THE DEVELOPMENT OF BOILER CONTROL MODELS FOR THE OPTIMIZATION OF BOILER EFFICIENCY

by

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Abstract

With Eskom's fleet rapidly reaching end of life and maintenance outages becoming more frequent, it has become more critical to be able to determine transient effects of auxiliary losses and system responses due to instabilities.

A low mono-nitrogen oxide (low-NOx) burner replacement project has recently been completed at Camden power station in Ermelo. It has thus deemed itself as a perfect candidate for a model which can be used to understand the new systems' response during transient scenarios.

The aim is to develop a boiler control model to be used for simulation of various process conditions and failure scenarios in order to predict the boiler plants' behaviour and improve its availability.

Research was done on common boiler control practices and modelling of boiler control. A theoretical boiler control model was developed based on the Camden power station's control system specification. The computational model of the boiler control was implemented in Flownex® simulation environment, which was found to be particular useful for modelling industrial applications.

A number of simulations with the computational model were performed and the results were compared against the historic plant data showing good correlation. In parallel, a thermo-fluid model of the boiler was developed using Flownex® by a Masters student at the University of Cape Town, which was then integrated with the control model.

The combined Flownex model was used for simulation of the following important cases: a mill trip, a Forced Draught fan trip and load changes. The obtained results show good correlation with the real plant data, indicating that the developed computational model can be considered accurate for Camden's particular type of boiler and its control. Hence, it is envisaged that the developed combined Flownex model can be applied for simulation of the boilers of the Camden power station.

Declaration

I, Andre Kellerman, student number 214360253, declare that this dissertation is my own work. References are listed to acknowledge inputs from literature, indicating other parties' work that has been conducted on the relevant topics. It is being submitted as a dissertation for the degree M.Eng in Mechatronics at the Nelson Mandela Metropolitan University, Port Elizabeth. It has not been submitted for any degree or examination at any other university.

Signature of candidate

7 March 2016

Date

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Nomenclature

Table 1-1 - Nomenclature

A	Ampere
AGC	Automatic Generation Control
AGCL	Auxiliary Group Control Level
BFP	Boiler Feedpump
C&I	Control and Instrumentation
CRI	Combustion Reliability Investigation
CSY	Coal Stock Yard
CV	Calorific Value
DCL	Drive Control Level for Binary Control
DCS	Distributed Control System
DG	Draught Group
DP	Differential Pressure
EFP	Electric Feed Pump
ESP	Electrostatic Precipitator
FBD	Function Block Diagram
FD	Forced Draught (Secondary Air)
FFFR	Fossil Fuel Firing Regulations
FFP	Fabric Filter Plant
FGD	Flue Gas Desulphurization
FNN	Fuzzy Neural Network
GCL	Group Control Level
HP	High Pressure
I/O	Inputs/Outputs
ID	Intermediate Draught
IP	Intellectual Property
IPP	Independent Power Provider
Kg/s	Kilogram per Second
KKS	Kraftwek-Kennzeichen System
kPa	Kilo Pascal
LH	Left Hand

LP	Low Pressure
MEX	Matlab® Executable
MJ	Mega Joule
MJ/s	Mega Joule Per Second
MPa	Mega Pascal
MW	Megawatt
NIR	Near Infrared Spectroscopy
NMMU	Nelson Mandela Metropolitan University
NOx	Mono-Nitrogen Oxides NO and NO_2
OSPC	Operator SP Controller
PA	Primary Air
PLC	Programmable Logic Circuit
PSS®E	Power System Simulator for Engineering
PT_x	Fist Order Time Delay
RH	Right Hand
RPM	Revolutions per Minute
RTS	Return to Service
RVC	Rotating Vane Control
SA	Secondary Air
SGCL	Sub Group Control Level
SH	Super Heater
SP	Setpoint
SPC	SP Controller
TA	Tertiary Air
TGOV5	Turbine Governor Dynamic Modelling
TXP	Teleperm Xp (Siemens)
UCL	Unit Control Level
UCT	University of Cape Town
V&V	Verification and Validation
WTP	Water Treatment Plant
IEC	Independent Electoral Commission
SAMA	Scientific Apparatus Makers Association

Definition of Key Terms

Table 1-2 - Definition of key terms

Control Variables	Controller input signals (temperature readings, flow rates and pressure readings).
Manipulated Variables	Controller output signals transmitted to a process.
Measured Variables	Controller input signals (temperature readings, flow rates and pressure readings).
Stoichiometric Ratio	Ratio between relevant quantities in combustion process, such as fuel to air.
Manual Trip	The tripping out of the boiler and/or turbine either directly or indirectly by means of an emergency push-button or other device to ensure safety of the plant is maintained.
Automatic Trip	Signal designed which will automatically trip the boiler/turbine without any human interface.
Deadband	Refers to the time or frequency interval where no action occurs on the manipulated variables.
Limiter	Limits the signal between upper and lower limits.
2oo3	Two out of three voting system.
Mill Load Line	Predetermined optimal air/fuel ratio between PA and PF.
Use of “*” In KKS	The use of the character “*” represents that this is applicable for all the plants/lines for that KKS. It substitutes numerical values 1-99.
OSPC	A controller containing an integrator with operator settable limits.
SPC	A controller containing an integrator.
Total Air	Total amount of air supplied by the FD fan.
Total Combustion Air	Total air required for combustion (FD – A/H leakages).

1. Introduction

The current surge of renewable generation technology places huge demands on the national power distribution grid and on existing conventional coal-fired power plants. Besides reducing the relative overall network inertia, the inherent variability of renewable energy sources implies that coal fired plants designed for continuous base load production must now be used for variable load frequency control operation. This will impact negatively on the overall efficiency and life expectancy of these plants. The current challenge faced is to balance the demands of accurate and responsive frequency and megawatt control with the demand for high thermal efficiency, availability and extended plant life expectancy.

One of the crucial building blocks in addressing this challenge is to simulate, analyse and optimize the transient behaviour of the complete power plant, integrated with all of the relevant control loops. For this reason, the EPPEI Specialization Centre in Energy Efficiency at UCT together with NMMU has set its sights on developing such a complete power plant model consisting of detail models focusing on the boiler and its auxiliaries, together with all the relevant control loops. The thermal-fluid plant model will be built on the Flownex® software platform, which allows for the integration of control loops via Matlab®/Simulink.

The study will include the evaluation of the different boiler capacity control methodologies currently employed across the Eskom fleet, as well as innovative new control methodologies that may result in improved efficiency and plant life expectancy while allowing for maximum responsiveness with regard to power output and frequency control.

1.1 Camden power station burner upgrade

During RTS at Camden power station, investment was made on the boiler and its auxiliaries to improve mainly the heat exchanger, milling plant, wind box and de-dusting plant performance with little attention given to the burners.

After a thorough CRI has been conducted on Unit 2 at Camden, it has been concluded that one of the most problematic pieces of equipment since the RTS is the burners [1]. It initially demonstrates that the boiler was under-sized at the design phase in the 60's and that the subsequent problems associated with high flue gas temperatures have been further exacerbated by a deterioration in coal quality since the units' RTS after more than a decade of mothballing [1]. Eskom continued with the proposition of replacing the burners [2], contracting Steinmüller to assist with the design and keeping the IP rights. This upgrade will be from the currently installed type R burners to SM V burners which belong to the low NOx burner group [3]. The burner replacement project at Camden power station has been initiated to ensure safe, reliable, stable complete and homogenous combustion [2]. The upgrade will also align Camden to low NOx emissions legislation as required by law.

In addition Siemens has been contracted to modify the DCS for the installation of the new burners. This will entail upgrading the application side of the DCS to the Siemens T3000 system while maintaining the current TXP (T2000) automation system running mainly on Siemens S5 PLC's [2]. Together with the new burners, additional C&I measurement equipment will be installed to accurately determine the total amount of air entering the boiler, thus optimizing combustion and lowering emissions.

This modification to the DCS will be the optimum time to intervene and perform re-optimization of the boiler control system. This creates the need for understanding the boiler control model at Camden and implementing a computational model of all the main control loops to verify and test the optimization parameters.

2. Problem statement

The South African power grid requires the capability to determine the response of power stations to fluctuating demand to mitigate the risk from the load variance introduced by renewables from Eskom and IPP's. Most renewables do not offer storage, and when the renewable source's generation fluctuates (such as sudden overcast for PV or sudden increase of wind on a wind farm) the conventional fossil fuel power stations have to compensate for the drop in load. Commonly large diesel generators can be used to quickly supply the grid until the slower responding coal fired power stations adjusts the firing rate to produce the required amount of MW to stabilize grid frequency [4].

As the use of alternative energy generation techniques increase, so will the mentioned transient conditions. It therefore becomes increasingly important to be able to simulate the power station's response to the transient network conditions.

Currently the TGOV5 modelling is being applied by the Eskom Generation business' C&I department. The TGOV5 modelling is used as a fast response model by solving a generic transfer function that has been tailored to represent the transient conditions throughout Eskom's fleet. It assists operators at National Control in complying with the grid code requirements.

National Control will then be able to distribute the required load to the power stations that will be best able to contribute to the grid [5]. The TGOV5 models further enables studying system stability during disturbances, such as loss of one or more generators, and used to determine defence schemes to prevent system blackout such as automatic under frequency load shedding schemes. Unfortunately this modelling has limited applicability. The need for an accurate thermal-fluid model with thermodynamic and physical phenomena should be implemented to accurately model properties of equipment, materials and fuels.

The purpose of this study will be the development of the required high level control loop models for the boiler capacity control. The control model will be integrated with thermal-fluid boiler and plant models within Flownex® and Matlab®/Simulink® to most accurately model the plant. This will grant Camden power station an engineering simulator with the ability to test plant alterations, new control methodologies and control parameters.

This is necessary to ensure that the balance between supply and demand on the national grid can be maintained. The ability to balance supply and demand will become more critical as more intermittent generation is added, such as wind and solar power.

2.1 Research aim

The aim of this project is to develop a computational model of the boiler control system to improve its efficiency, mainly focussing on the air requirements of the new burner which will be installed at Camden power station.

The model will then be utilized together with the thermo-hydraulic model developed by UCT to provide a comprehensive engineering simulator.

2.2 Research objectives

1. Comprehensive description of different control methodologies worldwide related to boiler control.
2. Detailed description of Camden’s combustion process and controls implemented to achieve safe and reliable operation.
3. Simulation model of high level boiler control linked to a Flownex® thermal-fluid model with primary focus on Camden’s air control.
4. Simulation and evaluation of the performance of the different control transients in terms of stability and response.

3. Literature review

3.1 Introduction

In the following chapter literature review will be done on various elements contributing to the boiler combustion control system and includes a study done on the software that will be used to model boiler control loops. The scope will include the typical process flow of a power station, the various mechanical elements in the system in operation at Camden, the necessary control measures to maintain safe and stable operation on these systems, software to model the responses of the control system and a comparison of these elements from Eskom's' fleet.

An overview on general practises on the boiler systems and boiler control regimes will be discussed and will be followed by Camden's specific setup, which will be compared to the rest of the Eskom fleet in order to address various strengths and weaknesses of these plants and their control systems.

Focus will be specifically given on the control requirements of the new Steinmüller SM V burners which will be installed at Camden, and how it will affect the SA and PA flows required to achieve the correct stoichiometric ratio of fuel and air for optimal low NOx combustion, and how the DCS will be modified to achieve these objectives. Understanding these new requirements will provide a basis for the modified control system's design.

3.2 Camden power station

Camden power station, located near Ermelo, was commissioned in 1967. It comprises of 8 x 200MW PF water-cooled units. It was mothballed in the 1980’s due to over generating capacity. However, due to rising energy demands and a lack of installed capacity in South Africa, the plant underwent a Return-to-Service (RTS) from 2005 to 2009, with all units now in operation.

The plant is now running in load following condition, with outputs ranging from between 120 MW and 200 MW on average per unit. After re-commissioning of Camden several problems where encountered such as poor combustion reliability and performance, even after retro-fitting key equipment during RTS.

The original design efficiency, at rated turbine MCR, was 33.4%. Apart from small differences, Camden’s units have been built identically. The boilers are two-pass (or back pass) boilers, and are drum-type boilers utilizing three-element control for the drum level.

The furnace has a front-wall fired configuration of burners, and is the only plant with this configuration in South Africa. There are a total of 20 burners per boiler, with 10 each for left-hand and right-hand swirl. At full load, 4 out of 5 burner rows consisting 16 burners are operational. A current project is underway to fit Unit 2 with new low NOx burners, and updating the DCS to provide the required control for safe and reliable operation.

3.2.1 Boiler process overview

At Camden power station, coal is received from the relevant coal mines via a redundant overland conveyor system from where it is stored on a coal stock pile on the power station's grounds. Long term contracts have been secured between the relevant mines and Eskom, ensuring a steady coal supply [6].

From the stockpile a stacker-reclaimer is used to distribute and store the coal in piles. The same stacker-reclaimer is used to scoop up coal which is then transported via a redundant overland conveyor to various coal staithes, which provides a buffer for the coal supply and located close to the mill bunkers. From the staithes the coal is transported to the feeders by an incline belt.

Mill bunkers are used as a quick response buffer for the necessary coal feed. They are positioned on top of the mill feeder, to easily provide coal to the feeders.

From the mill bunkers the coal is fed to the mill feeders, which supplies the mills with coal according to the kg/s requirement from the DCS. The coal fed to the mills is then pulverized to ensure optimum area for combustion. PA is then supplied by the PA fans, heated by an air heater and used to transfer the pulverised coal particles to the boiler via PA ducts. The fuel/air mixture ultimately passes through a burner before it enters the boiler furnace [6].

SA is supplied to provide stoichiometric air requirement ratio to boiler furnace. This is generated by large SA fans and is transported via common SA ducts, after being heated by the air heater. The SA is used to build up pressure inside a wind box from where dampers and vanes control the amount of air flow through the burners to the furnace.

After combustion has taken place, the flue gas is drawn through SA and PA air heaters. Before exiting though the stack, the flue gas passes through a particulate collection system, which removes most of the fly-ash. Some power stations also has SO_2 scrubbers which removes the sulphur from the flue gas before it is emitted into the atmosphere.

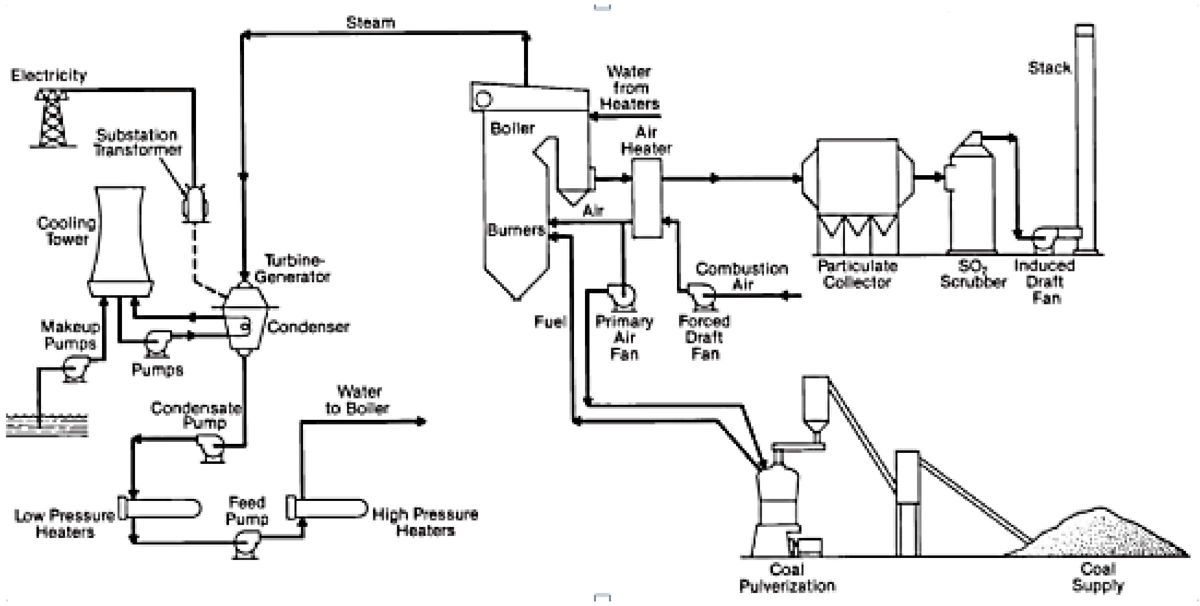


Figure 1 - Plant process overview [7]

3.2.1.1 Boiler

Camden boilers were supplied and manufactured by International Combustion Limited. The boilers are of the twin pass drum type without reheat. The power station design capacity is 8 x 200MW with a boiler acceptance test efficiency measured at 88.44%. These boilers are front wall fired as displayed in Figure 2.

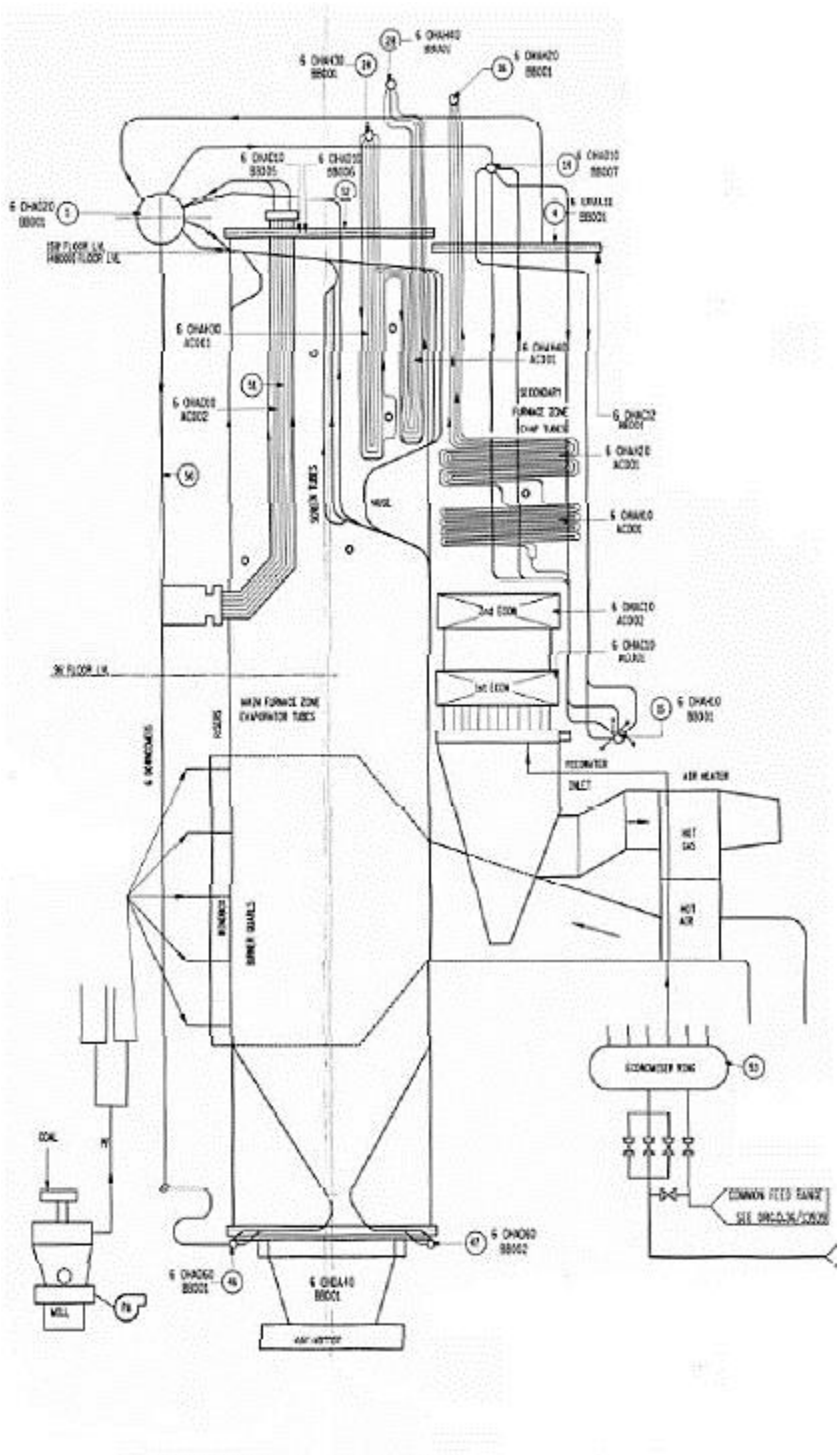


Figure 2 - Side view of Camden boiler [1]

The boilers were commissioned in the late 60’s, but mothballed in the late 80’s due to surplus of power generation capacity. During RTS in 2008, upgrades where made to improve the heat exchanger, the milling plant, wind box and de-dusting plant. However, no investments were made to improve the burners.

Prior to the PS being mothballed, the following problems where identified during the CRI conducted at Camden [1]:

- Furnace slagging (due to undersized design of the boiler)
- Late combustion (coal residence time of approximately 1.34 seconds between upper row of burners and furnace exit)
- High carbon in refuse, high back-end temperatures (due to late combustion and approximately 4.5% decrease in volatile matter of coal)
- Economiser and platen heat exchanger tube leaks.

3.2.1.2 Milling plant

The mills that are in service at Camden are vertical spindle Lopulco mills with rotary classifiers. The mill throughput of coal is roughly ±7.22 kg/s @ MCR, which requires a PA flow of about 11.75 kg/s [1]. Vertical spindle ball mills have the advantage of requiring less maintenance, as there are no fan blades on an exhauster that need to be replaced. The disadvantage of the vertical spindle ball mill is that the mill operates under pressure, so leaks or cracks will let PF leak out.

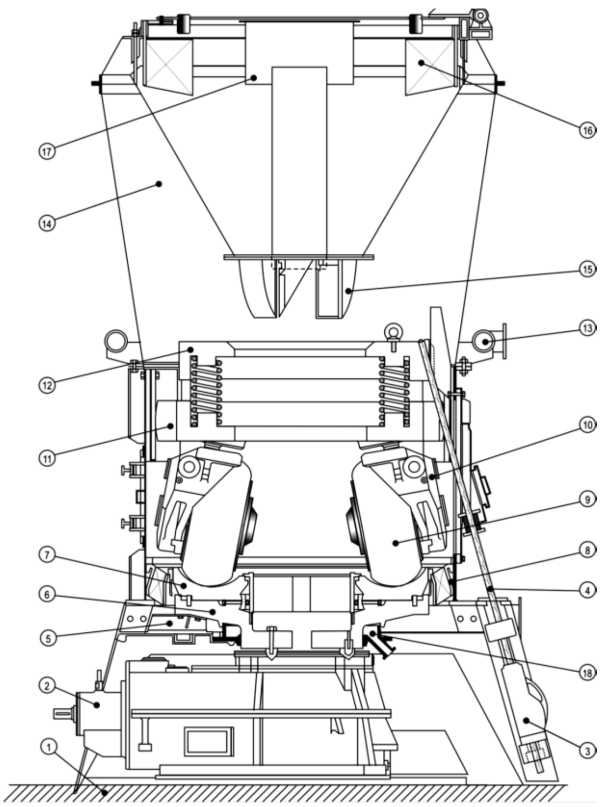


Figure 3 - Lopulco pressurised vertical-spindle ball mill [7]

Table 3-1 - Lopulco vertical spindle mill legend

Lapulco vertical spindle mill legend			
1	Mill foundation	10	Grinding roller yoke
2	Mill drive unit	11	Pressure ring
3	Mill tensioning device	12	Spring ring
4	Mill tensioning cable	13	Seal air manifold
5	Reject wiper bar	14	Static blade classifier
6	Grinding table base	15	Classifier reject traps
7	Grinding track	16	Classifier blades
8	Air nozzle ring	17	Product inlet
9	Tyres	18	Seal air ring

The coal is pulverised into a fine powder, so that less than 1.5% is +300 μm and 70-75% is below 75 microns, for a bituminous coal. It should be noted that too fine a powder is wasteful of grinding mill power. On the other hand, too coarse a powder does not burn completely in the combustion chamber and results in higher unburnt losses.

Table 3-2 - PF quality

PF Passing			
75μ	106μ	150μ	300μ
70.0 - 84.0%	82.8 – 91.4%	92.0 - 96.4%	99.4 - 99.75%

In order to determine the required amount of PA, the coal flow of the mill is compared to a mill load line. This mill load line equation is generally known as the amount of PA that is required to transfer the coal particles to the furnace. This is mixture of heated air from the windbox together with tempering air, keeping the mill inlet temperature around 180°C.

From CRI project conducted on Camden power station, the milling plant had the following problems that need to be addressed:

- Mill feeder flow rate is 13% less than actual flow rate
- Optimise mill load line and air fuel ratio
- Low vane capacity as result of deteriorating coal
- Maintenance philosophy lacking and needs to be reviewed and updated

3.2.1.3 Draught group

The draught group consists of the two FD fans, five PA fans and two ID fans to exhaust flue gas. Figure 4 is a schematic representation of Camden's air circuit layout, from the inlet of the FD fans to the outlet of the ID fans.

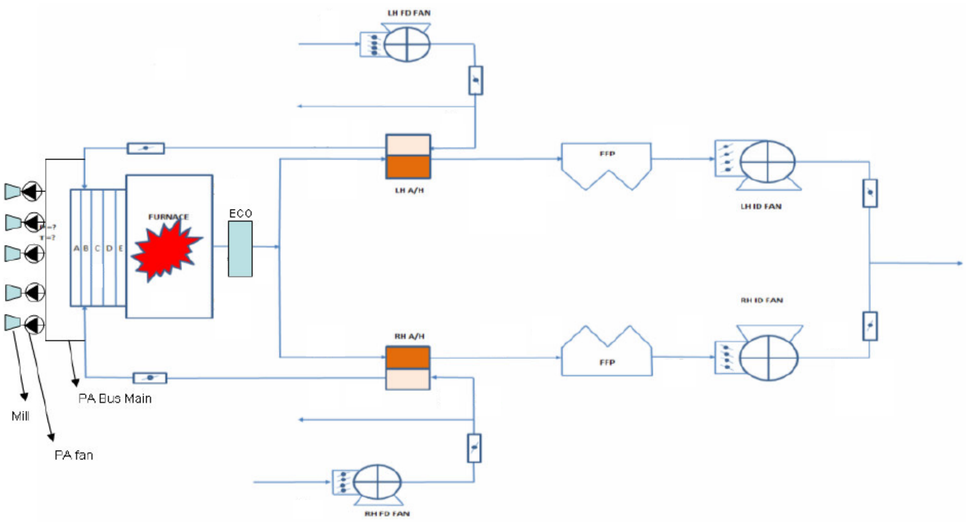


Figure 4 - Camden air circuit layout [1]

The FD fans supply the air to the entire system. This air is supplied through an air heater into two common ducts which feed into the windbox and from where the PA fans receive their inlet air. These common airflows are controlled by large dampers, located just before the windbox arrangement. The FD fans at Camden power station are currently running at approximately 40% of design capacity with DCS MW measurement of 200MW [1].

The windbox contains five rows of four burners each, and the air inlet on each row is controlled by damper pairs, one on LH and the other on RH. The windbox will remain under adequate pressure as per new burner requirements.

The PA fans receive its inlet air from the SA duct after the control vane. The five PA fans supply the mills with warm air to transport the PF into the furnace. The PA fans air temperature is controlled by controlling the tempering air (which is cooler than the air received from the SA duct). The lowest performing fan on unit 2 achieved 80% of its designed air flow with the inlet louver opened at 100%. This caused low PA velocities in the PF ducts and left no capacity for optimization of the PA flow.

The ID fans receive the flue gas after it has passed through the ESP/FFP and exhaust it into the atmosphere. A major problem is that there is an extreme amount of air ingress into the flue gas circuit. However, the ID fans still have adequate capacity to exhaust the flue gas, as the flue gas inlet of the ID fans where 5,5% above their design specification of 255 m^3/s [1].

3.2.1.4 Burners

The current burners at Camden will be replaced with the Steinmüller SM V burners, which was designed by Steinmüller engineering and Eskom, leaving Eskom with the IP rights. The SM V is primarily designed to reduce the NO_X emissions from combustion. The principle of the SM V burner design is provide the mixing of the pulverised fuel and the air in stages in order to achieve low emission combustion and the required stoichiometric fuel/air ratio. Optimization of the control system is required to meet the demands of the new burners [1].

The burner is designed to combustion process into stages/zones (air staging). The PF that is injected firstly encounters an oxygen deprived environment; where after the rest of the stoichiometric air is slowly delivered to the fuel [3].

To achieve the principles as mentioned above, the Steinmüller SM V burner has three main airflows, namely the core air, PA and the SA. Within the SM V burner the secondary air is further divided into two different streams, SA 1 and SA 2.The burner designed for Camden has a few features that are not present in the typical SM V burner. The first difference is the double core air pipe, the second is a set of special deflectors in the PF pipe and tangential inlet for the primary mixture as displayed in Figure 5.

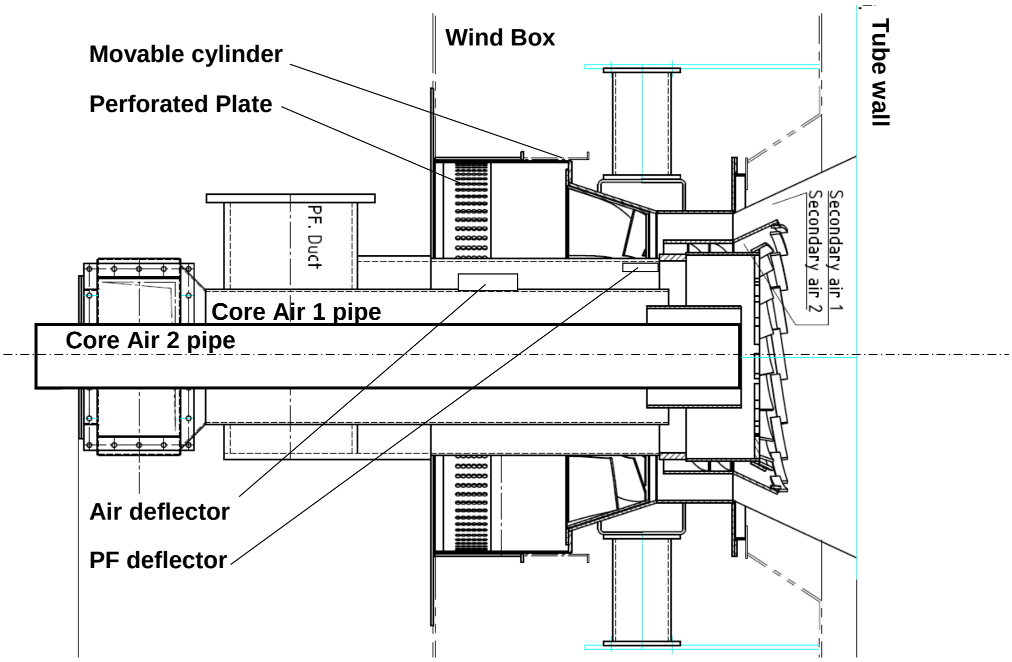


Figure 5 - Camden burner cross sectional view [3]

3.2.1.4.1 Core air pipe

The core air pipe within the SM V burner is used to supply the fuel oil burner with the required amount of air during operation. When the boiler is in steady state operation, only the cooling air for the oil burner flows through the core air pipe [3].

3.2.1.4.2 Pulverised fuel pipe

The function of the PF pipe is to transport PF from the mills into the combustion chamber. The construction of this part in the SM V burner also supports creation of combustion conditions that deter NO_X formation. To ensure proper ignition and flame stability the outlet of the PF pipe in the burner is equipped with stabilizers in form of “teeth” [3].

3.2.1.4.3 Swirl generator

The movable swirl generator function is to introduce swirl in the SA. When the swirl generator is moved forward it introduces a greater tangential component to the secondary air, thus increasing the swirl, and will introduce a smaller tangential component when it is retracted. The directions of the individual swirl generators are presented in Figure 6.

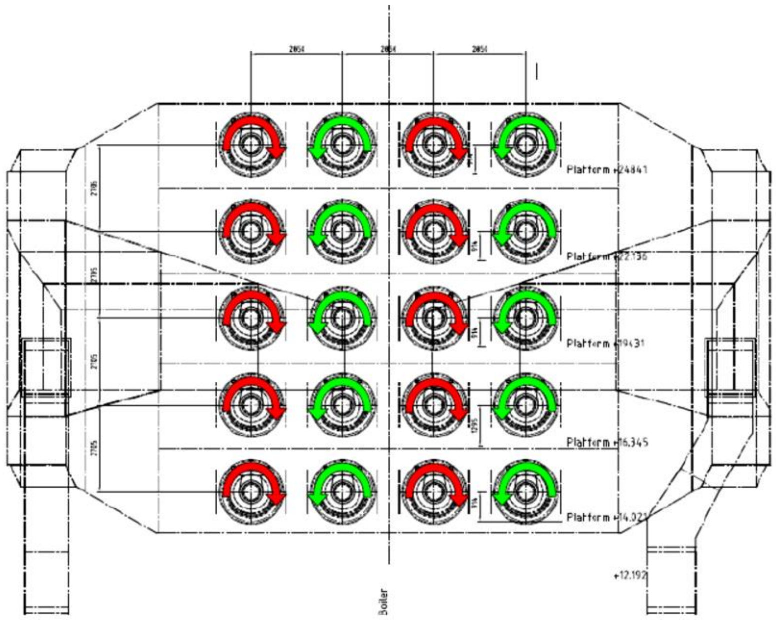


Figure 6 - Direction of the secondary air per burner [3]

3.2.1.4.4 Separating air (secondary air 1)

The separating airs' (SA 1) function is to prolong the staging air from mixing with the ignited PF/PA mixture to delay the process for as long as possible. This in turn enhances low NO_X combustion [3].

3.2.1.4.5 Staging air (secondary air 2)

The staging air (SA 2) will be to complete the combustion process, supplying the correct stoichiometric ratio. SA 2 is directed away from the ignited PF/PA mixture to prolong mixing and thereby create an environment favourable for low NO_X combustion [3].

3.2.1.4.6 Perforated plate and movable drum

The perforated plate and movable drum is designed to create a pressure drop at the entrance to the burner, ensuring a constant pressure in the wind-box which will allow for equal SA flow at each row of burners [3].

3.3 Generic boiler control overview

3.3.1.1 Control system configurations

3.3.1.1.1 Feedforward control

Feedforward control is usually implemented where the process is well known. Feedforward control does not make provision to correct an induced error between the process variable and SP [8], thus is not used to eliminate disturbances in the system.

3.3.1.1.2 Feedback control

Changes in the primary variable are fed back to the control function. The process variable from the readings is compared to a controller SP value. An output is generated to minimize the error between the process variable and the SP. The function can be PI (as in Figure 7), PD, I, or full PID controlled.

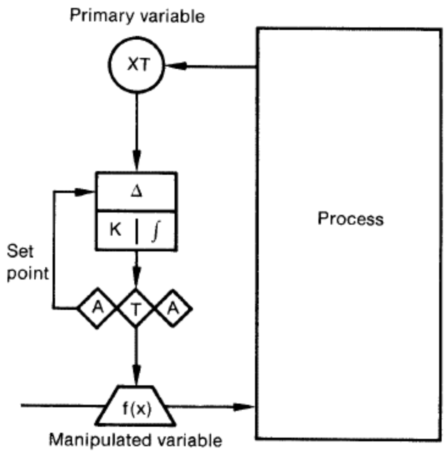


Figure 7 - Simple feedback control [9]

Simple feedback control can consist of positive feedback (where the error gets added to the signal) or negative feedback (where the error is used to minimize the offset between the SP and the measured variable).

3.3.1.1.3 Feedforward plus feedback control

With feedforward plus feedback control, another variable that has a calculated relationship with the manipulated variable is connected. A change that will occur in the secondary variable will cause the manipulated variable to change in accordance with the primary process variable which is controlled to a SP, and by more timely control it reduces the magnitude of change of the primary variable, due to more timely control action from the influence of the secondary variable.

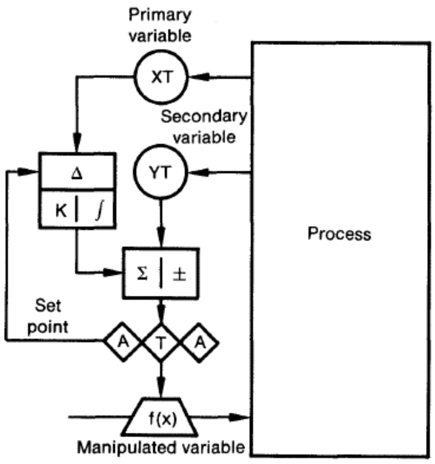


Figure 8 - Feedforward plus feedback control [9]

The SP is contained within the feedback portion of the loop, and in a time-based application of feedforward plus feedback control a change in the signal from the secondary variable acts without waiting for the primary process variable to change.

3.3.1.1.4 Cascade control

Cascade control, as opposed to previous control strategies discussed, is not based on single input, single output, but rather makes use of multiple variables as parameters to change a manipulated variable. This allows for a system to be more responsive to disturbances.

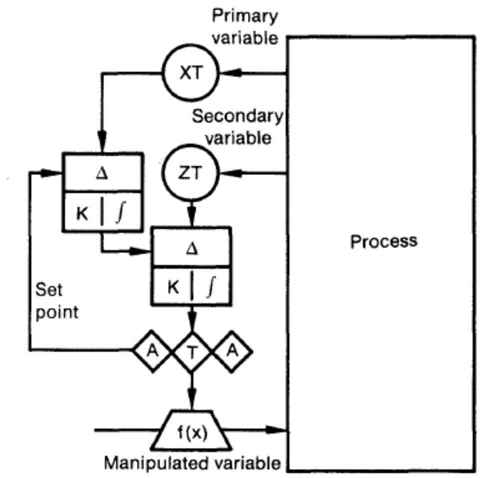


Figure 9 - Cascade control [9]

In cascade control, output signals from the primary controller will be used to form the SP for the secondary controller. The secondary controllers' output will be used to adjust the control variable. Usually the secondary controller has a faster response than the primary controller, thus allowing disturbances from fast changes in the measured variable of the second controller not to have an effect on the primary controller [9].

3.3.1.1.5 Ratio control

In ratio control, the feedback controller has a SP that is directly proportional to a secondary (uncontrolled) variable. The relationship between the two can automatically be set, or be set up by the operator. The ratio is calculated by multiplication of the controlled variable with the uncontrolled variable, so if the ratio is changed the relationship between the two variables will change proportionally.

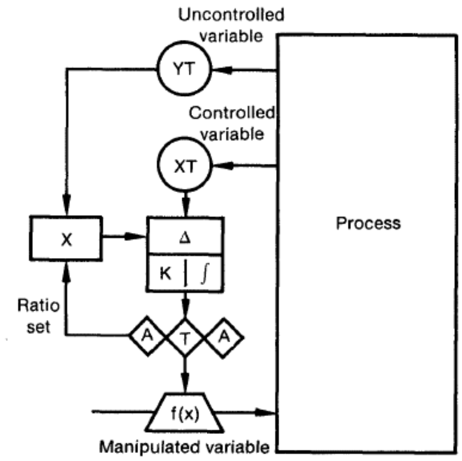


Figure 10 - Ratio control [9]

3.3.2 Conventional boiler control regimes

3.3.2.1 Control hierarchy

The concept and main design principle of control and monitoring system must be of a decentralized and hierarchical structure [10]. This essentially means that the control software is functionally distributed across several levels of the hierarchical structure. The higher the level of control, the less manual interventions are necessary.

Each hierarchical level has its own specific tasks and always depends on its subordinate lower control levels. If a lower level fails, the next higher control level will not be affected and will allow the levels to control the power plant with full safety, but will require additional supervision and manual interventions by the operator.

These hierarchical levels ensure high operational flexibility, as manual interventions are possible at any time at any of the control levels, without any specific operations necessary on the superimposed levels, such as transfer from automatic to manual.

There are two different types of hierarchical control, namely binary hierarchical and analogue hierarchical control.

3.3.2.1.1 Analogue hierarchical control

The analogue control system’s task is to control the process variable to a defined SP for different parameters. The objective of the analogue control is to provide SP values to subordinate control levels, which will ultimately reach the actuators to ensure that the process requirements are fulfilled. This task is required for the start-up, shut-down, steady state, load variations and transient conditions. There are 4 analogue control levels, as can be seen in Figure 11.

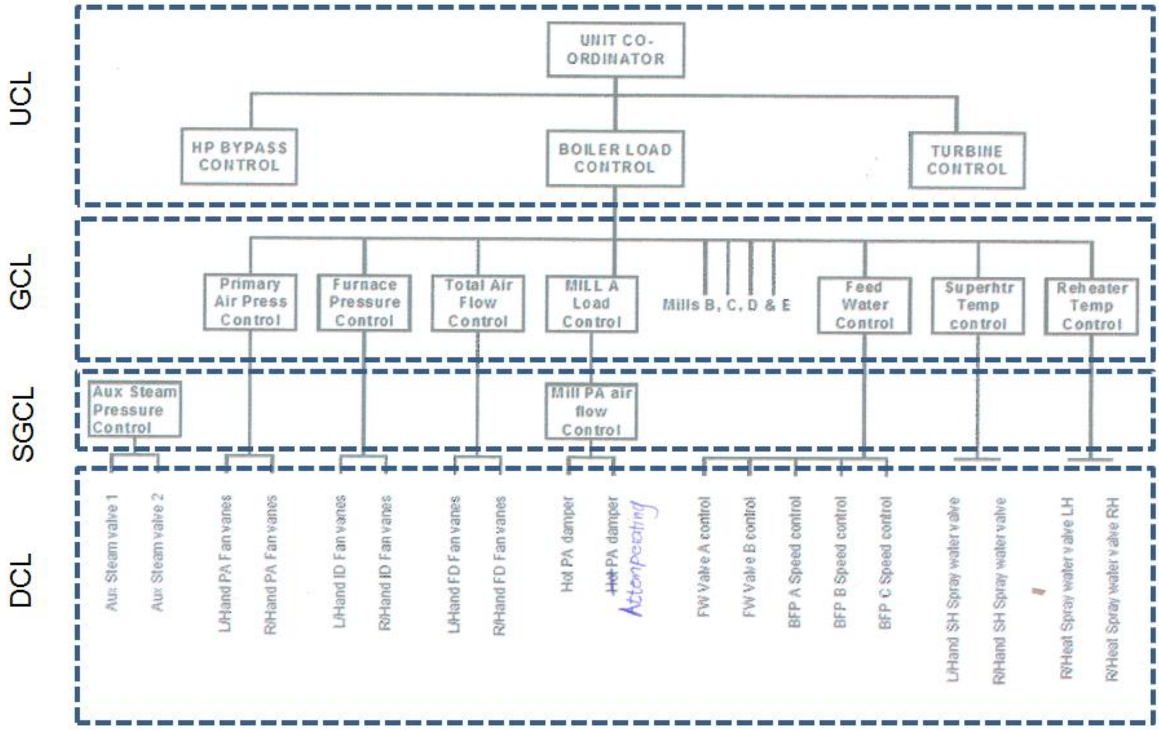


Figure 11 - Analogue hierarchical control structure [10]

- Unit control level (UCL)

The unit coordinator is found in this level. This is the highest control level for the unit, with the main boiler load controller residing in this unit.

- Group control level (GCL)

The group control level controls all the analogue signals for main system groups, such as mill loads, total air, feedwater, furnace pressure and primary air pressure.

- Sub-group control level (SGCL)

At sub group level controls for the different loops are found, such as primary air flow per mill.

- Drive control level (DCL)

This is the lowest control level. Its task is to monitor, control and provide feedback on specific drives. The drive level contains logic for the protection and interlocks for the individual drives.

3.3.2.1.2 Binary hierarchical control

The binary hierarchical control level's task is to control, protect and monitor which have binary functions (on/off or open/close). It is mainly implemented to ensure safety and reliability during start-up or shut-down conditions, providing the operator with clear information about the process under control and its binary interlocks and protections. There are five binary control levels, as displayed in Figure 12. The UCL is omitted from the figure.

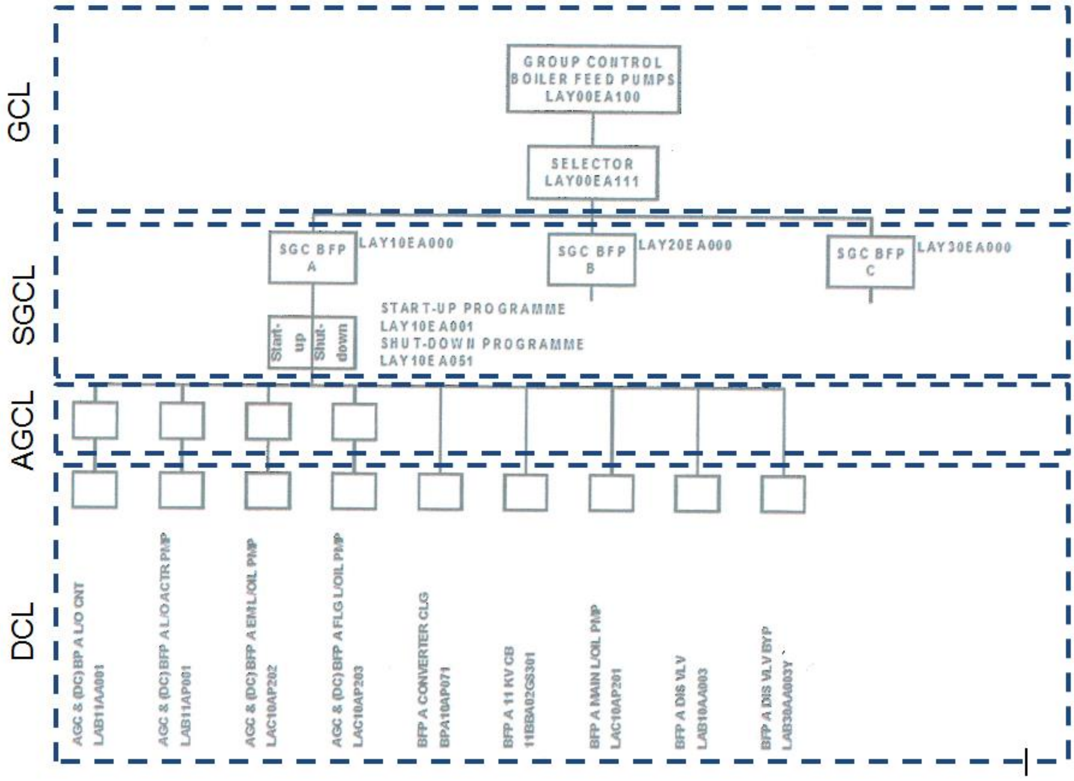


Figure 12 - Binary hierarchical control structure [10]

- Unit control level (UCL)

The unit control level is the highest hierarchical level if a Supervised Fully Automatic philosophy (single push-button) is adopted for start-up and shut-down of the plant.

- Group control level (GCL)

The group control level takes the place as the highest hierarchical level if a supervised, fully automatic philosophy is not implemented. The group control controls a unique main group of drives in the plant or a group of main drives with identical function. The main characteristic of the group control is sequence control. The operations to be performed when starting a system takes place step-by-step in a pre-set sequence and is monitored according to pre-set time interval.

The group control is divided into two different sub levels, namely sub-group control and auxiliary group control.

- Sub-group control level (SGCL)

The sub-group control level controls a unique group of drives in the plant which are important to get the main group started, such as turbine oil supply.

- Auxiliary group control level (AGCL)

The auxiliary group control controls the auxiliary drives of a main drive. The auxiliary group control is applied when its drive consists of more than one aggregate with which it must work in conjunction with, such as 2 pumps of which one is a standby.

- Drive control level (DCL)

As in the case with analogue controls, this is the lowest hierarchical control level.

3.3.2.2 Control modes

When looking at the control of the fireside operation, the unit coordinator receives the required amount of MW required by National Control, and responsible for coordinating the unit to meet the load demand.

Different modes are available for boiler operation. Depending of the boiler mode in operation, the unit coordinator adjusts the firing rate, air supply and governor valve position. There are four main boiler control modes, namely boiler-follow, turbine follow mode, manual and coordinated control.

Table 3-3 - Boiler control modes

Control mode	Boiler as master	Turbine as master
Manual control	Manual	Manual
Boiler follow	Automatic	Manual
Turbine follow	Manual	Automatic
Coordinated control	Automatic	Automatic

3.3.2.2.1 Boiler-Follow mode

Boiler-follow mode is designed in order for the boiler response to follow the turbine response, which is also referred to as constant pressure mode.

Boiler follow mode is where requirements in steam generation are fulfilled by governor valves responding to the required change in load or turbine speed.

The boilers control system will respond to take necessary control action when a change in steam flow or deviations in pressure are present, thus reacting to maintain steam pressure SP in the boiler by automatically increasing the fuel input to the boiler [11].

In boiler-follow mode the turbine can draw stored steam in the boiler, which provides a relatively rapid load response. This response provides a rapid response to meet fluctuating load demands.

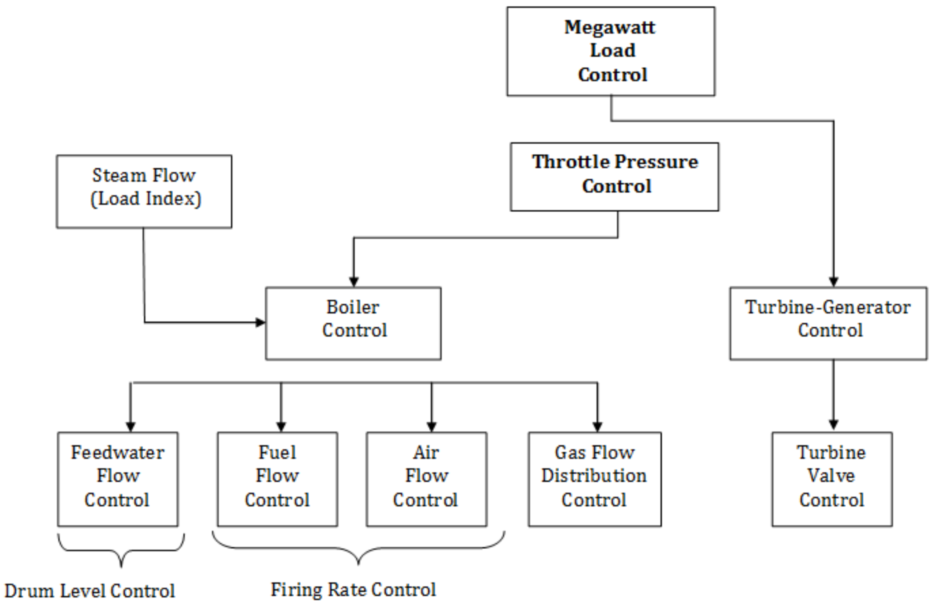


Figure 13 - Boiler-follow mode control hierarchy [7]

3.3.2.2.2 Turbine-Follow mode

In turbine follow mode the generator load response follows the energy (fuel) input into the boiler. Governor valves are usually controlled, with the amount of steam regulated by the amount of fuel burnt [11].

Energy stored in the boiler is not used as in boiler-follow mode. The response of the system is considerably slower than boiler-follow mode, but provides a sustainable base load response.

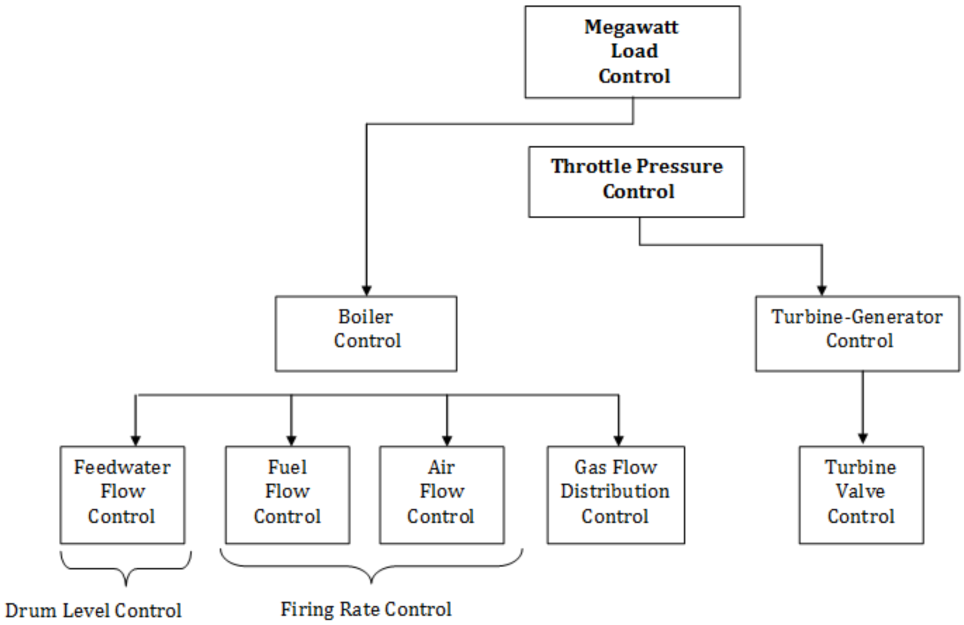


Figure 14 - Turbine-follow mode control hierarchy [7]

3.3.2.2.3 Coordinated control mode

Unit coordinated control uses the advantages of both turbine-follow and boiler-follow modes. Both the firing rate and the turbine governor valves react to load change demands.

When more steam is required, the governor valves will adjust to increase steam flow to the turbine, and in parallel the firing rate will adjust to provide sufficient steam flow and steam pressure.

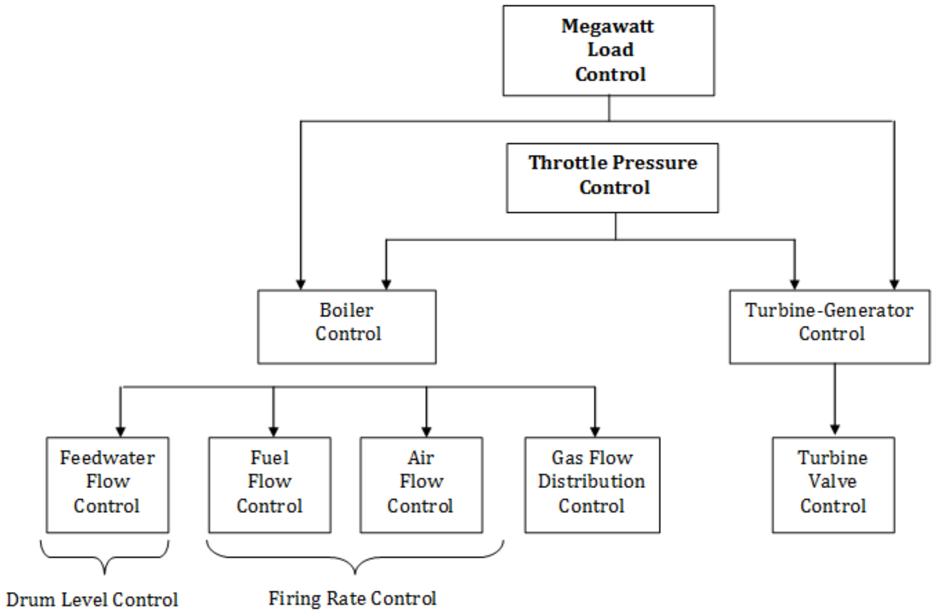


Figure 15 - Unit coordinated control hierarchy [7]

3.3.2.2.4 Sliding pressure mode

In sliding pressure control mode, the pressure SP is proportional to MW demand. The error in the pressure SP and actual throttle pressure drives steam generation through the fuel controls. On the turbine, the throttle valves are left fully open the throttle pressure varies proportional to the load.

There are numerous advantages in sliding pressure vs. fixed pressure, such as reduced stresses in the turbine at lower loads. The response to the change in load demands in relatively slow in comparison with fixed pressure as there is no stored steam within the boiler, and is well suited for start-up conditions for boilers.

3.3.2.3 Control loops

The hierarchical control structure (with reference to the boilers' side) can be further divided into two main loops, namely the steam/water (waterside) loop and the fuel/air (fireside) control loop. These loops will perform according to the hierarchical structure and the selected mode of operation.

Within the steam water cycle feedback control loops exist between the main loop and its sub-loops, namely the drum level/feedwater flow, steam temperature and steam pressure.

On the fuel/air side, feedback loops exist between the main control loop and its sub-loops, namely the furnace pressure, fuel flow and air flow control loops. The scope of this project will mainly focus on the fireside control loops and optimization thereof.

The process of steam generation is classified as a multivariable process. This term characterises processes in which two or more mutually coupled variables are to be controlled. In the boiler-turbine system, the output (dependant) variables are directly dependent on a number and state of the input variables (independent variables), which directly influences the two processes of combustion and steam generation [12]. All these variables are mutually coupled; meaning a change on an independent variable will have an effect on one or more of the dependant variables.

Figure 16 represents the independent variables on the left and dependant variables on the right in a boiler turbine system.

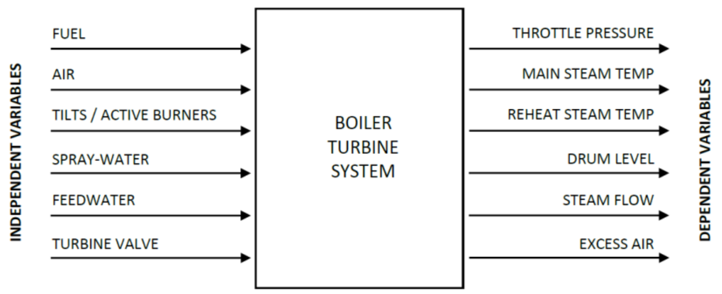


Figure 16 - Variables within a boiler control system

The image in Figure 17 displays the main boiler control system's variables and the relation between them. This is achieved by diving control into separate control loops, each interacting with each other. It can be seen that process relies heavily on the interaction between and feedback from the control loops.

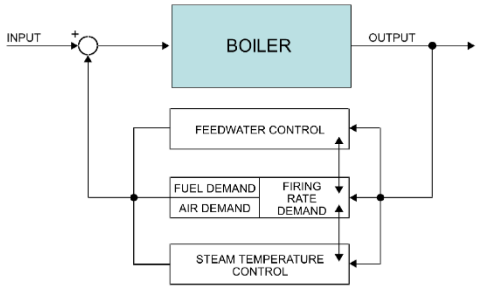


Figure 17 - Block diagram of main boiler control system elements [13]

3.3.2.3.1 Waterside control loops

The steam and feedwater circuit comprises of the drum level and feedwater flow, steam pressure and steam temperature circuits. The individual circuits are discussed below.

- <u>Drum level/feedwater flow</u>

Continuous type operations in large power plants are such that plant steam load characteristics vary continuously and usually unpredictably due to numerous factors, such as coal quality. A sophisticated drum level control mechanism is used to control the relation between the boiler drum pressure, feedwater flow and steam flow.

The drum level will be controlled with three element control. Three element control will ensure that the control signal to the feedwater flow valve will have a direct relationship. This is made possible by a feedback control loop. It is most commonly described by feedforward-plus-feedback cascade control [9].

Three element controls receive its inputs from drum level transmitter, steam flow transmitter and steam flow transmitter to throttle the boiler feed water control valve, thereby avoiding any fluctuation in steam/water flow to boiler.

- <u>Steam temperature</u>

The function of the steam temperature control loop is to maintain the steam temperature and the outlet of the superheater at the required SP. Maintaining the steam temperature at SP is crucial in ensuring efficiency, availably and load following capability, as well as increasing the lifetime of the plant by reducing thermal stress fluctuations.

Steam temperature is mainly influenced by the firing rate, and emergency control via attemperators is used to control the steam temperature just before it enters at the governor valve.

The steam temperature is initially controlled by the firing rate. Because the firing rate adjustment responds slowly, faster emergency loops have been put into place to control the steam temperature. The widest emergency method used in controlling the superheater steam temperature is using atomizing spray attemperators. The temperature of the steam after the first superheater stage is adjusted by spraying cool water droplets into the superheated vapour. This increases the volume of steam and lowers the temperature.

Generally a cascade controller is used for controlling the steam temperature [14]. Thermocouples are used to measure the temperature steam between the superheater stages. If the superheated steam's temperature is too high, the attemperator sprays water droplets into the stream, effectively bringing the temperature down.

The measurements are taken as close as to the inlet of superheater 2 to reduce system lag. At Camden power station the respective SPs for the steam are 535°C at the boiler exit or 532°C at the inlet of the turbine governor valve.

The inputs for the control are the thermocouple readings at the superheater outlet, and the steam temperature at spraywater injection. The cascade PI/PID control is used to maintain the temperature at desired SP. The outputs of the controller adjust the spray valve position.

- <u>Steam pressure</u>

The steam pressure control loop will maintain the main steam/throttle pressure at a desired SP (At Camden this SP is 10.4MPa. The control loop depends on the unit load controller and boiler control mode.

The most basic configuration is when the primary variable (i.e. the input) is the measured throttle pressure, which is compared to the fixed pressure SP. The error signal is processed in the throttle pressure controller, which would typically include proportional-plus-integral-plus-derivative action.

The input to the controller is obtained from the throttle pressure and the output from the controller is a demand signal to the fuel and air flow controllers to adjust the firing rate [12].

3.3.2.3.2 Fireside control loops

The fuel and air circuit comprises of the furnace draught, fuel flow and air flow circuits. The individual circuits will be discussed below.

- Furnace pressure

A balanced draught system is generally used, where ID fans are used to maintain furnace pressure. The furnace draught refers to the flow or air in and flue gas out, to maintain the boiler at slightly negative pressure relative to atmospheric pressure, thus keeping heat and flames from the boiler from escaping.

The Furnace pressure control loop maintains the furnace draught at SP, and adjusts dampers at the ID fans as required to control the amount exiting the furnace. The total air measurement at the ID fan outlet should slightly exceed the total amount of PA,SA and tramp air in order to maintain furnace pressure. A schematic of the furnace pressure control layout is given in Figure 18.

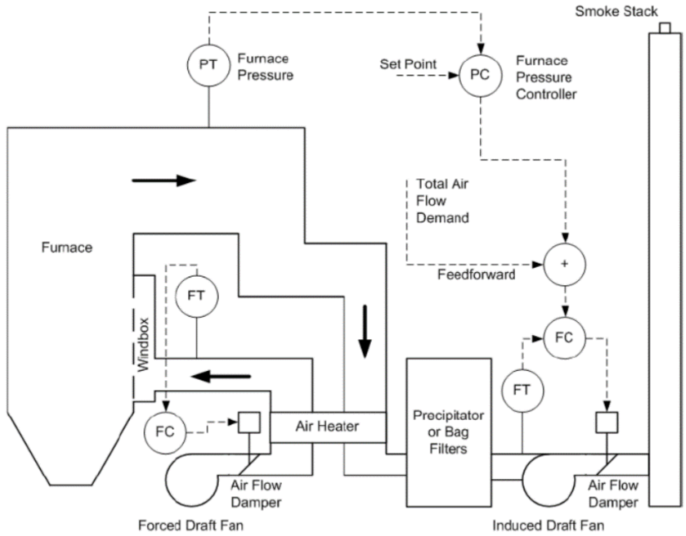


Figure 18 - Schematic layout of furnace pressure control [13]

The furnace draught gets inputs from the furnace pressure and total air flow demand, and after performing control with PI/PID control it changes the FD (or ID) fan inlet damper positions [12].

- Fuel flow

The DCS converts from the global boiler mega joule SP to the individual feeder speed. The addition in MJ from fuel oil is also taken into account [15].

The fuel flow is calculated by the differential pressure across the mill and the coal feeder speed. Some power stations have mass meters installed on the conveyor belts feeding the mill bunker. It is controlled via a cascade PID with additional demand calculations, such as mill load line. Its output signal is used to amend the coal feeder speed by adjusting the speed of the VSD motor [12]. In some powerstations the SP of the CV of the coal is udjusted by measuring the percentage 0_2 in the flue gas.

- Air flow

When more MW are required, the unit coordinator increases the firing rate until a feedback of steam flow is received which matches the master demand signal [16].

To ensure that the fuel has sufficient air for combustion, a technique called cross limiting control is used. Cross limiting control is a sophisticated concept which provides separate fuel/air devices, measurement of air/fuel and more powerful controllers, and provides optimum fuel/air ratio. Another possible function from cross limiting control is using information from continuously measuring oxygen and carbon monoxide in the flue gas as a further factor in air control.

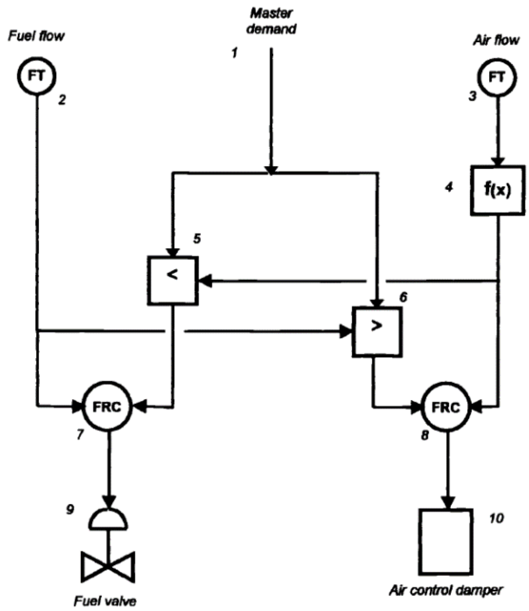


Figure 19 - Cross limited control system [9]

The controller arrangement is in the form of a cascade control loop. The primary input is the mill feeder speed, which interacts with the boiler fuel/air ratio correction controller to generate a SP for the air flow controller [12]. The output will determine the position of the control vanes in the FD fan ducts. The cross limiting control system is also influenced by the amount of 0_2 in the flue gas, and is also termed cross limiting control with 0_2 trim.

The unit total air flow is measured at the inlet of the FD fans, and the deviation of the air flow from its SP is fed into the proportional-plus-integral air flow controller.

3.3.3 Developments in boiler control

3.3.3.1 Siemens T3000 control system

The SPPA-T3000 system is a modern, Java-based design with system software running on a redundant Stratus server. Networking between the controller and application server is PROFINET and supports redundancy [17]. The SIMATIC S-7 controllers, referred to as Automation Servers, network to the field using Profibus DP.

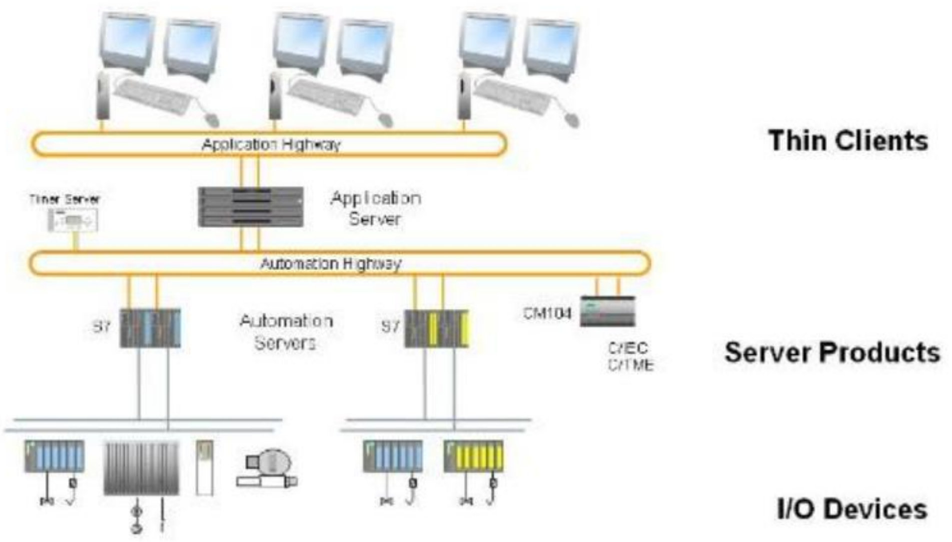


Figure 20 - Siemens T3000 overview [17]

Field controllers are Siemens SIMATIC S-7 controllers, but they are programmed with the new IDE specifically designed for the SPPA-T3000 system.

3.3.3.1.1 Integrated Design Environment

The system has a single integrated design environment for creating HMI screens and logic, allowing for efficient applications development. The entire system software goal is to have one integrated engineering software tool. The design tools are integrated and straightforward to use. It would still take a more in-depth analysis to really understand the use and limitations of the software.

The SPPA-T3000 system was all developed in JAVA and all operator stations, HMI, and engineering stations are thin client WEB browsers. The only place system software resides is in the redundant server, simplifying software maintenance.

Siemens offers software to automatically import configurations from older systems for migration projects.

The system software architecture is based on a Java framework. Algorithms for function blocks are written in JAVA and stored as an XML file. The software has a parser and other code that tokenizes the logic in a form understood by the controller runtime software engine in an S-7 controller.

OPC (Open Productivity & Connectivity), which is an interoperability standard is used as the primary interface to other software such as process management, enterprise, and asset management [17].

3.3.3.1.2 Function Block Programming

The system relies on function block programming and the user can create additional blocks using the existing function blocks. Engineers can switch between IEC and SAMA logic symbols views. The software has the facility for task scheduling and prioritization similarity to the IEC 61131-3 standard [17].

3.3.3.1.3 Controllers

The Siemens SIMATIC S-7 controllers referred to as Application Servers in this architecture are refined and established hardware platforms with a large set of I/O interfaces [17].

3.3.3.2 Fuzzy-neural networks

FNN is the combinations of fuzzy logic and artificial neural networks [17]. The combination of a fuzzy-neural network creates an intelligent hybrid system, utilizing the two techniques of combining the reasoning style of fuzzy logic with the learning structure of neural networks. In boiler control, the FNN will respond quickly to SP changes, and can adjust control parameters online to provide low settling time.

The controller in Figure 21 represents a boiler steam pressure controller, equipped with a FNN controller. The FNN controller enables the control loop to have a self-adapting ability and the advantage of fuzzy logic linguistic interpretation, thus having a low effect from disturbances.

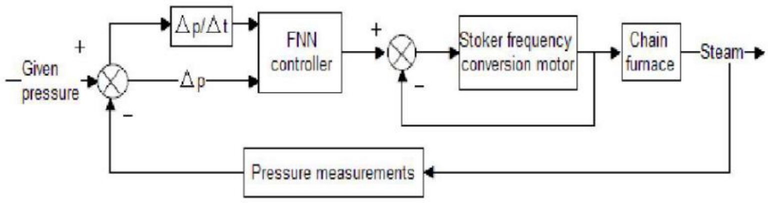


Figure 21 - FNN boiler steam pressure control loop [18]

After training the FNN system, the simulation results for a pressure controller were compared with other controllers used in the industry, such as PID control (L1), Fuzzy logic (L2) and FNN (L3). The systems SP was subject to a step response of 1 MPa, and the comparative results can be viewed in Figure 22 and summarized in Table 3-4.

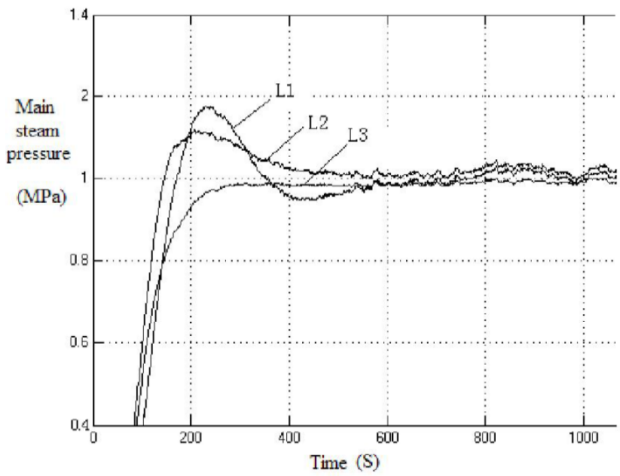


Figure 22 - Steam pressure vs. time for different control methods [18]

From the results below it is evident that the FNN implementation offers several advantages to boiler control, such as very little overshoot and a far better response time than its counterparts.

Table 3-4 - Comparison of three control methods [18]

	Method	Rise time (s)	Overshoot (%)	Response time (s)
L1	PID	180	18	580
L2	Fuzzy logic	170	5	400
L3	FNN control	200	2	220

3.3.3.3 Emissions control

One of the most important areas in boiler control is the focus on environmental legislation and adhering to the allowable emissions from the combustion process. Table 3-5 is an indication of the allowable concentrations of PM, SO_2 and NOx at 10% 0_2 for existing and new plants in South Africa.

Table 3-5 - Emissions limitations

	2015 "Existing plant" limit (mg/Nm^2 at 10% 0_2)	2020 "New plant" limit (mg/Nm^2 at 10% 0_2)
Particulate matter (PM)	100	50
Sulphar dioxide (SO_2)	3500	500
Nitrogen oxides (NOx)	1100	750

New technologies will be implemented in the flue gas path to ensure legislation is adhered to. These technologies include high frequency transformer ESP's, which lowers the time between possible arcs between the ESP and PM and thus maintaining its optimum charge. This is a non-invasive technique and does not interfere with the flue gas flow.

FGD plants are being implemented to lower the SO_x emissions. These are plants that dose the flue gas with limestone. The reaction between the limestone and SO_x forms gypsum which is dried and disposed of. The shortfall of the FGD plants is that it cools the flue gas, reducing its buoyancy and can thus not be emitted out the stack as easily. Solutions would require ID fans to work harder or to make use of an inline air heater.

Another technology which is currently being implemented is fabric filter bags replacing ESP's. The problem with the FFP is that the pressure drop across the bags become significant and requires the ID to work harder in order to maintain negative boiler pressure and emit flue gas out the stack.

3.3.3.4 On-line measurement devices

Measurement devices have improved over the years, offering real time measurement data which previously (and in some stations) have been done daily. This enables the DCS to react better to changes in properties of the substance measured, such as the CV value or moisture content of the fuel.

3.3.3.4.1 Near infrared spectroscopy

NIR is a technology which uses the near infrared electromagnetic spectrum, which is located between the infrared and visible light (between 850nm and 2500nm). The fuel sample passing through the emitted light is radiated by at least two different wavelengths for reference and for measuring. The measurement wavelength is absorbed by moisture in the PF and reflects against the fuel. The ratio of the reflection is proportional to the total moisture content of the coal. This is a fast reliable method, making it suitable for online measurement, but is sensitive to other light sources and surface moisture [19].

3.3.3.4.2 PF Microwave measurement

Microwave measurements use microwaves which are sent through a material, causing water molecules to move which causes a reduction in intensity and a phase delay. This can be seen as the moisture content when the reduction in intensity and phase delay is measured on the opposite side. This technique works best for heterogeneous fuels, such as coal, and will give a higher accuracy. Radiometry needs to be used in order to measure bulk density when determining moisture content. In radiometry gamma rays are radiated through the material and the decrease in intensity is a measurement of density [19].

3.3.3.4.3 Neutron technology

Methods that use neutron technology make use of the phenomena that hydrogen atoms reduce the speed of neutrons better than other atoms. By radiating material with neutrons and measuring the concentration thereof with a detector, which reacts on slower neutrons, the moisture content of the fuel can be calculated if the bulk density is known. This can be used in conjunction with gamma rays to determine the bulk density. A shortfall with this method is that it detects the hydrogen in compositions such as water, thus the hydrogen content of the fuel must be known beforehand [19].

3.3.3.4.4 Coal CV analyser

Various online coal CV analysers have become available. These are natural gamma and low level microwave CV analysers, which can easily be installed on conveyor belts. Most of these do not contain any nucleonic sources and do not require a radiation license for use. By combining the ash measurement with moisture content, tonnage and the DAFV (Dry Ash Free Value) of the coal CV can accurately be determined [20]. The online CV analyser assists the DCS in determining the CV of the coal coming in to the boiler, rather than adjusting the CV value from the measurement of oxygen content in the flue gas. This will allow optimal secondary air supply for combustion, with little or no excess air.

3.3.3.4.5 Water chemistry analysers

Many online water analysers have been developed for detecting silica, hydrazine and dissolved oxygen in the water. These analysers can help prevent erosion as well as deposits of solids on the pipework, prolonging the lifespan of the station.

These are implemented at the WTP’s outlet, or after the condenser before the BFP. Usually measuring the waters conductivity is a good indication of the TDS within the water. The silica, hydrazine and dissolved oxygen analysers are equipment specifically installed to measure a certain aspect.

3.4 Boiler control computational modelling

3.4.1 PSS/E parameterization

A modelling approach used within Eskom is based on the standard TGOV5 model from the Siemens PSS™E library. This is a tool to simulate, analyse and optimize a power systems performance and provides probabilistic and dynamic modelling features. It has been in use since 1976 and has become widely used to parameterize power generating units and predict its response to transient conditions [21].

The idea behind the concept is that generic transfer functions for power generation have been constructed. From here an exercise is undertaken to parameterize the individual components with historic plant data. This will then provide a model where input parameters can be changed and outputs will be predicted. It is mainly used for grid code compliance, and provides system operators with a quick response from the power stations model to verify which units can be used for optimal response to transient network conditions.

The shortfall of this model in the scope of this project is that the test conditions are bounded by AGC limits of the station, so the model can only predict values within the range of data the test conditions (or historic data) allows.

The model was divided into sections that correspond with the actual unit components [22]. Figure 23 shows the TGOV5 model, indicating how it has been sectionalized, with a brief description of key blocks for a drum boiler system that will follow.

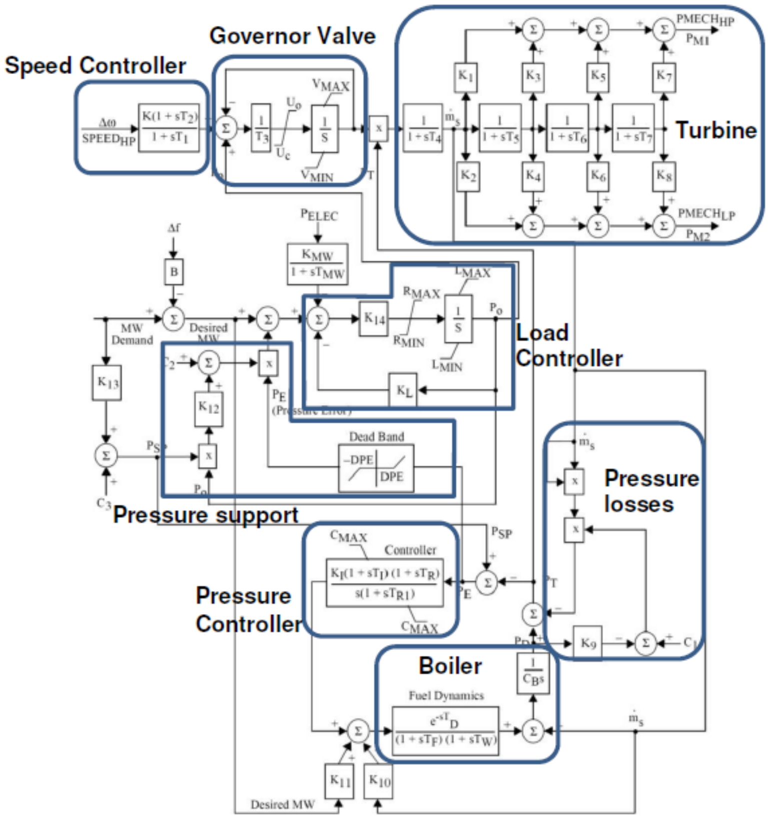


Figure 23 - Sectionalized TGOV5 model [18]

3.4.1.1 Governor valve

The governor valve step test with the boiler on auto was also used to determine the governor valve parameters of the model. The servo motor dynamics of the governor valve actuator can be represented as a first order delay with a time constant of T_3. The other parameters relevant to this section are the valve rate limits U_o and U_c, as well as the position limits V_{min} and V_{max}. The model takes the valve position SP as an input and the valve position area as an output [21].

3.4.1.2 Pressure losses

The pressure losses represent the drop in pressure from the drum outlet to the inlet of the turbine. The parameters relevant to this section are C_1 and K_9 which is the biasing parameters to the pressure losses. To calculate this pressure drop, any set of data can be used since it is continuously occurring during unit operation. For a better overall result the entire set of data during a test period should be used. The biasing parameters can now be calculated using Eq. [3.1] which holds for the pressure loss section in the TGOV5 model [21].

$$P_{drum} - P_{turbine} = Steamflow^2 * (C_1 - K_9 P_{drum}) \quad [3.1]$$

For a fixed pressure drum boiler K_9 can be set to zero, and making C_1 the subject yields the following:

$$C_1 = \frac{P_{drum} - P_{turbine}}{Steamflow^2} \quad [3.2]$$

3.4.1.3 Fuel dynamics and boiler storage

The complete boiler fuel dynamic response and storage is determined with the boiler fuel step test. With the boiler pressure controller on manual, this test exercises the boiler by injecting a sudden increase in fuel and capturing the response in the rise of the drum pressure after the step. A second test is also used to derive some of the characteristics of the boiler storage. This can be done with the governor valve step test with the boiler on manual [21].

The rate at which the pressure changes for a change in steam flow is an indication of the storage of the boiler, represented by the integrator with time constant C_b. Eq. [3.1] shows this relation where S is the storage capacity in kg/MPa [21].

$$S = \frac{\Delta steamflow}{\Delta pressure} \quad [3.3]$$

3.4.1.4 Boiler pressure controller

In order to determine the pressure controller parameters, the response of the controller to a step input is required. Therefore the pressure step test is usually used for this purpose. For this test the pressure SP is stepped up by 0.1 MPa while all other controllers were on auto [21].

The controller consists of PI section represented by the parameters K_i and T_i, as well as a lead/lag compensator section represented by the parameters T_r and T_{r1}. This equates to the Laplace domain transfer function in Eq. [3.4].

$$G_c(s) = \frac{K_i(1 + sTi)(1 + sTr)}{s(1 + sTr1)} \quad \textbf{[3.4]}$$

3.4.2 Dynamic systems modelling

Because of the nonlinearity of boiler control systems, a dynamic modelling system approach can be used [22]. Modelling of the boiler controls will be time based, and can be modelled using block diagrams, with the blocks representing components or transfer functions within the system. Each of these block diagrams represents the mathematical operation that will be performed on the input signal.

Even though the dynamic interactions between different system elements are well described by their transfer functions and mathematical equations, it is very useful to visualize the system with the use of function blocks.

A block diagram model of a dynamic system consists of block diagrams and signal lines which are interconnected and represented graphically. These block diagrams have been derived from engineering principles of signal processing and control theory [23].

FBD’s are available from Camden power stations DCS. These FBD’s can be modelled within the Simulink® environment by mimicking the FBD’s main components and content within a running Simulink® model.

3.4.2.1 Simulation block diagram structure requirements

Computer simulations are used to model a large variety of control systems, and should embody the following components [22]:

3.4.2.1.1 Mathematical model structure

This should reflect the fundamental physical governing laws of the system, and constitutes of a complete set of differential equations that describes the system behaviour.

3.4.2.1.2 Model parameter values

Model parameter values refer to constants that do not change over time and the course of the simulation, or the effect of the change is negligible due to the rate of change. When the function block has been completed, parameters can be populated with numerical values. This results in improved flexibility for parametric studies.

3.4.2.1.3 Initial conditions

An initial condition refers to the system given a point in the domain of the solution, such as starting conditions. When the function blocks are completed the integrator blocks can be populated with initial conditions. Together with block diagrams (mathematical model structures), model parameters and initial conditions, these elements represent the minimum which is required for implementing a simulation.

3.4.2.1.4 Inputs

A system typically responds to one or more inputs and the simulation should embody inputs as well. If inputs are not provided for the system, only a homogenous component will be found through the simulation. Arbitrary inputs can be formed from stored data which could be stored in the workspace or in a separate file. This gives the user the flexibility to use “real world” data as inputs to the blocks.

3.4.2.1.5 Outputs

Simulations do not require the user to specify the outputs, and is assumed that the goal of the simulation is the change in specific variables (outputs) within the dynamic system. The purpose of computer simulations is to study the response of the system with regards to its initial conditions and inputs. Simulation packages include various ways to examine the outputs, such as the “scope” block in Simulink.

3.4.2.1.6 Simulation solution control parameters

These parameters are chosen by the user and dictates how the numerical methods behind the simulation will operate, and includes: error tolerance, variable size, integration algorithm and output interval. The smaller the tolerances are, the smaller the step size will be.

The following five parameters define the run time control of a simulation [22]: Integration algorithm, initial and final time, minimum step size, maximum step time and error tolerance.

3.4.2.2 Simulink® modelling

Simulink® provides the advantage of implementing a mathematical model with physical representation, which is represented by blocks and lines within Simulink. The advantage of Simulink® is that it allows the user to easily model and analyse the response of complicated dynamic systems. Simulink® provides a large variety of blocks and libraries representing various phenomena in a range of formats. Simulink® is able to numerically approximate the solutions to mathematical models, separating the user from the need for mathematical modelling of the system.

3.4.2.2.1 Non-linear system blocks

Simulink® contains a rich collection of nonlinear simulation general purpose blocks, which are common encountered when modelling non-linear systems. These are frequently found in boiler control, and include blocks such as saturation, dead zone, product, transport delay and backlash. These are all common blocks used in boiler control modelling and simulation.

- <u>Saturation</u>

The Saturation Dynamic block bounds the range of an input signal to upper and lower saturation values. As per Eq. [3.5], the input for the block is $f(x) = u$ and the output is u, $y_{\max}$ or $y_{\min}$, depending on the input.

$$f(x) = u = \begin{cases} y_{\max} & for \;\; u \geq u_{upper} \\ u & for \;\; u_{lower} < u < u_{upper} \\ y_{\min} & for \;\; u \leq u_{lower} \end{cases} \qquad \textbf{[3.5]}$$

An input signal outside of these limits saturates to one of the bounds where:

- The input below the lower limit is set to the lower limit.
- The input above the upper limit is set to the upper limit.

  - Dead zone

When a dead zone is implemented an input must exceed some threshold value before the output will be monitored, and the mathematical representation is given in Eq. [3.5], the input for the block is $f(x) = u$ and the output is 0, $u - u_{upper}$ or $u - u_{lower}$, depending on the input.

$$f(x) = u = \begin{cases} u - u_{upper} & for \;\; u \geq u_{upper} \\ 0 & for \;\; u_{lower} < u < u_{upper} \\ u - u_{lower} & for \;\; u \leq u_{lower} \end{cases} \qquad \textbf{[3.6]}$$

The Simulink® dead zone block accepts and outputs floating point, integer and fixed point data types.

  - Product

The product block is used to multiply two input variables together. It should be noted that this is not the same as a linear gain block, where the gain is multiplied by a constant (parameter). The product block can also be used for division. The product block accepts data types in the form of scalar, vector or matrices inputs.

  - Transport delay

The transport delay is encountered in various industries and is also commonly known as “dead time”. The dead time is the amount of time after each event in which the control system is not able to record a new event. The transport delay also delays the output with a predetermined value.

3.4.2.2.2 Simulink® S-functions

Simulink® S-functions will be used in addition with standard Simulink® blocks. S-functions provide the flexibility of adding and C-script to a Simulink® model which can be used to manipulate and implement custom control algorithms [24]. These S-functions are compiles as MEX files using the MEX utility, and are compiled by an external compiler and allows interaction between the Simulink® environment and the compiler. S-functions accommodates continuous, discreet and hybrid systems, and can also be stored under user defined function blocks for easy retrieval [25].

Simulink® has a built in S-function builder. The dialog box contains all the relevant attributes within the S-function, such as name, inputs, data properties, build info and outputs. When he S-function is compiled through the builder, it automatically generates wrapper C code to enable the custom code to interface with Matlab®.

3.4.2.3 Flownex® control modelling

Flownex® Simulation Environment is an environment in which enables the user to study how systems will behave in the real world, where fluid is the driving factor. Flownex® system simulation relays the overall effect of changing specific properties on components, allowing users to examine extensively all possible variations in the design and optimization of systems.

Flownex® is equipped with a DCS add-on library, which can be used for simulation of system logic and has the ability to perform mathematical operations on the thermal-fluid Flownex® model.

The add-on library was developed to be used in conjunction with the Flownex® Simulation Environment, and uses the Data Link Tool to acquire data from the Flownex® model and enables the DCS library to be linked to other Flownex® libraries. By using the Flownex® DCS library, the entire process control system can be emulated which is simulated by Flownex® library components. The control system can be linked to data from any component in a flow network created with components from the Flownex® library. This data can be processed using components from the DCS library and can be used to control elements such as control switches, motors and actuators [26].

Flownex® has the capability to create entire plant simulators within a single environment by integrating DCS and flow components. This can also be visually represented by using the Flownex® Visualization library to create HMI, which can be used for operator training solutions.

Flownex® makes provision for the use of various components as found in the DCS, such as analogue- and digital components. By using these components an accurate simulator of the control environment can be set up within Flownex®, allowing the DCS several data types for I/O’s. These are accessible by using the appropriate Data Link for the required data type.

3.4.2.3.1 Analogue components

Flownex® DCS analogue library has components that can perform tasks on analogue inputs. These components are divided into five sub-functionality groups. The groups with their analogue components include, but are not limited to the following:

- Controllers
  - PID
- Filters
  - Integrator
  - Rate limiter
  - Rate of change
  - Time delay
- I/O
  - DCS I/O lists
  - DCS I/O with alarms
- Math
  - All general math operators
- Switches
  - Comparator
  - Toggle switch
  - Analogue value storage

3.4.2.3.2 Digital components

Flownex® DCS analogue library has components that can perform tasks on analogue inputs. These components are divided into five sub-functionality groups. The groups with their analogue components include, but are not limited to the following:

- Counters
  - Up Down counter
  - Counter
- IO

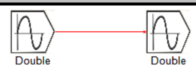
    - I/O
    - DCS DI & DO
- Logic operators
    - AND, OR, XOR gates
- Switches
    - Latches
    - 2oo3 Selector
    - 4oo6 Selector
- Timers
    - On delay timer
    - Pulse timer
    - Off delay timer

3.4.2.3.3 Data links

The Data Link library consists of data links which are used to convey different data types between Flownex® components. Flownex® has the ability to recognise the correct data type and adjusts the data link automatically to the correct data type when properties of components are connected.

The data links have a number of properties that are user specified and helps to simplify the control system design by eliminating certain small components like the NOT and Scale. Table 3-6 gives the four of the ten different data links that are used with the link line colour, link line style, and illustration of each data link.

Table 3-6 - Data link indicators [26]

FROM data type	TO data type	Colour	Style	Illustration
Double	Double	Red	Solid line	
Double	Integer	Green	Dotted line	
Integer	Integer	Green	Solid line	
Integer	Double	Red	Dotted line	

3.5 Testing and optimization strategies

There are many factors that can have an effect on boiler efficiency. These factors include high excess air, high flue-gas temperature, poor water treatment, decline in fuel quality, low feed water temperature, low secondary air temperature, radiant-heat loss, poor combustion, conduction-heat loss (fouling on tubes), operation at low or cyclic loads, and poor controls/instrumentation.

Some of these factors can be addressed by adjustment on the control's side, such as the amount of excess air and poor controls and instrumentation and the maintenance thereof. Together with physical alterations on the plant (such as the burner replacements at Camden) efficiency can be drastically increased by updating and tuning the control system.

3.5.1 Loop tuning

When a control system at properly tuned, the process variability is reduced, efficiency is maximized, energy costs are minimized, and production rates can be increased [26].

Controller tuning is to select the appropriate parameters for optimum response from the controllers. If the tuning is less aggressive, the system will respond slowly, lacking the ability to respond to upsets and will take long to reach setpoint. In contrast, when tuning is too aggressive the loop will become unstable with large overshoots.

Best practises have been defined for loop tuning and include checking the equipment, modelling the process dynamics, defining process needs, choosing the right tuning, and simulate before update and to monitor the results.

Loop tuning techniques can be implemented on the controllers on the boiler model within the simulation environment to determine the optimal values for the proportional, integral and derivative values. A comparison of 4 of the most widely used tuning methods is given in Table 3-7.

Table 3-7 - Advantages and disadvantages of tuning methods [27]

Tuning method	Advantages	Disadvantages
Chien, Hrones and Reswick	Quick response	Requires math, needs to be tuned offline.
Cohen–Coon	Good process models	Requires math. Tuning to be done offline. Most efficient for first-order processes.
Rule of thumb (Manual)	No math required. Tuning done online	Requires personnel with experience
Ziegler–Nichols	Tried and tested method. Tuning done online	Upsets process somewhat. Some trial-and-error. Very aggressive tuning

According to [27], the most widely used and most easily implemented is the Ziegler–Nichols tuning method. This method has also been tested and proven and offers fast settling time with low overshoot.

3.5.2 0_2 trimming

Combustion of the PF requires the right mixture between air and fuel (stoichiometric ratio). Too much or too little combustion air both has undesirable effects, but the error will rather be maintained on the high side than on the low side, as insufficient air causes CO to form, sooting and a possible explosion if unburned carbon in the boiler suddenly gets adequate heat and oxygen, thus the need to tune combustion air is crucial to boiler performance.

Boilers have usually been tuned manually on a periodic basis, but new automated tuning systems have become more popular. The combustion air (usually supplied by the FD fan) is adjusted to about 3% of excess oxygen when measured in the flue gas path, which is roughly 15% of excess air [28]. Eskom's FFFR states that any of the Eskom fleet' shall have between 2% and 9% of excess air [29]. Attention must be given to the effect the ambient conditions have on the boiler efficiency, such as air pressure, temperature and inherit quality of the air, as this would affect the oxygen reading in the flue gas path [27].

The objective is to find how the control systems reaction to the 0_2 trimming system will control the FD fan vanes. This will control the amount of combustion air available, as well as the windbox pressure and possibly increase boiler efficiency if excess oxygen can be kept at a minimum.

3.6 Data validation

Data validation will be done once both the control models are operational. This can be done remotely by using VaView client, which is a decentralized plant monitoring system.

KKS tags in question can be added to the user interface as in Figure 24, and can be viewed and compared to several other tags. The entries can be exported in a .csv format, which allows for further editing and interpretation within Matlab® or Microsoft Excel. The datasets will be set up according to controller inputs and outputs.

The tags in Figure 24 represent the main controller outputs, such as Boiler Load Demand Fuel, Total Coal Flow SP, Mills SP and Total Air SP for the unit at 17 August 2014, around 01:00 AM.

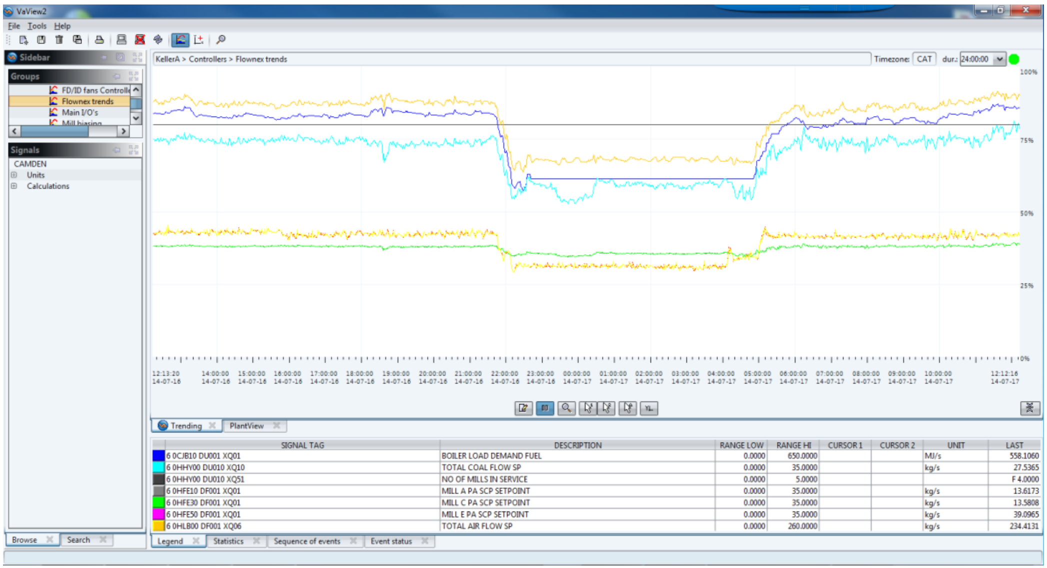


Figure 24 - VaView monitoring results

3.7 Literature review conclusion

One of the crucial building blocks in addressing the challenges within power generation is to be able to simulate, analyse and optimize the transient behaviour of a complete power plant, integrated with all of the relevant control loops. This will enable a power utility to simulate hardware and software changes to an existing plant – such as a DCS modification to meet the requirements of the installation of new burners. This will also allow a platform to test new control methodologies and optimize the system for efficiency.

With the scope on this project being the modelling of the boiler combustion system, a literature review has been done on the components found in the fireside of the boiler at Camden power station, the general approach to DCS architecture, control modes and control elements found in boiler control. An overview of modelling techniques used in boiler control has also been addressed.

For the construction of the boiler control model at Camden power station, Flownex® will be used, which is widely used in process modelling in various industries. The hierarchical approach will be used to separate the levels of control, containing all the relevant loops which will be implemented at Camden.

Loop tuning can be conducted on these loops after the model has been validated by users of the model. The primary focus will be on the windbox pressure which will supply the SA for combustion to maintain stoichiometric ratio and as low as possible excess 0_2 in the flue gas path.

The completed model will have an added HMI screen, allowing it to serve as a simulator which can be utilized for operator training on the new burner configuration and updated DCS.

4. Development of Camden combustion control model

4.1 Control system architecture

The Teleperm XP is divided into three main areas, namely the application side, automation side and the information highway. The application side constitutes of the engineering- , operating and monitoring- and diagnostic systems. The application side communicates to the automation side via a fibre ring network. The automation side then receives the commands and controls the relevant control levels depending on the commands received [31]. Figure 25 is an indication of Camden's control system architecture.

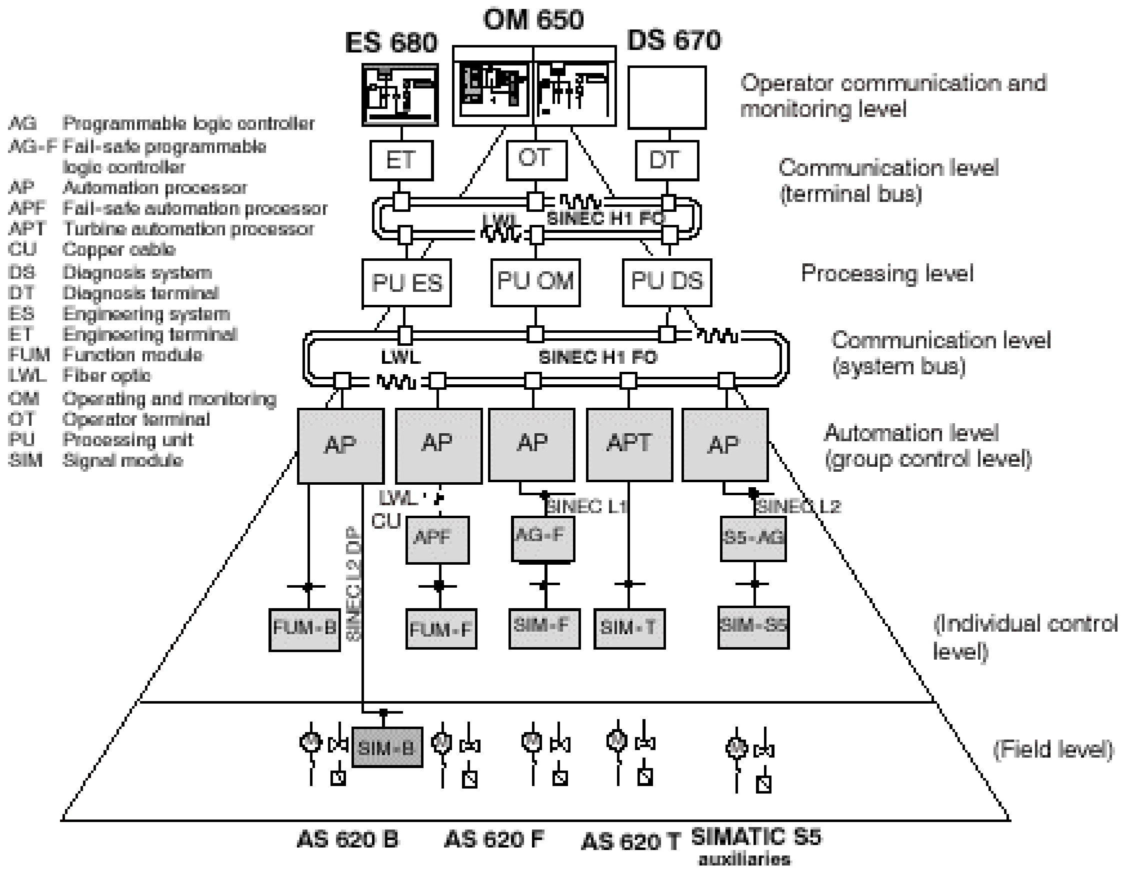


Figure 25 - Camden control system architecture [32]

From the automation servers, Camden's control system is split up in three levels, namely group control, subgroup control (individual) and device (field) control level, with each group reporting to the group higher in the hierarchy. Group control ultimately reports to the unit coordinator. Group control controls several subgroups, with the subgroups controlling various local control stations and switchgear for devices in the field. The control hierarchy for the three groups under the unit coordinator is displayed in Figure 26.

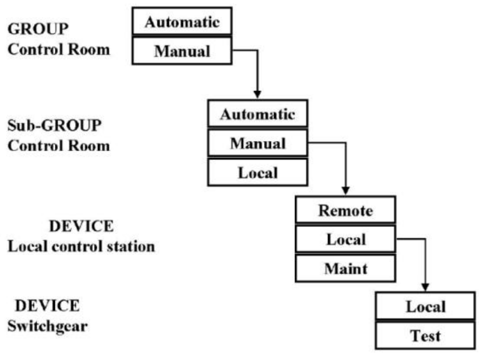


Figure 26 - Camden control hierarchy [30]

The operating philosophy is based on a level of automation where the plant is in auto mode for all normal operations. Each control level automatically controls one level lower. The control modes exist in order to provide flexibly for automatic control or manual intervention. "Auto Control Mode" is considered as the normal operational mode for the units. "Auto Control Mode" is the continuous or sequential control of the plant when initiated by the control room operator, and is performed by the control system without operator intervention. Lower groups can be decoupled from the "Auto Control Mode" if local operation is required and if pre-requisites are met.

Where manual control of a device is required, the operator will change the mode of operation from "Automatic" to "Manual" from the HMI in the control room and for manual control it needs to be changed from "Manual" to "Local" by the control room operator.

4.2 Unit control modes

At Camden power station 6 operating modes are available, with only 4 currently in use. These operating modes are set by the control mode selection in the unit coordinator. Camden only makes predominant use of 2 of these operating modes, namely coordinated control mode and turbine follows for light ups and steady state operation. The operating modes are as follows:

4.2.1 Mode 1 (Boiler manual turbine speed control)

During the turbine run up the turbine control is in speed control, subsequent to unit synchronization the operator can select the turbine back to speed control – a typical instance for this is to test the over speed but this however would not constitute normal operation.

In this mode the turbine is controlled to a speed SP that can be either entered by the operator in a manual run up or through a predetermined run up circuit for an automatic run up. The principal circuits of the unit co-ordinator are simply signal exchange as the turbine speed control is resident in the turbine control system.

4.2.2 Mode 2 (Turbine MW Control or pre-pressure control)

After synchronisation the turbine controls are automatically switched from speed control to block load control, i.e. MW control. After block load is achieved the operator can then load the unit up, normally to about 20MW, by adjusting the turbine MW load SP as required. In parallel to this the operator must increase the firing in order to achieve the required load. Note that up to 20MW there is no pressure de-loading active, but from 20MW up there is – this means the operator must maintain the boiler pressure above the de-loading curve values otherwise the turbine control system will de-load the unit along the de-loading curve.

From around 20MW the operator can switch to pre-pressure control mode CJB00 EE102=on. Note, CJB00 EE011=off implies open loop MW control and CJB00 EE011=on implies turbine pre-pressure control.

In pre-pressure control the turbine controls the turbine inlet pressure to a fixed pressure SP, normally around 10.4MPa. In this mode the operator can adjust the boiler firing to increase the load up to around 80MW before the co-ordinated modes can be considered. The boiler firing can be controlled either manually or if >1 mill is in automatic through a fuel demand SP, i.e. in MJ/s (typically 3MJ/s ≈1MW, this ratio can be considered as the unit efficiency which implies around 33%)

4.2.3 Mode 3 (Boiler MW control, Turbine pre-pressure control)

This mode of operation (turbine-follow) is similar to the mode of operation described in 4.2.2, pre-pressure control, except the boiler load fuel SP is set to automatic and the MW error from SP is used to correct the boiler firing SP. This mode is often called turbine follow boiler load control.

As the boiler is inherently a slow process in its energy generation this mode does not allow reasonable MW control. The boiler load SP fuel demand is calculated from the unit MW SP adjusted by the operator. As the operator adjusts the MW SP the boiler load fuel demand is automatically adjusted effecting a change in firing, the subsequent MW load change occurs consequently due to the change in energy in the steam admitted to the turbine in pre-pressure control. The unit then operates around the MW SP but load fluctuations are continuously present due to various reasons, e.g. coal quality changes, typical dynamic disturbances and in-house user changes.

4.2.4 Mode 4 (Boiler follows turbine control)

This mode of operation is principally MW control. The turbine no longer controls the final steam pressure but the actual MW load. The boiler now has the function of adjusting the boiler final steam pressure. The reason why this is the normal commercial mode of operation is that the generated load is stable and accurate.

The control of the final steam pressure by the boiler introduces a dynamic time problem. Changes in the firing rate to effect deviations in the final steam pressure is subject to the boiler delay times so only ‘long term’ pressure deviations can be effected by the boiler firing. Therefore the turbine, a fast operating loop, must be used to control these dynamic changes. This is done by automatically adjusting the unit load set to effect fast control of the final steam pressure. This means that the actual load can deviate by up to 2.5MW, normally less than 1.5MW.

In this mode of operation the CV controller should be left on automatic. It must be noted that where there seems to be regular dynamic fuel problems the CV controller will operate strongly to counter act these disturbances. This can cascade causing dynamic disturbance in the final steam pressure as well. It is possible to set the CV controller to manual with the loss of accurate oxygen control but this is not preferred.

In this mode there are a few monitoring circuits that will automatically change the unit co-ordination to pre-pressure control, these are like safety nets to stabilise the unit due to some disturbance that the load control circuits could not control quick enough. These are a final steam pressure deviation of >0.4 MPa or a controlled load deviation of >5 MW.

4.2.5 Mode 5 (Boiler MW control, turbine sliding pressure control)

Not in use at Camden power station.

4.2.6 Mode 6 (Boiler MW control, turbine M-Sliding pressure control)

Not in use at Camden power station.

4.3 Combustion controllers

4.3.1 Overview

In Figure 27, an overview of the flow of the combustion control system is displayed. The controllers are interconnected by feedback loops, and continuously adjusted by means of interpreting the various measurements from the field. Figure 27 only displays the flow of the main signals (XQ01) between the controllers [31].

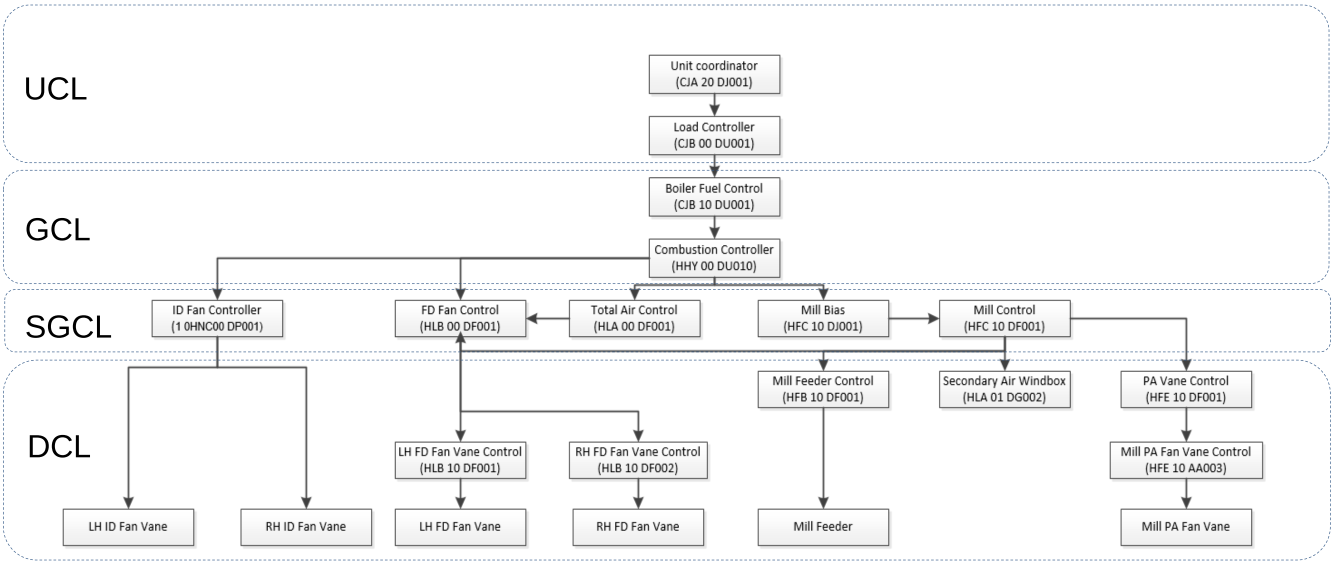


Figure 27 - Camden boiler control overview

The controllers are divided in different hierarchical levels, as described in Section 3.3.2.1. They have protections and device sub group controls, but will be omitted in the construction of the model. Alarms will be provided in contrast with protection and device sub group controls will not be utilized.

The controllers have been theoretically implemented and will further be described in the sections below.

4.3.1.1 Control blocks and circuits

4.3.1.1.1 OSPC/SPC

An OSPC is a SP controller which receives an external operator selected value and integrates the signal over a specified input time. The integration time is derived from the mechanical equipment specification the SP has relation to, such as the maximum rate of change.

A SPC acts in the same manner as the OSPC but receives its SP directly from the process and not an operator settable value.

4.3.1.1.2 LAG/LEAD Circuit

Lead/Lag circuits are implemented mainly in the fuel and air calculations. With large boilers it is crucial to manage the fuel and air in the furnace during up- and downramps. The Lead/Lag circuits will ensure that the airflow lags the fuel flow during downramps, and that the airflow will lead the fuel flow during upramps.

This will ensure that the furnace will not become oxygen deprived during load changes, and possibly cause an explosion due to suspended fuel particles suddenly receiving air and heat at unplanned times.

4.3.1.1.3 Deadband

The deadband, also called a Mechanical noose, is a circuit which allows a certain band around the input SP in which fluctuations will not cause the output to change.

Whenever the input SP is out of the allowed limits, the band shifts to form a new dead zone around the input SP.

4.3.1.1.4 PT_x

Process time delays, or PT_x's, acts as an $\frac{1}{s}$ integrator within a logic path. Multiple PT_x's can be used in order to change the order of the response.

4.3.2 Unit coordinator

The unit coordinator is responsible for the interaction between the different groups within group control, which in turn is responsible for subgroup control and device control and is shown in Figure 28.

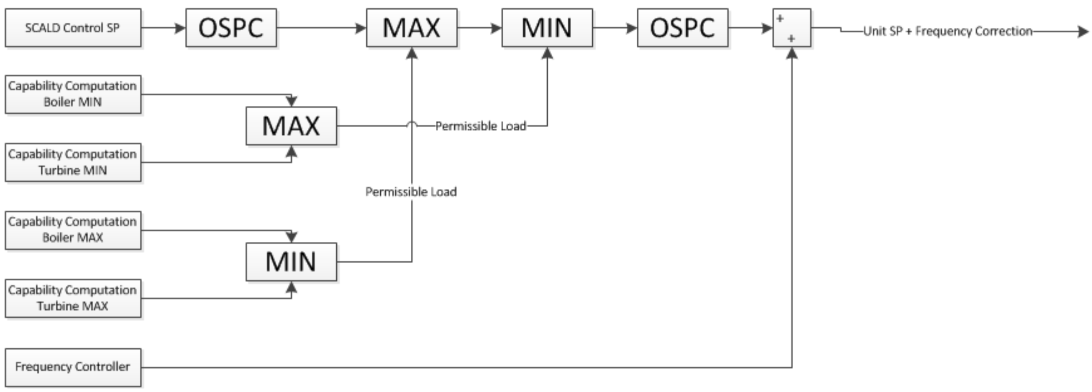


Figure 28 - Camden Unit Coordinator [32]

The unit coordinator calculates the boiler fuel requirement based on the MW SP, checks capability and handles load changes. The unit cordinator also makes provision of frequency support by increasing the load demand to accommodate deviating frequency values.

4.3.2.1 Unit target SP formation

The MW output is controlled by selecting the MW output SP in the unit coordinator. The desired output is entered in the OSPC, which has internal limits of 0 – 210 MW as well as operator settable and calculated upper and lower limits. From the OSPC the load demand is compared to the unit capability.

4.3.2.2 AGC selection

The unit coordinator also provides the AGC facility for remote load control from the centralised, computer based load dispatch system at National Control. The load dispatcher controls the generator output by varying the unit target load SP in the same way as the unit operator. Switching AGC into operation is only allowed if the unit coordinator is on automatic and in either boiler- or turbine follow mode. Transfer to the load dispatcher is done from the unit control desk by switching AGC on.

AGC will send raise and lower pulses to the unit coordinator, which is used to change unit target load SP within the allowable limits. It is not possible to change the unit load from both AGC and the UCR simultaneously. A ramp rate of 3% of MCR / minute is automatically selected when the unit is switched to AGC.

4.3.2.3 Capability computation

The unit capability is determined by assessing all the boiler aggregates that are in service. With only one DG on load the unit is limited to 105MW and with only one EFP in operation to 90MW. Each mill in operation allows 52.5MW. With a differential pressure over either the LH or RH FFP in excess of 2.7kPa the unit load is restricted to 180MW. If the differential pressure has been above 2.7kPa for longer than 30 minutes the load will be further restricted to 160MW. All the above are found in controller CJA10DJ001, and a summary of the contribution per auxiliary in Table 4-1.

The MW SP is then evaluated against the permissible loads. This is done by MIN and MAX selectors, ensuring that the demand does not exceed the maximum capability or does not go lower than the minimum capability the unit is able to produce with the available auxiliaries.

Table 4-1 - Camden auxiliary capabilities

Auxiliary plant	Max Load (% of MCR)
1 Mill	25
2 Mills	50
3 Mills	75
4 Mills	100
1 Draught Group	50
2 Draught Groups	100

4.3.2.4 Ramp rate OSPC

From the MIN selector of the MW SP formation the MW SP is passed to another OSPC, which controls the unit gradient at which the unit MW load SP is raised or lowered. Both the increasing and decreasing rates are operator selectable via a single setting that applies for both positive and negative load SP ramp rates in controller CJA20 DJ001.

For example, if the unit load SP is set from 100 MW to 200 MW with the ramp rate selected at 10, the OSPC will increase the SP from 100MW to 200 MW at a ramp rate at 10 MW/min, and the change in MW SP will take 10 minutes from 100 MW to 200 MW. The output of the MW ramp rate OSPC is then added to the MW SP from the unit frequency controller.

4.3.2.5 Frequency correction

When the unit frequency correction is activated, the governor system responds to frequency changes outside of a 0.05 Hz dead band with a 4 % droop for both a frequency decrease and increase. For a frequency increase the response must be at least 15 % of MCR and must be fully achieved with 10 seconds, and is only available between minimum load and 97 % MCR.

A minimum load limitation is also implemented only when the frequency controller is active. This is to ensure that the frequency controller does not try to de-load the turbine below the minimum load that it can maintain for stable firing of the mills in service.

The response as stated above will be executed only once the unit frequency controller is activated.

4.3.2.6 Unit load SP formation

The summed MJ/s load SP SP which consists of load demand, frequency, and boiler pressure is then evaluated at a MIN selector with the boiler capability signal to ensure the demand does not exceed the physical capability of the boiler before the final unit MJ/s SP is formed.

The MJ/s fuel SP from is then sent to another OSPC (Boiler MJ/s fuel demand CJB10 DU010) that follows the SP when the unit is in coordinated control or the internal operator selected SP when the unit is not in coordinated control.

This controller also compares the SP against a boiler maximum and minimum capability, again dependant on which of the boiler auxiliaries are on load. The signal from the controller, CJB10 DU010 XQ01, is the boiler MJ/s demand signal that drives both fuel flow and air flow to the boiler.

4.3.3 Load Controller

The Load Controller is used to convert the Unit Target SP to a MJ/s fuel requirement, by taking into account the units' efficiency. A deadband has also been included to remove noise that could possibly be induced by the frequency correction or sudden change in demand.

The Load Controller calculates the Unit efficiency from the Boiler Load Demand Fuel signal and compares it to the current MW output from the generator. The MJ/s output from the Load Controller forms the Boiler Load Demand Fuel input of the Combustion Controller.

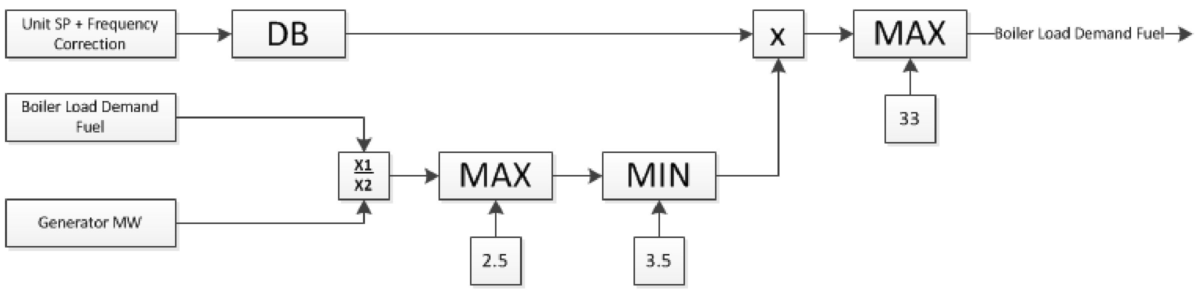


Figure 29 - Camden Load Controller [32]

4.3.3.1 Unit efficiency calculation

The unit efficiency is operator changeable via an OSPC within the load controller. The OSPC has internal limits of 0.9 – 1.1 which is divided by a constant of 2.85. The unit efficiency value can also be calculated by a SPC comparing the fuel demand with the output of the generated MW's. This is then passed through a MAX and MIN selector, ensuring that the efficiency constant remains within bounds of 2.5 and 3.5.

For example, if the boiler fuel demand set at 630 MJ/s and the measured generator MW output is 221 MW, it means the unit efficiency constant is considered to be:

$$Efficiency\ constant = \frac{Boiler\ fuel\ demand}{Generator\ MW} = \frac{630}{221} = 2.85 \qquad \textbf{[4.1]}$$

By either using the calculated efficiency constant or manually setting the efficiency constant to 2.85 and the operator changeable efficiency parameter to one, yields the unit efficiency to roughly 35%, as displayed in Eq. [4.2].

$$Unit\ efficiency = \frac{Operator\ settable\ parameter}{Efficiency\ constant} = \frac{1}{2.85} = 35.087\% \qquad \textbf{[4.2]}$$

The unit efficiency is added to the Unit SP + Frequency correction value from the Unit Coordinator, and results in a MJ/s fuel output signal. The MJ/s fuel demand signal is then compared at another MAX selector to a constant value of 33, which forces the minimum fuel demand from the unit coordinator to be 33 MJ/s. The output of the MAX selector is named the Boiler Load Demand Fuel signal.

4.3.3.2 Unit mode selection

From the Boiler Load Demand Fuel signal, the mode in which the boiler-turbine system will run is selected by the operator. This is done by the operator in the load controller, as displayed in Figure 29. The MJ/s fuel demand from the unit coordinator is then summed with a MJ/s fuel demand from the boiler pressure controller if the unit is in mode 4, which is the normal operating mode.

4.3.4 Combustion Controller

The function of the Combustion Controller in Figure 30 is to maintain a safe combustion environment by ensuring correct stoichiometric ratio. This is done by managing both the fuel and air flow into the furnace.

The Combustion Controller receives the Boiler Load Demand Fuel input from the load controller, takes the amount of mills online into consideration and divides the coal flow evenly between the mills. It also calculates the required airflow per MJ, and outputs the deviation in airflow to the CV controller in order for the CV to reflect actual conditions in the furnace.

The Combustion Controller also provides the total air required by interpolating a MJ/kg airflow curve.

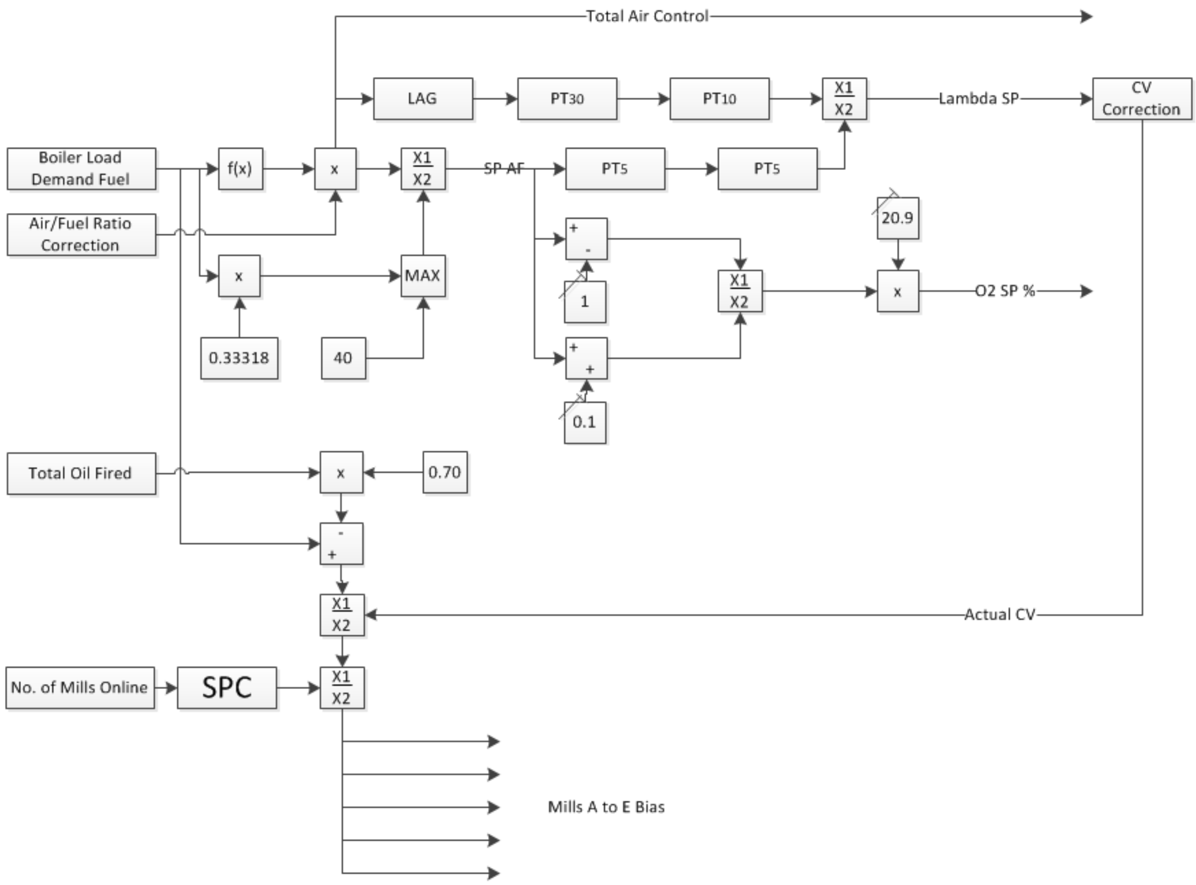


Figure 30 - Camden Combustion Controller [32]

4.3.4.1 Total air calculation

The total air required is calculated by comparing the boiler energy demand to a function generator that calculates a kg/s air flow requirement based on pre-programmed points, as presented in Table 4-2.

Table 4-2 - Boiler air flow curve data

MJ/s fuel demand	Kg/s air demand
-100	90
0	90
168	90
196	100
560	220
700	267
Linear interpolation is done when the value is in between points to determine the air flow requirement.	

The kg/s air flow requirement from the function generator is then multiplied by an operator changeable air fuel ratio SP within the Combustion Controller. This allows the operator to adjust the boiler air fuel ratio within limits of 0.9 to 1.2.

The stoichiometric air required is a fixed value based on the coal characteristics, i.e. 0.347 [kg Air/MJ Coal]. The basis of the formula for the total air required is presented in Eq. **[4.3]**.

$$\textit{kg/s air required} = \textit{fuel flow [MJ/s]} * \textit{Air/Fuel ratio [kg/kg]} + \textit{excess air [kg/s])} * \textit{stoichiometric air [kg/MJ]} \quad \textbf{[4.3]}$$

4.3.4.2 Fuel oil correction

The MJ input from oil combustion is determined by calculation. Per burner, the rate of oil consumption is 280 kg/h for low fire and 560 kg/h for high fire, which amounts to 4.67 l/min in low fire and 9.33 l/min in high fire as in Eq. **[4.5][4.4]**.

$$Fuel\ oil\ per\ mill = \begin{cases} 280\frac{kg}{h} \div 0.98\frac{kg}{l} \div 60\,\mathrm{min} = 4.76\ \frac{l}{min}\ (L) \\ 560\frac{kg}{h} \div 0.98\frac{kg}{l} \div 60\,\mathrm{min} = 9.52\ \frac{l}{min}\ \ (H) \end{cases} \quad \textbf{[4.4]}$$

The number of burners on load in high fire is multiplied by an oil flow rate of 9.52 l/minute and by 4.76 l/minute in low fire. The sum of the two flows is then converted to MJ/s by multiplying with a constant of 0.7023 as represented in Eq. **[4.5]**, which is subtracted from the boiler energy demand, leaving only the demand from coal.

$$\begin{aligned} Fuel\ oil\ energy\ addition &= 0.98\frac{kg}{l} * 43\frac{MJ}{kg} \div 60s \\ &= 0.7023\ \frac{MJ}{s} \end{aligned} \quad \textbf{[4.5]}$$

4.3.4.3 Total oil fired

The MJ input from oil combustion is determined by calculation. The number of burners on load in high fire is multiplied by an oil flow rate of 9.33ℓ/minute. Similarly the number of burners on load in low fire is multiplied by 4.66 ℓ/minute. The sum of the two flows is then converted to MJ/s signal by multiplying with a constant of 0.7023 *(0.98 kg/ℓ * 43 MJ/kg / 60s)*. This is deducted from the boiler MJ/s fuel demand to give the MJ/s demand from coal.

4.3.4.4 CV correction

The CV of the coal is calculated within the combustion controller. Firstly, the lambda SP is calculated by using the MJ/s SP and the output of the fuel to air curve. This relationship between the MJ/s fuel supply and the Kg/s air supply forms the initial calculated lambda SP.

The signal is passed through two first order delays, with the signal from the total air control signal passing through an additional lag-circuit. This ensures that the airflow will lag the fuel flow during down ramps, and prevents the furnace from being oxygen deprived which introduces a risk of explosion.

The measured lambda value is calculated by taking the average of excess O_2 which is measured by the O_2-matrix in the flue gas path. The deviation from the calculated and measured lambda SP is then sent to the combustion controller, which corrects the error in CV of the coal according to the amount of unused oxygen.

The unit is to run at 3% excess O_2 and the amount of excess O_2 is inversely proportional to the CV of the coal. This means that if the units' excess O_2 increases to 4%, which is 33% higher, the feedback control loop will lower the CV by the same fractional amount, given that the readings on the fuel flow and total air flow are correct. The amended CV signal is then passed through an integral controller which will drive the respective mills on load.

4.3.4.5 Number of Mills Online

The number of mills online is determined by the DCS by taking into account the "healthy" status signals received from the mills. Camden has five mills, four to be online to achieve full output and another on standby. The No. of Mills Online signal has a maximum of 4 and a minimum of 2.

4.3.4.6 Master coal SP to Mill bias

After the amount of FO energy has been subtracted from the master demand signal, the remaining MJ/s requirement is divided by the actual CV value, converting the signal to a global Kg/s signal required from coal. The demand signal is then divided equally amongst the online mills, and forms the input signal to the Mill Bias Controller.

4.3.5 Mill Bias Controller

This Kg/s demand from the Combustion Controller is then multiplied by the mill bias, an operator settable parameter that is limited between 0.9 and 1.1 in the OSPC located in the mill bias controller.

The signal is evaluated at a MAX selector with the minimum mill load, which is internally set at 3.1kg/s. The coal flow signal is evaluated again at a MIN selector with the maximum mill load, set at 7.5kg/s as in Figure 31.

The coal flow signal can also be biased by a DP controller, which checks the DP over the mill and increase or decrease the flow to prevent the mill from choking.

The output of the controller will form the Mill Load SP, which is sent to the Mill Controller.

The coal flow demand is then passed through a ramp rate controller that limits the rate of change between -15% and 22%. From the ramp rate controller, the demand signal splits to both the feeder control and the PA control.

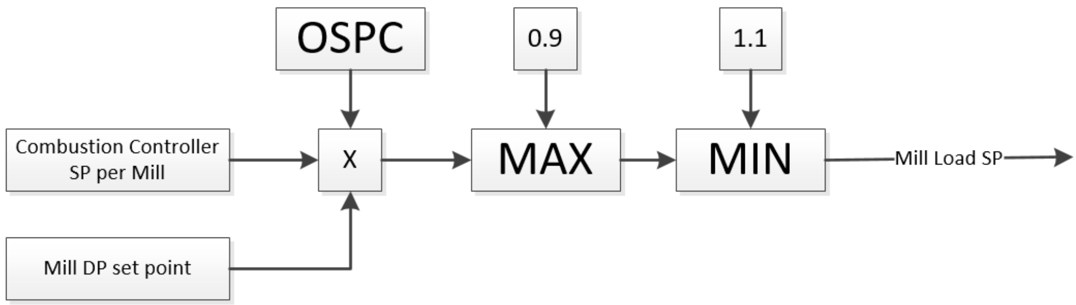


Figure 31 - Camden Mill Bias Controller [32]

4.3.6 Mill Controller

The Mill controller receives the Mill Load SP and determines the required coal flow rate, while cross checking several protection functions and interlocks. The protection functions and interlocks include the following:

- Allowing the mill to be changed between automatic (receives SP from Mill Bias Controller) or manual (maintains current SP).
- Maintaining a minimum coal flow of 3.9 Kg/s

- Sub group checks such as bearing temperature and oil supply.

If all the above interlocks and protection functions' requirements are met, the controller outputs the Mill Load demand to both the FD fan Controller and Mill Feeder Controller and the PA Vane Controller through an integral controller.

4.3.7 Mill Feeder Controller

The output of the Mill Controller integral controller within the fuel demand SP controller is then added to the kg/s coal flow demand signal that will increase or decrease the demand signal to the mills, until the actual measured kg/s coal flow matches the calculated demand. This feedforward action will compensate for mills that may be on manual and not following SP, has non-zero differential pressure controller settings or has bias settings not equal to one.

The Mill Load Demand signal is converted to the individual feeder speed, taking the fuel from oil firing into account. It is crucial that the boiler fuel flow matches the demand for fuel, as excessive or insufficient fuel flow will cause the boiler pressure to become unstable, and could result in combustion instability and will have incorrect stoichiometric ratio as effect, reducing the efficiency of the unit. The fuel flow consists of required PF from the load controller as well as the energy added from the fuel oil.

To prevent the mills from choking, a differential pressure controller is used to determine the pressure drop across the mill. From the differential pressure controller, the kg/s coal flow offset is then added to the kg/s coal flow demand signal before it is converted to a feeder speed SP by dividing it with a feeder factor. This feeder factor takes into account the feeder speed constant (32.01rpm/60s), volumetric constant (0.03165m^3/rev) and a coal density constant (950kg/m3) as per DCS specification.

4.3.7.1 Drive control

The feeder speed SP is then compared to the actual feeder speed before the speed error is passed to a PID controller. The output of the PI controller is sent to a variable speed drive that alters the feeder speed according to the demand from the controller as in Figure 32.

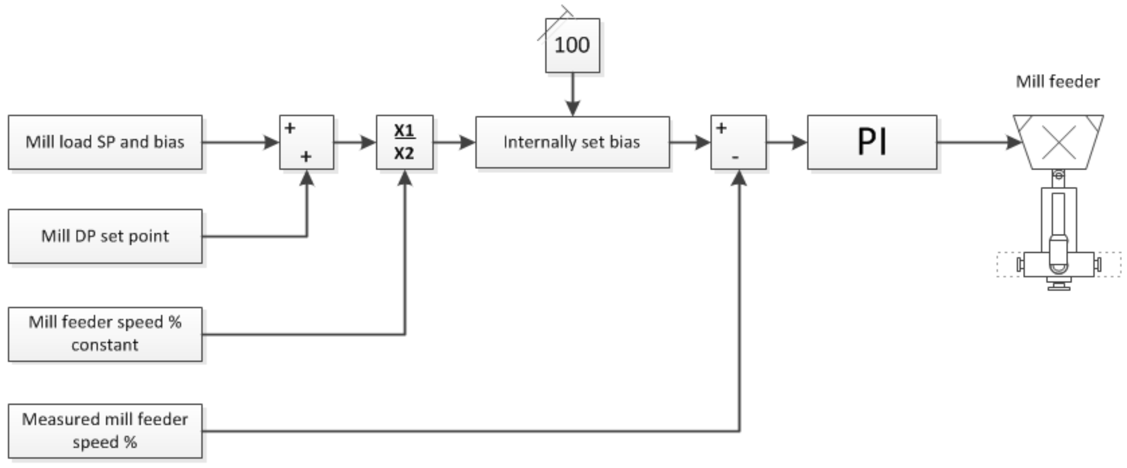


Figure 32 - Camden Mill Feeder Controller [32]

4.3.8 Mill PA Fan vane Controller

The Mill PA Vane Controller uses the Mill Load SP to determine the PA flow required to transport the PF effectively through the ducting to the furnace, ensuring that no PF settling occurs.

4.3.8.1 Mill Load line

From the Mill Controller the Mill Load Demand is passed through a feedforward response model. This is to ensure that the air demand models the coal flow dynamic reaction during up ramps and down ramps and is based on the mill feeder speed.

The output of the response model is then compared to the mill load line and converted to convert to an air flow SP by a linear equation as per Eq. [4.6].

$$PA\,SP\left(\frac{kg}{s}\right) = m(coalflow) + c \qquad \textbf{[4.6]}$$

For Camden the individual mill load lines is currently set as per Eq. [4.6] substituting coefficients as in Table 4-3. The load line results are displayed in Figure 33 and Figure 34.

Table 4-3 - Camden mill load line coefficients

Unit	m	c
1	0.664	8.55
2	0.664	8.55
3	0.664	8.55
4	0.664	8.55
5	0.6	7.77
6	0.664	9.05
7	0.664	8.55
8	0.664	8.55

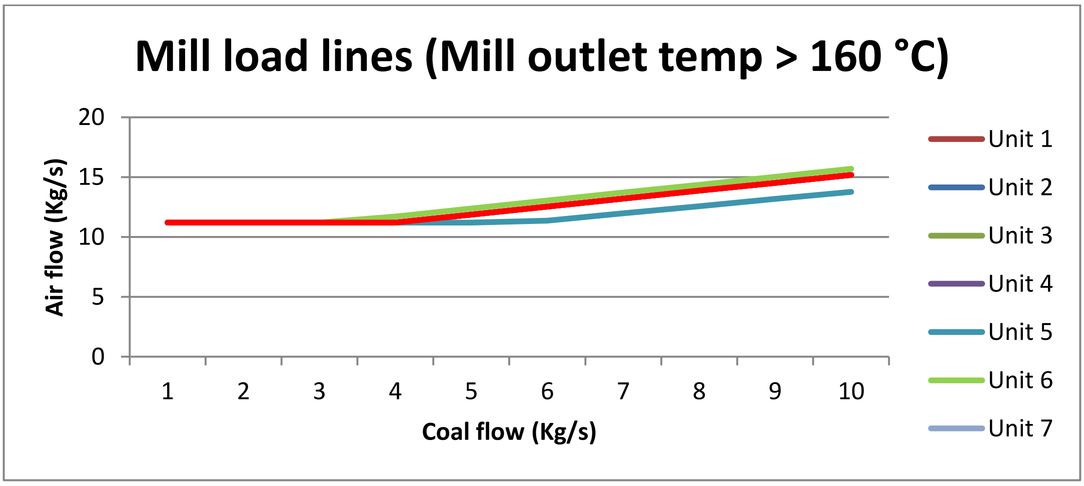


Figure 33 - Mill load lines (Mill outlet temp > 160 °C)

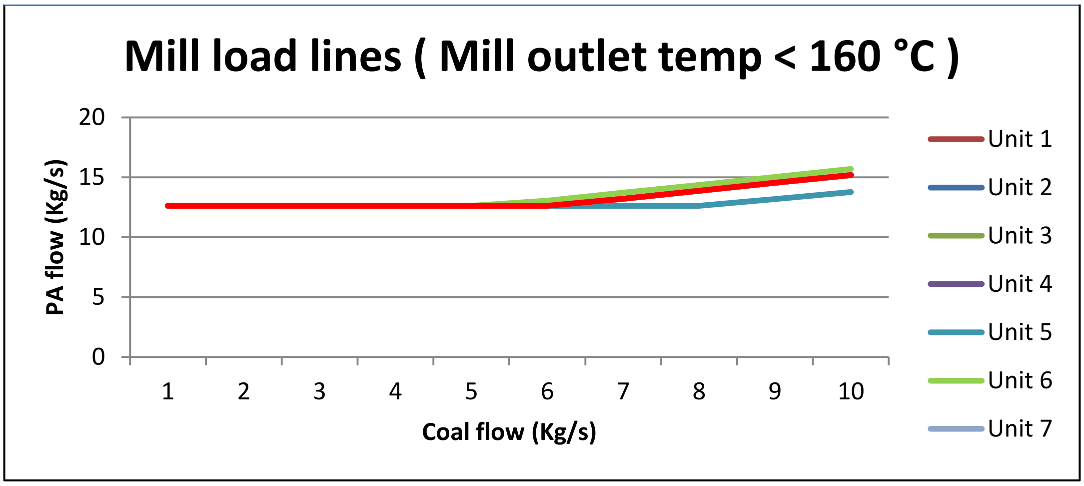


Figure 34 - Mill load lines (Mill outlet temp < 160 °C)

The kg/s PA SP from the Mill Load Line is then multiplied by a mill differential pressure correction factor, which is currently not in use and is set permanently to one.

4.3.8.2 Minimum PA flow

The flow SP is from the DP correction factor is then compared the minimum safe PA flow to prevent settling in the PF pipes at a MAX selector. The minimum PA flow SP is determined based in mill inlet temperature. With the mill inlet temperature below 160°C it is 12.6kg/s and with the temperature above 160°C it is 11.2kg/s.

4.3.8.3 Drive control

The PA flow SP is then compared to the actual measured PA flow before the error is passed to an ID controller for control of the PA fan inlet louver damper, as in Figure 35.

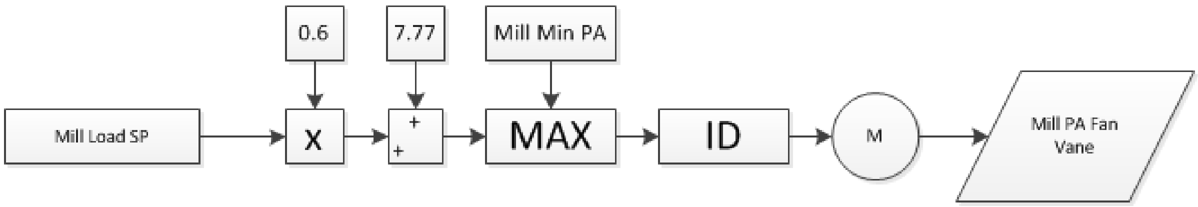


Figure 35 - Camden Mill PA Vane Controller [32]

4.3.9 Total Air Controller

The total air flow is controlled by firstly determining the actual coal flow rate to the boiler, and then supplying stoichiometric air plus a fixed excess air value. The air flow rate is then corrected by air fuel ratio control to ensure that the desired boiler outlet oxygen (O_2) is maintained.

The total air controller in Figure 36 calculates the deviation between measured and required airflow, which drives the FD Fans. A lag circuit is added for safety, with an additional first order delay of 30 s. An error strengthening circuit is also present, which has variable gain depending on the input SP deviation.

A PID controller corrects the deviation error before the signal is biased by an operator settable limit ranging between 90 and 130 %. The Air Fuel Ratio Correction from the Combustion controller is added to the corrected error before limited between 0.85 and 1.4. The controller outputs to the FD Fan Controller in order to drive the FD fan vanes.

4.3.9.1 Flow Deviation Strengthening Circuit

The Flow Deviation Strengthening Circuit has been implemented to drive the gain signal to the FD Fan Controller harder when the error is large and vice versa when the error is smaller. This is used to increase the responsiveness of the controller for large deviations in airflow SP's.

The circuit parameters have not been implemented correctly, and results in the Total Air Controller output to the FD Fan Controller staying at the maximum limit of 1.4, irrespective of the size of the error.

4.3.9.2 Down ramp lag circuit

The lag circuit has been implemented in order to increase combustion safety within the furnace. The lag circuit allows the circuit to follow SP during up ramps, but during down ramps will ensure that the airflow demand lags the fuel demand. This reduces the chance for the boiler to become oxygen deprived and decreases the chance for explosion due to unstable combustion.

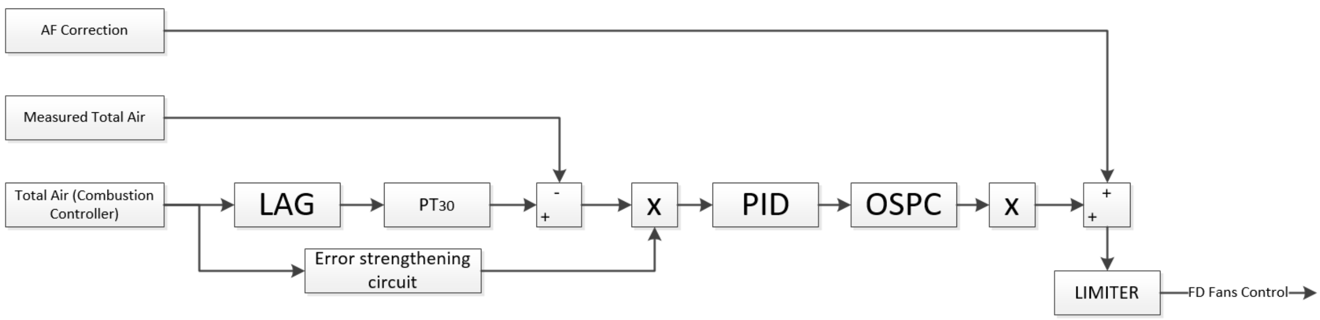


Figure 36 - Camden Total Air Controller [32]

4.3.10 FD Fans Controller

The FD Fans Controller in Figure 37 ensures that the FD Fans are driven to meet the total air demand required for stoichiometric combustion, taking into account the CV of the coal, leakages and the gain introduced by the Total Air Controller.

The deviation between the filtered airflow and SP is passed to a fan load distribution circuit from where it drives the FD fan vanes through a PI controller.

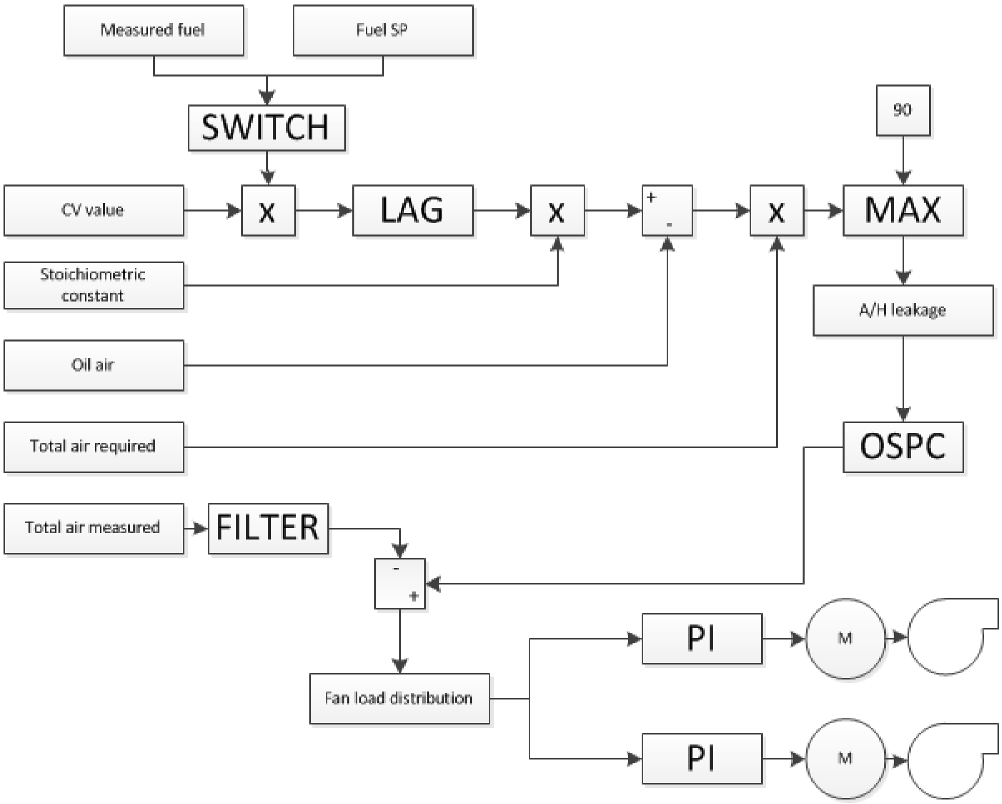


Figure 37 - Camden FD Fans Controller [32]

4.3.10.1 Total air SP formation

The total air SP is calculated by either using the measured or SP coal required to meet demand and multiplying it by the CV of the coal, converting the Kg/s coal flow signal to a MJ/s energy demand signal.

The total air required for combustion is then calculated by multiplying the MJ/s value with the stoichiometric ratio for the combustion of coal, resulting in a Kg/s air demand.

The calculated air demand SP is then evaluated against a minimum air flow demand of 90 Kg/s before the signal is sent to the air heater leakage calculation.

4.3.10.2 Air heater leakage

While research is ongoing to determine the exact air heater leakages at different loads, the logic implemented currently determines air heater leakage as a linear percentage of the total required airflow SP.

The air heater leakage is calculated as a fixed fraction of 8 % the air requirement, and is then added to the air flow requirement to form the unit total air flow kg/s SP, which is sent to an OSPC allowing the operator to introduce signal gain if necessary.

4.3.10.3 Fan load distribution

The unit total air flow SP is compared to the total air flow measured at the inlet of the FD fans. This creates an air flow error, consisting of the deviation between total air required and actual air flow. The total air flow measurement is calculated by summing the average of three measurements in the LH duct with the average of three measurements in the RH duct.

The calculated air flow error is then multiplied by 0.7 (response dampening factor that compensates for the fact that two DGs will respond together to correct for the error), before passing through a two way switch that tracks a different error signal should the boiler be in purge mode. The error is then strengthened by 0.3 if only one DG is in service before a bias constant is subtracted. The bias constant can either add or subtract to the error signal to either increase or decrease the air flow from the DG. The bias constant will always be the inverse of the other DG in service, allowing the operator to favour either one of the DG’s in an attempt to balance back end temperature.

4.3.10.4 Drive control

After the fan load distribution has been conducted, the error signal is then sent to a PI controller that drives the FD fan RVC in either direction.

4.3.11 Secondary Air Controller

The Secondary Air Controller is responsible for adjusting the dampers on either side of each of the individual burner rows. This distributes the total combustion air required to each of the burner rows to sustain stoichiometric combustion.

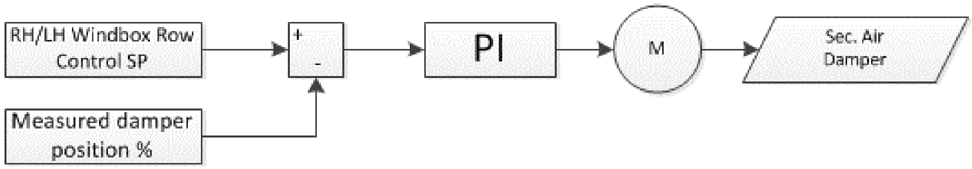


Figure 38 - Camden Secondary Air Controller [32]

4.3.11.1 Secondary air SP formation

The SP for the secondary air dampers are calculated by taking the coal flow SP received from the Mill Controller. The coal flow SP passes through a lag circuit with values equal to the lag introduced in the total air controller, which allows the controllers dynamics to act in accordance.

From the Lag circuit the coal flow signal is converted to a vane position by a function generator. The vane position can be strengthened by 80 % if the alternate DG is not on load. The vane position outputs to both LH and RH SA windbox controls.

4.3.11.2 Drive control

After the SA SP has been calculated it is compared to the current vane position which results in an error. The error can be biased individually for the LH and RH vanes independently.

The error signal is then sent to a PI controller that drives the dampers on either side of the burner rows in either direction.

4.3.12 Furnace Pressure Controller

The Furnace Pressure Controller (ID Fan Cane controller) function is to maintain the furnace pressure within safe operating ranges. Too low pressure can cause the furnace to implode, where high furnace pressure can cause flames to escape. Furnace pressure is typically set to -100 Pa.

The furnace pressure is inherently an extremely noisy signal and is pre-filtered by a discrete non-linear filter. The pressure deviation is reduced if both vanes are on automatic, as each vane will share the controlling task.

The Furnace Pressure Controller compares measured furnace pressure to SP and sends the error to PI controllers controlling each of the ID fans.

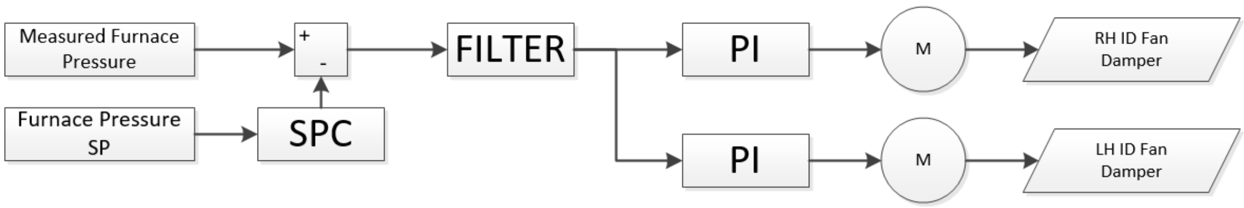


Figure 39 - Camden Furnace Pressure Controller [32]

4.3.12.1 Error calculation

The measured furnace pressure is compared to a furnace pressure SP received by the operator. The difference in passed to a filter, from where an internal settable gain can be introduced if the ID fans underperform.

4.3.12.2 Drive control

The filtered signal with gain is then sent to a PI controller that drives the dampers on either side of the flue gas exit paths.

4.4 New burner and control philosophies

The Steinmüller SM V burner has been selected to be installed at Camden power station and requires an updated control philosophy in order to operate within its design specification. These changes to the existing control logic will be made in parallel with the installation of the new burners.

The new control philosophy will entail moving away from total air being measured at the FD fan exit, and will maintain a windbox pressure of 2.5 kPa at LH and RH windbox exits. By using the pressure at the exit of the air heater, the leakages induced by the air heater do not have to be estimated in the control, thus ensuring closer to required stoichiometry for the combustion of the PF.

SA will be distributed by using pressure measurements in the individual windbox rows. This will be achieved by installing additional pressure measuring devices in the individual windbox rows, and control the SA dampers by maintaining pressure ratios based on predefined pressure drop calculations over each of the burners.

The configuration of the new burner will rely on 5 controllable devices to achieve four different firing modes. These control devices per burner are:

- Perforated drum (static setting)
- Secondary air swirler (static setting)
- Core air fan (on/off binary control)
- Core air 1 damper (full analogue control)
- Core air 2 damper (open/close binary control)

The four different firing modes the burner will operate in are:

- Both coal and oil burners out of service (off)
- Coal burner out of service with oil burner in service (on)
- Both coal and oil burner in service
- Coal burner in service with oil burner out of service

A further 2 controllable devices ensure overall combustion stability by controlling the total air flow rate as required from the boiler combustion controller. These two devices are:

- Left and right hand windbox dampers (x5)
- Left hand and right hand force draught fan vane control

The updated logic to meet the requirements of the new burners is given in the following section.

4.4.1 New Combustion Controller Logic

The new control philosophies that will be implemented at Camden will require a few new controllers and some controllers logic' to change. The new control philosophies are predominantly to the SA control per burner row and windbox pressure, with minor changes made to coupling controllers such as Total Air controller, FD fans controller and Combustion controller.

4.4.1.1 Minor Controller changes

Table 4-4 - Minor controller changes

Controller	Amendments
Total air controller	1. Lead action will be added to airflow calculation 2. Nonlinear filter will be removed
FD Fans controller	1. Boiler load vs. windbox pressure will replace boiler load vs. air demand curve 2. Lead action to be added to existing lag circuit. 3. Limiter added to DG fans to maintain maximum current drawn under 85 A, preventing the fans from entering overload conditions.
Combustion controller	1. SP changed from 3 % oxygen content in the flue gas to 3.5 %

4.4.1.2 SA flow controller

The Boiler Row SA flow controllers will replace the existing SA controllers. The controller receives the mill coal flow SP as its primary input to calculate burner row pressure. The mill coal flow SP is then passed through a lead-lag circuit; this ensures airflows to lead coal flow during up ramps and lag coal flows during down ramps.

The signal from the lead-lag circuit is then passed through a first order process time delay, from where it is multiplied by the measured CV value to convert the signal from Kg/s to MJ/s. The MJ/s signal is then multiplied by the stoichiometric ratio, with the total air required for combustion (per mill) as result.

The total air required for combustion (per mill) is then multiplied by the correction factor which is calculated in the Total Air controller, as in section 4.3.9. Both the mill PA flow and the amount of air required for fuel oil combustion is then subtracted, leaving the total air required SP by the SA supply from the windbox, as in Figure 40.

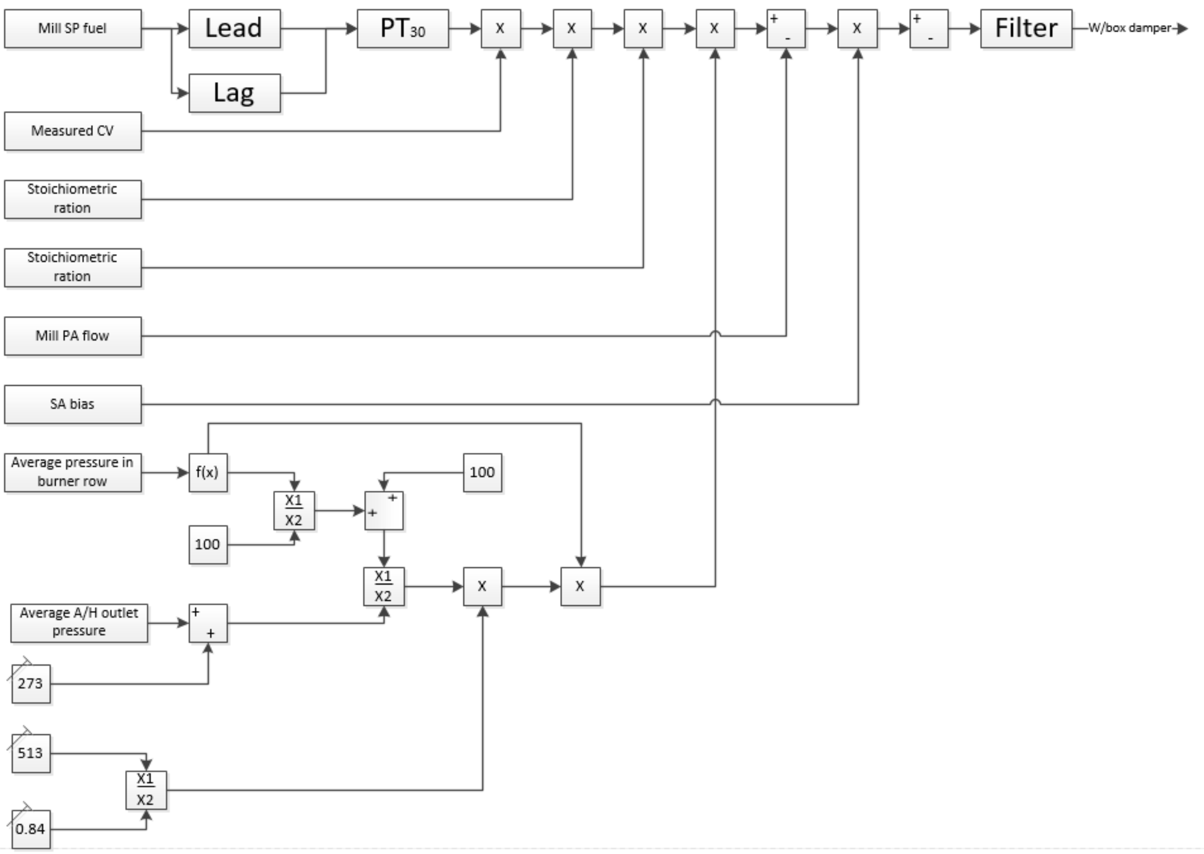


Figure 40 - SA flow controller (Low-NOx) [33]

4.4.1.2.1 SA damper biasing

Biasing of the SA flow is done via an OSPC, as displayed in Figure 41. The OSPC has values between 0.9 and 1.1. The bias is subtracted from the LH SA damper position SP, and added to the RH SA damper position SP, as given in Eq. **[4.7]**. The biasing is utilized in the drive control.

$$DG\ Damper\ position\ \% - 2(BIAS) = RH\ DG\ Damper\ position\ \% \qquad \textbf{[4.7]}$$

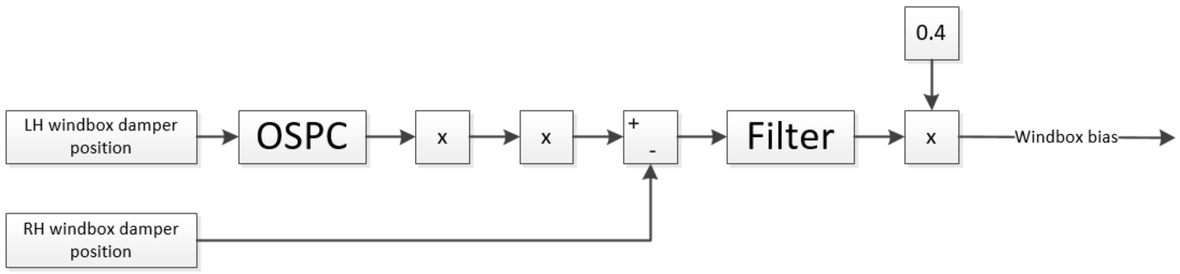


Figure 41 - SA bias (Low-NOx) [33]

4.4.1.2.2 Drive control

The SA dampers per burner row receive their percentage SP's from the Boiler Row SA controller. The biasing is subtracted from the LH damper position SP, and added to the RH damper position SP. From the biasing the signal is passed through a PI controller which drives the secondary air dampers.

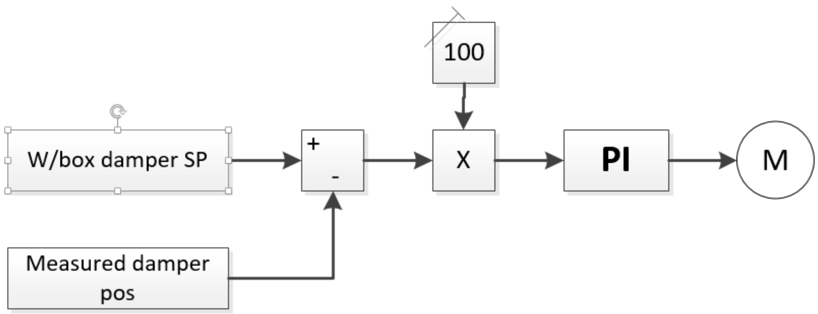


Figure 42 - SA drive control (Low-NOx) [33]

4.4.1.3 Windbox pressure Controller

The Windbox pressure controller will replace the current FD Fan controller. The Windbox Pressure Controller calculates a windbox pressure SP by comparing the boiler load demand fuel signal to predetermined points of a function generator, ranging from 1.5 kPa to 2.5 kPa. A bias is then introduced to the pressure signal allowing operators to bias windbox pressures evenly, as displayed in Figure 43. The biased pressure SP is compared to air heater outlet pressures, creating an error signal.

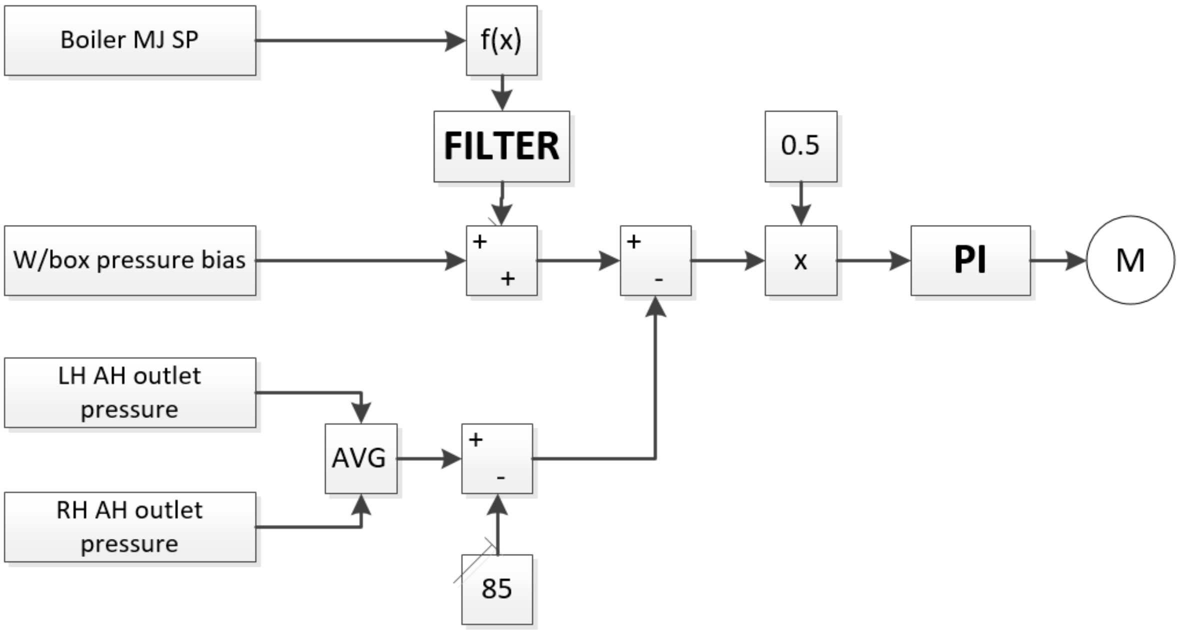


Figure 43 - Windbox pressure control (Low-NOx) [33]

The required error signals are then sent to both the LH and RH FD fan damper controllers. An additional strengthening of 30% is added to the signals if either of the DG's are offline.

4.4.1.3.1 Drive control

The FD Fan dampers are driven by a PI controller. The PI controller received the error signal calculated which drives the FD fan dampers.

5. Implementation of combustion control model

The Camden combustion control model has been implemented using two platforms, Matlab® and Flownex®. Matlab® was used on an experimental basis with the option of integration with Flownex® [34]. However, the complete control model was implemented using Flownex®.

The decision on which platform to use was influenced by the software used to develop the thermo-hydraulic model of Camden's' fuel, air and flue gas circuits. Sections 5.1 and 5.2 describes how the software was utilized to model Camden's control system.

5.1 Matlab®

The Matlab® model has been built to accommodate control loops in contrast to modelling individual controllers as has been done in Flownex®. After implementation within Matlab® it was evident that modelling individual controllers would ensure easier testing, troubleshooting and operation.

S-functions and subsystems were mainly used in the development of the model. Subsystems allows for creating components similar to compound components in Flownex®. This allows for grouping of calculations within the relevant control loop. S-functions are custom written C scripts, which executes the code when the model is run. The control loops were coded within the S-functions.

5.1.1 Control loops

These loops cover the entire boiler operation, however, being a testing ground no interface to PID control has been catered for. No provision for ID fan control has been made, as the furnace pressure control can be run independently from the rest of the model. The Matlab® control model is available in Appendix D - .

A brief description of the loops [15] that were implemented is as follows:

5.1.1.1 Unit coordinator MW SP to Boiler MJ/s input SP

The loop uses the calculations from the Unit Coordinator and Load controller as described in sections 4.3.2 and 4.3.3. The loops calculate the Boiler Load Demand fuel signal by converting the MW demand signal to a MJ/s signal using the unit efficiency.

The MJ/s signal is compared to unit capability to ensure the furnace operates within bounds. The Boiler Load Demand signal drives both the fuel and air circuits.

5.1.1.2 Boiler MJ/s fuel SP to Coal feeder speed

The loop drives the mill feeder speed calculated from the Boiler Load Demand Fuel signal. The loop contains calculations from the Combustion Controller, Mill Bias Controller, Mill Controller and Mill Feeder Controller, described in sections 4.3.4, 4.3.5, 4.3.6 and 4.3.7.

The Boiler load demand signal is compared to the current CV of coal from the Combustion controller, which results in a KG/s coal flow demand. The demand is then divided between the amount of mills online and results in a required mill feeder speed.

5.1.1.3 Primary air flow

The primary air flow loop calculates the required flow to transport the PF to the furnace, as in section 4.3.8.

5.1.1.4 Boiler Total air flow

The boiler total airflow loop calculates the stoichiometric air requirement for combustion, taking into account leakages and excess air. It receives the current rate of PF transported to the furnace from the online mills' feeder speeds and supplies air accordingly. The loop follows calculations as in the Total Ai Control, FD Fan Control and Sec Air Windbox Control in Sections 4.3.9 and 4.3.10.

5.2 Flownex®

The boiler control model was implemented within Flownex®, which allows verification of the capability of the software and will facilitate easy integration between the control and thermal-fluid models.

The control philosophies as described in Section 4 were used and implemented in Flownex®. The implementation has been done for both the flow control- and pressure control regimes, with comparison to actual plant data only done with flow control, as system response results are not yet available.

With the flow test results showing accurate results, the newly designed pressure control was implemented in Flownex®. The implementation was successful, yet various techniques had to be used in integration as the complete system was fairly sensitive to transient changes. The table below is an indication of common components/techniques used in the construction of the model, and is applicable to all controllers:

Table 5-1 - Description of commonly used Flownex® components

Component	Description
Rate Limiter	Rate limiters are used as integrators. The standard integrator within the Flownex® library requires inputs for both upward and downward integration, and would have required additional logic to utilize correctly. The rate limiters can be set to first order, which provides the same response as an integrator and works for integrating both upwards and downwards.
DCS AI/AO	The DCS AI/AO's are used as input/output nodes throughout the model. They provide easy accessibility between the controllers as well as between the control model and the thermal-fluid model. DCS AI/AO has been positioned similar to the Siemens control diagrams, with inputs on the left and outputs on the right.
Scripts	The scripts were used where custom calculations have been performed, or where the amount of Flownex® components needed to construct the calculation will clutter the model. Scripts run custom C code, which can be written and tailored according to the process requirements.
Compound components	Compound components where repetition in controllers occurred, such as the Mill Feeder Controller, SA Pressure Controller etc. The compound components can be

	seen as a separate drawing page within Flownex® running its own set of components.
View nodes	View nodes are indicated with a “V” on the left side of the component. View nodes are nodes which replicate through some controllers where necessary, and provide the same output throughout the model.

The implementation of a few boiler controllers will be discussed in the section below, as well as techniques used to allow for optimal integration response. The remaining controllers are available in Appendix E - .

5.2.1 Controllers

5.2.1.1 Unit Coordinator

The Unit Coordinator and Load Controller have been implemented together as both controllers are actively used in the calculation of the Boiler MJ Fuel demand SP, as described in Sections 4.3.2 and 4.3.3.

Figure 44 indicates the controller setup in the Flownex® environment and is sectionalised for easy reference.

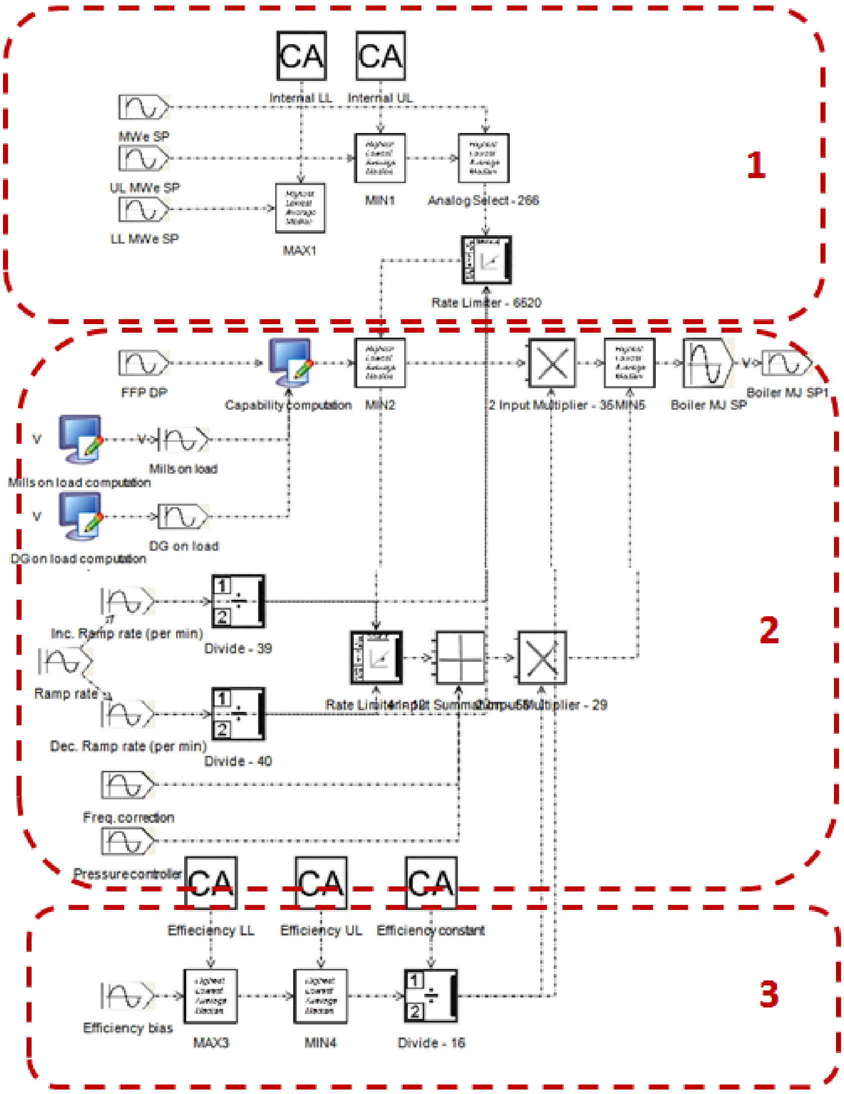


Figure 44 - Unit Coordinator and Load Controller in Flownex® environment

1. The first segment of the controller receives the Unit Load SP from the operator and compares it with standard MIN/MAX selectors ensuring the Unit Load stays with in DCS specified limits. The signal is then passed through a rate limiter, limiting the rate at which the unit will ramp up or down depending on the SP
2. The unit load is compared with the capability, which is determined by the amount of auxiliaries online, as well as the FFP DP over time. The capability is calculated by custom C scripts, which outputs signals between 0-210 MW. As there is no integration with the water circuit at this stage of the model, only DCS AI provisions has been made for the Frequency Correction Controller and the Pressure Controller.

3. The bottom segment is a clamping circuit to keep unit efficiency in range. The unit efficiency is used to convert the MW demand signal to a MJ requirement from fuel.

5.2.1.2 Combustion Controller

The implementation of the Combustion controller as in Section 4.3.4 is given in Figure 45, with a description that follows.

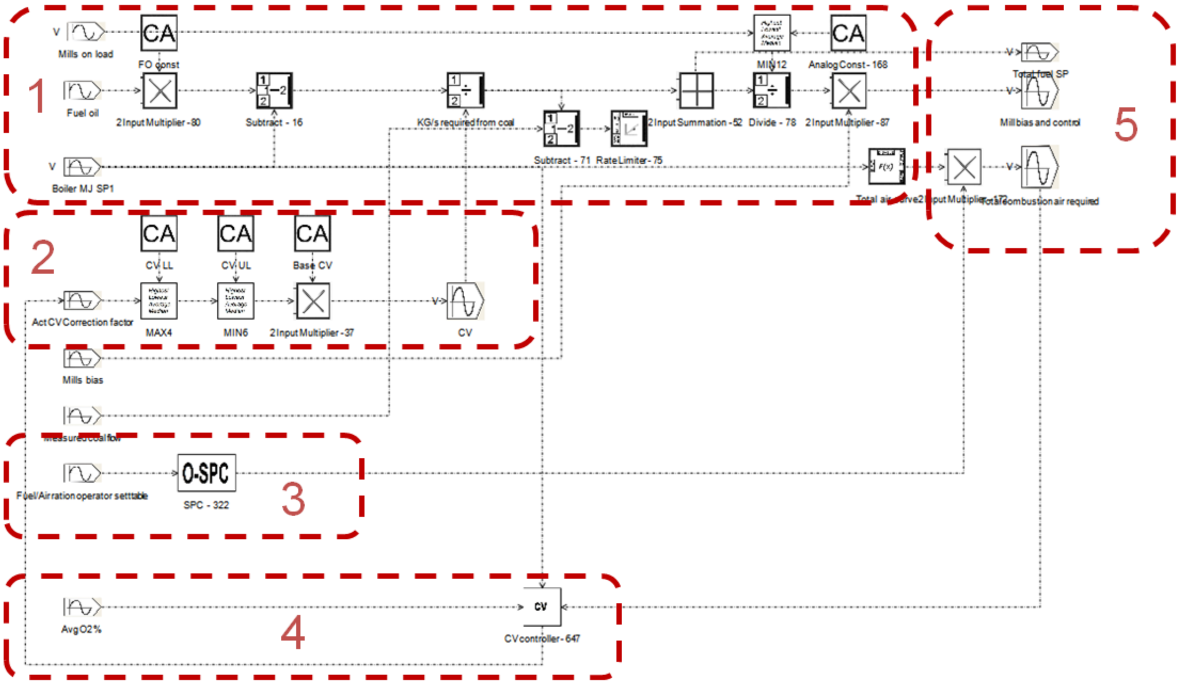


Figure 45 - Combustion Controller in Flownex® environment

1. The DCS AI view nodes were used to transfer data from the Unit Coordinator and Load controller, and where used in calculating the required coal flow per mill. The mills on load is compared to a MAX selector with a constant of 4, ensuring that the calculations will be based on maximum four mills, even though the model has the capacity to run all 5. The signal outputs as Mill Bias and Control, a view node which will be used in the calculation of the online mill feeder speeds.
2. This section consists of an input from the CV compound component which is then limited by a clamping circuit. The output is used to determine the amount of coal required to meet the unit MJ demand.

3. The Operator Settable Fuel Air ratio is an operator input from the Admin Panel which is used in the calculations for the amount of air per kg of coal. This input is only being used in the calculation of the CV in the CV controller, and not in any further calculations in the new control regime, as the new control only maintains pressure at the windbox inlets and does not calculate flow rate into the furnace.
4. The CV controller is a constructed compound component and will be further discussed in Section 5.2.1.2.1.
5. This section contains the DCS AO of the Combustion controller. They are used as view nodes in other controllers, such as the Mill Feeder Controller which will be discussed in the next chapter.

5.2.1.2.1 CV Controller

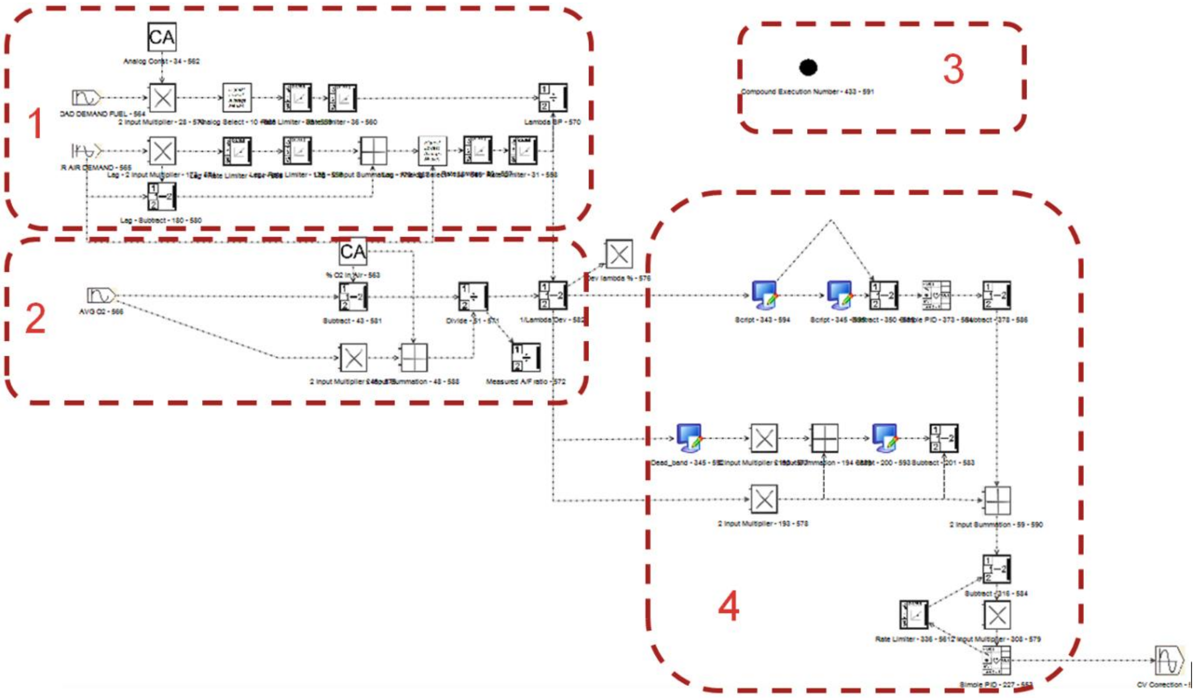


Figure 46 - CV Controller in Flownex® environment

1. The first section uses DCS AI to receive the Boiler Load demand Fuel. This is done by assigning the exposed properties of the compound component to components in the compound itself, exposing the properties of the compound component. Several rate limiters were used in series to create higher order filters. The output is compared to the average O_2 % in the flue gas.

2. This section uses mathematical components to determine the O_2 output which is checked against its SP.
3. The execution number is used to provide the compound component with an execution number in the system. The execution number determines the sequential point at which the compound will be executed. An execution number of -1 was used, which inherits the execution number from coupled components.
4. For the nonlinear filter, several custom scripts were used to create deadbands. Compound deadband components were created, but compound components could not be initialized within other compound components. The two deadbands in parallel off different responses depending on the magnitude of the input. The DCS AO is used as a CV correction factor output node which is exposed to the output section of the compound component.

5.2.1.3 Mill Feeder Controller

The Mill Feeder Controller as described in Section 4.3.7 is given below. The controllers receive its input from the Mill Bias and Control view node in the combustion controller. The compound component then calculates and outputs a mill feeder speed.

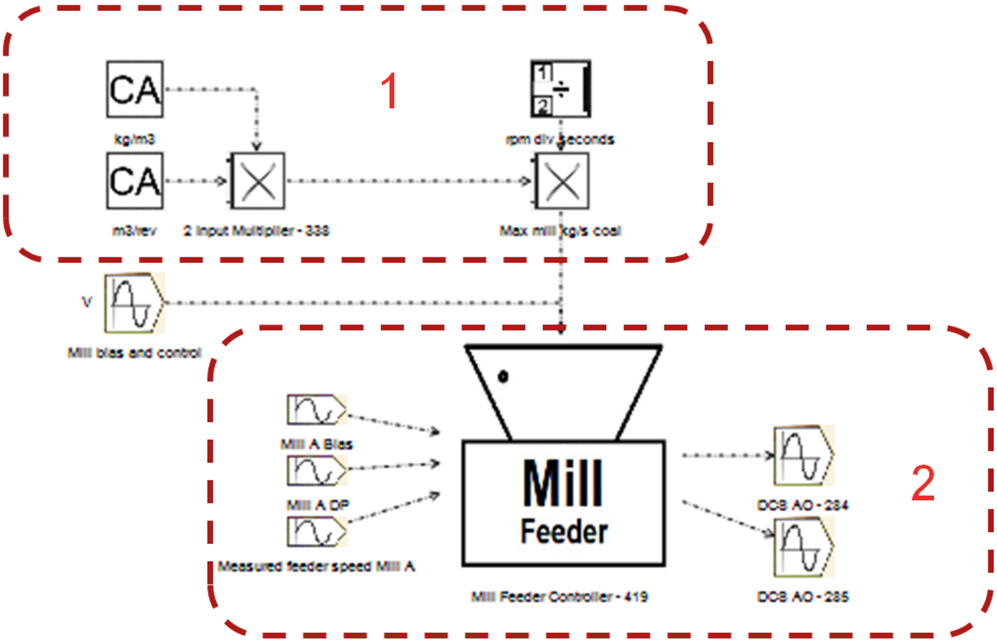


Figure 47 - Mill Controller in Flownex® environment

1. The first section indicates a mill feeder speed calculation constant. This calculates the mill feeder speed maximum from design specifications of the mill feeder, and outputs to the feeder speed compound component.
2. The Mill feeder speed compound component receives DCS AI from operator settable bias, the differential pressure across the mill (not currently in use at Camden) and the measurement of the current feeder speed. The outputs are tapped of at different points in the compound component using the compound exposers. The feeder compound component will be discussed in more detail in the section below.

5.2.1.3.1 Mill Feeder compound component

The mill feeder has been placed in a compound component. This ensures that all 5 of the mill controls are equal and eases the replication thereof. Figure 48 represents the elements within the mill feeder compound component.

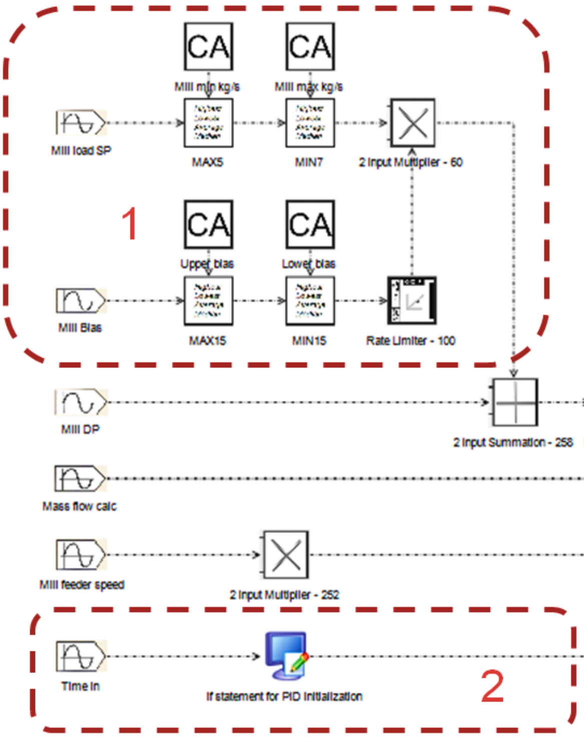


Figure 48 - Mill Feeder compound component in Flownex® environment

1. The compound component receives its SP from the exposer properties. The load SP is then limited in a clamping circuit by using MIN and MAX selectors,

ensuring that the mill load is between 3.63kg/s to 7.5kg/s. The load SP is multiplied by the bias which is also limited between 90 % and 120 %.

2. The if- statement for initialization is a hardcoded segment to assist the PID in order to initialize. The standard PID's in the Flownex® DCS library has a manual tracking value, but due to it not always functioning correctly a script has been written to manually set the lower limit of the PID.
3. The standard PID was used as it provides a manual tracking option, allowing the PID to initialize at a pre-determined value. This deemed useful as alternatively the PID would start at minimum value, and would cause the system to become unstable. Two outputs are available in both a mill feeder speed percentage and a kg/s signal.

5.2.2 HMI

The HMI's have been copied from the Siemens T2000 control system and inserted in Flownex®, which creates a familiar operating environment. Active labels have been created on top of the Siemens HMI image, which will indicate the coupled process variables. A navigation pane has been inserted in the top section of all the HMI's, allowing the user to navigate through the system effortlessly.

A custom HMI, the Admin Panel, has been built with added functionality, such as information and control over internal SP's, as well as the ability to trip boiler auxiliaries.

The majority of the HMI's are available in Appendix F - , with a few that will be discussed in the sections below.

5.2.2.1 Admin HMI

The Admin Panel HMI has been built to allow the user to interact with embedded control system variables and internal SP's. It also allows quick access to trip functions of auxiliaries to determine the system response in a transient scenario.

The labels on the Internal SP panel are directly coupled to the control system, and can be changed according to user preferences. This will be updated automatically and the response will be visible on the model results.

The mode selection allows the user to select between Simulator mode and Historic data mode. The Simulator mode will run the model according to the Unit Load SP in the Load Controller, which can be updated on the Unit Coordinator HMI. The response will then follow to meet set demand. Different trip scenarios can then be utilized to analyse the system response to load losses due to auxiliaries tripping.

When switched to Historic Data Mode, the unit will read the Unit Load SP from a predefined lookup table, and the results can be compared against plant data. The lookup table can be imported from VaView by selecting an appropriate dataset with the correct variable tags. Figure 49 displays the Admin Panel HMI.

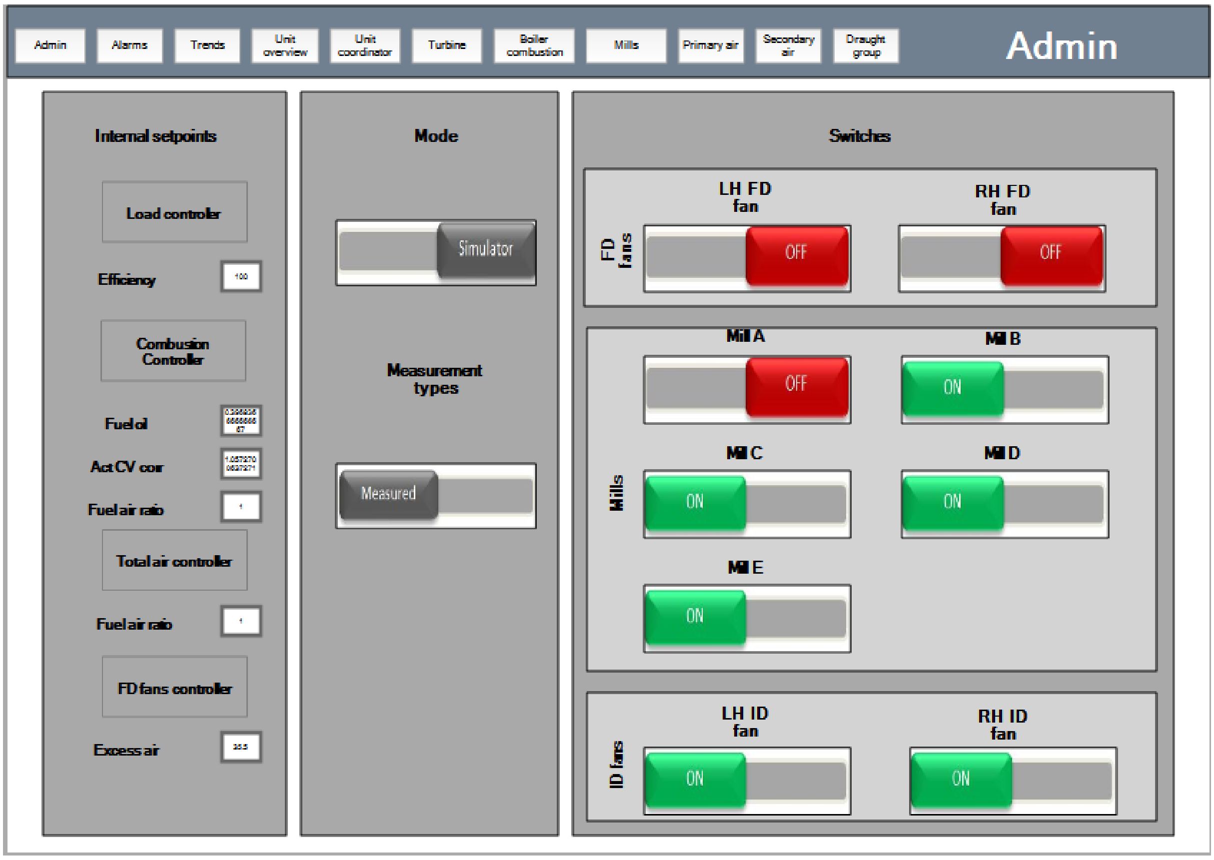


Figure 49 - Admin Panel HMI in Flownex® environment

5.2.2.2 Unit Overview

The Unit Overview HMI has been copied from the Siemens T2000HMI library. It indicates the overall status of the unit, such as total fuel-, steam- and air flows, online auxiliaries and information regarding the steam cycle which will be updated when the model expands.

As only static images are available from the T2000 system, sections had to be copied from different HMI displays indicating the state of the auxiliaries. The copied sections will have different frames associated depending on the state of the auxiliary and will be used to indicate on and off states. Figure 50 is a representation of the Unit Overview HMI.

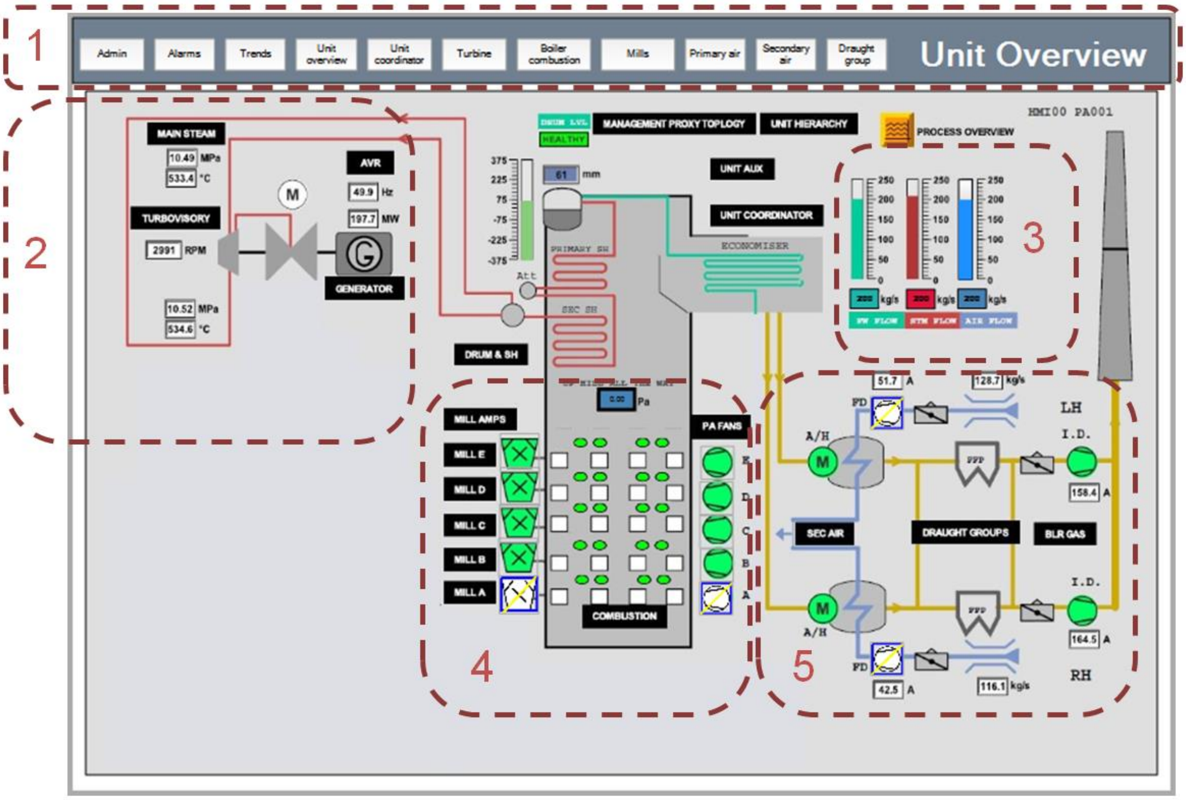


Figure 50 - Unit Overview HMI in Flownex® environment

1. The top section represents a navigation pane, allowing the user to easily navigate through different HMI screens. The navigation pane can be found on every HMI.
2. The unit overview includes current generator load, temperature and pressure. This is not part of the scope of this project, but provision has been made so that it can be added at a later stage.
3. This section indicates the total feed water, air and steam flows for the entire circuit. As with the generator load, this can be added when the waterside is added to the model.
4. This section indicates the online mill and furnace pressure. The display is coupled to the admin panel from where the auxiliaries can be switched on or

off. The furnace pressure updates from measurements within the thermal-fluid model, and also displays the SA flow measurement.

5. This section displays the current draught group status, as well as the ID fans which are currently online. Indications of the total air flow per FD fan are also available, which is measured in the thermal-fluid model and displayed on the HMI.

6. Simulation and results

6.1 Historic data mode

As the Low-NOx upgrade has not yet been complete, the controllers were tested against historic plant data available prior to the Low-NOx upgrade. The bulk of the control system will remain the same, with only the control of the FD fans and SA dampers that will change.

To validate the model, strategically selected historic values were used as inputs to the controllers. By using the simulation time as reference, the historic values can be acquired from the lookup table and used as inputs to the model.

By using the lookup table created, the inputs can be fed to the controllers and the outputs observed.

Thorough test has been conducted for each controllers at different points. By testing segments of the controllers propagating errors can be eliminated, as components in Flownex® had to be manipulated in order to obtain the same response as the controllers on the plant. The model responses were exported to Excel and empirically correlated.

The controllers have been tested at different transient scenarios. The historic plant data for controller comparisons was selected where all the relevant signals were healthy.

The results will be discussed in the sections below.

6.1.1 Combustion controller test results

The combustion controller has been tested against historic plant data with a transient scenario containing several mill trips within the sample period. The mill tripped twice and the results from the combustion controller calculations can be observed in Figure 51 to Figure 56.

The Unit load SP is displayed as a way to validate that the input into the model executes in the right timeframe. From the figure below it can be seen that the unit was running at roughly 550MW, after which the mill trip reduced the load to about 450MW.

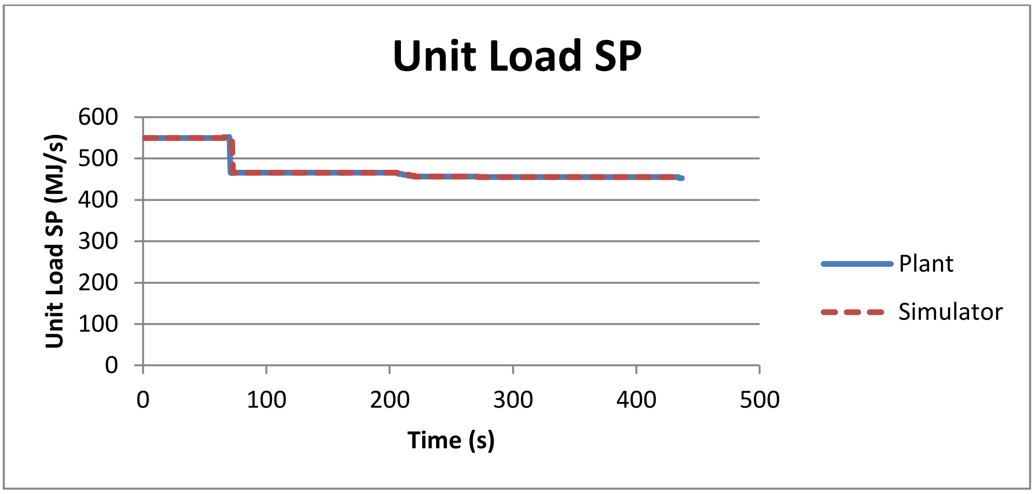


Figure 51 - Unit load SP input

The number of mills online is compared to plant data in the figure below. By comparing the historic plant data and the component output within the model, it can be seen that the calculations for the amount of mills online has been executed correctly. A mill trip can be observed at 80s into the simulation, where at 250s the mill is brought back into service and trips shortly thereafter. The loss in unit capacity will have a large effect on the unit and can be seen in the controller outputs.

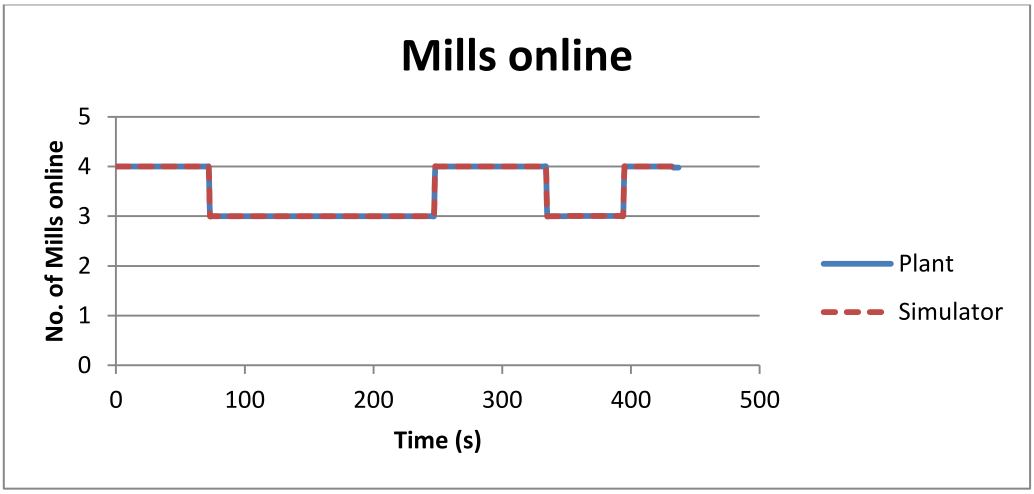


Figure 52 - Mills online input

The excess O_2 measurement value was used as an input to the system. This is a crucial input as it determines the amount of coal needed to meet energy demand. The CV input can be viewed in Figure 53.

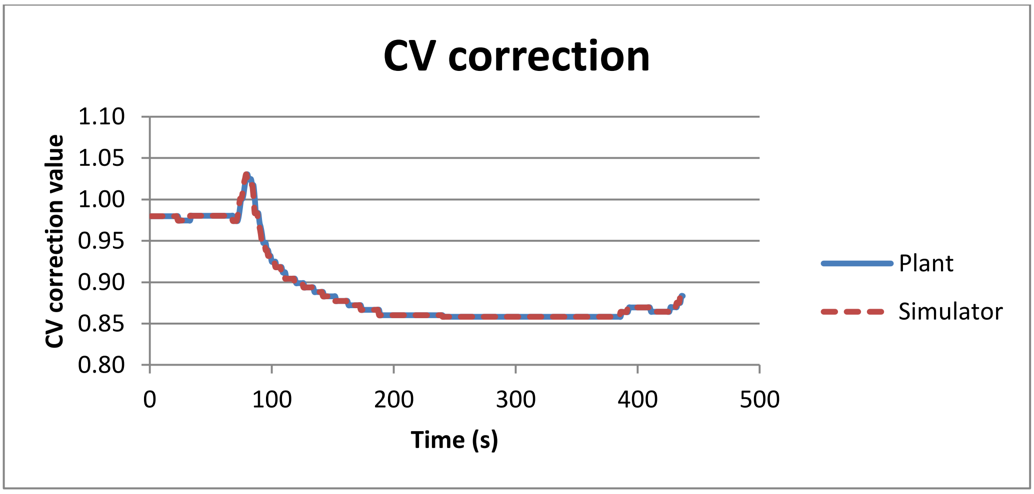


Figure 53 - CV correction input

The total air SP is derived from the boiler air demand curve. As can be seen in Figure 54, the total air calculation corresponds with the total air demand from historic data. A slight delay can be observed as the unit load decreases. This is due to the fact that the time steps chosen when simulation the model set at 1s for quick calculation, which will cause a short delay in the stepping of the model within Flownex®. However, amplitude and direction is in line with the historic plant data.

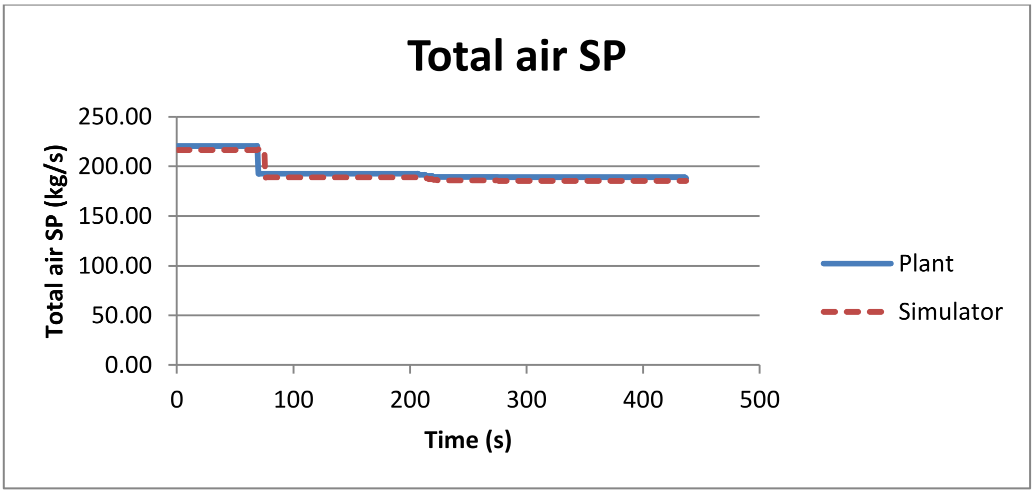


Figure 54 - Total air SP output

The total coal flow requirement, which is calculated by dividing the boiler load demand by the actual CV, is displayed in Figure 55. The slight delay at the start can also be contributed to the large time step factor as with the total air demand. Once again, amplitude and direction corresponds and indicates expected results.

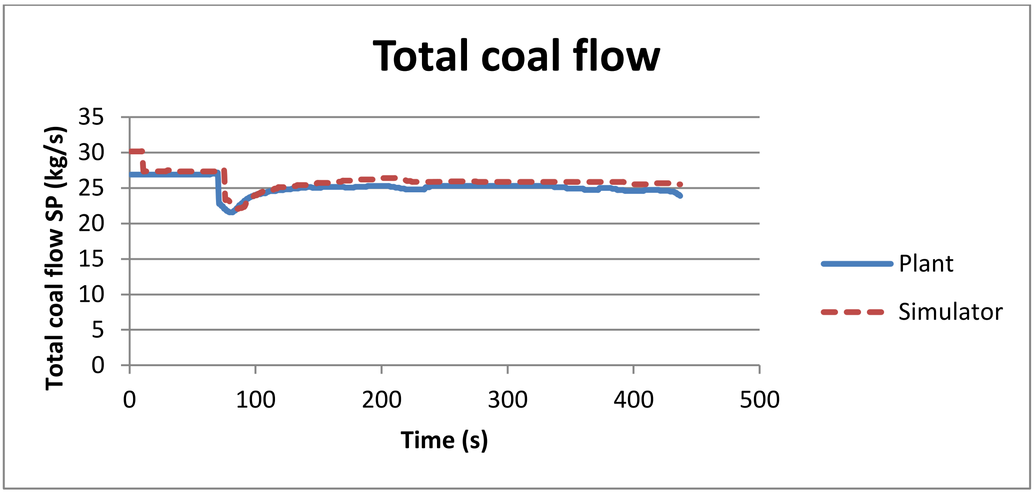


Figure 55 - Total coal flow SP output

The Mill bias and control is the required coal flow signal which is sent to the Mill Feeder Controller. This passes through a rate limiter, limiting the rate of change by the mill. From the figure below it can be seen that the rate limiter causes a momentary delay at 80s. As the rate limiter becomes active and gets closer to the input from the master coal requirement, the response starts to correlate with the plant data. The Mill Bias and control signal is crucial to the system, as it has a direct effect on the calculation of the secondary air in both the old and new logic.

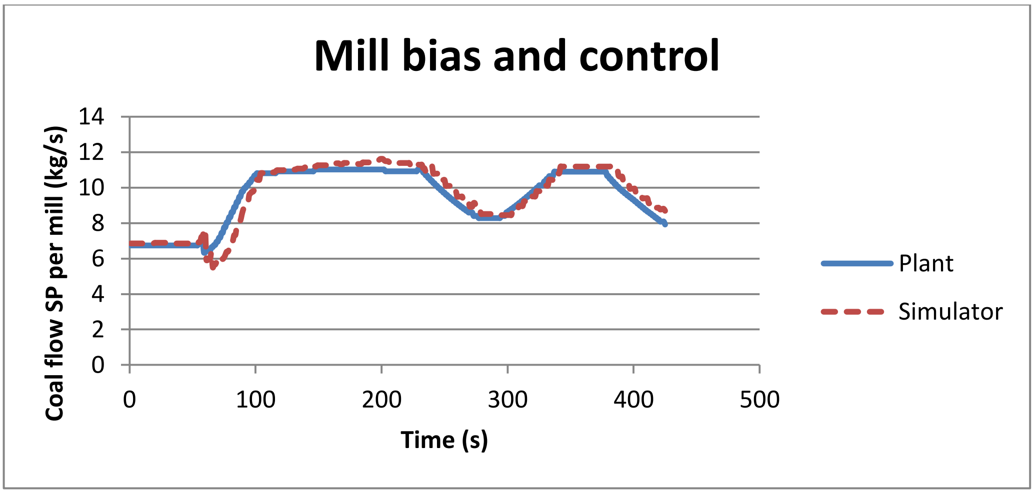


Figure 56 - Mill load SP output

6.1.2 Mill feeder test results

The mill feeder is crucial in the response of the entire system, as previously stated, the SP's for the SA and PA is derived from the mill feeder controller, at a point within the controller named Mill SP + Diff, located just before the error is sent to the PID. This output is considered as the main input for calculation within the SA and PA controllers. The mill feeder controller's test results are displayed in Figure 57.

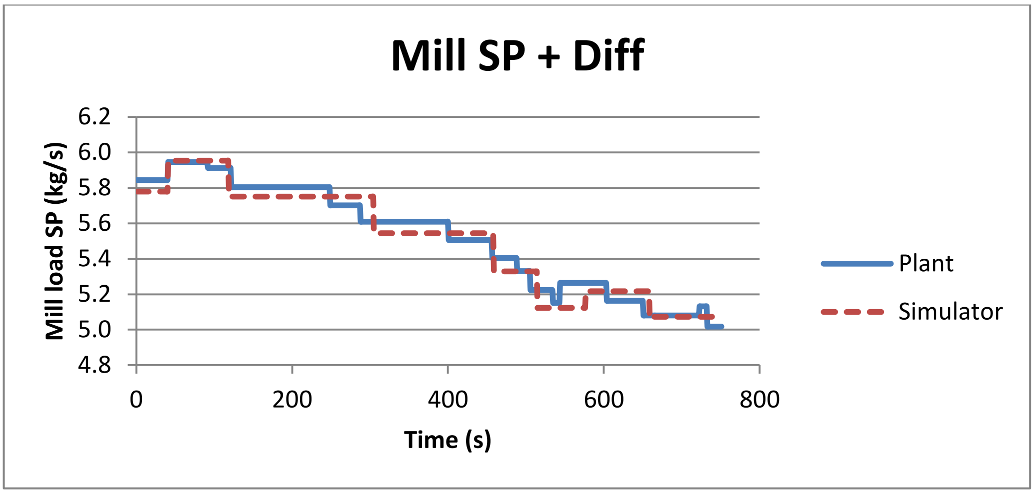


Figure 57 - Mill SP + Diff

A scenario of a typical load loss over time was chosen to test the controller. From the results it can be seen that the modelled controller follows the plant data trend. The output of the model ramps down at the same rate as the plant data.

The reason for the graphs showing slight discrepancies is because of the data available from the historian can only be accessed by an array of finite data points in contrast to the model where data can be extracted as per user specifications, thus it is possible to have sampling happen at different time steps.

6.1.3 PA controller test results

The PA flow SP is calculated by comparing mill SP to the mill load line. The PA controller in the Flownex® environment contains rate limiters which need to be populated at the start of the model. These rate limiters will even out as time progresses. The response in Figure 58 shows the PA control slowly decreasing the error as the rate limiters are populated. This will even out once the model has reached steady state.

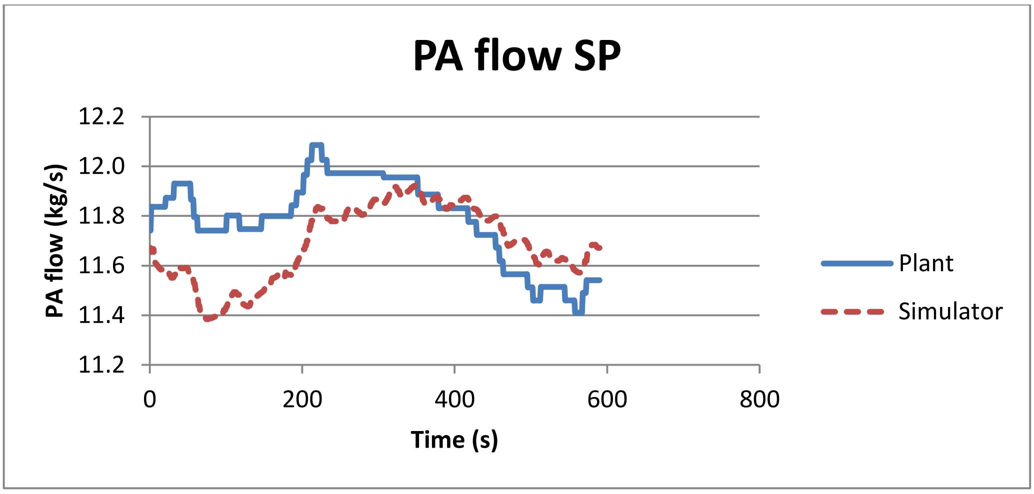


Figure 58 - PA flow output

6.1.4 Total air controller test results

The total air is used as a correction factor to strengthen the FD fan vane and SA damper control SP's. The controller outputs a bias between 0.9 and 1.3. From the results it can be seen that the models response correlates with the plant response. The total air controllers' test results are displayed in Figure 59.

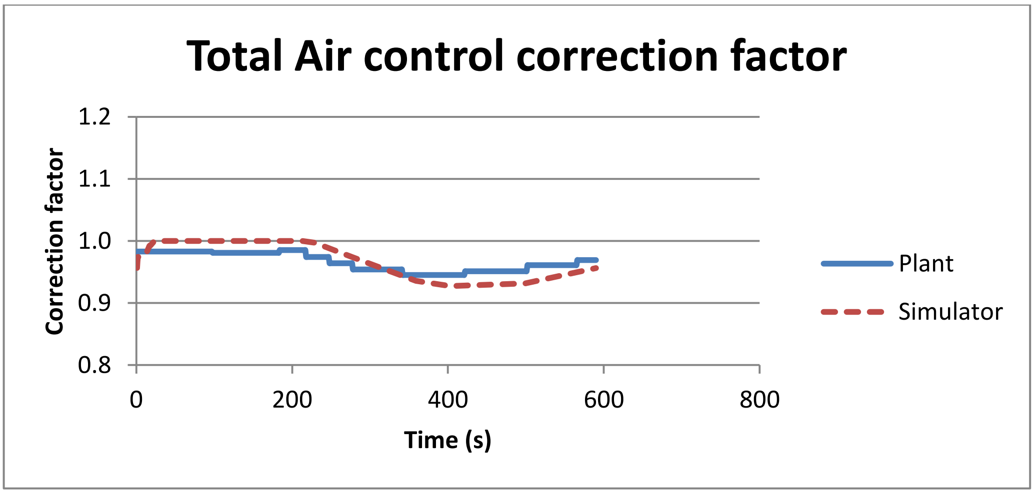


Figure 59 - Total air correction output

6.2 Simulator mode

By switching the simulator from "Historic Plant Data" to "Simulator mode", the model can be utilized as a fully functional engineering simulator.

In order to test for model robustness, several scenarios were set up in Flownex®. These scenarios allow for custom triggers to be inserted, which can change a property of a component at a user defined time. Two scenarios were created to view the controller SP's namely a multiple mill trip and a FD fan trip.

6.2.1 Mill trip

The trends in Figure 60 to Figure 64 displays a transient scenario of a Mill trip at 50 s when the unit was running at full load Maximum Continues Rating (MCR) at 200 MW with a Unit Efficiency set at 35 %. The Mills were biased individually at 90 %, 95 %, 100 %, 10 5% 110 % respectively from Mill A to E for illustrative purposes.

After the Mill trips, the unit capability is reduced by 25 %, which reduces the Unit Load SP and MJ/s energy demand by 25 % as displayed in Figure 60. The operator Load SP remains unchanged at 200 MW. The new MJ/s energy demand is sent to the Combustion Controller which is used in the calculation of the Master Demand signal.

By taking the CV into account, the Boiler Load Demand Fuel is converted to a total coal flow requirement SP, deemed the Master Demand signal. The Master Demand signal is then evaluated against the amount of mills online, which will form the coal flow requirement per mill as in Figure 64. The coal flow requirement per mill will be used to drive the PA and SA controllers. FO was activated at 80 l/h at 75 s, decreasing the coal flow requirement. The FO deactivated at 175 s and the Mill was brought back into service at 200 s.

The PA Controller's response in Figure 65 to the change in coal corresponds with the coal flow requirement trend in Figure 64. The primary air is calculated by referencing the coal flow SP to a Mill load line, with minimum flows of 11.2 kg/s and 12.6 kg/s, depending on the Mill inlet air temperature.

The total air SP displayed in Figure 63 follows the total energy requirement SP trend in Figure 60, with a reduction in total air requirement at 60 s and a gradual increase at 200 s when the mill was brought back into service.

The simulations results appear empirically correct as they follow relevant direction and amplitude.

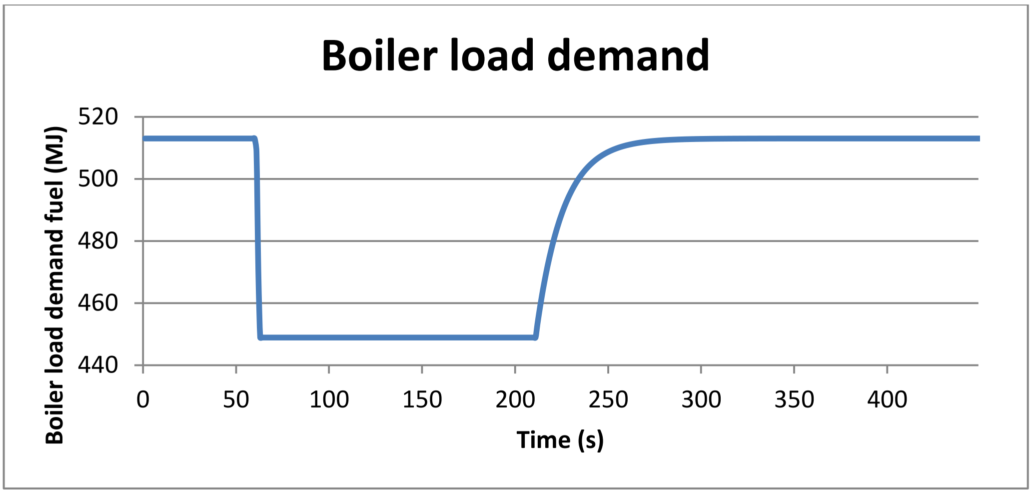


Figure 60 - Boiler load demand fuel (Mill trip)

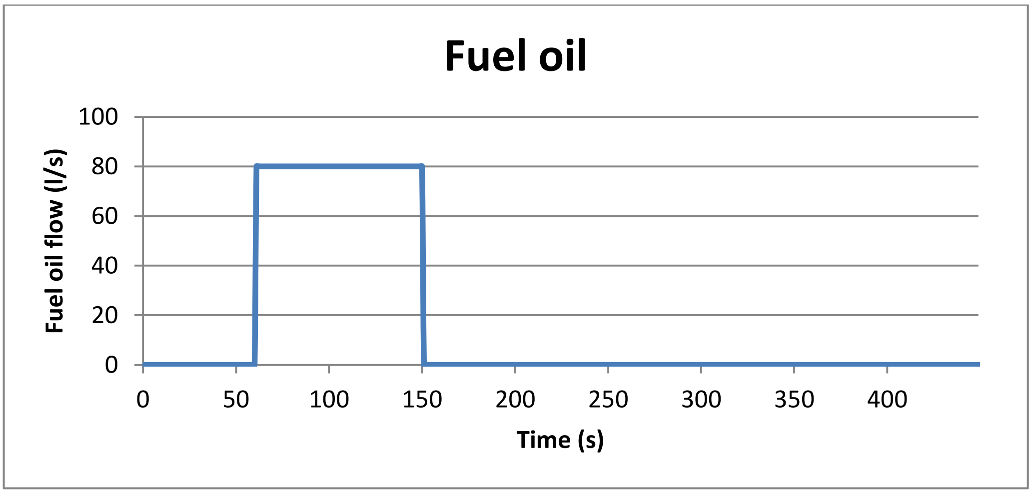


Figure 61 - Fuel oil (Mill Trip)

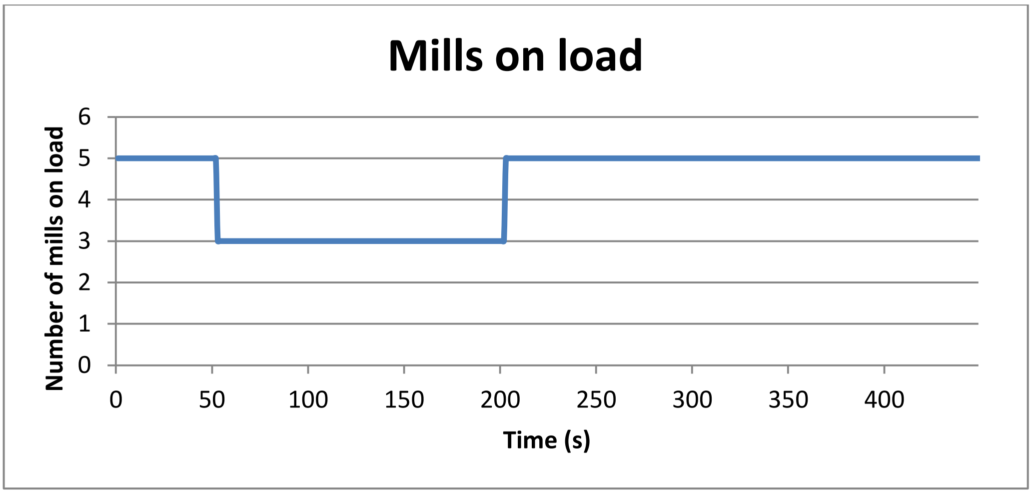


Figure 62 - Mills on load (Mill trip)

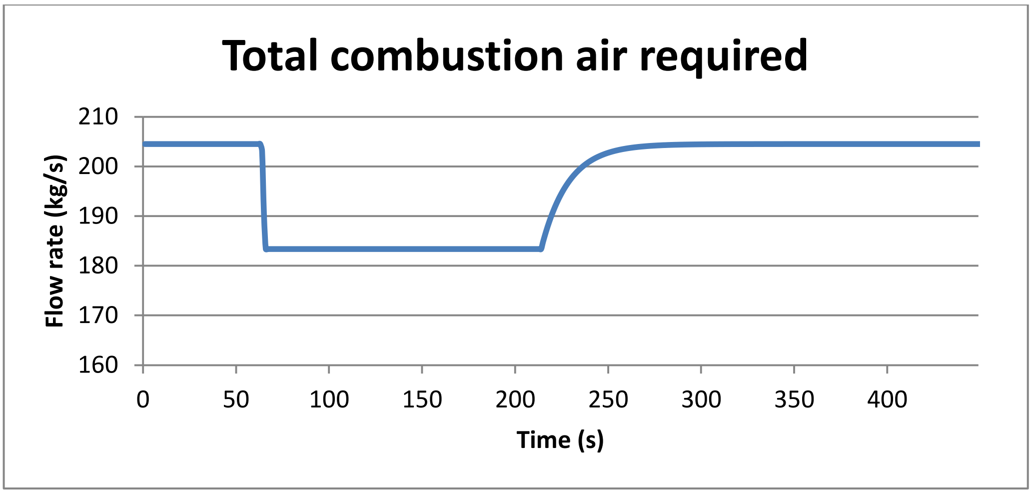


Figure 63 - Total combustion air required (Mill trip)

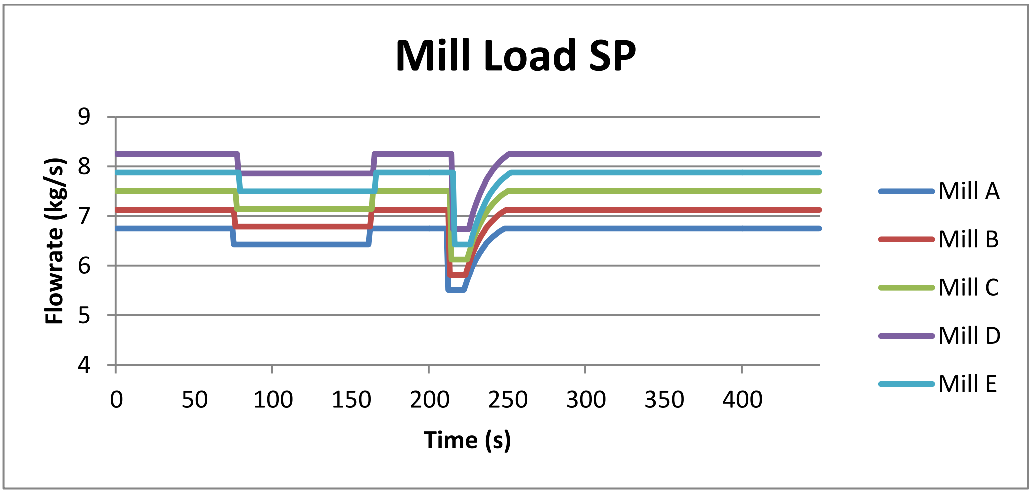


Figure 64 - Mill load SP (Mill trip)

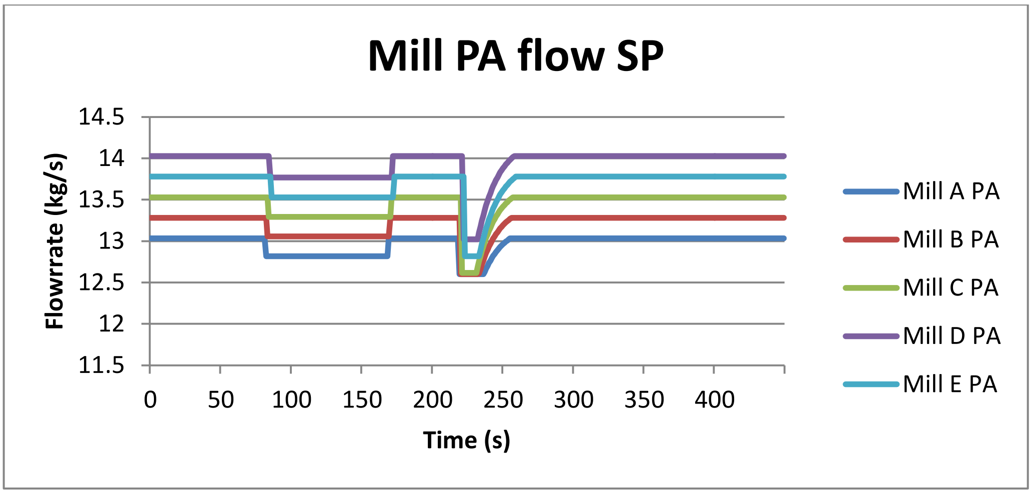


Figure 65 - Mill PA flow SP (Mill trip)

6.2.2 FD fan trip

The trends in Figure 66 to Figure 70 display a transient scenario of a single DG trip at 50 s when the unit was running at the same conditions as discussed in the mill trip section, while omitting the FO activation.

After the DG trips, the unit capability is reduced by 50 %, which reduces the Unit Load SP and MJ/s energy demand by 50 % as displayed in Figure 66. The operator Load SP remains unchanged at 200 MW. The remainder of the process follows the same steps to calculate the required coal, PA and Total Air flow rates. The FD fan was brought back into service at 75 s. The simulation results appear empirically correct as they follow relevant direction and amplitude.

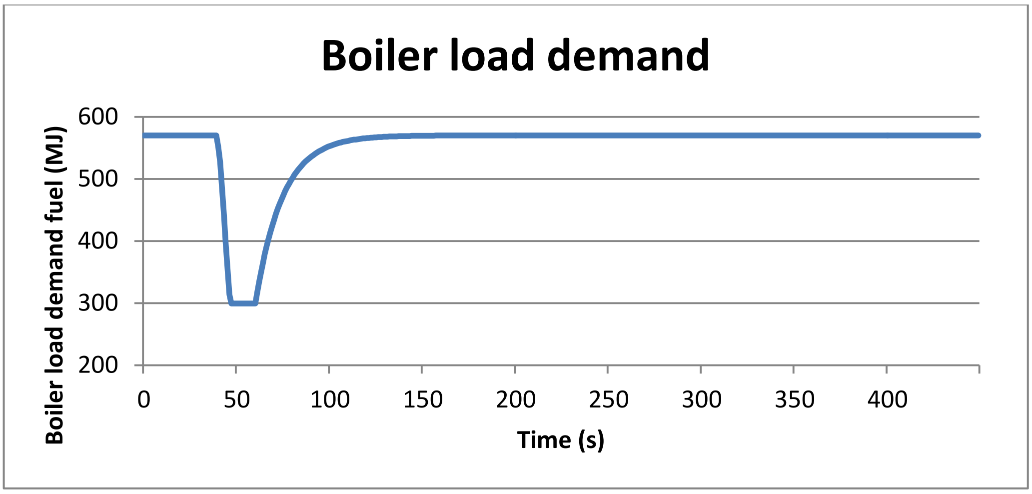


Figure 66 - Boiler load demand fuel (FD fan trip)

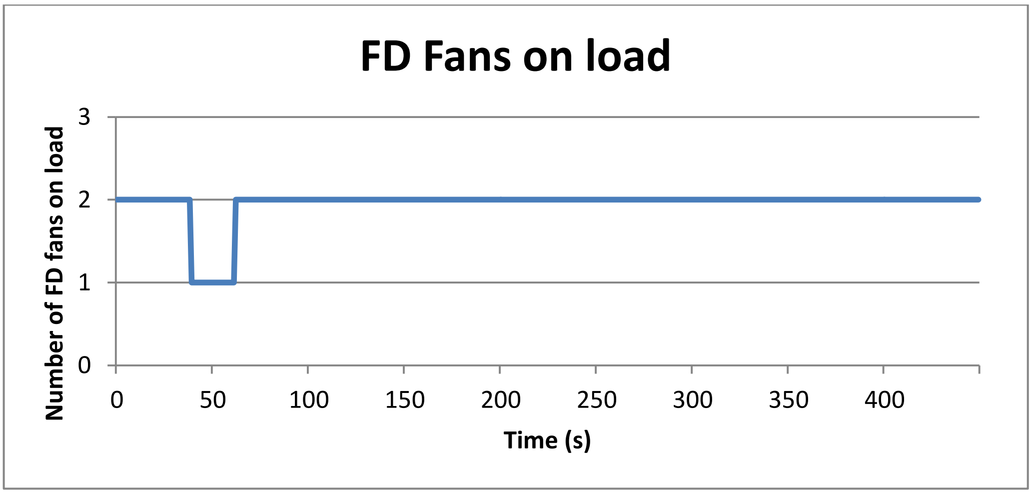


Figure 67 - FD fans on load (FD fan trip)

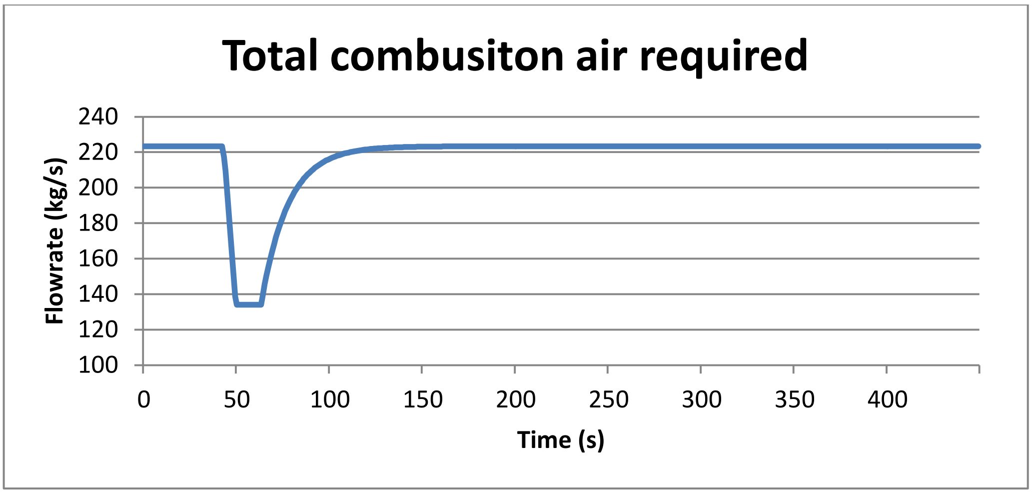


Figure 68 - Total combustion air required (FD fan trip)

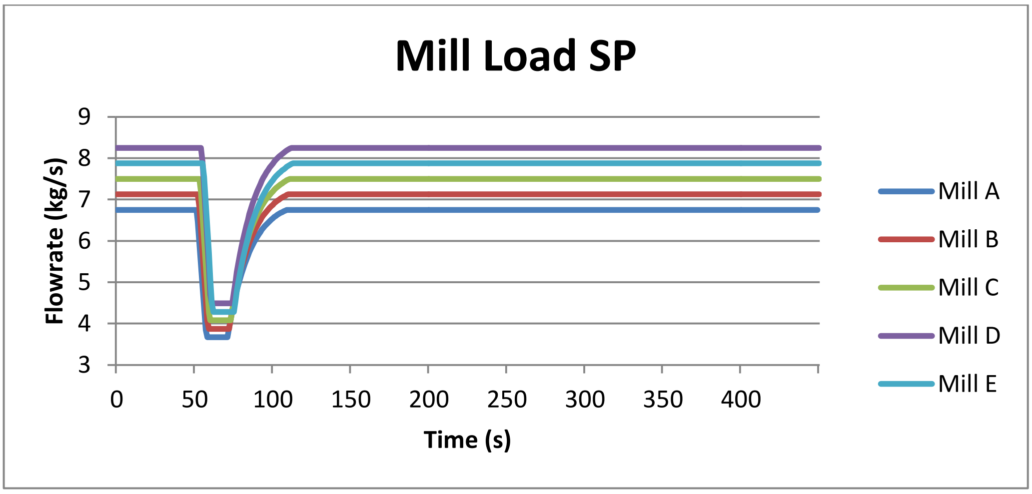


Figure 69 - Mill load SP (FD fan trip)

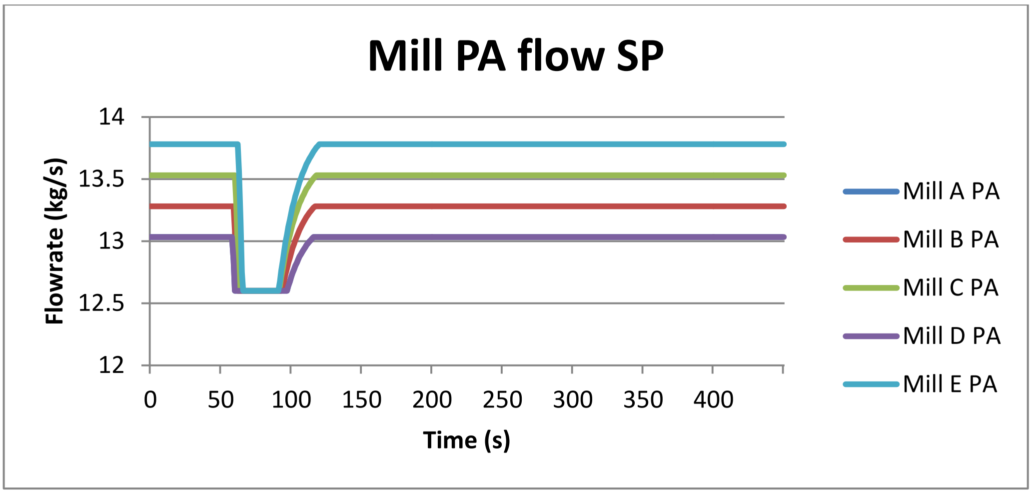


Figure 70 - Mill PA flow SP (FD fan trip)

6.3 Integrated thermal-fluid coupled model results

The model has successfully been integrated with a thermal-fluid model created by UCT [37], providing a complete system where responses can be viewed. The model has been constructed to view transient scenarios which cannot be tested at site, such as a load changes and FD fan trips, without taking the unit offline

The integrated model runs on the new control logic with the thermal-fluid model containing the low-NOx burners. The perforated plates allowing pressure drop at the furnace inlet has been set to 200mm within the thermal-fluid model. The responses for different transients can be viewed in the sections below.

6.3.1 Load change

The system response of a load change can be viewed in Figure 71 to Figure 78. The unit load has been ramped up from 160 MW to 175 MW. It can be seen that as the coal flow increases, the SA dampers responds by opening up further. This in turn decreases the pressure at the windbox inlets and ramps up the FD fan. The ID fans also ramps up to restore the furnace pressure to 84.9 kPa.

The values provided in the graphs are taken from the output of the thermal-fluid model, after the control philosophies have been applied to all the individual elements of the system.

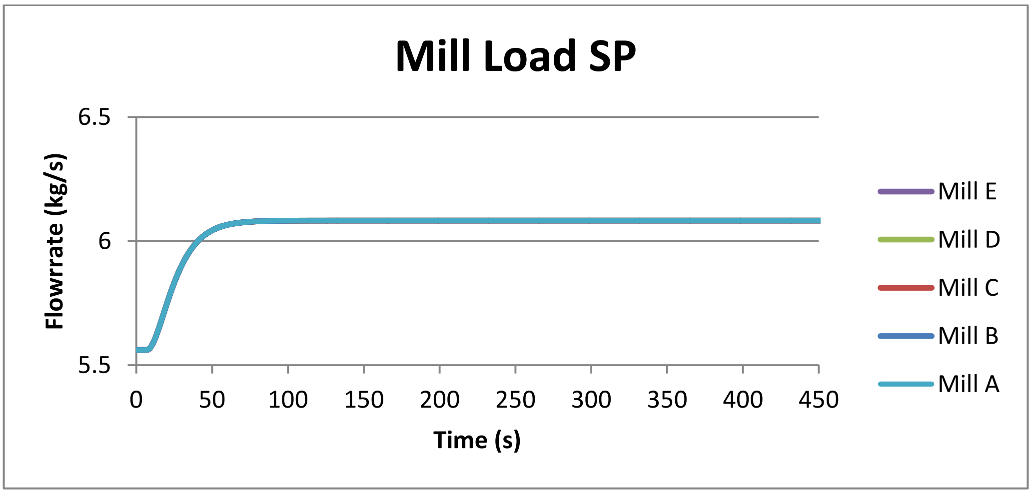


Figure 71 - Mill Load SP (Load Change)

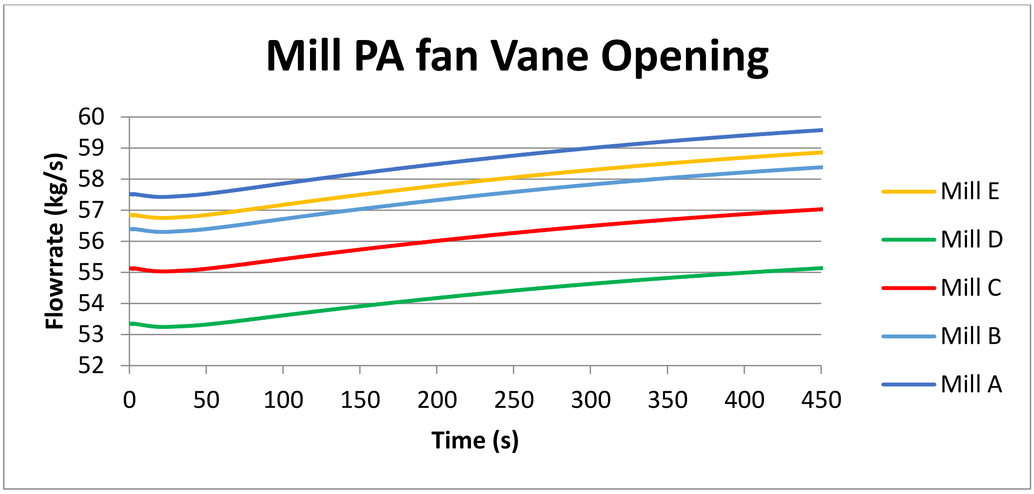


Figure 72 - Mill PA Fan Vane Opening (Load Change)

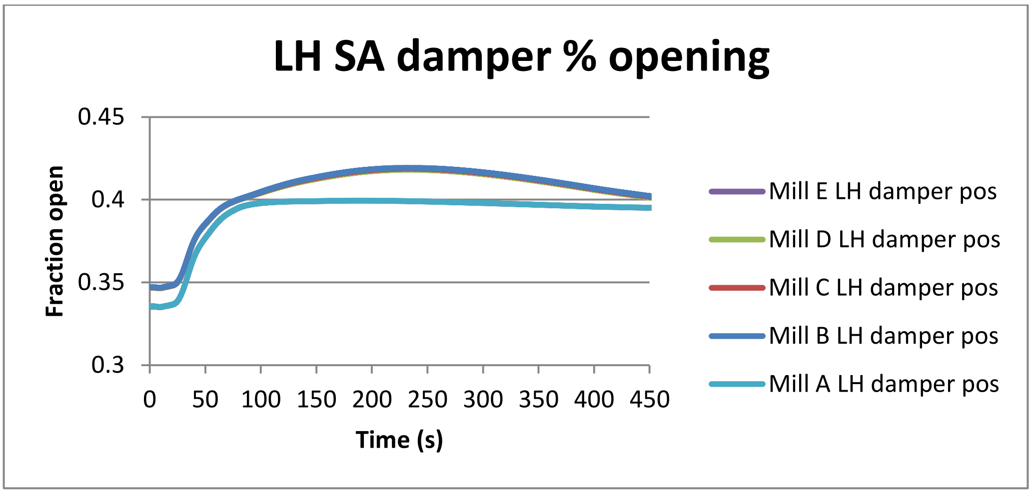


Figure 73 - LH SA damper position (Load Change)

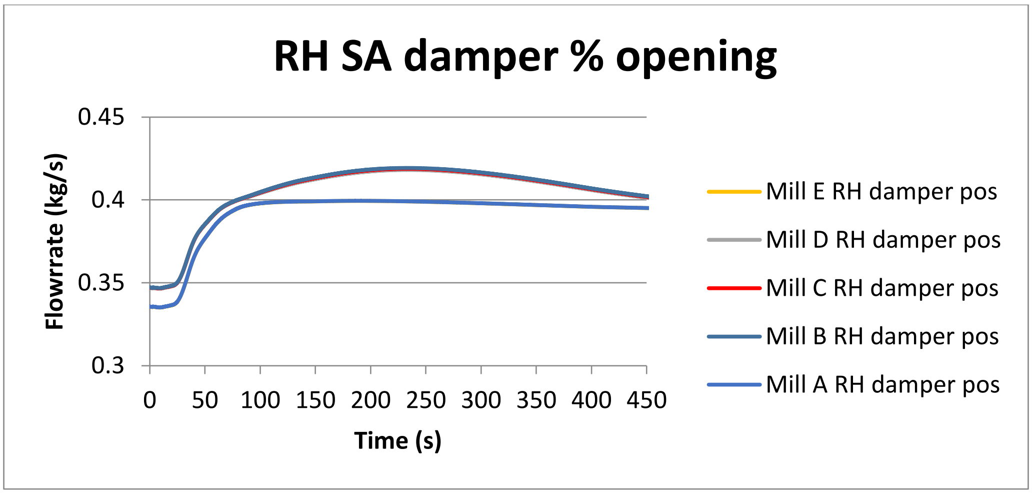


Figure 74 - RH SA damper position (Load Change)

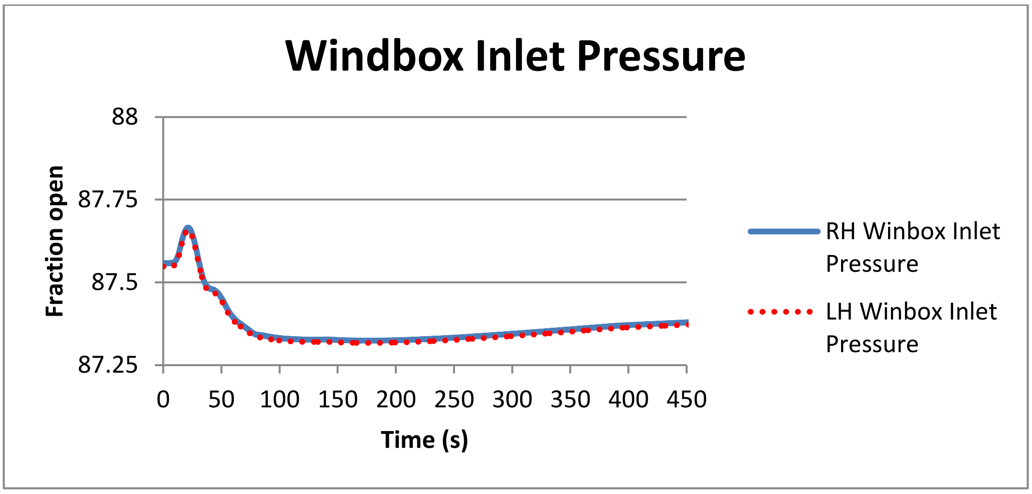


Figure 75 - Windbox inlet pressure (Load Change)

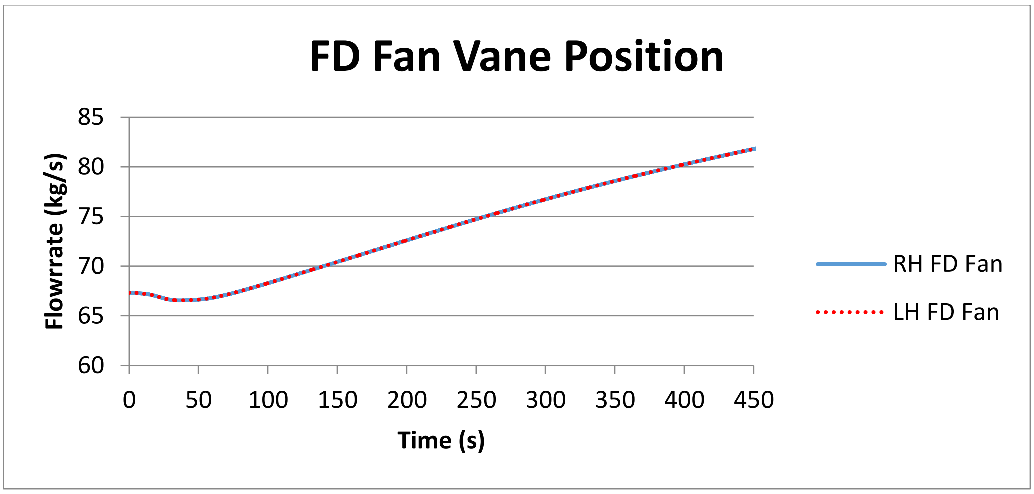


Figure 76 - FD Fan vane position (Load Change)

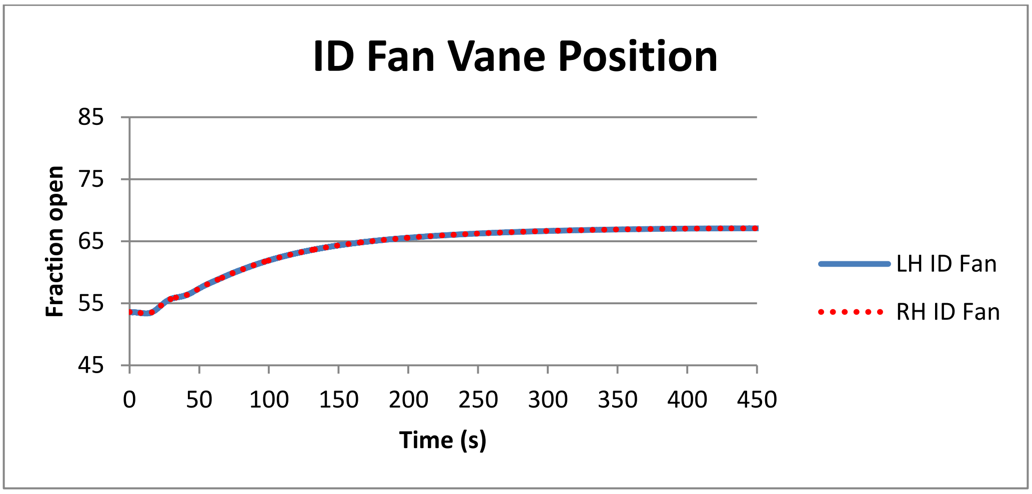


Figure 77 - ID Fan vane position (Load Change)

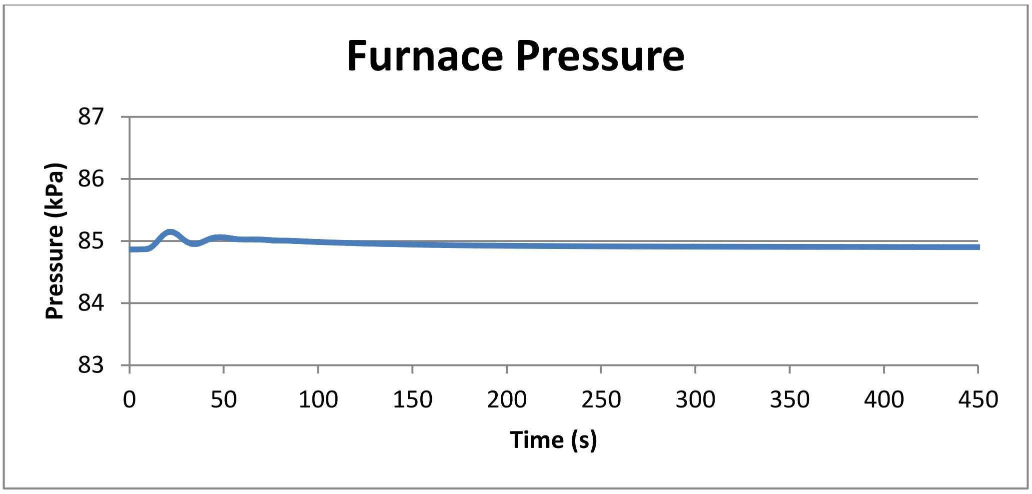


Figure 78 - Furnace pressure (Load Change)

6.3.2 FD fan trip

The system response for a RH FD fan trip can be viewed in Figure 79 to Figure 86. The FD fan was tripped 50 s in to the simulation. As the unit capability drops by 50 % the coal flows correspond by decreasing by the same amount while taking into account the mill feeders' inertia. While the RH SA dampers close, the LH SA dampers open up to supply the windbox with stoichiometric air for combustion. The ID fans also ramps up to restore the furnace pressure to 84.9 kPa.

The values provided in the graphs are taken from the output of the thermal-fluid model, after the control philosophies have been applied to all the individual elements of the system.

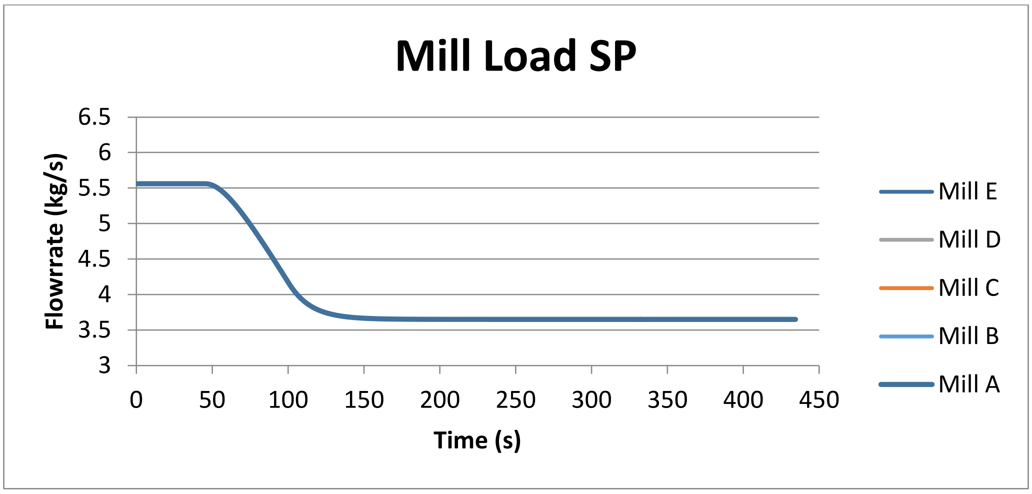


Figure 79 - Mill Load SP (FD fan trip)

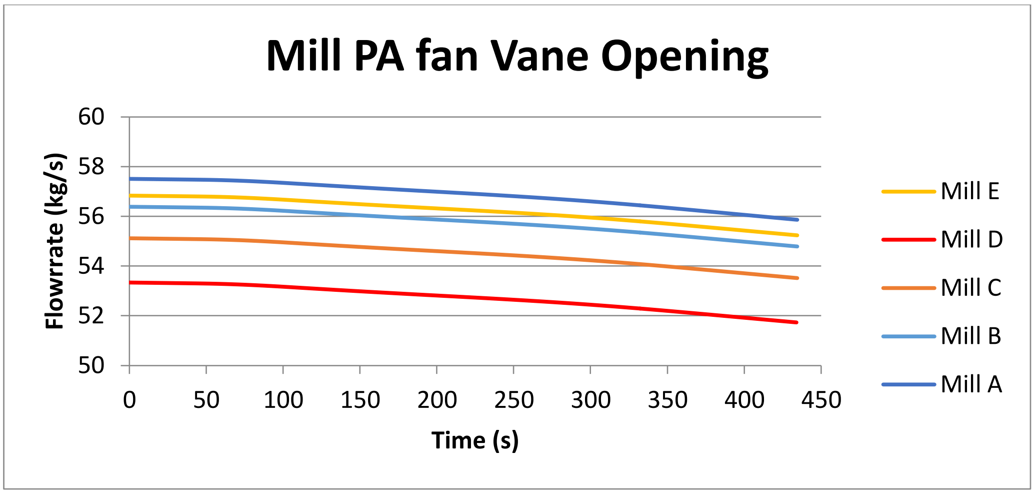


Figure 80 - Mill PA Fan Vane Opening (FD fan trip)

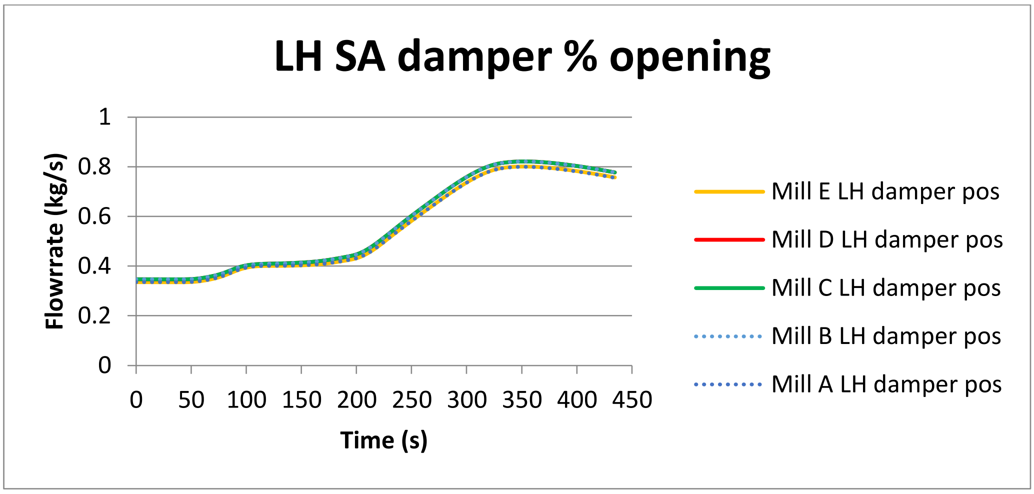


Figure 81 - LH SA damper position (FD fan trip)

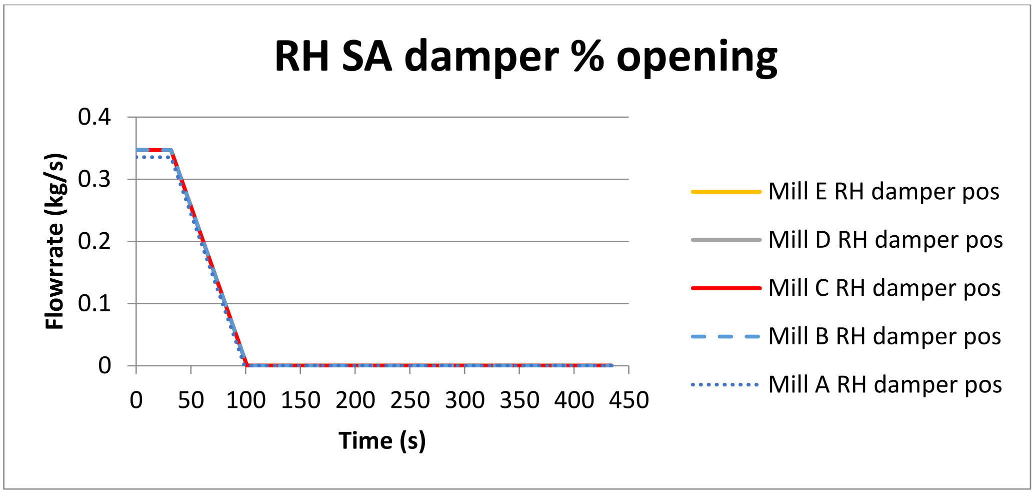


Figure 82 - RH SA damper position (FD fan trip)

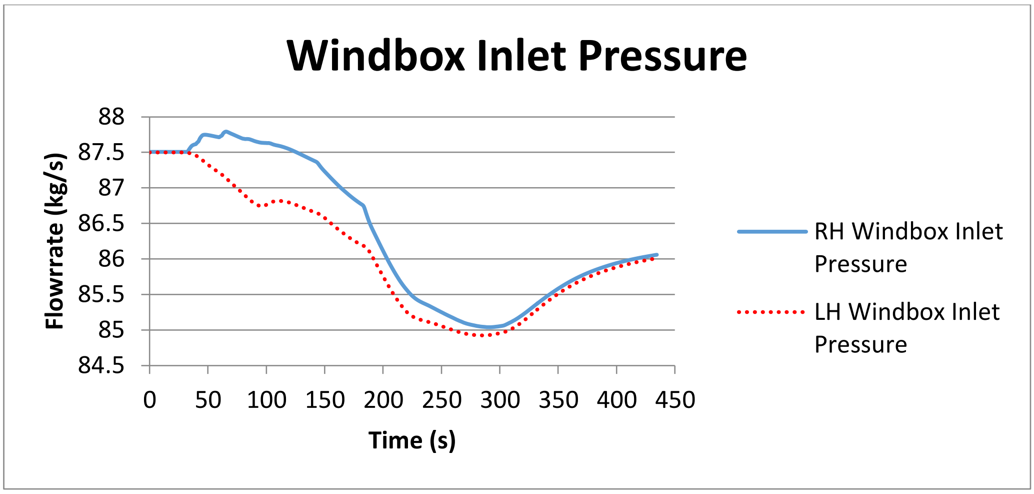


Figure 83 - Windbox inlet pressure (FD fan trip)

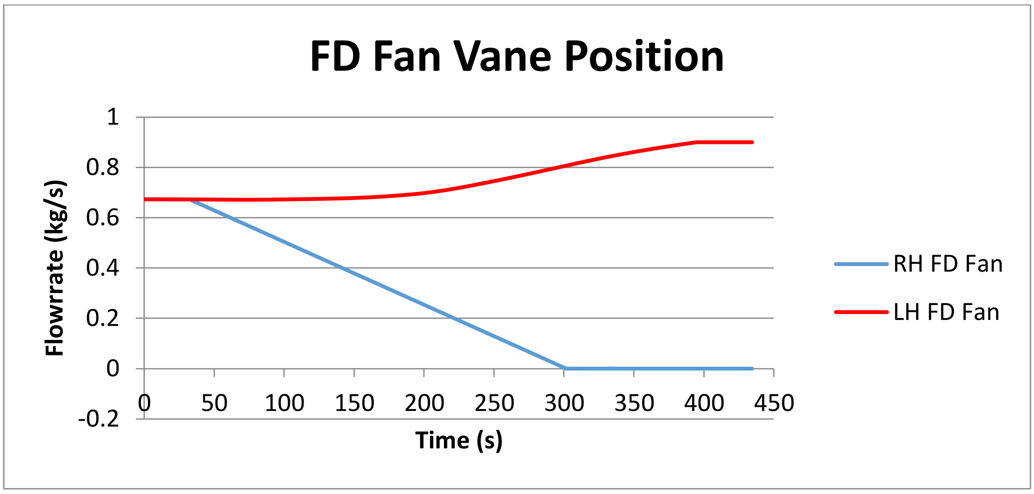


Figure 84 - FD fan vane position (FD fan trip)

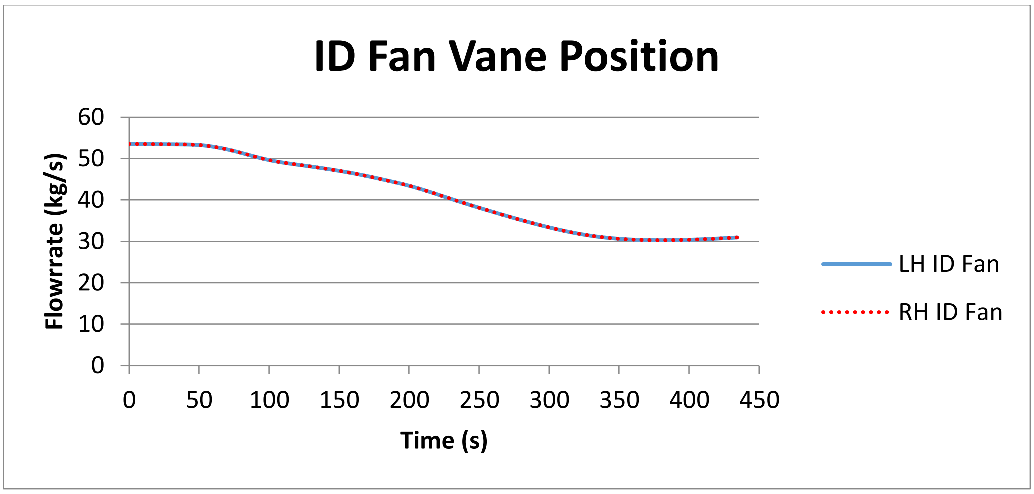


Figure 85 - ID fan vane position (FD fan trip)

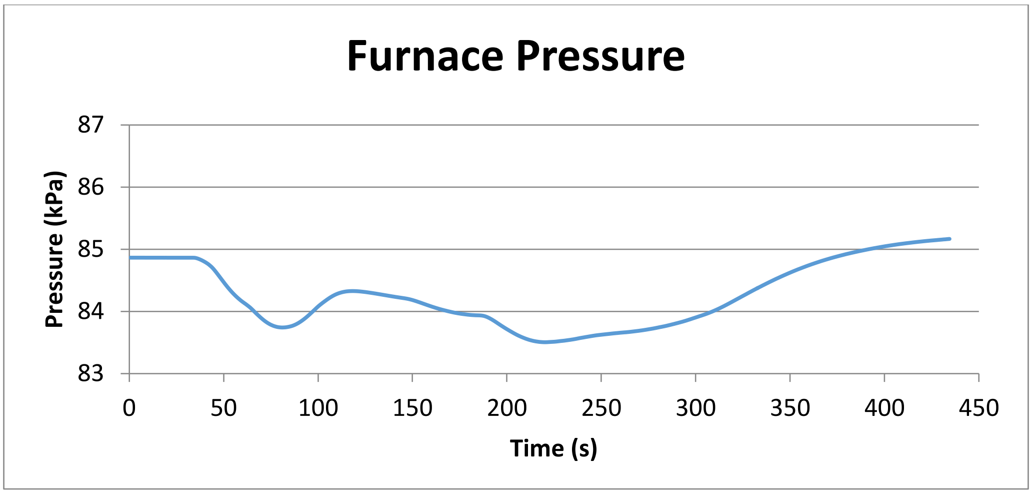


Figure 86 - Furnace pressure (FD fan trip)

7. Conclusion

With the low-NOx upgrade currently underway at Camden power station, it was deemed necessary to provide a model which would accurately provide a simulation environment to test the new control philosophies. These control philosophies cannot be tested while the plant is running, as the power grid is currently under pressure, and load losses would have a direct effect on the security of supply and in turn the South African economy.

The testing of FD fan trips is also deemed dangerous, as instabilities to the furnace pressure might cause the furnace to explode. Thus, the model is crucial in determining the effects of losing boiler auxiliaries and optimizing the responses thereof.

A detailed literature study has been conducted, in which several perspectives of boiler control has been researched. This includes the typical process flow of a power station, the various mechanical elements in the system in operation at Camden, the necessary control measures to maintain safe and stable operation on these systems and software to model the responses of the control system.

An overview on general practises on the boiler systems and boiler control regimes were discussed and would be followed by a Camden specific control setup. Even though the research has showed similarities with Camden’s control system, it is still unique in its own way and calculation of crucial parameters should be modelled to provide the closest response to the current control system.

In order to model the control system as accurately as possible, Camden’s function block diagrams were used to model the individual controllers. These function blocks contain the logic of the control system, and were used as it is the most defined representation of how the system will respond to changes.

All the controllers relevant to combustion control have been theoretically modelled from the available data. The controllers modelled include the Unit Coordinator, Load Controller, Combustion Controller, Mill Feeder Controller, FD Fan Controller, PA Fan Vane Controller, SA Controller, and Windbox Pressure Controller. The controller parameters were acquired by using the values as available in the plant description documents and the control system values available in the function block diagrams. By modelling the controllers theoretically an understanding has been gained regarding the inner working of the control system. The theoretical model formed the basis of the computational model design, which has been implemented on two platforms, namely Matlab® and Flownex®. The model was firstly implemented on previous logic, as new designs were not available yet. The new low-NOx design would be an amendment to the existing design, only reconfiguring the FD and SA controllers.

The initial model was implemented in Matlab®. The implementation was aimed at modelling control loops rather than modelling the controllers itself. The Matlab® model was not as refined as the later constructed Flownex® model, however, accurate mill load and required airflow rates were obtained. Usability of the control loop model was difficult, as troubleshooting could not be singled out to specific controllers. With the model built in Matlab®, future issues with integration was also a large possibility, therefore the construction of the model was continued in Flownex®.

Several small problems were encountered within Flownex®, which was escalated to the developers of Flownex®, M.Tech Industrial, whom responded swiftly with solutions. The control model was implemented fairly quickly in Flownex® by using the theoretical model as basis. The controllers were modelled separately as described in Section 4.3, and could be individually simulated and tested.

The Flownex® model was tested by creating lookup tables from historic plant data within Excel. The data for the lookup tables were taken from the plant historian, containing several transient scenarios where all relevant signals had a healthy status. These lookup tables were used as inputs to crucial parameters necessary for manipulated variable calculation, and the outputs of the controllers were observed.

A fully functional HMI was also created within Flownex®, which contains all the HMI screens relevant to the combustion control system. The HMI also contains additional information such as actual plant alarms and trend data, where the response of the system can be viewed.

The overall results of the model response to the lookup table inputs were empirically accurate when compared to the controller output from historic data. With the results being close to plant response, the implementation of the new low-NOx control was commenced, which required updating the FD Fan Vane Controller to a Windbox Pressure Controller and the SA Flow Controller to a low-NOx SA Controller.

The updated control model was integrated with a thermal-fluid model from UCT, also built in Flownex®. The initial stages of integration were partly successful, with problems arising when transient scenarios were triggered. The problems were mainly isolated to Flownex®, and not to the design of the control system or the thermal-fluid model.

The problems encountered include values being stuck in the control system from previous simulations, which are passed to the thermal-fluid control with each step increment. As there are many components in series within the control model, these values would be recalculated but only after the current value of the component has been sent out to the thermal fluid model. This single transmission of an incorrect variable would result in the model becoming unstable. This has been overcome by using snaps within Flownex®, which populate all the model components with historic values.

With the integrated Flownex® model working correctly, it would be provided to site personnel at Camden power station for training and optimization purposes. The model can be used to simulate different transient scenarios in order to set up efficient contingency plans when an auxiliary loss occurs. The system response can be viewed and fine-tuned to obtain the safest possible operating conditions.

The integrated model can also be utilized for operator training purposes, with the HMI providing the same environment as currently found at Camden's operator stations.

With the knowledge obtained with the research and construction of the combustion control model, models for all of Eskom's fleet upgrading their control systems can be constructed internally, without the need to approach contractors.

8. Recommendations and future work

The current integrated model only contains the control and thermal-fluid parts of the combustion control system. In order to obtain a holistic system response it is crucial for the construction of a waterside model and integrated into the current fireside model.

The waterside model will consist of the steam circuit (superheaters, economizer, boiler feed pump, drum and turbine), and will be integrated at furnace section in the thermal-fluid model, located at the top left point depicted in Figure 87. The controllers can be added in the same manner as they have for in the combustion control segment.

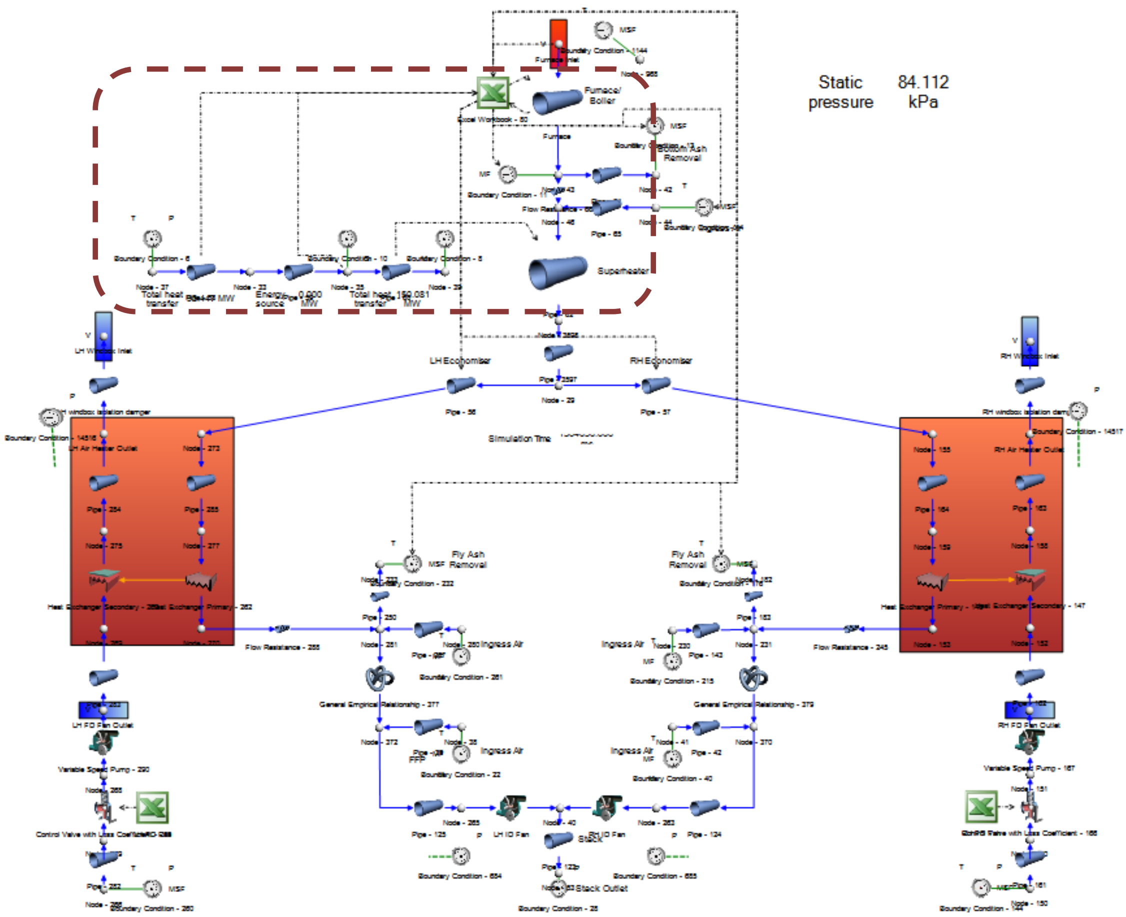


Figure 87 - Thermal-fluid model integration point (Furnace, FD- and ID Fans)

With a fireside model combined with a waterside model, calculations within the current implemented controllers would depict closer to real world responses, as the system relies on certain outputs from the waterside. For example, one of these inputs is the generator load. The generator load is used in determining the unit efficiency, which directly affects the calculation of the amount of coal flow required by the combustion system. With the coal flow changing, the inputs for SP calculation will change on the rest of the system such as the SP's for the SA damper positions. With variables such the generator load known, the model would become even more accurate.

With the process of creating the abovementioned model tied down, the opportunity exists to create similar models for of Eskom's PU3 stations (Komati, Kriel, Arnot and Hendrina). The models can assist in determining the response of the boiler controls in transient events.

As Eskom owns several floating Flownex® licenses, these models can be created by an internally led team of engineers, providing accurate models in very low turnaround time. This will assist engineers at the various stations to effectively plan for auxiliary losses.

The Flownex® simulation environment requires around 300mb of computer memory, which enables the option to run it from a corporate PC. However, transient scenarios can take longer to solve (5s for each 10ms of solving), but will increase in speed as the system becomes more stable.

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Appendix B - Plant coding systems

Coding systems are available on site. They are used to label and identify all components on a power station, where it is located in the plant and where it can be seen. There are mainly two different coding systems namely KKS and AKZ.

Since most of Eskom's fleet (inclusive of Camden) uses KKS, this will be discussed in further detail. The coding system will be used to reference instruments and apparatus within the plant. KKS coding is split into four main levels, namely:

1. Total plant - The total plant is the unit/plant the equipment will be located on. 10 for unit 1, 20 for unit 2, 01 for common (usually between unit 1 and 2 in a conventional six pack power station).
2. System - System identifies the system the equipment is found in. For example, HLA is the main air circuit, LAC the boiler feedpump etc.
3. Equipment unit - The equipment unit will indicate what type of instrument is being viewed, together with the set it can be found in.
4. Unit components - The unit components will indicate what type of sub component is present.

Structure of code (General):				
SERIAL NUMBER OF BREAKDOWN LEVEL	0	1	2	3
NAME OF BREAKDOWN LEVEL	TOTAL PLANT	SYSTEM	EQUIPMENT UNIT	UNIT COMPONENTS
Plant It has however been accepted by industry that a comprehensive plant breakdown structure is required and that all operable and maintainable equipment should be included in that structure. This structure should include all equipment that other disciplines might require in their day to day operating, maintenance and engineering duties. It will also facilitate the compilation of alternative plant views (Maintenance, process costing, Production etc.) **Process** Process related coding is the coding of systems and items of equipment according to their functions in mechanical, civil, electrical and control and instrumentation engineering.				

NAME OF BREAKDOWN LEVEL	**TOTAL PLANT**	SYSTEM						EQUIPMENT UNIT						UNIT COMPO-NENTS			
DESIGNATION OF DATA CHARACTER	**G**	F0						F1						F2			
NATURE OF DATA CHARACTER	**A or *N***	N	A	A	F 3	FN		A 1	A 2	AN			A 3	B 1	B 2	BN	
NATURE OF DATA CHARACTER	**A or N**	N	A	A	A	N	N	A	A	N	N	N	A	A	A	N	N
Typical =	1	0	L	A	C	1	0	A	P	0	0	1		-	M	0	1
	UNIT 1		**BFP**			**SET 1**		**PUMP SET**						**MOTOR**			

Figure B.1 - Structure of KKS coding [6]

Signal Coding Legend

The KKS standard is followed closely with addition of the following:

For signals related to a specific plant component:

KKS Number	Signal	Designation
. . . .	. . .	Follow normal KKS numbering system with the related signal code below.

For signals internal to the control system but not related to a specific plant component:

KKS Number	Signal	Designation
. . . . ET . . .	. . . . .	Analogue signals from a specific section of the control system. Use the KKS code for the specific section of the control system. (e.g. PLC).
. . . . ES . . .	. . . . .	Binary signals from a specific section of the control system. Use the KKS code for the specific section of the control system. (e.g. PLC).

For signals calculated in the SCADA system:

KKS Number	Signal	Designation
. . CKA 81 EQ . . .	Z . . .	Use this range for all analogue values calculated within the SCADA system.
. . CKA 01 EQ . . .	Z . . .	Use this range for all binary values calculated within the SCADA system.
. . CKA . . EQ 0 . .	Z . . .	Calculated process values that are not related to a major plant group.
. . CKA . . EQ 1 . . | . . CKA . . EQ 9 . .	Z . . . Z . . .	Calculated process values that are related to a major plant groups 1 - 9.
. . CKA . . EQ . 00 | | . . CKA . . EQ . 99	Z . . . Z . . .	Calculated process values of sub-sections 10 - 99 of a major plant group.

For all signals:

KKS Number	Signal	Designation
	E . . .	Internally generated (e.g. Internal to P.I.M.S.)
. . . . . .	X . . .	Source addressed (e.g. Signals from plant).
. . . . . .	Y . . .	Destination addressed (e.g. Signals to plant).
. . . . . .	Z . . .	Indirectly addressed (e.g. Internal to SCADA).
. . . . . .	. E . .	Analogue totalisers
. . . . . .	. I . .	(Future use).
. . . . . .	. K . .	(Future use).
. . . . . .	. O . .	(Future use).
. . . . . .	. N . .	Signals (Free use).
. . . . . .	. U . .	Linked external signals.

For all binary signals:

KKS Number	Signal	Designation
. . . . . .	. A . .	Binary signals of group control.
. . . . . .	. B . .	Binary signals of drive control.
. . . . . .	. C . .	Binary signals of drive control (extension).
. . . . . .	. D . .	Binary signals from control room (Pushbuttons).
. . . . . .	. G . .	Binary- /Limit signal (measured).
. . . . . .	. H . .	Programmed limit signal (measured).
. . . . . .	. L . .	Coded binary signals (e.g. collection of binaries).
. . . . . .	. M . .	Binary signals within the control system.
. . . . . .	. P . .	Binary signals from control room (releases etc.).
. . . . . .	. R . .	Binary signals (Closed loop control).
. . . . . .	. S . .	Binary signals (Free use).
. . . . . .	. V . .	Binary signals to J (Closed loop control).
. . . . . .	. W . .	Binary signals to Q (Measurement).
. . . . . .	. . 0 .	Feedbacks (Normal).
. . . . . .	. . 1 .	Pushbutton commands.
. . . . . .	. . 2 .	Automatic commands (Control system intervention).
. . . . . .	. . 3 .	Protection and interlocks.
. . . . . .	. . 4 .	Single and summation alarms.
. . . . . .	. . 5 .	Feedbacks (Inverse).
. . . . . .	. . 6 .	Summation alarms (Extension).
. . . . . .	. . 7 .	Power supply.
. . . . . .	. . 8 .	Lamps (Uncoded).
. . . . . .	. . 9 .	Commands.
. . . . . .	. . . 0	Internal to control system (Flags, datawords etc.).
. . . . . .	. . . 1	On, Mechanically open(ed), Contactor close(d), Breaker close(d), Automatic.
. . . . . .	. . . 2	Off, Mechanically close(d), Contactor open(ed), Breaker open(ed), Manual.
. . . . . .	. . . 3	Higher, Upper limit, Released.
. . . . . .	. . . 4	Lower, Lower limit, Acknowledge.
. . . . . .	. . . 5	Stop.
. . . . . .	. . . 6	Signal.
. . . . . .	. . . 7	Lamp in trip condition.
. . . . . .	. . . 8	Lamp in disturbed condition.

. . . . 9	Lamp in running condition.
For all analogue signals:	
. . . . C . .	Analogue signals within control system.
. . . . F . .	Signals within control system (Free use).
. . . . J . .	Analogue signal (Closed loop control).
. . . . Q . .	Analogue signal (Measured).
. . . . T . .	Analogue signals (Free use).
. . . . 0 0 . . . . | | 9 9	Range of analogue values.
For analogue Internal totalisers	
. . . . E 0 1	Daily running hours
. . . . E 0 2	Daily commutations
. . . . E 0 3	Total accumulated running hours
. . . . E 0 4	Total accumulated commutations
. . . . E 0 5	Weekly running hours
. . . . E 0 6	Weekly commutations
. . . . E 0 7	Monthly running hours
. . . . E 0 8	Monthly commutations
. . . . E 0 9	Daily volume (l, m^3)
. . . . E 1 0	Daily mass (Kg, Ton)
. . . . E 1 1	Weekly volume (l, m^3)
. . . . E 1 2	Weekly mass (Kg, Ton)
. . . . E 1 3	Monthly volume (l, m^3)
. . . . E 1 4	Monthly mass (Kg, Ton)

Figure B.2 - KKS signal coding legend [6]

Appendix C - DCS Alarms

Table C.1 - Key DCS alarms

Inst Functional Location	Description	Unit	Normal	Alarm	Trip	Comments
Draught group						
	Air Heater Average outlet temperature	°C	< 100 release to shutdown			
Fabric filter plant						
*0HNA11CT001-004, *0HNA12CT001-004, *0HNA21CT001-004, *0HNA22CT001-004	FFP Inlet Gas Temperature Measurement	°C		>175	>180	
Milling plant						
0HFC10 CT005	MILL A OUTLET T	°C	70-95	110 [High] 60 [Low]	120	
0HFC10 CP002	MILL A DIFF PRES	kPa	<7	8 9		
0HFE10 CF001	MILL A PA FLOW	kg/s	>9,7	<9,6	7	
Boiler furnace						
0HBK00 CP901	FURNACE P	Pa	-120	0 [High] -400 [Low]	2 <-400 or >500	Short range furnace pressure
0HBK00 CP901	FURNACE P	Pa	-120	>2000 [High] <-2500 [Low]	2 < -2500 or >2000	Long range furnace pressure

Should any ‘automatic-trip’ malfunction/fail to operate, a ‘manual trip’ shall be initiated by the operator, or ‘manual-intervention to trip’ shall be done. This means either by means of EPB or ‘switchgear’ / integrated protection equipment intervention used to trip the machine; the following are ‘Auto-trips’ or if they fail to operate. Action if auto trip fails:

- Turbine over-speed trip at 3300RPM - Turbine EPB
- Reverse Power Trip – long 15 seconds (ESV open) Short 0,5 seconds (ESV closed) (definite auto trip – no manual trip initiation needed)
- Condenser Pressure High > 34kPa - Turbine EPB
- Turbine bearing temperature > 85°C - Turbine EPB
- Turbine seal face temperature high > 100°C - Turbine EPB
- Turbine ESV inlet temperature > 560°C - Boiler/Turbine EPB
- Boiler Drum level Lo-Lo < 300mm - EPB Boiler
- Boiler Drum level Hi-Hi > 300mm - EPB Boiler
- Furnace Pressure Low (-2000Pa) - EPB Boiler
- Furnace Pressure Hi (+3000Pa) - EPB Boiler
- Total Flame Failure – EPB Boiler

Appendix D - Matlab® model

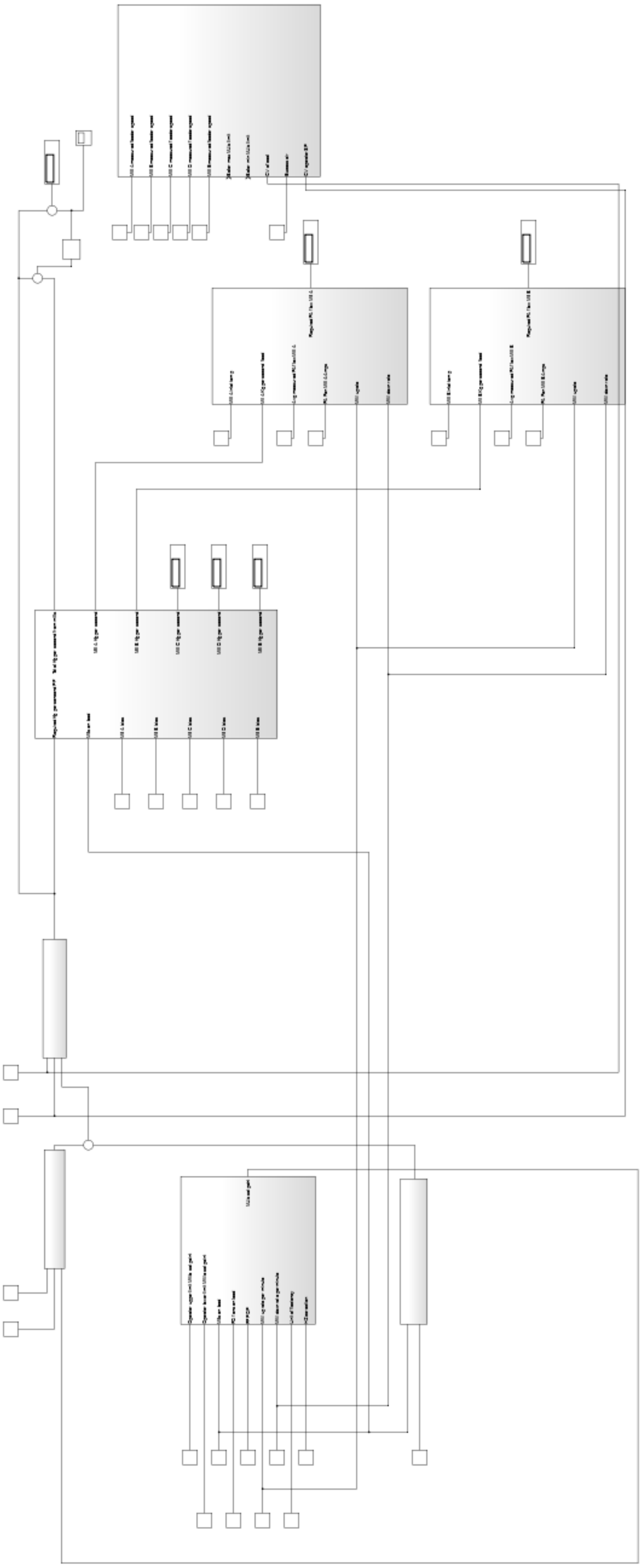

Figure D.1 - Matlab® model overview

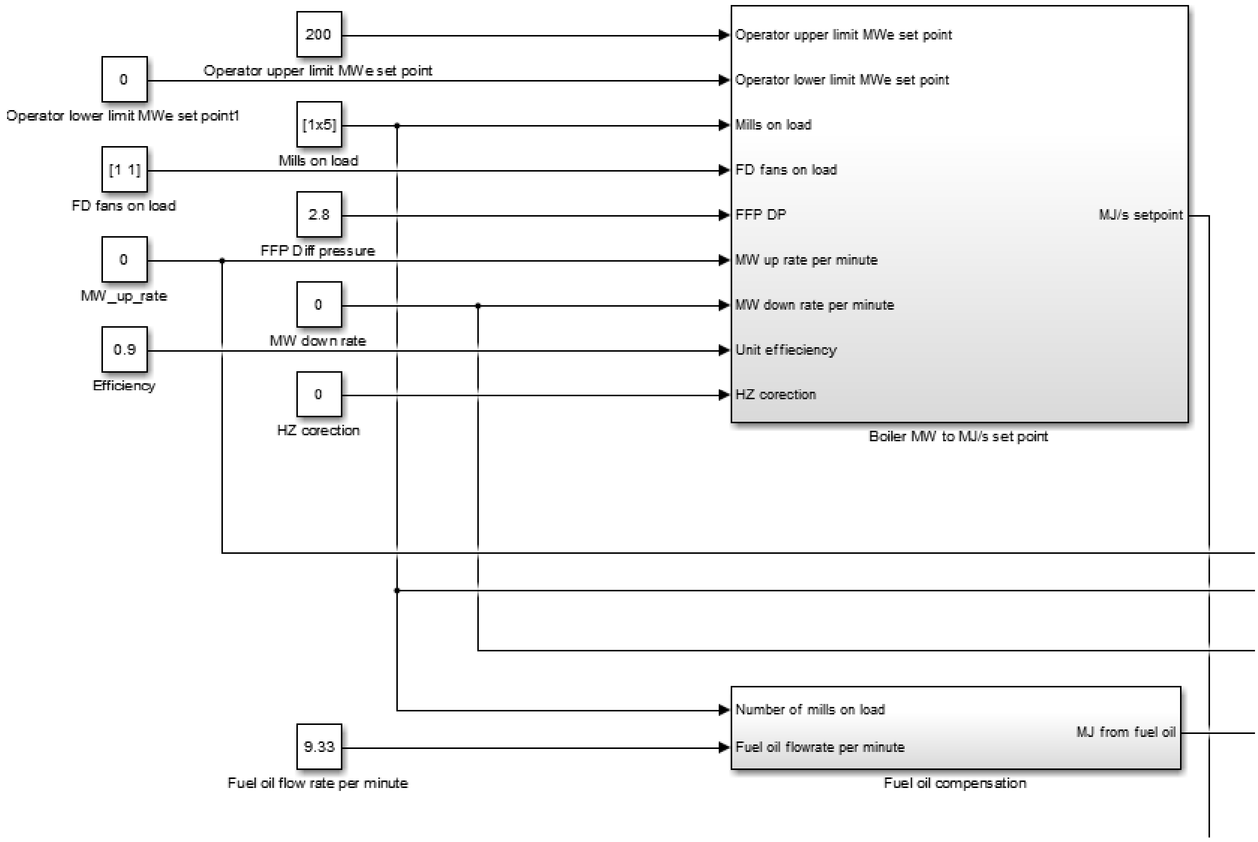

Figure D.2 - Boiler MW to MJ/s SP (Matlab®)

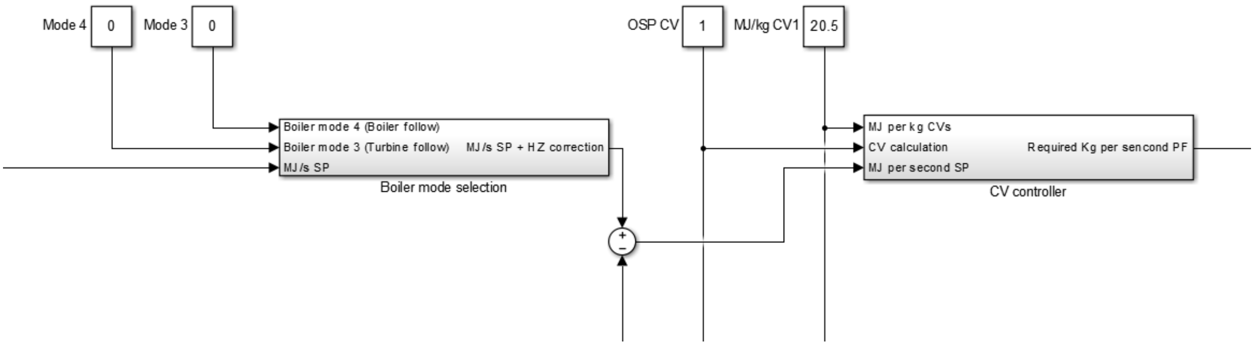

Figure D.3 - Boiler mode selection and CV controller (Matlab®)

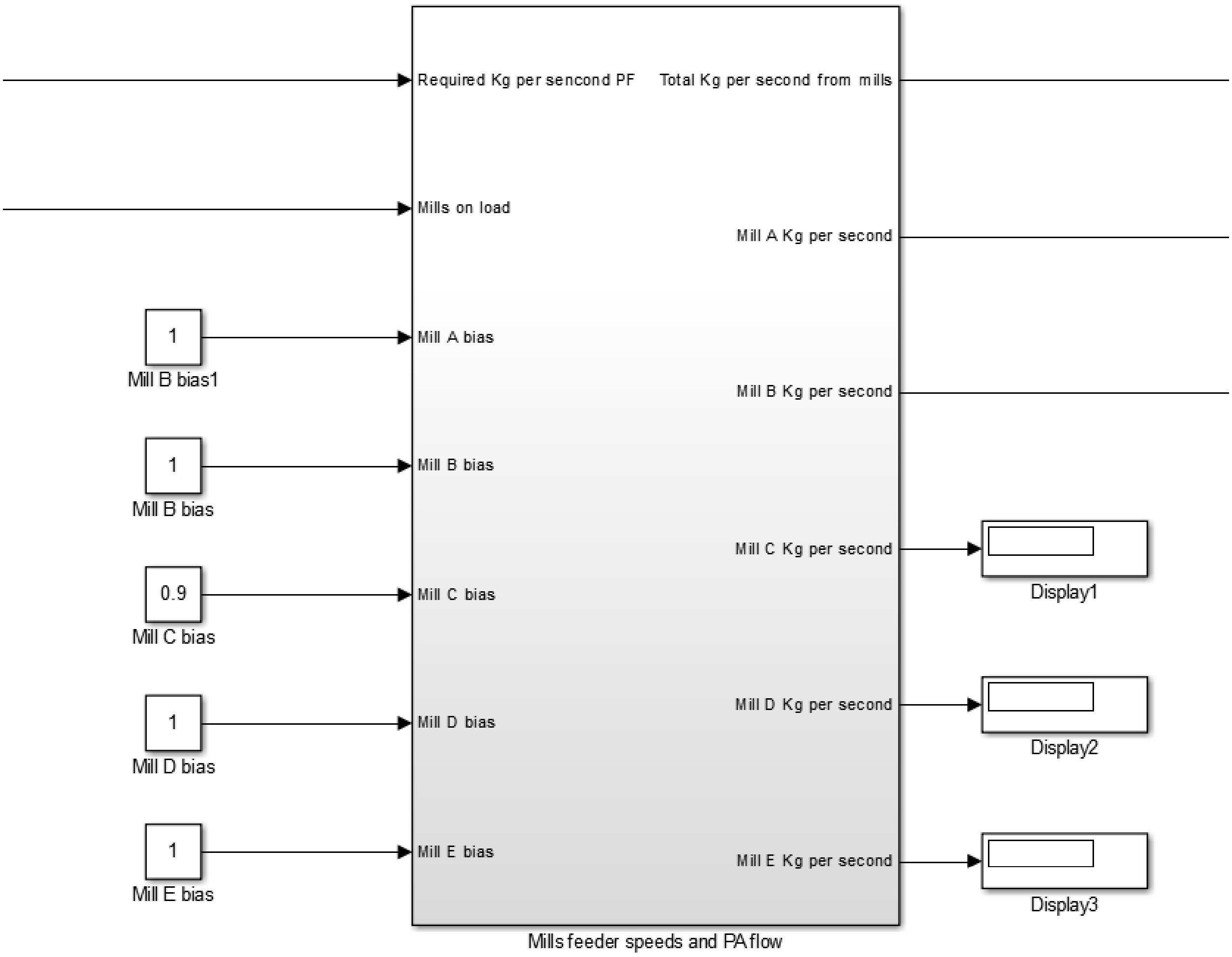

Figure D 4 - Mill Feeder speed calculation (Matlab®)

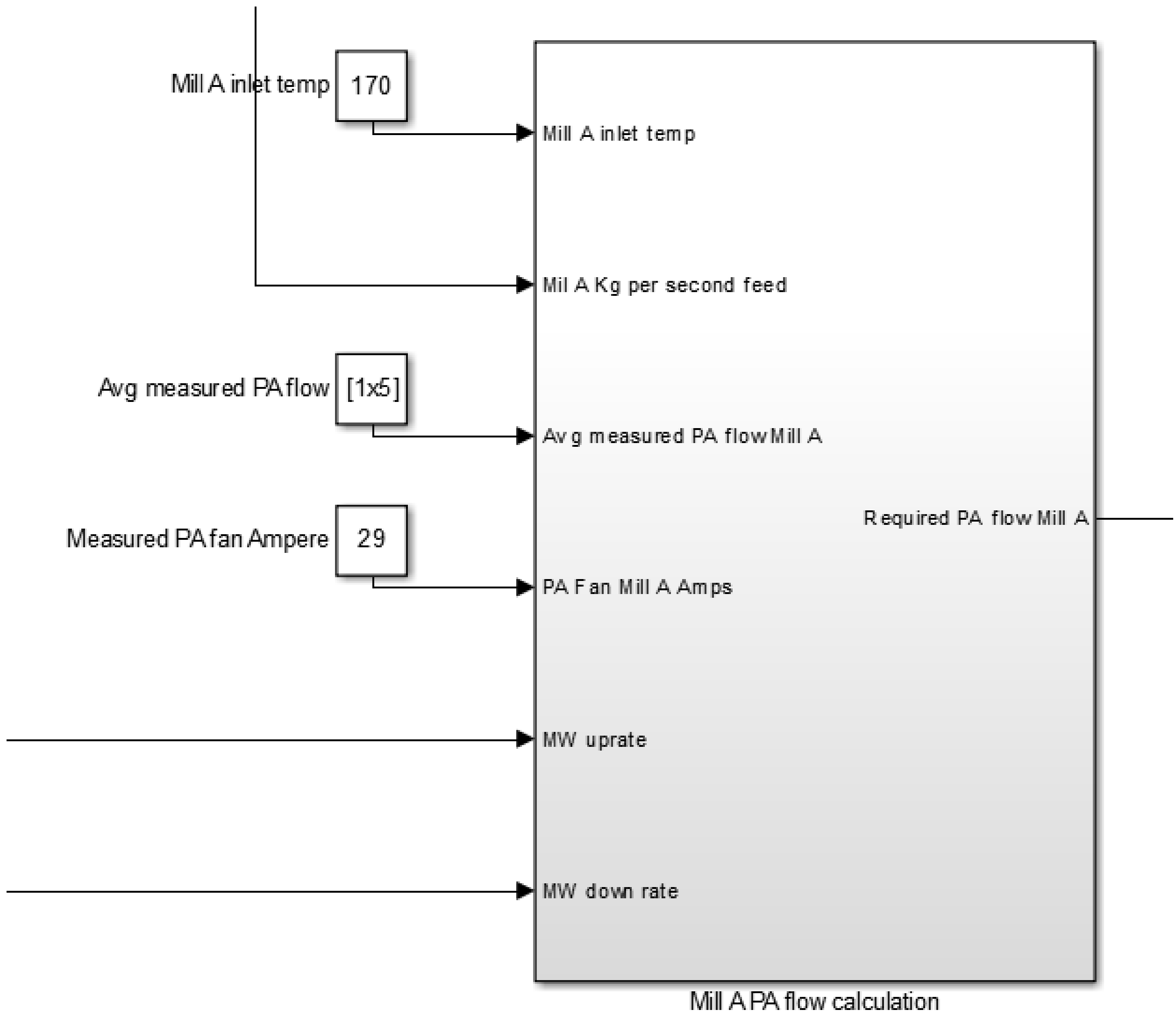

Figure D.5 - Mill PA flow calculation

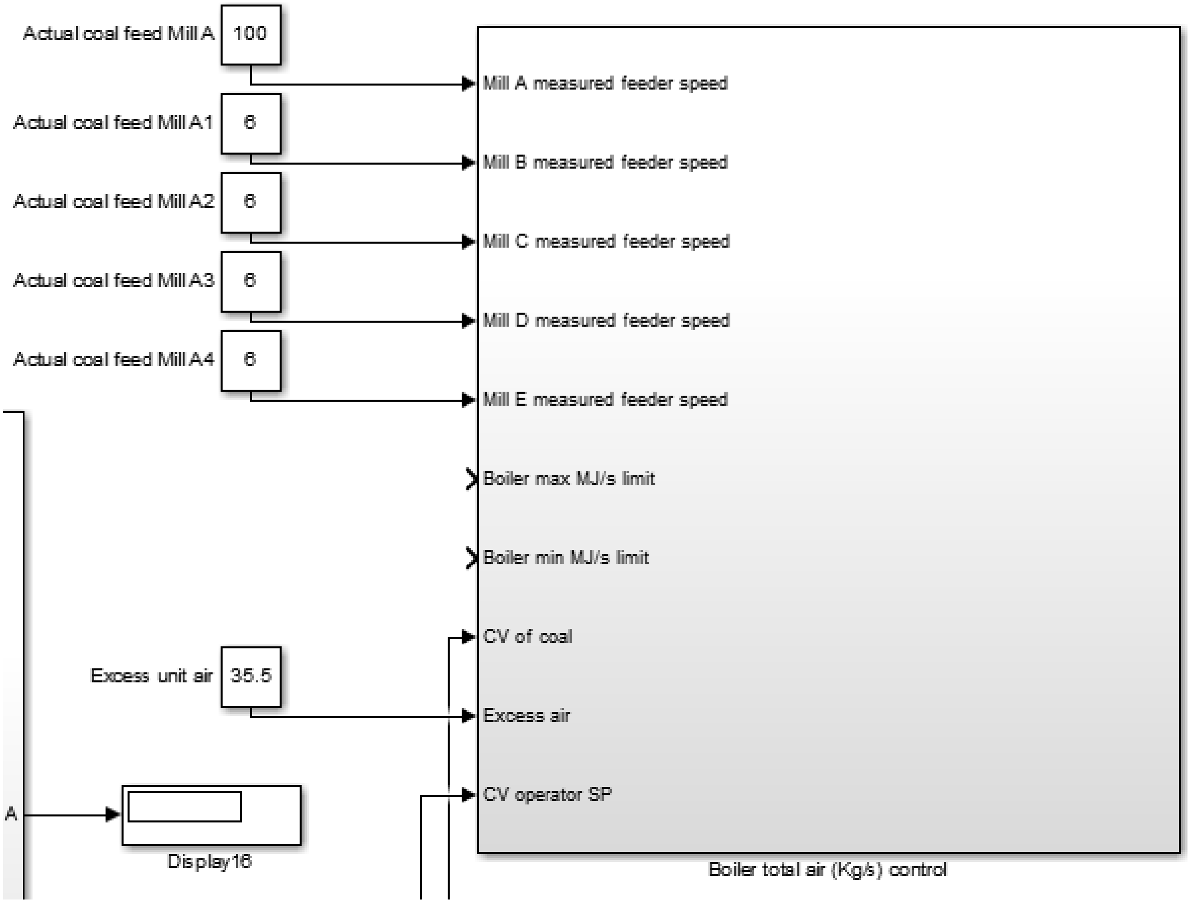

Figure D.6 - Boiler total air control (Matlab®)

Appendix E - Controllers in Flownex®

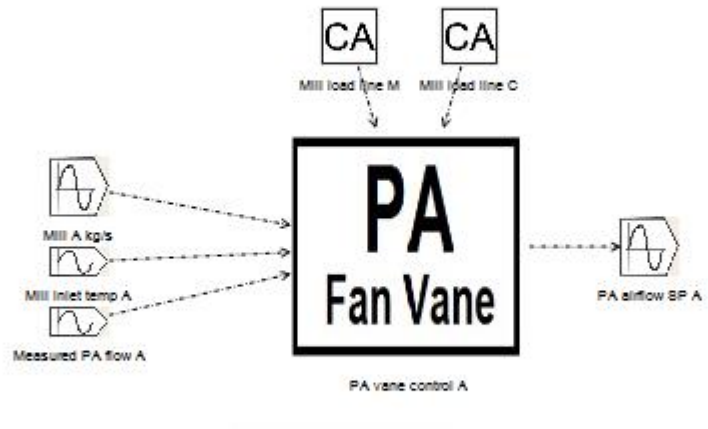

Figure E.1 - PA vane controller in Flownex® environment

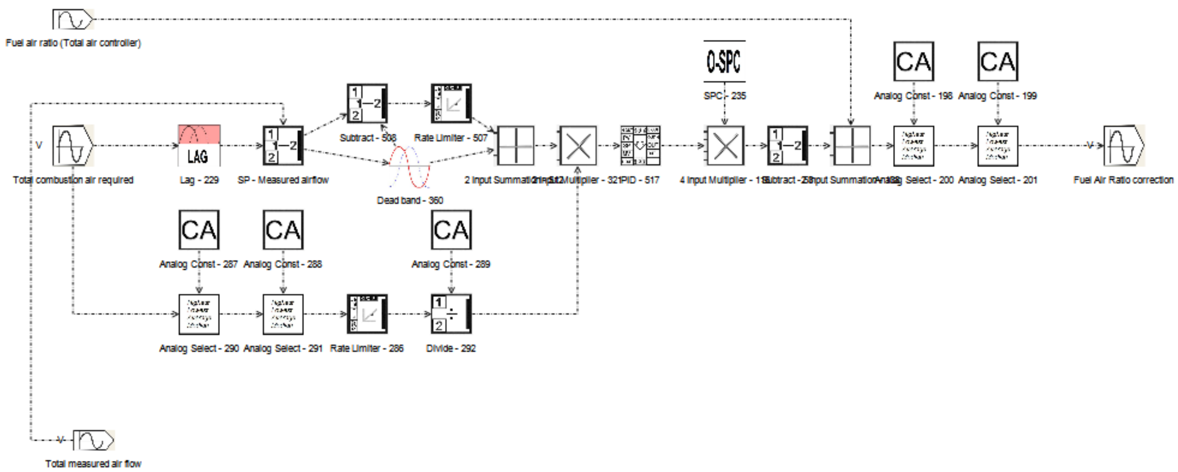

Figure E.2 - Total Air Controller in Flownex® environment

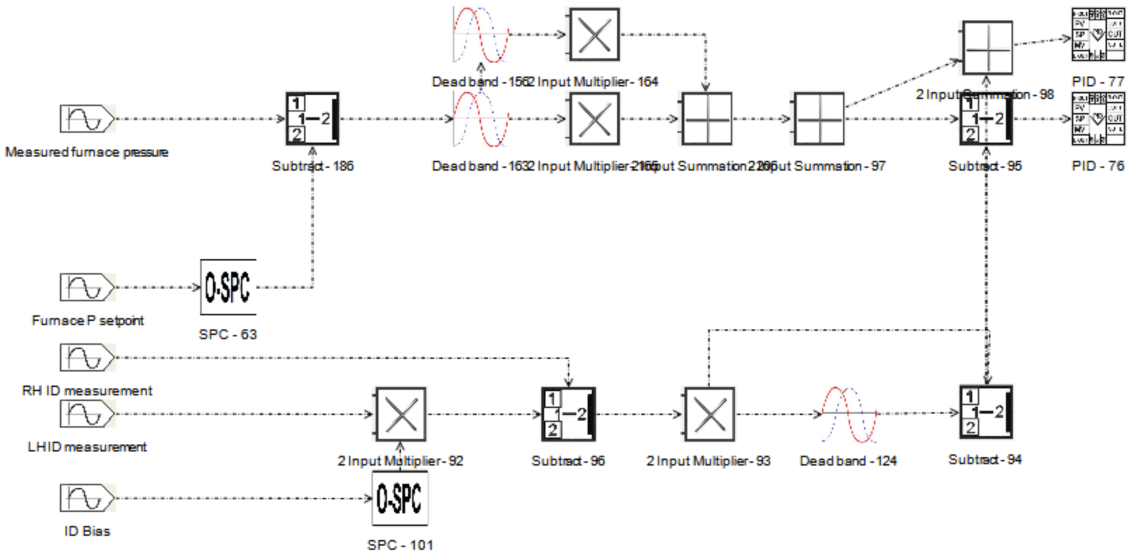

Figure E.3 - ID Fan Controller in Flownex® environment

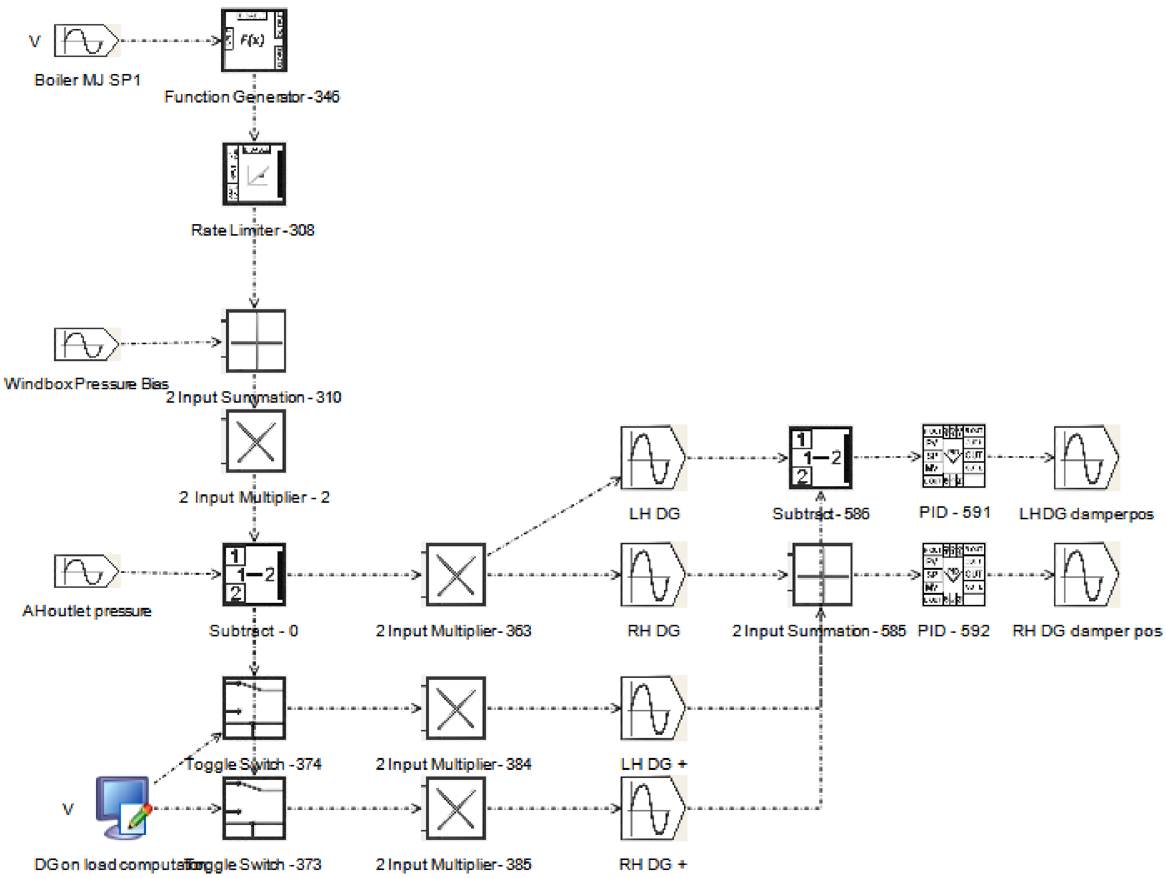

Figure E.4 - Windbox Pressure Controller (Low NOx) in Flownex® environment

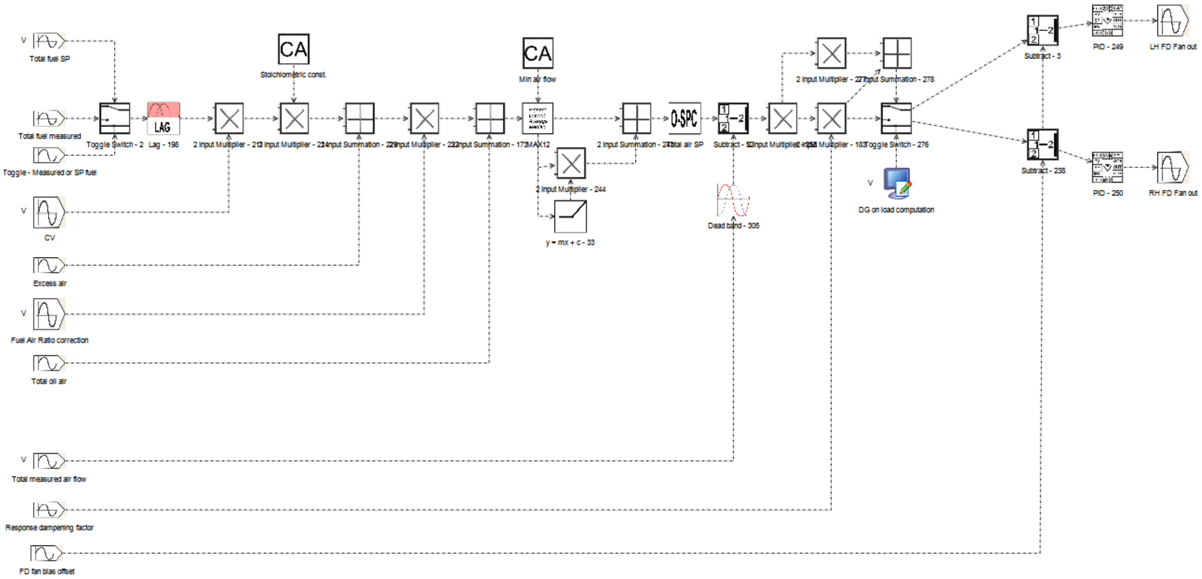

Figure E.5 - FD Fan Controller in Flownex® environment

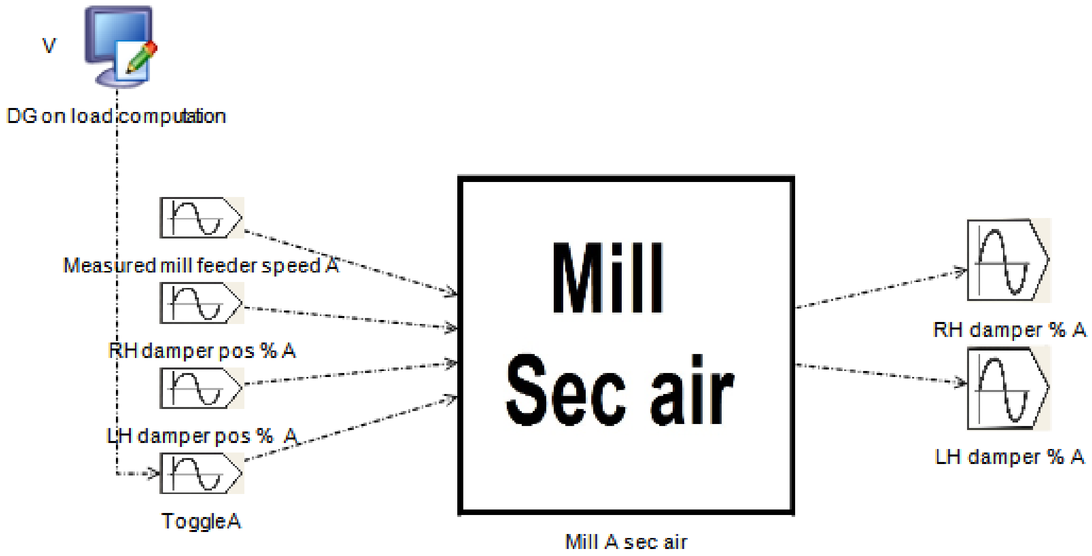

Figure E.6 - SA Flow Controller in Flownex® environment

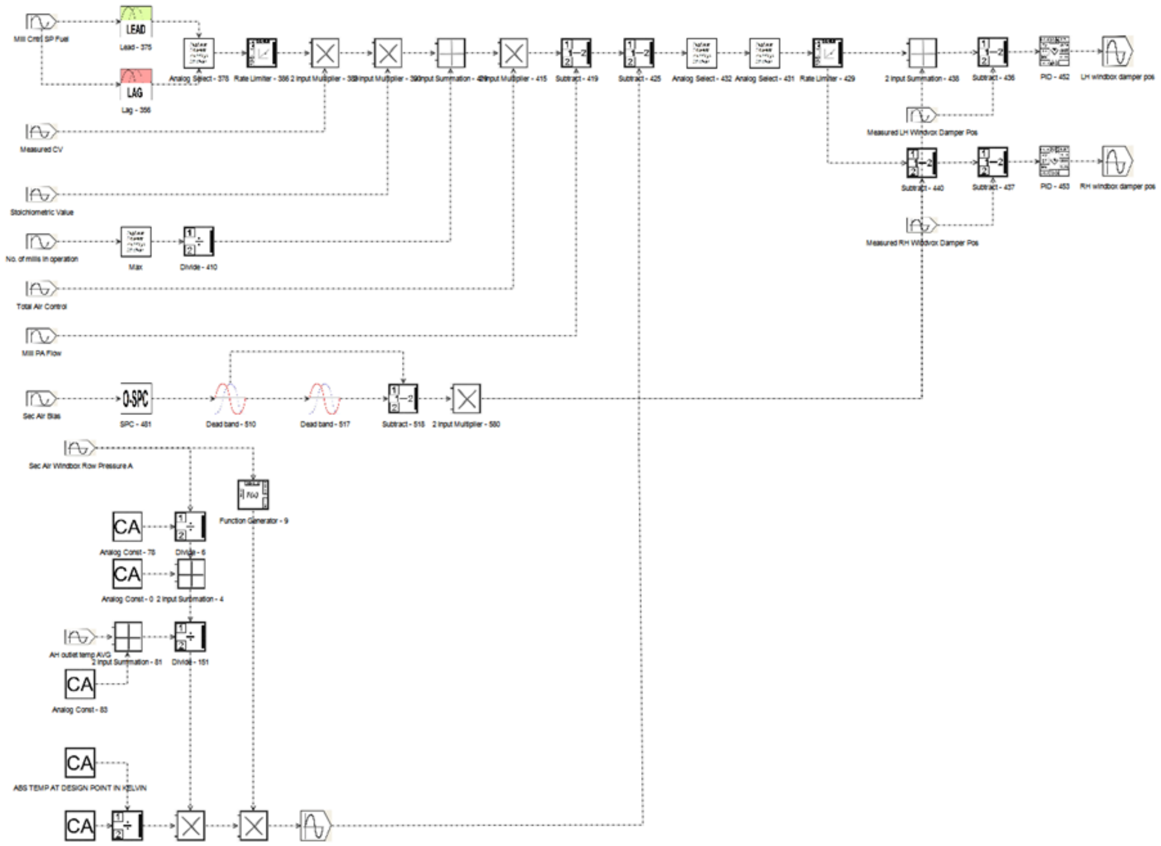

Figure E.7 - SA Flow Controller compound component in Flownex® environment

Appendix F - Flownex® HMI's

The HMI screens will serve as the user interface with the model, displaying trends and allowing operator interaction. The top bar of the HMI has a navigation pane, allowing the operator to browse through the various screens easily. There are several interactive buttons which, when clicked, will bring up an input dialogue. Here the operator settable values for the corresponding system can be inserted.

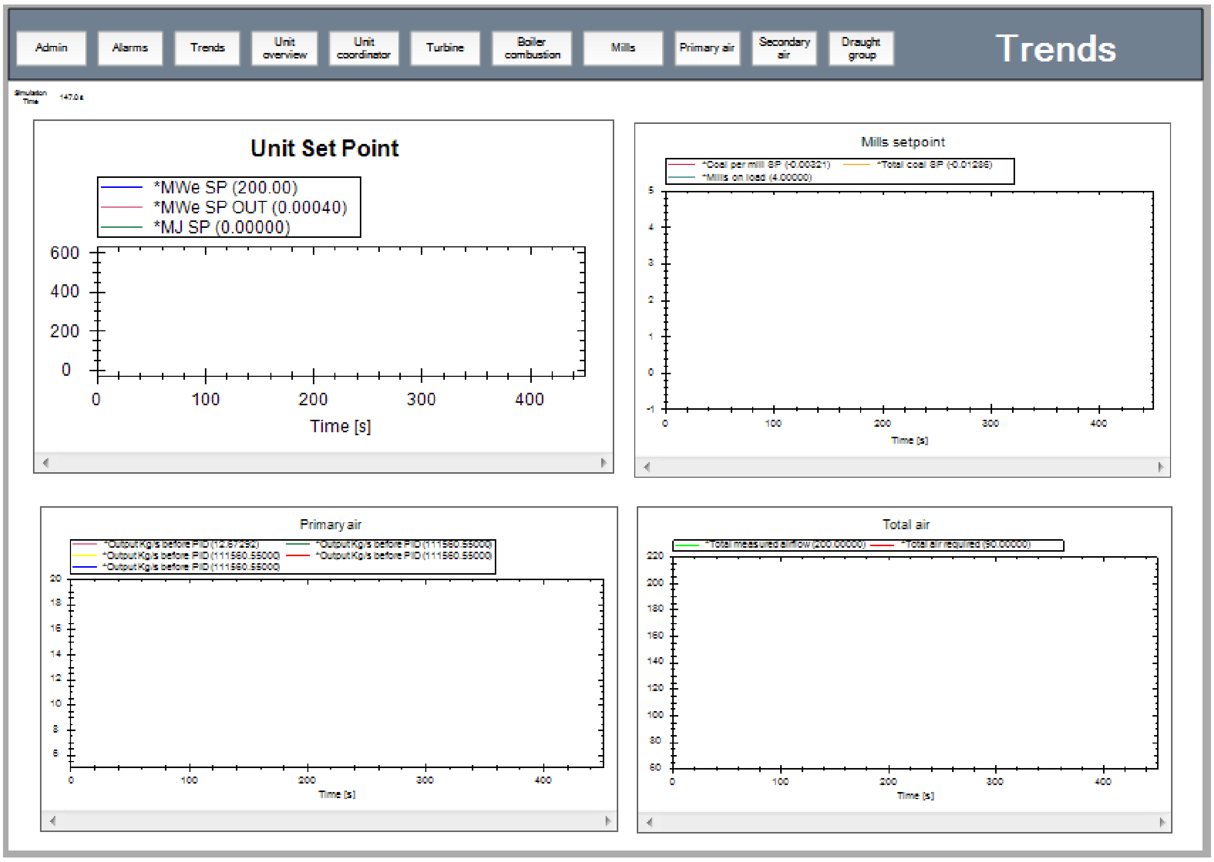

Figure F.1 - Unit Trends HMI in Flownex® environment

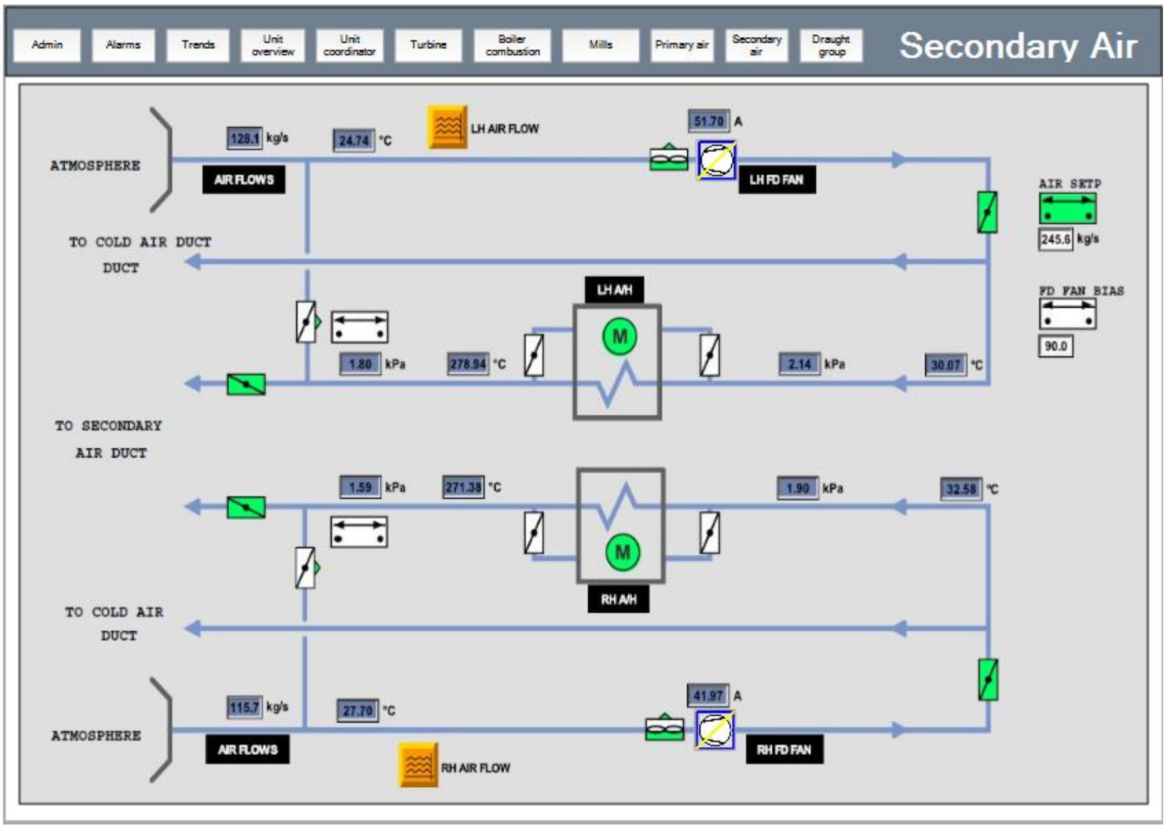

Figure F.2 - SA HMI in Flownex® environment

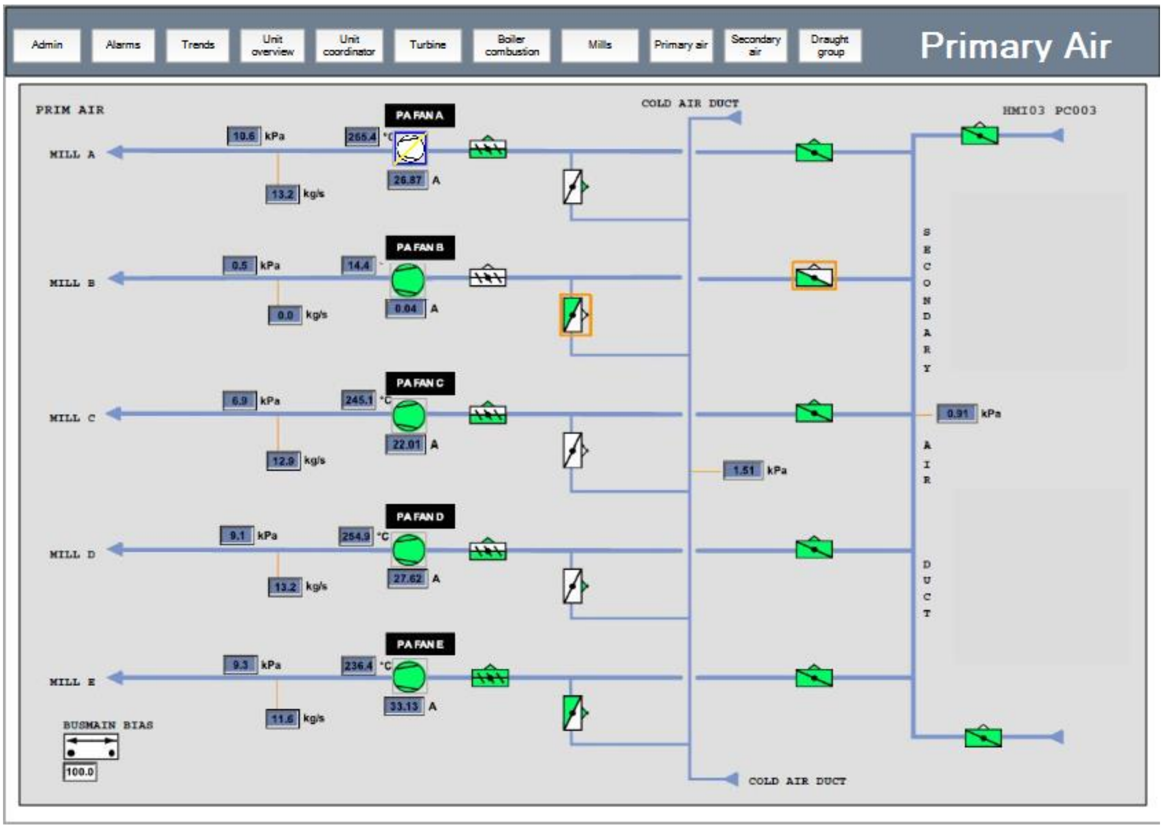

Figure F.3 - PA HMI in Flownex® environment

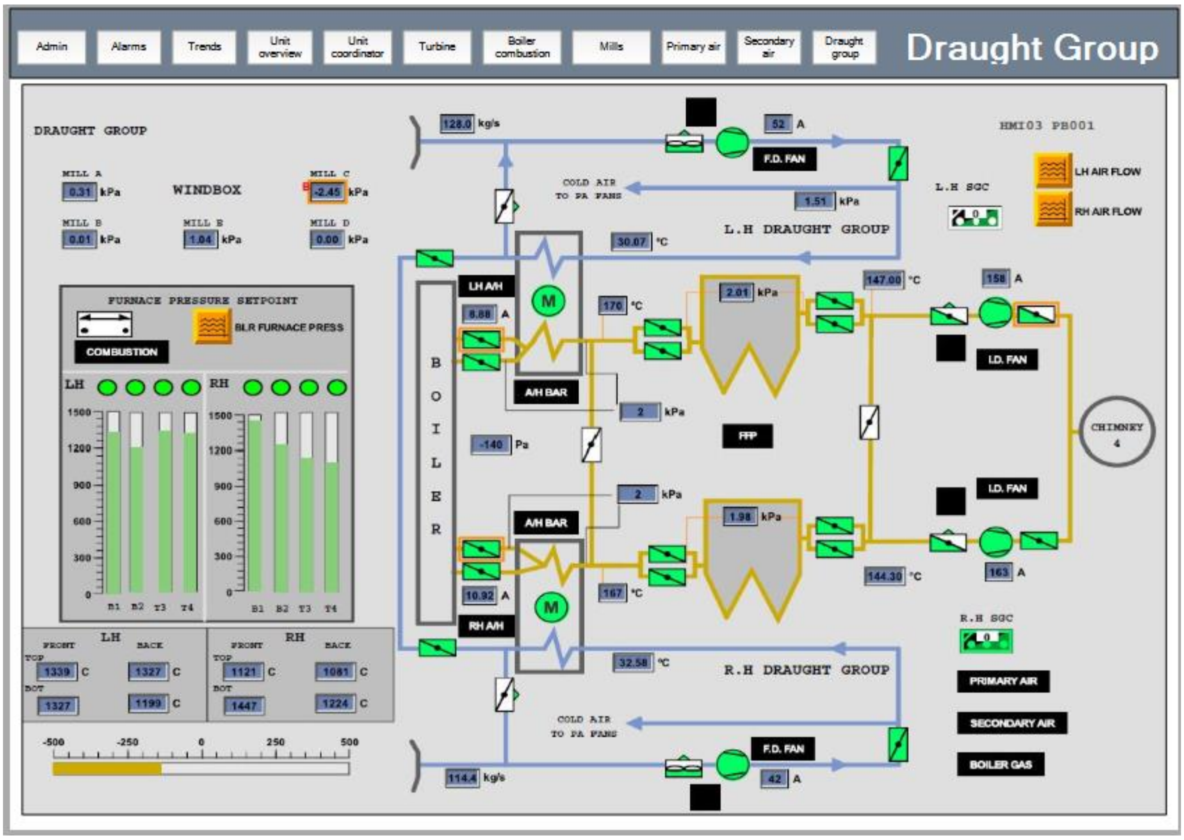

Figure F.4 - DG HMI in Flownex® environment

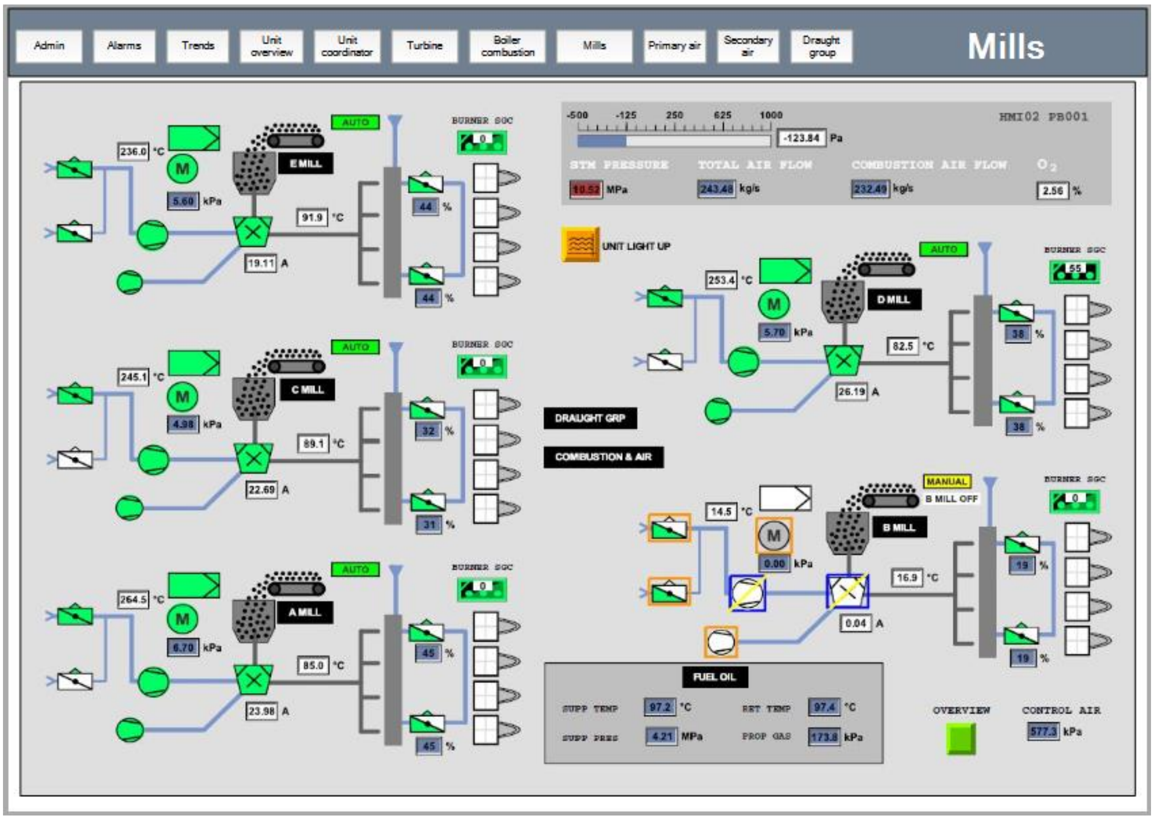

Figure F.5 - Mills HMI in Flownex® environment

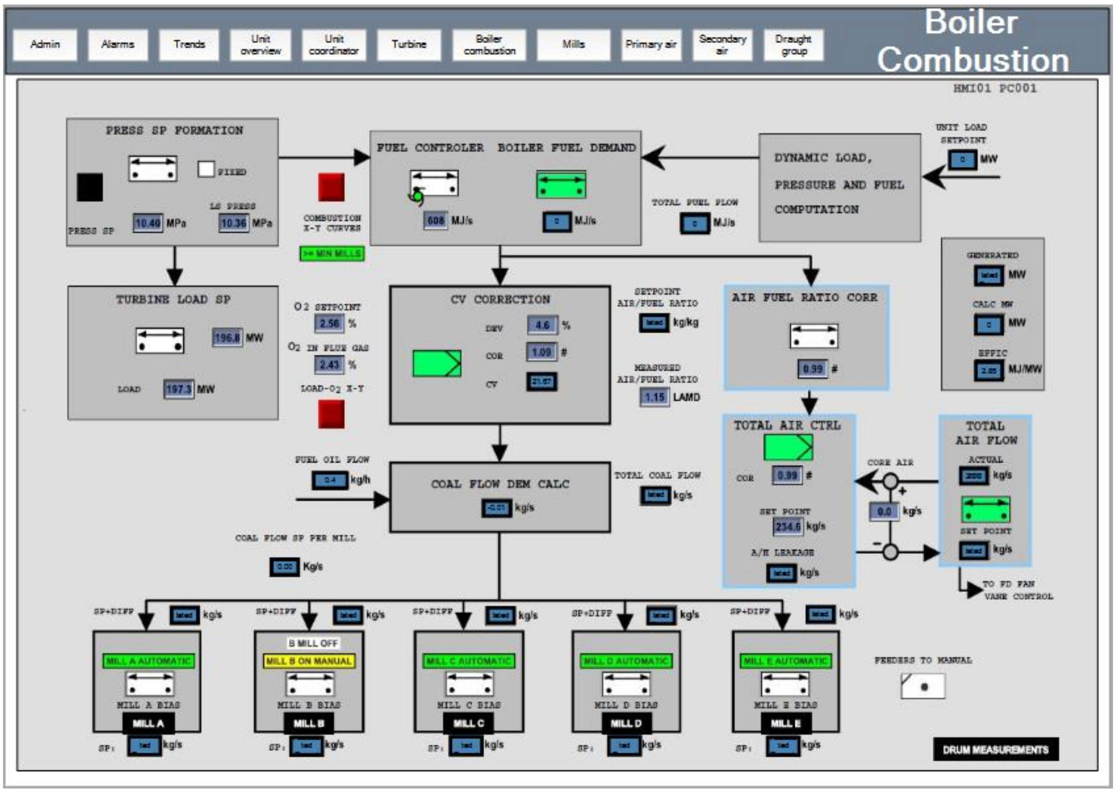

Figure F.6 - Boiler Combustion HMI in Flownex® environment

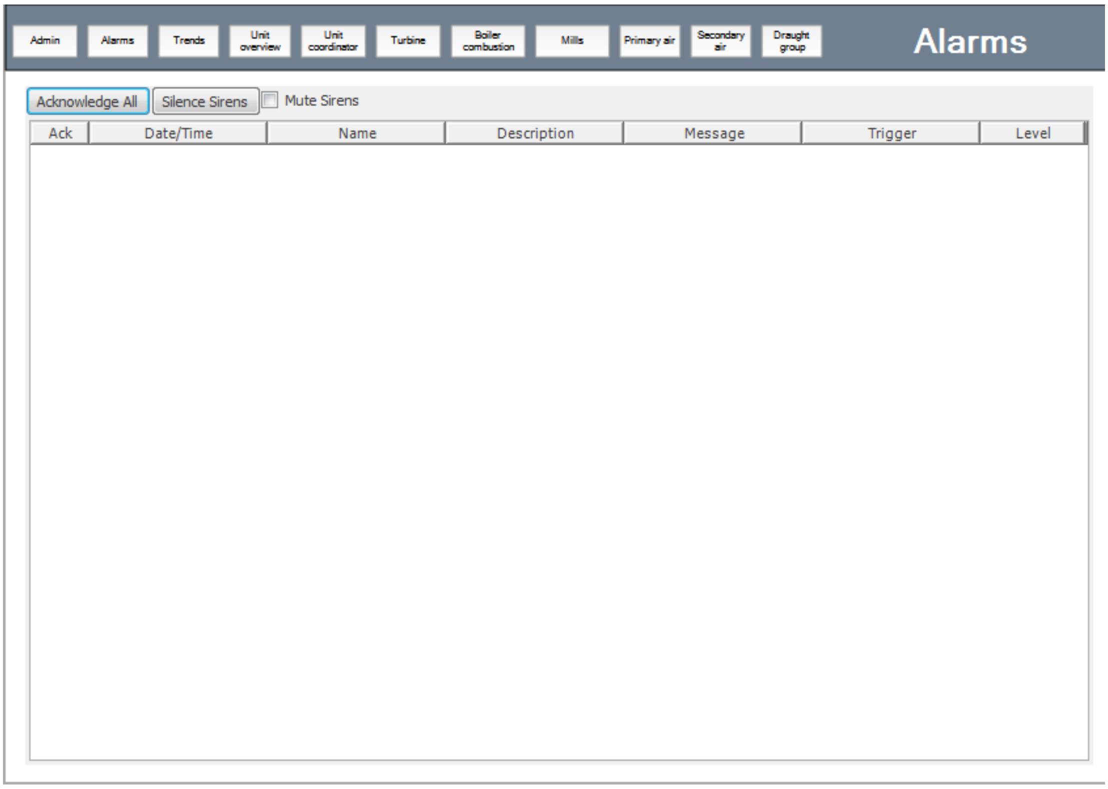

Figure F.7 - Alarm Panel HMI in Flownex® environment

Appendix G - Thermal-fluid model

In order to start the solver for the thermal fluid model in Flownex®, the solver needs to be given initial guess values in order to solve steady state. After the solver has solved steady state, it can be run in transient mode. In order to give the thermal-fluid model initial guess values, the flowing steps must be done completed:

1. On the FD fans page, disconnect the Furnace Pipe (2) and excel transfer (1) links from Furnace Inlet node and connect to Node – 968 (3).

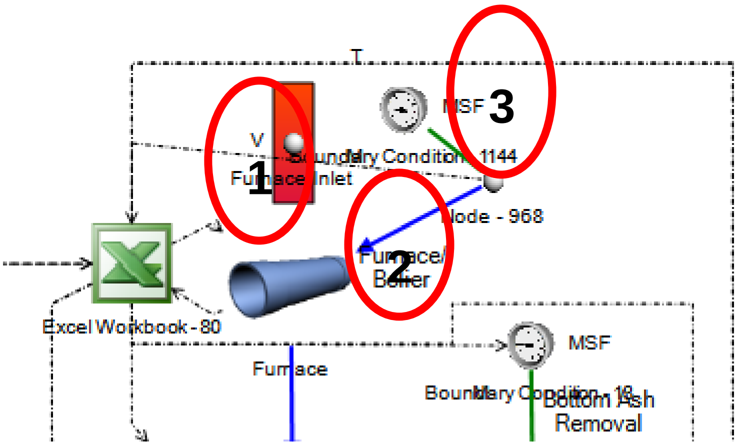

Figure G.1 - Furnace steady state initialization

2. On the Mills page, connect the floating boundary condition to the Furnace Inlet node.

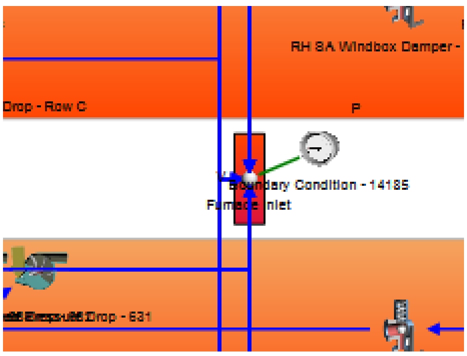

Figure G.2 - Windbox steady state initialization

3. Run steady state. After steady state is complete, detach the boundary condition from the Furnace inlet node on the Mills page.

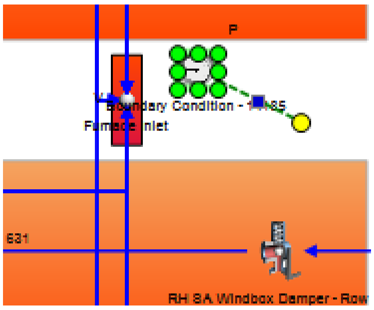

Figure G.3 - Windbox transient initialization

4. On the FD Fans page, re-attach the transfer links from the pipe and the excel sheet back to the Furnace Inlet node.

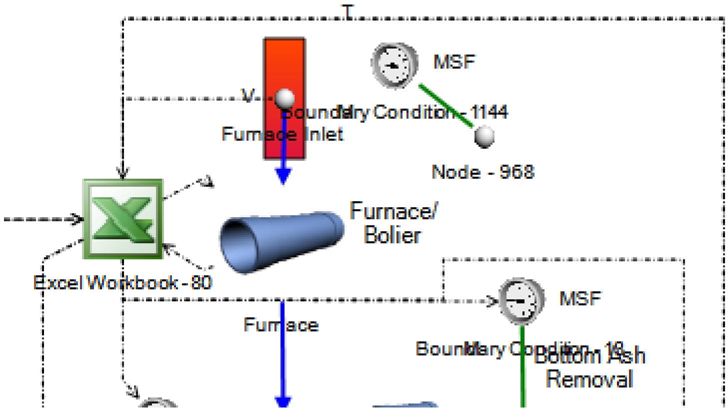

Figure G.4 - Furnace transient initialization

5. The model can now be run in transient. The model takes about 1 minute to stabilize, as there are some values in the system from previous simulations that have not been flushed out.

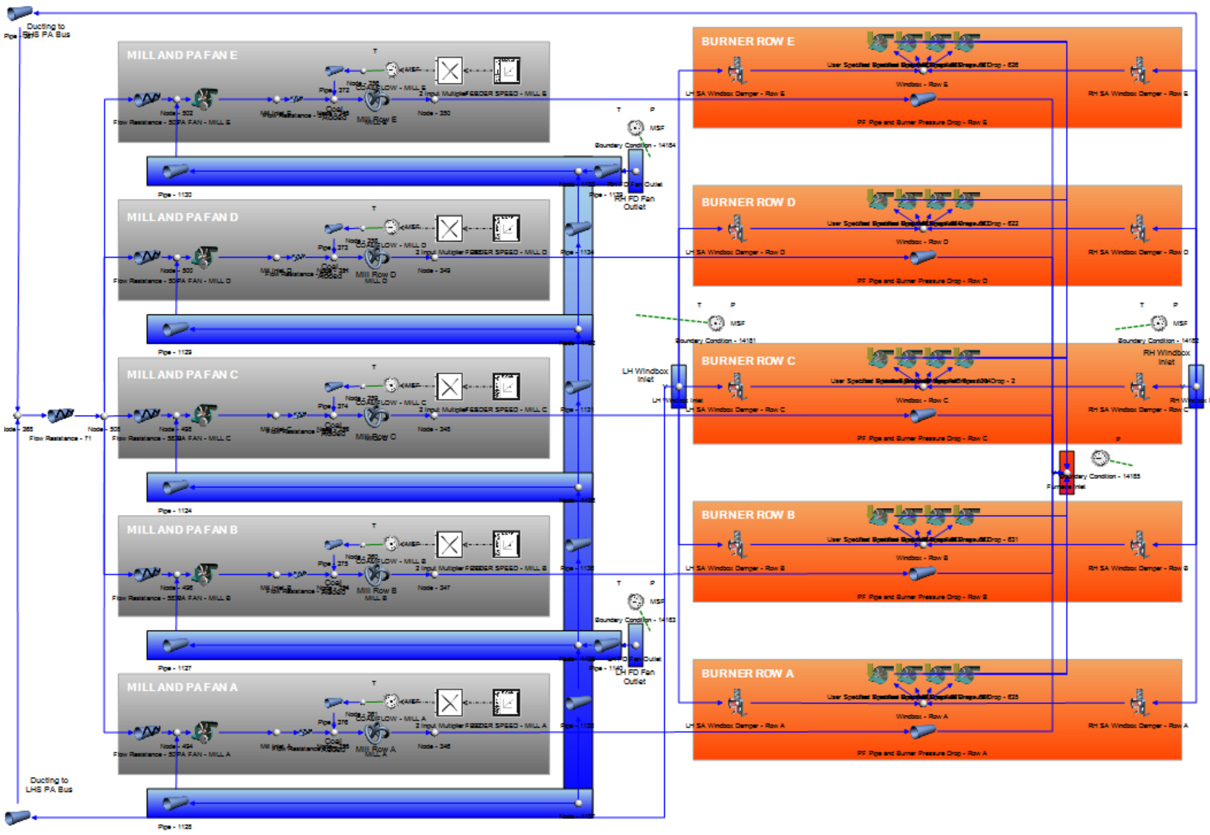

Figure G.5 - Thermal fluid model (Mills, windbox and burner rows) in Flownex®

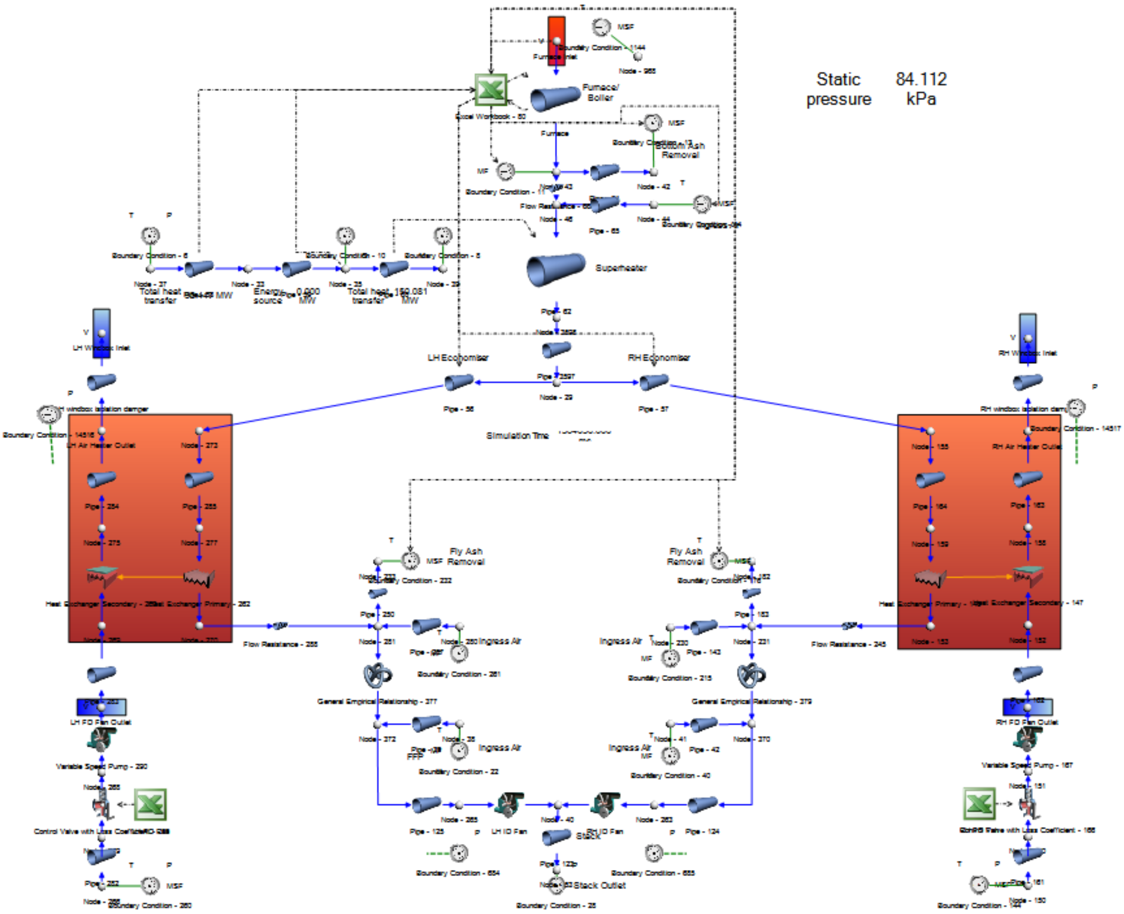

Figure G.6 - Thermal fluid model (FD- and ID fan, furnace, AH) in Flownex®

Appendix H - Additional controller tests

The procedure of testing the remaining two Low-NOx controllers followed the same methodology as described in Section 6.1, where plant data has been extracted from the historian and used as inputs to the two controllers. The graphs below indicate the controller output data taken from site with the controller output of the model.

Figure H.1 shows the damper position opening for a period where the boiler MJ SP has changed. Figure H.2 indicates the windbox pressure SP for a similar transient event.

From the graph below, it can be seen that the SA damper controller follows the same response as the model. A transient load change event caused the dampers to close, and can be seen from the down ramp between 200 s and 500 s. The load adjusted upwards again before falling again between 750 s and 900 s.

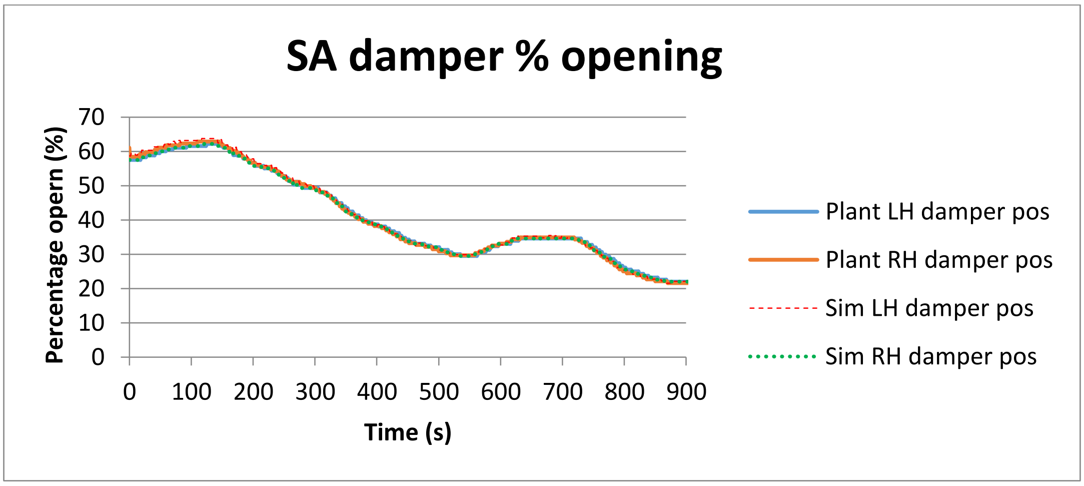

Figure H.1 – SA damper position controller

The windbox pressure controller has been tested and displayed below. The discrepancy can be due to the fact that not all the inputs can be extracted from the historian, such as the FD fan bias. A manual bias of 10 % has been added from 220 s to 420 s to correct the windbox pressure SP.

The windbox pressure SP signals are internally transferred between controllers and not stored on the historian thus cannot be added to the input data of the controller. The data in the graph below indicated an earlier point before the PID controller where data is available. The dynamics of the response are similar, however minor differences can be seen when the upward or downward ramps occur.

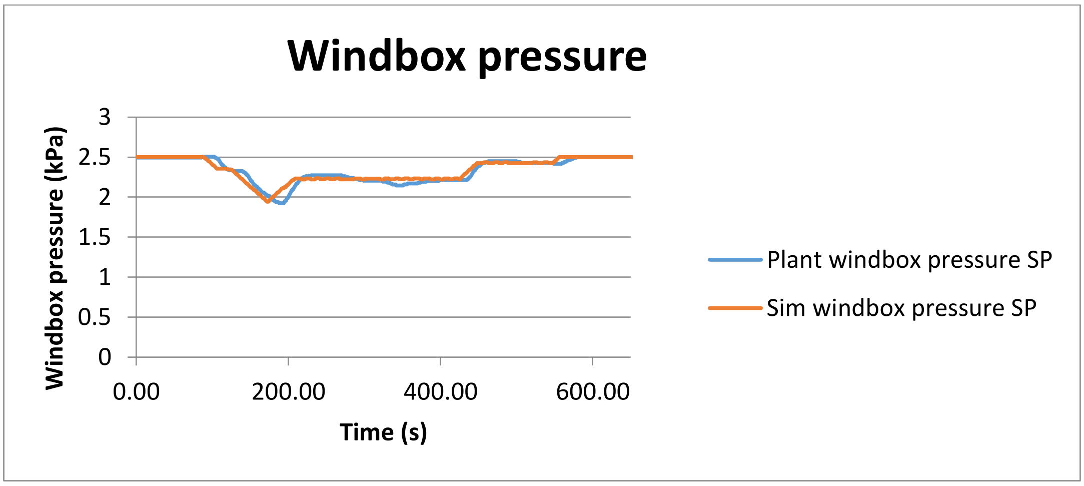

Figure H.2 – Windbox pressure controller