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Transient Efficiency Flexibility and Reliability Optimization of Coal-Fired Power Plants

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Report on High-Fidelity Dynamic Modeling of a Coal-Fired Steam Power Plant

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TECHNICAL REPORT

HIGH-FIDELITY DYNAMIC MODELING OF A COAL-FIRED STEAM POWER PLANT

DE-FE0031767

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Executive Summary

As a result of the growth of renewables including solar and wind energy with fluctuating production, fossil fuel power plants are being required to cycle between high and low power production. This cycling is both at a greater frequency and over a wider range than in the past. In many cases, power plants are not designed for this type of cycling operation but can nonetheless endure these challenging operation requirements under the right conditions. In this project, optimal solution for enhanced flexible operations are being investigated using model based estimation and control techniques.

To support the development of model-based estimator and model-based controls at GE Global Research, GE Steam Power configured a dynamic model using a reference steam plant design including the boiler, turbine, and water/steam conditioning systems as well as the controls needed for plant cycling with stability and reliability.

The dynamic model was built using the APROS® software from VTT, and then calibrated to multiple load conditions from full load (100%TMCR) to partial loads (75%TMCR, 50%TMCR and 25%TMCR) based on internally developed steady state heat balance models at the unit level. These internal heat balance models are based on first principles and extensive engineering experiences from GE Steam Power as an OEM and a services provider.

This topical report presents the structure of the unit level dynamic model, the tuning process, and representative simulation results from typical load cycling simulations using the dynamic model.

Keywords: Steam Power Plant, Dynamic Process Modeling, Model Calibration, Simulation Analysis

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1 Background and Objective

The model described in this report is being used as a plant (or unit) level simulator for developing model based control solutions based the so-called reduced order models (ROM). The reduced order models are coded in MATLAB, and they will be embedded into the model-predictive control systems that will enhance the flexibility, efficiency, and reliability of coal-fired power plants where the systems are implemented. The improved efficiency and flexibility will also result in reduced environmental impact from existing fossil fuel fired power plants.

The reference plant design used in this simulation study is based on an 820 MW_e (gross) coal-fired power plant in the United States. The plant equipment will be able to operate for decades but will be faced with increasing market and regulatory challenges. Optimization will enable this unit and other coal power plants to operate flexibly and efficiently alongside alternative power generation and storage technologies. As a power plant services company, GE Steam Power is fully motivated to develop plant optimizer tools for flexible operation of these power plants, which will better support the power grid operation in the future.

This report describes the design and calibration process of a full power plant model, including three modules:

1. Boiler systems
    - Boiler process, including the combustion and steam generation processes
    - Boiler temperature and flow control design and tuning
    - Heat balance calibration against empirical models.
2. Steam Turbine
    - Steam turbine process model structure and calibration
    - Controls design and tuning
3. Feedwater plant
    - Plant load control
    - Feedwater systems
    - Condensing systems

The integrated plant model was calibrated using the engineering design data that GE Steam Power produces using the thermal performance design tools for the boiler, the steam turbine and the water-steam cycle of the reference plant design.

2 Plant Description

2.1 Thermodynamic Cycle and Heat Balance

The reference plant uses a subcritical steam cycle with reheat. The evaporative process does occur near the critical point, however. plant steam cycle is a basic Rankine Cycle with reheat. Figure 1 shows the steam cycle of the plant at the maximum continuous rating (MCR).

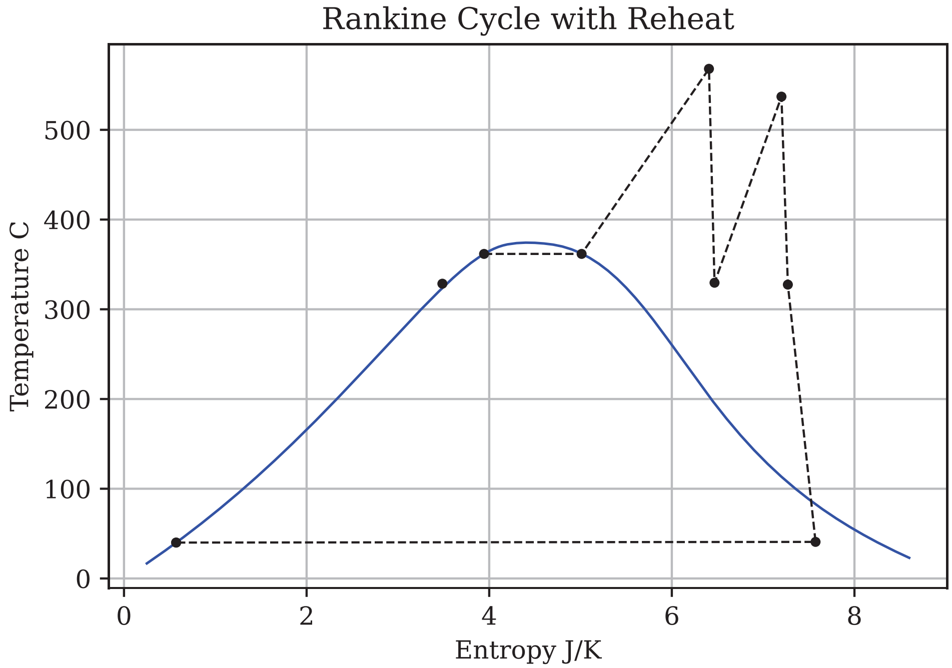


Figure 1. High-pressure subcritical Rankine steam cycle, typical for a CFPP at maximum rating.

GE Steam Power has used two internally developed tools for calculating and modeling the plant heat balance. The first is a process engineering tool for thermal performance design of the boiler systems. The second program is used for thermal performance design of the steam turbine, preheaters, and balance of plant. The plant performance design tool also includes modules for fossil boilers, which were not used for the reference plant design. Both engineering design tools are static thermodynamic calculation codes. Heat balances were calculated and used for operational points of the virtual plant: 100% TMCR, 75% TMCR, and 50% TMCR and 25%TMCR. These heat balances are used as calibration points for configuring and tuning the dynamic model.

GE Steam Power has configured a prototype plant-level dynamic model, which includes the high pressure turbine (HPT), intermediate pressure turbine (IPT), and the low pressure turbine (LPT) stages. It further includes the steam condensers, the deaerator, the high-pressure and low-pressure water heaters, and the feedwater pumps. Finally, a boiler section with steam economizers, superheaters and reheaters are integrated into the steam plant model. The process diagram in Figure 2 is representative of the steam-water process used in the reference steam plant.

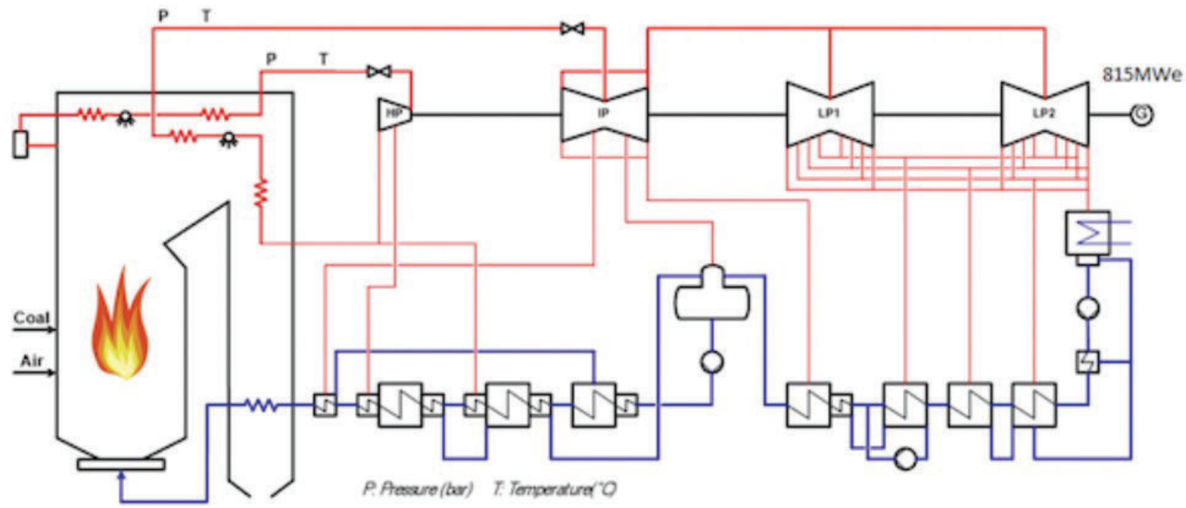


Figure 2. Typical process flow schematic for a Rankine steam cycle with reheat. Blue indicates saturated or sub-saturation liquid water, while red lines indicate saturated or superheated steam.

3 Model Description

3.1 APROS® Capabilities and Solution Method

APROS® stands for **A**dvanced **Pro**cess **S**imulation. It is a software platform for full-scale modelling and dynamic simulation of industrial processes. The applications include nuclear and thermal power plants, pulp and paper mills, and a wide variety of other industrial systems, where dynamics of material and energy flows, automation and electrical systems are of interest.

In the APROS® modeling environment, the model is regarded as a network of thermal hydraulic nodes, i.e., control volumes, and branches, i.e., connections between the nodes. Major uses of APROS® simulation software include:

- Development of process control strategies
- Analysis of system operations
- Verification of process designs
- Testing of control system designs
- Training of plant operators

The model solves for temperature, pressure, momentum, mass transfer and reactions. The software comes with extensive libraries for system components, both mechanical and electronics. The APROS® model libraries provide basic modules with reduced complexity as well as those modules with high fidelity.

3.2 Condensate and Feedwater Configuration

GE Steam Power has configured a plant-level dynamic model in APROS®, which includes the steam generator (the coal fired boiler), steam turbine (HP, IP and LP stages), condensers, the deaerator, the high/low pressure water heaters, and feedwater pumps.

Condensing System

After expansion in the turbine, steam is condensed by the condenser cooling water tubes. Condensate is collected in the hot well and pumped back to the feedwater tank by two condensate pumps. Control valves, installed upstream from the LP heaters, keeps the level of the condenser constant. The condensate flow is heated via two files of four LP heaters which are fed by turbine steam extractions. The LP feedwater heater levels are controlled by control valves returning to the preceding heater following a cascade principle.

The feedwater tank is fed by steam coming from the cold reheat steam line.

Feedwater System

Two sets of feedwater pumps operate in normal operation. Each set of pumps is composed with one Steam Turbine Feed Water Pump, one booster pump and one main pump.

The feedwater is heated-up via two files of two HP heaters fed by turbine steam extraction and by cold reheat steam. The HP heater condensate drains are cascaded by a control valve to the previous HP heater and to the feedwater tank.

In normal operating conditions, the deaerator is fed by the turbine steam extraction, meaning that the pressure is sliding along with the unit load. At turbine low load and at operation through bypasses, the supply of the deaerator is satisfied from the cold reheat steam by means of a valve controlling the feedwater tank pressure. The pressure controller performs two functions as follows:

- Maintains the pressure in the cold reheat steam supply
- Prevents sudden pressure drop in the tank (pressure gradient control) in case of sudden loss of bleed steam supply (i.e., turbine trip)

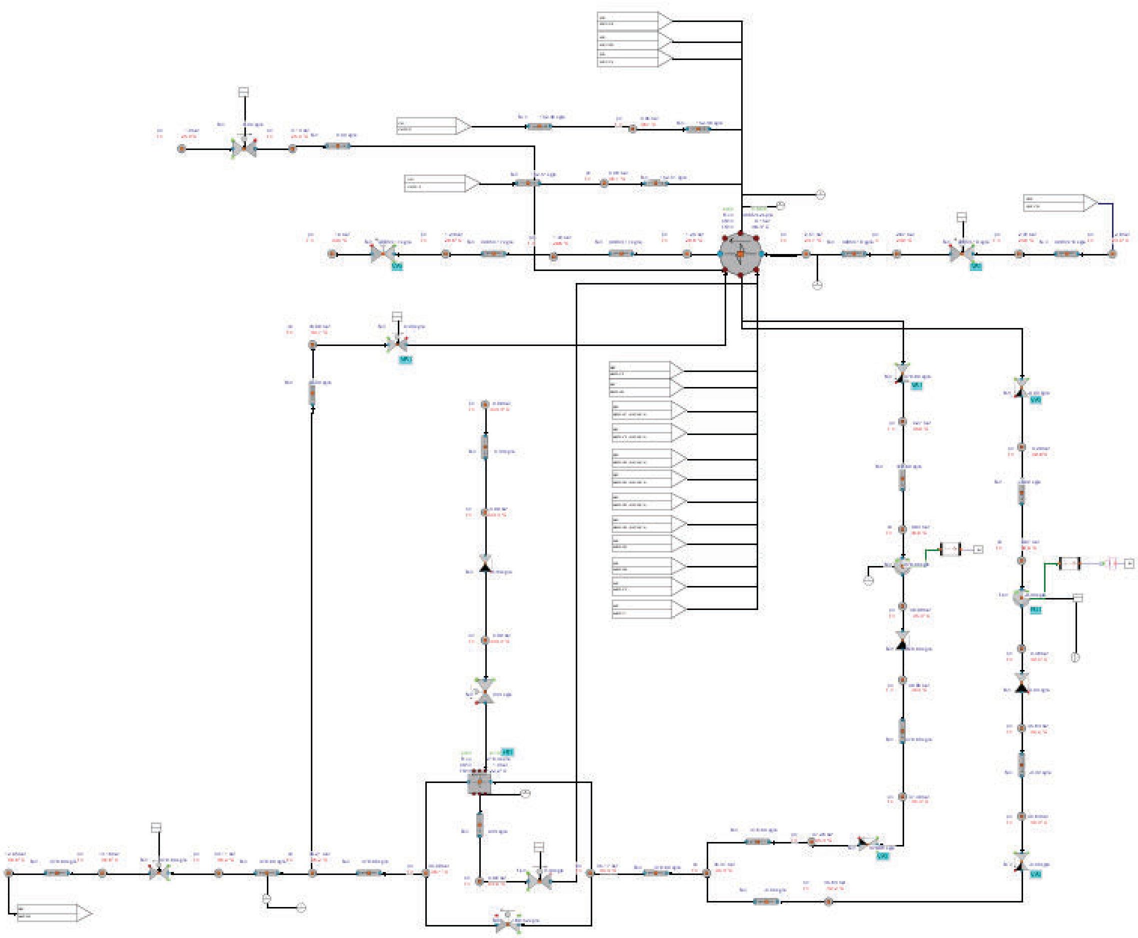


Figure 3. Steam/Water condenser system

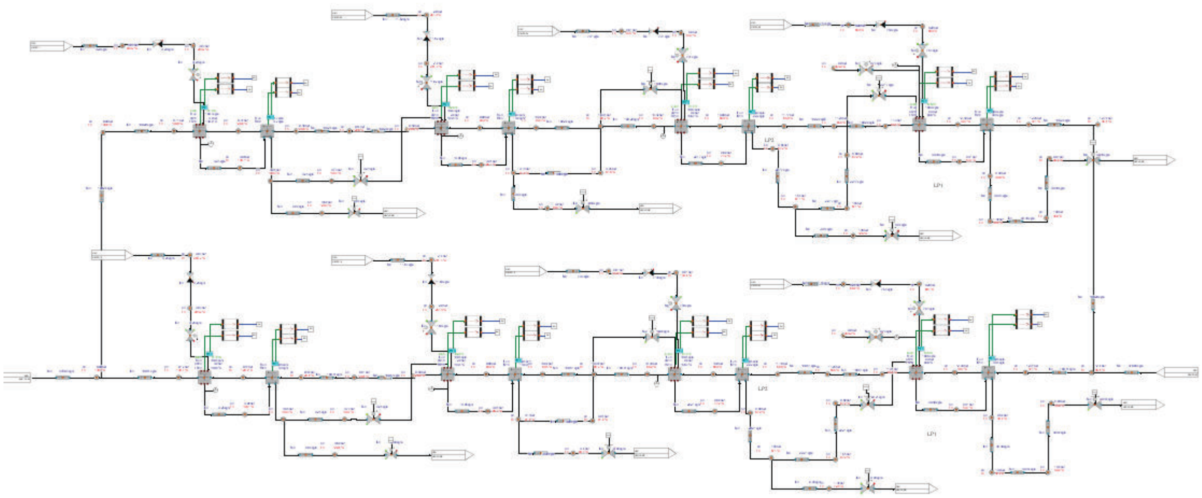


Figure 4. LP Heaters

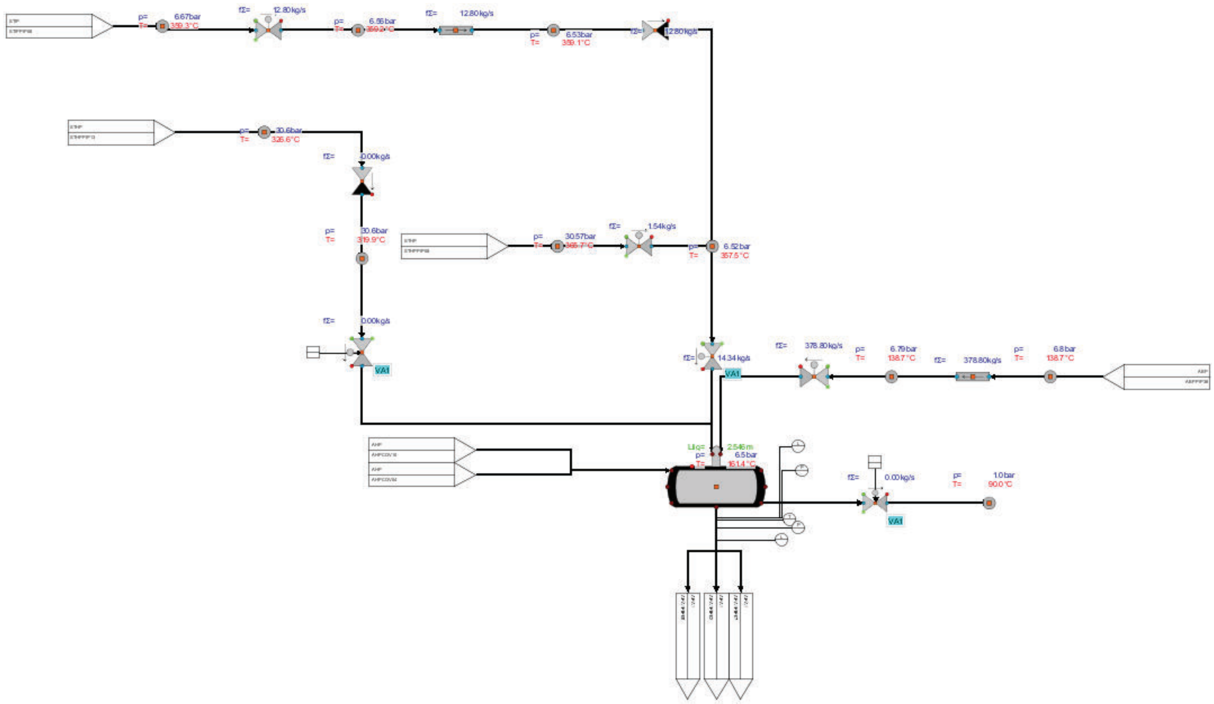


Figure 5. Feedwater tank, deaerator, and supply

3.3 Plant Load Controls

The plant load control coordinates the boiler with the steam turbine during loading/unloading or disturbance phases between unit minimum load and TMCR. During normal operation, the unit operates in modified sliding pressure mode.

The unit master load controller generates set points for the boiler load demand (thermal power), for turbine load demand (MW) and for the sliding steam pressure (turbine and HP bypass).

There are two kinds of coordination modes: turbine follow mode and boiler follow mode.

The turbine follow mode is used for smooth unit operation. The steam turbine will operate with a limited throttling corresponding to a modified sliding pressure curve, or eventually be in valves wide-open (VWO) configuration following operational requirements. The MW variation will be obtained by changing the boiler firing, thus the steam flow. This means the rate of load transition depends on the boiler inertia. The turbine valves react only to control the pressure according the sliding setpoint which is a function of the load.

The boiler follow (BF) mode is the usual mode of operation to have better MW dynamic behavior. The principle of the load control in this mode is the following: a load setpoint variation involves the opening/closing of the ST HP control valves. The load setpoint variation is simultaneously sent to the boiler to anticipate the thermal load variation. In case of load increase, at short term, the steam stored in the boiler is used to meet the load demand. The steam flow variation has an instantaneous effect on the superheated steam pressure. That leads to a variation in the fuel flow because of the action by the boiler pressure controller. The combustion air and feed-water controls modify the are and water flows respectively according to the new boiler load.

3.4 Feedwater Plant Level Controls

Condenser level Control

During normal operation the condenser hot well is controlled at a constant value by the condensate extraction control valves at the condensate extraction pumps discharge. In case of a turbine trip, the condensate flow entering in the FWT (Feedwater Tank) is reduced to prevent too high depressurization.

FW Tank Pressure Control

In normal operating conditions, the deaerator is fed by the turbine steam extraction, meaning that the pressure is sliding along with the unit load. At turbine low load and at operation through bypasses, the supply of the deaerator is satisfied from the cold reheat steam by means of a valve controlling the feedwater tank pressure. The pressure controller performs two functions as follows:

- Maintains the pressure during the cold reheat steam supply.
- Prevents sudden pressure drop in the tank (pressure gradient control) in case of sudden loss of bleed steam supply (turbine trip).

Level Control of HP/LP Heaters

The levels of the HP/LP heaters are controlled by the control valves returning to the preceding heater following a cascade design. If the heater level exceeds a maximum value, the accumulated condensate is drained to a flash box casing of the condenser by an emergency drain valve.

Feedwater pump speed control

The differential pressure across the drum level control valve is adjusted through a cascade control loop:

- a slave controller controls the turbine speed at the setpoint given by the master controller by changing the steam flow through the steam turbine of the feedwater pump.
- a master controller controls the differential pressure at the design setpoint by changing the pump speed setpoint of the slave controller.

3.5 Steam Turbine Process

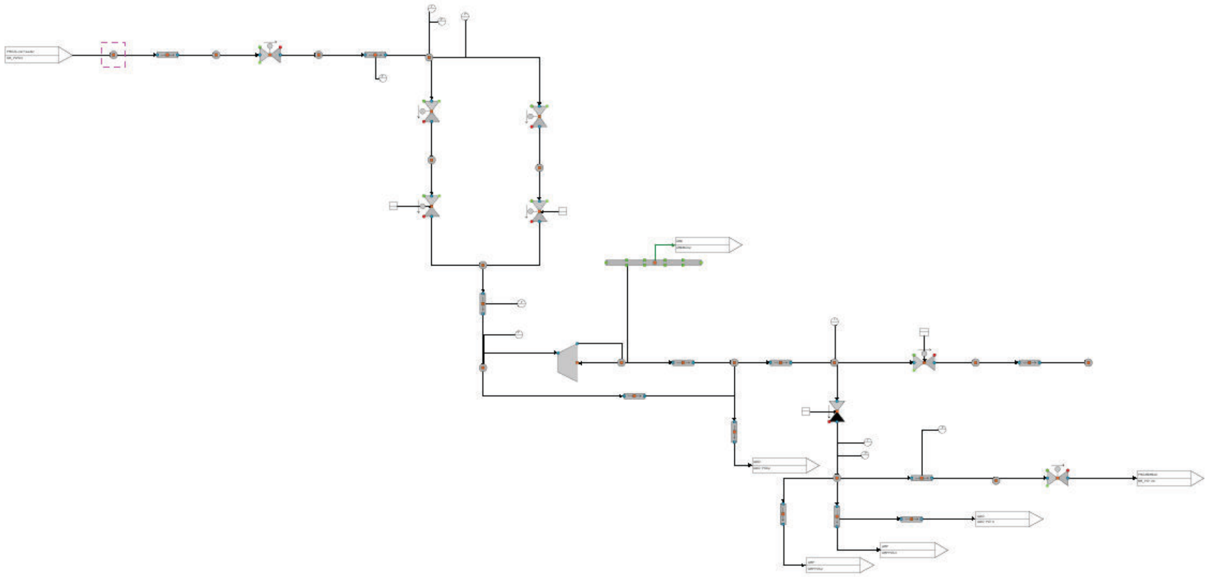
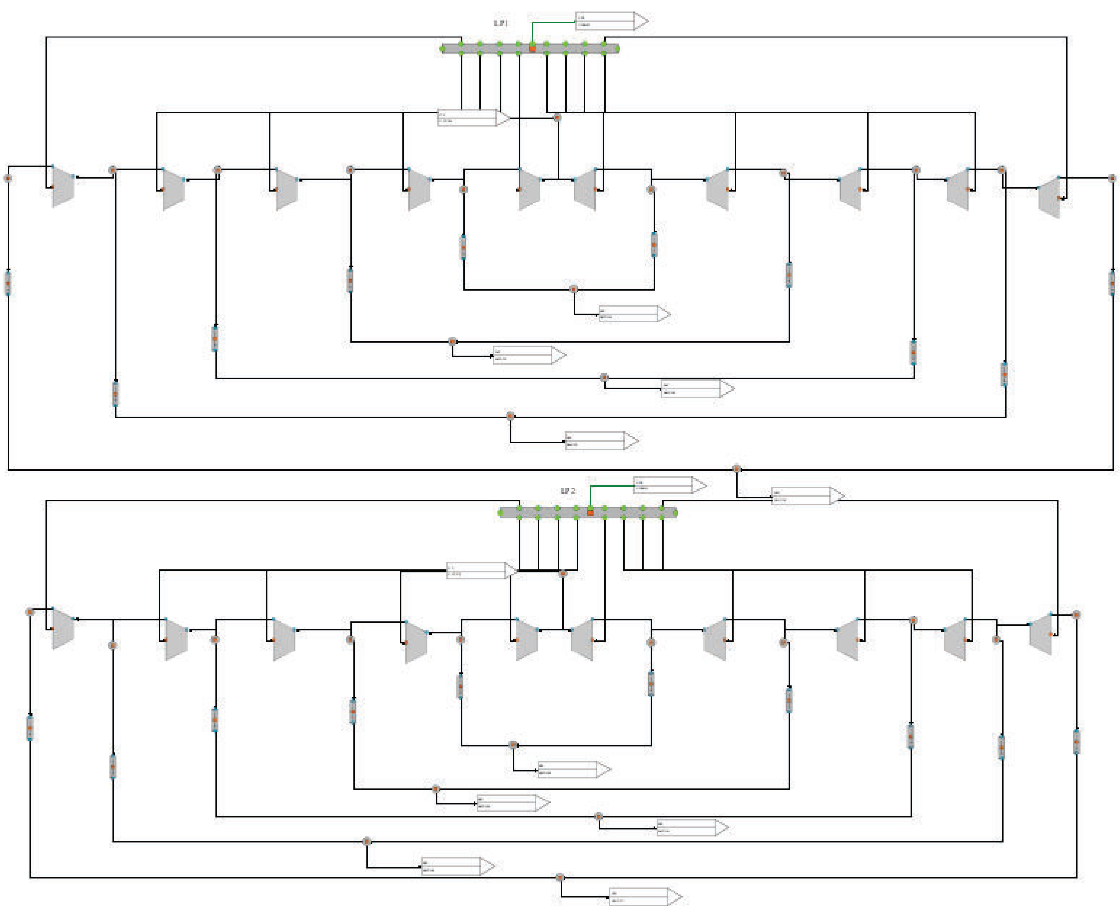


Figure 6. HP Turbine process

The established turbine process model in APROS® consists of one High Pressure (HP), one Intermediate Pressure (IP) and two Low Pressure (LP) turbine sections. The HP turbine section consists of one single flow turbine. The IP turbine consists of one double flow turbine and the LP turbine consists of two identical double flow turbines. The corresponding process models are shown in Figure 6 for the HP turbine, in Figure 7 for the IP turbine and in



for

the LP turbine.

The steam turbine (ST) process model in APROS® is established based on different valve, turbine and pipe modules to represent the ST model in a proper manner taking into account not only the thermodynamic aspects of the steam expansion but also e.g. leakages and pressure losses within the pipes such that they sufficiently match with the heat balance calculation for which they are tuned.

The process model of the HP turbine consists of one stop and one control valve in each of the two steam admission lines that are merged at the inlet in front of the turbine module. The pipe between the control valve and the turbine module is mainly used to represent the pressure losses between the exhaust of the control valve and the inlet of the HP turbine section. A small share of the steam mass flow entering the HP turbine module is bypassing the steam expansion within the turbine module. This leakage is fed directly to the exhaust of the turbine module. Immediately at the exhaust of the turbine module a steam extraction is in place, feeding steam to the glands.

The process model of the IP turbine consists as well of two steam admission lines with a stop and a control valve in each of the two steam admission lines that are merged at the inlet of the IPT before they are again split into two steam flows due to double flow configuration of the IP turbine section. Within each steam expansion line an extraction is in place, feeding steam to the heater.

The process model of the LP turbine consists of two identical double flow turbine modules that are identical in each flow direction. Each of the turbine modules consists of five turbine modules with four extractions in between, feeding steam to the heater to increase the thermal efficiency.

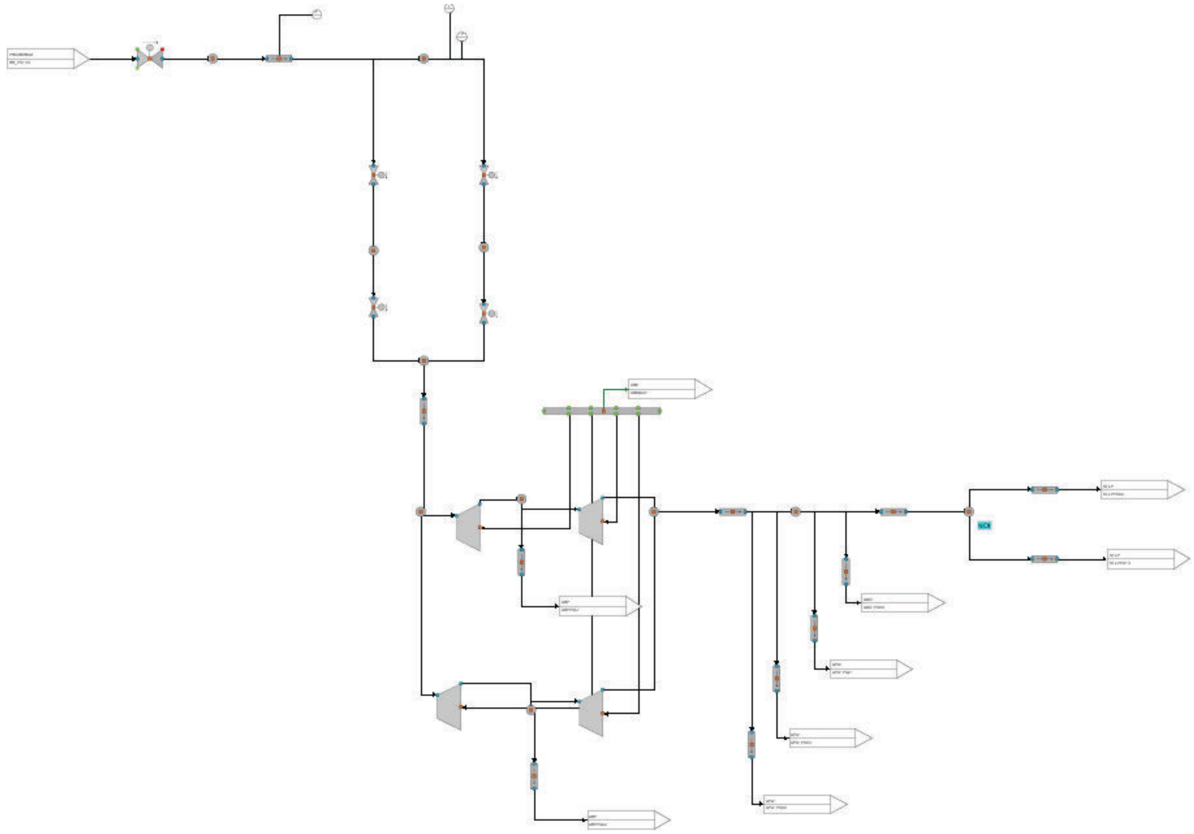


Figure 7: IP Turbine Process

The turbine process model in APROS® has been tuned as per heat balance calculation for the 100%TMCR.

This means that all the modules of the steam turbine train representing the specific physical effect, like the example of the steam expansion within the turbine modules, have been tuned to this load case such that they match to the applied heat balance calculation.

For any load case different from the tuned one, the calculations of the turbine process model are deviating from the heat balance calculations. To overcome this, it is feasible to adjust specific model components within the APROS® model of the turbine process model and thus to match it with the corresponding heat balance calculation.

The steam expansion within the turbine modules of the steam turbine process has an impact on the power generation. For the adjustment of the turbine process model the boundary conditions of the 75% and 50% load cases have been applied. The tuning parameter for the adjustment of the turbine modules in the turbine process model is the efficiency. The consideration of different load cases leads to an efficiency as a function of the flow.

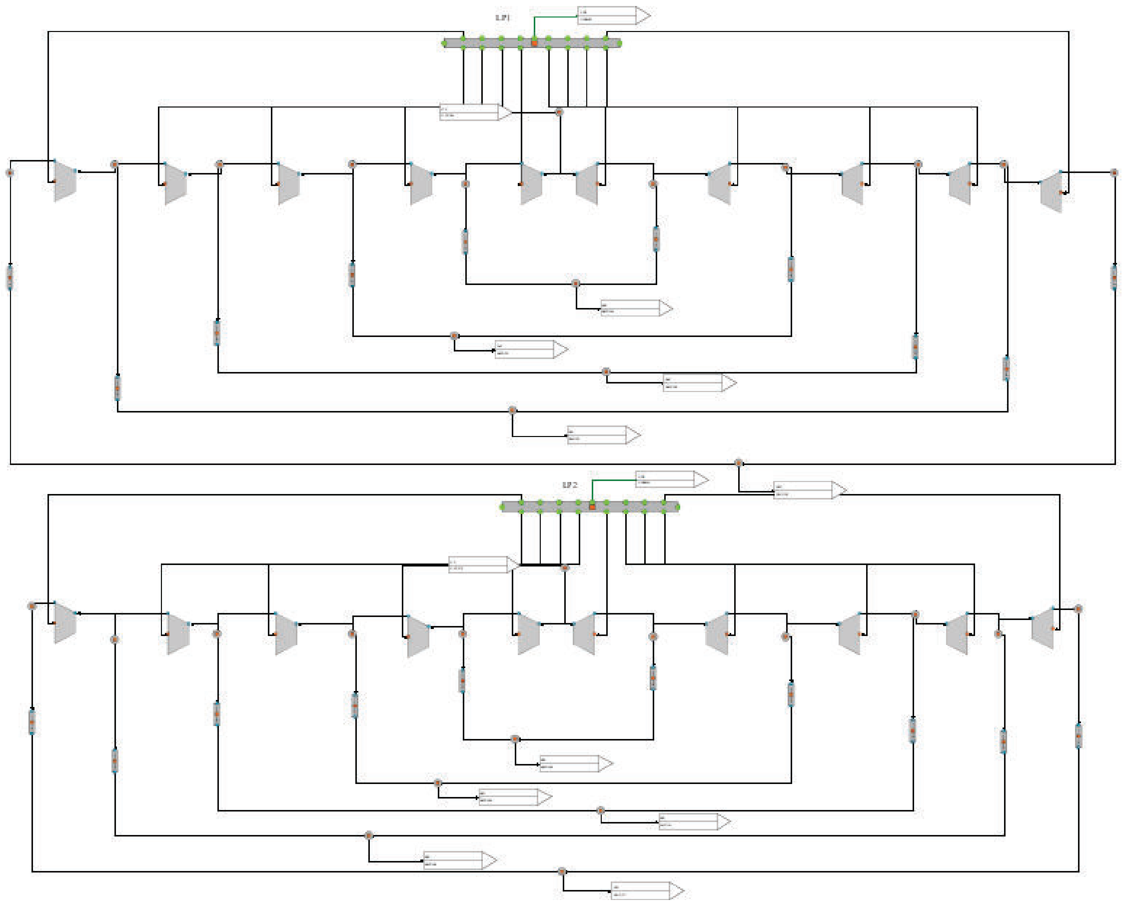


Figure 8: LP Turbine Process

The efficiencies of the turbine modules of the APROS® ST process model have been adjusted separately. The efficiencies of the steam expansion of the turbine modules have been adjusted to match with the calculated power from the heat balance calculation with a required accuracy of +/- 0.1 MW compared to the heat balance calculations of both full and partial load cases.

The efficiencies of the different turbine modules are shown in Figure 9. The HP turbine consists of one HP module. The IP turbine consists of four modules that are denoted as IP1/left, IP1/right, IP2/left and IP2/right. The two LP turbines are identical are as well double flow modules. Each LP turbine consists of two LP1, two LP2, two LP3, two LP4 and two LP5 modules.

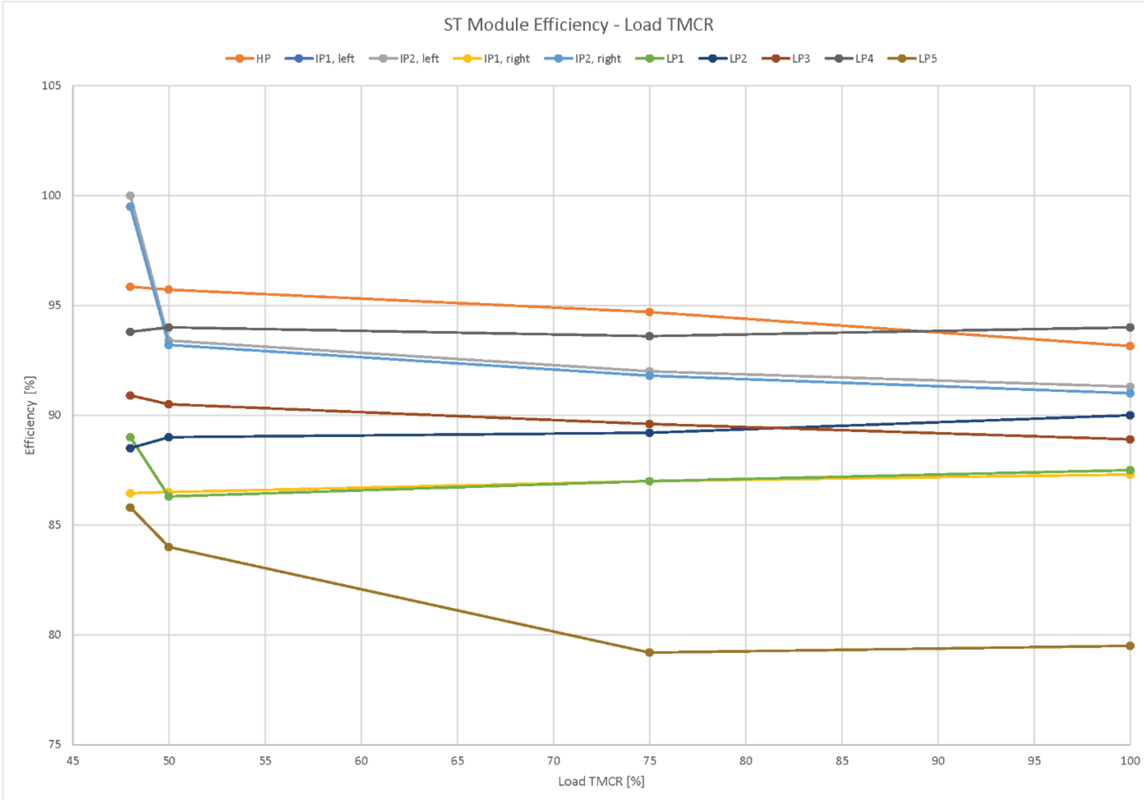


Figure 9: Efficiency of the steam turbine modules as a function of the load

3.5.1 Turbine Controls Structure

Figure 10 below shows the turbine control diagram. This is configured and tuned in APROS® based on GE Steam Power's engineering knowhow. However, it does not represent GE's full design of turbine controls at the engineering level. If you need any technical support on this subject at the engineering level, please contact GE Steam Power.

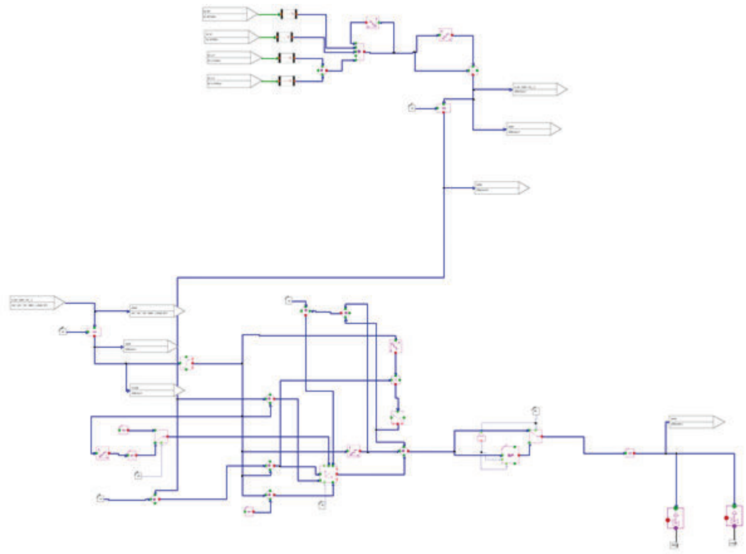


Figure 10: Turbine control diagram

3.6 Boiler Model and Controls

The model includes the physical arrangement data for all the major components and subsystems of the boiler that are of interest in simulation studies, i.e., the furnace, air system, waterwalls, superheater, reheater, economizer, back pass, pipes, circulation pumps and valves. The process components are modeled with sufficient details and fidelity to assure realistic and accurate results. The geometric properties of the heat exchangers, pumps, and valves are assigned according to the design information. However, connecting pipe components in the model are intentionally assigned size and roughness characteristics such as to have negligible influence on the temperature or pressure of the system.

3.6.1 Combustion and Heat Release

The combustion process model in APROS® is shown in Figure 11. This is a functional representation of the combustion process in the furnace. The primary and secondary air streams are combined, and the fuel is represented with fast chemistry and idealized yield and heat release.

Table 1: Heat balance by load from the boiler performance calculation program. The gas side heat extraction is greater than the steam side heat absorption, due to calculations accounting for losses.

	Flue Gas				Water/Steam			
Load	Mass Flow *lb/hr*	H_0 *BTU/lb*	H_f *BTU/lb*	Q-fired *BTU/hr x10^{-6}*	Mass Flow *lb/hr*	H_0 *BTU/lb*	H_f *BTU/lb*	Q^1 *BTU/hr x10^{-6}*
100%	7,212,035	644.9	170	7,164.70	5,118,295	474.43	1492.15	6,242.51
75%	5,338,239	581.9	150	5,303.20	3,670,255	441.67	1492.15	4,566.44
50%	4,199,609	498.8	133.8	3,773.90	2,481,523	400.1	1529.6	3,271.72
25%	2,527,664	395.5	121.3	2,086.60	1,331,592	341.3	1532.1	1,813.84

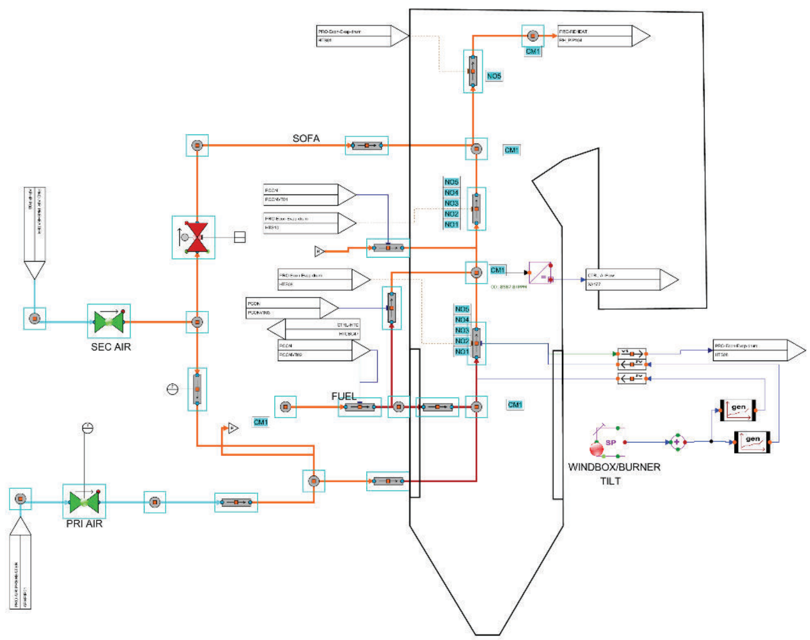


Figure 11: Air and fuel diagram with TMCR mass flow values shown

In Figure 11, the air streams coming from the air preheater are shown in light blue. The primary and a portion of secondary air are fed directly into the combustion zone. The remaining secondary air is sent to the separated over fire air (SOFA) zone. In this model, the windbox is represented by two points connected by a pipe section. The air and fuel react in the two points with completion of the combustion occurring as the gas stream leaves the SOFA zone. In this diagram, heat energy is being transferred to the waterwalls via heat radiation. There are two mechanisms for adjusting the heat distribution into the wall tubes: length and residence time from initiation of combustion to the top of the furnace and split of coal/air mixture between the lower combustion point and the upper combustion point.

The combustion and flue gas paths are modeled using flow model 2 (homogeneous) and fluid sections FC (Fuel Combustion) and FG (Flue Gas). In this model, the mathematical connection between the FC point and FG sections is explicit and it thus prevents concentrations of combustibles from falsely spreading to FG-section due to numerical diffusion. Forced ignition is set to "TRUE" so the fuel will be ignited when it mixes with air regardless of temperature. If the forced ignition is off the fuel will be naturally ignited only if the temperature in the furnace exceeds certain ignition temperature.

The air and fuel flows are matched to the performance program predictions, and fuel properties were adjusted to match the expected heat output after accounting for losses and net heating value of the fuel. The coal characteristics are configured as the boundary condition, with its composition modified to make the coal flow match with the design coal flow from the boiler design code. The air parameters, such as temperatures, pressures, are also determined as load dependent boundary conditions.

Table 2: Detailed heat balance calculation for the four loads simulated in the dynamic model.

Property	Units	TMCR	75% MCR	50% MCR	25% MCR
Steam Flow Rate	lb/hr	5,118,295	3,670,255	2,481,523	1,331,592
T, Turbine Inlet	° F	1050	1050	1050	1050
P, Turbine Inlet	psi(a)	2535	1833.3	1251.3	1185.3
Steam Line ΔP	psi	80	58.7	40.3	12.3
T, SHO	° F	1055	1055	1055	1055
P, SHO	psi(g)	2600.3	1877.3	1276.9	1182.9
SH ΔP	psi	200	156	110	35
Drum Pressure	psi(g)	2800.3	2033.3	1386.9	1217.9
Economizer Flow	lb/hr	5,118,295	3,670,255	2,481,523	1,331,592
Economizer ΔP	psi	30	15.43	7.05	2.03
Econ Static Head	psi	30	33	36	39
P, Econ Inlet	psi(g)	2865.4	2084.7	1430.9	1258.3
T, Econ Inlet	° F	488.5	458.6	421.7	366.6
T, HP Outlet	° F	662	670	677	665
P, HP Outlet	psi(a)	630.8	464.3	321.1	174.4
CRHT Line ΔP	psi	4.1	3.072	2.140	1.164
RH Steam Flow	lb/hr	4,640,916	3,388,507	2,320,944	1,257,196
T, CRH	° F	660	668	675	663
P, CRH	psi(g)	612	446.53	304.26	158.54
Reheater ΔP	psi	27.8	20.298	13.903	7.531
T, HRH	° F	1055	1055	1055	1055
P, HRH	psi(g)	584.2	426.23	290.36	151.00
HRHT Line ΔP	PSI	18.5	13.633	9.3763	5.095
T, IPT Inlet	° F	1050	1050	1050	1050
P, IPT Inlet	psi(a)	580.4	427.1	294.5	160.5
SH & Econ Duty	MMBtu/hr	5206.7	3934.8	2803.5	1586.2
RH Duty	MMBtu/hr	1033.8	714.83	468.15	254.97
Total Duty	MMBtu/hr	6240.4	4649.6	3271.7	1841.2

In Table 1, the original heat balance from the boiler performance design values are listed. The values show that the fuel fired and heat release from combustion is greater than the net energy increase in the steam side. The difference lies in the excess heat that leaves the system via cooling flows, heat lost to the walls, and heat in the ash leaving the system. Table 2 shows the heat duty calculation in more detail. These values in the bottom row of Table 2 are the basis for the simulated fuel net heating value. The heat from combustion for the dynamic simulation is tuned to match the heat required for the superheat and reheat processes, thereby assuming perfect heat balance with no waste heat. The heat release is tuned by a combination of "converting" fuel carbon content to ash in the fuel properties and fine-tuning fuel flows. Table 3 shows the simulated fuel composition.

Table 3: Simulated fuel composition, correcting for heat value required for an energy balance.

	Mass Fraction
Carbon	40.30%
Hydrogen	3.40%
Nitrogen	0.70%
Oxygen	11.39%
Sulfur	0.31%
Ash	9.20%
Moisture	29.70%

The heat released from combustion is transferred to the water/steam through radiation and convection. The radiation heat transfer mainly takes place in the furnace and the heat is absorbed by the water walls, superheater roof platen, and reheater finishing platen. The remaining heat transfer in the backpass is dominated by convective heat transfer.

The heat exchangers are configured using the same sequence as in the real unit. Some of the heat transfer coefficients are set as constants under different loads while the other heat transfer constants are load dependent to make the steady-state water/steam parameters match the reheater boiler data at different load levels.

3.6.2 Feedwater, Economizer, and Evaporator Superheater, and Reheater Sections

Feedwater coming from the HP heaters is sent to the boiler and passes through the heat exchangers to be heated to saturation, then to dry steam and finally heated up to the turbine specification temperature.

The feedwater first enters the economizer for heating up to near the saturation temperature at the operating pressure. The water then goes into waterwalls, where most of the radiant heat is absorbed by the water. The water is recirculated at a rate of approximately four times the feedwater mass flow rate. The water is not fully converted to steam in one pass through the waterwall sections and therefore the steam is separated from the liquid in the drum. However, there is sufficient heat release to produce enough steam mass out of the separator for the given load.

The model diagram of the above process is shown in Figure 12.

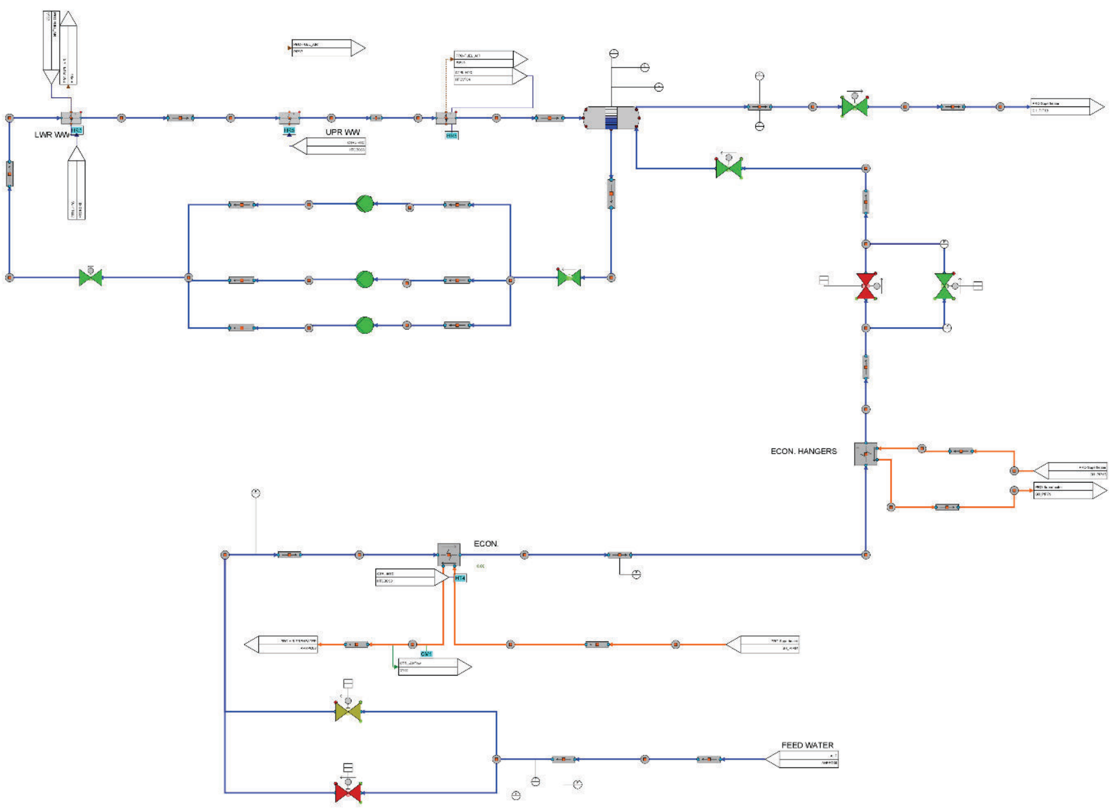


Figure 12. Feedwater, economizer, separator and waterwall sections.

Table 4: Summary of superheat section properties.

Section	Tube OD	Surface Area	Order (WS)	Order (Gas)	% of Duty
Radiant Roof	76.22 mm	946.14 m²	4	4	2%
Screen	33.5 mm	270.35 m²	5	9	0.5%
Cavity	52.32 mm	1169.9 m²	6	11	1%
LTSH Horizontal 0	53.98 mm	2334.47 m²	8	13	2%
LTSH Horizontal 1	44.45 mm	5317.58 m²	10	12	8%
LTSH Horizontal 2	53.98 mm	2444.56 m²	8	10	2%
LTSH Pendant	63.50 mm	987.56 m²	11	13	1%
Panel	47.63 mm	2668.0 m²	12	14	10%
Finishing Platen	50.8 mm	2477.9 m²	13	15	9%

Other than the feedwater and economizer sections, the two-fluid six-equation model of APROS® is used. This is done to resolve the liquid and vapor phases in the saturated water/steam mixture. The two-phase (6-equation) formulation is primary required in the evaporative waterwall sections and at the mixture of the spray stations with the superheated steam.

APROS® also contains a homogenous equilibrium model and a drift-flux model. The homogenous model is used in the feedwater, economizer, and spray components. In those other sections the homogenous equilibrium model is appropriate due to the presence of only a single phase; liquid water. Naturally, the flue gas sections are always of single-phase and are modelled as homogenous. The constitutive equations of numerical methods for these thermo-hydraulic models can be found in the APROS® documentation.

After leaving the drum the steam passes through the superheater sections starting with the radiant roof panel. The superheater sections comprise of SH screen, cavity, low-temperature superheat (LTSH) pendants, panel, and final superheat platen. On this type of boiler (drum-type subcritical tangentially fired) steam temperature control is accomplished by a combination of fuel nozzle tilt positioning and superheat and reheat desuperheating/attemperating sprays. Steam temperature is maintained by modulating the fuel nozzle tilt position based on the lower of either the SH or RH outlet temperatures with spray systems controlled based on the higher temperature of SH or RH. Under normal operating conditions, the fuel nozzle tilts will be controlled based on the RH temperature and consequentially, the sprays will respond based on the SH temperature. In the model, there is no fuel tilt component and temperature control is achieved solely with spay located between the last LTSH pendant and the panel on the SH and between the RH pendant and RH finishing platen on the reheat circuit. In the plant model, the spray comes from the downstream of feedwater pump. When tuning the stand-alone boiler model, however, the state conditions of the spray are set as load-dependent boundary conditions. An overview of the sizes of the superheat components is listed in Table 6. The main steam at the outlet of the final superheater goes to the turbine sections. The SH sections diagram is shown in Figure 13.

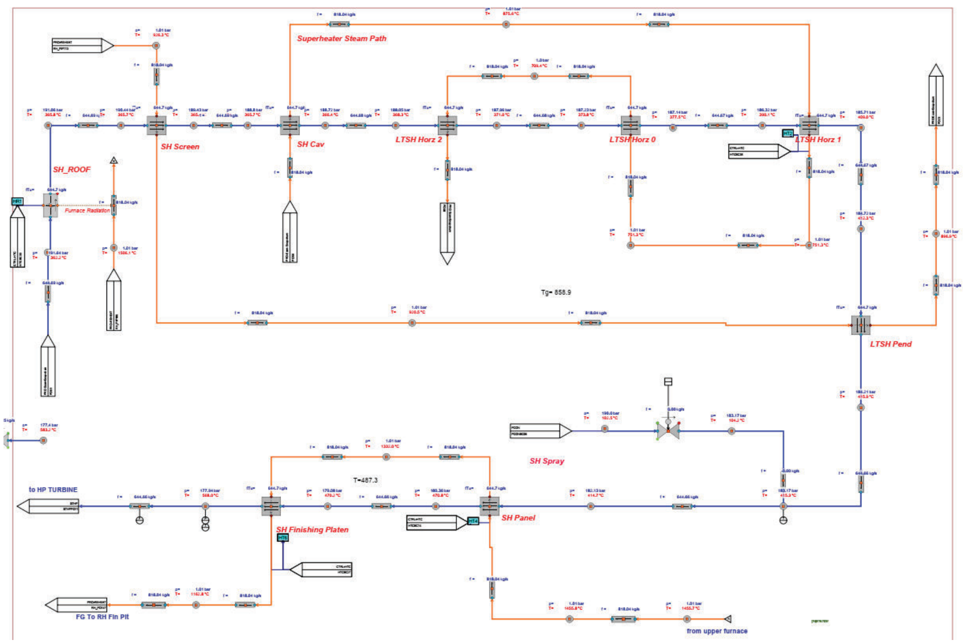


Figure 13: Superheat diagram

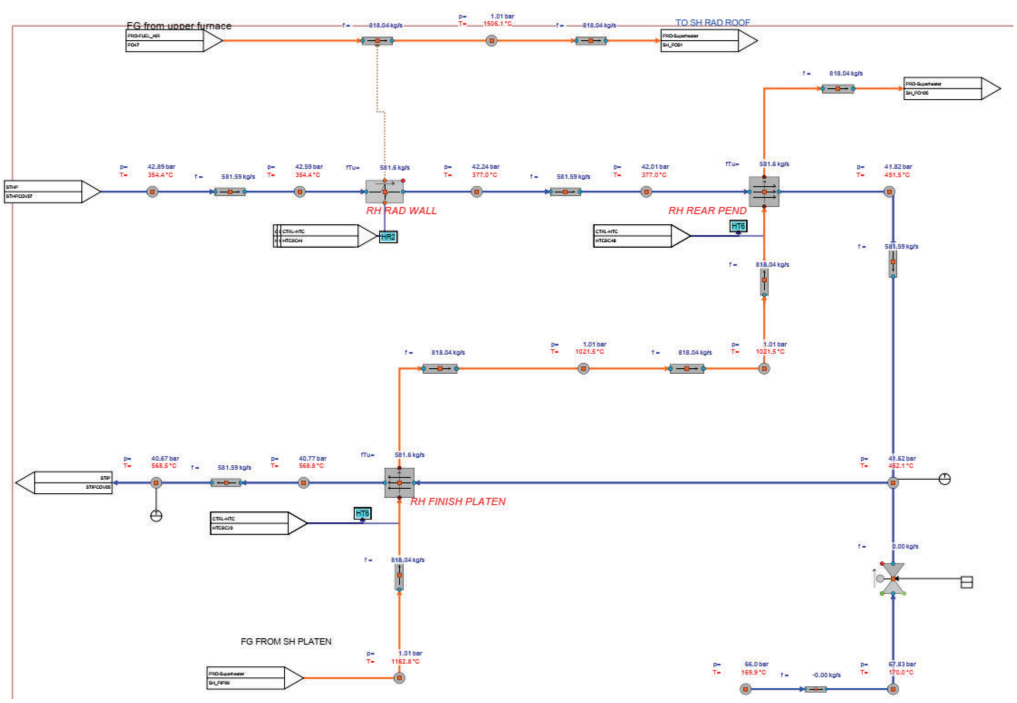


Figure 14: Reheater section diagram; TMCR values shown.

As shown in Figure 14, the steam from the HP turbine is sent back to the boiler for reheating. The reheater sections are divided into reheater radiant wall, pendant, and finishing platen sections. There is one stage of reheat spray with its pressures and temperatures specified as boundary conditions. At steady-state conditions there is no reheat attemperating spray specified or required. However, the reheat sprays are implemented to stabilize the reheat steam temperature during dynamic operations such as load transitioning. The geometric parameters and heat absorption of the reheater sections is summarized in Table 5.

Table 5: Reheat sections geometry and circuit parameters

Section	Tube OD	Surface Area	Order (Steam)	Order (Gas)	% of Total Duty
Radiant Wall	62.99 mm	1025.9 m^2	13	3	2%
Rear Pendant	69.85 mm	2954.2 m^2	14	8	6%
Finishing Platen	69.85 mm	3229.9 m^2	15	7	8%

Boiler Controls Tuning

The leading parameter for controlling the boiler unit is the load setpoint. In the model, this parameter (load setpoint) is sent to several boundary condition tables that calculate the appropriate flows, pressures, and temperatures at the boundaries of the model. The boundary conditions are defined for the four load points described earlier, and intermediate values are calculated by linear interpolation between the defined points. The "Boiler Master" network shown in Figure 15 shows the distribution of the load setpoint value to the boundary condition parameters and controllers.

Figure 16 shows the air flow control diagram. The air flow for combustion and fuel transport from the mills is defined for each load point, and a theoretical excess air is calculated. However, this O_2 measurement is not always met in load transitioning. Consequentially, a control loop is introduced to maintain a proper equivalence ratio through these load transitions or at intermediate loads between those explicitly defined in the boundary condition definition tables. The air demand is then transmitted to the fan speed regulator and the damper actuators to meet the required air for complete combustion. In addition, the air split to separated over-fire air (SOFA) streams is controlled to minimize NOx emissions. There is no direct model for NOx calculations in the APROS® code, and notice that CO is inversely correlated to NOx production. Therefore, in the model the concentration of CO in the main burner zone is used as a proxy value for NOx suppression.

Below, in Figure 17, the temperature control is shown. This is a simplified version of the actual steam temperature control used in the plant. The objective of both controls in this diagram is to keep the steam temperatures at superheater and reheater outlets to the temperatures determined by the specification of the turbine. De-superheating spray control is a cascade type. The master controller, with the final steam temperature as an input, gives a control set point to the slave controller. The slave controller measures error between the spray outlet temperature and the setpoint from the master controller, whereby a spray-flow control valve is actuated to minimize the error. The steam temperature is typically controlled via a combination of nozzle tilts in the firing zones and the addition of spray. Use of spray is minimized, as it is a source of efficiency loss in reheat steam temperature controls.

The drum level control was the most challenging to tune due to the non-linearity of the drum level. This is in part due to the impact of pressure, quality of steam, and flow fluctuations in the recirculation loop. The drum level control is designed in a typical fashion for this domain. It consists of two controllers but three measurements. Hence, it is called a "three-element control". The three input parameters for controlling the drum level are: drum level, boiler feedwater flow and steam outlet flow. Steam flow minus feedwater flow is compared in a mass balance calculation. The feedwater should be equal to the steam outlet, with a trim correction (subtracting or adding flow) to bring the drum level to the control setpoint. The output of this controller is the position of a control valve on the feedwater inlet.

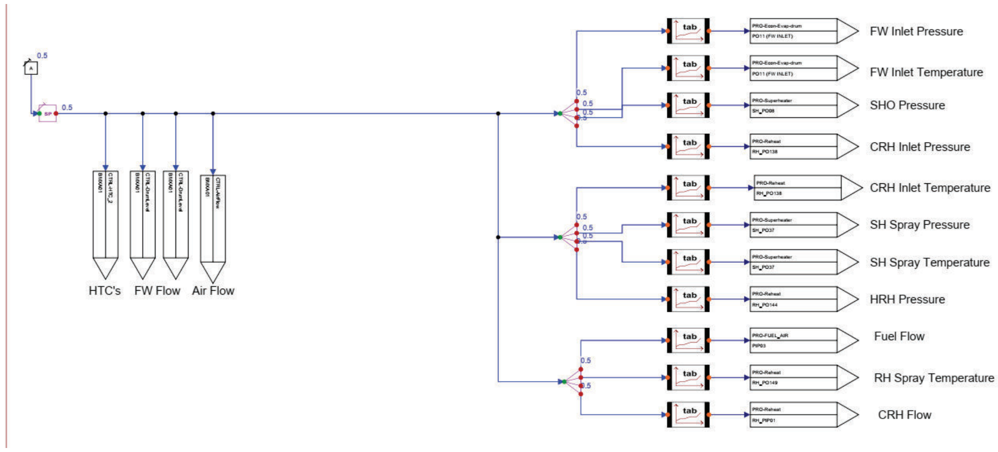


Figure 15. Boiler master diagram. The load is set as a fraction of MCR and sent to the boundary condition tables, which translate load into physical parameters.

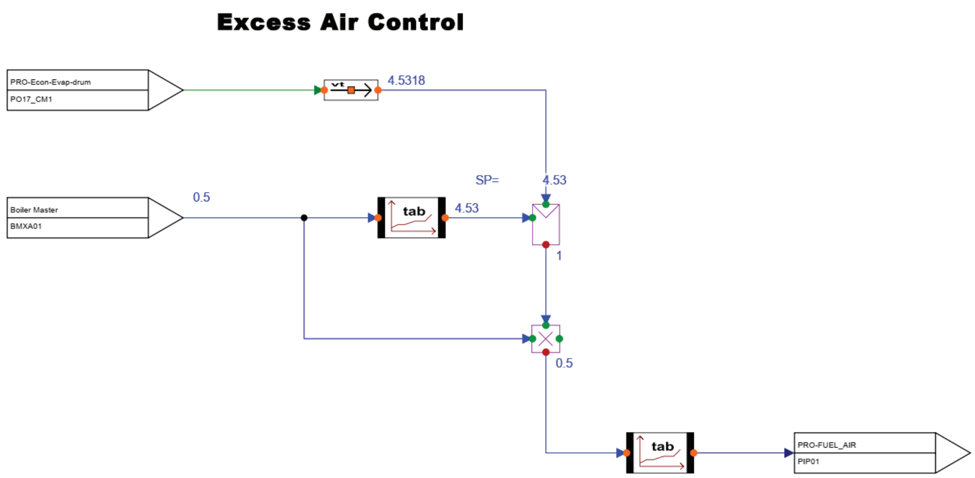


Figure 16. Air flow controller, using nominal air requirement and trimming based on the outlet O_2.

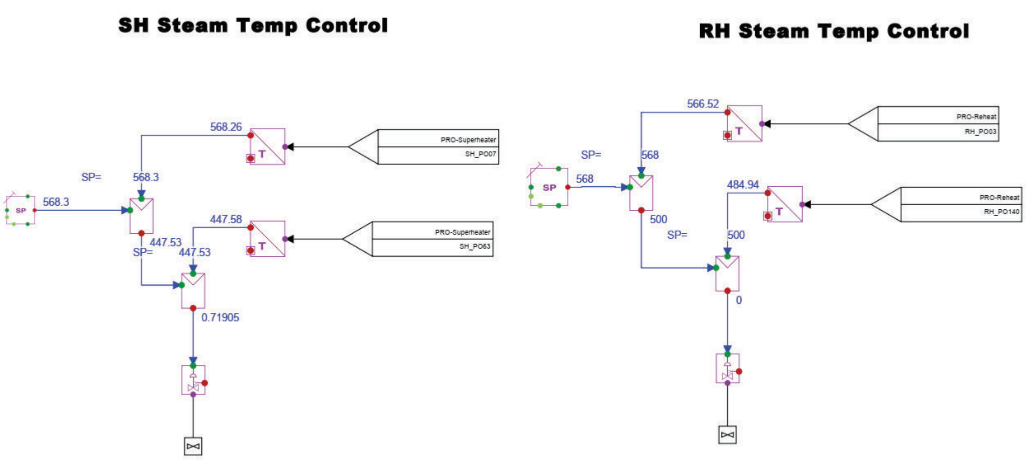


Figure 17. Controllers for spray, which control the steam outlets' temperatures.

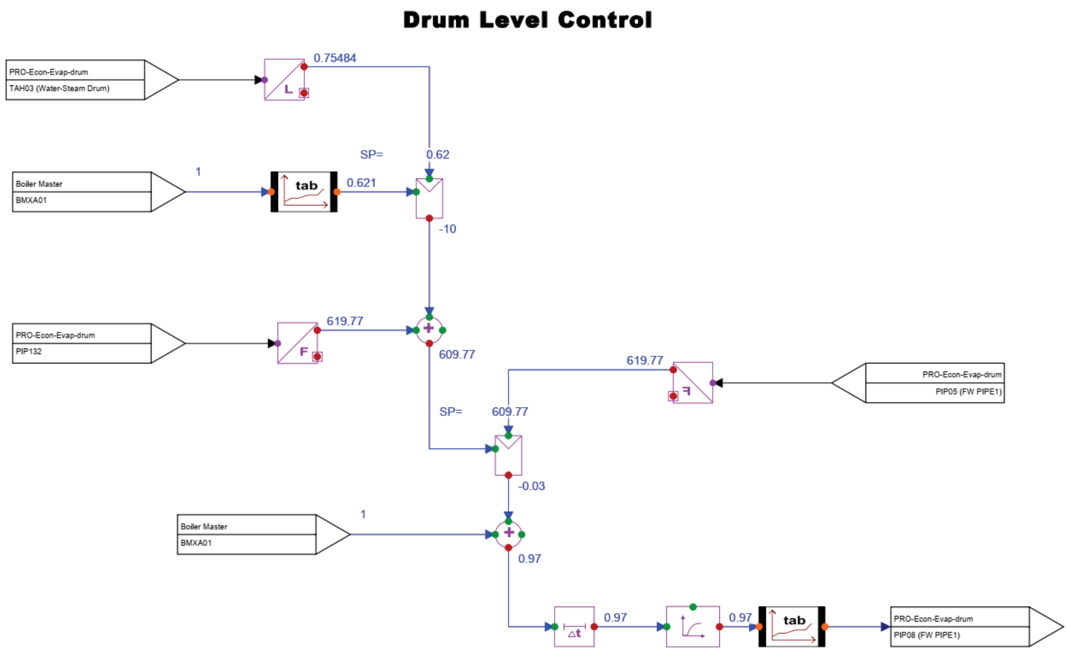


Figure 18. Steam drum level controller

4 Simulation and Results

This plant level dynamic model has been used for testing the reduced order model (ROM) based estimator developed by GE Research. This section shows some dynamic simulation results for the given reference steam plant exported from the APROS® program (see Figures 19 – 21).

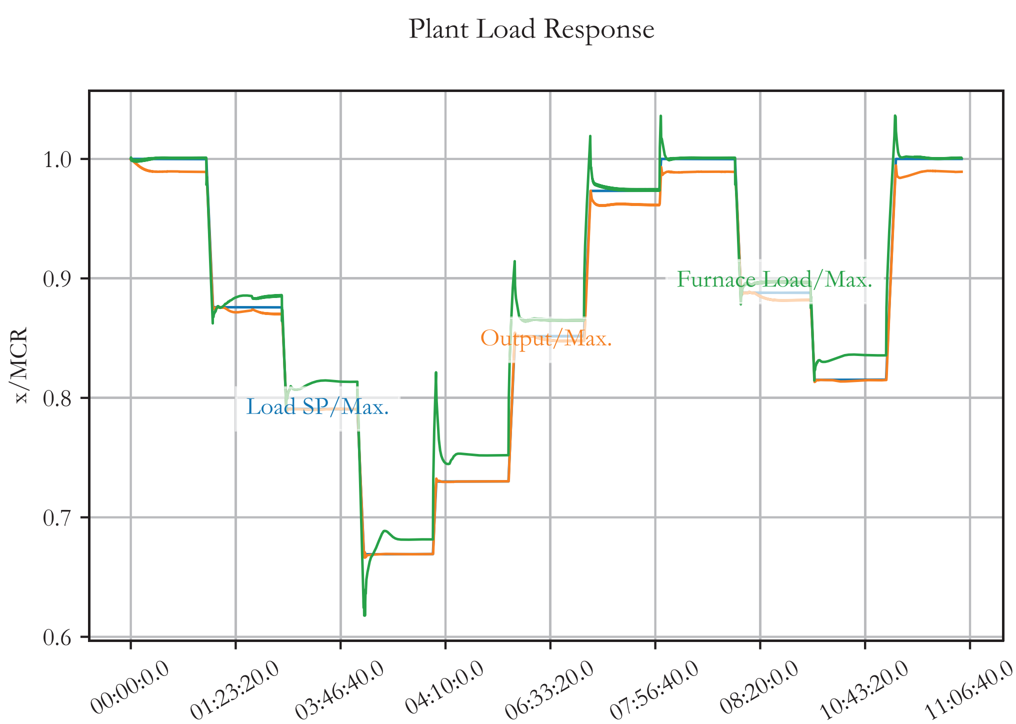


Figure 19: Plant load ramping sequence, with steam flows.

After re-adjustment in the heat transfer and the combustion process, the full plant model was run through a load ramping sequence. In the scenario shown in Figures 19 and following, the ramp sequence was a change of less than 25% load at a time at a rate of ± 2.5% per minute followed by a 50-minute hold. This is a relatively "gentle" load change gradient. However, it still within the typical range for plant operation. The plant output matches the load set point well in most cases. Furthermore, on the boiler, there is undershoot on ramp down and overshoot on ramp up observed. This has been cross-checked and confirmed with the unit operating data from the operating plant. This phenomenon is apparent due to the natural settling time of the simulated boiler system relative to the pressure demand of the turbine. The steam plant model will be further tuned when it is linked with the model-based optimal controller.

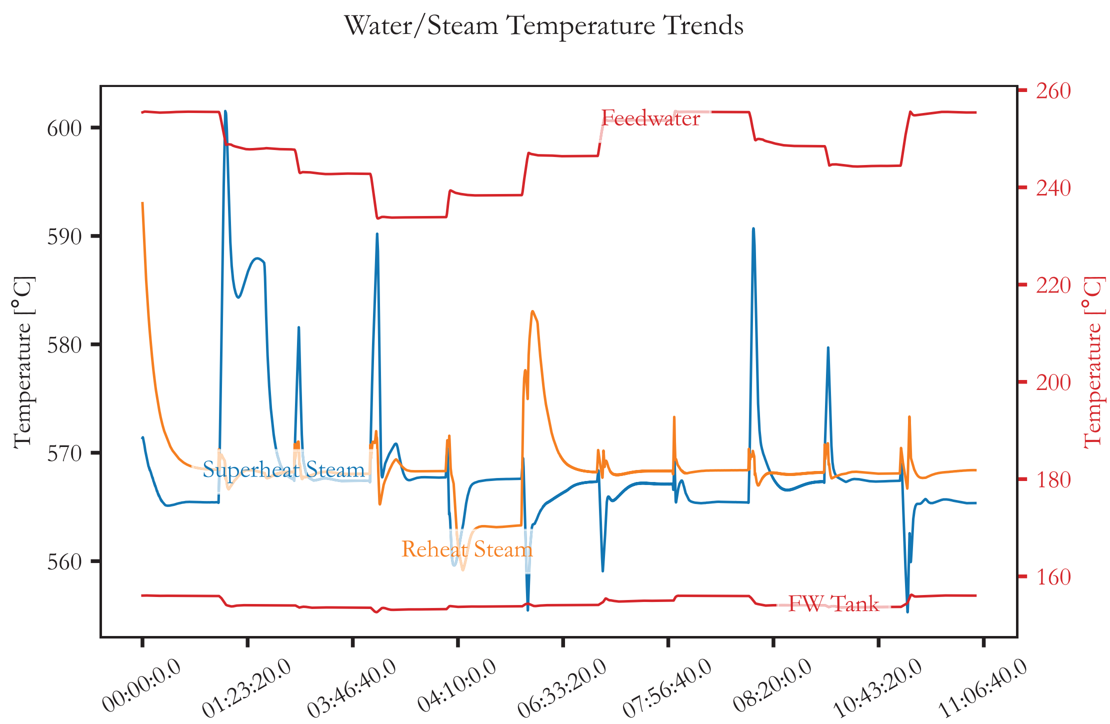


Figure 20. Steam and water temperatures through ramping cycle.

In Figure 20, the water and steam temperatures are presented. The target temperature for the superheat (SH) and reheat (RH) outlet is 568°C (1055°F) . The maximum temperature observed in the superheat output is 602°C (1116°F) while ramping down from 100% load to 87% load with a ramp rate of 2%TMRC/min.

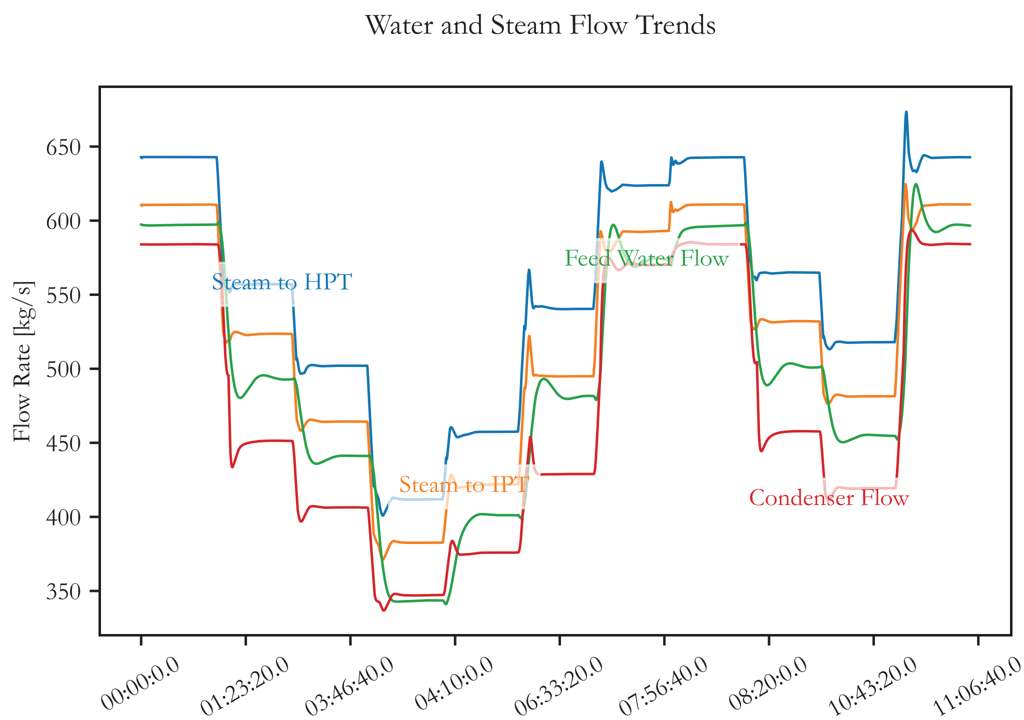


Figure 21. Trends of steam flows with load ramping.

5 Conclusions

This report covers modeling and simulation of a coal-fired steam power plant process. The dynamic model was built and calibrated against the steady-state data generated from GE's thermal performance design codes for boilers and steam plants. The model was calibrated for multiple load levels: 100%, 75%, 50%, and 25%. The efforts resulted in:

- Boiler process dynamic models, including combustion/heat release, water/steam path, and air/flue-gas path;
- Water/Steam conditioning systems, including condensers, feedwater heaters and pumps.
- Steam turbine dynamic model, including high-pressure, intermediate-pressure, and low-pressure turbines.
- Plant level process controls - feedforward and feedback controls to control ramping and stability.
- The plant model can ramp between 100%TMCR and 40%TMCR to generate simulation data

A process dynamic model was configured by referring to a typical pulverized coal-fired power plant operating at subcritical steam pressures and temperatures, dependent on the load. The calibrated model was used to generate time-dependent temperature and pressure data for use in transient boiler performance studies. The simulation model in APROS® is connected with MATLAB/Simulink as an integrated simulation platform for testing model-based estimation and model-based controls for steam plant monitoring and optimization. These efforts will support digital products that enable steam power plants to operate in an optimal fashion under challenging cycling conditions and remain cost-effective under emissions and life constraints.

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