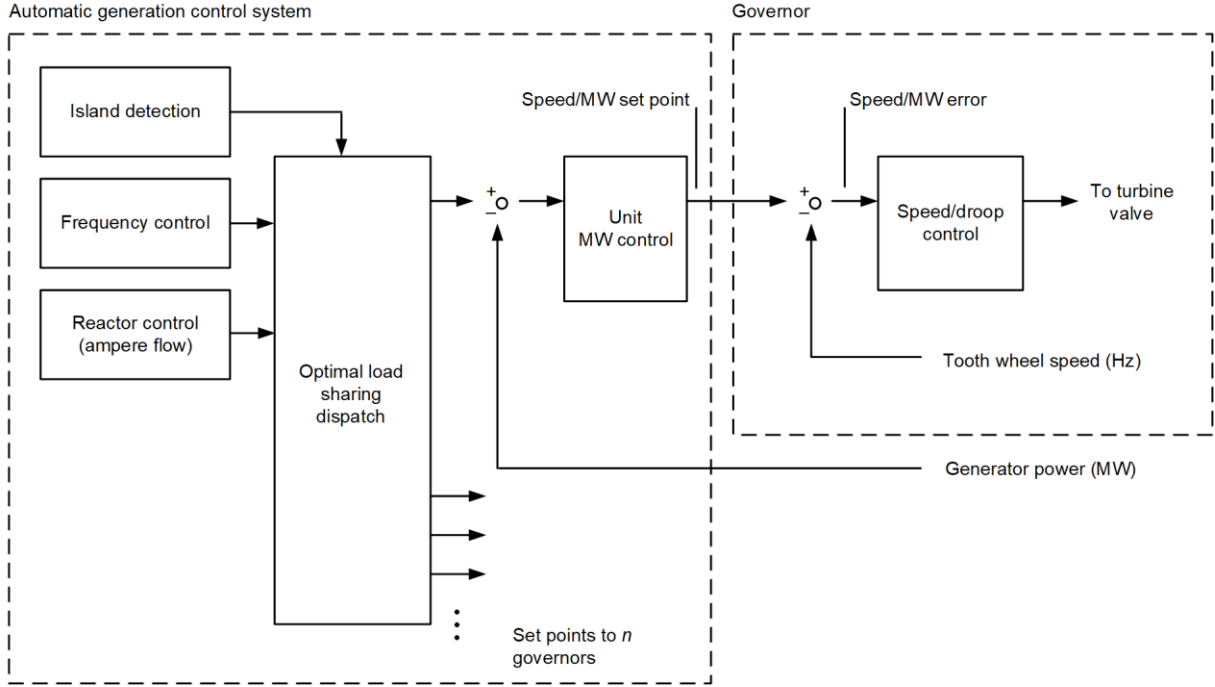


Fig. 6. Typical AGC control strategy

The typical AGC algorithm is presented in Fig. 6. The AGC sends a MW set point to the governors of running turbine generators. The set point for each generator is determined by the optimal load-sharing controller that receives biased commands from the frequency control loop. The required percent deviation from nominal is calculated using (1):

$$\%Deviation = \frac{\text{System_Load} - \sum_{i=1}^n \text{MWBaseSP}_{\text{GEN}_i}}{\text{Total_Capacity} - \sum_{i=1}^n \text{MWBaseSP}_{\text{GEN}_i}} \quad (1)$$

where:

- System_Load is the total present output of all generators (MW); this equals the plant load.
- Total capacity, as shown in (2) is equal to the summation of all the generator capacity, where the generator capacity is the least of the following three factors:
 - Operator-entered upper-regulation limit
 - Generator capability curve
 - Turbine capability

$$\text{Total_Capacity} = \sum_{i=1}^n \text{Generator_Capacity} \quad (2)$$

Equation (3) calculates the difference of the individual generator capacity and MW base set point multiplied by the percent deviation to give the individual generator deviation (in MW).

$$\text{Deviation}_{\text{GEN}_i} = \%Deviation \cdot (\text{Generator_Capacity}_{\text{GEN}_i} - \text{MWBaseSP}_{\text{GEN}_i}) \quad (3)$$

Equation (4) calculates the new power request for the AGC unit dispatch.

$$\text{Power_Request}_{\text{GEN}_i} = \text{MWBaseSP}_{\text{GEN}_i} + \text{Deviation}_{\text{GEN}_i} \quad (4)$$

In addition, if the ampere flow across the identified reactor breaker reaches the overload threshold, AGC demands the generators of the bus that is importing power to increase the output to the upper regulation limit until the current flow drops below 80 percent of the threshold and simultaneously manages frequency and load sharing among the generators on each side of the reactor, as shown in Fig. 6.

B. Voltage Control System (VCS)

The VCS dispatches generator exciter set points for percentage reactive load sharing while efficiently utilizing the active front end (AFE) drives and generator excitation to maintain the system voltage. The algorithm is designed to utilize the AFE drives for maximum VAR support to achieve better power factor and a stable reserve margin for the generators. Simultaneously, VCS also manages reactive power flow across the reactor breaker and monitors the generator terminal voltages to stay within acceptable limits. The VCS is also integrated into the automatic synchronization system (AS). Fig. 7 shows the overall strategy of the VCS.

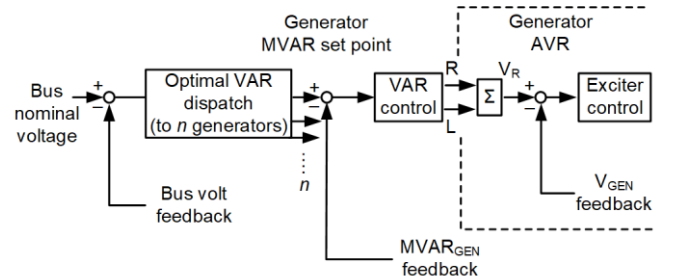


Fig. 7. Typical VCS control strategy

C. Islanding Control System (ICS)

The ICS tracks the number of islands in the system and monitors the generators and variable-frequency drives (VFDs)

connected to those islands. Accordingly, the ICS creates the individual AGC and VCS control loops for each island formed and assigns the modes of governor and exciter as required in those islands. In Red Dog, there is no utility connection, and the GCS controls the governors in Droop mode and exciters in Voltage mode.

D. Generator Capability Tracking System

An intelligent GCS is equipped with a generator capability tracking algorithm that uses a least-value method to determine the allowable operational region for the AGC and VCS. The controllers dispatch the generator within user-defined regulation limits of the machine. This region is used to calculate the MW and MVAR spinning reserves for each unit. Fig. 8 represents generic capability curves and shows different operating scenarios within the allowable operational region (shaded area). Fig. 8 (top) shows an example in which the user-entered regulation limits are within the capability curve and the turbine limit; however, they are outside the turbine limit for Fig. 8 (bottom).

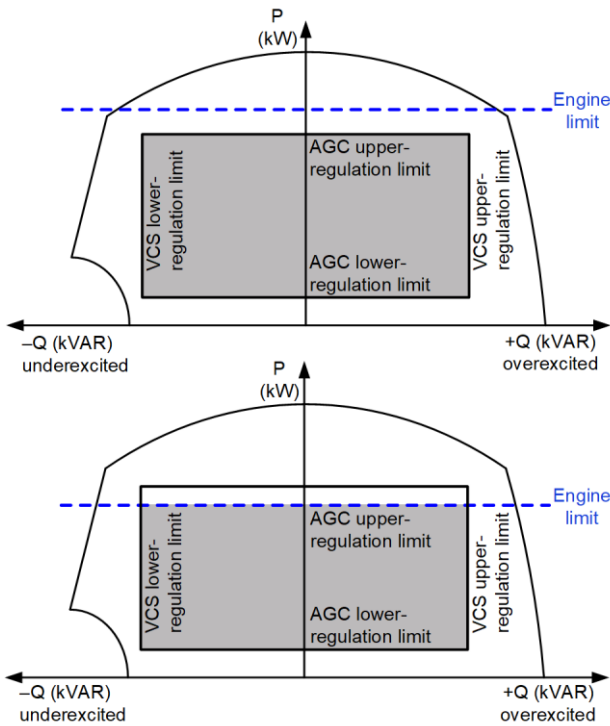


Fig. 8. Generator capability – regulation limits with generator boundary

E. AS System

An AS system is required to synchronize generators and different electrical islands across bus ties and to synchronize with emergency generators. Unit synchronization systems synchronize individual generators to power grids, while island synchronization systems synchronize and reconnect different 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. Once the sync is initiated, the AS system performs safe, secure,

unattended synchronization control of islanded power systems [6].

The AS system algorithm is presented in Fig. 9; the slip and voltage difference measurement from the AS IED is fed to the GCS. The GCS dispatches governors and exciters to bring the frequency and voltage differences within breaker closing limits. The AS IED automatically closes the breaker once the phase angle is within the defined band.

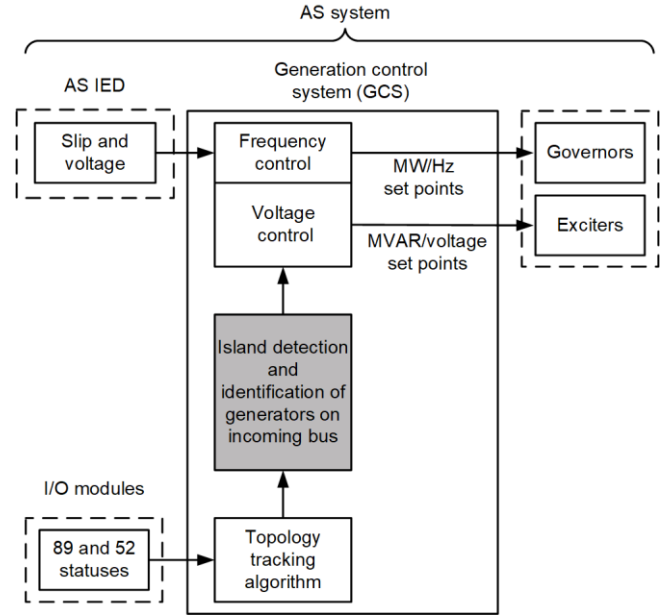


Fig. 9. Auto synchronization control system

VI. SIMULATION SYSTEM

A. Real-Time Digital Simulator (RTDS)

The authors of this paper designed and developed a state-of-the-art simulation system with a model specific to Red Dog. The simulator is capable of continuous real-time operation using a hardware-based electromagnetic transients program (EMTP). The simulator was connected to panels in the closed loop with PMS equipment, protective relays, governors, and exciters, all communicating via hardwired connections and project specific protocols. This simulator ran power system scenarios in real time, and data from these scenarios were fed into the closed-loop control system for validation. This also helped with training operators who were present during a factory acceptance test (FAT) [7]. The following section provides an understanding of how different components of the power system (generators, excitation systems, governors, transformers, loads, etc.) are modeled and validated for Red Dog.

B. Generator Validation

Step tests were performed to study the response of the exciter and governor models on a per-generator basis. For this validation, a test system was developed consisting of a generator connected to an infinite bus and two loads through a step-up transformer. Each of the components could be isolated by operating the breaker connected to the generator bus. This validation allowed the authors to see the effects of the

prescribed gains and time constants of the excitation and turbine governor system with the given generator. These tests included load acceptance, load rejection, and governor step response for the governor. For the exciter, the test included an exciter step response and Full Speed No Load (FSNL) test. Fig. 10 shows the frequency response of the generator unit's response for the step load acceptance test.

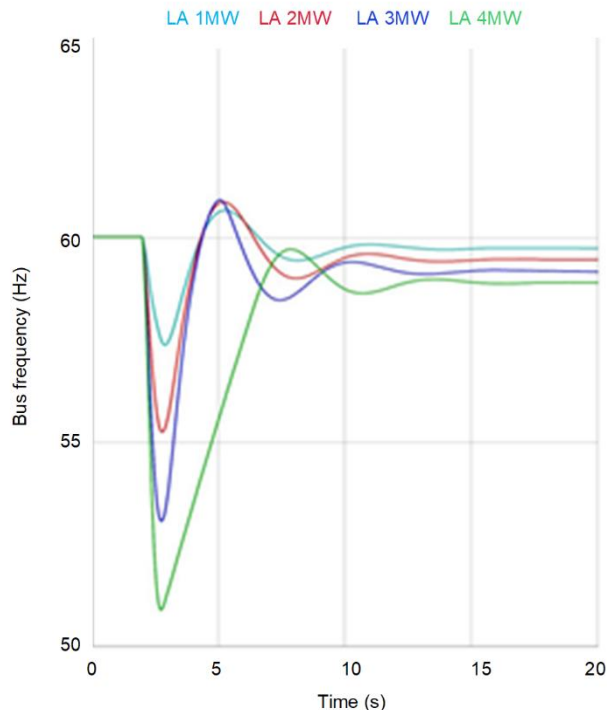


Fig. 10. Combined load acceptance test for 5 percent loading

1) Load Modeling Validation

Two types of load modeling are done for the Red Dog mine system: loads at 4.16 kV and 480 V. All substations containing sheddable loads with mitigation devices are modeled as sheddable loads, where the PMS could individually shed loads; whereas, in the substations where no mitigation devices are present, the loads are modeled as nonsheddable lumped. The detail model includes induction machines, synchronous machines, and drives that are unique to Red Dog. The VFDs had an AFE which could control the reactive power output to aid in system voltage regulation. Since load modeling accuracy

is required for system fault behavior and coordination, a detailed model was developed [8].

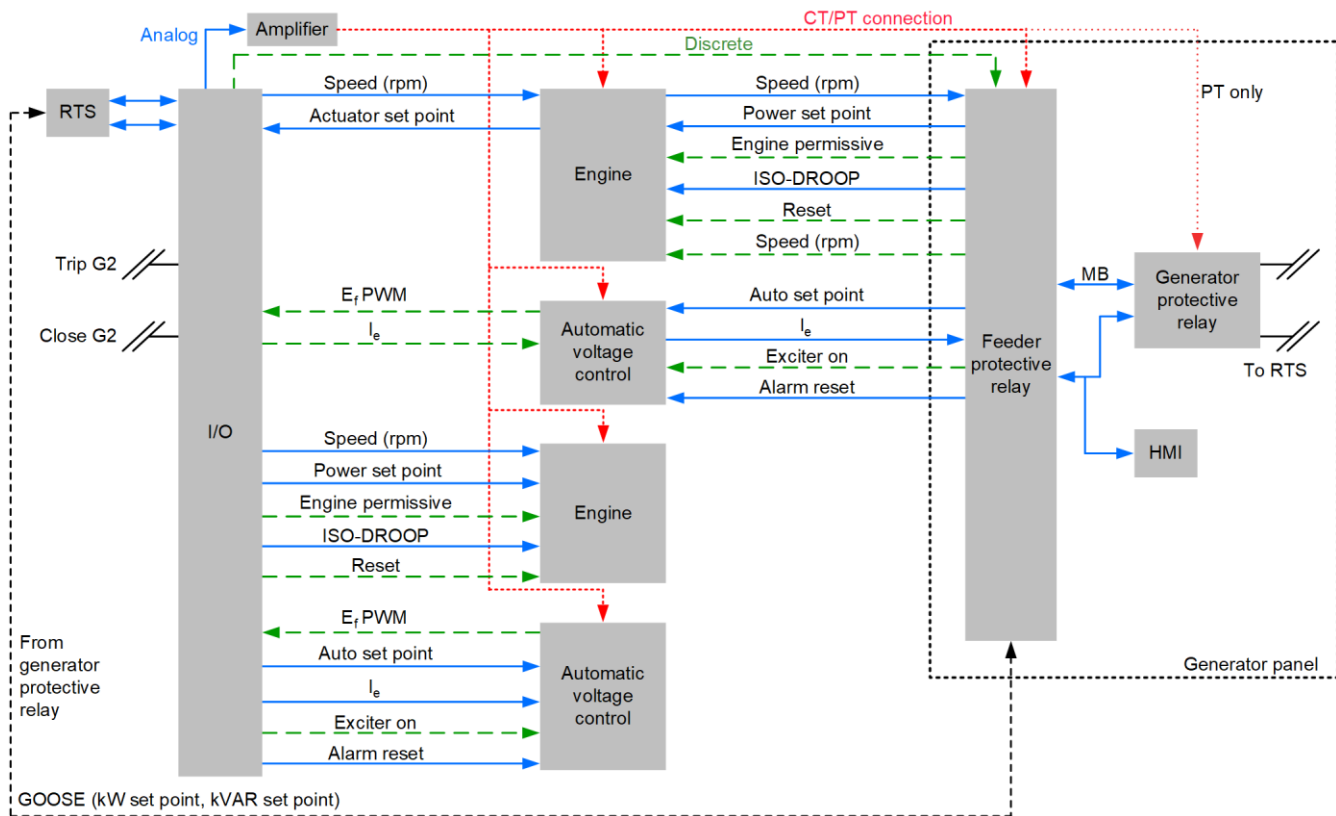
2) Drive Modeling and Validation

After receiving data from the manufacturer, the drive configuration is modeled as a three-level back-to-back voltage source converter (VSC), which results in a four-level stepping waveform, compared to an eight-level stepping waveform in the field. The control modules, such as current, speed, dc voltage, and voltage suppression control are all like the field model. The gains are scaled to the equivalent model but are tuned to provide the same response as the actual drive system. This drive model is then validated with the field model until the system response is deemed close for testing with the PMS functionality.

The simulation includes modeling protective tripping to understand the interaction of PMS with existing protection system. One relay of each type between generator protection, feeder protection, and bus protection was set up to test the protection logic, including the AS and bus separation relays. A system preservation scheme was developed in conjunction with PMS to improve resiliency of the mine operations. Initially, relays on the main feeder were coordinated with the next downstream device utilizing industry standard overcurrent coordination philosophies [9]. However, when the relay phase and ground instantaneous overcurrent set points were calculated and simulated using RTDS, it was deemed insufficient to isolate fault equipment within critical clearing times. This resulted in a preservation scheme for closed-in faults where a higher instantaneous element was utilized, which de-energized the bus where the fault occurred [10].

3) Dynamic Performance Validation

The governor and AVR models developed in RTDS were tested against hardware units for complete validation and tuning prior to field commissioning. The test setup, as shown in Fig. 11, allowed the control of generators with governors and AVR either in hardware mode or software mode within the model. Once the dynamic validation was completed, field settings for the governors and exciters were finalized [10]. Typically, governors and exciters are not included as part of control hardware-in-the-loop (cHIL) testing; however, for this critical islanded mine, it was important to test upgraded governor and exciter units with tested settings and validate the performance before interacting with PMS.



VII. DYNAMIC TESTING AND ANALYSIS

Prior to installation of the PMS, a complete FAT was performed in a laboratory. Several studies were done using the model, providing insight into plant operations, vulnerabilities, and system responses for many contingency events, including corner cases. Studies also determined optimal set points for PMS. As shown in Fig. 12, this was accomplished by connecting the PMS to the simulation hardware.

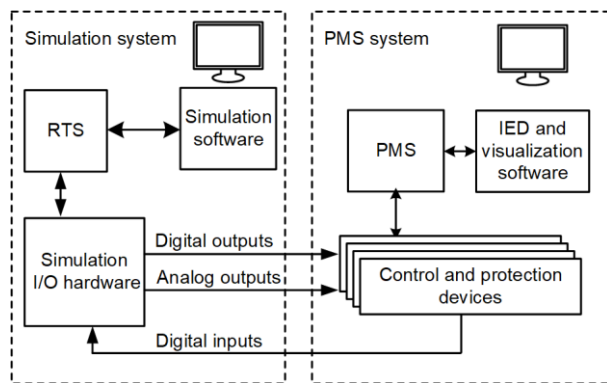


Fig. 12. System simulation setup

A. Case 1: Generator 1 Trip Contingency

The primary objective of this case was to demonstrate the operation and coordination between different components of the PMS, such as CLS, UFLS, PLS, and GCS. Generator 1 was tripped, while all six engines were running. Generator 1 was running at 4.955 MW. The total system Incremental Reserve Margin (IRM) was 2.5 MW (0.5 MW for each of the generators on the island, excluding Generator 1). The CLS calculated the Required to Shed (RTS) as 2.45 MW and Selected to Shed (STS) as 4.25 MW. The STS was greater than RTS because the next available load based on the priority was much larger. Once the contingency was triggered, the CLS shed the calculated loads. The frequency dipped to 59.5 Hz and recovered to nominal frequency after load-shedding.

This event demonstrated the mine's capability of surviving the loss of a generator during the peak loading scenario. The selected IRM value was sufficient, so no further frequency- or overload-based load shedding was necessary.

In Fig. 13, the active and reactive power of Generator 1 dropped to zero around two seconds, and the other generators slightly picked up the load. Fig. 14 shows the system voltage and frequency when the frequency initially dipped to 59.5 Hz but later recovered to nominal. There was also small voltage disturbance during this event which quickly recovered to a steady state nominal value.

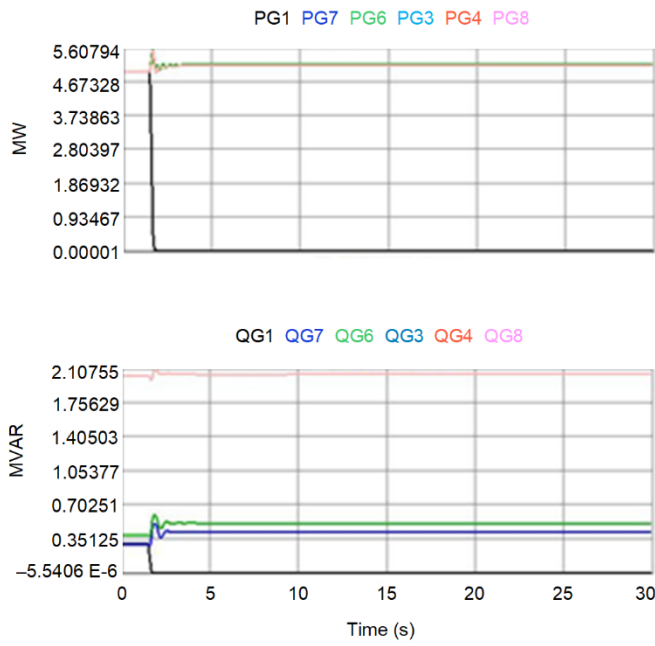


Fig. 13. Case 1: Generator active and reactive power

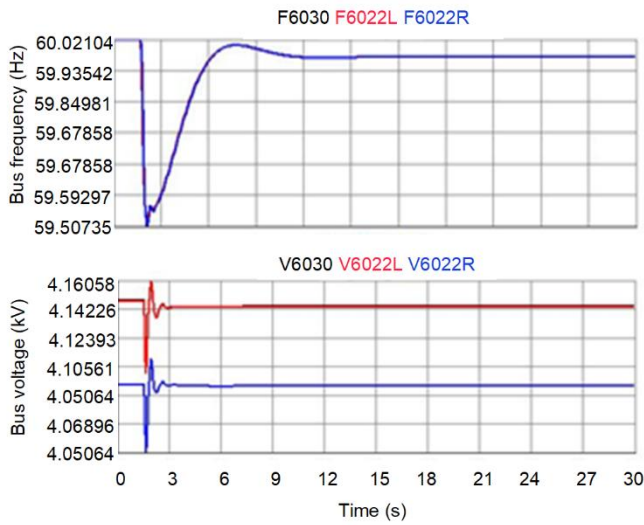


Fig. 14. Case 1: System voltage and frequency

B. Case 2: UF Event (CLS Disabled)

The goal of this test was to validate the frequency-based load shedding at Red Dog mine. The CLS system was disabled and the system response during a UF event was evaluated. The system initial conditions were setup up so that all six generators were operating at 4.9 MW. One generator was tripped, and system loading was approximately 29.6 MW. Since the CLS was disabled, the frequency continued to decay until UF Level 1 triggered. The calculated RTS was 2.765 MW. Based on the available load and priority setup, it resulted in shedding a total load of 4.245 MW. Fig. 15 shows the frequency and voltage response of the system during this event. The frequency dipped to 56.86 Hz before recovering close to nominal after load shedding. The decay in the system frequency before load shedding shows the effect of load characteristics and governor response on the power system.

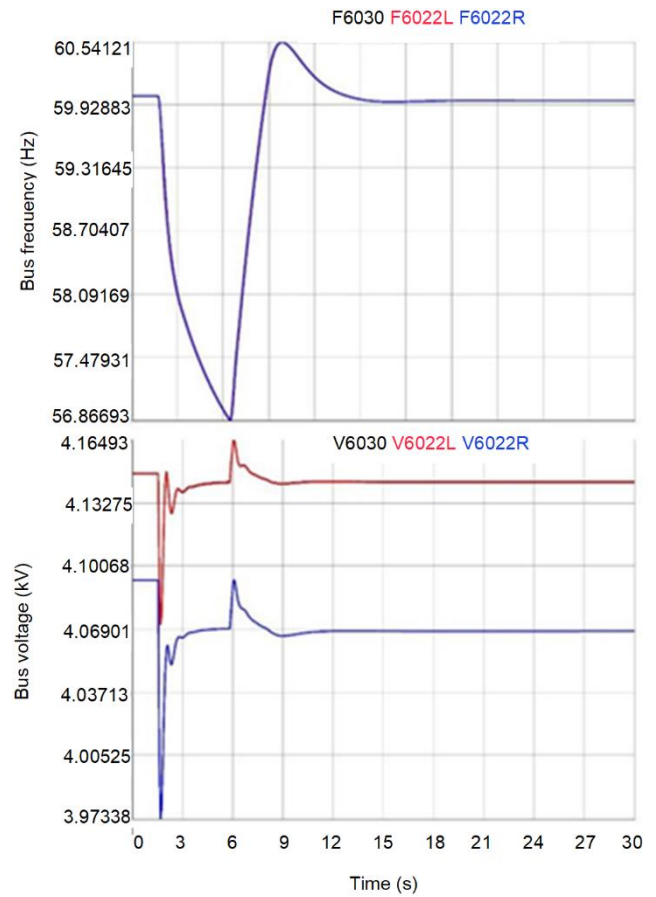


Fig. 15. Case 2: System frequency and voltage

C. Case 3: Two Simultaneous Island Events (CLS Disabled)

The goal of this test was to demonstrate how load selection is based on islanding by splitting the system into two islands. Buses B1 and B2 are part of one island (Island A), while Bus B3 is on the other island (Island B). Bus Tie T3 was opened with 2.8 MW flowing from B2 to B3. This loss of import on Island B caused the system frequency to decay; this was detected by UF trigger detection relay on the island. Two valid triggers initiated a UFL1 trigger. The RTS was 1.2 MW and STS was approximately 2 MW. Fig. 16 shows the decay in frequency in Island B and rise in frequency in Island A. After load shedding, both islands survived.

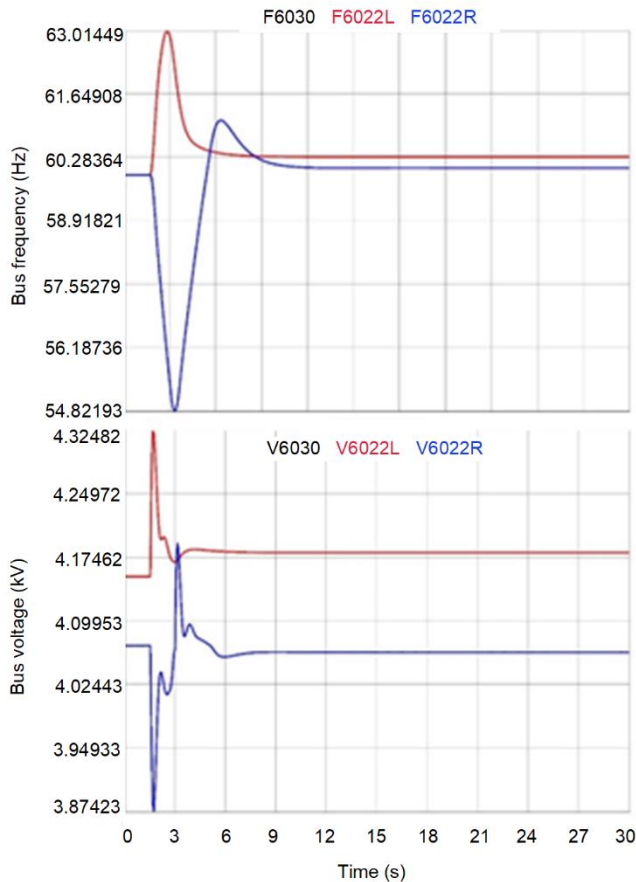


Fig. 16. Case 3: System voltage and frequency

VIII. CONCLUSION

This project augmented Red Dog's goal of resiliency, reliability, and survivability during system events. This paper demonstrates the design, development, and testing of the PMS implemented for the mine. Each PMS function is tested prior to running system-wide tests. CHIL testing helped to calculate all the required set points for the frequency- and contingency-based schemes while testing corner cases. CHIL testing also reduced overall commissioning time and is great for brownfield integration projects where production disruption can be critical.

The PMS has been commissioned into service at Red Dog mine and has been operating successfully for more than a year. In the words of the operators, the PMS has helped control generation without a constant need to adjust power between buses on either side of the reactor. It has also led to a more reliable local grid and helped avoid power failures on a few occasions which would have typically led to loss of production.

IX. ACKNOWLEDGMENTS

The authors gratefully acknowledge the contributions of Scott Barndt, Gabe Berbig, Daniel Rocco, Mahipathi Appannagari, and Asad Mohammed for their work supporting project development and commissioning efforts.

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XI. BIOGRAPHIES

Mehul Joshi received his diploma in electrical engineering in 1988, his BS degree from Gujarat University, India, in 1995, and his MS degree in electrical power systems from the University of Detroit Mercy in 2004. Mehul worked for Gujarat Electricity Board in Gujarat, India, as a junior engineer for 13 years before joining Fording River Operations, an operation of Teck Resources Limited, in 2006. He is currently a senior electrical engineer at Red Dog mine, an operation of Teck Resources Limited. Mehul has experience in ac/dc drives, generator protection and excitation, power system protection design and commissioning, short-circuit and coordination studies, arc-flash studies, electric shovels, drills, and haul trucks. He is PE certified by the Association of Professional Engineers and Geoscientists of British Columbia (APEGBC).

Greg Smith is an electrical and instrumentation reliability technician with Teck Resources Limited at Red Dog Operations located in a remote part of Alaska. He has 43 years of experience in instrumentation and control of chemical facilities, nuclear power stations, mining operations, and oil and gas production facilities. The last 30 years are mainly in the commissioning, maintenance, modification, and expansion of power generation. He has a certification in instrumentation technology from ITI Technical College in Baton Rouge, Louisiana.

Pradeep Varma Sangaraju received his BE in electrical engineering from Anna University, Chennai, India, and his MS in electrical engineering from Arizona State University. Pradeep currently serves as an engineering supervisor with SEL Engineering Services, Inc. (SEL ES) and has over ten years of experience in the field of power system automation and control, including power management schemes for industrial customers and microgrid solutions. He is a registered professional engineer in the state of Arizona.

Ashish Upreti is an ES manager at SEL Engineering Services, Inc.(SEL ES), subsidiary of Schweitzer Engineering Laboratories, Inc., (SEL) in Pullman, Washington. He received his bachelor's and master's degrees in electrical engineering from the University of Idaho. He is a registered professional engineer in the state of Washington and a senior member of the IEEE. He has experience in the field of power system protection and automation, including power management schemes for large-scale industrial power plants. He has over ten years of experience in the field of power system protection and automation, including power management schemes for large-scale industrial power plants, remedial action schemes, and microgrid solutions.

Maaz Kazmi is a senior engineer at SEL Engineering Services, Inc.(SEL ES), subsidiary of Schweitzer Engineering Laboratories, Inc.(SEL). He joined in 2011. He earned his BE degree from NED University of Engineering and Technology in Karachi, Pakistan. Before joining SEL, he was a senior executive engineer in the energy and automation unit of Siemens Pakistan Engineering Company, Limited. He is an IEEE member and has over fifteen years of experience in design, development, testing, commissioning, technical documentation, business development, and customer training in the areas of power management solutions, substation automation, and HMI development. He has also acquired extensive knowledge in generation control systems for industries and utilities, utility system operations, and remedial action schemes.

Fast and Reliable Load-Shedding Scheme for Wastewater Treatment Plant – A Case Study

G. M. Asim Akhtar
Schweitzer Engineering
Laboratories, Inc.
Calgary, Canada
asim_akhtar@selinc.com

Muhammad Waqar Ahmed
Schweitzer Engineering
Laboratories, Inc.
Toronto, Canada
muhammad_waqar_ahmed@selinc.com

Will Allen
Schweitzer Engineering
Laboratories, Inc.
Calgary, Canada
will_allen@selinc.com

Perry Zhang
The City of Calgary
Calgary, Canada
Perry.Zhang@calgary.ca

Kyle Jensen
Stantec Inc.
Calgary, Canada
Kyle.Jensen@stantec.com

Sujay Dasgupta
Schweitzer Engineering
Laboratories, Inc.
Pullman, U.S.A.
sujay_dasgupta@selinc.com

Abstract—Innovations in the fields of automation and networking have helped traditional power system substations evolve. Intelligent electronic devices (IEDs) accompanied by optimized and smartly engineered communications networks have provided engineers with opportunities to better design and implement various algorithms. Therefore, in the event of a disturbance or fault, the power system stability and process survivability are maintained.

Power systems are proven to have more stable operation while connected to a utility; however, the challenge arises when the power system is islanded and suffers from a loss or an excess of generation. In an islanded configuration, fast and selective shedding of loads and/or generators based on system topology is critical in responding to system disturbances to avoid blackouts and ensure minimum process downtime.

This paper presents a real-world implemented load-shedding scheme (LSS) for a North American wastewater treatment plant. The LSS was deployed in two tiers of primary and secondary controls via redundant substation-hardened controllers. The primary shedding system is based on calculation of a predictive power deficit or surplus for various predetermined contingency events. The primary system issues shedding decisions upon contingency detection, whereas the secondary shedding system is based on triggers asserted by underfrequency and/or overfrequency protective relays.

The paper also provides an overview of the implemented network scheme; however, a detailed discussion regarding engineering and performance will be included in the authors' future work.

Keywords—fast load shedding, contingency, underfrequency, software-defined networking, power management and control system, frequency response, wastewater treatment plant

I. INTRODUCTION

A power monitoring and control system (PMCS) is defined in [1] as:

A PMCS is ideal for industries with onsite generation and/or that are grid connected. It contains automated control functions specifically designed to prevent, detect, and mitigate system blackouts in either grid-connected or islanded mode. Automated functions within a PMCS control major power system assets for optimal economic operation. By properly collecting, processing, and presenting power system data as usable information, the PMCS system enables operators, maintenance personnel, and engineering staff to diagnose system events, predict equipment failures, and minimize unnecessary maintenance [1].

This paper presents a case study for one of the largest wastewater treatment plants in North America. The plant under consideration was constructed in 1932 and has had various updates during its life span. In 2017, the plant went through a major electrical infrastructure upgrade with the installation of a PMCS to ensure robust, reliable, and operator-friendly control and monitoring of the power system in the facility. As part of the complete PMCS suite, one important feature was to implement a fast, reliable, and robust load-shedding system that would guarantee power system stability and process survivability. In addition, it was essential to recognize that any misoperation could lead to the release of toxic waste or untreated water into the downstream river, posing a serious health and safety hazard for the public.

The paper describes the load-shedding scheme (LSS) implemented to meet the project requirements using the field proven engineering algorithms, design techniques, and testing methodologies. Section II examines the simplified power system of the wastewater treatment facility. Section III provides

an overview of the implemented system architecture using software-defined networking (SDN). Section IV presents the details of the two types of high-speed load-shedding algorithms and their implementation using the defined system architecture. Section V explores implementation details for intelligent and selective load shedding. Section VI evaluates testing scenarios and associated results.

II. OVERVIEW OF FACILITY POWER SYSTEM

The power system for the wastewater treatment plant is an industrial microgrid with multiple power sources, including onsite power generation and numerous high- and low-voltage buses distributed throughout the facility.

The plant is interconnected to the electrical utility via two 13.2 kV primary voltage service feeders. In addition to the utility feeders, there is 8.8 MW of onsite cogeneration, which includes three 4.16 kV/1.6 MW reciprocating engines and one 4.16 kV/4 MW gas-fired combustion turbine generator (GEN).

The 13.2 kV utility feed is transformed down to 4.16 kV at two different switchgears. These two switchgears are the

primary sources of high-voltage distribution to the various areas of the plant. Major process loads are fed at 600 V, except for the aeration blowers in the plant, which are fed at 4.16 kV. The 13.2 kV, 4.16 kV, and 600 V switchgears throughout the plant are configured as double-ended main-tie-main systems. Fig. 1 provides a simplified version of the facility power system as an overview for readers; however, to maintain the end user's system confidentiality, the asset tags and details have not been disclosed.

III. SIMPLIFIED SYSTEM ARCHITECTURE BASED UPON SDN TECHNOLOGY

Modern numerical relays and metering IEDs not only protect and monitor the plant power system, but also form the foundation of a load-shedding system. The IEDs are networked over Ethernet communications using two independent networks in a ring configuration utilizing parallel redundancy protocol (PRP) based on SDN technology.

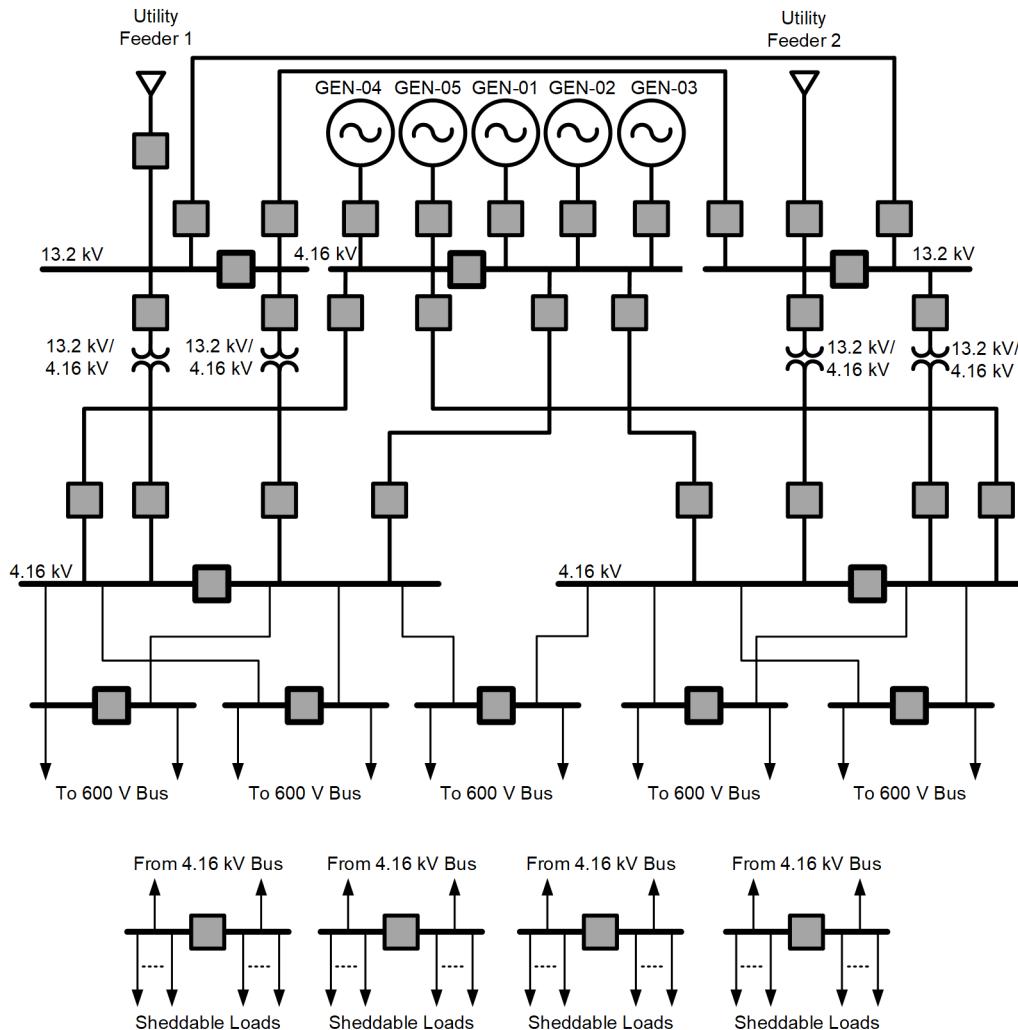


Fig. 1. Simplified Single-Line Diagram of the Power System for the Wastewater Treatment Plant

Data for load-shedding purposes are gathered by local relays, installed on various equipment across the power system. These data are then sent via International Electrotechnical Commission (IEC) 61850 Manufacturer Messaging Specification (MMS) and Generic Object-Oriented Substation Event (GOOSE) communications protocols over the Ethernet network to data concentrators (DCONs) that operate on redundant hardware as A and B devices. DCON-A and DCON-B are installed in two physically distant locations. These DCONs then distribute data to centralized controllers, which operate on redundant hardware installed in the same locations as DCON-A and DCON-B, respectively. Data are sent to the fast load-shedding (FLS) controllers by DCONs via User Datagram Protocol (UDP) over the Ethernet network. Each of the controllers performs its specific functions and outputs control signals. These control outputs are distributed through the DCONs via UDP communications protocol. From the DCONs, the signals are sent via IEC 61850 GOOSE signals over the Ethernet network to relays and trip units. From the relays, hardwired output contacts transmit controls directly to the desired control point.

Fig. 2 presents a simplified version of the system architecture used for implementation of an FLS system.

IV. HIGH-SPEED LOAD SHEDDING – FUNCTIONAL OVERVIEW

“High-speed [load-]shedding control functions are required to mitigate power system unbalance and prevent blackout[s]” [1]. The main purpose of these control functions is to maintain balance between power generation and demand and/or load by intelligently selecting and tripping load breakers based on a triggered contingency that may include a generator, utility tie line, and bus tie.

For the wastewater treatment plant under discussion, two types of FLS schemes have been designed and deployed. The primary FLS scheme is called contingency-based load shedding (CLS); whereas, the secondary FLS scheme is called underfrequency-based load shedding (UFLS). The details of both types of load-shed schemes are explained in the following subsections.

A. Contingency-Based Load-Shedding Scheme

“A CLS algorithm sheds load to maintain the power system balance by reducing the total plant electrical load to less than the calculated available turbine and generator capacity after a contingency occurs” [1]. A contingency is defined as the opening of a breaker that interrupts system power flow. Contingency triggers are communicated from protective relays to the DCONs using GOOSE messages.

When a contingency breaker opens, the CLS controller triggers load shed *“based on the contingency status and metering, user-settable load-shedding priorities, user-settable incremental reserve margin (IRM) values, topology status, load status, and metering. The CLS controller sends the load trip signals to the respective”* intelligent electronic devices (IEDs,) via DCONs, using GOOSE messages, *“the output contacts of which are wired to trip coils of the breakers”* [1] Fig. 3 shows the overall CLS algorithm.

The algorithm runs on real-time automation controllers, in advance of the event trigger taking place; therefore, the power deficit can be seen by the operator before any event occurs. If there is not sufficient plant load to balance the loss of power from a contingency source, an alarm will convey this to the operator, which allows the operator to take corrective action for avoiding an operation state that is vulnerable to a blackout.

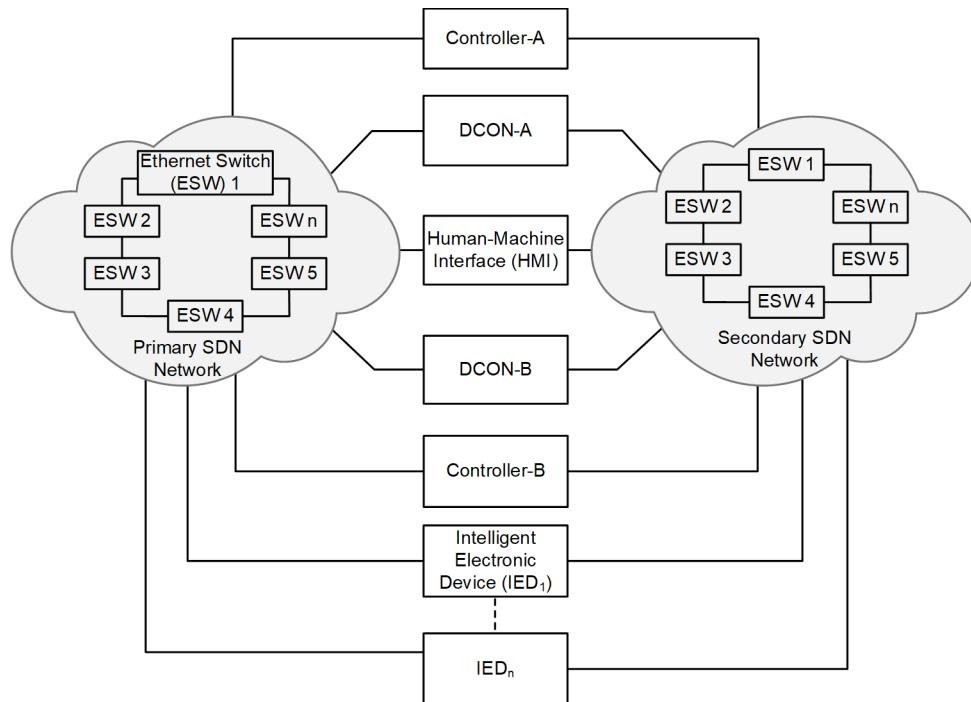


Fig. 2. Simplified System Architecture Based on SDN Technology

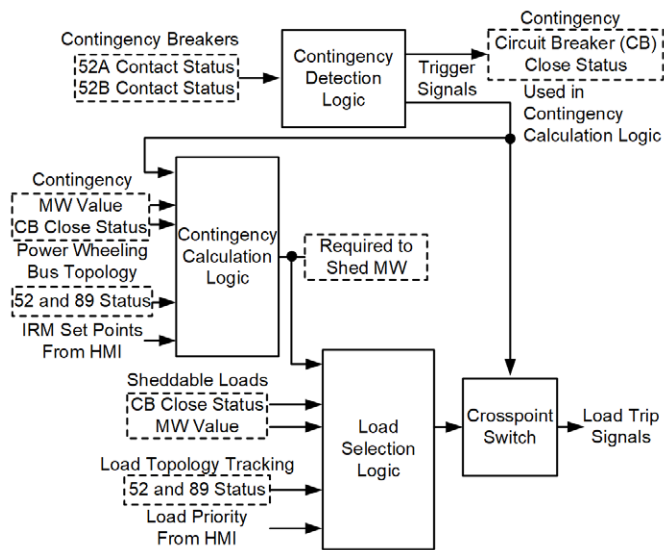


Fig. 3. Block Diagram for Contingency Load-Shed Algorithm

For the operator to understand the expected loads to be shed, based on the prospective contingency trigger, a crosspoint switch is populated and displayed to the operator by means of a human-machine interface (HMI). Fig. 4 shows a simplified version of the crosspoint logic. A crosspoint switch matrix is essentially a table constructed as contingency versus load.

Each contingency has an associated trigger. Trigger 1 corresponds with Contingency 1, and so forth. Each load is selected based on contingency and may be preselected for multiple contingencies. However, if a load was shed in one contingency, it will be inhibited from being selected for shedding by any other contingencies. The result of the crosspoint switch multiplication is trip signals that are sent directly to the DCONs at various locations. From there, they are sent to the field IEDs with output contacts wired to the trip coil of the associated load.

B. Underfrequency-Based Load-Shedding Scheme

According to [1], a UFLS scheme is an FLS:

algorithm that maintains the power system balance by reducing the total plant load by fixed amounts of load power at [four] separate underfrequency (UF) levels. The UF level detection occurs in [protective] relays located at each bus/generator.

When the [relay] detects a UF event, it sends a high-speed signal to the UFLS system. The UFLS controller determines the load to shed based on the UF trip level, user-settable load-shedding priorities, topology status, load status, and metering. The UFLS system sends the load trip signals to [the] IED[s]. The output contacts of [the IEDs] are wired to trip coils of the breakers [1].

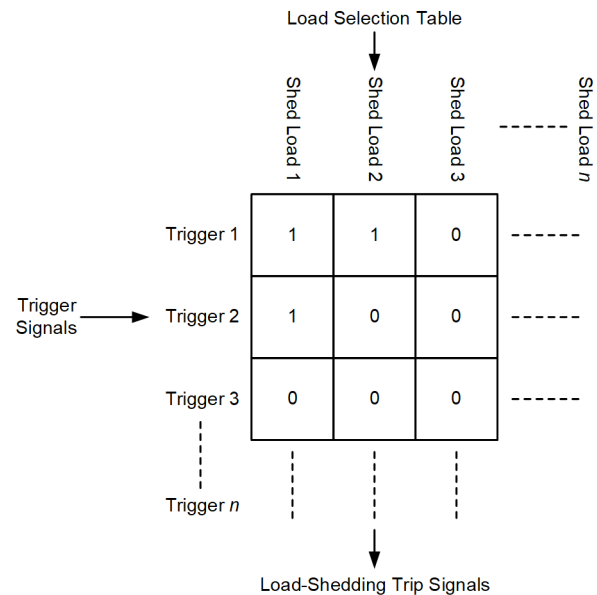


Fig. 4. Crosspoint Switch Matrix

This scheme backs up the primary CLS scheme by detecting frequency decay that was not prevented by the CLS, which was due to an alarmed breaker opening, overestimated generator IRM, or a load-shedding failure due to wiring and/or trip coil issues.

An added benefit of this centralized underfrequency load-shedding scheme is the ability to isolate events on an island-by-island basis. This ensures that only relevant loads are shed for frequency excursions throughout the island and that other islands remain unaffected. This is in contrast to relay-based underfrequency load-shed schemes in which feeders are tripped as soon as the UF trigger asserts, without any consideration of the required amount of load to be shed. Fig. 5 explains the UFLS algorithm.

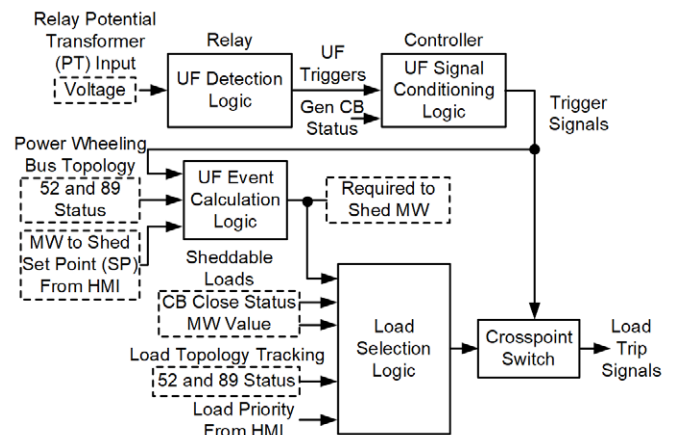


Fig. 5. Block Diagram for Contingency Load-Shed Algorithm

V. HIGH-SPEED LOAD SHEDDING – IMPLEMENTATION DETAILS

A. Selected Contingencies for Primary CLS Scheme

For the power system shown in Fig. 1, 27 breakers were identified that may initiate primary load-shedding contingencies. The contingencies are split into three different classifications: generator, tie line (loss of utility source), and bus coupler (loss of a link between system buses). Table I shows the contingencies identified for the specific case study.

B. Selected Contingencies for Secondary UFLS Scheme

The secondary LSS is based on the frequency degradation of the system and the corresponding power decrease for which it is stabilized. For the power system shown in Fig. 1, the underfrequency system operates on the 4.16 kV generator buses and will only operate when islanded from the utility. The underfrequency system will shed load based on a power setting entered for each level on the HMI. Underfrequency triggers are generated via relays that perform bus frequency measurements at generator buses. In addition, the relays installed in the 13.2 kV distribution buses are also programmed to provide underfrequency triggers to controllers for the identified underfrequency contingencies.

Table II lists the underfrequency contingencies identified for the specific case study.

C. Underfrequency Coordination

Fig. 6 shows a simplified visual representation of the frequency coordination for the UFLS scheme with the underfrequency protection settings of the two types of generators installed in the power system shown in Fig. 1.

The underfrequency load-shedding set points are coordinated with the utility decoupling requirements, such that the plant can ride through voltage and frequency excursions if there are disturbances on the utility network. To overcome this, the controller topology tracking informs the operator about the connected state of the utility in the plant power system. If the plant is utility connected, then the controller dynamically disables Level 1 and Level 2 of the underfrequency scheme.

TABLE I. PRIMARY CONTINGENCIES

Contingency Number	Type
1–5	Generator
6–7	Utility tie line
8–27	Bus tie

TABLE II. UNDERFREQUENCY CONTINGENCIES

Contingency Number	Bus	Underfrequency Level
1	Generator Bus-A	Level 1
2	Generator Bus-A	Level 2
3	Generator Bus-A	Level 3
4	Generator Bus-A	Level 4
5	Generator Bus-B	Level 1
6	Generator Bus-B	Level 2
7	Generator Bus-B	Level 3
8	Generator Bus-B	Level 4

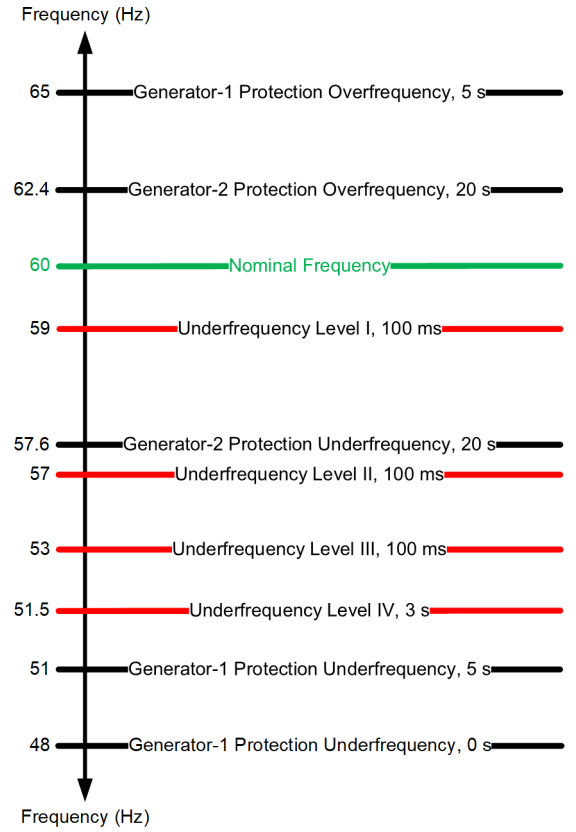


Fig. 6. Coordination Between UFLS Levels and Generator Frequency Protection Settings

Coordination of the UFLS and CLS should be performed so that when both algorithms are enabled, it would not cause any unnecessary load tripping. The CLS action takes place first; whereas, the UFLS waits for a trigger from the field. Because of the vast differences in the inertia and rating of machines, it was critical that the load-shedding system be designed to cover the maximum range of possible operation scenarios. Based on the aforementioned facts, the following conditions were established to achieve coordination between the CLS and UFLS:

- Block Underfrequency Levels 1 and 2 when the CLS is enabled. Levels 1 and 2 were designed as a backup for the CLS and will only come into effect when the primary load-shedding scheme is disabled.
- Keep Underfrequency Levels 3 and 4 active all the time, even with the CLS enabled. Levels 3 and 4 were designed to serve as a last resort for saving the system from a blackout.

D. Sheddable Loads

Based on recommendations from the customer's operations department, 66 loads were identified as sheddable loads for the power system shown in Fig. 1. These 66 loads are situated throughout the entire power system at voltage levels of 4.16 kV and 0.6 kV.

E. Load Selectivity Based on Load Group Priorities

All of the sheddable loads are organized into ten groups of loads. Each load has a group associated with it, which can be set

by an operator through the HMI. The CLS and/or UFLS algorithm will try to select the optimal amount of load to satisfy each contingency. Each load within a group will have equal priority to shed. The group assigned to each load does not need to be unique.

All load-shedding actions use an optimal load selection algorithm, which tries to select minimum number of loads to satisfy a contingency. Loads are selected for shedding based on their present power and their predefined group. Loads with a power value of zero, negative power value, or group value of zero will be inhibited and not selected for shedding. Operators may set load groups to zero to intentionally inhibit them from shedding. Loads with lower numerical groups are selected for shedding first, starting with the number 1 and moving up the list as loads are available, until the total amount of load selected for shedding matches or exceeds the amount of load required for shedding.

F. Load-Shedding Signals

Load-shedding signals are sent out by the redundant controllers, propagated through the DCONs, sent to the field relays that are installed on load feeders, and then sent to the load trip coils. When a load is selected for shedding, the load trip signal is sent out by the controller and held for 60 seconds. This ensures that the signal is propagated through all devices and reaches the load. The trip signal is then propagated through the load-specific relay to the breaker trip coil. The average round-trip time from contingency detection to load-shed command transmit was observed to be in the range of 25–30 milliseconds in this case study. This time does not include contingency and load-breaker opening time, which can vary from 45 milliseconds (three-cycle breakers) to as much as 200 milliseconds. Fig. 7 shows a typical data flow, including detection of the contingency trigger and sending out a load-shed command.

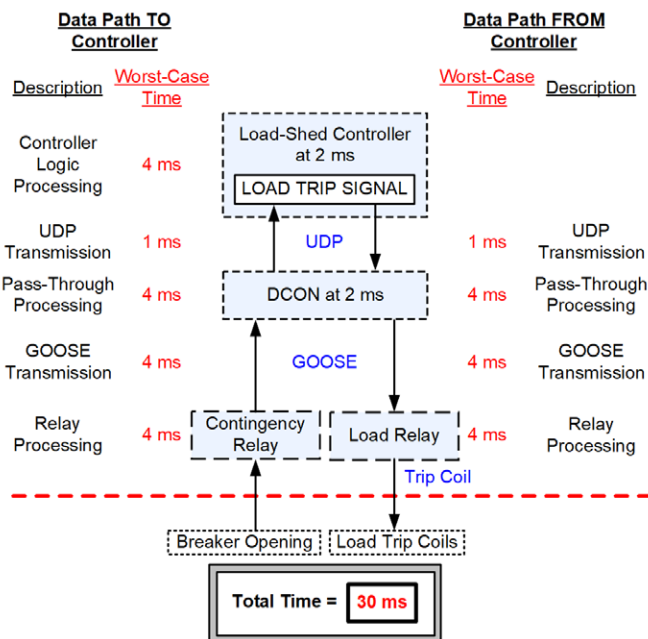


Fig. 7. Load-Shedding Timing Diagram

VI. TESTING SCENARIOS

A. Test-1: Islanded From Utility With Three Generators Running and One Type-2 Generator Tripping

The power system is islanded from the utility and two Type-1 generators each running at 1.15 MW and one Type-2 generator running at 3.6 MW are kept online. The UFLS is enabled, the load on the island is approximately 5.9 MW, and the Type-2 generator is tripped at $t = 1$ second. The frequency response of the island for the UFLS is represented by the solid blue line in the plot shown in Fig. 8. The observations are as follows:

- Level 1 was triggered at $t = 1.330$ seconds and UF L1 required to shed (RTS) = 1.6 MW.
- Level 2 was triggered at $t = 1.417$ seconds and UF L2 RTS = 2 MW.
- The minimum frequency was 53.86 Hz.
- The Type-1 generators did not trip and the remaining load on the island was 2.3 MW.

The same scenario was repeated with CLS enabled and UFLS disabled. The load on the island was approximately 5.9 MW and the Type-2 generator was tripped at $t = 1$ second. At $t = 1.200$ seconds, the CLS shed 3.6 MW of load on the island. The frequency response of the island for CLS is represented by the dashed black line in the plot shown in Fig. 8. The observations are as follows:

- The minimum frequency was 55.48 Hz.
- The Type-1 generators did not trip and the remaining load on the island was 2.3 MW.

B. Test-2: All Generators Running With Maximum Import and an Upstream Fault on the Utility

The power system is connected to the utility with a maximum import of 4.8 MW and all generators are kept online. The UFLS Level 1 and Level 2 are disabled and CLS is enabled.

A three-phase fault on the utility-side transmission line is simulated at $t = 0.917$ seconds. The transmission line breaker is opened approximately three cycles after the fault at $t = 1$ second to isolate the faulted section of line.

The island-side main utility breaker is opened at $t = 1.115$ seconds and CLS operates based on the status of this specific breaker. Two hundred milliseconds after the main breaker opened at $t = 1.315$ seconds, the CLS controller sheds 4.8 MW of load. The minimum frequency was 57.44 Hz.

The frequency response of the island is plotted in Fig. 9.

C. Test-3: Islanded With Two Type-1 and One Type-2 Generators and One Steam Turbine Running, and One Type-2 Generator and a Steam Turbine Tripping With the CLS Undershedding

The power system is islanded from the utility and two Type-1 generators each running at 1.15 MW, one Type-2 generator running at 3.6 MW, and a steam turbine running at 0.6 MW are kept online with the contingency-based load-shedding processor (CLSP) enabled and UFLS disabled. The

load on the island is approximately 6.5 MW. The Type-2 generator and steam turbine are tripped at $t=1$ second and at $t=1.200$ seconds, and the CLS shed 3.2 MW of load on the island. However, the required-to-shed amount was 4.2 MW. Therefore, undershedding by CLS caused the system frequency to decay. The frequency response of the island for CLS is represented by the dashed black line in the plot shown in Fig. 10. The observations are as follows:

- The minimum frequency was 51.27 Hz.
- At $t=2.303$ seconds, UF L3 picked up with $RTS=1.2$ MW, which helped with frequency recovery and saved the system from collapsing.

- The Type-1 generators did not trip and the remaining load on the island was 2.1 MW.
- The maximum frequency for this scenario was 63.84 Hz and the overfrequency protection of the Type-1 generators was 65 Hz for 5 seconds.

Based on the designed coordination between CLS and UFLS, the controller should block UF Levels 1 and 2 to prevent overshedding of the load on the island. However, Underfrequency Levels 3 and 4 should be kept active as a safety margin for the system in cases where CLS or other UFLS levels undershed loads on the island.

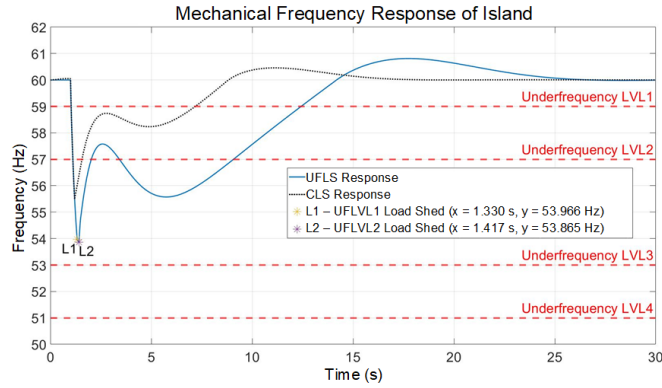


Fig. 8. System Frequency Response for Test-1

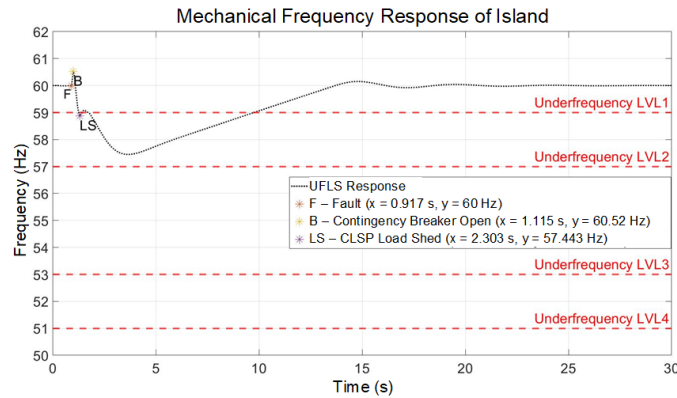


Fig. 9. System Frequency Response for Test-2

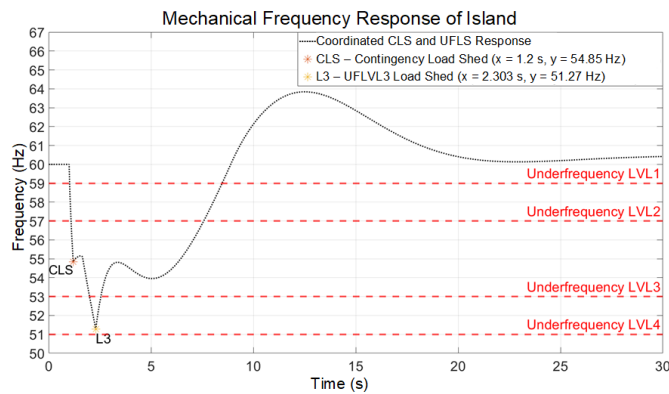


Fig. 10. System Frequency Response for Test-3

VII. CONCLUSION

A wastewater treatment plant is a critical infrastructure that is required to always operate with reliable and trusted operations. These operations can only be guaranteed with the availability of a reliable electric power system and processes. Any power system disturbance can easily destabilize the overall power system and can lead to blackout scenarios. Such blackouts can cause maloperations that can have a direct effect on the public health because usually water that is cleaned through these treatment facilities is released into river systems.

The work described in this paper explicitly focuses on the design and engineering of high-speed load-shedding systems, which are based on the latest SDN-based network infrastructure. The results presented show the significant impacts of timely load-shed actions that helped the power system survive without getting into a blackout situation.

The system developed for this plant will not only make the plant power supply more robust and reliable, but it also will allow the plant operator to make decisions in cases of natural disasters, such as flooding or hurricanes, and manage the power flow to critical loads, eventually keeping the plant running and safeguarding both the environment and public health.

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DYNAMIC POSITIONING CONFERENCE

Power Session

Power Management Systems for Offshore Vessels

Lew Weingarth
Transocean, Houston, Texas, USA

Scott Manson, Saurabh Shah, and Kamal Garg
Schweitzer Engineering Laboratories, Inc., Pullman, Washington, USA

Abstract

Large offshore mobile drilling vessels contain onboard power systems with load demands as high as 50 MW. The load demand is supported by six or more electrical generators running in parallel on a single bus. These generators are driven by a variety of prime movers; the most common ones are two- and four-cycle diesel engines.

Common modes of faults may result in a complete blackout of the power system. On DP (dynamic positioning) drilling rigs, undesirable electrical system outages can result in revenue losses of millions of dollars, increased risk of an environmental incident, and damage to public opinion of the industry. This makes the electrical power system protection and control package critically important for DP vessels.

This paper first explains some of the protection failures currently experienced on these vessels, including failure or misoperation of generator exciters and governors, islanding of defective generators, slow fault detection, and clearing of wrong machinery. The criticality of designing complete systems for simplicity, robustness, maintainability, testability, local support, ease of commissioning, longevity, and availability is also explained.

This paper concludes with the discussion of a new paradigm for advanced prevention of blackouts, the keystone of which is a sophisticated generator protection and control system specifically designed for the needs of DP rigs. This includes an overview of the generator protection system, communications architectures, hardware designs, and visualization system. The new paradigm offers many previously unachievable technological enhancements, such as continuous harmonic analysis, advanced visualization, high-speed protection, standard IEC 61131 programming, and modern communications protocols.

DP3 class notation requirements address reliability indirectly in that two components are more reliable than one of the same component. However, one component with a mean time between failures (MTBF) of 20 years provides more reliable service than two components with an MTBF of 6 months each. Redundancy and reliability are not synonymous. Where possible, the solution presented in this paper justifies reliability claims with actual statistical data. Redundancy alone is not assumed to achieve goals that require statistical data to justify.

Index Terms—Offshore vessel, power management system, PMS, load shedding, common failure modes, harmonic analysis, advanced generator protection, IEC 61850, GOOSE, exciter, governor, black start, synchrophasor, arc flash, automatic synchronizer, decoupling, real-time digital simulations.

I. Background

Transocean, the world's largest offshore drilling contractor, has a long history of operating DP (dynamic positioning) rigs,

dating back to the first DP drillship and semisubmersible units. During this time, Transocean has accumulated 325 rig years of understanding of power plant reliability. As a result, in major deep-water provinces today, the company has rigs with power plants that operate isochronously with load sharing and electronic protective relays, in droop mode with power management oversight, in droop mode with local (per-unit) protection, and many variations in between.

In addition to helping improve DP reliability working with the IMCA (International Marine Contractors Association), Transocean continues to collaborate with maritime equipment manufacturers and to train personnel to better prevent and mitigate power plant problems.

II. Typical System Overview

A. Electrical System

Fig. 1 shows an example of a power system one-line diagram for a DP ultra-deep-water drilling rig. In this example, the Transocean vessel has six main generators rated at 3.64 MW each, eight bow/stern thrusters rated at 2.3 MW each, and variable-speed drives to operate the system. There are two main 11 kV buses connected via the bus-tie breakers, which are normally open. Grounding transformers are provided at both of the main 11 kV buses. Each 11 kV main bus supplies power to a 480 V bus for vessel service and a 600 V bus for drilling. The 480 V supply is also stepped down to 208/120 V for small power and lighting loads.

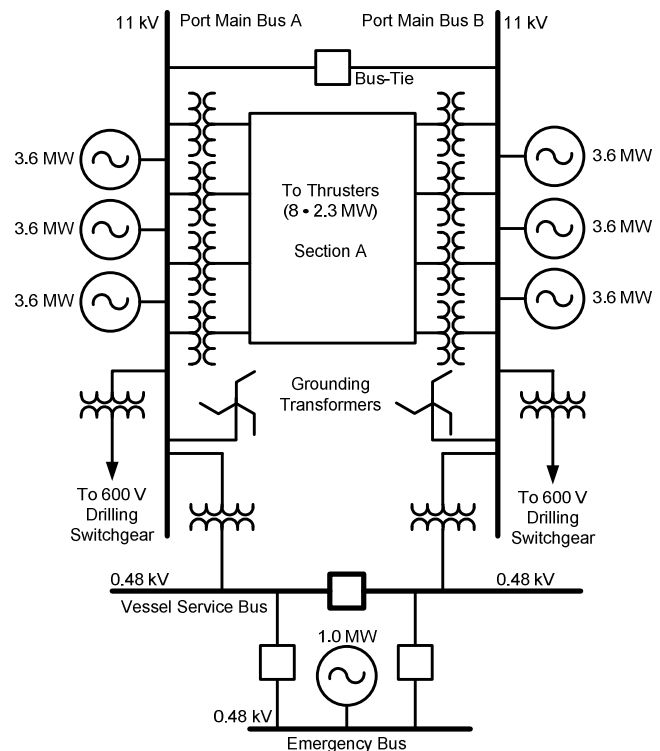


Fig. 1. Simplified Electrical System

The thrusters have dual feeds that can draw power from both buses. The 11 kV bus is a radial bus with bus-tie breaker and is fully insulated to provide protection against short circuits.

B. System Description

During normal and dynamic positioning operations, the 11 kV main switchboard bus-tie breakers can be open or closed. The power plant includes separation, requiring equipment redundancy to meet DP3 class notation. DP3 is the highest class of dynamic positioning for vessels requiring high levels of redundancy and separation to ensure the system can withstand the impact of fire and flood. As such, the plant is required to survive the loss of any active component in any compartment. Class redundancy requirements are primarily focused on maintaining station service. Class requirements do not address the larger issue of keeping the vessel drilling or maintaining maximum revenue. Maintaining maximum revenue requires a protection and management philosophy that significantly exceeds the redundancy requirements of meeting DP3 class notation. Operations and operability must be addressed as well as equipment protection.

Fig. 2 shows the configuration of typical thrusters, which are shown as a block in Fig. 1.

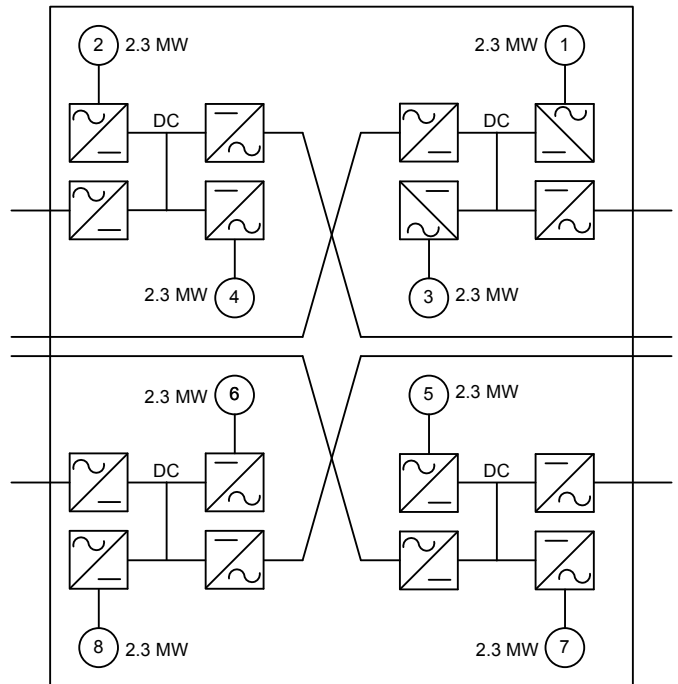


Fig. 2. Thrusters—Detail of Section A From Fig. 1

III. New Solution

Fig. 3 shows the conceptual block diagram for a future power management system (PMS) protection scheme. Generator protection is included in the local protection block. The local protection block also communicates with the generator control block. Local protection devices communicate via direct fiber relay-to-relay or using

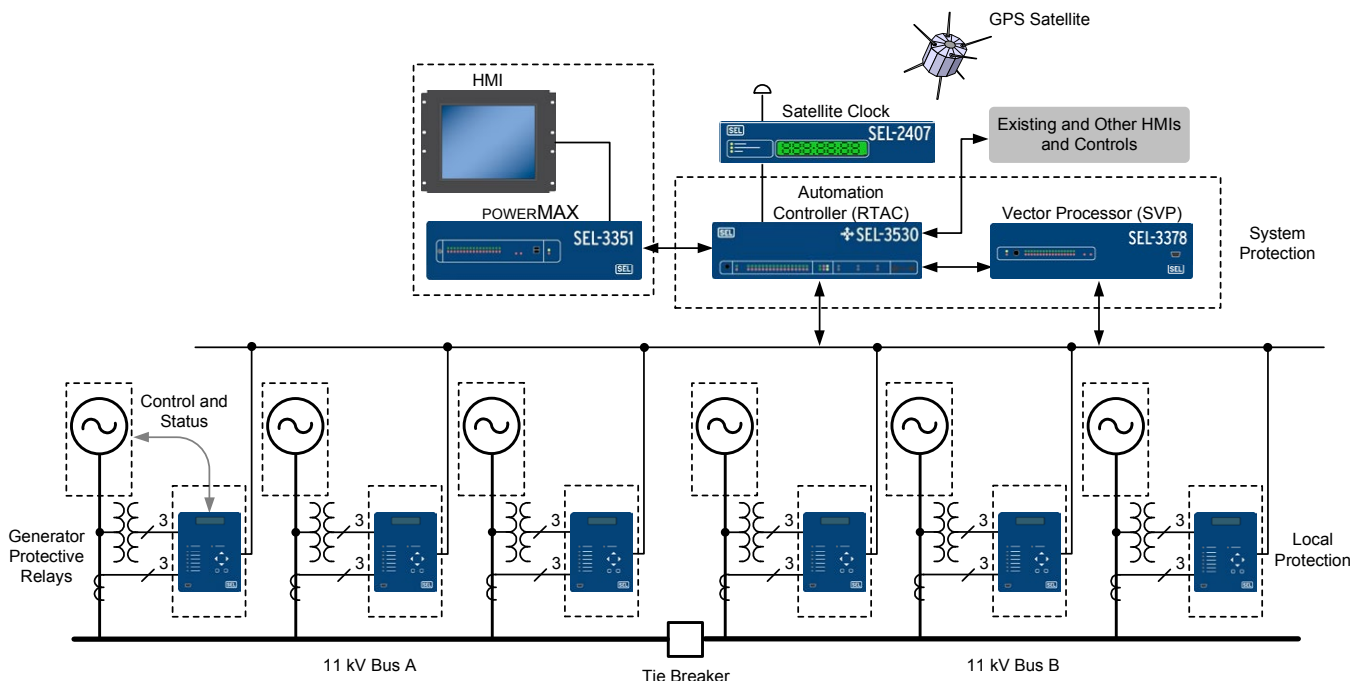


Fig. 3. Future Solution for PMS

IEC 61850 protocol using Ethernet in the system protection block. System protection is the hub of all the decisions for PMS control and data exchange. It processes all the relevant information from local protection and provides control and decisions for the PMS. The proposed future solution also provides decisions, like controls for black start, manual override, and load shedding [1]. The solution includes an HMI (human-machine interface) screen for system overview and control.

A. Local Protection

The local protection block includes the generator protective relays. For the existing scheme, only one relay per generator is installed. If redundancy is desired, more than one generator protective relay can be installed per generator [2][3]. The following protection is proposed to be programmed for generator protection:

- Excess or reverse power
- Reactive power
- Differential
- Loss of excitation
- Out of step
- RTD (resistance temperature detector) protection
- Trip-coil monitoring
- Current/voltage unbalance
- Phase reversal
- Negative sequence
- Under-/overvoltage
- Under-/overfrequency

B. System Protection and the Power Management System

System protection provides the function of a data concentrator and includes all the control for the PMS. Based on the overall DP system protection review, any additional protection, such as feeder, bus, motor, and transformer protection, is included as part of system protection. The PMS also provides the following functions:

- Load-dependent start/stop
- Generator running order selection
- Load shedding
- Heavy-consumer start block
- Blackout start and recovery
- Diesel engine control

The PMS provides the control for generator start/stop based on the loads and priority of the generator to start the assigned units in the sequence as required. Local generation can support the 100 percent load during normal operation; however, during the outage of some units, a load-shedding scheme is enabled. Algorithms must be designed (i.e., priority loads to shed) into the system in order to react properly. The PMS provides the control and start/stop of all generators.

The system uses low-impedance bus protection (e.g., SEL-487B Bus Differential and Breaker Failure Relay).

However, the protection can be designed for any of the following functions:

- Blocking
- Low impedance
- High impedance

Low-impedance bus protection was selected for this project because the appropriate protection operates in less than 1 cycle. One low-impedance SEL-487B Relay provides the bus protection for six inputs. So each solution provides bus protection that accommodates the necessary number of sources and clears faults in 1 millisecond relay operating time. The total clearing time is this relay's operating time plus the breaker operating time and is therefore shortened with rapid relay operating time. Bus faults are rare, but when faults are not detected and cleared quickly, millions of dollars in production losses may result. There is a direct correlation between faster relay operating time and a reduction in production losses.

Separate bus protection for each 11 kV main bus improves the system availability by islanding the faulted bus only.

C. Mean Time Between Failures and Redundancy

Using unavailability for each component of a system, fault trees are used to predict the overall system unavailability. MTTR is the mean time to detect and repair a failure. Schweitzer Engineering Laboratories, Inc. (SEL) assumes a worst-case MTTR number of 4 hours for the components in the proposed system. MTTF is the mean time to fail. SEL measures the MTTF of all their in-service products. MTBF is the mean time between failures, expressed as $MTBF = MTTR + MTTF$. Table I documents the failure rates. A review of the data shows that the likelihood of hardware component failure is very low.

TABLE I
MTBF FOR SEL PRODUCTS

Component	Observed MTBF (years)	Unavailability (multiply by 10^{-6})
SEL POWERMAX Controllers and FEP (front-end processor)	50	9.1
SEL-2411 Programmable Automation Controller	150	3.0
SEL Relays	300+	1.5
Ethernet Switch	50	9.1

Generator protection philosophies that operate entirely at the generator level cannot detect external faults such as main bus failure. Generator protection philosophies that operate at a higher, supervisory level may not detect individual generator faults or may not be able to determine the faulty generator in the case of "common-mode faults." Combined systems using local and supervisory protection offer more comprehensive protection but may not be optimal because of the widely different scan rates of the two systems. However, a system

designed upon synchrophasor data obtains the sampled data every cycle and generates control signals within 2 to 3 cycles. Considering the slower response time of exciters and governor, this proposed system design is adequate.

D. Communication and Integration to the Power Management System

Fig. 3 shows the complete system with communications and PMS integration. The proposal uses fiber optics and MIRRORRED BITS® communications to communicate between various components. These communications are self-monitored. The user is automatically notified of any communications failure. Alternatively, the system can be designed using the IEC 61850 protocol and GOOSE messaging. As an option, systems can be designed using both IEC 61850 and MIRRORRED BITS communications. The system protection block collects all the information from the local protection block, and the correct sample rate is selected based on proper testing and design. It is anticipated that synchrophasor data will be fed directly to a synchrophasor vector processor for time alignment and logic processing. Other relevant information is sent directly to a communications processor. Additionally, the proposed system is capable of providing a secure communications gateway via standard protocols such as Modbus®, DNP3, and others.

E. Engineering Diagnostics and Analysis Tools

The proposed solution includes various inbuilt tools for system analysis and self-diagnostics. All the relays and protection functions are self-monitoring and record any system discrepancy. Operators receive visual alarms. Using the PMS, the HMI continuously displays the operating parameters and custom screens with alarm details. A separate screen is developed for each system component. The proposed system is programmed to call and send important information to key personnel for critical alarms.

The proposed PMS solution will automatically archive sequence of events (SOE) records from all the relays. SOE records generate CSV (comma-separated value) files with accurate satellite clock time stamps. Fig. 4 shows an example of SOE records and lists the digital signals and time stamps. In addition, ACCELERATOR Report Server® SEL-5040 Software archives event report (ER) oscillography for both analog and digital signals of each major event. The ER is archived in the PMS. This information can be used for the analysis of any system operation. Fig. 5 displays an example ER.

GPIC.csv - Sequence of Events Record Viewer

Time	Equipment	Description	State	Device	Element
10/09/2007 08:05:31.822		S1A POWER UP	ASSERT	SEL451A	
10/09/2007 08:05:31.822		C82 LOCKOUT	ASSERT	SEL451A	
10/09/2007 08:05:31.822		C83 LOCKOUT	ASSERT	SEL451A	
10/09/2007 08:05:31.822		UV TRIP	ASSERT	SEL451A	
10/09/2007 08:05:31.822		S1A RELAY ABNORMAL	ASSERT	SEL451A	
10/09/2007 08:05:31.822		DFDT ALARM	ASSERT	SEL451A	
10/09/2007 08:05:31.822		PH ANG ALARM	ASSERT	SEL451A	
10/09/2007 08:05:31.822		UV ALARM	ASSERT	SEL451A	
10/09/2007 08:05:31.822		11F AT 60%	ASSERT	SEL451A	

Fig. 4. Example Sequence of Events

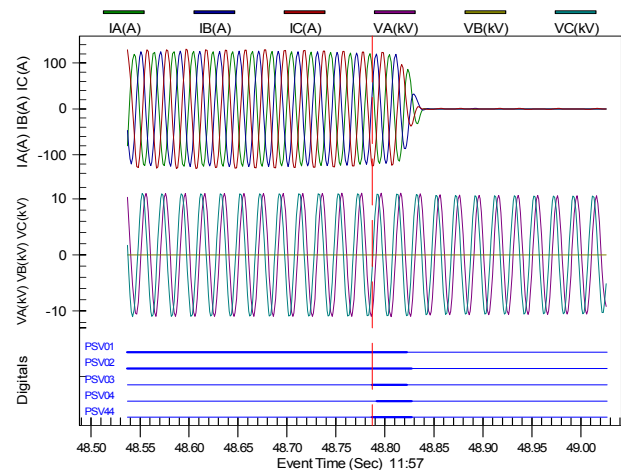


Fig. 5. Example Event Report

F. Additional Features

In addition to the functions of the PMS and generator protection, the proposed scheme includes the following features:

- Synchrophasors
- Flexible synchronizer
- Arc-flash protection

1) Synchrophasor

A definition of real-time (synchronized) phasors is provided in the IEEE Standard 1344-1995. Applying synchrophasors improves performance for these critical applications. As stated earlier, each machine state is based on highly accurate GPS (Global Positioning System) satellite clock signals and synchrophasor data [4]. Critically important signals (i.e., voltage, speed, MW, and MVAR) are received from each generator. This information is used to design the overall generator protection. The sampling rate of 60 messages per second provides this information every cycle.

Fig. 6 shows the phasor measurement of multiple machines. The logical comparison of the synchrophasor variables is performed using system protection. With this functionality, the system performs logic calculations and generate control signals. Using modal analysis (included in system protection), it is also possible to calculate the resonance and oscillation frequencies. This information will be used for the advanced generator protection design for this project. Fig. 7 shows the frequency spectrum using modal analysis.

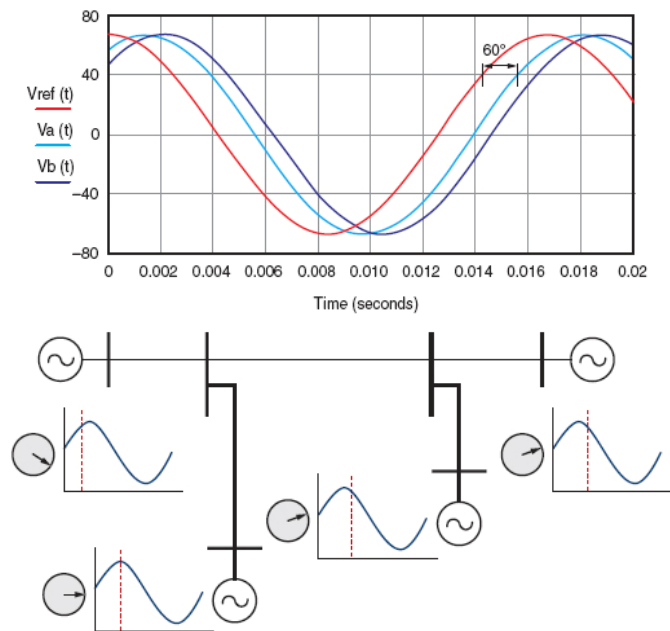


Fig. 6. Synchrophasor Measurement

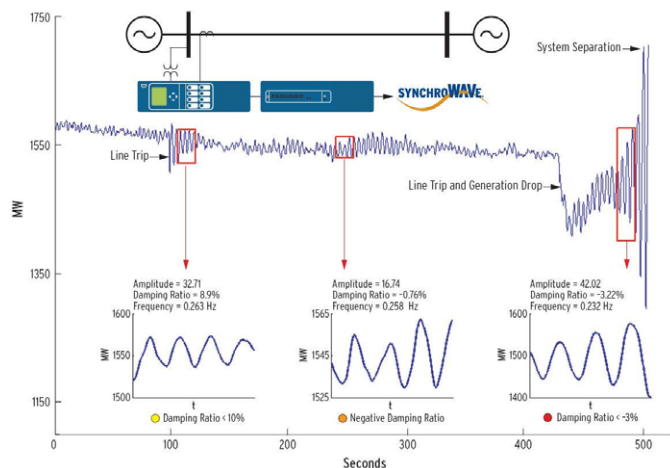


Fig. 7. Modal Analysis Using Synchrophasors

2) Flexible Synchronizer

The proposed solution provides automatic synchronization. Fig. 8 shows a sample screen of the synchroscope. This figure shows two voltages, phase angles, and slip frequency. Per system requirements, multiple settings for synchronization can be enabled. For some operating conditions, it is also acceptable to enable synchronization even with large slip and phase shift values. Using the synchrophasor visualization aids, it is possible to design the display screen and use this information for automatic synchronization. If desired, custom screens are created to meet system and project requirements.

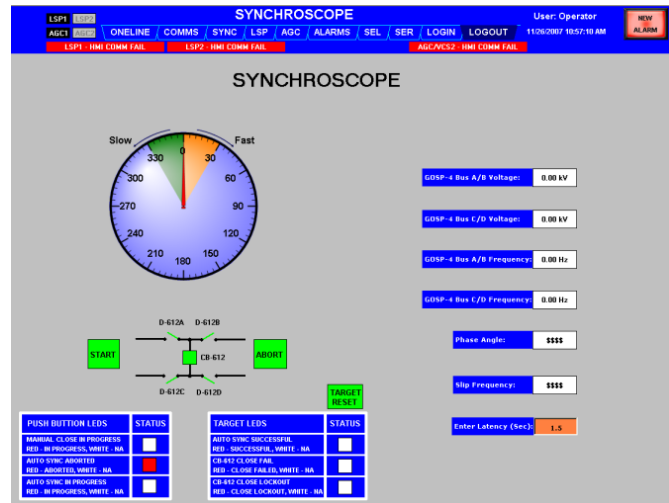


Fig. 8. Automatic Synchronizer

3) Arc-Flash Hazard

Arc-flash protection is very important for the personnel working on the DP vessel. Fast, reliable operation of an arc-flash protective relay improves safety and reliability. The proposed solution also provides feeder and arc-flash protection. Using advanced technology, faults can be detected in 2 to 3 milliseconds, limiting the arc-flash damage. The proposed relay logic uses both light and current to detect the fault. Peak detector logic is enabled to quickly determine the current without losing accuracy, because filtering requirements delay the sensing of current. A detailed arc-flash study, appropriate PPE (personal protective equipment) selection, system design, field commissioning, and product support are included as part of this project.

Fig. 9 shows the SEL solution for arc-flash detection. Up to four sensors, point and loop, are installed in this solution, and all the switchgear sections are protected using selective tripping. Fig. 10 shows that this protection operates in about 2 to 3 milliseconds. In addition to relay operation time, interrupting devices, such as breaker operation time, will also impact the overall arc-flash category. As part of an arc-flash study, possible ways to reduce the arc-flash category will be determined and appropriate warning labels will be posted at various switchgear locations to instruct people to use appropriate PPE. This will define the working boundary for qualified personnel.

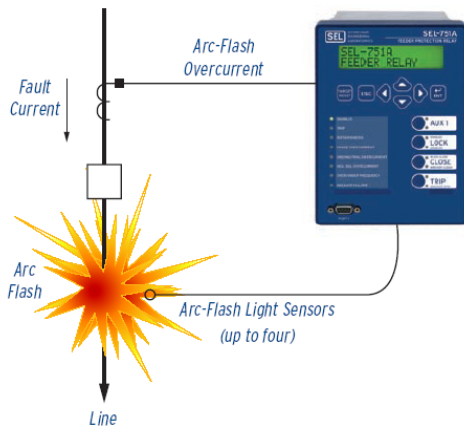


Fig. 9. High-Speed Arc-Flash Detection

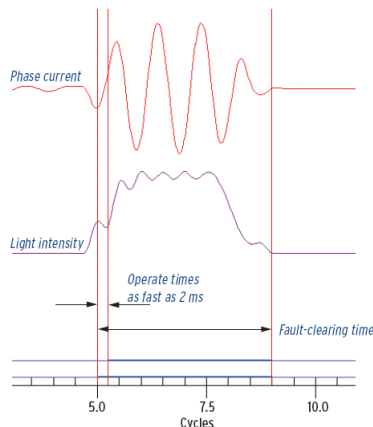


Fig. 10. Arc-Flash Operation Times

G. Common-Mode Faults

Common modes of failures are defined as faults that affect overall system operation and cause multiple redundant elements to react adversely. For normal operating conditions, all the generators operate in parallel droop mode. In case of a fault on one generator exciter/governor or any other common-mode fault, it is desirable to properly detect and isolate only the faulty machine/component from the system as soon as possible [5]. It is also required to evaluate the response time of controls (e.g., exciter/governor controls) before making decisions regarding any system isolation or islanding.

Otherwise, undesirable system operation may result in additional faults or failures.

Common modes of faults are classified into the following four categories:

- F1 – faults based on governors
- F2 – faults based on fuel/actuator
- F3 – faults based on exciters
- F4 – miscellaneous faults

Table II shows common faults and possible solutions. Each main type of fault and PMS operation during the fault is discussed later.

TABLE II
COMMON-MODE FAULTS AND SOLUTIONS

Fault No.	Description	Equipment
F1	Out of Droop Band	Governor
F2A	Actuator Current Low— Actuator Output Low	Actuator
F2B	Rack Not Tracking Actuator— Fuel Rack Problem	Actuator
F2C	kW Not Tracking Fuel Rack— Fuel Problem	Actuator
F2D	Fuel Rack Hunting— Generator Hunting	Actuator
F3A	Overexcitation/Underexcitation	Exciter
F3B	Unstable Voltage Control— Hunting	Exciter
F3C	Loss of Exciter Current	Exciter
F4A	Miscellaneous Faults	Miscellaneous
F4B	Breaker Status Fail, kW > 0 and Circuit Breaker Indication Open	Miscellaneous
F4C	Breaker Status Close, f = 0, Generator Running	Miscellaneous

When droop and no-load speed are set the same on all the diesel engines, units that are electrically or mechanically tied together will inherently share the load equally. Consistent droop results in a predictable speed for a given load on a generator based on a droop curve, the health of the connected diesel, and the speed control system. A deviation from this curve beyond an acceptable window is indicative of an unhealthy status in the engine (unable to deliver the required kW) or a problem with the speed control system or its control system tuning parameters. These symptoms occur if there is a loss of engine power, such as a sticky injector, fuel pump failure, dirty fuel filter, incorrectly set ballhead governor, or limited fuel rack linkage movement. The power generated is below the level expected for the running speed as determined from the established normal speed-load curve for this engine. Hence, for the bus frequency of 60 Hz, the engine operates at less than 50 percent of full load. The other engines online are generating more power than they would have to if all generators were sharing equally; therefore, the speed is

slightly lower than what would be expected for normal operation with that load.

Fig. 11 and Fig. 12 show the operation during the governor faults. Fig. 11 shows the slope and 3 percent droop characteristics for the generators operating in parallel. Curve A is selected if generators are operating normally around the 100 percent load. Curve B is selected if the unit normally operates around 50 percent load. For this analysis, Curve B is selected when normal operating load is 50 percent. The system is operating at 50 percent generator load with 60 Hz frequency. If the load is increased beyond 50 percent, this machine will share more load, but the system operating frequency goes down on the 3 percent slope. The operating frequency will be 59.1 Hz for the machine on Curve B if the load is increased to 100 percent.

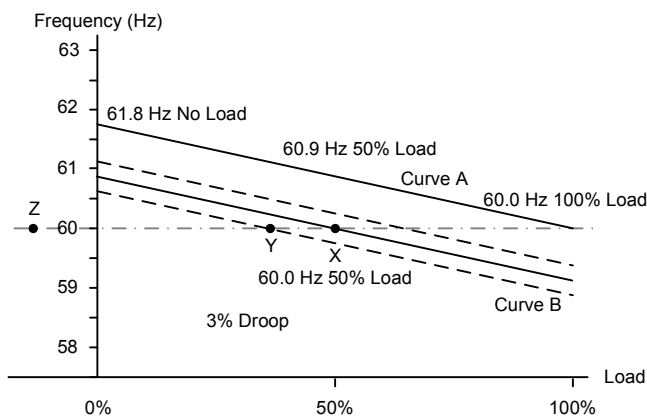


Fig. 11. Low kW and Droop Mode

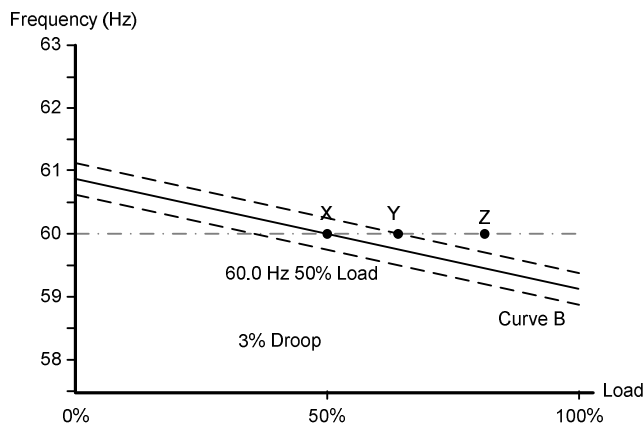


Fig. 12. High kW and Droop Mode

For a low kW fault (F1) when one machine is generating, the Curve B generator operating point moves from X to Y (see Fig. 11). For the operating point within the generator band, the control signal is only initiated for the faulty generator. However, if this generator goes outside the allowable band, system protection and the PMS will start to island the faulty generator. Now system load will be shared by the rest of the machines. System frequency drops, and PMS generates another control signal to correct the system frequency.

Fig. 13 and Fig. 14 document the typical exciter and governor controls connected with typical generator protective relays. These figures also show the appropriate control signals connected between the generators and local protection system. Hence, based upon the operating conditions, the PMS generates control signals to operate and control the overall system, including loads and generation.

A high kW fault may result from speed control feedback loss or actuator signal loss for a particular defective generator. This event results in producing more power than scheduled from this defective generator. This type of fault results in the remaining generators running lightly loaded. Fig. 12 illustrates that if the operating conditions for a generator change from X to Y, a control signal initiates for this generator. For this condition, system frequency increases. If this generator does not respond to the controls and drifts further to point Z, a trip signal is initiated. Similar to the system condition for low kW conditions, the PMS generates a control signal to correct the system frequency. This fault is also indicated as an F1 fault in Table II.

The generator voltage control system will also be running in droop mode. When droop and no-load voltages are set the same on all the generators, these units will inherently share the kVAR equally. However, voltage control is more complex because it depends on the exciter controls. Exciter control can be initiated based on the system conditions, allowing system protection to monitor these operating conditions and provide information to the PMS. Because of faulty AVR electronics, low settings, or unstable voltage control, hunting is sensed via local protection (F3 faults in the Table II). When a parallel generator is hunting, it periodically takes or sheds reactive power, resulting in hunting in the overall system. System protection identifies the generator with the faulty exciter and alarms the user to take corrective action. In the case of exciter loss of the current feedback because of a faulty exciter, the system generates another alarm. Hence, appropriate action is programmed based on the severity and acceptable operating conditions.

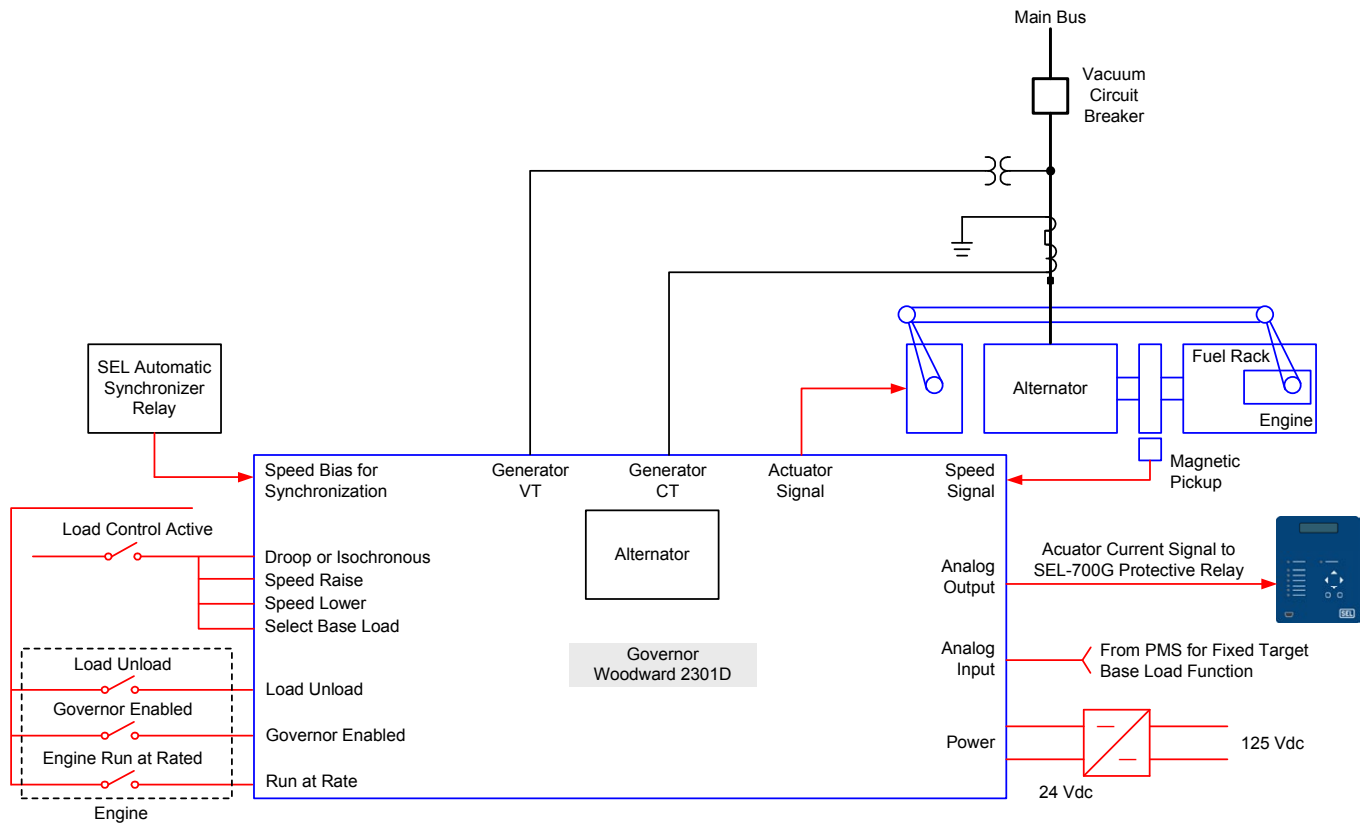


Fig. 13. Typical Woodward Governor and Controls

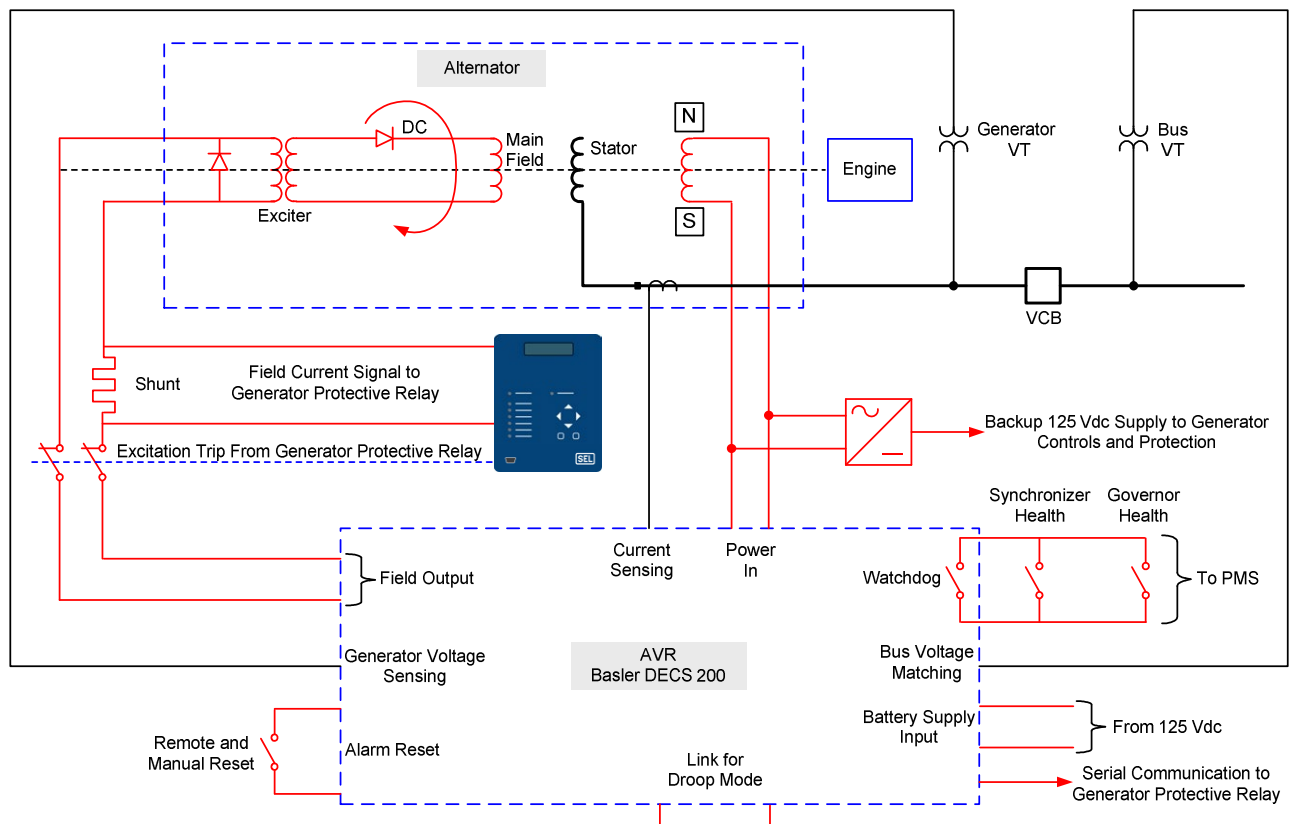


Fig. 14. Typical AVR (Automatic Voltage Regulator) and Exciter Controls

Some faults result because of the fuel rack position and actuator current (F2 faults in Table II). For this type of fault, when actuator current does not track the rack position, an alarm is generated. In the case of a generator fuel problem (damage to fuel line or fuel quality), generator output will not follow the generator fuel rack. Alarms are generated for the predetermined time, and subsequently, the unit is tripped because of the F1 fault discussed previously. Fuel rack hunting may be caused by a number of problems, including dead bands in linkages, faulty speed governor electronics, faulty engine generator shaft coupling, etc. The system protection block analyzes operating conditions and generates an alarm for the appropriate generator. The algorithm requires monitoring the generator parameters, including the fuel rack position for each generator.

For system fault conditions such as breaker status open and generator kW loss, an alarm is generated (F4 faults in Table II). This fault condition indicates that the system has lost the breaker status. For the system fault of breaker status close but frequency indication zero, an alarm is generated for the defective generator with some time delay. During this time, this generator is assumed to be operating properly, and, if system disturbance continues beyond a predetermined time, the system protection islands the faulty generator, similar to an F1 fault. For miscellaneous system faults, such as any protective relay failure, the breaker contact failure to operate or any abnormal system condition is indicated as an alarm.

IV. Other Critical Issues

A. Design Verification

The PMS is designed and validated in the laboratory before it is deployed in the field. Such critical systems need to have the controllers and associated equipment tested during factory acceptance testing. These critical systems need to have their controls validated and tested in a real-time simulation environment. Using this type of validation and testing accurately models governors, turbines, exciters, rotating machinery inertia, load and electrical characteristics, electrical component impedances, and magnetic saturation of electrical components [6][7]. The tests verify several system parameters, such as the voltage change rate with MVAR ($\delta V/\delta \text{MVAR}$) and the frequency change rate with MW ($\delta F/\delta \text{MW}$). This test also coordinate and verify underfrequency backup systems, contingency load-shedding systems, load makeup ratios, and total system inertia constant (H). The verification of these parameters is crucial to the proper operation and coordination of the modern PMS.

Properly designed, validated, and tested systems in the lab environment lead to less time spent on-site and commissioning the overall system. It also allows the PMS to be deployed quickly and safely. A poorly designed and untested PMS costs the end user more downtime and money, in some cases millions of dollars. From a budget perspective,

the end user typically recoups the cost of the PMS with the reduced downtime of one outage.

B. Model Power System Test and Example

The model power system (MPS) testing laboratory is the proposed site for complete testing of SEL systems using the Real Time Digital Simulator (RTDS®). RTDS equipment allows dynamic modeling of the customer's power system with a simulated small time step to test all closed-loop controls and protection systems.

Electrical transient studies use simplified positive-, negative-, and zero-sequence models of power system impedances and sources to calculate the short-circuit currents in a power system. These models are not acceptable for any form of dynamic stability study because they do not model system inertia or governor response times. This form of modeling is appropriate for protective relay coordination; however, for the design of PMS protection, a study that requires detailed system dynamics is required. Hence, the RTDS is an appropriate tool for the design verification of this project.

Fig. 15 shows an example system with two machines and one swing machine (external utility). For this example system, the GSU (generator step-up) transformer, step-down transformers, loads, generators, exciters, and governors are modeled in detail. All the major rotating and static loads are modeled per the information provided. Based on tests for the load flow, short circuit, motor start, and exciter governor, the model is verified for accuracy. Because the accuracy of the design and settings are based upon this verification, correctly modeling the system is critical. The system performance will also be verified during field installation. This successful test method will be applied to the DP system shown in Fig. 1, in which the RTDS model will use six machines with detailed dynamic models.

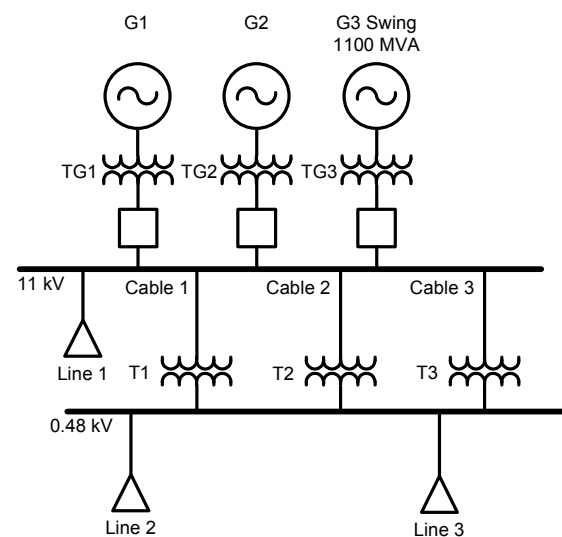


Fig. 15. Example One-Line Model in the RTDS

Fig. 16 shows the RTDS connection to a test rack. All the power system components are located in the RTDS rack, and information is exchanged between the RTDS rack and test rack for this system. Fig. 17 shows the generator parameters observed for the step-load test. This information will be used to benchmark the exciter and governor performance.

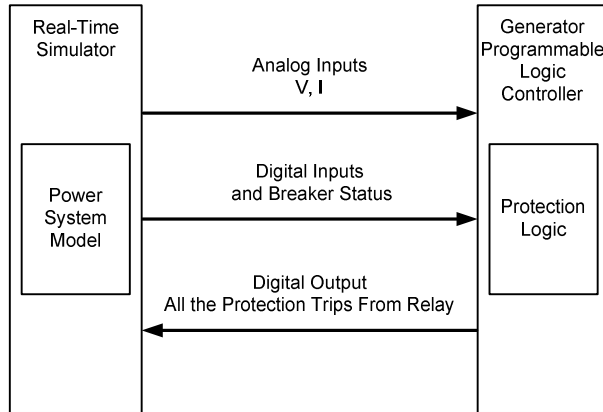


Fig. 16. RTDS and Test Model Connection

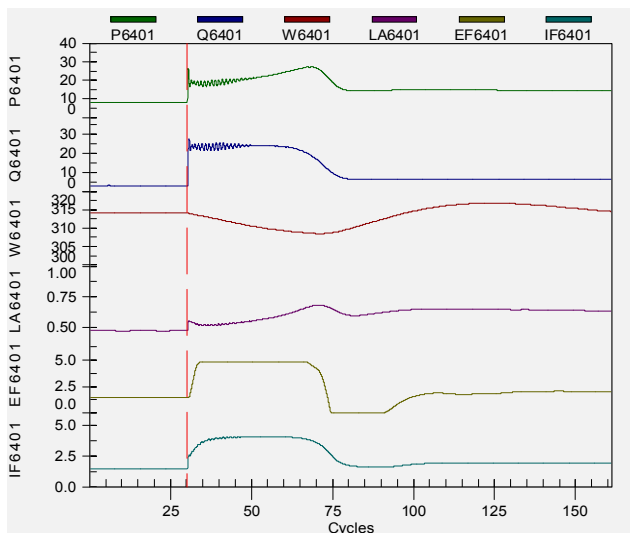


Fig. 17. Results of Step-Load Test Using an RTDS Modeling an Example System

The RTDS testing verifies the system design, settings for the protection, and overall system performance. Multiple faults and system problems are created and tested in a closed-loop system, evaluating the system performance even before the PMS is installed on-site. In addition, the results of on-site testing are used to revalidate the system design. Once the standard DP system model is built, it is easily used for future system expansion and design variation. SEL has used this tool for various projects with complicated system designs where settings are dependent on the system design parameters. Without detailed testing, selecting proper protection is not possible.

C. Off-the-Shelf and Expandable Projects

As mentioned earlier, the proposed system configuration is shown in Fig. 3. For this example project, only six generators are installed; however, this system is easily expanded for vessels designed with more than six generators. As part of this project, the overall protection scheme will also be reviewed. The scheme will be designed considering system contingencies and future growth. Using the proposed scheme as a template for future design reduces engineering costs. Once the system is designed and tested for one vessel, the same design is easily applied to other vessels. The cost of training, maintenance, and system operation is also reduced because of the standard system design.

D. Local Support, Documentation, and Training

Detailed documentation and local support is best provided at the customer location. Deep-water drilling platforms are located all over the world, so support and training for these critical projects are required “as needed” and “when needed.” Transocean found that a global presence of the support company (like that offered by SEL) is very important to the acceptance and success of the project.

V. Conclusion

The proposed PMS provides a highly reliable system design, using the solution shown in Fig. 3. The local protection block provides the generator protection; the system protection block includes all the system design components and programming for decision and control. This solution provides cutting-edge protection functions for generators using synchrophasor technology and optional IEC 61850 protocol. In addition, the solution includes a PMS (SEL POWERMAX), arc-flash protection, and automatic synchronizer. This solution is very robust, easily expandable, and self-diagnostic. It provides automatic archiving of SOE and ER. Using advanced technology and tools, a very reliable PMS is designed and implemented.

PMS design and deployment should include studies such as load flow, short circuit, arc flash, relay coordination, black start, and stability for proper system design. Detailed studies, factory acceptance tests, reports, and logic diagrams should address all possible contingencies and operating conditions, including the comparison with manufacturer provided information and on-site testing results. This testing facilitates system operation verification, because without proper documentation and analysis tools, accurate analysis of any system disturbance or operation is not possible. Documentation is very important for troubleshooting and analysis of any trip or misoperation. For this type of critical project, the operation staff relies on training and support to understand and operate their cutting edge power management system.

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VII. Biographies

Lew Weingarth received his BSEE from the University of Missouri-Rolla with honors in 1981, after which he worked for Southeastern Drilling Company as an engineer trainee. He is working toward an MBA. Until 2001, Lew worked in the offshore deep-water drilling industry, primarily on DP vessels. He then became an international consultant on DP and power management systems, working for oil companies and drilling contractors. In 2004, Lew accepted a position with Transocean as a DP superintendent for the purpose of assembling a discipline dedicated to eliminating DP and power system downtime by improving the reliability of control systems, power plants, and operations onboard modern DP rigs.

Scott Manson is a supervising engineer in the engineering services division of Schweitzer Engineering Laboratories, Inc. (SEL). He received his MSEE from the University of Wisconsin–Madison and BSEE from Washington State University. Scott worked at 3M Corporation as a control system engineer for six years prior to joining SEL in 2002. Scott has experience in designing and implementing control systems for electrical utility customers, high-speed web lines, multiaxis motion control systems, and precision machine tools. Scott is a licensed Professional Engineer in four U.S. states.

Saurabh Shah is a branch manager in the engineering services division of Schweitzer Engineering Laboratories, Inc. (SEL). He received his BS in 1995 and AS in computer systems in 1991 from Lewis-Clark State College. He has a broad range of experience in the field of power system operations, protection, automation, and integrated systems. He has served nearly 19 years at SEL, where he worked in relay testing, sales, business development, and engineering project management before becoming branch manager of engineering services.

Kamal Garg is a project engineer in the engineering services division of Schweitzer Engineering Laboratories, Inc. (SEL). He received his MSEE from Florida International University and India Institute of Technology, Roorkee, India, and a BSEE from Kamal Nehru Institute of Technology, Avadh University, India. Kamal worked for Power Grid Corporation of India Ltd. for about seven years and Black & Veatch for about five years at various positions before joining SEL in January 2006. Kamal has experience in protection system design, system planning, substation design, operation, testing, and maintenance. Kamal is a licensed Professional Engineer in five U.S. states.

COMPLETE POWER MANAGEMENT SYSTEM FOR AN INDUSTRIAL REFINERY

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Krishnanjan
Gubba Ravikumar
Member, IEEE
Schweitzer Engineering
Laboratories, Inc.
2350 NE Hopkins Court
Pullman, WA 99163,
USA

Turky Alghamdi
Saudi Aramco
P.O. Box 12663
Dhahran,
Saudi Arabia 031311

Jamal Bugshan
Saudi Aramco
P.O. Box 10031
Dhahran,
Saudi Arabia 031311

Scott Manson
Senior Member, IEEE
Schweitzer Engineering
Laboratories, Inc.
2350 NE Hopkins Court
Pullman, WA 99163,
USA

Sai Krishna
Raghupathula
Member, IEEE
Schweitzer Engineering
Laboratories, Inc.
2350 NE Hopkins Court
Pullman, WA 99163,
USA

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

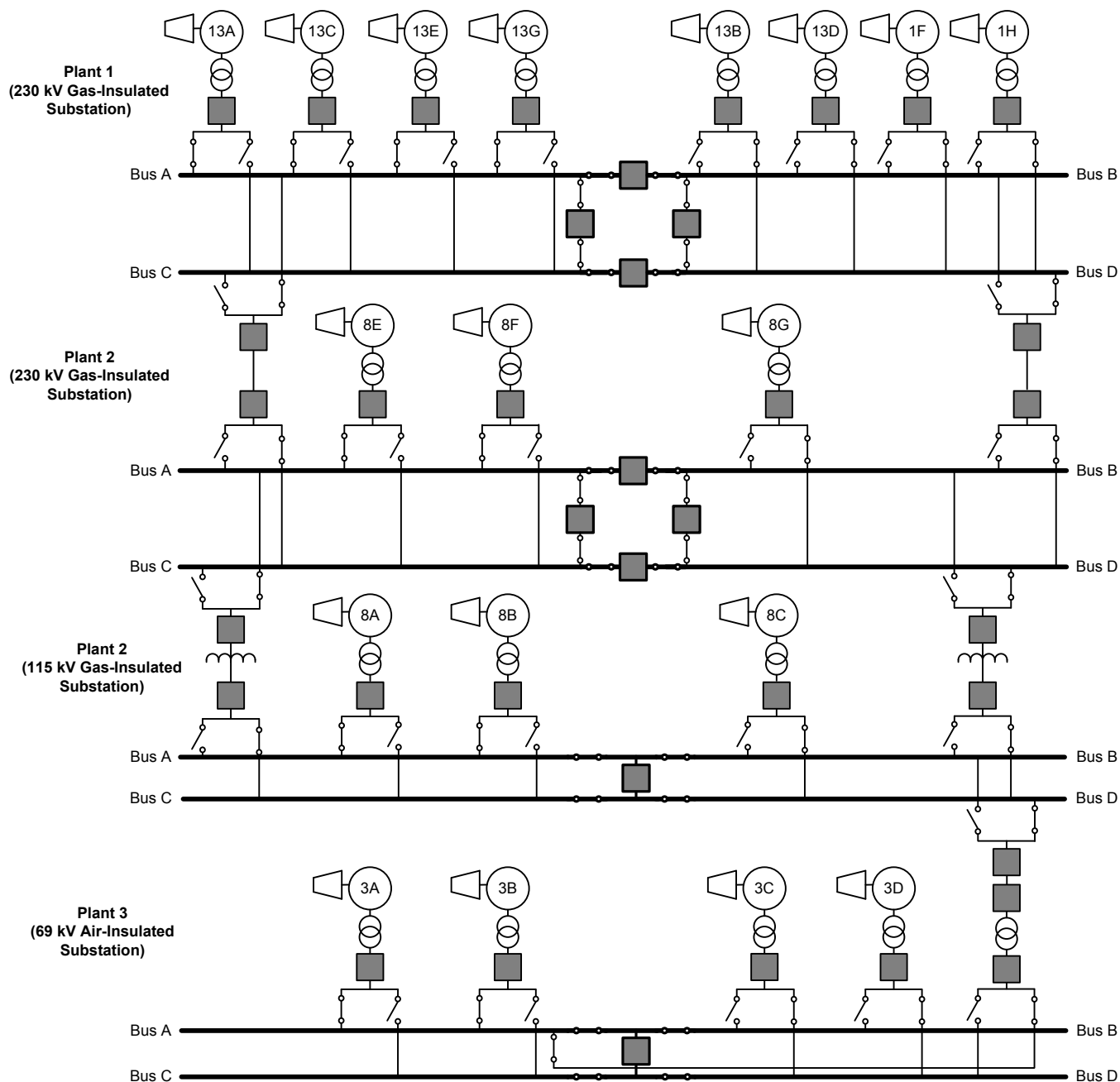


Fig. 1 Simplified One-Line Diagram of Power Generation and Transmission Systems

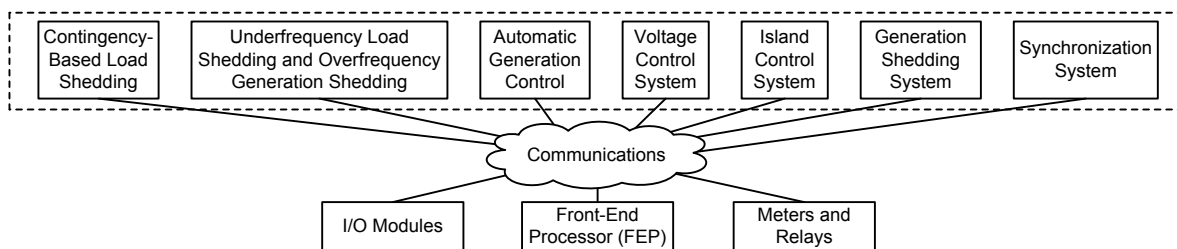


Fig. 2 Simplified PMS Architecture

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)

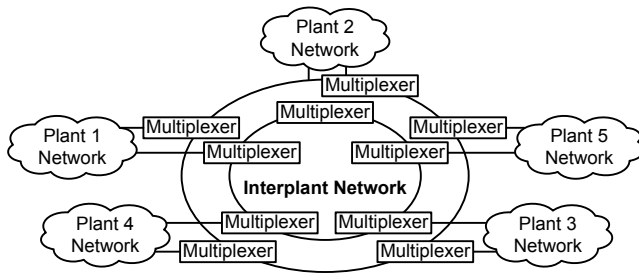


Fig. 3 Simplified Communications Architecture

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.

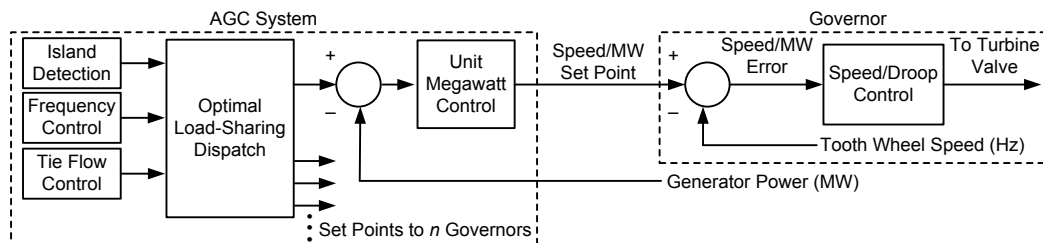


Fig. 4 AGC System

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.

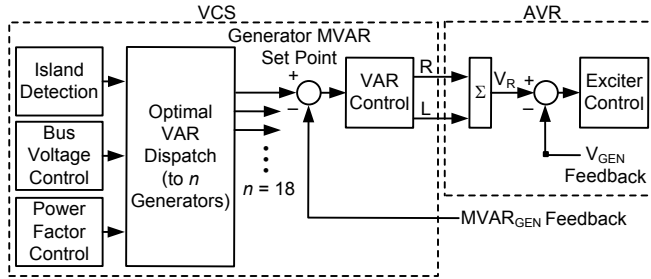


Fig. 5 VCS Strategy

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.

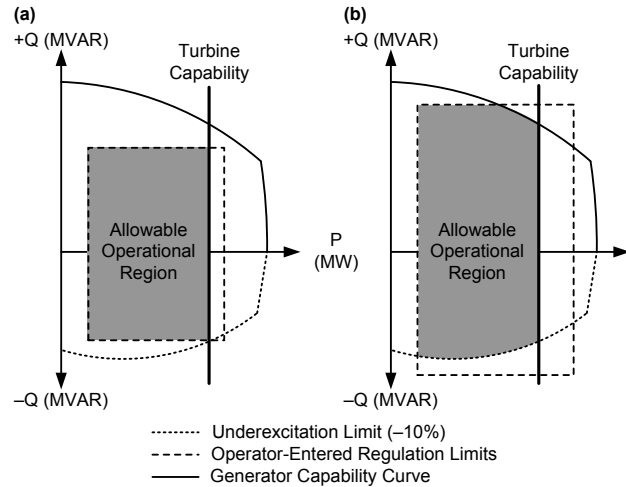


Fig. 6 Regulation Limits Within and Outside the Generator Capability Curve

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].

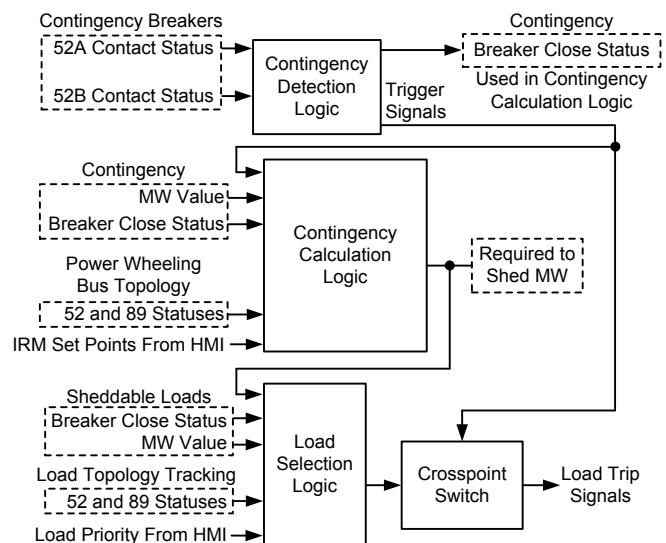


Fig. 7 CLS Algorithm

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.

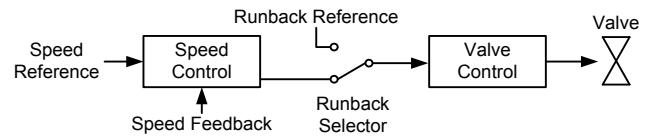


Fig. 8 Runback in a CGTG Speed Governor

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.

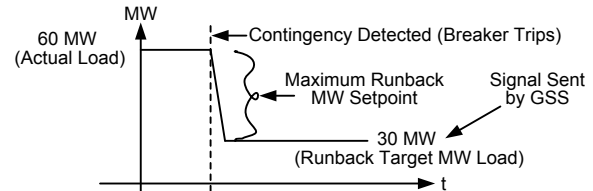


Fig. 9 Generator Runback Target Load Set Point

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).

$$2H\omega \cdot \frac{d\omega}{dt} = P_m - P_{elec} = P_{acc} \quad (1)$$

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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IX. VITAE

Krishnanjan Gubba Ravikumar received his MSEE degree from Mississippi State University and his BSEE from Anna University, India. He is presently working as a supervising engineer in the Schweitzer Engineering Laboratories, Inc. engineering services division, focusing on model power system development and testing for special protection systems. His areas of expertise include real-time modeling and simulation, synchrophasor applications, remedial action schemes, and power electronic applications. He has extensive knowledge in power system controls and renewable distributed generation. He is a member of the IEEE and the Eta Kappa Nu Honor Society. He can be contacted at krisgubb@selinc.com.

Turky Alghamdi joined Saudi Aramco in 2004 and received his BEng in Electrical and Electronic Engineering from Newcastle University, Newcastle, United Kingdom in 2009. Since then he has worked as a plant engineer in a gas-oil separation plant and as an electrical engineer in the Power Operation Department. Currently, he is a lead project engineer with the Saudi Aramco Project Management Team, working on a power generation project for oil and gas plants. He can be contacted at turky.alghamdi@aramco.com.

Jamal Bugshan received a BSEE degree from King Fahd University of Petroleum and Minerals (KFUPM) in 1994. Following five years with the Saudi Consolidated Electricity Company in the Eastern Province, Dammam, he joined Saudi Aramco in Dhahran, Saudi Arabia, in 2000. He is currently working as an Engineering Specialist in the corporate Consulting Services Department. Mr. Bugshan is the standard chairman of the Electrical Systems Designs & Automation Standards Committee at Saudi Aramco. He can be contacted at jamal.bugshan@aramco.com.

Scott Manson, P.E. (S 1991, M 1993, SM 2012), received his MSEE from the University of Wisconsin-Madison and his BSEE from Washington State University. Scott is presently the engineering services technology director at Schweitzer Engineering Laboratories, Inc. In this role, he provides consulting services for control and protection systems worldwide. He has experience in power system protection and modeling, power management systems, remedial action schemes, turbine control, and multiaxis motion control for web lines, robotic assembly, and precision machine tools. Scott is a registered professional engineer in Washington, Alaska, North Dakota, Idaho, and Louisiana. He can be contacted at scott_manson@selinc.com.

Sai Krishna Raghupathula is a regional manager for the engineering services division of Schweitzer Engineering Laboratories, Inc. (SEL). He received his MSEE from the University of Idaho. He has been employed with SEL since 2004 and has held several positions in the engineering services division. He has experience in designing and implementing control systems for utility and industrial customers. He can be contacted at saira@selinc.com.

State-of-the-Art Islanding Detection and Decoupling Systems for Utility and Industrial Power Systems

Krishnanjan Gubba Ravikumar, Ashish Upreti, and Adithiya Nagarajan, *Schweitzer Engineering Laboratories, Inc.*

Abstract—Islanding detection and decoupling needs are becoming a crucial part of power system operations due to the increasing penetration of distributed generation in utility power systems and the self-sustaining operational capabilities of industrial power systems. This paper presents a complete solution for determining a power system islanding condition using state-of-the-art technologies such as synchrophasors and microprocessor-based relays. This solution combines three independent schemes working together in a coordinated fashion to reliably detect an islanding condition under all power import and export scenarios with reliable detection speeds. The solution has been tested using real-time digital simulation in a closed-loop environment. The key objective of this solution is to provide the most reliable and affordable islanding detection and decoupling system (IDDS) to utility and industrial power systems for solving the critical challenges of today and tomorrow.

This paper presents the functionality, validation, and performance of the IDDS in a simulated model for a real-world application. The schemes are analyzed for speed and reliability in a wide variety of operating scenarios. The effectiveness of the overall solution has been tested in a controlled test environment as part of power management system functional testing for a 2 GW microgrid. This solution is currently in service.

I. INTRODUCTION

Islanding detection and isolation from disturbances are the first steps for enabling sustainable microgrids. When there is less than 10 MVA distributed generation, islanding detection is required by IEEE Standard 1547 to de-energize the distributed generator within 2 seconds for reasons such as personnel safety, power quality, and out-of-phase reclosing [1]. Some of these distributed generators are not only power electronics-based, but also synchronous machine-based and can sustain islands if provided with adequate controls and load-shedding and generation-shedding schemes [2] [3]. Decoupling schemes that detect disturbances in the grid and intentionally island the microgrid can sustain the microgrid operation while keeping the critical loads connected. This paper focuses on islanding detection and intentional decoupling schemes used to create a reliable and high-speed system for a microgrid that has an installed generation capacity of 2 GW.

II. ISLANDING DETECTION AND DECOUPLING SYSTEM (IDDS)

In the context of this paper, it is important to define and differentiate islanding detection and decoupling. An islanding detection scheme detects an islanding condition when the microgrid is disconnected from the utility power system.

A decoupling scheme detects disturbances in the utility power system and intentionally islands the microgrid. Disturbance detection settings for such intentional decoupling systems should be carefully set to avoid being too sensitive and to prevent nuisance tripping.

To sustain the operation of the microgrid and to prevent microgrid blackout, the microgrid load-shedding and/or generation-shedding scheme needs to be triggered following the islanding condition.

The IDDS in this application consists of three independent schemes operating in parallel.

A. Direct Transfer Trip (DTT)

DTT is a communications-based transfer tripping scheme widely used in protection systems. In this application, DTT is used to detect an islanding condition through direct isolation of the transmission line at the remote (utility) end via breaker status and initiate a load-shedding and/or generation-shedding scheme to sustain microgrid operation. The breaker status is supervised with open-phase detection (undercurrent element) to increase the security of the line-open detection. The transfer trip signal is sent over two completely separate physical communications media for redundancy using different protocols. The first communications method employs a proprietary high-speed peer-to-peer protocol that exchanges digital word bits. The second method uses the IEEE C37.118 synchrophasor protocol to send the digital bits. Fig. 1 shows the DTT scheme used to trigger the load-shedding and/or generation-shedding scheme.

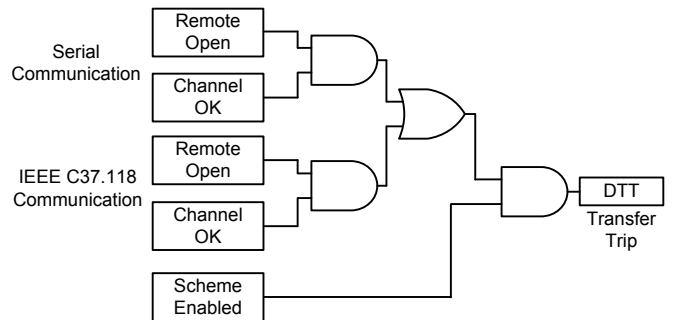


Fig. 1. DTT Scheme

B. Local-Area-Based Detection

The local-area-based detection schemes are based on local measurements. This paper discusses three elements that can detect islanding conditions as well as grid disturbances. These are all passive detection schemes that can be programmed into a microprocessor-based protective relay [4].

1) Underfrequency/Overfrequency (UF/OF) and Undervoltage/Overvoltage (UV/OV) Elements

Abnormal voltage and frequency detection with qualifying time delays allows for disturbance detection and successful islanding detection and decoupling. These elements should be carefully coordinated with existing protection systems to avoid false tripping during fault conditions.

Fig. 2 shows the overfrequency- and underfrequency-based scheme.

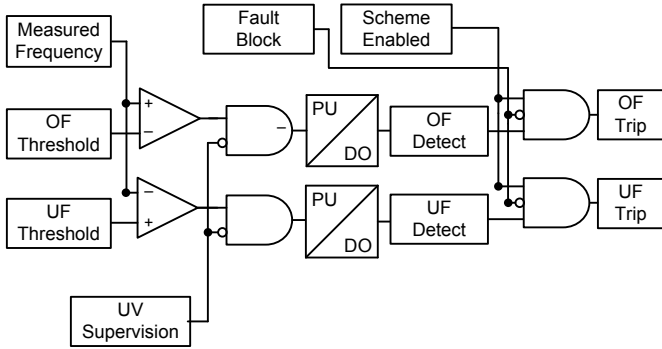


Fig. 2. Overfrequency- and Underfrequency-Based Scheme

Fig. 3 shows the overvoltage- and undervoltage-based scheme.

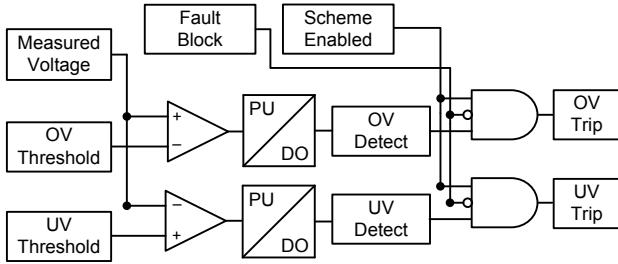


Fig. 3. Overvoltage- and Undervoltage-Based Scheme

2) Rate of Change of Frequency (81R) Element

The rate of change of frequency (ROCOF) element is typically used to detect if the power system is accelerating or decelerating due to unbalance between load and generation. This rate above a certain threshold can be used to detect system disturbances and initiate a decoupling scheme based on an abnormal grid condition. The decoupling scheme can also be set to detect islanding conditions. Fig. 4 shows the logic diagram for the 81R element.

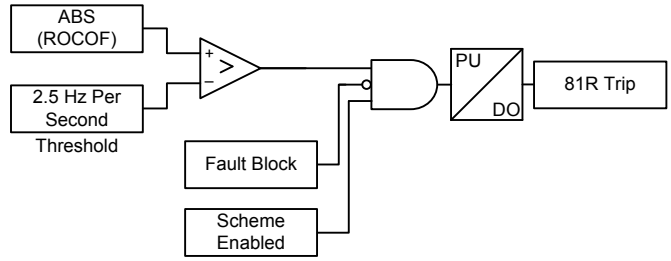


Fig. 4. 81R Scheme

3) Fast Rate of Change of Frequency (81RF) Element

The 81RF element provides a faster response compared with the frequency (81O and 81U) and rate of change of frequency (81R) elements. The faster response times make the 81RF element suitable for detecting islanding and system disturbance conditions with critical time requirements.

Fig. 5 shows the 81RF characteristic. This element uses frequency deviation from nominal frequency ($DF = \text{FREQ} - \text{FNOM}$) and rate of change of frequency (DFDT/ROCOF) to detect islanding conditions. Under steady-state conditions, the operating point is close to the origin. During separation from the utility power system, depending on the frequency difference and the rate of change of frequency, the operating point enters the operating region of the characteristic. If the system is accelerating, the operating point enters Trip Region 1, and if the system is decelerating, the operating point enters Trip Region 2.

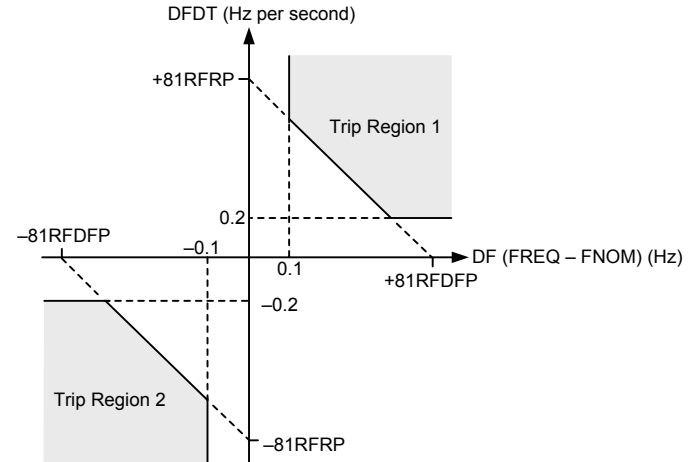


Fig. 5. 81RF Characteristic

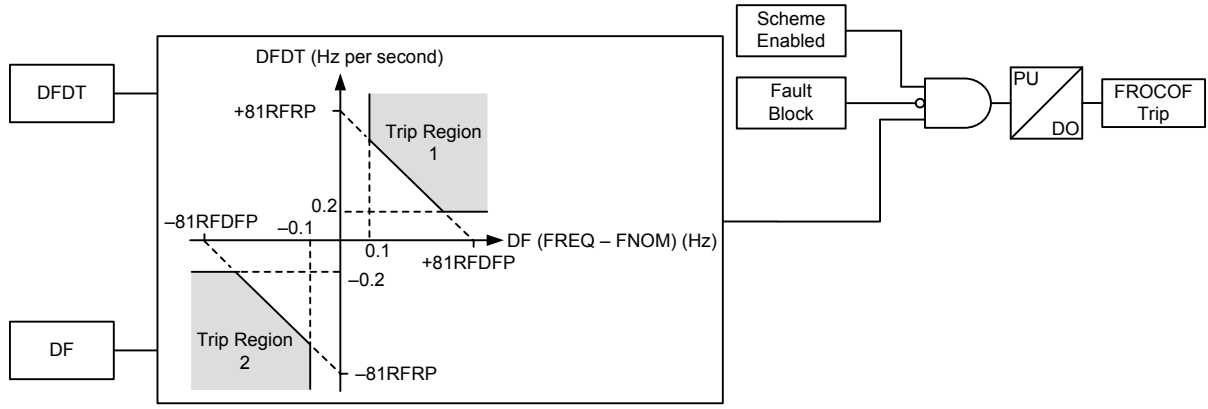


Fig. 6. 81RF Fast Rate of Frequency (FROCOF) Scheme

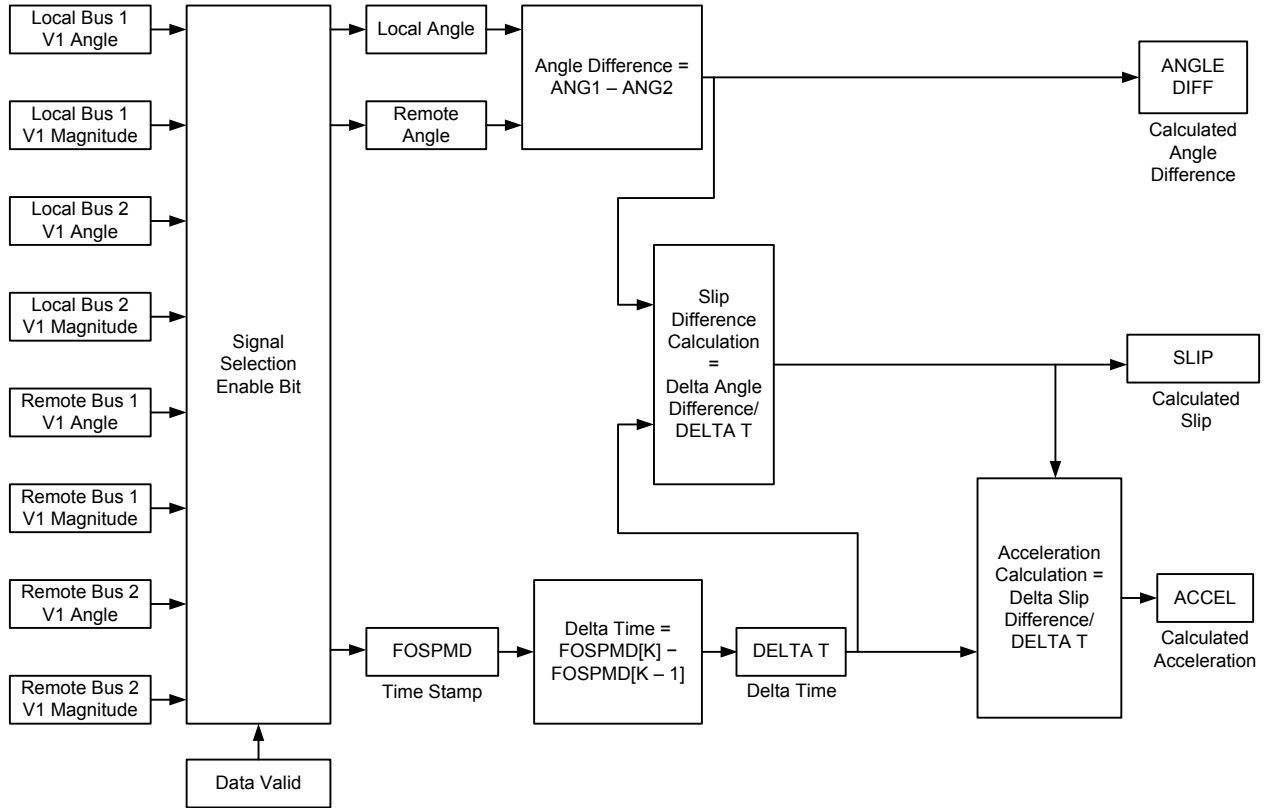


Fig. 7. Overall Wide-Area-Based Islanding Detection Scheme

The element uses the settings 81RDFDP in Hz and 81RFRP in Hz per second to configure the characteristic. Fig. 6 shows the 81RF scheme using the characteristic. Blocking logic is used to restrain the element under fault conditions or other conditions where the frequency measurements are not reliable.

C. Wide-Area-Based Detection

Synchrophasor technology allows for the implementation of wide-area-based power system control schemes. In addition to requiring GPS time synchronization, these wide-area-based schemes can use various forms of communication (serial,

Ethernet, radio, and so on) for transferring time-synchronized phasor data. We focus on two wide-area schemes that compare local and remote synchrophasor measurements to detect islanding conditions [2]. Fig. 7 shows the parameters used from the local and remote relays for calculating the variables required for the wide-area-based schemes. The local positive-sequence voltage angle and remote voltage angle are measured and qualified before calculating the angle difference. This angle difference is further used to calculate the slip and acceleration in wide-area-based detection.

The change of angle difference (δ_k), with respect to time, defines the slip frequency (S_k), as shown in (1). The change of slip frequency, with respect to time, defines the acceleration between the two terminals (A_k), as shown in (2).

$$S_k = (\delta_k - \delta_{k-1}) \frac{\text{MRATE}}{360} \quad (1)$$

$$A_k = (S_k - S_{k-1}) \text{MRATE} \quad (2)$$

where:

S_k is the slip frequency at the k processing interval.

A_k is the acceleration at the k processing interval.

MRATE is the synchrophasor message rate.

1) Angle Difference-Based Scheme

An angle difference-based wide-area scheme uses positive-sequence voltage angles between two locations (local and remote) to determine islanding conditions. These two locations can be either ends of a transmission line or a microgrid point of common coupling (PCC) substation and a reference substation in the utility power system. The angle difference element operates if the phase angle difference between the positive-sequence voltage phasors at the two locations (local and remote) exceeds a programmable threshold for a specified duration. Fig. 8 shows the angle difference-based wide-area scheme.

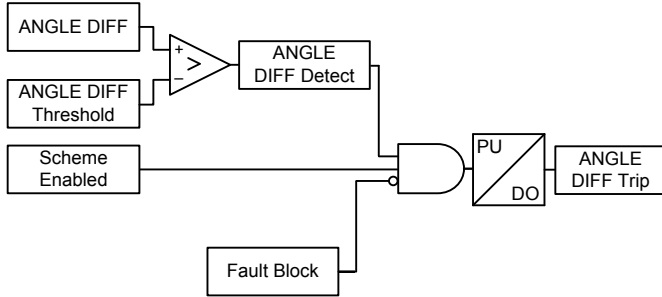


Fig. 8. Angle Difference-Based Wide-Area Scheme

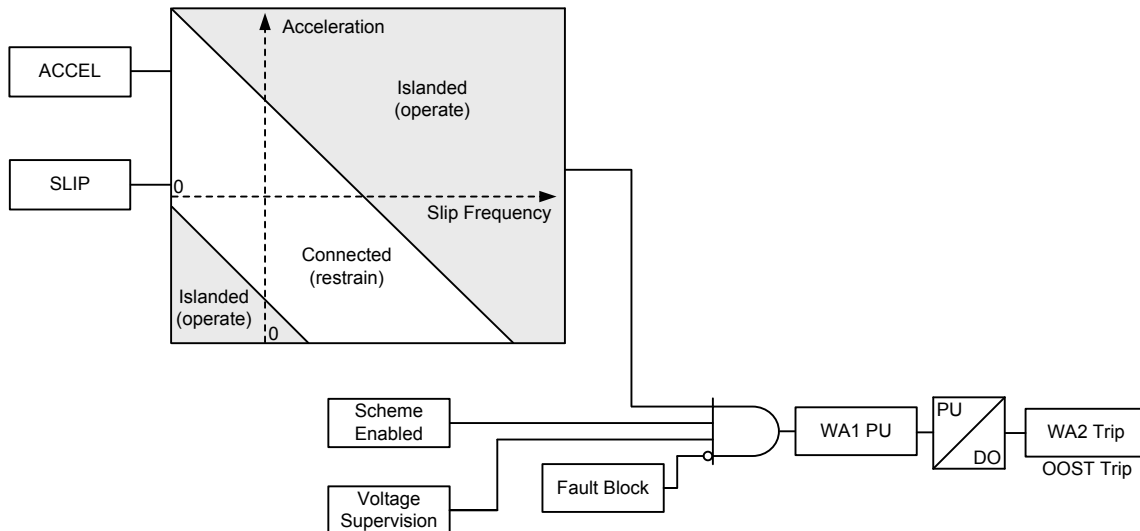


Fig. 9. Slip and Acceleration-Based Wide-Area Scheme

2) Slip and Acceleration-Based Scheme

The slip and acceleration-based scheme is very similar to the 81RF characteristic. We use the slip acceleration characteristic shown in Fig. 9 to detect if the system is interconnected and if it is subjected to an oscillation.

Fig. 9 shows the logic for islanding detection based on this characteristic. When the system is interconnected, the operating point is at the origin of the slip acceleration characteristic. Once the systems separate, the operating point starts to move from the restrain region to the operate region. The unshaded area represents the thresholds that are selected for security. The logic declares an islanding condition and/or grid disturbance when the operating point stays in the operate region for a specified duration (PU) and initiates local breaker opening, which in turn triggers the appropriate load-shedding and/or generation-shedding scheme.

III. TEST SYSTEM AND IDDS IMPLEMENTATION

This section describes the closed-loop simulation environment, test power system, and IDDS implementation.

A. Simulation Environment

The hardware-based Electromagnetic Transients Program (EMTP) simulator used for this application is a fully digital power system simulator capable of continuous real-time operation. It performs electromagnetic power system transient simulations, with a typical simulation time step in the order of 50 microseconds, using a combination of custom software and hardware.

The real-time EMTP simulator was specifically used to connect the IDDS in a closed loop with the power system model to emulate field testing. We created a power system model representing the microgrid and the utility power system. This model includes components of both the mechanical and electrical subsystems, such as governors, turbines, exciters, busbars, generators, inertia of loads and the lower-voltage network, nonlinear mechanical characteristics, electrical component impedances, and magnetic saturation of electrical components. This level of modeling provides an accurate depiction of frequency, voltage, current, turbine speed, generator rotor angles, and governor response characteristics for steady-state and dynamic studies.

B. Test Power System

The microgrid facility tested comprises six 220 kV substations and one 400 kV substation. All of these substations are connected through intertie lines and interconnecting transformers. The 220 kV substations serve several critical and noncritical load transformers, while the 400 kV substation connects to the utility grid through two parallel transmission lines.

With about 2 GW of installed generation capacity distributed across the 220 kV substations, the facility exports about 1 GW of power to the utility in addition to serving its own load. Fig. 10 shows a simplified diagram of the test system.

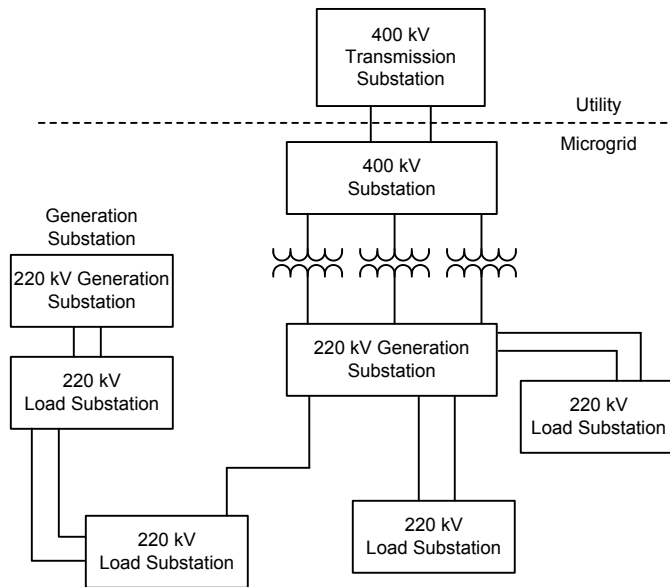


Fig. 10. Simplified Power System Overview

C. Islanding Detection and Decoupling System

Fig. 11 shows the IDDS connections in the microgrid and utility 400 kV substations. The islanding detection part of this system tracks any remote breaker open condition to immediately open the local breaker and trigger the generation-shedding and/or load-shedding system of the microgrid. The decoupling part is tasked with detecting any severe utility disturbances that require intentional islanding to save the microgrid from a blackout and to ensure continuity of microgrid operation. In the case of both islanding detection and decoupling, the local breaker opening triggers the microgrid generation-shedding and/or load-shedding systems to stabilize the frequency and voltage after disconnecting the microgrid from the utility power system.

Redundant microprocessor-based protective relays are installed at the local and remote ends of the 400 kV interconnected line for this application. Relays installed at the utility end of the 400 kV transmission line are used to provide necessary remote data to the local relay for making control decisions. The relays at the remote end are wired to the instrument transformers to measure current and voltage information on Transmission Lines 1 and 2. Additionally, the remote relays are configured to sense the remote breaker status. The breaker status and the current information are used by the remote relays for the DTT scheme, whereas the voltage magnitude and angle information are communicated via fiber-optic communications to the local relays for the wide-area scheme. Similarly, the local relays are also wired with current, voltage, and breaker information to assist with local- and wide-area schemes. In addition to the digital and analog inputs, the local relays are configured to perform tripping of microgrid side line breakers CB1 and CB2 during islanding detection and utility disturbance conditions.

All three of the previously mentioned schemes are used to detect and decouple the microgrid system from the utility grid. The communications for this microgrid use point-to-point fiber connections between the local and remote relays.

Fig. 12 and Fig. 13 show the local relay and remote relay front-panel configurations. These configurations indicate the protective relay targets and user control interface.

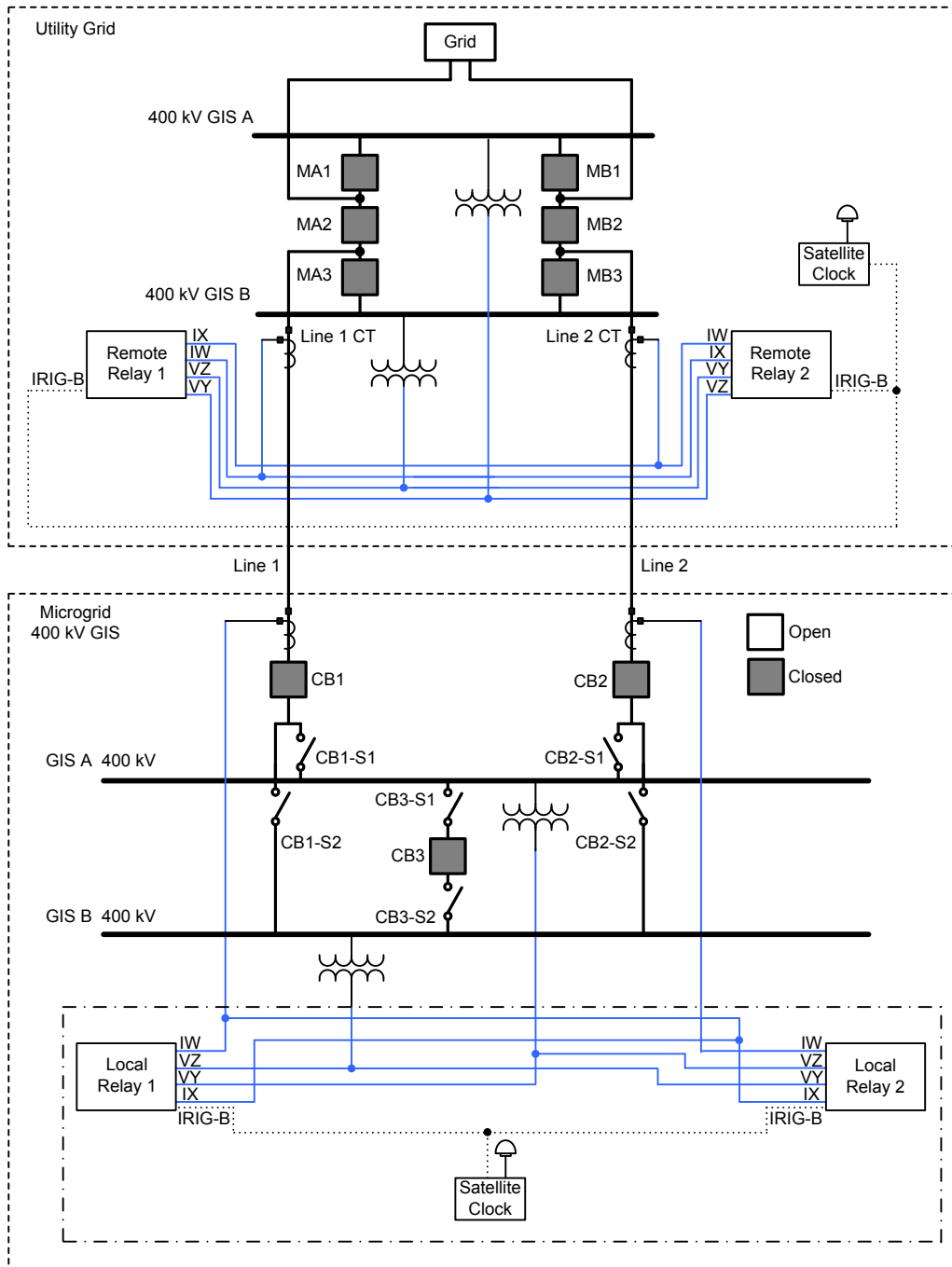


Fig. 11. IDDS Implementation

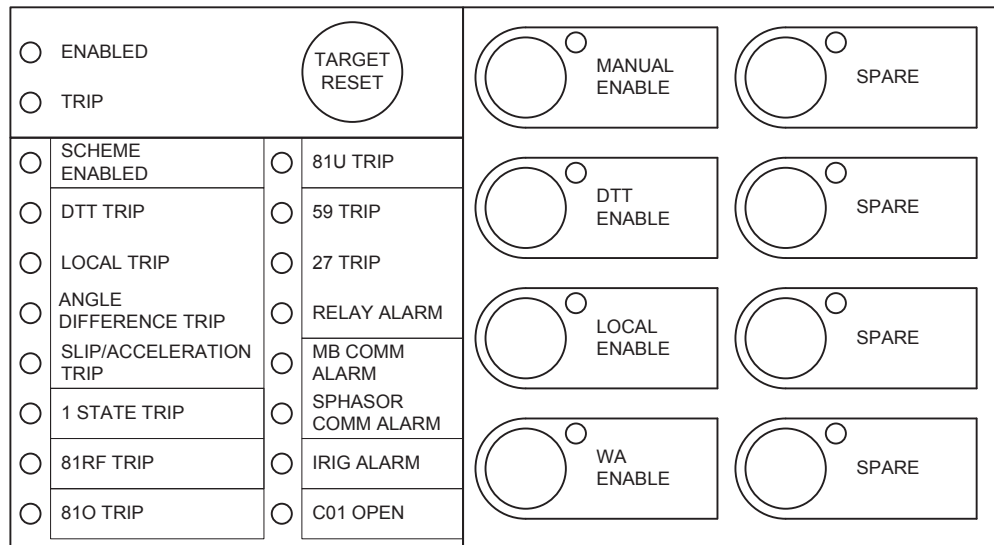


Fig. 12. Local Relay Front Panel

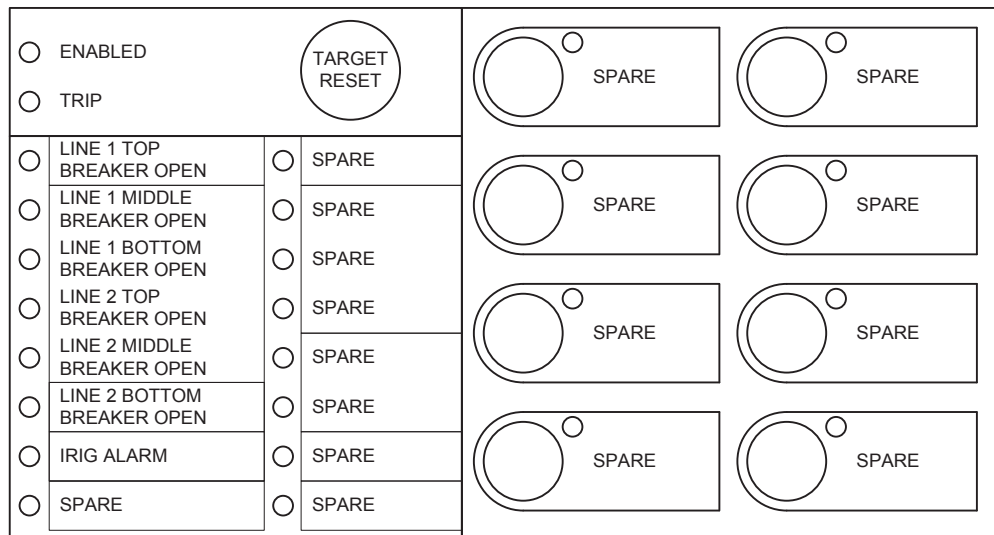


Fig. 13. Remote Relay Front Panel

IV. DYNAMIC SIMULATIONS

Factory acceptance testing was performed prior to the installation of the IDDS at the microgrid. We created an EMTP model of the power system to validate the functionality of the IDDS in terms of speed and reliability.

Several studies were done using the model, providing insight into microgrid operation, existing design vulnerabilities, and the system response for various contingency events. We conducted several tests on the system to determine the optimal thresholds for the IDDS. The real-time closed-loop testing approach also helped minimize IDDS commissioning time.

Fig. 14 shows the connection between the IDDS hardware and power system simulation hardware. Analog outputs from the real-time digital simulator include voltages and currents from the local and remote terminals of the 400 kV intertie. Digital outputs include the breaker statuses. We wired the relay (configured with IDDS) outputs indicating islanding and/or system disturbances to the real-time digital simulator to

disconnect the microgrid from the utility and initiate the generation-shedding scheme. The generation-shedding scheme was implemented in an external power management controller, which was also connected in a closed loop with the simulation hardware.

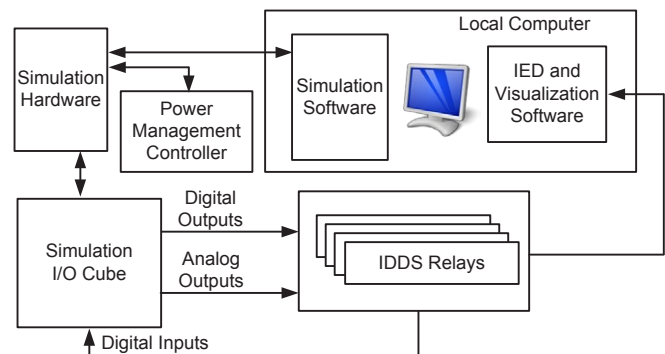


Fig. 14. Real-Time Digital Simulation Interface With IDDS

TABLE I
DECOUPLING TEST SIMULATED USING REAL-TIME DIGITAL SIMULATION (MICROGRID INTERCONNECTED WITH UTILITY GRID)

Case	Condition	Desired Result	Operation	Detection Time	Pass/Fail
A	Internal disturbance (loss of 1,200 MW generation followed by load shedding)	Ride through	No operation	NA	Pass
B3	Utility frequency increase at the rate of 1.5 Hz per second while exporting 260 MW	Decouple	Local (81RF operation)	900 ms	Pass
B4	Utility frequency increase at the rate of 2.5 Hz per second while exporting 800 MW	Decouple	Local (81R operation)	380 ms	Pass
B5	Utility frequency decrease at the rate of 1.8 Hz per second while exporting 800 MW	Decouple	Local (81RF operation)	720 ms	Pass
B6	Utility frequency increase at the rate of 0.6 Hz per second while exporting 800 MW	Decouple	Local (81RF operation)	1,380 ms	Pass

TABLE II
ISLANDING DETECTION TESTS SIMULATED USING REAL-TIME DIGITAL SIMULATION

Case	Condition	Desired Result	Operation	Detection Time	Pass/Fail
C	Utility breaker opening (protected by DTT) during 0 MW import and export condition	Decouple	DTT	50 ms	Pass
D1	Utility breaker opening (unprotected by DTT) during 520 MW export condition (medium-export condition)	Decouple	Wide area (angle-based)	160 ms	Pass
D2	Utility breaker opening (unprotected by DTT) during 70 MW export condition (low-export condition)	Decouple	Wide area (angle-based)	300 ms	Pass
D3	Utility breaker opening (unprotected by DTT) during 0 MW import and export condition	Decouple	Wide area (angle-based)	500 ms	Pass

TABLE III
FAULT TESTS SIMULATED USING REAL-TIME DIGITAL SIMULATION

Case	Condition	Desired Result	Operation	Detection Time	Pass/Fail
E1	Single-phase fault and fault isolated by opening Line 1	Ride through	No operation	NA	Pass
E2	Three-phase fault and fault isolated by opening Line 1	Ride through	No operation	NA	Pass

The cases simulated are listed in Table I, Table II, and Table III, along with their performance. We used the settings in Table IV to evaluate the performance of the IDDS.

TABLE IV
SCHEME PARAMETERS

Scheme	Setting	Parameter
81RF	81RFRP	5 Hz per second
81RF	81RDFDP	1.5 Hz
81R (ROCOF)	Threshold	2.5 Hz per second
Angle difference	ANGLE DIFF threshold	7.5 degrees
Slip and acceleration	Slip	1.5 Hz
Slip and acceleration	Acceleration	2.5 Hz per second
All schemes	Pickup timer	5 cycles

The 81R and 81RF settings were chosen based on data from disturbances that the microgrid experienced in the past. The angle difference threshold was chosen based on maximum power flow conditions across the utility tie during the worst-case condition of a single line in service, along with considering the angle difference transient response during normally cleared fault conditions.

The IDDS is disabled after the detection of a disturbance or islanding condition. It is reenabled after it confirms that the microgrid and the utility power system are back to normal operating conditions.

A. Case A

Case A represents an internal disturbance within the microgrid when the microgrid is interconnected to the utility network. When connected to the utility, a change in generation and/or load should not trigger the IDDS, and it should be able to ride through the event. In this case, a total generation of

1,200 MW was intentionally tripped, followed by load shedding. As expected, the IDDS did not operate. Fig. 15a shows that the operating quantity is in the restraint region of the 81RF element, and Fig. 15b shows that angle difference is within the preconfigured threshold of 7.5 degrees.

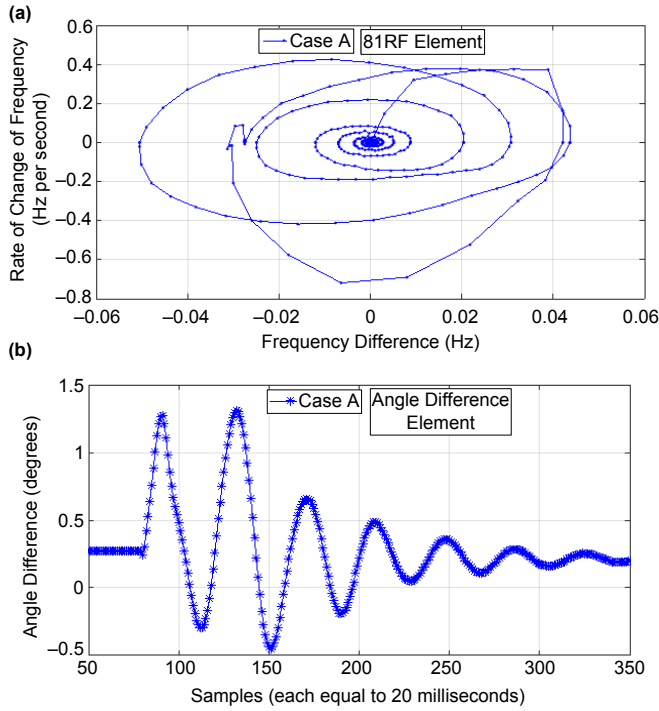


Fig. 15. Case A

B. Cases B3 to B6

Cases B3 to B6 simulate frequency disturbances in the utility power system when the microgrid is interconnected to the utility. For example, Case B3 simulates the utility frequency increasing at a rate of 1.5 Hz per second while the microgrid is exporting power to the utility. These cases represent fault conditions in the utility power system that fail to clear or sustain longer than expected. In these cases, the IDDS is designed to detect the disturbance and intentionally decouple from the utility to avoid a blackout condition in the microgrid. We configured the thresholds for the IDDS to reliably identify severe disturbances in the utility network in order to disconnect the microgrid.

Fig. 16 shows the operation of the local-area 81RF element for Cases B3, B5, and B6. It is important to note that for severe utility disturbances that have a rate of change of frequency higher than 2.5 Hz per second, the local-area 81RF element is set to operate faster than the local-area 81RF element to quickly decouple and preserve microgrid system stability.

Fig. 17 shows the operation of the 81R element for Case B4, where the utility disturbance has a rate of change of frequency higher than 2.5 Hz per second. Severe disturbances resulted in faster detection and decoupling, as desired.

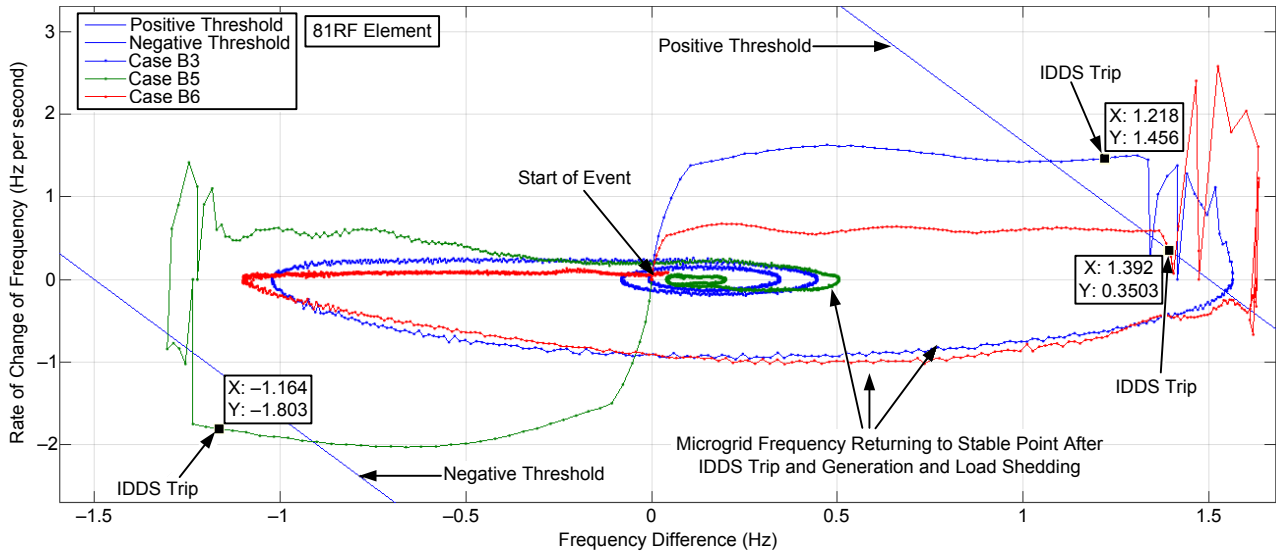


Fig. 16. Cases B3, B5, and B6

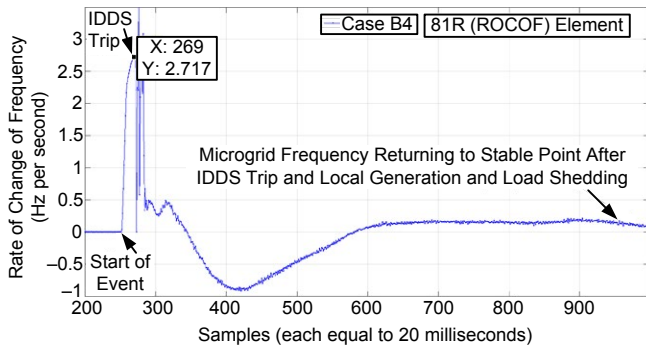


Fig. 17. Case B4

C. Case C

Case C represents a situation where an unintentional utility side breaker opening creates a power system island for the microgrid during normal operating conditions. To accommodate this case, the IDDS is designed to detect the opening of the remote breaker using breaker status and a low-current condition to trip the local breaker. High-speed generation shedding and/or load shedding is triggered when the local breaker opens to preserve microgrid stability.

D. Cases D1 to D3

Similar to Case C, Cases D1 to D3 represent the unintentional utility side remote breaker opening condition. In contrast to Case C, Cases D1 to D3 simulate an upstream breaker opening that creates an islanding condition. It is not

practical and very expensive to cover all of the utility breakers that can cause an island for a microgrid with a DTT scheme. In such cases, the IDDS uses the wide-area-based elements to reliably detect the islanding conditions. Even though some of the local-area-based elements can assist in the islanding detection cases, they cannot cover all of the scenarios and provide the required detection speed in addition to maintaining the scheme security and system reliability.

Fig. 18 shows the operation of the wide-area-based angle difference element for Cases D1, D2, and D3. Fig. 19 shows the operation of the 81RF element for Case D1, which has maximum power mismatch during pre-event conditions.

The angle difference element operated for each of the cases, and it is important to note that the greater the amount of power mismatch before the islanding, the faster the detection speed. Another important observation to make is, in Case D3, the real and reactive power exchange was set up to be very minimal (close to zero). During such conditions, the local-area-based schemes fail to detect an islanding condition because there is very minimal frequency or voltage excursion in the microgrid. In contrast, the synchrophasor-based wide-area scheme still detects the island and trips the local breaker. Also, Fig. 19 shows that the angle difference element operates faster than the 81RF element for the maximum power mismatch case (Case D1). Thus, wide-area detection schemes provide effective islanding detection capability, even during low-import and low-export conditions, for the microgrid power system.

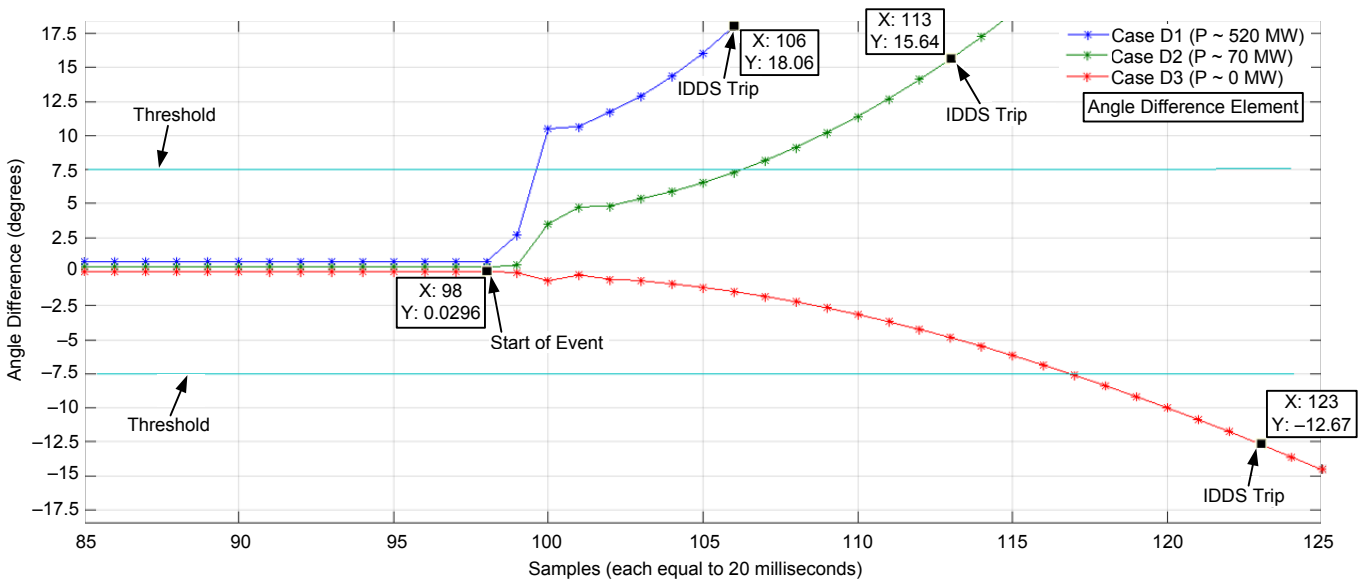


Fig. 18. Angle Difference Element for Cases D1, D2, and D3

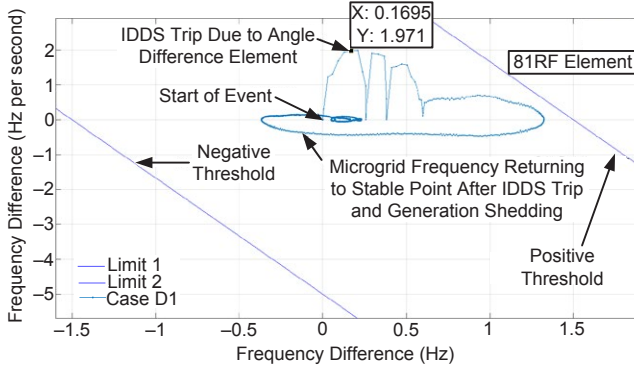


Fig. 19. Case D1 81RF Element

E. Cases E1 to E2

Cases E1 to E2 represent other negative tests, similar to Case A. In these cases, the IDDS is expected to ride through and not decouple for temporary fault conditions. A three-phase fault and a single-phase fault are simulated on one of the 400 kV lines between the utility and microgrid. The IDDS is programmed with a temporary fault block logic to ride through single-phase and three-phase faults that are expected to be cleared within normal clearing times. The IDDS did not operate during the faulted condition and was able to successfully ride through. All of the simulated faults were cleared after 100 milliseconds (including breaker opening time). Fig. 20a shows the behavior of the local-area 81RF element and Fig. 20b shows the wide-area angle difference element for Case E1.

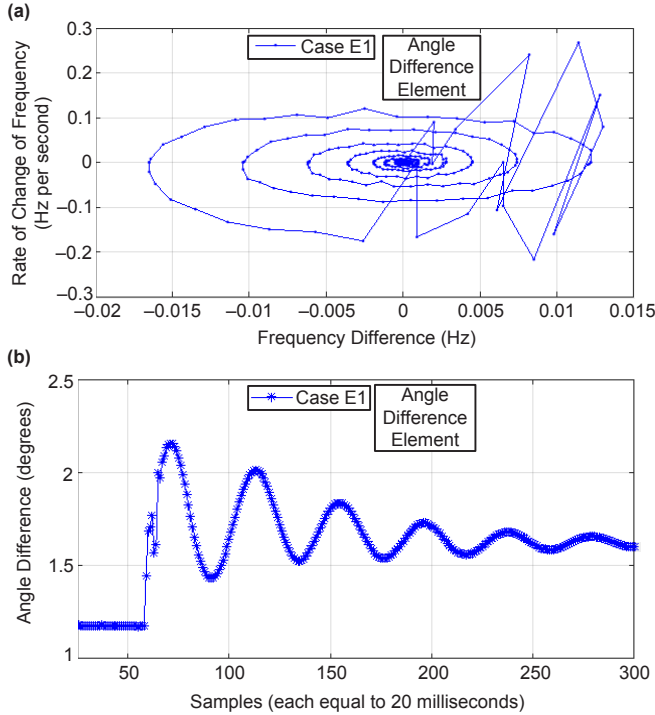


Fig. 20. Case E1

Table V shows the relative effectiveness of each scheme in this application, as concluded from the testing.

TABLE V
RELATIVE EFFECTIVENESS OF SCHEMES

Criterion	DTT	Local Area	Wide Area
Remote communications available	Effective	Effective	Effective
Remote communications not available	Not effective	Effective	Not effective
Local generation matches local load during unintentional islanding	Effective	Not effective	Effective
Several remote side breakers that can create islanding	Not effective	Effective	Effective
Utility disturbances and no breaker opening	Not effective	Effective	Partially effective

From Table V, we can see that each scheme has its own advantage when it comes to reliably detecting islanding conditions and system disturbances. For example, when compared to DTT and wide-area-based schemes, local-area-based schemes are not effective in detecting islanding conditions when the microgrid generation closely matches the microgrid load. Similarly, DTT and wide-area-based schemes cannot work if there are no remote communications available. So, a system with all three schemes complementing each other increases the overall reliability and speed of islanding and utility disturbance detection.

V. CONCLUSION

Sustainable microgrids require a fast and reliable IDDS that can initiate local generation-shedding or load-shedding schemes when required. This paper presents the functionality, validation, and performance of an IDDS in a simulated environment for a real-world application. Three different implemented schemes—DTT, local-area-based, and wide-area-based—were analyzed for speed and reliability for multiple operating scenarios. These tests ranged from typical scenarios to challenging cases where it is impossible for some schemes to reliably detect islanding conditions and disturbances in a utility power system. The real-time digital simulation of the model power system provided qualitative analysis of speed and reliability for the IDDS. Simulations allowed for testing scenarios that were not possible to test in the field, providing functional validation.

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

- DTT schemes provide the fastest speeds for islanding detection cases. When utility breakers are unprotected by DTT for detecting islanding conditions, wide-area-based synchrophasor schemes provide a reliable and economical solution.
- The local-area-based 81RF element reliably detects utility disturbances. The element operating time depends on the utility disturbance severity.

- Wide-area-based synchrophasor schemes reliably detect islanding conditions during very low power import and export conditions.
- Each scheme has individual advantages and disadvantages depending on the operating scenario of the microgrid system. But, combining all three of them in a single system provides a reliable solution to detect islanding and utility disturbances for all system conditions.
- IDDSs can be easily and economically implemented with industry-grade microprocessor-based relays using peer-to-peer communications.

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VII. BIOGRAPHIES

Krishnanjan Gubba Ravikumar received his M.S.E.E. degree from Mississippi State University and his B.S.E.E. from Anna University, India. He is presently working as a supervising engineer in the Schweitzer Engineering Laboratories, Inc. engineering services division, focusing on model power system development and testing for special protection systems. His areas of expertise include real-time modeling and simulation, synchrophasor applications, remedial action schemes, and power electronic applications. He has extensive knowledge of power system controls and renewable distributed generation. He is a member of the IEEE and the Eta Kappa Nu Honor Society.

Ashish Upreti is a protection engineer in the engineering services division at Schweitzer Engineering Laboratories, Inc. in Pullman, Washington. He received his B.S.E.E. and M.S.E.E. degrees from the University of Idaho. He is a registered member of the IEEE and has experience in the field of power system protection and automation, including power management schemes for large-scale industrial power plants.

Adithiya Nagarajan is a design engineer in the engineering services division at Schweitzer Engineering Laboratories, Inc. in Bangalore, India. He received his B.S.E.E. from Anna University and his M.S.E.E. from Arizona State University. He has experience in the field of power system protection and automation, including power management schemes for large-scale industrial power plants.

Case Study: Smart Automatic Synchronization in Islanded Power Systems

Scott M. Manson

Senior Member, IEEE
Schweitzer Engineering
Laboratories, Inc.
2350 NE Hopkins Court
Pullman, WA 99163, USA
scott_manson@selinc.com

Ashish Upreti

Member, IEEE
Schweitzer Engineering
Laboratories, Inc.
2350 NE Hopkins Court
Pullman, WA 99163, USA
ashish_upreti@selinc.com

Michael J. Thompson

Senior Member, IEEE
Schweitzer Engineering
Laboratories, Inc.
340 Office Court, Suite D
Fairview Heights, IL 62208, USA
michael_thompson@selinc.com

Abstract—Automatic synchronizing systems are used to reconnect multiple islanded power grid sections. These systems are required to function automatically with minimal human supervision because they must dispatch multiple generators simultaneously to reduce slip and voltage difference at the interconnection point.

This paper describes a smart automatic synchronizing system that can connect multiple generators in an industrial power system during islanded and utility-connected modes via six different bus-tie and utility tie breakers. The automatic synchronizing system performs matching by controlling multiple governor and exciter interfaces within the facility.

Controlling slip and voltage difference across any of six different breakers in any combination is accomplished with up to six different and simultaneous power system islands. The power system studied is a large refinery containing six generators, totaling about 260 MW of generation.

The functionality, operation, and validation of this automatic synchronizing system using real-time digital simulator (RTDS) tests are discussed.

Index Terms—Automatic Synchronization; Case Study; Closed-Loop Real-Time Simulation; Exciter Control; Generation Control; Governor Control; IEC 61850 GOOSE; Microgrid; Optimal Load Sharing; Redundancy.

I. INTRODUCTION

An alumina processing facility (refinery) installed a new double-bus, single-breaker gas-insulated substation (GIS) to meet plant growth and reliability requirements. Included in the project was a plant-wide generator control system (GCS) that can perform reliability islanding to ensure uninterrupted power and steam service to the critical process loads throughout the facility. The refinery power system includes six steam turbine generators that can operate in up to six independent microgrids. The focus of this paper is the synchronizing system that is used to resynchronize an island back to the utility grid or to other islands within the facility.

Due to the nature of and the complexity involved in the many possible islanded microgrids, the refinery project included the requirement that no manual synchronization is allowed. For this reason, the automatic synchronizing system had to be fully redundant to allow operations to continue in the event that the primary system failed.

An automatic synchronizing system connects a spinning power system to another spinning power system. Breaker closing ideally happens when the voltage, frequency, and phase angle are within tolerable limits for the two power systems.

The automatic synchronizing system for this project performs the following tasks:

- Identifies the electrical equipment connected on either side of the breaker being synchronized. This includes breakers, buswork, generators, utility tie lines, on-load tap changers (OLTCs), loads, and so on.
- Measures the slip, angle, and voltage difference across the breaker being synchronized.
- Controls multiple governors, exciters, and OLTCs to minimize slip, angle, and voltage difference.
- Closes the breaker once slip, angle, and voltage criteria are satisfied.

The automatic synchronizing system described in this paper automatically synchronizes multiple generators in the power system during any combination of islanded and utility-connected modes. The functionality and operation of the automatic synchronizing system are discussed.

The refinery is an operating facility. Therefore, the new generators, bus and feeder circuits, load-shedding system, and GCS had to be commissioned while not causing major disruption to production processes. To reduce risk, the system upgrade was fully validated in the laboratory by simulating the power system and generator controls using a closed-loop real-time digital simulator (RTDS).

II. ELECTRICAL NETWORK FOR REFINERY

Fig. 1 shows a simplified one-line diagram of the refinery. The top half of the diagram, including Buses GIS1A, GIS1B, GIS2A, and GIS2B, shows the new GIS. Generating Units G5 and G6 were also added in the plant power system upgrade. Note that the power system includes six steam generators, totaling 260 MW of capacity. The two utility tie lines can support up to 85 MW each. This GIS transfers power between medium-voltage (11.5 kV) busbars (B1 through B6), utility tie lines, and the two GIS-connected

generators (G5 and G6). Note that the 11.5 kV bus is connected to the 132 kV GIS bus with OLTC transformers.

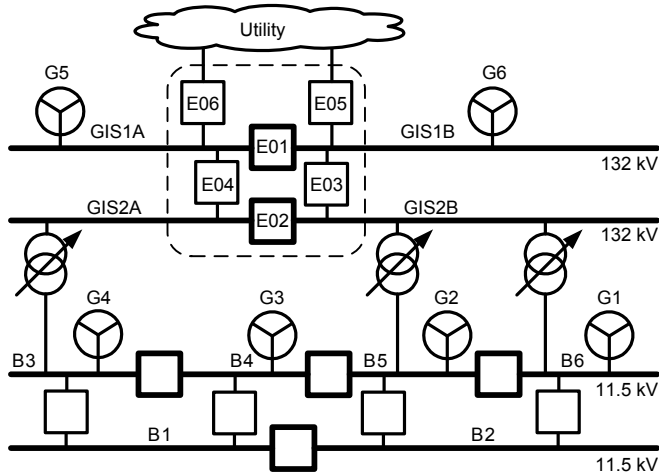


Fig. 1. Simplified One-Line Diagram of Refinery Power System

The power system supports loads on multiple buses, many with no generation. Each of the six generators can support loads independently on different islands, making it possible for six islands to occur simultaneously. These generators also supply power to the GIS bus for loads throughout the refinery. The refinery power system can be connected in various topologies, requiring the automatic synchronizing system to be flexible and adapt to all refinery electrical grid topologies. The automatic synchronizing system controls synchronization for the two bus sectionalizing breakers (E01 and E02), two bus-tie breakers (E03 and E04), and the two

utility tie breakers (E05 and E06). Each generator has its own synchronizer for coming online during startup, so the generator breakers are not controlled by the system.

III. AUTOMATIC SYNCHRONIZING SYSTEM DESIGN

This section describes the design and functionality of the automatic synchronizing system. This system (shown in Fig. 2) has two major components: the advanced automatic synchronizer (A25A) and the GCS. For redundancy, there are two A25A devices. When a synchronizing scenario is selected, the A25A sends the slip and voltage difference error signals to the GCS.

The GCS monitors the power system topology and identifies which generators are within each island or utility connection. The GCS receives the slip and voltage difference from the A25A and determines which group of generators to control for the synchronizing scenario that is selected. The GCS provides proportional correction pulses to adjust the governors and exciters of the parallel-connected generator units on each bus section as necessary for synchronization.

The A25A monitors the slip and voltage difference and, once the GCS has reduced them to within the synchronizing acceptance limits, initiates breaker closing at the slip-compensated advanced angle to ensure that the two systems are joined at the instant of zero-degree angle difference.

This synchronizing system can synchronize across six breakers in any island formation to create a larger island from two islanded systems or synchronize an island to the utility grid.

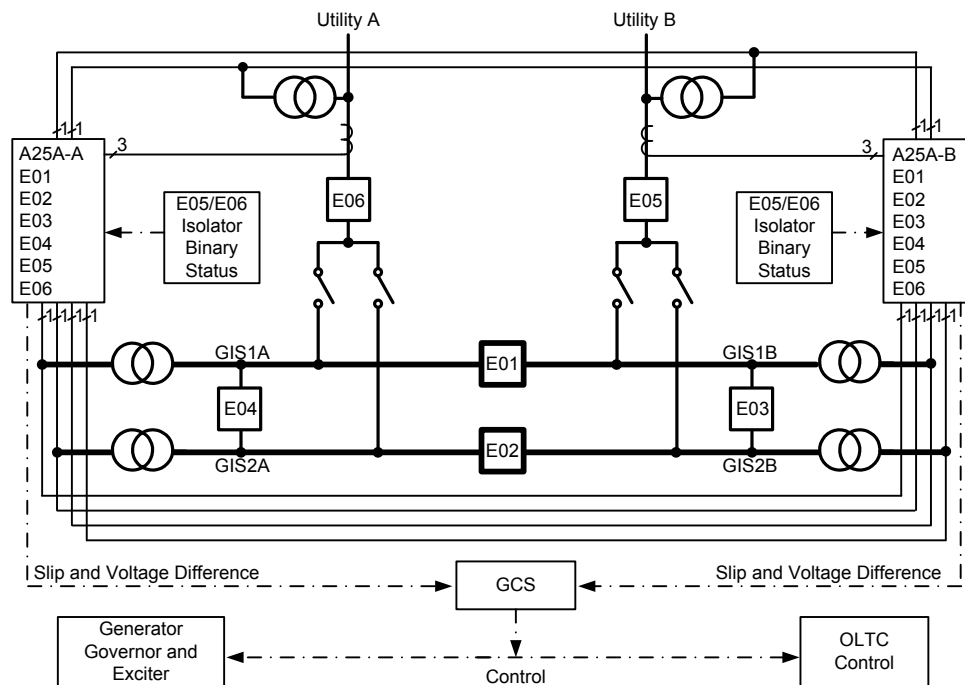


Fig. 2. A25A and GCS Interaction

The synchronizing system described in this paper must identify all island formations and dispatch generators appropriately. Simultaneous steam extraction requirements in tons per hour complicate the generator dispatch during the synchronization. Generator terminal voltages and bus voltages must be kept within manufacturer tolerances simultaneous with MVAR output load sharing between generator excitation systems. This is accomplished by controlling both OLTCs and exciters.

The automatic synchronizing system implemented at the refinery is a fully automatic, closed-loop system that dispatches multiple generators in parallel for synchronization and actively monitors the process until synchronization. The A25A can detect a failed or successful close by monitoring the breaker after the close command is initiated.

One of the features of this system is its ability to calculate advanced angle and issue a close command to compensate for the breaker closing delay. The A25A measures the slip and calculates the advanced angle at which the close coil should be energized. The slip-compensated advanced angle is calculated using (1) [1].

$$\text{ADVANG}^\circ = \left(\frac{(\text{SLIP})\text{cyc}}{\text{sec}} \right) \left(\frac{\text{sec}}{60 \text{ cyc}} \right) \left(\frac{360^\circ}{\text{cyc}} \right) ((\text{TCLS})\text{cyc}) \quad (1)$$

where:

ADVANG is the advanced close angle.

TCLS is the circuit breaker close mechanism delay.

A. A25A Device

The A25A, which is a microprocessor-based protection-grade relay, can synchronize across 6 breakers at the GIS as previously described. For each breaker, there are 2 synchronizing scenarios, resulting in a total of 12 synchronizing scenarios.

In the case of the bus sectionalizer and bus-tie breakers, the two scenarios govern which bus is to be controlled by the GCS to match frequency and voltage. For example, Breaker E01 can synchronize Bus GIS1A to GIS1B, or it can synchronize Bus GIS1B to GIS1A. The GCS must determine which generators are on the bus to be controlled by monitoring the system topology and send matching pulses to the correct governors and exciters.

The utility tie breakers also have two scenarios; these breakers can be connected to either of two buses. For example, Breaker E05 can synchronize Bus GIS1B to the utility grid or GIS2B to the utility grid, depending on the status of the bus isolators. Note that buses connected to the utility grid cannot be controlled.

The A25A also provides underfrequency and overfrequency tripping functions for the buses connected to the utility tie lines. These elements are used to intentionally island the refinery during power system disturbances on the

electric utility grid. These elements operate at the set points shown in Table I.

TABLE I
FREQUENCY-BASED ISLANDING FROM UTILITY

	Frequency	Pickup Time
Underfrequency	49.1 Hz	5 cycles
Overfrequency	50.5 Hz	5 cycles

The A25A selects the appropriate incoming and running voltages from its six voltage inputs based on the scenario selected. The large number of voltage transformer (VT) inputs on the relay allows this selection to be performed without any physical switching of the VT signals. Two A25A devices are provided for redundancy. Each A25A is designated as the primary synchronizer for 6 of the 12 scenarios and as the alternate synchronizer for the remaining 6 scenarios.

Both A25A devices have inputs from single-phase VTs from all four buses and each utility tie, as shown in Fig. 2. Both of the 52A and 52B statuses from the synchronizing Breakers E01 through E06 are wired to the terminals of each A25A and are monitored for the validity of the breaker status. Isolator status signals (89A and 89B), shown in Fig. 2, are wired to a separate I/O module and communicated to the A25A devices using the IEC 61850 Generic Object-Oriented Substation Event (GOOSE) protocol. Both 89A and 89B isolator statuses are monitored for the validity of the isolator status, and any incongruence creates an alarm, inhibiting the operator from initiating an automatic synchronizing process. The communications link status between the I/O module and the A25A is monitored internally in the A25A for the reliability of the GOOSE messages from the I/O module.

There are three conditions that the A25A must recognize to close a circuit breaker. They are:

- Synchronizing close (slip is detected, and matching is required).
- Parallel permissive close (both buses are live, but no slip is detected).
- Dead-bus permissive close (one or both buses are dead).

Automatic synchronizing close permissive asserts when voltage and frequency across the breaker are in normal operation; therefore, slip and voltage differences exist across the breaker, and frequency and voltage matching is required. The GCS needs to send raise and lower pulses to the governors, exciters, and OLTCs to bring the slip, voltage difference, and angle on both sides of the breaker within the synchronizing acceptance criteria, as shown in Table II [2] [3].

The parallel permissive close asserts when voltage and frequency on both sides of the breaker are within normal operating range and there is no slip across the breaker. This

permissive is used to close a breaker when the two systems are synchronized through another path, such as when three of the bus breakers are closed and it is desired to close the fourth.

TABLE II
SUPERVISION SETTINGS FOR AUTOMATIC SYNCHRONIZING
FOR SYNCHRONIZED CLOSE

	IEEE C50.12 and IEEE C50.13	A25A Acceptance Criteria
Angle	$\pm 10^\circ$	Target 0°
Voltage	$\pm 5\%$	$\pm 5\%$
Breaker Close Time	NA	3 cycles
Slip	± 0.067 Hz	± 0.04 Hz

A dead-bus permissive close asserts when either bus, or both buses, in the selected synchronizing scenario is dead. The permissive logic excludes a live bus and dead tie line condition for the utility bus-tie breakers to prevent ever backfeeding the utility grid from the refinery.

The synchronizing process can be initiated from multiple places, either from the front panel of the A25A (see Fig. 3

and Fig. 4) or from a remote human-machine interface (HMI). In both cases, the operator makes a selection for the breaker to synchronize the two systems together. Once a breaker is selected, if any three of the permissive conditions described are true, then the **OK TO INI AUTO SYNC/CLOSE** light-emitting diode (LED) asserts and the breaker is ready to be closed. The front-panel LED provides indication in terms of voltage, frequency, slip, and angle to the operator.

The A25A also provides analog data regarding voltage and frequency on either side of the breaker to the HMI and GCS. In the case of automatic synchronizing close, the control signals need to be sent to the generator and the OLTCs to reduce slip and voltage difference so that the breaker can be closed.

Once the slip and voltage difference come within the user-specified synchronizing acceptance criteria, the A25A sends a close command to the close coil at the advance angle to close the breaker. The A25A monitors the breaker for closing, and if the breaker fails to change state, the A25A asserts a close fail alarm to notify the operator. If the breaker closes but opens again immediately, the A25A asserts a close lockout alarm to notify the operator.

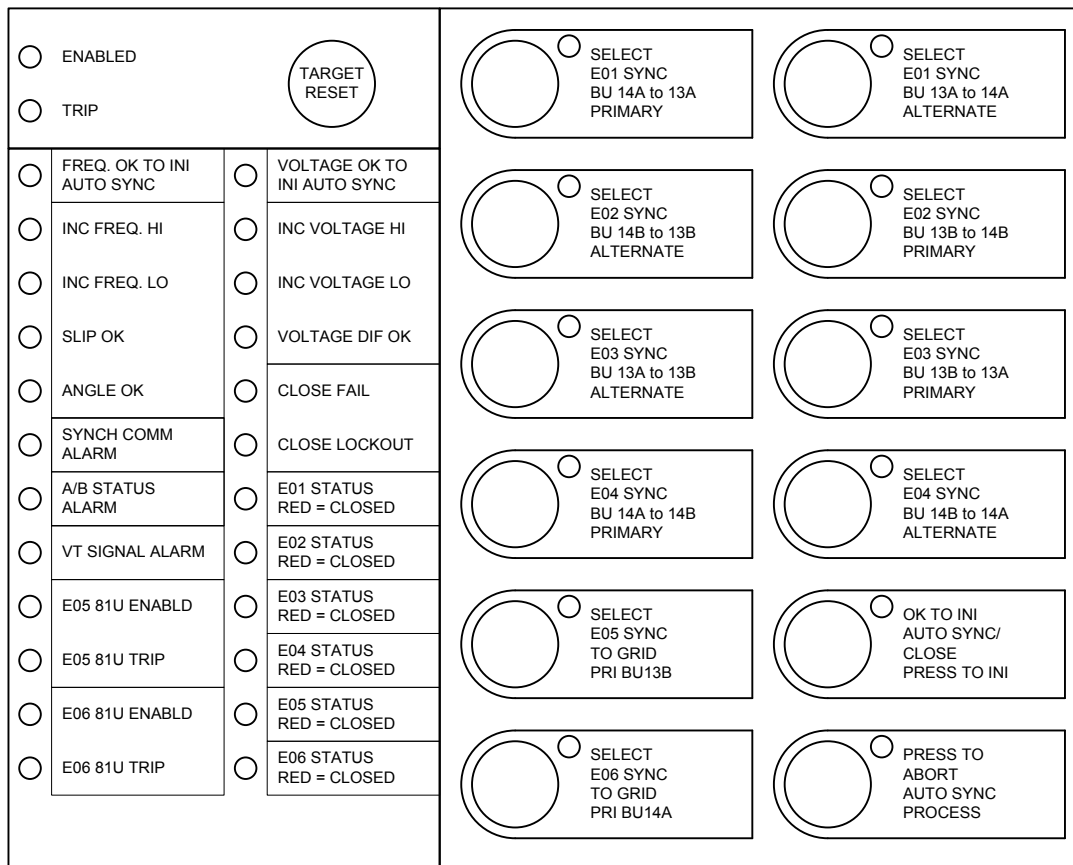


Fig. 3. Front Panel of the Automatic Synchronizer A25A-A

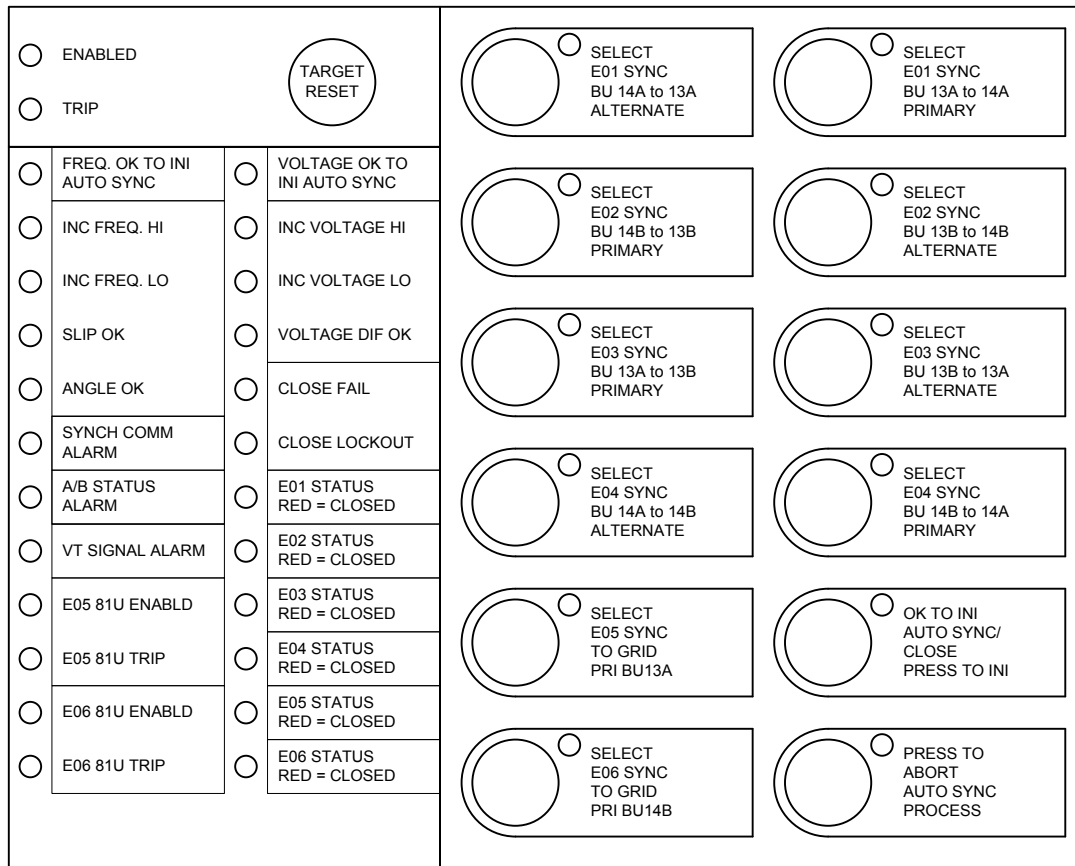


Fig. 4. Front Panel of the Automatic Synchronizer A25A-B

The A25A devices have extensive recording capability. There are 98 logic points for critical logic signals inside the A25A that are programmed to be monitored by the Sequential Events Recorder (SER) function. These logic points have been programmed with human-readable aliases.

The A25A devices record two types of oscillographic records. COMTRADE files contain raw sample data at a 1 kHz sampling rate. Compressed event (CEV) files contain filtered data that are synchronized to the one-eighth power system cycle processing interval of the A25A. The A25A devices are programmed to record a 4-second oscillographic record with 2 seconds of pretrigger capture when triggered. An oscillographic record is triggered when the A25A attempts to close a circuit breaker.

The front-panel display of the A25A provides information regarding the synchronizing process and its parameters along with any associated alarms. Fig. 5 shows the front-panel rotating display that provides any alarms that an operator needs to be aware of before initiating a breaker. The A25A also provides detailed information regarding the breaker selected for the synchronizing process. The right side of Fig. 5 shows the information regarding the breaker. A similar screen for each of the breakers is available in the front-panel display of the A25A.

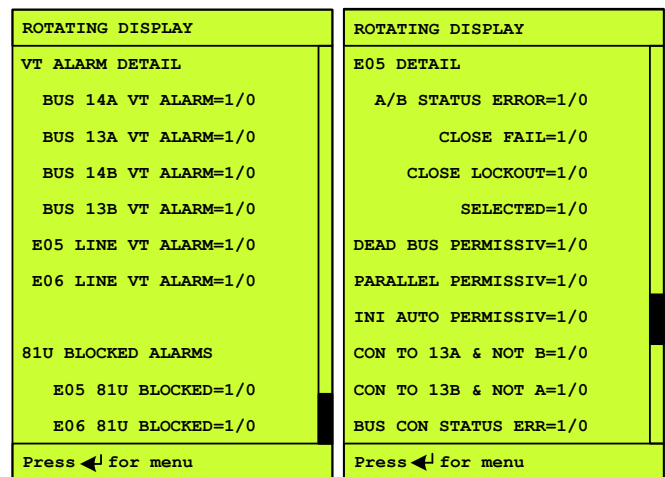
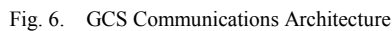


Fig. 5. Front-Panel Rotating Display

B. Generation Control System

The A25A does not have sufficient data processing power to dispatch the six governors, exciters, and OLTC controllers in accordance with plant operating requirements. The GCS augments the A25A by providing topology tracking, equal percentage load sharing of governors and exciters, and simultaneous bus voltage regulation. The GCS in this project

Because of the diversity of bus-switching scenarios, any of the six governors, exciters, or OLTCs can be on either side of the breaker being synchronized. The function of determining which islanded section these devices are connected to is called topology tracking. Topology tracking requires complete knowledge of all the switching devices. To track all the possible topology scenarios, 82 breaker (52) status inputs and 64 isolator (89) status signals were supplied to the GCS via intelligent electronic devices (IEDs) located throughout the plant, as shown in Fig. 6. These input signals are run through topology tracking and island detection algorithms, as shown in Fig. 7.



The refinery in this example required that the generators always be load-balanced to minimize the possibility of tripping during transient conditions, which can occur after separating into an island. The GCS does this by keeping the output from generators on a grid section (island) equally balanced throughout the entire synchronizing process. Part of the reason the load is balanced is to prevent operating any of the six turbines at their upper or lower limits, which lessens the likelihood of tripping a unit offline. For example, should a disturbance such as a large motor load trip occur, a generating unit operating close to zero output could potentially trip on reverse power as the governor correctly tries to close the control valve and prevent frequency overshoot. It is for these reasons that the GCS has an optimal load-sharing algorithm, as shown in Fig. 7.



To further complicate matters, it is common for generators to have unstable operational areas or undesirable areas of operation. The solution to this problem is to create artificial upper- and lower-limit boundaries that are user-settable limits, as shown in Fig. 8. Equal percentage (optimal) load-sharing techniques load all the turbines to an equal dispatched location within the lesser of the upper and lower bounds, the capability of the turbine, and the capability of the generator. The turbine capability is entered by the user, and the generator capability is derated according to cooling water temperature measurements.

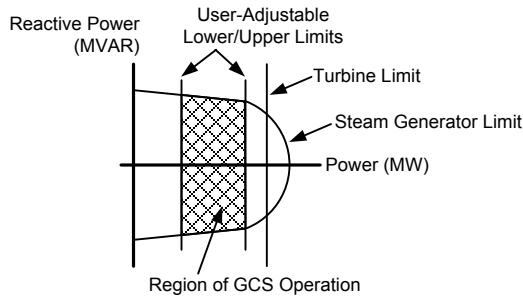


Fig. 8. Region of GCS Operation

The GCS also provides optimal exciter load (VAR) sharing and simultaneous bus regulation of all the buses in Fig. 1. Similar to optimal load (MW) sharing, the optimal exciter load (VAR) sharing equally shares the VAR contribution percentage from each generator. Unlike exciter load (MW) sharing, however, the exciter VAR contribution is limited by terminal and bus voltage magnitudes. To accommodate this, an adaptive volt/VAR-sharing algorithm regulates the OLTC to keep exciters away from their upper and lower bounds simultaneously, ensuring that the generator stator terminals remain inside equipment ratings.

C. Human-Machine Interface

The automatic synchronizing system installed at the refinery also has an HMI for remote automatic synchronizing. The front panel of the A25A was replicated in the HMI screen. Operator training was minimized by making the HMI and A25A front panel identical in look and feel. The LED display and pushbuttons shown in Fig. 3 and Fig. 4 are replicated in the HMI along with voltage, frequency, and analog variables, as shown in Fig. 9. The incoming and running frequencies reflect the frequencies of the incoming bus and the running bus. The automatic synchronizing system controls the frequency and voltage of the incoming bus to match the running bus by controlling the governors, exciters, and OLTCs on the incoming bus.

The HMI also provides alarms regarding communications failures, incongruence of the breaker status, close failures, VT failures, and overfrequency and underfrequency trips.

Capability curves for each generator, such as the one shown in Fig. 10, are included in the HMI. The capability curves show the desired set point and current operating point for the GCS MW (load) and MVAR (excitation) controls. The turbine capability is shown as the vertical line. The synchronous generator capability curves are dynamically updated with live generator cooling water temperatures.

INC FREQ	(Hz)	0
SLIP FREQ	(Hz)	0
RUN FREQ	(Hz)	0
ANGLE DIFF	(Deg.)	0
VOLTAGE DIFF	(kV)	0

Fig. 9. Analog Variable Display for HMI

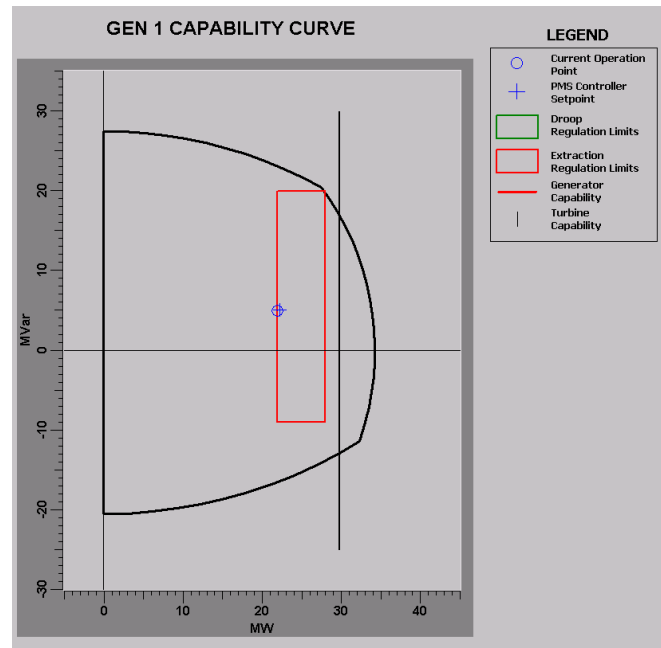


Fig. 10. Generator Capability Curve

IV. SYSTEM VALIDATION

Prior to installation of the advanced automatic synchronizing system at the refinery, complete testing was performed in a laboratory. An RTDS model was created to validate the functionality of the synchronizing system. This model included six custom governor, exciter, and turbine models, detailed load modeling, and a detailed electrical system model, which included all generators, turbines, exciters, breakers, loads, transformers, cables, and buses.

The RTDS model was validated by comparing model performance with known site conditions. This included the comparison of short-circuit fault currents, governor and turbine response characteristics, exciter response characteristics, and load reactive and active power consumption as a characterization of voltage and frequency.

Several studies were done using the model, providing insight into plant operation, vulnerabilities, and the system response for many contingency events. Studies were also completed to determine optimal set points for the power management system load-shedding system and GCS controllers.

The real-time model also permitted the A25A devices and GCS to be tested as a live simulation in the user-observed factory acceptance test. As shown in Fig. 11, this was accomplished by connecting the GCS and A25A to the simulation hardware.

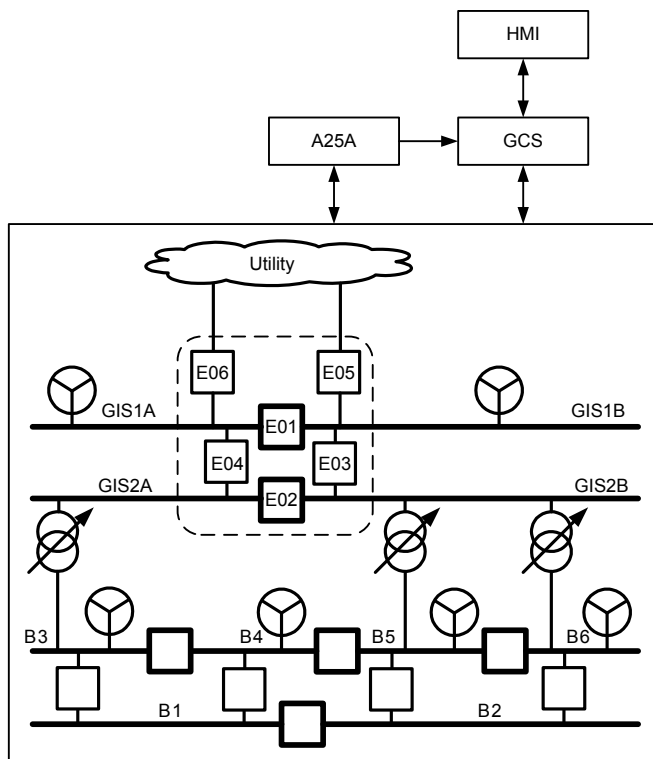


Fig. 11. Closed-Loop Real-Time Simulation

A real-time model allowed the authors to model the dynamics of the refinery power system with a simulation time step sufficiently fast to test all closed-loop controls of the automatic synchronizing system. Thousands of test cases were run, improving the likelihood that all systems will react as expected under the most adverse field scenarios. This

testing method also minimized the commissioning time and expense in the large control and protection system, something especially valuable in an operating facility.

Several communications protocols were used in the testing and implementation of the automatic synchronizing system for the refinery. The communications protocol used between the A25A and I/O module was IEC 61850 GOOSE. Transmission Control Protocol/Internet Protocol (TCP/IP) was used for communication from the controllers to the HMI. The breaker statuses and VT connections were brought to the A25A and I/O modules using the hard-wired I/O from the real-time simulation hardware. The low-level injection voltages from the real-time simulation hardware to the A25A provided VT connections.

Several test scenarios were created for all the breakers, including dead-bus close, parallel permissive close, and automatic synchronizing close. These scenarios allowed an opportunity for the careful observation of the dynamic response of the power system after synchronization, which is especially valuable for a dead-bus close scenario. These tests proved that the functionality of the A25A and GCS fit the specifications of the refinery. Two of the test cases are described in the following subsections.

A. Case A: Island-to-Island Synchronization

In the case of island-to-island synchronization, Breakers E01, E02, E05, and E06 were opened so that the system was islanded from the utility and the refinery was split into two separate islands. Breaker E01 was selected to synchronize. Across E01, on GIS1A and GIS1B, bus voltage difference, frequency difference, and angle difference were present.

Breaker selection was performed using the HMI. Once the synchronizing scenario was selected, the **OK TO INIT AUTO SYNC/CLOSE** LED indicated the system was ready for synchronization. Once initiated, the A25A began sending the breaker selection, voltage difference, and slip to the GCS. The GCS then sent control pulses to the governor, exciter, and OLTC to match the voltage and frequency across the breaker. The GCS controlled the incoming bus. However, in this case, the selection of the incoming bus was somewhat arbitrary because neither side of the bus was connected to the utility.

While the GCS reduced slip and voltage difference, the A25A monitored the process and provided the operator with continuous feedback using the front-panel display and the HMI. Once the A25A detected that the synchronizing acceptance criteria were satisfied, the A25A sent a breaker close command to close the E01 breaker at the slip-compensated advanced angle. In this scenario, an event report and SER reports were generated in the A25A.

Fig. 12 shows the slip across Breaker E01 during the automatic synchronizing process. At 30 seconds, the automatic synchronizing process was initiated; it was completed at 190 seconds. The starting slip was -0.21 Hz, and then at 90 seconds, it was less than 0.02 Hz, which was within the acceptance band. The automatic synchronizing system waited for the compensated breaker angle to come to zero. At 100 seconds, the slip went from negative to zero to positive. This process continued until the angle criteria were met. The instant the angle difference was nullified, which was at 190 seconds, the system transformed from two separate islands to one large island.

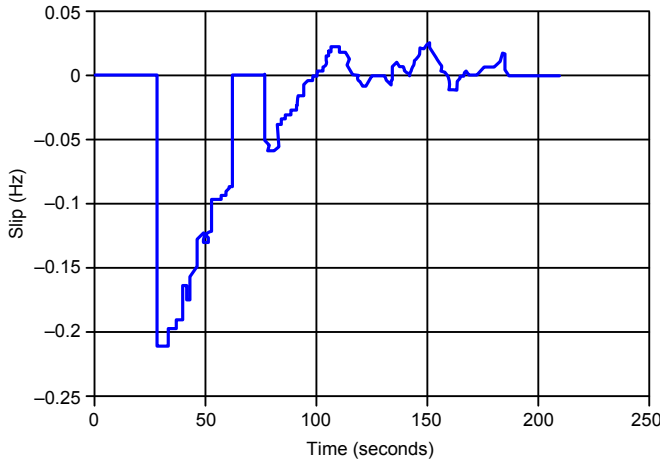


Fig. 12. Slip During Island-to-Island Synchronization

B. Case B: Island-to-Utility Synchronization

In the case of island-to-utility-connected power system synchronization, E03 and E04 were closed and Breakers E01, E02, and E05 were opened so that the island on GISA (GIS1A and GIS2A) with multiple generators was islanded from the utility and GISB (GIS1B and GIS2B) with multiple generators was connected to the utility via E06. The refinery was split between two islands. GISA and GISB where utility was connected to GISB bus while GISA was islanded. Breaker E01 was selected to synchronize. Across E01 on GIS1A and GIS1B, bus voltage difference, slip, and angle difference were present.

Breaker selection was performed using the HMI. The front-panel rotating display shown in Fig. 5 provided indication as to the selection. Once the breaker was selected, the **OK TO INI AUTO SYNC/CLOSE** LED indicated the system was ready for synchronization. Initiation of this process resulted in the A25A communicating with the GCS

regarding the breaker selection, voltage difference, and slip. The GCS then sent controls to the governor, exciter, and OLTCs to match the voltage and frequency on both sides of the breaker. The GCS controlled the incoming bus. However, in this case, the selection of the incoming bus was GISA because the GISB bus was connected to the utility.

During the process of control signals being sent by the GCS, the A25A monitored the synchronizing acceptance parameters and provided operator feedback using the front-panel display and front-panel LEDs.

When all of the synchronizing parameters shown in Table II were met, the A25A sent a breaker close command to close the breaker at the slip-compensated advanced angle. The breaker status was monitored for a successful close.

V. CONCLUSION

Synchronization between multiple generators and utility tie lines or between the multiple generators in an isolated system creates a need for a smart and flexible automatic synchronizing system that is composed of both an A25A relay and a GCS controller.

The fully redundant automatic synchronizing system installed at the refinery improved the reliability and accuracy of breaker synchronism across all six GIS breakers without the need for physical VT switching

Testing of the automatic synchronizing system provided critical insight into the system operation. The real-time digital simulation of the model power system allowed for a better understanding of system functionality and provided a valid test in terms of meeting the specification of the design, which reduced the amount of labor and expense during commissioning of the system.

VI. ACKNOWLEDGMENTS

The authors gratefully acknowledge the contributions of Dr. Abdel R. Khatib and Jordan Bell from Schweitzer Engineering Laboratories, Inc. for providing support during testing.

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VIII. BIOGRAPHIES

Scott M. Manson received his M.S. in electrical engineering from the University of Wisconsin–Madison and his B.S. in electrical engineering from Washington State University. Scott worked at 3M as a control system engineer for six years prior to joining Schweitzer Engineering Laboratories, Inc. in 2002. Scott has experience in designing and implementing control systems for electric utility customers, refineries, gas separation plants, mines, high-speed web lines, multiaxis motion control systems, and precision machine tools. Scott is a senior member of IEEE and a registered professional engineer in Washington, Alaska, North Dakota, Idaho, and Louisiana.

Ashish Upreti is a protection engineer in the engineering services division at Schweitzer Engineering Laboratories, Inc. in Pullman, Washington. He received his bachelor's degree and master's degree in electrical engineering from the University of Idaho. He is a registered member of IEEE and has experience in the field of power system protection and automation, including power management schemes for large-scale industrial power plants.

Michael J. Thompson received his BS, magna cum laude from Bradley University in 1981 and an MBA from Eastern Illinois University in 1991. He has broad experience in the field of power system operations and protection. Upon graduating, he served nearly 15 years at Central Illinois Public Service (now Ameren), where he worked in distribution and substation field engineering before taking over responsibility for system protection engineering. Prior to joining Schweitzer Engineering Laboratories, Inc. (SEL) in 2001, he was involved in the development of several numerical protective relays while working at Basler Electric. He is presently a principal engineer in the engineering services division at SEL, a senior member of IEEE, chairman of the substation protection subcommittee of the IEEE PES Power System Relaying Committee, and a registered professional engineer. Michael was a contributor to the reference book *Modern Solutions for the Protection, Control, and Monitoring of Electric Power Systems*, has published numerous technical papers, and has a number of patents associated with power system protection and control.

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CASE STUDY

Motor Oil Hellas Corinth Refineries S.A. (MOH)—Agii Theodori, Corinth, Greece

Automated Power Management System—An Economical Approach to Greater Operational Dependability

With industrial, commercial, and governmental power users seeking electric power system reliability and energy efficiencies, collocated electric power generation capabilities (e.g., power islands) are becoming increasingly popular. As the number of individual on-site generators increases, so does the need for more powerful means to monitor and optimize power generation and load management throughout facilities. Automated power management systems with inbuilt technology, such as high-speed load shedding and generation control, are now a proven solution to such needs.

Agii Theodori, Corinth, Greece—Motor Oil Hellas Corinth Refineries S.A. (MOH) is the largest privately held industrial complex in Greece. Headquartered in Maroussi, Greece, the company supplies a full range of petroleum products, including fuels and lubricants, to both domestic and international oil companies. MOH is the only lubricant producer and packager in Greece.

MOH constructed its original electric power production unit in 1984. The company installed a gas turbine power generation system to power operations at the refinery in Agii Theodori (province of Corinth) and to supply electricity to the domestic market. By 2005, the plant grew to include four gas turbine generators, each one a different model. Because of a recent major plant expansion, MOH decided to upgrade its on-site power generation and distribution system. The electrical department, directed by section head Vassilis Viziryiannakis, sought out a power management system to increase reliability of the refinery's electrical network and reduce energy costs.

Refineries have elaborate processing systems, many of which are interconnected. Power outages or interruptions can prove catastrophic, potentially creating large, expensive, and toxic messes.



Figure 1—MOH is the largest privately held industrial complex in Greece and is one of the most modern refineries in Southeast Europe. Because of its flexibility, it can process crude oils of various characteristics and produce a full range of petroleum products. MOH complies with the most stringent international specifications and serves major petroleum marketing companies in Greece and abroad.

“With our old system, based on electromechanical relays, we had slow reaction times to events,” explains Viziryiannakis. “Sometimes, we were simply unable to identify what occurred first and why something tripped, since there was no sequence-of-events monitoring or advanced diagnostics available. Also, the old protection system was not very selective or reliable.”

He adds that the old MOH power protection system had many different relays, products from many vendors, and several generations of relays, most of which were electromechanical. The array of equipment with old technology made training the maintenance staff a huge problem. Plus, they often did not know if the old relays actually worked.

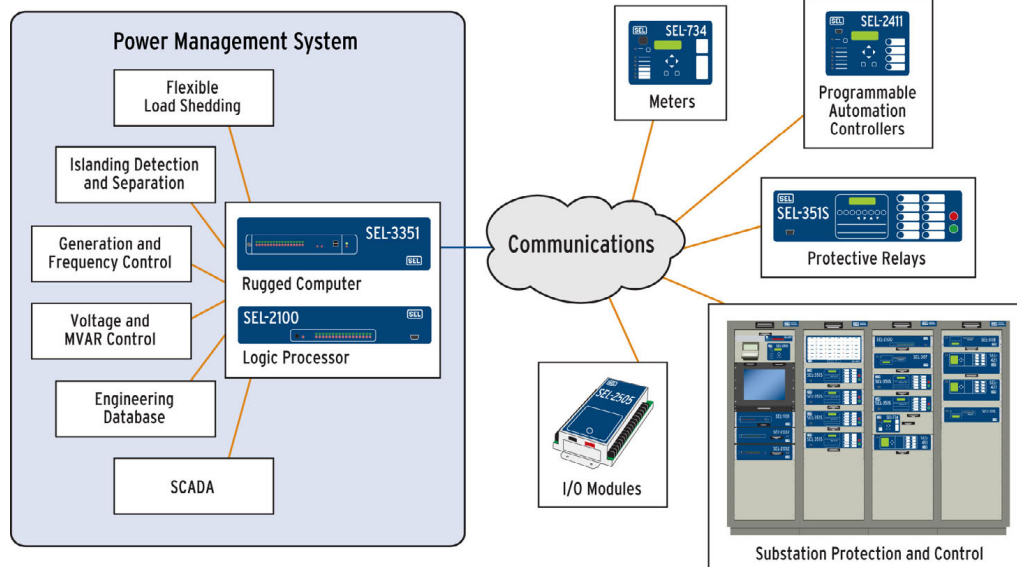


Figure 2—MOH anticipated that upgrading to modern microprocessor-controlled relays would provide the base for a complete power management system. Modern relaying devices offer I/O, programmability, data collection, metering, and power system diagnostics. These capabilities previously required integrating remote terminal units (RTUs), programmable logic controllers (PLCs), digital fault recorders (DFRs), and multiple single-function devices. Reducing device counts and complexities significantly lowers costs and greatly extends power system reliability and automation capabilities.

“One of the primary objectives in upgrading to a complete power management system was to improve our speed and accuracy in finding out exactly what happened to cause a trip or an outage,” says Viziryiannakis.

After reviewing the power system requirements, the MOH electrical department selected the SEL POWERMAX™ Power Management and Control System designed and installed by Schweitzer Engineering Laboratories (SEL), based in Pullman, Washington. POWERMAX is the most flexible, robust, cost-effective, and comprehensive system available for power management and control of electrical power systems. The system performs advanced wide-area control using reliable, field-proven SEL hardware devices and universally accepted IEC 61131-3 software programmability.



Figure 3—MOH directed switchgear manufacturers to purchase and install SEL protective relays in new installations.

“Protection systems safeguard expensive power system assets, such as transformers, buses, generators, motors, and switchgear,” explains Scott Manson, PE, supervising engineer with SEL.

Comprehensive power management systems include protection and wide-area control systems as well as diagnostic, engineering, visualization, and data archiving tools. “Wide-area control systems used by utilities prevent and mitigate blackouts. Properly tuned wide-area voltage/MVAR control and automatic generation control systems reduce the likelihood of cascading blackouts. When a major disturbance occurs in the power system, a cascading outage is mitigated by load and generation-shedding systems,” says Manson. “Diagnostic and engineering tools generally include engineering databases, such as archives for automatically retrieved event reports (oscillography) or detailed Sequential Events Recorder (SER) data. Highly evolved visualization and data archiving tools are integrated into asset management tools to provide sophisticated functions, such as continuous monitoring of breaker wear, motor degradation, or accumulated through-fault current in transformers.”



Figure 4—For an economical, high-speed retrofit, MOH abandoned the existing protection and metering, and installed new SEL relays in the switchgear.



Figure 5—SEL relays protect all MOH's major electrical system assets.

Manson adds that MOH's POWERMAX system manages all major power system assets with advanced built-in control and monitoring to increase system uptime.

"For example, SEL provided a suite of advanced algorithms to help the MOH power system survive local utility outages," says Manson. "Those algorithms proactively control generators, transformers, motors, loads, and capacitors. The diagnostic and reporting tools in the POWERMAX system allow the MOH electrical department to be proactive in their maintenance program. They actively monitor the status of all critical equipment, thereby minimizing unscheduled process downtimes."

Manson adds that fault-tolerant design principles in POWERMAX wide-area control systems greatly enhance power system reliability. For example, self-healing data selection enables high-speed load shedding that selects an alternative load to shed if the algorithm cannot verify the status of the first-choice load.



Figure 6—Ultrahigh-speed, remote-mounted I/O modules were installed throughout the plant for the SEL POWERMAX load-shedding system. These control (DIP) switch-configured I/O modules have trip-rated output contacts, devoted communications, on-board power supplies, and full self-monitoring for the utmost reliability.

SEL coordinated the design and installation with PROTASIS, a local representative. PROTASIS provided protective relay settings that worked seamlessly with the POWERMAX system.

Prior to installation, SEL fully simulated the MOH power management system in SEL's model power systems laboratory. The simulation included a full RTDS[®] (Real Time Digital Simulator). Because of thorough upfront testing, no misoperations occurred during the commissioning of the 70,000-tag system. "Commissioning the load-shedding system was a matter of verifying the customer's wiring and turning the system on," says Manson.



Figure 7—Remote-view stations used throughout the MOH plant allow for continuous visualization and diagnostics of the entire system.

"With the new complete package of integrated protection and monitoring, we have made significant progress toward improving the reliability of our electrical distribution system," says Viziryiannakis. "The system is much better now. We have standardized on a few prod-

ucts from SEL, reducing our training problems. We also now truly know that our protection is always working. We know, for example, that the new POWERMAX system has several times helped us avoid losses of major transformers and motors.”

Viziryiannakis is very pleased that the SEL POWERMAX solution is an open system, which has allowed MOH to expand and change the system since installation in 2004.

“We also appreciate that we can make the modifications ourselves,” he says. “This was not expected, since none of SEL’s competitors could offer such a feature.”

About MOH

Headquartered in Maroussi, Greece, MOH supplies a full range of petroleum products to domestic and international oil companies. The company produces and processes gasoline, light diesel, illuminating kerosene, fuel oil, heating gas oil, basic and final lubricants, mineral oils, and other petroleum products. It also purchases, stores, transports, and distributes crude oil, petroleum products, hydrocarbons, minerals, ores, chemicals, and byproducts. MOH is the only lubricant producer and packager in Greece. For more information, visit the MOH website at www.moh.gr, or contact MOH by phone: +30 (210) 809-4000; fax: +30 (210) 809-4444; email: viziryvz@moh.gr; or mail: 12A Irodou Attikou St., 151 24, Maroussi, Greece.

About SEL

SEL has been making electric power safer, more reliable, and more economical since 1984. This ISO 9001:2000-certified company serves the electric power industry worldwide through the design, manufacture, supply, and support of products and services for power system protection, control, and monitoring. For more information, visit www.selinc.com, or contact SEL by phone: +1 (509) 332-1890; fax: +1 (509) 332-7990; or mail: 2350 NE Hopkins Court, Pullman, WA 99163, USA.

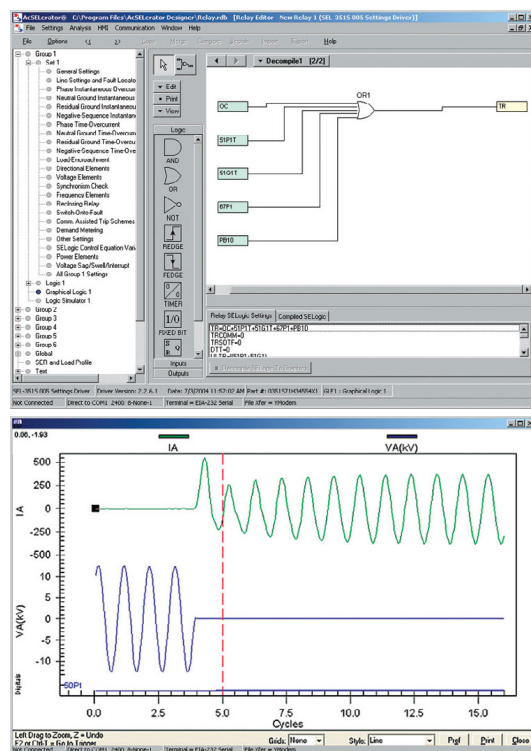


Figure 8—Simple-to-use SEL ACSELERATOR® Software allows engineers to maintain settings for all the protective relays at MOH.

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2350 NE Hopkins Court • Pullman, WA 99163-5603 USA
Tel: +1.509.332.1890 • Fax: +1.509.332.7990
www.selinc.com • www.selindustrial.com
Email: marketing@selindustrial.com





Customer Highlight



RED DOG MINE

SEL POWERMAX® blackout mitigation solutions for mining operations

Islanded power systems prioritize stability and resiliency over tripping selectivity to avoid widespread blackouts and ensure power can be fully restored after breakers trip. POWERMAX Power Management and Control System solutions offer features like load shedding, generation control, and load management to mitigate blackouts and other electric system events.

Customer problem

After experiencing three separate blackout incidents within one year, Red Dog Mine, a remote mine in Northwest Alaska, decided to improve their blackout mitigation as part of a larger electrical system improvement. Their existing solid-state protection equipment provided minimal data after a trip—only targets with no time tagging—making it impossible to find a definitive root cause after an event. An improved protection system was needed to clear faults with as much of the system surviving as possible and to provide information as needed to assist in the quick restoration.

Solution

Engineers designed a POWERMAX generation control and load-shedding system to maintain voltage and frequency stability. They also designed a reliable and secure protection system and SCADA control system for implementing a bus preservation scheme that allowed systems to operate as separate islands. The POWERMAX system interfaced directly with interconnected protective relays to control generators and for load shedding. Electromagnetic power system transient simulations were used to demonstrate how the system would operate with a generation control system, load-shedding system, and protective-relaying bus preservation scheme. The system was also tested for faults at different locations to ensure system operation and stability following a disturbance.

Results

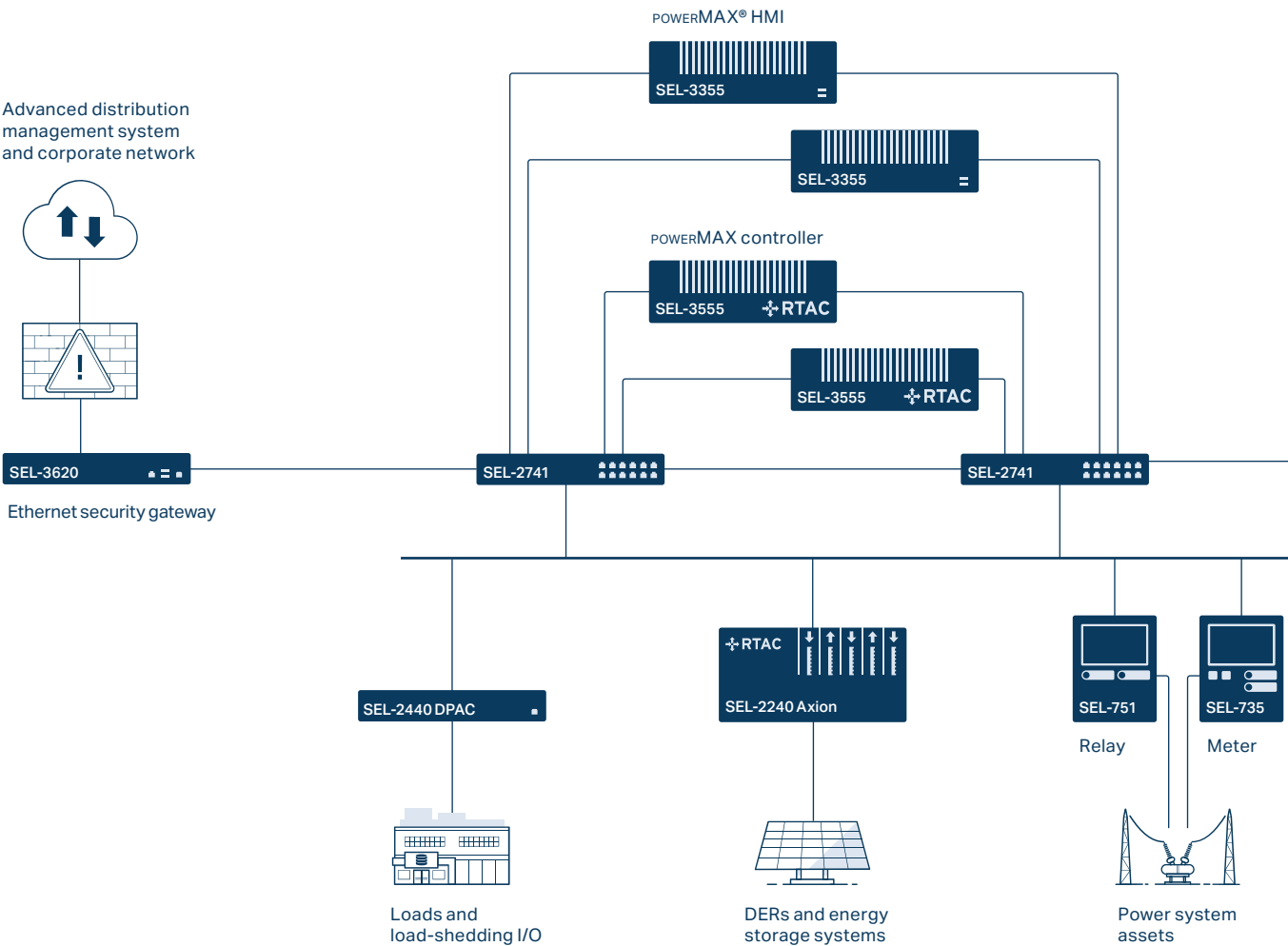
Red Dog Mine typically uses six generators to carry their load, up to 30 MW. When the mine experienced an overcurrent event, the POWERMAX system properly isolated and shut down one generator, temporarily reducing production loads. The mine saw a 2 percent reduction in throughput until full power was restored, but it remained operational otherwise with full visibility of the operating parameters. Operators noted that the cost of a total blackout—including damaged equipment and lost production—would have exceeded the cost of the POWERMAX system.

POWERMAX® for Microgrids

SEL works closely with microgrid owners and integrators to design, engineer, and implement the optimal microgrid control system (MCS) for your operational requirements.

An SEL POWERMAX system for microgrids provides a reliable, resilient, and secure solution for maintaining uninterrupted energy delivery. MCSs serve utilities; municipalities; college campuses; and facilities, such as hospitals, data centers, and research labs—wherever constant delivery of electricity is critical, even if the grid goes down.

SEL MCSs maintain stability with deterministic control that operates at subcycle speeds to preserve load and generation balance while seamlessly islanding and resynchronizing with the grid. Power system engineers streamline integration of distributed energy resources (DERs) into microgrids by selecting and prioritizing the most efficient mix of renewable and nonrenewable energy resources to support local demand.



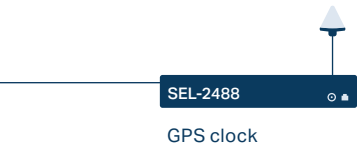
Features of SEL microgrid control systems include:

- Scalability, from a few kW to thousands of MW.
- The ability to manage a variety of generation sources, such as steam, gas, diesel, photovoltaic (PV), battery energy storage systems (BESSs), fuel cells, wind, and hydroelectric power.
- Control for both grid-connected and islanded modes of operation.

- Startup islanding.
- Isochronous (ISO)/droop control.
- Load sharing.
- Economic optimization and priority dispatch.
- Power quality management.
- Load shedding, shifting, and restoration.
- Maximization of DER production.
- Point of common coupling (PCC) import/export limit management.
- Power curtailment to avoid PCC export.
- PV smoothing.
- BESS state of charge management, with coordinated charge and discharge.
- Demand and reserve management.

SEL Devices in a Reliable, Resilient, and Secure Solution

Level 5 Business	Computer (Load and Weather Data)		Third-Party Advanced Distribution Management System (ADMS)
Level 4 Perimeter	SEL-2741 Ethernet Switch		SEL-3350 ADMS (Remote Terminal Unit)
Level 3 SCADA	SEL-2488 Network Clock		SEL-3355 Computer (HMI)
Level 2 Automation	SEL-3555 Microgrid Controller Primary/Secondary Control		
	SEL-3555 Simulator Front-End Processor Real-Time Digital Simulator (RTDS) Interfaces		
Level 1 Field Devices	SEL-451, SEL-651R, or SEL-751 (PCC)	SEL-2240 Axion or SEL-2411 (Remote I/Os)	DER Controllers/ Field Electronic Devices
Level 0 Physical	Circuit Breakers	Transformers	DERs
	MCS Components	RTDS Model	External Systems





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Microgrid Systems: Design, Control Functions, Modeling, and Field Experience

S. Manson, *Senior Member, IEEE*, K. G. Ravikumar, *Member, IEEE*,
and S. K. Raghupathula, *Member, IEEE*

Abstract—This paper describes the authors' experience in designing, installing, and testing microgrid control systems. The topics covered include islanding detection and decoupling, resynchronization, power factor control and intertie contract dispatching, demand response, dispatch of renewables, ultra-fast load shedding, volt/VAR management, generation source optimization, and frequency control.

Index Terms—distributed power generation, islanding, grid resilience, microgrids, smart grids.

I. INTRODUCTION

Microgrids are electrical grids capable of islanded operation separate from a utility grid. These grids commonly include a high percentage of renewable energy power supplies, such as photovoltaic (PV) and wind generation. Microgrids, therefore, commonly have problems related to their low system inertia and the intrinsic limitations of power electronic sources (PESs). Further compounding these problems is the fact that the modern electrical load base has an ever-growing percentage of power electronic loads (PELs). In the authors' experience, PELs do not provide natural grid stabilization like motor loads connected directly to a power system do. (Note that emulation of inertia by PES and PEL is possible; however, this technique is not yet in general use.)

High PEL and PES compositions have several characteristics that do not promote the stability of the electric power system. These electronic sources have control systems that act to self-preserve the thyristors or insulated-gate bipolar transistors (IGBTs) from damage. This self-preservation is accomplished by tripping the PES and PEL offline upon detection of spurious voltage or current waveforms. The fault ride-through capacity of the PES and PEL is significantly smaller than that of conventional rotating generation and loads.

The second problem commonly associated with PES and PEL relates to the control systems used to drive the power electronic interfaces. These control systems have uncertain behavior when islanded from a stiff utility grid. They are known to have interoscillations with mechanical shafts, electrical power system equipment, and other PESs and PELs [1]. These controls also limit the amount of fault current in a manner very unlike conventional power generation.

The third problem associated with these PESs is that they provide no inertial contribution to the power system. Electrical rotating generators and motors have their rotational inertia coupled to the power system through the electromagnetic air gap formed between a rotor and stator. The combination of machine winding ratios (pole counts) and the electromagnetic forces in these air gaps allow all rotating machines on a power system to sum their individual inertias into a single grid inertia. Without the inertia associated with electrical machines, a power system frequency can change instantaneously, thus tripping off power sources and loads and causing a blackout.

Microgrid control systems (MGCSs) are used to address these fundamental problems. The primary role of an MGCS is to improve grid resiliency. Because achieving optimal energy efficiency is a much lower priority for an MGCS, resiliency is the focus of this paper. This paper shares best practices in the design, installation, and validation of MGCSs and summarizes the typical control and protection functions of an MGCS.

II. MGCS DESIGN

An MGCS is an integrated system comprised of the following systems:

- Centralized and distributed control systems.
- Coordinated protection systems.
- Communications infrastructure.
- Power quality and revenue metering.
- Visualization systems.
- Engineering tools.
- Economic optimization systems.

A. Architecture

Fig. 1 shows a typical MGCS architecture in a layered representation. Layer 1 through Layer 4 are referred to together as the MGCS. The primary purpose of Layer 1 through Layer 3 is to improve grid resiliency. Layer 4 is the only level devoted to non-resiliency MGCS functions.

Layer 0 contains the equipment within the microgrid. Such as circuit breakers, transformers, transmission lines, cables, motors, traditional generation, renewable resources, and the like. The equipment at Layer 1 has hardwired connections to monitor and control this equipment, such as current transformers (CT), potential transformers (PT), and digital status and controls.

Layer 1 includes multifunction protective relays, remote I/O modules, and meters. Layer 1 devices provide all of the I/O, data collection, metering, protection, and physical control of

S. Manson, K. G. Ravikumar, and S. K. Raghupathula are with Schweitzer Engineering Laboratories, Inc., Pullman, WA 99163 USA (e-mails: scott_manson@selinc.com; krisgubb@selinc.com; saira@selinc.com).

Layer 0 devices. All of the protection and some of the controls are programmed in these Layer 1 devices. Typical controls in Layer 1 include islanding detection, decoupling, and resynchronization. The microprocessors in the Layer 1 equipment provide a robust distributed control and protection system that mirrors the well-proven designs of the utility power system.

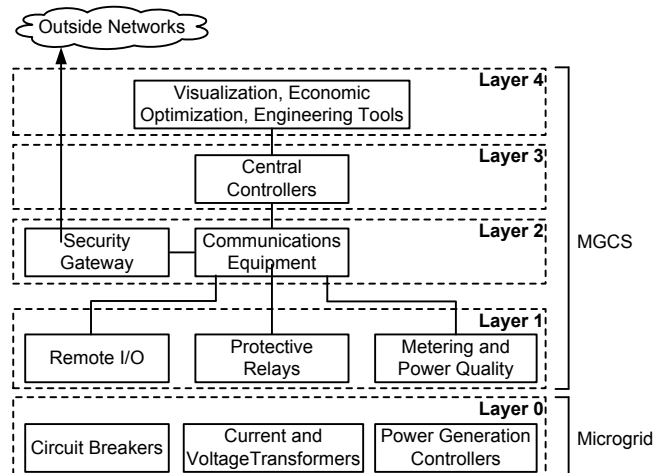


Fig. 1. MGCS Architecture

Layer 1 protection systems protect tremendously expensive assets such as transformers, buses, lines, generators, motors, heaters, capacitors, and switchgear. These protection systems can prevent or minimize catastrophic damage to equipment. Much of the Layer 0 equipment has long manufacturing lead times, thus, a properly coordinated Layer 1 protection system reduces microgrid downtime.

Layer 1 devices provide much of the diagnostic information of a power system, such as sequence of event (SOE) records, oscillography recordings, synchrophasor data collection, and more. The failure of equipment in higher layers does not have any effect on the functionality of the Layer 1 equipment.

Layer 2 communications equipment interrogates the protective relays, remote I/O modules, and meters and aggregates data to be transported to the centralized Layer 3 controllers. Security gateways at Layer 2 provide visibility of the MGCS to external users, businesses, or electric utilities. The MGCS communications backbone is constructed with Ethernet- or serial-based technology. The data flowing on these channels are segregated into real and non-real time channels to ensure deterministic and prompt delivery of status and controls data. The failure of equipment in higher layers does not have any effect on the functionality of the Layer 2 equipment.

The Layer 3 centralized controllers provide control functions that require status information from one or more Layer 1 devices. The algorithms in Layer 3 devices make decisions and send commands back to the Layer 1 equipment. Typical controls in Layer 3 include power factor control, inertia contract dispatching, demand response, dispatch of renewables, load shedding, volt/VAR management, generation source optimization, and frequency control. The failure of

equipment in higher layers does not have any effect on the functionality of the Layer 3 equipment.

Layer 4 equipment includes diagnostic and engineering tools, such as automatic event report (oscillography) retrieval, detailed sequential events recorder (SER) reports, and settings management for all MGCS equipment. Human-machine interfaces (HMIs) provide the real-time status of the MGCS to operations and maintenance staff. Economic optimization, automated financial transactions, forecasting, and time-synchronization equipment reside at Layer 4. Failure of equipment in Layer 4 has no effect on the functionality of the lower, more critical layers.

B. Building a Reliable MGCS

This section details the accumulated experience of the authors in building hundreds of MGCSs focused on resiliency. Following these basic design principles has achieved MGCSs with design lifetimes of approximately 30 years.

Critical to low-cost, long-term ownership is the use of environmentally rated equipment. Caustic or salty environments require conformal coating of electronic boards. Equipment with large temperature ranges is required for outdoor enclosures. Resistance to electromagnetic interference (EMI) prevents misoperations caused by high levels of harmonics present from PES and PEL. Today, solid-state memory offers much higher reliability than rotating memory storage devices. Carefully match MGCS components with the environmental requirements.

Failures in the MGCS must be immediately identified in the equipment. All Layer 1 through Layer 4 equipment must continuously self-test the status of its memory, CPU, power supplies, or other failure modes. It must report internal errors outside the MGCS to alert maintenance staff of failures.

Reliability analysis techniques [2] commonly determine that the power supply to the MGCS electronics is the weakest link in reliability. The simplest way to improve MGCS reliability is to power all equipment directly from dc battery supplies. Uninterruptible power supplies (UPSs) that convert dc battery storage to ac voltages reduce the overall reliability of an MGCS; this is because they are an unnecessary component. Power supplies inside all MGCS equipment are oversized for long lifetimes (in Layer 1 through Layer 4) and should connect directly to battery dc.

Because Layer 4 systems are continuously monitored by operations staff, they are often given an undue amount of fiscal attention. This has led to many systems with wonderful visualization systems but poor grid resiliency. Designers are advised to focus first and foremost on Layer 1 through Layer 3 MGCS equipment and functionality.

Most microgrids are brought online as partially constructed systems. This can pose complications for central control systems that are designed for all grid assets to be online. MGCS designs must therefore incorporate software switches to enable the protection and controls to be enabled and commissioned incrementally. For example, load shedding algorithms existing at Layer 3 must be designed to operate

properly with only part of the I/O commissioned. Another example is that assets must be protected from destruction with protective relays at Layer 1, regardless of the commissioned state of a central microgrid controller.

It is preferable that all central control schemes run on separate devices. By having these algorithms run autonomously, the loss or modification of one system will not affect the others. Fault tree analysis shows that single points of failure greatly reduce system availability. Thus, the reliability of an MGCS is increased by distributing central controls among several fully independent hardware modules.

The MGCS shown in Fig. 1 yields a very modular, expandable, and easily commissioned system. Integrating a new Layer 1 controller can take place while all other systems are running. Modifications to an existing control system must not affect other systems.

PES and PEL are commonly dispersed across large geographic, and often remote, regions. This puts Layer 1 equipment large distances from Layer 3 and Layer 4 equipment. Layer 2 equipment must therefore be capable of long-distance communications.

Using fault-tolerant code in Layer 3 controller algorithms greatly enhances system reliability. One example is called self-healing data selection. This technique works by switching the data used by the algorithms from the primary to secondary source when the quality or status of the primary source changes. One example of self-healing is that load shedding systems should select an alternative load to shed when the algorithm cannot verify the status of the first-choice load.

Some form of data quality and time-stamping is also required. Poor data quality requires the algorithm to either select another source or shut down the algorithm. Old time stamps indicate unacceptable communications latency and may also require reselection of a data source or shutting down. Some examples of a poor data quality indication include the following:

- Out of range, unrealistic, or intermittent data.
- Communications failures or latencies between layers.
- Layer 0 equipment not responding to commands.
- Equipment alarms.

Essential to any successful MGCS integration and long-term ownership is proper documentation. Inadequate documentation makes it impossible to hand over ownership to new engineers and invariably causes early obsolescence of an MGCS. The long-term success of any MGCS supplier is dependent upon its ability to teach end users to troubleshoot and maintain their own systems. Long-term and expensive maintenance contracts are not required if an MGCS is properly designed and documented.

Designers must specify a comprehensive testing plan for each layer of the MGCS. The procedure of testing usually involves multiple factory acceptance tests (FATs) at interface equipment suppliers, a dynamic FAT of the central controller, field installation and commissioning, and a unified site acceptance test (SAT).

C. Cybersecurity

No paper on MGCS is complete without a cautionary note on security. For MGCSs, a defense-in-depth cybersecurity architecture must be used to ensure the resiliency of the MGCS as well as keep out malicious and unauthorized communications. Compliance to National Institute of Standards and Technology (NIST) or North American Electric Reliability Corporation Critical Infrastructure Protection (NERC CIP) criteria further complicate the design, installation, and ownership of these systems. The following summarize the authors' successful implementation of rigorous security systems on many MGCSs. In no way is this section comprehensive, because the art and science of cybersecurity is an ever-changing field.

Security perimeters must be defined on every project. Both physical means, such as a fence, and virtual means must be employed to prevent intrusion. The best security perimeter is an "air gap," wherein no outside networks are connected to the MGCS. Unused communications ports are shut down. Industrial fiber-optic connectors prevent all but the most skilled from physical connection to the MGCS communication systems. Non-typical fiber-optic wavelengths can be selected to prevent a mistaken connection with the outside world. All physical communications ports should be kept behind locked doors.

Sometimes outside systems require status information from an MGCS. Security appliances used to bridge networks are expensive to keep up to date because new types of attacks require new countermeasures. These security appliances are the first to be attacked, and as such the authors prefer single directional (unsolicited) serial data traffic emanating from the MGCS for sending data to an outside entity. Universal asynchronous receiver/transmitter (UART) integrated circuits used only as transmitters do not respond to remote controls when their receivers have no hardwired line connected. This design has no way to respond to command messaging from the outside world.

Should remote engineering access or control be required for the MGCS, these unidirectional serial communications methods will not work. The typical solution for this is firewalls that provide secure remote administrative access to all Level 4 equipment via virtual private networks (VPNs). The cost of this sort of remote access and control must be carefully evaluated because the costs of maintaining such equipment far outweigh the initial installation and commissioning costs. Keeping rule sets and firmware up to date on the firewall equipment requires information technology (IT) professionals to perform periodic audits and updates; all of this comes with a hefty price tag.

Another key tenet to any comprehensive cybersecurity program is security against incidental misoperation. For example, induced voltages and ground plane rise caused by power system fault conditions can cause wired message packages to be distorted. Radios, PESs, and PELs commonly emit sufficient energies to cause malformed digital messages. Hardware used in the MGCS must be type tested for difficult

EMI environments to guard against misoperation. Protocols that are purpose-built for the substation power system environment are also required. Some power system protocols include additional security features that prevent misoperation under these adverse conditions; industrial, commercial, and business protocols do not have these features.

MGCS equipment must have strong, multilevel passwords; strict port time-outs; and automatic reporting of attempted access to equipment. All systems must monitor and record every access and/or change to each device. Remote access to all equipment should be blocked unless the local operations staff intentionally put equipment into remote mode.

Risk management requires transparent communication of risks from supplier to user. Service bulletins must inform the user of risks of misoperation, loss of data, or possible outside intrusion caused by defects found in a product.

Background screening, training, and regular employee monitoring must be done by all suppliers. Suppliers have the obligation to keep track of every component and setting in their system. All systems must be traceable back to a supplier, a specification, and a test sequence.

The complications and cost associated with antivirus protection, white-listing, keeping the operating system (OS) up to date, and system testing can be staggering. For example, a central controller using a commercial OS requires a complete retest and revalidation for every OS patch that is applied. For MGCSs to have more than 30-year design lifetimes, Level 1 through Level 3 devices should be embedded operational devices instead of devices with commercially available OSs.

III. CONTROL FUNCTIONS

The authors have a history of developing new and innovative MGCS control and protection algorithms. This section focuses on the essential methods and algorithms used to achieve grid resiliency.

A. Grid-Connected Controls

MGCSs simultaneously manage several points of common coupling (PCCs) to an adjacent utility grid. The MGCS can provide support to the utility when operating in this connected mode. The available functionality when operating in grid-connected (non-island) mode is described as follows.

Automatic generation control (AGC) algorithms dispatch the power output of distributed power resources to maintain power interchange at the PCCs within predetermined limits. AGC algorithms dynamically recalculate energy resource set points under all system bus configurations (topologies). The dispatch of resources is accomplished via a number of methods, including economic dispatch, renewable prioritization, grid resiliency, utility operating reserve, or demand response methods. AGC can operate to buy or sell exact amounts of power on an intertie. Additionally, an advanced AGC scheme can control the system to maintain the intertie value at zero during periods when system separation is likely (e.g., extreme weather conditions).

Peak shaving algorithms dispatch energy sources, such as

batteries and conventional generation, to relieve transmission corridor congestion. For example, battery system discharging occurs during peak usage times, while charging is accomplished during minimal usage times.

A power factor control system (PFCS) is used to regulate the reactive power output of distributed energy resources to maintain reactive power interchange at the PCC while maintaining system voltages within predetermined limits. PFCSs dynamically dispatch on-load tap changers (OLTCs), capacitors, synchronous generator excitation systems, static synchronous compensators (STATCOMs), and other reactive current-producing assets. PFCSs must follow IEEE 1459-2000, the standard for calculating power factor.

The MGCS must detect island formation and, in some cases, actively decouple a power system to create a microgrid island. Automatic island detection systems use breaker status indications, disconnect switch statuses, voltage measurements, current measurements, and synchrophasor measurements to automatically detect when grid islands are formed. The island detection system handles any number of system topology bus-connection scenarios. The outcome of an island detection can be one of two options: 1) shut down the islanded microgrid by stopping generation (known as anti-islanding), or 2) modify the mode and dispatch of islanded generation sources to keep the microgrid alive (known as islanding).

Automatic decoupling systems intentionally island microgrids from a utility. Decoupling is most commonly performed after a fault outside the PCC to stop intergrid instabilities, to prevent damage to distributed energy supplies, or for a contractual requirement between two entities. This intentional islanding can have a cascading effect, forming additional microgrids that are composed of their own distributed energy sources and loads. This decoupling is typically accomplished by opening circuit breakers at the PCC. Modern automatic decoupling schemes typically include frequency, rate-of-change of frequency, and directional power elements (32). Combinations of several protection elements are commonly coordinated to improve sensitivity and selectivity.

B. Islanded Controls

After a microgrid island is formed, the MGCS modifies the mode and dispatch of islanded generation and provides immediate load balancing through load shedding, generation shedding, load runback, and generation runback. These actions keep the frequency and voltage within allowable parameters for any number of islands. These systems are sometimes referred to as load management schemes.

Load and generation shedding schemes quickly stabilize system frequency during periods of sudden loss of generation and/or load. Load shedding systems automatically reduce electrical loads in response to island events or loss of distributed power generation. Modern load and generation shedding and runback schemes dynamically select loads based on live power measurements, operator-selectable prioritization, and changing bus topology conditions.

Contingency-based load shedding, generation shedding, load runback, and generation runback (CBLSGSLRGR) schemes operate when a breaker is opened under current flow. CBLSGSLRGR schemes track every combination of system topology and bus configuration by dynamically tracking the system state of the microgrid. These schemes are well-described in the literature [3] [4] [5]. Contingency-based load and generation shedding responds in less than one power system cycle to prevent frequency and/or voltage collapse.

Multiple simultaneous or closely timed breaker openings pose significant challenges to designers of CBLSGSLRGR schemes. For example, after a line fault the state of a power grid is changing rapidly. Power flows are changing near instantaneously, rotors are swinging, multiple circuit breakers open sequentially, system impedances change, transient and subtransient effects from rotational machines occur, and the more fragile PES and PEL shut down. Compounding this problem is that Layer 1 equipment has filtering, debounce, delay, and asynchronous updates in power measurements and message propagation to a central controller. Thus, during these times of rapid power system changes, the CBLSGSLRGR algorithms must operate without real-time information. Without mitigation, these transient problems will cause the CBLSGSLRGR scheme to misoperate. MGCS designers must ensure that suppliers have provided adequate protection against these inevitable events. Testing of CBLSGSLRGR algorithms under the duress of this condition is a primary rationale for the real-time closed-loop testing described later in this paper.

Load runback and shedding are used when islanding events result in insufficient generation on a microgrid, such as during an islanding event during import of power from a PCC. Under these conditions, power system frequency can quickly fall out of control and result in a power outage. Load runback schemes reduce but do not entirely shut off loads. Load runback schemes require adjustable loads, such as pumps on adjustable speed drives, building ventilation fans, and heaters. Load shedding schemes trip loads off by opening circuit breakers.

Generation runback and shedding are used when islanding events result in excessive generation on a microgrid, such as an islanding event during export of power to a PCC. Under this condition, power system frequency can quickly rise out of control and result in a power outage. Generation runback schemes reduce the output of distributed generation faster than PES and rotation governor frequency controls can, thus keeping the generation online. Generation shedding schemes trip circuit breakers to get power supplies offline, and runback schemes bypass frequency control systems and send feed-forward commands directly to valve controls.

Frequency-based load and generation shedding methods have recently advanced with inertia compensation and load-tracking (ICLT) schemes. ICLT schemes track system inertia, load composition, frequency, and rate of change of frequency in their calculations [6]. ICLT schemes have the added robustness of not requiring any breaker status data to make real-time island and state measurement decisions. ICLT

schemes are a critical backup to CBLSGSLRGR schemes because CBLSGSLRGR schemes do not detect broken wiring in a circuit breaker, shorted CT windings, dc battery failures, or a long list of control system and mechanical problems that shut down power systems without opening breakers.

Of particular importance in all MGCS control strategies is the continuous and dynamic monitoring of the active (P) and reactive (Q) power capabilities of conventional and PES generation on a microgrid. These P and Q capabilities must be ascertained for both momentary capability and longer-term capacities. Fig. 2 shows a typical set of capability curves for a combustion turbine and a battery storage system that must be dynamically monitored by a MGCS.

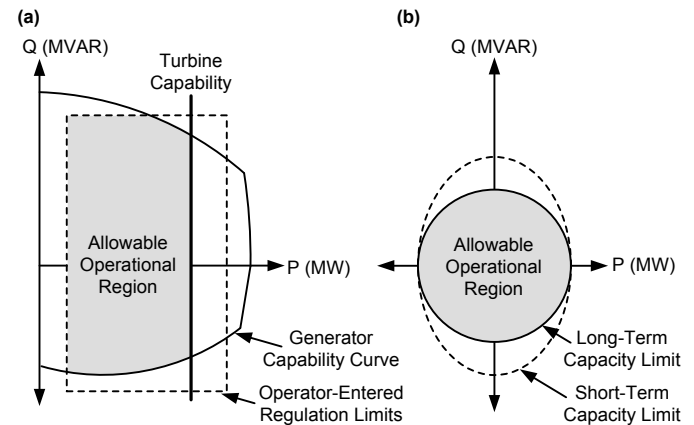


Fig. 2. Dynamic Capability Monitoring in a Typical Combustion Turbine Driven Generator (a) and a Typical Battery Storage System (b)

Islanded microgrids do not have a strong utility connection to control the power system frequency. For this condition, MGCSs use advanced AGC techniques, as shown in Fig. 3, to hold system frequency at nominal while simultaneously maintaining distributed generation outputs within an allowable operational region, as shown in Fig. 2. When a distributed generation source is switched into stiff frequency control (also known as isochronous operation), the AGC system dispatches all nonfrequency regulating sources to keep the isochronous units within an allowable operational region.

MGCS central controllers have volt/VAR algorithms that regulate the reactive power output of distributed energy resources to maintain islanded bus voltages within predetermined limits. These systems dynamically dispatch OLTCs, capacitors, excitation systems, electronic inverters, and others reactive current-producing assets.

MGCSs contain both unit synchronization and system synchronization systems. After either a manual or automatic initiation, these systems automatically reduce slip, phase angles, and voltage differences before automatically closing a circuit breaker.

Unit synchronization schemes adjust slip, phase angles, and voltage differences by sending control set points to a single distributed energy supply. These schemes are most commonly provided in a single Layer 1 protective relay. The relay automatically closes the circuit breaker once acceptable slip, phase angles, and voltage differences are detected.

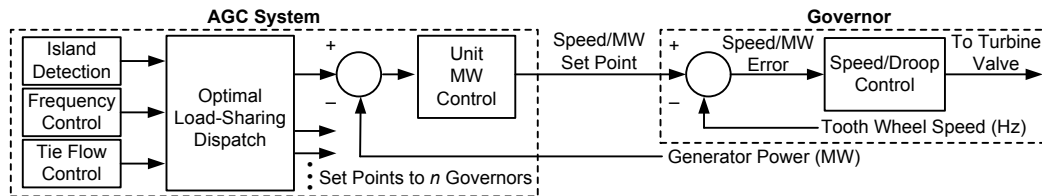


Fig. 3. Typical AGC Strategy

System synchronization schemes resynchronize two or more islanded microgrids. These systems adjust slip, phase angles, and voltage differences between the two grids by sending control set points to any number of distributed energy supplies [7]. These schemes require several relays, I/O modules, and a central controller. Relays at each synchronization point automatically close the circuit breaker once acceptable slip, phase angles, and voltage differences are detected.

C. Adaptive Protection

The distributed generation of a microgrid can create a complicated protection coordination problem. Utility distribution circuits have unidirectional power flows that greatly simplify the coordination of protection systems. Some loads in a microgrid can become sources (batteries and flywheels). Fault current levels can be dramatically different in grid-connected versus islanded operation.

Differential schemes (87) and zone-interlocked schemes can be configured to work for all operational conditions of both grid-connected and islanded modes. Differential techniques are less sensitive to fault levels, thus overlapping bus, transformer, and cable differential schemes are a very popular choice. Zone-interlocked schemes use directional elements and communications to form schemes that can improve selectivity and operating times [8]. Designers are advised to be aware that 87 elements must be supervised by harmonic and other restraint elements to prevent misoperation during load and transformer energization.

Time coordination schemes must be set for all grid-connected and islanded mode conditions and can become very complicated and expensive. Time coordination schemes must adapt to the different fault currents, grounding conditions, and topology of a microgrid. Fault currents of a utility are typically tens of thousands of amperes, whereas smaller distributed generation, such as PES, often provides little or no fault current. The fault currents of an islanded grid can become very close to the upper load limits, making proper time-overcurrent type coordination difficult and sometimes impossible. The loss of a transformer can change grounding conditions from solidly grounded to no grounding, thus making ground fault detection very difficult. Microgrids that island with different formations of cables, sources, feeders, and load buses can require a complete topology tracking supervisory system to advise protection relays of which settings to use.

IV. CONTROL SYSTEM VALIDATION

Modeling and real-time closed-loop modeling of microgrid power systems is essential in determining the efficacy of MGCS protection and control schemes.

PESs and PELs do not generate continuous fault current at levels similar to synchronous generators. This can create serious (and dangerous) protection coordination problems. MGCSs must therefore be tested with real-time, Electromagnetic Transients Program-style (EMTP-style) modeling of the combined protection and controls system to validate that all protection and control systems function safely.

With all of the possible permutations in state and time that a power system can take on, it is essential to test all MGCSs prior to installation. This section describes a real-time simulation of a power system being connected directly to a MGCS, as shown in Fig. 4. The MGCS shown in Fig. 4 is most commonly the Layer 3 central MGCS controller. The real-time power system model (RTPSM) is a full EMTP that provides real-time changes in power, frequency, rotor angle, voltage, and load reactions to frequency and voltage.

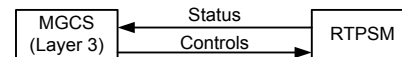


Fig. 4. Closed-Loop Testing Environment

A. Modeling Methods

The RTPSM represents the behavior of only Layer 0 equipment. The RTPSM predicts the electrical, magnetic, and mechanical dynamics of power sources, loads, transformers, generators, turbines, and associated Layer 0 control systems. Accurate electrical and magnetic phenomena require a simulation time step of 80 microseconds or faster. Governors, hydraulics, steam control, and mechanical valves can be modeled at slower simulation time steps.

The advantage of running the test in real time is that a model operates sufficiently fast to test all the closed-loop control and protection systems. Because the RTPSM is real-time, thousands of test cases are run, providing site personnel with a great amount of confidence that all systems will react as expected under the most adverse scenarios.

User-attended FATs with the testing arrangement of Fig. 4 are strongly recommended. The microgrid owner's intimate knowledge of their power system is useful in testing tough corner-case scenarios; an owner will commonly recall unusual phenomena to be modeled with the RTPSM. The FAT also serves as a fast training program for operators of the MGCS. Because thousands of tests cases are run, an operator can gain more experience from an RTPSM FAT than from a decade of field work.

B. Fit-for-Purpose Modeling

Model development for the RTPSM of a microgrid system can take from weeks to years, depending on the complexity and accuracy requirements. Modeling engineers should therefore build fit-for-purpose models that are the simplest model possible to accurately replicate the field behaviors and interactions with the MGCS.

To accurately model dynamic microgrid phenomena, RTPSM mechanical, electrical, and magnetic models must be derived from first-principle physics. Validation reports must be accompanied with the mathematical derivation of model components. Microgrid modeling specialists now have proven and validated first-principle RTPSM models for systems such as flywheel storage, wind generation, battery storage, turbine and reciprocating driven (conventional) generation, governors, exciters, PV controls, dump loads, dispatchable loads, battery storage, and power electronic devices.

Once a complex and first-principle model has been validated with field results, it is common to find simplifications for these modeling blocks that expedite overall model development and have no impact on model accuracy. These simplifications take decades of experience and significant field testing to validate.

The nature of the MGCS algorithm being tested can significantly affect the RTPSM electrical, mechanical, and magnetic models developed. For example, an AGC system may take 30 seconds to return the frequency to nominal after an event; this sort of control scheme is much slower than rotating machinery transient and subtransient electrical time constants, thus a less detailed generator and motor electromechanical model will suffice. There are many quality papers available to guide MGCS modeling engineers in their efforts to build the simplest possible models that depict relevant dynamic behaviors [9]. For example, Fig. 5 is a fit-for-purpose model of an islanded microgrid power system that was sufficiently accurate to replicate frequency instabilities caused by a steam governor low-load instability [10].

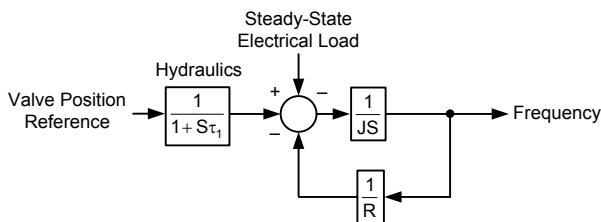


Fig. 5. Simplified Power System Model

Fig. 5, however, would not be an adequate model for transient rotor angle stability studies.

C. Model Validation

Model validation is the process of proving that a microgrid model accurately depicts pertinent dynamic electrical, magnetic, and mechanical behaviors. It is typical to build detailed models of steam boiler controls, governor hydraulic systems, gas turbine valve nonlinearities, wind turbine blade controls, PV reactive power controls, battery charging

controls, generator transient models, complex load models, and more. These models can be only considered accurate enough once live performance test data are collected from real equipment and compared with model performance. To make RTPSMs match field performance requires rigorous validation, which commonly takes more effort than building the model itself.

Fig. 6 shows a comparison of frequency responses for a complete microgrid model versus data captured from a live field event. This model was deemed accurate enough because the peak and steady-state frequency were very close. Note that the transients difference between 5 and 20 seconds in Fig. 6 are different; this is acceptable because this had no impact on the MGCS strategies being deployed.

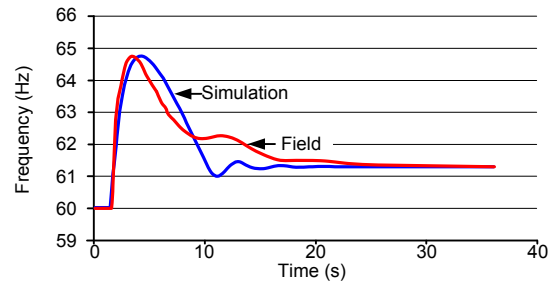


Fig. 6. Simulated and Field Frequency Response

RTPSM developers must prove that their models accurately depict field phenomena. This evidence is best compiled into a model validation report to be delivered before the FAT occurs. This report usually has individual validations of the following genres of behavior: steady-state electrical conditions, short-circuit conditions, power generation active and reactive power controls, utility power system models, and load dynamics.

Steady-state electrical conditions are validated by the tabulation of power flow results. These results should include bus voltages, island frequencies, active and reactive power flows, and generator outputs. These tabulated values are compared to the known operation of similar microgrids and known flows of installed equipment. Several cases should be provided, including PCC open, islanded conditions, and cases with some power production offline. These data validate that the electrical impedances, nominal load levels, distribution of load to feeders, normal operating status of breakers, and isolation switches are correct.

Short-circuit conditions are validated by the tabulation of phase-to-ground and phase-to-phase fault values at several locations in the microgrid. These tabulated values are compared to known operations of similar microgrids and known fault levels of installed equipment. Several cases should be provided, including PCC open, islanded conditions, and cases with some power production offline. These data validate the electrical transient impedances, magnetic models, grounding schemes, and the simplified models of the utility beyond the PCC.

RTPSMs of power generation and load and associated frequency, power, voltage, and stabilization control systems are validated by plotting modeling data against data captured in the field. Field data are typically collected from modern microprocessor-based protective relays, digital governor controls, and digital field excitation controls. Common tests to run are load rejection and load pickup tests; these must be run in both islanded and grid-connected modes.

V. CONCLUSION

The essential requirements for a successful MGCS deployment include the following:

- An architecture that allows for easy testing, high reliability, and proven maintainability.
- System resilience achieved before designing economic optimization systems.
- Cybersecurity designs, methods, and processes followed during the entire lifecycle of the MGCS.
- Active and reactive power dispatch programs that work seamlessly as the grid transfers between islanded and grid-connected modes of operation.
- Active and reactive power dispatch programs that keep power generation supplies within allowable long-term operational limits.
- Automatic de-coupling and separation at all PCCs.
- Subcycle wide-area load and generation shedding systems that keep a microgrid alive during all loss of PCC, distributed generation, or load.
- A proven ICLT scheme to act as a backup load and generation shedding scheme.
- System-wide synchronization schemes that automatically recombine any number of separate islanded grids.
- Coordinated protection during all possible grid-connected and islanded operation modes.
- Dynamic models that are mathematically based on first-principle physics, are validated against field captured data, and have undergone customer-witnessed factory acceptance testing.

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VII. BIOGRAPHIES



Scott Manson received his M.S.E.E. in electrical engineering from the University of Wisconsin-Madison and his B.S.E.E. in electrical engineering from Washington State University. Scott is currently the engineering services technology director at Schweitzer Engineering Laboratories, Inc. (SEL). In this role, he provides consulting services on control and protection systems worldwide. He has experience in power system protection and modeling, power management systems, remedial action schemes, turbine control, and multi-axis motion control for web lines, robotic assembly, and precision machine tools. Scott is a registered professional engineer in Washington, Alaska, North Dakota, Idaho, and Louisiana.



Krishnanjan Gubba Ravikumar received his M.S.E.E. degree from Mississippi State University and his B.S.E.E. from Anna University, India. He is presently working as a supervising engineer in the Schweitzer Engineering Laboratories, Inc. engineering services division, focusing on model power system development and testing for special protection systems. His areas of expertise include real-time modeling and simulation, synchrophasor applications, remedial action schemes, and power electronic applications. He has extensive knowledge of power system controls and renewable distributed generation. He is a member of the IEEE and the Eta Kappa Nu Honor Society.



Sai Krishna Raghupathula received his M.S.E.E. degree from University of Idaho. He is currently a regional manager for the engineering services division of Schweitzer Engineering Laboratories, Inc. (SEL). He is an electrical engineer who specializes in control system design, power management systems, remedial action schemes, power system controls, system integration, power electronics, and consulting services.

Microgrid Control System Protects University Campus From Grid Blackouts

John Dilliot, *University of California San Diego*

Ashish Upreti, Bharath Nayak, and Krishnanjan Gubba Ravikumar, *Schweitzer Engineering Laboratories, Inc.*

Abstract—Today's microgrid controls are designed to maximize generation availability, preserve critical loads, and ensure system stability. Microgrids are also capable of autonomous operation during a loss of utility or intentional islanding during grid disturbances. Such autonomous operation requires sources that can provide primary frequency and voltage regulation within the microgrid system. Additional controls also use optimization algorithms for saving costs, improving efficiency, and maximizing green energy usage. The University of California San Diego (UC San Diego) is a world-class research university with an advanced campus electrical utility system. The university's microgrid system consists of a diverse generation and load portfolio. This paper discusses details of microgrid monitoring and control system (MMCS) components implemented for UC San Diego, such as contingency-based load shedding, frequency-based load shedding, peak shavings, synchrophasor-based islanding detection and decoupling, high-speed generator switching, adaptive protection systems, and automatic synchronization with an overview of the overall system architecture. The paper also presents the dynamic performance of the MMCS during hardware-in-the-loop (HIL) testing with a real-time and dynamic digital simulator, and how the MMCS protects the UC San Diego system from blackouts, supports the islanded operation, and performs resynchronization to the grid.

The paper also presents the efforts put into the modeling and simulation of the campus microgrid, its benefits for system validation, and commissioning using HIL testing and the commissioning results.

This MMCS is currently in operation.

I. INTRODUCTION

One important function of a microgrid monitoring and control system (MMCS) is its ability to perform high-speed control of the electrical system to preserve frequency and voltage stability. With the fast development of microgrids around the world, several new control systems and techniques are being designed to better monitor, operate, and protect the microgrid systems. This paper discusses a reliable, high-speed control system that protects the University of California San Diego (UC San Diego) microgrid at wide-area speeds of less than 25 milliseconds.

The sustainable energy project started in the wake of the 2011 Southwest blackout. When the power outage disrupted critical operations, campus officials recognized the need for an islanded system. Today, onsite generation at UC San Diego covers approximately 85 percent of the campus annual load and 75 percent of peak demand—a total of approximately 50 MW. The remainder is imported from the San Diego Gas & Electric

(SDG&E) grid. UC San Diego's diverse portfolio includes a 2.8 MW fuel cell, a 2.2 MW solar network, a 30 MW gas-turbine cogeneration plant, a 2.5 MW energy storage system, and a chiller plant. UC San Diego has centers for science, engineering, and medicine; the campus is required to ensure a reliable source of energy and prevent a power supply disruption.

This facility has three utility ties, which can split into multiple power islands for continued system operation. The MMCS has been designed to track all such possible islands and provide simultaneous control. Fig. 1 represents the simplified microgrid power system.

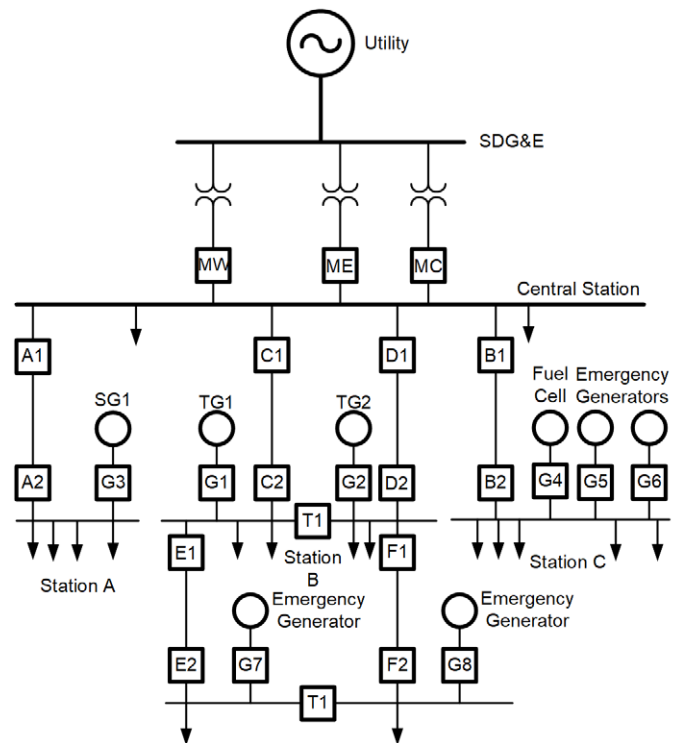


Fig. 1. UC San Diego Simplified One-Line Diagram

II. MICROGRIDS

Microgrids are capable of autonomous operation during loss of utility caused by grid disturbances. Such autonomous operation requires sources that can provide primary frequency and voltage regulation within the microgrid. To effectively manage these sources for smooth islanded operation, the

MMCS interfaces with all assets. Some examples of such assets include diesel generators, photovoltaic sources, wind sources, and fuel cells. The MMCS components include islanding detection and decoupling systems [1], primary and backup load-shedding systems [2], slow- and high-speed generation control systems [3], adaptive protection systems, peak shaving, energy source optimization, and other analytical and control functions.

Unlike traditional sources, power electronic-based renewable sources (found typically in microgrids) are not so predictable. Concerns such as intermittency and reduced inertia can have a large impact on power system dynamics as the installed capacity of distributed generation increases. Such concerns warrant the need for fast-acting control systems that can potentially avoid situations that could destabilize the microgrid power system. In addition, turning radial distribution configurations into meshed configurations may require changes in the distribution protection philosophy and adaptive protection schemes. Fig. 2 shows a simplified system architecture of the MMCS used to protect and control the electrical network shown in Fig. 1.

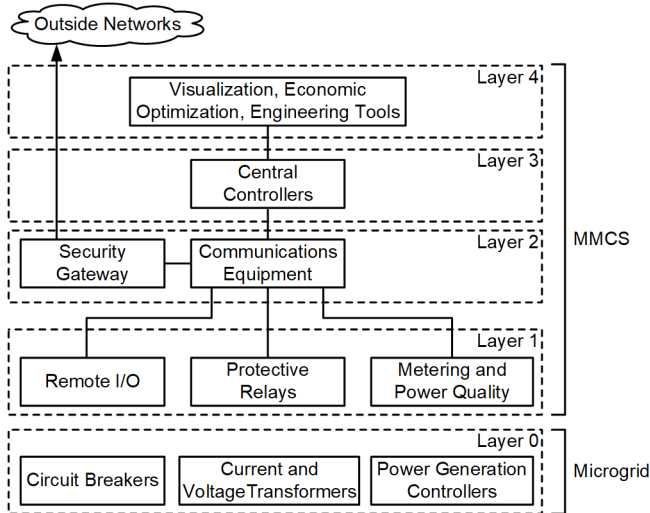


Fig. 2. High-Level Microgrid Architecture

III. UC SAN DIEGO SYSTEM OVERVIEW

The UC San Diego microgrid as shown in Fig. 1 is connected to the SDG&E utility via three 28 MVA step-down transformers. The SDG&E utility tie is rated at 69 kV and feeds the 12 kV Central Station. Central Station acts as a power-wheeling bus and connects to Station A, Station B, and Station C with some sheddable and non-sheddable loads connected. Station C has two generators, Station C G1 and Station C G2, and a fuel-cell generator (FC).

Station A is connected to Central Station through the incoming feeder breakers and has a sheddable load. Station B is connected to Central Station through incoming feeder breakers and has one generator (PG1). The largest source of generation inside the UC San Diego microgrid is at Station B. Station B has emergency diesel generators, two gas generators (TG1 and TG2), and one steam generator (SG1).

IV. COMMUNICATIONS AND NETWORK ARCHITECTURE

Modern-day electrical control systems rely significantly upon analog and digital communications [4]. Most of the newer systems use various forms of communication mediums such as radio, copper, and fiber. These mediums enable connections between microprocessor-based programmable logic controllers (PLCs), computers, intelligent electronic devices (IEDs), and several other devices that are normally found on the power grid. The application of monitoring, controlling, and managing microgrids is no different. The MMCS uses a wide range of electronic devices and industry standard communications protocols such as DNP3, Modbus, Inter Control Center Communications Protocol (ICCP), Network Global Variable List (NGVL), IEC 61850, and IEEE C37.118. Communications protocols are mainly classified into high- and low-speed protocols.

High-speed protocols are often used in situations where speed matters. For example, applying IEC 61850 GOOSE for high-speed breaker tripping can be commonly found in load-shedding applications. On the contrary, low-speed protocols work great for interfacing with microgrid assets, moving data between the human-machine interface (HMI) and storage systems, and other functions.

Depending on the application criticality, it is very important to identify and segregate communication networks to guarantee dedicated bandwidth and network latency. A good design stage activity is to identify all the input/output (I/O) signals required for the monitoring and control functions. Using the I/O list, network calculations should be performed to calculate the required bandwidth and the type of communications.

Fig. 3 shows the Ethernet network connections between the multiple data concentrators located at various substations on the UC San Diego campus. The network communications allowed for the monitoring of system parameters along with microgrid management.

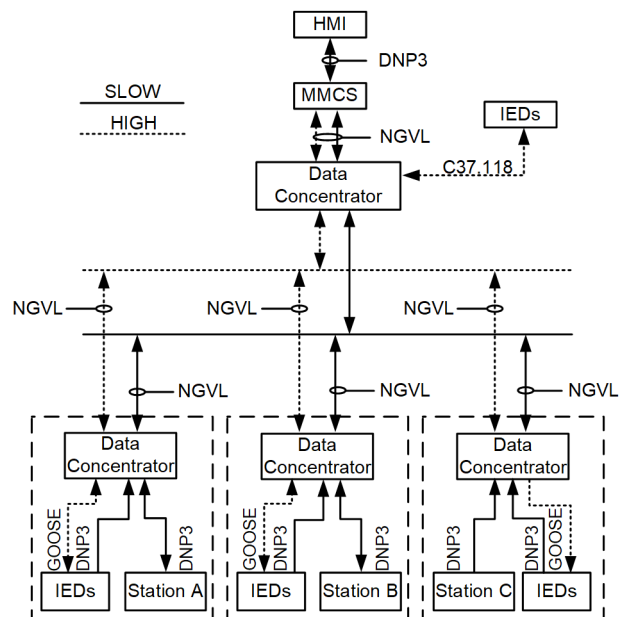


Fig. 3. Microgrid Communications Network

V. MICROGRID MONITORING AND CONTROL SYSTEMS

A. Load-Shedding Systems

Historically, power systems have implemented load-shedding systems to keep the steady-state frequency close to nominal during major loss of generation capacity (contingency). The typical contingencies include loss of utility interconnection or generators. In addition, the load-shedding system minimizes the disturbance toward sensitive critical loads and prevents system-wide blackouts.

Load-shedding systems can be mainly classified into two types: primary contingency-based load shedding (CBLS) systems and backup frequency-based load shedding (FBLS) systems. The CBLS is much faster and more accurate compared to an FBLS. The CBLS is an independent control system that makes decisions based on topology, contingency, and load calculations from field IED data. Because of its high-speed nature, the CBLS comes pre-armed for load-shedding events and provides a fast response in a range of milliseconds. In addition, the CBLS tracks the entire system's topology and sheds sufficient load to limit any power and frequency oscillations, as shown in Fig. 4. The fundamental principle of a CBLS is to maintain the power balance equation by shedding load before the frequency starts to decay. Finally, the CBLS dynamically tracks the various system islands to avoid shedding on different islands and prevent unnecessary tripping.

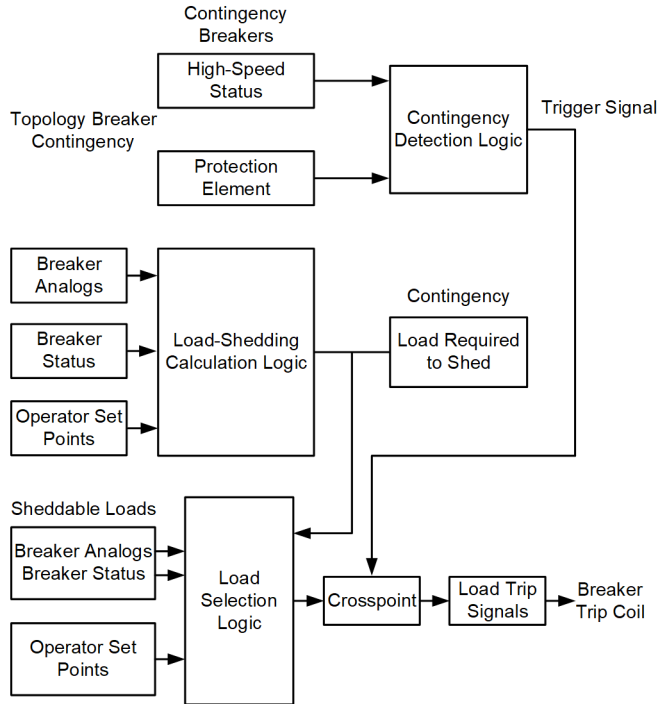


Fig. 4. Contingency-Based Load-Shedding Algorithm

Both the CBLS and the FBLS are implemented in the UC San Diego MMCS.

The amount of load to be shed is the difference between the amount of source power lost and the sum of the instantaneous power that can be supplied by the remaining sources, as described in the following equation. The equation is performed for each island on the system, meaning that the terms of the

load, power disparity, and incremental reserve margin (IRM) [2] are all specific to individual islands.

$$L_n = P_n - \sum_{g=1}^m \text{IRM}_g$$

where:

n = contingency event number

m = number of sources connected to the affected island after n event

g = generator number, 1 through m

L_n = amount of load selected for n event (MW)

P_n = power disparity caused by n event (MW)

IRM_g = incremental reserve margin of all sources after n event (MW)

Fig. 5 shows the load-selection logic. Additional loads are selected until the required-to-shed calculation is met. The Hysteresis algorithm was added for the UC San Diego CBLS and the FBLS to keep the discrepancy between the required-to-shed and the selected-to-shed calculations minimal and to preserve system stability.

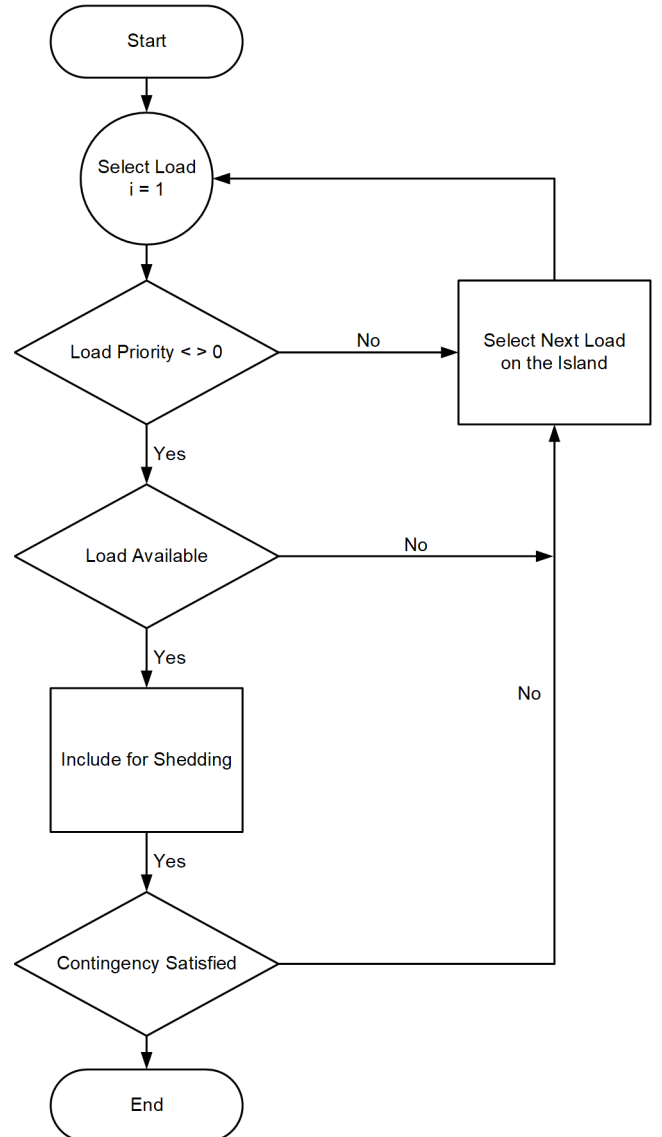


Fig. 5. Load-Selection Logic

The FBLS operates as a backup to the CBLS. Underfrequency triggers are generated from the IEDs located at Station B. Two levels of underfrequency thresholds were selected as indicated in the frequency line diagram in Fig. 6. A frequency line diagram provides a visual indication of major frequency dependencies in a power system and allows coordination between different asset protection schemes to be seen. MMCS decoupling and FBLS underfrequency triggers are supervised with voltage and communications qualifications. The frequency for the underfrequency was coordinated along with generator protection set points and decoupling set points. The underfrequency operation for load selection is similar to the CBLS system except that the required-to-shed calculation is based on the island, topology status, and user-settable inputs. This testing was validated using hardware-in-the-loop (HIL) testing [5].

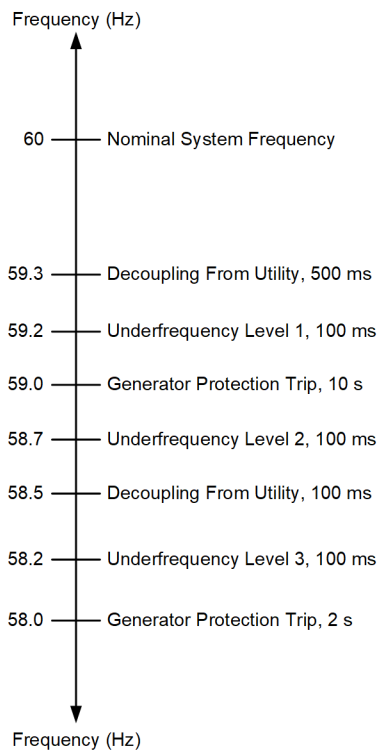


Fig. 6. Frequency Line Diagram

B. Generation Control Systems

When the utility is connected, microgrid generators are paralleled with the utility using droop characteristics. Under such situations, an important function of a generation control system is a slow-speed rebalancing act to share load proportionally in terms of real and reactive power. Typical functions that are active during this time include the automatic generation control (AGC) and volt/volt-ampere reactive (VAR) control system.

When disconnected from the utility, generation control systems should validate the microgrid separation from the utility and change speed control modes on governors (from droop to isochronous). For systems that allow isochronous load sharing, multiple governors can be set to isochronous speed control mode.

An MMCS is programmed to track the internal islands of the system when disconnected from the utility. This allows for simultaneous voltage and frequency control of the islands with available generation capacity.

Such high-speed generator mode switching combined with a fast load-shedding, generation-shedding, or runback system stabilizes the power system response during high import or export conditions. A simplified generation control system (GCS) and an automatic synchronization system [6] were provided for the UC San Diego MMCS. During islanding conditions, the modes of the generators were switched to isochronous and back during automatic synchronization for the TG1 and TG2 at Station B.

C. Islanding Detection System and Decoupling System

When the utility is connected, the MMCS should be able to detect utility disturbances and decouple. It should also detect a loss of utility for local or remote breaker openings. This can be achieved via status-based and analog-based measurements. The status-based schemes typically rely on breaker-open conditions for several points of common coupling breakers. The analog-based measurements include local and wide-area methods. Local methods employ voltage- and frequency-based schemes, whereas wide-area schemes can use angle difference-based schemes [1].

An islanding detection and decoupling system (IDDS) was provided as a part of the UC San Diego MMCS. The main purpose of this IDDS was to detect any utility disturbance and decouple in case the disturbance had a negative impact on the system stability and reliability of the UC San Diego power system. The wide-area-based system islanding detection monitoring scheme was implemented; this wide-area scheme is currently in the monitoring state.

1) Local-Based IDDS Scheme

The local-based scheme uses standard frequency- and voltage-based elements, such as 81 O/U and 27/59, along with advanced 81RF functionality. The protective relay at the local utility performs this function. Fig. 7 demonstrates the functionality.

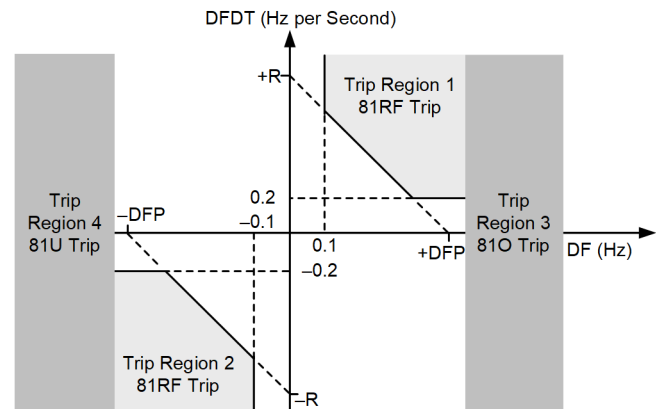


Fig. 7. Decoupling Scheme Characteristics

2) Wide-Area-Based IDDS Scheme

An angle difference-based wide-area scheme (see Fig. 8) uses positive-sequence voltage angles between two locations (local and remote) to determine islanding conditions, as shown in Fig. 9. For the UC San Diego system, angle differences between the measurements from the phasor measurement units (PMUs) on the 69 kV yard and 12 kV switchgear are compared. The angle-difference element operates if the phase angle difference between the positive-sequence voltage phasors at the two locations exceeds a programmable threshold for a specified duration.

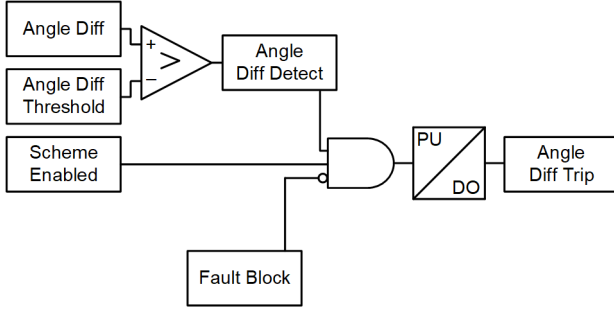


Fig. 8. Wide-Area Angle-Based Detection

Wide-Area Calculation

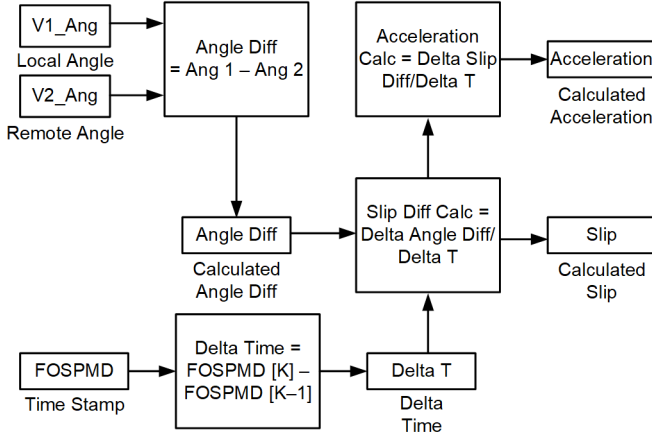


Fig. 9. Wide-Area Parameter Calculation

When the utility is connected, the MMCS should be able to detect a loss of utility for a local or remote breaker opening. This can be achieved via status-based and analog-based measurements. The status-based schemes typically rely on a breaker-open condition for several points of common coupling breakers. The analog-based measurements include local and wide-area methods. Local methods employ voltage- and frequency-based schemes, whereas wide-area schemes can use angle-difference-based schemes [1]. The UC San Diego MMCS currently employs a status-based and local analog-based scheme along with a wide-area-based scheme.

The slip- and acceleration-based scheme, as shown in Fig. 10, was implemented to detect the islanding condition for the UC San Diego system.

When the system is interconnected, the operating point is at the origin of the slip acceleration characteristic. Once the systems separate, the operating point starts to move from the restrain region to the operate region. The unshaded area represents the thresholds that are selected for security. The out-of-step detection (OOSD) declares an islanding condition and/or grid disturbance when the operating point stays in the operate region for a specified duration.

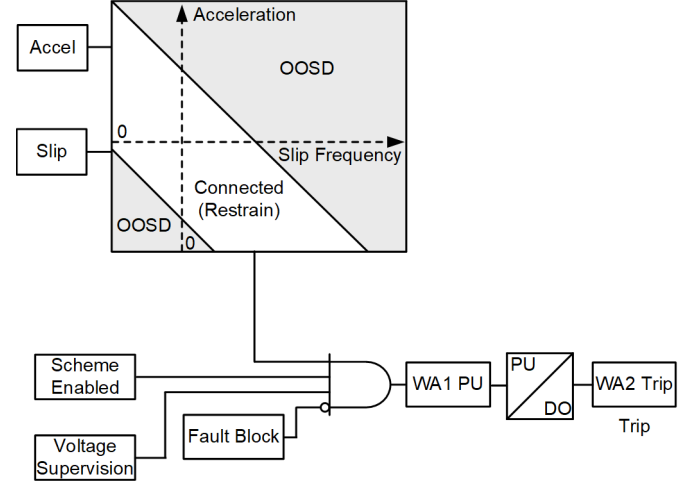


Fig. 10. Slip- and Acceleration-Based Wide-Area Scheme

D. Human-Machine Interface

The MMCS at UC San Diego also has an HMI for remote monitoring and control of the MMCS. The front panel of the protective relays and control devices was replicated in the HMI for system monitoring and control. The load-shedding system cross-point matrix, load status, and contingency status were also displayed in the HMI.

The HMI also provides alarms regarding the communication failures, incongruence of the breaker status, close failures, voltage transformer (VT) failures, and islanding detection and trips.

VI. SYSTEM VALIDATION

Prior to installation of the MMCS at UC San Diego, complete testing was performed at the laboratory. A real-time digital simulator (RTDS) model capable of continuous real-time operation was developed to validate the functionality of the MMCS.

This section describes the UC San Diego microgrid power system, simulation environment, and dynamic simulation results.

A. Simulation Environment and Test Setup

The hardware-based Electromagnetic Transients Program (EMTP) simulation environment was modeled in the RTDS. The RTDS model based on the electrical configuration of the UC San Diego power system, as described previously, was specifically developed to validate the microgrid control functionality.

The RTDS model of the UC San Diego power system was developed to run a simulation for evaluating potential interaction of the load-shedding controller, asset controller, and protective devices. Each component of the model was validated and tested to determine asset performance when subjected to system disturbances. Logic to transition the Station B generators from droop mode to isochronous mode during a loss of utility connection was also implemented. The model was built to study the dynamic response of the system in tandem with controller action to a wide range of electrical network transients and faults. To mimic field setup, the load-shedding controllers were connected in a closed loop with the UC San Diego power system model. A data concentrator was programmed to collect analog measurements and the digital status of contingency breakers. Simulating field IEDs, the interaction between the UC San Diego RTDS model and the microgrid controller was established using various communications protocols. For high-speed control, an action-like load trip was implemented. Along with data concentrators, relays were hardwired to simulate and test the performance of the IDDS logic. The closed-loop capability provided a test bed to investigate vulnerabilities of the controller and its response to simulated contingency events. The closed-loop setup designed for the UC San Diego test bed is shown in Fig. 11.

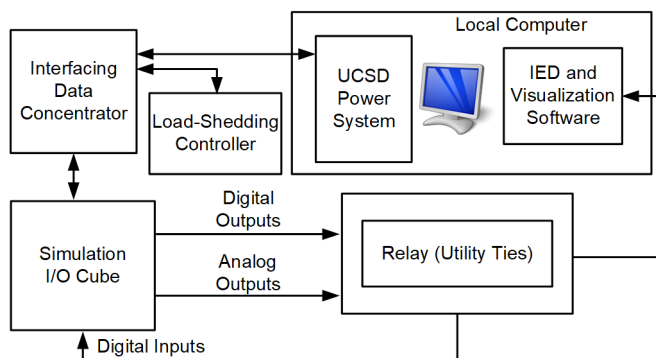


Fig. 11. RTDS Closed-Loop Interface

The model was primarily developed to test the performance of the primary contingency load shedding and backup underfrequency load shedding, and to provide frequency coordination settings among underfrequency controller triggers, decoupling relays, and generator frequency-based protection.

A list of system-wide events was simulated to study the load-shedding controller actions. Critical parameters such as system-wide frequency, voltage, and breaker status were monitored to study and ensure system stability after a controller action. A set of tests that were conducted as part of a factory acceptance test is presented in Table I.

TABLE I
SIMULATED SYSTEM EVENTS

Case	System Event	Precondition	Operation	Pass/ Fail
A	Decouple of UC San Diego due to frequency disturbance (decay rate 2.5 Hz/s).	- Utility ties MW and MC are closed. - MW is importing 3.69 MW. - MC is importing 3.6 MW. - TG1 and TG2 are running at 13.5 MW. - SG1 is running at 2.8 MW. - FC is running at 2.5 MW. - Emergency diesel and pharmacy are running at a total of 12.27 MW. - All bus couplers are closed.	Primary contingency-based load shedding.	Pass
B	Loss of generation at Station B (TG2).	- Two out of three utility tie breakers are open. - MW breaker is importing 17.83 MW into UC San Diego. - TG1 and TG2 are running at 13.5 MW. - SG1 is running at 1 MW. - FC is running at 2.5 MW. - All bus couplers are closed. - Other emergency generators are offline.	Primary contingency-based load shedding.	Pass
C	Island-based load shedding (loss of intertie breakers and loss of generation at Station B).	- Utility ties MW and MC are closed. - MW is importing 12.07 MW. - MC is importing 11.98 MW. - TG1 and TG2 are running at 10.88 MW. - FC is running at 2.5 MW. - All bus couplers are closed. - Other emergency generators are offline.	Primary contingency-based load shedding.	Pass
D	Three-phase fault on utility tie and loss of generation.	- Utility ties MW and MC are closed. - MW is importing 8.92 MW. - MC is importing 8.85 MW. - TG1 and TG2 are running at 13.5 MW. - SG1 is running at 1 MW. - FC is running at 2.5 MW. - All bus couplers are closed. - Other emergency generators are offline.	Primary contingency-based load shedding.	Pass

1) *Case A: Decouple of UC San Diego due to Frequency Disturbance (Decay Rate 2.5 Hz/s)*

The goal of this test was to demonstrate the operation and coordination between the different components of the MMCS. The components of interest include the IDDS scheme, CBLS, and FBLs. In this test, grid frequency disturbance was simulated with a decay rate of 2.5 Hz/s. As the frequency decayed past the threshold indicated in Fig. 12, the UC San Diego decoupled from SDG&E. The disconnection initiated CBLS action. A total of 5.35 MW of load was shed.

This testing demonstrated UC San Diego's capability of islanding from the utility during grid disturbance and successfully operating in islanded mode. During this test, the TG1 and TG2 generator modes were also switched from droop to isochronous.

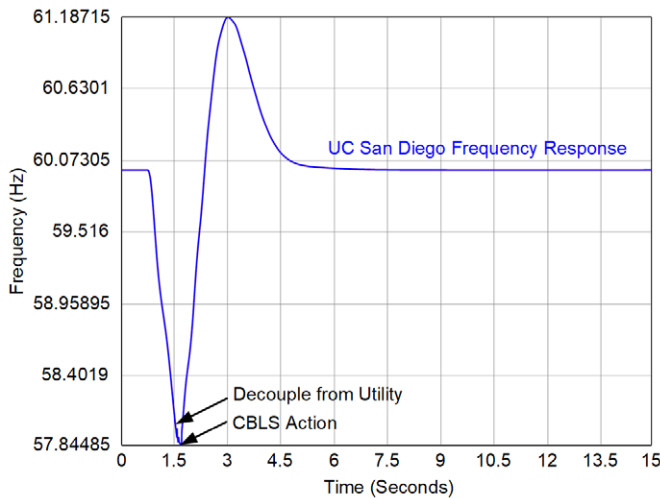


Fig. 12. Case A: Islanding for Grid Disturbance

2) *Case B: Loss of Generation at Station B (TG2)*

The goal of this test was to demonstrate how the CBLS would prevent overloading and tripping of the utility transformer tie using the IRM threshold during internal loss of generation within UC San Diego. The IRM set points can be used to restrict the utility tie from becoming overloaded via a user-operated HMI.

Prior to simulating the event, the loads in the UC San Diego system were fed through the utility breaker MC along with local generation within the UC San Diego plant. To simulate the contingency event, generator breaker TG2 was tripped. Tripping TG2 caused the power flow to increase to 31.33 MW on the utility breaker incomer, as shown in Fig. 13.

As the normal power rating is set at 22 MW, the CBLS shed 10.41 MW of loads (the amount required to shed was reported as 9.33 MW). Fig. 14 shows the frequency response post-CBLS action.

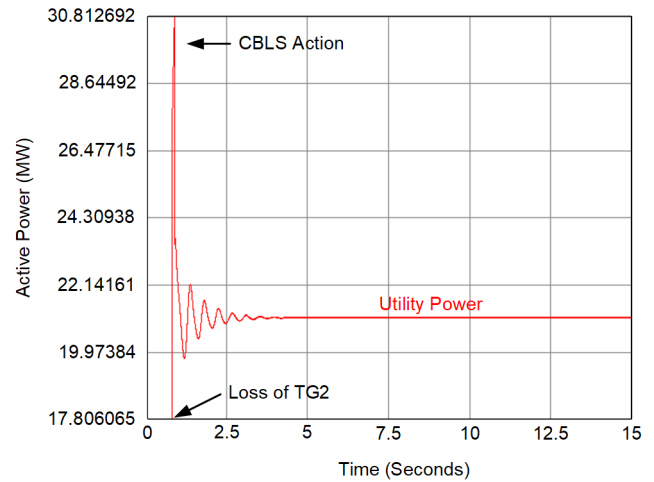


Fig. 13. Power Flow Across the Utility

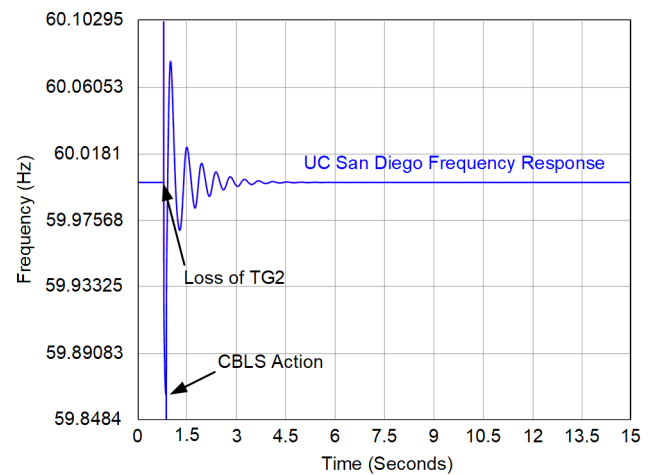


Fig. 14. Case B: Loss of Generation at Station B

3) *Case C: Island-Based Load Shedding (Loss of Intertie Breakers and Loss of Generation at Station B)*

The goal of this test was to demonstrate how load selection is based on islanding by splitting the system into two islands. Island 1 consisted of Station B. Island 2 consisted of Station A and Station C with a connection to the grid.

To demonstrate load selection based on islanding, TG2 was tripped under load, causing a contingency event. The CBLS detected the loss of TG2; based on the available IRM set point of TG1, the CBLS selected loads in Island 1 for load shedding. The CBLS selected loads based on the available priority in Island 1 and shed the loads accordingly. Proper topology tracking and priority-based load shedding functionality were validated. This also proved UC San Diego's capability of forming and maintaining a small island within the UC San Diego electrical network. Fig. 15 shows the frequency response of Island 1.

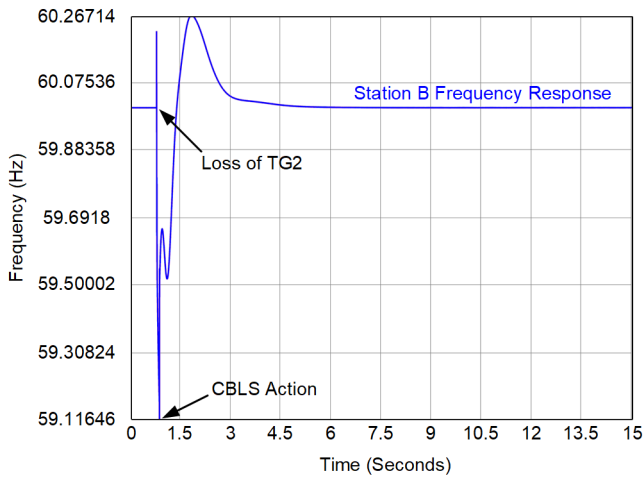


Fig. 15. Case C

4) Case D: Three-Phase Fault on Utility Tie and Loss of Generation

The goal of this test was to demonstrate the functionality of the CBLS regarding simultaneous and closely timed contingencies. In this case, a fault was simulated that tripped the utility breakers simultaneously, followed immediately by the tripping of six breakers in close succession.

- Event 1: Trip utility tie MC, MW, and ME.
- Event 2: Within 10 s of Event 1, trip fuel cell.
- Event 3: Within 10 s of Event 2, trip SG1.
- Event 4: Within 10 s of Event 3, trip TG2.

The tripping of the utility tie, fuel cell, SG1, and TG2 in sequence caused load shedding as the system did not have enough IRM to account for the loss of utility. Fig. 16 shows the system frequency response during this sequential event. The system stabilized and continued to operate as an island.

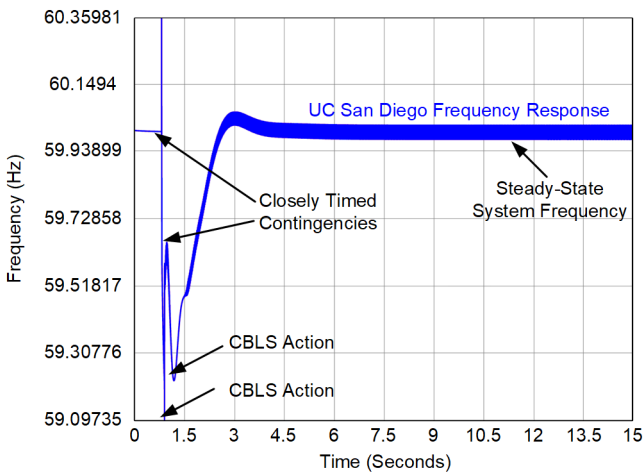


Fig. 16. Case D

VII. CONCLUSION

This paper demonstrates the design, development, and validation testing of the UC San Diego MMCS using an HIL testing method. Each function of the UC San Diego MMCS was tested prior to running system-wide tests to validate integrated operation. Since then, the system at the UC San Diego campus has been commissioned and is in service. This project augmented the UC San Diego goal of resiliency, reliability, and survivability during grid disturbances. The goal to preserve the UC San Diego critical loads from blackout during utility disturbance by islanding and prevent system blackouts using load-shedding schemes was met.

VIII. ACKNOWLEDGMENT

The authors gratefully acknowledge the contributions of Tyler McCoy and Nathan Bridges for their work on the development, testing, validation, and commissioning for this MMCS.

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X. VII. BIOGRAPHIES

John Dilliot, PE, is an Associate Director of Energy and Utilities at the University of California San Diego.

Ashish Upreti is a protection engineer at SEL Engineering Services, Inc., a subsidiary of Schweitzer Engineering Laboratories, Inc., in Pullman, Washington. He received his Bachelor's and Master's degrees in electrical engineering from the University of Idaho. He is a registered professional engineer in the state of Washington and a member of the IEEE. He has experience in the field of power system protection and automation, including power management schemes for large-state industrial power plants.

Bharath Nayak received his M.Sc. in electrical engineering from the University of Wyoming and his B.Sc. in electrical engineering from the P.E.S. Institute of Technology, India. Bharath joined Schweitzer Engineering Laboratories, Inc., in 2012 as an associate automation engineer. In his present role, he serves as a power system modeling engineer with SEL Engineering Services, Inc. His focus includes tuning and commissioning of generator control systems, validation and modeling of large-scale industrial plants, countrywide remedial action schemes, power management systems, distributed energy resource modeling, microgrid modeling, and hardware-in-the-loop testing.

Krishnanjan Gubba Ravikumar received his M.S.E.E. degree from Mississippi State University and his B.S.E.E. degree from Anna University, India. He is presently working as a senior engineer at SEL Engineering Services, Inc., a subsidiary of Schweitzer Engineering Laboratories, Inc., in Pullman, Washington, focusing on the design, development, and testing of special protection systems. His areas of expertise include real-time modeling and simulation, synchrophasor applications, remedial action schemes, power management systems, and power electronic applications. He has extensive knowledge of power system controls and renewable distributed generation. He is a senior member of the IEEE and a member of the Eta Kappa Nu Honor Society.

Case Study: Implementing a Microgrid Protection and Control System for Avista's Shared Energy Economy Project

John Gibson and Michael Diedesch, *Avista Corporation*

Tyler McCoy, Niraj Shah, Tim George Paul, and Ashish Upreti, *Schweitzer Engineering Laboratories, Inc.*

Abstract—Microgrids provide assurance that electric power is available using reliable, resilient, and secure solutions for maintaining energy delivery with a high level of operating efficiency. This is achieved by integrating state-of-the-art protection, automation, and control schemes along with energy storage management and load-generation dispatch strategy.

This paper describes the authors' experiences in planning, designing, developing, testing, and validating a microgrid control system (MCS) implemented for Avista's Shared Energy Economy project. This project was implemented for a university campus consisting of two buildings supplied by one 13.2 kV utility feed. Each building contains a battery energy storage system (BESS), a photovoltaic (PV) rooftop installation, a building energy management system (BEMS) with optimization capability, as well as existing protection, control, and visualization systems.

The MCS serves as the protection, control, and monitoring layer for all assets within the extent of the microgrid, providing several different modes of successful microgrid operation: high-speed island detection and decoupling, grid-connected optimization mode, islanded mode operation, distributed energy resource (DER) and load management schemes, and automatic synchronization to the grid.

Details of system objective, design challenges, hardware selection, designed functionality, and communication and cybersecurity aspects are discussed, and results from controller hardware-in-the-loop (cHIL) testing are presented.

I. INTRODUCTION

The Washington State Department of Commerce's vision to promote clean energy via a grant to Avista Corporation is leading to innovative work on electric microgrid projects. Avista's pilot project of a microtransactive grid using a shared energy economy model focuses on demonstrating how distributed energy resources (DERs) can benefit consumers, prosumers, and the distribution system by orchestrating the operation of groups of assets based on system conditions and economic signals. The project and its studies will aim to develop use cases for efficient and reliable sharing of resources while maintaining grid resiliency.

A shared energy economy model can best be explained with an example from the transportation industry. To start a taxi company a decade ago, one would have needed a fleet of cars, a staff of drivers, and the resources required for a dispatch center. An individual or an entity owned the resources and required customers to pay for the services. Today, the industry is built on a shared economy model where anyone who owns a vehicle can share it to provide a service to a group connected

through the internet. Multiple individuals bound by a common set of taxi service rules now participate in a common market to share the cost and benefits. What would the shared economy model or the participation model mean for the energy industry?

Microgrids are small electrical grids capable of islanded operation separate from the main utility grid. These grids include high percentages of distributed power electronic energy sources including photovoltaic (PV) and battery energy storage system (BESS) sources. The fault ride-through capacities of these energy sources are smaller than those of conventional rotating energy sources. A microgrid control system (MCS), such as the one discussed in this paper, is used to address these inherent problems in a microgrid. The primary role of an MCS is to improve grid resiliency. Another objective of this project is to design an advanced, scalable, powerful, yet economical MCS solution that can be easily repeated by utilities as DERs become more prevalent. This MCS facilitates the sharing and optimization of DERs to improve building efficiency, renewable integration, grid coordination, and transactive energy use.

This paper details the system objectives, design challenges, hardware selection, designed functionality, communication and cybersecurity aspects, and results from controller hardware-in-the-loop (cHIL) testing. The design and optimization goals of the MCS are also discussed. In addition to improving grid resiliency, an MCS facilitates economic value exchange by sharing and optimizing the DERs and allowing transactive energy use while operating in parallel with the utility.

II. MICROGRID FUNCTIONALITY OVERVIEW

The Washington State University (WSU) Spokane campus was chosen for the pilot microgrid for several reasons, one of which was the switching abilities of the existing infrastructure.

Fig. 1 shows an overview map of the microgrid power system and the point of interconnection with the utility.

The point of common coupling (PCC) between the microgrid and utility includes an automatic transfer switch (ATS). The ATS includes a voltage-based automatic transfer scheme programmed in an intelligent electronic device (IED) to switch between the two available utility sources. The site includes campus building loads. The building energy management systems (BEMS) will be integrated into the MCS.

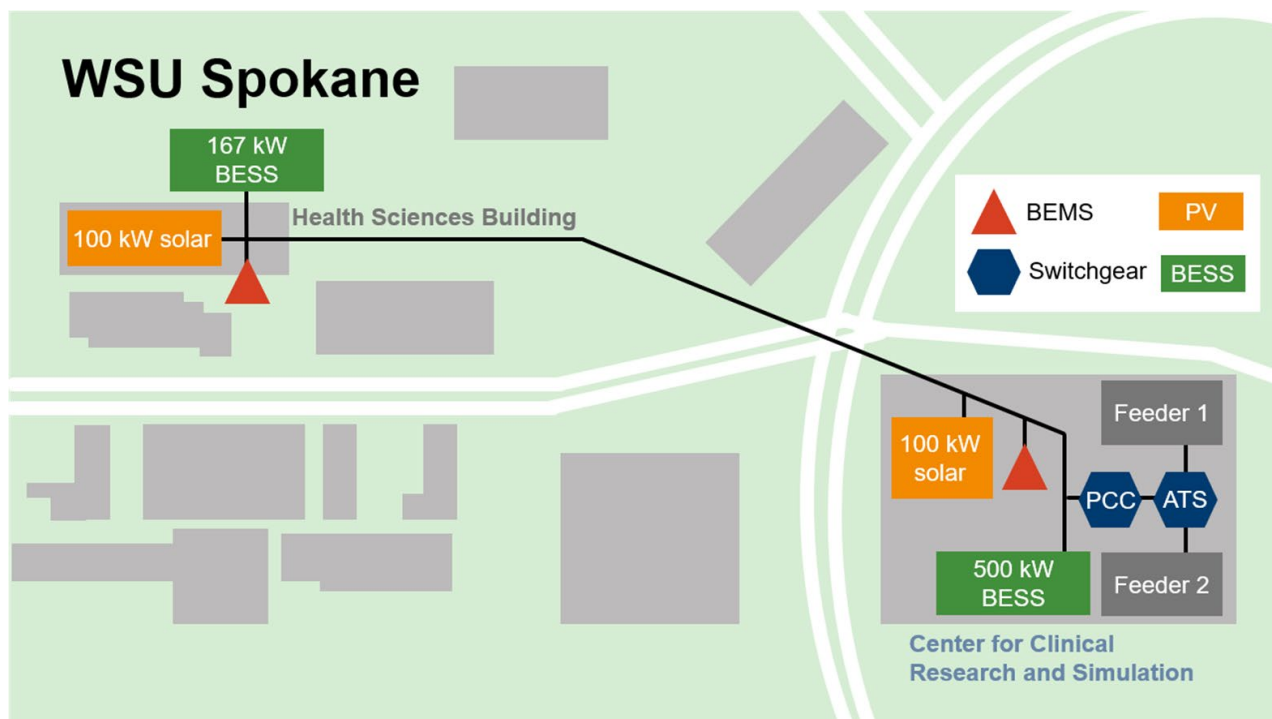


Fig. 1. Microgrid power system overview map

The site is strategically located so the project partners can collaborate on future research. The microgrid power system consists of two islands (north and south).

Each microgrid island will have one BESS, the south one (BESS 1) with an aggregate dc capacity of 756 kW/1,506.6 kWh, and the north one (BESS 2) with 168 kW/334.8 kWh. The BESS 1 inverter is rated at 500 kVA and the BESS 2 inverter is rated 250 kVA. There is also PV generation of 100 kW at each island. There are no rotational energy sources such as diesel generation connected to either island.

Fig. 2 shows the simplified one-line diagram of the proposed microgrid.

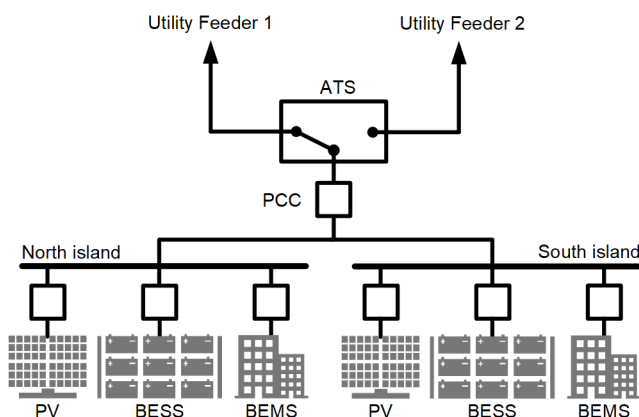


Fig. 2. Simplified one-line diagram of proposed microgrid

III. MCS

All hardware devices chosen for the MCS are protection-class substation-hardened equipment with extended temperature range, shock resistance, electromagnetic

immunity, and static discharge capabilities. Fig. 3 shows the MCS architecture using a layered and segmented representation. This architecture provides a logical representation of the MCS and is used to identify and define the security controls and patterns of the network design.

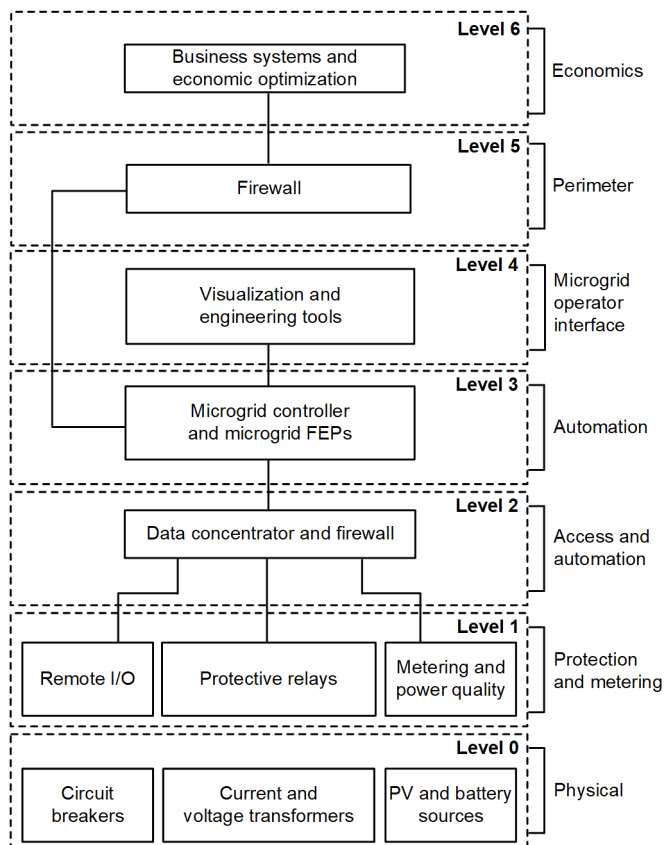


Fig. 3. Segmented MCS architecture

Level 0 comprises equipment within the microgrid power system. This equipment includes the circuit breakers, switchgears, instrument transformers, and energy sources. The devices at Level 0 integrate into the MCS via the devices in Level 1, which include protective relays, remote input/output (I/O) modules, and metering devices. The protective relays are required to protect the power system assets from damages during a power system fault. These protective devices are typically located at each PV site, BESS site, and the PCC between the utility and the microgrid. Apart from overcurrent protection, the protective relay at the PCC is also capable of localized controls, such as automatic transfer scheme or a synchronism-check element (25). Automatic synchronization schemes programmed in protective relays (A25A) adjust slip and voltage differences by having the MCS send raise or lower signals to a single DER. The meters at the electrical load center provide information about the electrical loads.

Level 2 of the MCS includes a data concentrator (DCON) that collects data from the protective devices, meters, and I/O modules and passes the information on to the devices in the upper levels. These data concentrators also serve as protocol translators and communicate securely with the devices at Level 2 using a standard set of protocols. This design allows the processing burden associated with the protocol translation to be limited to Level 2 devices. The stateful deny-by-default firewall (FW) at this level improves system awareness and provides the network segmentation explained later in this section.

Front-end processors (FEPs) provide great flexibility for microgrid scalability. They serve as the primary communications interfaces for all devices. The FEPs at Level 3 communicate with the data concentrators at Level 2 and collect information pertaining to the power system topology, load statuses, and DER statuses. The FEPs also communicate with external control systems, such as the distribution management system (DMS) and distributed energy resource management system (DERMS) at Level 6, to provide MCS visibility for operators. In certain cases, the FEPs also receive DER optimization control signals from the DERMS. It is important to maintain a single point of communications and a single control interface between the different control systems and the DERs in the field. The FEP in Level 3 serves as the data bus or the single point of communications integrating the different control systems. The MCS is always aware of the present state of the power system topology, fault conditions, and overall health of the DERs. Regardless of its mode of operation, the MCS continuously communicates the status of the power system and the DERs to the DERMS and the DMS. The DMS has the capability to shut down the MCS if required. Section IV of this paper explains the different modes of operation of the

MCS. The microgrid controller (MGC) at Level 3 is the brain of the MCS. It runs algorithms that make decisions and sends commands back to devices at Level 1.

Level 4 equipment includes a human-machine interface (HMI) that provides graphical system representations, access to real-time data, the ability to override points in a system, an interface with external management systems, and access to all supervisory monitoring and control functions. These visualization systems properly collect, manipulate, and present power system data as usable information. These systems enable operators, maintenance staff, and engineering staff to operate and manage the microgrid system and diagnose system events and minimize unnecessary maintenance. An electric power engineer can use these data for post-event analysis or fault diagnostics. Level 5 is the security perimeter that allows the MCS to communicate with other control systems, such as the DMS and the DERMS in Level 6. The MCS is designed such that any failure of equipment in Level 5 or Level 6 has no effect on the functionality of the microgrid.

A. MCS Network Architecture

Extreme care must be taken in designing a network for a critical infrastructure such as an MCS [1]. Designs involving a flat network reduce the number of switches and routers on the network, but they have drawbacks including poor security and lack of scalability. A segmented network approach was followed in designing the network for the MCS in this project. It is best to segment a network that follows the security principle that devices should communicate only with other devices that have a need to share data.

Network segmentation allows for fewer end points in a subnet, making it easier to set up end points for each type of multicast traffic. In addition, any broadcast traffic that is not filtered is much easier for devices to handle in a segmented network.

An intruder who gains access to a flat network can communicate with all devices on the network. On a segmented network, an intruder has access to only a portion of the network and must also gain access to individual subnets to cause significant damage.

Network management is simpler and more efficient when the network is segmented. Misconfigurations or device failures on a flat network are harder to detect, isolate, and fix. By segmenting the network into smaller, more manageable sections, the design implemented for the MCS can provide better security, resiliency, and control. A segmented network design also provides the distinct advantage of network scalability. Additional devices can be easily integrated into the network by extending the existing subnet with new device addresses or by adding a unique subnet for the new devices.

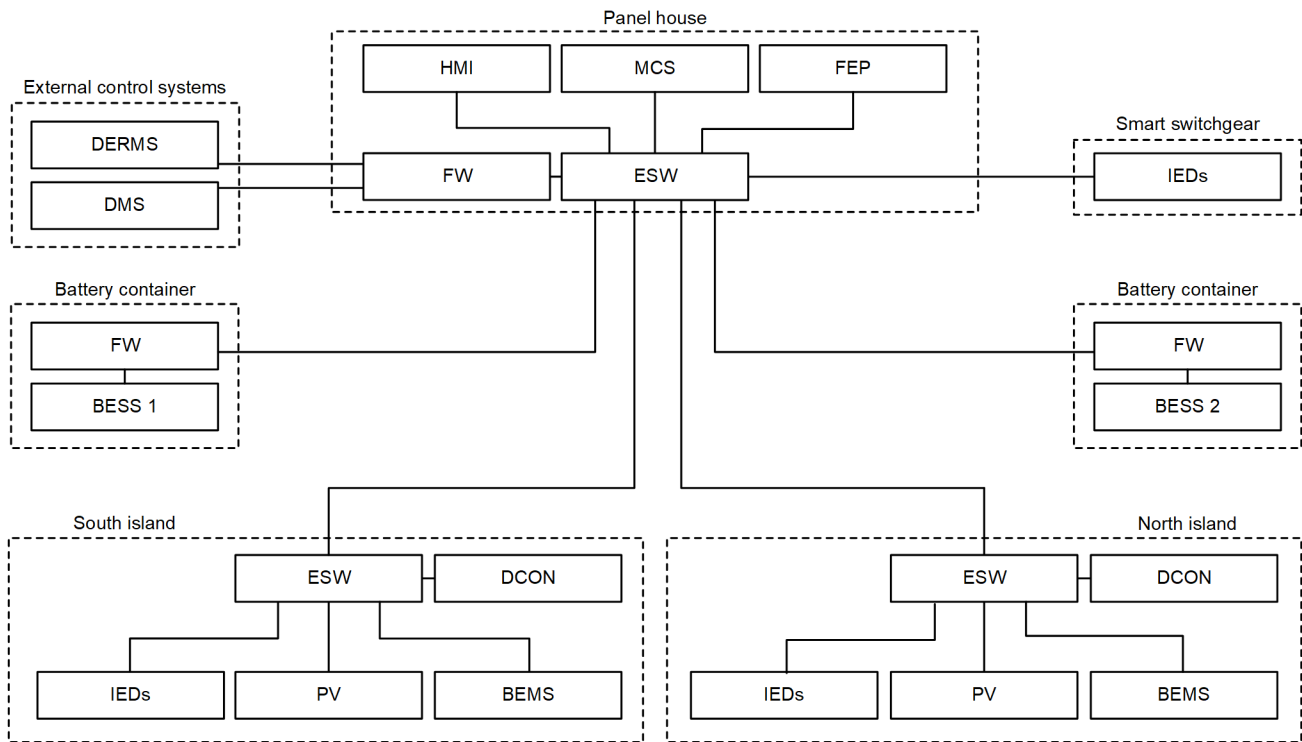


Fig. 4. Overall MCS network architecture

Fig. 4 shows the overall implemented architecture of the MCS and how typical DER assets and loads integrate with the central controllers. A typical PV, battery, and building site include Level 0, Level 1, and Level 2 devices. The FW device at Level 2 can be used to establish network segmentation between the different physical locations. The central control room (CCR) includes Level 3 and Level 4 devices. The FW at the CCR is the Level 5 FW that can be used to establish the MCS security perimeter. Relays in the smart switchgear and the external control system have dedicated fiber links to the microgrid CCR. The FWs at the ingress and egress points of each subnet allow rules to be established where multicast traffic within a subnet is contained within that portion of the network, reducing device load caused by multicast traffic. For example, rules can be generated on the segmented network to allow certain types of traffic to flow from the PV site to the CCR and not between the PV site and the battery site.

B. Data Flow Diagram

Data required for the operation of the MCS are collected from Level 1 equipment. The MCS also communicates certain important information with other control systems in Level 6. These data can be classified into high-speed data and low-speed data categories. Metering information, such as real power, load status, power factor, and voltage values required for calculating the actions, is not necessary at high speeds. Collecting all data at high speeds would require wide communication bandwidth, demanding additional communication infrastructure. In addition, the segregation of data into high speeds and low speeds has been proven to yield better performance on both large-scale and small-scale projects [2] [3] [4]. All digital and

analog data used by the MCS for calculations are based on speed and reliability. The MCS monitors the communications for failure at different levels of the network and selects the best data available. The final data used in the controller algorithms are chosen based on data quality. Data validation is accomplished by comparing the two sets of data and ensuring that neither is outside a given threshold from the other.

Data required for the operation of the MCS are collected from field devices using the Network Global Variable List (NGVL), IEC 61850 Generic Object-Oriented Substation Event (GOOSE), Distributed Network Protocol 3 (DNP3), and Modbus protocols. DNP3 and Modbus are traditional open-source protocols that operate on a client-server-based architecture, while GOOSE and NGVL operate as peer-to-peer protocols.

Fig. 5 shows the communications data flow diagram of the MCS. Communications between the DCON in the field and the centralized FEPs in the CCR will include both high-speed and low-speed data. The NGVL protocol is used as the primary protocol. The NGVL protocol allows data to be transmitted in a peer-to-peer format, using a configurable and flexible cyclic transmission interval between the DCONs and the FEPs. Message confirmations from remote devices using peer-to-peer protocols are required for the communications integrity. This can be achieved by establishing a data echo signal to ensure successful transmission. Network bandwidth allocations and timing of echo response signals should be taken into consideration while designing the data flow between devices using peer-to-peer protocols. Future provision for a second Open FMB protocol is also considered in the project design.

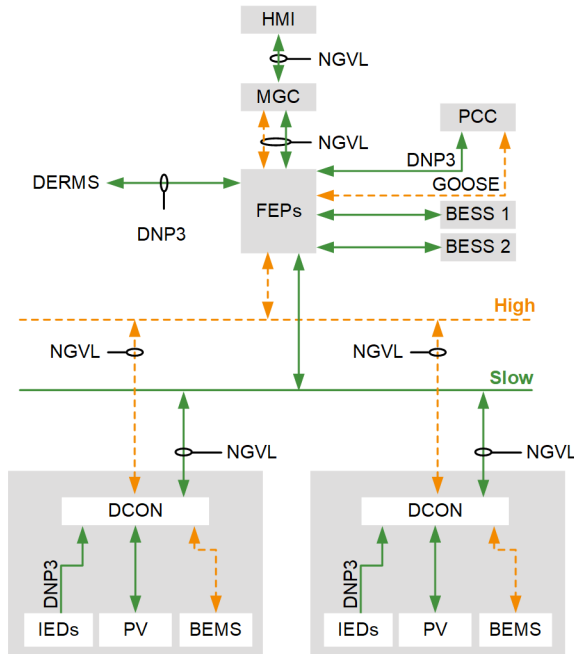


Fig. 5. Communications data flow diagram

C. HMI

The following sections show the HMIs developed for the project. This HMI (Fig. 6, Fig. 7, and Fig. 8) is also replicated at the DMS system for seamless integration with the current Avista DMS system for easy operation for the digital outputs (DO). Fig. 6 shows the overall HMI. The HMI includes a single-line diagram of the power system. This also allows the operators to view the status of each DER, including information such as state of charge (SOC), asset status (running, stopped, charging, or discharging), active power, reactive power, voltage, and frequency of the entire system in one glance. This also provides information to the operators regarding status of the MCS and current mode of operation. When the MCS is islanded, the total SOC and available operation time is also included as part of this screen.

1) Overall HMI

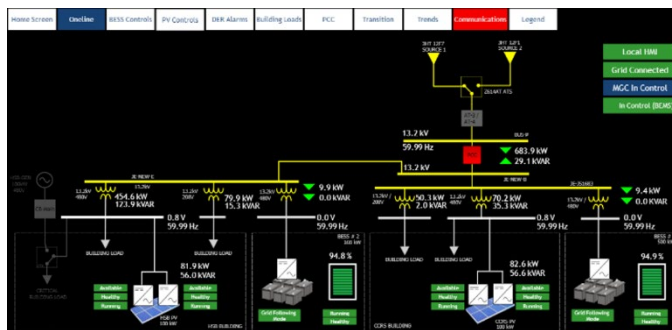


Fig. 6. Overall HMI

2) DER Status Screen

The DER status screen includes information such as auto or manual mode, along with the ability to manually control each of the DERs. This screen also features the ability to set the outage duration for the given utility so the MCS can manage the system loads by curtailing or restoring them to meet the

user-enterable set point. There is a unique screen for BESS and PV control.

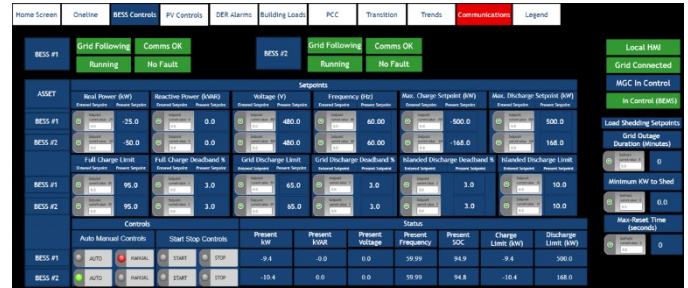


Fig. 7. DER control

3) MCS Control

The MCS can operate in multiple scenarios, such as grid-connected or islanded. There are three transition periods during these stages, and they can be automatically or manually controlled using the MCS control screen. This screen also provides status while those transitions are in progress. The transition modes, such as automatic reconnect dead, automatic reconnect live, and black-start campus, can be set using this screen. Each of these transitions are explained in further detail in later sections.

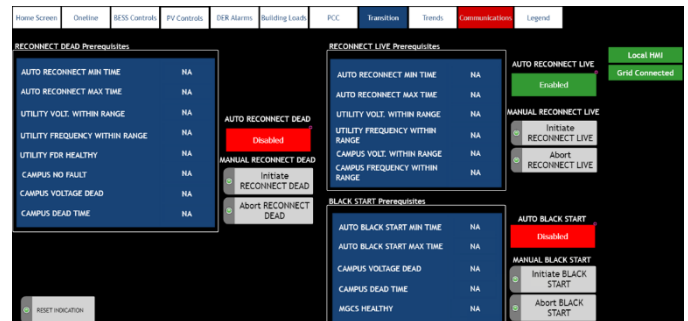


Fig. 8. MCS control

IV. MGC OPERATION

The microgrid power system is capable of operating in parallel with the utility in grid-connected mode and operating completely independently of the utility in islanded mode. The primary role of the MCS is to maintain power system stability whether operating in islanded mode or in grid-connected mode. It maintains the power system within the stability boundaries, or the boundary conditions set by the operator, by limiting the impact of user error or other third-party control decisions for optimization and protecting the DER assets.

The Avista WSU Spokane campus' MCS does not include seamless islanding due to project requirements and will either intentionally (during testing) or unintentionally (due to fault conditions) black out to initiate islanded mode. The MCS will manage the microgrid asset by allowing DERMS Spira controls to manage loads, dispatch PV inverters, and dispatch BESS energy during grid-connected mode and assume full control during islanded mode the MCS will provide monitoring, visualization, and operator control during both grid-connected and islanded modes.

A. Grid-Connected Mode

During grid-connected operation the MCS passes on commands from the DERMS server based on DER optimization and economic operation decisions. The FEPs communicate the present state of the power system topology and overall health of the DERs to the DERMS. When DERMS is not available, the MCS continuously monitors and tracks the status of PV generation and present loading and load-status information. The MCS will then charge the batteries to their grid-connected maximum and await either islanded mode operation or return of DERMS. Because the MCS continuously monitors the topology of the power system, dispatch control signals are dynamically recalculated under all system bus configurations.

B. Islanded Mode

The MCS communicates with the smart switchgear to collect breaker status indications and voltage and current measurements to detect the loss of a utility tie. Although possible, seamless islanding of a microgrid was not applied for this use case. Automatic decoupling schemes using frequency, rate-of-change of frequency, and directional power elements were investigated and can be enabled in future stages of this project. These types of decoupling schemes are required to prevent damage to the microgrid components during a disturbance on the main utility grid.

After a microgrid island is formed, the MCS modifies the mode and dispatch of islanded generation and loads to keep the microgrid stable. The system keeps the frequency and voltage within allowable parameters for any number of islands. Load-shedding management is performed to disconnect loads in the microgrid after the formation of an island. This is to avoid cold load pickup that may trip the BESS asset. This also includes incremental load additions after the black-start process is completed. The MCS places BESS with greater SOC in terms of kWh in grid-forming mode and provides the voltage and frequency set-point reference for an island such that the PV sources can start providing power to the islanded microgrid. Once all available assets are energized, the MCS energizes all critical loads incrementally, and following critical load restoration, the MCS dispatches any excess energy in the islanded system to the noncritical loads based on the results of the SOC calculation. If there is additional energy available, the second grid-following BESS can be charged prior to PV curtailment.

C. Frequency Control

When the microgrid is islanded from the utility the MCS will select one DER for isochronous operation. The selected DER will regulate its power output to maintain a provided frequency set point on the island. An isochronous priority is assigned to each BESS based on available SOC in kWh.

Table 1

DER Mode Selection for Frequency and Active Power Control

DER	Grid-Connected	Islanded
BESS 1 and BESS 2	Grid-following Constant power (P) and (Q)	Grid-forming Grid-following*
PV 1 and PV 2	Constant power (P) and (Q)	Constant power Volt-VAR mode

*Only one grid-forming allowed in any given island

D. Voltage Control

When the microgrid is connected to the utility, the MCS does not control the voltage of the power system. In this case, all DERs at the campus will produce or consume reactive power based on a dispatch signal received from DERMS, or by an autonomous operating mode, such as volt/VAR, also known as voltage droop. The DERs will be either in a voltage droop mode or a constant power mode of operation when the microgrid is connected to the utility.

When the campus is islanded from the utility, the MCS will attempt to regulate voltage at the main bus at the PCC by adjusting the reactive power output of all participating DERs.

The MCS will command participating DERs to the following modes based on grid-connected or islanded operation.

E. BESS Strategy

During grid-connected operation, the BESS for the Avista microgrid will be primarily used for experimentation to achieve the use case evaluation outcomes that Avista has agreed upon with the Washington State Department of Commerce. Examples include optimizing PV utilization, distribution power quality and efficiency, and demonstrating participation in wide-area grid services.

While the campus is islanded, the BESS will provide backup power to a subset of loads on the WSU campus for as long as possible given the amount of load requested, battery SOC, and PV generation available. The BESS is controlled by its dedicated controller, which accepts set points from MCS.

The BESS control strategy is summarized in Fig. 9. Depending on the state of energy, the BESS will have three distinct areas of operation, which will in turn reflect the availability of BESS to charge or discharge energy. Each area is bounded by user-settable limits. The user-defined HMI-settable limits are defined as follows:

1. Full charge limit
2. Grid-limit
3. Islanded discharge limit

BESS can be controlled in Areas 1 and 2 during grid-connected mode and Areas 1, 2, and 3 during islanded mode. The reserve capability limit is provided for any emergency use and auxiliary loads for the BESS. The BESS will not be permitted to operate in Area 4.

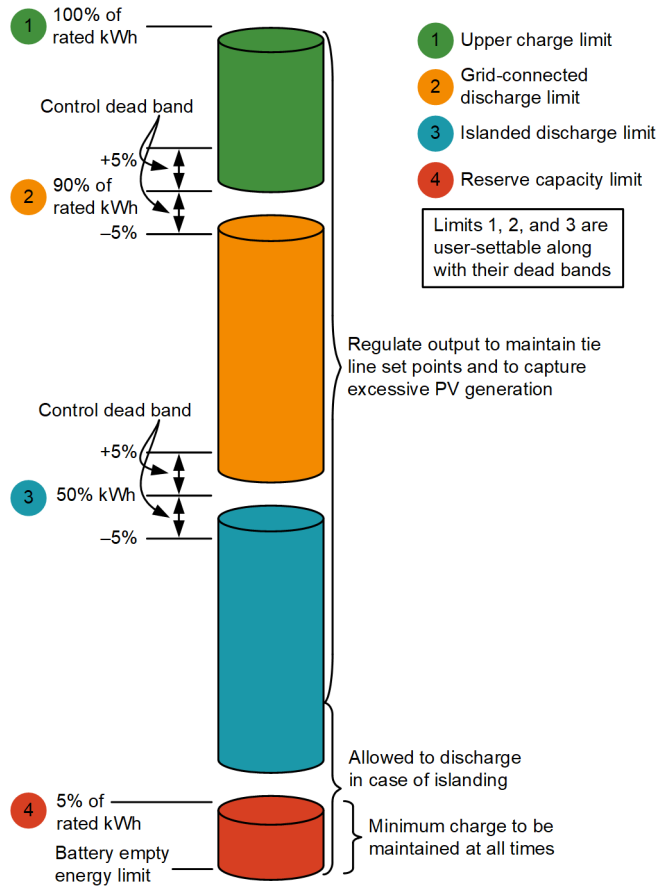


Fig. 9. Areas of operation

F. PV Strategy

There are a total of two installations of PV systems at Avista's MCS. Each PV system has two inverters with a dedicated controller accepting the power set points from the MCS. The main intent of PV dispatch is to displace the electricity consumption from the utility to evaluate smart inverter operation for the use case experiments.

The inverters have three main control modes, and they were investigated during testing:

- Constant Power mode, which generates fixed real and reactive power
- Volt-VAR mode, which regulates the grid voltage by supplying reactive power
- Frequency-Watt mode, which limits real power in case of high frequency

All PV output will be directed to serve the load or charge the BESS in the Avista MCS electrical network. The inverters will generate maximum electrical power based on irradiance and temperature. During grid-connected mode MCS will pass the controls from DERMS as long as it is within the use settable limits. PV output can be curtailed if no further loads are available to restore or BESS is fully charged and cannot absorb excess PV generation.

V. MCS TRANSITIONS

Unplanned islanding can happen due to a sudden loss of utility voltage, fault at the utility substation, or the opening of circuit breakers or switches in the utility system upstream from the microgrid.

These scenarios will likely result in a blackout. When the PCC is open, the MCS will issue a command to disconnect all DERs from the dead electrical system and set all set points to prepare for a manual or automatic black-start operation.

Once the system is blacked out, one or more of the following methods may be initiated.

A. Reconnect Dead

Reconnect dead is the process of connecting the microgrid to the utility after a blackout. This is the fastest way to restore power and operation after an event. This requires that the utility is available and healthy, and the campus has been dead for predefined time window.

The MCS will respond to a request to reconnect the dead campus to the utility by executing the following actions:

1. Confirm that the utility voltage and frequency are within healthy limits for the predefined time limit.
2. Confirm that the campus voltage is below the dead threshold for the predefined time limit.
3. Confirm via the breaker protective relay for dead bus and live utility scenario.
4. Close the campus PCC breaker to energize the campus.
5. Restore all system loads.

B. Reconnect Live

Reconnect live is the process of connecting the microgrid to the utility after a blackout, and power to the microgrid is restored. This is a seamless process that requires the utility to be available and healthy. The campus also needs to be available and healthy for predefined time window.

1. The MCS will respond to a request to reconnect the dead by executing the following actions:
2. Confirm that the utility campus to the utility voltage and frequency are within healthy limits for the predefined time limit.
3. Confirm that the campus voltage and frequency is within in healthy limits for the predefined time limit
4. Confirm via the breaker protective relay for live bus and live utility scenario..
5. Close the campus PCC using slip compensated algorithm to close when system parameters, such as voltage, frequency, slip, voltage difference and angle difference, are all within range.
6. Restore any system loads if curtailed during islanded mode are automatically restored following the PCC breaker close with mode transitions for the DERs assets.

C. Black-Start Campus

Black starting the campus differs from the Reconnect Dead Campus procedure because this sequence will start the campus under its own power using available DERs. This method will allow the campus to be restored and operate during a utility outage. If both the black-start campus and reconnect dead are set in automatic mode, the reconnect-dead sequence will start if the utility voltage is healthy and black-start campus will start if the utility is not available.

The MCS will respond to a request to black start the dead campus by executing the following actions:

1. Confirm that the campus voltage is below the campus dead threshold for a predefined time.
2. Trip all DERs, and noncritical loads from the campus island.
3. Enable BESS with highest SOC in grid-forming mode and establish system voltage and frequency.
4. Bring all DER assets online gradually.

Fig. 10 shows the MGC operational flow chart.

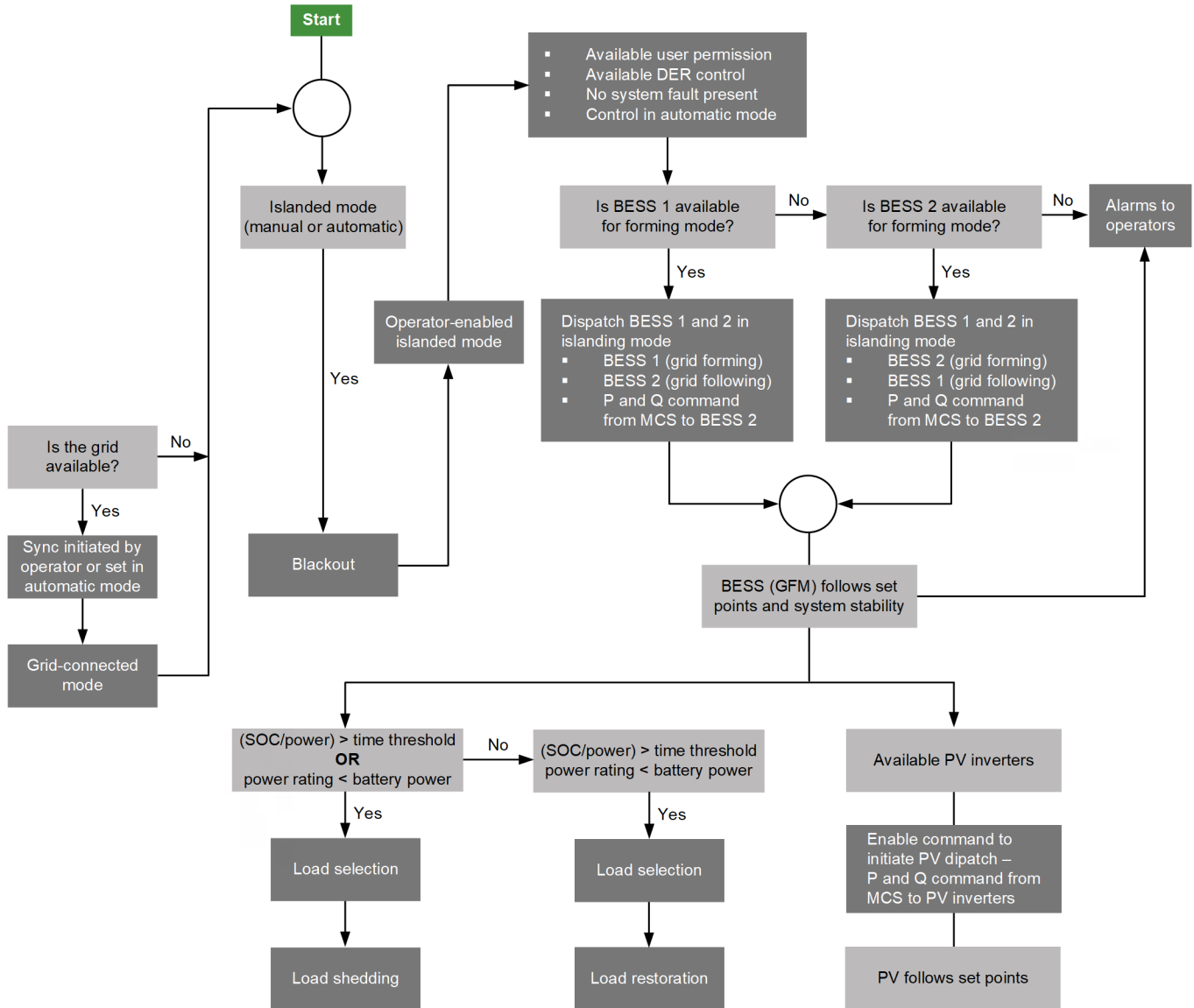


Fig. 10. Simplified MCS SOE flow chart

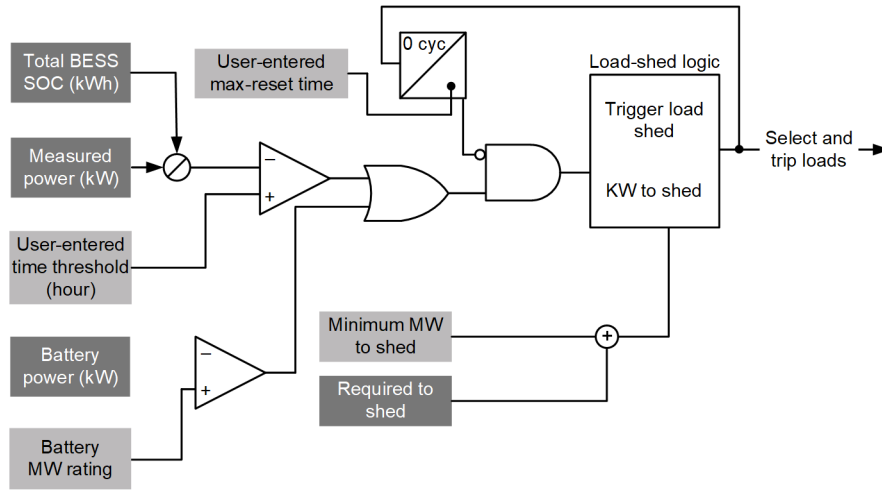


Fig. 11. Load management algorithm

VI. AUTOMATIC LOAD MANAGEMENT

The MCS performs automatic load management to equalize the load with generation for grid stability. For this project, access to individual load breakers was not available so a load management algorithm was utilized to manage system loads. Fig. 11 shows the load management algorithm where additional loads are shed if available SOC limits the operation of the MCS outside of user-defined outage time, whereas if calculated outage time is smaller than available SOC, loads are restored. The load restoration or curtailment is based on user-defined priorities that can be set from the HMI, as seen in Fig. 12.

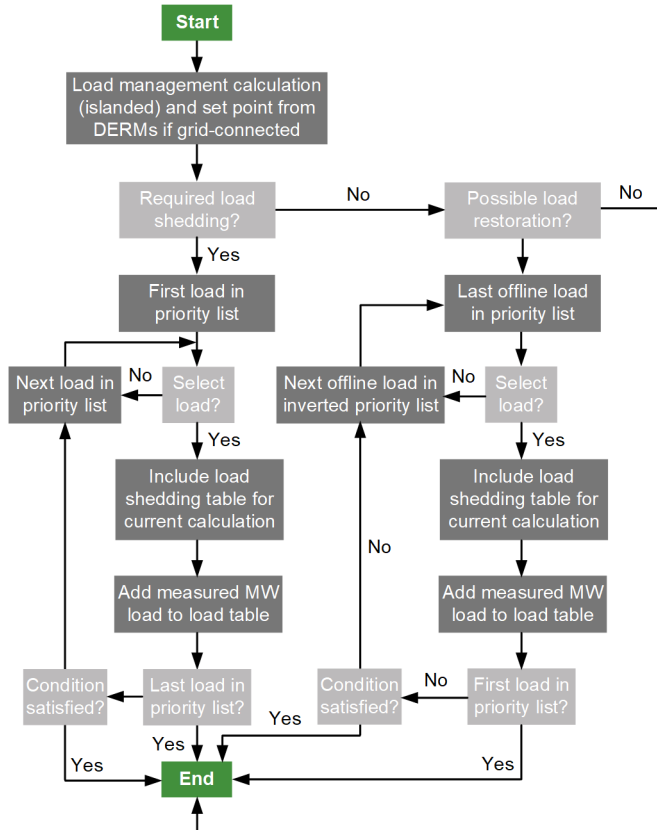


Fig. 12. Load selection logic

VII. MG PROTECTION

Avista's microgrid protection is designed to protect the campus during grid-connected mode and islanded mode. The breaker protective relay installed at the PCC will be the primary protective device along with fuses and DER assets. The system loads, such as variable-frequency drives (VFDs), also have built-in protection from any abnormal operation. Fig. 13 shows the protection scheme and elements implemented for Avista's MCS. The Yg/Yg transformer is used for interconnecting the DERs since this connection supports better ground faults and detection, and also prevents overvoltage induced by LG faults [5].

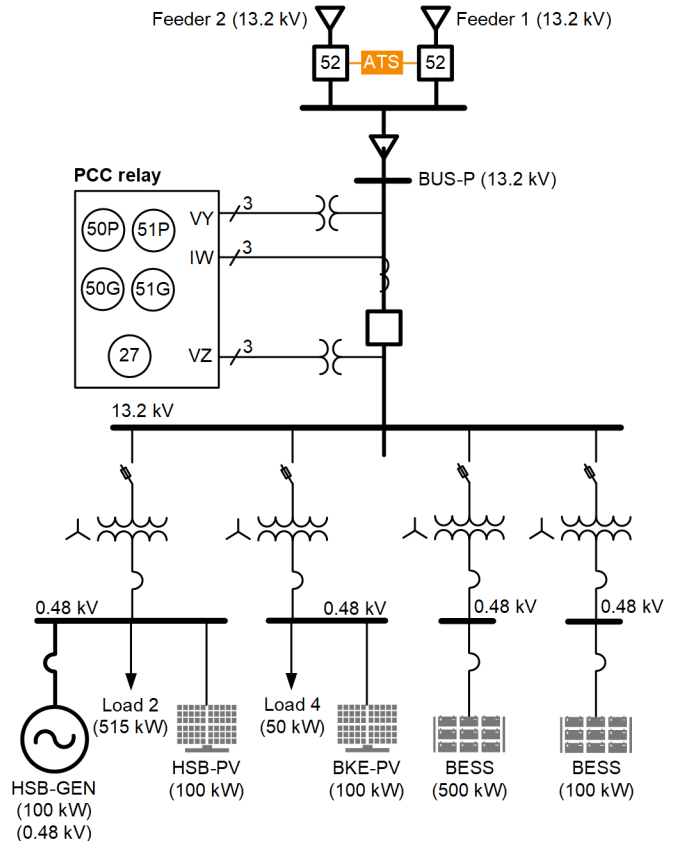


Fig. 13. Protection scheme and elements

A. Grid-Connected

During grid-connected mode, both internal and external faults can occur. The internal faults, which can occur in the microgrid network during grid-connected mode, will have sufficient fault contribution from the utility. The overcurrent elements enabled on the breaker protective relay at the PCC will detect those faults and protect the microgrid network components (transformers, cables) by tripping the PCC breaker. Phase time-overcurrent (51G1), phase instantaneous (50P1), residual-ground time-overcurrent (51S2), and residual-ground instantaneous (50G1) were enabled in coordination with transformer's high side fuses for phase and ground fault protection.

It was confirmed that DERs will stop their contributions independently for the prolonged internal faults on the microgrid 13.2/0.48 kV network and provide a faulted status to the MCS.

For external faults on the utility side distribution network, the PCC relay cannot detect low fault current contributed from online DERs, hence, the relay is insufficient for making tripping decisions. This can be investigated in the future for this project.

For close in external faults, it was confirmed that all the DERs will stop their contributions and alarm the operators based on the fault detection and will not restart until they receive the START command from the MCS.

B. Islanded

When the MCS is islanded, overcurrent elements enabled on the breaker protective relay will be unable to protect the islanded grid. The fuse in the high side of transformers will not operate for the fault on 13.2 kV buses because of insufficient contribution from the DERs. It was confirmed DERs will stop their contributions independently for the faults on the microgrid's 13.2 kV or 480 V networks.

The undervoltage (27) element supervised was utilized with the PCC breaker status as backup protection of the microgrid for faults in the MCS network. The delay on the 27 elements will incorporate the response time of the DERs after the instant of islanding and the time required by the DERs to clear the fault on the 480 V side. If the undervoltage condition rides through the delay on the 27 element, the breaker protective will give the command to isolate all the DERs feeding the faults via MCS.

VIII. HARDWARE-IN-THE-LOOP (HIL) TESTING

The main objective of real-time HIL testing of this concept microgrid is to analyze the combined performance of the MGCs and other control systems, such as DERMS or BEMS. A real-time simulator allows for dynamic modeling of the microgrid

and the utility power system interconnection with a simulated small-time step to test all closed-loop controls. The power system model built-in the real-time simulator will represent the Level 0 equipment in the microgrid. The real-time simulator I/O module allows the dynamic model to interface with relays, meters, and other equipment in Level 1 and higher levels.

Significant time and effort are devoted to configuring and testing the power converter models and communications interface between different components of the MCS.

A. Model Development

The model developed for real-time digital simulator testing will represent the complete system based on the simplified one-line drawing approved by Avista. The data required for modeling different power system components (generators, transformers, distribution lines and cables, and loads) shall be provided by Avista. Appropriate assumptions were made based on its previous modeling experience at places where there are insufficient data.

B. PV Validation

The objective of this section is to show the model development and validation for the two developed real-time digital simulator 100 kW PV systems.

Fig. 14 shows the schematic of a two-level voltage source converter (VSC) grid-connected PV system. The main building blocks of the PV system are an array of panels, a VSC, and interface reactors. The PV array is comprised of a parallel and series connection of strings of modules. The PV array is connected in parallel to the dc-link capacitor (CAP dc) and the dc-side terminals of the VSC.

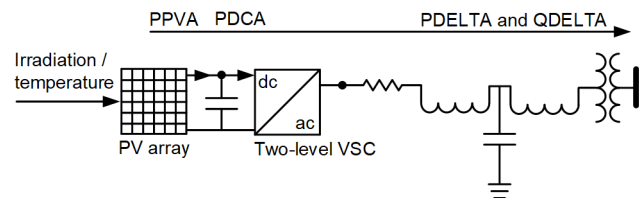


Fig. 14. Typical circuit of a PV system

The PV inverter is modeled as a VSC using an average converter model with low loss. Typically, the topology of actual control systems is not made available by the manufacturer. For this reason, a traditional direct-quadrature (DQ) current mode VSC controller strategy was adopted [5]. The interface reactors connect the ac-side terminals of the VSC to the corresponding phases of the PCC.

The PV module is a function of three inputs: irradiance watts per square meter (W/m^2), temperature ($^{\circ}\text{C}$), and module dc voltage. To analyze the effect of external factors on the PV

power, a PV module needs to be simulated to represent semiconductor material characteristics. Then, a set of curves must be developed by varying the irradiance input to analyze the power versus voltage curve and current versus voltage curve (Fig. 15).

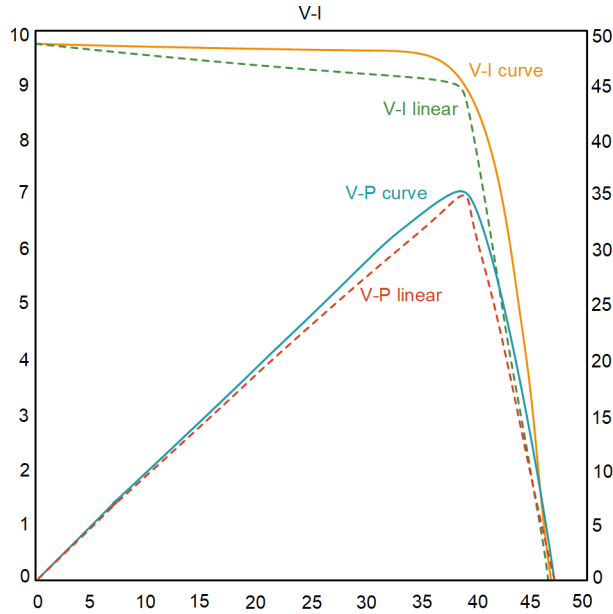


Fig. 15. PV curves

C. BESS Validation

The objective of this section is to show the model development and validation for the developed real-time digital simulator BESS systems. To validate the BESS control and response. The control strategy is based on voltage control of a VSC, which is applicable to grid-connected and islanded modes of operation. The control strategy regulates voltage and frequency when the BESS is not connected to the grid and follows the active and reactive power command when connected to the grid.

A BESS load acceptance test was performed with field equipment. The BESS system is disconnected from the utility grid and placed in islanded mode of operation. A load of 0.5 MW is added, and the frequency settles around 60 Hz (Fig. 16). The frequency waveform of the simulated model (Fig. 17) is compared with the waveform obtained from the field to validate the system performance.

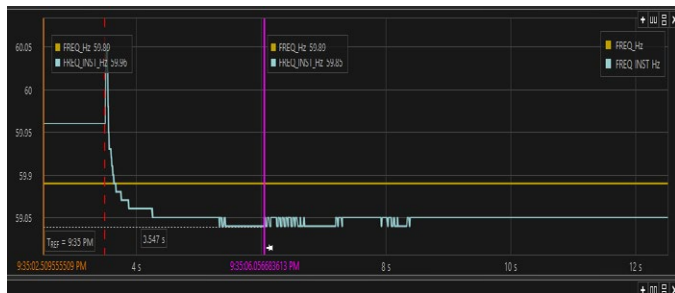


Fig. 16. Field result

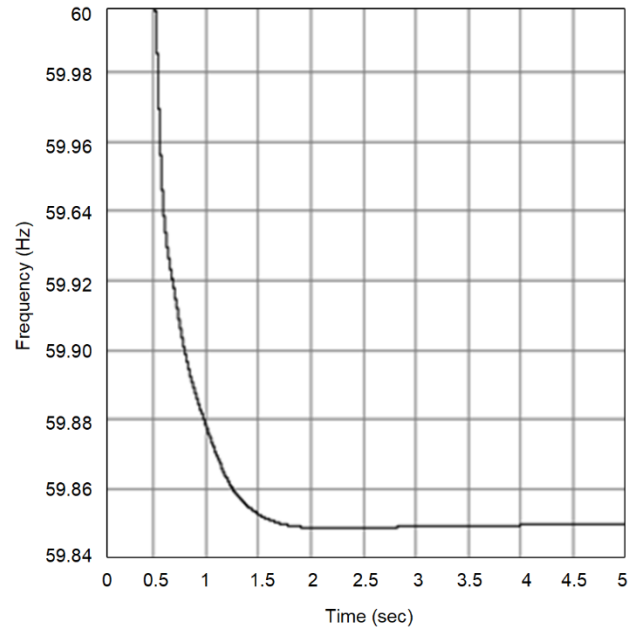


Fig. 17. Simulated result

IX. DYNAMIC TESTING AND ANALYSIS

Prior to installation of the MCS at the facility, complete factory acceptance testing (FAT) was performed in a laboratory using a real-time digital simulator model created as described above to validate the functionality of the MCS. The real-time model also permitted the MCS to be tested as a live simulation in the user-observed FAT. This was accomplished by connecting the MCS to the simulation hardware as shown in Fig. 18.

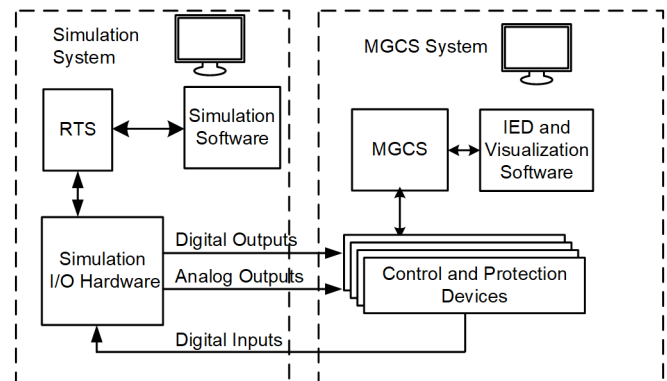


Fig. 18. System simulation setup

Several studies were done using the model, providing insight into system operation, vulnerabilities, and the system's response for contingency events. Studies were also completed to determine optimal set points for the MCS. This section provides details for witnessing microgrid states and transitions handled by the MCS as described in Section V.

A. Case 1—Reconnect Dead

The objective of this testing was to demonstrate the operation of the MCS when the operator initiates a reconnect-dead command from the MCS HMI. For this test, initially, the PCC breaker is opened, and the campus blacks out. The MCS responds to the request to reconnect the dead campus to the utility by executing the functions as mentioned in Section V. Fig. 19 shows the system response after the sequence is initiated. The MCS closes the PCC breaker, and the campus is energized by the utility. The MCS starts the BESS in the South and North islands in grid-following mode with charging set points of 130 kW and 0 kW, respectively. Then the PVs are started in PQ mode and are dispatched to produce maximum power of 100 kW each. In grid-connected mode, the DERs are dispatched to maintain a fixed power factor across the PCC. Initially, the campus is dead, and after it is reconnected, the frequency is recovered to nominal. The voltage also recovers quickly to a steady state nominal value.

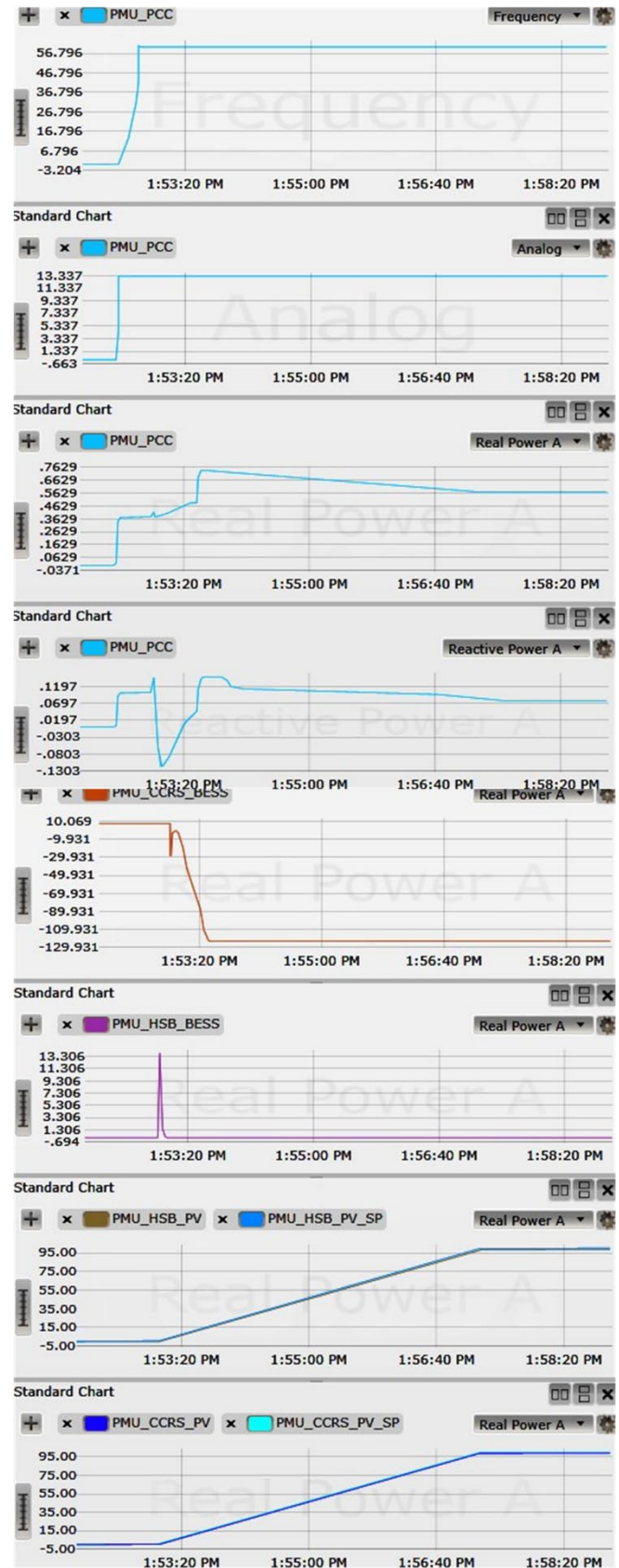


Fig. 19. Case 1—DER active and reactive power

B. Case 2—Black-Start Campus

The objective of this test was to demonstrate the operation of the MCS when the operator initiates a black-start command from the MCS HMI. For this test initially the PCC breaker is opened and the campus blacks out. The MCS responds to the request to black start the dead campus by executing the functions as mentioned in Section V. Fig. 20 shows the system response after the sequence is initiated. The MCS starts the BESS 1 in grid-forming mode and the BESS 2 is started in PQ mode after a time delay with a set point of 57 kW. The PV is started in PQ mode and dispatched to produce maximum power. The load management system adds building loads based on the BESS SOC and outage time as entered by the operator.

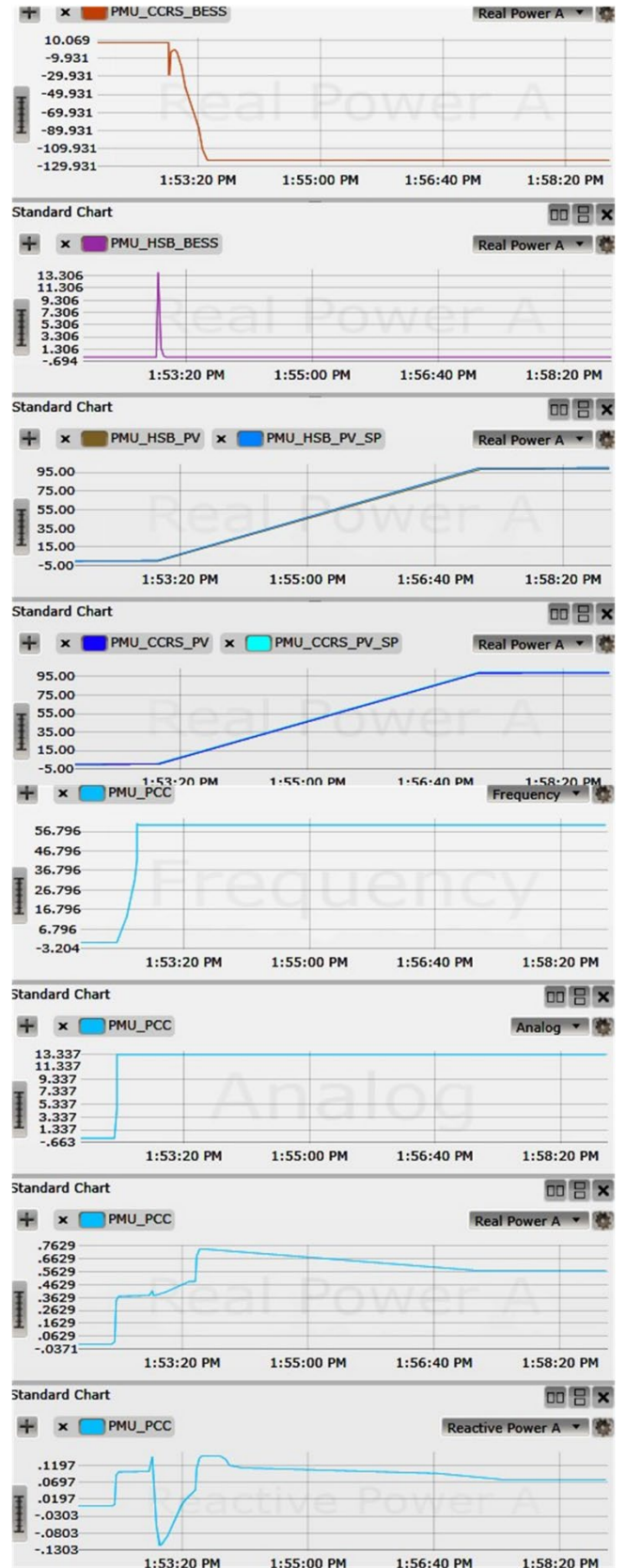


Fig. 20 Case 2—system frequency and voltage

C. Case 3—Reconnect Live

The objective of this test was to demonstrate the operation of the MCS when the operator initiates a reconnect live from the MGCS HMI after the black-start sequence is completed. For this test, the system is in an islanded state and has completed a black-start sequence. The MCS responds to the request by executing the functions as mentioned in Section V. The MCS sends a frequency bias to the BESS 1 to synchronize the PCC breaker. There is a slight frequency overshoot of 60.087 Hz after the breaker closes as shown in Fig. 21. The MCS dispatches the BESS 1 and BESS 2 with charging set points of 140 and 40 kW, respectively. The PVs continue to produce maximum power of 100 kW each. The utility import starts to increase as the MCS is charging the battery.

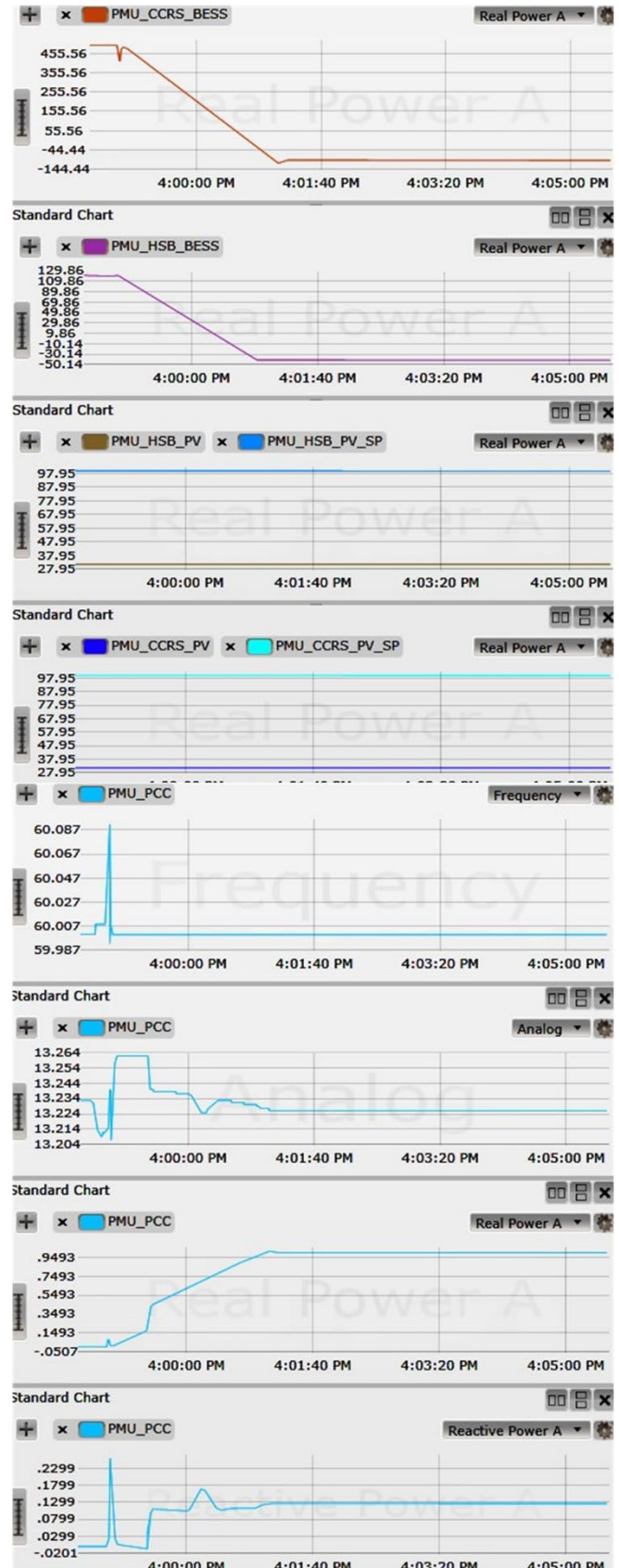


Fig. 21. Case 3—system voltage and frequency

X. CONCLUSION

This paper demonstrates the design, development, and validation testing and commissioning of the MCS implemented for the Avista Clean Energy Fund (CEF) 2 project in Spokane, Washington. Each function of the MCS was tested prior to running system-wide tests to validate integrated operation. Since then, the system at the Avista MCS has been commissioned for MCS functionality and in service.

Avista's CEF project demonstrated the benefits of a shared energy economy model for the control and optimization of DERs. The goal is to increase the use of the electric distribution system and DERs, benefiting consumers and the utility system. The MCS design for this pilot project was focused on addressing and investigating the following:

- Experimenting with various modes of microgrid operation and determining their values in a real-world scenario
- Verifying protection coordination in transitioning from grid-connected mode to islanded mode and vice versa
- Investigating advantages, challenges, and use cases of a microtransactive grid

The system presented in this paper describes the MCS functionality needed to achieve the project goals while providing safe and reliable energy service to customers within the microgrid, whether it is islanded or grid connected. This microgrid will serve as a platform for future research and experimentation related to distributed energy.

XI. ACKNOWLEDGMENTS

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XIII. BIOGRAPHIES

John Gibson, PE, received his BS in electrical and civil engineering from Gonzaga University and his master's degree in engineering management from Washington State University. He is a registered PE in the state of Washington and has worked in the electric utility industry for over 25 years. His experience in the industry consists of electric distribution planning, distribution system

analysis, and smart grid technology projects. He was Avista utilities' project manager for the Smart Grid Investment Grant project as well as program sponsor for the Turner Vanadium Flow Battery and the University District Microtransactive Grid projects. He is presently director of Avista's innovation lab and chief research and development engineer and leads a team that develops grid products and services for Avista's electric customers.

Michael Diedesch, PE, is the Avista Grid Innovation Lab Manager. He received his BS in electrical engineering from Washington State University in 2008 and is a registered professional engineer in Washington. Since joining Avista Utilities in Spokane, WA, he has worked in various engineering roles including generation controls, SCADA, system protection, and smart cities lead.

Tyler McCoy has worked as an automation engineer in the special protection systems group at Schweitzer Engineering Laboratories, Inc. (SEL) since 2010. He has worked on a variety of large power management schemes for industrial and utility customers, including a country-wide remedial action scheme, offshore platforms, and other islanded facilities.

Niraj Shah is a director of special protection systems group of SEL Engineering Services, Inc. (SEL ES) of Schweitzer Engineering Laboratories, Inc. (SEL). He received his BE in instrumentation and control from Gujarat University, India, in 1996. He is a senior member of IEEE. He joined SEL in 2007. He has more than 25 years of experience in process control, substation automation, microgrids and industrial power management, electrical power distribution automation, applications engineering, configuration, and onsite commissioning.

Tim George Paul received the BE degree in electrical engineering from Anna University, Chennai, India, in 2010, and a master's degree in electrical engineering from the University of North Carolina at Charlotte in 2015. He joined SEL Engineering Services, Inc. (SEL) in 2016, as a project engineer focusing on power system modeling using a real-time digital simulator. He has experience in modeling industrial power plants and microgrids with renewable sources to perform hardware-in-the-loop testing of power management schemes.

Ashish Upreti, PE, is a senior engineering manager at SEL Engineering Services, Inc. (SEL ES) a subsidiary of Schweitzer Engineering Laboratories, Inc., (SEL) in Pullman, Washington. He received his bachelor's and master's degrees in electrical engineering from the University of Idaho. He is a registered professional engineer in the state of Washington and a senior member of the IEEE. He has over ten years of experience in the field of power system protection and automation, including power management schemes for large-scale industrial power plants, remedial action schemes, and microgrid solutions.

Lessons Learned From Hardware-in-the-Loop Testing of Microgrid Control Systems

E. Limpaecher*, R. Salcedo*, E. Corbett*, S. Manson†, B. Nayak†, and W. Allen†

***Massachusetts Institute of Technology Lincoln Laboratory**

†Schweitzer Engineering Laboratories, Inc.

USA

SUMMARY

A key ingredient for the successful completion of any complex microgrid project is real-time controller hardware-in-the-loop (C-HIL) testing. C-HIL testing allows engineers to test the system and its controls before it is deployed in the field. C-HIL testing also allows for the simulation of test scenarios that are too risky or even impossible to test in the field. The results of C-HIL testing provide the necessary proof of concept and insight into any microgrid system limitations. This type of testing can also be used to create awareness among potential microgrid customers.

This paper describes the modeling benefits, challenges, and lessons learned associated with C-HIL testing. The microgrid system used in this study has a 3 MW battery, 5 MW photovoltaic (PV) array, 4 MW diesel generator set (genset), and 3.5 MW combined heat and power generation system (CHP).

KEYWORDS

Microgrid, C-HIL, system testing, switching transients, controller integration.

1 INTRODUCTION

Microgrids can increase energy resilience [1] and improve operating efficiency, but they are challenging to deploy. Because relatively few of these multimillion dollar systems are fielded, most engineers do not have experience assessing microgrid and distributed energy resource (DER) control technology. Some equipment vendors lack the prototyping capabilities to fully demonstrate their control solutions, leading to a higher perceived risk by project developers and financiers and concerns about “vaporware” by system integrators. The integration and testing method currently used by the industry—which typically requires all of the steel to be in the ground before control integration begins—pushes all project risk to the final field deployment stage rather than reducing risk through lower-cost laboratory integration and prototyping.

To help address these issues and accelerate microgrid adoption, the Department of Energy’s Office of Electricity Delivery and Energy Reliability sponsored the Massachusetts Institute of Technology Lincoln Laboratory (MIT-LL) to build a microgrid and DER control prototyping platform. MIT-LL is a U.S. Department of Defense federally funded research and development center, which provides neutral, third-party technical expertise to the federal government.

The source code and circuit designs for the resulting hardware-in-the-loop laboratory testbed and open platform (HILLTOP) have been made available as open-source on the electric power hardware-in-the-

loop controls collaborative (EPHCC) repository [2], and the microgrid test feeder, code named “Banshee,” is now being used as a reference feeder by the industry, IEEE P2030.8, U.S. National Renewable Laboratories (NREL), and universities.

The HILLTOP platform was used to simulate the Banshee model during the Microgrid and DER Controller Symposium, held at the MIT campus in February 2017. Videos of these live demonstrations are available online at [3]. The symposium showcased how to use modern, real-time simulation technology to integrate, evaluate, and reduce the risk of distribution-level control deployments. Symposium attendees included utility engineers, project developers, systems integrators, engineering students, policymakers, and equipment vendors. The symposium was organized and hosted by the Massachusetts Clean Energy Center, National Grid, IEEE Power and Energy Society, Electric Power Research Institute, Greenovate Boston, Microgrid Knowledge, and MIT. MIT-LL used C-HIL, relaying, governor control, and inverter equipment from several manufacturers to build the prototyping platforms. Four manufacturers integrated their commercial microgrid controllers into the HILLTOP. NREL analyzed test results collected prior to the event.

2 GENERIC POWER SYSTEM MODEL

The Banshee power system, shown in Figure 1, corresponds to a real-life, small industrial facility supplied via three utility radial feeders. The system resembles microgrids seen around the world and presents challenges found in a community microgrid, a small island, or industrial facilities, making it a solid benchmark for evaluating microgrid performance. The microgrid is composed of three adjacent feeders that may interconnect through normally open tie switches. The Banshee electrical demand ranges from 5 MW to 14 MW for minimum and peak load. System voltages include 13.8 kV at the distribution level and service voltages of 4.16 kV, 480 V, and 208 V. There are 18 aggregated loads categorized as critical, priority, and interruptible.

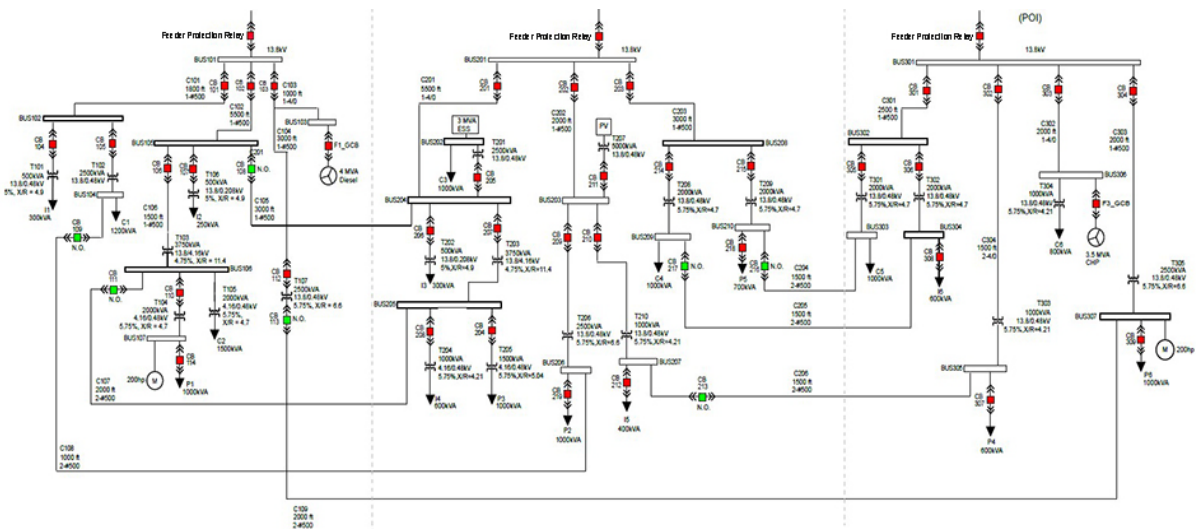


Figure 1 Banshee Power System

Loads follow electrical demand profiles extracted from the smart metering equipment installed at the existing site buildings. Critical loads, such as hospitals, denote high requirements for continuous electrical service and power quality. Priority loads are buildings that ideally have continuous electrical service, but during contingencies, these buildings may be disconnected. Interruptible loads are buildings that do not require electrical service during contingencies.

The Banshee power system contains a 4 MVA diesel generator and a 3.5 MVA combined heat and power system operating at a 13.8 kV nominal voltage. The generators are hardware interfaced with generation load-sharing controllers that operate and protect both units. The load-sharing controllers receive commands from the microgrid controllers without operator intervention.

The Banshee power system includes a PV array rated at 3 MW and a battery energy storage system (BESS) rated at 2.5 MW. Two power inverter module controllers capable of four-quadrant operations

and grid mode transition techniques operate these assets. The PV follows a user-defined irradiance profile. The microgrid controller dispatches the BESS unit to perform power factor correction and peak shaving and support power export requirements. The lack of generation and storage available in the Banshee system facilitates the evaluation of the microgrid controller's ability to perform smart load shedding before and during islanded conditions.

System reconfiguration is available using 47 virtual circuit breakers commanded by the microgrid controller via hardware or virtual relays. Three hardware protective relays control and protect the three points of common coupling (PCC1, PCC2, and PCC3) with the utility grid. The virtual relays provide fault protection, automatic synchronism back to the grid, and telemetry. Additionally, these breakers can trip and close via Modbus[®] TCP for slow microgrid control schemes or quickly via IEC 61850 GOOSE for fast load shedding. Design and implementation details for the hardware interface circuitry of controllers and relays as well as the source code of simulated components are publicly available in the EPHCC repository [2].

3 C-HIL PLATFORM

A simplified diagram depicting the C-HIL architecture is shown in Figure 2. The system is comprised of four main components:

- Microgrid controller (MGC) and communications interfaces.
- Device controllers, relays, and high-speed digital interface.
- Custom electronics interfaces for device controllers and relays.
- C-HIL real-time simulation platform.

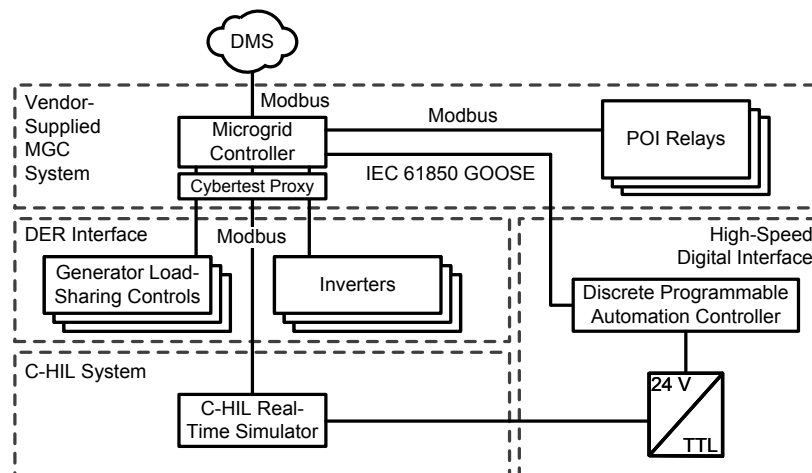


Figure 2 C-HIL Architecture

The microgrid controller communicates with all hardware and software devices primarily through a Modbus TCP interface. A cybertest command and control proxy computer is used to assess communications resistance to man-in-the-middle cyberattacks. An optional IEC 61850 GOOSE high-speed message interface is available to directly control simulated circuit breakers through a discrete programmable automation controller for fast load-shedding capability.

Two genset load-sharing controllers are used for control, one for the simulated 4 MW diesel genset and another for the 3.5 MW simulated natural-gas-fueled engine used in the simulated CHP plant. The load-sharing controllers are custom-configured to match the engine type (diesel or natural gas) and are operated in linear frequency and voltage droop. The load-sharing controllers are interfaced to the C-HIL platform analog outputs using transconductance amplifiers as CTs and voltage amplifiers as PTs. The C-HIL analog and digital inputs are driven directly by load-sharing controller outputs.

Two power inverter controllers are also used, one for controlling a simulated 5 MW PV inverter and another for controlling a 3 MW simulated battery storage system inverter. Three hardware protective relays are implemented as feeder protection relays with protection elements for overcurrent,

undervoltage, underfrequency, and rate-of-change of frequency. A discrete programmable automation controller is used to sample the status of 32 of the 45 simulated circuit breakers and report status to the microgrid controller over the IEC 61850 communications link.

4 C-HIL MODEL VALIDATION

The Banshee power system model was built in three different C-HIL platforms. Modeling engineers validated the Banshee power system models against data collected from several similar in-service grids. Validated models confirm that the simulated response to a disturbance or event reasonably matches the measured response to a similar disturbance.

To validate these models, specific tests were performed to confirm that their behaviors were normal for such systems. These tests included, but were not limited to, PV irradiance profiles, PV performance during fault conditions, PV dynamic response to MGC commands, distributed generation load rejection and load acceptance tests, distributed generation fault condition tests, grid compliance tests, load flow tests, and voltage and frequency response validation. Figure 3 shows an example of the genset load rejection tests performed on the two diesel engines.

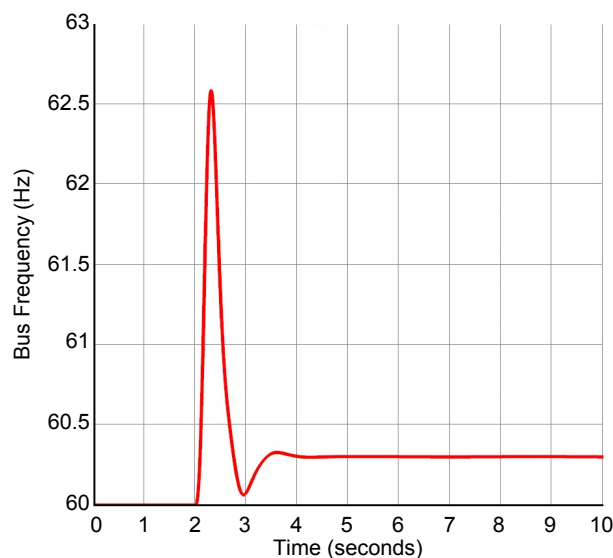


Figure 3 Genset Load Rejection Test

Once the entire C-HIL model was validated against known behaviors of similar power systems, the team continued to validate the microgrid controller and relaying operations using a live simulation of the C-HIL environment.

5 MICROGRID CONTROLLER

MGC systems include a vendor-supplied microgrid controller and three protective relays, one at each PCC. Relays and controllers work together symbiotically in the MGC system. The MGC system's primary function is to allow a small grid section to operate independently by preventing, detecting, and mitigating system blackouts. Automated control systems simultaneously control the DER for optimal economic dispatch and environmentally sound operation.

MGC systems contain power factor control, distributed generation sharing and optimization, load shedding, load management, bidirectional power flow management, peak shaving, grid decoupling, grid autosynchronization, monitoring, and alarming. The MGC system dispatches the DER power output to maintain power interchange at the PCC within predetermined limits simultaneously to share load between parallel-connected DERs.

Figure 4 shows protective relay recordings at PCC1 during an upstream utility power system fault. As part of the test sequence and before triggering the fault, the diesel genset was set to carry portions of the feeder load. Approximately 200 ms after the fault, the relay sends a trip command to the PCC1 breaker. The breaker contacts opened about 100 ms after receiving the trip signal due to inherited mechanical delays. At this point, all of the feeder load is transferred to the diesel genset, momentarily

exceeding its capacity. To maintain microgrid island stability, the MGC executes its fast load-shedding mechanism and disconnects sufficient load to support frequency recovery. This is a normal sequence of events for seamless islanding of a microgrid after a system fault.

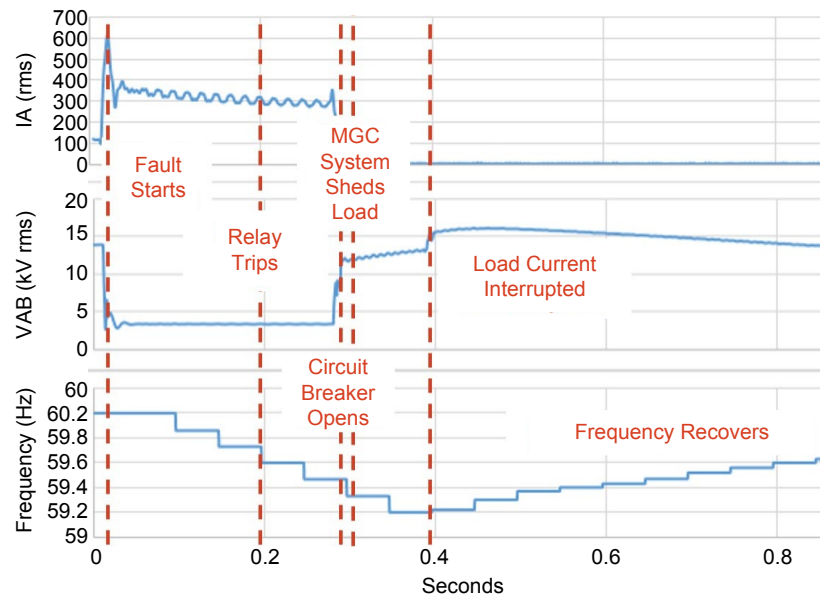


Figure 4 Simulated Islanding Event

6 STANDARDIZED TEST SEQUENCE

The main goal of the symposium test was to illustrate some of the major benefits of utilizing a microgrid controller to manage the generation, distribution, and protection resources of a smart power distribution system. The three plots in Figure 5 show the standard test sequence used at the symposium to evaluate the four different microgrid vendor solutions.

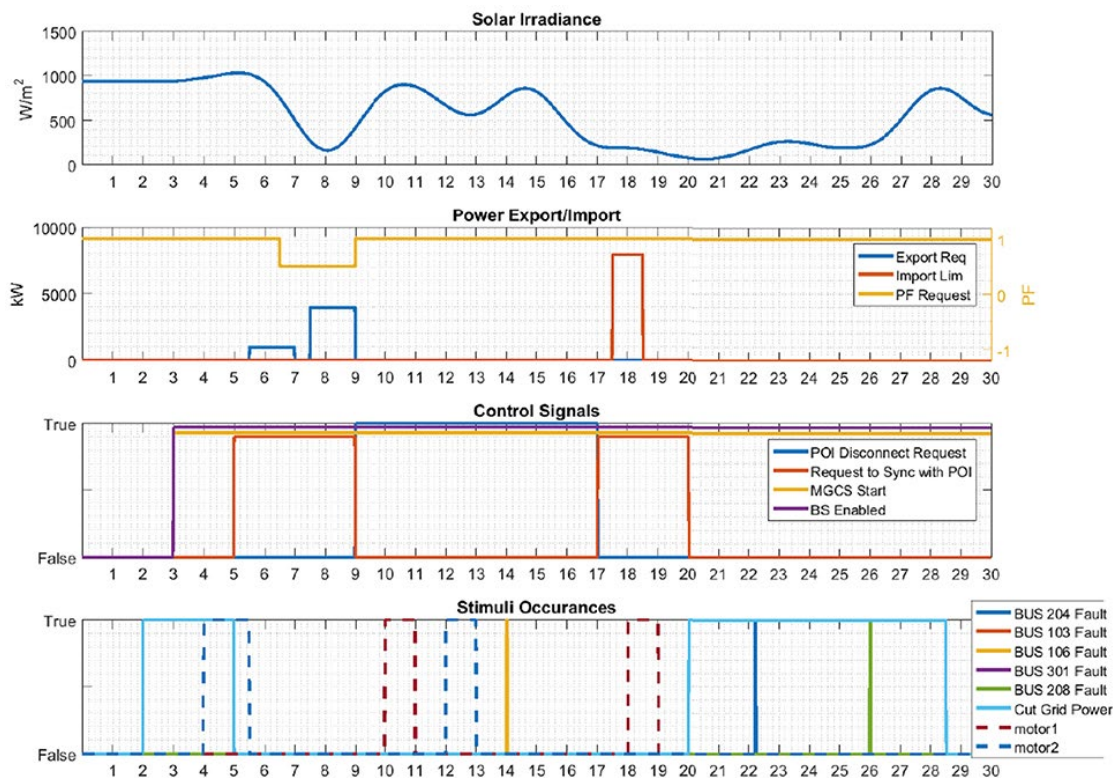


Figure 5 Standardized Test Sequence

At initialization of the real-time simulation, all three microgrid feeders are importing power from the grid. At 2 minutes into the test, the grid power is cut (see the light blue trace in the bottom plot), which causes Feeder 1 to black out unless the diesel genset is running and the microgrid controller can shed load fast enough to avoid tripping the genset. At 3 minutes, a black start enabled control signal (the purple trace in the second plot up from the bottom) is received by the microgrid controller from the distribution management system, which allows all DERs to start and pick up load. At subsequent points, requests are sent from the distribution management system to the microgrid controller to synchronize at the PCC, disconnect from the PCC, or honor a particular real power flow condition across the PCC. The application of faults on several buses assesses the microgrid controllers' reaction to protective relay events.

7 LESSONS LEARNED

Key lessons learned in this project include:

- Significant time is needed to configure and test the communication and data model interfaces to power converter and genset controllers.
- The C-HIL prototyping system needs to include at least one of each hardware device until the C-HIL modeling team becomes intimately familiar with the hardware devices and can model them accurately on future projects.
- Automated test sequences need to be developed that thoroughly test all edge conditions to expose emergent interdependent control behaviors and carefully preserve test results.
- Synchronization coordination is essential to avoid damaging field equipment. Test the edges of the synchronization window, especially for large phase angle offsets. Unlike industrial power systems, community microgrids may consider load shedding to assist synchronization.
- The planned revision to IEEE 1547 benefits microgrid stability during transition events.

8 DISTRIBUTION STATEMENT

Approved for public release: distribution unlimited.

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Robust Microgrid Control System for Seamless Transition Between Grid-Tied and Island Operating Modes

Scott Manson, Bharath Nayak, and Will Allen, *Schweitzer Engineering Laboratories, Inc.*

Abstract—Critical facilities require electric power systems to stay fully energized during transitions between grid-connected and island modes. Providing this seamless transfer between island and grid modes is a complex challenge because of multiple dynamic interactions between distributed energy resources (DERs), electrical loads, and the bulk electric power system. Further complicating these transitions are the reduced kinetic energies and new dynamics associated with the black-box controls of power electronic DERs, such as photovoltaic (PV) and battery storage.

The solutions to these challenges are fast, reliable, and adaptive protection and control systems commonly called microgrid control systems (MGCSs). This paper explains the design, testing, and results of an MGCS that uses subcycle (less than 16 ms) fast and deterministic control strategies to improve grid and island resiliency during the transitions from grid mode to island mode. The MGCS is known to prevent power outages (blackouts) during events such as islanding, synchronization, PV shading, islanded loss of generation, and variable loading under islanded conditions.

I. INTRODUCTION

This paper describes the microgrid controller functionality developed and tested to control a theoretical power system referred to as Banshee. The Banshee microgrid was created by the Massachusetts Institute of Technology Lincoln Laboratory (MIT LL) to assess distributed energy resources (DERs) and microgrid control system (MGCS) technology [1]. The U.S. Department of Energy, Office of Electricity Delivery and Energy Reliability sponsored the MIT LL to build this model. The authors constructed both the controller and a model of the Banshee system with a hardware-in-the-loop (HIL) test bed. Both were demonstrated at the Microgrid & DER Controller Symposium held at MIT in Boston, Massachusetts in February, 2017 [2].

The authors created a real-time Electromagnetic Transients Program (EMTP) model for control hardware-in-the-loop (CHIL) testing. The CHIL model was created to test the MGCS. Once fully tested in the laboratory, the controller was sent to Boston for the symposium for test and evaluation by MIT LL.

The MGCS for this system includes configured protective relays at the point of common coupling (PCC) and custom software libraries running on an automation controller. Many real-life MGCS projects are accomplished entirely in the protective relays; the authors chose to use an automation

controller for this project because of the programming flexibility and capability, human-machine interface (HMI), and protocol interfaces provided by the automation controller. Because of the complex topology of the microgrid, the number of DERs, and the intended testing regimen by MIT LL, an all-relay MGCS would have been very difficult to provide.

II. SYSTEM OVERVIEW

The Banshee model is shown in Fig. 1. The microgrid is comprised of three areas, each of which are connected to the utility through separate PCC circuit breakers. Area 1 includes the 4 MVA diesel generator, Area 2 includes the 3 MVA battery energy storage system (BESS) and 5 MVA photovoltaic (PV) assets, and Area 3 includes the 3.5 MVA combined heat and power (CHP) generation system. Every load is assigned a priority: interruptible (I), priority (P), and critical (C).

There are several normally open (NO) tie breakers among the three areas that can be closed to form a larger microgrid and/or to transfer load from one area to another:

- One tie breaker (CB108) between Area 1 and Area 2 at 13.8 kV through a 3,000-foot cable run.
- One tie breaker (CB111) between Area 1 and Area 2 at 4.16 kV through a 2,000-foot cable run.
- One tie breaker (CB109) between Area 1 and Area 2 at 480 V through a 1,000-foot cable run.
- One tie breaker (CB113) between Area 1 and Area 3 at 480 V through a 2,000-foot cable run.
- Three tie breakers (CB213, CB216, and CB217) between Area 2 and Area 3 at 480 V through a 1,500-foot cable run.

The microgrid is normally operated in the topology state as shown in Fig. 1. However, the following scenarios are likely to occur in the microgrid:

- Areas 1, 2, and 3 are separated from each other.
- Areas 1 and 2 are connected through one or more tie breakers.
- Areas 1 and 3 are connected through a tie breaker.
- Areas 2 and 3 are connected through a tie breaker.
- Areas 1, 2, and 3 are connected through tie breakers.

Additionally, any breaker (i.e., PCC, topology, or load) may be opened or closed.

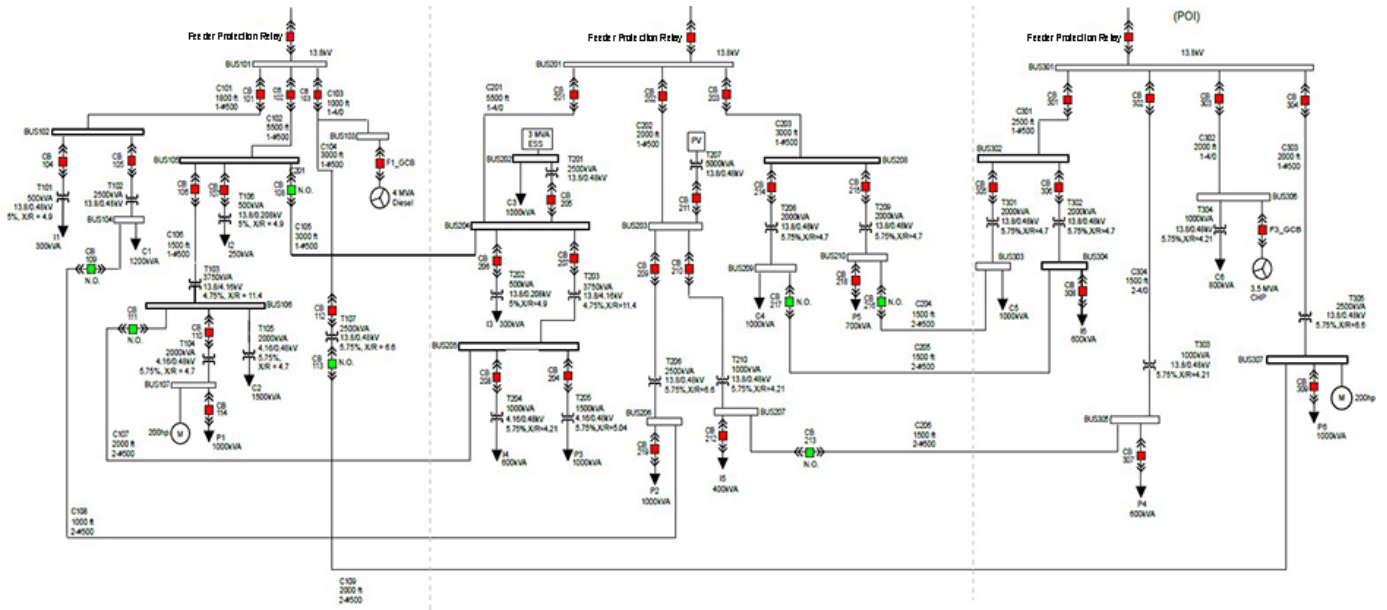


Fig. 1. One-line diagram of the Banshee microgrid

III. TECHNICAL OBJECTIVES

The technical objectives of the centralized MGCS designed for this project are as follows:

1. Operate all islands without power outages (seamless operation) during transitions between island and grid modes.
2. Interface with diesel and natural gas (NG) CHP generation control systems.
3. Interface with PV and BESS converters.
4. Interface with PCC breaker relays.
5. Interface with load bank breaker relays.
6. Assess the diesel generator, CHP, PV, and BESS control capability.
7. Implement an automatic generation control (AGC) parallel load-sharing system [3] to:
 - a) Control all generation assets to share active load while maintaining favorable individual machine margins.
 - b) Control generation assets to regulate frequency when disconnected from the utility grid.
8. Implement a voltage control system (VCS) parallel VAR-sharing system [3] to:
 - a) Control all generation assets to share reactive load while maintaining favorable individual machine margins.
 - b) Control all generation assets to regulate voltage when disconnected from the utility grid.
9. Employ the island control system (ICS) to detect and track island conditions and to inform the AGC and VCS of grid topology changes [3].
10. Simultaneously control multiple DERs (PV, BESS, diesel generator, and NG CHP generation control system).
11. Provide resilience (prevent blackouts) during scenarios such as an open PCC breaker, rapid load changes, loss of generation, or a motor start [4].
12. Dispatch active and reactive power at the PCC.
13. Implement simultaneous advanced automatic synchronization to all three areas of the grid [5].
14. Program automatic black-start and load restoration functions.
15. Provide an operator interface via the HMI and provide post-event analysis.

IV. DATA FLOW DIAGRAM

The microgrid controller (MGC) consists of a centralized automation controller that executes functions such as AGC, VCS, ICS, contingency load-shedding processor (CLSP), and advanced automatic synchronization. The HMI is configured to provide all necessary operator interface functions. Fig. 2 illustrates the physical architecture connecting the MGC with the microgrid equipment.

V. MGC CONTROL PHILOSOPHY

The control philosophy of the MGC is mainly composed of the utility-connected mode of operation (grid mode of operation) and the utility-disconnected mode of operation (island mode of operation). The idea is to control various DERs with appropriate modes to ensure reliable and sustained microgrids. The control strategy is tabulated in Table I.

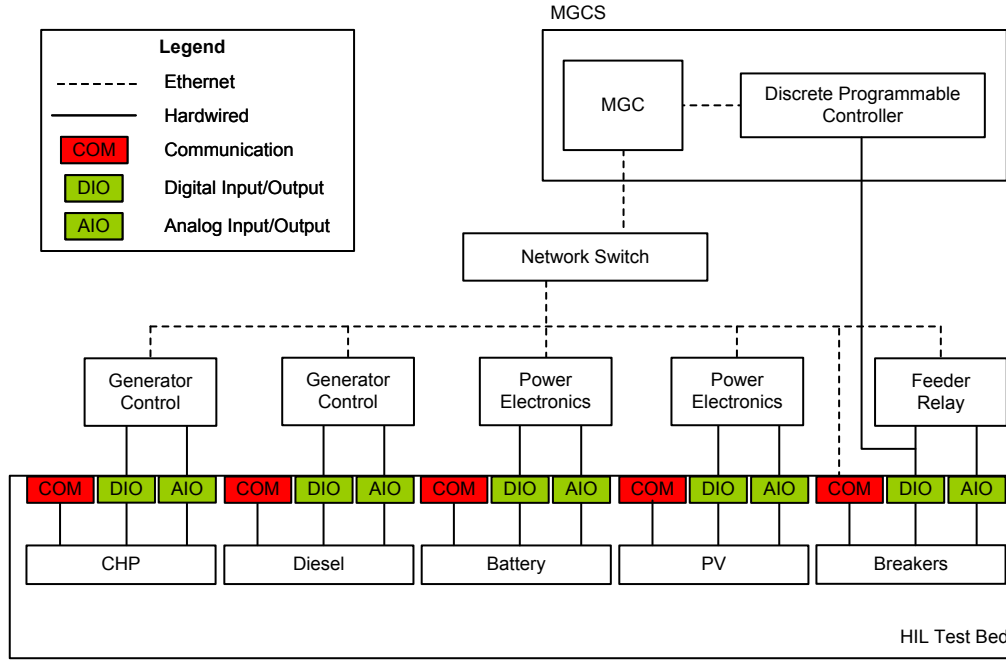


Fig. 2. Physical data flow diagram

TABLE I
MGCS CONTROL STRATEGY MATRIX

Strategy	Grid Mode	Island Mode
PCC power flow	MGC ¹	NA ²
PCC power factor	MGC ¹	NA ²
Microgrid frequency	Utility ³	MGC ¹
Microgrid voltage	Utility ³	MGC ¹
Diesel generator	Droop ⁴	Droop ⁴
NG generator	Droop ⁴	Droop ⁴
BESS asset	P/Q ⁵	P/Q ⁵
PV asset	P/Q ⁵	P/Q ⁵

Note 1: Microgrid controller is responsible.

Note 2: Not applicable.

Note 3: Utility is responsible.

Note 4: Active frequency droop and voltage droop.

Note 5: Constant real and reactive power control to set point.

A. Utility-Connected Mode of Operation

When utility-connected, the MGC controls the total power flow across the PCC breakers to achieve the target set point. The total power flow is the sum of power measurement across each PCC breaker.

The MGC controls the combined power factor (PF) at the PCC breakers to achieve a target set point. The MGC calculates a reactive power set point based on a user-defined power factor set point and the user-defined power set point. The MGC defines a dead-band control boundary in the PQ plane to avoid excessive control adjustments due to hunting and inherent instability of the power factor controls during low-power conditions. Fig. 3 illustrates the power factor control strategy used by the MGC. Values shown on the P and Q axes have units of megawatt (MW) and megavolt-ampere reactive (MVAR),

respectively. Positive values indicate flow into the microgrid. The dark area represents the region where active power factor control occurs. The light area represents the region where active power factor control is suspended.

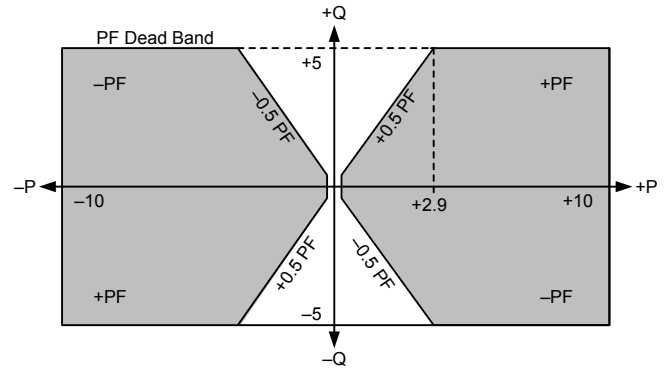


Fig. 3. Power factor control strategy

Voltage and frequency are assumed to be the responsibility of the utility when grid-connected. The MGC commands the DERs to the modes indicated in Table I.

The diesel and NG generators are controlled to share load and maintain operating margins to enhance disturbance rejection. The real power set point for the PV asset is set to maximize the PV power output. The real power set point for the BESS asset is normally maintained at zero. The MGC responds quickly by increasing or decreasing power output to compensate for frequency deviations (e.g., if the microgrid is islanded).

The reactive power set points for the two generators, as well as the PV and BESS assets, are dispatched to share (i.e., equal percentage sharing based on asset capability limits). Simultaneously, the DERs dispatch reactive power to maintain the power factor control at the PCC. While the PCC is open,

these same assets are equally dispatched to an MVAR output while maintaining system bus voltages.

B. Island Mode of Operation

The capacity of the microgrid is the summation of the online diesel generator, CHP generation system, PV, and BESS capacities. The available capacity is the present power plus the incremental reserve margin (IRM) of the generation assets. Load is shed based on the user-settable priorities to balance load and available capacity in the resulting microgrid(s).

The diesel and NG generators are controlled to share load and maintain operating margins to enhance disturbance rejection. The MGC dispatches the real power set point for the PV asset to maximize the PV power output.

The MGC dispatches the real power set point for the BESS asset to maintain the power output at zero. The MGC responds quickly by increasing or decreasing the power output to compensate for frequency deviations. Frequency deviations may be caused by sudden shading of the PV array, large motor starting, or topology changes.

The MGC biases the operation of the diesel and NG generators to maintain islanded system frequency at the set point and drive the BESS power output to zero (if possible).

The MGC dispatches reactive power set points for the two generators, as well as the PV and BESS assets, to share (i.e., equal percentage sharing) the reactive power load required to maintain system voltage at the set point.

If load with priority P is shed to survive a disturbance, then the MGC restarts these P loads (one at a time at 10-second intervals) after the disturbance is cleared. Loads are only restarted if the IRM of the associated island can support it. Loads are restored based on user priority.

If the reserve margin is not sufficient to accommodate all the P loads that were shed, then the MGC sends a start command to an available generation asset in the associated island.

Fig. 4 illustrates the strategy employed by the MGC related to real power and frequency control. Fig. 5 illustrates the strategy employed by the MGC related to reactive power and voltage control.

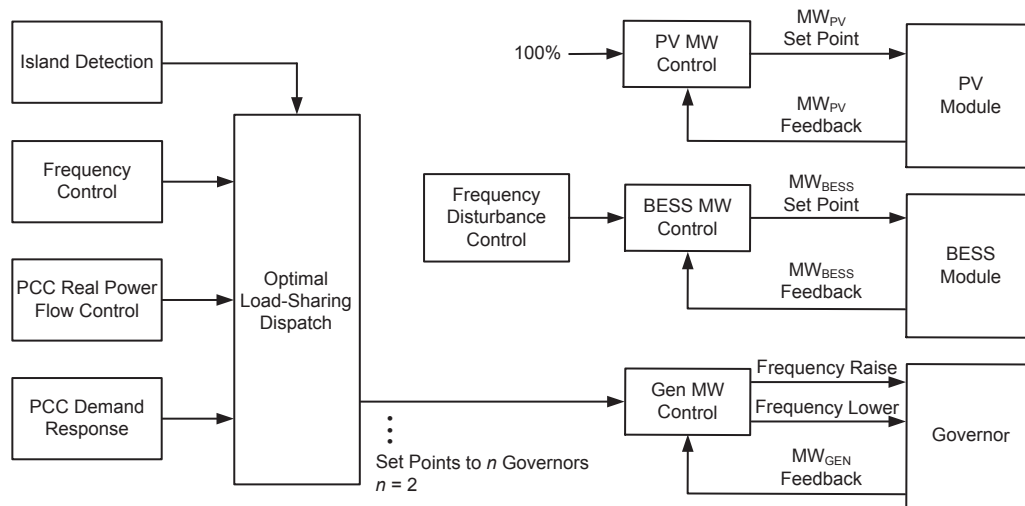


Fig. 4. Real power and frequency control strategy

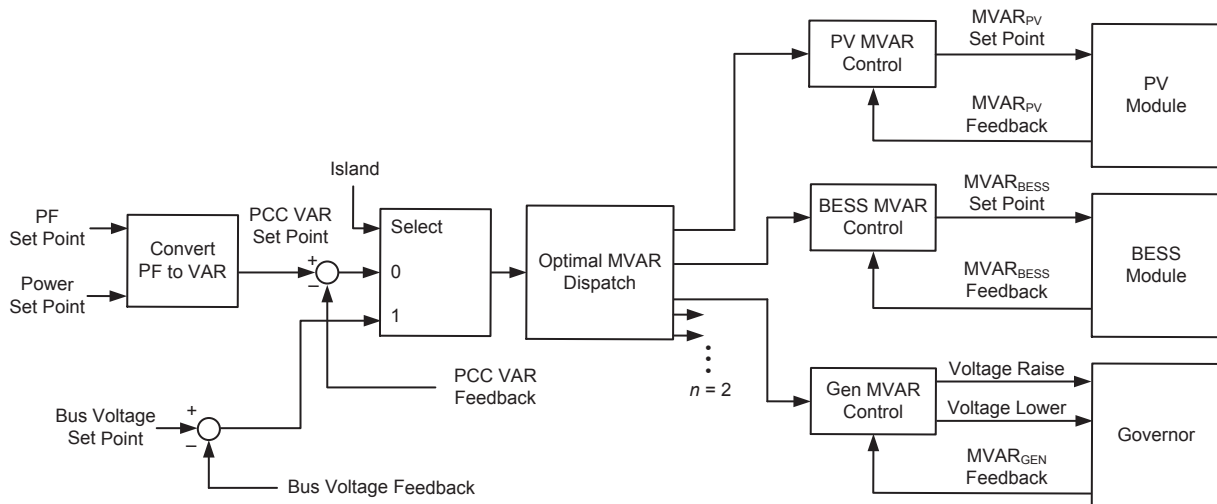


Fig. 5. Reactive power and voltage control strategy

C. BESS Charging Strategy

The MGC charges the BESS based on a two-strategy approach. Strategy 1 is independent of the PV output power. It is designed to ensure that the BESS charge is maintained even if the PV asset is offline or producing at a low level. Strategy 2 is designed to favor charging the BESS during times of high PV power output.

In Strategy 1, as shown in Fig. 6, the MGC starts to charge the BESS if it has less than A% charge and there is excess power available from any source. The charging power C is configurable; however, it is limited by the available capacity of the connected island. The MGC stops charging the BESS once it exceeds B% charge. This ensures that the battery has sufficient charge available when it is called on to reject disturbances such as sudden shading of the PV array, load changes, and topology changes. Parameters A, B, and C are configurable. Default values are set to A = 50%, B = 75%, and C = 10%.

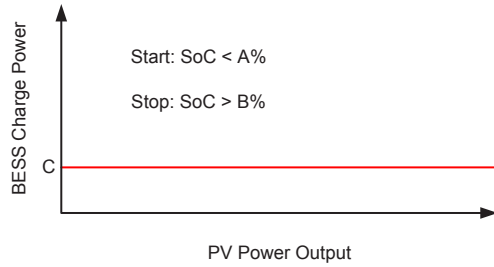


Fig. 6. BESS state-of-charge Strategy 1

In Strategy 2, as shown in Fig. 7, the MGC controls the BESS to charge in times when the PV output is high (i.e., above a configurable threshold F). In this case, the MGC starts to charge the BESS if it has less than D% charge. The charging power is proportional to the PV output that is above the threshold F. The MGC stops charging the BESS once it exceeds E% charge. Parameters D, E, and F are configurable and can be tuned during the factory acceptance test. Default values are set to D = 80%, E = 90%, and F = 80%.

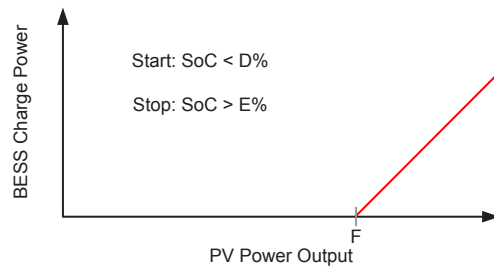


Fig. 7. BESS state-of-charge Strategy 2

D. Black-Start Functions

The MGC provides effective blackout prevention in most scenarios. However, in some cases a blackout is unavoidable.

The Banshee model power system includes three areas. Areas 1 and 3 incorporate conventional generation assets. If these assets are running, the MGC provides seamless transition from grid-connected to islanded operation for most decoupling

events. If these assets are not running, then the MGC black starts the area according to the flow chart in Fig. 8.

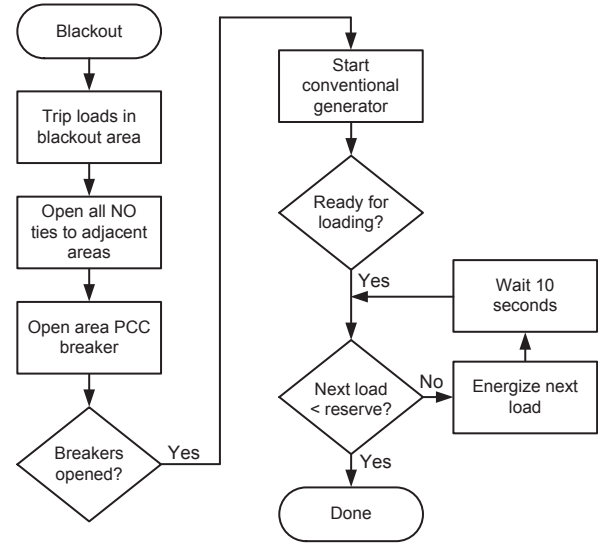


Fig. 8. MGC black-start sequence for Areas 1 and 3

Area 2 of the Banshee model includes two inverter-based sources. If only the PV asset is connected, then decoupling from the utility results in tripping the PV, leaving Area 2 de-energized. The battery storage asset may also not be able to survive if islanded on its own. The black-box controllers that are commonly used with inverter-based sources often trip the inverter at the first sign of trouble. This results in no other option except to de-energize Area 2 and connect it to Area 1 or Area 3, followed by full Area 2 energization. Fig. 9 shows the black-start sequences employed by the MGC to re-energize Area 2 and restart the inverter-based sources.

VI. CLOSED-LOOP TESTING AND RESULTS

The objective of the closed-loop test setup is to create a test interface that simulates power system dynamics of DER sources, local controller functions, electrical network with transformer and cable impedances, and communications protocols between local controllers and the MGC. Fig. 10 shows the closed-loop test interface used to validate the functionality of the MGC.

An interface data concentrator was programmed to serve as a bridge between the power system model and the MGCS hardware. To simulate communication between the data concentrator and the field IEDs, the DER's primary local controller, and the MGC, two steps were required. First, an extensive input/output (I/O) list was developed to analyze the data types (such as active power, reactive power, bus frequency, bus voltage, breaker status, trip commands, and analog control set points). Second, the interface data concentrator was programmed to represent parallel communications channels simulating communications delays and protocols, such as IEC 61850, DNP 3.0, and Modbus®. The following subsections contain results from the tests performed with HIL testing for this project.

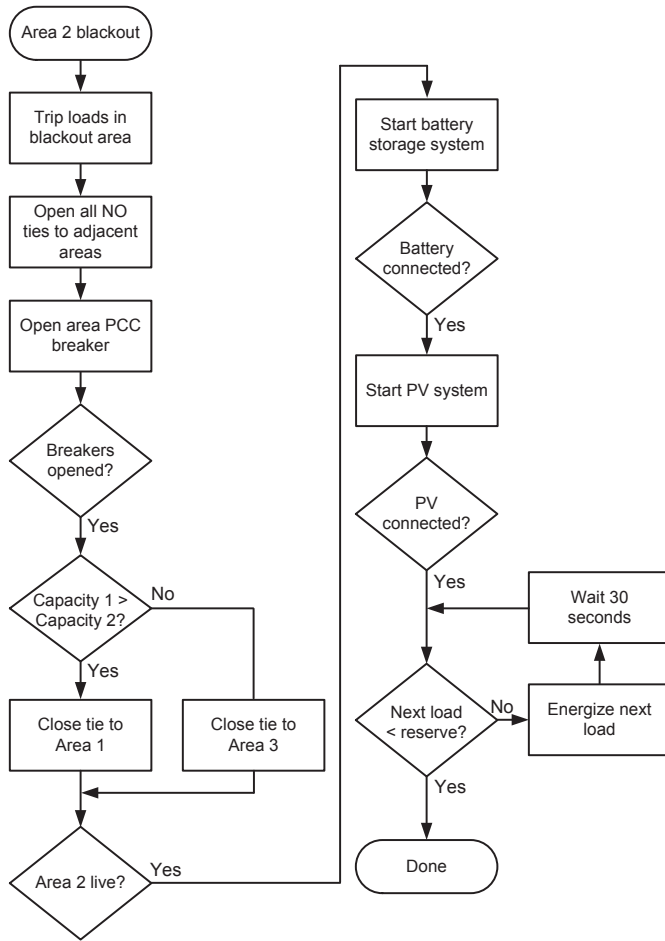


Fig. 9. MGC black-start sequence for Area 2

A. Test A: Utility-Connected Tie Flow Control

This scenario simulates a condition in which the system is connected to the grid in tie line control mode and power factor control mode.

The tie line power flow initially decreased because of the sudden loss of load. The MGCS controlled the diesel and CHP generation systems governors to restore the tie line set point to 1 MW import. Equal percentage load sharing between the two generators was accomplished.

The MGCS controlled the exciters of the diesel and CHP generation systems, as well as the reactive power set points of the BESS and the PV array, to share the reactive power requirement to restore the tie line power factor to 0.95. Fig. 11 shows the precondition set points programmed in the HMI.

To achieve the target set point of 1 MW and 0.95 PF (0.31 MVAR), the MGCS dispatched DERs in each area to regulate power flow across each PCC breaker. Therefore, the aggregate of all PCCs resulted in approximately 0.94 MW and 0.96 PF. Fig. 12 shows the variations in tie flow control and Fig. 13 shows the redispatch of the DERs to achieve the results shown in Fig. 12. Fig. 14 shows the dispatch values of each DER after the event.

It is noteworthy that there is no overshoot, ringing, or unstable behavior in the PCC or DER active or reactive power because the PCC and DER controls do not use proportional integral derivative (PID) control methods; instead, they use advanced adaptive control methods, which creates a more reliable strategy than using PID.

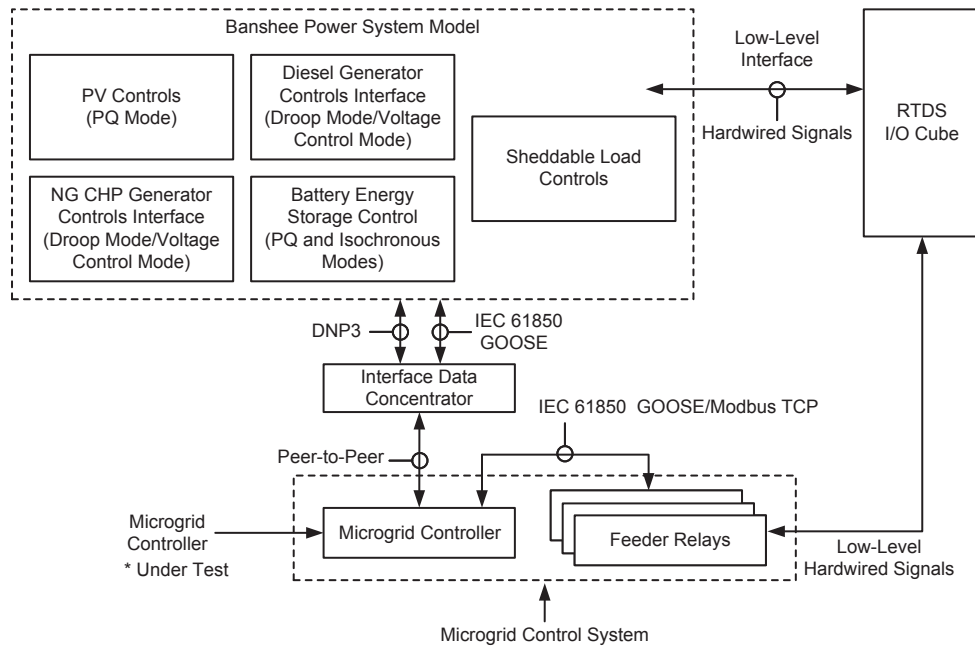


Fig. 10. HIL test setup

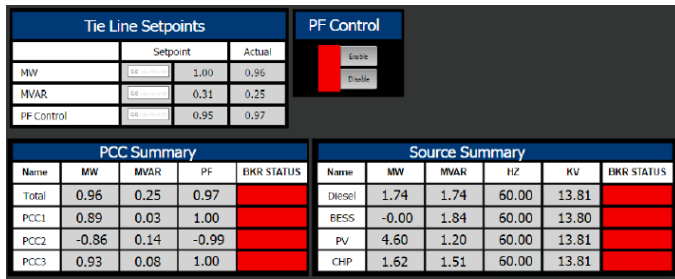


Fig. 11. HMI summary before the event

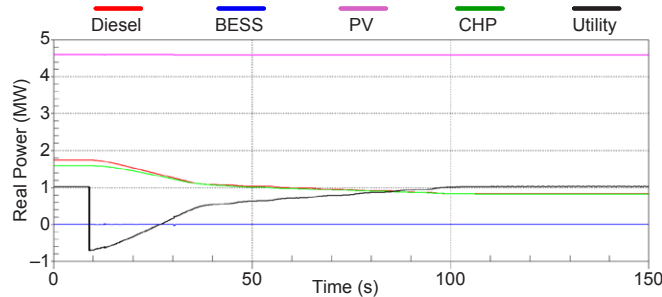


Fig. 12. MGCS real power tie flow control action to the event

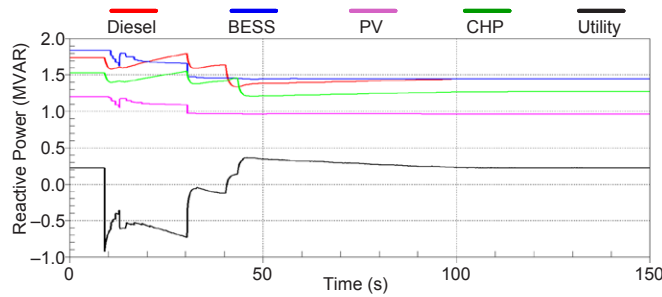


Fig. 13. MGCS reactive power tie flow control action to the event

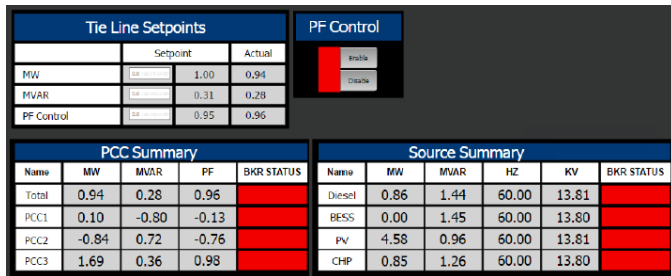


Fig. 14. HMI summary after the event

B. Test B: Decoupling Event – Simultaneous Formation of Multiple Islands

This scenario simulates a condition in which PCC1, PCC2, and PCC3 all trip simultaneously because of a decoupling event (81RF element feeder relays) to form three simultaneous islands. Fig. 15 and Fig. 16 show the frequency response of the DERs to the formation of three islands. During the transition from grid-connected mode to island mode, it is shown that the MGCS load-shedding systems prevent the frequency and voltage from collapsing. These transients are typical for seamless islanding controls when accompanied by a fast, contingency-based load-shedding method.

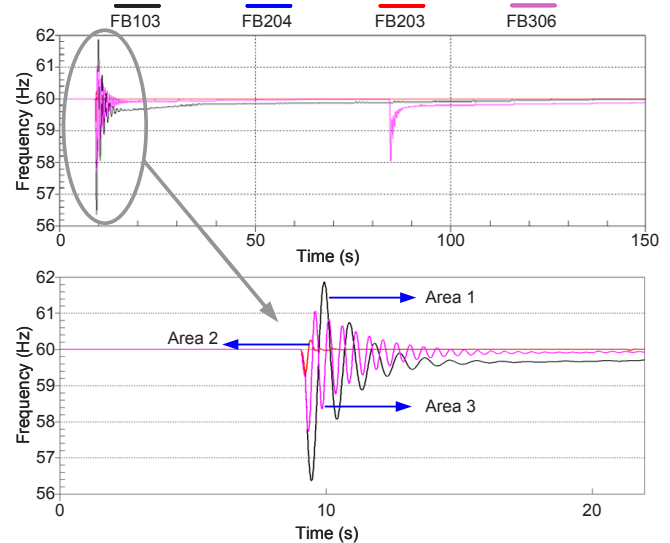


Fig. 15. Frequency response of all PCCs (top) and zoom in of the dynamic frequency response to the event (bottom)

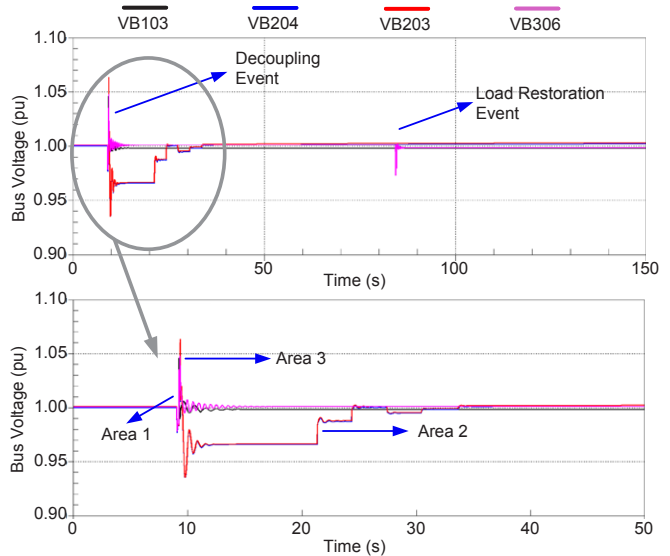


Fig. 16. Voltage response of all PCCs (top) and zoom in of the dynamic voltage response to the event (bottom)

In Area 1, the MGC shed Loads I1, I2, and P1 to ensure that the diesel generator would survive the opening of PCC1. Following the load shedding, the MGCS controlled the diesel generator governor and exciter set points to bring the islanded grid frequency and voltage to nominal.

In Area 2, when the PCC2 breaker opened, the MGC put the PV and BESS in nonregulated mode. The MGC set the PV Q_setpoint to zero. The BESS was put in voltage/frequency (V/F) mode to regulate voltage and frequency at its terminals in Area 2. The MGC incremented the PV Q_setpoint to restore system voltage to nominal in Area 2. The MGC chose not to shed loads in Area 2 because the BESS had sufficient IRM to support the event.

In Area 3, the MGC shed Loads I6 and P4 to ensure that the CHP generation system would survive the opening of PCC3. Following the load shedding, the MGCS controlled the CHP generation system to adjust the frequency and voltage to

nominal. After a certain time, Loads I6 and P4 were automatically restored.

VII. CONCLUSION

The main objective of this project was to develop and test a centralized MGCS that would improve stability, survivability, and resilience in the Banshee system. During the phases of the project, the authors observed several key points that are critical to both the design of the model and testing of the MGCS. These key points are as follows:

1. The MGCS requires fast, subcycle communication and logical interactions between the MGC and the PCC relays.
2. Because of fast, contingency-based load shedding, seamless islanding is possible for microgrids with mixed DER types with high renewables penetration.
3. The mature MGC libraries used by the authors successfully controlled the Banshee power system.
4. The results of HIL testing of the Banshee power system and the MGCS are similar to those of many other in-service MGCSs.
5. To confirm a successful transition from grid-connected mode to island mode, protection coordination of various DERs and MGC actions were analyzed to verify that no protection thresholds were violated. This also ensured the successful transition from grid-connected mode to island mode.
6. HIL testing is necessary on projects of this complexity to ensure the MGCS strategy supplied functions as designed.

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IX. BIOGRAPHIES

Scott Manson received his M.S. in electrical engineering from the University of Wisconsin–Madison and his B.S. in electrical engineering from Washington State University. Prior to joining Schweitzer Engineering Laboratories, Inc. (SEL) in 2002, Scott was a control systems engineer responsible for designing, installing, and commissioning automated control systems for manufacturing and research processes with The 3M Company. Scott is presently a principal engineer and director of technology at SEL Engineering Services, Inc. In this role, he provides consulting services on control and protection systems worldwide. He has significant experience in power system protection, real-time

modeling, power management and microgrid control systems, remedial action schemes, turbine control, multi-axis motion control, web line control, robotic assembly, and precision machine tools. Scott is a registered professional engineer in Alaska, Idaho, Louisiana, North Dakota, and Washington.

Bharath Nayak received his M.Sc. in electrical engineering from the University of Wyoming and his B.Sc. in electrical engineering from the P.E.S. Institute of Technology, India. Bharath joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2012 as an associate automation engineer. In his present role, he serves as a power system modeling engineer with SEL Engineering Services, Inc. His focus includes tuning and commissioning of generator control systems, validation and modeling of large-scale industrial plants, countrywide remedial action schemes, power management systems, distributed energy resource modeling, microgrid modeling, and hardware-in-the-loop testing.

Will Allen received his B.Sc. in electrical engineering from the University of Alberta. He has broad experience in the fields of industrial control systems and power system automation. He joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2000 and is currently a senior engineer with SEL Engineering Services, Inc. His current focus is on applying protection and control strategies to improve the operation of microgrids that include diverse resources. He is a registered professional engineer in Washington and in the provinces of Alberta, Ontario, and Saskatchewan.

Design and Development of a Microgrid Control System for Integration of Induction Generation With Storage Capability at Saint Paul Island, Alaska

Abdel Rahman Khatib, PhD, PE

Bharath Nayak

Bowen Dai

Schweitzer Engineering Laboratories, Inc.
Pullman, WA, USA

Jito Coleman

Steve Hoskins, PE

Jan Tierson, PE

TDX Power, Inc.
Anchorage, AK, USA

Abstract—This paper presents a centralized microgrid control system for effective operation of wind turbines and diesel engines coupled to a flywheel electrical storage component on Saint Paul Island. The wind turbines have sufficient capacity to support the entire island without using the diesel engines, allowing the formation of an islanded power system completely powered by renewables.

The proposed strategy includes use of the flywheel, wind turbines, and diesel generators to attain survivability and resilience. The strategy is challenged and validated against different low to turbulent wind gust profiles and low to peak loading. Multiple permissive-based decoupling schemes, tie-flow controls, and heat load trading features are implemented. The tie-line flow control/heat load trading is operated in tandem with local diesel generators and wind turbines to maintain a minimum flow from the utility. The control system was tested using hardware-in-the-loop (HIL) with a simplified electrical model of Saint Paul Island.

Index Terms—Centralized control, distributed energy resources, microgrid, storage, and wind turbines.

I. INTRODUCTION

Increasing renewable market penetration, rising fuel costs, increased renewable generation coupled with congested and aging power grids, the demand for carbon dioxide reductions, and the impact on energy resilience from extreme weather and unintended outages have led to the birth of a semi-autonomous, decentralized grid structure referred to as a microgrid. Technical advances have made it possible to integrate distributed energy resources (DERs) within remote communities to serve their load and generation demands. Controlling the energy balance in the microgrid is one of the most difficult challenges of a reliable microgrid operation. Seamless transition to island mode, automatic generation, tie flow, intelligent response to intermittent changes in power source, load management, coordinated operation with protection relays, and resynchronization are crucial capabilities of microgrid controllers. Reference [1] discusses

the control strategy implemented in the industry and [2] discusses a typical microgrid control system (MGCS) layout. This paper focuses on the design philosophy and developments of a centralized MGCS for Saint Paul Island. A centralized control strategy was developed based on the key functionality requirements of the Saint Paul microgrid in tandem with the requirements of IEEE 1547 [3].

A reliable control network is developed based on existing intelligent electronic devices (IEDs) and local DER controller protocol properties. For this project, high-speed industry protocols, such as IEC 61850 Generic Object-Oriented Substation Event (GOOSE), and existing protocols, such as Modbus[®], were implemented. Relays protecting the point of common coupling (PCC) were also integrated into the architecture. The designed control strategy and communications network were then tested in a closed-loop configuration with a real-time digital simulator (RTDS) test bed to demonstrate the MGCS functionality in response to actual events such as excessive wind energy influx, loss of the diesel generator, and turbulent wind speeds.

II. SYSTEM OVERVIEW

On Saint Paul Island, which is located in the Bering Sea, electrical power is generated by six synchronous diesel generators, with a total generation capacity of 3.7 MW. The city of St. Paul's power plant is a municipally owned utility. All loads can be managed by the city power plant (referred to as "the utility"), except the internal loads of the Trident plant and the Pribilof Offshore Support Services (POSS) camp. The city power plant is the dedicated utility connection to the Saint Paul Island distribution system.

The island has two other significant generation assets: the POSS camp generation station and the Trident power plant. The POSS camp consists of two 175 kW diesel generators (DG1/DG2) and three 225 kW wind turbines (WTs). In addition, there is a 160 kW flywheel (FW) to mitigate power fluctuations from the WTs. The camp also consists of a frequency regulator (SSR1) rated at 446 kW, a resistive dump

load (SSR2) rated at 333 kW, and a synchronous condenser (SC) rated at 300 kVA.

The Trident power plant is intended to power the required loads for its plant operations. It functions with four diesel-powered generator sets with a combined capacity of 2.4 MW feeding a common 480 V bus. For the study, an aggregate representation of Trident plant was implemented. The electrical distribution grid on the island is connected by underground cables operating at 7.2/12.5 kV. The utility feeds a medium-voltage switch that powers three feeders. Fig. 1 shows a simplified one-line diagram of the Saint Paul Island electrical system. For the study, remote heat loads rated at 200 kW were modeled at locations M, N, O and P.

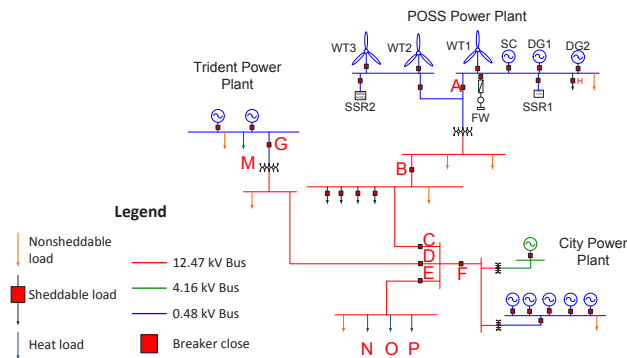


Figure 1. Simplified diagram of the Saint Paul Island electrical system

III. EXISTING ELECTRICAL CONFIGURATION

The city of St. Paul is responsible for operating its power plant and is the local electric utility.

POSS camp is an industrial facility owned by TDX Power, Inc. It is located approximately 2.5 miles from the city power plant. Presently, the POSS power plant operates as a separate grid feeding the local POSS camp load with one wind turbine and two diesel generators. POSS camp Breaker A is in the Open position. The Trident power plant operates as a separate

grid feeding loads to the Trident plant with Breaker G is in the Open position.

Presently, the utility is connected to the POSS camp wind farm bus that feeds most of the city loads.

IV. MGCS OBJECTIVES

The MGCS objectives are as follows:

- Unit commitment, tie-flow control (TF), and heat trading (HT).
- Detecting islands and performing automatic synchronization (A25A).
- Assessing load and generation capacity.
- Maintaining power balance by fast load-shedding control and load restoration.
- Controlling WT, FW, and heat loads.
- Determining enable criteria to the SSR1 frequency regulator.
- Providing access to an operator via the human-machine interface (HMI).

The MGCS has different operating philosophies depending on whether the microgrid is operating with the utility connected, without utility-connected modes, or with or without Trident connected. Table I summarizes modes of operation. The synchronous condenser (SC) is not included in the table because it will dispatch reactive power as required.

A. Forming the Microgrid Operation Philosophy

Enabling the breakers for decoupling is based on two inputs, the city operator permissive and MGCS capacity calculations.

The city operator can only enable the following configurations: Breaker A; Breakers A and B; or Breakers A, B, and C.

TABLE I. MODES OF OPERATION

Initial Condition	Wind Profile	Decoupling Permissive	Event	Assets					
				DG1/DG2	FW	SSR1	SSR2	WT	Remote Heat Load
Utility connected to POSS and Trident	Low	Enable Breaker A	No Event	ON	NA	NA	NA	NA	NA
		Enable Breaker B		ON	Q Dispatch	NA	NA	NA	NA
		Enable Breaker C		ON	Q Dispatch	NA	NA	NA	NA
	High	Enable Breaker A	No Event	OFF	NA	NA	TF/HT	NA	TF/HT
		Enable Breaker B		OFF/ON	Q Dispatch	NA	TF/HT	Pref** - Curtail	TF/HT
		Enable Breaker C		OFF/ON	Q Dispatch	NA	TF/HT	Pref - Curtail	TF/HT
	Low	Enable Breaker A	Breaker A Decouple	OFF/ON	P Dispatch	Freq-Reg*	NA	NA	TF/HT
		Enable Breaker B	Breaker B Decouple	OFF/ON	P, Q Dispatch	Freq-Reg	NA	NA	NA
		Enable Breaker C	Breaker C Decouple	OFF/ON	P, Q Dispatch	Freq-Reg	NA	NA	NA
	High	Enable Breaker A	Breaker A Decouple	OFF/ON	P Dispatch	Freq-Reg	TF/HT	NA	TF/HT
		Enable Breaker B	Breaker B Decouple	OFF/ON	P, Q Dispatch	Freq-Reg	NA	NA	NA
		Enable Breaker C	Breaker C Decouple	OFF/ON	P, Q Dispatch	Freq-Reg	NA	NA	NA

*Freq-Reg is frequency regulation. **Pref is power reference.

Based on inputs from the city operator, the MGCS determines the decoupling PCC breaker in such a way that it respects the selection of the city operator, uses the spinning reserve, and feeds the essential loads within the microgrid. The MGCS can perform the following actions:

- If the city operator selects Breaker A, the MGCS will always select Breaker A.
- If the city operator selects Breakers A and B, the MGCS will enable either Breaker A or B, depending upon the spinning reserve in the island.
- If the city operator selects Breakers A, B, and C, the MGCS will enable either Breaker A, B, or C depending on the spinning reserve in the island.

The POSS camp operator can select the spinning reserve capacity to turn on or turn off the diesel generators. The POSS camp operator selects the breakers based on capacity levels. These levels can only be enabled one at a time:

- Level 0 implies capacity supporting loads to Breaker A.
- Level 1 implies capacity supporting loads to Breaker B.
- Level 2 implies capacity supporting loads to Breaker C.

Based on inputs from the POSS camp operator-selected levels, the MGCS determines whether to turn the diesel generators on or off as follows:

- Level 0 – The MGCS turns on the diesel generators as required to cover the loads up to Breaker A; otherwise, it turns off the diesel generators.
- Level 1 – The MGCS turns on the diesel generators as required to cover the loads up to Breaker B; otherwise, it turns off the diesel generators.
- Level 2 – The MGCS turns on the diesel generators as required to cover the loads up to Breaker C; otherwise, it turns off the diesel generators.

B. Utility-Connected Operation Philosophy

For this configuration, the MGCS has four critical control functionalities:

- Maintain tie-flow control across the utility tie (Breaker F) to regulate a minimum percentage loading of diesel-powered generator sets (30 percent of rated power) at the utility by dispatching excess wind power to the resistive loads and remote heat loads.
- Control OFF/ON of the generators at POSS camp.
- Charge or discharge the FW and provide active and reactive power (P and Q) support.
- Curtail the WT power reference in case of a high-wind profile if Breakers B or C are enabled for decoupling. This logic is implemented to prevent an overfrequency condition after decoupling.

C. Island Operation Philosophy

If microgrids are formed because of disconnection from the utility by opening either Breaker A, B, C, or F, the MGCS will perform as follows:

- For frequency and voltage control, the MGCS will switch Trident to isochronous (ISOC) mode if Trident is connected to the newly formed microgrid.
- If Trident is not connected to the microgrid, the MGCS will function to maintain the voltage and frequency as follows:
 - Enable the SSR1 to regulate frequency and allow the SC to regulate the terminal voltage.
 - Provide resilience by transitioning the POSS camp diesel generators from Base mode to ISOC mode for a fixed period before switching the generators back to Base mode. This function is only enabled under special circumstances when the island is operating in peak load and SSR1 is limited by its capability thresholds.
 - Command the FW to dispatch reactive and active support and simultaneously send a Start command to the diesel generator (with a startup time of 20 seconds). The delay in startup time is coordinated with the FW dispatch. This condition occurs when the wind profile is less than 5 m/s cut in and greater than 22 m/s cut off.
- The MGCS determines normal and abnormal conditions based on voltage and frequency measurements. If the utility is normal, A25A can be performed through Breakers A and B.
- The operator may enable or disable A25A through Breakers A and B. Breaker C is not equipped with A25A functionality.
- Manual close operation to Breaker C is performed as follows:
 - The operator opens Breaker B and then issues a Dead-bus Close command on Breaker C.
 - The operator initiates A25A to Breaker B and restores loads based on priority.
- If a microgrid is formed with the utility in an abnormal state, the MGCS determines whether enough spinning reserve exists with the newly formed microgrid. If so, the MGCS indicates this state to the operator. The operator can then issue a Breaker Open command to Breaker B or C. The MGCS will issue a Dead-bus Close command on either Breaker A or B, and will restore power.
- Loads can be shed if necessary to mitigate frequency excursions after disconnection.

D. Contingency-Based Load-Shedding Philosophy

After the islanding event, the main objective for the MGCS is to stabilize the new island. Because the MGCS determined the decoupling point based on the essential loads

within the microgrid, the MGCS will decide whether load shedding is required to maintain balance between the generation and loads.

The contingency-based scheme sheds load based on a predicted power deficit when a contingency occurs. Contingencies are defined as breaker openings that cause the loss of one or more power sources. This scheme reduces the total plant load to less than the calculated available capacity based on the measured capacity. The calculation occurs before a contingency and includes the spinning reserve of the power sources [4].

E. Heat Load Trading Philosophy

The MGCS will dispatch excessive wind power to resistive load SSR2 and charge the FW, if necessary. The MGCS will constantly record the SSR2 power value and calculate an average power. If the average power is set to a specific kW value for a specified period, the MGCS will trade a certain percent of this average excessive wind power value from SSR2 to the remote heat loads. This trade value will be distributed evenly to all heat loads based on topology and heat loads status (M, N, O, and P). If the SSR2 active power value is less than the average power set kW value for a specified period, the MGCS will declare the heat load trading complete. If excessive wind power drops to zero, the MGCS will immediately shut off the heat loads. The time settings in the trade philosophy are adjustable on the MGCS HMI.

V. CLOSED-LOOP TEST INTERFACE

Fig. 2 shows the communications architecture that was designed to simulate a field setup. The system modeled in the RTDS is a replication of the power system for Saint Paul Island shown in Fig. 1. The existing DER protocol (Modbus) and IEC 61850 GOOSE protocol were programmed to communicate status and control signals between the RTDS and the MGCS to mimic the interaction between the MGCS and the diesel generators, PCC breakers, WTs, FW, SC, sheddable loads, dump loads, and heat loads.

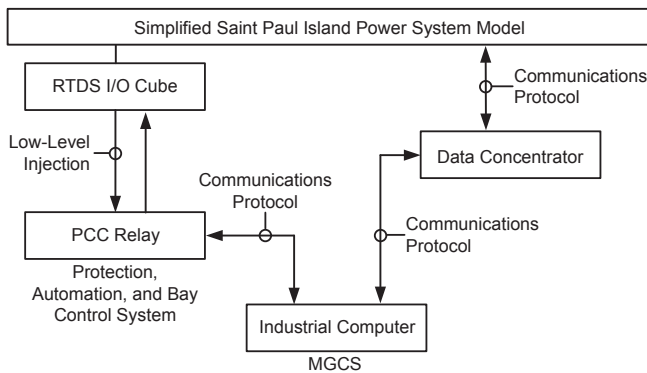


Figure 2. Closed-loop test interface

The protection relays at the PCC were connected in a closed loop with the RTDS to test the A25A logic [5] and the decoupling strategy.

An interface controller was programmed to serve as a data concentrator and function as a bridge between the power system model and the MGCS communications architecture to simulate communication between the data concentrator and the field IEDs. The critical step in the process was to develop an extensive input/output (I/O) list to analyze the data type (e.g., active or reactive power, bus frequency or voltage, breaker status, trip commands, analog control set points).

VI. CLOSED-LOOP TEST RESULTS

More than 70 tests were performed as part of the factory acceptance test (FAT). Two of those tests are explained in this paper.

A. Decoupling Event With Steady-State High Wind

In this test, the city generator was operating in ISOC mode, the POSS camp diesel generators were operating in Droop mode, and the wind speed at POSS camp was set at 14 m/s. A decoupling event was simulated by applying a single-line-to-ground fault for 300 ms at Breaker C.

As the POSS camp operator selected Level 2, the city operator selected Breakers A, B, and C. Also, the MGCS enabled Breaker C based on sufficient spinning reserve. In response to the fault, a new microgrid was formed at Breaker C. The MGCS enabled SSR1 and dumped 300 kW to regulate frequency (see Fig. 3). The MGCS used the FW to dispatch 100 kVAR of reactive power to support the bus voltage. Fig. 4 shows the frequency response to the decoupling event at Breaker C and the unintentional opening of that breaker. The authors superimposed both events to indicate the formation of a resilient and stable microgrid.

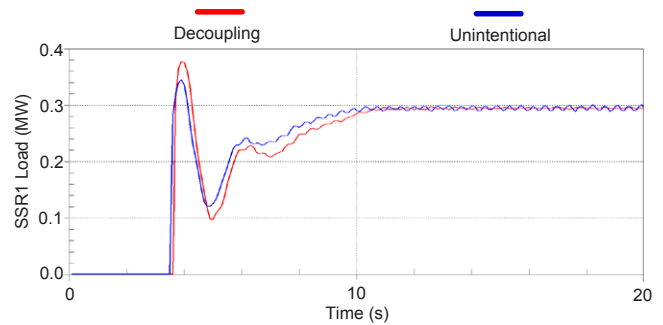


Figure 3. SSR1 response for high-wind decoupling

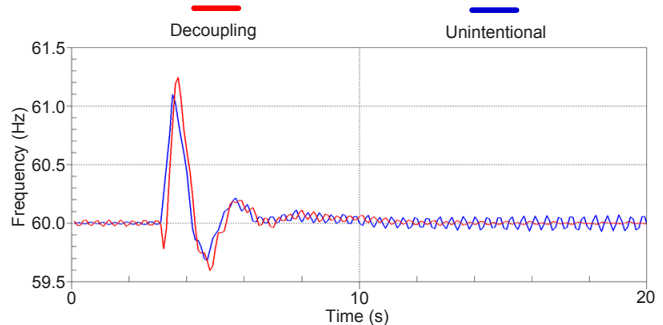


Figure 4. Frequency response for high-wind decoupling

B. Actual High-Wind Condition With the Utility Connected

In this test, an actual wind profile extracted from the site WT tower anemometer was programmed into the model as shown in Fig. 5. Fig. 6 shows the interaction of city generator operating in ISOC and the wind power influx into the system. Based on Table I, the MGCS regulated the minimum set point across Breaker F by controlling the SSR2 power, as shown in Fig. 7. As MGCS selected Breaker C, it commanded the FW to dispatch 100 kVAR for reactive power. The MGCS also implemented WT power reference curtailment to avoid any overfrequency trips if a decoupling event occurred, as shown in Fig. 8.

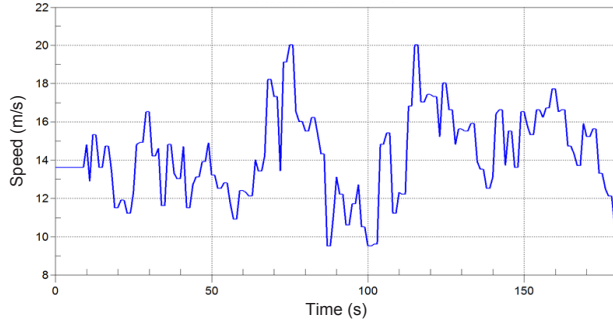


Figure 5. Actual high wind profile

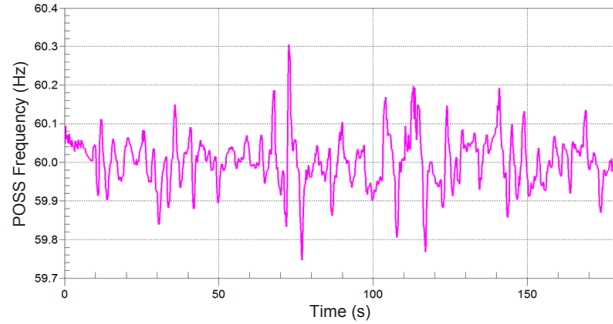


Figure 6. System frequency response to actual high wind profile

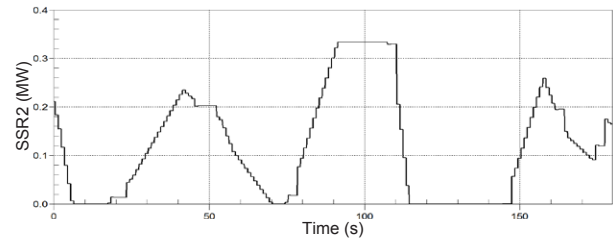


Figure 7. SSR2 response for controlling the tie flow

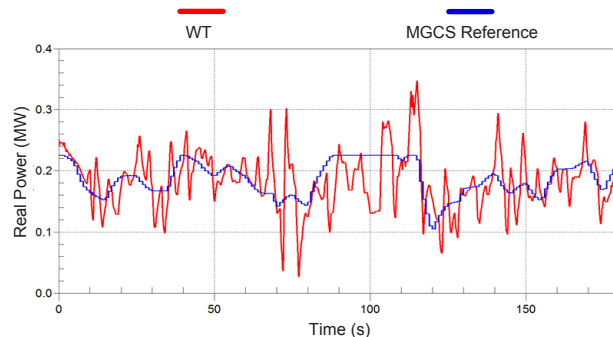


Figure 8. Wind power reference curtailment with utility connected

VII. ADVANTAGES OF CLOSED-LOOP TESTING

The effects of connecting the St. Paul city power plant, POSS camp, and Trident plant together as one island were studied. The following insights were identified:

- Although an active power balance was attained, the microgrid collapsed because of a shortage of reactive power, especially during high-wind conditions.
- Preliminary solutions were discussed with TDX Power, Inc. to solve the reactive power shortage during decoupling events. These solutions included placing static capacitors at different local buses, increasing WT tower capacitance, and using the FW as a reactive source. Further studies are required to determine a final solution.
- The MGCS actions were studied with the existing protection settings of the DERs in the island. The conclusion was that the existing settings must be coordinated to achieve survivability.
- The existing SSR1 frequency regulator must be retuned when all three WTs are on one islanded system.
- Implementing fast communications protocol for enabling/disabling the SSR1 frequency controller is important for system instability.

VIII. CONCLUSION

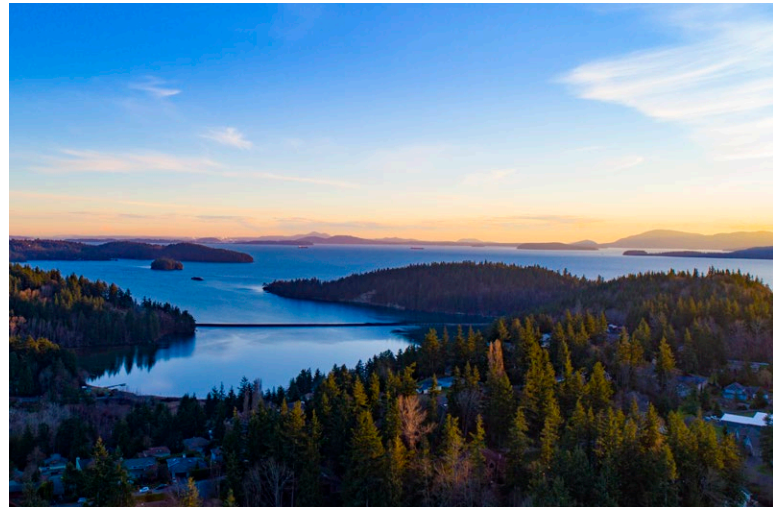
This project was conducted in collaboration with TDX Power, Inc. with the prime objective of establishing a proof of concept of the MGCS functionality against critical criteria such as disconnection, resynchronization, steady state, protection, and dispatch. In the process, a robust MGCS was developed to provide resilience, survivability, and stability. Multiple permissive-based decoupling schemes, tie-flow controls, and heat load trading features were implemented and tested using hardware-in-the-loop (HIL) simulation with a simplified electrical model of Saint Paul Island. In the process of closed-loop testing, several insights were identified, lessons learned from the HIL are also discussed in this paper.

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Customer Highlight



PUGET SOUND ENERGY

SEL POWERMAX® microgrid control system ensures reliable power for community fire station during storm season

MICROGRIDS that incorporate energy sources like BESS (battery energy storage system) and photovoltaic (PV) systems allow islanding from the grid during outages to ensure the reliable and resilient delivery of electric power to critical infrastructure and communities. With the SEL POWERMAX Microgrid Control System (MCS), microgrids disconnect and operate independently when there is an outage on the main grid. Upon service restoration, the microgrid resynchronizes with the grid and recharges the BESS.

Customer problem

Samish Island's position in the Salish Sea between Samish and Padilla Bays in northwest Washington exposes it to high winds during the fall and winter storm season. Puget Sound Energy (PSE) provides electric service to Samish Island. Their electric system is often damaged due to the severe weather and downed power lines, leaving critical emergency services vulnerable to frequent and prolonged grid outages.

Solution

PSE, in collaboration with SEL, installed an advanced POWERMAX MCS to provide flexible management of their BESS- and PV-powered microgrid. The solution provides islanded power support to the fire station and neighboring residences at the end of the line during power outages. Other features of the custom-built solution include the ability to actively manage numerous generation sources and loads, along with an HMI to enable real-time control.

Results

During the first storm season of operation, the microgrid operated successfully through multiple islanding events, providing local power, sometimes for several hours, until PSE restored service to the incoming line. The MCS isolated the microgrid and maintained voltage and frequency, which supported the load of the fire station and neighboring homes during the outages. The solution also seamlessly reconnected and synchronized with the grid when conditions improved and managed recharge of the BESS.



Customer Highlight



UNIVERSITY OF NOTRE DAME

POWERMAX® Microgrid Control System Adds Reliability and Security for Campus' Expanding Grid

Managing the load balance on a university campus is crucial. Any blackout hinders critical activity, including research, student living, and more.

Customer problem

The SEL Plymouth, Michigan, office had been supporting the University of Notre Dame (UND) with their SEL relay settings for a year when UND identified the need to grow their campus load with more robust infrastructure, expanding from an older 4 kV system to a new 12 kV system.

UND needed a new power management control system to tie together their expanding grid—two new Solar turbines on the 12 kV system and the existing 4 kV system—and to manage the load balance of the two halves of campus.

Solution

SEL designed the infrastructure needed to provide SCADA automation, a control system, and protection for the campus once the system was up and running. The POWERMAX Power Management and Control System included generation control, a load-shedding scheme, an automatic synchronization scheme, and a tie flow control scheme to manage the import of power. SEL also provided control panels for each of the substations.

Cybersecurity services were added to provide software-defined networking (SDN) and additional security features, like secure remote access, an intrusion detection system, malware prevention, and disaster recovery solutions.

Results

UND has achieved a robust and reliable power system that also provides the opportunity to expand in the future as their campus and power needs change and grow. The system developed includes a large and secure SDN network configuration for cutting-edge cybersecurity. The increased visibility and access to data has shown immediate benefit for UND.



Customer Highlight



WASHINGTON STATE UNIVERSITY

SEL POWERMAX at Washington State University

A combination of variable load demands and critical facilities—such as student housing and research labs, respectively—means that university microgrids require a high level of adaptability and resiliency. SEL microgrid controls help prevent widespread outages and keep systems operational by delivering seamless islanding, critical asset protection, and reliable system control.

Customer Problem

On its 640-acre campus, WSU operates multiple electric power substations and a steam plant responsible for heating the university's classrooms and residences. These facilities are supported by two gas-fired engine generators, a diesel generator, and a programmable logic controller (PLC) originally installed in 2000. After more than twenty years in service, the PLC was difficult to maintain: the manufacturer no longer offered technical support, documentation was limited, and spare parts were few and far between.

Solution

SEL evaluated the existing systems and recommended a POWERMAX® Power Management and Control System—a combination of hardware and software designed to improve system reliability. POWERMAX's microgrid control library tracks the local electrical power system topology and responds to power loss by quickly shedding noncritical loads, restoring power with local generation sources, and then resynchronizing with the utility when possible.

Results

WSU partnered with SEL to update their system to the POWERMAX solution, which involved installing new panels, wiring new relays and other SEL equipment into existing panels, and drafting new documentation for the system.

With POWERMAX installed and fully operational, WSU has gained increased resiliency, as-built documentation, and 24/7 emergency technical support for the lifetime of their products.

POWERMAX® Remedial Action Schemes (RASs)

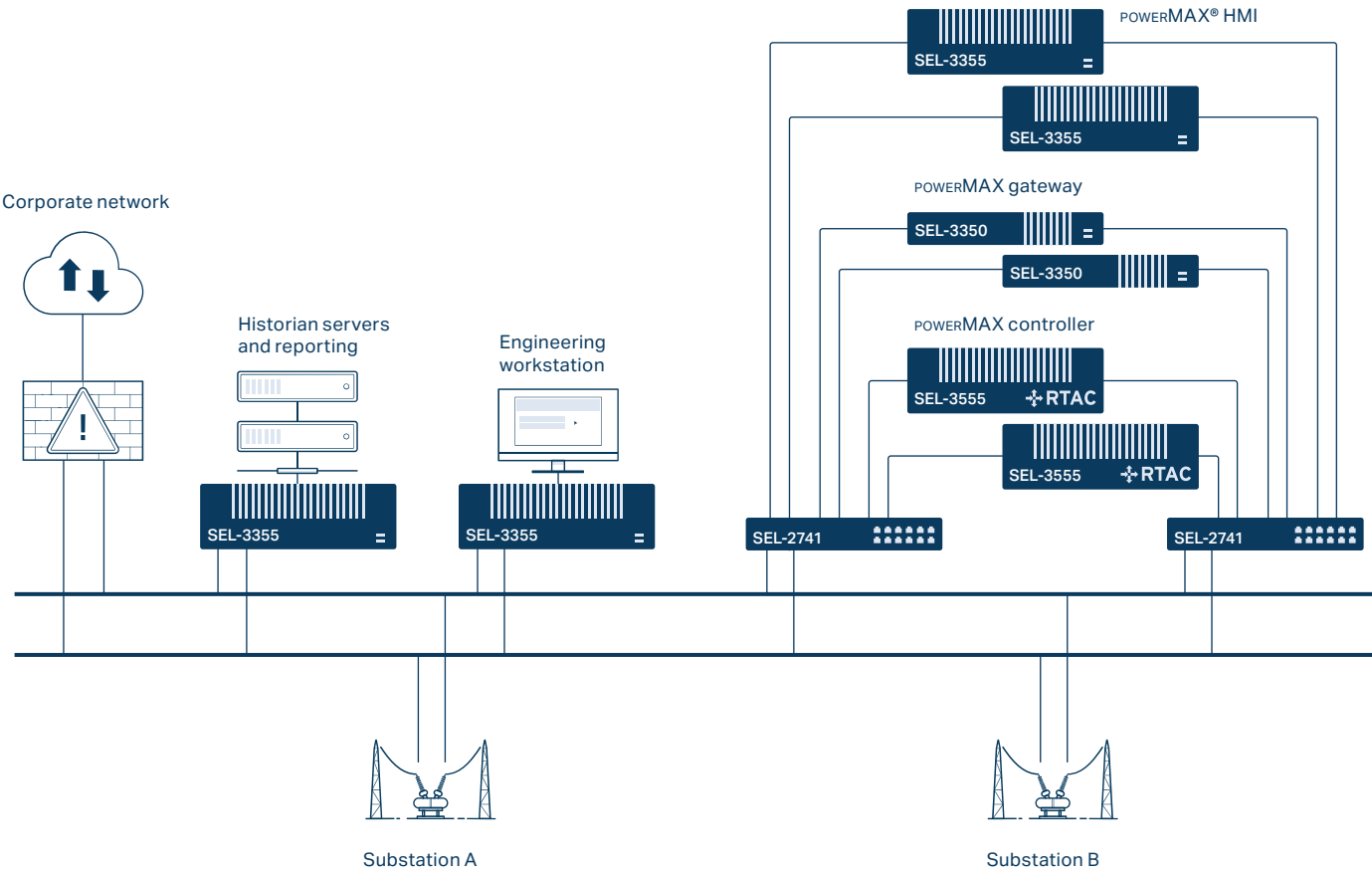
SEL POWERMAX RASs provide the foundation to integrate large geographic regions of interconnected generation sources, such as wind, photovoltaic, steam, gas, and hydroelectric sources, with transmission systems.

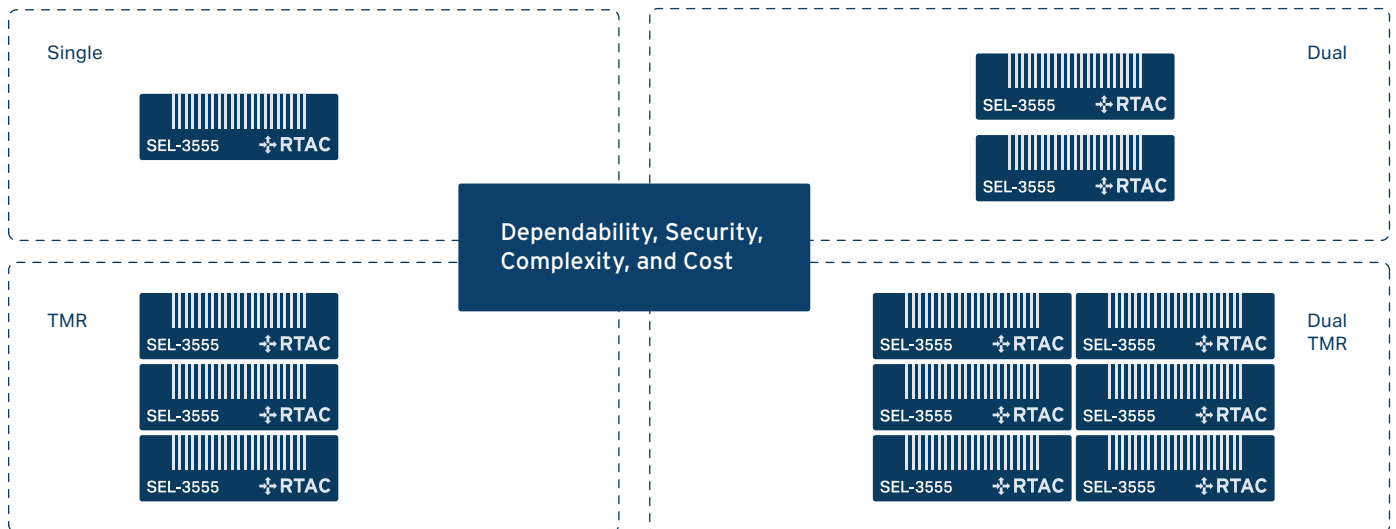
Every POWERMAX RAS is built to your unique specifications. Integrating a POWERMAX RAS with your existing relays, meters, and communications systems reduces overall project costs.

Optional features include:

- Wide-area systems communications and operations at relay speeds.
- Synchrophasor monitoring and control.

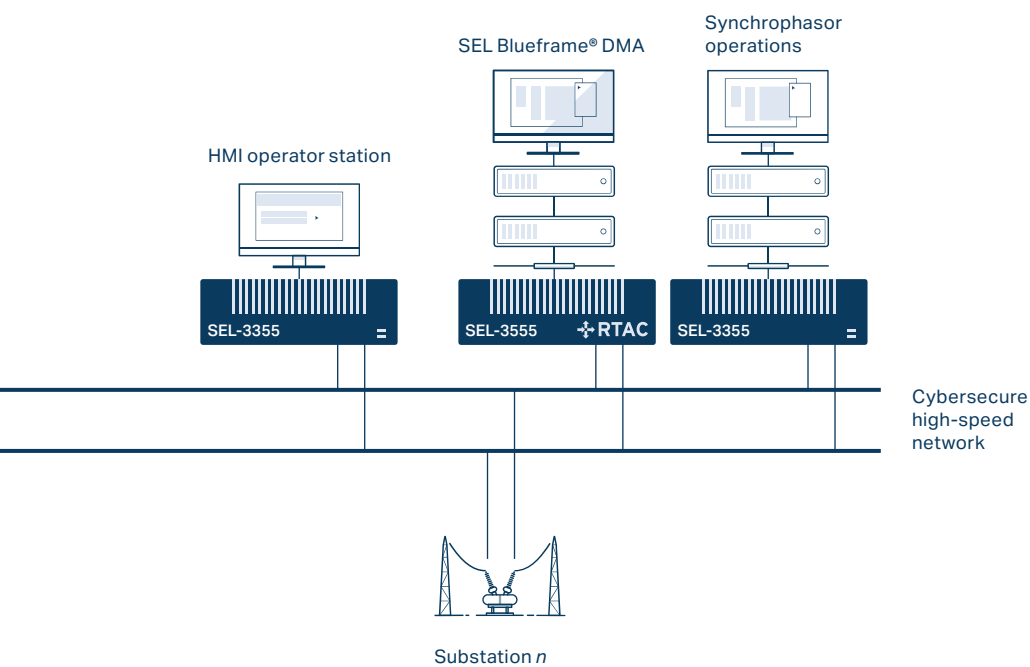
- Fast decoupling solutions.
- Distributed computing and communications for smart transmission grid management.
- High-speed triggering using either breaker status change, protective relay trigger, or current change.
- Triggering logic to utilize custom user-defined logic, nomograms, or polynomial gain equations.
- Shedding requirements for generation, load, dc interconnect, capacitor banks, or other system controls.
- Subcycle speed to maintain power system stability.
- Incorporation of active system states of loads and generation.
- The ability to select actions based on predefined system contingencies.
- Action selection based on optimization algorithm—optimize to minimize overshed, minimize units shed, or minimize operator input.
- Support of dual primary, triple module, and dual triple module redundancies.
- Support of online or offline simulation with a playback feature.
- Assistance in complying with NERC PRC-5.
- Compliance with NERC PRC 12-2.





All dual systems can be hot-standby or dual-primary.

POWERMAX Systems offer hot-standby, dual-primary, and triple-modular redundancy (TMR), so you can select the system reliability that matches your needs.





POWERMAX® Remedial Action Schemes (RASs)

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PacifiCorp's Jim Bridger RAS: A Dual Triple Modular Redundant Case Study

Dean Miller, *PacifiCorp*

Robert Schloss, Scott Manson, Sai Raghupathula, and Trent Maier, *Schweitzer Engineering Laboratories, Inc.*

Abstract—The Jim Bridger Power Plant, located near Rock Springs, Wyoming, is a mine-mouth, coal-fired generation station jointly owned by PacifiCorp and Idaho Power Company. Jim Bridger operates four 530 MW units that transmit the majority of their power through three 345 kV lines west through the Borah West Corridor in southern Idaho. Two 230 kV lines connect to the Wyoming transmission system as well. A subcycle remedial action scheme (RAS) allows system operators to push more power through their existing transmission infrastructure, meanwhile protecting against several known dynamic stability problems.

The existing RAS consists of two systems, one a triple modular redundant (TMR) programmable logic controller (PLC) and the other a hard-wired relay panel. Both systems are obsolete and at the limit of maintainability. They are also difficult to expand in terms of improving logic and adding I/O for new transmission.

PacifiCorp contracted with a supplier to implement a dual TMR RAS system to satisfy PacifiCorp and WECC (Western Electricity Coordinating Council) requirements. The system utilizes proven substation-grade, IEC 61131-3-compatible programmable controllers and high-speed I/O. Each TMR system consists of three identical systems gathering I/O, performing two-out-of-three voting on the data, and performing calculations to decide if an action is necessary. Total loop timing from input assertion to output contact conduction is less than 17 milliseconds. An action (generator trip or capacitor insert/bypass) cannot be executed unless two of the three systems in a TMR RAS agree. The two fully independent TMR RAS systems have dual supervisory units to ensure that a different action can never be taken by the two independent RAS systems. Due to the dual TMR nature of the RAS, a total of four very specific device failures is necessary before the RAS is incapable of reaching a decision.

I. BACKGROUND

A. Power System

The Jim Bridger Power Plant is located 22.7 miles east of Rock Springs in southwestern Wyoming. The coal-fired electrical generating plant with its four 530 MW units is adjacent to a coal mine from which most of the fuel for the plant is obtained. The plant, which is jointly owned by PacifiCorp and Idaho Power Company, is operated by PacifiCorp. The transmission system that connects the Jim Bridger Power Plant to the transmission grid consists of three 345 kV lines and three 230 kV lines. Although the plant is in Wyoming, it is an energy resource for the PacifiCorp and Idaho Power loads in Idaho, Oregon, and Washington. The power from the plant is transported over three 345 kV and two 230 kV transmission lines that radiate out to the west. Those transmission lines and the critical parts of the transmission

system across the states of Wyoming, Utah, Idaho, and Oregon are parts of the transmission system monitored by a remedial action scheme (RAS) located at the Jim Bridger Substation. Since the plant was built in the early 1970s, a RAS has been required to achieve the transmission path rating needed to move the energy from the plant to the loads. When the transmission path is being operated at the path limit and a transmission line in the path is lost, the generation at Jim Bridger must be reduced to maintain the transient stability of the power grid.

The complete loss of the RAS for any reason requires that the Jim Bridger Power Plant be reduced to 1,300 MW. The full capacity of the Jim Bridger Power Plant is greater than 2,200 MW.

B. History

There have been three generations of Jim Bridger RAS control systems, and each successive system has increased in complexity. The reason for the additional complexity has been to reduce the number of times that generator units must be tripped. Each generation of Jim Bridger RAS has monitored additional statuses of the power system. With the additional information, the arming levels for tripping generator units for different line faults were raised. The worst-case scenario must be assumed for any condition that is not being actively monitored by the RAS. The less complex, older systems have therefore caused unnecessary tripping of generator units for the loss of transmission lines. The system being described in this paper has more inputs, a more complex algorithm, and therefore will shed less generation than any of the preceding systems used for the Jim Bridger RAS.

C. Description of Dynamic Problem

When a fault occurs on the transmission system, the power flow, as a result of the fault, is predominantly reactive power, since the impedances of the transformers and lines are predominantly inductive. During the fault, the voltage at the fault is zero, and the voltage at the terminals of the generators is significantly reduced. The low voltage restricts the real power flow from the generators. Since the turbines driving the generators are continuing to pour real power into the generators, the units start to accelerate. This acceleration continues until the faulted transmission line is disconnected from the system. With the fault removed, the real power starts moving from the generators to the load, and the generators decelerate. With the removal of the faulted transmission line from the power system, the transmission path impedance is increased.

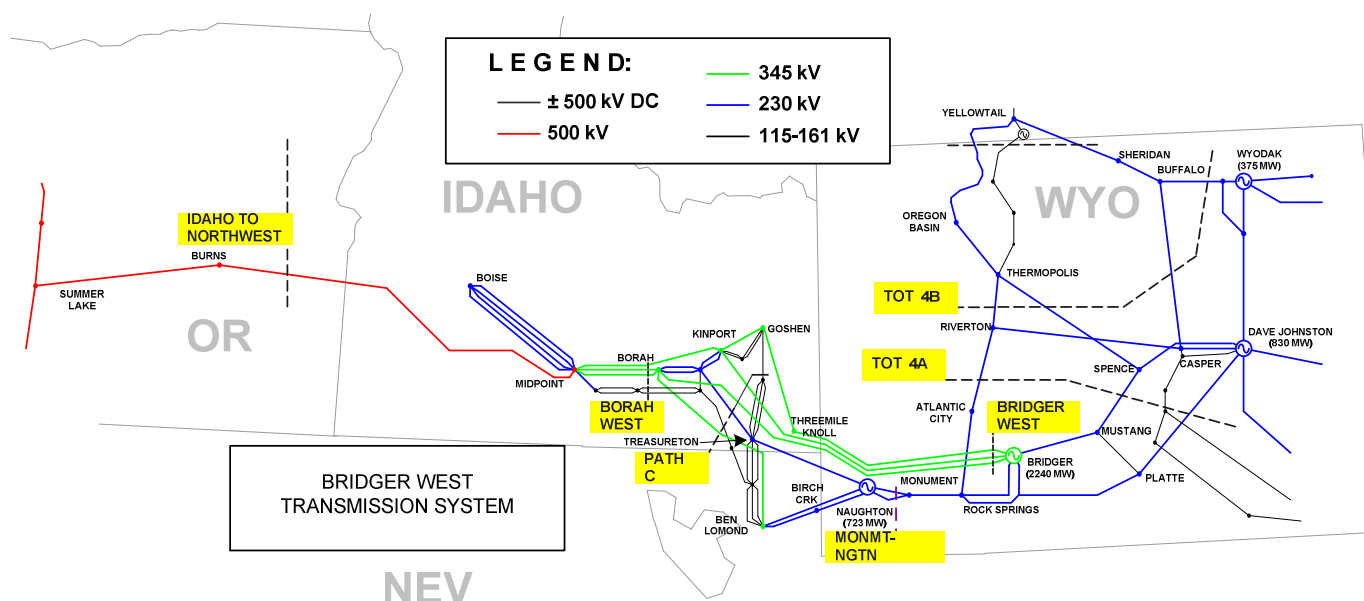


Fig. 1. Map of Transmission System

The increase of the transmission path impedance combined with the generator acceleration during the fault results in an oscillation between the generator rotors and the power system. If the real power flow is low enough and the increase in transmission path impedance small enough, the oscillations will dampen, and a new equilibrium state will be reached. If the new conditions are too extreme, the oscillations will not dampen, and the Jim Bridger generators will go out of step with the PacifiCorp power system.

The generation oscillations will cause the voltage at Jim Bridger to swing in magnitude. The voltage magnitude on the first swing after the fault is cleared is an indicator of the stability of the system. The Western Electricity Coordinating Council (WECC) requires that the voltage on the first swing not drop more than 30 percent from the prefault value. The Jim Bridger RAS action is needed to prevent the voltage at Jim Bridger from dropping more than the 30 percent limit following the loss of a transmission line when the plant is operating near the transmission path limit. To arrest the voltage dip, the power output from the plant must be reduced and, in the most severe cases, within 5 cycles on a 60 Hz base. The 5 cycles are measured from the inception of the fault until the generator breaker disconnects the generator.

II. RAS CONTROLLER REQUIREMENTS

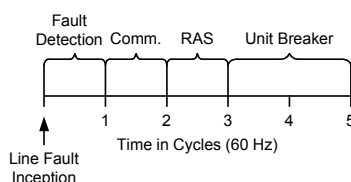
A. Timing Requirements

Based on stability studies for the most severe fault case (a multiphase fault on a 345 kV line close to Jim Bridger), the total time from event to resulting action must not exceed 5 cycles. Fig. 2A1 shows the time allocation for this case. Zone 1 faults (faults close to Jim Bridger) are the most severe N events; for these events, the overall reaction time is 3.7 cycles. (See Section VI, "RAS Design," for a further explanation of N events.) The breakdown for Zone 1 events includes 16 milliseconds for the line relays, no communica-

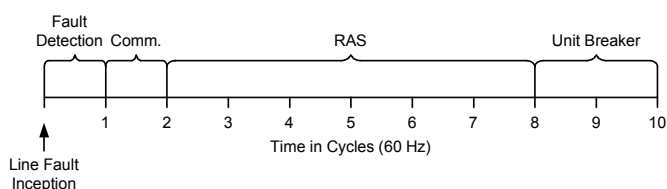
tions time, 20-millisecond RAS processing time, and 25-millisecond unit breaker clearing time. When the typical fault detection, communications time, and unit breaker opening time are excluded from the total time budget, the RAS is left with 20 milliseconds of operating time. The RAS operating time is the total measured time from an input voltage asserting to 90 percent to an output (trip contact) fully conducting.

A: For Jim Bridger Area Line Loss

A1: For Multiphase Line Faults



A2: For Nonmultiphase Line Faults (Single-Line-to-Ground or Nonfault Line Opening)



B: For Non-Jim Bridger Area Line Loss

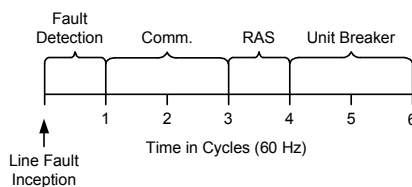


Fig. 2. Timing Charts

For less severe fault cases, less speed is required. Fig. 2A2 shows the time allocation for a single-line-to-ground fault on a 345 kV line. Although the Jim Bridger RAS has the capability to process the signals in the time needed for the most severe

case, the process is deliberately delayed for single-line-to-ground faults. Since a single-line-to-ground fault can evolve to a multiphase fault in the time it takes to detect and clear the fault, delaying the RAS response is beneficial. If the processing for the initial event is not delayed, excessive generator tripping could result. If, due to system conditions, a small amount of generation tripping was required for the single-line-to-ground fault but the output of the selected generator for tripping was inadequate for a multiphase fault event, multiple generators could be tripped when the fault evolved to a multiphase fault. By delaying the RAS to see if the fault condition will worsen, the minimum amount of generation will be tripped.

For the loss of a transmission line at a great distance from Jim Bridger, the line loss status needs to be communicated to Jim Bridger. This communication over several hundred kilometers adds additional delay, but studies have shown that the delayed response will not have an adverse effect on the stability of the power system. Fig. 2B shows the time allocation for the loss of a remote transmission line, such as the Three Mile Knoll – Goshen line.

B. Triple Modular Redundant Requirement

With the correct and timely response of the Jim Bridger RAS being critical to the stability of the power grid, the dependability of the Jim Bridger RAS is important. For this reason, the Jim Bridger RAS must be a system containing redundant inputs, outputs, and processing units. Transmission line fault incidents are unusually high for this transmission system due to the following factors:

- The 240-mile length of the transmission lines
- The rugged terrain the lines cross
- The 8,300-foot elevation of the lines
- Difficult grounding conditions
- Many unknown factors

The average incidence of faults on this transmission system is 0.8 faults per week. The plant is base loaded 24 hours a day. Between the plant's loading and the transmission line fault incidents, the Jim Bridger RAS is often called on to react. Most of these events do not require generator unit tripping, because the plant is operated at loading levels below the arming level for the most common transmission line faults, single-line-to-ground faults. The consequence of tripping a 530 MW coal-fired unit involves significant costs and reduces the reliability of the unit. For these reasons, balancing dependability with security against false operations is very important. This is why the Jim Bridger RAS is a triple modular redundant (TMR) voting control system. Two out of three identical systems must agree on the status of the inputs and the resulting outputs for the system to cause a generator unit to trip.

This triple modular redundancy is extended to the power transducers feeding the RAS data. Due to cost and complexity, the triple redundancy was not extended to two of the major

subsystems of the Jim Bridger RAS: the communications systems from remote locations and the fault severity units. These subsystems are only redundant. To accommodate the limitations of these subsystems and TMR system maintenance, dual TMR systems were specified and installed. The transmitters and receivers that use one communications network and one set of fault severity units, which are associated with each transmission line terminating at the Jim Bridger Substation, are connected to one TMR system. The communications equipment using the alternative communications network and fault severity units is connected to the second TMR system. Both TMR systems are normally in service, and either system can trip the generator units.

Due to the speed at which the Jim Bridger RAS must operate, the accuracy of the power transducers, and the scanning nature of a programmable logic controller (PLC), there are several predictable circumstances where the two TMR systems will not select the same generator unit to trip for the same event. The most likely circumstance would be when a unit's power output is near an analog threshold; in this case, one of the TMR systems could select one unit and the other select a different unit as the apparent level of the unit operating at the edge moves in and out of selection. This condition would result in tripping two generators rather than one. Since this is an unacceptable event, provisions were designed into the Jim Bridger RAS to prevent this type of event from happening. Two independent processors review what each of the TMR systems is planning to do if an event were to occur. This is possible because of the way the TMR systems predetermine their action for each of the possible line loss events based on current system conditions. Statuses as to the health of the subsystems are communicated to the monitoring systems. If the predetermined actions of the two TMR systems do not agree, the system with the healthier subsystems is permitted to take the action if the event takes place. If the health of all systems is equal and the two TMR systems will perform different actions for the event, a predetermined TMR system will be permitted to perform the action.

The other important issue is that the previous TMR systems were not designed to tolerate and perform correctly in the substation environment. Most TMR systems on the market are designed for industrial applications, and the substation introduces different environmental issues. The previous TMR system was designed with external protection elements on the inputs and outputs of the system that brought the overall system up to meeting the IEEE relay equipment environmental standards. These auxiliary systems performed well in protecting the TMR system, but later in the life of the RAS, these auxiliary systems began failing at a higher rate than the TMR primary systems. The new systems meet the IEEE relay equipment environmental standards out of the box, which should provide longer trouble-free life to the overall RAS.

C. Events and Actions

The following is the list of transmission lines for which the statuses are monitored in a real-time, high-speed manner. The single or combined loss of multiples of these lines is an event that could trigger an action from the Jim Bridger RAS.

- Jim Bridger – Borah 345 kV line
- Jim Bridger – Kinport 345 kV line
- Jim Bridger – Three Mile Knoll 345 kV line
- Jim Bridger – Rock Springs 230 kV line*
- Jim Bridger – Rock Springs via Point of Rocks 230 kV line*
- Three Mile Knoll – Goshen 345 kV line
- Goshen – Kinport 345 kV line*
- Midpoint – Borah #1 345 kV line*
- Midpoint – Borah #2 345 kV line*
- Midpoint – Kinport 345 kV line*
- Midpoint – Summer Lake 525 kV line

The loss of a transmission line marked with an asterisk will not, as a lone condition, cause generation tripping at Jim Bridger, regardless of the plant loading. However, closely timed or simultaneous successive combinations of line outages will cause generation to trip. The RAS was designed to respond to closely timed or simultaneous events; this functionality is key to a successful RAS control strategy.

The cause of the transmission line loss is taken into consideration for the loss of the lines that radiate out from the Jim Bridger Substation. The severity of the fault will impact the action to be taken. Relays throughout the PacifiCorp system are set up for fault detection and discrimination; the relays categorize each detected fault into one of the following:

- No fault or single-line-to-ground fault
- Phase-to-phase close-in fault
- Phase-to-phase remote fault
- Three-phase close-in fault
- Three-phase remote fault

The following is the list of the Jim Bridger RAS actions:

- Jim Bridger Unit 1 trip
- Jim Bridger Unit 2 trip
- Jim Bridger Unit 3 trip
- Jim Bridger Unit 4 trip
- Burns series capacitor bypass transmitter signal
- Goshen shunt capacitor transmitter signal
- Kinport shunt capacitor transmitter signal

The Jim Bridger RAS evaluates the pre-fault conditions and determines which of the above actions needs to be executed for each contingency. The primary conditions used to determine whether generator units need to be tripped for the different line loss events are the real power output of the plant or the real power flow on the three Jim Bridger 345 kV transmission lines and the impedance of the remaining lines. The 345 kV lines are series compensated with multisegment series capacitor banks. The number of series capacitor segments that are bypassed in the remaining lines prior to the line loss reduces the stability of the system and lowers the arming levels in the RAS. In addition to the power flows and compensation levels, an extensive number of critical power

network elements are also monitored. The status of those critical power network elements as well as the prior outage of transmission lines for which the loss of the lines has triggered an event are considered preexisting states for the RAS. The pre-event state of the power system establishes the arming levels for RAS action.

III. ANCILLARY CONTROL FUNCTIONS

There were two functionalities added to the RAS controllers that were not part of the core Jim Bridger RAS. These are described in the following subsections.

A. Subsynchronous Resonance Avoidance

The three 345 kV transmission lines that terminate at the Jim Bridger Substation are series compensated with multisegment series capacitor banks at the remote substation terminals. Each series capacitor has a bypass breaker. When a fault or switching event (N event disturbance) occurs on the local transmission system with the series capacitors bypassed, the system currents change from the previous operating state to the new state with less than a quarter cycle of high-frequency transients. In contrast, when a fault or switching event occurs on a system with series capacitors, the currents change from one state to another with a low-frequency transient characteristic.

The low-frequency switching transient forces an exchange of stored energy in the series capacitors (electrical field) and the stored energy in the inductance (magnetic fields) of the transmission system. During normal operation (prior to an event), the energy in these two systems is in a state of equilibrium. The frequency of this electromagnetic oscillation is dependent on the natural frequency associated with the value of the inductive and capacitive reactance of the power system.

Unfortunately, several turbine generators in the local system have mechanical resonance frequencies that coincide with the electromagnetic natural frequency of the electrical power system. Because of this, the fault or switching event that initiated the low-frequency transients in the electric power system will also initiate mechanical oscillations on the turbine generator. Because the electromagnetic and mechanical natural frequencies are so close, they exchange energy at the frequency of oscillation. Unfortunately, there is not sufficient damping in the combined electrical and mechanical system; this causes the amplitude of the natural frequency oscillation to be maintained or grow indefinitely. This phenomenon is called subsynchronous resonance (SSR). SSR events place additional stress on the shaft of the mechanically oscillating turbine-generator units. The cumulative effect of multiple SSR events has caused shaft fatigue and failures at power plants in the PacifiCorp system.

Several control systems are applied on the Jim Bridger power system to prevent SSR. One of these systems is implemented in the same hardware as the RAS. The RAS controllers monitor status points from the plant to determine when it is permissible to insert the last stages of the series capacitors on all three transmission lines. This prevents series

capacitor compensation from increasing to levels known to cause SSR. The plant status signals monitor generator conditions known to promote SSR.

The RAS controllers send the series capacitor insertion permit signals when the following four conditions are met:

- The protective relays used for SSR detection must be in service.
- The generator excitation systems must be in service (they damp out low-frequency oscillations on the turbine generators by varying the generator field current).
- All the on-line generators must be operating above a critical power threshold.
- The total plant power output must be above another threshold.

If these conditions are met, the RAS controllers communicate the signal to the remote terminals to permit the final segments of series capacitors to be inserted at each location. The permit insert signal must be maintained to keep the capacitors in service.

B. Scheduling Limit Functionality

Corridor capacity limits are dynamically changing and are often difficult for PacifiCorp Operations to track. The state of the power system (lines in or out of service) strongly impacts corridor capacity limitations.

The RAS controllers use the known line and equipment outages (J states) to first come up with the system state. The system state is then used to derive the scheduling limit for the Jim Bridger West Corridor. This is done in a fashion similar to

arming level calculations, by using a weighted equation of gains to evaluate the system state and come up with a single scheduling limit number for the Jim Bridger West Corridor.

IV. RAS ARCHITECTURE

Fig. 3 is an overview of the major systems in the Jim Bridger RAS. RAS Systems C and D are identical, triple redundant systems with full two-out-of-three voting. Each input/output (I/O) point to the field is wired to three independent I/O points on both systems. Each half of the RAS I/O is separately wired to terminal blocks, and all RAS controllers and whetting voltages are powered by separate dc battery systems. This creates a system of two completely autonomous control systems, hence the system is considered “dual primary.”

Within each RAS system (C and D), there are three autonomous IEC logic controllers with fully independent I/O modules. These three controllers perform two-out-of-three voting via high-speed communications links. A single substation-hardened computer provides a user interface (human-machine interface, HMI), sequence of events viewing (SERviewer Software), and event report viewing (oscillography). Another hardened computer is used as an engineering workstation and contains the development environment for all hardware (IEC 61131-compliant programming).

Each RAS system (C and D) has its own protocol gateway for communication to the PacifiCorp energy management system (EMS). These gateways communicate the necessary status, metering, and controls to and from the SCADA (supervisory control and data acquisition) masters via serial DNP3.

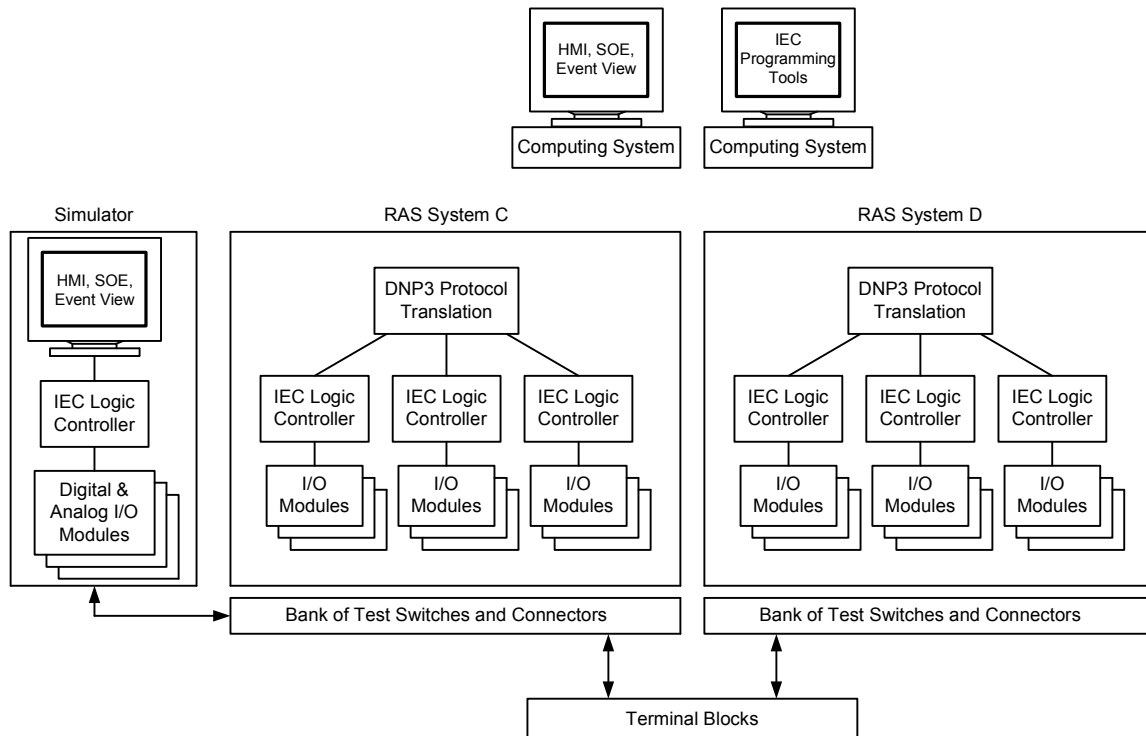


Fig. 3. System Architecture Overview

RAS Systems C and D are completely isolated on separate networks, and all logic on each system runs without any knowledge of the other system. The router between the two systems is configured to prohibit all traffic between the two RAS systems. The router limits communication from the RAS systems only to the HMI, engineering workstation, and supervision systems.

A. SCADA Communication

The SCADA gateway systems function as the intermediary for receiving data from the PacifiCorp EMS that will be used in the RAS system calculation algorithms. These gateways are also used for providing data to the EMS regarding the status and operating characteristics of the RAS system. The tasks performed by the gateways are as follows:

- Receive status and analog values from PacifiCorp and Idaho Power and make them available to the IEC controllers.
- Validate that each redundant data stream contains identical data (status and analog values) that are returned from the three controllers. Select the data source (controller) that represents the best quality data, and pass this on to the EMS.
- Flag and alarm any and all data not consistent within each redundant data stream.
- Identify and alarm any and all communications path failures via a watchdog routine.
- Code using the IEC 61131-3 programming system in a library that can be accessed from any program.

Each IEC controller performs integrity comparisons of data set points coming from the two PacifiCorp EMS front-end processors. One front-end processor is located in Casper, Wyoming, and the other is located in Salt Lake City, Utah. Based upon quality indicators, the controllers select which data source (gateway) to use. Because the code (library) running in each controller is identical, the decisions will be identical. The quality indicators used to decide data source selection include:

- Loss of communications watchdog to the EMS.
- Loss of communication between the gateway and controller.
- Alarm contact assertion on the gateway.
- Unchanging or high latency data from the EMS.

B. Simulator Design

The test simulator for the RAS control system simulates all RAS external inputs, including digital status, control inputs, analog data, and DNP3 data streams. The test simulator contains a user interface (HMI) from which an operator can perform all system tests. All systems run autonomously from the RAS.

The test simulator has the following two operating modes:

- Static simulator. This mode provides the operator the ability to drive each individual input to the RAS to a desired value. For example, the system is used to set EMS set points, set breaker status conditions, and detect generator trips from the RAS. This is extremely

useful for testing all I/O points and creating any desired power system scenarios for presentation to the RAS controls.

- Playback simulator. In this mode, the simulator is used to replay one or more event report files to the RAS system. There are two types of playback files:
 - Playback of RAS system recordings of actual events. This is identically analogous to replaying an event report created by a relay back to that very same relay. The only difference is that the response of the RAS in the recorded event is deleted for the playback, and the test simulator emulates the power system response to the output of the in-test RAS, changing the inputs to the in-test RAS.
 - Playback of recordings created by the engineers. These test records are similar to the RAS report records but are for events that the RAS has never seen before. The records cover a series of events over a period of time. The test simulator again emulates the power system changes that would occur as a result of the RAS unit tripping.

Both RAS subsystems have separate disconnect equipment (test switches) for all status, control, and low-level analog signals. The test simulator plugs into either RAS C or D for testing purposes. When under test, the RAS will not receive any inputs other than the conditions supplied by the test simulator.

The test simulator was used extensively during factory acceptance testing and on-site commissioning and will be used for future verification and maintenance testing.

C. Rugged Design Characteristics

All hardware in the Jim Bridger RAS is protective relay-class, substation-hardened equipment with extended temperature range, physical shock resistance, electromagnetic immunity, and static discharge capabilities.

The control algorithm resides on a substation-hardened controller running an embedded real-time controller engine. This engine is programmable in all IEC 61131 programming languages. There are no fans and no spinning hard drives in any equipment. All components run off of the substation battery (dc). No ac power is used in the RAS panels.

All outputs are Form A, trip-rated dry contacts; there are no interposing relays in the system. These outputs are therefore failsafe (i.e., they remain open unless a tripping scenario has occurred).

Additionally, every zone of the RAS hardware, firmware, and software contains continuous self-diagnostics. This guarantees the detection of catastrophic failures of any component(s) in the system. Every device in the RAS design has a normally closed, watchdog alarm contact that will assert if any device is powered down or has a hardware or firmware failure. These contacts are crosswired to other devices for monitoring, which guarantees that a failure in one device will not propagate further.

The logic, settings, and configurations installed on each hardware system are developed and tested to be fault tolerant,

meaning that bad computations are intentionally rejected. For example, if a line metered value is out of range or coming from a failed device, an alarm will be asserted, and the logic will declare that specific data as bad. All logic, settings, and configurations are set up to automatically reject bad data and reselect available (good) data. Bad data will not be used to make decisions.

A dual Ethernet communications network completely replaces the need for failure-prone, backplane technologies present in most industrial PLCs. The traditional technique for TMR systems is to use three central processing unit (CPU) controller modules on a single backplane, making the backplane the inherently weak point of the design. The Jim Bridger RAS TMR system uses dual redundant Ethernet hardware and redundant communications lines to eliminate this single point of failure.

The result of these design decisions is a RAS that requires four carefully selected, simultaneous hardware failures to prevent RAS operation.

V. COORDINATION WITH NEIGHBORING RAS

The Jim Bridger RAS is tightly integrated with a neighboring RAS system on the Idaho Power transmission system. These two RASs are designed to complement each other with intertripping and coordination, a nontrivial task for any RAS crossing company boundaries.

The Jim Bridger RAS receives two digital inputs (Level 1 and Level 2 trips) from the RAS located at the Idaho Power Midpoint Substation. For Level 1 and Level 2 trips, the Jim Bridger RAS is expected to trip two selectable levels of generation (Level 1 and Level 2). Based on the loss of key facilities in Idaho and prefault conditions, the Idaho Power Borah West RAS will send transfer trip signals to the Jim Bridger RAS for the processing and tripping of predetermined generation amounts. Idaho Power can trip up to two units (Level 2) within a 30-minute window; further trips are blocked during this time to prevent Idaho Power from tripping more power than necessary from the PacifiCorp Jim Bridger Power Plant. The transfer trip signals are sent via high-speed, protective relay communications channels. The Jim Bridger RAS also monitors some key facilities in Idaho. Some data required for monitoring these facilities are sent from the Idaho Power Borah West RAS to the Idaho Power EMS system. These data are shared between the Idaho Power and PacifiCorp EMS systems.

VI. RAS DESIGN

The RAS scheme implemented at Jim Bridger dynamically calculates the generation needed to be shed for each of the pre-identified events and then selects generators to shed, based on a generation selection algorithm. The main requirements of the RAS are as follows:

- Available
- Reliable
- Deterministic
- Fast (operation must be less than 20 milliseconds)

The RAS should be available under all circumstances. Having dual primary systems (RAS C and D) satisfies this requirement. The two systems are independent of each other, which gives the flexibility to disable RAS C or D for testing or maintenance and keep at least one RAS available at all times. Having a triple modular system, two-out-of-three voting, and independent communications paths in each RAS greatly increase system availability. The other two concerns are speed and determinism. Once a contingency is detected, the RAS is required to process the inputs, perform two-out-of-three voting, and trigger remedial action in less than 20 milliseconds. It has to be deterministic under all circumstances. Failure of the RAS to respond within 20 milliseconds may lead to blackouts. To make the RAS fast and deterministic, the RAS logic needs to be efficient. The RAS logic has two parts: data acquisition and processing of the RAS algorithm.

A. Data Acquisition

The RAS needs to gather analog and digital information from the field. Both high-speed and low-speed serial lines are used to gather the data. The dual TMR RAS implemented at Jim Bridger is replacing an existing RAS scheme, so a portion of the I/O required for the RAS was already available. Of the remaining I/O, some had to be wired from the field, and some had to be brought in from remote locations.

Not all data need to be fast. Some of the data are needed in detecting contingencies and some to calculate the RAS actions. This leads to the classification of the required data into two categories: high-speed and low-speed data.

1) High-Speed Data

The communication and input voting logic required to detect contingencies (N events) are accomplished in less than 8 milliseconds. The output voting logic, communication, and contact closure required to energize the trip coils are accomplished in less than 9 milliseconds. The total loop time of the system is therefore less than 17 milliseconds. If the detection of a contingency is delayed, the power system may collapse into a blackout. A proprietary communications protocol was used for high-speed data communication. This protocol provides data with deterministic, 2-millisecond updates of digital I/O to the logic processing units.

2) Low-Speed Data

Low-speed data are processed every 200 milliseconds. These data are used in determining the power system state (J states), determining the appropriate arming levels, and calculating the remedial actions for all the predefined contingencies. Data from the EMS system, analog data, breaker statuses, and out-of-service conditions fall under this category. Once the arming levels and actions for each contingency are calculated, they are fed into a crosspoint switch (CPS). The high-speed input data are then cross-multiplied with the CPS to issue digital output signals (trips).

B. RAS Algorithm and Logic Processing

The RAS algorithm is shown in the flow chart in Fig. 4. The following subsections discuss the different sections of the RAS algorithm.

1) Two-out-of-Three Voting

All data inputs, control outputs, and internal data in each RAS go through two-out-of-three voting. Specifically, all input data (slow and fast) are voted, all internal computations are voted (slow and fast), and all outputs are voted (fast).

For example, in RAS C, there are three logic processors that run similar logic. The data are fed to all the processors, and the processors share the data between them. Processor 1 now has three sets of data, and it performs two-out-of-three voting. At least two sets of data need to agree for the data to be considered valid. Fig. 5 shows the two-out-of-three voting logic.

2) N Events

Any event in the power system that may require a RAS action is identified as an N event (contingency). The following

is the digital information (in order of preference) required to identify an N event:

- Line relay trip signals
- Fault severity signals (single-line-to-ground, phase-to-phase severe and nonsevere, and three-phase severe and nonsevere)
- Breaker auxiliary contact status
- Breaker disconnect switch status
- Lockout relay status
- Transfer trip receiver outputs

Not all of the above data are required for every N event. It all depends on what the end user can provide. Trip signals come first, because they are fast. The line loss status is then maintained for the breaker auxiliary contact status. All of the data required to detect N events must be high-speed data.

3) J State

Any event that changes the configuration of the power system is identified as a J state. Most N events become J states in the RAS after a fixed amount of time. For example, a

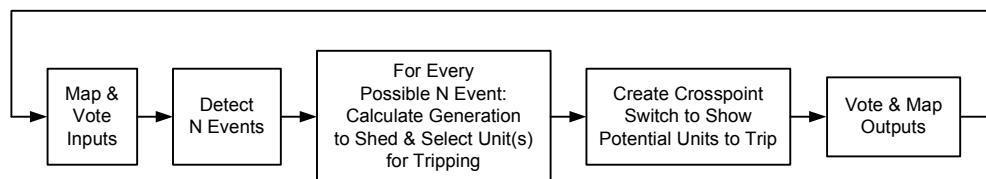


Fig. 4. Basic RAS Algorithm

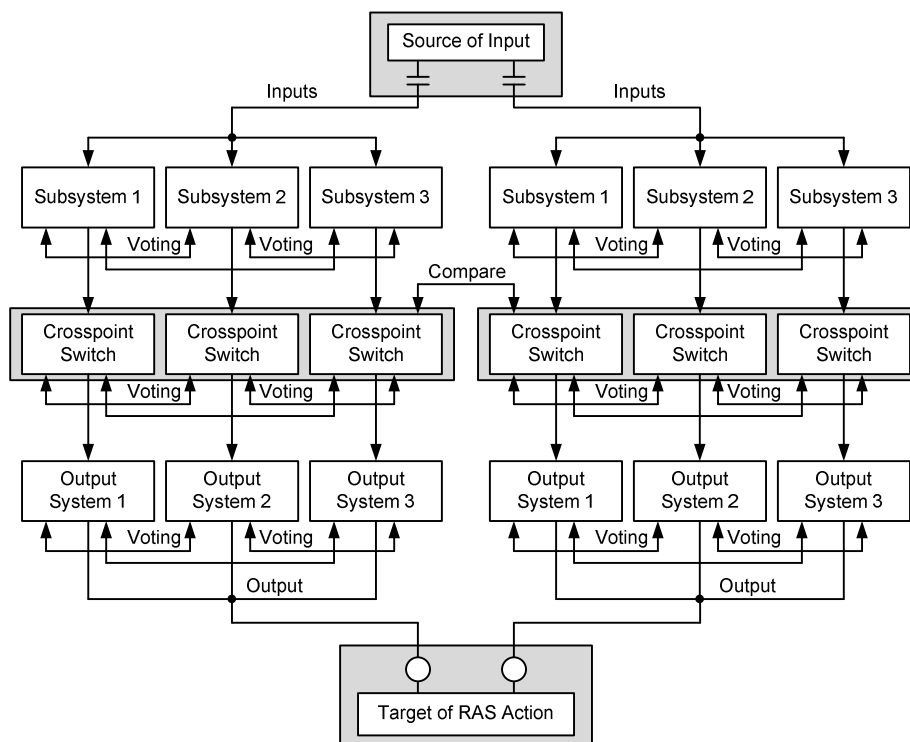


Fig. 5. Two-out-of-Three Voting on All Data

remote phase-to-phase fault on the Jim Bridger – Borah line is an N event. This N event becomes the J state that the Jim Bridger – Borah line is out of service. But J states are not limited to just N events. The outage of each power network element that is critical to the flow of power from the Jim Bridger Power Plant to the west is a J state.

A change of a J state will not require a RAS action but will change the configuration of the power system. Other examples of J states are the outages of synchronous condensers, transformers, shunt capacitors, and transmission lines. J state data do not need to be high speed.

4) System State

The combination of J states is called a system state. For example, in an instance when there are two lines open and a capacitor is out of service, three J states are identified in the system. These three states converge to a system state, and this system state determines the limits of the system. In other words, the system state actually mimics the present condition of the power system. The RAS uses the system state to determine which gain constants need to be used in the action-determining calculation.

5) Arming Level and Generation-to-Shed Calculation

The RAS uses the arming level equation and calculates up to 64 arming levels every 200 milliseconds. The arming level equation is basically a polynomial equation that uses measured real and reactive power generation (local inputs), compensation level of the 345 kV lines (remote inputs), several path flows (local and remote inputs), and eight gain factors that define system sensitivity. Data are gathered from local and remote systems, and all the J states that are active in the system are identified. The identified J states are mapped to a new system state. This system state identifies which gain factors need to be used in the arming level calculation equation. A total of eight gain factors can be loaded from a lookup table, and there are four lookup tables that represent each season (spring, summer, autumn, winter). These gain factors define the system sensitivity to each component in the arming equation and are developed from system studies.

6) Generator Selection Algorithm

The arming level calculation logic calculates an arming level for each contingency. This arming level will be used in the generation-to-shed calculation equation (1) for each contingency, which results in a generation-to-shed value for each contingency. The values will be zero if no generation needs to be shed. For all values greater than zero, the generator selection algorithm will determine which of the four generators needs to be shed. Operators are given preference in selecting units to shed. If no unit is selected by the operators, the algorithm will select the optimum units. At any point of time in one scan, the RAS is allowed to trip only two units. This restriction prevents the RAS from tripping all the units for contingencies detected in one scan.

The following is the generation-to-shed calculation equation:

$$G = K_{nj} \cdot (F_{nj} - AL_{nj}) - X \quad (1)$$

where:

AL_{nj} = calculated arming levels from previous logic.

K_{nj} = coefficient that changes with facility outage and fault type. These are predetermined values that reside in a lookup table. In most cases, the value equals 1.

F_{nj} = either net Jim Bridger generation or net Jim Bridger flow, which depends on the preexisting outage combination j and fault type n . The selection of Jim Bridger generation or Jim Bridger flow is predetermined by system planning.

X = generation dropped by the RAS in the last 5 seconds.

7) Crosspoint Switch

The CPS is the final result of the RAS algorithm. The CPS shows the N event and the actions. The results from the generator selection algorithm are used to populate the CPS. The CPS is preloaded and will give operators information on how the RAS is going to respond for each contingency. As soon as an N event is detected, the RAS knows which actions it needs to take and triggers the actions. Fig. 6 shows a typical CPS.

Ns		Actions															
		N ₁	N ₂	N ₃	N ₄	•	•	•	•	•	•	•	•	•	•	•	N ₆₄
Trip Gen1	I ₁	X			X											X	
Trip Gen2	I ₂		X		X								X				
Trip Gen3	I ₃							X			X						
Trip Gen4	I ₄		X					X									
•	•	X			X												
•	•		X										X				
I ₁₆	I ₁₆		X					X									

Fig. 6. Crosspoint Switch

8) RAS Logic Processing

The logic processing in the RAS controllers is done as multithread processing, which provides flexibility in dividing the tasks into groups, based on how fast they need to be computed. This also makes the RAS algorithm deterministic and prevents time-consuming tasks from delaying the RAS actions. The RAS algorithm is arranged into three schedulers: 1-millisecond, 8-millisecond, and 1-second tasks.

The Jim Bridger RAS has dual primary systems running in parallel. The two systems are independent of each other and come up with their own trip remedial actions. Theoretically, both systems are running the same logic, and if all communications paths are good and the data fed to both systems are the same, the decisions of both systems will

match. However, in foreseeable situations, the decisions made by the RAS Systems C and D may be different due to the following reasons:

- The analogs are fed from different transducers and have measuring discrepancies.
- There can be failed communications paths or equipment that may force a RAS to make a different decision.

VII. SUPERVISION SYSTEM

The analog differences seen in each RAS can cause each RAS to come up with different decisions for a contingency. This is especially dangerous because different decisions increase the chance of shedding more generators than required. To overcome this problem, a supervision system was designed to monitor the crosspoint discrepancies between the systems. In the case of discrepancies, the supervision system will assess the overall quality indicators of the system and decide which RAS should be allowed to operate. The quality indicators are the weighted average of the system communications and hardware alarms. Primary and backup supervision units are designed for redundancy and use different technology hardware, software, and communications protocols to further ensure reliability.

Testing has shown that the RAS systems quite often come up with different decisions, caused primarily by analog transducer scaling discrepancies. This is especially frequent as analogs create arming levels around preset tripping thresholds. Note that direct digital communication to the power measurement devices eliminates many of these problems.

VIII. MULTIPLE N EVENTS AND CLOSELY TIMED EVENTS

There are two special logic timers used in the RAS logic. Any contingency that happens in the power system creates a disturbance. For example, a line is tripped. Due to this line loss, the power is redistributed across different paths, or there are power swings, causing the gathered analog data to fluctuate as the power system settles towards a steady-state condition. During this time, if the gathered analog data are used in the arming level calculation, it may result in poor-quality decisions. To prevent these disturbances from affecting RAS decisions, all generation-to-shed values calculated prior to this event are frozen for a certain period of time, in this case, 5 seconds. At the end of the analog freeze, the N events are transitioned to J states. If a second event happens during this time, the timer is reset, and the 5-second counter starts again.

If the CPSs in RAS C and D are different, the supervision system decides which system is allowed to operate for the next contingency. However, it takes around 12 milliseconds to send the CPS to the supervision unit and receive a decision from it. During the 12 milliseconds after the first contingency, the RASs can have different CPSs, which may lead to different decisions if a second contingency happens in this 12-millisecond window. The closely timed event logic is used to prevent these cases. Once a first contingency (that sheds

generation) happens, a 16-millisecond timer is started. During this timer duration, if a second or additional events happen, all of these events are queued and evaluated at the expiration of the timer. This gives the supervision unit enough time to evaluate the CPSs, make a decision, and prevent the RASs from making different decisions for closely timed events.

IX. FAST RECALCULATE ALGORITHM

If an event happens and a line is tripped, the RAS detects the contingency, verifies the generation-to-shed values, and trips a generator. The 5-second timer starts, and the generation-to-shed values are frozen. If, after some time (e.g., 100 milliseconds), the RAS detects another contingency, it will overtrip if it does not take into account the loss of line and generator tripping that happened during the last scan. This is because the generation-to-shed values are frozen and have not yet updated. They are waiting for the 5-second timer to expire. The fast recalculate code is designed to address these issues.

As soon as a contingency is detected, if the RAS detects another contingency in the next 5 seconds, the fast recalculate code is run, which modifies the generation-to-shed values based on how much generation was shed for the previous contingency. X in (1) serves this purpose. It deletes the generation shed by the RAS in the last 5 seconds, yields fewer generation-to-shed values, and prevents overtripping.

X. GRAPHIC INTERFACES

A. RAS HMI

The RAS HMI runs on a substation-grade computer. Although it is designed to run continuously, it is not necessary for the RAS to operate. The HMI is only necessary for changing the settings used for the RAS computations. These settings are stored in nonvolatile memory in the individual RAS controllers, making the RAS operations independent of the HMI.

The RAS HMI station serves as the user interface to all RAS controllers and subsystems. The functionality includes:

- Status display of live power system data on a summarized one-line screen.
- Status display for every system input and output, including data shared through the EMS system.
- Ability to change and view adjustable settings and gains loaded in the RAS controllers.
- Real-time view of the CPS matrix that shows the action to be taken for every contingency.
- Communications and alarm screens that reflect current device and communications alarms.
- Sequence of events (SOE) gathering, archiving, and viewing.
- Historical alarm and event viewing. The event files can be played back to the RAS through the test simulator.

The HMI collects data from all six RAS controllers and the four EMS interfaces. Screens exist to view the data individually for verification that they agree and to view the one-line screen that reflects the system status as determined by the

two-out-of-three voting logic. The data set for the one-line screen is picked by the same algorithm that is present in the supervision logic. The one-line and I/O screens are critical for factory acceptance testing, site acceptance testing, and commissioning purposes, because they provide visual verification of what occurs during each test.

Due to the immense amount of data required to fill the system adjustable gains, a database file was created to hold these large matrices. There are eight matrices that are of the dimensions 64 x 1,000 x 4 (256,000 gains) and several other matrices of smaller sizes. When edits are made to any one of the 256,000 gains, the controllers detect that new settings are available and issue a signal that the loaded settings are old. At this point, the database file is compacted into several binary files; these files are then transferred to the RAS controllers at the operator's request. These binary files are stored in non-volatile memory on the RAS controllers and are viewable in tables through the HMI.

Each RAS controller creates SOE logs, event report logs (oscillography), and OPC (Object Linking and Embedding [OLE] for Process Control) alarm tags. There are two main ways to view alarms on the HMI: through the communications and alarm screens (OPC point) and through the SERviewer Software (SOE logs). The communications and alarm screens show the active state of major device, communications, and diagnostic alarms. If an alarm clears but was not acknowledged, there is still an indication that the alarm was not viewed by an operator. The SERviewer shows all alarm points time-stamped as to when any changes occurred. All data in the SERviewer are time-stamped with 1-millisecond accurate resolution.

Event reports are in a flat file format, similar to COMTRADE format. Event report viewing on the HMI is performed using special software that displays all digital and analog information before and after each event. The event report logs contain the status of every I/O point in the RAS, sampled at 2-millisecond intervals. The event report logs contain data for 2 seconds prior to each event and 4 seconds after every event. This allows for easy diagnostic evaluation of what occurred during the event. Also, the event file can be replayed to the RAS from the test simulator.

B. Simulator HMI

The simulator HMI has two modes of operation: operator controlled and file playback. The operator-controlled mode allows the user to interactively change any digital or analog system input from the default value. The user can then trigger a contingency and observe the results on the RAS connected to the simulator. File playback allows user-generated files or actual event reports from the RAS to be fully simulated. This allows the RAS gains to be easily adjusted for desired operation.

Additionally, the simulator has controls for biasing the analog values to test the voting logic. Discrepancies between the redundant analog inputs are the most likely source of differing inputs to the RAS, due to the maintenance required on transducers to keep them calibrated. The controls to bias

the inputs allow for skewing the analog inputs to each RAS subsystem. Running tests this way verifies that two out of three systems agree before an action is taken. Controls are also present to skew the analog signals between RAS C and D for verifying the supervision logic when testing both RAS systems.

C. Event and System Diagnostics

The RAS has complete diagnostic capability that automatically pinpoints any faults or errors within the system (hardware and software) to a failure location within a hardware device or a software module. Every N event, input, and output occurring in the RAS system is also tracked by these tools. All SOEs and event reports are saved as flat *.csv files and saved in nonvolatile, flash-type memory on the substation-hardened computers.

There are three types of diagnostic tools for these purposes:

- HMI displays. This is generally the first place to look. The HMI describes failures pictorially by color changes on the HMI screen. This provides a high-level view of the system. These data are provided through an OPC data link out of each controller.
- SOE logging and viewing. SOEs from both systems are simultaneously logged. These events are viewable with the SERviewer and are time-tagged at 1-millisecond accuracy. Alarms are given descriptions detailed enough to specify the faulted device or software module.
- Oscillography logging and viewing. These oscillography reports (event report logs) capture the system conditions monitored by the controllers. The reports are generated on the controllers and passed to the computers for long-term storage and viewing. These oscillography files have an identical structure to the event reports created by all of the protective relays used for fault discrimination in the RAS. For this reason, these log files are called event reports.

D. Sequence of Events Logger

The SOE logger contains raw, digital I/O, internal digital values of great interest in the controller, and all system alarms (e.g., data disparities, equipment failures). The SOE logger is responsible for detecting, identifying, and making available to file the SOEs of selected, critical variables. The main features of the logger include:

- Monitoring of up to 512 digital variables.
- Detection of up to 4,000 events per minute on a continuative basis with no data loss.
- Detection of up to 2,000 events over 160 milliseconds (simulation of a fault with clearance time of proximally 10 cycles) with no data loss.
- Visualization of the SOE file with the SERviewer or any text reader.
- Multiple SOE file creation when the end of the file is reached or problems are encountered during the writing process.
- Minimal CPU consumption.

E. Oscillography

Any N event contingency will cause an event report to be gathered. The event report records all control outputs, all digital inputs, all analog inputs (in engineering units), all data provided through the SCADA interface, the contents of the CPS, the J states, the current state, the arming levels, and the generation to shed. Some of the main features of the event report logger include:

- The event report library has the capability to store 320 Boolean values (10 DWORDS) and 64 analog (REAL) values.
- Each analog and Boolean quantity has a textual name associated with it. This name is saved in the event report file (*.csv). The analog and Boolean variable names are each limited to 15 characters.
- Each event stores up to 6 seconds of data. The 6-second time is a combination of the pre-event and post-event length.
- The CPU usage is minimal.
- The event report library is designed to log data every 2 milliseconds.
- The event report library has the capability to store at least five event reports triggered in a 2-millisecond time gap.
- The file written to the storage location is readable with off-the-shelf COMTRADE-viewing software.
- There is no limit to the number of files that can be stored on the substation computer. The limit is purely the maximum free space left on the compact flash.

XI. TESTING

A. Test Simulator

The test simulator was designed to play back power system events into one of the redundant RASs (C or D). Through a pair of interconnection panels and software interlocks, the test simulator can be isolated and connected to either RAS C or D. Because of the sensitivity of the RAS system to changes in gain files used in the RAS algorithm, it is necessary to test modifications in a fully functional, triple redundant system prior to applying them to a live system. The hardware and software designs implemented within the Jim Bridger RAS satisfy this requirement.

A playback simulator is used to easily simulate system conditions and events. This allows the creation of text files that contain analog and digital data reflecting specific scenarios to be sent to the RAS system. The files are sent through an algorithm that separates each value in time, thereby properly compensating for the communications delays of the various test simulator components. Several hundred playback files are then queued up for automatic playback, one after another. In this fashion, engineers can observe the reaction of the RAS algorithm to hundreds of different scenarios in a few hours.

The test simulator uses hard-wired analog and digital signals to communicate to the RAS. The test simulator also communicates to the RAS with serial links, emulating the

EMS DNP3 interface. All RAS and test signals are sent through an interconnect panel, which allows for easy insertion of the test simulator signals into the RAS. By using test paddles and isolation test blocks, the signals from the live power system are disconnected from the RAS while simultaneously inserting the test signals.

Once a contingency occurs, the RAS system records each event for a period of 2 seconds before and after the event, for a total of 4 seconds. By doing this, the RAS can capture key information within the event and place that data within a .cev file. This file is then sent to the main HMI, where it can be transferred back to the test simulator for playback. The file structure is exactly the same as those created by PacifiCorp engineers, as described earlier. In this way, each event recorded on the power system can quickly be played back into the RAS and observed with no interruption to the performance of the RAS. This allows PacifiCorp to quickly evaluate the control system response with new settings for all known and recorded events.

B. Project Execution

A primary design objective of the RAS was to allow future modifications to occur with little interruption to the performance of the RAS. The hardware design allows for interconnect panels so either RAS C or D can be disconnected from the live power system and reconnected to a series of simulated signals. This not only allows for quick changes to occur within the RAS but also for expansion and other maintenance corrections without taking the entire system out of service. With one of the two systems connected to the test simulator, there is still a triple redundant RAS operating normally.

The test simulator and dual RAS design proved very valuable during the validation phase of the project. Engineers were able to interact with both systems and observe all levels of performance within the RAS systems.

It was discovered during the design phase that a close working cooperation between PacifiCorp and the supplier's engineers was critical. Instant feedback for the specific requirements and performance of the RAS system proved to be valuable. It is important for the PacifiCorp engineers to have a full understanding of the algorithms and logic within the RAS. This understanding allows for timely analysis of events once the system is fully operable. Their understanding of the power system provided critical information that modified the design of the control system algorithms. It became possible to incorporate very specialized solutions to past problems with the existing system. It was necessary for PacifiCorp and the supplier's engineers to spend no less than two months working in close cooperation at one location during final software implementation of the RAS.

C. Quality Control

Several forms of testing were involved in maintaining a high level of quality and ensuring that the integrity of the complete RAS control system was upheld throughout the RAS development and implementation. Unit testing was completed within the software, hardware, and communications designs. This involved isolated testing to detect failures prior to

integrating the components into the system. Using a peer review process to fully inspect each other's designs allowed each component to assimilate into a compatible scheme.

A series of internal validation tests were then completed to ensure the integrity of the system as a whole. This involved pushing the system past the ordinary limits described by initial specifications and was effective at capturing potential failures that were unforeseen at the component level. This testing was immediately followed by external validation in the form of factory acceptance testing prior to delivery. This process was repeated several times throughout the project as problems and solutions were discovered.

D. Timing Results

The throughput time of the RAS system is less than 17 milliseconds; this is the measured total time from an input voltage asserting to 90 percent of full voltage to an output point fully conducting. This includes the time required to accomplish both I/O voting schemes. All output contacts are rated for tripping; therefore, interposing relays were not used. All contact outputs used are a high-speed, high-current interrupting design; this design closes an output in less than 10 microseconds and can interrupt up to a 30 A inductive current.

XII. COMMISSIONING

The process of commissioning a system of this magnitude is highly critical and involved many groups within PacifiCorp, including protection engineering, field service technicians, planning, operations, dispatch, communications, and technicians. Because of this dynamic, it was key to have a primary individual or small group of individuals responsible for the coordination of each independent group's efforts.

Once the system was delivered to the substation, the immediate task was to coordinate efforts from each group to allow the system to be integrated in parallel with the existing system. This had to be accomplished without interruption to the existing system.

A checklist was created prior to commissioning that systematically checks each input and output of the RAS. This ensures that each individual component is operable. Once this is completed, the previous functionality from the factory acceptance test will be preserved.

A one-time site acceptance test involving the test simulator connected to both RAS C and D was performed in order to again prove the functionality of the entire system. Because the system was designed with the test simulator flexibility discussed earlier, this was possible.

Careful steps were taken to avoid unnecessary generation shedding at Jim Bridger. Each and every item within the checklist contained a specific method for testing and was described within the commissioning documentation. By doing this, everyone involved could gain an understanding of the reasoning behind the process. Upon completion of the checklists, all parties signed their approval.

Communication between the RAS and the PacifiCorp EMS is another critical piece. Information regarding system alarms and history is provided to the EMS through four SCADA machines, and likewise, data from the EMS are passed to each of the four SCADA components. Commissioning these systems depends on first establishing reliable communications circuits between the source and destination of each circuit. It also relies heavily on any DNP3 protocol conversion and settings involved in the communication. There was a very high dependence on having a constant working relationship between the engineers and technicians out in the field and those involved with the DNP3 master.

XIII. IN-SERVICE PERFORMANCE

At the time of writing this paper, the Jim Bridger RAS was undergoing final site commissioning. Presenters will share their experiences on system performance during the presentation of this paper.

XIV. BIOGRAPHIES

Dean Miller is a principal engineer in Protection & Control Engineering at PacifiCorp and an adjunct professor at Portland State University, teaching a course on power system relaying. He received his Bachelors degree in Electrical Engineering from the University of Idaho. During his 36 years at PacifiCorp, Dean has held a variety of positions in the engineering and operations organizations. He holds a patent in the area of distribution automation. Dean is a senior member of IEEE, an active member of the Power System Relaying Committee of IEEE, and a registered professional engineer in the State of Oregon.

Robert Schloss is an automation engineer for the Engineering Services Division of Schweitzer Engineering Laboratories, Inc. (SEL). Robert received his Bachelor of Science degree in Electrical Engineering from the University of Idaho and has been with SEL since 2004. He has experience in power system automation, specifically with remedial action schemes, load shedding, voltage control, and generation control.

Scott Manson is a supervising engineer for the Engineering Services Division of Schweitzer Engineering Laboratories, Inc. (SEL). He received a Masters in Electrical Engineering from the University of Wisconsin-Madison and his Bachelors in Electrical Engineering from Washington State University. Scott worked at 3M Corporation as a control system engineer for six years prior to joining SEL in 2002. Scott has experience in designing and implementing control systems for electrical utility customers, high-speed web lines, multi-axis motion control systems, and precision machine tools. Scott is a registered professional engineer in Washington, Alaska, North Dakota, and Louisiana.

Sai Raghupathula is an automation engineer for the Engineering Services Division of Schweitzer Engineering Laboratories, Inc. (SEL). He received a Masters degree in Electrical Engineering from the University of Idaho. Sai has been employed with SEL since 2004 and has experience in designing and implementing control systems for utility and industrial customers.

Trent Maier is an automation engineer for the Engineering Services Division of Schweitzer Engineering Laboratories, Inc. (SEL). Trent received his Bachelor of Science degree from Michigan State University and spent five years within the automotive industry prior to joining SEL in 2007. He has experience in control system design and application within power systems, conveyor systems, and robotics.

Upgrading PacifiCorp's Jim Bridger RAS to Include Wind Generation

Rikin Shah, Robert Hines, and Pamela Palen, *PacifiCorp*

Hariharan Subramanian, Rameez Syed, and Alejandro Carbajal, *Schweitzer Engineering Laboratories, Inc.*

Abstract—Adding generation assets to the power grid can create challenges for existing generation-dropping remedial action schemes (RASs) if the transmission capacity remains the same. An update to the control scheme is required to maintain the stability and reliability of the power system in the event of a contingency.

Eastern Wyoming, with its abundant wind generation capabilities, has seen significant growth in wind farm operations, which are interconnecting with the eastern Wyoming transmission system. To transmit the power from these wind farms in addition to the existing power generation, new transmission from eastern Wyoming is being connected to the Jim Bridger Power Plant through a new 500 kV line. The power transmitted to the west of the Jim Bridger plant now includes the power produced from these wind farms along with the Jim Bridger generation, but the total path flow to the west of the plant is kept the same as before. With these additions, it is necessary to update the control algorithm that integrates the wind farms with the Jim Bridger RAS.

In this paper, we discuss the updates to the generation-dropping Jim Bridger RAS algorithm to integrate the additional wind generation assets with existing coal-fired generation. The updates to the RAS algorithm include monitoring the new 500 kV line and wind generation assets and using new criteria for selecting a combination of thermal and wind generation for tripping and new unit-selection logic. The updated RAS algorithm was tested using a test simulator system with actual RAS controllers and a simulator running test cases in playback fashion and providing the data to controllers. Test cases covered several system conditions involving various combinations of thermal and wind generation values. Using simulation and analysis, we show that tripping a combination of coal-fired and wind generation for transmission line contingencies helps to maintain system stability.

I. INTRODUCTION

The Jim Bridger Power Plant located near Rock Springs, Wyoming is a mine-mouth, coal-fired generation station jointly owned by PacifiCorp and Idaho Power Company. The power from the plant is transported over three 345 kV and two 230 kV transmission lines that radiate out to the west. Those transmission lines and the critical parts of the transmission system across the states of Wyoming, Utah, Idaho, and Oregon are parts of the transmission system monitored by a remedial action scheme (RAS) located at the Jim Bridger substation. Since the plant was built in the early 1970s, a RAS has been required to achieve the transmission path rating needed to move the energy from the plant to the loads. When the transmission corridor is being operated at the path limit and a transmission line in the path is lost, the generation at Jim Bridger must be reduced to maintain the transient stability of the power grid. The Jim Bridger RAS maintains the stability of the power system by shedding appropriate generation in the Jim Bridger

plant for the loss of the lines in the transmission corridor and balancing the generation to the load. The complete loss of the RAS for any reason requires that the Jim Bridger Power Plant output to be reduced to 1,300 MW.

II. THE EXISTING RAS SYSTEM

The existing RAS for PacifiCorp's Jim Bridger Power Plant went into service in 2009 with an algorithm designed to trip excess generation in the case of a fault on the interconnecting lines going west [1]. This RAS allows operators to push more power through the transmission infrastructure by taking actions within the subcycle operating time to protect against disturbances. All actions initiated by the RAS scheme are preplanned based on studies of several predefined system operating conditions. Based on the current system outages, specific scaling factors are applied to arming level calculations for each credible fault type and location [2] [3]. The Jim Bridger RAS system quickly sheds generation to stabilize the plant and the transmission system. The existing RAS system is a dual triple modular redundant (TMR) scheme, and it has two RAS systems, RAS C & RAS D, with three controllers and three I/O modules in each of them. The system also has two redundant supervisory controllers to monitor the RAS controllers, so the actions taken by the RAS systems are consistent.

III. PACIFICORP'S EASTERN WYOMING TRANSMISSION SYSTEM CHANGES

Eastern Wyoming, with its abundant wind generation capabilities, has existing and planned wind farms which are going to get connected to PacifiCorp's eastern Wyoming transmission system. Specifically, new wind farms at Windstar, Shirley Basin, and Aeolus are getting connected and integrated into PacifiCorp's eastern Wyoming transmission network. Three 230 kV transmission lines connect eastern Wyoming to the Jim Bridger substation through Point of Rocks and Mustang and 230/345 kV transformers at Jim Bridger, but the transmission lines do not have enough capacity to transfer all the power from the wind farms. Hence, a new 500 kV transmission line was constructed from Aeolus to the Anticline substation and then connected to the Jim Bridger substation through a 345 kV line. Fig. 1 shows the map of PacifiCorp's transmission system as described in this section. The power transmitted to the west of Jim Bridger now includes the power produced from the wind farms in eastern Wyoming, but the total transmission capacity to the west of the plant remains the same.

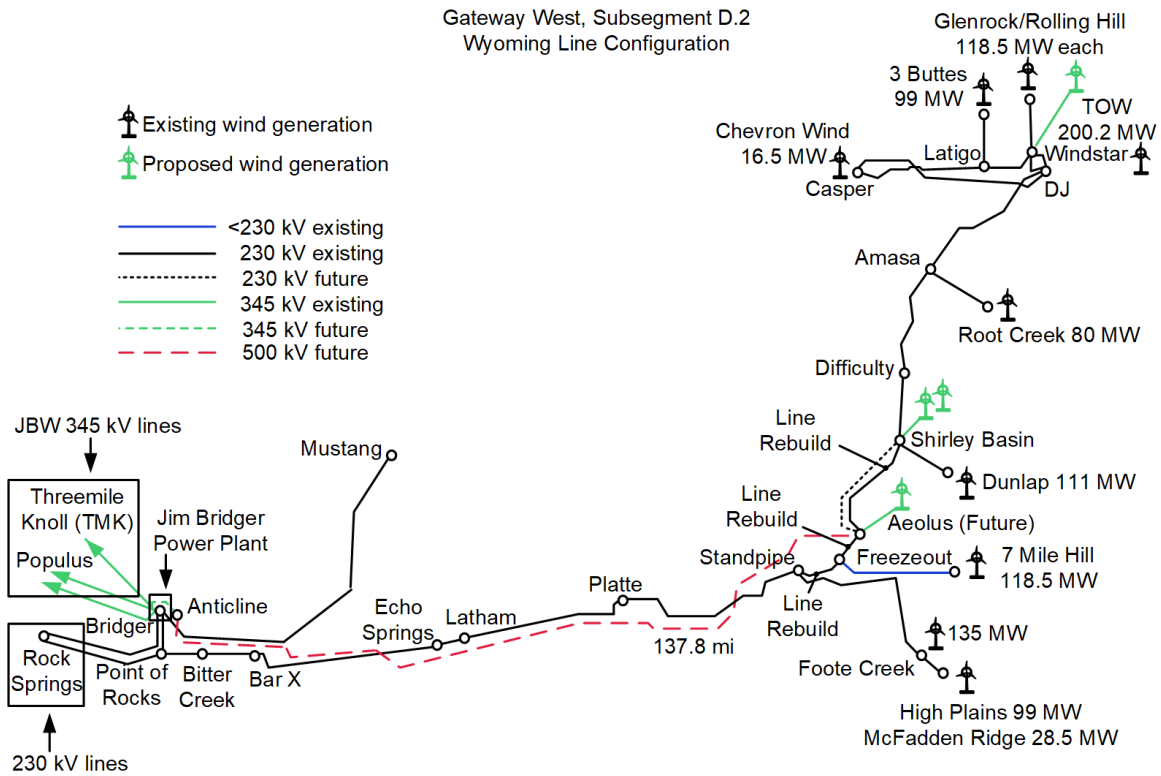


Fig. 1. Map of transmission system.

IV. WIND GENERATION CHALLENGES TO THE EXISTING RAS

The primary function of the Jim Bridger RAS is to initiate fast remedial actions while minimizing generator tripping in response to power system disturbances, thereby maximizing power transfers and ensuring power system stability. The amount of generation to be dropped is calculated based on system configuration, fault type, and severity of the fault. The unit to be dropped is selected by the Jim Bridger RAS control system. With the wind generation coming available through the energization of the new 500 kV line from Aeolus to Anticline, there are several possible combinations of wind generation and Jim Bridger generation that could lead to heavy flows on the path to the west of Jim Bridger. Therefore, the Jim Bridger RAS logic was modified to integrate the newly installed wind generation as part of the transmission system upgrade. The Jim Bridger RAS algorithm has been modified to include tripping of the new wind generation in Wyoming to achieve the appropriate amount of tripping for each line outage contingency.

The transmission path rating to the west of Jim Bridger is being maintained at 2,400 MW so there are no physical transmission system changes and no additional J-states and N-states [1] are being added, but the generation selected for tripping must now include both Jim Bridger and wind generation units. The flows on the Anticline–Bridger 345 kV line, in combination with the three 345/230 kV transformers, are considered as a fifth Jim Bridger unit in the Jim Bridger RAS algorithms to calculate the appropriate trip amount to

maintain reliability. Wind generation is located far away from Jim Bridger, which presented a dilemma about how to account for its effectiveness in tripping, so a parameter named effectiveness factor (Ef) was identified. The Ef factor is an empirical value based on studies used by operators to determine the equivalent amount of wind generation tripping for the RAS scheme; this factor can be provided by operators through supervisory control and data acquisition (SCADA) to give operational flexibility. The existing Jim Bridger bus configuration changed from four bays to five bays, which added another change in selecting the Jim Bridger units to trip to avoid a bus split condition. Fig. 2 shows the system overview with new wind generation along with the rest of the system under RAS control.

V. RAS SYSTEM DESIGN UPDATES

A. Remote Substation Devices

The critical system facilities that are monitored to support the new wind generation resources in Wyoming are:

- Aeolus 500/230 kV substation switch statuses and analog values.
- Anticline 500/345 kV substation.
- Aeolus–Anticline 500 kV new line.
- Anticline–Bridger 345 kV new line.
- Shirley Basin substation switch statuses and analog values.
- Foote Creek substation switch statuses and analog values for High Plains wind generation.

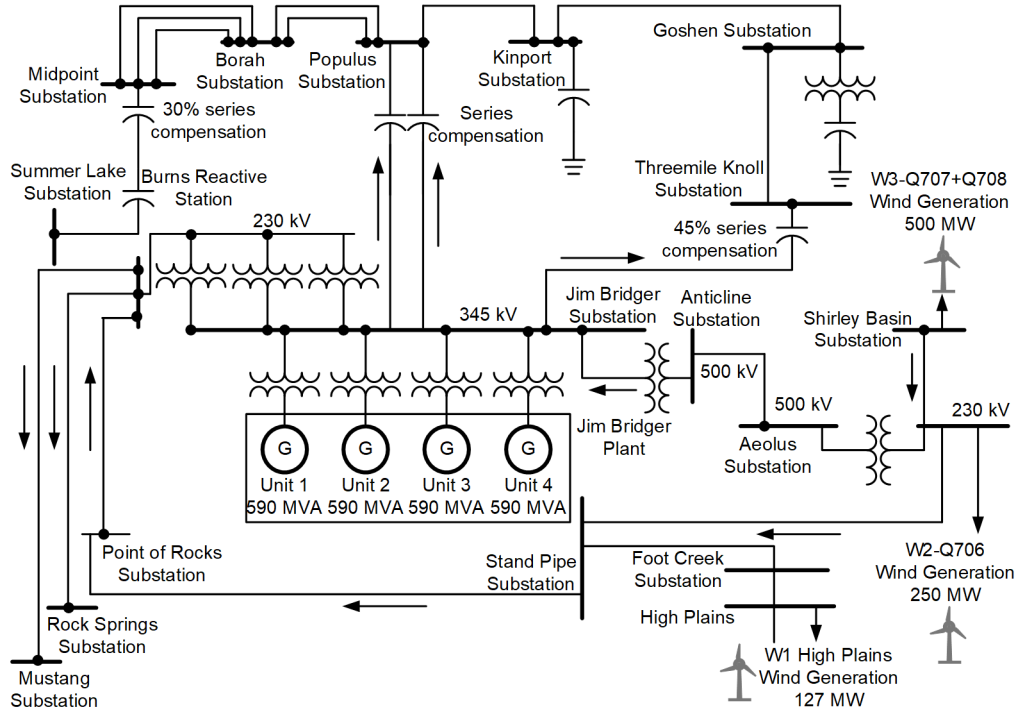


Fig. 2. System overview.

Input/output (I/O) devices are installed at the new substations to collect digital and analog data and send them to the RAS system through the existing front-end processor (FEP) in the Jim Bridger substation. Digital data are sent through high-speed channels and analog data through slow-speed channels; this segregation has been proven to yield good performance on both large-scale and small-scale RAS schemes [4] [5] [6] [7]. Digital data include breaker status and switch status, which are used to determine the wind generation connection to the substation and the 500 kV line status. Analog data include real and reactive power from the wind generation sources, real and reactive power flowing through the new 500 kV line, and power flowing through the three 230/345 kV transformers in the Jim Bridger substation. After the upgrade, the trip signals to the wind generation units are sent through a high-speed channel from the RAS system to the remote devices in the Aeolus, Shirley Basin, and Foote Creek substations where the wind generation units that the RAS trips are connected.

B. Arming Level Calculation

The RAS uses the arming level equation and calculates up to 64 arming levels every 200 milliseconds. The arming level equation is a polynomial equation (1) that uses measured real and reactive power generation (local inputs), compensation level of the 345 kV lines (remote inputs), several path flows (local and remote inputs), and eight gain factors that define system sensitivity [1]. Data are gathered from local and remote systems, and all the J-states that are active in the system are identified. The identified J-states are mapped to a new system state. This system state identifies which gain factors need to be used in the arming level calculation equation. A total of eight gain factors can be loaded from a lookup table, and there are

four lookup tables that represent each season (spring, summer, autumn, winter). The gain factors ($K_{ai_{nj}}$, $K_{c_{nj}}$, $K_{aConst_{nj}}$) in (1) define the system sensitivity to each component in the arming equation and are developed from system studies.

$$AL_{nj} = \sum [K_{ai_{nj}} \cdot (G_i - Rf_i)] + K_{c_{nj}} \cdot \left(\frac{Comp_{rem}}{135} \right) + K_{aConst_{nj}} \quad (1)$$

where:

G_i is the various path flows of Jim Bridger real power and reactive power in the system.

Rf_i is the constant established in the gain files for $K_{ai_{nj}}$.

$K_{ai_{nj}}$ is the sensitivity coefficient for each G_i .

$K_{c_{nj}}$ is the coefficient that represents the relative sensitivity to the remaining series compensation level on the Jim Bridger lines following a Jim Bridger line outage.

$Comp_{rem}$ is the series compensation remaining after a line loss.

$K_{aConst_{nj}}$ is a base coefficient.

The n_j subscript indicates that there is a separate value of each possible combination of N-states and J-states. Each pre-existing facility outage is given a unique J-state number. Combinations of single J-states are given unique system-state numbers. Any combination of J-states forms a system state, i.e., system states are formed from J-state conditions within the system. Each fault event that is detected as a contingency by RAS is assigned a unique N-state.

The changes to the arming level calculation due to the additional wind generation are reflected in real power generation, as shown in (2) and Fig. 3.

$$\text{Gen} = \text{JBGen} + \text{Xt} \quad (2)$$

where:

JBGen is the measured Jim Bridger real power generation.

X is the MW of the Anticline–Bridger line plus the MW of the Bridger 345/230 kV transformers.

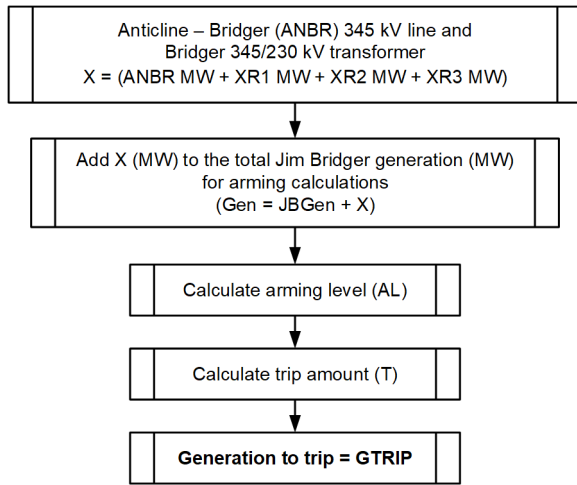


Fig. 3. Arming level and generation to shed calculation flow chart.

C. Generation-to-Shed Calculation

The arming level calculation logic calculates an arming level for each contingency. This arming level is used in the generation-to-shed calculation (3) for each contingency, which results in a generation-to-shed value for each contingency. The values are zero if no generation needs to be shed. For all values greater than zero, the generator selection algorithm determines which of the four generators in Jim Bridger and which of the three wind generation units needs to be shed. Operators are given the choice of selecting units to shed for Jim Bridger unit selections. If no unit is selected by the operators in the Jim Bridger plant, the algorithm selects the optimum units considering both Jim Bridger units and wind generation units. At any point of time in one scan, the RAS is allowed to trip only two Jim Bridger units and not more than a certain amount of wind generation. The limit on the wind generation is determined by system planning. This restriction prevents the RAS from tripping all the units for contingencies detected in one scan.

$$G = \text{Knj} * (\text{Fnj} - \text{ALnj}) - X \quad (3)$$

where:

Fnj is the net Jim Bridger west flow.

ALnj is the calculated arming levels.

Knj is the coefficient that changes with facility outage and fault type. These are predetermined values that reside in a lookup table. In most cases the value equals one.

X is the generation dropped by the RAS in last five seconds.

D. Integrating Wind Generation to the Jim Bridger RAS

The flows coming on to the Jim Bridger 345 kV bus from the Aeolus–Anticline 500 kV line and the Jim Bridger

345/230 kV autotransformers are added to the Jim Bridger plant generation to accurately determine the arming level and generation-to-shed calculations as shown in Fig. 3.

Power values, along with the breaker status of the generator tie lines from the eastern Wyoming wind generation, are used to determine the different combinations of the wind generation units that can be tripped as shown in Fig. 4. The wind generation that is subject to tripping as part of the RAS logic includes the following:

- Ekola Flats (Pmax = 250 MW) interconnecting to the Aeolus 230 kV substation
- TB Flats (Pmax = 500 MW) interconnecting to the Shirley Basin 230 kV substation
- High Plains (Pmax = 127 MW) interconnecting to Foote Creek 230 kV substation

The new RAS logic uses the different combinations of the three wind farms that can be tripped. The criterion is that the wind generator tripping combinations should not exceed Wmax (627 MW).

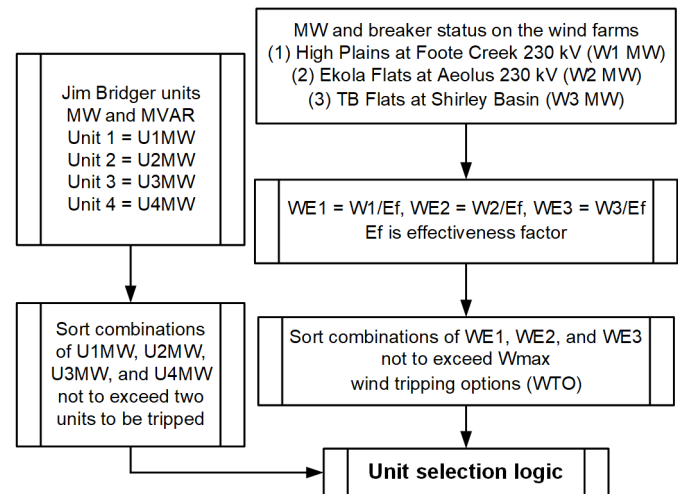


Fig. 4. Inputs to unit selection logic.

If the Anticline–Bridger 345 kV or Anticline–Aeolus 500 kV line is out of service, only Jim Bridger units are used to satisfy any trip call and tripping of wind generation is not required under Jim Bridger outage conditions. A specific path availability logic has been programmed into the RAS controllers to determine the 500 kV line status and the path availability of wind generation in each specific remote substation.

When tripping wind generation units, to achieve similar reliability performance compared to Jim Bridger generation, an effectiveness factor (Ef) has been applied to the wind generation. This factor is based on studies developed to determine how much wind generation needs to be tripped to have the same impact as tripping Jim Bridger generation. This is a user-provided input from the system operators to the RAS depending on the system conditions.

Table I describes the wind generation units and the effectiveness factor when applied to them. Table II shows the various Wind tripping options (WTO) available for the RAS based on the different combination of wind generation units.

TABLE I
WIND GENERATOR SELECTIVITY

Generator	Wind Farm	Effective Wind Power ($WE_x = P_{max}/E_f$)
W1	High Plains	$WE1 = W1P_{max}/E_f$
W2	Ekola Flats	$WE2 = W2P_{max}/E_f$
W3	TB Flats	$WE3 = W3P_{max}/E_f$

TABLE II
WIND GENERATOR COMBINATION

WTO	Wind Generator Combination
WTO 1	$WE1 = \text{High Plains } (W1P_{max}/E_f)$
WTO 2	$WE2 = \text{Ekola Flats } (W2P_{max}/E_f)$
WTO 3	$WE3 = \text{TB Flats } (W3P_{max}/E_f)$
WTO 4	$WE1 + WE2 = \text{High Plains} + \text{Ekola Flats}$ $(W1P_{max}/E_f + W2P_{max}/E_f)$
WTO 5	$WE1 + WE3 = \text{High Plains} + \text{TB Flats}$ $(W1P_{max}/E_f + W3P_{max}/E_f)$
WTO 6	$WE2 + WE3 = \text{Ekola Flats} + \text{TB Flats}$ $(W2P_{max}/E_f + W3P_{max}/E_f)$
WTO 7	$WE1 + WE2 + WE3 = \text{High Plains} + \text{Ekola Flats} + \text{TB Flats}$ $(W1P_{max}/E_f + W2P_{max}/E_f + W3P_{max}/E_f)$

Any of the combinations of wind tripping options that are available to meet the trip call and are less than W_{max} are considered in the unit selection logic. W_{max} is the total maximum wind generation that can be tripped.

E. Human-Machine Interface (HMI) Screen Updates

RAS HMI screens were updated to show the 500 kV Aeolus–Anticline line, wind generation connected to the remote substations, and all the breaker and switch statuses associated with them. Separate screens showing the analog and digital data from each remote substation were added to the HMI. Communication points with energy management system (EMS)/SCADA were also updated to reflect the Aeolus substation, the Shirley Basin substation, and Foote Creek substation breaker and switch connection status. The HMI software was also upgraded to its latest version, which is compatible with new Microsoft Windows software, to keep the system operating on the latest software and operating system versions.

F. Simulator System Updates

The test simulator system for the RAS system simulates all the external inputs, both hardwired and communications-based signals. The simulator has an HMI screen that can initialize the system and run tests. The simulator can operate in both static and playback modes. The inputs related to the wind generation units, the new 500 kV line, and the wind units' connections to remote substations were added to the existing simulator system. The playback file structure was also modified to include the new inputs and system conditions. New test files were created by planners and the operation team for testing and validating the RAS system logic for integrating the wind generation units. The existing old test case files were modified to fit into the new

file structure, so the playback feature can be used to simulate both existing test scenarios and new test scenarios. Both the simulator system logic and the simulator HMI were modified to reflect the new system changes.

VI. SIMULATION RESULTS

A study was conducted to find how a combination of wind and thermal generation tripping for line outages (contingencies) helps to maintain system stability. Critical clearing times for 345 kV line loss contingencies with and without the Jim Bridger RAS are analyzed. Further, the equivalent amount of wind generation which must be tripped in relative to the Jim Bridger generation is discussed.

A. Clearing Time Without the Jim Bridger RAS

Simulations were performed to determine the critical clearing time for the 3-ph faults near Jim Bridger and other critical contingencies. The critical contingencies selected are one 345 kV line loss (F1 in Fig. 5) and two 345 kV line loss (F1F2 in Fig. 5). The 345 kV line loss contingencies due to faults in the transmission corridor, limits the power transfer through them and hence generator-dropping due to RAS and its effectiveness are studied.

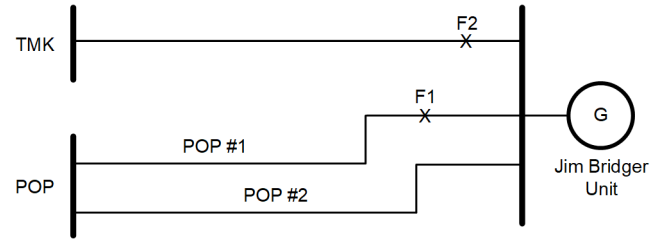


Fig. 5. Contingencies on Jim Bridger lines.

The following are the study results for clearing times without the RAS:

- For a three-phase fault at Jim Bridger for the loss of the Bridger–Populus 345 kV line
 - At low values of JB Generation (less than 50% with 4 units online), the critical fault clearing time is 6 cycles.
 - At high values of JB generation (greater than 90% with 4 units online), the critical fault clearing time is 4 cycles.
- For N–2 fault conditions (JB_POP12 or JBPOP_TMK), loss of two of the three 345 kV lines west of Jim Bridger
 - Irrespective of JB generation levels, the voltage profile is lot worse for clearing times of more than 4 cycles and without the Jim Bridger RAS the system does not meet Western Electrical Coordinating Council (WECC) requirements.
 - Further, the voltage at the Threemile Knoll side is much worse without the RAS system.

B. Clearing Time With the Jim Bridger RAS

The outages were also simulated with the Jim Bridger RAS in service. Using the arming level and the generation tripping level calculations, the generation that would be tripped was

calculated. For cases with low Jim Bridger generation, a combination of both the Jim Bridger units (maximum of two out of four) and the new wind farms were tripped at different tripping times to evaluate the critical clearing time. Different times for tripping the generation were simulated, and the results did not show a significant difference in performance. There is not a significant difference in voltage performance when the Jim Bridger generation is lower.

However, the voltage performance is different when the Jim Bridger generation is high and wind generation that is loading the Jim Bridger west transmission path is low. The study demonstrated that the clearing time for a fault is as equally critical as the tripping of Jim Bridger units. Combinations of simulations with different tripping times and different clearing times were conducted to understand the timing requirements. The study demonstrated that irrespective of the Jim Bridger generation, it is necessary to trip Jim Bridger generation faster than wind generation. The study showed that Jim Bridger generation has to be tripped within 5 cycles of the fault inception in order to maintain stability of the system for some of the critical outages between Jim Bridger and Populus. The study also demonstrated that if the Jim Bridger units are tripped within 5 cycles of fault inception and the wind generation in eastern Wyoming at the latest by 8 cycles, the system stability is maintained for the N-2 outages west of Jim Bridger.

Fig. 6 and Fig. 7 show the voltages at the Jim Bridger 345 kV bus and Threemile Knoll 345 kV buses of the N-2 outages for the 345 kV lines west of Jim Bridger with the Bridger RAS tripping the Jim Bridger units at 5 cycles and the wind farm at 8 cycles. Both of the simulated N-2 outages met performance.

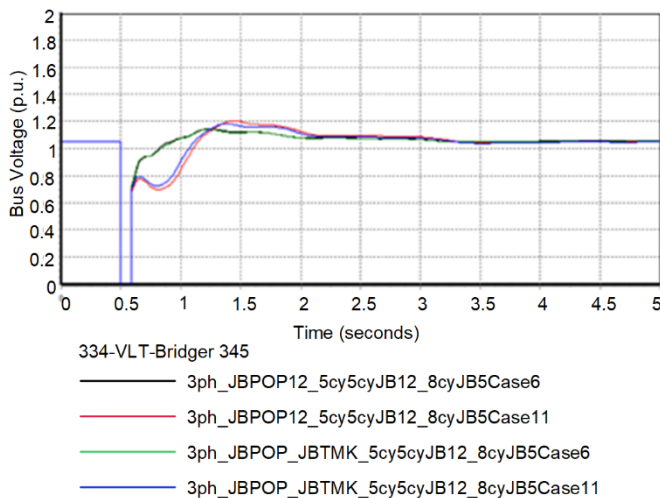


Fig. 6. Bridger 345 kV Voltage for N-2 outage of 345 kV lines west of Jim Bridger.

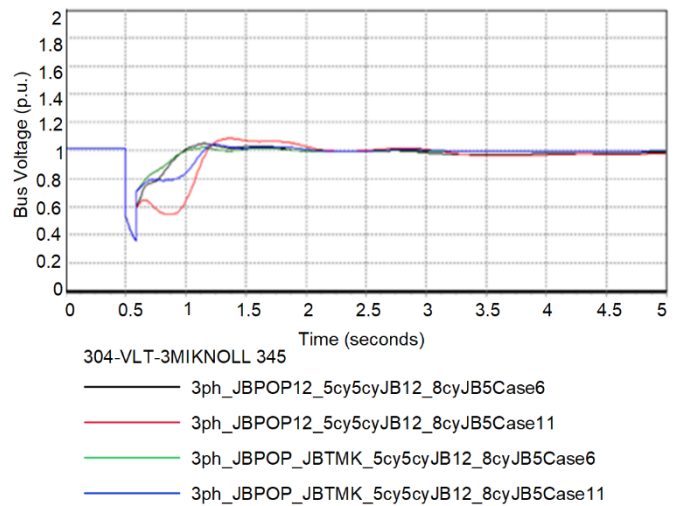


Fig. 7. Threemile Knoll 345 kV voltage for N-2 outage or 345 kV lines west of Jim Bridger.

The study also demonstrated that for close-in three-phase faults, the Jim Bridger units need to be tripped within 5 cycles and the wind generation in 8 cycles in order to maintain reliability of the system.

C. Jim Bridger Generation vs Wind Generation Tripping (Effectiveness Factor)

Electrically, the wind generation in eastern Wyoming is farther away than the Jim Bridger generators. Hence, the impact of tripping 1 MW of Jim Bridger generation is not the same as tripping 1 MW of wind generation in eastern Wyoming. The effectiveness factor ratio was calculated to determine how much wind generation needs to be tripped in order to have the same impact as tripping Jim Bridger generation.

Both power flow and transient stability analyses were performed to determine the effectiveness factor for the eastern Wyoming wind generation. For the case with lower Jim Bridger generation and high wind generation transfers, the RAS needs to trip 498 MW for a severe three-phase fault at Jim Bridger, losing any one of the 345 kV lines west of Jim Bridger.

This tripping can be achieved either by tripping Jim Bridger units or tripping an appropriate portion of wind generation that yields similar results. Different levels of wind generation tripping were simulated to determine how much more wind needed to be tripped instead of Jim Bridger generation.

Fig. 8 illustrates the comparison of the voltage performance at the Jim Bridger 345 kV bus and Threemile Knoll 345 kV bus for a three-phase fault at Jim Bridger resulting in loss of the Jim Bridger–Populus 1 line. Based on the model, the RAS requires a tripping of 497 MW at Jim Bridger for this outage. One simulation was performed by tripping 497 MW of Jim Bridger generation and another one by tripping 627 MW of wind generation. The 627 MW of tripped wind generation is 1.3 times higher than the actual Jim Bridger generation required to trip. As seen in the plot, the yellow and red curves represent the voltage at the Threemile Knoll 345 kV bus, and the green and blue curves represent the voltage at the Bridger 345 kV bus. The voltage performance is very similar.

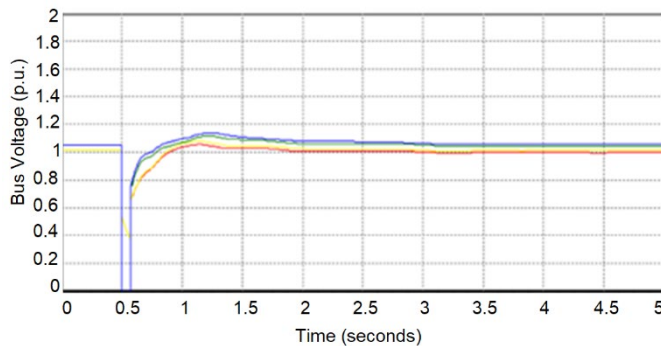


Fig. 8. Voltage performance of tripping wind versus Jim Bridger units to determine effectiveness factor.

The voltage performance for the simulation that trips the Jim Bridger generation is little worse than the simulation in which the eastern Wyoming wind generation is dropped, as the reactive support provided by each Jim Bridger unit is reduced when the Jim Bridger units are tripped. The Aeolus voltage performance is also better when the wind generation is dropped as compared to Jim Bridger units.

The study concluded that in order to achieve similar reliability performance by tripping wind generation instead of Jim Bridger generation, an effectiveness factor of 1.30 should be applied to the wind generation. For example, if the RAS requires tripping 100 MW of Jim Bridger generation, then a total of 130 MW of wind generation tripping is required to achieve similar results.

VII. TRIPPING LOGIC

A. Optimal Unit Selection Algorithm

This study has shown that under rare but critical outage conditions such as N–2 outage of Jim Bridger–Populus 1 and 2 345 kV lines or other N–2 outage conditions, the Jim Bridger RAS may call for tripping higher generation levels that require tripping the combination of both thermal and wind generation. Under these conditions, a maximum of two Jim Bridger units should be allowed to trip, and the rest of the tripping should be

achieved by tripping wind generation. The study also has shown that the most effective system performance is achieved by tripping a combination of both the Jim Bridger generators and the wind generators.

The following steps are necessary to properly select a unit for tripping. The Fig. 9 flow chart also shows how the RAS controller calculates generation to trip.

1. Check to see which generators (both thermal and wind generation) are online and if the Anticline–Bridger line is connected.
2. Predict for each generator whether it will be taken offline due to an N-state and consider their combined generation output.
3. Based on the shedding requirement, if GTrip is less than lowflow MW (~200 MW), then verify if any of the wind combination (WTO) can satisfy the requirement; if not, move to single Jim Bridger unit selection.
4. Determine for each unit whether it will split the bus if tripped. Calculate the single unit that best satisfies the shedding requirement.
5. If it is determined that a single unit does not satisfy the power-shedding requirement, then multiple-unit (one Bridger unit plus wind combination) selection logic is used.
6. If the largest Jim Bridger unit and a combination of wind generation units (WTO) is less than Wmax MW and satisfies the shedding requirement, it is selected. If the largest Jim Bridger unit and wind combination does not satisfy the requirement, then jump to pair of units logic.
7. First, calculate all the power generation associated with each pair by adding the generation of the units together. Then determine if there is at least one pair of units that satisfies the power requirements.
8. Next, determine if a pair of units satisfies the power requirements and prevents splitting the bus. If so, select that pair and move to the end of the logic.
9. If none of the unit pairs satisfy the shedding requirement, then check if a combination of pairs of units (which does not split the bus) and wind combination (WTO) less than Wmax MW will satisfy the power requirements. If a combination does and if the pair of units does not split the bus, then select those units and move to the end of logic.
10. If a combination of a pair of Jim Bridger units and wind combination (WTO) less than Wmax MW does not meet the shedding requirements (the shedding requirement is more than this combination), then select the largest pair of Jim Bridger units (which do not split the bus) and largest wind combination greater than Wmax MW and trip them.

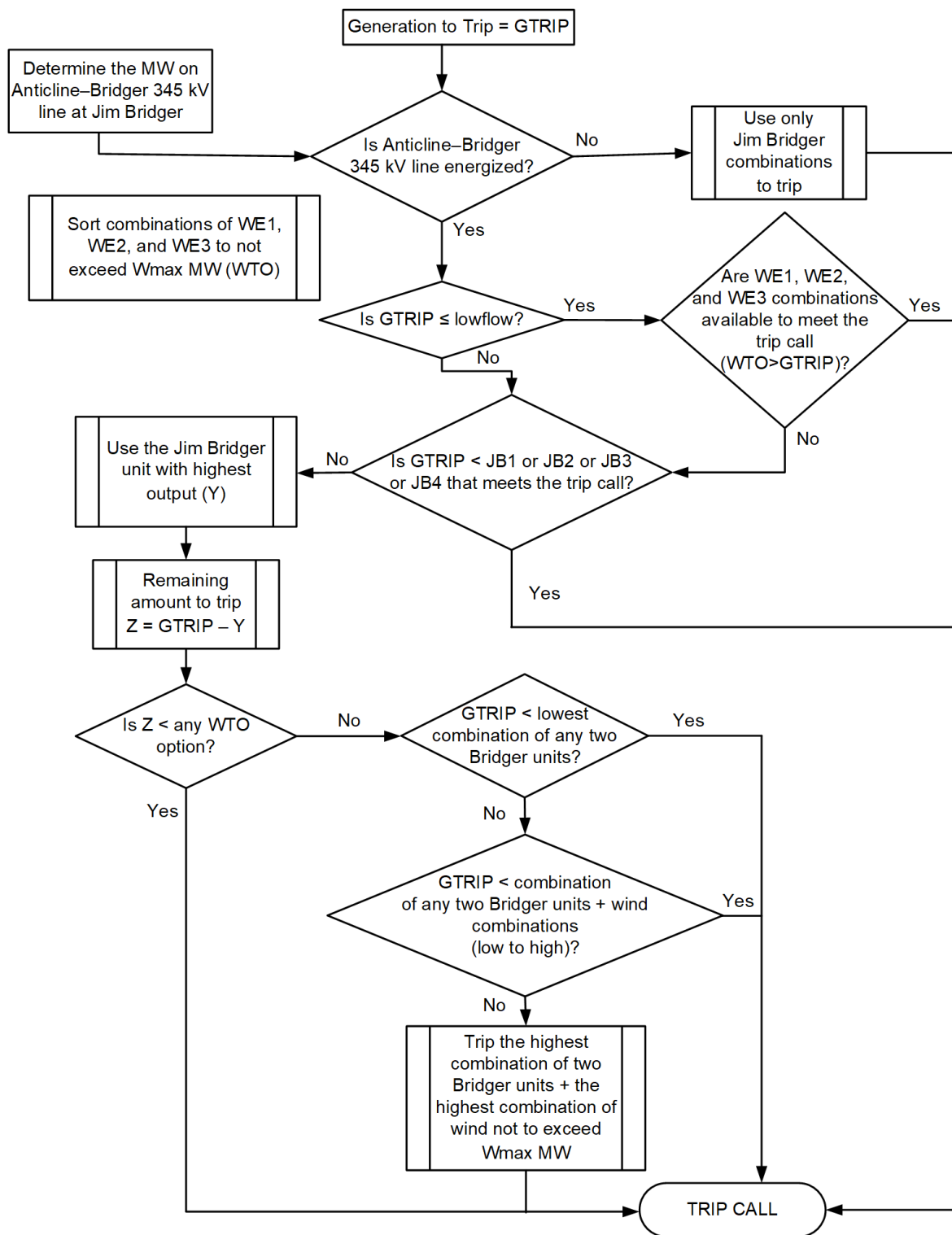


Fig. 9. Optimal unit selection flow chart.

B. Split Configurations

If the RAS calls for tripping one or more units via the unit selection process, it ensures that tripping them does not result in splitting the Jim Bridger 345 kV bus. If the RAS requires two Jim Bridger units to trip, but all the combination of units results in splitting the Jim Bridger 345 kV bus, then it trips only one unit with the highest power, irrespective of the generation that is required to be tripped.

As shown in Fig. 10, there will be an additional bay on the Bridger 345 kV bus connecting to Anticline, to bring the wind generation into Jim Bridger. Under a bus split condition, in addition to the highest Jim Bridger unit being tripped, wind generation is tripped. Hence, there is a possibility of tripping more generation under the configuration where tripping more than one Jim Bridger unit splits the bus. The bus split logic has

been updated accordingly to account for the new bay on the Jim Bridger 345 kV bus.

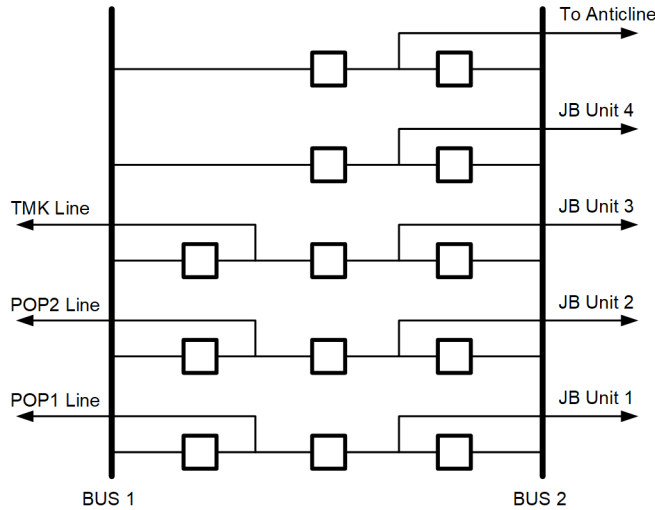


Fig. 10. Jim Bridger bus configuration.

C. Coordinating With Neighboring RAS

The RAS also receives trip calls from the adjacent Idaho Power (IPCO) RAS [8]. When the existing RAS receives either the IPCO Level 1 or Level 2 trip signal from Idaho Power, it issues a trip of either 350 MW or 700 MW, respectively. The existing RAS trips up to two Jim Bridger units for this call. With the availability of wind generation, the trip call of 350 MW is treated like a shedding requirement and units are selected accordingly.

Under operating conditions where the Jim Bridger units are at lower output and tripping two units does not satisfy the IPCO Level 2 requirement, then additional wind generation is tripped to achieve the remaining amount. In tripping the wind generation for the IPCO Level 2, the effectiveness factor is applied to achieve the required impact of an IPCO Level 2 trip.

VIII. RAS SCHEME VALIDATION WITH TEST SIMULATOR

In addition to the test simulator at the site, there is a replica test system simulator at PacifiCorp which was designed with future upgrade projects and updates in mind. This replica test system simulator includes the simulator system and one RAS system (RAS C). The test system simulator was updated for the wind generation integration and all the items associated with it. After updating the RAS controllers, FEPs, simulator system, and HMI and SCADA interfaces, the RAS scheme was validated with the test system simulator.

A series of test cases were developed to test the RAS logic with the all the power system information including the existing Jim Bridger configuration and the newly added wind generation, new 500 kV line, and all related data. System planning identified the required actions for each test case; using the playback simulator mode, the test cases were played one after the other to verify and validate RAS actions. RAS logic and its actions were verified by looking at the Sequential Event Recorder (SER) and event report files generated after each contingency event, capturing all the relevant system data during

a contingency. Including the old test cases and new test cases, a total of 130 test cases were simulated and the response for each test recorded, verified, and validated. This rigorous testing effort helped the team identify certain scenarios for which the RAS actions have to be modified for an appropriate response.

After the internal testing, a factory acceptance test (FAT) was performed with the customer in a remote fashion given the pandemic situation at the time. The remote FAT took longer than normal but at the end gave the team the confidence in the ability of the updated RAS scheme to be commissioned in the field.

IX. COMMISSIONING AND CHALLENGES FACED WHILE UPGRADING AN IN-SERVICE RAS SYSTEM

The process of commissioning an upgrade on an existing functional RAS system with dual TMR architecture as shown in Fig. 11 is highly complex and critical and required people from many different groups within the two authoring companies, such as protection engineering, operations, and dispatch as well as field service and communication technicians, etc. It was critical to have the team working together to achieve the commissioning in a smooth manner.

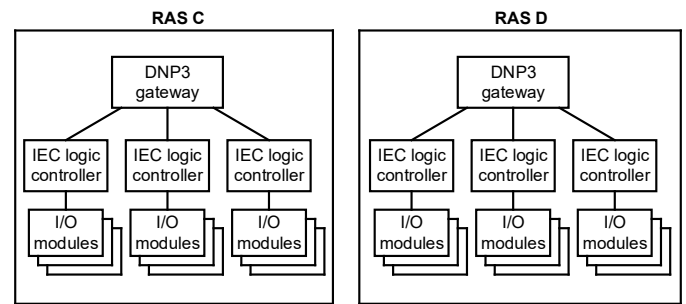


Fig. 11. Dual TMR architecture.

Dual TMR architecture has two RAS systems, RAS C and RAS D, with triple modules in each. There are three RAS controllers and three I/O modules for each RAS. A detailed commissioning procedure and checklist was developed for RAS C and RAS D. According to the plan, one RAS was kept active all the time except for a short amount of time during switchover while one RAS was upgraded. Commissioning was carefully planned to upgrade the system one RAS at a time. All three controllers in RAS C were upgraded first, along with the FEP C and new I/O points for RAS C. RAS D was still operating with existing I/Os without the changes. A site acceptance test with some of the predetermined cases was performed using the test simulator system.

After RAS C was completely upgraded, it was in monitoring mode for a short duration while its performance, calculations, and decisions were monitored and verified before putting it in service. Both RAS systems were out of service during a short time during which the Microsoft Windows HMI system was upgraded. The updated RAS C was put back in service, then RAS D went offline. RAS C was monitoring and protecting the system; it was configured to work both with the wind generation and without it, depending upon the status of the new 500 kV line and the wind generation units. This helped in

seamless transition of the system in monitoring and including the new assets once they came online.

RAS D was upgraded while RAS C was in service. After the upgrade and completion of the functional tests, it was put in monitoring mode for a short duration and then the system was turned on and made operational. With careful planning between all the parties involved the system was updated in 4 weeks.

X. CONCLUSION

The Jim Bridger RAS was upgraded after 10 years. The additional wind generation from eastern Wyoming was incorporated in the arming level and generation-to-shed calculations. Wind generation units were included in the generator-dropping algorithm in the RAS. Data from the wind farms is integrated to the RAS scheme and RAS sends trips to the wind farms through the FEP located in Jim Bridger and I/O modules located in the wind generation substations. As part of the upgrade, RAS HMI screens were updated with information related to the new 500 kV line and the wind generation substations. The RAS simulator system and the replica simulator was updated to include the new details.

The system study results showed that a combination of Jim Bridger and wind generation tripping was beneficial in maintaining the system stability and reliability. The effectiveness factor (Ef) determined the equivalent wind generation tripping for comparable Jim Bridger generation to achieve similar results. Testing of the RAS scheme with the simulator system using a multitude of test cases validated the RAS logic and proved the design. The RAS system has been commissioned and working.

The RAS is designed to allow future expansion with little interruption to performance. The hardware design allows for RAS C or D to be disconnected from the live power system and connected to a test simulator. This not only allows for quick changes to occur within the RAS, but also for expansion and other maintenance actions without taking the entire system out of service.

XI. ACKNOWLEDGMENTS

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XIII. BIOGRAPHIES

Rikin Shah is currently working as a principal engineer in the Area/Transmission planning department at PacifiCorp. He has a master's degree in general engineering-electrical option from Montana Tech. He received his bachelor's degree in electrical engineering from India. In his 17 years of transmission planning experience, he has worked on several transmission related studies such as reliability planning analysis, generation interconnection, and compliance-related studies. He is currently performing studies for the development of the Gateway South project, which is a 400 mi, 500 kV line connecting eastern Wyoming to central Utah. He has participated in the regional standard drafting committee for the Western Electricity Coordinating Council (WECC).

Robert Hines received a Bachelor of Science in electrical engineering from Washington State University in 1993. In 1999, Robert joined the protection and control engineering department at PacifiCorp where he has worked on protection systems for equipment ranging from distribution to extra-high voltage (EHV). His experience includes over 12 years of specialized control system design and relay settings development with multiple large scale remedial action schemes (RASs). Robert is currently a senior engineer in the protection and control engineering department where he continues to focus on the development, testing, commissioning, and field support of complex control systems for high-voltage and EHV equipment. In a recent project, Robert worked with Pamela Palen (PacifiCorp) to design, test and, commission protection and automated controls for the paralleling of 3 345 kV phase-shifting transformers at Pinto Substation. This is the only arrangement of its kind in the Northwest power system.

Pamela Palen received her bachelor's degree in electrical engineering from Portland State University in 1996. In 2004, she joined PacifiCorp where she has worked on substation design, protection, control, and automation. Pamela is currently a senior engineer II in the protection and control engineering department where she specializes in substation control and automation. She has experience in the design, development, testing, commissioning, and field support of complicated control systems for high-voltage and extra-high voltage (EHV) equipment. In her 17 years at PacifiCorp, Pamela has been responsible for the creation of multiple company design standards for capacitor control automation, phase shifting transformer control, substation HMI, and automation for distribution and transmission. In a recent project, Pamela worked with Robert Hines (PacifiCorp) to design, test, and commission protection and automated controls for the paralleling of 3 345 kV phase-shifting transformers at Pinto substation. This is the only arrangement of its kind in the Northwest power system.

Hariharan Subramanian received his BE from College of Engineering Guindy in 2005 and an ME from Texas A & M University in 2009. In 2005, he joined Neureol Technologies Pvt Ltd as an electrical design engineer working on battery monitoring systems for two years. Prior to joining Schweitzer Engineering Laboratories, Inc. (SEL) in 2018, he worked at Bechtel Corporation for six years in different roles in electrical engineering and also previously worked in SEL as automation engineer for three years. He is

presently a senior engineer at SEL. He has experience in power system design, power system automation, power system protection and studies, and power management systems. He is experienced in the design, development, testing, and commissioning of projects. He has worked on multiple projects with various customers in the oil and gas and utility industries. He is a senior member of the IEEE and a registered professional engineer in Texas.

Rameez Syed received a Bachelor of Applied Science in electrical engineering from the University of Windsor, Ontario, Canada. He joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2008 and is currently an SEL Engineering Services, Inc. (SEL ES) manager. He has 12+ years of experience in the field of power system automation, including power management schemes for large-scale industrial power plants, remedial action schemes (RASs), and microgrid solutions.

Alejandro Carbajal received his electronic engineering degree in 2008 from the Universidad Autónoma de San Luis Potosí (UASLP) in San Luis Potosí, Mexico. In August 2009, Alejandro joined Schweitzer Engineering Laboratories, Inc. (SEL) as a development engineer. After working in different areas of SEL, he specialized in automation and gained international experience working with various project architectures. In 2014, he joined the special protection schemes team in Mexico, working with remedial action scheme (RAS) projects. His specialty is programming different controller platforms for RAS automation. In 2019 he moved to SEL Engineering Services, Inc. (SEL ES) in Boise, Idaho as an automation engineer. He is presently working in the same office gaining experience in different roles in design of automation systems.

Idaho Power RAS: A Dynamic Remedial Action Case Study

Michael Vaughn, *Idaho Power Company*

Robert Schloss, Scott Manson, Sai Raghupathula, and Trent Maier, *Schweitzer Engineering Laboratories, Inc.*

Abstract—Two separate remedial action scheme (RAS) algorithms reside on a single set of hardware at a transmission substation located in Idaho. The substation is the terminus of three 345 kV, one 230 kV, and one 500 kV transmission circuits. This substation transports power from power plants in the Rocky Mountains to load centers in Oregon, Idaho, and Utah. When one or more of the high-voltage circuits are lost, overloading can occur on the remaining lines across the path.

The primary function of this RAS is to protect lines against thermal damage, while helping optimize the transfer across critical corridors. The secondary function of the RAS is to dynamically predict power flow scheduling limits on critical transmission lines and corridors.

Idaho Power Company contracted with a supplier to build a state-of-the-art RAS that can trip generation units, bypass series capacitors, insert shunt capacitors at remote substations, or take any combination of these actions. To most effectively determine which level of remediation should occur, a user-configurable set of action tables is used alongside a dynamic arming calculation. A user-configurable nomogram and logic are used for the simpler RAS for lines flowing into Oregon.

I. BACKGROUND

A. Introduction

As the demands placed on a power system grow, maintaining the stability, reliability, and security of the power system becomes a balancing act for engineers. As consumers, we continually find ourselves embracing more and more power-consuming technology, which increases demand for power and further stresses our installed infrastructure. Owners of electrical power transmission systems constantly juggle the need to build more power plants and transmission lines with how much they cost and when the right time is to invest those costs. Because it is so expensive to build more plants and lines to make our systems more robust, we need to operate the installed infrastructure closer to its operating limits and at higher utilization levels. It is a constant conundrum. Where and when do we spend money to operate systems at their most cost-effective levels?

Another inherent problem of highly stressed power systems is that they will degrade in an unrecoverable cascading fashion when certain significant events occur. The solution to this is millisecond-speed (subcycle) identification and control actions to keep the problems from growing larger, commonly referred to as a remedial action scheme (RAS) or special protection scheme (SPS). Without these schemes in place, permanent damage to electrical and mechanical power system equipment will happen. The more significant the event, the greater the potential damage and, therefore, cost that could be incurred.

The revenue dollars lost while system repairs are made further compounds such problems.

A RAS becomes a necessary and cost-effective solution when a power system is not robust enough to accept failures or outages of components without some subsequent response. When a primary protective relay system operates to protect individual components or portions of a power system, a RAS monitors the effect to the larger overall system. If conditions exist that are detrimental to the operation of the larger system or to adjoining systems, then actions are taken by the RAS to remediate the effects. A RAS is the safety control system that monitors and protects a larger power system from additional problems when something within the power system fails.

A fast (subcycle) RAS can double the power transfer capacity across an existing transmission grid [1]. Operating speed, determinism, expandability, processing power to run complex algorithms in milliseconds, and data capture for post-event analysis are key factors that need to be addressed in these schemes.

As shown in Fig. 1, the RAS supports loads served in Idaho and Oregon. Without the RAS in operation, it is generally necessary to lower the operational transfer limit (OTC) of the path when contingencies or operations and maintenance activities remove key lines from service. When demand is high enough and the RAS is in operation, the OTC does not have to be lowered. This allows Idaho Power Company and PacifiCorp to operate path flows (MW) at higher levels throughout the year. Both RAS algorithms meet the Western Electricity Coordinating Council (WECC) requirements, while allowing maximum power transfer across related paths during changes in the system topography.

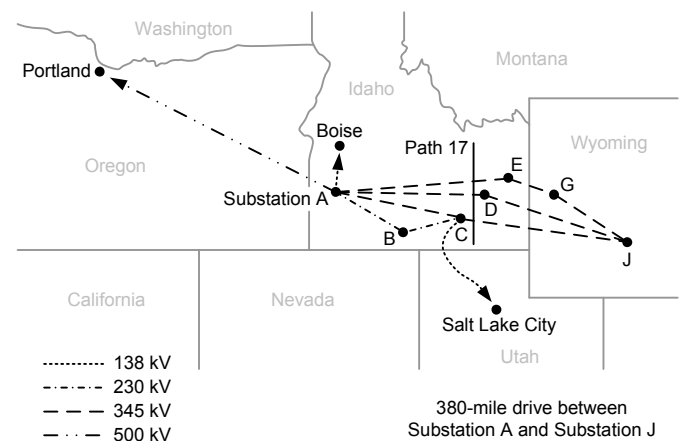


Fig. 1. Geographic area involved

The RAS system described in this paper cost a fraction of what it would have cost to build a new transmission line or to bring a new power plant online, allowing those major costs to be postponed. The RAS allows increased operating revenues during normal maintenance or repair operations and during emergency operations when key system components fail. It also allows Idaho Power Company to be good neighbors with adjoining utilities by preventing problems from propagating out into other systems. With the relatively small investment of the RAS, Idaho Power Company gains more secure and reliable operations, as well as higher utilization levels for key system components, resulting in higher profits and more cost-effective delivery of power to customers.

B. History

The RAS was installed to replace a series of aging and limited systems that worked independently to accomplish a similar, yet much more limited, generation-shedding scheme.

The previous RAS consisted of a collection of discrete contacts, power flow monitoring devices, timers, and tripping relays that had the ability to initiate a very limited response to a small number of conditions. The previous RAS had only two outputs, a Level 1 or Level 2 trip. It could only consider input on conditions from the local substation. It was not adaptive and had to be manually adjusted in order to respond to different system conditions. As such, its functionality and area of influence no longer matched the needs of the system. This initial RAS had to be manually disabled or adjusted whenever related lines were taken out of service for maintenance or repair. During those maintenance or repair activities, the flows across the monitored path had to be drastically reduced to safe operating limits, which translated to reduced revenues. Therefore, a new RAS was needed to meet all operating requirements and to optimize path utilization.

RASs are applied to solve credible single- and multiple-contingency (event) problems. RASs in the Western Electricity Coordinating Council (WECC) supplement ordinary protection and control devices (fault protection, reclosing, automatic voltage regulators, power system stabilizers, governors, automatic generation control, etc.) to prevent violations of the North American Electric Reliability Corporation (NERC) and WECC reliability criteria for Category B and more severe events.

The previous RAS did not meet current WECC design requirements, as outlined in the WECC “Remedial Action Scheme Design Guide” dated November 28, 2006. Also, when a RAS is in place, its operation must be monitored and analyzed to ensure proper response. When a RAS has to be taken out of service, the path flows need to be reduced to safe levels. If a RAS is found to have misoperated, it must be taken out of service and repaired or corrected within the described time frame. Otherwise, the RAS owner could face penalties and fines. These requirements are found in WECC Standard PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation, dated April 16, 2008. The WECC requirements mandate a more complex RAS with high

availability, continuous self-monitoring, and the ability to automatically capture data for later analysis.

The new RAS has the ability to monitor much more data and different classes of data inputs from very widely dispersed locations. It can rapidly consider changes to system data and make decisions and effect responses that mitigate further problems, while allowing optimized use of the system. This RAS senses when key system components are removed from service and automatically adjusts its responses as needed. This new system is also redundant, providing very high levels of reliability and availability. It is self-monitoring and captures time-stamped data for analysis and evaluation that are accurate to 1 millisecond. These captured data can be replayed in the original captured form back to the RAS via the playback simulator.

C. Cross Company Boundary Complications

Idaho Power Company owns the RAS equipment that is described in this paper, and is part owner of another RAS installed in Wyoming. The major transmission lines flowing into Oregon are owned by PacifiCorp, but they originate at a substation owned by Idaho Power Company. This cross company ownership of assets makes for a great deal of complication in a RAS. These RASs communicate together over hundreds of miles to form a cohesive control system. Both RASs were designed specifically to protect the interests of both companies.

II. RAS CONTROLLER REQUIREMENTS

A. Timing Requirements

The majority of the system is thermally limited, meaning that upon outages of key resources, overload conditions can occur on other resources. This requires a response time on the order of minutes.

Certain system contingencies for a portion of the system require remediation for voltage stability concerns. This requires a much faster response time. When the typical fault detection, communications time, and unit breaker opening time are excluded from the total time budget, the RAS is left with 20 milliseconds of operating time in which it must operate for certain contingencies. Table I shows the installed RAS throughput time, which meets Idaho Power Company requirements. The RAS total throughput time is the total measured time from an input voltage asserting to 90 percent to an output (trip-rated contact) fully conducting.

TABLE I
RAS TIME BUDGET

Item	Time (ms)
I/O module input debounce	2
I/O module output contact closure	0.01
RAS controller central processing unit (CPU) processing time	2
Communications transmit and receive signals	<8
Total throughput time	<12

B. Reliability Requirements

WECC design guidelines do not require absolute redundancy as long as the failure of nonredundant components does not result in the interconnected transmission system violating its performance requirements. Alternatives to redundant design can also be implemented as long as the resulting response meets system requirements. This is based on an evaluation of the consequences of nonredundant component failure. In most areas, the new RAS implements full redundancy. Some aspects are not redundant, but are monitored and alarm upon failure. All the RAS equipment was designed and hardened to operate and survive in a substation environment.

C. Functional Requirements

WECC monitors a transmission path that lies just east of a key substation. This substation, located in south central Idaho, is the terminus of one 230 kV transmission line and three 345 kV lines coming in from the east that bring power from one of the larger power plants in Wyoming. When one or more of these lines are lost, overloading can occur on remaining lines across the path. This RAS exists to protect against thermal damage to any of these lines, while helping optimize transfer of power across the path.

Much of the power from the power plant in Wyoming is then sent on to Oregon via another path monitored by WECC. This RAS monitors availability of and power flow on the related transmission lines flowing into Oregon. The RAS takes action as needed to maintain voltage stability and protect against thermal damage to underlying circuits in the event that one of those transmission lines open under particular conditions.

Under some circumstances, particularly the loss of the 345 kV lines, the 138 kV line can become overloaded. In order to alleviate overloads on these lines and keep overloads from occurring on surrounding transmission lines, it is preferable to open breakers at remote stations. A transfer trip signal from a thermal overload element programmed in a microprocessor-based multifunction distance relay on the overloaded 138 kV line is sent to the remote breaker that best alleviates the overload condition. This is incorporated into the communications infrastructure of the system.

Three existing RASs were replaced by the new RAS. These RASs performed the following actions:

- Generator dropping scheme for loss of the 345 kV lines.
- Generator dropping scheme for loss of the 500 kV line.
- Line overload RAS for the 138 kV lines.

The first of the three original RASs was initially installed in the 1980s, the last in 1995. Though they have been reliable and have served their purpose, they were very limited in design and were no longer able to meet current and future needs. These RASs were replaced with new, state-of-the-art redundant systems that improve the reliability and maintainability

of the transfer paths. This replacement project allows for optimized power transfers across both WECC paths during equipment outages.

The RAS was required to provide a set of fast, reliable, automatic controls to monitor power flow in the system components and monitor ambient air temperatures. The controls are also required to sense changes in the system configuration, determine the optimized response for maximum power transfer and minimum generation tripping, and transmit an output (such as a trip signal to the remote RAS in Wyoming) in less than 20 milliseconds from input detection to output trip initiation (total throughput time). The scheme needed to be reliable and secure with very high levels of availability.

Failure of this scheme to operate correctly could result in damage to the transmission lines, unnecessary tripping of generators, or expansion of disturbances into adjacent systems. Thus redundancy is implemented in this system.

D. Events and Actions

The N events or contingencies that can result in remediation being taken by this RAS are the following:

- The loss of one or more lines from service.
- An overload condition sensed in one of the monitored lines or transformers.

The control actions the RAS can take are the following:

- Add shunt capacitors.
- Bypass series capacitors.
- Shed generation at the power plant.

The RAS was designed to respond to multiple closely timed or simultaneous events; this functionality is key to the optimization of the system with this RAS control strategy.

Table II shows that the RAS logic is all performed at the main substation, whereas digital and metering status information is gathered at six remote substations and control actions are made at eight substations. Many of these substations are hundreds of kilometers from the RAS controller at the main substation. This makes for a system that depends heavily on communication.

TABLE II
SUBSTATION SUMMARY CHART

Substation	Detection	Logic	Action
A	X	X	X
B	X		X
C	X		X
D	X		X
E	X		
F	X		X
G			X
H	X		X
J			X

III. RAS DESIGN

A. System Architecture

Fig. 2 is an overview of the major systems in the RAS. Notice that the right side of this image is a mirror of the left side. This critical equipment duplication creates a system of two completely autonomous control systems; hence the system is considered dual primary redundant. Dual primary redundant schemes have no failover time because both RAS controllers are running at all times. This is in stark contrast to many of the failover or standby redundant schemes employed with outdated programmable logic controllers (PLCs). Dual primary technology is used extensively in transmission protection schemes in North America.

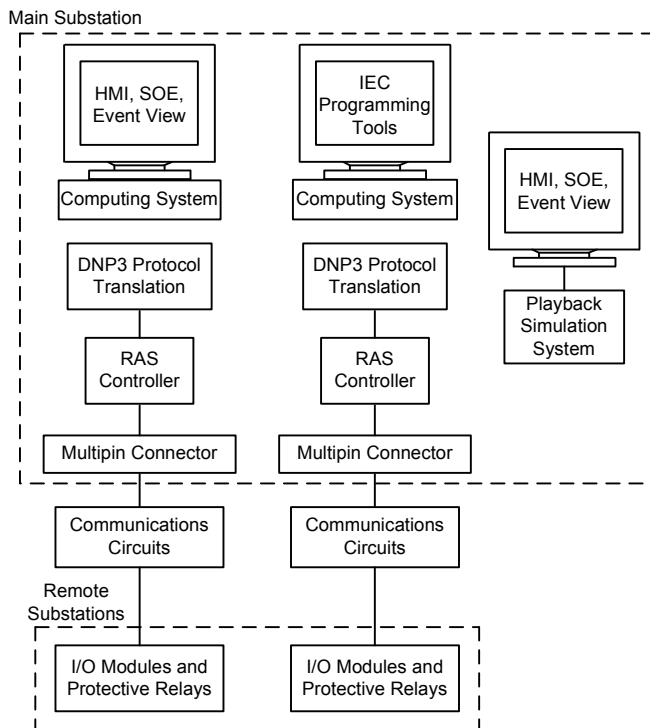


Fig. 2. System architecture overview

Within each RAS system, a single substation-hardened computer provides a user interface (human-machine interface [HMI]), sequence of events (SOE) viewing (SERviewer Software), and event report viewing (oscillography). Another hardened computer is used as an engineering workstation and contains the development environment for all hardware (including the IEC 61131-compliant programming).

Each RAS system (A and B) has its own protocol gateway for communication to the Idaho Power Company energy management system (EMS). These gateways communicate the necessary status, metering, and controls to and from the supervisory control and data acquisition (SCADA) masters via serial DNP3.

RAS Systems A and B are completely isolated on separate networks, and all logic on each system runs without any knowledge of the other system. The decisions taken by the two RAS systems are monitored by a supervision system. If the control actions are identical, both RASs are allowed to

operate. If the two RASs come up with different control actions, only the system with the best overall health is allowed to operate.

The router between the two systems is configured to prohibit all traffic between the two RAS systems. The router allows communication from each independent RAS system to the HMI, engineering workstation, and supervision systems.

Not shown in Fig. 2 is a multifunction playback test simulator designed to test the RAS in all system conditions. Modifications or improvements to the RAS can be tested easily by forcing one RAS to test mode and connecting it to a test simulator, while keeping the other RAS online.

B. SCADA Communications

The SCADA gateway systems function as the intermediary for receiving data from the PacifiCorp EMS that will be used in the RAS system calculation algorithms. These gateways are also used for providing data to the EMS regarding the status and operating characteristics of the RAS system.

The RAS can run autonomously from the EMS. This is because all data used by the RAS are provided through independent communications channels.

C. Rugged Design Characteristics

All hardware in the RAS is protective relay-class, substation-hardened equipment with extended temperature range, physical shock resistance, electromagnetic immunity, and static discharge capabilities.

The control algorithm resides on a substation-hardened controller running an embedded real-time controller engine. This engine is programmable in all IEC 61131 programming languages. There are no fans and no spinning hard drives in any equipment. All components run on the substation battery (dc). No ac power is used in the RAS panels.

All outputs used on remote I/O modules are hybrid Form A, trip-rated dry contacts; there are no interposing relays in the system. These outputs are therefore fail-safe (i.e., they remain open unless a tripping scenario has occurred). The hybrid outputs feature submillisecond closing times; this saves approximately 5 milliseconds on the total throughput time of the RAS. These hybrid outputs can also interrupt up to 30 A of inductive current while opening.

Additionally, every zone of the RAS hardware, communications system, firmware, and software contains continuous self-diagnostics. This guarantees the detection of a catastrophic failure of any component in the system. Every device in the RAS design has a normally closed, watchdog alarm contact that asserts if any device is powered down or has a hardware or firmware failure. These contacts are crosswired to other devices for monitoring, which guarantees that a failure in one device will not propagate further.

Communications systems are continuously monitored with protocols that detect the loss of a single serial packet. Additionally, watchdog counters are implemented on all programmable intelligent electronic devices (IEDs), then transmitted to other IEDs, and thus used to detect communications failures.

The logic, settings, and configurations installed on each hardware system are developed and tested to be fault tolerant, meaning that bad computations are intentionally rejected. For example, if a line metered value is out of range or comes from a failed device, an alarm asserts, and the logic declares that specific data as unusable. All logic, settings, and configurations are set up to automatically reject bad data and reselect available (good) data or default to a more conservative value.

A dual Ethernet communications network completely replaces the need for failure-prone, backplane technologies present in most industrial PLCs. The RAS system uses dual redundant Ethernet hardware and redundant communications lines to eliminate all single points of failure in communications between the EMS gateways and RAS controllers.

The result of these design decisions is a RAS that requires two carefully selected, simultaneous hardware failures to prevent RAS operation.

The design considerations for such RASs are nearly identical to those of the industrial power management and control systems regularly deployed by the supplier [2].

IV. RAS ALGORITHM

To make the RAS fast and deterministic, the RAS logic needs to be efficient. The RAS logic has two parts: data acquisition and RAS algorithm processing.

A. Data Acquisition and Communications Systems

Not all data used within the RAS need to be fast. High-speed data are needed to detect contingencies, whereas low-speed data, such as metering (MW) information, can be used to calculate the RAS actions. This leads to the classification of the required data into two categories: high-speed and low-speed data. This type of data segregation has been proven by the vendor to provide excellent performance on both large and small RASs, industrial load-shedding systems, generation control schemes, and automatic decoupling projects [3] [4] [5] [6].

Between the main substation and all remote substations, there are both high-speed and low-speed data communications streams. Making all the data high speed would require T1 or faster data connections; these were not available or necessary.

Both high-speed and low-speed serial lines are multiplexed together at the remote substation and then transmitted to the RAS over a variety of media, such as devoted fiber optics, leased lines, and microwave. Path diversity was used to reduce the likelihood of simultaneous communications failures to a single location. Statistical multiplexing satisfies the requirement of a fast, deterministic, high-speed data stream and simultaneously passes the large volume of low-speed data over a single low-bandwidth data communications line.

1) High-Speed Data

A proprietary communications protocol was used for high-speed data communications. This protocol is the dominant serial communications protocol used for pilot protection schemes in North America. At 19200 bps, this protocol

provides data with deterministic, 4-millisecond updates of digital I/O to the controllers. The protocol itself is built for operational security and therefore is an excellent choice for digital communication for a high-speed RAS. Because of its low-bandwidth usage, it works naturally with bridge multiplexers and microwave equipment. These high-speed data are used to detect N states and will be explained in detail in later sections.

2) Low-Speed Data

Low-speed data are processed every 200 milliseconds by the RAS. These data are used in determining the power system state (J states), determining the appropriate arming levels, and calculating the remedial actions for all the predefined contingencies. These low-speed data include data from the EMS, analog data (such as MW and MVAR), breaker statuses, and out-of-service conditions. Every 200 milliseconds, the RAS decides on the actions that must take place for each contingency, should it occur. These actions are fed into a crosspoint switch (CPS). The high-speed input data are then cross-multiplied with the CPS to issue digital output signals (trips).

B. RAS Logic Processing

The following subsections discuss the major components of the RAS algorithm logic.

1) Data Source Validation and Selection

Digital and analog data selections are accomplished by selecting the data that are deemed the fastest and most reliable, while filling an entire data set with one source. The data selection monitors communications failures with different levels of equipment to select the best data path available. In the RAS, the data are sent through two separate communications processors, as well as the EMS. The RAS operates with a single set of data for all decision-making processes. The single set is determined with this data selection logic. The data validation logic follows the data selection logic and is used to determine whether the analog data selected are valid. This is accomplished by comparing sets of data with those not chosen to ensure that neither is outside of a given threshold from one another. If a single value from two equally healthy data sources exceeds a 5 percent difference, the more conservative (larger) value is used for all generation-shedding calculations.

2) Detect N Events

Any event in the power system that may require a RAS action is identified as an N event (contingency). All of the data required to detect N events must be high-speed data. Two closely timed N events are treated as N-minus-two events, and the RAS is designed to take higher-level actions for these N-minus-two events. The RAS currently has 64 N states. With simple modification, it can be expanded to any number of N states. The following are some of the N states identified in the RAS:

- Substation D to C 345 kV line out
- Substation D to A 345 kV line out
- Substation A to C 345 kV line out

- Substation E to A 345 kV line out
- Substation C to B 230 kV line out
- Substation F to C 138 kV line out

3) J State

Any event that changes the configuration of the power system is identified as a J state. Most N events become J states in the RAS after a fixed amount of time. For example, a loss of a line is an N event. After a period of time, this N event transitions to a line-out-of-service J state. The following are some of the J states identified in the RAS:

- None (system normal)
- Substation E to C #2 345 kV line out
- Substation A to E 345 kV line out
- Substation C to A #1 345 kV line out
- Substation A to C #2 345 kV line out
- Substation C to B 230 kV line out
- Substation F to C 138 kV line out

A J state change does not require a RAS action but changes the configuration of the power system, which forces the RAS system to load a new set of gains into the arming level calculations. Other examples of J states include the outages of synchronous condensers, transformers, shunt capacitors, and transmission lines. J state data do not need to be high speed. The RAS is designed to accommodate 64 J states and, with simple modification, can be expanded to any number of J states.

4) System State

The combination of J states is called a “system state.” For example, in an instance when there are two lines open and a capacitor is out of service, these three J states are identified in the system. These three states converge to a system state, and this system state determines the gains used in the calculation of the arming level calculation. In other words, the RAS determines the power system state to categorize every combination of possible scenarios that can exist on the power system.

The RAS uses the system state to determine which gain constants need to be used in the action-determining calculation. A set of user-entered tables selects which system state comes out of each cross-combination of J states. With 64 J states, a total of 64! (64 factorial) system states are possible, but not all system states are valid or possible. Considering future expansions and valid states, a total of 1,000 system states is provided within the system.

The present system state identifies which gain factors need to be used in the arming level calculation equation. These gain factors define the system sensitivity to each component in the arming equation and are developed from system studies.

5) Arming Level Calculation

The dynamic calculation and action tables used for the RAS are a novel way of providing remediation to a power system under stress. These techniques add considerable flexibility and intelligence to the power grid and achieve a RAS throughput time of less than 12 milliseconds.

The arming level equation is basically a polynomial equation that is a function of ambient temperature conditions, local area load and generation, initial loading of the underlying 138 kV and 230 kV lines, compensation level of the 345 kV and 500 kV lines (remote inputs), and seven gain factors that define system sensitivity. The RAS uses the arming level equation and calculates 32 arming levels every 200 milliseconds for each N state identified in the system. These 32 arming levels calculated for an N state are associated with a unique index number that identifies a specific set of actions that need to be taken if that contingency were to occur. The 32 arming levels for each N state are arranged in descending order, and the current path flow is compared to arming levels for each N state. The arming level that is slightly below the current path flow is chosen, and the RAS is armed with the actions associated with the index number of the arming level for that N state.

There are a total of seven matrices that are of the dimensions 64 x 1,000 x 32 x 4. This adds up to a total of 57,344,000 gains, not including several other matrices of smaller sizes. Table III summarizes all the major matrices used in the RAS.

TABLE III
GAIN TABLE ARRAY STRUCTURE

Table	N State	J State	System State	I State
Action index	N/A	N/A	N/A	32
N actions table	64	N/A	N/A	32
N actions reference	N/A	N/A	1000	N/A
Kgins	64	N/A	1000	32
Kloadins	64	N/A	1000	32
Kgenins	64	N/A	1000	32
Kpre138ins	64	N/A	1000	32
Kpre230ins	64	N/A	1000	32
Ktins	64	N/A	1000	32
Kaconstins	64	N/A	1000	32
Two J lookup table	N/A	64, 64	N/A	N/A
PostXX	64	N/A	1000	32
Critical element table	64	N/A	1000	32
Miscellaneous settings	N/A	N/A	N/A	N/A

The RAS also calculates the OTC limit. This limit determines the maximum permissible path flow limit, while not exceeding the permissible overload on the parallel circuits under various overload mitigating actions, line outages, and system configurations.

The path OTC limit for each predetermined outage N and facility out of service J can be expressed by the following equation:

$$\begin{aligned}
 BW_{anj} = & K_{ganj} \cdot JB_{Gen} + K_{tanj} \cdot AT + K_{loadanj} \cdot \\
 & LALoad + K_{genanj} \cdot LAGen + K_{pre138anj} \cdot Pre138 + \\
 & K_{pre230anj} \cdot Pre230 + K_{constanj}
 \end{aligned} \quad (1)$$

6) Action Table Prioritization

The RAS implemented for the 500 kV line to Portland dynamically calculates 32 action levels that need to be satisfied for each of the preidentified events. These “I actions” consist of combinations of multiple control actions to restrict the system from not exceeding the permissible overload on the parallel circuits. Through the action table technique, the RAS optimizes various overload mitigating actions for all possible line outage and system configuration (system state) combinations.

Using the action table prioritization has many advantages. Its main advantage is to provide a larger number of possible remediating actions out of a handful of actual possible actions. For example, 10 total actions can provide 10! (3,628,800) total possible combinations of actions. This provides more flexible use of various assets, minimizes impact on the system and customers, and prevents over-remediation of events. Because the action table combinations are entered by the user on the HMI, they are easy to understand. Most importantly, this action table lookup technique provides a simple, elegant, and deterministic solution to a complicated problem.

7) Crosspoint Switch

The CPS is the final result of the RAS algorithm. The CPS is a two-dimensional array with indices of N events and actions. The results from the action table selection algorithm are used to populate the CPS. The CPS is loaded dynamically every 200 milliseconds by the RAS. The CPS gives operators information regarding how the RAS will respond for each N event. As soon as an N event is detected, the RAS knows which actions must be taken and triggers the actions. Fig. 3 shows a typical CPS.

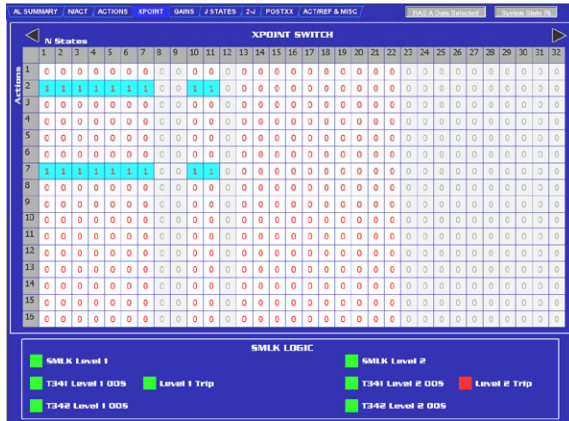


Fig. 3. RAS status screen—CPS tab on RAS HMI

V. MULTIPLE, CLOSELY TIMED EVENTS

There are several logic timers used in the RAS logic. Any contingency that happens in the power system creates a disturbance. Consider, for example, a line is tripped. Because of this line loss, the power is redistributed across different paths, or there are power swings causing the gathered analog data to fluctuate as the power system settles toward a steady-state condition. During this time, if the gathered analog data are used in the arming level calculation, it may result in poor-quality decisions.

To prevent these disturbances from affecting RAS decisions for closely timed N events, all values calculated after the first event are frozen for a certain period of time. At the end of the analog freeze timer, the N events are transitioned to J states. If a second event occurs during this time, the timer resets and the process repeats.

VI. RAS HMI

The RAS HMI runs on a substation-grade computer. The HMI is not critical to RAS operation; it is only necessary for changing the settings used for the RAS computations. A complete failure in the HMI will not affect the RAS functionality. All settings inserted by the user at the HMI are stored in nonvolatile memory in the individual RAS controllers.

The RAS HMI station serves as the user interface to all RAS controllers and subsystems. The functionality includes the following:

- Status display of live power system data on a summarized one-line screen.
- Status display for every system input and output, including data shared through the EMS.
- Ability to change and view adjustable settings and gains loaded in the RAS controllers. See Fig. 4 for an example.
- Real-time view of the CPS matrix that shows the action to be taken for every contingency.
- Communications and alarm screens that show the active state of major devices, communications, and diagnostic alarms.
- SOE gathering, archiving, and viewing. All data in the SERviewer Software are time-stamped with 1-millisecond accurate resolution.
- Oscillography event viewing. Event files are saved in a flat file format, similar to COMTRADE format. Equivalent to a digital fault recorder (DFR) in size and sampling rate, these files can be replayed to the RAS from the test simulator. The reports are generated on the controllers and passed to the computers for long-term storage and viewing.

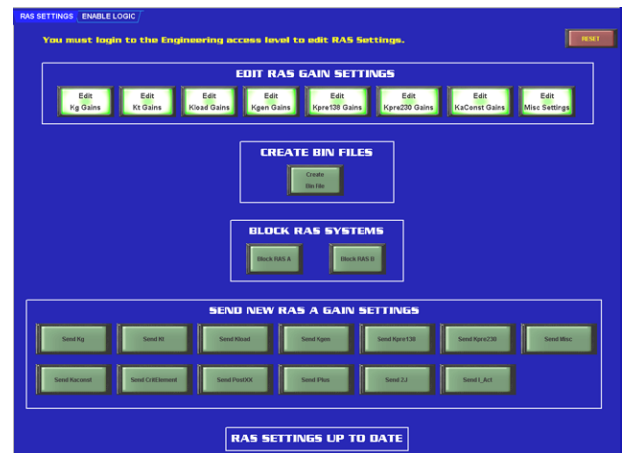


Fig. 4. Sample RAS HMI screen

Database files were created to hold the large number of gain matrices. When edits are made to any one of the gain matrices, the controllers detect that new settings are available and issue a signal that the loaded settings are old. These files are then transferred to the RAS controllers at the request of the operator.

VII. TESTING SIMULATOR

The dual primary systems (RAS Systems A and B) are independent of each other. This gives the flexibility to disable either RAS for testing or maintenance and keep at least one RAS available at all times. As shown in Fig. 5, the test simulator communicates to the RAS with serial links, emulating both the EMS DNP3, low-speed, and high-speed serial data streams.

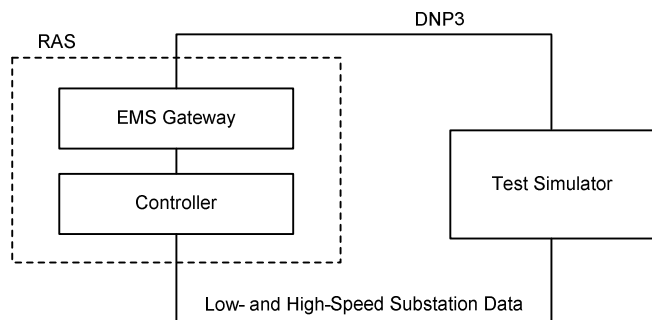


Fig. 5. RAS playback simulator

The test simulator for the RAS simulates all RAS external inputs, including digital statuses, control inputs, analog data, and DNP3 data streams. The test simulator contains an HMI user interface from which an operator can perform all system tests. The test simulator has the following two operating modes:

- **Static simulator.** This mode provides the operator the ability to drive each individual input to the RAS to a desired value. For example, the system configures EMS set points, set breaker status conditions, and detects generator trips from the RAS. This is extremely useful for testing all I/O points and creating any desired power system scenarios for presentation to the RAS controls.
- **Playback simulator.** In this mode, the simulator is used to replay one or more event report files to the RAS system. The simulator can play back real RAS system event report recordings of actual events. This was valuable during factory acceptance testing because playback files created by Idaho Power Company could be played back to the system. This is an especially valuable tool for a live RAS because it allows engineers to fine-tune RAS gains for desired operation, with no risk to maintaining power system stability.

Both RAS subsystems are connected to all field I/O through communications lines. For the simulator to actively interact with one of the RASs, large, multipin military-style

connectors are used to “unplug” the RAS from live field data and to “plug in” the simulator. When a RAS is connected to the test simulator, the RAS will not receive any inputs or send any outputs to field equipment.

The test simulator has a feature to hold several hundred playback files, which are then queued up for automatic playback, one after another. In this fashion, engineers can observe the reaction of the RAS algorithm to hundreds of different scenarios in only a few hours. This is extremely useful for factory and site acceptance testing.

VIII. CONCLUSIONS

The RAS was successfully commissioned in July 2009 and, with outputs disconnected, allowed to run in parallel with the existing RAS over a period of six months. The RAS responses to several events during this monitoring period were analyzed, and the system performed perfectly. Therefore, the RAS went live in November 2009.

The RAS is designed to allow future modifications to occur with little interruption to the performance of the RAS. The hardware design allows for RAS Systems A or B to be disconnected from the live power system and connected to a test simulator. This not only allows for quick changes to occur within the RAS but also for expansion and other maintenance corrections without taking the entire system out of service.

Considering the complexity of the RAS, it was identified that a close working relationship between Idaho Power Company engineers and supplier engineers was crucial. Idaho Power Company engineers spent nearly two months at a supplier site to fully test system performance. Idaho Power Company engineers brought site-specific experience to the factory acceptance testing, proving that all problems on the old RAS were overcome by the new RAS.

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X. BIOGRAPHIES

Michael Vaughn is a project manager for Idaho Power Company. Mike has a Bachelor of Science degree in Electrical Engineering from the University of Idaho and is registered as a Professional Engineer in the state of Idaho. Mike has 26 years experience working in the power/systems/facilities engineering realm working for the U.S. Air Force, Power Engineers, the Idaho National Laboratory, and Idaho Power Company.

Robert Schloss is an automation engineer for the Engineering Services Division of Schweitzer Engineering Laboratories, Inc. (SEL). Robert received his Bachelor of Science degree in Electrical Engineering from the University of Idaho and has been with SEL since 2004. He has experience in power system automation, specifically with remedial action schemes, load shedding, and generation control.

Scott Manson is a supervising engineer for the Engineering Services Division of Schweitzer Engineering Laboratories, Inc. (SEL). He received a Masters in Electrical Engineering from the University of Wisconsin–Madison and his Bachelors in Electrical Engineering from Washington State University. Scott worked at 3M Corporation as a control system engineer for six years prior to joining SEL in 2002. Scott has experience in designing and commissioning generation control systems, load- and generation-shedding schemes, special protection schemes, high-speed web line controls, multi-axis motion control systems, and precision CNC machine controls. Scott is a registered professional engineer in Washington, Alaska, North Dakota, and Louisiana.

Sai Raghupathula is an automation engineer for the Engineering Services Division of Schweitzer Engineering Laboratories, Inc. (SEL). He received a Masters degree in Electrical Engineering from the University of Idaho. Sai has been employed with SEL since 2004 and has experience in designing and implementing control systems for utility and industrial customers.

Trent Maier is an automation engineer for the Engineering Services Division of Schweitzer Engineering Laboratories, Inc. (SEL). Trent received his Bachelor of Science degree from Michigan State University and spent five years within the automotive industry prior to joining SEL in 2007. He has experience in control system design and application within power systems, conveyor systems, and robotics.

Design, Implementation, and Practical Experience of an Emergency Control System for the Country of Georgia Power System

Alexander Didbaridze and Siegmund Leutloff, *JSC Georgian State Electrosystem*
Diego Rodas and Fernando Calero, *Schweitzer Engineering Laboratories, Inc.*

Abstract—The country of Georgia power system is subject to severe instability when any of the 500 kV lines are lost due to power system faults and/or accidental disconnections. Two islands are formed, requiring load shedding in the load center and generation shedding in an important power center of the system. The amount of power shedding is determined by the load served by the 500 kV system prior to the opening of the line terminals. An emergency control system (ECS) was proposed by Georgian State Electrosystem to quickly and safely balance generation and load during a system event. The ECS was implemented with customized logic, off-the-shelf protection, control, and monitoring devices, and high-speed IEC 61850 Generic Object-Oriented Substation Event (GOOSE) messages. Human-machine interfaces (HMIs) are used by operators for system control, monitoring, and management of the power threshold settings. In the months following the successful installation and commissioning, the ECS successfully prevented power system total blackouts five separate times in two weeks during the summer when the power consumption reached peak load.

This paper first presents the challenges in the existing power system and the requirements for the ECS. Then the ECS solution design and communications network are described. The system communicates over a dedicated Ethernet network, allowing the use of IEC 61850 GOOSE control messages, as well as engineering access with the remote devices via Telnet and File Transfer Protocol (FTP). The implemented ECS logic is discussed in detail, as well as the timing required to meet the specifications. The experience of commissioning the system and testing it with in-service devices in a staged country-wide blackout is described. The unique ECS functionality of providing Global Positioning System-synchronized (GPS-synchronized) events allows the verification of the logic and its functionality with a number of real events that were experienced by the power system immediately after the ECS commissioning. The oscillography allowed Georgian State Electrosystem to verify and tune the power thresholds used.

I. INTRODUCTION

The country of Georgia is located east of the Black Sea with boundaries with Russia to the north, Turkey to the southwest, Armenia to the south, and Azerbaijan to the southeast. Most of the electrical load is consumed at the capital city Tbilisi, located in the southeast of the country. To the west of the country, an important hydroelectric plant in Enguri generates the majority of the power to be transmitted to Tbilisi. There are links to the neighboring countries, but at the

present time, these links do not influence the stability concerns of the power system.

Fig. 1 shows the Georgian major transmission lines and substations. Georgian State Electrosystem ensures electric power transmission over the entire territory of Georgia. Georgian State Electrosystem is responsible for operations, management, and dispatching within the Georgian power system and has responsibility for the operation of the 500 kV, 220 kV, 110 kV, and 35 kV transmission facilities while maintaining power system stability. The system comprises 3,000 kilometers of transmission lines (500 kV, 220 kV, 110 kV, and 35 kV) and 89 substations dispersed in the Georgian territory.

The Enguri power plant in the Imereti power plant region, identified by a pointing arrow in Fig. 1, generates the power that is delivered to the Tbilisi load region via the 500 kV Imereti and Kartli 2 lines. The flow in the 220 kV system to the Tbilisi region is considered secondary compared with the 500 kV backbone.

If either the Imereti or the Kartli 2 line is lost, the power system can be effectively divided into two electrical islands (considering the 500 kV system only), and as a consequence, the 220 kV system can be overloaded. The Tbilisi load region will lack generation, and the Enguri power plant region will have a power surplus; therefore, the two electrical islands will be unstable. In the Tbilisi load region, loads should be shed to mitigate the generation deficit. At the Enguri power plant, the excess generation needs to be reduced by shedding the appropriate number of generators.

In the summer of 2010, the scenario described in the previous paragraph occurred several times, leading to a blackout of a large percentage of the power system. Traditional underfrequency schemes are too slow to guarantee the stability of the system under these circumstances. The average recovery time for these incidents was more than 1 hour.

Occurrences of instability and long recovery times from blackouts are not acceptable in modern power systems. Georgian State Electrosystem therefore proposed a wide-area protection scheme, referred to as an emergency control system (ECS), to provide fast-acting stability control of the power system.

POWER SUPPLY OF GEORGIA

GEORGIAN STATE ELECTROSYSTEM

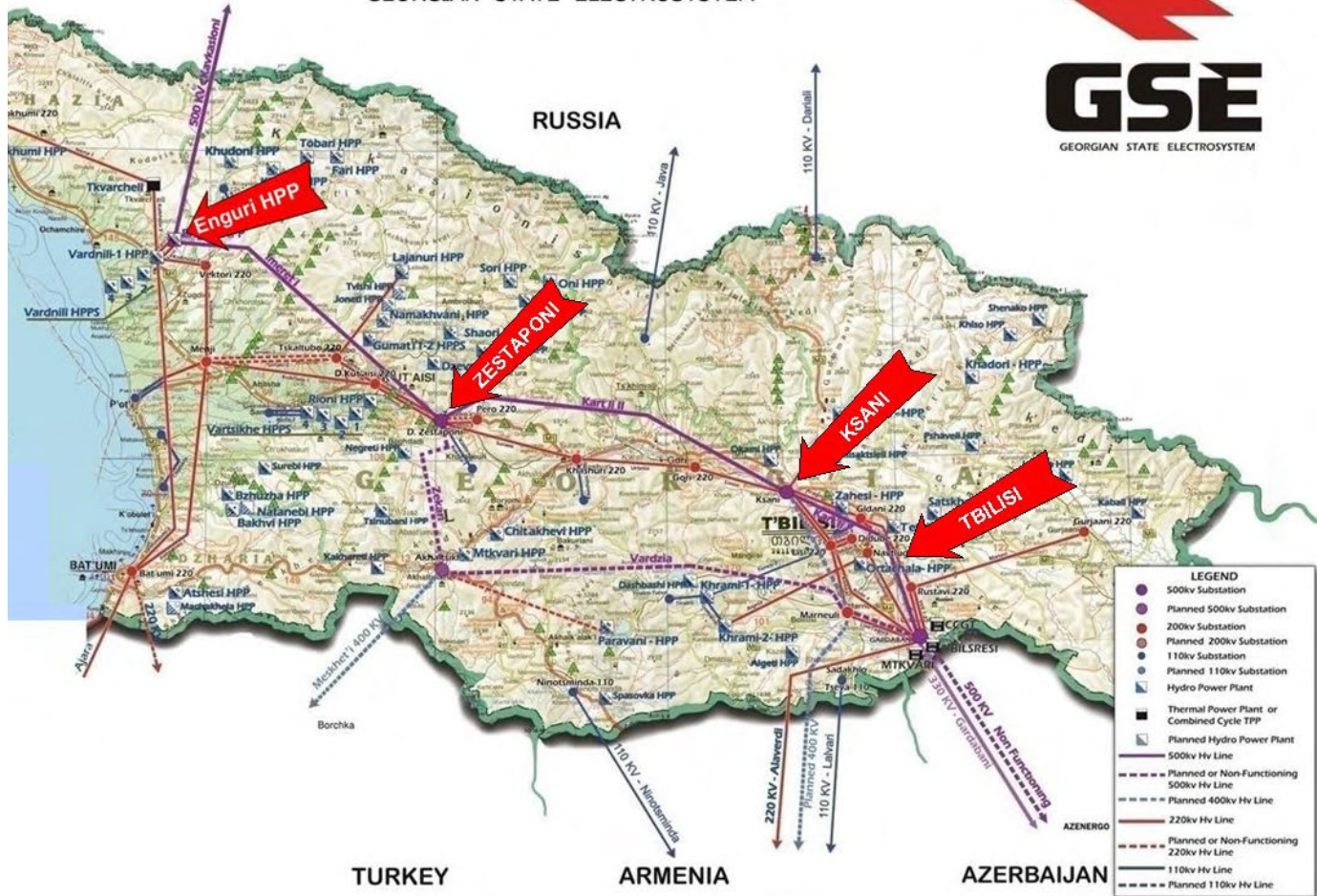


Fig. 1. The Georgian Power System

II. EMERGENCY CONTROL SYSTEM DESCRIPTION

The ECS requirements were defined by system studies performed at Georgian State Electrosystem. Based on the experience of several blackouts during the summer of 2010, the system needed to be in service before the summer of 2011. Simplicity of design and field implementation was necessary in order to simplify deployment.

Based on stability studies and considerations, the ECS is required to operate by shedding appropriate loads and generation at Enguri in less than 100 milliseconds, excluding breaker operation time. The load and generation shedding need to consider the power flow at the time of the loss of the 500 kV line and compare it with three predetermined thresholds linked to the amount of load and generation to be shed.

A. Contingency Recognition

The loss of either the 500 kV Imereti or Kartli 2 transmission line and the overload of the 220 kV circuit can effectively split the power system in two. The system must therefore quickly and reliably recognize the opening of breakers associated with these transmission lines. The lines are subject to frequent transmission line faults during the summer, and the line protection systems clear the faults by opening the breakers.

Single-pole tripping relays and breakers are used, but the opening of a single pole of the breaker is not a contingency. However, for multiphase and permanent faults, the protective relays open the three phases of the breakers. This is recognized as a contingency.

Fig. 2 is a simplified diagram of the power system shown in Fig. 1. The Imereti line loss is detected at the Zestaponi substation. The Kartli 2 line loss is detected at the Ksani substation.

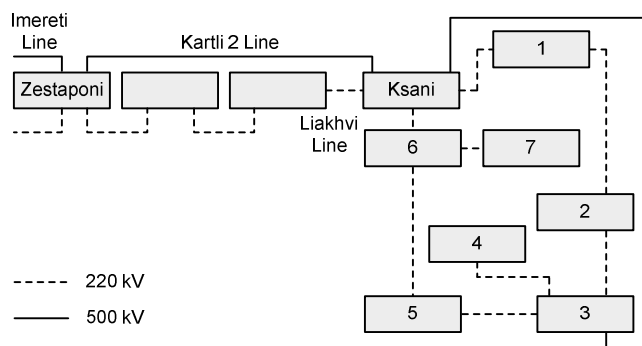


Fig. 2. Simplified Georgian Power System

At both the Zestaponi and Ksani substations, the power flow is constantly monitored and remembered to provide pre-event measurements in the event of line loss. These measurements are used for calculating the load-shedding signals sent to seven substations in the Tbilisi region. The severity of the load shedding is based on the comparison of the measured power flow with three defined power thresholds. These three severity levels are used to decide which loads to disconnect among the seven substations in the Tbilisi region, as shown in Fig. 2.

The system also uses the three severity levels and the load shedding to determine if it needs to initiate disconnection of generation units in the Enguri power plant.

The ECS uses two decision-making devices located in the 500 kV Zestaponi and Ksani substations. These devices, referred to as ECS processors, are the “brains” of the ECS. Their main purposes are to measure power flow, determine the severity levels based on the power flow, detect the loss of the 500 kV lines, and provide indication, oscillography, and sequential events records.

The ECS requires a human-machine interface (HMI) to interrogate the ECS processors to collect and display system operational data. The graphical interface allows operators to configure the thresholds for the different severity levels.

B. Communications Infrastructure

Georgian State Electrosystem is the owner of the single-mode fiber-optic network linking the majority of the substations in the country. The ECS project was implemented using a single fiber-optic pair to complete the entire scheme. IEC 61850 Generic Object-Oriented Substation Event (GOOSE) messages were selected for digital transmission of the severity limits to mitigation substations. These messages and all other required Ethernet traffic coexist on the fiber network. IEEE 802.1 network segregation and message priority methods are used to allow the IEC 61850 GOOSE messages to travel efficiently and with more deterministic behavior. The fiber-optic pair provided for this project allows separation from other forms of communication using other fiber-optic pairs from the bundle. The availability of a fiber

pair for exclusive use by the control system is unique to Georgian State Electrosystem, but the architecture of the network would not change much if other communications were multiplexed onto this fiber pair via time-division multiplexing (TDM). The addition of TDM multiplexers at each station would allow the same fiber pair to multiplex numerous communications with the determinism and dependability required for the high-speed ECS [1].

C. Additional Considerations

The requirements were defined after the summer 2010 events. The system needed to be ready and installed before the summer of 2011. Using protection, control, and monitoring (PCM) specialized for mission-critical applications simplified the implementation, allowing the complete solution to be designed and implemented in four short months.

III. ECS DESIGN

The foundation of the ECS design was simplicity and efficiency. In order to quickly and locally configure the system and execute the ECS logic, easily programmable ECS processors and complementary HMIs were installed at the Ksani and Zestaponi substations. At the mitigation substations and Enguri power plant, programmable input/output (I/O) modules supporting IEC 61850 GOOSE were selected.

A. Communications Considerations

The availability of fiber-optic links between substations makes it easier to implement a system with modern protocols. Two possible solutions were analyzed: the first using MIRRORRED BITS® communications as a peer-to-peer protocol recognized as high speed with triple-redundant payload integrity [2] and the second using GOOSE messages. For this type of control system over a wide area, security and low latency in the delivery of the control signals are required.

The main advantages of MIRRORRED BITS communications were its successful history in similar ECS projects for more than a decade [3] and the direct connection of the devices via a simple serial-to-optical converter. No additional communications equipment was required.

Although the serial MIRRORRED BITS communications protocol can send control bits in as little as 4 milliseconds point to point, in this solution, some of the devices would have acted as repeaters to downstream devices, adding delays to the system. It was evident that, for this wide-area protection scheme, the use of this serial protocol would not be efficient for system expansion. Another consideration was that MIRRORRED BITS communications did not support the multiplexing of other protocols on the same communications link for additional functionalities, including engineering access.

Having the available fiber pair over long distances allowed the proposal of an Ethernet network. IEC 61850 GOOSE messaging was selected as the solution for sending the severity signals. The decision-making ECS processors and action-taking shedding processors therefore needed to have Ethernet ports and provide IEC 61850 connectivity.

Fig. 3 shows the implemented Ethernet network. Managed substation-rated Ethernet switches with single-mode optical ports are used. The network uses redundant paths where possible. There are additional switches in intermediate substations because of the long distance involved and for future mitigation substations. For the link between Zestaponi and Enguri, the signals are sent via two different paths, one as shown in Fig. 2 through a fiber-optic Ethernet link and a second through a power line carrier (PLC) system as a backup.

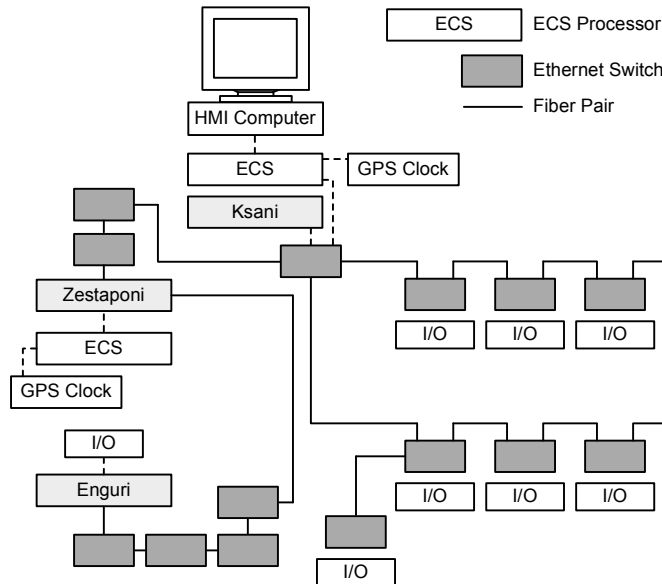


Fig. 3. ECS Ethernet Network

It is a benefit to use fast IEC 61850 GOOSE messaging that is multicast (i.e., published simultaneously to multiple devices on the network) with high priority on the network [4]. This multicast feature requires disciplined use of IEEE 802.1p and Q virtual local-area network (VLAN) GOOSE message priority and segregation in the PCM intelligent electronic devices (IEDs) and Ethernet switches for fast and dependable delivery. The low latency in the Ethernet switches means that the control messages arrive at the shedding processors from the ECS processors at effectively the same time.

The Ethernet network also provides the following benefits.

1) Transmission Control Protocol/Internet Protocol (TCP/IP)

File Transfer Protocol (FTP) and Telnet are used to interrogate remote ECS devices for engineering purposes. Other protocols native to the ECS processors are also implemented over this network.

2) Remote Access

The HMI computer can easily access each of the remote ECS devices to configure them and retrieve sequential events records and oscillography.

3) Expansion Opportunities

If additional mitigation substations are to be included in the scheme, the addition in the network is straightforward.

4) Fast-Acting System

Because GOOSE messaging is multicast, the severity signals are sent to all network nodes simultaneously. Settings within Ethernet switches allow these messages to reach the appropriate devices and be easily delivered to new mitigation substations as they are added without affecting the source device or requiring repeating.

5) System Settings

It is easy to modify the number of thresholds and severity signals by making slight changes to the present GOOSE messages to add more discrete signals to the payload.

6) Redundancy

The system can be easily modified to duplicate the I/O programmable modules at each mitigation substation for redundancy purposes.

7) Interoperability

The system can accept devices that support IEC 61850 GOOSE messages but are from different manufacturers.

B. Device Selection

All the devices in the ECS were required to have Ethernet ports. All the devices except the HMI computer were required to have IEC 61850 GOOSE message capabilities.

1) Ethernet Switches

Managed Ethernet switches with IEEE 802.1p priority and IEEE 802.1Q VLAN tagging were selected. The priority tagging is used by IEC 61850 GOOSE messages to send control messages with higher priority than regular Ethernet traffic. The selected switches have single-mode fiber ports, allowing long-distance communications.

2) ECS Processors

The devices selected to act as the logic processors for the ECS are capable of measuring power system currents and voltages for two lines. With the measurements, the power flow in each line can be calculated. Logic gates, timers, and arithmetic operations are available for the programming of the ECS logic. The ECS processor has its own binary I/O. Breaker status and disconnect switch status information can also be incorporated in the scheme.

The ECS processor selected runs the main logic every one-eighth of a power system cycle. The ECS processor automation scheme is a deterministic process focused on high-speed logic applications.

3) Shedding Processors

The selected shedding processor device supports IEC 61850 with high-performance GOOSE messages and provides discrete I/O, as well as the ability of implementing programmable logic. The device outputs are substation grade for connection to the trip circuitry of the selected loads.

4) HMI Computer

A substation-hardened computer with Microsoft® Windows® XP Professional runs the ECS HMI to interface with the user.

D. Ksani Severity-Level Thresholds

The Ksani ECS processor computes the power flow in the 500 kV Kartli 2 line and the 220 kV Liakhvi line. Fig. 8 illustrates the block diagram.

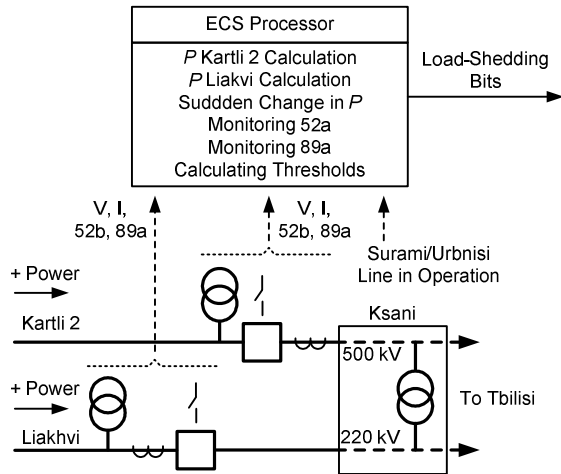


Fig. 8. Ksani ECS Processor Block Diagram

The ECS processor monitors both voltage levels and calculates the power flow with the appropriate direction for both the 500 kV Kartli 2 line and the 220 kV Liakhvi line. The loss of the 500 kV power requires calculating the severity of the loss and sending the appropriate commands to the load substations and the generation-shedding commands to Enguri.

The severity levels are calculated continuously. As shown in Fig. 9, when the 220 kV Liakhvi line is in service, the severity-level bits (SB01, SB02, and SB03) are determined by comparing a memorized sum of power flow in the 500 kV and 220 kV lines to three thresholds (Th01, Th02, and Th03). One of the elegant features of this simple but effective ECS is that the threshold values are parameters that are set by the operator via the HMI. Therefore, as stability conditions change, the sensitivity of the ECS is tuned via operator settings. A logic calculation similar to the one in Fig. 9 is implemented when the Liakhvi line is out of service.

The threshold comparisons are implemented with latches, as described in Fig. 9, with a reset threshold at 95 percent of the operating threshold, providing hysteresis in the measurement and avoiding chattering near the decision point.

The three bits (SB01, SB02, and SB03) are multicast via GOOSE messages. Within each of the mitigation substations, a shedding processor subscribes to the multicast message, receives the bits, and interprets the shedding level. Fig. 10 illustrates the simple block diagram of the required logic. For each load, the bits are interpreted according to the conceptual position of load-shedding selection switches (SW01, SW02, and SW03). The load-shedding selection switches are implemented in programmable logic, and their position is a setting in the shedding processor. This logic is also tuned via operator settings changes to the HMI so that each load is selected to be shed at one or more severity limits based on present power system stability parameters. Inside the shedding

processor, assignments to physical outputs are programmed, and these outputs control the breakers to open.

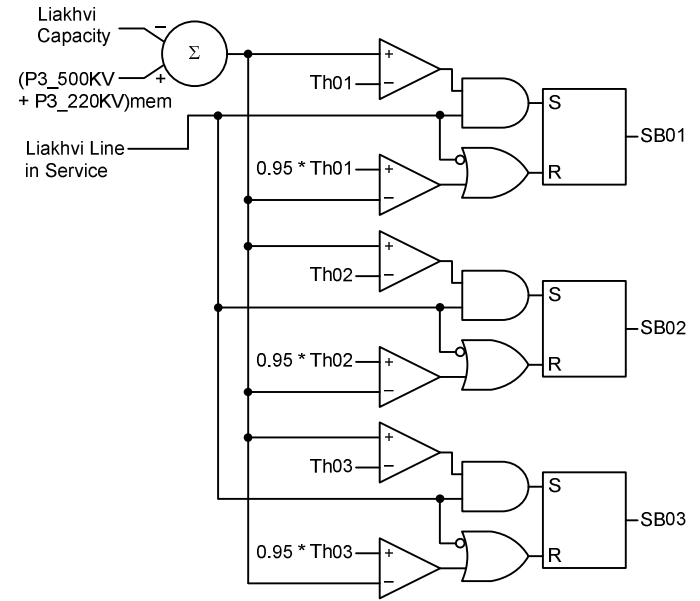


Fig. 9. Ksani Substation Severity Bit Calculation

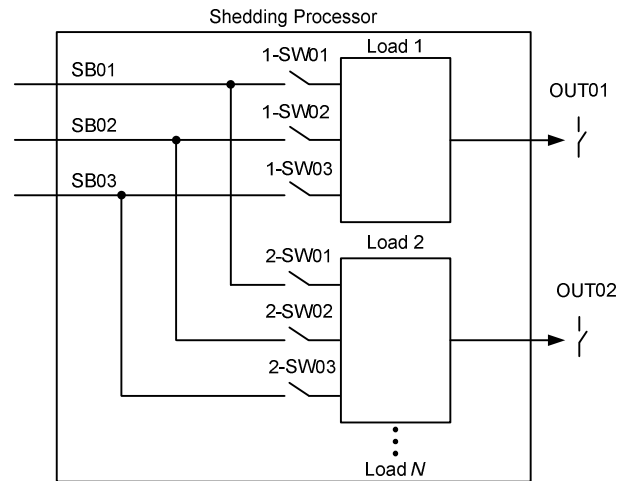


Fig. 10. Shedding Processor Block Diagram

E. Zestaponi Contingency Detection and Logic

Zestaponi is the second substation where an ECS processor is installed. This location does not have an HMI computer because the one at Ksani provides the HMI access for all devices across the network.

The ECS processor at Zestaponi monitors the 500 kV flow in the Imereti transmission line and detects the loss of this line. The functionality is similar to and based on the logic already described for the Ksani substation.

The ECS processor at Zestaponi transmits three other severity bits to the shedding processors at the mitigation substations and the Enguri power plant. In the mitigation substation shedding processor logic, the severity-limit signals generated at Zestaponi are connected by OR gates to the severity-limit signals generated at Ksani.

F. GOOSE Message Programming and Shedding Processor Interface

The load-shedding signals are multicast from the two ECS processors at Ksani and Zestaponi to all mitigation substations using IEC 61850 GOOSE messages. Every substation checks the quality of a message before using it to trip the respective loads. The loads are shed depending on the overload severity-level signal and a load-shedding selection table set on each I/O module from the HMI. The GOOSE message quality indicator is used to supervise all the logic that depends on received control bits. In the selected IEDs, a message quality parameter is calculated based on message statistics, message receipt performance versus predicted delivery, and the time-to-live (TTL) attribute within the message that declares how long the payload should be considered valid. Message quality provides real-time supervision of the health and performance of the digital message delivery of system condition, threshold, and shed indications, which adds security to the scheme.

Each I/O module also stores a sequential event report that is retrieved by the HMI for further post-event analysis and maintenance purposes.

Additional loads can be added to each I/O module, or more units can be added to each substation with minimal engineering efforts.

During the testing and installation, it was confirmed that the system reaction time was less than 15 milliseconds from line open detection at the monitoring substations to the opening of the tripping contacts at the mitigation substations.

There are also dedicated maintenance control signals within the GOOSE message specific to each substation to confirm its operation. Each I/O module sends a GOOSE message to be received by the monitoring unit to confirm the correct operation of the maintenance control signal through the network. This feature was used during commissioning and later during maintenance.

Any problems with GOOSE messages are immediately detected and indicated as a major alarm in the system.

G. HMI

The HMI, shown in Fig. 11 and Fig. 12, contains a collection of objects that represent power system devices. The animation of these objects represents status and conditions, display of analog values, input fields for analog values, dialog boxes, and message boxes that help the operator maintain and control the ECS. The HMI continuously monitors the status of the different field devices in the system. It updates the screen on a periodic basis and maintains a diagnostic alarm history. System tuning is allowed through password-protected screens. These security features prevent unauthorized access and limit access based on user groups.

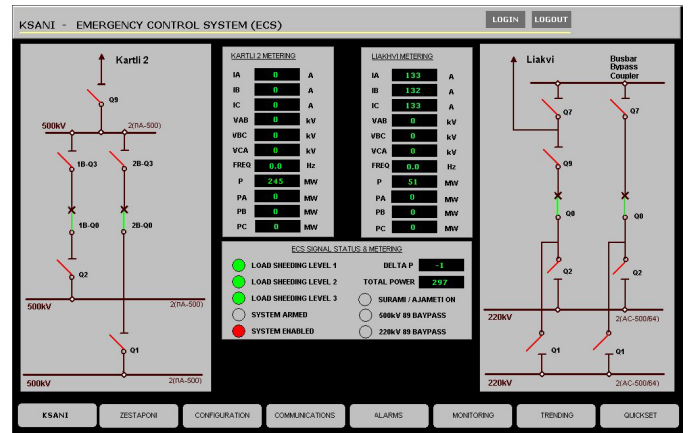


Fig. 11. ECS Status – Operator Screen

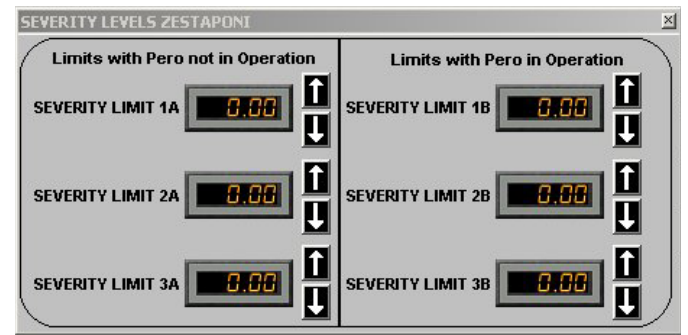


Fig. 12. ECS HMI Severity-Limit Settings – Engineering Screen

IV. COMMISSIONING AND VALIDATION

The field deployment time schedule required a smooth installation and commissioning process. Steps were taken to prevent unforeseen circumstances when commissioning the system.

A. Laboratory Simulation

The ECS logic described previously is contained in the ECS processors, and the contingency detection logic schemes can be isolated in each processor. In a laboratory environment with a relay test set, the logic was properly simulated and debugged. Initial logic problems were encountered and fixed in this environment.

Testing in the laboratory environment provided the first verification of the speed of the system. The requirements were fully satisfied with ample margin, as compared with the original 100-millisecond operating time requirement. The results were used as validation of the project proposal and design. The laboratory experience proved valuable in the implementation of the scheme, saving implementation time by exposing a few initial ineffective logic operations so that they were quickly identified and improved.

B. Network Installation

In the field, the installation of the Ethernet switches and devices with their corresponding network addresses was the first step. At each of the participating substations in Fig. 3, the adequate transmission and reception of the optical signals were verified.

Because this is a closed network with no routing, appropriate IP addresses were selected for each device. The mitigation substation I/O modules were shipped from the factory with all the default settings, IP addresses, and logic settings. The IEC 61850 Configured IED Description (CID) files were downloaded to each unit on-site at the time of installation to avoid any conflicts. Connectivity to each device from the ECS processors was then verified from both monitoring substations. Once the connectivity to the remote substation was established, the proper logic settings and the CID files describing GOOSE publications and subscriptions were reconfirmed remotely.

The high-level operation testing was performed by using a dedicated maintenance command. Within the GOOSE message, one signal is dedicated for each substation. This discrete Boolean signal operates a test output that is physically wired to a test input. The status of this input is transmitted back, confirming the operation of the output and the performance of the GOOSE message. Other tools, like the GOOSE diagnostic reports available within these devices, were necessary to verify GOOSE operation and integrity.

The second step of the commissioning process was to configure the monitoring substations and verify installation settings, logic, and communications.

C. Commissioning in the Field

ECS processors, shedding processors, and switches were in place for commissioning. The proper polarities of the analog inputs were verified, making sure the measurements of the power flow were correct. The breaker position binary inputs were properly verified together with the disconnect switch inputs.

GOOSE message exchange was verified by sending test severity bits through the network and verifying the shedding processor outputs.

With relay test sets, the same types of tests as in the laboratory environment were performed, validating the scheme again.

The access to the network for each of the involved IEDs was a big advantage. It allowed the modification of small pieces of logic (e.g., I/O assignments and disconnect switch interlocks) from the HMI location.

D. Staged Country-Wide Blackout

The commissioning of the system proved to be very straightforward. Georgian State Electrosystem decided to test the system and response times with a staged in-service test. The test was conducted at 1:41 a.m., as shown in the oscillographic record in Fig. 13, in order to affect as few people as possible if it did not work correctly.

Fig. 13 displays the oscillography record from the Ksani ECS processor. The 500 kV Kartli 2 line breaker was opened

manually and the power thresholds adjusted very low to account for the low power flow at the time of the test. The severity bits (SB01, SB02, and SB03) were sent to all shedding processors, and load shed according to the HMI set logic. In Fig. 13, PSV31, PSV32, and PSV33 correspond to the severity bits after the logic determined to send the bits. The test was effectively a staged country-wide blackout that proved to be successful because the system operated as expected, very quickly, and mitigated a full blackout.

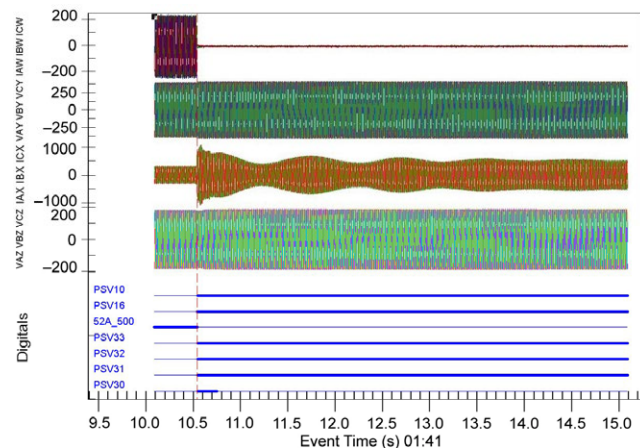


Fig. 13. Staged ECS Test Oscillography

V. FIELD OPERATION

A. Importance of Oscillography

The ECS processors at the Ksani and Zestaponi substations are capable of storing oscillography. This function allows Georgian State Electrosystem to observe and verify the operation of the ECS and the power system.

For the commissioning testing and the staged blackout attempt, the oscillographic records proved to be very useful in confirming the operation of the system. The effects of opening the breakers on the 500 kV line, shown as waveform IAW-IBW-ICW in Fig. 13, and the overload in the 220 kV system, shown as waveform IAX-IBX-ICX, were easily verified. The ECS shedding commands, shown as PSV31, PSV32, and PSV33 in Fig. 13, operated breakers at Tbilisi 12 milliseconds after the 500 kV breaker opened to reduce some but not all load. The 220 kV system can be seen to take on additional remaining load, oscillate slightly, and then hold at the higher power flow to prevent the blackout.

Together with the sequential events records synchronized with the GPS clock, the oscillographic records provide all the documentation required for analysis and verification of the load-shedding levels to the operators and planners at Georgian State Electrosystem.

B. ECS Operations

The ECS was commissioned at the beginning of the summer of 2011. Summer is a critical period of the year for the power system. The load is high in the 500 kV systems, and the probability of faults on the 500 kV Imereti and Kartli 2 lines is high. Even though the lines are equipped with line differential systems with single-pole trip capabilities, high-

resistance ground faults can force the opening of the three poles, as shown in Fig. 14, which illustrates the operation of the ECS processor on the Zestaponi side. A high-resistance ground fault required the opening of the three poles with sufficient load in the line to activate the ECS Level 1 (PSV31) threshold.

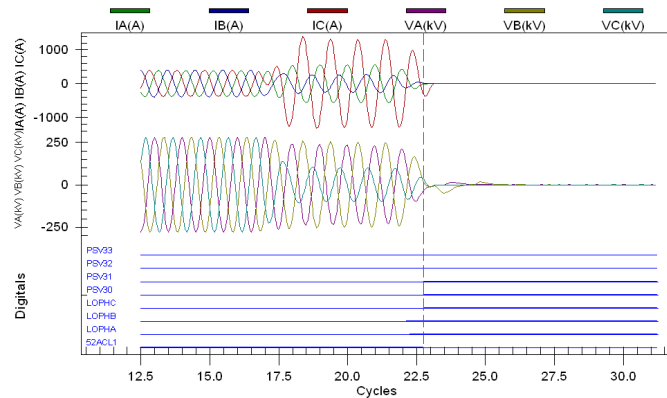


Fig. 14. Loss of the Imereti Line

The event shown in Fig. 14 illustrates a real system event. Similar events occurred five times in July 2011, and the ECS responded by properly shedding the operator-predetermined load levels.

With this ECS and others, a single successful operation pays for the cost of the project.

VI. CONCLUSION

This paper summarizes the successful implementation of an emergency control system in the country of Georgia.

For the simple requirements for emergency control, flexible, off-the-shelf devices were programmed to make the appropriate decisions and communicate to the load-shedding and/or generation-shedding processors.

The implementation of the scheme demanded careful planning to select the appropriate devices, study the programming requirements, select the communications medium, and perform laboratory testing and commissioning.

While not always possible, real power system staged blackout attempts validate the system and provide a significant trust level to the user.

Multicast GOOSE messages, together with message quality supervision, prove to be an effective means of sending control commands and monitoring the health and performance of digital message delivery. The availability of analog quantities in the GOOSE messages can prove to be useful in other applications.

With the successful operation of the ECS, the project cost was justified.

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VIII. BIOGRAPHIES

Alexander Didbaridze received his diploma in electronic and control engineering from Moscow State Technological University in 1994. Upon graduating, he worked for nearly 11 years as an instrumentation and control (I&C) chief engineer for Gardabani Thermal Power Plant, a design and commissioning engineer for Enguri Dam Drain System, and an I&C engineer for companies "Wood Group" and "Capital Turbines." From 2006 through 2011, he was the manager of the projects SCADA and Emergency Control System (ECS) implemented by Georgian State Electrosystem. He has been involved in other projects linked to telecommunications systems and fiber-optic stringing on overhead lines. Since 2011, he has been the International Projects Technical Manager at Georgian State Electrosystem.

Siegmar Leutloff received his diploma (Dipl.-Phys.) in applied physics from Darmstadt Technical University in 1970 and his PhD degree from the same university in 1974. He worked for the international engineering company Lahmeyer International GmbH as a consulting engineer in the fields of measurement techniques, environmental protection, and control and telecommunications engineering from 1975 until 2010. He was involved in the implementation of national, regional, and distribution control systems of electric power transmission and distribution grids and of gas management systems in Germany and several other countries. Since August 2010, he has been the Advisor of the Chairman of the Management Board of Georgian State Electrosystem.

Diego Rodas received his BS in electronic and control engineering from Escuela Politécnica Nacional in 1994. He has broad experience in automation and control systems. Upon graduating, he worked for nearly 16 years in automation systems, from senior field engineering for the oil industry to senior systems design engineering for several additional industries, including food and pharmaceutical. In the last five years, he has been involved in integration and automation projects for numerous substations. Prior to joining Schweitzer Engineering Laboratories, Inc. in 2007, Mr. Rodas was involved in the development of automatic machinery for process control and validation of new technology petrochemical data acquisition and telemetry systems.

Fernando Calero received his BSEE in 1986 from the University of Kansas, his MSEE in 1987 from the University of Illinois (Urbana-Champaign), and his MSEPE in 1989 from the Rensselaer Polytechnic Institute. From 1990 to 1996, he worked in Coral Springs, Florida, for the ABB relay division in the support, training, testing, and design of protective relays. Between 1997 and 2000, he worked for Itec Engineering, Florida Power and Light, and Siemens. In 2000, Mr. Calero joined Schweitzer Engineering Laboratories, Inc. and presently is a senior automation systems engineer.

Implementing a Country-Wide Modular Remedial Action Scheme in Uruguay

Julián Malcón and Nicolás Yedrzejewski, *Usinas y Trasmisiones Eléctricas*

Ashok Balasubramanian, Rameez Syed, and Sai Krishna Raghupathula, *Schweitzer Engineering Laboratories, Inc.*

Abstract—This paper presents a country-wide remedial action scheme (RAS) implemented in Usinas y Trasmisiones Eléctricas (UTE) in Uruguay. When a single contingency or multiple closely timed contingencies occur, the RAS protects the power system from thermal damage to lines, voltage collapse, generation load unbalance, and overvoltage/undervoltage conditions. The RAS consists of six different schemes operating independently and, in certain cases, simultaneously to calculate power system states and define the remedial actions. Operator-defined gain constants and zone priorities are used to calculate the amount and location of load to shed respectively. Supplementary control modules such as the Brazil power exchange override are used to reduce the amount of load shed. The line-shed module prevents power oscillations on the Uruguay to Argentina interconnections. The post load-shed reactive power compensation module improves system voltage profile and eliminates possible overloads that could still be in the system.

I. BACKGROUND

A. Uruguayan Power System

The Uruguayan power system is connected to the Argentinian and Brazilian power grids at the northwest and northeast borders. Usinas y Trasmisiones Eléctricas (UTE) is a government-owned company and regulates most of the generation and transmission in Uruguay. The transmission network consists of 500 kV and 150 kV transmission lines. The Uruguayan power system relies heavily on its 500 kV interconnection to the Argentinian power grid. The Uruguayan power system at 50 Hz is connected to the Brazilian power system at 60 Hz through two converter stations. Fig. 1 shows a map of the UTE power system, identifying 500 kV and 150 kV transmission lines and substations. The UTE power system is connected to Argentina at the Salto Grande and San Javier (500 kV) substations and to Brazil at the Rivera (230 kV) and Melo (500 kV) substations.

Peak demand of approximately 1,900 MW occurs typically during the winter months. To meet the increasingly higher demand during the drier years, Uruguay relies on power imported from Argentina. There has been a dramatic increase of dry years within the past decade. Building additional transmission lines and generation plants to meet the seasonal demand is expensive. UTE is hence required to operate the installed and existing equipment closer to their operating limits at high utilization levels. Such highly stressed power systems have an inherent problem of growing oscillations resulting from a single event, eventually leading to complete or partial system outages.

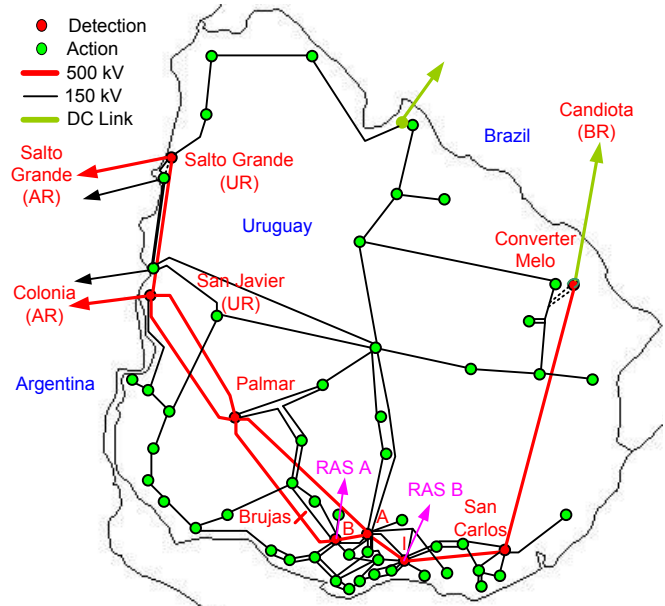


Fig. 1. The 500 kV/150 kV UTE Power System Grid

A contingency-based system-wide fast remedial action scheme (RAS) that can detect events and take remedial actions in milliseconds is required. Some key feature requirements included speed of operation, security, dependability, expandability, reliability, and ability for post-event analysis.

B. History

The RAS becomes a necessary and cost-effective solution when the power system by itself is not capable of recovering after a failure. Power transfer capacity in the western United States power grid has nearly doubled with a RAS in place [1]. The RAS remediates detrimental conditions on larger systems and protects power systems from additional problems that could surface.

Several remedial schemes to mitigate system outages were investigated by UTE. Existing schemes in the neighboring grids rely on generator shedding to mitigate loss of high-voltage assets. Shedding the limited available generation resource was not an option for UTE. With low damping strength of the UTE power system, any additional generator shedding as a remedial action, in most cases, worsens the system stability. The underfrequency-based load-shedding systems have slow response times and typically shed more load than required.

The RAS discussed relies on accurate load shedding to balance generation and load and to mitigate system overload and voltage collapse. The installed RAS replaces a slow-response, limited, and nonredundant load-shedding system. The old system was limited in the sense that its responses were contained to a small number of conditions and geographical zones. The area of influence of the old system did not match the growing system needs. The old system was not adaptive, and did not take into account the existing power system state and the power transfer between UTE and neighboring grids, which are both important factors in determining the level of remediation.

With the old system not being adaptive to changes in the power system configuration, small changes in the power system operations (e.g., taking a line out of service for maintenance or repair) demanded power flows across the monitored path to be drastically reduced. The old system did not include other remedial actions such as reactive power compensation and Brazilian intertie power demand override actions. Reliability, fast operation speeds, and system expandability were some of the features that the old system lacked.

The newly installed RAS can monitor a wide diversity of data from dispersed locations. The module selection and parameter definition feature of the RAS make it very flexible for future expansion. The RAS design allows easy modifications to accommodate new discoveries related to system stability response and operation. With a robust communications backbone in place, the RAS can rapidly consider changes to the power system state, continuously monitor the status of power exchange corridors, and make decisions that allow optimal use of the power system. The RAS also accounts for operator inputs such as load priorities, load-shed inhibits, and other system definitions like critical equipment selection, allowing routine maintenance of equipment without reducing the power flow levels across the monitored path. Post load-shed ancillary controls such as reactive compensation, voltage control, Brazil intertie power exchange override, and a backup underfrequency remedial system are some additional features of the RAS that the old system lacked. The new system is redundant in providing higher levels of availability.

II. RAS REQUIREMENTS

A. Timing Requirements

The response time required by the RAS to prevent thermal overloading of equipment due to the outage of certain critical assets is in the order of minutes. Certain contingencies require remediation for voltage and frequency stability. The response times required for these contingencies are much faster.

When the typical fault detection time, communication time, field equipment response times, and other communications delays are excluded from the total time budget, the RAS is left with less than 20 milliseconds of operating time. The total throughput time shown in Table I is the total measured time

from an input in the RAS input/output (I/O) module asserting to the front-end processor (FEP) sending control signals. Although the RAS has the capability to process the detection signals faster, the process is deliberately delayed to differentiate between single event and multiple event contingencies. Prior experience has shown that a single event contingency can evolve to a multiple event contingency while the RAS already responds to the first contingency. If the processing for the initial event is not delayed (in a few milliseconds), it could result in excessive load tripping.

TABLE I
RAS TIMING REQUIREMENTS

Item	Process Time (ms)
I/O module input debounce	2
I/O module to FEP communication	4
FEP to RAS central processing unit (CPU) communication	4
RAS processing time	2
RAS to FEP communication	4
Total time	< 16

The communications between the RAS substations and the remote substations are separated over several hundred kilometers, and the load breaker opening time adds additional latency. Dynamic simulation studies have shown that a total round-trip clearing time of less than 200 milliseconds from the contingency is required for maintaining power system stability. Since the level of load shed performed is adjusted based on the power transfer override capabilities on the Brazilian intertie, faster response times similar to initial load shedding are required for control signals to the convertor. Ancillary modules such as reactive power compensation and supplemental load shedding have typical response times in the order of a few seconds.

B. Contingency Detection and Remedial Actions

The status of 500 kV transmission lines and 500 kV substation transformers are monitored at high speed. Following the breaker status contacts (52a or 52b) for declaration of an open line requires several changes to the existing breaker wiring scheme. Moreover, the existing breaker auxiliary contacts are prone to mechanical failures. To avoid faulty detection, loss of a 500 kV transmission line is detected by an open line detection algorithm (OLDA) programmed in the peripheral controllers designated as detection equipment. The OLD A uses currents and voltages to monitor the status of the 500 kV line and declares an open line. With several inherent security checks, it also differentiates between the opening of the local end or the remote end of a line.

It is necessary to monitor the status of critical lines and/or other equipment to declare an event in the power system. Table II lists the 500 kV equipment monitored by the RAS and the associated event number.

TABLE II
RAS EVENTS

Event #	Description
E1	Palmar – Brujas Line
E2	Brujas – Montevideo B Line
E3	Palmar – Montevideo A Line
E4	San Javier – Palmar1 Line
E5	San Javier – Palmar2 Line
E6	San Javier – Colonia Elia Line
E7	San Javier – Salto Grande Line
E8	Salto Grande Uruguay – Salto Grande Argentina Line
E9	Montevideo A – Montevideo B Line
E10	Montevideo A – Montevideo I Line
E11	Montevideo I – San Carlos Line
E12	San Carlos – Melo Line
E13	Converter Station at Melo
E14	500 kV/150 kV Transformer at San Carlos

Any power system event for which a remedial action is required is defined as a contingency. A contingency can be a single event contingency like event E8 or can be a multiple event contingency such as events E2 and E3. The possible combinations of contingencies in the RAS are defined by the user as explained in Section IV.

The RAS responds to multiple closely timed and simultaneous contingencies. The RAS control actions are classified as the follows:

- Fast load shedding to prevent voltage collapse, eliminate the overload conditions on critical equipment, or correct the generation-load imbalance.
- Power transfer controls for run-back, increment or disconnection of 50 Hz/60 Hz power converter station to regulate the power flow to and from Brazil.
- Reactive power compensation to avoid overvoltage conditions after a fast load shed. The reactive power is reduced by disconnecting capacitor banks in certain substations.
- Slow load shedding to eliminate overloads that could remain in the system after fast load shedding due to undesired loss of generation or an action not executed.
- Automatic disconnection of certain 150 kV lines after a fast load shed for certain power system states to disconnect Uruguayan and Argentinian power systems.
- A backup decentralized underfrequency load-shedding system that has five levels, f_0 - df/dt , f_1 , f_2 , f_3 , and f_4 .

III. SYSTEM ARCHITECTURE

Fig. 2 shows the overall architecture of the RAS. RAS A and RAS B are dual primary systems, and both RAS controllers are running at all times. The communications backbone for the RAS system is based on a synchronous data hierarchy (SDH) network over a fiber-optic cable. SDH

multiplexers are installed at the RAS substations, detection substations, and action substations. Ethernet over SDH is used as the interface for communications. Each RAS system (A and B) consists of remedial action controller (RAC), FEP, supervisory control and data acquisition (SCADA) gateway (GTS), human-machine interface (HMI) system, synchrophasor vector processors (SVPs), I/O modules, and managed Ethernet switches.

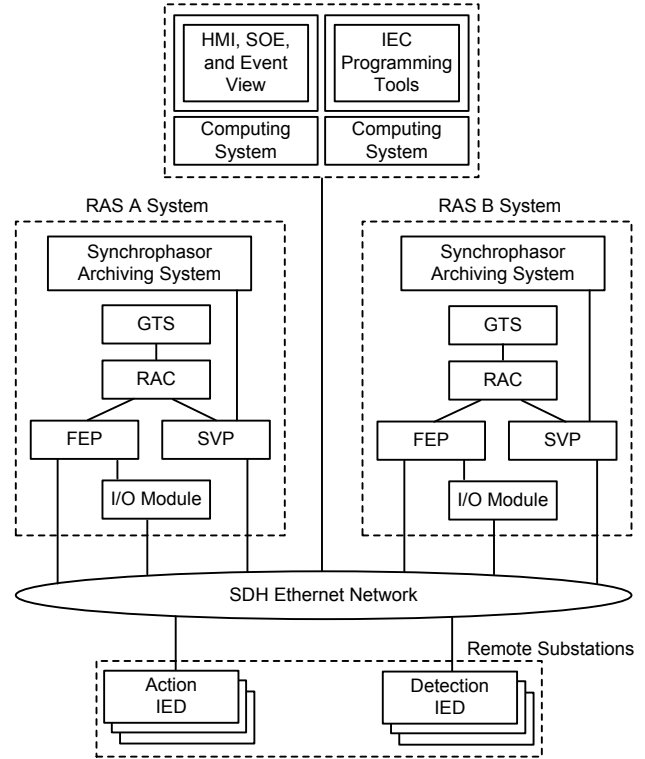


Fig. 2. RAS System Architecture Overview

The detection and action equipment in the field serve as phasor measurement units (PMUs), which transmit the data required by RAS to the SVP using C37.118 synchrophasor protocol. The SVP collects power system information such as analog data, breaker position, and out-of-service conditions and passes the data to the RAC for processing. The GTS acts as an Inter-Control Center Communications Protocol (ICCP IEC 60870-6/TASE.2) gateway link between the RAS and UTE dispatch control center. These gateways serve as a redundant, secondary source of data for the RAC. The RAS health status and other RAS diagnostic information are transmitted to the UTE SCADA via ICCP. All the high-speed data such as contingency detection and remedial actions are transmitted using IEC 61850 Generic Object-Oriented Substation Event (GOOSE) protocol. Within each RAS panel, a substation-hardened computer provides an HMI, Sequence of Events (SOE) viewing, and event report viewing (oscillographic) capability. All OSI layer 2 GOOSE and OSI layer 3 protocols (C37.118, ICCP, FTP, and Telnet) are communicated over the SDH network.

All synchrophasor measurement data are archived. The archiving allows UTE to investigate power system events and to analyze the power system behavior. The high sampling rate

of the archived synchrophasor data also opens up possibilities of small signal analysis for monitoring system stability.

A. IED Communications Settings Management

The expansive RAS communications architecture includes up to 50 remote substations. Each substation has at least one action intelligent electronic device (IED) and one or more detection IEDs depending upon the location. Managing the settings and keeping them consistent for a critical application such as the RAS with approximately 200 action and detection IED can be challenging.

The implemented settings management philosophy addresses efficient and consistent substation IED settings. The settings management philosophy implemented in the RAS relies heavily on network address translation (NAT) and virtual local-area network (VLAN) translations. Depending upon the equipment type, all the IEDs at substations are configured with the same settings including internet protocol (IP) addressing.

For example, all action IEDs will always have a B.0.0.90/24 IP address and identical RAS settings irrespective of the substation location. The substation NAT is used by the RAS to differentiate devices in multiple substations. The substation firewalls keep the IED local IP address transparent and exposes the IED with the IP address A.B.SEID.90/24 to other RAS devices. A, B, and SEID represent the first, second, and third octets of IPV4 nomenclature.

Similarly, the IEDs in all substations will subscribe and publish IEC 61850 GOOSE messages over the same VLAN ID. Because of network congestion, multiple IEC 61850 GOOSE messages on a large network over the same VLAN are not recommended. VLAN tag translation by a managed Ethernet switch are used to efficiently manage internal substation and external SDH network VLAN tags. Using consistent subscription and publication settings over the same GOOSE VLAN allows use of consistent network management settings for the substation automation engineers. These translations streamline IED settings and provide enhanced network security. Table III shows the IP addressing that is used for RAS equipment in each substation, where SEID stands for the unique substation identification number.

TABLE III
TRANSMISSION SUBSTATION NAT SCHEME

Equipment Type	Local Address	WAN Address
Action IED	B.0.0.90	A.B.[SEID].90
Detection IED 1	B.0.0.91	A.B.[SEID].91
Detection IED 2	B.0.0.92	A.B.[SEID].92
Detection IED 3	B.0.0.93	A.B.[SEID].93
Detection IED 4	B.0.0.94	A.B.[SEID].94
Detection IED 5	B.0.0.95	A.B.[SEID].95

Fig. 3 represents the RAS VLAN translation scheme for two remote substations. On the Ethernet switch at the substation for VLAN mapping, the specified RAS PVID (3000 + SEID, 3500 + SEID) packets are mapped to the

specified substation PVID (3901, 3902) when they enter the port. Symmetrical mapping back to the RAS PVID occurs when the packet exits the port.

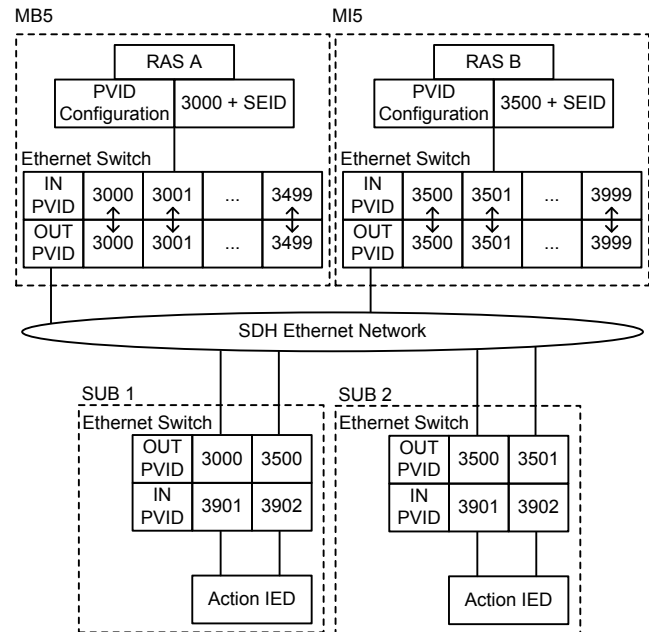


Fig. 3. VLAN Translation Scheme

B. Rugged RAS Design

All hardware devices shown in Fig. 3 are protective class substation-hardened equipment with extended temperature range, shock resistance, electromagnetic immunity, and static discharge capabilities. There is a small chance for equipment failure due to dust accumulation; therefore, there are no fans or spinning hard drives in any of the IEDs and controllers.

A dual primary UTE RAS system is a redundant system where both controllers gather I/O, performs calculations, and make decisions at all times. Other redundant architectures based on failover time between the primary and the secondary sources require a failover delay time between the two systems. The two RAS controllers are located in different 500 kV substations, MI5 and MB5. The redundant design is set up such that all critical controlling devices are duplicated at both main substations creating two systems that are capable of performing independently of each other. The RAS uses dual-Ethernet communications connections to eliminate all single points of failure in communication between the remote substations and the RAS substations. It would take two simultaneous hardware failures or two simultaneous process failures to disable and prevent operations [2]. Path diversity in the SDH network eliminates loss of communications due to a single point failure.

The main control algorithm resides on an embedded RAC. The algorithm is programmed using IEC 61131 programming language. Watchdog counters implemented on all programmable IEDs detect communications failures. All data used by the controllers are checked for out-of-range conditions. The RAS is set up to automatically reject bad data

and reselect available good data or in certain cases default to a more conservative value.

IV. RAS ALGORITHM

The RAS algorithm designed for and specified by UTE dynamically calculates load to shed based on power system state and predefined set points. System definition parameters for the RAS are defined by the operating engineers. The data required for the operation of the RAS originate from the equipment in the field and from the UTE SCADA system. To make the RAS flexible, reliable, fast, and efficient, the RAS logic has four parts: module selection and parameter definition, data handling and acquisition, RAS algorithm calculations, and ancillary controls. Fig. 4 shows an overview of the RAS algorithm.

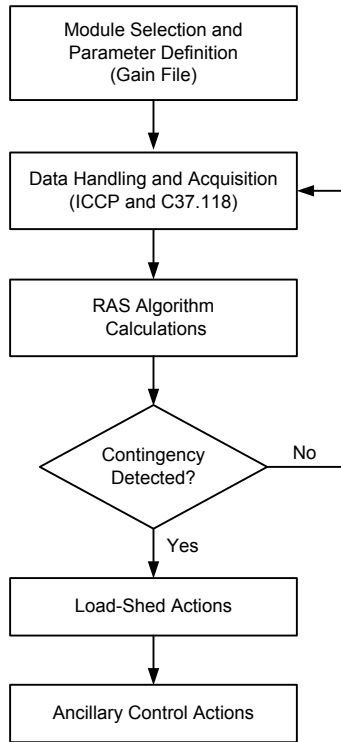


Fig. 4. RAS Algorithm Overview Flowchart

A. Module Selection and Parameter Definitions

The UTE RAS design allows the operator to define and control the type of remediation. Engineers at the dispatch control center can define the scope, geographical zone, and the level of the remedial actions. The definitions vary based on the day-to-day operation of the power system. However, the level of remediation required depends on the severity of the power system event and the present load demand. An event in the power system due to the loss of a 500 kV line or transformer is identified as an E event (Table II). Contingencies identified as C require remedial actions. The UTE RAS incorporates 32 events and allows definition for as many as 64 contingencies.

The UTE RAS allows engineers to define contingencies and the remedial action module to be executed for each contingency in a tabular format identified as a RAS file. The

RAS file is a combination of multiple gain tables, maintained in comma-separated variable (CSV) format. The automatic error tracking tool in the RAS file prevents the user from entering erroneous values. The RAS file in CSV format is converted to a binary format and then loaded in the controller for further calculations. Contingencies requiring remedial actions are defined as single or multiple event contingencies in the gain table for contingency definition. Each UTE RAS module remediates a different type of stability issue in the power system and has different types of actions. The RAS algorithm modules for each contingency are defined in Table IV.

TABLE IV
EXAMPLE OF MODULE SELECTION

Module	Contingencies						
	C1	C2	C3	C4	C5	...	C64
Load Shed – Module 1	1	0	0	1	1	...	0
Load Shed – Module 2	0	1	0	0	0	...	0
Supplemental Load Shedding	0	0	1	1	0	...	0
Reactive Compensation Module 2	0	0	0	0	1	...	0
Brazil Power Override	1	1	0	1	0	...	1
Line Shed	0	0	0	1	1	...	1

B. Data Acquisition and Handling

Data required for the operation of the RAS are collected from the remote substations and the central SCADA system. These data can be classified into high-speed data and low-speed data. Contingency signals that trigger a remedial action are detected at high speeds. Metering information such as real power, reactive power, and voltage values required for calculating the level of remediation are not needed at high speeds. Collecting all data at high speeds would require wide communications bandwidth, demanding additional communications infrastructure. Moreover segregation of data into high and low speeds has been proven to yield better performance on both large scale and small scale schemes [3][4][5]. Both the high- and low-speed data are multiplexed at the remote substations and transmitted to the RAS through the SDH network.

1) High-Speed Data

The UTE RAS uses the teleprotection equipment for high-speed digital communication such as power system event detection. Contact transfer cards in the SDH network transfer the hardwired digital input signals to dataflow and transmit the event detection signals from the remote substations to the RAS substations.

These SDH data signals are converted to output signals and wired to I/O modules in the RAS panel. The communications between the contact transfer cards to the I/O modules are accomplished in less than 20 milliseconds. The IEC 61850 GOOSE protocol is used to transmit the contingency detection signals from the I/O modules to the RAS controllers. The same protocol is used to then transmit the action signals from

the RAS controllers to the FEP. Other calculations such as output selection logic and communication required to initiate the remedial action signals are also accomplished in less than 8 milliseconds.

2) Low-Speed Data

Low-speed data includes information from the SCADA system and data collected using the C37.118 protocol. This data includes analog data like active and reactive power, capacitor bank status, and out-of-service conditions.

The C37.118 data are collected from the IEDs dedicated to the RAS at 50 times a second. The C37.118 data are archived in the RAS substations for future analysis. The SVP in the RAS panel then sends the data to the RAS controller every 100 milliseconds. Data are collected from the SCADA system at two different speeds. Data required for the operation of RAS are polled at a faster rate (200 milliseconds) and are configured for unsolicited reporting. Other noncritical data such as analogs and status information required for display on the HMI are polled every 2 seconds.

The RAS processes the low-speed data and calculates the actions for all contingencies every 100 milliseconds. These actions are then fed into the Crosspoint Switch (CPS) [4]. The high-speed detection inputs are cross multiplied with the CPS to issue remedial trips.

C. RAS Algorithm Calculations

This section discusses specific components of the RAS algorithm: data selection and validation, critical equipment and power system state, load shed – gain table technique, process of load selection, CPS – line trip versus substation trip, and multiple and closely timed contingencies.

1) Data Selection and Validation

All digital and analog data selected by the RAS for calculations are based on their speed and reliability. The RAS monitors the communications for failure at different levels of the network and selects the best data available. The final data used in the RAS algorithm are chosen based on data quality. The majority of the data are collected from both the SVP and the UTE SCADA system that act as a redundant data sources. Data validation is accomplished by comparing the two sets of data from both sources and ensuring that neither is outside a given threshold from one another. If the analog values from two different healthy sources are within 5 percent of each other, the average value of the two sources is used by the RAS. If a single value from the two equally healthy sources exceed a 5 percent difference, the larger value is chosen and used by the RAS.

2) Critical Equipment and System State

Critical equipment identified as j are important 500 kV/150 kV transmission lines and transformers in the UTE power system. The RAS currently monitors 64 critical equipment. During a contingency (C), certain critical equipment (j) are operating at a level beyond their normal operating limits until a remedial action is taken. With years of experience, UTE engineers use detailed power flow and dynamic simulation studies to select up to eight critical

devices for each contingency. The selection of the critical equipment to monitor depends upon their geographical location and their pre- and post-contingency connectivity to the out-of-service equipment that triggered the contingency. The load-shed level for a contingency will depend on the total overload levels in the critical equipment selected for that contingency. The selection of critical equipment for each contingency is done using the critical equipment selection table in the RAS file.

The valid combination of in-service and out-of-service conditions of critical equipment converge to a system state S . In other words, the system state actually represents the present power system configuration in terms of critical equipment. With 64 critical equipment, a total of 2^{64} (1.8×10^{18} values) system states theoretically exist. Since all combinations are not possible or valid, the UTE RAS includes 1,000 system state definitions using the state table in the RAS file (e.g. the RAS system state $S1$ is defined as critical equipment $J1$ out-of-service and $S235$ is defined as $J23$ and $J45$ and $J63$ out-of-service, in the state table). The present system state S is very critical in determining the level of remediation.

UTE investigated several earlier RAS for system state calculations. The approach used in earlier RAS defines up to 1,000 fixed system states representing possible power system configurations, as recorded in the state table. The RAS compares the present critical equipment statuses from the field with the predefined combinations in the state table. With this approach at any point in time, a single system state is chosen for all contingencies. If the RAS comparison does not converge to a predefined system state, then a default system state is chosen. For example, if there are 32 possible system states defined by the combination of 9 critical equipment, the probability of finding the exact system state will be $32/(2^9) = 0.06$. Under this condition the RAS resolves to the default power system state. For certain contingencies, the difference in the load-shed calculations between the default system state from the state table, and the actual system state based on equipment status could lead to excessive load shedding. The UTE RAS uses a dynamic system-state calculation algorithm and calculates a system state for each contingency instead of selecting one system state for all contingencies. Based on its geographical location, every contingency has a few critical equipment's that are more relevant than the rest. By only considering the critical equipment relevant for that particular contingency, the probability of finding the exact system state increases. The relevant critical equipment for each contingency for state calculations are defined in the RAS file. The UTE RAS uses the following parameters to identify the gain constants to be used in the load-shed calculation for each contingency:

- Critical equipment selected for each contingency
- Calculated system state (S)

These gain factors are then applied along with the filtered analog and digital data from the field to calculate the amount of remediation (MW required to shed). The location of loads to shed is explained in detail in later sections.

3) Load Shed – Gain Table Technique

For each contingency, a combination of multiple control actions restricts the power system from not exceeding its limits. The polynomial equation used to calculate the amount of load to shed (MW) depends on the load-shed module chosen for the contingency in the module selection table of the RAS file. Load-shed module 1 is based on calculating load-shed levels to reduce the overload in critical equipment below its thermal limit after a contingency. The equation for load-shed module 1 is a function of critical equipment status, pre-event loading conditions of the 500 kV and 150 kV equipment, nominal rating of the critical equipment and gain constants that are used to control sensitivity. Load-shed module 2 is based on calculating the load-shed levels for an isolated grid (disconnection from Argentina). The load-shed levels calculated for module 2 focus on preventing generation-load imbalance, which if not corrected could lead to loss of additional assets and frequency fluctuations. The equation for load-shed module 2 is a function of pre-event loading conditions of 500 kV and 150 kV equipment and gain constants that are used to control sensitivity. The load-shed modules work independently of each other. The RAS controller executes the two load-shed modules simultaneously. However, only one load-shed module can be selected per contingency.

The load-shed level for each critical equipment for a predetermined contingency for module 1 is expressed as:

$$DAC_{0_Ci}(j) = \left[\frac{DFV_{Ci}(j) \cdot \Phi_{500} - (NM_j - \Phi_j)}{AFV_{Ci}(j)} \right] \cdot S_j \quad (1)$$

$$DAC_{0_Ci} = \text{MAX} [DAC_{0_Ci}(1), \dots, DAC_{0_Ci}(8), 0] \quad (2)$$

where:

$DAC_{0_Ci}(j)$ is the MW load to shed for each critical equipment.

j is the critical equipment for contingency C_i ($j = 1$ to 8).

$DFV_{Ci}(j)$ and $AFV_{Ci}(j)$ are the distribution factors and alleviation factors load gain constants for critical equipment j and contingency C_i .

NM_j is the post contingency power flow desired in the critical equipment, typical thermal rating for 1 hour, voltage drop limitation, or stability limit.

Φ_{500} is the power flow in the lost 500 kV equipment that triggered the contingency.

Φ_j is the power flow in the critical equipment j before the contingency.

S_j is the status of critical equipment j .

DAC_{0_Ci} is the MW load to shed for contingency C_i .

The final load to shed is then adjusted based on the power transfer with Brazil through the convertor. The final load-shed level is expressed as:

$$DAC_{Ci} = \text{MAX} [DAC_{0_Ci} - DAD_{Ci} \cdot R_{Ci}, 0] \quad (3)$$

$$R_{Ci} = \frac{AFC_{Ci}(j)}{AFV_{Ci}(j)} \quad (4)$$

where:

DAC_{Ci} is the final load-shed value for contingency C_i .

DAD_{Ci} is the calculated final power demand override through Brazil intertie.

R_{Ci} is the DAD adjustment factor.

$AFC_{Ci}(j)$ is the alleviation factor convertor gain constants for critical equipment j .

For the eight critical devices chosen for each contingency based on the calculated power system state, eight distribution factors, alleviation factor loads, and alleviation factor convertor gain constants are chosen. The gain constants (DFV_j , AFV_j , and AFC_j) for each critical equipment are updated using the gain constant table. The dimension of each gain constant table is system state by contingency by critical equipment. The final dimension of the DFV gain table is 1,000 by 64 by 8 gain constants. This equates to a total of 512,000 gain constants not including matrices for other modules and several other gain constant matrices of smaller sizes. Fig. 5 shows the three dimensional DFV , AFV , and AFC gain table. For each contingency (C) and based on the power system state (S) calculated, the gain constants from the corresponding cells are chosen for up to eight critical equipment (j) and are used in the formula shown above for calculating the load shed. For example, $G1$ is the gain constant for $C3$, $J3$, and $S1$. Similarly, $G2$ is the gain constant for $C45$, $J1$, and $S100$. UTE engineers update the gain constants depending on the system load flow and detailed stability studies.

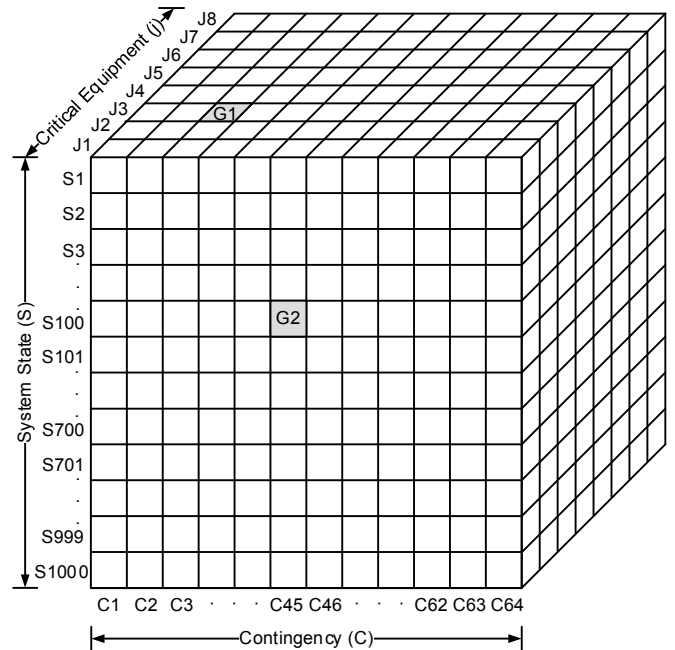


Fig. 5. Gain Constant Table for DFV , AFV , and AFC

Module 2 uses a different equation with a different set of gain constants. The gain constants however are defined in a similar fashion. The final load-shed value for module 2 is also adjusted based on the power flow through Brazil (DAC_{Ci}) explained in Section D ancillary controls.

4) Process of Load Selection

After calculating the load-shed value for each contingency, the RAS performs the process of load selection. The loads selected to be shed are located throughout Uruguay. The loads are grouped into geographical zones identified as Z. The RAS considers 128 loads and 32 zones for process of load selection (PLS) calculations.

The grouping and assignment of loads to a particular zone is done through the zone selection table in the RAS file. For each contingency, a unique priority number (Z_{PRTY}) is assigned for each geographical zone. Location of load to shed is determined by the assignment of loads and Z_{PRTY} to a particular zone. The same zone can have Z_{PRTY} for different contingencies. A zone threshold (Z_{THLD}) is defined for each zone. The Z_{THLD} are defined based on the reactive power

generated by the susceptance of lines in the zone. Z_{PRTY} and Z_{THLD} are entered through the RAS file.

Loads are generally shed by disconnecting transformers in the substation. The RAS operator has the ability to inhibit a load from tripping. If the sum of loads available (noninhibited loads) to be tripped is greater than the threshold value for the zone, then the RAS trips the entire zone through its interconnecting lines followed by the substations in the next zone until the DAC_{Ci} number is satisfied. Lines are tripped by opening breakers on both ends of the line.

Table V shows an example of the PLS for a contingency with $DAC_{Ci}=700$ MW. The RAS sorts the substation in descending order of MW within each zone and arranges each zone in ascending order of zone priority. The PLS selects Zones 3 and 2 to be tripped by lines and substations MVE and PAN in Zone 4 are selected to be tripped individually. The total load shed for this contingency will be $140 + 350 + 148.1 + 66 = 704.1$ MW. The PLS discards Substations NOR and MVC in Zone 4, because there are smaller substations available that can satisfy the required DAC_{Ci} .

TABLE V
EXAMPLE OF PROCESS OF LOAD SELECTION

Zone #	Z_{PRTY}	Z_{THLD}	PLS Substation List	Load (MW)	Zone Load (MW)	Trip by Lines	Trip by Substation
3	1	80	MAL	48.0	140	✓	
			BIF	35.2			
			PES	21.1			
			SCA	14.0			
			ROC	11.0			
			PAZ	10.3			
2	2	90	MVF	98.3	350	✓	
			MVJ	98.1			
			MVH	92.6			
			MVR	36.7			
			MVG	34.0			
4	3	0	MVE	148.1	533		✓
			NOR	109.6			
			MVC	76.3			
			PAN	66.0			✓
			MVL	45.7			
			MVK	45.1			
			PIE	42.5			
			Laisa	0.0			
			MVM	0.0			
1	4	0	ROS	32.7	83		
			FLO	26.4			
			DUR	14.1			
			TRI	9.7			

5) CPS – Line Trip Versus Substation Trip

The RAS dynamically calculates the load shed value and location for each contingency. The RAS mitigates overload conditions and reduces generation load imbalance for up to 64 contingencies, using the gain table technique [6]. The process of load selection provides a more flexible use of system assets and prevents over-remediation. All system definitions and load selection parameters are entered and managed by the dispatch engineers using the RAS file.

The output of the RAS algorithm is the CPS. The results from the load-shed level calculation and the process of load selection are used to populate the CPS. It is a two-dimensional array that shows contingencies (C) and actions. Each cell of the array displays the zone number where the action is taken. The CPS also indicates whether the loads will be shed by tripping individual substations or entire zones will be shed by tripping lines. The CPS results are updated every 100 milliseconds by the RAS. As soon as a contingency is detected, the RAS triggers the actions as represented by the CPS. Fig. 6 shows a UTE RAS CPS. The CPS also identifies if a substation is inhibited by the operator from tripping.

	SUB 1	SUB 2	SUB 3	SUB 4	SUB 5	SUB 6	...	SUB 127	SUB 128
C1	1	1			5				
C2	1		18		5	5		26	
C3	1				5	5	2	2	
C4	1	1							
C5					5		2		
.	1	1	18					26	
.					5				
C63	1				5	5			
C64		1	18						

Not Selected to Trip

Selected to Trip Line

Inhibited

Selected to Trip Substation

Fig. 6. CPS Action Table

6) Multiple, Closely Timed Contingencies

When remedial actions are taken for multiple closely timed contingencies, additional care and checks are performed by the UTE RAS to avoid poor decisions. Any contingency that happens in the system creates a disturbance. These power disturbances could cause the gathered analog data to fluctuate before the power system settles to a new steady-state level. To prevent these disturbances from affecting the RAS decisions for closely timed contingencies, all values representing the pre-event power system are frozen for a certain period.

If a second contingency happens during this time, the freeze timer is reset and data are frozen until the new timer is elapsed. However, not all contingencies in the UTE power system produce strong enough oscillations to cause the analog data to fluctuate. A freeze flag associated with each contingency is updated using the freeze flag table in the RAS file. Data are frozen only if a freeze flag is active for the contingency.

There are several logic timers and counters used in the RAS logic. The total number of consecutive RAS actions allowed within a freeze window is limited by counter value NB. When the power system reaches a state when more than a predetermined number of 500 kV equipment are out-of-service, defined by counter value NT, the RAS disables automatically. No further actions are taken until the number of out-of-service 500 kV equipment falls below NT value. System studies and prior operator experience have shown that power system state calculations for an NT value greater than 4 does not represent the system accurately.

D. Ancillary Controls

Besides the initial high-priority load-shed actions, additional control actions may be required for certain contingencies. These ancillary controls are required for power exchange override with Brazil, stabilizing voltage, reactive power compensation, and post load-shed power flow control. The following ancillary control modules are implemented based on the module selection for each contingency.

1) Brazilian Power Exchange Override

The Brazilian power exchange override module (BPOM) can be implemented for contingencies by choosing in the module selection table (Table IV). Since the level of load shed is adjusted based on the calculations in this module it is executed simultaneously with the load-shed module. The main function of the BPOM is to reduce the total amount of load shed. The theoretical goal for the RAS is to calculate a required power exchange value with Brazil ($DAD\Delta_{Ci}$) that achieves zero MW of load shed ($DAD\Delta_{Ci} - DAC0_{Ci} = 0$ MW). This is done by controlling the power exchange through the convertor at the 500 kV Melo substation. Table VI summarizes the required convertor power exchange actions after a contingency.

TABLE VI
POWER EXCHANGE WITH BRAZIL

Convertor Power Exchange	Required Exchange Action
Import	Increase import
Export	Decrease export and start import, if required

The theoretical goal $DAD\Delta_{Ci}$ is limited by two factors:

- Import and export limits set by Brazil and Uruguay power authorities. The operator enters this value in the RAS.
- Convertor power demand override (PDO) set points defining the converter capabilities and limits.

The RAS adjusts the $DAD\Delta_{Ci}$ based on the power exchange limits. The adjusted power exchange value, $DAD\Delta_{1Ci}$, is further adjusted based on the PDO selection process. Based on the current operating status of the convertor, six different PDOs are entered by the operator. Each PDO corresponds to a target exchange of power that can be achieved by the convertor. The RAS uses the threshold values defined for each contingency to choose a final PDO when the calculated $DAD\Delta_{1Ci}$ is between two PDO set points. A PDO set point that is closest to the adjusted $DAD\Delta_{1Ci}$ is chosen as the final power exchange.

The BPOM module of the RAS continuously calculates the final DAD_{Ci} for each contingency and reduces the final load shed (DAC_{Ci}) required. When a contingency is detected, control signals are sent to the convertor simultaneously with the load-shed signals. The maximum convertor ramping rate is 1,500 MW per second.

2) Supplemental Load Shed

The RAS implements the supplemental load-shed module after an initial load shed and the Brazilian convertor controls are exercised. A very accurate load-shed action is required for certain contingencies involving the loss of 500 kV lines connecting the north and south of the country. Supplemental load shedding may be required to achieve this accuracy. Small discrepancies such as load breaker failure, improper measurement of analog quantities by certain field equipment, and even undesired generation loss can lead to DAC_{Ci} variations of up to ± 100 MW. This leads to undervoltage and overvoltage conditions in the 500 kV Montevideo bus that serves the majority of the electrical load or overloads in the 150 kV system.

Supplemental load shedding is triggered by monitoring the voltage and power flow of critical equipment. Individual substation loads are shed after a small time delay (until the voltage and loading of the critical equipment are operating at acceptable levels). Block close signals are sent to prevent static compensation capacitors from turning on during the supplemental load shedding. Turning on the static compensation capacitors leads to an increase in power flow through the critical equipment for which supplemental load shedding is being performed. Parameters required for the operation of this module, like the critical equipment to monitor for voltage and power flow, the number of supplemental load-shed actions, and the trigger levels for each contingency are updated using the supplemental load-shed table of the RAS file.

3) Reactive Power Compensation

The reactive power compensation module monitors the pre-event reactive power flow (Q) in the 500 kV equipment lost during the contingency. This module attempts to normalize the

reactive compensation in the power system after a remedial action. For contingencies involving events E4 and E5 for example, excessive reactive power compensation may be present after a load shed. The RAS achieves this by tripping capacitor banks located in the three 500 kV substations to prevent overvoltage conditions. The RAS calculates the correct amount of capacitors to trip. Excessive capacitor tripping could lead to severe undervoltage conditions. The RAS allows supplemental load-shedding and reactive power compensation ancillary controls to be chosen for the same contingency.

The amount of reactive power compensation required is expressed as:

$$Q_{Ci} = X_{Ci} \cdot DAC_{Ci} + Y_{Ci} + (Z_{Ci} \cdot \Phi_{500q}) \quad (5)$$

where:

Q_{Ci} is the calculated reactive power compensation for contingency Ci (Mvar).

X_{Ci} , Y_{Ci} , and Z_{Ci} are the reactive gain constants for contingency Ci .

Φ_{500q} is the reactive power flow (Mvar) in the lost 500 kV equipment that triggered the contingency.

The RAS has the capacity to trip up to 32 capacitor banks. The operator assigns a unique priority number for each capacitor bank. The RAS sorts and trips the capacitor banks in ascending order of their assigned priority until the calculated reactive compensation is satisfied for the contingency.

4) Line Tripping

The line tripping module is implemented simultaneously with the initial load shed. However, for certain contingencies, it is implemented following an operator-entered time delay. Line shedding is performed for the following two reasons.

First, for certain contingency combinations that lead to loss of Argentinian and Uruguayan 500 kV interconnection, a supplemental 150 kV line shed is required. There are inter area oscillations in the Uruguayan power system, following a large DAC_{Ci} load-shed action, The RAS controller disconnects the 150 kV lines interconnecting Argentina and Uruguay to prevent these undamped oscillations.

Second, line tripping is required as a remedial action to force the power system state (S) to a desired value, by forcing certain lines out of service. Moreover, the lines tripped in this process are carrying limited or no load, because of a prior load-shed action. Selection of gain constants based on an inaccurate power system state can lead to insufficient or excessive load shedding. Forcing certain lines out of service increases the probability of an accurate S . An accurate S , in turn, allows a more definitive gain constant definition, assuming these lines are not in service.

V. RAS HMI

The RAS HMI is launched from a substation-hardened computer. It is used for setting changes and monitoring purposes only. The RAS functionality is not affected by a failure of the RAS HMI. Some key screens of the HMI include:

- Status display of live power system data used in the RAS calculations.
- Real-time view of the CPS.
- Communication of diagnostics and alarming.
- SOEs and oscillographic event viewing.
- RAS file settings — definition and status screens.
- Backup underfrequency load-shed settings and status.

The RAS file includes a large number of tables. Edits made to any single table are detected by the RAS by comparing the date and time stamp of the gain files. The operators use the RAS HMI to load the new files to the controllers.

A backup underfrequency load-shed system serves a backup of the primary contingency-based system. Underfrequency threshold levels are monitored at the 31.5 kV substation IEDs that trigger load-shed signals. The settings and operations of underfrequency-based load shedding (UFLS) are centrally managed and operated from the RAS HMI. At the RAS operator's request, these settings are then transferred to all the underfrequency action IEDs in the 31.5 kV substations.

The RAS HMI has three tiers of UFLS screens. The Level 1 screen is used to define up to five levels (f0–df/dt, f1, f2, f3, and f4) of underfrequency thresholds (Th) and the corresponding time delays for pickup. Thresholds defined on Level 1 screens are enabled and disabled for each substation using the UFLS Level 2 screen. The UFLS Level 3 screen is used to apply the selections from UFLS Level 1 and Level 2 to individual outputs of action IEDs. The Level 3 screen for each substation allows selection of threshold levels for each output. For example, Level 3 UFLS screen selection can be set up to operate OUT301–305 for f1, OUT306–309 for f3, and OUT310–OUT312 for f4. Note that each output sheds a load in the substation. HMI is also used to inhibit individual outputs from operating, irrespective of the threshold selections. The three levels of UFLS screens in the RAS HMI provide RAS operators with a wide range of options and higher selectivity for the UFLS settings. Fig. 7 shows the simplified IED logic for the backup underfrequency load-shed system supervised by set points and selected from the RAS HMI. These options are set up and updated based on the current operating conditions.

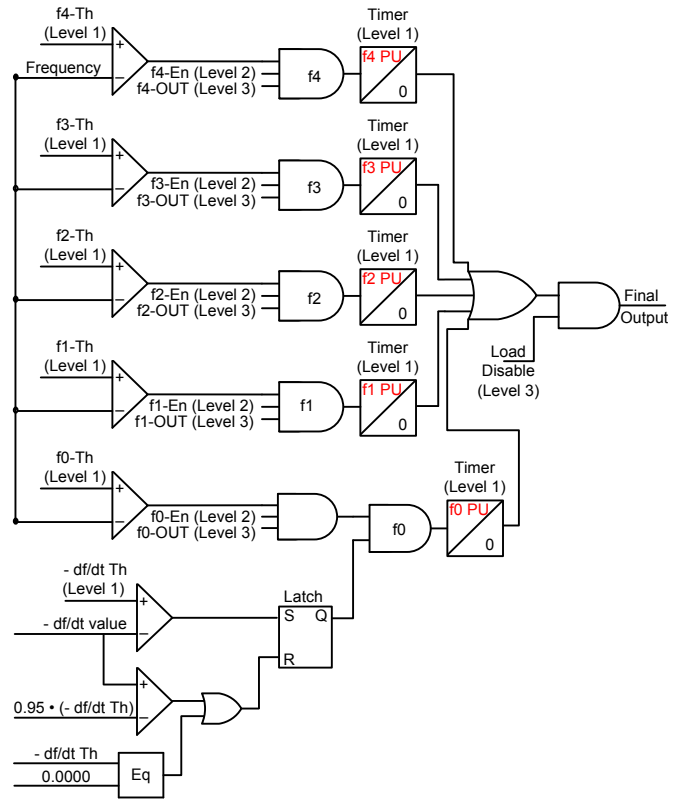


Fig. 7. Simplified Backup Underfrequency Logic Diagram

VI. SUPERVISORY SYSTEM

Differences in analog values or communications loss can result in the dual RAS controller making different remedial decisions. Different decisions in the controllers can lead to excessive load shedding. A quality index generated in each RAS based on the operational and communications status of all RAS and field devices are used to address the discrepancies in the CPS calculation. All field devices communicating to the RAS controller are given a different quality number that correlates with information it's providing to the RAS controller. For example, an action equipment is given a smaller quality rating than an FEP or an SVP, since the loss of one FEP or an SVP may constitute loss of communication with several equipment in a remote substation. A single quality index (QI) number is generated based on the weighted average of the individual device quality numbers. The QI number is used to supervise and decide which RAS has better data availability. The controller with better data quality supervises the actions of the other controller. The QI number generated at the RAS controller is compared every processing cycle between the two RAS systems.

VII. TESTING SIMULATOR

The dual primary architecture of the system gives the flexibility to disable either RAS for testing or maintenance and keep at least one RAS available at all times. The modular RAS has many features and set points that an operator can enable and disable to change the nature and magnitude of actions. Approximately six million gain constants are used for the primary load shedding and the ancillary control logic calculations. A thorough testing of the applied changes are required to verify and validate the results compared to the desired outcomes before applying the changes in the live RAS system. Fig. 8 shows the simulator communicating with the RAC using Network Global Variable List protocol.

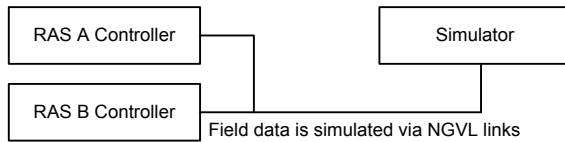


Fig. 8. Simulator Panel Connections

The test simulator for the RAS simulates all inputs, including digital statuses, analog data, PMU data, and data from the ICCP SCADA system. The simulator is built using the same hardware platform used for the RAS controllers. The simulator provides two options for testing; static simulation and playback simulation.

The static simulation method uses a CSV file to simulate the field data in the controller and to create event(s) to observe controller actions. The CSV file provides the operator an ability to drive each analog and digital input quantity to a desired value. It is also extremely useful for testing all I/O points and creating any desired power system state for RAS controllers. Communications failures can also be simulated to test the supervisory logic.

In the playback simulation mode, the simulator is used to replay event report files generated by RAS controllers. The RAS allows replay of actual events, which is very helpful in understanding the behavior of the control system and fine tune gain constants. The simulator playback mode provides a valuable method during factory acceptance testing because playback files generated by UTE for historical events could be played back with no risk to the actual power system.

Although the test simulator is an excellent tool for the RAS algorithm validation, a closed-loop power system test for validating the post load-shed ancillary controls was required. An equivalent Uruguayan power system and the interconnections with Argentina and Brazil are modeled using the Real Time Digital Simulator (RTDS®). RTDS equipment allows dynamic modeling of the Uruguayan power system with a simulated small time step to test all closed-loop controls [7]. Modeling the system inertia, governor response times, and generator exciter controls provide dynamic stability validation of the Uruguayan power system after a remedial action.

VIII. CONCLUSION

A portion of the RAS was successfully commissioned in July 2015, which included a select few contingencies and limited loads. Including the open line detection time, communications time and the field equipment response times, and other communications delays, the RAS performed remedial load shedding within 200 milliseconds from the actual contingency. Commissioning a system of this magnitude involved many groups in UTE and the supplier. A thorough factory acceptance testing procedure prior to field commissioning greatly reduced the commissioning time. Several test cases including the most probabilistic combinations of closely timed contingencies, device communication failures, different gain constants, and different levels of power demand were tested to validate the RAS.

The RAS is designed to allow future expansion with little interruption to the performance. The dynamic module selection feature of the RAS allows the operating engineers to control the power system based on the current operating scenarios and power system state. Synchrophasor data archived from the field PMUs are used by UTE for detailed analysis of the power system that was not possible earlier. This information coupled with the post-event analysis tool of the RAS helps UTE fine tune the system performance and define more accurate gain constants.

Time alignment of PMU synchrophasor data in the SVP coupled with efficient data processing techniques can be used for model analysis and synchrophasor-based controls in the future. Interfacing the RAS with the dynamic simulation tool, which calculates the gain constants and other parameters critical for the operation of RAS, will be investigated in the future. This direct interface will make the RAS more dynamic and eliminate the requirement of maintaining a RAS file.

A close working relationship between UTE engineers and the supplier engineers was crucial for the execution of the project. Site-specific experience brought by UTE engineers and special protection system experience brought by the supplier engineers were critical in replacing the old system with the RAS.

IX. ACKNOWLEDGMENT

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XI. BIOGRAPHIES

Julián Malcón graduated in electrical engineering from Universidad de la República, Uruguay, in 1984. He joined Usinas y Trasmisiones Eléctricas in 1983. Since 1984, he has worked as a protection engineer, assistant manager in maintenance in protection systems, manager in protection system, and since 2014 is the manager in protection, automation, and control. He leads projects in protection, automation, synchronization, and control for the 500 kV and 150 kV network in Uruguay, including the remedial action scheme.

Nicolás Yedrzejewski graduated in electrical engineering from Universidad de la República, Uruguay, 2006. From 2004 to 2007, he worked in CIME Ingeniería projects related to comprehensive protection against atmospheric discharge. Since 2006, Nicolás is an associate professor with the Electrical Engineering Institute at Universidad de la República. He has been with Usinas y Trasmisiones Eléctricas since 2007 as a dynamic studies expert at the National Dispatch Center.

Ashok Balasubramanian, P.E., received his BE degree in electrical and electronics engineering from the University of Madras, India, in 2004 and an MS in power systems from the University of Alaska, Fairbanks, in 2006. Upon graduation, he worked in the process automation industry in Alaska for more than three years, where he worked on projects and gained experience integrating programmable logic controllers with microprocessor-based protective relays. Ashok joined Schweitzer Engineering Laboratories, Inc. in January 2010 and is currently an automation engineer in the engineering services division. He has experience in designing and implementing control systems for utility and industrial customers.

Rameez Syed is an automation engineer for the engineering services division of Schweitzer Engineering Laboratories, Inc. (SEL). He received a Bachelor of Applied Science in electrical engineering from the University of Windsor, Ontario, Canada. Rameez has been employed with SEL since 2008 and has experience in designing and implementing control systems for utility and industrial customers.

Sai Raghupathula is a regional manager (West Region) for the engineering services division of Schweitzer Engineering Laboratories, Inc. (SEL). He received a Masters degree in electrical engineering from the University of Idaho. Sai has been employed with SEL since 2004 and has experience in designing and implementing control systems for utility and industrial customers.

Remedial Action Scheme Based on Synchrophasor Measurements and System Angle Difference for Peru's 500 kV Grid

Yofre Jacome, *COES SINAC*

Luis Figueroa, *Sociedad Minera Cerro Verde*

Eduardo Palma, Fernando Calero, Pedro Loza, Alejandro Carbajal, and Ashish Upreti,
Schweitzer Engineering Laboratories, Inc.

Abstract—A remedial action scheme (RAS) implemented in the south of Peru reacts to excessive angle differences between the synchronized voltage measurements of two nodes that are 400 km apart in order to disconnect loads and maintain the stability of the country's power system. The RAS was required for the safe operation of the power system because of the recent expansion of large loads in the southern region of the country.

The RAS concept was developed by the system operator (COES) after a detailed analysis of the power system response for certain system contingencies. The study was performed with power system stability software, and it identified six contingencies that could jeopardize the operation of the southern part of the Peruvian power system. It was determined that the best indicator of a problem was the angle difference between substations and that the remedial action would be to disconnect some of the large mining loads.

The RAS architecture uses phasor measurement and control units (PMcus) installed in the substations of the country's southern 500 kV corridor. These PMcus supply synchronized measurements to redundant synchrophasor processors, where the measurements are time-aligned and the phase angles compared. Decision-making logic is applied by the synchrophasor processors, and trip commands are sent to the large mining loads. The RAS operation takes place within milliseconds after the angle threshold is satisfied. The implemented system has allowed the large mining installation to connect to the Peruvian grid while complying with power system stability regulations and reliability requirements.

This paper describes the power system stability problem, the RAS logic design, the communications infrastructure used, and the real-time testing that was performed before commissioning, as well as the staged testing of the system.

I. INTRODUCTION

The Cerro Verde mine is located 30 km south of Arequipa, Peru's second-largest city after the capital city of Lima. Lima is approximately 1,100 kilometers north of Arequipa. Currently, the radial 500 kV Chilca-Poroma-Ocoña-San José-Montalvo transmission corridor (shown in Fig. 1) is the main transmission path for Peru, feeding all loads in the south, together with the 220 kV Mantaro-Cotaruse-Socabaya-Moquegua-Montalvo system. Most of Peru's power is generated north of Chilca (near Lima) and power is supplied to the south through this 500 kV corridor.

The partial or total loss of the 220 kV transmission path can be tolerated because the 500 kV system can support the load; the reverse is not true. This 500 kV north-central-to-south corridor and its Synchronous Digital Hierarchy (SDH) fiber-optic communications link run along the Pacific Ocean coast of Peru.

Fig. 1 shows a geographical view of the 500 kV and 220 kV southern transmission systems, and Fig. 2 shows the system as a one-line diagram. Bus reactors are present in the 500 kV substations to provide voltage compensation.

The Cerro Verde Production Unit Expansion (CVPUE) mining project requires approximately 300 MW of power, which is supplied by Peru's 500 kV national transmission system, Sistema Interconectado Nacional (SINAC). CVPUE receives power from the 500 kV transmission system at the San José substation through two 500/220 kV autotransformers. Two lines branch to the San Luis and San Carlos substations at 220 kV. These two CVPUE 220 kV substations provide power to loads such as the ball mills, fresh water pump motors, crushers, high pressure grinding rolls, conveyors, and so on inside the mine. The project loads are connected to 220/34.5 kV transformers.

The Economic Operations Committee of the Interconnected National System (Comité de Operación Económica del Sistema Interconectado Nacional [COES]) is responsible for the power flow and operation of Peru's grid. Phase 1 of the RAS, drafted by COES, called for the implementation of automatic load shedding by angle difference (desconexión automática de carga por diferencia angular [DACA]) based on synchronized phasor (synchrophasor) measurements of the loads of the Cerro Verde mine. It also called for local disconnection of reactive power compensation (desconexión automática de reactores locales [DARL]) to control the busbar reactors of the 500 kV substations. The operational study deemed it necessary to trip the busbar and line reactors after a load shedding action because an undervoltage condition might occur on the 500 kV substation bus. The DARL acts in 500 ms, but there is a supervisory control and data acquisition-operated (SCADA-operated) control for the same reactors.



Fig. 1. Geographical view of the 500 kV (orange) and 220 kV (blue) lines

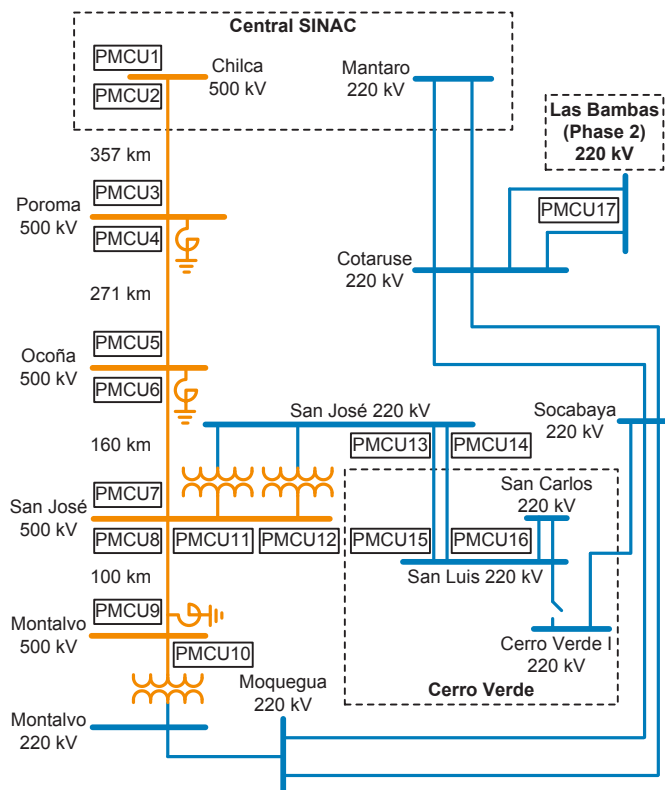


Fig. 2. Simplified representation of the components of the remedial action scheme (RAS)

The southern Peru mining industry is expanding. These expansions represent high loads that could threaten the stability of the Peruvian power system if the 500 kV corridor is lost. The implementation of a RAS was deemed necessary due to the lack of a redundant 500 kV path in the transmission system.

The operating speed of the RAS to trip mining loads is less than 100 ms, starting from the time that a contingency (angular difference) is detected by the phasor measurement and control unit (PMCU) to the contact output time of the load-shedding controller (LSC). The function of the PMCU and LSC are described later in the paper. The RAS takes up to 100 ms to respond, and an additional 100 ms for the circuit breakers to open provides a total time of 200 ms.

Phase 1 has already been commissioned. Phase 2, an expansion of the initial system, will be implemented during the coming years to increase the load sharing table and accommodate more loads from the southern mines of Peru.

II. THE SOLUTION

The Peruvian power system transmission network operates at 500 kV and 220 kV. The bulk of the power transmission to the southern part of the country uses the 500 kV corridor shown in Fig. 2. The 220 kV system is a secondary path for power transmission.

Fig. 3 shows a very simplistic representation of the Peruvian power system. Notice that the equivalent 500 kV and 220 kV systems are represented by equivalent reactances (X_{500} and X_{220} , respectively).

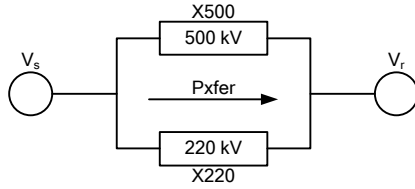


Fig. 3. Simplified representation of the Peruvian power system

Based on the formula for power transfer capability in [1] (where V_s is the sending source and V_r is receiving), when the two systems are in service, the equivalent reactance (X_{eq}) is the parallel combination of X_{500} and X_{220} [2]. When the 500 kV transmission network is lost, X_{eq} is X_{220} or larger. To keep the power transfer intact, the angle difference between the sources needs to increase.

The maximum power that is transmitted from the source to the receiving end is at 90 degrees. The equal area criterion, based on (2), illustrates that a power system becomes unstable if there is not enough power transfer capability [2]. In the previous example, the X_{220} equivalent reactance may not provide the capability required to transmit the electrical power and the system could become unstable.

$$Pxfer = \frac{|V_s| |V_r|}{X_{eq}} \sin(\gamma_{V_s} - \gamma_{V_r}) \quad (1)$$

An angle difference increase is a good indicator that the power system is becoming unstable. The solution algorithm proposed for the Peruvian system incorporates angle difference monitoring between the sending and receiving measuring points. Simulations of this transmission network in power stability software have provided angle difference thresholds for logic schemes that were implemented as a RAS. Synchrophasors allow for this comparison of power system angle differences.

Fig. 4 shows two PMCUs time-synchronized by high-accuracy GPS receivers. These PMCUs are the measuring devices. The GPS time signal provides a common reference for both PMCU 1 and PMCU 2. The phasor measurements, with magnitude and angle, are transmitted by the PMCU communications ports to a centralized measuring device for the purpose of analyzing angle differences between different locations on the transmission line.

The project described in this paper illustrates the use of PMCUs to monitor angle differences between sending and receiving measuring devices. The synchronized measurements travel through communications channels to reach two phasor data concentrators (PDCs), which ensures that the data being received are archived and time-aligned. The PDCs are the centralized measuring devices that receive messages from the PMCUs. These PDCs with control capabilities are able to process the information and make control decisions. The decisions become control actions that are sent via a communications network to the appropriate devices to perform them.

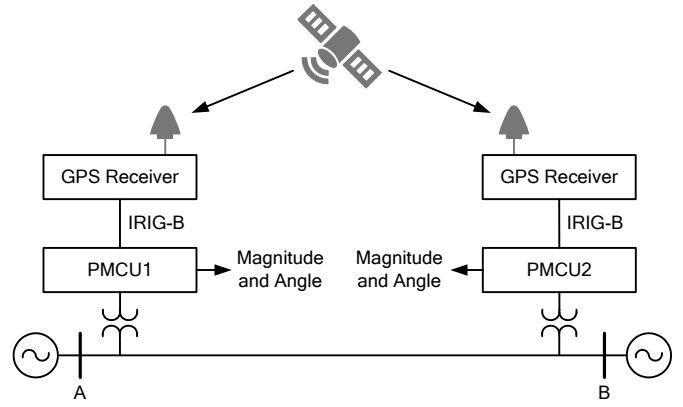


Fig. 4. Synchrophasor technology components

The two PDCs with control capabilities, shown in Fig. 5, receive the synchronized measurements from two (or more) substation PMCUs and process the measurements with built-in logic. Typically, the programming language is a real-time control language like IEC-61131-3.

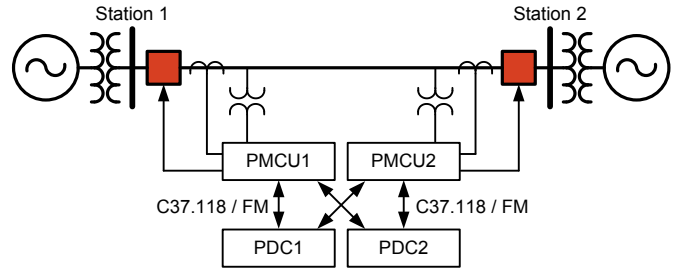


Fig. 5. PDCs with control capabilities monitoring the angle difference

PMCUs are distributed along the 500 kV corridor, as shown in Fig. 2. These PMCUs monitor and send the voltage and current magnitude and angle values (and other values) of the lines they are connected to via IEEE C37.118 protocol. The measurements are sent to two redundant PDCs with control in the San Luis and San José substations, as shown in Fig. 5.

III. LOGIC AND ARCHITECTURE

In the Cerro Verde project, the logic schemes designed were programmed with IEC 61131-3 languages in two redundant PDCs with control capabilities called synchrophasor vector processors (SVPs). These SVPs act as PDCs and time-align incoming IEEE C37.118 messages from the sixteen PMCUs. The SVPs process these messages with an internal logic engine that calculates and validates conditions to implement the RAS logic. They send IEEE C37.118 messages or derived data to devices such as other PDCs, and monitoring systems (e.g., transmission system operators).

Moreover, the SVPs implement Network Global Variable Lists (NGVLs). NGVL is a variable sharing network technology that allows the sending of commands and analog values to other NGVL-capable devices [3]. They also send proprietary control messages, such as Fast Messages (FM), for control of other devices.

The SVPs in this project implement the logic schemes and send control messages to other devices. The control messages from each SVP are as follows:

- FMs to the PMCUs for reactor control.
- NGVL commands and data exchange to the LSC to trip loads and to update the human-machine interface (HMI) with real-time data.

Fig. 6 is a data flow diagram showing the protocols used between each measuring and control device for load shedding and for the RAS in general.

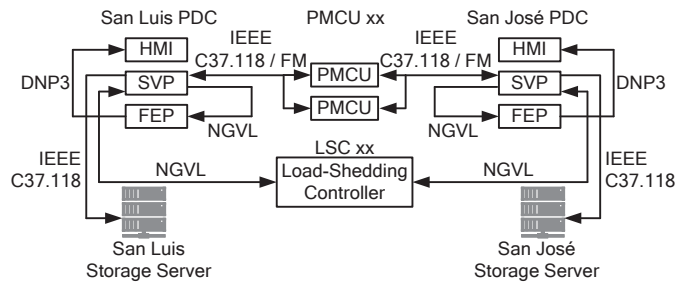


Fig. 6. Data flow diagram

The system is redundant, with two SVP controllers functioning in parallel, along with two front-end processors (FEP). All sixteen PMCUs send data simultaneously to both SVP controllers in real time. Both SVP controllers receive IEEE C37.118 messages with the same exact data frame and perform the same deterministic logic functions. When a contingency is validated by both SVP controllers, each of them sends a fast control message simultaneously to the LSCs to trip only the loads that are selected for that contingency. The LSC is an I/O device with several binary outputs to control circuit breakers. The LSCs are located in three separate stations inside of the Cerro Verde mine, and these trip the assigned load(s) after receiving the fast control message from only one SVP.

The HMI of the RAS has a static list of loads that correspond to the amount of power to shed. The HMI operator selects loads from this list and assigns them to a contingency.

IV. COMMUNICATIONS

The sixteen PMCUs communicate via fiber-optic links in a closed network implemented on SDH station multiplexers. The geographical distances between the nodes are shown in Fig. 7. The longest distance that a message has to travel (from the Chilca substation to the San Luis substation) is approximately 800 km.

When designing the network, the most important consideration was speed. Various tests were conducted before commissioning to define the channel requirements. Based on the number of exchanged messages, a calculation was performed to derive the necessary bandwidth.

After all of the RAS components were installed and the communications channel was commissioned, latency tests were conducted to measure the real-time delay between each of the geographical locations (i.e., from each of the sixteen PMCUs to both the San Luis and the San José SVPs). Fig. 8 shows these results in milliseconds.

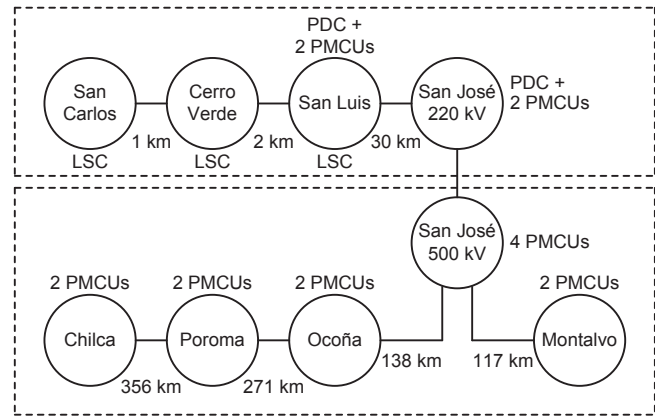


Fig. 7. Geographical distances between SDH nodes

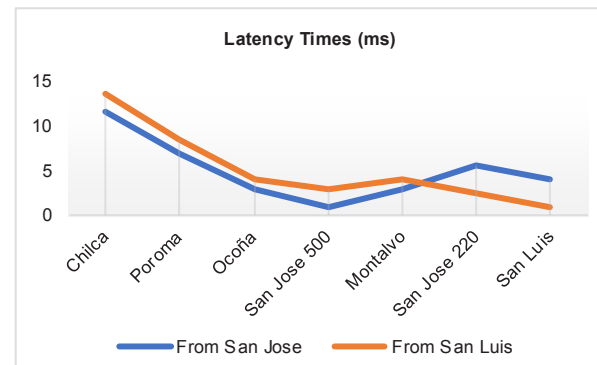


Fig. 8. Latency times from each PMCU to the SVPs in milliseconds

V. TIME SYNCHRONIZATION

High-accuracy time stamps are required for the correct performance of the PMCUs. GPS clocks were used to synchronize the PMCUs and controllers in this project.

Solar flares, jamming, and antenna failures can cause a clock to lose its GPS signal. When a GPS clock determines that it has lost the GPS signal, it switches to its internal holdover oscillator until a GPS signal is acquired. A system-logged event is recorded as a holdover alert with a time stamp, and the clock does not use the GPS signal until the primary source is properly verified.

GPS clocks retain appropriate time-stamp precision for a period of time and maintain the PMCU functionality. Certain designs use very accurate oscillators to keep the accuracy. The GPS clocks in this project use internal oven-controlled crystal oscillators (OCXOs) that maintain the relative time error to within $\pm 5 \mu s$ for 24 hours, which generally provides ample time to rectify the loss of the GPS signal.

VI. LOGIC

The purpose of the fast and automatic load shedding is to mitigate abnormal power system conditions when a contingency occurs. These abnormal power system conditions are summarized broadly as follows:

- Overloaded lines and transformers, which may also cause severe low-voltage conditions.
- Loss of the 500 kV line leading to angular instability.

The positive-sequence voltage angles of two PMCUs are compared by the DACA logic. Two consecutive comparisons are required to signal the detection of a contingency, and these decisions are processed by the DACA logic in real time. The remedial action command is received by the LSCs inside the mine to shed the loads that correspond to the contingency, which are selected by the Cerro Verde operators. Table I lists the six contingencies to be detected, which were identified by COES and Cerro Verde's system study.

TABLE I
CONTINGENCIES

Contingency Number	Description	Voltage Level (kV)
C1	Chilca-Poroma Line opened	500
C2	Poroma-Ocoña Line opened	500
C3	Ocoña-an José Line opened	500
C4	Mantaro-Cotaruse Line opened	220
C5	Cotaruse-Socabaya Line opened	220
C6	Mantaro-Cotaruse Line opened and the 500 kV corridor is open	220

The RAS system monitors the angle difference of two pairs of PMCUs according to Table II. Two angular differences are monitored, and the decisions are based on both. This is done for security purposes and to ensure that two independent measurements confirm the angular separation in the power system. Fig. 2 shows the geographical location of each PMCU listed in Table II. For example, in Contingency C1, the first pair of PMCUs compared are PMCU1 (Chilca) and PMCU4 (Poroma), and the second pair are PMCU1 (Chilca) and PMCU10 (Montalvo). The electrical degree or angle thresholds were obtained from COES and Cerro Verde's system study.

TABLE II
ANGLE DIFFERENCE THRESHOLDS

Contingency Number	First Pair of PMCUs Compared in SVP		Phase Angle 1 Threshold	Second Pair of PMCUs Compared in SVP		Phase Angle 2 Threshold
C1	1	4	40°	1	10	45°
C2	3	6	50°	2	9	50°
C3	5	8	50°	2	9	50°
C4	2	9	25°	1	7	65°
C5	2	9	n/a	1	7	n/a
C6	2	17	50°	2	9	30°

Table III specifies the amount of load to be shed for each contingency. This table includes the amount of power that was assigned to be shed by the Cerro Verde and Las Bambas mines. At the time of this writing, only Cerro Verde had LSCs to shed the power assigned.

TABLE III
LOAD-SHEDDING PERCENTAGE

Contingency Number	Cerro Verde Percentage	Las Bambas Percentage
C1	25% (91 MW)	NA
C2	60% (224 MW)	60% (90 MW)
C3	60% (224 MW)	60% (90 MW)
C4	NA	49% (74 MW)
C5	NA	NA
C6	NA	100% (150 MW)

The RAS system implements arming logic to add an extra level of security to the system. The PMCU programmable logic is used to check a list of conditions that are validated both in the PMCUs and the SVPs. Each PMCU sends an IEEE C37.118 message with the synchronized measurements of currents, voltages, real power of the transmission line, and binaries such as breaker status. The following conditions were used for the arming logic:

- No drastic changes of angle difference in consecutive measurements.
- No drastic changes of power flow in consecutive measurements.
- Current flow in each end of the line to confirm that breakers are closed in at 500 kV.
- Minimum power flow threshold met in the 500 kV corridor.
- No DACA logic previously operated.

Fig. 9 is a logic diagram for the arming of DACA1. The pickup and dropout times of the logic were carefully selected, taking into consideration the protection relay's reclosing times to avoid pole-open conditions or pole discrepancies.

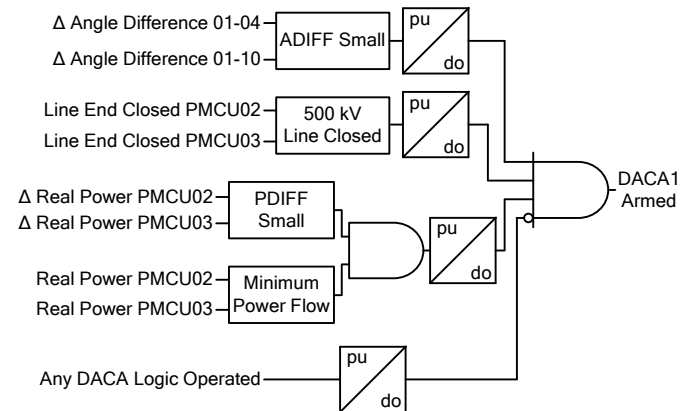


Fig. 9. DACA1 armed logic diagram

The following conditions are monitored to enable the DACA logic:

- Communications link quality bit in good status for data exchange between PMCUs and SVPs.
- High-accuracy time synchronization quality bit in good status for the PMCUs.
- No loss-of-potential logic operated in the PMCUs that participate in the DACA logic.

- No low-voltage threshold operated.
- No operator manual block of the RAS system from the HMI, which might be used in maintenance mode.

Fig. 10 shows the logic for DACA1.

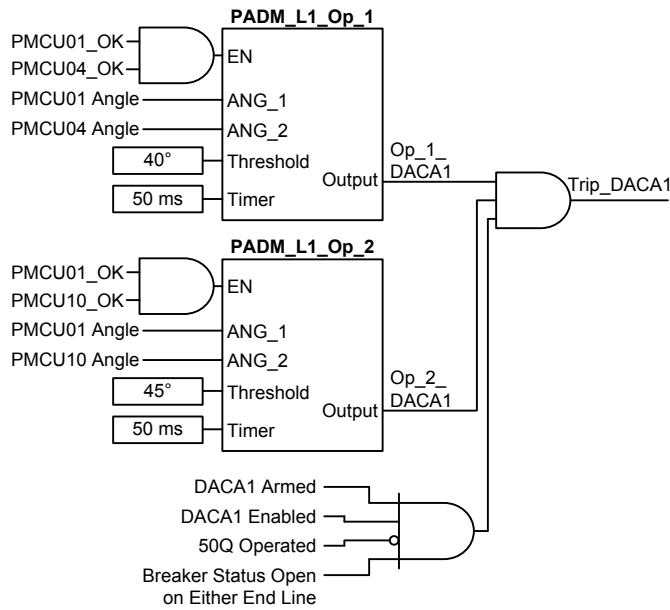


Fig. 10. PADM logic diagram to send trip command

The PADM (phase-angle difference monitoring) logic is used to detect whether the phase angle difference is over a threshold when a 500 kV line is opened. The DACA1 logic should be armed and enabled. No fault or single-pole-open condition should exist, which is verified by the absence of negative-sequence current (50Q). When all of this logic is met, then DACA1 operates and sends a control message to the LSC. Only one DACA logic operation at a time is permitted to trip the loads of the Cerro Verde mine, which means that the LSC only accepts the first control message received from either of the two SVPs that are working in a hot-hot configuration. The LSC is hard-wired to the breakers inside the mine to trip their loads.

It is possible that after any of the DACA schemes operates that the voltage might drop in the 500 kV transmission system. When an angle difference contingency is detected and the DACA logic operates, a DACA_Operated status bit is sent to all PMCUs. There are three PMCUs that have internal logic to trip either the line or bus reactor. The logic implemented is called DARL, and it operates if the low-voltage threshold is met and the DACA_Operated bit is received by the PMCU. The DARL logic was also identified by COES and Cerro Verde's system study.

VII. RTDS MODEL VALIDATION

A real-time digital simulator (RTDS) was used to validate the RAS. It performs electromagnetic power system transient simulations, with a typical simulation time step in the order of 50 μ s.

The overall network solution technique employed in the simulator is based on nodal analysis. The Dommel algorithm [4] allows the following two levels of parallel processing:

- Level 1 entails parallel processing of components connected to a common admittance matrix (i.e., within one subsystem).
- Level 2 entails parallel processing of subsystems (i.e., decoupled admittance matrices).

The simulator mimics Level 1 by using tightly coupled processors to solve components connected to a common admittance matrix. Level 2 is implemented by using separate processors to solve different simulation subsystems. In addition to being designed to execute the Dommel algorithm in real time, the simulator is designed to test physical protection and control equipment, such as RAS systems.

The RTDS uses a model that is based on the electrical configuration of the Peruvian power system. The model was specifically developed to validate the RAS. The RTDS with the Peruvian power system model had the RAS control system connected to it so that a closed-loop validation of the RAS could be accomplished during factory acceptance testing prior to field installation.

The RTDS model represents the Peruvian power system based on one-line drawings. All data required for modeling the different power system components (generators, transformers, transmission lines, distribution lines, cables, and loads) were provided by COES. Each power system component is validated prior to RAS testing. The Peruvian electrical system is modeled graphically and data are assigned to each component. The completed model, with graphics and data, is designated as a "case."

Once a power system case is built, it is compiled on the RTDS hardware and then executed in the RTDS run-time module. All the controls for interfacing with the model in real-time are placed there. This includes, but is not limited to, sliders to change set points, raise and lower controls, breaker controls, fault controls, and plots for capturing data.

A. Generator Modeling

The mechanical and electrical parameters of physical generators, along with governor and exciter systems, were developed for the simulation model. Step tests were performed to study the response of the exciter and governor models on a per-generator basis. For the validation, a test system was developed consisting of a generator connected to an infinite bus and two loads through a step-up transformer. Each of the components could be isolated by operating the breaker connected to the generator bus. This validation demonstrated the effects of the prescribed gains and time constants of the excitation and turbine governor system with the given generator. These tests included load acceptance, load rejection, and governor step response. For the exciter, these tests included exciter step response and a full-speed, no-load test.

B. Load Modeling

Constant impedance and constant power load models were developed for the power system model. The loads were further divided into sheddable and non-sheddable loads. Sheddable loads were hard-wired to the RAS system with the ability to be individually shed during a contingency. The active power, reactive power, voltage, and frequency could be monitored in real time during testing.

C. Network Aggregation

Parallel transformers and transmission lines that did not directly impact the RAS system were aggregated into a single transformer. Network equivalents were also created at the boundaries for simplicity. System inertia, impedance, and capacity were considered during the network and system aggregation.

D. Protection and Line Reactor Modeling

The RTDS model of the Peruvian system included the modeling of protective tripping to understand the interaction of the RAS with the existing protection system. Protective tripping included generation protection, transmission line protection, and voltage-based load-shedding schemes. The system model also included automatic reactor control at all 500 kV transmission lines.

Generator protection included trips for abnormal frequency and voltage excursion on the system. This included two levels of overvoltage, undervoltage, overfrequency, and underfrequency protection. Line protection trips for overvoltage on the system were implemented, which included two levels of overvoltage protection. Excursions beyond predetermined pickup thresholds result in protection-based tripping in the given transmission line or generator.

An undervoltage-based, load-shedding scheme at the feeder level was implemented for the RTDS model for extreme voltage excursions to verify the RAS interaction and stable operation.

VIII. RAS DYNAMIC TESTING AND ANALYSIS

Once the model components were individually verified, the combined system model was validated using the dynamic response of the power system during different contingencies. The validation of the model involved the comparison of the RTDS results to those from stability simulations performed by COES.

Prior to installation of the RAS system, complete I/O testing was performed in a laboratory. The RTDS model described in the previous section was used to validate the

functionality of the RAS system. Several studies were performed using the model, providing insight into plant operation, vulnerabilities, and system response for many contingency events. Studies were also completed to determine the optimal set points for RAS system.

The real-time model also permitted the RAS system to be tested as a live simulation in the factory acceptance test. This was accomplished by connecting the RAS system to the simulation hardware, as shown in Fig. 11.

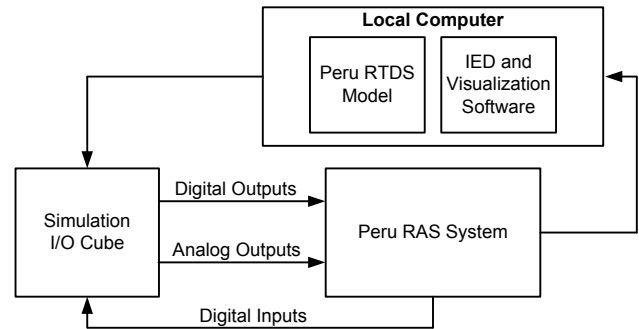


Fig. 11. RTDS interface with RAS System

A variety of tests were performed to determine the speed and reliability of the RAS system. These tests ranged from typical scenarios to corner cases. Several predefined tests were used in the testing of the centralized RAS system. These included line faults, sudden breaker open, successful and unsuccessful single-pole reclosing, load rejection, and loss of generation. The following subsections illustrate some of these tests.

A. Case 1: Three-Phase Fault and Opening of Chilca-Poroma 500 kV Transmission Line

A three-phase fault was applied on the Chilca-Poroma 500 kV transmission line and the line was opened. The Cerro Verde-San Luis transmission line was closed. The opening of the line (simulating protection system operation) yielded the gradual increase of the angular difference between the Chilca-Poroma and Chilca-Montalvo substations. The DACA1 logic operated, and the RAS shed load.

Fig. 12 shows the synchrophasor plot for Case 1. The DACA1 logic monitors the angle difference between PMCU1 and PMCU4 and the DACA2 logic monitors the angle difference between PMCU1 and PMCU10. When the fault is applied, the angle difference jump is monitored and once the breaker opens, the angle difference increases across the threshold. Once the pickup timer is satisfied, the RAS system operates to perform load shedding and preserve system stability.



Fig. 12. Software plot for angle difference TDS interface.

A three-phase fault was applied at 0.75 seconds. Fault detection took approximately 30 ms before a trip signal was sent to the breaker, and the three-phase breaker (CB) opened after another 50 ms. At 1.084 seconds, the angle difference threshold was reached, and another 50 ms internal pickup was required before the load trip was issued at 1.21 seconds. Fifty milliseconds after the load trips were received, the loads were shed. The total round-trip time, from the threshold crossing to the initiation of the load trips minus the 50 ms internal pickup, was calculated to be 76 ms. The timeline for this case is shown in Fig. 13.

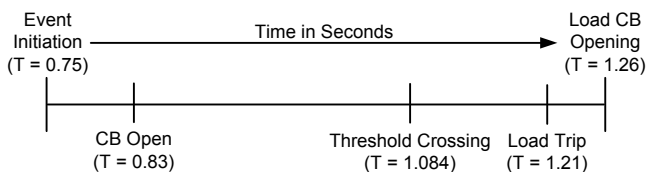


Fig. 13. Case 1 timing chart

B. Case 2: Single-Phase Fault and Three-Phase Open of Chilca-Poroma 500 kV Transmission Line

A single-line-to-ground fault was applied to the Chilca-Poroma 500 kV line with an approximate power flow of 940 MW to the south. The test simulated a failed single-pole-trip reclosing sequence. The single-pole-open interval of 900 ms was followed by a reclose attempt onto a permanent fault. A three-pole trip followed. The loss of the line increased the angle difference between the Chilca 500 kV and Poroma 500 kV substations. The angle difference between the Chilca 500 kV and Montalvo 500 kV substations also

increased (the second requirement). The DACA logic detected the power system angular differences above the thresholds and the RAS system operated.

The single-line-to-ground fault was applied at 0.75 seconds. Fault detection took approximately 30 ms before a trip signal was sent to the fault phase breaker, and the breaker opened after 50 ms. The faulted phase opened for 900 ms, which is the reclose interval. After reclosing, due to the presence of the permanent fault, all three phases opened at 1.78 seconds. At 1.967 seconds, the angle difference threshold was reached, and another 50 ms internal pickup was required before the load trip was issued at 2.09 seconds. Fifty milliseconds after the load trips were received, the loads were shed. The total round-trip time, from the threshold crossing to the initiation of the load trips minus the 50 ms internal pickup, was calculated to be 73 ms. The timeline for this case is shown in Fig. 14.

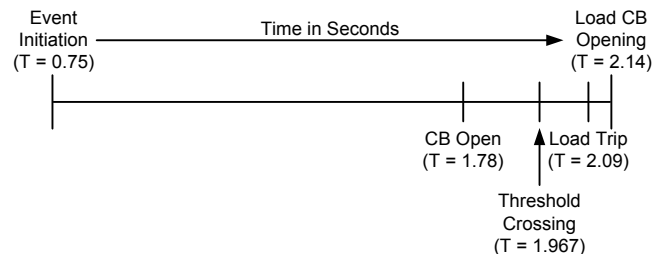


Fig. 14. Case 2 timing chart

The DACA1 logic operated, and the RAS action shed load according to user selections on the load status screen in the RAS HMI (see Fig. 15).



Fig. 15. Software plot for angle difference

IX. FIELD TEST AND FIELD EVENT ANALYSIS

A. Field Test

A field test operation was carried out after validation of the system status. This served as the final test to demonstrate the system functionality, with the aim of measuring operating time.

The operation of the system for the real test was performed by means of manual opening the Ocoña-San José line on the San José substation side. The operation of the DACA3 logic was expected to operate the scheme with the RAS armed. In order to achieve RAS operation, lower thresholds than normal were used, which were provided by COES. These thresholds are as follows:

- Power arming (pickup) = 180 MW
- Power disarming (dropout) = 120 MW
- First pair angle difference = 30°
- Second pair angle difference = 30°

The load-shedding test was conducted controllably. Two loads were selected from the system HMI, and critical loads were manually blocked from the operation of the dual-redundant RAS systems.

The operation of the DACA3 is shown in the Fig. 16. The first section shows the angular difference between PMCU5 (Ocoña) and PMCU8 (San José). The second section shows the angular difference between PMCU2 (Chilca) and PMCU9 (Montalvo). The third section shows the digital inputs that were enabled in PMCU16 to receive signals from the LSCs. Input IN206 is a replica of the trip signal to the load selected, while IN207 is the breaker status of the same load.

In Fig. 16, the vertical yellow line corresponds to the time the threshold of 30° is exceeded between Chilca and Montalvo, which begins the RAS operating time. The vertical magenta line corresponds to the moment where the trip signal to the breaker is recorded. The gray box displays the operation time of the RAS, which is 102 ms. Considering that an intentional delay of 50 ms was used in the system to provide security, the operating time of the RAS was 52 ms.

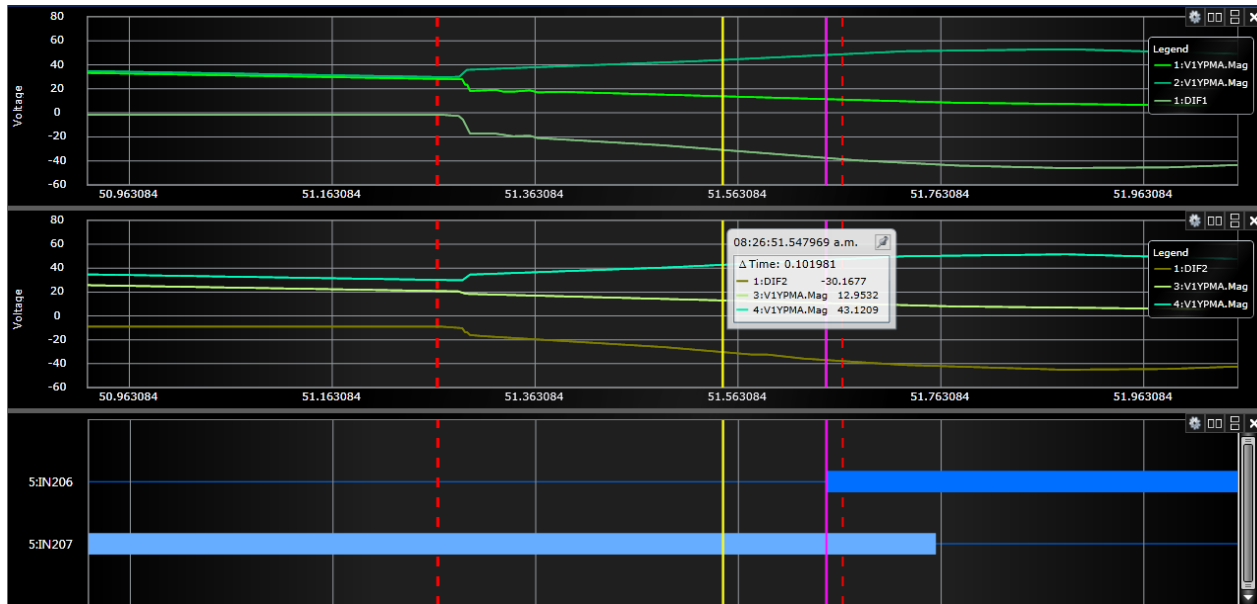


Fig. 16. Real test (operation time) showing operation of DACA3

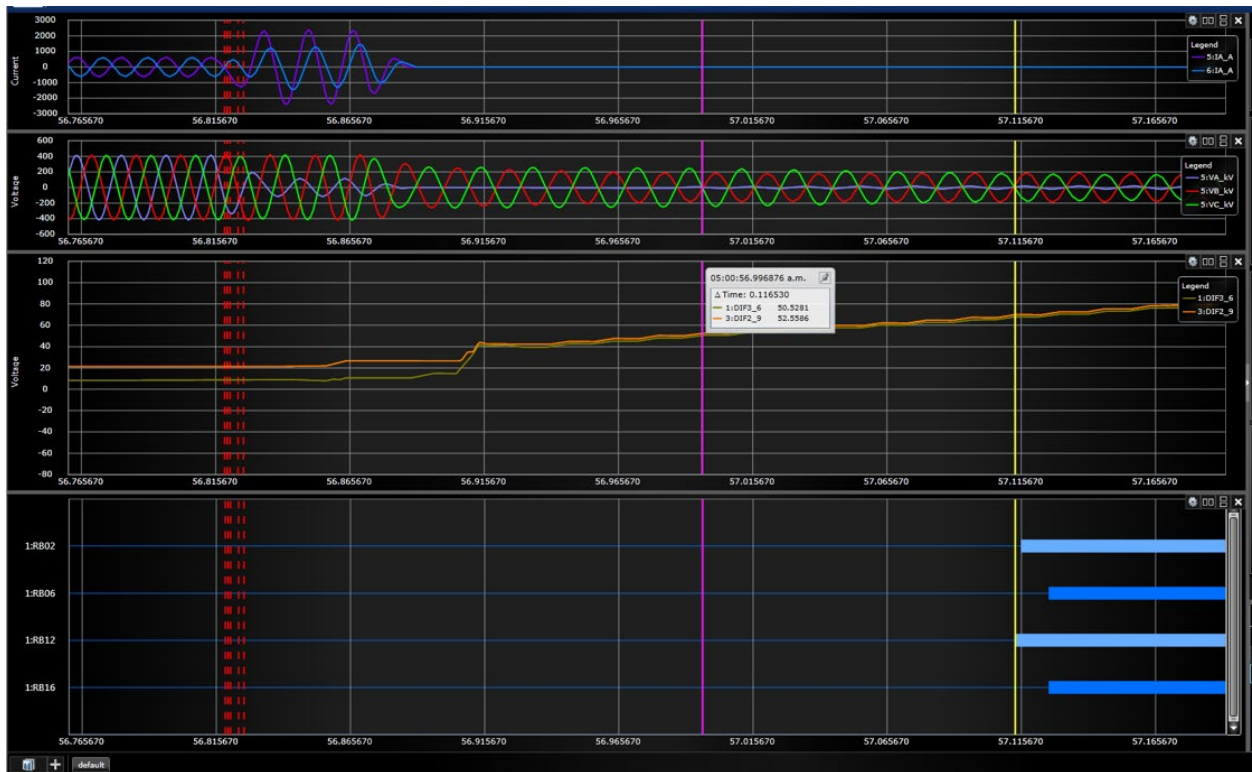


Fig. 17. Real event (operation time) showing operation of DACA2

B. Field Event Analysis

A three-pole opening event of the Poroma-Ocoña line occurred on February 22, 2016, at 5:00:56 a.m. Records of PMCU equipment at both ends of the line provided by Cerro Verde were used to analyze the event.

Fig. 17 shows the operation of the DACA2 logic. The first section shows current into Poroma-Ocoña at both ends of the line (i.e., measurements from PMCU4 [5:IA_A] and PMCU5 [6:IA_A]). The second section shows three-phase voltage at Poroma substation (i.e., measurements from PMCU5

[5:VA_kV, 5:VBA_kV, and 5:VC_kV]). The third section shows the angular difference between PMCU3 and PMCU6 (1:DIF3_6) and the angular difference between PMCU2 and PMCU9 (3:DIF2_9). The fourth section shows the trip binary elements related to the DACA2 logic into PMCU4. These elements are trips from the dual-redundant RAS systems (RB02 and RB12).

The time for the real event is measured from when the threshold of 50° for both pairs of angle differences is exceeded (magenta vertical line) and when the first trip signal indication is received from the PMCU in Poroma substation

(yellow vertical line). The gray box shows that the operation time of the RAS was 117 ms. Considering the intentional delay of 50 ms, the actual RAS operating time was 67 ms.

X. CONCLUSION

The Peruvian power system required a solution to maintain stability when transmission capacity was lost in the southern region. A RAS was implemented that uses synchrophasor measurements to monitor angle differences and make operation decisions to trip large loads.

The RAS was implemented with PMcus located in several locations on the 500 kV and 220 kV corridors. The PMcus send IEEE C37.118 synchrophasor streams to SVPs in two locations to implement predetermined decision logic. The contingency detection logic is based on angular differences and arming conditions to increase the security of the decision. The operation of the RAS logic requires the sending of trip signals to LSCs that open predetermined loads, mitigating the loss of transmission capacity.

The RAS was tested and validated using a real-time power system model. A staged field test was used to validate the installation of the system. A real field event is documented in this paper, illustrating the successful operation of the scheme.

The RAS scheme has operated successfully since the end of 2015.

XI. REFERENCES

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XII. BIOGRAPHIES

Yofre Jacome graduated as an electrical engineer from the Universidad Nacional de Ingeniería-Lima in Peru. Yofre has taken courses on power system protection in the United States, Germany, and Mexico. His main interests are power system protection and fault analysis. He works as a protective relaying engineer for the Comité de Operación Económica del Sistema Interconectado Nacional (COES), and he is responsible for relay settings in the Peruvian power system. He has experience with transmission, distribution, and generation relays.

Luis Figueroa graduated as a mechanical electrical engineer from the Universidad Nacional de San Agustín in Arequipa, Peru. He also obtained an M.B.A. at Centrum Graduate Business School in Lima, Peru. He is a power systems supervisor and the head of the load transmission control center for Freeport-McMoRan Inc.'s Cerro Verde operations in Arequipa, Peru. His responsibilities include coordination, analysis, and leadership of the high-voltage and extra-high-voltage transmission systems and distribution systems that supply electrical energy to the mining complex. He began his professional career with ETESUR as field engineer, where participated in the implementation of the first regional control center to manage and control the energy and power of southern Peru. He then worked for Red de Energía del Peru, an ISA Group company, performing operational analysis and coordinating substations.

Eduardo Palma received his Bachelors of Science in electrical engineering from the University of South Florida in Tampa, Florida in May 2003, and his Master of Business Administration with a concentration in globalization and international business in May 2012. Eduardo joined Schweitzer Engineering Laboratories, Inc. (SEL) in January 2003 and is the regional technical manager for the Latin America region. He has experience in international sales, applications, automation, integration, and the testing of digital protective relays and industrial-grade communications equipment. Eduardo conducts and provides international technical seminars, technical sales presentations, and training to introduce and implement SEL solutions and services worldwide.

Fernando Calero is a principal engineer in the Schweitzer Engineering Laboratories, Inc. (SEL) international organization. His responsibilities include application support for SEL products, training and technical support for SEL customers, and internal training and mentoring of SEL engineers. He started his professional career with the ABB relay division in Coral Springs, Florida, where he participated in product development and technical support for protective relays. He also worked for Florida Power & Light in the energy management system group and for the Siemens energy automation group. Since 2000, he has worked for SEL as an application engineer. He holds five patents and has written technical papers on protective relaying, remedial action schemes, and other protection and control applications.

Pedro Loza received his B.S.E.E. degree in 1998 from the National Autonomous University of Mexico (UNAM). He also obtained a M.Sc. degree in electrical power systems at UNAM. From 1998 to 1999, Pedro worked in the Electric Research Institute in Mexico. In September 2000, he joined Schweitzer Engineering Laboratories, Inc., where he worked as a protection design engineer and as a field application engineer in the Mexico City office. He is currently a protection engineer, working on protection electrical studies and special protection systems.

Alejandro Carbajal received his electronic engineer degree in 2008 from the Universidad Autónoma de San Luis Potosí (UASLP) in San Luis Potosí, Mexico. In August 2009, Alejandro joined Schweitzer Engineering Laboratories, Inc. (SEL) as a development engineer. After working in different areas of SEL, he specialized in automation and gained international experience working with various project architectures. In 2014, he joined the special protection schemes team in Mexico, working with remedial action scheme (RAS) projects. His specialty is programming different controller platforms for RAS automation.

Ashish Upreti is a protection engineer in the engineering services division at Schweitzer Engineering Laboratories, Inc. in Pullman, Washington. He received his Bachelors and Masters degree in electrical engineering from the University of Idaho. He is a registered professional engineer in the state of Washington and a member of the IEEE. He has experience in the field of power system protection and automation, including power management schemes for large-scale industrial power plants.

Case Study: Modern RAS Applied to Furnas 765 kV Transmission Corridor Improves Itaipu Power Plant and Brazilian Power System Stability

Paulo Max Maciel Portugal, Renato Weingartner Pernas,
Lucas Vernot Amaral, and Renata Ribeiro Silva, *Furnas Centrais Elétricas S.A.*
Ricardo Abboud, Rafael Cernev, and Marcos Cabral, *Schweitzer Engineering Laboratories, Inc.*

Abstract—Furnas, one of the largest generating and electrical transmission companies in Brazil, recently implemented an important remedial action scheme (RAS) to improve the reliability of the national interconnected power grid. A mission-critical RAS was deployed to replace an aging system for a 765 kV transmission corridor, which consists of 9 765 kV lines, 4 500 kV lines, 10 765/500 kV autotransformers, and 4 500/345 kV autotransformers.

The paper discusses the problems the RAS solves, the design criteria and challenges, the deployment of such a system, and the wide-area communications system configuration and test results to accomplish a fast and reliable tunnel for the IEC 61850 Generic Object-Oriented Substation Event (GOOSE) messages.

I. INTRODUCTION

A large interconnected system needs a set of coordinated control measures with high levels of complexity to plan and operate reliably and economically. Power systems have a stability limit, and the desired operating conditions may require special protective systems, known as remedial action schemes (RASs), to operate the system in a secure manner. Thus, RASs are essential to maintain the safety and integrity of the electrical system when it is subjected to phenomena that cause instability or cascade shutdowns.

RASs are applied to protect the electrical system against events that have a low probability of occurring but a high impact on stability when they do, such as multiple trips of transmission lines or loss of critical busbars or entire substations.

There is no doubt that the use of RASs plays a significant role in interconnected systems, serving to [1] [2]:

- Improve the operation of power systems by increasing safety margins, providing greater flexibility, and removing or minimizing operating restrictions.
- Operate power systems safely close to limits.
- Increase power and energy transfer limits while maintaining a level of safety.
- Find a temporary solution to compensate for delays in the construction program of works (operation outside the transfer limits) or situations of equipment shutdown.
- Increase the security of the system, particularly in regard to extreme or multiple contingencies that can lead the system to collapse.

RAS schemes can provide different types of remedial control actions, based on the problems created when major disturbances occur. Some schemes trip generator units, intentionally open transmission lines, perform load shedding in multiple locations, apply dynamic braking, rapidly change power transmitted through high-voltage direct current (HVDC) links, and create islanded systems at predetermined locations through controlled system separation. RAS schemes have common characteristics [1] [2]:

- They are dynamic security control systems designed to control power system stability in cases where an uncontrolled response is likely to be more damaging than a controlled response.
- They require offline power system studies and simulations to qualify and quantify contingencies and their impacts on power system stability and identify which actions are required to remediate their effects in the power system.
- They are armed for certain operating system conditions, for instance, when the power flow in a given transmission corridor is greater than a specified threshold.
- They provide one or more types of remedial actions that are designed to alleviate a certain observed system condition or take a predetermined action when a certain event or a combination of events occur whose resulting effects are deemed too serious to ignore.

In the Brazilian system, the RAS associated with the 765 kV transmission corridor from the Itaipu Power Plant (Itaipu) plays a key role in keeping the stability of the National Interconnected Power Grid (NIPG). The 765 kV transmission corridor can carry a high-power flow, up to approximately 6,600 MW. Thus, any contingency involving this transmission corridor presents great risks to the stability of the NIPG. So, a reliable and efficient RAS is required to maximize the electrical energy production at Itaipu and quickly react to contingencies that could jeopardize the overall reliability of the NIPG.

II. BACKGROUND

Furnas, one of the largest generating and electrical transmission companies in Brazil, recently implemented an important RAS to improve the reliability of the NIPG. A mission-critical RAS is deployed to replace an aging system for

the 765 kV transmission corridor that connects the 60 Hz section of Itaipu to the Southern and Southeastern Electrical Transmission Systems.

Itaipu is a binational (Brazil and Paraguay) hydroelectric power plant with 20 generating units (GUs), 10 of which are operating at 60 Hz (connected directly to Brazil) and 10 at 50 Hz (connected to Paraguay), totaling 14,000 MW. From its 10 GUs, Paraguay only needs 3 GUs to supply loads nationally; the remaining generated energy, produced by 7 GUs, is transmitted to Brazil by bipolar 600 kV Furnas HVDC lines. Itaipu provides about 10.8 percent of the energy consumed in Brazil and 88.5 percent of the energy consumed in Paraguay. The Brazilian part of the energy produced in Itaipu is carried out over a 1,000 km ac transmission corridor, which consists of 9 765 kV circuits, 7 500 kV lines, 11 765/500 kV transformers, and 4 500/345 kV transformers. This system is known as the 765 kV system. Figure 1 shows the single-line diagram of the 765 kV transmission system and its components.

A contingency in this transmission system, depending on its operating states (like power flow values or line-out quantities), can lead to serious consequences for the NIPG. In extreme cases, it leads to system blackouts. To avoid such drastic situations, the new 765 kV RAS was designed considering reliability, speed, and selectivity as the utmost requirements. The RAS also allows the National System Operator (NSO) to operate the Brazilian NIPG with more reliability and optimization of water resources for all existing hydroelectric power plants. The main purpose of the RAS is to avoid, under certain operating conditions, the following situations in case of

contingencies on autotransformers or lines from the 765 kV transmission corridor:

- Loss of synchronism between the Itaipu 60 Hz sector and the southern and southeastern power systems, see Fig. 1, leading to instability in the NIPG.
- Self-excitation in Itaipu 60 Hz GUs.
- Overvoltage of 765 kV and 500 kV systems.
- Overload of 765/500 kV and 765/345 kV autotransformers.
- Overload of 765 kV and 500 kV lines.
- Overfrequency with the consequent shutdown of thermal plants in the southern region.
- Voltage collapse in the 765 kV system.

The first RAS started operation with the second 765 kV circuit in 1989, maximizing the transmission of generated energy by the Itaipu 60 Hz sector. The RAS originally operated with auxiliary relays and control switches located at different points in the transmission system. The states of the control switches were changed by the operators according to operating conditions and the configuration of the transmission system at the time. Failures in the selection of proper position of these control switches led to numerous misoperations of the RAS during contingencies. Since the first version of the RAS proved not to be reliable, a second version of the RAS, based on programmable logic controllers (PLCs), was deployed in the second half of 1995, and it has performed satisfactorily for over 20 years.

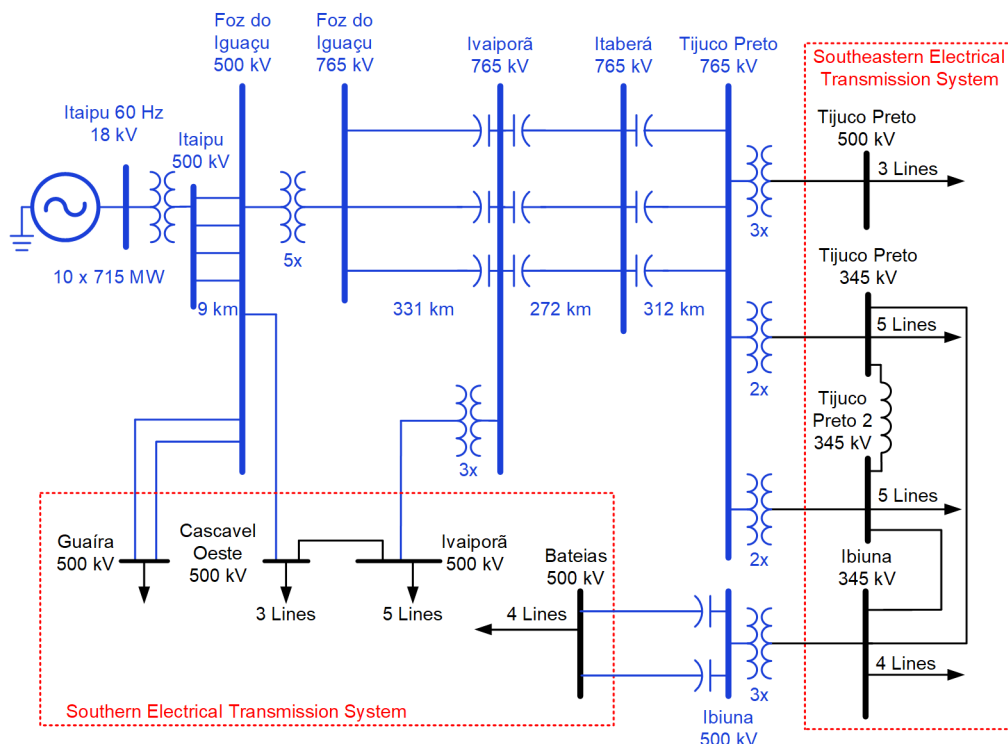


Fig. 1. Single-line diagram of the 765 kV transmission corridor. The system components covered by the 765 kV RAS are outside the dotted, red borders.

In 2011, the 500 kV Foz do Iguaçu—Cascavel do Oeste transmission line was commissioned and energized. This transmission line is composed of a 115 km single circuit and has created a connection between the Itaipu 60 Hz sector and the southern system, see Fig. 1. The connection of this transmission line has allowed the full transmission of Itaipu 60 Hz generation, making it necessary to reevaluate the logic and references of the second-version RAS.

Considering the need to maximize the energy exchange between the subsystems, the PLCs obsolescence of the second version of the RAS, the impossibility of the second version of the RAS hardware to meet the new implementation demands, and the expected transmission system expansion, it was decided to carry out a technological update of the RAS and the consequent reevaluation of the logic and their references. This third version of the RAS will be called the 765 kV RAS for the rest of this technical paper.

The 765 kV RAS covers the generation and transmission assets in blue (outside of the red, dotted borders) in Fig. 1. For each of these substations, new devices were installed to monitor circuit-breaker and disconnecter statuses, load flow in the lines and transformers, and status of the series compensation, etc., and then send the data to the redundant controllers in Itaipu, as discussed in the next sections.

Most of the logic of the 765 kV RAS operates by shutting down a certain number of GUs at Itaipu for contingencies occurring in the power system, based on the precontingency power flow in the transmission lines.

Considering the total distance of the 765 kV transmission system from the Tijuco Preto substation to Itaipu and the number of substations, transmission line circuits, autotransformers, series capacitors, and generators in the system, the design, implementation, and operation of this protection system is a great challenge to all engineers involved in this project. These characteristics make this project a unique implementation. Furthermore, for the correct operation as designed and acceptable reliability in day-to-day operations, the implementation of a large communications infrastructure, system redundancy, and optimized configuration of communication channels are necessary. Added to that, the

765 kV RAS has a large amount of data that are exchanged among different components of the system.

III. 765 kV RAS REQUIREMENTS

For the new 765 kV RAS, the NSO performed a comprehensive power system stability study and prepared a report describing the contingencies and remedial actions required to ensure secure operation of the power system. The same report defined the performance and redundancy requirements for the RAS. The total response time requirement for the scheme is 200 milliseconds, from the inception of the contingency until the circuit breaker opens.

The 765 kV RAS is based on data acquisition and control units (DACUs) installed at the four substations of the 765 kV transmission system, Foz do Iguaçu, Ivaiporã, Itaberá, and Tijuco Preto at Itaipu, and the Ibiuna 500 kV substation. The local DACU is responsible for acquiring the substation binary data—such as the status of transmission line shunt reactors (open or closed), series capacitor banks, circuit breakers, and disconnecting switches—acquiring the analog data—such as the magnitudes of voltages, currents, active power, and reactive powers—and checking the consistency of the acquired data. Each local DACU sends all these data to the master controllers (MCs), physically located at Itaipu, through the IEC 61850 Generic Object-Oriented Substation Event (GOOSE) communication protocol. The MC receives these data and runs the RAS algorithm and, depending on the contingency and the system state at the moment, sends command signals to Itaipu with the number of GUs to be shut down, or the power generation reduction at Itaipu, or the lines to be tripped at the 500 kV or 345 kV busbars at Tijuco Preto substation.

The RAS topology is totally redundant with Systems A and B working in a dual principle. Each substation has at least two DACUs, which send the data to the two MCs through communication tunnels configured in redundant, multiplexed communication systems. One of them is based on a multiplexed fiber synchronous digital hierarchy (SDH) and the other on a microwave radio system, which provides redundant and independent communication links to Systems A and B. See Fig. 2.

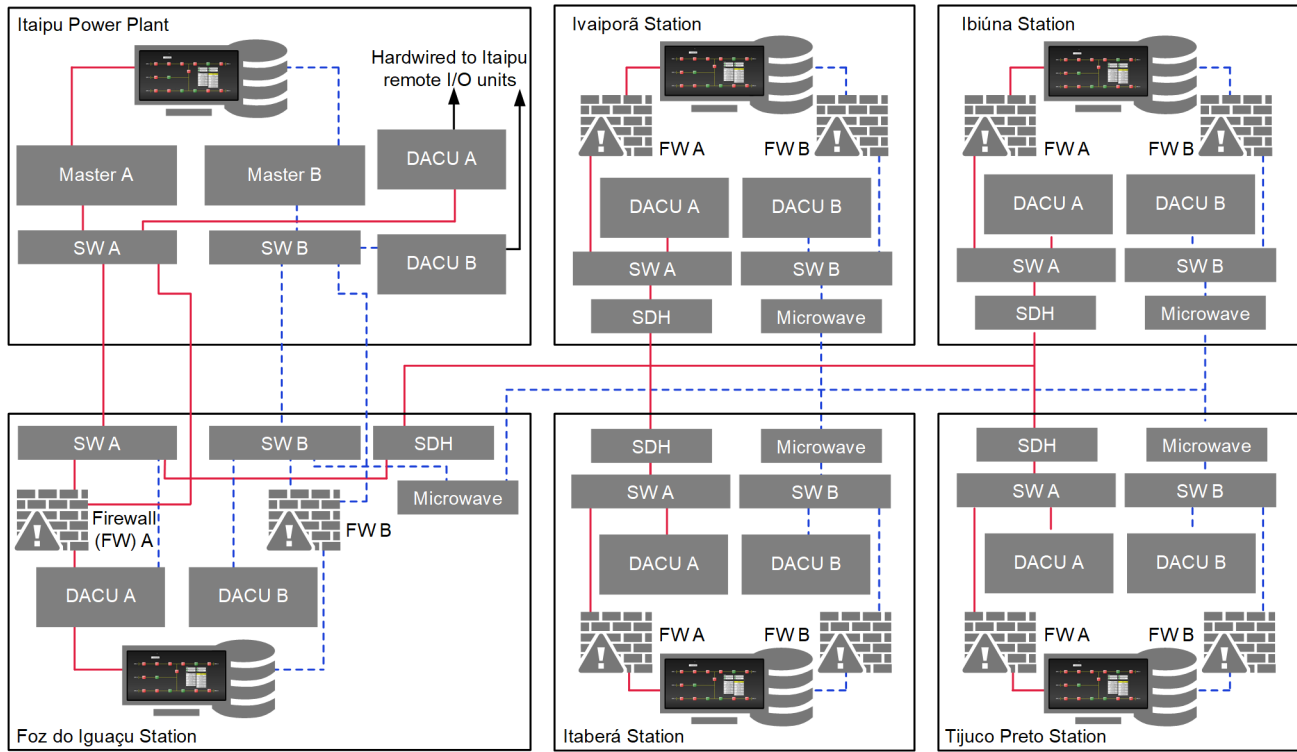


Fig. 2. Simplified network architecture. Solid, red lines are System A communications and dotted, blue lines are System B communications.

IV. 765 kV RAS ALGORITHM

In each substation, the DACUs collect the following information: the statuses of circuit breakers and disconnectors and the quantities of current and voltage in the transmission lines. Additionally, the actions on the electrical system are performed through the digital outputs of the DACUs. In addition to acquiring data, the DACUs locally process the logic for data consolidation, such as the consistency of circuit breakers and disconnectors, as well as analog quantities. This consolidation is important to validate the data and guarantee the correct operation of the system. In case of inconsistencies, the logics perform the appropriate actions to block the operation and inform the operator.

In the following items, the algorithms of the implemented logic are presented, from the consolidation of measurements, through the detection of contingencies and selection of the remedial action, to the operation of the special protection system.

A. Power Flow Measurements

The measurements of the analog quantities, currents, and voltages for the calculations of the system power flow are taken in duplicate, that is, in two different substations, and a selection logic is implemented to decide which value should be used in the RAS logic. This selection logic considers local DACU alarms, voltage transformer failure supervision, circuit-breaker alarms, and the ratio between zero-sequence and positive-sequence quantities to detect failures in the current transformers. Therefore, the power measurement switches from one terminal to another in the event of any failure detected for the terminal currently being measured, as shown in Fig. 3, generating an alarm to the supervisory control and data acquisition (SCADA) system. In Fig. 3, the terms GIPU and FSE are the active power flows between the Itaipu 500 kV bus and Foz do Iguaçu 500 kV bus and the Ivaiporã 765 kV bus and Itaberá 765 kV bus, respectively, and are used to arm some of the RAS logic.

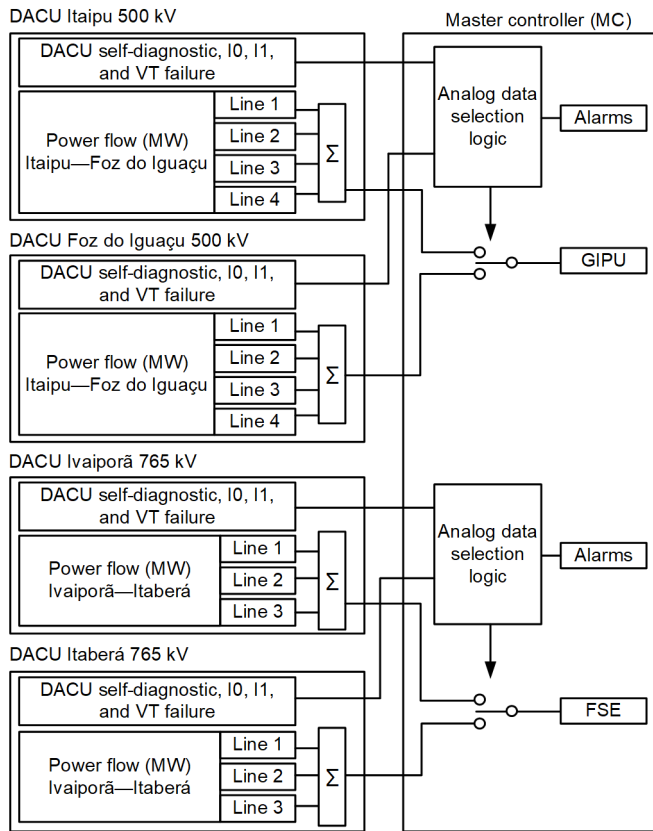


Fig. 3. Analog data selection for the arming logic.

B. Contingency Detection

The main possible contingencies for the system are:

- Line opening
- Transformer overload
- Line overload

In cases of an overload, the local DACU identifies a magnitude above the nominal value for a certain period of time and sends a signal to the MC to command the reduction of generation before the transformer or the line overload protection trips, thus avoiding the unavailability of the equipment.

The open-line detection logic, shown in Fig. 4, adopts an approach more focused on dependability, trying to ensure the operation of the RAS to preserve the system; this logic does not use the current or voltage measurement, for example, and does not wait for confirmation from the remote terminal. The equipment's open and closed signals are verified to check their consistency; however, the simple opening of a terminal triggers the contingency. Another characteristic determined by the implementation report is that the inconsistency of the open or closed position must declare the equipment as open. However, series capacitor banks must be considered out of service in case of failure in the indication of the status of their circuit breakers or disconnecting switches.

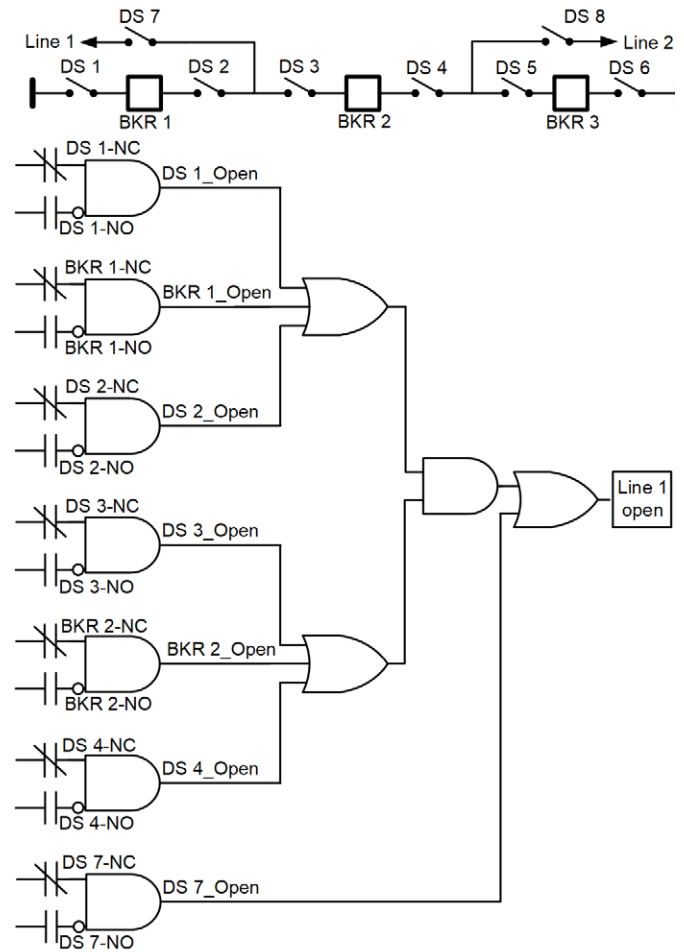


Fig. 4. Open-line detection logic.

In addition to detecting a single contingency, just one line tripped, for instance, the RAS algorithm has provision to respond properly to multiple contingencies, two or three lines tripped close in time, for instance. For multiple contingencies detection, a 5-second window is opened from the first contingency trigger, and the power flow values are frozen for calculating the reduction of generation. Any new event occurring in the 5-second window is added to the previous event, and multiple contingencies are considered by the logic. Any event occurring out of the 5-second window is considered a new single contingency event. If any event occurs that leads to a multiple loss of circuits in different sections, the number of Itaipu GUs to be shutdown must be decided by the logic that commands the largest cut, limiting the total cut to a maximum of four GUs. This approach aims to avoid the risk of self-excitation in the GUs at Itaipu, which can be caused by the large reactive power produced in the transmission corridor when operated in a degraded state [3].

After identifying a contingency, the 765 kV RAS algorithm sends a required command from the MCs to the DACUs to accomplish the proper remedial action to preserve system stability. The DACUs, in turn, physically act on the power system through their digital output contacts. If the required remedial action leads to the opening of a transmission line or the shutdown of a transformer, the outputs directly command the opening of the circuit breaker associated with that primary equipment. In the case of actions that lead to a reduction in generation, the commands of the DACUs are directed to Itaipu. These remedial actions, directed to Itaipu, take into account a special logic based on a rotating-priority queue, developed to select the GUs to be shut down in an optimized way and avoid

tripping more GUs than required. This logic is described in a later section.

C. Examples of RAS Logic

This section describes some examples of the remedial actions logic that are triggered due to contingencies in the 765 kV system. Figure 5 shows the logic of detecting line-open contingencies between the substations Foz do Iguaçu 765 kV and Ivaiporã (FI-IV). The logic detects how many circuits are open and declares single, double, or triple contingencies in the FI-IV section. The line-open condition is detected in each terminal by the DACUs and sent to the MCs, which defines the number of contingencies, as shown in Fig. 5.

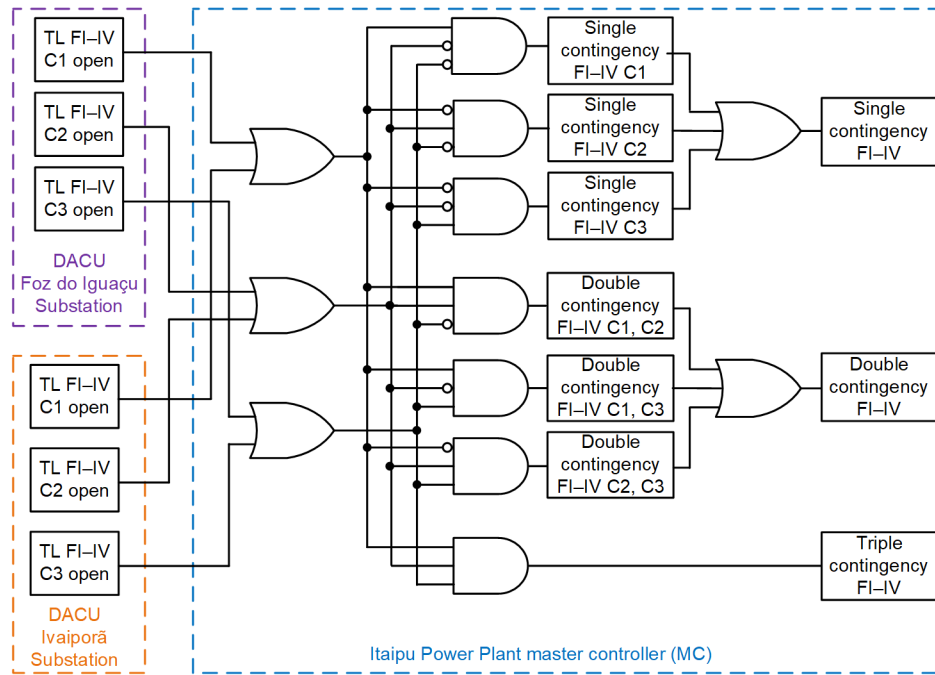


Fig. 5. Logic to detect the number of contingencies between the Foz do Iguaçu and Ivaiporã substations (FI-IV).

Figure 6 shows an example of remedial actions that must be taken to preserve power system security. Based on the pre-event power flow (GIPU) between the Itaipu 500kV and Foz do Iguaçu 500 kV buses and the number of contingencies detected for the section between substations Foz do Iguaçu and Ivaiporã, a certain number of GUs must be shed at Itaipu. Figure 6 shows an example of a double contingency, i.e., two lines between substations Foz do Iguaçu and Ivaiporã tripped.

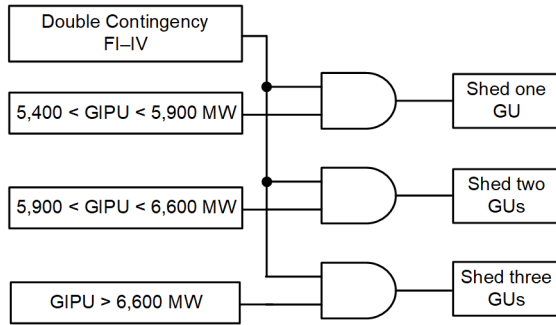


Fig. 6. Remedial action logic for a double contingency between the Foz do Iguaçu and Ivaiporã (FI-IV) substations.

Figure 7 shows another example of remedial actions to avoid tripping the 765/500 kV autotransformers at the Tijuco Preto substation due to an overload condition. The DACUs monitor the load in each of the three autotransformers and send a signal to the MCs if the load is greater than 150 percent of the rated autotransformer capacity. In the case of an overload, the MCs send a command to trip a 500 kV transmission line connected to the Tijuco Preto substation. If the autotransformer overload persists, commands to shed GUs at Itaipu in intervals of six seconds are sent, as shown in Fig. 7.

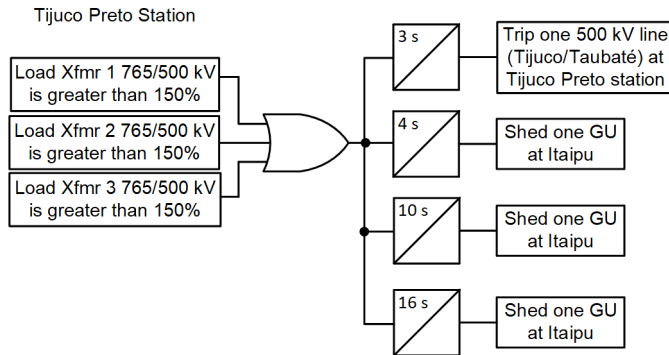


Fig. 7. Remedial action logic for an overload contingency on the 765/500 kV autotransformers at Tijuco Preto substation.

D. Rotating-Priority Queue

The RAS 765 kV logic defines the number of GUs to be shed but does not define which GUs to be tripped. Itaipu has defined a logic to rotate the GUs in a rotating-priority queue to optimize the maintenance schedule of the machines and avoid overshedding.

The shed queue must be formed so that the GUs that have been operating for the longest time occupy the first positions in the queue for shutdown. When a GU is shut down, it is removed from the queue, and when one is synchronized, it is added to the end of the queue, forming a rotation of the GUs, as shown in Fig. 8.

The Itaipu SCADA system includes a logic switch for each GU that allows it to be intentionally placed at the end of the rotating-priority queue, the middle, blue box (“GUs out of the rotation queue”) in Fig. 8, thus inhibiting its participation in the rotation of the GUs.

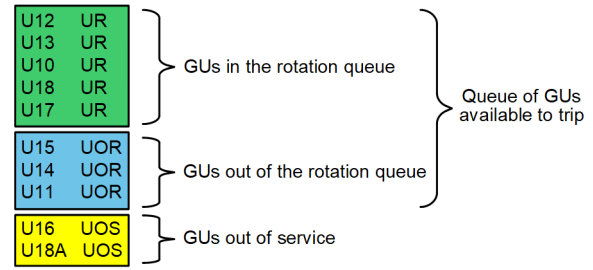


Fig. 8. Example of a generator rotating-priority queue.

Due to the breaker-and-a-half arrangement for the 500 kV 60 Hz busbar at Itaipu, see Fig. 9, the queue logic must also take into account the state of the circuit breakers associated with the GUs. If the bus circuit breaker of a GU is open and the two GUs of the span are synchronized, the GU that shares the span must be allocated to the end of the shutdown queue, to occupy a later position in the queue with respect to the GU that has the circuit breaker open and to avoid shutting down two GUs when only one needs to be turned off.

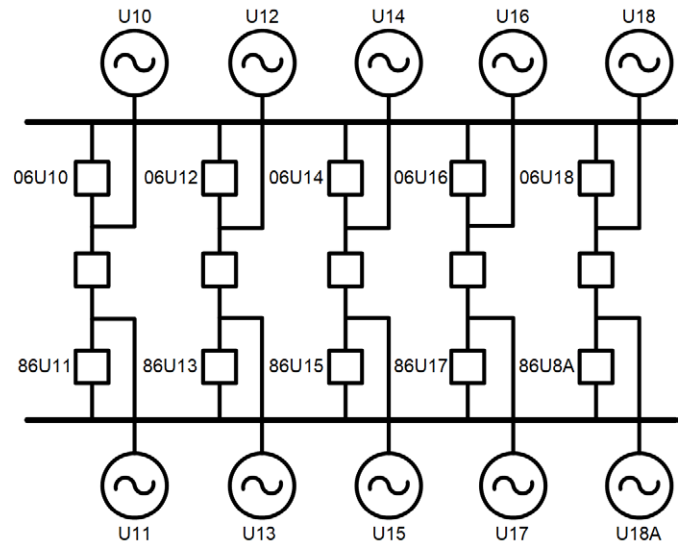


Fig. 9. Busbar and circuit-breaker configuration in the 60 Hz section of Itaipu.

Figure 10 exemplifies how the GU shedding queue is dynamically formed. Refer to Fig. 9 for the GUs and circuit breakers identification. For instance, if Circuit Breaker 06U14 is open for any reason, Generators U14 and U15 are connected to the same bus through a single breaker (86U15), so shedding Generator U15 will also shed U14. For this reason, U15 is put in the last place in the rotation queue. Now suppose Circuit Breaker 06U10 is open. With this configuration, Generators U10 and U11 are connected to the same bus through a single circuit breaker. As Generator U10 is out of the rotation queue for a given reason, Generator U11 is also pulled out from the rotation queue because tripping U11 will also trip U10.

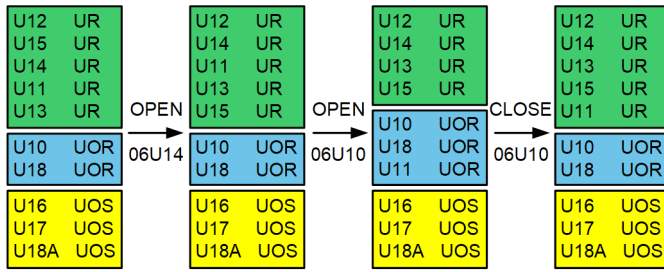


Fig. 10. Example of the logic sequence for the rotating-priority queue.

V. NETWORK ARCHITECTURE

The data acquired and consolidated by DACUs are sent to the MCs via the IEC 61850 GOOSE protocol. This protocol was chosen mainly due to the speed required for sending and updating information to guarantee the shortest possible total operating time of the RAS system. If a contingency occurs, the MCs process the logic then send the remedial action commands to the DACUs through the same IEC 61850 GOOSE protocol. Finally, actions on the equipment are performed through the DACUs output contacts.

The communications between the DACUs, local human-machine interface (HMI), and remote SCADA are carried out via the IEC 61850 Manufacturing Message Specification (MMS) protocol. Through the HMI, it is possible to visualize the local data processed by DACUs as well as information about diagnosis, alarms, or faults. Likewise, the MCs also make the data available for the SCADA systems of Furnas and Itaipu. The HMIs play an important role in monitoring and supervising the 765 kV RAS system. This system also represents a major advance compared to those previously implemented, allowing more visibility, better diagnosis, and more comprehensive controls for the operation of the RAS.

A. Physical Topology

The communications interconnection between the substations involved in the 765 KV transmission lines is made through two routes, see Fig. 11. The main route is composed of fiber-optic links in the optical ground wire (OPGW) cable of the transmission lines, while the secondary route is composed of microwave radio links.

The fiber-optic route is about 967 kilometers long and involves five substations and three repeaters, which are responsible for signal regeneration due to the large distances involved. Its data transmission capacity is STM-16, 2.5 gigabits per second (Gbps), which is sufficient for data transmission in corporate, operational, and telephony networks.

The microwave radio route, in turn, involves 15 repeaters for signal regeneration and has a capacity of STM-1, 155 megabits per second (Mbps), which is sufficient for redundancy of critical channels of operational and telephony networks.

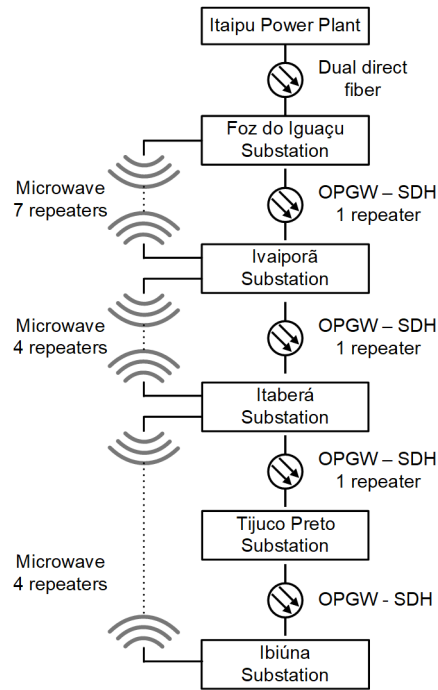


Fig. 11. Multiplexed fiber (SDH) and microwave radio communication systems.

Services are multiplexed into deterministic channels and different hierarchies according to traffic volume and criticality. For the 765 kV RAS traffic, exclusive 2 Mbps (E1) pipes between the Foz do Iguaçu substation and the other substations were created in the multiplex equipment of the fiber-optic and radio systems. These pipes are completely separate from operational and corporate traffic. To determine the bandwidth of the pipes, a detailed study was carried out to certify that the size of the messages would not exceed the transmission capacity of the channels.

B. Logical Topology

The data transport systems involved in the 765 kV RAS communications are interconnected to redundant switches in the substations, which are exclusive to the special protection system. These switches are connected to DACUs, the local HMI, and the remote SCADA system. An important aspect of such a major project is the optimization and reliable use of communications systems. In other words, it is important to avoid saturation in communications channels during the occurrence of an event, especially due to the repeatability (burst) in sending GOOSE messages when an event occurs. For this purpose, virtual local-area networks (VLANs) are used to segregate message traffic only for devices that should receive such information. Therefore, 20 different VLANs are configured on the switches, allowing the correct segmentation of GOOSE and MMS traffic. In this way, it is possible to guarantee that there is no interference in the traffic between the two protocols, allowing only the transport of GOOSE packets between substations. Additionally, the use of VLANs is necessary to limit the broadcasting of GOOSE messages.

As said, for transporting the GOOSE messages, each DACU transmits to the MCs using a distinct and unique VLAN. In the Foz do Iguaçu substation, all GOOSE communications from other substations end in a specific transport Ethernet switch with high-capacity packet routing.

For the transport between the Foz do Iguaçu substation and Itaipu, two pairs of dedicated fiber optics are made available. The first pair allows redundant GOOSE communications from the substations, which are multiplexed in the transport Ethernet switch to the Master unit. The second pair of fiber optics also allows redundant MMS communications between the devices installed at Itaipu and the Furnas SCADA system. In this way, the total separation between GOOSE and MMS messages is maintained.

C. Network Cybersecurity

At this point, it is important to emphasize that the 765 kV RAS is implemented in two different companies, Furnas and Itaipu. Naturally, both companies value the security of their information.

Additionally, four DACUs belonging to Furnas are installed in Itaipu. Therefore, it is necessary to adopt network cybersecurity policies for both companies. It is known that firewalls may add undesired latency to the traffic; thus, it is not possible to apply them in the network topology that involves the traffic of GOOSE messages.

Therefore, it is necessary to consider all GOOSE communications as unreliable traffic and introduce firewalls in all Furnas sites between switches and the SCADA system, as shown in Fig. 2. This allows the proper security practices to be adopted without causing an increase in latency to GOOSE packets.

Another possible solution would be the use of software-defined networking (SDN) technology, which, in addition to ensuring security in the interconnection of the networks, also brings a gain to the RAS final operation time since there is no need for interconnection between the Itaipu and Furnas DACUs through physical input/output (I/O) (digital inputs and output contacts). Using SDN, the MCs can send a GOOSE message directly to the Itaipu DACU. The SDN switches make it possible to physically interconnect the networks of the two companies while maintaining complete logical separation. SDN switches are deny-by-default, ensuring that only the allowed GOOSE messages are able to travel between the two networks. SDN is a very suitable technology for RAS systems, especially when the RAS involves multiple power companies.

VI. MONITORING

The DACUs inform the local HMI and the remote SCADA system via the IEC 61850 MMS protocol of any abnormality that may occur, such as internal errors in the DACU hardware or software, status inconsistencies in circuit breakers and disconnecting switches, and failures of analog measurement. The MCs inform the same systems in which the logic operated, which contingencies occurred and which analog quantities are being measured or calculated, such as GIPU and FSE. See Fig. 3.

In addition to the supervisory points being reported to the supervisory system, DACUs have an internal Sequence of Events (SOE). To keep the events synchronized, the DACUs have their internal clock synchronized through a GPS satellite clock via Inter-Range Instrumentation Group time code B (IRIG-B). Besides SOE, a special function is also implemented to record oscillographs of the entire system in the occurrence of events. When a contingency triggers a remedial action logic, the MCs send GOOSE messages to all DACUs installed in the substations to trigger event recording, so that they generate synchronized oscillographs from local analog channels. These oscillographs can be analyzed to evaluate the behavior and response of the entire 765 kV RAS system; however, they also provide a complete view of the system under large disturbances, providing important data for postanalysis and decision making.

As the system is distributed, it is also important to monitor the entire communications system. Communication is essential for the reliable operation of the 765 kV RAS. For this purpose, real-time monitoring of any communication failure was implemented. In addition to monitoring, points of failure are also used in the logics for decision making; for example, a communication failure of the GOOSE links in a specific network causes the block of the failed system and any remedial action will be performed by the healthy system without any additional delay.

VII. SIMULATOR

The simulator is designed to allow the logic to be tested before being effectively implemented in the field. For this, a rack was assembled with replicas of the DACUs of each substation involved and a replica of the MC.

The DACUs from the simulator are identical to the units installed in the substations, except that they do not have analog and digital I/O modules. This is due to the fact that a data generation controller produces all analog and digital information and sends them to the DACUs via IEC 61850 MMS and GOOSE protocols for emulating the static scenarios. Figure 12 shows the simulator schematic diagram.

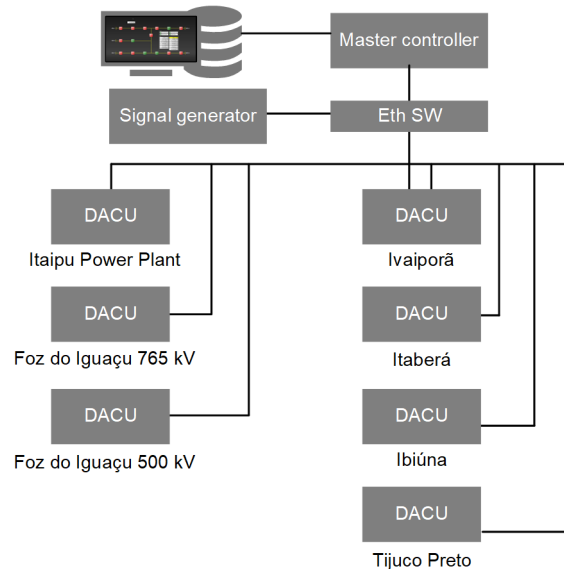


Fig. 12. A schematic diagram of the simulator.

The simulator has four static stages with configurable timing to switch from the current to the previous one, like in a state sequencer, which can be preprogrammed to simulate scenarios with multiple contingencies within a 5-second window. These stages are previously configured and then it is possible to run the simulation, verifying through the HMI system and the monitoring functions if the remedial action logic worked and performed as expected. Figure 13 shows the overall single-line diagram from the simulator HMI.

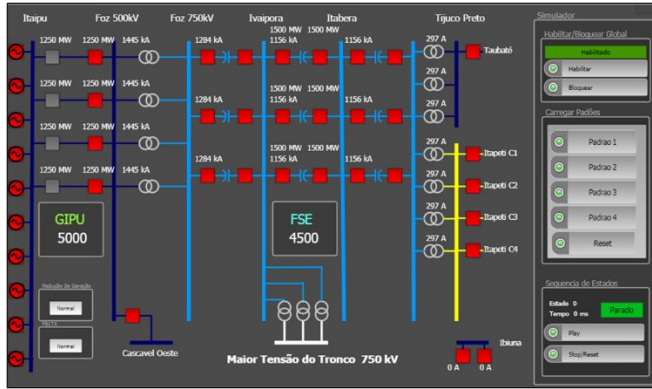


Fig. 13. HMI single-line diagram of the overall system.

This solution allows the remedial actions logic for all contingencies to be tested exhaustively during the factory acceptance test before the deployment and commissioning of the system. The simulator is also very important to test and validate any additions or changes to the logic after commissioning the 765 kV RAS.

Due to the static characteristic of the simulator, Furnas started a project to integrate the simulator with a real-time digital simulator (RTDS). This project aims to replace the previously mentioned data generation controller with an RTDS, which generates all analog and digital values and reports this information to the DACUs via IEC 61850 MMS and GOOSE protocols, see Fig. 14.

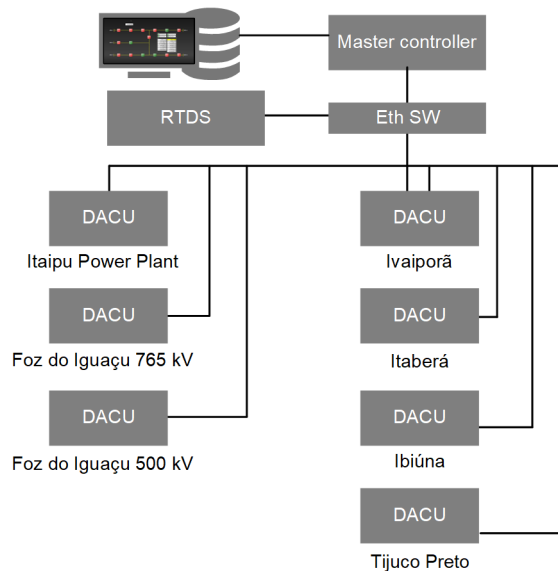


Fig. 14. A schematic diagram of the simulator integrated with an RTDS.

The most important difference of the simulator integrated with the RTDS is to allow analysis and configuration of all RAS logic in a hardware-in-the-loop simulation environment, allowing dynamic simulations and considerably increasing the capacity of the tests performed. Additionally, it is possible to simulate events out of the 765 kV transmission corridor to check the effects in the 765 kV RAS algorithm.

This project involves a real-time simulation of approximately 100 analog quantities and 370 digital quantities that are sent to the DACUs via MMS and GOOSE messages. The RTDS itself subscribes to the GOOSE messages generated by the MCs and checks if the remedial actions are correct.

VIII. FIELD TESTS AND COMMISSIONING

Tests are an extremely important phase for the implementation of such an RAS system. It is necessary to safely and reliably guarantee that the logic, actions, and performance of the system are within the required specifications. For this purpose, several tests were performed with specific methodologies and objectives to meet these requirements. Some of these tests are described in the following sections.

A. Initial Tests for Validation of Communications Network

At the beginning of the project, it was necessary to evaluate the transmission time of IEC 61850 GOOSE messages through the two communication systems, multiplexed fiber optics and microwave radio, for validating the possibility of the 765 kV RAS using such protocol to exchange high-speed data among substations. The Tijuco Preto substation was selected for this test, as it is the farthest substation, about 1,000 km from the Foz de Iguaçu Substation and Itaipu.

For these tests, a “ping-pong” approach was used. The received GOOSE messages from System A and B DACUs in Tijuco Preto were configured in loopback at the MCs in Foz do Iguaçu. That is, the DACU was configured to publish GOOSE messages and the MCs to subscribe to these messages and send them back to the DACU. See Fig. 15. For measuring the round-trip time of the messages, the SOE of the DACU was used. The total round-trip time was measured as the difference between the time of the transmission and the reception of messages. The one-way transmission time, which is the communication channel latency, is approximated as half of the measured time. The tests were performed with different traffic loading in the communication network.

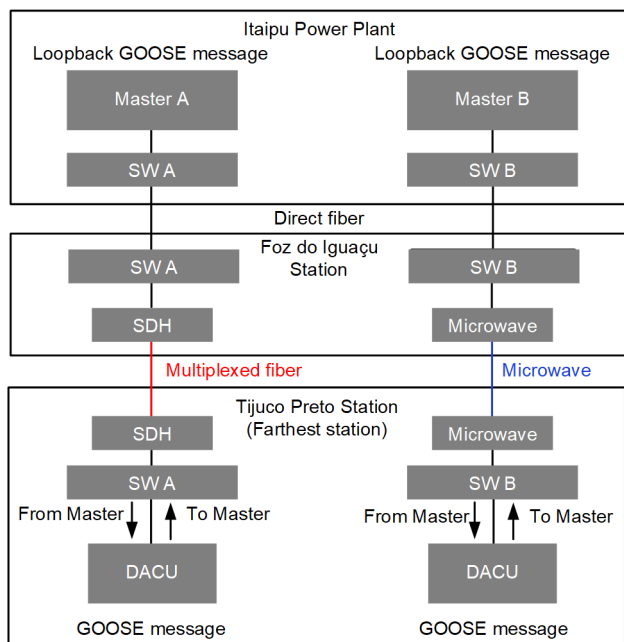


Fig. 15. Staged test to measure communication channel latency.

The results of the network performance tests are shown in Table I.

TABLE I
MEASURED ROUND-TRIP TIME FOR IEC 61850 GOOSE MESSAGES

Communications system	Round-trip time (ms)	Observations
Multiplexed fiber (SDH)	25	Minimum
	31	Average
	39	Maximum
Microwave	39	Minimum
	40	Average
	50	Maximum

For the tests, the GOOSE messages were carefully configured, based on the expected size for the project, to simulate the loading of the communication channels. The test results were satisfactory, indicating the possibility of continuing to use the IEC 61850 GOOSE protocol for exchanging information and sending remedial action commands.

B. Integrated Tests

After installing the DACUs at their respective substations and the MCs at Itaipu, an integrated test procedure was developed to validate the operation and performance of the new 765 kV RAS system. The staged tests had the purpose of validating the communications infrastructure and the integration of DACUs with the MCs in the real system, since the RAS algorithm had already been exhaustively tested through the simulator during the factory acceptance tests.

The procedure had a total of 51 tests: 49 simulated tests, e.g., forcing the line contingency in the DACUs via software, and 2 real tests, the actual opening of the line and command to open a GU at Itaipu.

The tests basically consist of contingency simulations, verification of the information traveling through the telecommunications network, validation of the correct performance of the logic in the MCs, and verification of the commands for shedding the GUs and transmission lines in the SCADA alarms and SOEs of the MCs and DACUs.

The two real, staged tests consisted of opening one of the 765 kV transmission lines between the Itaberá and Tijuco Preto substations. The expected remedial action is to open one GU at Itaipu, to evaluate the total response time of the RAS. This section of the 765 kV transmission corridor system was chosen since it is the farthest from Itaipu. The implementation team was interested to check the longest RAS response time, measured from the instant that the local DACU detects the contingency and the GU at Itaipu is tripped.

The two real, staged tests were performed three times for each RAS system, A and B. The total response time, which includes the circuit-breaker time, for each test is shown in Table II.

TABLE II
TOTAL RAS RESPONSE TIME

Communications system	Staged test (GU tripped)	*Total response time (ms)
Multiplexed fiber (SDH)	First test (GU 15)	111
	Second test (GU 15)	112
	Third test (GU 15)	98
Microwave	First test (GU 18A)	164**
	Second test (GU 14)	133
	Third test (GU 14)	135

*Total response time includes circuit-breaker time.

**The response time for this configuration was expected to be the longest of the tests because it is referred to the B chain and the UG 18A, which has a longer circuit-breaker opening time.

The total response time average, from the open-line detection in the Tijuco Preto substation to the opening of the circuit breaker in Itaipu, was 144 milliseconds for the microwave and 107 milliseconds for the fiber-optic communication systems. Both total response times and the performance of the system were considered excellent since the requirement was for the system to respond within 200 milliseconds. That is, the performance of the system was better than the required by the studies developed by the NSO.

IX. CONCLUSION

The 765 kV transmission corridor is very important for the Brazilian NIPG, because the RAS allows Itaipu to maximize energy production while maintaining the security of the NIPG.

Multicast IEC 61850 GOOSE messages, containing binary and analog data, together with message quality supervision, are considered an effective solution for the 765 KV RAS to receive information and to send remedial action commands and monitor the health and performance of the scheme. The communications network was tested and traffic-engineered to ensure proper operation of the RAS.

The 765 kV RAS was tested and validated using a static simulator and a real-time power system model. A staged field test was used to validate the installation of the system.

Including the open-line detection time, communications time, the circuit-breaker response times, and other communications delays, the RAS performed the remedial action of tripping GUs at Itaipu in less than the required 200 milliseconds from the actual contingency.

The project involved several stakeholders, so a close working relationship among all the engineers involved in the project was crucial for the execution and successful deployment of the 765 kV RAS project.

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XI. BIOGRAPHIES

Paulo Max Maciel Portugal received his BSEE degree in electrical engineering (emphasis on power systems) from Rio de Janeiro State University, Brazil, in 2002, and his master's degree (power systems) and doctoral degree (power electronics) from Federal University of Rio de Janeiro, in 2007 and 2015, respectively. In 2002, he joined Furnas as a transmission planning studies engineer. In 2003, he joined Eletrobras as a transmission planning studies engineer. In 2015, he joined Furnas again as an operation planning studies engineer. He has expertise in line-commutated converter (LCC) and voltage-sourced converter (VSC)-HVDC transmission systems, self-excitation of synchronous generators, electromechanical stability studies, and special protection systems for transmission systems and synchronous generators. He is a CIGRE Member of the SC B4 (HVDC and power electronics) and C2 (system operation and control).

Renato Weingartner Pernas is an electrical engineer graduated from Fluminense Federal University (UFF), Brazil, in 2009. He has an MBA in project management and information technology. He worked for ten years in production and development of the information system at Caixa Econômica Federal Bank. Since 2015, Renato has been with Furnas Centrais Elétricas, working in the areas of supervision and protection of electrical systems.

Lucas Vernot Amaral is a telecommunications engineer graduated from Fluminense Federal University (UFF), Brazil, in 2006. He has an MBA in digital transformation and another in private equity and venture capital. He worked for ten years in telecom operator companies. Since 2015, Lucas has been with Furnas Centrais Elétricas, working in the areas of telecommunications and automation of electrical power systems.

Renata Ribeiro Silva is an electrical engineer graduated from Federal University of Rio de Janeiro (UFRJ), Brazil, in 2008. In 2009, she joined the National Electric System Operator, Brazil (ONS, in Portuguese) participating in several activities including recomposition and stability studies. In 2011, she received her master's degree in electrical engineering from COPPE/UFRJ, working on PSS adjustment and commissioning of a system in an area which had been recently connected to the National Interconnected Power Grid. In 2013, Renata joined Furnas, performing activities related to power system regulation as well as operation studies.

Ricardo Abboud received his BSEE degree in electrical engineering from Federal University of Uberlândia, Brazil, in 1992. In 1993, he joined CPFL Energia as a protection engineer. In 2000, he joined Schweitzer Engineering Laboratories, Inc. (SEL) as a field application engineer in Brazil, assisting customers in substation protection and automation. In 2005, he became a field

engineering manager, and in 2014 he became an engineering services manager. In 2016, he transferred to SEL headquarters in Pullman as an international technical manager. In 2019 Ricardo joined SEL University as a professor. Currently he is a fellow engineer with SEL Engineering Services, Inc. (SEL ES). He is a senior member of IEEE.

Rafael Cernev received his BSEE degree in electrical engineering from Federal University of Paraná, Brazil, in 2005. In 2006, he joined Schneider Electric as an application engineer. In 2009, he joined Schweitzer Engineering Laboratories, Inc. (SEL) as an application engineer, assisting customers in electric power system automation. In 2015, he became an automation engineer coordinator. In 2019, he took the position as engineering and services manager for Brazil. Rafael also has taken two specialization courses, the first one in project management (2010) and the second in electric power automation (2013).

Marcos Cabral received his BS in electrical engineering from the State University of Campinas (UNICAMP) in 2008. He began working at General Electric as an automation engineer in 2008 and has been with Schweitzer Engineering Laboratories, Inc. (SEL) since 2010, when he was responsible for training and customer support, configuration, factory testing, and commissioning. Marcos has taken a specialization course in automation of electric power systems at the National Institute of Telecommunications (INATEL) in 2014. Marcos is presently the special protection system leader at SEL Brazil.

A Utility Transmission System RAS That Uses Systemwide Measurements to Detect Generation Loss

Abdulaziz Faisal A. A. Talfat, *KAHRAMAA*

Aaron Esparza, Jerin Monzi Mathew, Muthuraman Shanmugam, and Héctor J. Altuve Ferrer,
Schweitzer Engineering Laboratories, Inc.

Abstract—The Qatar General Electricity and Water Corporation utility (KAHRAMAA) imports power from multiple independent power producers (IPPs). The KAHRAMAA system connects via two 400 kV tie lines to the transmission network operated by the Gulf Cooperation Council Interconnection Authority (GCCIA) that interconnects the power systems of six GCC countries. Power system studies performed by GCCIA in 2020 and 2021 showed that the loss of generation in the KAHRAMAA power system caused tripping of both tie lines and separation of the KAHRAMAA power system from the GCCIA network. The authors describe the remedial action scheme (RAS) designed to detect generation loss and perform countrywide adaptive load shedding when required. In this project, we had no access to local generator measurements and breaker status information. We implemented a loss-of-generation detection logic based on wide-area measurements. We also describe the cybersecure communications network developed applying software-defined networking (SDN) technology. Finally, we report the results of the RAS factory acceptance testing using a hardware-in-the-loop environment based on real-time digital simulators.

I. INTRODUCTION

The Qatar General Electricity and Water Corporation utility (KAHRAMAA, referred to as “the utility” throughout) manages the country’s transmission and distribution system. It imports power from multiple independent power producers (IPPs). The country’s total power generation is 8,612 MW; seven IPPs generate 8,421 MW.

Qatar is a member of the Gulf Cooperation Council Interconnection Authority (GCCIA), which manages the transmission network that interconnects the power systems of six GCC countries, as shown in Fig. 1. The utility power system connects to the GCCIA network through two 400 kV tie lines (Tie Line 41 and Tie Line 42) at the interconnection substation. During normal operating scenarios, the total active power flow on Tie Line 41 and Tie Line 42 fluctuates in the ± 20 MW range.

The protection schemes of Tie Line 41 and Tie Line 42 include the following:

- An out-of-step tripping (OOST) scheme that trips the tie lines to separate the utility power system from the GCCIA system during unstable power swings.
- A thermal protection scheme that trips the tie lines for overload conditions.



Fig. 1. The GCCIA network interconnects the power systems of six GCC countries.

Power system studies performed by GCCIA in 2020 and 2021 showed that a sudden, large generation loss in the utility system caused unstable power swings in Tie Line 41 and Tie Line 42. As a result, the OOST scheme trips these lines. The loss of these tie lines may also cause tripping of tie lines that interconnect the power systems of other countries to the GCCIA network.

The authors performed additional power system studies. We found that the sudden loss of more than 1,800 MW of generation (more than 20 percent of maximum demand) in the utility system caused unstable power swings in Tie Line 41 and Tie Line 42. We also found that shedding load in less than 400 ms prevented these unstable oscillations.

The utility system had a wide-area underfrequency load-shedding scheme that provided frequency stability in case of generation loss. However, this scheme was too slow to prevent the OOST scheme from tripping Tie Line 41 and Tie Line 42. Therefore, GCCIA recommended implementing a countrywide remedial action scheme (RAS) in the utility system to prevent Tie Line 41 and Tie Line 42 from tripping on power swings or overloading conditions.

In this paper, the authors describe the RAS that was designed, tested, and commissioned to prevent undesired tie-line tripping. In this project, we had no access to local generator

measurements and breaker information, so we implemented a novel logic based on wide-area measurements.

One scheme (RAS 1) detects sudden, large generation loss and performs fast, adaptive load shedding to prevent the OOST scheme from tripping the tie lines. Another scheme (RAS 2) detects slow generation loss and performs adaptive load shedding to prevent tie-line thermal protection operation.

We also describe the cybersecure communications network with four rings developed by applying software-defined networking (SDN) technology.

Finally, we report the results of the RAS factory acceptance tests (FATs) using a hardware-in-the-loop environment based on real-time digital simulators (RTDSs).

II. RAS SYSTEM ARCHITECTURE

The RAS system covers 53 substations, including 10 substations receiving feeders from IPP stations (generation-receiving substations), 42 load substations (load-shedding substations), and the GCCIA interconnection substation.

Fig. 2 shows the RAS overall system architecture, which comprises redundant front-end processors (FEPs), redundant RAS controllers (RACs), redundant HMI gateways (GTWs), remote substation input/output (I/O) modules, SDN switches (not shown in the figure), a central computing platform, and an HMI.

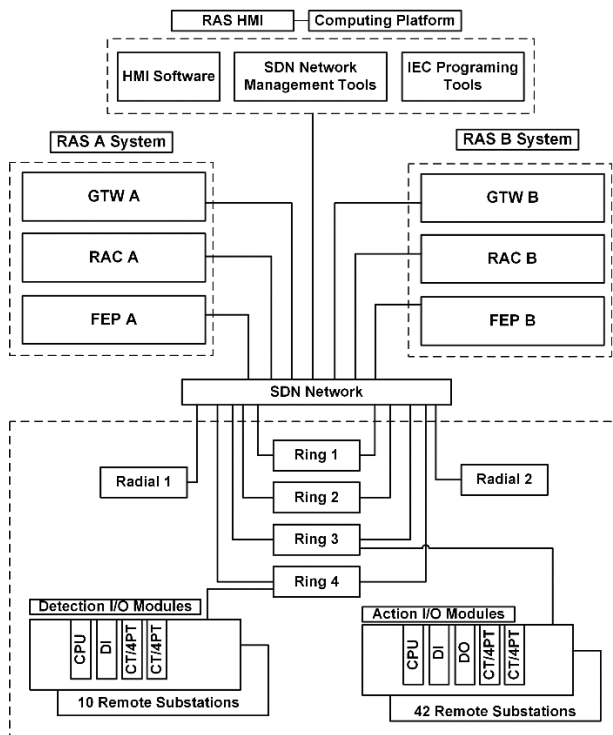


Fig. 2. RAS system architecture.

The RAS communications architecture is an SDN-based fiber-optic network that consists of four rings and two radial connections.

The remote substation I/O modules are placed in all 53 substations. These I/O modules are distributed among the four rings and the two radial connections. The I/O modules fall into two main categories:

- Detection I/O modules in the 10 generation-receiving substations.
- Action I/O modules in the 42 load-shedding substations.

Remote substation Detection I/O modules have digital input (DI) cards for monitoring breaker status and multiple current transformer (CT) and voltage transformer (VT) cards to obtain the necessary analog data from the CTs and VTs associated with the breakers monitored at each substation. Remote substation Action I/O modules have digital output (DO) cards for load shedding, in addition to DI, CT, and VT cards.

Remote substation I/O modules send analog and digital data using the Network Global Variable List (NGVL) protocol to the FEPs. The FEPs collect the data from the I/O modules, and then group, encapsulate, and segregate data based on speed. After segregation, the FEPs send the data to the RACs using the NGVL protocol for logic processing.

The RACs collect all the raw data from the FEPs and process them through a data conditioning filter to smooth out the continuously varying analog data and to identify breaker and metering alarms. After processing data, the RACs arm and execute the two main RAS algorithms described in Section III. The RACs perform logic calculations in subcycle processing intervals on the real-time measurements received from the field. Based on the load to shed values determined by the RAS algorithms and the load-shedding priorities set by the operator in the HMI, the RACs select loads to shed at every processing cycle. Then, the RACs send load-shedding commands to the FEPs, which in turn send these commands to the Action I/O Modules of the remote load-shedding substations.

The GTWs collect data from the RACs for HMI signaling. They also allow the HMI to send set points to the RACs.

The HMI performs comprehensive RAS monitoring. It provides detailed contingency summary screens for the two redundant systems. Other screens show load status, alarm status, network status, Sequence of Events (SOE), and event records.

The RAS has a dual-redundant architecture. Both RACs receive data, perform calculations, and independently initiate load-shedding actions. This approach is necessary because the inherent delay of traditional hot standby systems can exceed the permitted time budget, compromising system reliability. However, dual-primary redundancy poses a challenge: when a communications loss occurs, the two RACs may process different analog or digital values, leading to different calculation results and incorrect load shedding.

To address this, the RACs use a data quality index (DQI) to determine the RAC that will serve as a primary controller. Each RAC calculates the DQI based on the operational and communications status data for all field devices. The RACs assign different quality weights to the field devices based on the criticality of the information they provide. For instance, a FEP receives a higher weight than a general field device because of its potential impact on multiple devices. The resulting DQI is a weighted average of individual device DQI values.

The RAC with the highest DQI becomes the primary controller and replaces the output of the other controller. The

RACs dynamically determine this primary-secondary relationship in each processing cycle based on the comparison of the DQI values. By replacing the output of the secondary controller with that of the primary controller, only one set of load-shedding commands is transmitted to the FEPs, ensuring system consistency and preventing unintended operations.

III. RAS LOGIC DESIGN

We performed a contingency analysis of the utility power system using modern simulation tools under various operation conditions. We studied the effect on Tie Line 41 and Tie Line 42 of the sudden or slow loss of IPPs. We determined the IPP losses that would either cause an unstable power swing or an overload condition on the tie lines.

We found that fast load shedding avoids unstable power swings and prevents the OOST scheme from tripping the tie lines on this condition. Similarly, slower load shedding prevents tie-line overloading and avoids thermal tripping of these lines.

Based on these results, we designed a RAS logic that reliably identifies these contingencies for diverse operating conditions. Given the lack of access to local generator measurements and breaker information, the RAS logic uses other measurements. We designed the following RAS functions:

- RAS 1: Fast load shedding for sudden generation loss.
- RAS 2: Load shedding for slow generation loss.

A. RAS 1: Fast Load Shedding for Sudden Generation Loss

Our studies showed that the sudden loss of any of the four largest IPPs has the potential to cause an unstable power swing on Tie Line 41 and Tie Line 42. The capacity of each of these IPPs falls in the 1,800 to 2,650 MW range. Our studies also showed that shedding load in less than 400 ms avoids unstable power swings and prevents the OOST scheme from tripping the tie lines. The utility selected 300 ms as the target RAS minimum load-shedding time.

Fig. 3 shows the RAS 1 activation logic. This activation logic considers additional factors (not shown in the figure), such as HMI enable and disable commands, contingency reset commands, and timers, to provide security.

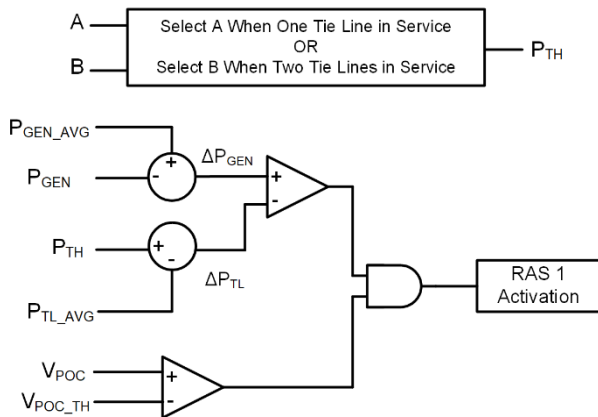


Fig. 3. RAS 1 activation logic.

The logic uses power measurements to detect unstable power swings in the tie lines and voltage measurements to prevent activation for faults.

- Unstable power swing detection: The RAS 1 activation logic compares the power generation loss in the utility power system with the change of power flowing through Tie Line 41 and Tie Line 42. For a sudden loss of any of the four largest IPPs, power generation drops fast and the tie-line power flow changes more slowly because of the large inertia of the GCCIA system.
- Security during faults: The RAS 1 activation logic compares the voltage measured at the generation-receiving substations with a threshold.

Fig. 3 shows the following variables and constants:

- P_{GEN} is the sum of the active power values measured on each in-service feeder line connecting the IPPs to the utility substations.
- P_{GEN_AVG} is the P_{GEN} average value. The controller calculates this value in each time step using a four-second data window.
- $\Delta P_{GEN} = P_{GEN_AVG} - P_{GEN}$.
- P_{TL_AVG} is the P_{TL} average value, where P_{TL} is the sum of the active power values measured on Tie Line 41 and Tie Line 42. The controller calculates this value in each time step using a four-second data window.
- $\Delta P_{TL} = P_{TH} - P_{TL_AVG}$.
- P_{TH} is an automatically selected tie-line power threshold value that depends on the lines in service. For one line in service, $P_{TH} = A$; for two lines in service, $P_{TH} = B$. A and B are user-defined settings.
- V_{POC} is the voltage measured at the point of common coupling of each IPP (the utility substation-side terminals of IPP-connecting lines). The controller compares V_{POC} with a threshold value V_{POC_TH} , which is a user-defined setting.

As shown in Fig. 3, the RAS 1 activation logic asserts when ΔP_{GEN} is greater than ΔP_{TL} and V_{POC} is greater than V_{POC_TH} .

Fig. 4 illustrates the RAS 1 process to calculate the amount of load to shed. The controller performs this calculation in parallel with the execution of the RAS 1 activation logic.

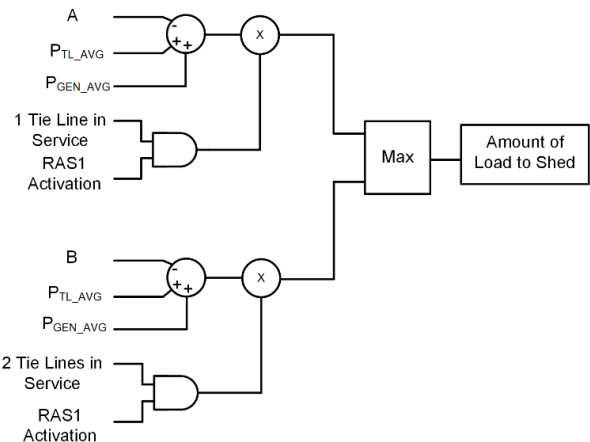


Fig. 4. RAS 1 calculation of load required to shed.

The RAS 1 logic calculates the sum of the average values of the IPP-generated power (P_{GEN_AVG}) and the tie-line transfer power (P_{TL_AVG}). When one tie line is in service, the logic subtracts the A power threshold value from the average value sum; when two tie lines are in service, the logic subtracts the B power threshold value from the average value sum. Then, the logic selects the maximum of the two values as the amount of load to shed.

B. RAS 2: Load Shedding for Slow Generation Loss

Our studies showed that certain slow or partial generation loss scenarios lead to an overload condition on Tie Line 41 and/or Tie Line 42 without causing an unstable power swing in these lines. The tie-line power transfer may reach the maximum power transfer limit (MPTL) set by GCCIA. In addition, the tie-line current may reach the line thermal limit and cause overload protection tripping. Our studies also showed that shedding load in the utility system prevents violating the tie-line MPTL and thermal limits and avoids overload protection tripping.

Fig. 5 shows the RAS 2 activation logic. This activation logic considers additional factors (not shown in the figure) to provide security.

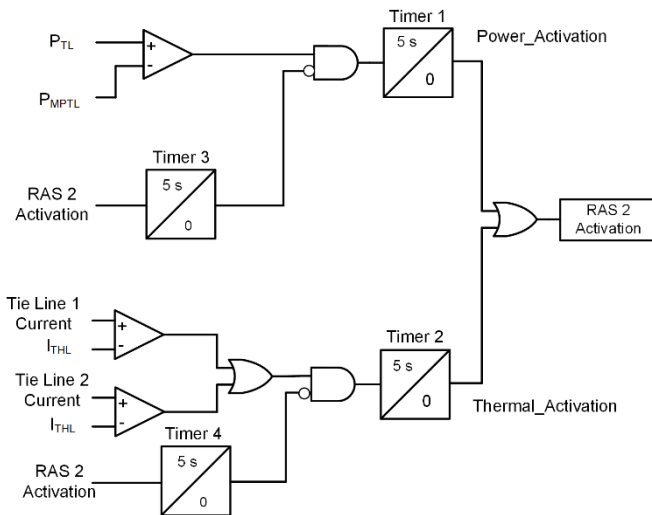


Fig. 5. RAS 2 activation logic.

The logic uses power measurements to detect tie-line MPTL violations and current measurements to detect tie-line thermal limit violations.

- Tie-line MPTL violation detection: The RAS 2 activation logic compares the active power value measured on the tie lines (P_{TL}) with the MPTL set by GCCIA (P_{MPTL}).
- Tie-line thermal limit violation detection: The RAS 2 activation logic compares the current measured on the tie lines with the current thermal limit (I_{THL}).

As shown in Fig. 5, the RAS 2 activation logic asserts when P_{TL} is greater than P_{MPTL} for 5 seconds (Timer 1 pickup setting), or either Tie Line 41 or Tie Line 42 current is greater than I_{THL} for 5 seconds (Timer 2 pickup setting). The five-second timer pickup adds security to ensure that the limit violation detected is not a transient condition. Furthermore, the timers are set for RAS 2 to operate faster than the tie-line overload protection.

The tie-line overload protection uses an IEC inverse curve with a pickup setting of 3,140 A primary. With these settings, overload protection trips in 30 seconds for the loss of the largest IPP in the utility system.

In addition, the RAS 2 activation logic opens a five-second time window (Timer 3 and Timer 4) for load shedding to take place. If the Power_Activation or Thermal_Activation bits are asserted when the timers expire, the timers reset the RAS 2 activation logic via the AND gates. This way, RAS 2 is ready to start a new load-shedding cycle if still required.

Fig. 6 illustrates the RAS 2 process to calculate the amount of load to shed. The controller performs this calculation in parallel with the execution of the RAS 2 activation logic.

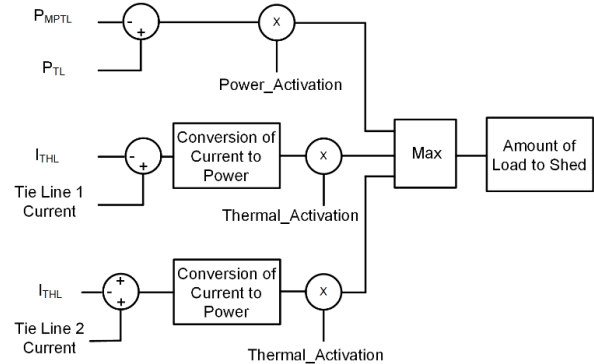


Fig. 6. RAS 2 calculation of load required to shed.

The RAS 2 logic calculates the value of $P_{TL} - P_{MPTL}$ and multiplies this value by the Power_Activation bit. Similarly, the logic subtracts I_{THL} from the Tie Line 41 and Tie Line 42 currents and converts the resulting current values to power values. Then, the logic multiplies these values by the Thermal_Activation bit. Finally, the logic selects the maximum of the three values as the amount of load to shed. The logic outputs a value of the required load to shed when the Power_Activation bit and/or the Thermal_Activation bit assert.

IV. RAS COMMUNICATIONS NETWORK DESIGN

The 53 substations covered by the RAS project are spread across the utility power system. The communications network needed to interconnect all these substations requires a communications technology that is purpose-engineered, deterministic, and cybersecurity [1].

The utility power system has more than 200 substations that are interconnected by a meshed fiber-optic network. We used the existing dark fibers to develop the RAS fiber-optic network backbone.

Using the dark fiber network drawing, we determined the lengths of the optical fibers between all pairs of substations. We found the longest distance to be 40 km. As a result, we decided to use single-mode optical fibers in the RAS communications network. Since most RAS substations are not adjacent in the utility fiber-optic network, many links between RAS substations include passive connections via fiber-optic patch panels (FOPPs).

These passive connections increase the overall attenuation in the fiber-optic link. The maximum link loss shall not exceed

18 dB. We calculated the link loss to optimize the design before system implementation in the field. We used the following equation to calculate the link loss in dB:

$$\text{Link Loss} = (F_{\text{LNGT}} \cdot F_{\text{LOSS}}) + (S_{\text{LOSS}} \cdot N_s) + (C_{\text{LOSS}} \cdot N_c) + M_{\text{SAF}}$$

where:

F_{LNGT} is the fiber-optic link length in km.

F_{LOSS} is the optical fiber attenuation in dB per km (typically 0.3 dB).

S_{LOSS} is the loss per splice (typically 0.1 dB).

N_s is the number of splices.

C_{LOSS} is the loss per connector (typically 0.75 dB).

N_c is the number of connectors.

M_{SAF} is the safety margin (typically 4.5 dB).

In the communications network design, we selected 30 km as the maximum fiber-optic link length to keep link loss within allowable limits.

Fig. 7 depicts an example of a fiber-optic ring interconnection between substations. The ring connects with two different centralized RAS switches (SWs). The switches located in generation-receiving substations are called Detection Switches, and the switches located in load-shedding substations are called Action Switches. The figure also shows the FOPPs located in some substations not covered by the RAS.

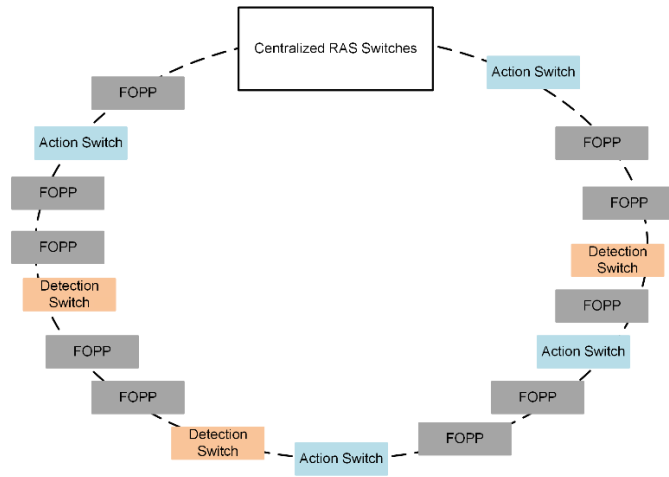


Fig. 7. Example of a fiber-optic ring connecting several substations.

Fig. 8 depicts a simplified RAS SDN communications network diagram. The distance and operation time limitations require a network topology with four rings. Each ring connects with two switches in the centralized switch panel. Each ring interconnects switches located in generation-receiving and load-shedding substations and FOPPs located in other substations.

We selected a network ladder topology to reduce the length of the optical fibers and minimize the use of passive connectors. We limited the number of RAS substations in each ring to 15. This arrangement reduces the number of switches to lose to 15 in case of two optical fibers failing in the same ring.

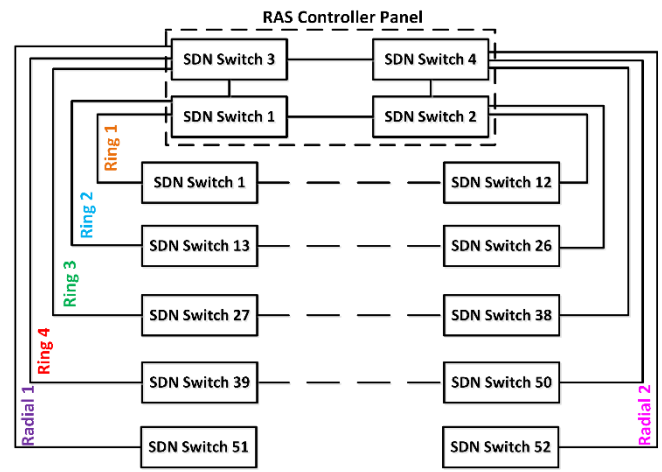


Fig. 8. Simplified RAS SDN network diagram.

SDN Switches 1, 2, 3, and 4, located in the RAS main controller panel, facilitate data exchange with the ring switches. SDN Switches 1 and 2 connect to Rings 1 and 2 and only exchange signals with the RACs. SDN Switches 3 and 4 connect to Rings 3 and 4 and only exchange signals with the RACs. This arrangement prevents unwanted data flow between rings.

The ring switches collect and aggregate critical data from the generation-receiving substations and the tie-line substation, and then send the data to the centralized RACs. They also transfer tripping commands from the RACs to the load-shedding substations.

We implemented a multicentric ladder topology to optimize bandwidth utilization in each ring and enhance network robustness. This configuration ensures resilience by preventing a single device failure from causing a complete loss of RAS data. For example, a malfunction of the RAS controller panel SDN Switch 1, connected to Rings 1 and 2, would not result in the total disruption of these rings, as they can continue sending and receiving data through Switch 2. No data exchange occurs between rings. In case of a total ring loss, the RAS selects loads from substations connected to the remaining rings, which ensures dependability.

We selected operational technology (OT) SDN technology because of its advantages compared to traditional communications network technology [2]. SDN technology has the following benefits:

- Inherent cybersecurity by applying deny-by-default technology.
- Fast failover by proactively engineering primary and backup paths. Does not require network reconfiguration.
- Easy configuration using the zero-touch deployment (ZTD) tool.

Cybersecurity was one of the primary considerations when designing the RAS network because the RAS performs load-shedding actions in 42 substations. Any unintentional load

circuit tripping of a load-shedding substation because of a cyberattack can affect many customers, as occurred in the 2015 cyberattack on the Ukrainian power system [3]. SDN switches are deny-by-default Ethernet switches; they only allow configured communications in the network as per a flow configuration table.

In addition, because all the network communications are pre-engineered, including the primary and backup communications paths, the SDN network can failover to a backup path within 100 μ s, compared to the 15 ms failover time of an Ethernet network using the rapid spanning tree protocol (RSTP) [2].

Fig. 9 illustrates a simplified diagram of SDN data flow in the RAS communications network. The figure shows the primary and backup path selection process that the SDN switches follow to dependably perform data exchange between the RAC substations. For example, in the event of an optical fiber failure between Switches 3 and 4, the SDN switches automatically transfer the data path to a preprogrammed backup path within 100 μ s to ensure uninterrupted information exchange in the RAS.

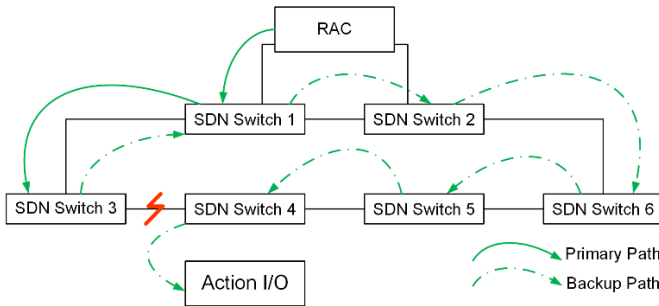


Fig. 9. Simplified diagram of SDN data flow in the RAS network.

The ZTD tool simplifies the SDN network configuration process. Configuring an SDN network only requires a network architecture drawing and a data flow diagram in a format compatible with the ZTD tool [4]. The information the ZTD tool requires to configure the SDN network includes device types and protocol information, device IP addresses, and network interconnection information.

The control plane of the SDN network resides in the SDN controller software; the SDN switch software contains only data planes [2]. This arrangement allows a user to centrally manage the SDN network through the SDN controller software. The SDN controller also performs comprehensive monitoring of the communications network, including real-time communications link monitoring, SDN switch health monitoring, SOE monitoring, and monitoring of all configured flow rules.

Centrally managing the SDN switches also allows all firmware upgrades and configuration updates of the SDN switches to be performed from a central location. SDN technology offers ease of maintenance to the users whose substations are unmanned.

V. RAS HARDWARE-IN-THE-LOOP TESTING

We performed FATs in a hardware-in-the-loop test environment to validate the RAS logic. We linked the RACs and associated equipment with an RTDS.

We validated the RTDS model by comparing simulation results with those obtained from power system studies using a complete Power System Simulator for Engineering model of the utility system. We also compared RTDS simulation results with real contingency events provided by the utility. The validation process showed that the RTDS model faithfully represents the power system and ensures that FAT results are reliable.

Fig. 10 shows the FAT network architecture. We used a reduced system with six generation-receiving substations and six load-shedding substations spread across four rings and two radial connections in the communications network. Action I/Os and Detection I/Os receive field information from the RTDS. The FEPs receive information for all remaining substations directly from the RTDS. Action I/Os and FEPs send load-shedding commands to the RTDS when the RACs make a remedial action decision.

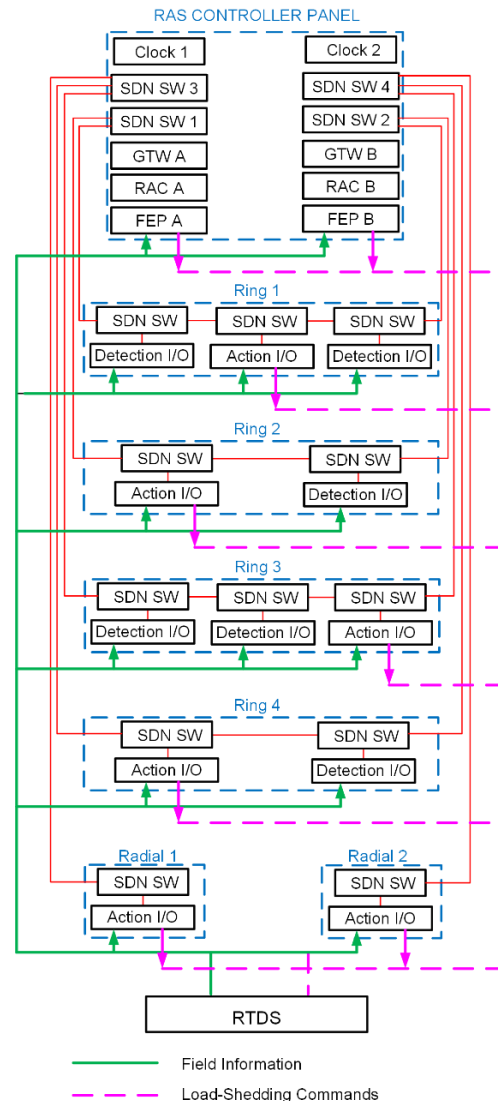


Fig. 10. FAT network architecture.

This configuration allows the following validations to be performed:

- RAS logic performance (activation when required, no activation when not required, and correct load-shedding operations).
- Communications equipment performance.
- Total RAS operating time (the time from contingency detection to load-shedding execution).
- HMI performance.

We conducted many tests to verify the performance of RAS 1 and RAS 2 logic.

As an example of a RAS 1 logic test, Fig. 11 and Fig. 12 show the response of the utility power system for a major contingency (the sudden loss of the largest IPP of the country). The total power loss in the system is 2,220 MW. The predisturbance power transfer through the tie lines equals zero.

The figures show the active power measured on eight generation-receiving substations and on the tie lines (GCCIA_EQ_P). The power from the substation connected to the largest IPP drops suddenly to zero. The power of the other seven generation-receiving substations shows the typical oscillatory inertial responses of the IPPs to the disturbance. The tie-line power transfer increases to compensate for the generation loss, but this inertial response is slower because of the large inertia of the GCCIA interconnected system.

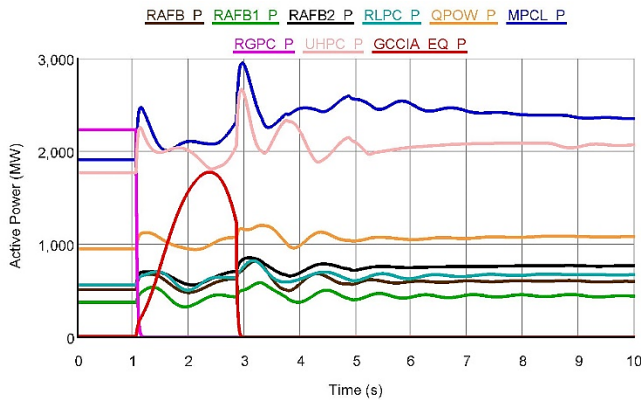


Fig. 11. Power system response to the sudden loss of a large IPP with RAS disabled.

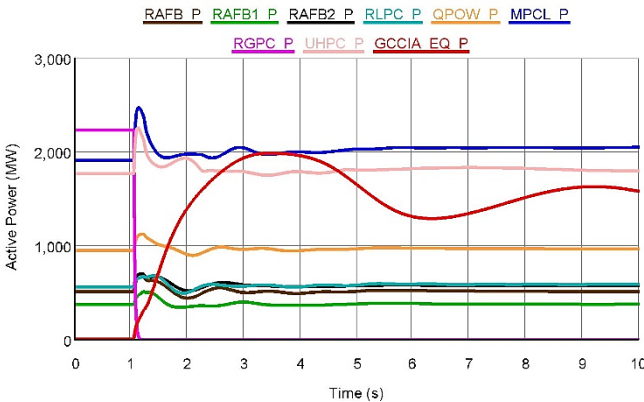


Fig. 12. Power system response to the sudden loss of a large IPP with RAS enabled.

When the RAS is disabled (see Fig. 11), the tie-line OOST scheme detects the unstable power swing and trips the tie lines two seconds after the disturbance starts. The tie-line transfer power (GCCIA_EQ_P) drops to zero.

When the RAS is enabled (see Fig. 12), it detects the contingency and sheds load in less than 100 ms. This load shedding prevents the unstable power swing. After some time, the tie-line power oscillations dampen out, and the interconnection between the utility system and the GCCIA system remains intact. For this event, the RAS selected to shed approximately 432 MW.

Fig. 13 shows the active and reactive power transfer through the tie lines and the power system frequency.

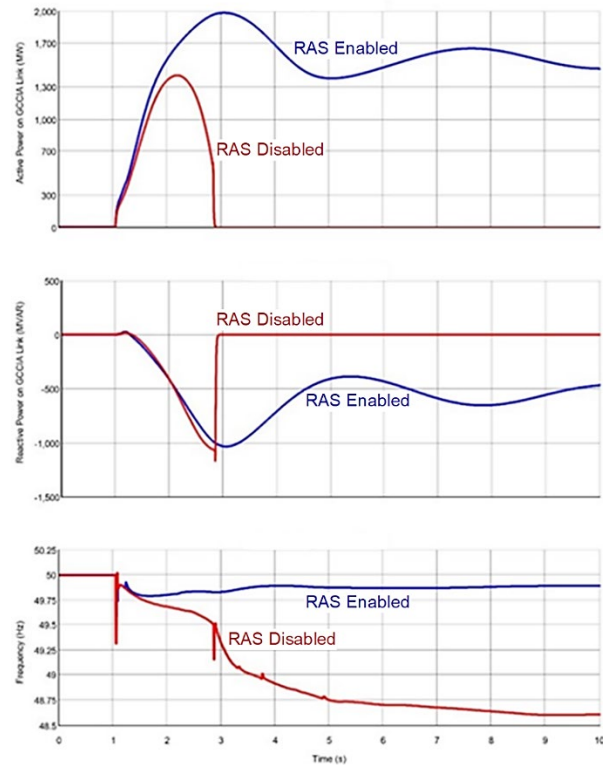


Fig. 13. Tie-line active and reactive power transfer and power system frequency for the cases with the RAS is disabled (red line) and enabled (blue line).

When the RAS is disabled, the tie-line active and reactive powers grow monotonically and then drop to zero when the OOST scheme trips the tie lines. The power system frequency drops to 48.54 Hz. The frequency stabilizes when three of the five steps of the underfrequency load-shedding scheme operate. Load shedding occurs at $t = 3.16$ s, $t = 3.6$ s, and $t = 4.82$ s. The total amount of load to shed is around 950 MW. This value is more than twice the 432 MW of load shed by the RAS when enabled.

When the RAS is enabled, it sheds load and the tie-line power swing is stable. The active and reactive power oscillations dampen out after some time. The power system frequency only drops to 49.75 Hz because of the high inertia of the GCCIA interconnected system.

The RAS 1 action provides two important results. First, the system maintains the interconnection closed (the main objective of RAS 1). Second, RAS 1 sheds less load than the load the underfrequency scheme would have shed if the RAS had been disabled.

Fig. 14 illustrates the OOST scheme performance during the event. The figure shows the power swing impedance trajectories measured by the tie-line OOST elements (green lines in the figure). The OOST elements use a double-blinder scheme for power swing detection. The blue lines in the figure represent the blinders with their actual settings. The external blinder settings are ± 50 ohms.

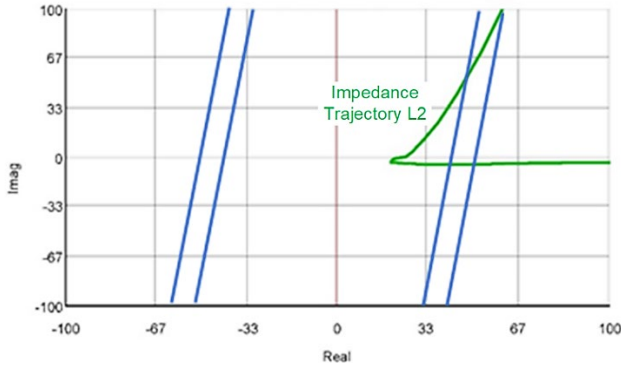


Fig. 14. Impedance trajectory for the sudden loss of a large IPP with RAS disabled.

When the RAS is disabled (see Fig. 14), the impedance trajectory crosses both right-side blinders and the OOST scheme trips. When the RAS is enabled (see Fig. 15), the impedance trajectory does not reach the external blinder because RAS 1 fast load shedding prevents the system from losing synchronism.

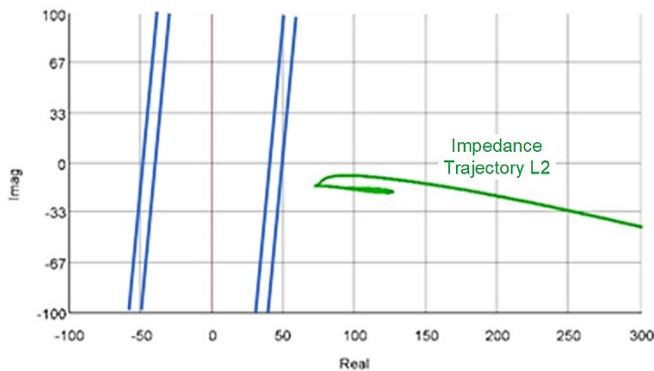


Fig. 15. Impedance trajectory for the sudden loss of a large IPP with RAS enabled.

We conducted many similar tests considering loss of other large IPPs for different power system operating conditions and states. We found that the RAS 1 operation avoided the OOST scheme tripping in all cases.

As an example of a RAS 2 logic test, we simulated a power loss of the largest IPP (for example, a failure in the gas supply system). The total generation loss occurred in approximately 60 seconds.

Fig. 16 shows the response of the power system for this slow generation loss condition. The figure shows the slow decrease of power from the substation connected to the IPP (trace labeled RGPC in the graph). The tie-line power transfer (GCCIA_EQ_P) increases to compensate for the generation loss and even becomes greater than the P_{MPTL_TH} value. RAS 2 triggers load shedding in approximately 15 seconds; the tie-line power transfer stabilizes and no thermal tie-line tripping occurs. The tie-line power transfer remains above P_{MPTL_TH} for only 5 seconds.

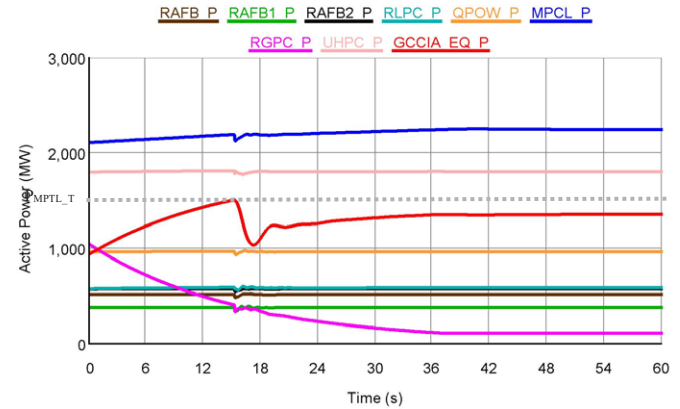


Fig. 16. Power system response to a slow generation loss condition.

Fig. 17 shows the active and reactive power transfer through the tie lines and the power system frequency. Active power increases, reactive power decreases, and frequency falls to 49.9 Hz. Load shedding occurs in approximately 15 seconds, and power transfers stabilize. Frequency grows by 0.02 Hz.

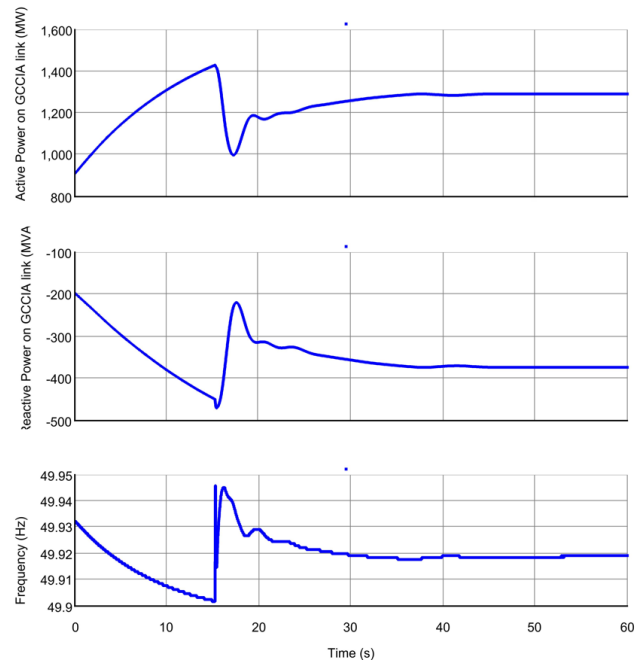


Fig. 17. Tie-line active and reactive power transfer and power system frequency for a slow generation loss condition.

Fig. 18 illustrates the OOST scheme performance during the event. As expected, the impedance trajectory remains far away from the blinders for this slow generation loss condition.

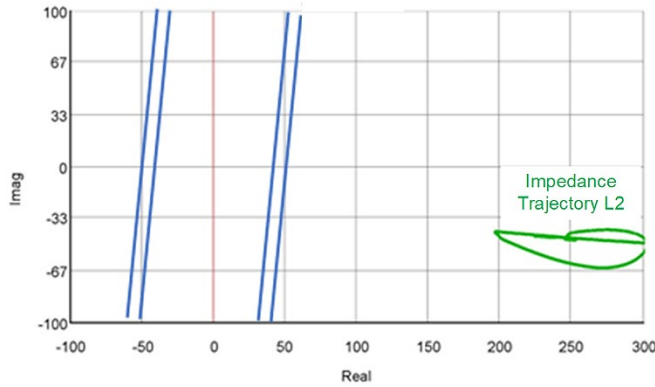


Fig. 18. Impedance trajectory for a slow generation loss condition.

We conducted many similar tests considering slow generation loss conditions of other IPPs for different power system operating conditions and states. We found that the RAS 2 operation avoided thermal line tripping in all cases.

VI. CONCLUSION

KAHRAMAA imports power from multiple IPPs. The utility system connects through two tie lines to the GCCIA interconnected power network. Power system studies performed by GCCIA showed that the loss of generation in the utility system causes tie-line tripping and separation of its power system from the GCCIA network.

Our own studies showed that the sudden generation loss of more than 1,800 MW in the utility system causes unstable power swings in the tie lines. We also found that shedding load in less than 400 ms prevents these unstable power swings.

We describe the RAS that we designed, tested, and commissioned to prevent undesired tie-line tripping. The RAS covers 53 substations, including 10 generation-receiving substations, 42 load-shedding substations, and the GCCIA interconnection substation. In this project, we had no access to local generator measurements and breaker information, so we implemented a novel logic based on wide-area measurements.

RAS 1 detects sudden, large generation loss and performs countrywide fast, adaptive load shedding to prevent the OOST scheme from tripping the tie lines. RAS 2 detects slow generation loss and performs countrywide adaptive load shedding to prevent operation of the tie-line thermal protection.

The RAS communications network has a ladder topology with four rings. Each ring connects with two switches in the centralized switch panel. Each ring interconnects switches located in generation-receiving and load-shedding substations and FOPPs located in other substations. We limited the number of RAS substations in each ring to 15 to reduce switch losses in case of optical fiber failures.

We selected SDN technology for the communications network. SDN networks are inherently cybersecure, provide fast failover actions, and are easy to configure.

We tested the RAS using a hardware-in-the loop system based on RTDSs. We conducted many tests simulating the

sudden loss of large IPPs. We found that RAS 1 shed load in less than 100 ms and prevented the OOST scheme from tripping the tie lines in all cases. We also conducted many tests simulating IPP slow output power loss conditions. We found that RAS 2 operation avoided thermal line tripping in all cases.

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IX. BIOGRAPHIES

Abdulaziz Faisal A. A. Talfat is manager, Electricity Transmission Department, Qatar General Electricity and Water Corporation (KAHRAMAA), in Doha, Qatar. He has 11 years of experience: eight years working as an overhead line engineer and three years in managerial positions. He received the BSEE degree from Cardiff University, Wales, UK, in 2013. His areas of interest are the latest protection and switchgear developments, substation automation systems, overhead line networks, and digital substations.

Aaron Esparza is a project engineer in the special protection systems department of Schweitzer Engineering Laboratories, S.A. de C.V. (SEL) in Mexico. He received the ME and PhD degrees in electrical engineering from the Autonomous University of San Luis Potosí, San Luis Potosí, Mexico, in 2013 and 2018, respectively. His research interests are in power system digital modeling and simulations, wide-area protection, and control applications.

Jerin Monzi Mathew is a project engineer in the special protection systems group of Schweitzer Engineering Laboratories Middle East FZCO (SEL) Engineering Services (ES) in Dubai, United Arab Emirates. He started his career at SEL in 2017. He received his BE degree in electrical and electronics engineering from Anna University, Chennai, India. He also received a postgraduate diploma in subtransmission and distribution from the National Power Training Institute, Bangalore, India. His areas of interest are in power management systems, substation automation systems, digital secondary systems, and OT networks.

Muthuraman Shanmugam is the special protection systems manager of the Engineering Services Division of Schweitzer Engineering Laboratories Saudi Limited (SEL) in Saudi Arabia. He received the BE EE degree from Annamalai University. He has been employed at SEL since 2014 and has experience in designing and implementing control systems for utility and industrial customers.

Héctor J. Altuve Ferrer received his BSEE degree in 1969 from the Central University of Las Villas in Santa Clara, Cuba, and his PhD degree in 1981 from Kiev Polytechnic Institute in Kiev, Ukraine. From 1969 until 1993, Dr. Altuve served on the faculty of the Electrical Engineering School at the Central University of Las Villas. From 1993 to 2000, he served as professor of the Graduate Doctoral Program in the Mechanical and Electrical Engineering School at the Autonomous University of Nuevo León in Monterrey, Mexico. In 1999 through 2000, he was the Schweitzer Visiting Professor in the Department of Electrical and Computer Engineering at Washington State University. Dr. Altuve joined Schweitzer Engineering Laboratories, Inc. (SEL) in January 2001, where he is currently a distinguished engineer and dean of SEL University. He has authored and coauthored more than 100 technical papers and several books and holds four patents. His main research interests are in power system protection, control, and monitoring. Dr. Altuve is an IEEE life fellow.

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2350 NE Hopkins Court, Pullman, WA 99163 USA

+1.509.332.1890

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