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Retrofit and Design of a DP-2 Medium Voltage Protective Relay and Control System

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Abstract

This paper will discuss results of a major retrofit of electrical protection and generation control systems on the DPS Class 2 Ensco 7500 drilling unit. Originally constructed in 2000, the E7500 has successfully operated around the world; however, upgrades to modern technology for the DP Control and Protection system have increased reliability, and addressed several common cause failure modes. Focusing on more elaborate protective relaying, alarming, and diagnostics the additional changes ensure faster fault clearing and better selectivity to keep more propulsion online. Implementation of these features in the protection/automation system instead of the PMS is a new application of the technology allowed for the desired results in a very short implementation. Advanced time domain simulation of the power plant also allowed for proving of the protection design. Finally, the future system upgrade considerations that were designed into this system will be discussed along with new applications in marine power plant protection and management.

Index Terms—Offshore vessel, power management system (PMS), common-mode failure, advanced generator protection, exciter, governor, automatic transfer, black start, synchrophasor, automatic synchronizer, real-time digital simulations, data management system (DMS), vessel control and annunciation system.

Electrical System Overview

The ENSCO 7500 is a DPS-2 class semi-submersible drilling unit with a 5 kV, 2-bus main system with a single inter-tie circuit breaker [1]. The main power plant has six 5000 horsepower turbo-charged, low-speed diesel engines with 4.16 kV generators feeding the main 4.16 kV line up (see Figure 1). There are two engine rooms each containing three engine-generator sets. Each engine room has separate systems for auxiliary support including fuel oil, low pressure air and cooling water, which can be manually cross-connected. The engine cooling water system can also be supplied from the raw water service system in the event of a failure.

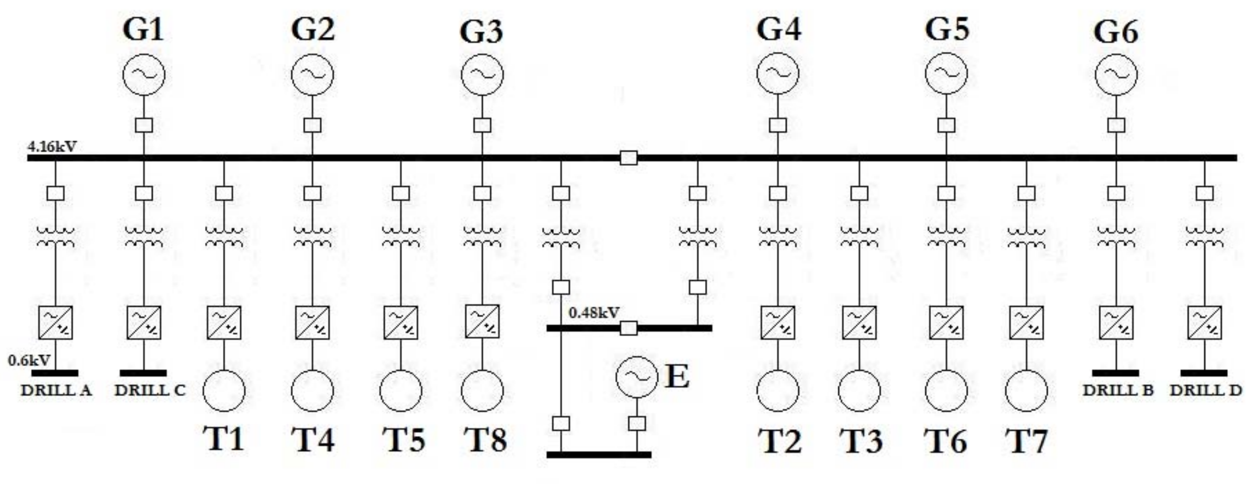

Figure 1 – E7500 Electrical System

Original Switchgear Protection System

The original protection system for E7500 consisted of basic relays with no interconnectivity, communications or data export employed. The system operated successfully as designed as basic protection and was not integrated into the PMS, data logger, voltage regulation or generator load sharing control systems. Dedicated relays for each generator and feeder were installed, as well as bus voltage protection. The original system had two major design compromises: 1) Lack of any relay protection for the tie breaker rendering it an isolation switch, and 2) A single, shared relay for generator breaker synchronization check in manual mode. Both of these were addressed in the upgrade and are further discussed in detail.

<u>Generator Protection</u> – The existing protection scheme used generator differential with overcurrent as backup for the primary generator protection. In addition, frequency and voltage protections were also enabled. Synchronization check was handled exclusively by the synchronizer/load controller in the automatic mode. In the manual synchronization mode, a single synch check relay was installed along synchro-scopes and indication lights at a central location in the switchboard. Hard-wired contacts allowed for sharing of the synchronization relay and scopes in manual mode for all 6 generators.

Feeder Protection – Each of the fourteen feeders had a single 51 overcurrent relay. These relays were coordinated with the upstream generator breakers and the downstream device incoming circuit breakers.

Bus Inter-tie Protection - The existing bus inter-tie circuit breaker was not designed to be tripped by the protection system so it acted only as an isolation switch. It could be opened manually in the event of a sensitive operation for segregated operation. There was originally no means to re-synchronize the two buses in the event that a re-close with load was required. The inter-tie circuit breaker was a primary focus in the system upgrade, especially its role in the overall plant stability. As increased functionality was added to the tie, the overall fault tolerance of the plant increased. Sensitive sectionalizing of the bus and a means to manually reclose without completely unloading one of the buses is a major system improvement.

Main Generator and Engine Control Configuration

In the original system, each generator had a multifunction generator management relay, synchronizer/load controller, generator control plc (with I/O interfaces to the local and remote control system), power transducers and front panel control switches complete with an alarm annunciator (see Figure 2). Each engine has an electronic control unit providing closed loop speed control, injector firing, start/stop functions and alarms. Each generator's switchgear equipment and engine are supplied with independent dc control power from a dedicated battery bank.

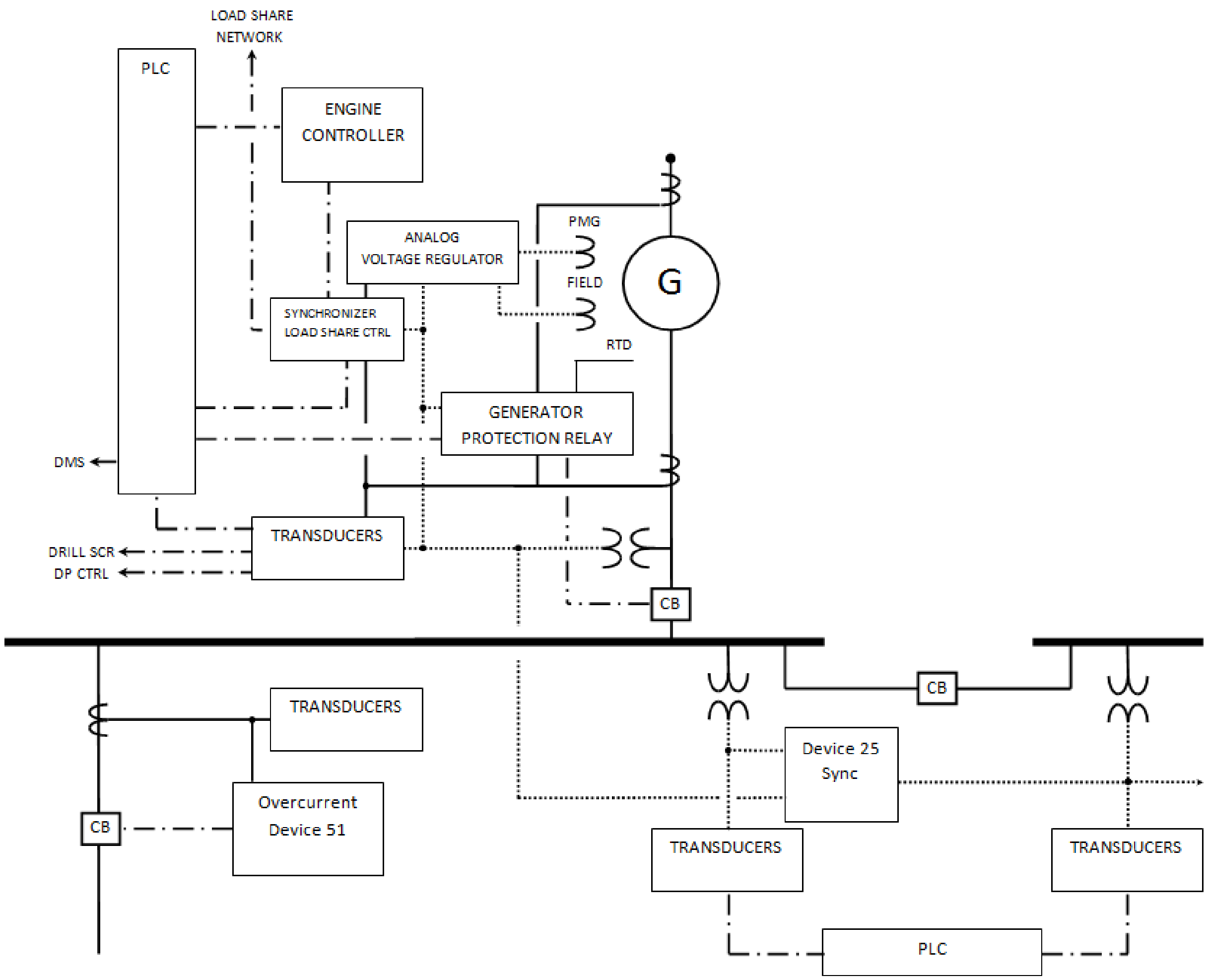

Figure 2 – Original Protection and Control Scheme

Switchgear Automation Platform

There were several goals driving replacement of the protective relay system including: inter-tie functionality to improve plant fault response, improve generator protection, data gathering from the system, communication alarms from the generator control and excitation systems, and increased blackout recovery functions implemented outside the DMS. The new protection system would have to evolve into a true switchgear automation platform to accomplish these goals, as well as allow for a secondary goal of implementing a full PMS system in the future. Originally, the switchgear was designed with open-delta voltage monitoring, which is common for marine systems. However, this arrangement does not allow for detection of zero-sequence voltage for use in sensitive fault detection. The E7500 upgrade originally included a plan to upgrade to 3-phase voltage monitoring; however, it was moved to a future date because of an aggressive schedule.

The current state of technology for microprocessor-based protection relays allows for almost limitless customization, which allows for a switchgear automation platform. For the E7500 upgrade (see Figure 3), this capability was used in the following several applications, in addition to standard protection functionality [2] [3] [4]:

Generator Protection – Generator protection was improved with multiple additional functions including differential, negative-sequence overcurrent, overflux, reverse power, over/under frequency, voltage-restrained overcurrent, over/under voltage, loss of field, and thermal. In addition, as the new generator protection relays are capable of two reference voltages, the synchronization checking was moved into the individual relays, removing the common cause fault of the single synchronization check relay.

Inter-tie Protection – The original inter-tie was strictly a switch with no automatic tripping, so the addition of a dedicated inter-tie relay was a large improvement in the plant reliability. The addition of bus sectioning on phase overcurrent, negative-sequence overcurrent, loss of synchronization, and over/under voltage, gave the protection system the ability to set a sensitive set of conditions to trip the inter-tie and increase the chances that a blackout would be limited to one of the main buses. Also added to the inter-tie was a single-breaker synchronizer, which allows for the re-closing of inter-tie without having to shed the entire load from one bus to reclose.

Power Quality Monitoring – On each bus, a revenue-grade power quality meter was added to monitor harmonic distortion levels independently per bus. In addition to engineering purposes, the PQ meter was also used to augment the inter-tie functionality.

Generator Synchronization and Load Sharing Control – As the power plant of the E7500 is run in parallel isochronous mode, particular attention must be paid to the load controller communications to ensure plant stability. The original network comprised of generator synchronizer/load controller units. Although this network proved reliable during 10 years of operation, it lacked redundant communication via its single LON network which could result in a plant blackout in the event of a communications failure. For this reason, the controllers were upgraded to a newer version of a similar generator controller product, with only the synchronizer/load controller functions being used. The modern generator controllers have a member-polling feature and allow for action on loss of member. This action was programmed to place each generator controller into droop operating mode and alarm making the operator aware of the problem. This action on communication failure prevents uncoordinated isochronous generation groups from competing for frequency control and compromising plant stability.

Excitation Control – The original system operated with analog voltage regulators that were replaced with modern digital excitation controllers for improved voltage control, system stability, and resistance to drift. Self-diagnostics and alarming to the DP system were also implemented to improve operations response and troubleshooting.

Dedicated Alarming from Switchgear Automation Platform – In addition to the HMI located at the switchgear, the automation controller was augmented with a standalone I/O processor to pass the major switchgear automation platform system alarm messages to the DP system. These include: Excitation trouble, generator load controller trouble, power plant in droop, protection system trouble, switchgear automation system trouble, and switchgear automation alarm trouble. The self-diagnostic feature of modern microprocessor-based devices was used to annunciate to the DP system immediately on any device or communications issue (see Figure 4).

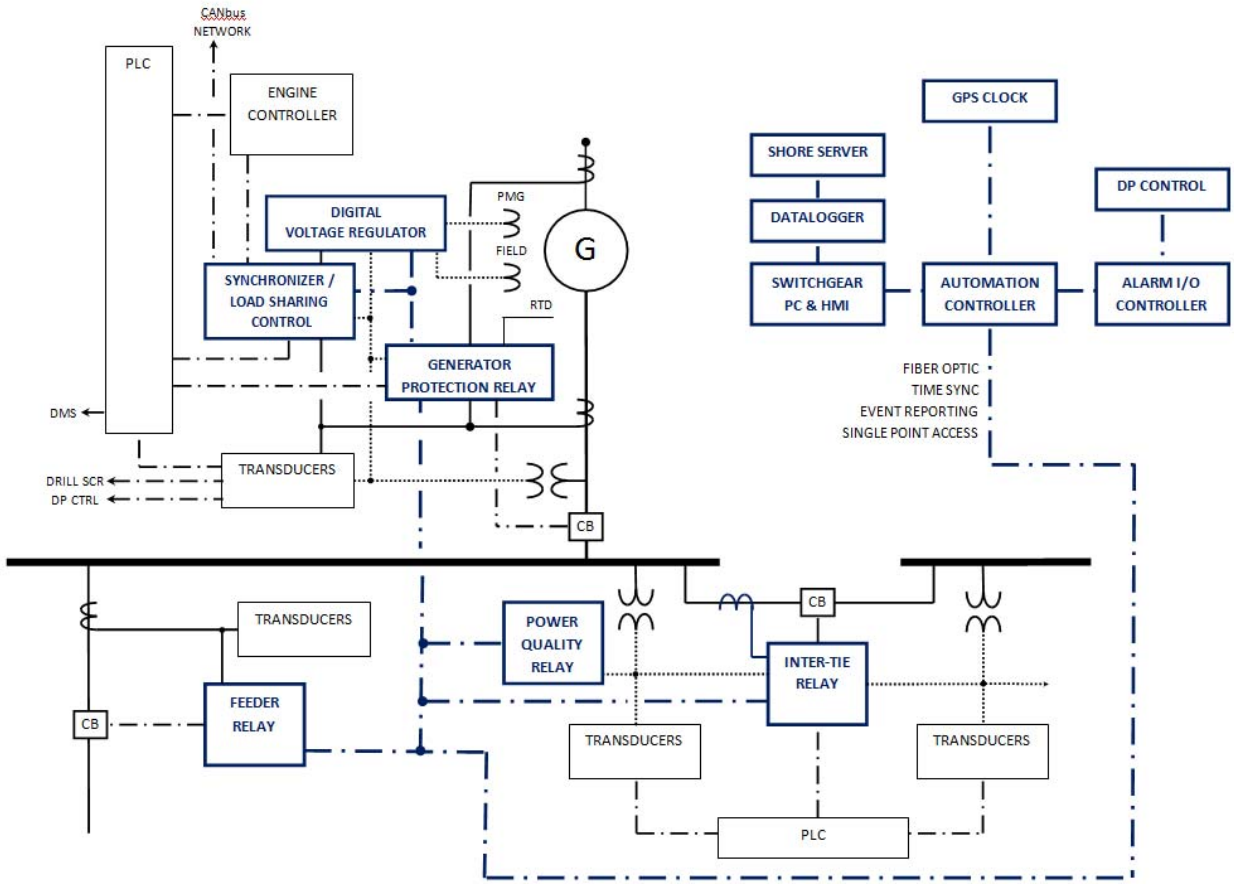

Figure 3 – Revised Protection and Control Scheme

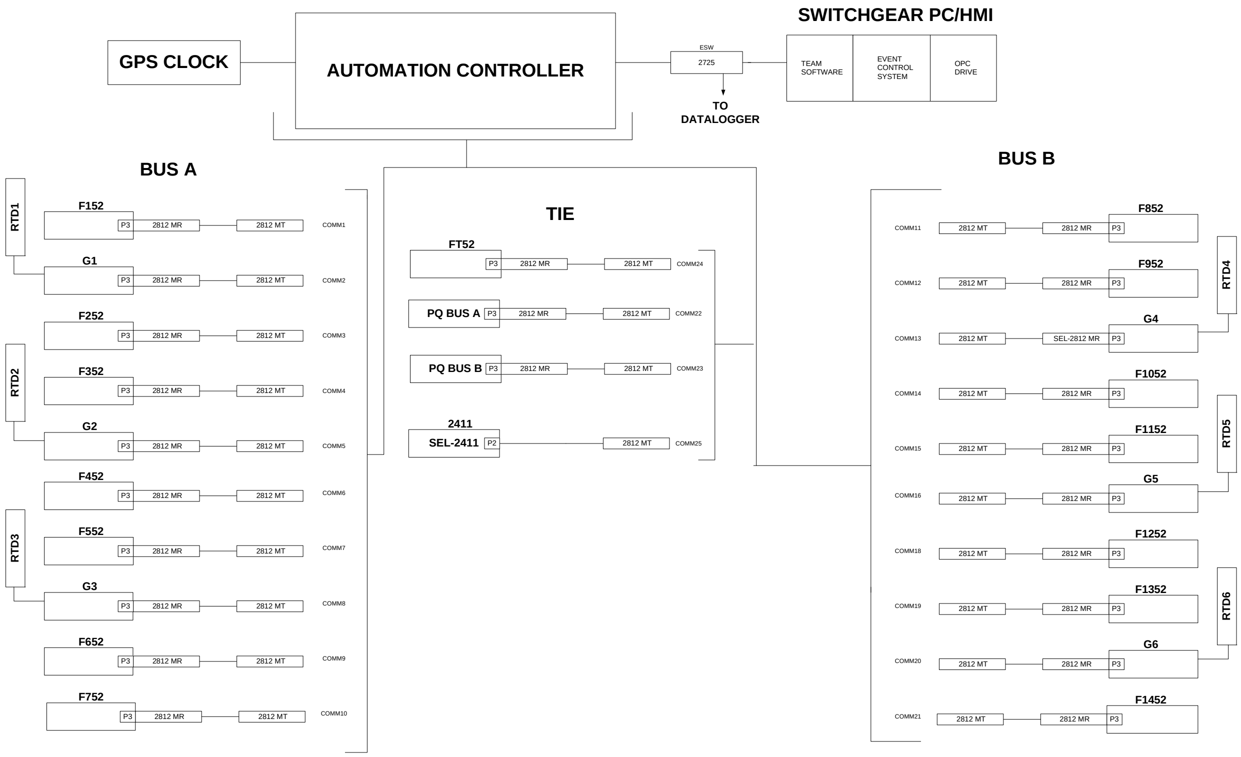

Figure 4 – Revised Protection and Control Communication Scheme

Upgrade Focus – Common Failure Mode Improvements

As the original configuration of the E7500 electrical system was proven successful in operations, one of the main goals of the plant protection and control upgrade project was to address common failure modes. Several different methods were used including revised distribution configurations, replacement devices with better reliability and diagnostics, advanced design verification, and safe primary failure states.

Inter-Tie Circuit Breaker Operation – With no protection trip or current transformers on the tie circuit breaker in the original system it only functioned as an isolation switch. Closed-tie operation is acceptable for DP-2 Class systems; however, this setup is far from optimal. As with all distribution systems, selectivity was closely examined in the original system to ensure low-level faults were cleared by the closest upstream device in the event that all devices operate as designed with timing per design. For backup protection, an active inter-tie connection between the two buses that segregates the system is an advance which addresses protection system failure of selectivity to isolate a remote fault in time to save system stability, if possible. Although it may not be possible to segregate the system fast enough, in the event of a very severe or close in fault, upgrading the tie circuit breaker from an isolation switch to a full active inter-tie is a definite improvement. A large focus of the real-time model testing is to ensure the tie breaker is set as sensitive as practical for plant segregation.

Critical Generation System Alarms – Self-diagnostic features and alarm communication of critical generation protection and control devices were hardwired to the DP control system via a separate automation controller with error checking configuration.(dual NO and NC contacts). Alarms being directly communicated to the DPO include: Excitation controller trouble, synchronizer/load share controller trouble, plant in droop, protection relay trouble, primary automation controller trouble, secondary automation controller trouble, and automatic reclose on blackout disabled. The spare for the main automation controller was also installed in the switchgear with its self-diagnostic trouble alarm. This alarm is wired to alert the crew in the event that the spare unit is not functional

Load Sharing – Of particular importance operating in parallel isochronous mode is loss of communication. As a multi-generator parallel isochronous setup is not a 'natural' state for an islanded power system, for continued stability, the load sharing controllers must remain in communication. In the event of loss of communication for any reason, the plant could become unstable as the two separate generation groups compete to set the system frequency. As the original load share controllers had a single LON communications network, and there was no communication monitoring, there would be no way to monitor communication and no safe failure state. The generator synchronizer/load share controllers were replaced with a modern unit of similar design using a CANbus communication for load sharing. The new controllers monitor the communication and member assignments of the current group (based on inter-tie position) and allow for action if one of the members stops communicating. A safe failure mode of changing all load sharing controllers to droop mode and alarming to the bridge was selected to mitigate the impact of loss of communication of controllers. Although this failure mode was rare in the original system, the potential impact is severe, thus justifying controller replacement.

Voltage Regulation – Replacement of the original analog voltage regulators with modern units allowed for several improvements. A known passive failure mode of drifting set points was eliminated by using a modern digital excitation controller. Also, the self-diagnostic/watchdog alarm features of the device were wired out to the alarm automation controller as noted for immediate communication to the crew, even if the unit is not currently operating. Excitation or internal faults for the voltage regulator will trip the generator circuit breaker lockout device.

Switchgear Relays and Automation Devices – Modern microprocessor protection devices with their internal self-diagnostic routines have mean-time-between-failure rates that are incredibly low compared to past devices. Both hardware and software alarms are monitored for all the protection relays via the dedicated alarm I/O to the DP control system.

Ground Faults – The inability to upgrade the switchgear PTs to three-phase hampered the ability of the project to significantly improve the ground fault detection at this stage. However this upgrade was planned for the future. Some of the phase faults can also be detected using the negative sequence OC and voltage protection with the revised protection scheme.

Column UPS Power Supplies – Each column contains a UPS system critical for continued DP operations in the event of a power system issue, which was replaced with up-to-date technology. A separate automatic transfer switch, maintenance bypass and internal battery bypass were added to allow for all maintenance operations.

Thruster Auxiliary MCC Feeds – A large modification was made to the column MCC power supplies that feed the thruster auxiliaries. Originally the E7500 fed all eight column MCCs which supplied power necessary for propulsion from only two ship service transformers and switchboards. Although it will not be discussed in detail in this paper, this modification removed a common fault for the two groups of four thrusters.

Data Logger and Central Data Collection

The switchgear automation platform is centered around a programmable automation controller that concentrates data from relays and other intelligent switchgear devices. The relays are connected via a serial protocol over fiber-optic links to the controller. Dedicated switchgear GPS time reference is passed via the fiber link; so all devices and system event reports are available for system performance evaluation and after-event analysis coordinated with the DP system (see Figure 5). The automation controller also transfers data to the data management system Datalogger to provide the critical information and real time data points. The Datalogger is also connected to a shore server that provides internet access for remote data analysis and troubleshooting.

The switchgear automation controller also supports the creation of logic solutions in the embedded IEC 61131 logic engine. The logic engine has access to all system tags, contact I/O, protocol data and communications statistics.

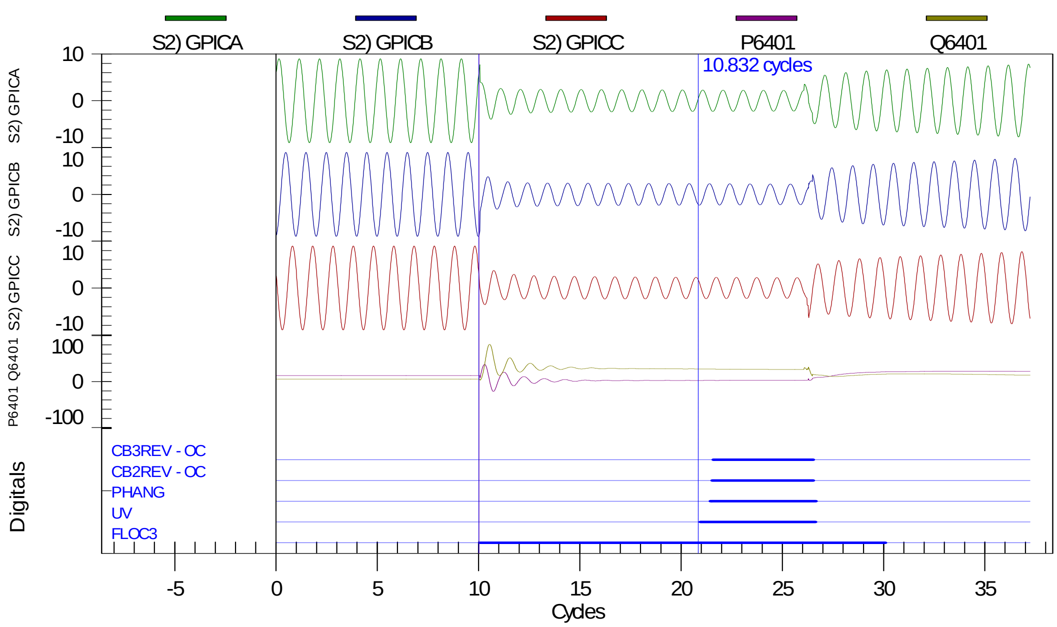

Figure 5 – Example Event for a Three-Phase Fault Reported from the System

Automatic Blackout Recovery Implementation

One of the disadvantages of dynamically positioned vessels is that a blackout may result in drift off and emergency disconnect. The goal of the blackout recovery logic is to automate the procedure to restore power in order to reduce the outage duration. This is achieved by closing the circuit breakers of the thruster feeders after a critical event (blackout) upon restoration of nearly nominal voltage and frequency [5] [6] [7].

Although the existing data management system already had an automatic restart system for emergency engine restart, the circuit breakers could not be reclosed automatically. This was implemented by the switchgear automation platform and protection relays. As the inter-tie breaker tips immediately on under voltage, the logic implemented for E7500 handles Bus A thruster feeders and Bus B thruster feeders separately. Restoring power to the thruster circuit breakers independently by bus is preferable after a complete or partial blackout. The PAC independently verifies the normal system conditions for Bus A and B. The thruster feeders are closed with time delay of 1 second between each feeder upon restoration of nominal voltage. Each blackout detection will issue a single close command to each Bus A feeder and a single close command to each Bus B feeder, if the other conditions are satisfied.

The logic will use the acquired data only if the relays are enabled and do not have any software or hardware alarms. If one relay is not in good operational condition, the logic will use the second redundant relay (i.e., Feeder 1 and 2 for Bus A and Feeder 13 and 14 for Bus B). In addition, each analog quantity is checked for quality. If one relay has faulty quality data, the logic will use the data coming from the second redundant relay. If both relays are not in good operational condition or if they both have faulty quality data, the logic will raise an alarm and it will not take any action.

Stage 1: Blackout Detection

The Blackout Detection logic uses data coming from two different relays for each bus in order to have redundancy. Bus A will use data acquired through the protection for Feeder F152 and F252. Bus B will use data acquired through the protection for Feeder F1352 and F1452. The logic will check if the value of the voltage is zero on all three phases for each bus (dead bus). If both buses are dead, the logic will initiate a timer. The timer keeps counting as long as both buses are dead. It is reset to zero, should the initializing condition disappear. Once the counter reaches t=5s, the logic will determine that there is a blackout condition.

Frequency cannot be used to determine the status of the dead bus, because when frequency is far from its nominal value it is not possible for the relay to track frequency. The relay then forces the frequency to its nominal value.

Stage 2: Bus Recovery Detection

This logic runs only if a blackout condition was previously detected and the operator has not disabled the logic. The logic will handle Bus A and Bus B separately, unless the tie breaker is in the closed position. For each bus, if voltage is back to its nominal value (4160 V ±10%) and if frequency is between 58 and 62 Hz, the logic will initiate a timer. The timer keeps counting as long as the bus voltage and frequency are within the thresholds. It is reset to zero, should the initializing condition disappear. Once the counter reaches five seconds, the logic will determine that the bus is healthy.

Stage 3: Close Command to Thruster Feeders

If the logic determines that a bus is powered again after a blackout event, it will send a close command to each thruster feeder connected to the same bus. The logic handles Bus A and Bus B separately (see Figure 6).

Programmable Automation Controller (PAC) Functions

The PAC performs two different tasks. It is used to enable/disable the blackout recovery and to output system alarms to the DP system. The PAC has programmable pushbuttons on the front-panel. One of these pushbuttons has been programmed to disable the Blackout Recovery logic (see Figure 7). The pushbutton needs to be pressed for over three seconds for the blackout recovery logic to be enabled or disabled. When the logic is disabled, a programmable LED placed on the PAC front-panel will start blinking.

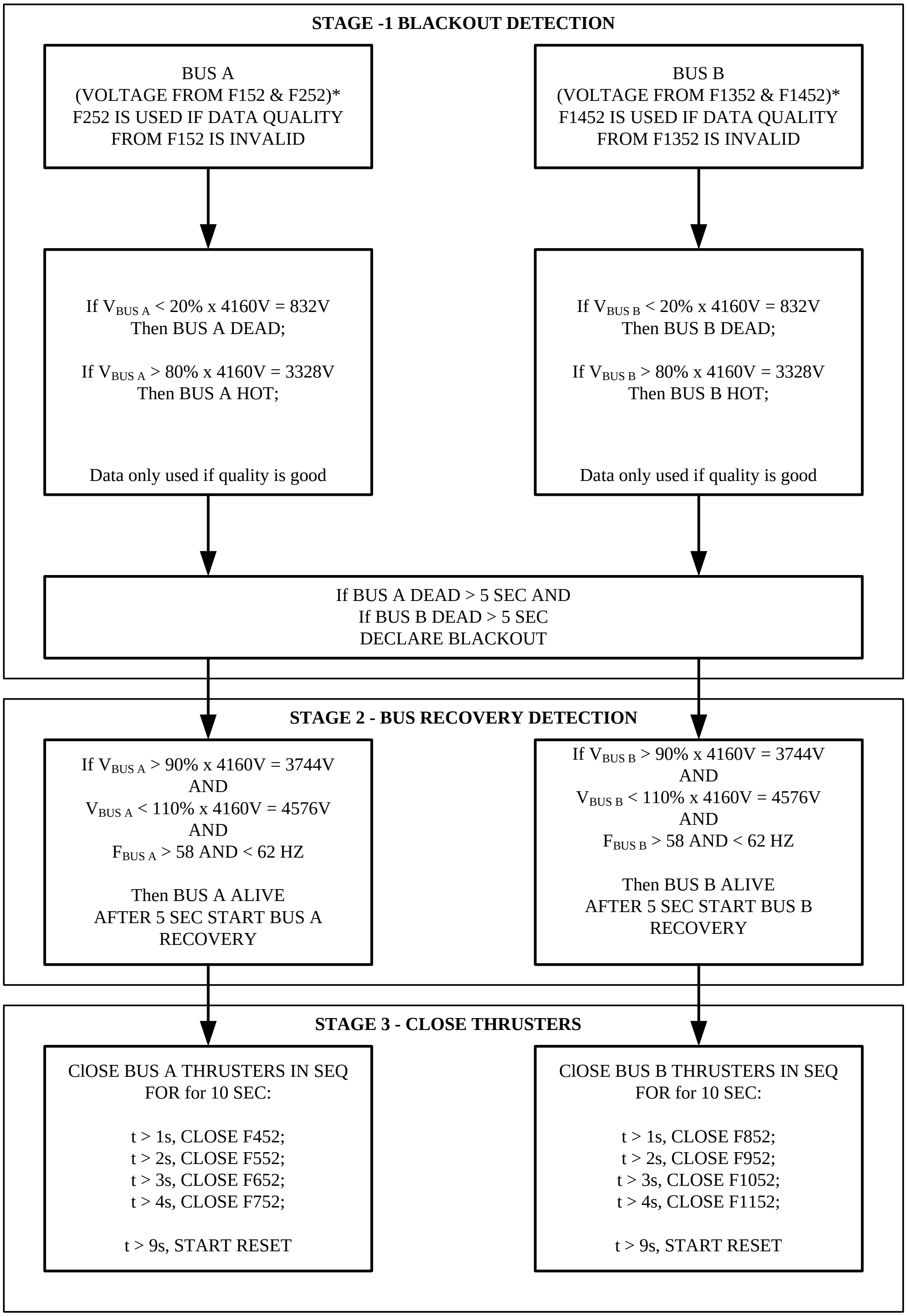

Figure 6 – Blackout Recovery Logic Implemented in Protection System

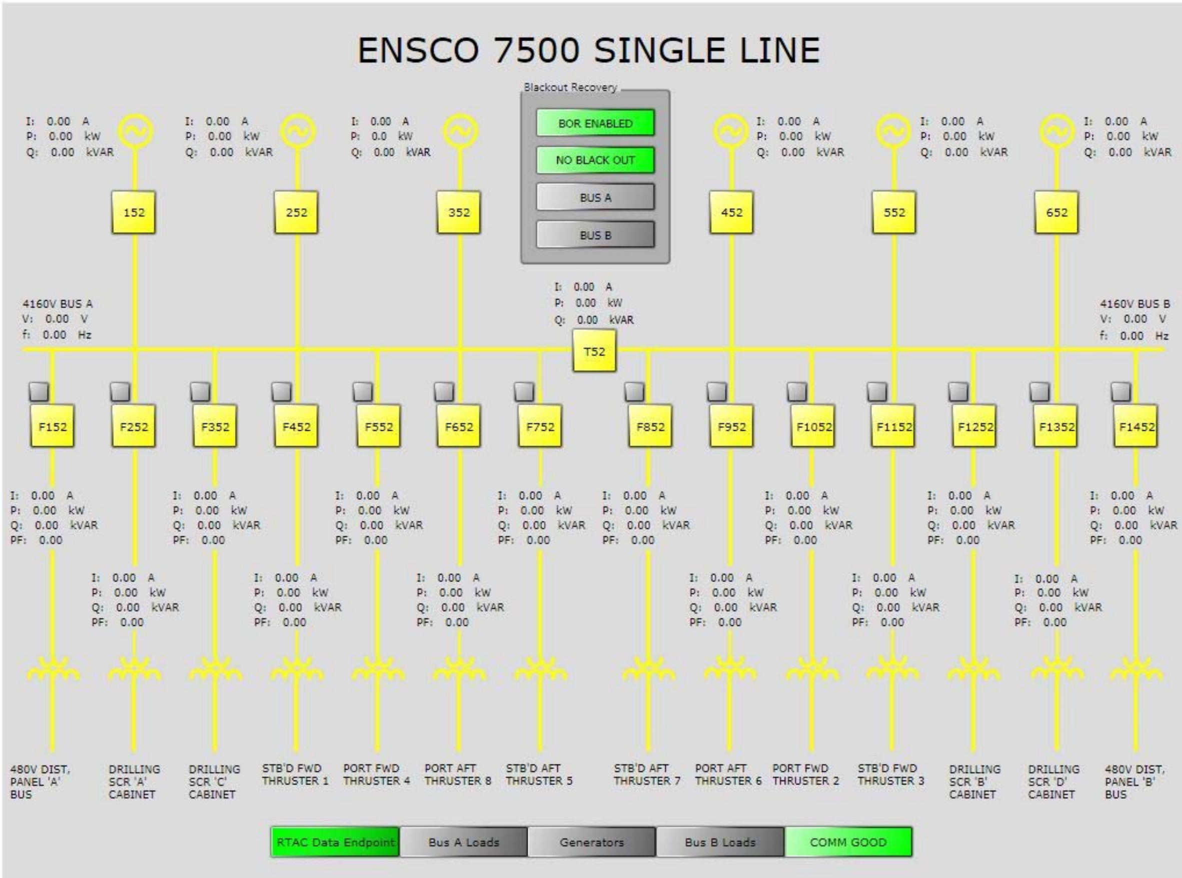

Figure 7 – HMI at Switchgear PC Running in Automation Controller

Time Domain Model and Design Verification

The model power system testing laboratory is the proposed site for complete testing of systems using a Time Domain Model and Simulator [8] [9] [10]. This equipment allows dynamic modeling of a power system with simulated small time steps to test all closed-loop controls and protection systems. The power system was modeled using the time domain dynamic simulator, and system performance will be benchmarked using the actual field results.

An example of generator parameter verification using load shedding is shown in Figure 8. The time domain dynamic simulator system study helps with relay settings and verifying the correct protection system operation of offshore vessels for system contingency conditions, system dynamics, and transient faults. This analysis was especially useful in the inter-tie addition to the E7500 upgrade. Refer to Figure 9 for the E7500 Real-Time System Model.

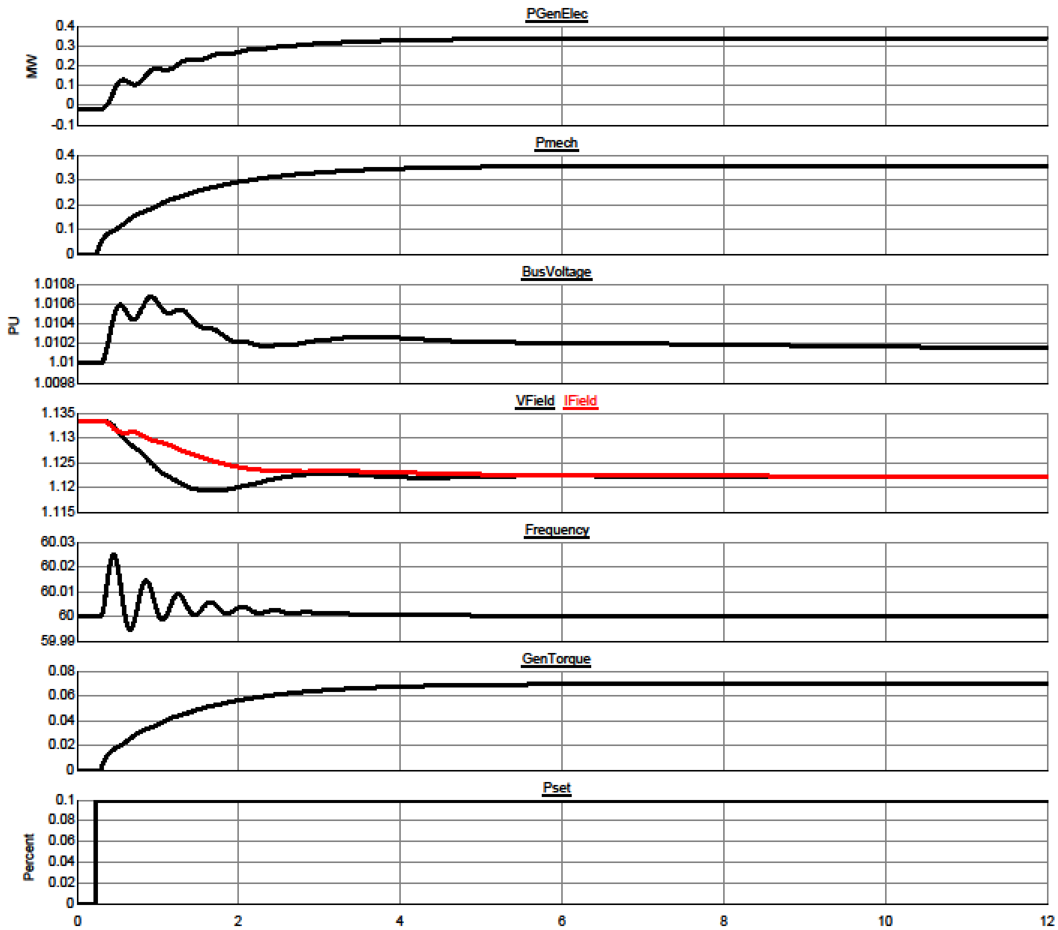

Figure 8 – Generator Step Change Result Benchmark Using Time Domain Model

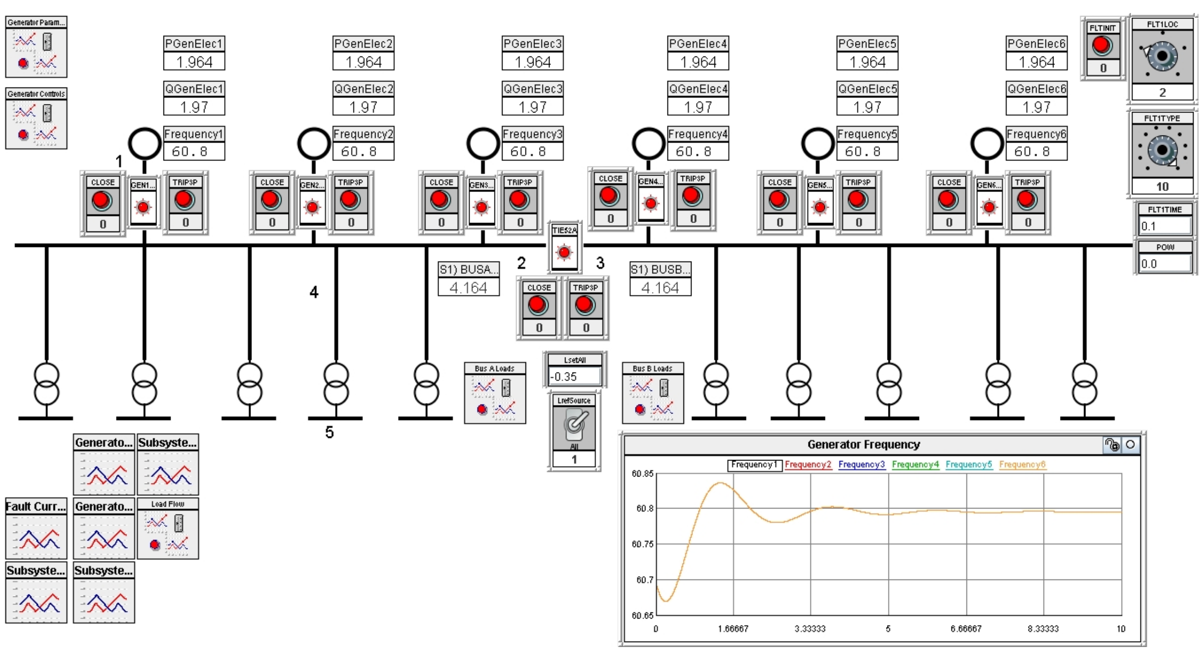

Figure 9 – E7500 Real-Time System Model

Future System Elements

Figure 10 shows the conceptual block diagram for a DP offshore power management system (PMS) protection scheme. The proposed scheme is dual redundant, with two independent sets of local protection are included to improve system reliability. Generator protection is included in the local protection block, that communicates with the generator control block. Local protection devices communicate via direct fiber relay-to-relay or via IEC 61850 protocol using Ethernet in the system protection block. System Protection one and two are the hub of all the decisions for PMS control and data exchange. The system protection processes all of the relevant information from local protection then provides control decision for the PMS. By properly collecting, manipulating, and presenting power system data as usable information, the system enables operations, maintenance, and engineering staff to diagnose system events, predict equipment failures, and minimize unnecessary maintenance. The proposed solution also guides operators in making decisions, such as controlling black start, manual override, and load shedding. The solution includes a human-machine interface (HMI) screen for system overview and control.

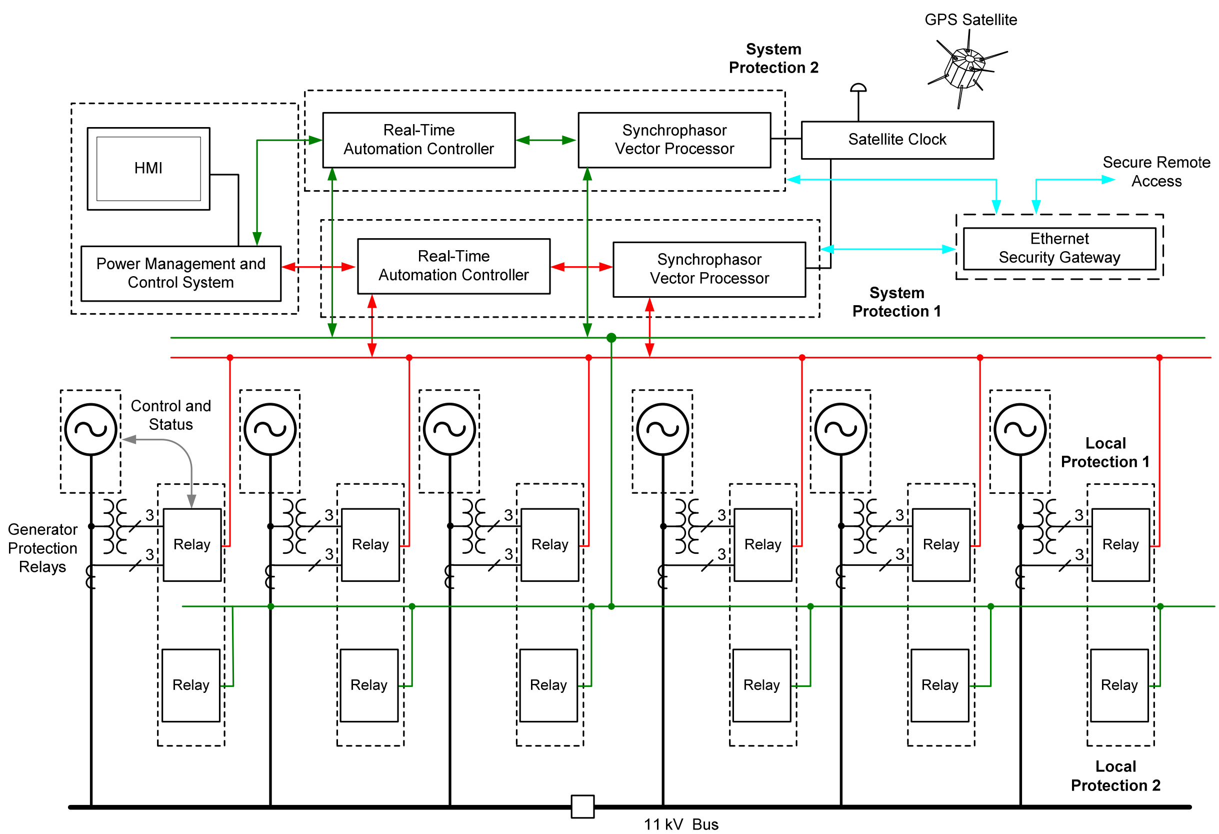

Figure 10 – Proposed Solution – Redundant Protection

Local Protection

The local protection block includes generator protection relays. For the existing scheme, only one relay per generator is proposed. However, when redundancy is required, more than one generator protection relay is installed per generator [11] [12]. The following additional optional generator protection elements can also be programmed:

- Field ground (64G)
- Compensator distance (21C)
- Out of step (78)

Additional Features

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

- Synchrophasors
- Feeder protection and arc-flash detection
- Transformer protection
- Bus protection
- Motor protection
- Common-mode generator protection
- Time domain model design verification

Synchrophasors

A definition of real-time (synchronized) phasors is provided in IEEE 1344-1995. Applying synchrophasors improves performance for critical applications. As stated earlier, each machine state is based on highly accurate Global Positioning System (GPS) satellite clock signals and synchrophasor data. Figure 11 shows the phasor measurement of multiple machines. The logical comparison of the synchrophasor variables is performed using system protection.

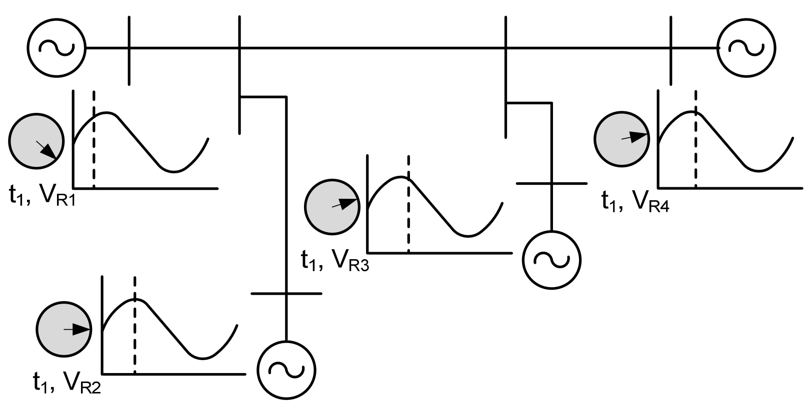

Figure 11 – Synchrophasor Measurement

Synchrophasors can be applied to visualize the overall system performance with reference to the same time frame, and the data can be automatically archived for future analysis [13]. Using model analysis (included in system protection), it is also possible to calculate the resonance and oscillation frequencies. This information is critical for advanced generator protection design. Existing DP vessel common-mode generator protection cannot detect the resonance and oscillation frequency accurately.

Conclusion

This paper discusses benefits gained of applying the latest technology to improve the protection and control to a modern DP semisubmersible rig during a recent upgrade. Blackout recovery, advanced protection system functions, data gathering, system visualization, time reference and disturbance analysis are major functions that were added with relatively small equipment investment and wiring changes. In addition, the inter-tie breaker control and protection was designed to quickly segregate the system in an attempt to avoid total blackout. With the advancement in technology it is possible to further improve the design in the future via application of a scalable switchgear automation solution. This project is an example of up-to-date technology applied to an existing design to address common mode faults and improve reliability for a DP power plant in a novel way. It is expected that real-time testing will provide greater insight in the overall system information during critical faults and in some cases it may be possible to improve the system stability.

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Biographies

Cameron Craig received his degree in Electrical Engineering from the University of Alberta, Canada and has eight years of experience in several industries including petrochemical, oil refining and offshore exploration. Currently Senior Engineer – Electrical Systems with Ensco International plc, he supports their large fleet of offshore drilling assets. Mr. Craig is a member of multiple industry groups, is an active Project Management Professional with PMI, and is a current graduate student at Texas A&M University. Mr. Craig holds multiple professional engineering licenses in the US, Canada and Australia.

Steve Savoy is currently Electrical Superintendant with the North America Deepwater group of Ensco International PLC. He has been with Ensco for over 10 years and was a driving force in the company's expansion into DP rigs with the E7500 and E8500 series.

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