Plant Control Philosophy for UHP Combined Cycle Cogeneration Plant

Presenting Author
David G. Rice
Project Manager
Sargent & Lundy, L.L.C.
55 E Monroe, Chicago,
IL 60603 USA

Presenting Coauthor
Steve Wylie
Project Manager
Sargent & Lundy, L.L.C.
55 E Monroe, Chicago,
IL 60603 USA

INTRODUCTION

The Umm Al Houl Power (UHP) Independent Water and Power Facility is a 2520 MW combined cycle cogeneration plant currently under construction near Doha, Qatar that will produce 136.5 million imperial gallons of potable water a day. Approximately 55% of the potable water will be produced using Multi-Stage Flash (MSF) technology with the remainder being produced using Reverse Osmosis (RO) technology.

The power plant portion of the project is comprised of two (2) combined cycle power blocks where each block includes three (3) Siemens SGT5-4000 natural gas fired turbine generators, three (3) heat recovery steam generators (HRSGs) with bypass stacks and duct burning, and two (2) Siemens SST5-4000 condensing steam turbine generators with controlled low pressure (LP) steam extractions. Both power blocks send LP steam to a common header that supplies the five (5) MSF modules. Condensate from the MSFs is returned to each power block through a common header.

The selected plant configuration lends itself to a wide range of operating conditions with the capability of producing power and water nearly independent of each other. This results in a rather complex control scheme that includes the following challenges:

- Maintain proper steam supply to the MSFs with varying power demands.
- Maintain reliable steam supply to the MSFs with back-up sources coming on line automatically as required or in case of equipment failure.
- Maintain the required plant power output during transient conditions such as varying MSF steam loads or tripped equipment.
- Start a cold steam turbine in a 3 x 2 configuration without affecting the operating steam turbine or block power and steam production.
- Maintain proper steam supply to the MSFs during multiple MSF trips while automatically dumping excess steam.

- Properly regulate the flow of condensate from four (4) steam turbine condensers and five (5) MSF hotwells that all supply a common condensate header while also controlling demineralized water make-up to the system to account for losses.
- Select the proper number of gas and steam turbines in operation to meet the required plant power and water output.
- Keep the steam turbines within their operational limits considering the HP and LP turbine section flows and their effects on the extraction steam conditions.
- Start-up the gas turbines and HRSGs using a HP steam bypass system that can dump to multiple steam turbine condensers.

This paper will explore the challenges in controlling the above plant operating parameters and illustrate the approach taken to meet these requirements.

UHP PLANT DESIGN INFORMATION

1. GENERAL PLANT INFORMATION

Owners	Qatar Electricity and Water Company (QEWC) (60%), Qatar Petroleum (5%), Qatar Foundation (5%) and Mitsubishi Corporation (30%)
Published Overall Plant Cost	$3.15 Billion
Published Power Block EPC Cost	$2.46 Billion
Power Island EPC Contractor	Samsung C&T
Power Island Design Engineer (Basic Design)	Sargent & Lundy LLC
Gas and Steam Turbine Supplier	Siemens
Location	20 km South of Doha, Qatar
Net Capacity	2520 MW
Potable Water Capacity	162.8 MGD (136.5 MIGD)
Simple Cycle Commercial Operating Date	May 2017
Combined Cycle Commercial Operating Date	May 2018

2. POWER BLOCK INFORMATION

Configuration	Two (2) Blocks in a 3 x 3 x 2 Configuration
Gas Turbine Generators	Six (6) Siemens SGT5-4000F (300 MW) Evaporative Cooling Wet Compression
Steam Turbine Generators	Four (4) Siemens SST5-4000 (275 MW) Condensing Turbine MP Extraction (14”), Uncontrolled LP Extraction (56”), Controlled

Heat Recovery Steam Generators	Six (6) Nooter Eriksen SRL HRSGs Two (2) Pressure Non-Reheat Duct Burning (185 MW) Bypass Stack For Simple Cycle Operation
LP Steam Supply to MSFs	1650 tons per hour (TPH), 22 PSIG, 275 °F, 2 x 80” Lines
Source of LP Steam	Steam Turbine Extraction (Controlled) HRSG LP Drum Extraction High Pressure Steam to LP Steam Letdown Valve*
Medium Pressure (MP) Steam Supply to MSFs	55 TPH, 170 PSIG, 445 °F, 2 x 8” Lines
Source of MP Steam	Steam Turbine Extraction (Uncontrolled) High Pressure Steam to MP Steam Letdown Valve
Condensate Return	1650 TPH, 320 PSIG, 245 °F, 2 x 16” Lines

* – Backup Source

3. POWER PLANT OPERATION OVERVIEW

The power plant portion of the project has the following features:

- Each of the two (2) power blocks consists of three (3) gas turbines, three (3) HRSGs, and two (2) steam turbines.
- The three (3) HRSGs of each block supply high pressure (HP) steam to a header that in turn feeds the two (2) steam turbines.
- Each HRSG is provided with a start-up bypass valve that directs excess steam to a condenser during HRSG start-up until the steam is accepted by a STG.
- The steam turbines are single pressure turbines with an uncontrolled MP extraction and controlled LP extraction.
- The LP extraction steam is taken from the HP to LP turbine crossover piping upstream of a 52” throttling butterfly valve. This control valve throttles the steam flow to the LP turbine to maintain sufficient upstream pressure to supply LP steam to the MSFs at the required pressure and flow rate. Each STG can extract a maximum of about 800 TPH of LP steam.
- Each STG has an associated HP to LP bypass valve that can operate to supply sufficient steam to the LP header replace the extraction steam lost following a STG trip.
- LP steam for the MSFs is also bled directly from the HRSG LP drums. A control valve on each HRSG LP drum outlet maintains a constant drum pressure of about 60 PSIG while bleeding off steam into the LP header. Each HRSG produces a maximum LP export flow of about 55 TPH.
- The LP extractions from the two (2) STGs, LP bleeds from the three (3) HRSGs, and outlets of the two (2) HP to LP bypass valves are combined into a common header. The header from each power block ties in separately to a common header on the water island portion of the plant that supplies the five (5) MSFs.
- At each STG, MP steam (used for the steam ejectors in the MSF plant) is taken from either the uncontrolled STG extraction or from the associated HP to MP steam bypass valve. The maximum MP export flow for a single block is only 28 TPH. The source of this steam (Extraction or bypass valve) has minimal effect on the overall plant power production and STG operation. Thus the MP extraction steam controls are not critical and are not examined in detail in this paper. The MP steam supply header is configured in the same manner as the LP header except that the HRSGs have no connection to the MP system.

- Each STG has an associated HP to condenser bypass valve that will direct excess HP steam to the condenser following a STG trip and thereby minimize the HP steam pressure rise. This bypass is sized for the maximum HP turbine throttle flow realized during two (2) steam turbine operation.
- Intermediate pressure (IP) Feedwater is used to attemperate the LP and MP extraction steam systems to obtain the proper export steam temperatures.
- The plant also features a cold STG start-up bypass valve that will be discussed later in the paper.
- The condensate return from the five (5) MSFs feed a common header that supplies the HRSG LP drums of both power blocks. The condensate pump discharge flow from the four (4) condensers also feed the same common header. Thus there are nine (9) sets of condensate pumps that feed six (6) HRSGs.
- Demineralized water is sent to the hotwells of the operating condensers to make-up for the steam cycle losses.

A model rendering of the plant is provided in Figure 1. A process flow diagram of the overall plant configuration is provided in Figure 2.

Figure 1 Plant Layout

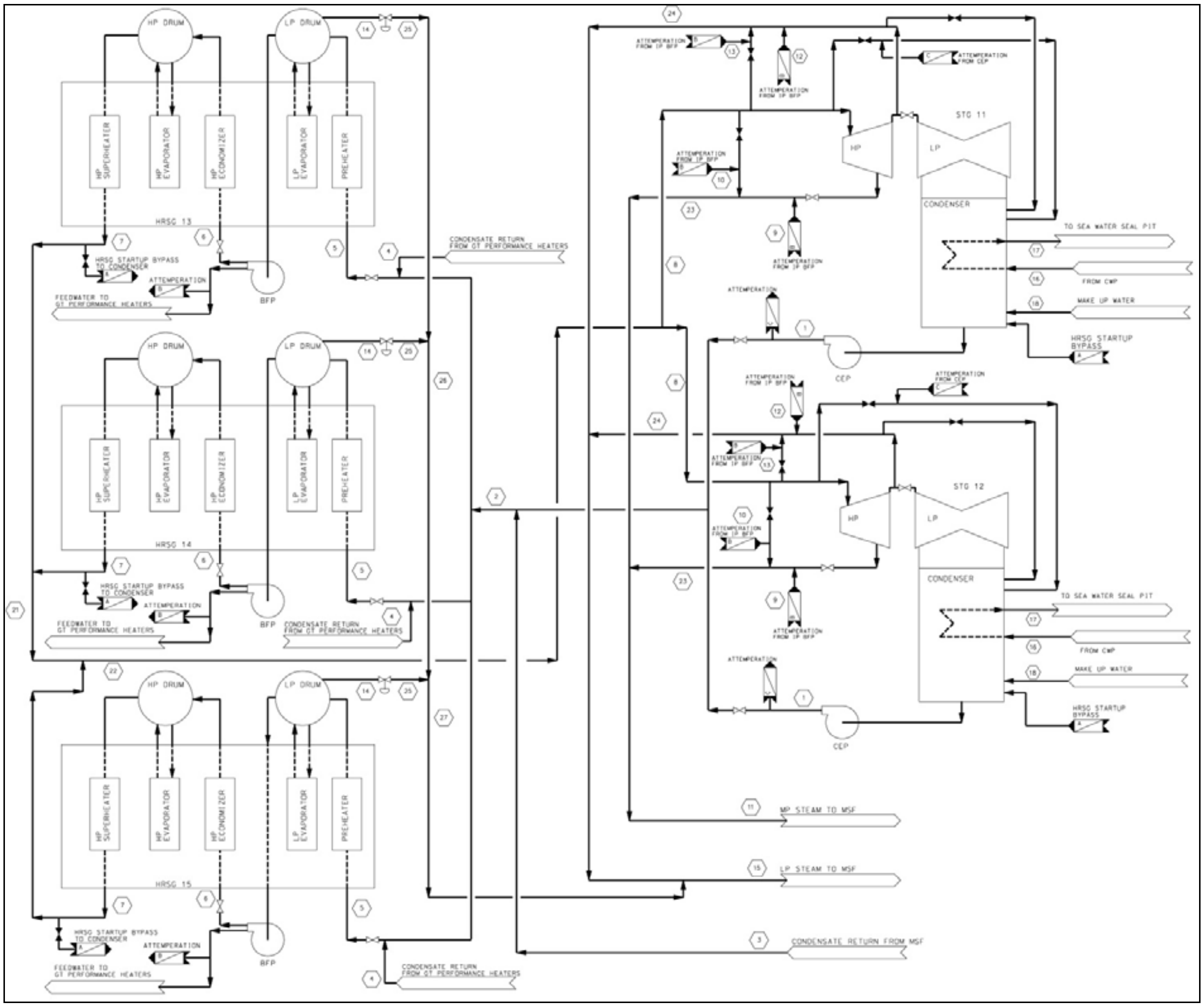

Figure 2 Process Flow Diagram

The UHP plant provides high operational flexibility through its design that encompasses the following wide range of operating conditions:

- 100% power production while at 0% water production can be achieved by sending all the generated steam to the condensers.
- 100% water production while producing as little as 27% power can be achieved by using the high capacity HRSG duct burners to generate additional LP export steam.
- 100% power and 100% water output with ambient air conditions as high as 122 °F and 35% relative humidity can be achieved by using the gas turbine wet compression system to boost GTG power.
- The plant can operate continuously at 11% power and 7% water output during periods of low

demand by operating only two gas turbines and two steam turbines at reduced loads.

With so much operating flexibility, one of the primary controls challenges was to have the proper number of generators in service and operating at a point where the desired plant power and water output is met while maximizing efficiency and still being able to react to potential transient conditions. This challenge is discussed in the next section.

3.1. ESTABLISHING PROPER PLANT OPERATING POINT

The bounding operating conditions for the plant in terms of power and water production were given in the previous section. Within these bounds, there are a large number of operating conditions that can be realized based on the following:

- Number of gas turbines in service
- Gas turbine load
- Evaporative cooling on or off
- Wet compression on or off
- HRSG duct burner duty
- Number of steam turbines in service
- Ambient temperature and humidity
- Condenser cooling water temperature

One of the biggest controls challenges was to establish the most efficient operating point by controlling gas turbine load, duct burner duty, and number of turbines in operation.

3.1.1. GAS TURBINE LOAD VERSUS HRSG DUCT BURNING

In examining the optimized heat balances prepared for various operating conditions, it became clear that there was no established pattern for the gas turbine loads versus duct burner duty. There were many cases where the gas turbines were at partial load while the duct burners were in operation and other cases having no duct burners in operation. Moving from one operating point to another close by point would sometimes involve changing gas turbine load only, changing duct burner load only, or changing both. The project considered developing a table to map out the number of units in service, the gas turbine load, and HRSG duct burner duty for every possible operating case not covered by a heat balance. Factoring in the varying ambient and cooling water conditions and the desire to optimize the plant efficiency at each point, this proved to be impractical.

Instead the following concepts were used to establish the detailed logic for the GTG and duct burner load control:

- Being the most efficient means of generating power, the gas turbine load is increased to meet the plant electric power demand as required. If the gas turbines alone cannot meet the demand then the HRSG duct burner duty is increased to meet the power demand.
- The steam turbines normally operate in sliding pressure valves wide open mode to maximize their power output.
- The position of the STG LP crossover control valve is used assess the amount of LP extraction steam available for export to the MSFs. When the valve is nearly closed and diverting steam away from the LP turbine, it indicates a shortage of LP steam and prompts the control system to increase the duct burner duty. This should increase the STG power output which could cause the GTGs to run back based on the meeting the target plant power output.
- If the LP crossover valve is at a more open position while the duct burners are in operation and the duct burners are not being used for plant electrical output control, this indicates a surplus of extraction steam and the duct burner duty is decreased. The GTG duty is increased as necessary to meet the target plant electrical power output.

In summary, the duct burner duty will increase when the GTGs are at maximum load but the plant power output is lower than the target. (Note that the GTG maximum load setpoint is dependent on the need to keep spinning reserve and a decision on whether use wet compression.) Otherwise, the duct burner duty will be minimized while keeping the crossover valve near a minimum position setpoint. This valve position is based on the desire to maximize the throttling to reduce duct burner duty while keeping the valve in a position to react to changes in export steam flow. A review of the project heat balances developed for specific operating points confirmed that maximizing the LP extraction steam throttling while duct burners are in operation to support MSF steam production (as opposed to plant load control) results in the most efficient operating point. Thus using the above concept the optimal gas turbine and duct burner loads can be established for any operating point over the entire range of ambient conditions. While not obvious at first, it is now intuitive that if the duct burners are being operated to only supply sufficient steam to the MSFs, the amount of steam being sent to the LP turbine and condenser should be minimized by throttling the crossover valve.

3.1.2. NUMBER OF TURBINES IN SERVICE

A relatively large number of generators are supplied (six GTGs and four STGs) such that a wide range of operating conditions can be realized by turning generators on and off as required. The decision on the number of turbines in operation is left to the plant operators using feedback from the control system. Operating configurations of 3x2, 3x1, 2x2, 2x1, and 1x1 are considered for each block.

As described in the previous section, gas turbines are run at specific power outputs to meet the plant load set point with the HRSG duct burners operating in load control or LP steam production control with the steam turbines following. Additional gas turbines are added or taken out of service as they approach their load limits while trying to meet the plant power set point.

The decision to bring STGs in and out of service cannot be made based on only STG load. There are other considerations such as HP turbine loading, LP turbine loading, and condenser backpressure that affect when units are brought in and out of service.

The decision for switching from one operating STG to two would be based on the operator receiving the following feedback:

- High HP throttle steam pressure alarm.
- Low LP extraction steam temperature alarm. When the HP turbine section becomes highly loaded, the temperature at the LP extraction can drop below the required 5 to 9 °F of superheat. This will initiate a turbine alarm and the operator should consider starting up another STG or otherwise address the low temperature issue.
- The HP to LP or HP to Condenser bypass valves open automatically to regulate the STG inlet HP steam pressure.
- High LP extraction pressure. When the LP section of the STG is highly loaded, the throttle valve can be wide open and no longer able to regulate the extraction pressure. At this point, the extraction pressure floats with the LP turbine inlet pressure and can exceed the allowable export limits. Starting up another turbine would share the LP turbine flow between the two turbines and reduce the extraction pressure.
- The LP to condenser bypass valves open automatically to regulate the LP steam export pressure. If the Operator does not take action on the high LP extraction pressure, the LP to condenser bypass valves will automatically begin dumping steam directly to the condenser to control the LP extraction pressure to within acceptable limits.

The decision for switching from two operating STGs to one would be based on the operator receiving the following feedback:

- Low HP throttle steam pressure alarm or turbine taking action to boost the HP steam pressure by throttling the inlet valves.
- High LP extraction steam temperature alarm. When the HP turbine section becomes lightly loaded, the temperature at the LP extraction can exceed the allowable limit.
- Low LP turbine flows as indicated by high LP turbine temperature alarms. This is an unlikely scenario as the LP section can operate at very low flows (around 10% of design flow) with the hood spray in service.

3.2. REACTION TO TRANSIENT CONDITIONS

The plant reaction to a GTG trip is fairly standard in that the other operating GTGs will automatically ramp up and HRSG ductfiring will be increased as necessary to minimize the loss of electrical power. The HRSG duct burners are oversized by about 15% to accommodate this type of trip scenario.

On a HRSG trip, the associated GTG will automatically switch to simple cycle mode by diverting the GTG exhaust to the bypass stack.

The plant reactions to STG and MSF trips are somewhat unique as described below.

3.2.1. STG TRIP

During normal operation, LP steam for the MSFs is extracted from the HP to LP crossover pipe at each operating turbine. See Figure 3 for a simplified schematic of the HP and LP steam piping for a single STG (Attemperating water flows are not shown for clarity).

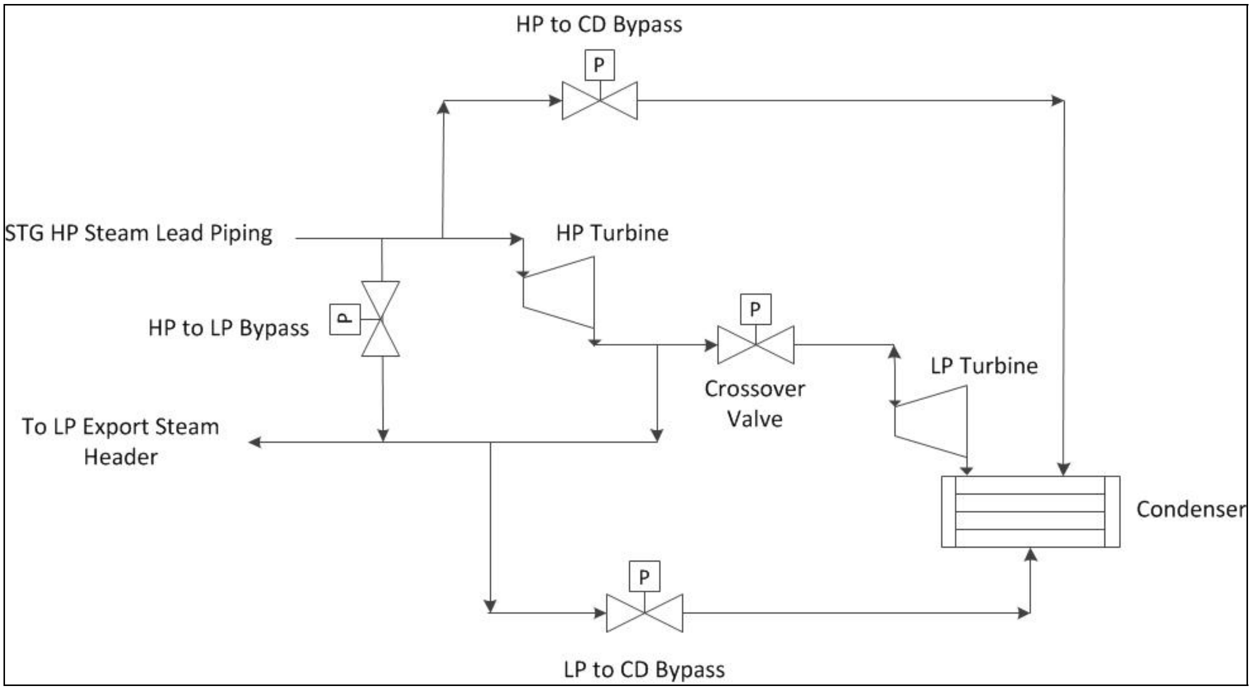

Figure 3 STG HP and LP Piping Schematic

A project decision was made that during a STG trip, only the HP to LP and HP to condenser bypass valves associated with the tripped turbine would automatically react. The LP crossover valves on the operating turbines would be held in place and they would not react to replace the lost LP extraction flow from the tripped turbine. Instead this steam would be supplied from the HP to LP bypass valve associated with the tripped turbine. This valve would automatically open to a position calculated based on the LP extraction steam flow from that turbine prior to the trip and then it would be released to control LP export steam pressure. The excess HP steam would be bypassed to the condenser associated with the tripped turbine. This bypass valve would automatically open to a position calculated based on the HP throttle flow of that turbine prior to the trip minus its LP extraction flow prior to the trip. It would then be released to control HP steam header pressure.

Having the system react in the manner described above should minimize the pressure fluctuations in the HP and LP steam systems and keep the operating STGs at nearly the same conditions as they were prior to the trip. This minimizes the chances of transients causing other operational problems or tripping additional STGs.

The bypasses associated with the tripped turbine will continue to operate in pressure control mode until the operator takes action to close them by restarting the tripped turbine or by changing the operating points of the other turbines and HRSG duct burners as necessary.

3.2.2. MSF TRIP

During a MSF trip, the LP steam export flow requirements will be rapidly reduced. In an anticipatory action taken upon receipt of the trip signal, all of the LP to condenser bypass valves associated with a condenser in operation will open to a position based on the amount of LP steam being consumed by the tripped MSF(s) immediately prior to tripping. They will then be released to control LP steam pressure.

Again, to minimize the effect of transients on the operating steam turbines, their ST crossover control valves will not react to try reduce the LP extraction flow. The system will continue to operate in LP to Condenser bypass mode until the operator takes action.

Also, during a MSF trip, any operating condenser with only one (1) associated condensate extraction pump in operation will have the 2nd pump automatically started in anticipation of increased LP steam flow into the condenser. The condensate pump configuration is 3 x 50% where 100% capacity is only needed in cases where steam is being bypassed to the condenser.

3.3. COLD TURBINE START-UP

For a cold STG start-up, Siemens requires a live steam temperature not exceeding 735 °F. It is not possible to start-up a cold STG with steam temperatures hotter than this under any circumstances. For this reason, final stage attemperators are provided at the outlet of each HRSG for starting up the first STG. If two STG operation is anticipated, it is recommended that the second STG be brought online immediately following the first one while still maintaining the HP steam temperature at 735 °F.

There are operating scenarios when a cold STG must be started up while the other STG within the same block is operating at the design steam temperature of 1040 °F. Since both STGs take steam from the same header, it is not possible to supply 735 °F to the cold turbine without installing some type of steam attemperating system.

Lowering the steam temperature to the operating turbine is not an option as its load would have to be significantly reduced and the MSF LP steam would have to be taken from the HP to LP bypass system since the STG cannot extract LP steam when operating at such low inlet steam temperatures. Operating in this manner could result in a load reduction in the order of 250 MW at a time when a 2nd STG might be starting based on increased power demand.

To address STG cold start-up while the other STG is in service, a cold start-up system was designed which consists of the following features:

- A STG cold start-up bypass valve, with attemperator, sized to pass the required steam flow for cold STG start-up while reducing the steam temperature to 735 °F from a maximum of 1040 °F.
- The cold STG start-up bypass valve is piped up such that it can supply either STG. A motor operated valve is located upstream of each STG such that it can be isolated from the high temperature header steam during a cold start-up.
- Automated isolation valves are located upstream and downstream of the cold start-up bypass valve attemperator to minimize the chance of water leakage into the main steam piping system when the attemperator is not in service and to be able to supply either STG.
- The system was designed to meet the requirements of ASME TDP-1. The use of attemperators downstream of the final superheater are discouraged however, “it is recognized that under some conditions it cannot be avoided”.

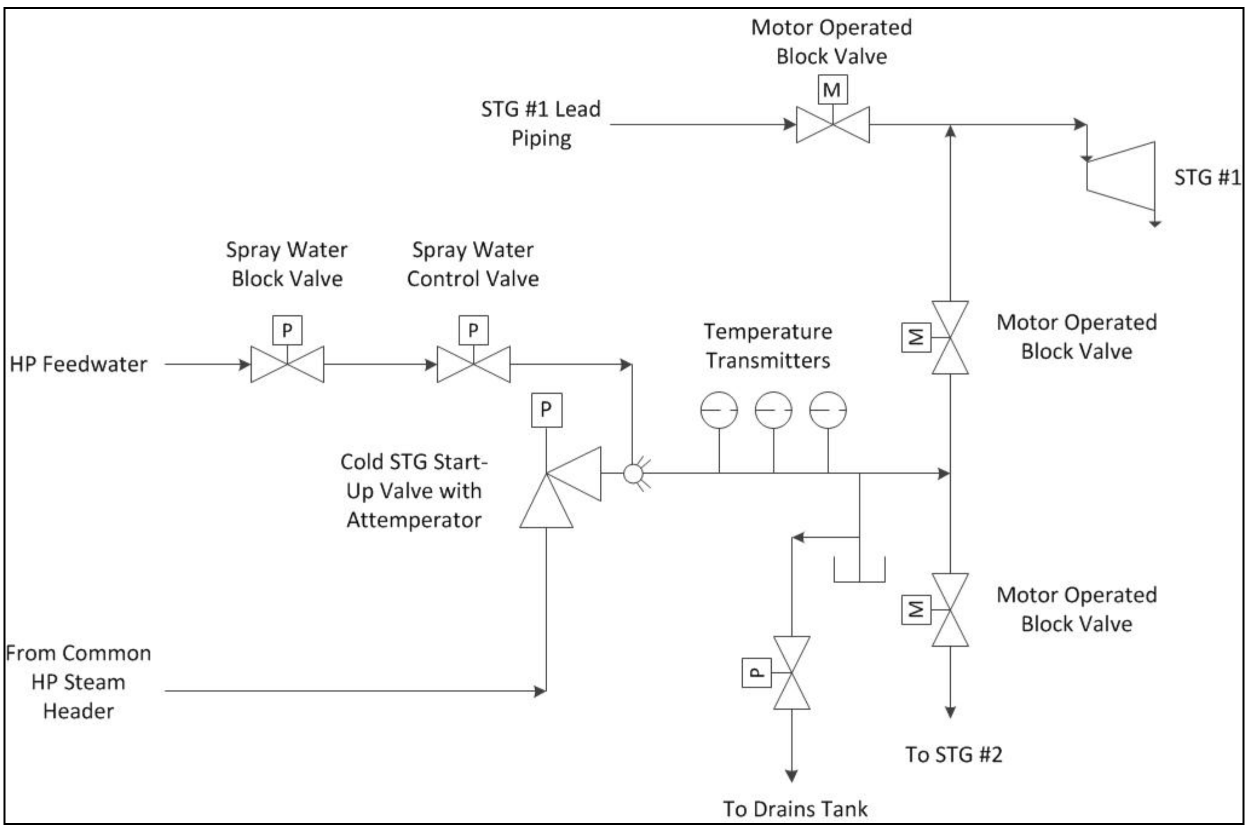

Figure 4 Cold STG Start-Up System

Prior to placing this system into operation, the motor operated valve at the inlet of the STG will be closed to isolate the STG from the high temperature header. The proper cold start bypass isolation valves will be opened to create a flow path to the STG being started. The cold start bypass and HP to condenser bypass valves are both opened and a flow path is established to the condenser while the bypass valve attemperates the steam flow down to 735 °F. The STG goes through its warming cycle and begins to admit steam. As more steam is directed into the STG, the HP to CD bypass valve begins closing. The STG load is ramped up and the cold bypass steam temperature is increased to match the recommended steam temperature signal received from the turbine control system. This continues until the cold bypass attemperating flow is reduced to zero. At this point, the motor operated valve at the turbine inlet is opened and the turbine receives full temperature steam from the main header. The valves for the cold STG start-up system are then all closed.

Despite requiring more piping and steam isolation valves, the system was designed in this manner instead of putting an attemperator in each turbine lead for the following reasons:

- The attemperator is completely valved out on the steam side when not in use and an inadvertent attemperator water spray or leak will not go into the STG lead. The use of this system will be sporadic, therefore, we believe this design reduces the likelihood of water induction or rapid steam temperature drop.
- A single attemperator system can be shared between the two steam turbines.
- With this design the attemperator can be located further away from the STG and upstream of a piping low point.

3.4. CONDENSATE SYSTEM CONTROLS

The condensate system includes nine (9) separate condenser hotwells (five MSF hotwells and four STG condenser hotwells) pumped into a common header that supplies the LP drums of six (6) HRSGs. The flow to each HRSG is regulated by its drum level control valve. The key issues that the controls for this system need to address include:

- Extract the proper amount of condensate from each hotwell to maintain a proper level.
- Inject the proper amount of demineralized make-up water into each hotwell especially during high make-up transient conditions such as a tube leak on an MSF causing condensate to be dumped to the sea based on high conductivity.

- Ensure that the HRSGs receive sufficient flow at the inlet of the drum level control valves such that they will be able to maintain the proper LP drum level.

Using a pump discharge valve to simply maintain the level in each hotwell would not control the system properly since it could starve the flow to the HRSGs as each hotwell tries to preserve level. It would also make it difficult to determine the amount of make-up required to the system.

The controls implemented for this system are as follows:

A condensate discharge control valve is installed downstream of each condensate pump. On the MSF side, these control valves are always in hotwell level control mode. On the power block side they are configured to maintain the correct condensate header pressure and control the condensate level in the condenser. The control valve will operate in one of two control modes: Condensate Header Pressure Control or Condenser Level Control. The discharge control valve of the first condenser placed in service will be in Condensate Header Pressure Control mode. Subsequent condensers placed into service, including those from the other Block, will have their control valves in Condenser Level Control mode. The control mode is operator selected once two or more condensers are in service, but there must always be one and only one discharge valve in Condensate Header Pressure Control mode.

The demineralized water system provides the turbine condensers with makeup water to replace HRSG blowdown, MP steam sent to the MSF units, vents, leaks, and in rare cases MSF condensate dump to the sea. The level for the Condenser whose discharge control valve is in Condensate Header Pressure Control mode will be selected for the control of the Condensate Level control Make-up. This condenser level will be used to control the level of all in service Condensers, with a proportioned bias based on the LP turbine load. This will split the make-up between all operating condensers and avoid introducing large amounts of demineralized make-up water flow into a condenser that is operating at a low condensate flow.

By having one valve in header pressure control mode, this ensures the HRSG drum level control valve will have an adequate pressure for filling the HRSGs. Since this valve only reacts to header pressure and not condenser level, a sudden loss of condensate in the system will quickly be reflected in the water level of this condenser. As the level in the condenser that is on pressure control drops due to a sudden loss of condensate then increased condensate make-up flow will be injected into all operating condensers. This will minimize the chance the other condenser valves try restrict flow to maintain level during this transient.

3.5. HRSG START-UP SYSTEM CONTROLS

Directing excess steam to the condenser rather than to atmosphere during HRSG start-up to preserve demineralized water is a common concept. What makes UHP unique is the 3 x 2 power block arrangement where there are two condensers that could be used for bypass. Also, to minimize the piping, the outlets of each bypass valve are headered together and this header is connected to each condenser via two pipelines, each with a motor operated isolation valve. This allows the flow to be sent to either condenser but not both. Cross tying of the condensers is avoided to minimize the chance of tripping both condensers during a loss of vacuum on one. The bypass valve is sized for tying in the 3rd HRSG while the other two are in operation. That is the worst case basis.

4. SUMMARY

Due to its unique configuration, the UHP project has a number of system controls and design challenges. Some of the unique solutions used to address these issues include:

- Basing HRSG ductfiring duty on both plant power output and position of the LP cross-over valve. At times of high ductfiring to support water production, the crossover valve will be mostly closed. At times of high ductfiring for increasing plant electrical power output, the plant electrical set point is used to determine duty and the position of the crossover valve is not used. We believe these controls result in operating the plant at the most efficient point over many different power and water production combinations and at varying ambient conditions.
- Several factors need to be considered when determining if one to two STGs should be in operation for a given plant operating point. These factors include turbine throttle steam pressure, LP extraction steam temperature and pressure, bypass valve operations, and LP turbine exhaust temperatures.
- A decision was made to have bypass valves primarily react to transient steam conditions rather than changing the steam turbine operating point. Although changing the STG operating point could reduce the amount of lost plant electrical output during a transient, it could also trip the STG if the turbine operating limits are exceeded. We believe using the bypasses will minimize the transients and reduce the chances of a steam turbine trip.
- A cold steam turbine start-up attemperating system was installed to allow the start-up of a

cold steam turbine without impacting the operation of the already in service steam turbine. Due to the risk of water induction for such a system, the ASME TDP-1 recommendations were strictly followed and the system was designed so it is completely isolated from the STGs when not being used for cold turbine start-up.

- The condensate controls utilize a system where one condenser discharge valve is on header pressure control while all the others are on level control. We believe this type of system will maintain a constant water level in all condensers while still being able to control proper make-up flows into each condenser even during transient conditions.

