Power Management System Challenges of Upgrading Gas Turbines From Simple Cycle to Combined Cycle for the Oil Field

Abdel-Rahman Khatib and Maaz Kazmi
Schweitzer Engineering Laboratories, Inc.

Jeetesh Desai
Saudi Aramco

Niannian Cai
Google LLC

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POWER MANAGEMENT SYSTEM CHALLENGES OF UPGRADING GAS TURBINES FROM SIMPLE CYCLE TO COMBINED CYCLE FOR THE OIL FIELD

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

Jeetesh Desai
Saudi Aramco
C26 Building 3108, LIP
Dhahran 31311 KSA
jeetesh.desai.1@aramco.com

Niannian Cai
Member, IEEE
Google LLC
1600 Amphitheatre Parkway
Mountain View, CA 94043
nianniancai@google.com

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

Abstract—This paper presents the challenges to a power management system that were introduced during the upgrade of an existing oil field from a simple cycle gas turbine to a combined cycle gas turbine. The combined cycle block consists of three gas turbines and one steam turbine from two manufacturers. The paper discusses the impact to processes during the upgrade and main milestones of commissioning the steam turbine. New modes of running steam turbines that were introduced are compared with the existing gas turbines. Steam coupling between the gas turbine and steam turbine is presented that includes high-pressure and low-pressure steam calculations and associated steam turbine output power. The impacts of the steam coupling to the existing generation control system and load shedding system are explained. Steam equations of the model and the slow response impact to the electric power system model are also presented.

Index Terms—Steam turbine, gas turbine, combined cycle, power management system, steam coupling.

I. INTRODUCTION

This paper explains the functionality of upgrades to an existing power management system (PMS) currently in use at an islanded industrial oil field [1] [2]. The oil field upgrades include the following new additions:

- Steam turbine generators (STGs) into the primary contingency-based [3] [4] [5] [6] and backup underfrequency-based load shedding system [7].
- STGs into the primary contingency-based and backup overfrequency-based generator-shedding system.
- A progressive overload shedding system for preventing the 18 gas turbines from overloading.
- STGs into the generation control system (GCS), including data acquisition for new STGs.

This paper does not describe the existing PMS. The functions and scope of the existing system can be found in [2].

The new STGs are electrically connected via the Plant 2 gas-insulated substation. Refer to Section VII for the simplified one-line diagram. The six existing combustion gas turbine generators (GTGs) in Plants 2 and 3 have been retrofitted to become combined cycle machines [8] [9] [10]. The waste heat from as many as three GTGs is used to produce steam for one STG. Two steam "blocks" are thus created that can be operated independently. This paper discusses GTG load optimization with steam production and STG outputs.

II. STG/GTG COUPLING

The thermal coupling between the GTGs and the new STG is of vital importance in the oil field understudy in this paper. This coupling relationship affects the existing generation shedding system (GSS), automatic generation control (AGC), and contingency load shedding (CLS). It also introduces new progressive load shedding (PLS) algorithms. A step change in the output of a combined GTG corresponds to a proportional change in the steam generated. This can have an undesired effect on the preceding algorithms if not correctly accounted for. This section describes the approach and modeling methods used to account for this coupling effect.

There are two combined cycle power blocks in the oil field:

- Block 1 (STG-A, GTG-8A, GTG-8B, and GTG-8C)
- Block 2 (STG-B, GTG-8D, GTG-8E, and GTG-8F)

The active power generated from the STGs is based on the total amount of steam mass flow kilopound per hour (klb/hr) multiplied by the enthalpy difference between the inlet and outlet of the STG. The steam mass flow is based on the percent loading of the GTG, with a small amount of variation due to ambient temperature, ambient humidity, or type of fuel (rich or lean).

A. Steam Mass Flow

The high-pressure (HP) and low-pressure (LP) steam mass flow of Block 1 can be modeled as per (1) and (2).

$$HP = A_{1H} \bullet T_{AMB}^2 - A_{2H} \bullet T_{AMB} + A_{3H} \bullet GTG_{LOADING} \bullet 100 + A_{4H} \quad (1)$$

where:

HP is the HP steam mass flow in klb/hr.
T_{AMB} is the ambient temperature in Fahrenheit.
$GTG_{LOADING}$ is the GTG loading value in percent.
A_{1H}, A_{2H}, A_{3H}, and A_{4H} are constants.

$$LP = A_{1L} \cdot T_{AMB}^2 - A_{2L} \cdot T_{AMB} + A_{3L} \cdot GTG_{LOADING} \cdot 100 + A_{4L} \quad (2)$$

where:

LP is the LP steam mass flow in lb/hr.

A_{1L}, A_{2L}, A_{3L}, and A_{4L} are constants.

The base of the GTG percent loading is influenced by the ambient temperature. GTG loading of 100 percent in summer generates approximately 65 MW; in contrast, 100 percent loading in winter generates approximately 80 MW. The steam generated by GTGs with loading between 55 and 100 percent can be used for the STG.

1) Different Operating Modes for GTGs for Combined Cycle Operation

There are five operating modes for GTGs: combined cycle mode, dry run mode, dry out mode, Benson mode, and level mode. The following describes the operating modes:

- **Combined cycle mode**—the boiler is using the heat energy from the GTG to produce steam. When the boiler is operating in this mode, the PMS considers the steam from the boiler as a component of the power reserve in the STG.
- **Dry run mode**—in this mode, the boiler is off and the GTG is running with no steam being produced. The PMS does not consider any steam contribution in from the GTG when determining power reserve in the STG.
- **Dry out mode**—in this mode, the boiler is transitioning from combined cycle mode to dry run mode. The PMS does not consider any steam contribution from the GTG when determining power reserve in the STG.
- **Benson mode**—this mode is for the boiler specifically, and indicates that the GTG percent loading is sufficiently high enough to produce LP, high-quality steam for the STG. While in this mode, the PMS calculates the HP and LP steam from the boiler as a component of the power reserve in the STG.
- **Level mode**—this mode is also for the boiler specifically. This mode indicates that the GTG percent loading is not sufficiently high enough to produce LP, high-quality steam for the STG. While in this mode, the PMS only calculates the HP from the boiler as a component of the power reserve in the STG. The LP component of the steam is considered to be 0.

2) Output of STG Unit 1

Fig. 1, based on information from the generator manufacturer, presents the relationship between the steam mass flow and megawatt (MW) output of the unit STG1.

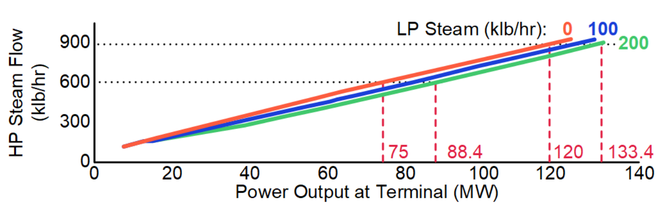

Fig. 1 Steam Consumption Diagram of STG1

3) Output of HP Steam Flow

As seen in Fig. 1, an HP steam flow of 900 klb/hr generates about 120 MW, and an HP steam flow of 600 klb/hr generates about 75 MW (with reference to the 0 LP steam line). Therefore, the linear relationship between the HP steam flow of STG1 and the MW output (coming from the HP steam flow) can be expressed as per (3), where HP is the HP steam flow of STG1 in klb/hr.

$$MW_{HP} = 0.15 \cdot HP - 15 \quad (3)$$

The total HP steam flow of STG1 is the sum of the individual HP steam flows from the GTG that go to the STG1.

4) Output of LP Steam Flow (HP > 500 klb/hr)

An LP steam flow of 200 klb/hr generates about 133.4 MW, and LP steam flow of 0 klb/hr generates about 120 MW. The MW output of LP steam flow is modeled as follows. The expression of MW output that resulted from the LP steam flow of STG1 is assumed linear and independent on HP; it can be expressed as shown in (4).

$$MW_{LP, HP>500} = 13.33 \cdot \frac{LP}{200} = 0.067 \cdot LP \quad (4)$$

where:

LP is the LP steam flow of STG1 in klb/hr.

5) Output of LP Steam Flow (HP < 500 klb/hr)

As shown in Fig. 1, the power produced by LP 200 steam varies with different HP steam flow. By measuring the produced power difference between LP 200 steam and LP 0 steam, the MW values shown in Table I can be obtained.

TABLE I
STEAM FLOW POINTS

HP Steam Flow (klb/hr)	MW Output Coming From LP Steam (MW)
200	5.33
250	8
300	10.33
400	12
500	14

Equation (5) can be used to best fit these five values.

$$MW_{LP=200} = 4.766 \cdot 10^{-7} HP^3 - 5.74 \cdot 10^{-4} HP^2 + 0.245\,HP - 24.592 \quad (5)$$

where:

$MW_{LP=200}$ is the MW output resulting from 200 klb/hr of LP steam flow.

HP is the amount of HP steam flow in klb/hr.

The curve that fits these five points is displayed in Fig. 2.

If the portion of MW output that results from LP steam has a linear relationship with the LP steam, (6) is used.

$$MW_{LP,HP<500} = \frac{LP}{200}\left(\begin{array}{l}4.766 \bullet 10^{-7} HP^3 - 5.74 \bullet 10^{-4} HP^2 + \\ 0.245\,HP - 24.592\end{array}\right) \quad (6)$$

where:

LP is the LP steam flow of STG1 in klb/hr.

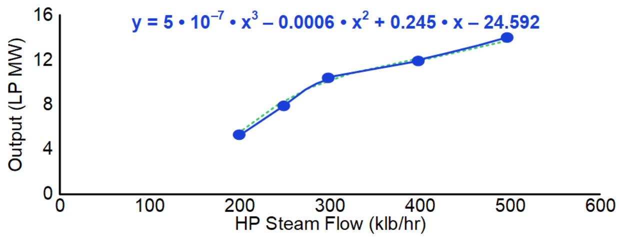

Fig. 2 Curve Fitting Relationship Between HP Steam Flow and MW Output of 200 klb/hr LP

6) Output of STG Unit 2

A similar technique is used for STG2, with different curves, as shown in (7), (8), and (9).

$$MW_{HP} = 0.15 \bullet HP - 12 \quad (7)$$

$$MW_{LP,HP>500} = 10.675 \bullet \frac{LP}{175} = 0.061 \bullet LP \quad (8)$$

$$MW_{LP,HP<500} = \frac{LP}{175}\left(\begin{array}{l}2.85 \bullet 10^{-7} HP^3 - 3.433 \bullet 10^{-4} HP^2 + \\ 0.15893\,HP - 16.962\end{array}\right) \quad (9)$$

B. Time Constant

The time constant for steam flow change (provided by the manufacturer) is 12 seconds, which means it takes 1 minute (five-times the time constant) for the steam flow to reach the steady state (refer to Section II, Subsection A). For example, if the loading of a GTG is changed from 55 percent to 60 percent, it takes the steam flow around 1 minute to increase from 182 klb/hr (corresponding to 55 percent loading) to 194 klb/hr (corresponding to 60 percent loading).

If the loading of a GTG is kept below 55 percent for 10 minutes, the steam flow generated by this GTG is then bypassed to the condenser and the once-through steam generators (OTSGs) then switch to level mode. If the breaker of a GTG is opened, the steam flow of this boiler is bypassed to the condenser after 1 second.

C. Diagram of the Steam

The simplified diagram of the steam coupling is shown in Fig. 3. $HP8A_G$, $HP8B_G$, and $HP8C_G$ represent the HP steam generated by GTG-8A, GTG-8B and GTG-8C, respectively, and $LP8A_G$, $LP8B_G$, and $LP8C_G$ represent the LP steam generated by each GTG. They are determined by the loading of each GTG with little variation due to ambient temperature or ambient humidity. $HP8A_C$, $HP8B_C$, $HP8C_C$, $LP8A_C$, $LP8B_C$, and $LP8C_C$ represent the amount of HP and LP steam that is bypassed to the condenser. The remaining HP steam ($HP8A_N$, $HP8B_N$, and $HP8C_N$) and LP steam ($LP8A_N$, $LP8B_N$, and $LP8C_N$) is transmitted to the STG. HPt is the sum of $HP8A_N$, $HP8B_N$, and $HP8C_N$. LPt is the sum of $LP8A_N$, $LP8B_N$, and $LP8C_N$. HP_C and LP_C represent the steam that is bypassed to the condenser by the STG. HPt and LPt represent the steam that is used by the STG to generate MW power.

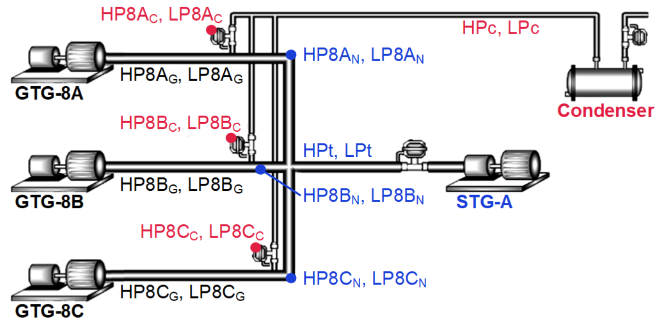

Fig. 3 Steam Coupling of STG-A

III. EFFECT OF COUPLING ON LOAD SHEDDING

When a cogeneration unit in Plants 2 or 3 trips, or if either of those plants becomes islanded, the output of a STG might be affected. Either of these two events can cause a reduction in available steam to the coupled STG, resulting in reduced MW output. This reduced MW output might not occur instantaneously, but rather after a short period. To account for this additional loss of system capability, and to prevent an underfrequency situation due to not shedding enough load, the CLS may shed load in addition to the original required-to-shed value.

This additional requirement is calculated based on the equation for STG and GTG coupling, described in the steam mass flow section. (Note: if the GTG is running in dry mode, then the CLS calculates steam contribution from the GTG as 0.)

A. Decremental/Incremental Reserve Margin (DRM/IRM) for STG and Run Up

The STG has DRM/IRM similar to the GTGs if there is available steam, because the STG normally operates in droop mode. Operating the STG in modes other than droop mode disables DRM/IRM. For example, if the STG is in load control mode or inlet pressure control mode, the IRM of the unit is automatically considered to be 0. Also, if there is sufficient steam available, the CLS can use the runback function of the STG to rapidly increase the output of the STG ("run up") to minimize or eliminate load shedding. The runback mode can be used up to a maximum of 55 MW to run up the STG. The 55 MW limitation is based on the rate-of-change curve provided by the generator manufacturer.

The PMS subtracts a 10 percent security margin (a minimum of 2 MW) from the calculated amount of available steam when deciding how much to run up. This is because the calculation for available steam can vary by plus or minus 10 percent depending on steam temperature, pressure, and exhaust variations. When issuing the run up command, the PMS still sends the command to run up to the maximum STG rating (120 MW). This is because, in load shedding situations, this helps the frequency settling point if there is sufficient steam and the STG will be limited by the amount of steam.

The exact amount of run up that the STG can provide to be included in the load shedding algorithm is the lesser of the following three values: the STG generator capability curve, a user-configured run up set point (maximum 55 MW with the steam limit considered), or the value of 90 percent of calculated available steam.

B. Example: Loss of Combined Cycle GTG

The following load shedding example has been selected to demonstrate the effect of coupling between the combined cycle GTGs and the STG. These examples go over the load shedding algorithm at a high level.

In this example, the system is interconnected during winter, resulting in one island. The total system load is 545 MW. The total system IRM is assumed to be 0 to make the calculations transparent. The Block 1 train has three GTGs running at 55 MW and the STG running at 90 MW. CLS will be evaluated for tripping the Plant 3 GTG-8A.

For this example, we manually calculate the expected HP and LP steam based on loading conditions for the sake of thoroughness. These values are also available using direct measurement. The calculations method serves as a backup to measurements from the field.

For simplicity, we will assume that the current ambient temperature is 80°F (27°C) and that this temperature gives a maximum loading of 75 MW for all three units (this would be the field measurement as well). This gives a current loading of 55 / 75 = 73.3 percent for each GTG.

Using the mass flow equations from Section II, we can calculate the steam mass flow for HP and LP using (10) and (11).

$$\begin{aligned} HP = {} & A_{1H} \bullet (80)^2_{AMB} - A_{2H} \bullet (80) + \\ & A_{3H} \bullet (0.733) \bullet 100 + A_{4H} = 237.1 \text{ klb/hr} \end{aligned} \quad (10)$$

$$\begin{aligned} LP = {} & A_{1L} \bullet (80)^2_{AMB} - A_{2L} \bullet (80) + \\ & A_{3L} \bullet (0.733) \bullet 100 + A_{4L} = 51.1 \text{ klb/hr} \end{aligned} \quad (11)$$

The maximum HP and LP steam flows that can flow to the STG are shown in (12).

$$\begin{aligned} HP_{MAX} &= 237.1 \bullet 3 = 711.3 \text{ klb/hr} \\ LP_{MAX} &= 51.1 \bullet 3 = 153.3 \text{ klb/hr} \end{aligned} \quad (12)$$

Using (13), we can determine the maximum amount of expected power output from the HP steam to the STG.

$$MW_{HP} = 0.15 \bullet HP - 15 = 0.15 \bullet 711.3 = 91.69 \quad (13)$$

Because the total HP is greater than 500 klb/hr, we use (14) to determine the maximum amount of expected power output from the LP steam to the STG.

$$MW_{LP,\,HP>500} = 0.067 \bullet LP = 0.067 \bullet 153.3 = 10.27 \quad (14)$$

The total expected output of the STG in these conditions is then calculated in (15).

$$MW_{MAX} = MW_{HP} + MW_{LP,\,HP>500} = 91.69 + 10.27 = 101.96 \quad (15)$$

Because we can measure the STG MW output from a protective relay, we know that the actual output of the STG is 90 MW. From this, we can determine with (16) the MW equivalent of steam that is being bypassed to the condenser. Equation (16) is calculated for information and not used in PMS decisions.

$$MW_{COND} = MW_{MAX} - MW_{ACTUAL} = 101.96 - 90 = 11.96 \quad (16)$$

After GTG-8A trips, we know that the system generation will be reduced immediately by 55 MW. Because the IRM for the system is set to 0 for this example, the CLS would normally select 55 MW of load to shed and issue the trip. However, in this case, we also need to add the anticipated drop in the STG.

After losing the HP and LP steam from the GTG-8A trip, the HP steam mass flow rate to the STG becomes 474.2 klb/hr and the LP rate 102.2 klb/hr. Equations (17) and (18) show the calculations. Because the steam mass flow drops below 500 klb, we must use the alternate equation for the LP steam.

$$MW_{HP} = 0.15 \bullet HP - 15 = 0.15 \bullet 474.2 - 15 = 56.1 \quad (17)$$

$$MW_{LP,\,HP<500} = \frac{102.2}{200}\begin{pmatrix} 4.766 \bullet 10^{-7} 474.2^3 - \\ 5.74 \bullet 10^{-4} 474.2^2 + \\ 0.245 \bullet 474.2 - 24.592 \end{pmatrix} = 6.81 \quad (18)$$

Equation (19) illustrates these added together.

$$MW_{MAX} = MW_{HP} + MW_{LP,\,HP<500} = 56.1 + 6.81 = 62.91 \quad (19)$$

Because this 62.91 MW is lower than the current operating point, we need to consider the drop in the STG for load shedding, as shown in (20).

$$CLS_{ADDITIONAL} = 90 - 62.91 = 27.09 \text{ MW} \quad (20)$$

This gives us a required-to-shed total of 82.09 MW, as shown in (21).

$$CLS_{TOTAL} = 55 + 27.09 = 82.09 \text{ MW} \quad (21)$$

The CLS uses a modified algorithm for selecting loads to shed until the 82.09 MW required-to-shed threshold has been satisfied. This modified algorithm normally issues a run up command to the STG to increase its output before resorting to load shedding, but since there is no available steam, run up is 0, and the CLS does not use the run up on the STG.

In summary, the CLS for tripping GTG-8A at 55 MW sheds 82.09 MW, because the STG turbine output is impacted and run up is not used.

IV. UNDERFREQUENCY LOAD SHEDDING (UFLS) AND OVERFREQUENCY GENERATION SHEDDING (OFGSS)

The UFLS and OFGSS algorithms are updated to incorporate underfrequency and overfrequency triggers from the STG-A and STG-B relays. These underfrequency and overfrequency pickup timers and thresholds remain the same as the settings from the GTGs. The UFLS tracks the bus connection of the STGs and associates the trigger with the correct island. The UFLS then sheds load (for an underfrequency trigger) or generation (for an overfrequency trigger) as normal. The STG-A and STG-B are added as sheddable generators for the OFGSS algorithm.

Because the OFGSS does not shed based on the MW calculations, it does not consider the effect on the STG of shedding a cogeneration unit. If the OFGSS sheds cogeneration units, then any possible reduction in STG is mitigated by the AGC and progressive overload shedding.

In the former OFGSS system, the algorithm selected a few generators (usually one or two) to shed, because all the generating units in the oil field were similarly rated gas turbines with load sharing. The new STGs have higher ratings than the GTGs. This could introduce a potential overshedding scenario if the STG is selected for shedding while producing a higher amount of power. Therefore, the recommended priority list for the OFGSS is the following:

1. Simple cycle GTGs in Plant 1 and Plant 4.
2. Plant 2 and Plant 3 cogeneration GTGs.
3. STGs.
4. Plant 1 cogeneration GTGs.

V. GENERATION CONTROL SYSTEM (GCS)

The modifications to the GCS include a change in operating philosophy toward MW dispatch to account for the thermal coupling and economic advantage of using the new STGs. This section explains this new philosophy for the PMS GCS currently in service at the oil field. For information about the implementation and control philosophy currently in service, please refer to [2].

A. AGC Updates

The operating philosophy for frequency control in the oil field power system with the two new STGs remains roughly the same. All gas turbines still use load sharing, but there are additional considerations to account for the thermal coupling, the preservation of steam in the cogeneration units, and maximizing the use of available steam for power generation. If the OTSG is in dry out mode (applicable to the Plant 2 and Plant 3 GTGs), the AGC cannot control those units.

When the GTGs are operating in combined cycle mode, the lower regulation set points cannot be set to a lower value, which can cause the OTSG to switch from Benson mode to level mode. The AGC manages this situation by monitoring the HP and LP steam from the OTSG. If the HP steam is less than 182 klb/h (as measured or calculated by the AGC for defined time), or if the LP steam is less than 25.5 klb/h (as measured or calculated by the AGC for defined time), then the AGC overwrites the GTG lower regulation limit with the current present power to prevent the GTG from lowering its output. If the GTG is operating in dry run mode, dry out mode, or level mode, then this limitation does not apply.

1) STG Operating Modes

The PMS can change the STG mode using the digital output contact. The STG can operate in one of the following three modes:

- **Inlet pressure control mode**—the STG uses all available steam to produce power or maintain constant pressure at the steam header.
- **Load control mode**—the STG maintains a constant power output. Any additional steam is bypassed to the condenser. If there is not enough steam to maintain the load control set point, then the STG uses all available steam to produce as much power as possible.
- **Speed control mode**—the STG governor is used to regulate the speed of the machine. While in the speed control mode, the unit can run in isochronous or droop modes.

In all cases, the PMS operates the STG in speed control mode (droop) to better regulate MW dispatch in the oil field. The operator can place the STG into inlet pressure control or load control mode via the human-machine interface (HMI).

2) STG AGC Modes

The STGs have modes that allow the PMS to control the STG to use available steam in different ways. The operator can select the mode of operation from the AGC screen. The modes include the following:

- **Disabled mode**—the STG is not controlled by the AGC. The STG output is dictated by the natural response of the governor and depends on if the STG is in inlet pressure control mode, load control mode, or speed control mode.
- **Maintained mode**—the STG maintains the output to be constant, in accordance with the user-configured base set point on the HMI. If there is not sufficient steam to maintain the desired output, the AGC operates the STG using all available steam and the Max Steam Capacity alarm on the HMI becomes asserted. Any excess steam is bypassed to the condenser and any excess steam is *not* considered by the CLS for run up.
- **Regulation mode**—This is the normal operating mode for the GTGs. In this mode, the STG also participates in load sharing. This means that the STG tries to share with the GTGs. It might not be necessary to use all the steam flows, or the STG might request more steam than is available. In a case where there is not sufficient steam to maintain the desired output, the AGC operates the STG using all available steam, and the Max Steam Capacity alarm on the HMI becomes asserted. Any excess steam is bypassed to the condenser. This excess steam can be considered by the CLS for run up.
- **Steam mode**—the STG does not participate in load sharing but instead attempts to use the maximum available steam. The AGC increases the STG output until the upper regulation set point has been reached. During this process, if the steam limit alarm asserts from the field, the system frequency goes above 60.1 Hz, or the tie export limit (user-configured set points) alarm asserts from Plant 1 to Plant 2 or Plant 3

to Plant 4, then the AGC uses the present MW as the base set point for the STG to avoid demanding more output. This is to avoid frequency disturbance, pushing too much from Plants 2 and 3 to Plants 1 and 4 based on the loading condition.
- **Inlet pressure control (IPC) mode**—the PMS does not have any control over the output of the STG, as it will consume all steam. Once the operator selects this mode, PMS switches the STG to IPC mode.

B. Voltage Control System (VCS)

For the upgrades, control of the STG-A and STG-B exciters is incorporated into the existing VCS algorithm. The VCS HMI screen is updated with two new rows, one for each STG. The operating philosophy of the VCS remains the same.

C. Tie-Line Control System

In the system, five intertie lines can be controlled for active power flow by the PMS: two tie lines between Plant 1 and Plant 2, two tie lines between Plant 2 and Plant 3, and one tie line between Plant 3 and Plant 4.

In the system upgrade, the tie-line control philosophy is not changed. The cogeneration units and STG units are constrained by the functionality imposed by the AGC.

VI. GENERATION SHEDDING SYSTEM (GSS)

The two STGs are added as units for shedding and runback to the GSS. The operating philosophy of the GSS remains the same; however, some special consideration and limitations need to be introduced to maintain steam quality for the cogeneration GTGs in Plants 2 and 3 and to maximize usage of the steam. The GTGs in Plant 1 and Plant 4 are simple cycle GTGs and do not need to consider the steam coupling. Therefore, their traditional shedding algorithm is not covered in this paper.

A. Effect of Coupling on GSS and Runback

If the GSS performs runback on a Plant 2 or Plant 3 cogeneration unit, then the output of the GTGs might trip the OTSG. For this reason, the GSS does not consider cogeneration units for runback while in combined cycle mode. However, the cogeneration units are still available for shedding. If the GSS sheds a Plant 2 or Plant 3 cogeneration unit, then the output of the STG decreases. To account for this additional reduction in STG output, the GSS calculates the revised STG MW output through the available GTGs' HP and LP calculations. If the GSS trips the STG as part of the contingency, or if the GTGs are operating in dry run mode, then the cogeneration units may be considered for runback.

All Plant 2 and Plant 3 cogeneration units have two different set points for runback. One set point is for combined cycle mode. In this mode, the runback is recommended to be 0 percent. Another set point is for dry run mode. In this mode, the runback can be set to normal values (e.g., 50 percent).

Based on the above philosophy, the priority list for GSS is recommended to be as follows (this can be changed at any time through the HMI interface):

1. Simple cycle GTGs (four GTGs in Plant 1 and four GTGs in Plant 4).
2. Plant 2 and Plant 3 cogeneration GTGs.
3. Plant 1 cogeneration GTGs.
4. STGs.

B. Runback Requirements for STG

The STG can support fast runback. The runback command can also be used to rapidly increase the load set point of the machine (e.g., run up). The STG can achieve an instantaneous step change of 55 MW. Beyond 55 MW, the STG has a rate limitation based on the load increase and load decrease curves indicated by the generator manufacturer. The process for initiating a runback is as follows:

1. Send continuous runback set point in MW via analog output.
2. Pulse runback enable control via digital output for two seconds.
3. Allow unit to perform runback.
4. When the unit has reached the runback set point, resume normal AGC control of STG in droop.

The turbine control system automatically places the STG in the correct mode for runback. After executing the runback, the STG automatically returns to the previous control mode and releases control back to the PMS with the current set point, allowing for bumpless transfer.

C. Example: Islanding Between Plant 1 and Plant 2

In this example, the event is an islanding between Plant 1 and Plant 2 by the opening of the tie circuit breaker in Plant 2. Plant 4 is islanded and not considered in this example. This example uses the GSS and CLS to stabilize the power system. IRM and DRM in the system are assumed to be 0.

Fig. 4 shows the system before the bus-tie trip.

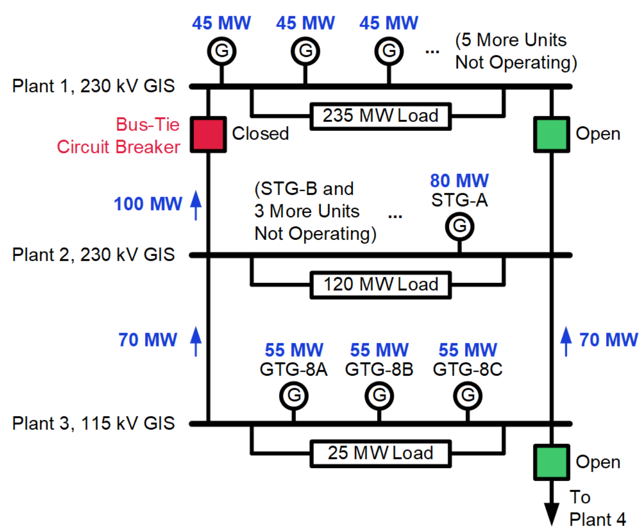

Fig. 4 Example Before Bus-Tie Trip

Plants 2 and 3 are exporting 100 MW to Plant 1. When the tie line trips, this creates a generation surplus in Plants 2 and 3 of 100 MW and a generation deficit in Plant 1 of 100 MW. The PMS needs to shed load in Plant 1 and shed or run back generation in the Plants 2–3 side.

Plants 2 and 3 are operating with three cogeneration units, three OTSGs, and one STG (3-3-1 configuration). Per the GSS philosophy, the GSS will not run back a GTG that is in combined cycle mode.

For simplicity, we assume that the steam signals from the field are used rather than performing the steam calculations.

The PMS calculates that the three cogeneration units are producing enough steam to generate a maximum of 101.96 MW from the STG; see (15) in Section III for example calculations. Fig. 5 shows the steam conditions as read from the field.

GTG-8A	GTG-8B	GTG-8C
Present Power: 55 MW	Present Power: 55 MW	Present Power: 55 MW
HP Steam: 237.1 klb/hr	HP Steam: 237.1 klb/hr	HP Steam: 237.1 klb/hr
LP Steam: 51.1 klb/hr	LP Steam: 51.1 klb/hr	LP Steam: 51.1 klb/hr

STG-A
Present Power: 80 MW
Maximum Power: 101.96 MW
HP Steam: 711 klb/hr
LP Steam: 153.4 klb/hr

Fig. 5 Present Steam Conditions

When the bus-tie trips, the GSS calculates 100 MW surplus generation and first checks if there is sufficient DRM. We are assuming that the DRM is 0, so the 100 MW needs to be run back or shed. Next, the GSS checks if there is enough runback capacity. The recommended operator-entered runback of the GTGs is 0 to reduce the risk of tripping the boiler during runback, so only 55 MW for the STG is available. Because this is less than 100 MW, the GSS is required to additionally shed one or more generators. The GSS selects the generator per the priority list.

We assume that the priority list is the following:

1. Plant 3 GTG-8A.
2. Plant 3 GTG-8B.
3. Plant 3 GTG-8C.
4. Plant 2 STG-A.

According to the priority list, the GSS selects the Plant 3 GTG-8A for shedding. Because the GTG-8A is a cogeneration unit, we also need to calculate the expected loss to the STG from shedding that unit. From the field, we know the HP and LP steam mass flow for Plant 3 GTG-B and GTG-C is as shown in (22).

$$\begin{aligned} HP &= 237.1\,\text{klb/hr} \\ LP &= 51.1\,\text{klb/hr} \end{aligned} \tag{22}$$

Multiplying 237.1 klb/hr by 2 (because both GTGs are the same in this example) gives the total HP steam flow to the STG at 474.2 klb/hr. Multiplying 51.1 klb/hr by 2 gives the total LP steam flow to the STG at 102.2 klb/hr.

Using (23), we can determine the maximum amount of expected power output from the HP steam to the STG.

$$MW_{HP} = 0.15 \bullet HP - 15 = 0.15 \bullet 474.2 - 15 = 56.1 \tag{23}$$

Because the total HP is less than 500 klb/hr, we use (24) to determine the maximum amount of expected power output from the LP steam to the STG.

$$MW_{LP,\,HP<500} = \frac{102.2}{200}\begin{pmatrix} 4.766 \bullet 10^{-7} 474.2^3 - \\ 5.74 \bullet 10^{-4} 474.2^2 + \\ 0.245 \bullet 474.2 - 24.592 \end{pmatrix} = 6.81 \tag{24}$$

The total maximum possible output of the STG is as calculated in (25).

$$MW_{MAX} = MW_{HP} + MW_{LP,\,HP<500} = 56.1 + 6.81 = 62.91 \tag{25}$$

Tripping GTG-8A sheds 55 MW and consequently reduces the STG by 17.1 MW. This results in a remaining surplus generation of (100 – 55 – 17.1) = 27.9 MW. The contingency is still not satisfied, as seen in the simple equation STG MW maximum – surplus generation = STG runback, or 62.91 MW – 27.9 MW = 35 MW.

Again, the GSS checks if there is sufficient runback on the island. Instead running back 55 MW, the STG can only run back (55 – 17.1) = 37.9 MW to avoid statistical loss of life. This runback is sufficient to meet the required-to-shed of 27.9 MW, so no more generator shedding is required. GT-8A is tripped while STG-A is simultaneously run back. The final actions by the PMS in response to this contingency are a GTG-8A trip (55 MW) and an STG-A runback (80 to 35 MW).

VII. PROGRESSIVE OVERLOAD SHEDDING (PLS)

The progressive overload portion of the CLS code is treated as a contingency within the system, similar to a contingency breaker being tripped. However, instead of being based on a monitored breaker state, this contingency is asserted when the progressive overload integrator value exceeds a user-configured value. Each island in the oil field is considered as a possible overload contingency. The PLS uses the same topology tracking present in the CLS to dynamically track islands in the oil field.

The PLS starts integration when the power produced by all generators in an island is above a user-configured percentage of the generator capacity. When the integration reaches the user-configured value, and the frequency of the island is below the frequency threshold, the PLS then sheds load according to the overload amount plus a minimum to-shed value. The PLS then waits for a user-configured period to allow the system to settle before the integrator begins again. The PLS locks out after two instances of load shedding. If additional load shedding is still required, the system relies on CLS and UFLS algorithms.

This island-based approach relies on the AGC to perform equal load sharing between the generators. Thus, if one individual generator is overloaded, the AGC is responsible for unloading that generator. The PLS only begins integrating when all generation on an island becomes overloaded and load sharing cannot resolve the issue.

The PLS calculates the MW required-to-shed quantity to bring loading on the island down to less than the user-configured integrator pickup value. For example, if a user sets 95 percent as the threshold of an island with ten generators, with each generator having 60 MW of generation capacity and the generators all fully loaded, then the overload amount in the system is (0.05 • 60 • 10) = 30 MW. To reduce this island to less than its pickup threshold, the system must lose 30 MW.

In another example, a user has again set 95 percent as the threshold of an island with ten generators, each generator having 60 MW of generation capacity. If five of the ten generators are maxed out at 60 MW, but the remaining five are only operating at 50 MW, that gives a total island load of 550 MW (0.95 • 10 • 60). That load is less than the 570 MW integrator pickup; therefore, the integrator will not be active. In this case, the AGC is responsible for unloading the maxed-out units via load sharing.

If island loading is above the integrator pickup value and has reached the integrator threshold, but the island frequency is still above the user-configured frequency pickup value, then any shedding by the progressive overload will be inhibited. Shedding can only occur after the island frequency is below the frequency pickup value and the frequency threshold timer has elapsed. If the island load reaches the integrator threshold before the frequency threshold, then the contingency sheds as soon as the frequency threshold is reached.

A. Example: 115 kV Islanding of Plant 3

In this example, the event is an islanding between Plant 3 and Plant 2 via the opening of a tie breaker. This example uses the GSS and CLS to stabilize the power system. IRM and DRM in the system is assumed to be 10 MW.

Plant 3 is exporting 100 MW to Plant 2. When the tie line trips, this creates a generation surplus in the Plants 3–4 island of 100 MW and a generation deficit in the Plants 1–2 island of 100 MW. The PMS needs to shed load in the Plants 1–2 island and shed or run back generation in the Plants 3–4 side.

In this example, the GSS runs back the cogeneration units in Plant 3, which causes a slow reduction in the maximum output of the STG, causing an overload situation on the Plants 1–2 island.

B. GSS Action for the Plants 3–4 Island

Starting off by examining the impact to the Plants 3–4 island, per the GSS philosophy, the GSS will not run back a GTG to 55 percent base load to preserve steam quality. For simplicity, we assume that the environmental conditions result in a maximum loading of 75 MW for all three units. This gives us a loading of (55 / 75) = 73 percent for each GTG and a minimum MW output equaling 55 percent of 75 MW, which is 41.25 MW. Plant 3 is operating with three cogeneration units and three OTSGs, and Plant 2 has one steam generator. The PMS calculates that the three cogeneration units are producing enough steam to generate a maximum of 101.96 MW from the STG; see the example in Section III for the calculation, (15). Fig. 6 shows the steam conditions.

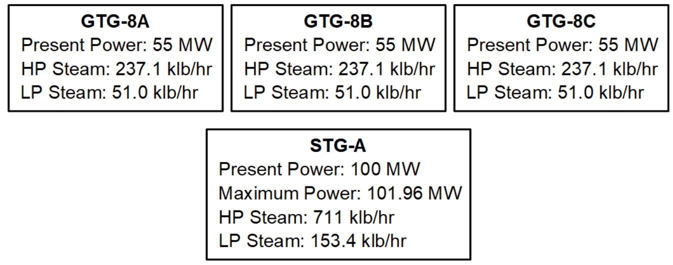

Fig. 6 Pre-Event Steam Conditions

When the tie breaker trips, the GSS calculates 100 MW surplus generation in the Plants 3–4 island and first checks if there is sufficient DRM. Because we are assuming that there is 10 MW DRM in the system, and the Plants 3–4 island has 6 GTGs (60 MW of DRM) the DRM total is not sufficient.

Next, the GSS checks if there is enough runback capacity. We determined that the minimum MW for each cogeneration GTG was 41.25 MW. We also assume 50 percent runback for the Plant 3 GTGs. That results in (55 – 41.25) = 13.75 MW for each cogeneration GTG and 22.5 MW for each Plant 4 GTG. That is a total runback capacity of 108.75 MW. Because this is greater than 100 MW, the GSS is not required to shed any generators. The GSS selects the generator to run back per the priority list, and starts running back the first generator on the island to the maximum allowed runback, then move to the next generator on the priority list. The GSS is designed to run back one generator at a time until maximum runback is reached, and then move to the next generator. It is not designed to run back generators with similar sizes and characteristic as a group, to reduce the risk of tripping the whole group during runback. The GSS simply moves through the priority list, reaching conclusions and executing at once. For this example, the following are the runback set points in order of priority:

1. Plant 4 GTG-3A—run back to 22.5 MW.
2. Plant 4 GTG-3B—run back to 22.5 MW.
3. Plant 4 GTG-3C—run back to 22.5 MW.
4. Plant 3 GTG-8A—run back to 41.25 MW.
5. Plant 3 GTG-8B—run back to 41.25 MW.
6. Plant 3 GTG-8C—run back to 50 MW.

At this point, the GSS contingency is satisfied and the Plants 3–4 island is in equilibrium.

The expected steam conditions (not accounting for CLS action in the Plants 1–2 island) are shown in Fig. 7 and Fig. 8.

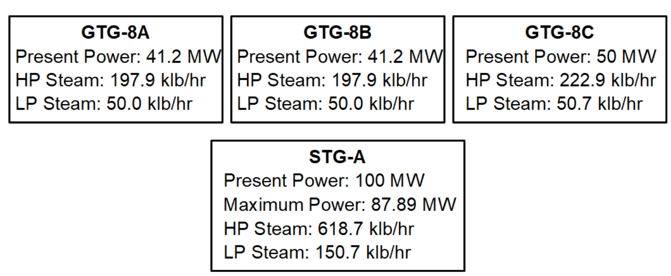

Fig. 7 Expected Steam Conditions After GSS Action

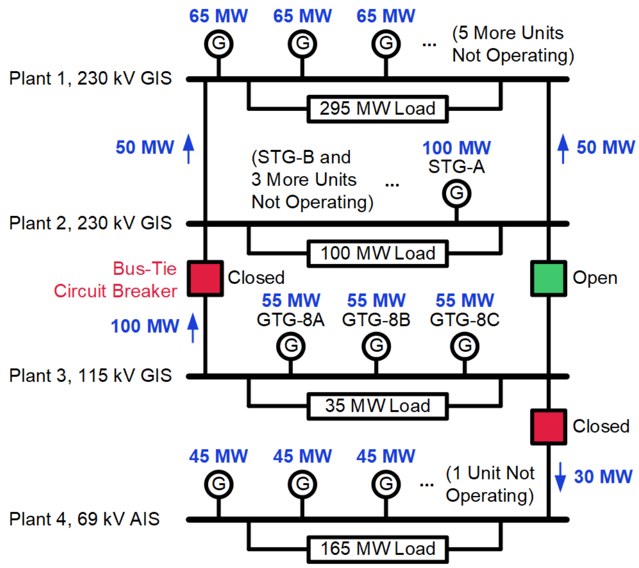

Fig. 8 Example Scenario Before Tie Circuit Breaker Trip

The steam calculations for Fig. 8 are calculated as explained in Section III. As shown in Fig. 8, after the GSS runs back the Plant 3 cogeneration units, the expected STG maximum output becomes 87.8 MW, which is 12.2 MW lower than the current operating point.

C. LSS Action for the Plants 1–2 Island

Examining the PMS action in the Plants 1–2 island, when the tie circuit breaker trips, the PMS detects a 100 MW deficit in generation in the island. The CLS acts by shedding according to the amount of available IRM. 10 MW of IRM per GTG is assumed, and 0 MW is calculated for the STG because the calculating steam amount is less than 10 percent of the present power (101.96 MW calculated versus 100 MW present power). Therefore, the CLS sheds 70 MW of load against the 100 MW lost; the remaining 30 MW is supplied by the GTG IRM. This means that the three Plant 1 units need to increase their output by 10 MW.

After the event, the Plant 1 units are running at 75 MW, but the effect of GSS runback on the Plant 3 cogeneration units must be considered. The STG is losing steam, and its output will be reduced to 87.9 MW over an indeterminate period. This additional loss of power needs to be absorbed by the Plant 1 units. This example assumes that the maximum capability of the Plant 1 units based on current environmental conditions is 75 MW, and that the slow decrease in STG output causes a frequency decay, because there is a mismatch in load and generation on the Plants 1–2 island. There is now only (75 + 75 + 75 + 87.9) = 312.9 MW of generation versus 325 MW of load after shedding. This is a mismatch of 12.1 MW.

In this example, the integrator pickup value is set to 95 percent and the units are maxed at 100 percent. The PLS sheds load on the island (the island frequency needs to be less than the set point to enable PLS) to bring the load below the 95 percent threshold, which is (0.95 • 312.9) = 297.2 MW. Because the current load on the island is 325 MW, the PLS needs to shed more than (325 – 297.2) = 27.8 MW of load.

This 27.8 MW reduces the load on the island to below the maximum amount of generation that the island can support, and the frequency returns to 60 Hz. In this case, if Underfrequency Level 1 is reached (refer to [2]), the system sheds according to the underfrequency required-to-shed set point, which is much more than 27.8 MW, based on island-based underfrequency study.

VIII. BRINGING AN STG ONLINE

Each STG can be brought online manually by the operator at the control cabin. This can be done with the STG and associated GTGs in local mode. The operator runs the STG up and synchronizes it with the bus. The PMS GCS does not perform any control of a generator while in local mode.

Once the generator is connected to the system, the operator is satisfied that the unit has started properly, the temperature matching process has been completed, and the boilers are operating in Benson mode, the operator places the generator in remote mode, thereby handing set-point control over to the GCS. The GCS then begins to regulate the power and voltage set points of that generator in accordance with its operating mode. If the unit remains in local mode or is placed in local mode again so it can be taken offline manually, then the GCS does not include this generator in its MW- and MVAR-sharing algorithms and simply keeps the remaining generators sharing load equally. If the STG is not in disabled mode, the PMS always picks up STG control on the transfer from STG local to remote mode.

Any time a GTG is to be started or included into the steam block, the operator must take manual control of the STG and GTGs to perform temperature matching. The PMS does not perform the temperature matching process. After the GTG temperature has been matched and is successfully included into the steam block, control can be transferred back to the PMS by placing all units into remote mode.

IX. CONCLUSIONS

This paper presented a mathematical model to quantify the steam coupling effect between combined cycle GTGs and an STG. It also presented the impacts of the steam coupling on the load/generator shedding and generator control systems, and proposed solutions to revise these control systems to resolve the impacts. A few examples were also given to illustrate how the control systems are taking care of the impacts. The solutions have been implemented in the actual control system and are under commissioning in an oil field.

X. ACKNOWLEDGMENT

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XII. VITAE

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

Jeetesh Desai is an electrical subject matter expert at Saudi Aramco's Shaybah Producing Department. He joined Saudi Aramco in 2014, after extensive construction experience in Southern Africa and Africa. He received a degree in electrical engineering from Durban Technical College, South Africa. Prior to joining Saudi Aramco, he was a senior construction specialist in design, installation, and commissioning quality control in vast fields spanning from oil and gas to mining, manufacturing, and rail. Based on the Shaybah fields being an islanded generation system, he has gained extensive knowledge and experience in generation equipment and control systems.

Niannian Cai received his BS in electrical engineering from Huazhong University of Science and Technology, Wuhan, Hubei, China, in 2009, and his PhD in electrical engineering from Michigan State University in 2014. He is a senior engineer at Google. He worked as a power system engineer at Schweitzer Engineering Laboratories, Inc. (SEL) from 2015 to 2021. In 2021, he joined Google as a senior power system engineer. His research interests include power system modeling, power system dynamics and control, power system optimization, and microgrids.

Maaz Kazmi is a senior engineering manager at SEL Engineering Services, Inc. (SEL ES), a subsidiary of Schweitzer Engineering Laboratories, Inc. (SEL). He joined SEL in 2011. He received his bachelor's degree in electrical engineering from NED University of Engineering and Technology in Karachi, Pakistan. Before joining SEL, he was a senior executive engineer in the energy and automation unit of Siemens Pakistan Engineering Company, Limited. He is an IEEE member and has over 16 years of experience in design, development, testing, commissioning, technical documentation, business development, and user training in the areas of power management solutions, and substation automation. He has also acquired extensive knowledge in generation control systems for industries and utilities, utility system operations, and remedial action schemes.

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