Case Study: Integrating the Power Management System of an Existing Oil Production Field

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

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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.

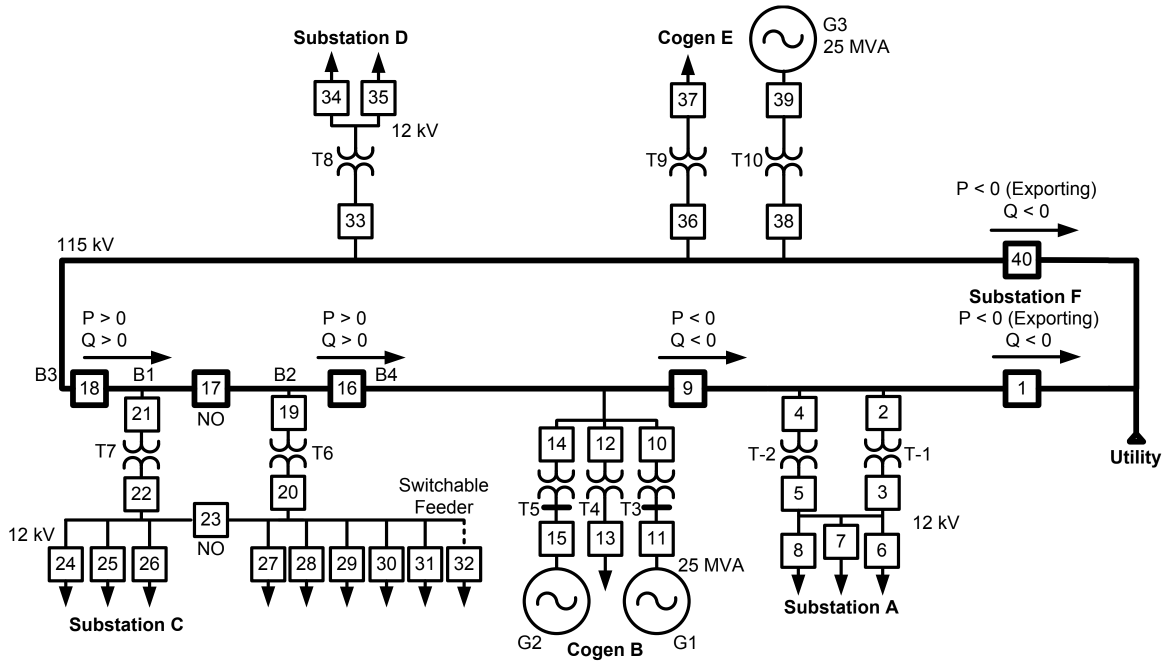

Fig. 1 Simplified One-Line Diagram of the Oil Production Field

III. COMMUNICATIONS ARCHITECTURE

Modern PMSs are a complete integration of protection, control, automation, and communications devices. The PMSs include devices such as protective relays, computers, logic controllers, I/O modules, converters, switches, and routers. The capability and determinism of such PMSs are heavily dependent on the communications networks, devices involved, and the implementation of communications schemes.

Redundancy of the critical devices is the crucial part of a PMS (for reliability), especially when it is applied to an existing facility. As shown in Fig. 2, the communications architecture at this facility uses redundant critical control system components. The communications system is clearly designed for two different objectives: to support the control system and to support the typical SCADA application [1]. Control system devices include a load-shedding processor (LSP), GCS, front-end processor (FEP), central FEP (CFEP), and high-speed I/O (HS I/O) module. They use 100 percent redundancy with high-speed proprietary peer-to-peer protocol and IEC 61850 Generic Object-Oriented Substation Event (GOOSE) protocol. Typical SCADA devices include relays, SCADA FEPs, I/O servers, operator work stations (OWS), and data gateways (GW). The protocols include Modbus® TCP, and DNP3 IP.

IV. THREE INDEPENDENT LOAD-SHEDDING SCHEMES AND INTEGRATION WITH AUTOMATIC TRANSFER SCHEME (ATS)

Three independent and redundant load-shedding schemes are implemented in the field to counteract an unbalance of supply and demand.

A. Contingency LSP

The contingency LSP (CLSP) system is a fast, contingency-based algorithm that sheds load based on a predicted power deficit [2]. This scheme attempts to reduce the total field load to slightly less than the calculated available capacity based on the measured capacity before a contingency occurs. The individual field loads are automatically selected for shedding based on user-selectable priorities on the HMI and power topology and conditions.

Loads are sorted into priorities or “action tables.” Each action table contains various load groupings in order to provide a range in the sum-total of load that can be shed. The system predetermines which loads to shed for every scenario. This “required-to-shed” calculation drives the selection algorithm that evaluates the priority list. The system selects loads to shed from the top of the priority list and continues to move to the next load on the list until the required-to-shed load has been met or all available loads have been selected. If all loads are selected to shed for a contingency and the required-to-shed amount has not been satisfied, the system sheds only the loads that can be shed and creates a contingency not satisfied alarm (or blackout alarm) because the load-shedding system does not have sufficient loads to shed in order to maintain system stability.

To prevent shedding an excessive amount of load in response to a contingency, the CLSP first takes into account the user-settable incremental reserve margin (IRM), which significantly reduces the amount of load to shed. The load-shedding tables accommodate the system with adequate loads to allow the system to shed without significantly over-shedding under normal operating conditions.

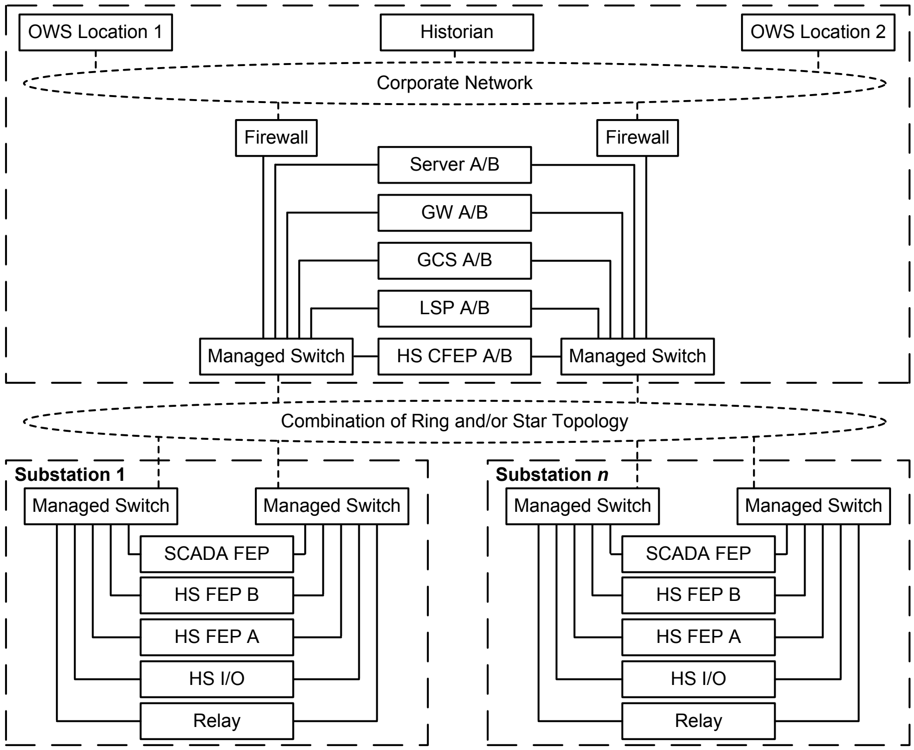

Fig. 2 Communications Architecture of the Oil Field

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.

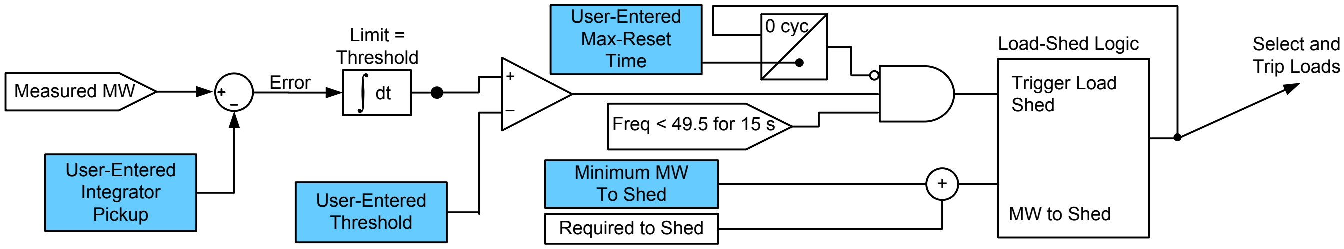

Fig. 3 Progressive Overload-Shedding Logic

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 VSnom = 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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