Distributed Generation Control in Islanded Industrial Facilities: A Case Study in Power Management Systems

Musaab M. Al-Mulla
Saudi Aramco

Nicholas C. Seeley
Schweitzer Engineering Laboratories, Inc.

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DISTRIBUTED GENERATION CONTROL IN ISLANDED INDUSTRIAL FACILITIES: A CASE STUDY IN POWER MANAGEMENT SYSTEMS

Musaab M. Al-Mulla
Saudi Aramco
Dhahran
Saudi Arabia
musaab.mulla@aramco.com

Nicholas C. Seeley
Schweitzer Engineering Laboratories, Inc.
10110 W. Sam Houston Parkway S.
Suite 130
Houston, TX 77099, USA
Nicholas_Seeley@selinc.com

Abstract—Distributed generation in islanded power systems has unique characteristics when it comes to power system stability and control. Relatively low system inertia and the power system configuration of intertie connections between distributed generation facilities necessitate the implementation of power management control algorithms that provide both proactive and reactive stabilization techniques to ensure optimum system operation.

Saudi Aramco recently installed and commissioned a power management system that incorporates smart, real-time generation, voltage, and islanding control in an effort to ensure that generators operate properly in terms of load balancing, maintaining system frequency and voltage levels under all operational scenarios. Furthermore, the power management system also incorporates a contingency-based and backup frequency-based load-shedding system to compensate for large generation and transmission line disturbances. This paper explores the technical aspects governing the design of the power management system—incorporating the performance characteristics of the provided combustion gas turbines (CGTs), system inertia, and CGT control modes—while also examining the operational history and how previous events shaped the current system design.

Index Terms—stability, governor control, droop, isochronous, voltage control, incremental reserve margin, islanding, power management system.

I. INTRODUCTION

From the time a person leaves an airport in the United States to the time that person sets foot in the remote region of Saudi Arabia under study in this paper, approximately 48 hours have elapsed, and descriptors such as “remote” or “middle of nowhere” fail to capture the true sense of isolation that person experiences. While in the more populous regions of Saudi Arabia there is no shortage of power lines supplying the growing energy needs of consumers, the particular region associated with this project (with no surprise considering its relative distance to any major or minor residential or commercial development) lacks the power lines connecting it to a larger power grid that would traditionally be used to support the vast industrial infrastructure thriving in the area. These industrial facilities have popped up in an ocean of sand to further expand production of the chief export in Saudi Arabia. Islanded facilities such as these require special consideration in regards to the electric power system. The greatest challenge concerning overall electric power reliability is the lack of an intertie connection to a major utility. Such a physical limitation introduces a host of stability and frequency problems associated with low system inertia, because the lack of connection to a strong utility subsequently dictates that the inertial makeup of the system relies solely on the machines connected to the system rather than the cumulative effort of the system and the entire grid behind the utility connection.

This being the case, Saudi Aramco was interested in developing a power management system (PMS) for this particular facility to ensure that the low inertial symptoms of the power system would be mitigated and restricted from introducing large-scale, system-wide disturbances. Therefore, the PMS needed to address two important factors regarding power systems: voltage and power. In doing so, the PMS was designed for proactive and reactive control of the power system to maximize the effectiveness of such a system and optimize the operations of the facility while increasing its availability.

The PMS invokes a voltage control strategy utilizing the exciter controllers of both the combustion gas turbine (CGT) generators and the synchronous motors (SMs). To accomplish this, the PMS has controllers hard-wired directly to the exciter controllers on the CGT generators and SMs.

Control of power through the PMS specifically refers to its ability to allow operators to define the real power in MW and reactive power in MVAR flow between two plants or the constant output from the CGT generators. In addition, the PMS identifies when there is a generation-to-load deficit by monitoring key circuit breakers within the system. In doing so, the PMS calculates when load shedding is necessary to maintain generation-to-load equilibrium. Fig. 1 shows the simplified PMS system architecture. Note that the generation control system controls more than one generator.

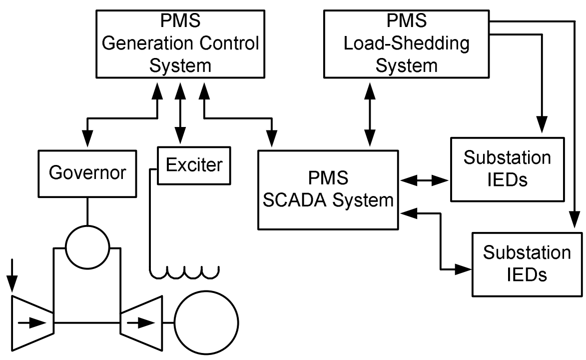

Fig. 1 Simplified PMS system architecture

Before the technical details of the system are explained, it will be useful to understand the operational history of the facility under study.

II. OPERATIONAL BACKGROUND

Fig. 2 shows a simplified one-line diagram of the system under study. The construction of Plant B was the driving force behind implementation of the PMS. Plant A had been in full operation for several years and was used as justification for the introduction of a PMS. Plant A is equipped with a multistage underfrequency load-shedding scheme to reject load when the system frequency drops below certain set points. Such simple schemes are common but often produce unpredictable results [1]. Previous incidents had occurred at Plant A where the first stage of underfrequency load shedding failed to buoy the decaying system frequency. By the time the second stage of load shedding initiated, the system frequency was decaying too quickly to be recovered, and the system was lost. As is explained later, Plant A also suffered from bus synchronization difficulties. Given the amount of time Plant A had been in service, Saudi Aramco was able to leverage the operational history of Plant A to develop a full set of PMS specifications to help improve the performance of Plant A while also ensuring that Plant B would be designed with these lessons learned in mind.

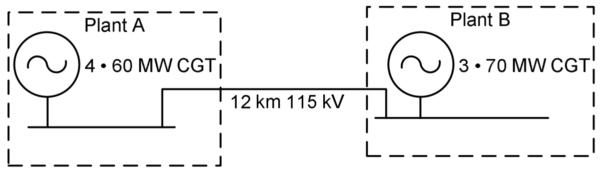

Fig. 2 Simplified system one-line diagram

III. PROBLEMS WITH INERTIA

Because the inertia of an islanded system is relatively low compared to a utility, a system disturbance will have a greater impact on the system frequency. Equation (1) represents the relationship of inertia to frequency in a synchronous machine.

$$J\frac{d\omega_m}{dt} = T_m - T_e \tag{1}$$

where:

J = combined moment of inertia

ω_m = angular velocity of the rotor

T_m = mechanical torque

T_e = electrical torque

Equation (1) shows that the rate of change of frequency (df/dt), or angular acceleration, is inversely proportional to the inertia. The lower the inertia, the greater the rate of change of frequency for a given torque unbalance.

For cases pertinent to load shedding, torque unbalance caused by the loss of a generation unit is dictated by (2).

$$\left(\frac{P_m - P_e}{\omega}\right) = T_m - T_e \tag{2}$$

The total electrical torque is roughly equal to the mechanical torque in a steady-state system. A loss of generation causes an increase in load on the remaining generator(s), which constitutes an increase in the mechanical torque on the system. At the instant the disturbance occurs, the mechanical torque remains constant until the generator speed governor controllers begin to react. This time delay between the occurrence of the event and the initiation of a governor response depends on the tuning parameters of the governor control system. Accordingly, before the governor controllers start to react, a net decelerating torque (T_a), as shown in (3), will be present on the system, and the frequency begins to decay.

$$\frac{d\omega_m}{dt} = \frac{T_a}{J} \tag{3}$$

where:

$T_a = T_m – T_e$ = net accelerating torque

Equation (3) shows that the inertia of the power system (J) dictates the rate at which the frequency will decay—the larger the inertia, the slower the decay.

Despite the fact that inertia plays a role in power system stability, it is neither simple nor economical to manipulate. The most economical way of improving system stability is to equalize the load-to-generation balance (via load shedding), thereby minimizing the disturbance impact to the power system.

Using high-speed governors and turbines with quick reaction time is another method to mitigate power deficiencies; however, a sensitively tuned governor can be detrimental to the system. Further proactive techniques consist of a variety of methods to maintain capacity reserve margins, ensuring that the protection systems have enough time to react to disturbances, thereby preventing system instability.

Islanded electric power systems are often prone to inertia problems due to the lack of an interconnection to a strong utility. Whereas a strong utility can help support the power system in undesired events involving large power flow disturbances, an islanded system has less reserve power available for such events, and the availability of the majority of reserve power is subject to more laborious mechanical processes (i.e., CGT governor reaction) that introduce unavoidable and often unacceptable time delays.

Fig. 3 shows the response of a CGT to a 5 MW step-load increase. Series 3 represents the electrical response of the machine to this 5 MW load increase. As the figure shows, the machine electrically responds to the additional 5 MW instantaneously; however, Series 2 shows the mechanical response of the machine to the load increase. The mechanical response lags the electrical response because of the time involved to increase the mechanical power output (send a signal to open the fuel valve, mechanically open the fuel valve, counteract the deceleration of the turbine, etc.). The result is that the frequency (Series 1) begins to decline very steeply until the increase in mechanical power catches up to the increase in electrical power. Hence, the electrical output of the machine can accommodate the increase in load; however, it comes at a cost of frequency, and the frequency will continue to erode until the mechanical output of the machine catches up to the electrical output. Accordingly, depending upon the speed of this response, the frequency may degrade to a point where the machine experiences fuel and air flow pressure problems.

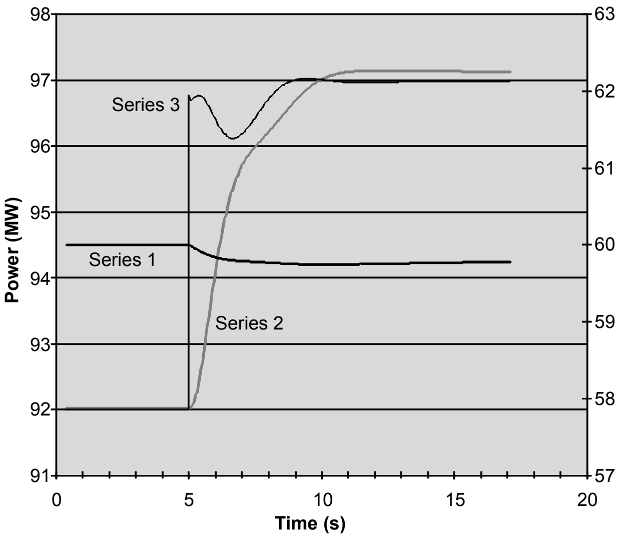

Fig. 3 CGT response to a step-load increase [1]

IV. HIGH-SPEED LOAD SHEDDING AS A SOLUTION

To prevent frequency excursions beyond stability margins as a consequence of generation loss, dynamic high-speed load shedding is becoming an essential solution. The theory behind load shedding is a simple principle of balancing generation to load. If load exceeds generation by way of unexpected power system faults, the high-speed load-shedding system responds by tripping a precalculated amount of load that allows the system to maintain a generation-to-load balance while minimizing the impact on system processes.

In simple terms, high-speed load shedding does nothing more than add and subtract available system capacity and current system load to determine what is required to shed, given any predefined contingency (power loss event). To that extent, the most basic way of describing the load-shedding process and, specifically, the amount of load required to shed, given any predefined contingency, can be defined as shown in (4).

$$L_n = P_n - \sum_{g=1}^{m} IRM_{ng} \tag{4}$$

where:

n = contingency (event) number

m = number of sources (generators) in the system

g = generator number, 1 through *m*

L_n = amount of load selected for event *n* (MW)

P_n = power disparity caused by event *n* (MW)

IRM_{ng} = incremental reserve margin of all generators (sources) remaining after *n* event (MW)

The only term in the above equation that solicits further explanation is the concept of incremental reserve margin (IRM), which is the instantaneous reserve that any given source is capable of supplying to the power system. This concept varies from source to source, and there are several ways to derive a value. In general, as described in Section III, every machine inherently possesses the ability to instantaneously supply a percentage of its base load capability. This percentage varies from machine to machine based on a variety of factors. The key to assessing the IRM of a particular machine lies in modeling that machine and simulating its response to various step-load increases under a variety of system configurations.

V. IRM CALCULATION

While there are several ways to determine the specific value for an individual machine IRM, this paper highlights only the most conservative technique. This technique simply involves modeling the machine and observing its frequency response to the sudden application of load or, in simple terms, the machine step-load response.

To do this properly, the machine must be modeled, and the computer model must be assumed to have no governor controller interaction. Essentially, the machine is operating in a locked valve condition where fuel flow to the machine cannot be increased or decreased. Under this scenario, when a machine is loaded, the electrical power matches the system loading, but the mechanical power lags, creating a negative frequency deviation. By observing the frequency deviation for a given step load, determining an IRM value is as simple as specifying an acceptable frequency deviation and matching that frequency deviation to a step-load response. The step-load value that corresponds to the specified frequency deviation can reasonably be assumed to be the IRM value of the machine.

For example, Fig. 4 shows multiple simulation runs to determine an IRM value.

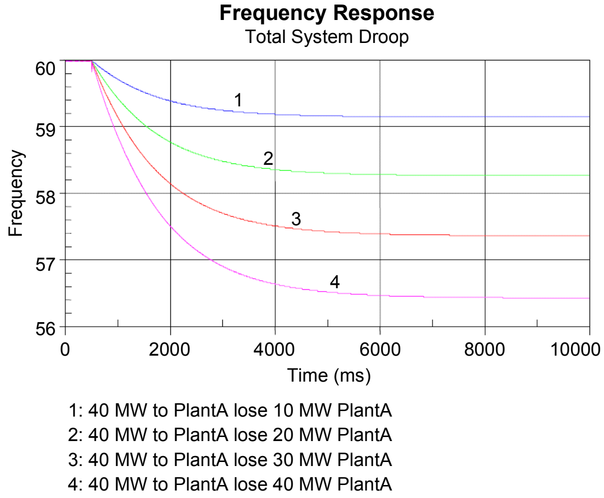

Fig. 4 CGT response to various step-load increases

These simulations show the response of the entire system to specific losses of power and how available machines would react to this loss of power, given no response from the machine governors. Obviously, some of these responses are acceptable and some are not. Cases where the system frequency stays above 58 Hz (on this 60 Hz system) can be considered acceptable. Anything below 58 Hz would not be acceptable because of coordination problems with the underfrequency backup load-shedding scheme and general machine flow and pressure operational thresholds.

More sophisticated calculations of generator IRM are possible, the most obvious inclusion being the reactivity of the governor controller. Whereas the above calculation neglects the response of the governor entirely, which may be a sensible idea and, if nothing else, at least sustains a more conservative approach, the inclusion of the governor response provides a more accurate depiction of the system response. The reasoning stands that the machine will react to a sudden increase in load according to its governing mode, not solely according to the merits of the machine itself. For example, machines in isochronous control mode vary their output power to maintain the system frequency. As load demand increases and decreases, the machine(s) operating in isochronous mode varies its power output to ensure the system frequency remains constant. All of this is done automatically and without user intervention, based on several parameters, the most obvious being system frequency feedback.

Considering that this control system is a mechanistic response to changes in system loading, it seems perfectly sensible to include this parameter in a model whose purpose is to provide a measurement of overall system response. Notwithstanding the apparent benefits of including the governor response to the machine model, the answer to the question "Why shouldn't the governor response be included?" can be most effectively rebutted with a question in return, "How well is your governor modeled?" The answer to the latter question is seldom encouraging, meaning that governor models are often severely lacking in adequacy and generally do not represent the actual response of the governor to an accurate enough degree.

Insomuch as the above paragraphs allude to the possible lachrymose outcomes resulting from the inclusion of an ill-prepared governor model, such outcomes can be avoided with proper testing. This is to say that the governor model should be simulated against the live system. Only after the simulated governor response has been properly vetted against the live system response can the model be relied upon for system calculations. This type of testing implies that the CGTs must undergo step-load testing. While most companies often find it difficult to justify the expense and complexity of such testing as a necessary preparation for proper system model validation, this testing is the only true indication of model accuracy. It should be noted that such testing requires, to the best of one's ability, a controlled environment. The authors understand the implications (in the eyes of the system owner) of doing such testing.

VI. AUTOMATIC GENERATION CONTROL

While high-speed load shedding can be thought of as a reactive control technique, meaning that only after a system disturbance has occurred will the remediation techniques (in this case, shedding load) be initiated, automatic generation control can be thought of as a proactive technique. By controlling the MW and MVAR output of the machine, operation within the optimal regions of the machines and sharing between the machines can be realized. The Saudi Aramco facility where this controller was installed is shown as Plant B in Fig. 2. Fig. 5 shows a slightly more detailed version of Plant B.

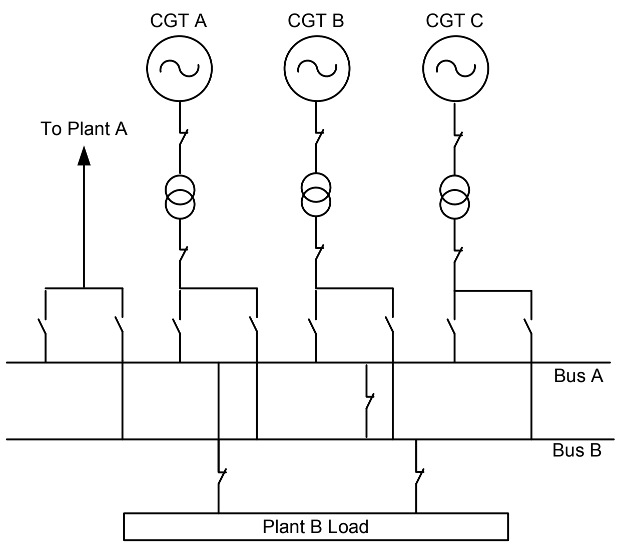

Fig. 5 Plant B detail

The generation control system (GCS) was implemented to control bus voltage via an interface with the generator exciter controller and MW output through an interface with the turbine governor controller. In addition, the units at Plant B control the MW and MVAR flow across the tie line to Plant A. Under this control strategy, the units at Plant B increase or decrease MW and MVAR output to maintain a given tie flow set point.

As a general operating principle, the tie line connection between Plant A and Plant B is normally closed. Units at Plant A are predominately operated in an isochronous current share control mode. This being the case, when Plant A is connected to Plant B, the units in Plant B operate in droop control mode, as Plant A is responsible for maintaining system frequency. It is the responsibility of the GCS to determine when the tie line connection is severed and shift an appropriate unit in Plant B to isochronous control mode to maintain the system frequency. Not only does the GCS recognize when Plant B islands from Plant A, it also recognizes when any system island occurs and responds by shifting an appropriate unit in Plant B to isochronous control mode. Looking at Fig. 5, Plant B can be islanded if it separates from Plant A, and it can also develop an island if the bus coupler coupling Bus A and Bus B opens together. Under any scenario, the GCS tracks the system islands and shifts an appropriate unit to isochronous control mode when it detects that an island has been created or dissolved.

It should be noted that the shifting of units to isochronous mode is not wholly necessary for proper system operation. Operating all units in droop mode while controlling the frequency speed reference set point is a perfectly adequate control scheme. While the frequency of the system will not be locked to the nominal system frequency, the variations and deviations from the nominal system will be relatively small and do not present undue operational risk to the machines connected to the system, except for any electric clocks that may still be in operation around the plant.

Load sharing is also accomplished through the GCS. Load sharing is a means to share the load evenly across the operating units to prevent one unit from being more heavily burdened than another unit. This particular feature is effective considering that the system is in operation with at least one isochronous unit at any given time. The isochronous unit is responsible for maintaining nominal system frequency; therefore, it must adjust its output to accommodate the plant load cycles. As the plant gets more heavily loaded at certain points throughout the day, the isochronous unit works to supply that demand. As a consequence, the isochronous unit will be more heavily loaded during peak demand and subject to considerable load variations in case of disturbances that may lead to a trip of the unit. It is this condition where the GCS load-sharing controller actively adjusts the output of the droop units to ease the burden of the isochronous unit and eventually distribute the load equally. This lasts until the next load shift, when the isochronous unit reacts first and machine loading is evened out by the droop units under control of the load-sharing control algorithm.

VII. AUTOMATIC SYNCHRONIZATION

Considering that the GCS has a means to control the generation output and voltage, an obvious feature of the system would be to automatically synchronize two buses together after an islanded condition has been created. As shown in Fig. 6, the ability to interface with the governor control system of the unit provides the ability to control the power output. Consequently, the frequency of the system and an interface into the exciter controller of the generator offer a means to control the voltage of the system. Combining these two features, provides everything that is needed to efficiently and effectively synchronize two separate systems and close in a coupler breaker.

As can be seen in Fig. 6, the autosynchronizer is receiving currents and potentials from both sides of the bus coupler. In this particular example, the autosynchronizer is controlling CGT B to adjust the frequency and voltage of the system to facilitate the closing of the coupler breaker. Once the frequency, slip, phase angle, and voltage are within a certain bandwidth, the bus coupler can be closed. Until the two buses are within the bandwidth, CGT B is being controlled very loosely.

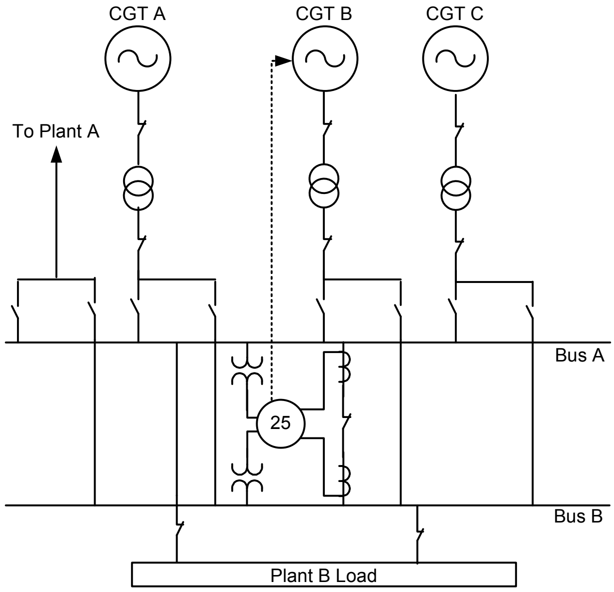

Fig. 6 Autosynchronizing (example scenario)

The autosynchronizer controller chooses the unit to control based on which CGTs have been islanded and, from the CGTs that have been islanded, which CGT is in isochronous control mode. Based on these factors, the actual unit chosen by the system to perform the synchronizing varies according to different operational scenarios. It is the responsibility of the autosynchronizing controller to decide, based on the above criteria, which unit is controlled.

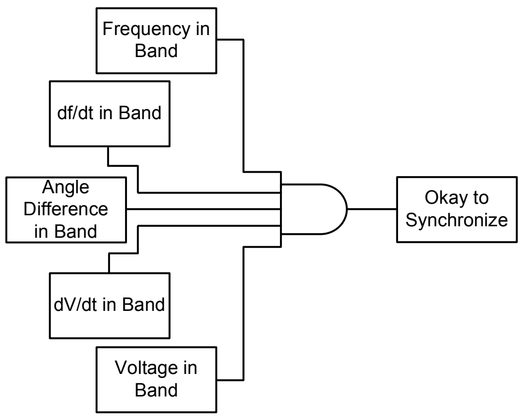

Fig. 7 High-level synchronization logic

An operator initiates the automatic synchronization function through an HMI (human-machine interface). As shown in Fig. 8, the real-time synchroscope serves as a visual indication of when the two buses are within proper range for bus coupler closure. While the indication is in real time (manual operation of the synchroscope is not permitted), the controller is solely responsible for permitting the coupler breaker to close.

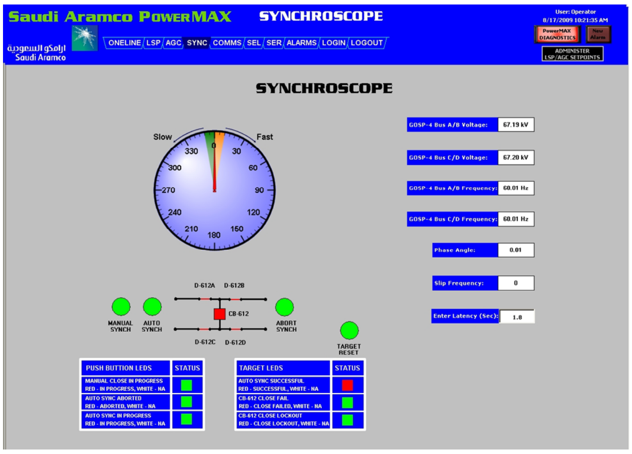

Fig. 8 HMI synchroscope interface

VIII. MOTOR STARTING

In an islanded mode of operation, the starting of large motors is a challenge because of the limitation in voltage control capability. The PMS utilizes the CGT and synchronous motor excitation capabilities to support the motor starting of large motors as a prestart condition. This has been achieved through direct interface between the PMS and the CGT and synchronous motor excitation systems.

Operationally, large synchronous motors can be started through the PMS when the operator initiates the starting signal via the PMS HMI interface. The PMS controller interfaces directly with the exciter packages of the CGT and large synchronous motors that are available and issues commands to overexcite the units. The CGTs are monitored in real time to ensure each unit is operating safely within its capability. The overexcitation boosts the system bus voltage and helps reduce the anticipated voltage drop during motor starting. After a certain time delay, the PMS returns the excitation of the generation and synchronous motors to their nominal values.

IX. CONCLUSION

With the use of microprocessor-based relays, the addition of a PMS to any facility is becoming less of a separate system and more of an integrated package. The only equipment added to the Saudi Aramco facility outside of the requisite protective relays was rugged, highly reliable controllers running the load-shedding and GCS control algorithms. The protective relays provide all required status and analog values, and load-shedding trip signals are sent from the load-shedding controller directly to the relays protecting the sheddable motor loads. The combination of the protective relays interfacing directly with the PMS controllers provides a simple and elegant solution, without the need for communications gateway devices or less reliable PLCs (programmable logic controllers). (See the appendix for further explanation.) Such architecture requires minimal extra equipment, thereby providing superior reliability at a price only marginally higher than the price of the protective relays alone.

X. REFERENCE

[1] E. R. Hamilton, J. Undrill, P. S. Hamer, and S. Manson, “Considerations for Generation in an Islanded Operation,” proceedings of the 56th Annual Petroleum and Chemical Industry Committee Technical Conference, Anaheim, CA, September 2009.

XI. APPENDIX

Using PLC Vendor A as a comparative test case (a major PLC manufacturer who has an advertised mean time between failures [MTBF] of 400,000 hours, which equates to roughly a 46-year MTBF) and rugged computer Vendor B, who advertises an observed MTBF of roughly 150 years, shows the advantage of using ruggedized computers in lieu of PLCs.

XII. VITAE

Musaab M. Al-Mulla graduated from King Fahd University of Petroleum and Minerals in 1998 with a B.S. in Electrical Engineering. After graduation, Musaab joined Saudi Aramco in the power distribution department, where he was responsible for the engineering, operation, and maintenance work related to power generation and distribution at Saudi Aramco facilities, focusing mainly on relay coordination studies and generation control. In 2002, Musaab graduated from Arizona State University with an M.S. in Electrical Engineering/Power Area. In 2005, he joined the project management team at Saudi Aramco, where he has been involved in the development, design, construction, and commissioning of all electrical activities related to the power generation facilities in the Shaybah Expansion Project. In 2009, Musaab rejoined the Power Distribution Department as a power generation specialist.

Nicholas C. Seeley graduated from the University of Akron in 2002 with a B.S. in Electrical Engineering. After graduation, Nic began working at American Electric Power in Columbus, Ohio, for the station projects engineering group, where he focused on substation design work. In June 2004, Nic was hired at Schweitzer Engineering Laboratories, Inc. in the engineering services division, where he is currently an engineering supervisor involved in the development, design, implementation, and commissioning of numerous automation-based projects specifically geared toward power management solutions.

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