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Features of Kawerau Geothermal Plant Control System

Hiroshi Funaba (Fuji), Toshie Muto (Fuji) and Ian Stabler (Mighty River Power)

Fuji Electric Systems Co., Ltd. 1-1 Tanabeshinden, Kawasaki-ku, Kawasaki-shi 210-9530, Japan

funaba-hiroshi@fesys.co.jp, muto-toshie@fesys.co.jp, ian.stabler@mightyriver.co.nz

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ABSTRACT

This paper presents some of the control challenges associated with the application of a distributed control system intended to provide integrated control of all functions across Mighty River Power's Kawerau plant in New Zealand. The control system provides seamless integration of all operations throughout the steamfield, power generation and switchyard of the plant.

1. INTRODUCTION

Mighty River Power's Kawerau plant became operational in August 2008. At this time, Kawerau was the world's largest single unit dual flash geothermal power station, capable of providing a nominal output of 100MW. The main generation elements of the plant comprise of a 113MW(MCR) condensing steam turbine, a ten cell cooling tower system, a dual flash steam separation system, a non condensable gas extraction system, and an automatic brine pH control system to prevent deposition of silica. An integrated steamfield supplies the plant with two phase fluid, and enables the controlled injection of resulting brine and condensate streams. Six production wells keep the plant supplied with a nominal flow of 45,000 tonnes per day (to a maximum of 55,000 tonnes per day) of two phase fluid at an average enthalpy of 1300kJ/kg (559 Btu/lb).

A Distributed Control System (DCS) provides all supervisory monitoring and control functions for the station. Control is provided for the main generation and support systems, but more fundamentally is also provided for the control of the steam supplies and reinjection systems as one integrated package. This allows the two phase fluid, brine and condensate flows to be optimized to match the generation plant's exact requirements and minimizes the need for manual intervention. The same integrated control system also controls an acid dosing system to modify the pH of the brine stream to prevent silica deposition.

2. CONTROL SYSTEM CONFIGURATION

Figure 1 shows a cut down representation of the DCS architecture. A dual redundant Fault Tolerant Ethernet (FTE) provides the communications backbone that links major system components.

Two Controller Stations communicate with plant instrumentation, actuation devices and specialist processing systems to carry out all data acquisition, monitoring and control functions. As Figure 1 shows, the Control Stations interface with both the generation and steamfield areas of the plant to provide plant-wide integrated control. The majority of plant interfaces are hardwired, but where remote steamfield connections were necessary, Foundation Fieldbus running on fibre-optic media was used instead.

A number of Operator Stations provide the user interface, whilst all system management activities such as configuration, alarm and event handling, historical data collection and storage, etc are handled by the Server Unit. In addition, a dedicated historian server is provided for long-term storage of historical data.

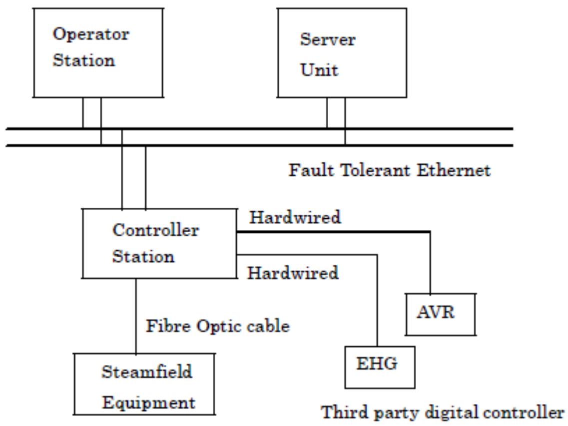

Figure 1: Control System Overview

3. PROCESS CONTROL SYSTEM

3.1 Steam Separation System (SSS)

Figure 2 presents an overview of the Steam Separation System (SSS). This part of the plant receives two phase fluid from the production wells and separates it into steam and brine using three separators. The steam is also scrubbed of impurities before being fed to the steam turbine.

The first steam separation stage consists of the High Pressure (HP) Separator. This vessel operates at a pressure of approximately 12 bar absolute and it is here that the two phase fluid separates into steam and brine. The top portion of the vessel is the steam zone, and the bottom of the vessel is the liquid drum. The high pressure steam is routed to the HP Scrubber passing a number of wash water injection points on the way. The water removes any impurities in the steam which is then removed in the HP Scrubber. Cleaned steam exists the HP Scrubber and is fed to the HP feed side of the steam turbine.

Brine is removed from the HP Separator under level control and is fed to the two Low Pressure (LP) Separators. The brine flashes at the level control valves and becomes two phase before it enters these vessels. Here the fluid is separated once more at a pressure of approximately 1.8 bar absolute. The LP steam output from these vessels is scrubbed in the same manner as the HP steam and fed to the LP side of the steam turbine.

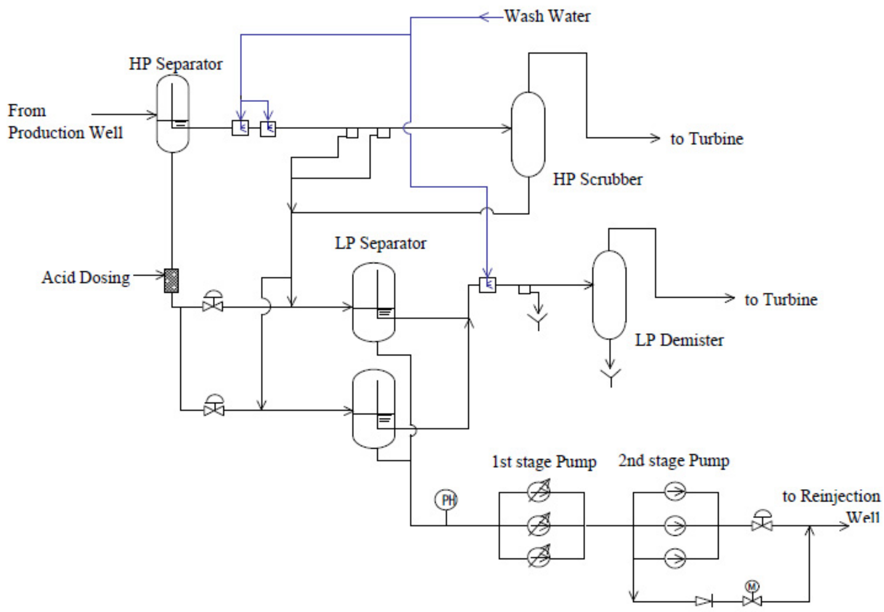

Figure 2: Steam Separation System Overview

3.2 Steam Separation System Control Features

(1) HP Separator Level Control

Brine level in the HP Separator is controlled using a combination of four valves:

- 2 x 50% capacity Level Control Valves
- 2 x 100% capacity Emergency Dump Valves

Under normal operation, the HP Separator level is measured by two voting level transmitters and controlled by operation of the two 50% level control valves. The emergency dump valves divert excess brine to a soak-pit (thermal pond) if normal level ranges are exceeded. Unfortunately, tuning for optimum level control caused excessive disturbances to the stability of the subsequent brine pH control system, a system that presented a challenging control problem (as described later). Hence tight tolerance level control was sacrificed (through tuning) and more emphasis was placed on minimizing disturbances to the HP brine flowrate (See 3.2.(3)).

(2) LP Separator Level Control

Brine level in the LP Separators is controlled using one of two “control modes”, selectable by the operator. Mode 1 control is used in normal operation and employs variable speed pumps to send the excess brine to the plant reinjection wells. Mode 2 control employs up to six pumps (running at fixed speed) to provide extra reinjection pressure if there are changes to the reinjection well configuration or back-pressure. In this case, level control is provided by a modulating control valve. In both cases, emergency dump valves divert brine to the thermal pond if normal level ranges are exceeded. All pumps have 50% process capacity, with all six giving a potential of 150% plant capacity plus the extra injection pressure.

Referring to Figure 2, the 1st stage brine pumps are capable of variable speed operation, whilst the 2nd stage pumps are fixed speed. When in Mode 1, only the 1st stage pumps are used and are speed controlled according to the level of both separators. In this mode, the 2nd stage pumps and level control valve are bypassed. Mode 2 control uses all pumps running at fixed speed, with the level control modulating valve reacting to changes in separator level.

Since Mode 1 control does not employ a control valve there is no mechanism (other than the wellhead valves) to produce any back pressure for the pumps. Since the wellhead valves are slow to respond, they are unable to increase the back pressure quickly enough to prevent pumps tripping under overrun conditions. This can occur whenever there is a fault with a running pump, or when operation is switched between modes. Under these circumstances, the LP Separator level control valve will quickly close to a defined position and provide the required back-pressure. This is done at the expense of LP Separator level stability, and any excess brine in the Separator will be dumped to the Thermal Pond.

(3) Brine pH control

Separation of the two phase fluid causes the residual brine in the system to become saturated with silica which can be prone to polymerization and can subsequently become deposited within the downstream plant. By lowering brine pH, the polymerization can be limited. A closed loop acid injection system is therefore used to maintain the LP brine pH between 5.0 +/- 0.25.

The pH control system comprises of

- 2 x 100% capacity variable speed acid dosing pumps
- Main static mixer and 2 x 100% pre-mixers
- Wash water pumps to supply dilution water to the pre-mixers
- Continuous brine pH measuring equipment (duplex pH probes)

The system measures the pH of the LP brine and doses an appropriate volume of 98% sulphuric acid to maintain pH in the required range. As with all pH control applications, the titration curve around the neutral pH point is extremely steep, and during commissioning it became clear that a very small addition of acid could cause a significant drop in brine pH. For this reason, the acid injection dosing pump speed (and hence the dosing rate) was configured to modulate according to two process measurements.

The coarse acid dosing flowrate was set as a fixed ratio of the *HP brine flowrate*. This effectively created a mid-point dosing bias around which smaller dosing adjustments could be made in accordance with variations in the measured LP brine pH. Variations in HP brine flowrate would then be compensated by the ratio flowrate, whilst smaller variations in pH due to more subtle process changes would be compensated by the finer measured control loop.

The LP brine pH is measured by one of two pH probes working a duty/standby rota. Since silica deposition is a potential issue for the probes, each one undergoes a washing cycle when it has been taken out of duty. By superimposing the output from a 2 term controller onto the coarse ratio dose flowrate, we were able to control pH within the required tolerance and good disturbance rejection for normal plant operations was achieved.

Having the coarse dosing flow set as a ratio to the HP brine flowrate, it was now critical to alter the HP Separator level control method to minimize brine flowrate disturbances. As discussed earlier, this was achieved by relaxing the control of the HP Separator level.

Other potential disturbances can occur due to changes in overall plant brine demand, brine pressure and chemistry. All three can change simultaneously during well changeovers or plant runback conditions (initiated by a turbine trip or steamfield fault). Under such circumstances, the pH control loop is too slow to respond to the significant changes in LP pH that occur. During this condition therefore, the acid dosing system is designed to trip to prevent overdosing of acid and subsequent control instability. The incapacity to respond to a significant disturbance is a limitation of the pH control system, but rapid recovery of control can be achieved through re-starting control from the last good controller output. This is operator initiated.

(4) Steam Pressure Control by Vent Valves

The Steam Separation system is protected from over-pressurisation by three 50% capacity HP Vent Valves and three 50% capacity LP Vent Valves. The HP Vent Valves direct excess steam to atmosphere through the plant Rock Muffler, whilst the LP Vent Valves direct it through a mechanical silencer. All Vent Valve operation is performed by DCS closed loop pressure control logic. In addition to the DCS control, mechanical protection of the pipes is provided by rupture discs.

The ability to vent steam under tight control is necessary for successfully controlled plant start up and shut down. Under these conditions, the changing steam requirements of the turbine are set by the turbine Governor. Any excess steam is vented automatically until the slower steam field control valves can throttle back supply.

3.3 Power Generation Facility (PGF)

The Power Generation Facility (PGF) consists of three main plant functions. The Steam Turbine Generator (STG) receives the HP steam and LP steam from the SSS and directs this to a condensing turbine to produce up to 113MW of electrical power. The exhausted steam is condensed and circulated through a cooling tower system, and any non condensable gases (NCGs) are extracted and processed by the Gas Extraction System (GES). The steam turbine, generator and condenser are manufactured by FES. Any excess condensate from the cooling system is pumped back to the steamfield for reinjection. Figure 3 shows the PGF system overview.

The steam turbine maximum output is 113MW and utilizes 31.4 inch long last stage blades. At the time of writing, these are the largest blades to be used in a geothermal application, and make the Kawerau facility the largest single casing dual flash geothermal power station. The generator is a totally enclosed water-to-air-cooled (TEWAC) type with a brushless exciter.

The GES employs three vacuum pump trains sized at duties of 40%, 60% and 80% capacity respectively. Each train is equipped with two steam ejector stages and a liquid ring vacuum pump.

By running various combinations of the three trains, up to seven levels of extraction can be achieved according to plant requirements. This provides for a flowrate range of 40% to 180% of the plant design point. Having such capacity makes provision for any uncertainty in the makeup of the non condensable gases, a fact that can only be established once all production wells have been drilled and tested. It also allows for any changes of gas composition of the geothermal two phase fluid from wells over the lifetime of the field. Although all three trains were operated during plant commissioning, operation at Kawerau today only requires operation of the 40% and 80% trains.

The cooling tower is a mechanical draft counterflow type constructed from fiber reinforced plastic (FRP). It consists of ten cells and arranged in one line. Two cells are fitted with dual speed cooling fans, whilst the remaining eight are fitted with fixed speed ones. By selecting various combinations of fixed and dual speed cells, operators can achieve precise cooling requirements that match the plant and atmospheric conditions. Allowing unnecessary cells to be idle also gives the operator the ability to make energy savings.

Condensate is continuously recirculated between the cooling tower and the condenser. The total volume in the circuit is increased by the addition of condensate from the cooled steam turbine exhaust, and excess condensate (steam turbine exhaust minus evaporation loss at the cooling tower) is pumped to condensate reinjection wells. The original design intent was to reinject on an intermittent basis and allow fluctuations in cooling tower basin holding water volume. However, the reinjection well proved it was capable of accepting larger volumes than expected, leaving the reinjection piping to develop a vacuum during the idle periods. The reinjection pump control was therefore changed to be continuous.

3.4 Power Generation Facility Control Features

(1) Steam Turbine Control

The steam turbine is equipped with two HP pressure control valves and two LP pressure control valves. All four are controlled by the generator governor system (separate from the DCS). An emergency governor is also provided to turbine and overspeed protection functions. The governor control system is designed to provide the following control modes:

- Speed/Load control
- HP inlet steam pressure control
- LP inlet steam pressure control

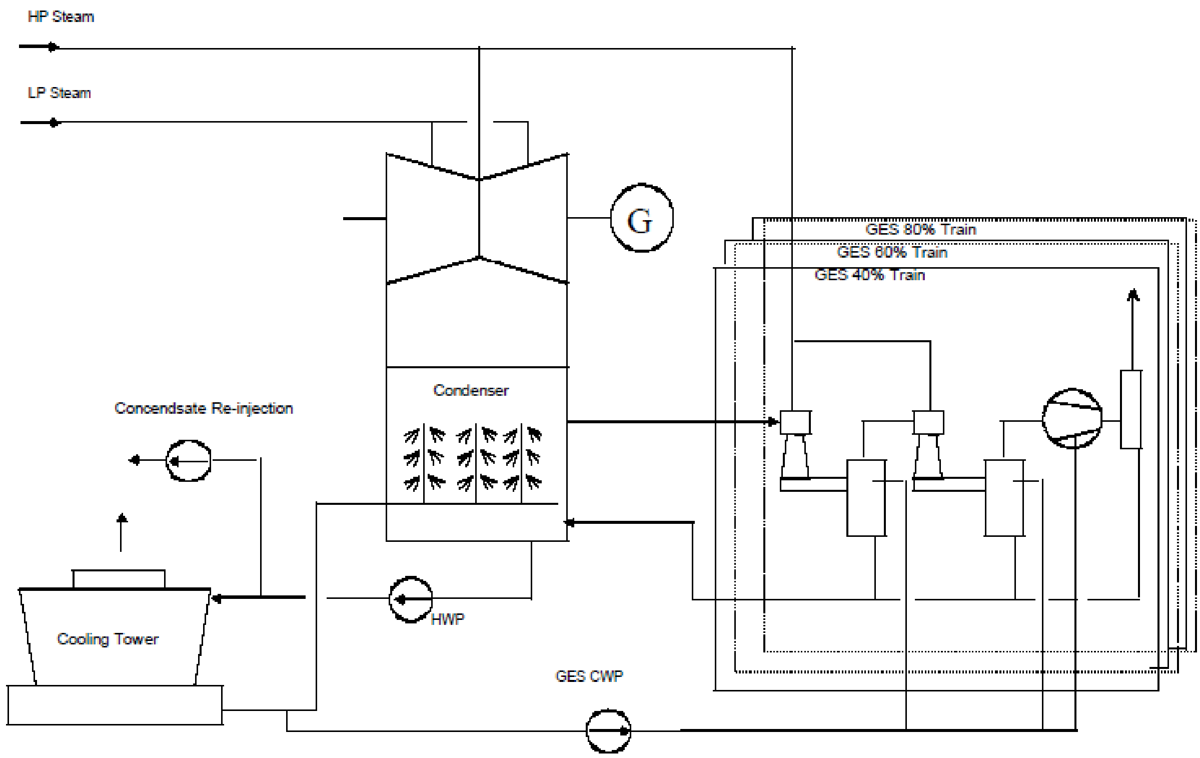

Figure 3: PGF System Overview

During plant start up, the speed/load function controls the turbine until it reaches the 30% MW load condition. Once this is reached, control is switched over to the HP inlet steam pressure control mode (this works in coordination with the vent valves described in section 3.2.(4)). Under HP steam control, the turbine load can be further increased. The turbine is able to run on HP steam alone, and this is done during startup and shutdown operations. To gain optimal efficiency from the turbine, the LP steam is introduced under LP inlet steam pressure control to provide additional steam.

(2) Generator Voltage Control

The Generator voltage is controlled by a dedicated digital controller that is separate from the DCS. It controls the real (MVA) and reactive power (KVAR) in accordance with the power grid requirements.

(3) Coordination Control

The plant control system provides the overall control and supervision not only for the SSS and PGF, but also for the steamfield and switchyard. Operation of all four areas is coordinated seamlessly by the DCS and its supporting systems.

The turbine governor controls the entire turbine steam pressure demand, and through the DCS it commands the steamfield production well control valves to open or close in accordance with the required generator output. If a steam vent valve opens, or a burst disc rupture occurs, the DCS will effectively hold the steamfield production well valves at their current setting to minimize energy waste whilst allowing the plant to continue running until repairs are effected or a shut down is initiated.

Should a more significant failure occur (the loss of a Hot well pump for instance), the system will switch to 'Turbine Runback' mode. In this mode the turbine load is automatically reduced by the governor to a reduced MW setpoint. Excess steam is vented through the HP and LP vent valves during turbine runback. This occurs quickly to prevent the turbine from tripping on low condenser vacuum. At the same time, a steamfield runback is initiated to close the production well control valves to a point at which excess turbine steam no longer needs to be vented, leaving the turbine running on reduced MW.

Steamfield runback is also initiated during certain plant upset conditions (Examples are turbine trips, turbine load rejection and loss of all brine re-injection pumps). A steamfield runback will remain in force for up to one hour. If no operator action is taken with one hour, an automatic plant shutdown is initiated. A sequence will initiate shutdown of the turbine and will subsequently shut down all production wells once the turbine speed has reduced to a defined level. The same sequence will shut down all supporting major plant items to leave the plant in a safe state.

4. CONCLUSION

Kawerau geothermal power station was designed and constructed with the latest power generation technologies.

The plant presented a number of new control challenges, and good working experience was gained in overcoming them during plant commissioning. This is particularly true of the brine re-injection system controls and the PGF to steamfield control coordination.