Case Study: Simultaneous Optimization of Electrical Grid Stability and Steam Production

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CASE STUDY: SIMULTANEOUS OPTIMIZATION OF ELECTRICAL GRID STABILITY AND STEAM PRODUCTION

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Abstract—Steam production and electric power system stability are often competing interests in an industrial refinery. Optimal control of steam production is required to meet plant process operating requirements, and electrical grid stability is required to prevent power system blackouts. For many industrial plants connected to a utility grid, both operating criteria cannot be met simultaneously, placing the power system in serious jeopardy of a blackout.

Steam turbines, which are controlled to produce a desired tonnage per hour of steam, can hinder the ability of a power system to avoid blackouts. This issue occurs at any facility in which electric power is derived from steam turbines running in extraction flow or pressure control modes.

The issue is explained using modeling and in-field results from a refinery with several three-stage extraction turbines, a large refinery load, and several utility grid interconnections. The implications of running these turbine governors in pure extraction priority, pure power priority, or mixed extraction and power priorities are explored in this paper.

A comprehensive electric dispatch control strategy used at the facility is shared. This control system optimizes electrical grid stability throughout the facility while simultaneously interfacing with a steam optimization system.

Index Terms—Steam optimization, grid stability, droop, blackout prevention, dynamic disturbance rejection, real-time modeling, turbine load sharing.

I. INTRODUCTION

The first part of this paper explains the basics of how steam turbines (STs) produce power, how they are controlled for extraction and droop, and how governors provide dynamic disturbance rejection in an electric power system. The authors discuss and explain the contradiction between steam control and a stable electric power system. The topic of islanded frequency control is shared to clarify this often-debated point.

In the second part of the paper, the specifics of the case study project at a refinery are shared. This discussion includes a review of frequency control, adaptive boundary controls, and autosynchronization. The paper also reviews the modeling of the case study facility, which included performing model validation, modeling a three-valve turbine and governor, and examining system performance data.

II. POWER PRODUCTION IN STEAM TURBINES

STs operate across a pressure differential, producing power as the mass flow of steam flows across the turbine blades. Equation (1) states that the rotational mechanical power output of an ST is proportional to the mass flow rate of steam in tons per hour. This equation holds true assuming that the pressure and moisture content of each pressure header remain constant.

$$\text{Turbine Power Output (MW)} \propto \text{Steam Flow (tons/hr)} \quad (1)$$

As shown in Fig. 1, steam is produced at the high-pressure (HP) header by some type of boiler.

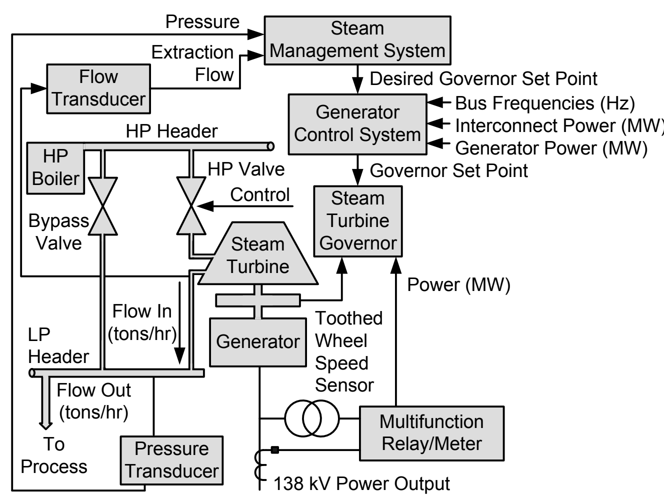

Fig. 1 Typical Industrial Steam and Turbine Control System

Boilers convert the thermal energy of a burning substance, such as coal, oil, or gas, into HP steam. The ST exhausts steam to the low-pressure (LP) header. This LP steam is commonly used throughout an industrial process to drive loads, such as dryers, heaters, and rotating turbines. These process loads consume steam in tons per hour. The difference in steam production and consumption mass flow rates determines the pressure in a header, as shown in (2).

$$\text{Pressure} \propto \text{Time} \int \begin{pmatrix}\text{Steam Flow In [tons/hr]} - \\ \text{Steam Flow Out [tons/hr]}\end{pmatrix} \quad (2)$$

Equation (2) shows that for the pressure to rise, there must be more steam going into the header than leaving it. For the pressure to fall, there must be more steam leaving the header than going in. Thus a system controlling header pressure has to gain control of the steam flow into or out of the header.

STs in industrial process facilities are commonly set to produce steam using one of the following two methods:

- Extraction control. The ST is controlled to produce a constant amount of steam in tons per hour.
- Pressure control. The ST is controlled to produce a constant pressure (kPa) at the LP header.

For both of these schemes, the steam management system (SMS) accomplishes extraction and/or pressure control by sending a desired governor set point to a generator control system (GCS). The GCS then evaluates the set point, determining if the requested value is acceptable to maintain electrical grid stability. If it is acceptable, the set point is passed on to the ST governor.

Steam extraction or pressure control loops commonly exist in the SMS, GCS, or governor. Regardless of where they exist, these extraction or pressure control loops operate at slow time constants of 60 seconds or slower. These time constants are defined by the rate at which the LP header changes pressure in response to changes in flow caused by new governor set points.

For this discussion, STs running in extraction or pressure control mode are constant power devices for time constants above 60 seconds. For the LP header to stay at a constant pressure, the ST power output must be directly proportional to the average process steam consumption in tons per hour. Thus, to maintain LP header pressure, the long-term droop characteristics of the ST are overridden by process steam consumption on the LP header.

III. GENERATOR FREQUENCY CONTROL

Electrical motors and generators must operate in a narrow frequency range. Frequencies outside of this range can cause motor damage through overheating or excessive internal mechanical stresses on the motor windings and/or steel laminations. (Note that most rotating loads, such as compressors, fans, conveyors, and crushers, are very resilient when it comes to speed variations.) The synchronous generators converting mechanical power to electric current and voltage must also operate within these strict frequency boundaries for a large host of reasons [1]. Protective relays are used to trip the motors and generators if the measured frequency of the voltage is outside of this range. Therefore, some type of speed (frequency) control system is required to keep a power system online.

Turbine governors indirectly control power system frequency. Turbine governors control the rotating speed of a turbine to within a tolerable range during disturbances such as a sudden loss of electrical load or generation. The generator creates a voltage with the same frequency as the rotating speed of the turbine. Electromagnetic forces in the air gap between the generator stator and rotor keep the generator rotor (and turbine) in synchronism with the power system frequency. Thus a governor controls power system frequency by changing the mechanical power output of the turbine.

Governors modify their turbine valve control signal as a function of both speed (frequency) and power; this is called droop. The following are two ways to accomplish droop in a governor:

- Active power control with a speed droop term.
- Speed control with an active power droop term.

These two methods provide the same steady-state relationship between active power and speed (frequency). The droop relationship between power and frequency is plotted as the solid line in Fig. 2.

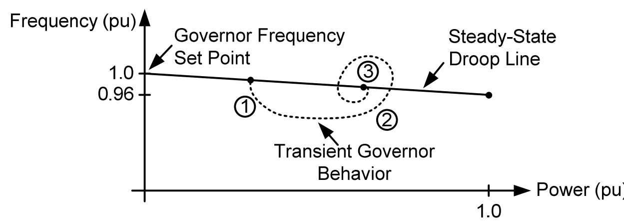

Fig. 2 Steady-State and Transient Droop Characteristic

The dotted line in Fig. 2 illustrates what happens to the power system frequency when a load is suddenly added to an islanded power grid. At Point 1, the starting of the motor extracts kinetic energy from the rotating mass of the ST, generator, and all other spinning loads, slowing down the power system frequency. The governor then responds (typically in less than 1 second) by increasing the turbine power, as shown with Point 2. The power and frequency commonly oscillate, eventually converging onto the steady state at Point 3. The droop line in a governor defines the steady-state operational point of the electric power system. However, inertia, tuning, and load composition define the transient relationship between frequency and electric power consumption in Fig. 2.

It is worthwhile to note that the frequency set point in Fig. 2 is raised or lowered by the GCS to maintain the long-term system frequency at nominal.

IV. DYNAMIC DISTURBANCE REJECTION

Properly tuned governors prevent unstable frequency runaway and, hence, maintain electric power system frequency stability. Because not all governors run in droop mode, it is worthwhile to categorize the possible relationships between frequency and power in a governor. Fig. 3 shows the droop, isochronous, unstable, and constant power modes of operation.

To quantify the ability of a governor-turbine combination to maintain system frequency, a simple scenario is used to evaluate each of the characteristics shown in Fig. 3. Consider for a moment a scenario where the electrical load increases from Point A to Point B.

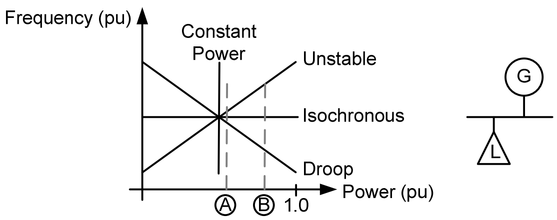

Fig. 3 Frequency and Power Characteristics

The increase in electrical load causes a drooped governor to increase power output, thus preventing a cascading fall in frequency. A governor configured for isochronous control also increases its power output in this scenario. Thus both droop and isochronous governors increase the turbine power output to compensate for the increase in load. This tends to keep the power system frequency stable. A governor rejects disturbances when the power system frequency is kept relatively constant in this manner.

The result of increasing electrical load on a constant power governor is quite different. Because the governor constantly forces a specific power output from the turbine, the frequency of the power system falls catastrophically if the load exceeds the constant power production set point. The same occurs, but to a lesser extent, for the unstable line. Note that steam extraction and pressure control are effectively constant power modes of operation, and thus they cannot reject long-term disturbances or keep islanded power system frequency constant.

To prevent a steam extraction turbine from destabilizing a power system, the governors are kept in droop mode operation, with slow outer-loop ST extraction and pressure control, as shown in Fig. 4. The outer extraction or pressure loops are tuned to be very slow (60 seconds or slower, commonly). This allows the drooped characteristic to maintain short-term transient stability, as shown in Fig. 2. Thus, in a time domain, the droop line is obeyed for a few seconds, but the constant power and flow rate are obeyed after several minutes. In other words, the governor droop control saves the electric power system from frequency decay for a few seconds, but the ST extraction loop drops the power system frequency a few minutes later.

Thus the constant power mode behavior of extraction turbine controls creates long-term frequency instability when a plant is islanded from the utility grid.

V. CONTROL TIME CONSTANTS

It is problematic that constant steam extraction and robust speed control cannot be satisfied simultaneously in a power system. This problem is resolved in the short term by cascading loop control systems with different time constants of control within each cascading loop (see Fig. 4). It is important to understand the control time constants of each of the control loops shown in Fig. 4.

The unit megawatt control, tie flow control, and frequency control in the GCS control loops are typically set 10 times slower than the governor closed-loop speed and droop control time constant. With most ST governors tuned to approximately 1 second, the GCS unit megawatt control is typically set to 10 seconds or slower.

The SMS steam extraction and pressure control loops are set approximately 5 to 10 times slower than the GCS controls; therefore, time constants of 60 seconds or greater are common.

VI. THE CONTRADICTION

If an industrial power system is connected to a large electric utility, the power system frequency changes little. However, once the industrial power system is islanded, the frequency becomes heavily dependent on the tuning of the governor, load composition effects, machine droop, and disturbances.

It is during these islanded conditions that the contradiction between steam production and power system stability occurs most dramatically. The drooped governor speed regulator is sent new set points by the slower extraction control system, which has the sole purpose of keeping a constant tonnage per hour of steam production and therefore a constant electric power production level. This extraction control system raises or lowers the governor speed set point to achieve the required steam flow, regardless of what is happening to the power system frequency. Changes in process steam consumption can run a power system frequency too high or low, causing a frequency-induced blackout of the electric power system.

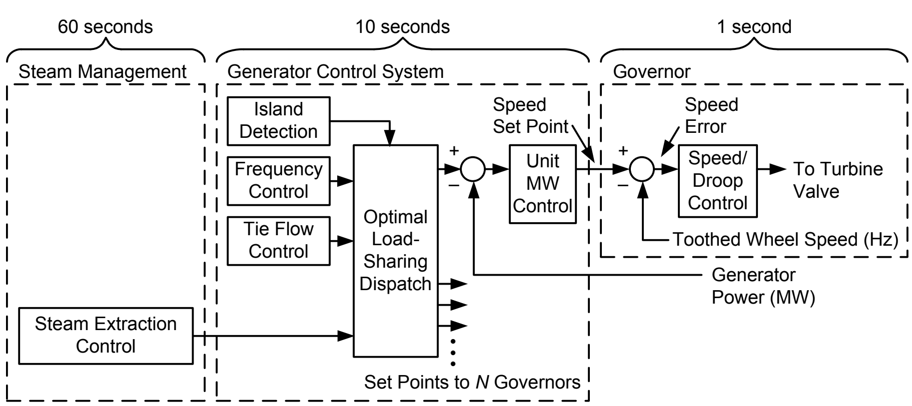

Fig. 4 Steam, Power, and Frequency Control Loops

To avoid a frequency-induced blackout during islanded conditions, the outer extraction control loops controlling the generator set points must be removed. To maintain the header pressures, the SMS therefore switches from controlling the generator set points to controlling the bypass valve between the HP and LP headers (see Fig. 1). Thus, in an islanded mode, the process load (not the turbines) must be throttled up or down to maintain steam header pressures. Steam load shedding and valve feed-forward control are commonly employed to preserve header pressures should the bypass valve provide insufficient control for the SMS.

VII. KEEPING GENERATOR OUTPUTS BALANCED

Islanded or not, the output from parallel-connected generators must be balanced in some way. The riskiest place to operate a turbine is at its upper or lower limit because the likelihood of tripping a turbine offline increases substantially. For example, should a disturbance in the form of a motor trip occur, a turbine close to zero output is likely to trip on reverse power as the governor correctly tries to close the control valve and prevent frequency overshoot. It is for these reasons that a turbine balancing system is used in a GCS.

For utility-connected generators, the need to balance turbine loading is less critical, unless it is possible that an islanded condition could happen at any moment. Generators that are expected to operate while separated from a utility grid (islanded) should always be load-balanced to minimize the possibility of tripping during transient conditions that may occur after islanding.

Balancing the loads of multiple turbines becomes more complicated when multiple differently rated units are connected in parallel on an industrial power system. For example, if a 20 MW unit is on the same grid section as a 100 MW unit, both units cannot possibly be dispatched to the same power output. Instead, the technique of equal percentage load sharing between generation units is used.

The concept of equal percentage load sharing is a matter of loading all the units on a grid to the same percentage loading factor. To further complicate matters, it is common for turbines to have unstable operational areas or undesirable areas of operation (for example, low NO_x emission lines in combustion turbines). The solution to these problems is to create artificial upper and lower limit boundaries that are user-settable, as shown in Fig. 5.

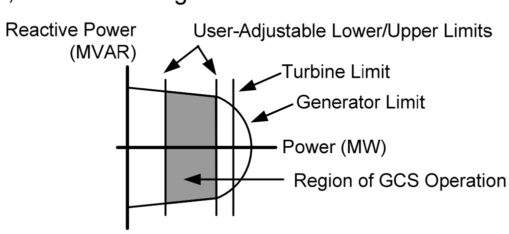

Fig. 5 GCS Operational Conditions

A fully functional GCS must accomplish the following simultaneously:

- Keep a generator and turbine within the region of GCS operation shown in Fig. 5.
- Satisfy equal percentage load sharing between turbines of different ratings and technologies.
- Keep an islanded power system at nominal frequency by raising or lowering the power output of all turbines in the island.
- Keep a grid-connected power system at a nominal intertie power flow by raising or lowering the power output of all turbines that are electrically connected to the tie line.
- Dispatch turbines to the SMS set points when connected to the grid.
- Ignore SMS turbine set points when islanded.
- Send feed-forward signals to the bypass valves and trip the steam loads to prevent steam header pressure problems during islanded conditions.

VIII. GOVERNOR MODES AND ISLANDED FREQUENCY CONTROL

There are many options to control system frequency on an islanded power system with multiple generators. These options are often debated and worth explanation. In each of these cases, an outer-loop controller (such as a GCS) is required to keep one or more units within their limits. The control scheme for each option is detailed in the following subsections.

A. All Governors in 0 Percent Droop (Isochronous)

A 0 percent droop turbine (also known as an isochronous unit) keeps the power system at a constant frequency. With multiple parallel-connected isochronous governors, it is very common for a small disturbance to cause units to oscillate in megawatts unnecessarily. Generators have been known to trip when paralleled in this mode. Governor tuning and some isochronous-sharing control strategies can reduce these effects. The authors consider parallel-connected isochronous turbines to not be naturally stable and to be difficult to tune robustly.

Parallel-connected isochronous turbines require a high-speed isochronous sharing control system to dispatch the governors simultaneously and provide interturbine electrical oscillation damping. The central controller and associated power supplies, wiring, and communications cabling become points of failure. If any of these fail, the turbines will oscillate dangerously and, commonly, the electric power system will also fail.

The authors do not recommend this method for any power system.

B. One Unit Isochronous, Remainder in Droop

Some small, low-inertia power systems with very tight frequency requirements can take advantage of operating one unit in isochronous mode and the remainder in droop mode. Grid operation with one unit in isochronous mode is commonly used by power system utilities to start up a grid after a system-wide blackout.

In this scenario, the isochronous unit keeps the power system at a constant frequency. The remaining droop units must therefore be redispatched by the GCS load-sharing algorithm to keep all the units equally sharing load. The strategy is to push the isochronous unit to equal percentage load sharing with the droop units by raising or lowering the droop unit set points. Without continuous load sharing, the isochronous unit will commonly run to a maximum or minimum, often resulting in the isochronous unit tripping. Should multiple islands form, the GCS must force one generator on each island into isochronous mode. The loss of GCS load sharing is not catastrophic to the power system.

The authors recommend this method as a viable second-choice scheme for governor-mode control of islanded industrial facilities.

C. All Units in Droop

Most power systems throughout the world operate with all units in droop mode. However, droop mode is sometimes not appropriate for low-inertia power systems with very tight frequency requirements.

In this mode, all turbine speed governors are set to the same droop. This mode of operation is suitable for large systems because the system inertia (the spinning mass of all its generators and loads) of a large system makes the natural rate of decay of frequency slow enough for the combined efforts of a GCS and drooped governors to effectively regulate frequency within reasonable limits. Without a GCS dispatch, the frequency is not constant and can deviate from nominal by several hertz.

In droop mode, a GCS adjusts the governor set points of all units simultaneously to keep the power system at nominal frequency. Equal percentage load sharing is accomplished simultaneously with nominal frequency control. Droop mode is always recommended by the authors as the first-choice scheme for governor-mode control of islanded industrial facilities. This mode is considered the most robust frequency control scheme because there are two layers of backup load sharing and frequency control, thereby eliminating single points of failure. The loss of GCS frequency regulation and load sharing is not catastrophic to the power system because parallel units operating in droop naturally provide limited amounts of frequency regulation and load sharing. The case study facility this paper describes is set up with all of its governors in this mode.

IX. CASE STUDY CONTROL SYSTEM

A simplified one-line diagram of the case study plant is shown in Fig. 6.

Several issues make the plant unusually complex in regard to simultaneous optimization of steam and electricity, including the following:

- The plant uses three different governor controllers and three different turbine technologies.
- The system has three three-stage STs.
- The plant has a very complex electrical topology. Six different potential power system islands must be tracked concurrently.
- The plant has been in service for approximately 30 years. This made the installation, wiring, commissioning, and testing of the control system complicated and time-consuming.
- Significant modeling effort was required to accurately predict the dynamic response of this large facility. This included significant load composition modeling and customized governor models.
- This system is known to exhibit both voltage- and frequency-induced power system collapses. The supplied control system corrected both problems.

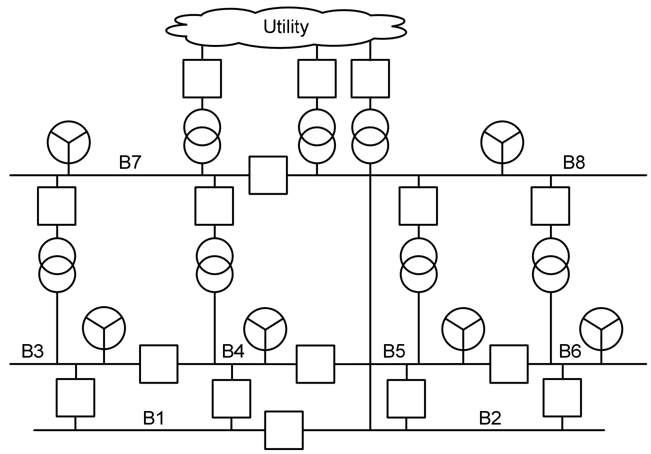

Fig. 6 Simplified Plant One-Line Diagram

A. Control System Design

The detailed functional design of the plant control system is itemized in a voluminous proprietary document; therefore, this section can only serve to provide a high-level overview of the major control systems put into place at the facility. Many details of these systems are omitted, such as voltage control, VAR control, on-load tap changer (OLTC) control, load shedding, and generator tripping. Only controls related to power and steam are explained here because they are pertinent to the conclusions in this paper.

The supplied control system is a *separate, survive, and synchronize* type of scheme, which is described as follows:

- Separate. Automatically separate the system from a failing utility grid.
- Survive. Shed load or generation to rebalance the electric power system. Simultaneously control system frequency, generator power output, generator VAR output, and bus voltage of the entire islanded facility.
- Synchronize. Upon operator initiation, quickly and automatically resynchronize after the adjacent grid recovers.

B. Islanded Frequency Controls

The case study power system shown in Fig. 6 can be broken into six independent and simultaneously operational islands. The GCS was therefore designed to detect and track six different possible island formation combinations. Should any of these islands form, the controls automatically switch each of the three-stage governors out of extraction priority into droop. The GCS automatically creates new control arrangements for each of the multiple islanded systems. For example, in the condition where six islands exist, six completely simultaneous and autonomous solutions are required for active GCS control.

The GCS simultaneously controls the dispatch of any number or combination of parallel-connected turbines to equal percentage load sharing and the frequency set point criterion. Load sharing keeps the positive and negative reserve margin allocation between turbines to an identical percentage loading. Identical percentage load sharing optimizes the spinning reserve of all the units operating in parallel in the same island. By keeping each unit equally loaded as a percentage of its total capability, the controls ensure that each unit has an equalized percentage of spinning reserve.

C. Adaptive GCS Operational Boundary Conditions Based on Steam Condensing Valve Positions

The user-entered upper and lower boundaries of the generic GCS algorithms shown in Fig. 5 were found to be insufficient for the three-stage governors in the case study facility. During nonislanded conditions where the GCS was to control intertie flows with the utility, only the third valve (condensing valve) was available for active power dispatch control. This was because the governor controlled Valves 1 and 2 (V1 and V2) to meet steam extraction requirements at the intermediate-pressure (IP) and LP headers (see Fig. 7). During nonislanded conditions, this particular governor gave clear priority to the needs of the plant for continuous steam extraction flow.

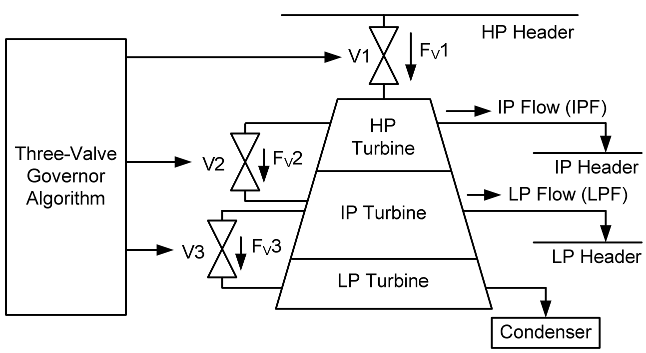

Fig. 7 Three-Valve Turbine System Model

The third valve (condensing valve) was discovered to supply approximately 14 percent of the turbine power output as the third valve varied from fully closed to fully open. The governor algorithm used the third valve to provide a 4 percent droop characteristic over this 14 percent power swing range. This created a scenario where the lower operational boundary for generator power dispatch was defined by the position of the extraction valves of both pressure headers (as shown by Line A in Fig. 8). The upper operational boundary was created by the 14 percent power contribution limit of the third valve (as shown by Line C in Fig. 8). Thus the GCS derived the upper and lower operational boundaries of the three-stage turbines by tracking the position of the third valve (condensing valve) and the unit extraction.

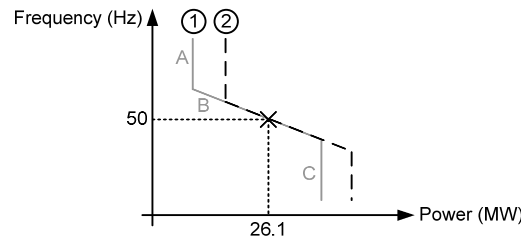

Fig. 8 Graphical Depiction of the Droop Line for a Change in IPF Set Point From 100 (Line 1) to 105 (Line 2) Tons Per Hour

D. Nonislanded Tie-Line Controls

The GCS was designed to detect hundreds of possible tie-line and grid-connected plant configurations (topologies). The GCS automatically creates new control arrangements for each of the multiple tie lines. For example, in the condition where three grid sections are fed by three different tie lines, three completely autonomous solutions are required for active GCS tie-line megawatt control. Simultaneous to controlling the three tie lines, load sharing keeps the positive and negative reserve margin allocation between turbines to an identical percentage loading.

Alarms are generated should any two generators or incoming transformers be paralleled together at Busbars B1, B2, B3, or B4 (see Fig. 6). This condition is not allowed because the combined fault duty exceeds breaker ratings.

E. Island Autosynchronization

The autosynchronization systems for the facility measure voltage and frequency on all possible combinations of islanded and utility-connected grid sections. The systems send proportional correction pulses to adjust the governors and exciters of multiple parallel-connected units on each bus section as necessary. The close supervision relay automatically closes the breaker upon identifying satisfactory conditions of slip, voltage, and slip-compensated advanced angle [2].

X. CASE STUDY MODELING

A custom governor and turbine model was built to accurately depict the nonlinear extraction mode characteristic of these three-stage turbines and associated governors. This nonlinear characteristic provides for an easily controllable steam generation system for the on-site process; however, this same characteristic provides very limited dynamic stabilization for the electric power system.

The model was specifically developed to validate the functionality of the *separate, survive, and synchronize* control system described previously. The control systems were connected to simulation hardware, with a real-time software model loaded onto it, to enable closed-loop testing of the control systems during factory acceptance testing.

A closed-loop real-time simulation, as depicted in Fig. 9, minimizes commissioning time for large control and protection systems. The authors modeled the dynamics of the plant power system with a simulation time step sufficiently fast to test all closed-loop control and protection systems. Thousands of test cases were run with the automated capability of the modeling equipment, providing plant personnel with a great amount of confidence that all systems would react as expected under the most adverse scenarios.

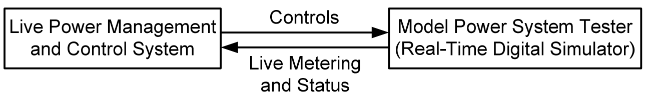

Fig. 9 Closed-Loop Real-Time Simulation

A. Model Validation

Once a model is constructed, it must be validated. A methodical validation process was used to prove that the created model was an accurate representation of the plant power system.

The following subsections outline the model validation methods.

1) Short-Circuit Validation

Fault current magnitudes between the real-time model and the values provided by plant personnel were compared. This confirmed that the transient and subtransient impedance values were correct. Saturation modeling was validated in this process as well. Real fault currents from protective relays are the best source of data for this validation method if the records can be correlated with system topologies and units.

2) Load Flow Validation

For standard islanded and nonislanded conditions, the active and reactive power flow and voltage magnitudes were compared to field experience. This confirmed that steady-state impedances and load values were correct in the model.

3) Generator, Turbine, and Governor Transient Validation

Standard IEEE models are rarely adequate to provide any realistic validation results. IEEE models are built to categorize different types of governing systems used in the industry, but they do not represent the actual detailed models required to create an accurate dynamic model. To overcome the shortcomings of these oversimplified models, custom models are used. Custom models can be acquired from some governor and turbine manufacturers, but these are often oversimplified and have inaccurate or unknown tuning constants. The only way to truly model the dynamics of a combined governor, turbine, and generator unit is to use a detailed back-to-basics mathematical derivation of the system. The system model parameters are derived from mechanical designs, operational experience, and observational data [3].

To validate the transient behavior of a power system, it is critical to first validate the individual governor, turbine, and generator sets. Step response data captured from the real-time digital simulator model are compared to field experience in this exercise. The outcome of these tests validates the generator, turbine, and governing system models. Inertia, damping constants, and slew limiters are all confirmed to be accurate in this exercise. This is the most rigorous and time-intensive form of validation. It also requires the largest amount of skill and experience to properly evaluate.

During the validation of the case study plant extraction turbine and governor model, it was discovered that the relationship among steam, droop, and controls was nonlinear and data from the site could not be reconciled with model output. Therefore, a custom model was designed, built, and validated to simulate the three-stage steam extraction turbines and their associated governors.

B. Load Validation

Due to the limitations of the number of loads that can be modeled, all of the plant loads in the facility were lumped into one of five categories: induction motors connected to pumps, induction motors connected to conveyors, synchronous motors connected to compressors, pulse-width modulated variable speed drives, or constant current variable speed drives.

Sheddable and nonsheddable lumped loads from one or more of the five categories were added to every load bus to enable real-time tripping of sheddable loads. A total of 123 lumped load models were derived from approximately 500 total plant loads.

Load inertia was calculated for all load types. Inertia was not counted for some loads because the high gearbox ratios connecting the induction motor to the belt made the transferred inertia to the electric power system insignificant.

Lumping the direct-on-line (DOL) load models was challenging due to the greatly varying starting and running torque versus speed characteristics of the different types of DOL loads in the plant. The double-cage induction motor model shown in Fig. 10 was selected as the lumped DOL induction motor model for all locations. The model shown in Fig. 10 was adapted to model all single and double rotor bar-constructed motors throughout the plant. The equivalent resistance and reactance parameters of the lumped double-cage induction machines were derived through a proprietary process.

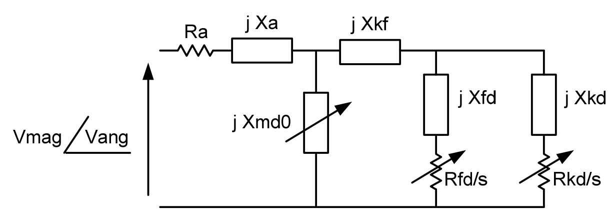

Fig. 10 Equivalent Circuit of the Double-Cage Induction Motor

C. Three-Valve Turbine and Governor Model

The authors created a new three-valve turbine and governor model (see Fig. 7) to accurately represent the following:

- The turbine governor controls both power production and steam production simultaneously.
- Two modes of control are possible: droop priority and extraction priority.
- In droop priority mode, the droop line is met as the first priority, and IP and LP extraction set points are

followed if possible. Fig. 2 depicts this mode of operation.

- In extraction priority mode, IP and LP extraction set points are met as the first priority, and the droop line is met if possible. Fig. 8 depicts this mode of operation.
- In extraction priority mode, a limited 4 percent droop line is accomplished, as shown in Fig. 8.
- The three valves are simultaneously controlled to simultaneously follow extraction set points from the SMS and power set points from the GCS.

D. Validation of Three-Valve Turbine and Governor Model

Fig. 11 shows the typical response characteristics of a three-valve turbine governor set.

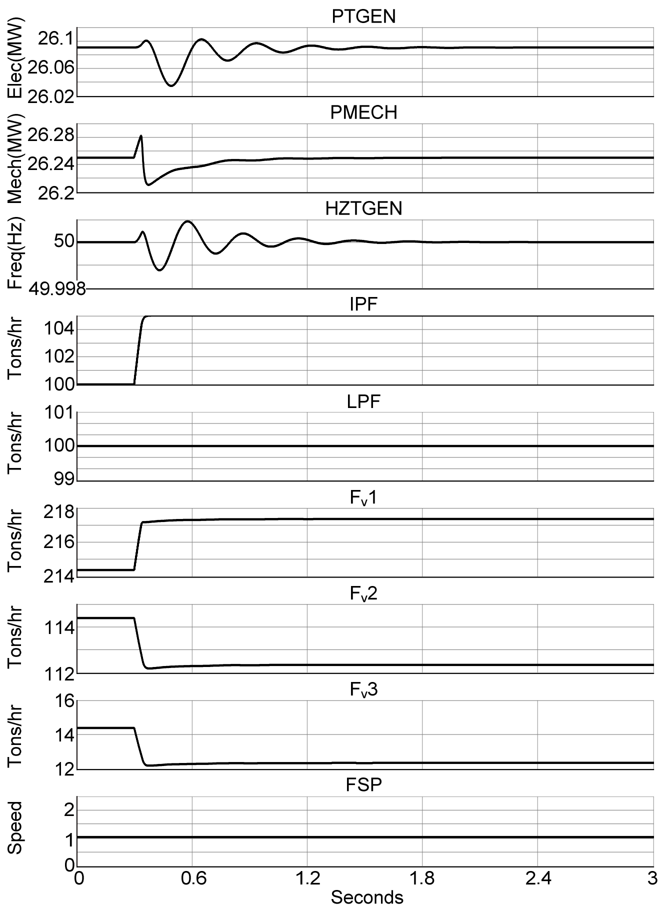

Fig. 11 Changing IPF Set Point From 100 to 105 Tons Per Hour

The plot in Fig. 11 represents a case whereby the IPF set point was changed (without a ramp rate limiter) from 100 to 105 tons per hour of steam flow. There are a number of critical items to point out from Fig. 11, including the following:

- IPF followed the new set point of 105 tons per hour.
- LPF stayed at 100 tons per hour throughout the disturbance.
- Valve 1 (V1 in Fig. 7) opened, causing the flow in Valve 1 (F_v1) to increase.
- Valves 2 and 3 (V2 and V3 in Fig. 7) closed, causing the flow in Valves 2 and 3 (F_v2 and F_v3) to decrease.
- The power produced by the turbine was momentarily disturbed, but it regained its steady-state set point after about 1 second.

Fig. 8 shows the movement of the droop line for the event shown in Fig. 11. The change in IPF rates adjusted the low power limit upward, as signified by the movement from Line 1 to 2. Simultaneously, the droop line did not move; however, its upper and lower limits were adjusted by the new IPF rates.

XI. SYSTEM PERFORMANCE

Fig. 12 shows the case study plant (from Fig. 6) broken into six different islands without the GCS. Each island had one generator and multiple loads. As expected, each island settled to off-nominal frequency.

Fig. 13 shows the same situation as Fig. 12 but with the GCS enabled. The GCS simultaneously regulated all six islands to a nominal frequency of 50 Hz. Both Fig. 12 and Fig. 13 were captured from closed-loop real-time simulation with the GCS.

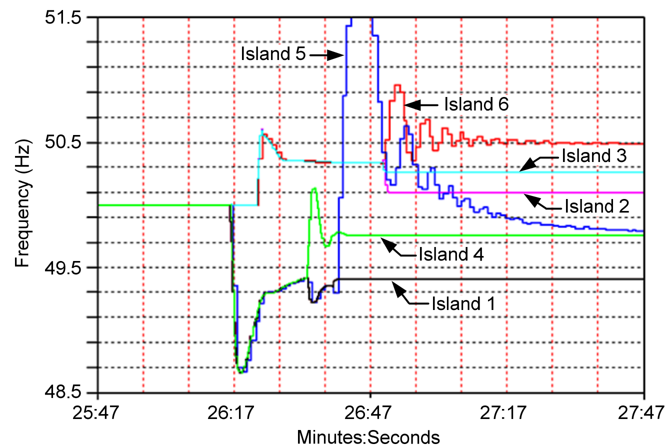

Fig. 12 Six Islands Without GCS

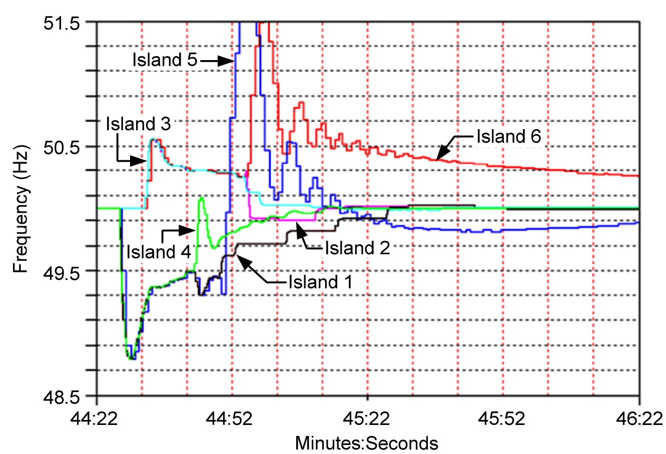

Fig. 13 Six Islands With GCS

XII. CONCLUSIONS

During nonislanded conditions, the following conclusions can be made:

- GCS schemes can simultaneously dispatch the generators to equal percentage turbine loading and tie-line power dispatch set points.
- The GCS must use adaptive boundary conditions based on steam extraction flows and third-valve (condensing) position measurements.
- As long as the ST extraction and pressure controls are tuned to be very slow (60 seconds or slower, commonly), the natural stabilization of the governor droop control is not compromised for transient conditions.
- Three-stage turbines in extraction mode meet most interconnect standards for droop control only if V3 (shown in Fig. 7) is not fully open or closed.

During islanded conditions, the following conclusions can be made:

- ST generators must be switched out of steam extraction to droop priority control mode to support the electric power grid from collapse.
- GCS schemes must focus on frequency dispatch and equal percentage turbine loading.
- Governors are switched from extraction to droop mode when a plant is islanded to improve electrical disturbance rejection.
- An SMS without a GCS can cause an electric power system blackout during islanded conditions.
- A GCS may have to send feed-forward signals to bypass valves and trip loads to prevent header pressure problems during islanded conditions.

XIII. REFERENCES

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XIV. VITAE

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