

Power Station Thermal Efficiency Performance Method Evaluation



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February 2021

Submitted to the Department of Mechanical Engineering at the University of Cape Town in partial fulfilment of the academic requirements for a Master's of Science degree in Mechanical Engineering

Key Words: STEP, thermal performance, coal-fired, power plant, sequential perturbation, uncertainty propagation.

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Abstract

Due to global warming, there is an escalated need to move towards cleaner energy solutions. Almost 85% of South Africa's electric energy is provided via Eskom's conventional coal-fired power plants. Globally, coal-fired power plants have a significant share in the power generation energy mix and this will be the case over the next 20 years. A study, aligned with the aspiration of improving the thermal efficiency of the coal-fired power plants, was initiated, with a focus on the accuracy of energy accounting. The goal is that: if we can accurately quantify efficiency losses, the effort can be prioritized to resolve the inefficiencies.

Eskom's thermal accounting tool, the STEP model, was reviewed against relevant industry standards (BS 2885, BS EN 12952-15, IEC 60953-0/Ed1) to evaluate the model uncertainty for losses computed via standard correlations. Relatively large deviations were noted for the boiler radiation, turbine deterioration and make-up water losses. A specific review of OEM (Original Equipment Manufacturer) heat rate correction curves was carried out for the determination of turbine plant losses, where these curves were suspected to have high uncertainty, especially when extrapolated to points of significant deviation from design values. For an evaluated case study, the final feed water correction curves were adjusted based on an analysis done with the use of power plant thermodynamic modelling tools namely: EtaPro Virtual Plant® and Steam Pro®.

A Python® based computer model was developed to separately propagate systematic (instrument) and combined uncertainties (including temporal) through the STEP model using a numerical technique called sequential perturbation. The study revealed that the uncertainties associated with thermal efficiency, heat rate and individual thermal losses are very specific to the state of operations, as demonstrated by individual unit performance and the power plant's specific design baseline performance curves. Whilst the uncertainties cannot be generalized, a methodology has been developed to evaluate any case. A 3600 MWe wet-cooled power plant (6 x 600 MWe units) situated in Mpumalanga was selected to study the impact of uncertainties on the STEP model outputs.

The results from the case study yielded that the thermal efficiency computed by the "*direct method*", had an instrument uncertainty of 0.756% absolute (abs) versus the indirect method of 0.201% abs when computed at the station level for a 95% confidence interval. For an individual unit, the indirect efficiency uncertainty was as high as 0.581% abs.

A study was conducted to find an optimal resolution (segment size) for the thermal performance metrics to be computed, by discretizing the monthly data into smaller segment sizes and studying the movement of the mean STEP model outputs and the temporal uncertainty. It was found that

the 3-hour segment size is optimal as it gives the maximum movement of the mean of performance metrics without resulting in large temporal uncertainties. When considering the combined uncertainty (temporal and instrument uncertainty) at a data resolution of 1 minute and segment size of 3 hours, the “*direct method*”, had a combined thermal efficiency uncertainty of 0.768% abs versus the indirect method of 0.218% abs when computed at the station level for a 95% confidence interval. This would mean that the temporal uncertainty contribution to the combined uncertainty is 2.915% for the “*direct method*” and 14.919% for the “*indirect method*” of the above-stated uncertainties.

The term “STEP Factor” can be used synonymously with effectiveness (percentage of the actual efficiency relative to the target efficiency). For the case evaluated, the mean “*indirect method*” STEP Factor at the station level moved from 86.698% (using monthly aggregated process data) to 86.135% (when discretized to 3-hour segments) which is roughly a 0.189% abs change in the station’s thermal efficiency. This would appear fairly small on the station’s overall efficiency but had a significant impact on the evaluation of the STEP Factor losses and the cost impact by the change in the plant efficiency, e.g. the final feed water STEP Factor loss at a unit level moved from 2.6% abs to 3.5% abs which is significant for diagnostic and business case motivations.

Later the discrepancy between the direct STEP Factor and indirect STEP Factor were investigated as the uncertainty bands did not overlap as expected. The re-evaluation of the baseline component performance data resulted in the final feed water and the condenser back-pressure heat rate correction curves being adjusted. The exercise revealed that there could be potentially be significant baseline performance data uncertainty. The corrected indirect STEP Factor instrument uncertainty was now found to be 0.468% abs which translates to 0.164% abs overall efficiency. The combined uncertainty was corrected to 0.485% abs at a 3-hour segment size which translates to 0.171% abs overall efficiency.

It has been deduced that the figures stated above are case-specific. However, the models have been developed to analyse any coal-fired power plant at various operating conditions. Furthermore, the uncertainty propagation module can be used to propagate uncertainty through any other discontinuous function or computer model.

Various recommendations have been made to improve: the model uncertainty of STEP, data acquisition, systematic uncertainty, temporal uncertainty and baseline data uncertainty.

Declaration

I, Heeran Heerlall, hereby declare the work contained in this dissertation to be my own. All information that has been gained from various journal articles, textbooks or other sources has been referenced accordingly. I have not allowed, and will not allow, anyone to copy my work with the intention of passing it off as their own work or part thereof.

Signed by candidate

H Heerlall

Acknowledgements

The Almighty is acknowledged in all my achievements and endeavours.

I would like to thank my wife, Karen Heerlall and children for the support given during the period of this study and always.

Thanks to my academic supervisor for providing guidance, insight on the subject matter of this study and steering me to acquire new valuable skills in the process of carrying out the study.

Thanks to Eskom's: EPPEI, Energy Efficiency Care Group, Steering Committee of Technology, Hendrina Power Station management and Production Integration Coal management for the support.

Thanks to my team (Hendrina Power Station - Process Engineering Department) for affording me time through their flexibility and diligence in their duties.

Thanks to Matimba Power Station's –Performance and Test Department for the data provided.

Thanks to Kusile Power Station's –Performance and Test Department for including me in their performance tool development.

Thanks to Duvha Power Station's –Performance and Test Department for access to plant data, and signal processing tools.

Thanks to Nick Moolman for sharing his wisdom and information on the subject matter.

Thanks to the academic team at the Department of Mechanical Engineering at UCT for contributions and insight and advice during course work and colloquiums.

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1. Nomenclature

1.1. General symbols

C_p	Specific heat capacity at constant pressure (J/kg.K)
Eff or η	Efficiency
h	Specific enthalpy (J/kg)
h	Hour
i	Range variable – each power cycle unit (i.e. 1..6 for a 6 unit power plant)
j	Range variable - generic
J	Energy
k	Empirical constant
L	Loss (%)
m	Mass
M	Molar mass (kg/kMol)
$\dot{m}$ or $\dot{m}$ or MFR	Mass flow rate
N, n	Number
P	Pressure
P or Pow	Power
PF	Power factor
Q	Heat
S	Sample standard deviation
T	Temperature
t	Time
u	Uncertainty
V	Volume
w	Absolute humidity (kg/kg)
x	Mass fraction (kg/kg)
y	Volume fraction (V/V)

Greek symbols

η or Eff	Efficiency
μ	Mass ratio relative to the mass of fuel
σ	Population standard deviation

1.2. Acronyms and abbreviations

Abs/abs	Absorbed / absolute
ACC	Air Cooled Condenser
Acc /Acct	Accounted
Act	Actual
Adj	Adjustment
AH	Air heater
AI	Abrasive Index
Amb	Ambient
AP	Available plant (running plant)
AR	As-received / as-fired

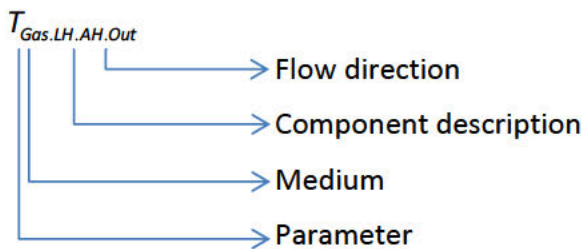
AS	Atomizing steam(for fuel oil firing)
ASME	American Society of Mechanical Engineers
AT	Acceptance test
Aux	Auxiliary
AVL	Average load generated
BA	Bottom ash
BD	Blow down
BFPT	Boiler feed pump – turbine driven
BMCR	Boiler maximum continuous rating
Boil	Boiler
Bool	Boolean
BP	Backpressure (Condenser Pressure)
BR	Burn rate
BS	British Standard
BSI	British Standards Institute
Ce	Carbon equivalent
BCEGB	British Central Electricity Generating Board
CEP	Condensate extraction pump
CF	Correction factor
CIR /CIG	Carbon In refuse / Carbon in grit
CLF	Capability loss factor (unavailability)
CO	Carbon Monoxide
Comb Prod	Combustion products
Comm	Commissioning
Cond	Condensate
Cons	Consumption
Corr	Correction or corrected
CSV	Comma-separated values
Cu	Unburned coal (fraction of coal-fired)
CV	Calorific value
DA	Dry Air
Depres	Depression (difference between LP turbine exhaust temperature and steam saturation temperature at low-pressure exhaust pressure)
Det	Deterioration
DFC	Mass ratio of Dry Flue Gas to 1kg Carbon burned
DFG	Mass ratio of Dry Flue Gas to 1kg fuel burned
DIN	Deutsches Institut für Normung (German Institute for Standardization)
DMAIC	Define, Measure, Analyze, Improve and Control
EFP	Electric (driven) feed water pump
EM	Excess moisture
EPPEI	Eskom Power Plant Engineering Institute
Equiv	Equivalent
Extr	Extraneous
FA	Fly ash
FC	Fixed Carbon
FD	Forced draught fan
FO	Fuel oil
FW	Feedwater
Gen	Generator
GQ	Gaussian Quadrature
GT	Generator transformer

HGI	Hard Grove Index
HPT	High-pressure turbine
HR	Heat rate
HV	High voltage
IEC	International Electrotechnical Commission
Imp	Import
Incr	Incremental
IPT	Intermediate pressure turbine
ISO	International Organization for Standardization
L	Loss (%)
Leak	Leakage (%)
LF	Load factor
LH	Left hand
LPT	Low-pressure turbine
LS	Live Steam (steam at high-pressure turbine inlet)
LV	Low voltage
MCR	Maximum continuous rating
MCS	Monte Carlo simulations
MF	Moisture-free Basis
moist	Moisture
MP	Measurement point
MR	Mill rejects
MS	Main steam
MU	Make-up (demineralized water)
MV	Medium voltage
NER	Normal economic rating
NL	No load
OL	Off -load
Opt	Optimum
PCLF	Planned capability loss factor (%) -the measure of planned unavailability
Pract	Practical
R&E	Revenue and expenditure
Rad	Radiation
RC	Radiation and convection
ref	Reference
ReH	Re-heater
Rej	Rejection (To Atmosphere)
RH	Right hand
RSS	Root sum square
RT	Run time
RW	Raw water
SA	Steam air heater
SAH	Sulphur
Sat	Saturation
SB	Station board
Sby	Standby
SD	Shutdown
SF	STEP factor (actual – target)
SFP	Steam (driven) feed water pump
SM	Surface moisture
STEP	Station Thermal Efficiency Performance

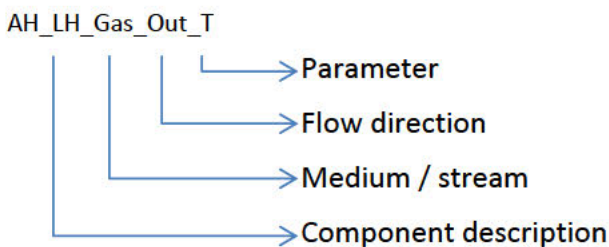
Stm	Steam
Stn	Station
SW	Spray water
Targ	Target
TM	Total moisture
TMCR	Turbine maximum continuous rating
Turb	Turbine (HP+IP+LP)
Tx	Transformer
U	Unit / cycle
UB	Unit board
UC	Unburned combustibles
UCF	Unit capability factor
UCLF	Unplanned capability loss factor (%) -the measure of unplanned unavailability
Unacc / Unacct	Unaccounted
USO	Units sent out (electricity transmitted to the grid)
Var	Variance
VDI	Verein Deutscher Ingenieure (Association of German Engineers)
VM	Volatile matter
WP	Works power
WW	Waste water

1.3. The naming convention for equations and program variables

It was attempted to maintain all equations in this text in a standardized form with symbols and abbreviations described in sections 1.1 and 1.2. See naming convention applied to equations below:



Generally, program languages have very specific rules for the naming variables. For results and graphs that are produced from programs specifically coded in this research, the following convention had been used:



Refer to Appendix D and Appendix E for a list of program variable tags and their detailed descriptions.

1.4. Definitions

Term	Description
Aux / Works Power	Electric energy consumed by the power plant in the process of generating electricity i.e. supplied to motors, heaters, etc.
Check Meter	2 nd Electrical Meter to validate the Main Meter (in series)
Cycle / Unit	Includes all inputs, all outputs, and processes for electric power generations. In a coal-fired station, it would start from coal supply to transmitting electricity onto a power grid. (Common/auxiliary plants, boiler plant, turbine plant and electrical plant)
Direct Method	The thermal efficiency of a system that is determined by only quantifying the energy flowing into a system and the desired energy output. $\eta = \frac{E_{Output}}{E_{Input}}$
Energy availability factor	The ratio of the available energy generation over a given period to the reference energy generation over the same period.
Extraneous Aux Works Power	Electric energy used for non-generating purposes i.e. lighting, compound supply.
Grid	The electrical network that connects power producers to the consumers. It consists of power generators, high voltage power lines, sub-stations and medium voltage distribution lines.
Heat Rate	The heat rate is the amount of energy used by an electrical generator/power plant to generate one kilowatt-hour (kWh) of electricity. It is the inverse of thermal efficiency.
Hot Standby Time	The time at which heat is used when the unit is off-load.
Indirect Method	The thermal efficiency of a system that is determined by quantifying energy losses as a percentage of the total energy input. The principle employed is that the energy output must be equal to

Term	Description
	the input energy minus all the losses. $\eta = 100 - \sum Losses$
Loss	Any form of energy released except for sent out electricity.
Main Meter	1 st Electrical Meter that is in series with another.
Make-up Heat Ratio	The ratio of energy in 1 kg of water lost from the cycle to 1 kg of steam raised.
Normal Economic Rating	The unit rated generating capacity (electrical power generated) at max efficiency. Typically 80% of the maximum continuous rating.
Permanent Data	STEP refers to non-volatile data as permanent data. This includes design ratings and correlation coefficients determined during acceptance testing.
Sent Out Energy	Energy transmitted to the national electric grid i.e. generated power minus the works power (parasitic load).
Std / Standard Coal	Coal qualities at the time of acceptance testing.
STEP Factor - Direct	The percentage of the actual efficiency realized when compared to the target. i.e. $SF = \frac{\eta_{Actual}}{\eta_{Target}} \times 100$ using the direct method of evaluation.
STEP Factor - Indirect	The percentage of the actual efficiency realized when compared to the target using the indirect method of evaluation. i.e. $SF = 100 - \sum Losses$
STEP Factor Loss	Actual loss % - Target loss %
Turbine Cold Start	Start after 30hr from last the operation.

Term	<i>Description</i>
Turbine Hot Start	Start before 30hr from last the operation.
Unaccounted Losses	The difference between direct (through measurement) energy accounting and indirect methods (calculations such as heat balances).
Unit Capability Factor	The ratio of the available energy over a given period to the maximum amount of energy that could be produced over the same period.

2. Introduction

South Africa and Africa as a whole is currently faced with a significant challenge of meeting its energy demand whilst transforming to cleaner electric energy production. Eskom is a state-owned power utility that manages the distribution, transmission and dispatching of electricity on the South African power grid. Almost 85% of South Africa's electric energy is provided via Eskom's conventional coal-fired power plants [1]. One of the challenges identified is the ageing of Eskom's power generation fleet with limited capital to meet the maintenance requirements for optimal performance and reliability. Over the last decade or two, there has been a great focus on minimizing load shedding which might have meant that some of the assets would have been operated at higher load factors and in some cases exceeding recommended maintenance intervals, to compensate for diminished capacity. A significant portion of the power production fleet is in the final 10 years of its designed operating life. Six out of the thirteen fully commercial power plants are to be decommissioned by 2030 as per the Integrated Resource Plan 2018 Update [2]. Naturally, significant investments in these power plants would be curbed as it would be difficult to justify a return on investment for a short remaining operating life.

A consequence of the cited challenges and constraints is the decline in the fleet's thermal efficiency. Thermal efficiency is an indication of the state of the plant's performance and correlates with the plant's availability. A lower thermal efficiency will result in: plant components having to work near design limits for extended periods which reduces the remnant life of the components, or the power plant not being able to achieve the rated generating capacity. The improvement of a power plant's thermal efficiency should contribute positively to the power generation capacity and is a significant aspect in reducing the cost of operations.

The path to recovery would require some engineered methods of getting the maximum performance gains with minimum capital injection. Whilst there are various tools employed in industry, Eskom being the largest power producer in Africa has adopted a program called Station Thermal Efficiency Performance (STEP) to evaluate the thermal performance of their coal-fired power plants.

The goal of this research is to improve the means of efficiency and thermal loss evaluation for coal-fired power plants so that improvement initiatives can be confidently justified. A key focus of the study is the evaluation of the accuracy of the stated method that is used.

2.1. Purpose

South Africa is the largest power producer in Africa [3]. Eskom claims to produce 95% of this power [1], with 90% of its generating capacity in the form of conventional coal-fired power plants [4]. These plants employ the typical regenerative-reheat Rankine cycle where: the turbines are driven by superheated steam (see Figure 2-1), the LP turbine exhaust steam is condensed via condensers supplied by wet or dry cooling water systems, the condensate is preheated by regenerative feedwater heaters and steam is generated by pulverized fuel (PF) boilers. Eskom uses a thermal performance model called STEP to evaluate the Rankine cycle performance and identify losses in the power generation process. Although there are differences in technology, such as drum-boilers vs once-through, air-cooled condenser (ACC) vs wet natural draught cooling towers, subcritical vs supercritical boilers, reheat and non-reheat cycles, the model uses a standardized approach with a few differences in the calculation methodology applied. The differences in the calculation methodologies are augmented with customized inputs for each power station. There is also functionality to compensate for differences in the configuration (positions of measured inputs) and technology (mainly the cooling water system employed).

The STEP model intends to provide an assessment to quantify the state of operations and monetary impact for the deviations from ideal or expected performance (see section 4.1 for more details). The calculation principles of STEP are based on industry standards for acceptance testing of boilers [5] and turbines [6], which typically employ energy balances based on the Rankine cycle thermodynamics (see Figure 2-1: Diagram of a typical coal-fired thermal power station [9], the principles are further elaborated in section 4.1 and Appendix B).

The current topic for research and development was initiated from the need for continuous improvement on the thermal efficiency performance/accounting tools. In the current global context, there is a strong focus on cleaner electricity production coupled with affordability. Even though coal-fired power plants are viewed as a “dirty” production process, it is envisaged that coal-fired generation will have a significant contribution to the energy mix in the next fifty years to come [7].

In the South African context, the power plants are ranked in merit order for the dispatching of electricity to the national grid. The ranking is determined predominantly by the cost of primary energy. The power plant industry is transitioning to competitive dispatching of energy that considers the cost of productions, thermal efficiency and emission offsets such as carbon tax [8].

STEP is an instrument that can be used to drive the medium-term objectives of environmental sustainability and cost reduction through energy efficiency maximization. In the current work, the STEP model is extended to evaluate instrument and temporal (random) uncertainties on the

model output values. The quantification of these uncertainties, and insights gained from the STEP modelling approach, could lead to an increase in accuracy. To implement the uncertainty estimation, a computer model of the STEP calculation methodology is developed using the Python 3.8 programming language. During the development of the computer model, the calculation approach will also be reviewed.

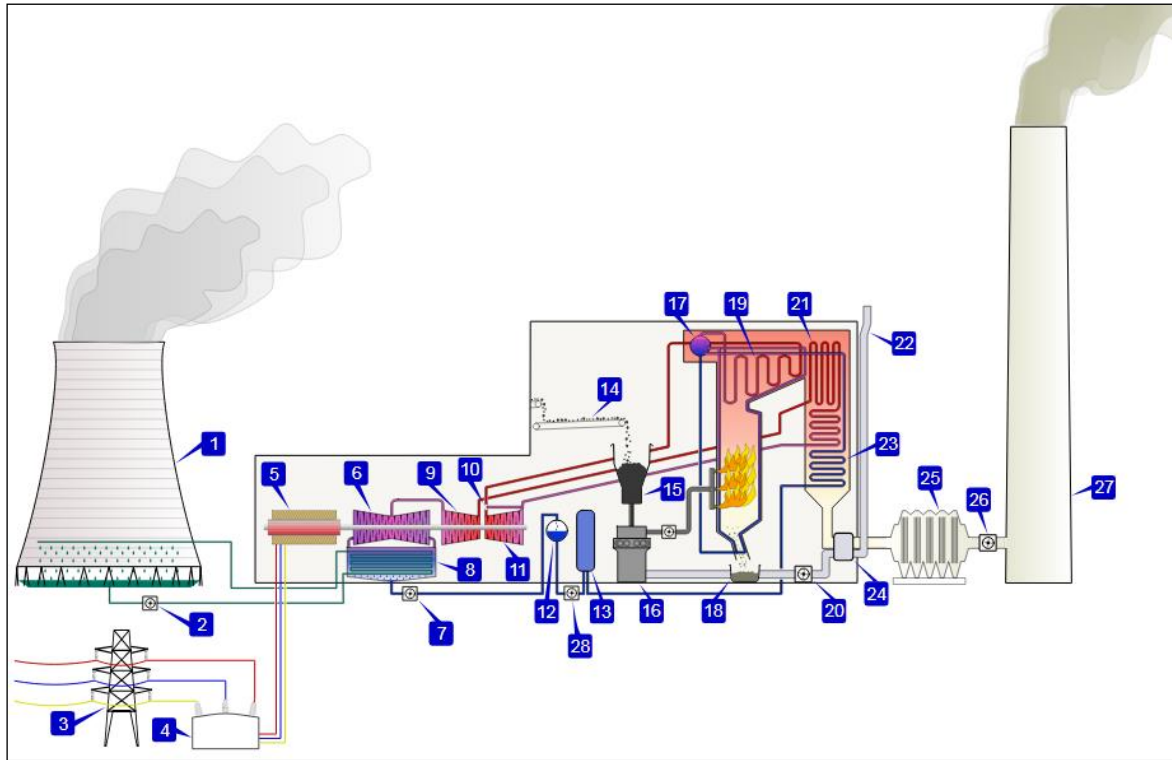


Figure 2-1: Diagram of a typical coal-fired thermal power station [9]

Table 2-1: Legend to Figure 2-1

No.	Description	No.	Description	No.	Description
1	Cooling tower	10	Steam control valve	19	Superheater
2	Cooling water pump	11	High-pressure steam turbine	20	Forced draft fan
3	Transmission line (3-phase)	12	Deaerator	21	Reheater
4	Step-up transformer (3-phase)	13	Feedwater heater	22	Combustion air intake
5	Electrical generator (3-phase)	14	Coal conveyor	23	Economiser
6	Low-pressure steam turbine	15	Coal hopper	24	Air preheater
7	Condensate pump	16	Coal pulverizer	25	Precipitator
8	Surface condenser	17	Boiler steam drum	26	Induced draft fan
9	Intermediate pressure steam turbine	18	Bottom ash hopper	27	Flue-gas stack

2.2. Goals and objectives

A strong understanding and credibility of such tools are required to influence decision-making at various levels of operations within the power generation industry. These tools are used for the justification and prioritization of both capital and R&E injection to the plant. STEP is prone to errors during configuration, operations and field data acquisition. The study intends to investigate the accuracy of the STEP model by:

- a) Reviewing the STEP calculation procedure against industry standards to identify gaps in the modelling approach and develop a verified computer model of the STEP calculation methodology for further expansions to the calculation approach.
- b) Identifying areas of improvement.
- c) Conducting an uncertainty analysis to estimate the model confidence and identify key areas where measurement can be improved or investigated further. This area of the study will focus on the input measurement uncertainty impact.
- d) Establishing ways to minimize input errors e.g. signal pre-processing. Develop a prototype program to weight process parameters by the magnitude of the electricity generated.
- e) Assessing the impact of the input time-series resolution on the accuracy of the model. This area of the study investigates the impact of temporal uncertainty on the model outputs. Establish an ideal input data resolution with cognisance of computational expense e.g. monthly averages versus hourly averages of process parameters. It is hypothesized that shorter intervals of analysis would discretize the plant operating profile into multiple segments of stable operations that can be compared more accurately with baseline performance data. The averaging of transient input parameters would lead to errors when used with non-linear relationships as illustrated in Figure 2-2.

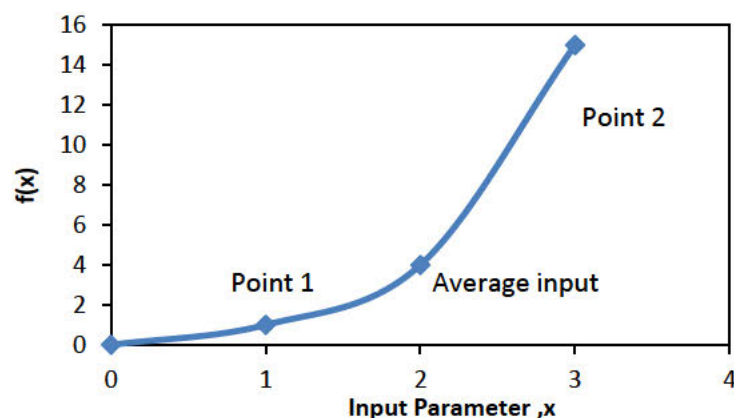


Figure 2-2: Illustration of the impact of averaging inputs rather than the result

The function evaluated at the average input, $x = 2$ (4) does not equate to the average of the results for $x = 1$ and $x = 3$ (8). The above principle demonstrated would be much more critical in the case of flexible operations i.e. load swings for non-baseload power plants. With the increasing penetration of renewable power generation, it is expected that the power plants would operate with an increase in load transients due to the nature of renewable power production.

3. Literature review

This chapter will focus on the evolution of thermal power plant technology and the development of performance standards, the adoption of these standards in the development of the STEP modelling approach and uncertainty propagation methods employed in power plant efficiency evaluation applications.

Thermal power plants

Thermal power plants were developed during the 18th century with the first commercial plant being commissioned in 1882 based on the reciprocating steam engine technology [9]. The first steam turbine was developed in 1884 with a thermal efficiency of only 1.6% [10]. By 1905 steam turbines replaced all reciprocating engines in large central power stations. During the 1900s boilers were constructed with evaporators, economizers and superheaters. By the 1910s condensing turbines with extractions for feed heating operated at a thermal efficiency of 15%. In the 1930s, pulverised fuel boilers with reheat steam had become prominent. Supercritical steam plants were produced by the 1960s. A summary of the technology evolution for coal-fired power plants can be found in Table 3-1.

Table 3-1: Summary of the evolution of coal-fired power plants (adapted from[9][10])

Period	Technology changes	Thermal Efficiencies Achieved (%)
1882	Reciprocating Steam Engines	6
1884	First Steam Turbine	1.6
1900s	Condensing turbine, the addition of economizer, superheater,	
1910s	Addition of feed heating and air preheaters	15
1920s	Once through boilers	
1930s	Inclusion of re-heaters	
1940	Subcritical main steam temperature increases	37
1960	Supercritical steam generation (typically above 250 bar and 565 °C)	47
2016	Ultra-Super critical steam generation (>600°C)	50

World energy outlook

The permanence of coal-fired power generations technologies is threatened by the penetration of renewable energy technologies into the energy and power generation sectors. However, from Figure 3-1 and Figure 3-2, it can be seen that the projections by the International Energy Agency

(IEA) and Statista suggest that coal and other fossil fuels will maintain a significant share in the world's energy mix in the medium-term. Coal-fired technologies are still maintained by 2050 even on the "New Policy Scenario", hence significant effort must be made to improve the thermal efficiencies of conventional fossil plants to reduce the carbon footprint as well as NO_x and SO_x emissions. According to The World Bank, about 40 countries have already implemented carbon pricing globally with significant commitments from others to move in this direction [8]. These countries particularly in Europe have demonstrated this improvement [11].

The South African average power generation efficiency has shown a steady decline over recent years as observed from Figure 3-3 (x and y labels removed for confidentiality reasons, indicative only) The planned and unplanned unavailability has increased from the financial year 2012. A direct relationship between thermal efficiency and plant availability can be observed. In the current state, there are significant opportunities to improve thermal efficiency through enhanced deficiency identification and resolution. There are significant factors that may have a detrimental effect on thermal efficiency which include: inadequate funding, execution of maintenance strategies, remnant design lifespan, skills, coal quality, etc.

Other parts of the world have shown an upward trend in thermal efficiency where carbon pricing has been implemented, particularly in Europe. Thermal efficiency had been on a decline in this region from 2010 but has recovered post-2014 as demonstrated in Figure 3-4 by the European Environment Agency (EEA).

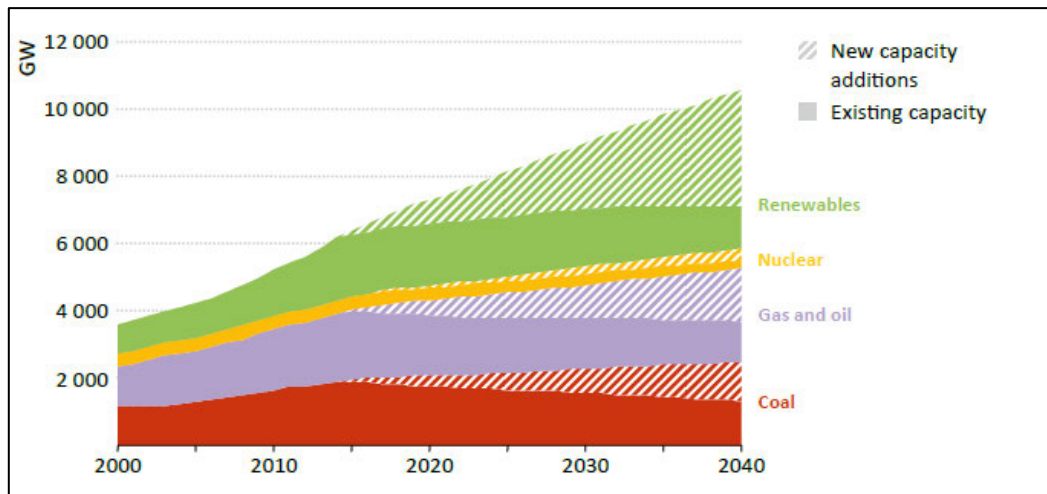


Figure 3-1: World projected energy mix [7]

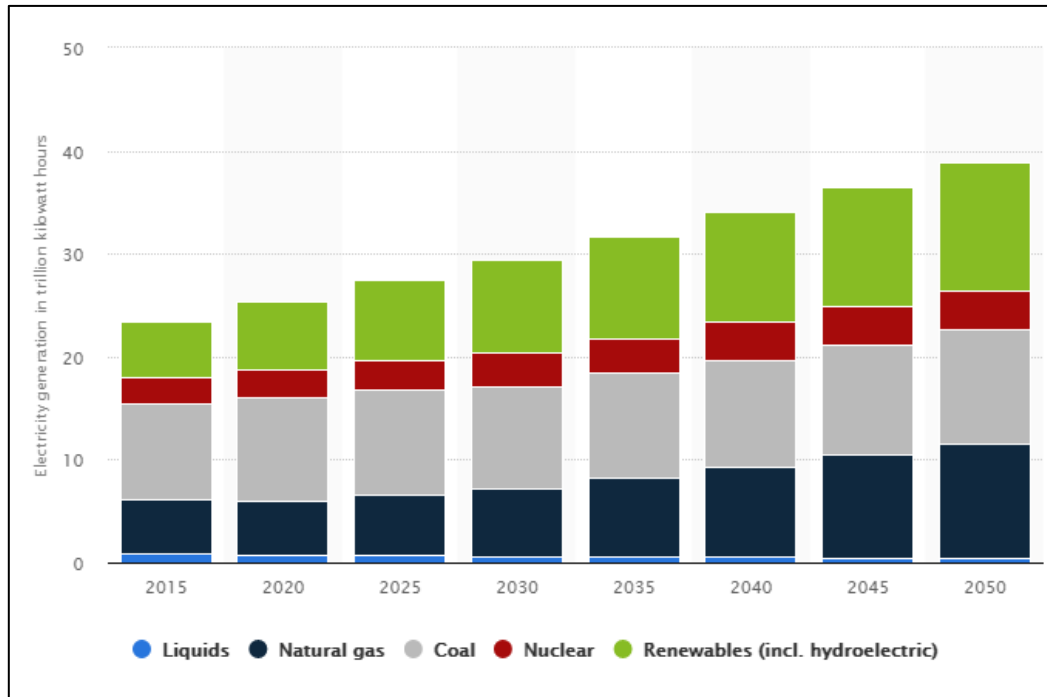


Figure 3-2: World projected electricity generation mix [12]

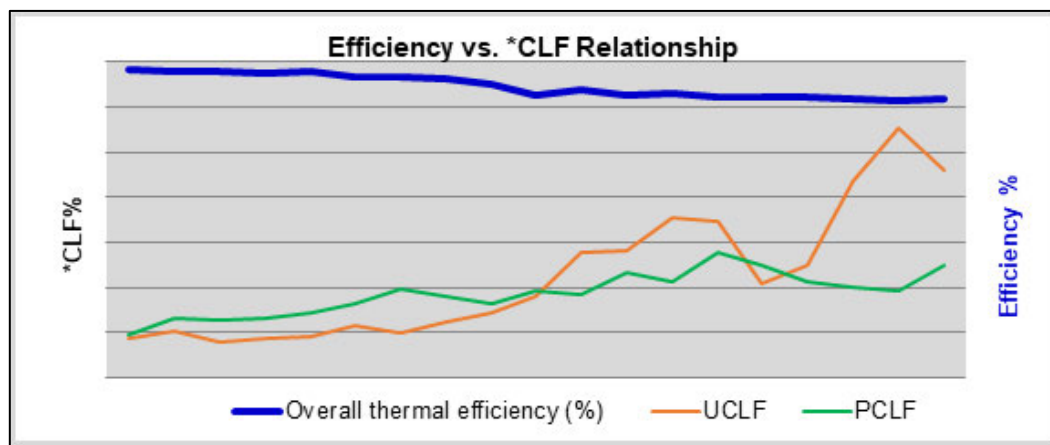


Figure 3-3: South African overall efficiency vs availability [13]

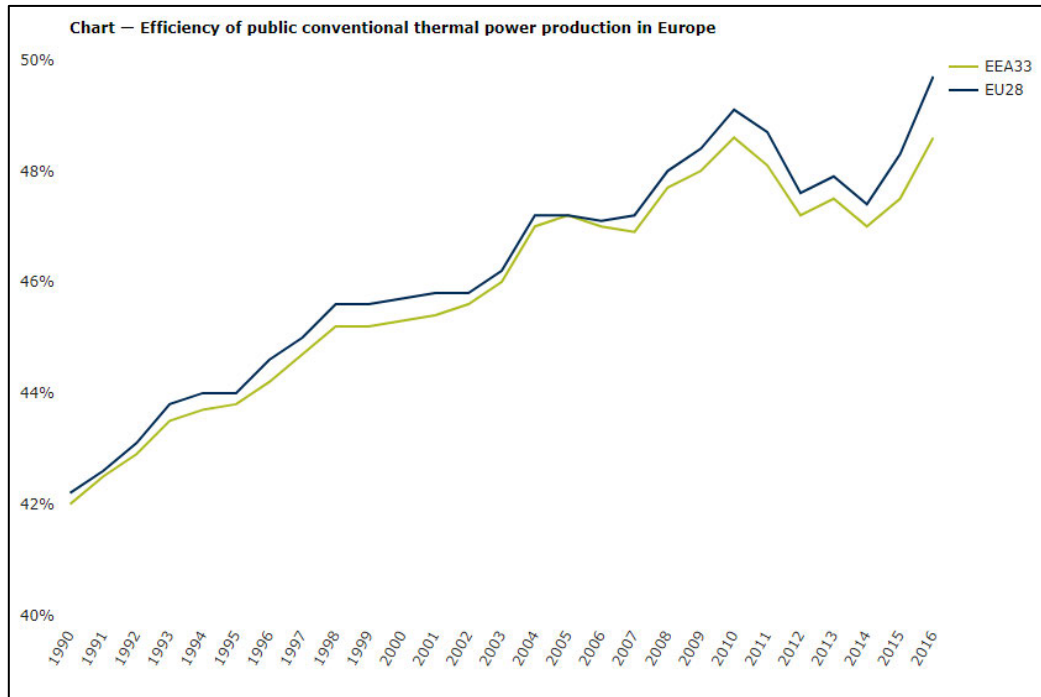


Figure 3-4: Efficiency of public conventional thermal power production in Europe [11]

Thermal efficiency performance methodology

Standard energy balance methods have been employed in the power plant industry since the 1800s. The first ASME boiler test code was established in 1884 (ASME established in 1880) [14]. The DIN 1942 and BS 2885 standards can be traced back to 1975 and 1974 respectively.

Of late, the number of performance standards has reduced due to merging and collaborations of standards by the standards institutes, especially in Europe. The major standards applied to Eskom's generating fleet thermal performance analysis are the: BS-EN standard [15], BS-EN(IEC) standards [6][16] and ASME standards [17][18][19].

From the mid-'90s to current, there is a growing interest in exergy analysis which has yielded various studies on fossil-fired power plants. The exergy efficiency method accounts for non-useful energy by using the 2nd law of thermodynamics i.e. entropy change of a stream to be brought to equilibrium with its surroundings (destruction of exergy) and hence usually yields higher efficiencies when compared to standard thermal efficiency calculation techniques. Many authors deem exergy analysis to be the preferred method of analysing an energy conversion process as it would differentiate between losses to the environment vs internal irreversibilities. Rashad and Elaihy [20] presented both an energy and exergy analysis on a 1260 MWe natural gas power plant in Egypt in 2009 which demonstrated the above point. Aljundhi presented an exergy study done for 396 MWe heavy fuel oil power plant in Jordan also in 2009 [21], and Mahamad et al. presented

an analysis done on a coal-fired power plant in Queensland, Australia in 2013 [22]. The exergy analysis is very useful for component design and quantification of component degradation.

Boiler efficiency principles

Boiler energy accounting can be fairly straightforward as fundamental mass and energy balances can be applied from 1st principles. Here the flue gas composition is calculated from the stoichiometric combustion reactions and adjusted by the equivalence ratio (total air-fuel ratio to stoichiometric air-fuel ratio requirements) and air in leakages. The heat capacity (c_p) of the flue gas stream is determined by weighting the heat capacities of the individual species by its composition mass fractions for a specific temperature [17],[23]. Paraschiv et al. [24] have used similar principles in the development of an online combustion air requirement and combustion product calculator to optimize combustion concerning thermal losses and pollution reduction. The most basic form of efficiency calculation also known as the “Direct Method” [15] or the “Input-Output Method” [17] is applied as per generalized form below:

$$\eta_{Direct} = \frac{\dot{Q}_{Boil.Out}}{\dot{Q}_{Boil.In} + \dot{Q}_{Credits}} \quad (3.1)$$

Where $\dot{Q}_{Credits}$ is the heat other than chemical heat e.g. pulverizer power, recirculating gas fan power, power of circulating pumps and any other drive motors.

The direct method is generally not recommended for boiler performance testing or analysis if the coal mass flows cannot be accurately determined, as in the case where volumetric feeders are used. The “Indirect Method” [15] also known as the “Energy Balance Method” [17] is preferred as the measurement uncertainty has a lesser effect on the result and gives a breakdown of the losses.

$$\eta_{Indirect} = 1 - \frac{\dot{Q}_{Boil.Losses}}{\dot{Q}_{Boil.In} + \dot{Q}_{Credits}} \quad (3.2)$$

The methods for the determination of the boiler losses as per BSI are detailed in Appendix A.1. Studies on boiler efficiency using the ‘Indirect Method’ are abundantly available. Lahijani et al. [25] demonstrated the heat loss method (indirect method) for fire tube steam boilers in 2017. Their study included sensitivity analysis related to the gross CV, ambient temperature and the flue gas exit temperature. Chirag et al. [26] had applied the above principles in the analysis of a 210 MWe unit in India to identify operational opportunities to improve the boiler efficiency by comparing the losses to that of the design losses in 2014. Laubscher and Rousseau [27] have recently (2020) demonstrated the impact of variable particle radiation properties on heat transfer at the various elements in the boiler. It was achieved by 1D modelling to represent heat transfer

across and within the boiler tubes coupled with a CFD simulation to acquire fluid properties external to the wall tubes. The CFD simulation incorporated combustion dynamics. The method could further be expanded to explore the impact of coal properties on the dry flue gas loss. It would be interesting to explore the heat transfer impact as a function of the coal elemental composition, that influences the thermodynamic losses.

Turbine plant efficiency

The turbine plant efficiency is computed conventionally by the method below [16] in generalized form:

$$\eta_{Turb.Plant} = \frac{P_{nett}}{\sum(\dot{m}_j \Delta h_j)} \quad (3.3)$$

where P_{nett} is the power measured at the generator terminal less the power consumed for auxiliaries and j is the flows to which heat is added from external sources. The above method was demonstrated by Geete and Khandwawala [28] which had been applied to a 120 MWe thermal power generating unit. They used the method to study the impact on heat rate by varying the main steam (throttle) temperature. Similar work was carried out by Rout et al. [29] where the output power was also studied. Karakurt and Gunes [30] used this methodology to investigate the turbine performance relative to partial loads.

The specific efficiency of a turbine cylinder is computed by the “Enthalpy Drop” method:

$$\eta_{Turb.Cylinder} = \frac{h_{in} - h_{out}}{h_{in} - h_{isentropic@P_{out}}} \quad (3.4)$$

where $h_{isentropic@P_{out}}$ is isentropic enthalpy (or enthalpy of steam at the turbine outlet pressure and inlet entropy). The word cylinder implies all turbine stages including the inlet valves.

Turbine plant losses or the indirect method are detailed in Appendix A.2. The quantification of losses are derived from the heat rate correction factors associated with parameter deviations from design. These curves are typically supplied by the plant designers. GE Power Generation [31] presented examples of typical heat rate correction curves which are aligned with the requirements of the ASMEs performance test code [32]. There are various turbine process modelling tools that can be used to generate the heat rate correction curves; Akpan and Fuls [33] recently (2020) demonstrated a methodology for developing and validating such models and went on to develop a generalized means of predicting the turbine cycle heat rate as a function of load. The validation

included a comparison to actual performance data from 11 South African coal-fired power plants against models developed with the ETAPro® -Virtual Plant software.

Cycle losses

Works power loss is typically expressed as a percentage of electrical energy used for internal operation in the power plant to the electrical energy that is supplied to the national grid [34],[35]. Naturally, electricity will be consumed by components in the power generation cycle i.e. motors, heating elements, controllers, etc. Therefore, this loss cannot be avoided but it is important to quantify and compare to a baseline, to be able to detect plant performance abnormalities. The measurement is done at strategic locations i.e. unit transformers, station transformers, station electrical boards and unitized electrical boards. Some online performance tools such as EtaPro® can calculate the power consumption by using the current transducer readings for each motor installed in the power plant. Whilst this method is very useful for diagnostics, the uncertainty is considered to be too large for energy accounting purposes and not all components are measured.

Cycle Make-up water losses are usually quantified by measuring the top-up that is required to maintain the deaerator or condenser levels and is expressed as a percentage of the total steam raised. Ideally, the steam-condensate-feed-water system is a closed loop, however practically it is not the case, as losses can be experienced from passing drain/blowdown valves across the cycle, boiler tube and pipe leaks, venting, pump gland leakage, etc. Generally, the boiler and turbine plant manufacturers estimate an acceptable loss relative to the MCR live/throttle steam flow. Eskom targets these losses to be between 0.8 to 1%. The heat efflux through these losses is attempted to be quantified through simple thermodynamics which employs various assumptions (see Appendix A.3.1 for details on a methodology used in industry). A study conducted by Sewlall [36] in 2019 indicated that: for purpose of water accounting in Eskom, it is assumed that 50% of the total make-up is evaporated and the balance is recovered as a liquid into the station drains. It is stated that actual plant data is required to improve this estimate of a typical split between losses at steam and feedwater conditions. There are various texts [37],[38],[39],[40] involving power plant water balances, energy conservation and cycle isolation, that mention feedwater make-up losses, but omit detail in localized quantification and costing. However, these texts do suggest that make-up loss targets could be as low as 0.5%. A study by Kaushik and Khanduja [41] was carried out on a combined cycle thermal plant in 2007. A great effort was made to quantify the contributions to demineralized water make-up using the Six Sigma DMAIC methodology. It was assumed that all of the make-up water supplied is due to losses at main steam conditions.

Fundamental principles of STEP

STEP was developed by the Central Electricity Generating Board (CEGB) in the U.K in 1966. In 1970 STEP was adopted by Eskom and over the years been adapted based on operational experience gained from plants within their fleet [42]. The STEP program baselined the power plant performance as per the acceptance test data acquired during the initial commissioning of each type of unit design. The acceptance tests were based on the boiler performance standards [5],[43] and the turbine performance standard [6]. The current version of STEP is prescribed in an internal standard [34] and has been implemented to run on a centralized application server in 2015 (the STEP model is computed using the application software - ETAPro®). A superseded manual [44], also contains a detailed calculation methodology on how the calculations were previously performed which give some history in the development.

In general, heat rate targets for acceptance tests are produced by applying correction factors deduced by design sensitivity analysis to account for externally imposed conditions that differ from design parameters namely: load factors, ambient temperature, ash in coal, H₂ and moisture in fuel feedstock, power factor, turbine backpressure associated with ambient temperature, etc. The target is then compared to the actual performance test results. The STEP model differs by applying these correction factors when the actual condition deviates from the parameters established during acceptance testing and compare to the actual performance. In South Africa, most of the coal-fired plants employed the British and IEC standards for acceptance testing.

The resolution of the STEP program input is one month (monthly average operating parameters are inputted to the model). The typical outputs of STEP include targets, actuals, SF (STEP Factor) and cost impact of losses reflected in Table 3-2.

Table 3-2: STEP loss categories generated from [33]

Cycle	Boiler	Turbine
Cycle efficiency	DFG loss	Condenser BP loss
Heat rate	CIR loss	FW temperature loss
Aux power loss	H ₂ & moisture loss	Turbine Deterioration loss
MU loss	Radiation loss	Re-heat steam temperature loss
	Mill reject loss	Main steam temperature loss

Exergy analysis considers the conditions of surroundings to determine the quality of energy available, thereby giving a more realistic measure of effectiveness. It only considers the useful portion of energy that is to be transformed as a maximum base for effectiveness analysis. The SF approach achieves this by calculating the deviation in thermal performance from the ideal case (maximum base), which essentially focuses on what is within the utility's control. The SF method goes further to consider the impact of other externalities e.g. the grid-induced power factors and

load factor. Refer to Appendix B for a detailed calculation methodology in the form of sample calculations or section 4.1 for a summarized calculation flow in the form of a diagram.

Uncertainty analysis

There are two main approaches to uncertainty propagation, namely the derivative approach which is also known as the *Law of error propagation* [44] and the probabilistic approach [52]. Both these approaches have various numerical methods for their implementation. Whilst there is a multitude of approaches and variants of these methods, this study will be limited to some of the more popular methods. General statistics and probability principles are explained in more detail in section 4.3.2.

Law of Error Propagation

Uncertainty indication in power plant thermal performance evaluation has been included in the performance standards in recent revisions and has also been included as a quality measure for acceptance testing contracting. Typical turbine efficiency uncertainty for turbine acceptance should be within 0.6 -0.9% [16], the typical uncertainty for steam generators that is coal-fired is between 0.4% and 0.8% [17] and the maximum acceptable for the cycle is 3.0% using the direct method [18]. The performance standards as per previous references prescribe a method for uncertainty propagation as per the *Laws of Error Propagation*. Most texts on error propagation make some reference to the GUM- Guide to the expression of uncertainty in measurement by ISO [45], which demonstrate these laws by the equations below (derived from the 1st order Taylor expansion of a function. The laws are synonymous with other standard publishers such as VDI[46] and ASME[47]. BSI has also adopted the GUM which is described by the equations below:

$$u_R = \sqrt{\sum_{i=1}^L \left(\left(\frac{\partial R}{\partial x_i} \right)_{x_i = \bar{x}} \cdot u_{\bar{x}_i} \right)^2} \quad (3.5)$$

The equation (3.5) is used for uncorrelated inputs:

$$u_R = \sqrt{\sum_{i=1}^L \left(\left(\frac{\partial R}{\partial x_i} \right)_{x_i = \bar{x}} \cdot u_{\bar{x}_i} \right)^2 + 2 \sum_{i=1}^{L-1} \sum_{j=i+1}^L \frac{\partial R}{\partial x_i} \cdot \frac{\partial R}{\partial x_j} \cdot u(x_i, x_j)} \quad (3.6)$$

The equation (3.6) is used for correlated inputs:

$$u_{\bar{x}_i} = \sqrt{\sum_{k=1}^K u_k^2} \quad (3.7)$$

The uncertainties are combined by the Root Sum Square (RSS) method as per the equation (3.7),

where:

R - result

u_R - propagated uncertainty to the result of a function at the mean of each input variable

x_i - each variable in a function

$x_j = x_{i+1}$ - sequential pair of variables

$u_{\bar{x}_i}$ - combined uncertainty of variable for a single measurement point

$u(x_i, x_j)$ - estimated covariance of associated with x_i and x_j

u_k - each type of uncertainty (systematic, random-temporal, random-resolution...)

Sequential Perturbation (SP)

Sequential Perturbation is a controlled numerical method that gives the same result as the equation (3.5) as demonstrated by Figliola and Beasley [48]. The method circumvents the need for carrying out the first-order differentiation of complex functions. SP is ideal for smaller amounts of input variables and is relatively computationally inexpensive. This method had already been employed by Moffat [49] in 1988 and demonstrated by Mantheufel [50] in 2013 for thermal fluid applications. Sequential Perturbation is further detailed in section 4.3.1. There are variations in sequential perturbation such as the Sigma Point methods, where the perturbations for each variable are weighted as a function of its probability density function [51].

Monte Carlo

Monte Carlo simulation (MCS) is a probabilistic numerical method where the uncertainty of each variable in a function is randomly varied as a function of its probability density function. MCS was experimented with during the 1930s and developed in the late 1940s for use in nuclear weapons projects [52]. Monte Carlo simulation for uncertainty analysis is currently used in a broad spectrum of applications i.e. finance, engineering, physical science, supply chain, risk management, applied statistics, computational biology, etc.

The MCS method is used in complex functions with a significant multitude of the input variables but can be computationally expensive as the iterations could run into the order of 10^4 to 10^6 before the distribution of the result converges to the specified standard deviation [48]. Padulo et al. [51] have deemed this method as impractical for robust engineering design due to the high number of iterations required for numerical convergence to be reached (see also Figure 3-6: Demonstration of Monte Carlo convergence as a function of the number of iterations [55]).

MCS is the most commonly used method due to its flexibility, minimal limitations and ease of scripting. There are variations in the employment of the method (i.e. Sequential Monte Carlo, Quasi-Monte Carlo, Markov Chain Monte Carlo) to reduce the computational expensive by the improved sampling of the input variables [53]. The method has a reasonable comparison with the GUM [45] as proven by Papadopoulos and Yeung [54] with an average deviation of 0.03% and maximum sample deviation of 0.8% shown in their study.

Figure 3-5 demonstrates the application of Monte Carlo simulation where x' is the true value of any input variable which is estimated to be $\bar{x}$ and R' is the true value of any output variable. Monte Carlo simulations were recently applied (2017) by Keshavarzian in reliability analysis for cyclic fatigue [55]. Figure 3-6 is an example of a convergence graph for a bolt hole damage parameter demonstrated in this study which further demonstrates the computational expense of the method.

The MCS is commonly used as a benchmark in various comparative uncertainty studies. There are multitudes of numerical and probabilistic methods with their variations that are lessor used in the research work involving uncertainty propagation. These include Gaussian quadrature [56], method of moments [51], sigma point [57], polynomial chaos expansion and probabilistic collocation method [51],[58],[59],[60],[61],[62],[60],[63],[64]. Refer to Appendix A.4 for more detail on these techniques.

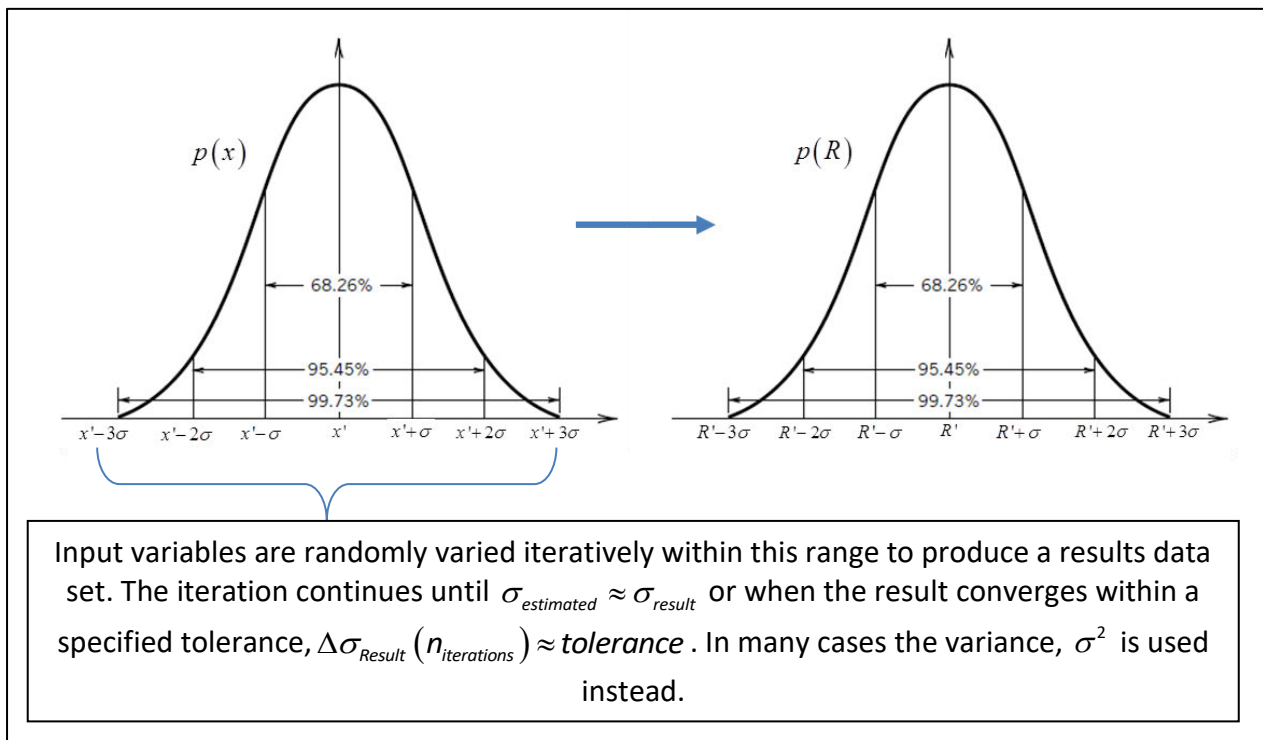


Figure 3-5: Illustration of Monte Carlo randomized iterations for Gaussian distributed inputs and outputs - adapted from [48]

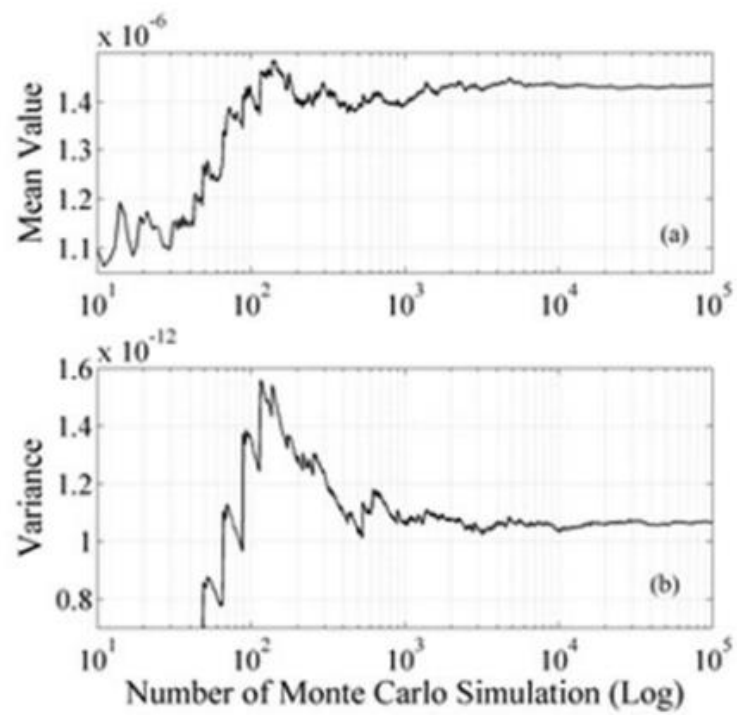


Figure 3-6: Demonstration of Monte Carlo convergence as a function of the number of iterations [55]

4. Methodology

A 6 x 600MWe wet-cooled power plant situated in Mpumalanga-South Africa, was modelled using the STEP methodology. The power plant was selected based on its location, availability of process data, and support of site personnel. See Table 4-1 for technical description.

Table 4-1: Case study - power plant description

Power rating	6 x 600MWe
Boiler type	Twin tower, once through, single re-heat
Main steam pressure	16.6 MPa fixed
Main steam temperature	540 °C
Fuel	Sub-bituminous coal
Cooling	Wet natural draught

4.1. Understanding STEP

Eskom’s thermal accounting models (server-based EtaPro® application and Excel versions) were reviewed against Eskom’s standard [34] and its referenced industry standards. The STEP calculations are based on general power plant thermodynamics, heat and mass balances. In a few calculations, organizational intelligence such as turbine deterioration factors and start-up heat had been included in the calculations. Certain power cycle component efficiency calculations are technology-specific and require certain modifications; for example, the calculation of wet-cooled vs. dry-cooled condenser performance and the effect on the overall power cycle efficiency it has.

It is important to reiterate some of the concepts and terminology that is used in STEP to understand the findings and results of the current study. Thermal performance can be measured/calculated using two methods. The first being: the “Direct Method” also known as the “Input-Output Method”. Here the thermal efficiency of a system is determined by only quantifying the energy flowing into a system and the desired energy output. So the conventional rule applies:

$$\eta_{Direct} = \frac{E_{Output}}{E_{Input}} \quad (4.1)$$

In the case of a power plant, the desired output is the electrical energy sent out to the grid, the input energy would be the chemical energy of the fuel. The second approach is the “Indirect Method” also known as the “Energy Balance Method”. Here the thermal efficiency of a system is determined by quantifying energy losses as a percentage of the total energy input. The principle employed is that the energy output must be equal to the input energy minus all of the losses.

$$\eta_{Indirect} = 100 - \sum Losses \quad (4.2)$$

Ideally, both methods should give the same value; however, a deviation can be expected due to the uncertainty of the measurements used in both approaches.

From Figure 4-1 it can be observed that STEP intends to normalize thermal performance against the target efficiency, so the STEP Factor (SF) is the percentage of the target efficiency achieved. The STEP Factor can be viewed as a thermal effectiveness metric. The STEP Factor losses are also relative to the target, so the $\sum$ STEP Factor losses and the indirect STEP Factor must add up to 100%. The unaccounted STEP Factor losses will then be the difference between the direct STEP Factor and the indirect STEP Factor. The mathematical expressions can be found below:

$$SF_{Direct} = \frac{\eta_{Direct}}{\eta_{Target}} \times 100 \quad (4.3)$$

$$Loss.SF_j = Loss_{j.Actual} - Loss_{j.Target} \quad (4.4)$$

$$SF_{Indirect} = 100 - \sum_{j=1}^N Loss.SF_j \quad (4.5)$$

where j is the individual losses i.e. Carbon in Refuse, Dry Flue Gas, Hydrogen & Moisture, Backpressure, etc.

Figure 4-2: STEP calculation architecture, illustrates the basic architecture of STEP, where the calculations are categorized into four sections namely the boiler, turbine, cycle and station sections. The outcomes of each section are listed in Figure 4-2. Figure 4-3, Figure 4-4 and Figure 4-5 show an overview of the inner workings of the STEP calculation methodology. The detailed STEP calculations are provided in Appendix B. The station section of the calculation as depicted in the architecture diagram (Figure 4-2), are merely the aggregating of the calculations performed at the unit level to acquire station results.

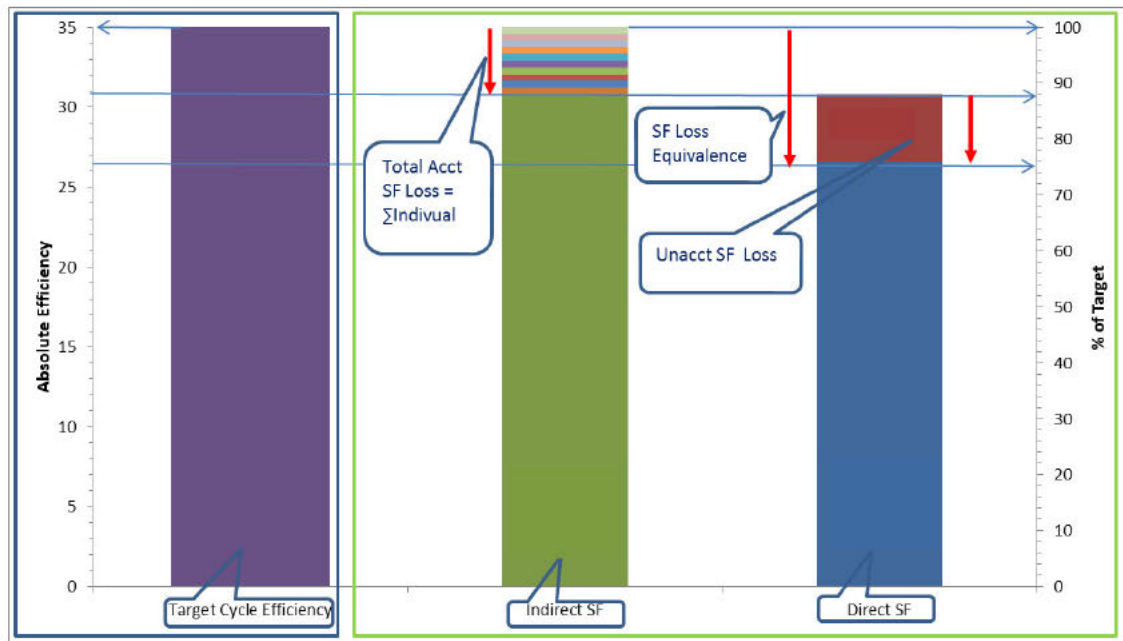


Figure 4-1: Illustration of STEP Factors

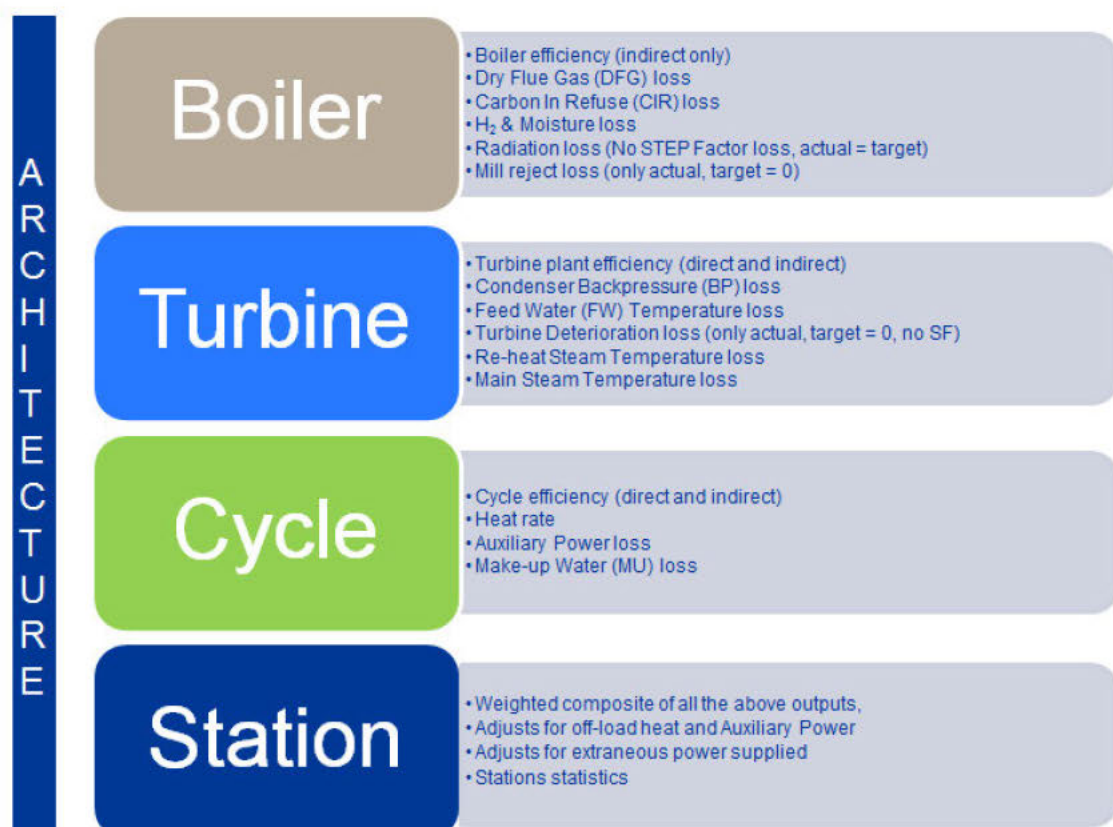


Figure 4-2: STEP calculation architecture

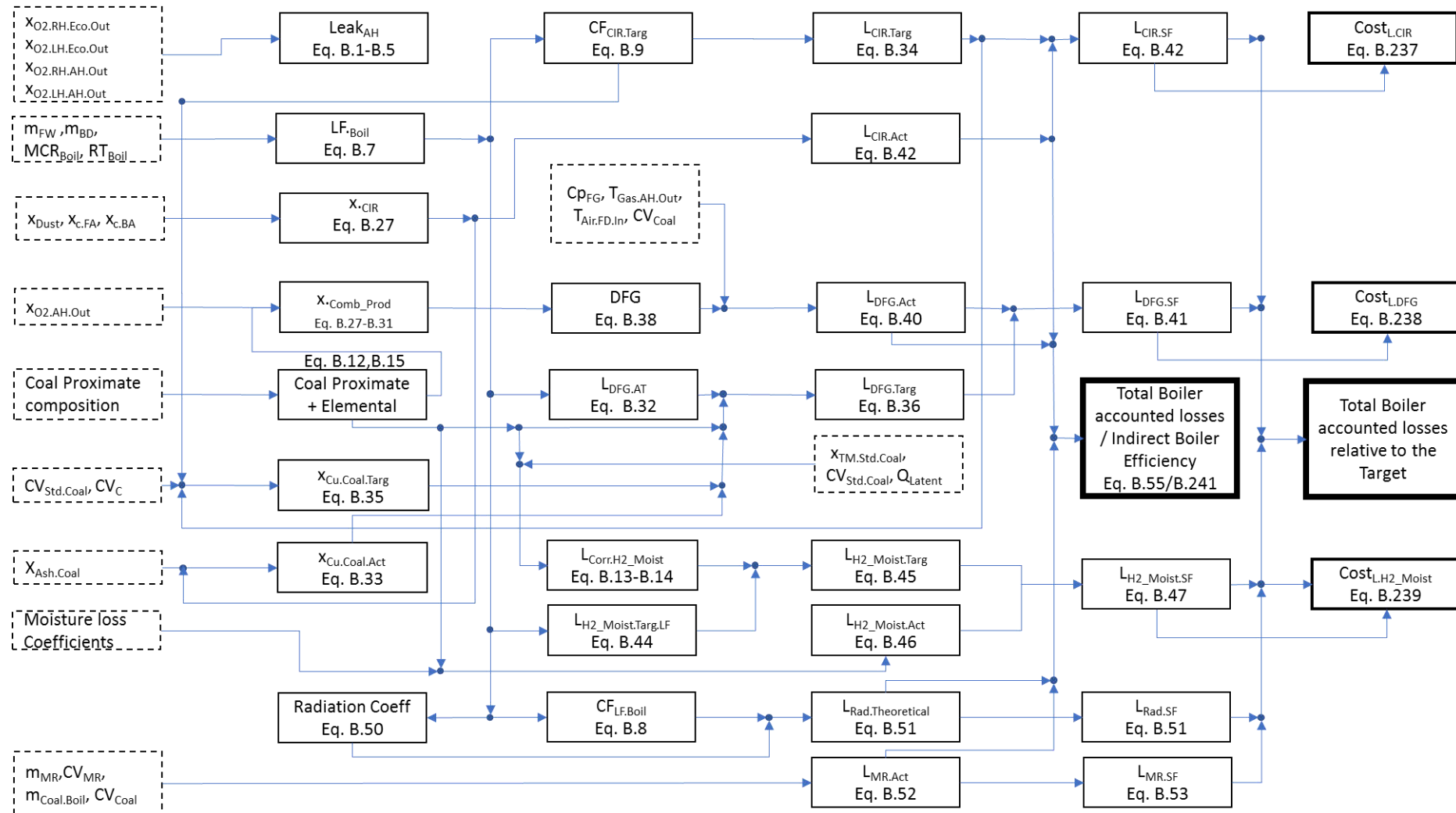


Figure 4-3: STEP boiler calculation sequence

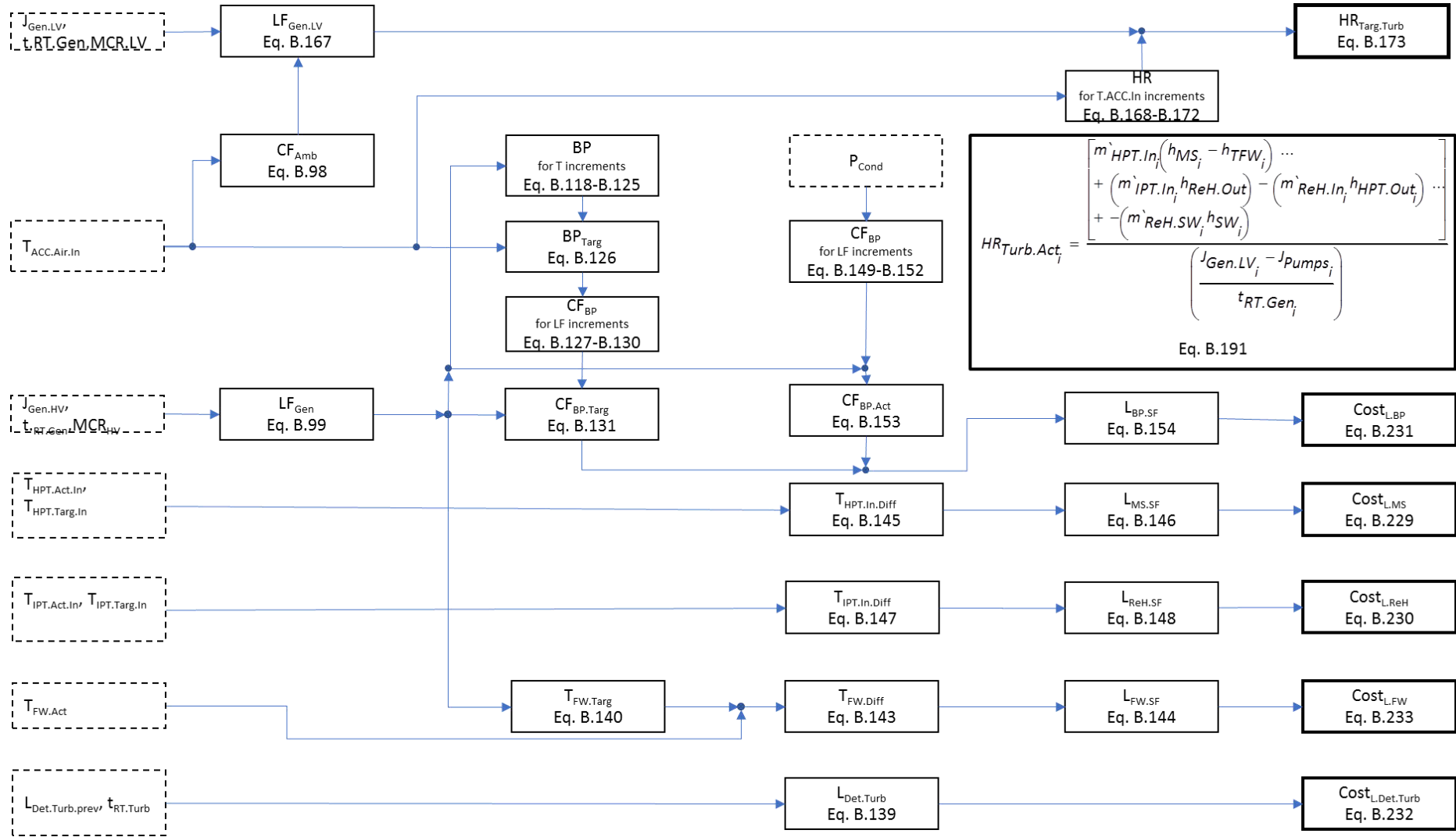
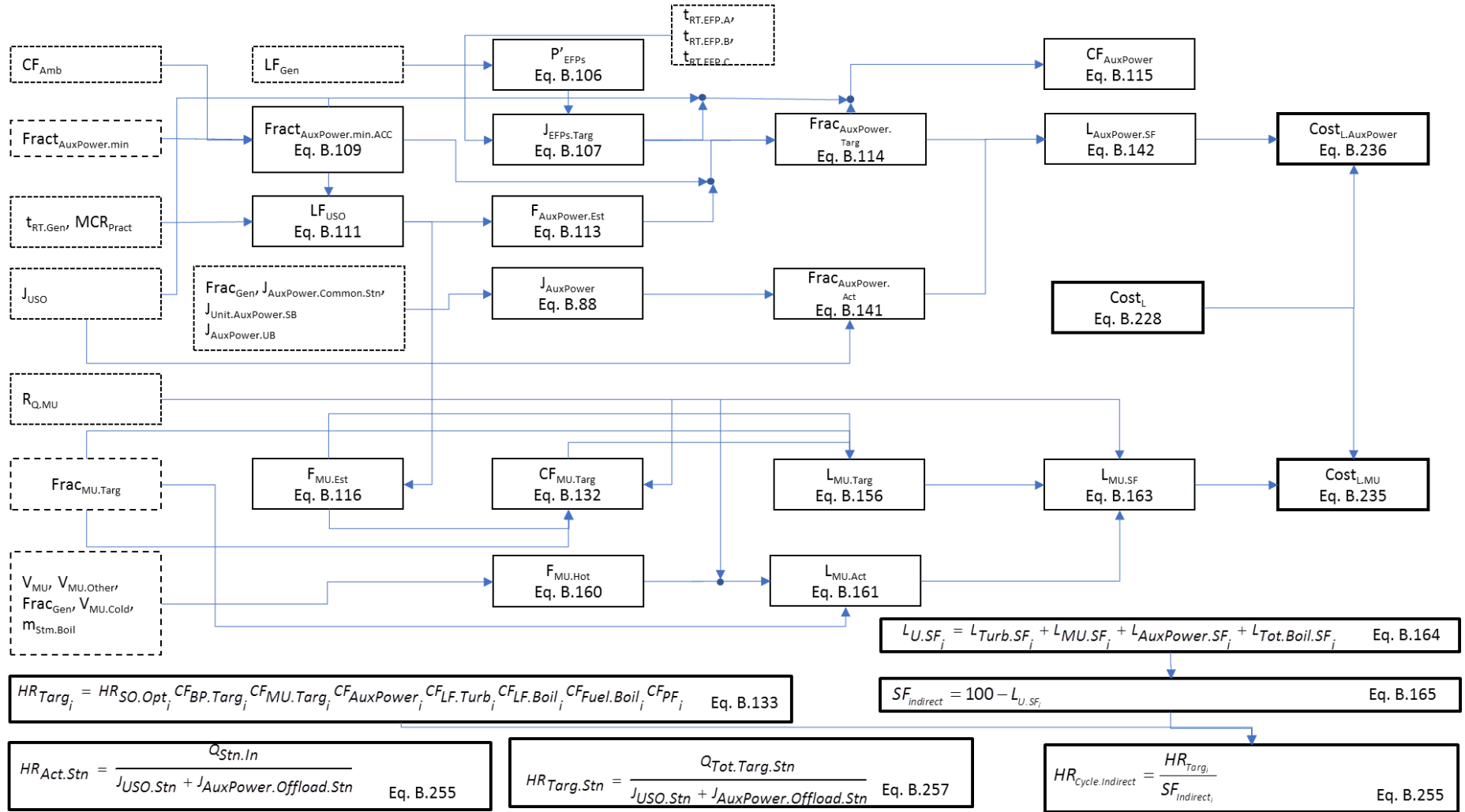


Figure 4-4: STEP turbine calculation sequence



No direct actual HR for cycle at unit level. Probably due to no accurate coal flow. It is calculated at the station level.

Figure 4-5: STEP cycle calculation sequence

The STEP model is developed using a unique tag referencing system (numbering system employed for variables i.e. IDT001, IDB005, IDS100... etc.). Roughly 255 calculations are performed per unit and 60 calculations at the station-level. There are approximately 800 input variables for a 6-unit power plant (refer to Appendix B: Step Calculations for the full calculation methodology). The STEP calculation methodology was deconstructed and interpreted into a computer algebraic software (CAS) platform for readability, understanding the flow of the calculation methodology and performing the verification of the Python computer model results, thereby circumventing the need to perform detailed hand calculations. MathCAD® 15 was the software application chosen as it fulfilled the above-mentioned need with the ability to carry out symbolic computations and error flagging (without having to run and debug code). It was proven to be very useful in determining the sequence of calculations considering: the number of calculations and variables, and that none of the sources reviewed provided a calculation sequence of the STEP calculation procedure. The comparison between the Mathcad® and Python® based models can be found in Appendix G, which serves as the verification of the Python® computer model.

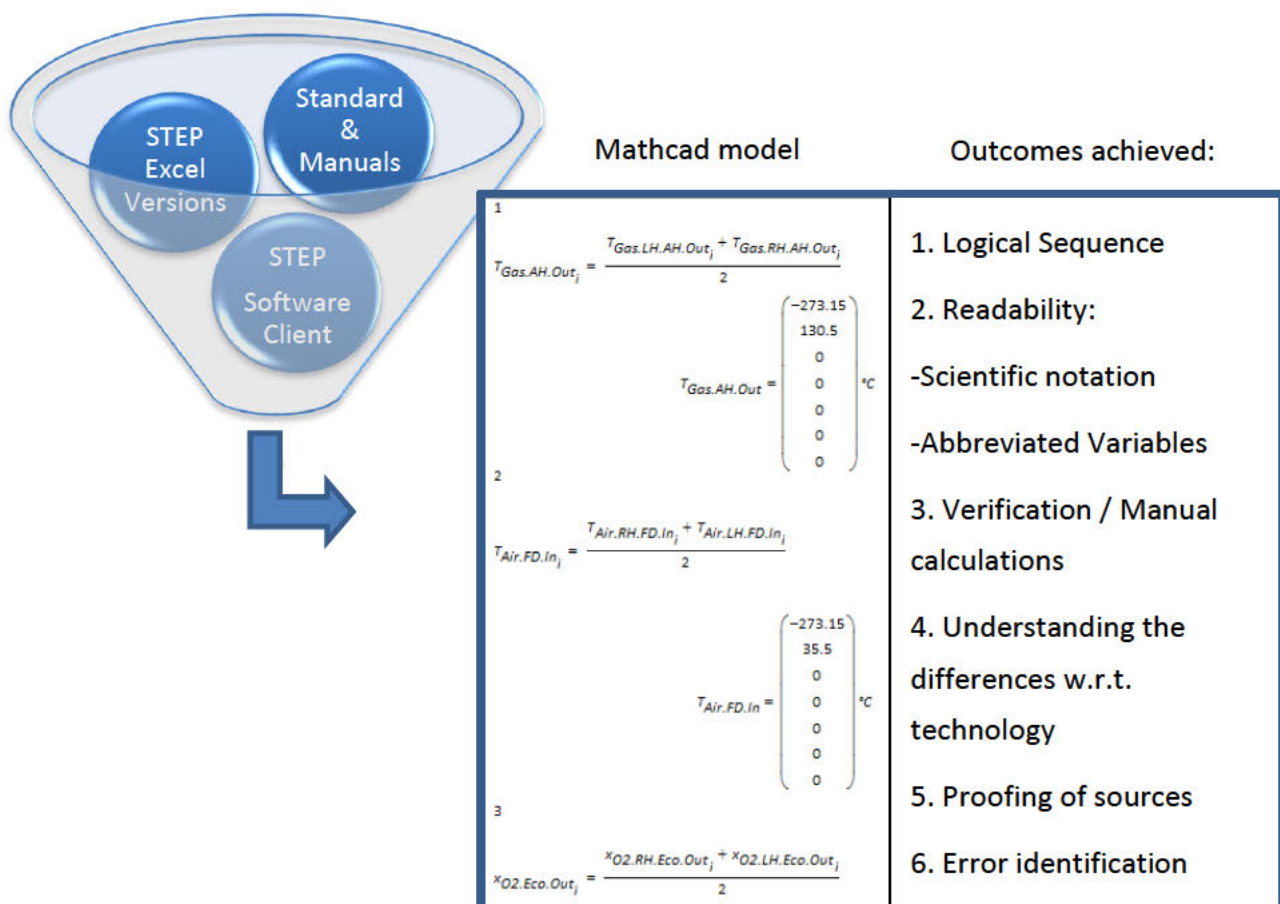


Figure 4-6: Development of the Mathcad STEP model

The model uncertainty is appreciated by reviewing the thermal losses computed in STEP against its latest version of its referenced standards [6],[15]. In some cases, other standards are explored where there are significant conflicts. Sample calculations are performed for losses that are omitted in the STEP program, to appreciate the magnitude of such model omissions. The model uncertainty would then be relative to the adopted set of standards as used in the performance baseline testing [65]. The losses that are reviewed include Carbon in Refuse, Dry Flue Gas, Carbon Monoxide, Make-up Water, Radiation, Turbine Deterioration, and Hydrogen and Fuel Moisture. The turbine plant losses are mostly a function of parameter sensitivity studies performed on thermodynamic modelling packages. (Refer to Appendix C for calculation methodology and results of the sample calculations). The results are discussed in Section 5.1.

4.2. Data validation

The section describes how the data used in this research, otherwise known as the specific case data, is acquired and processed before being applied to the STEP and uncertainty propagation models for observation.

4.2.1. Data acquisition

Figure 4-7: Power plant data flow, illustrates how the data used in this research is acquired. Online plant data was sourced from the power plant's data server. The VA View[®] (database software) web interface had been utilized to query raw data on a minute interval for one month (this was the set limitation for the server queries). Electrical metering data had been made available through integrating software namely EMDAS[®] which publishes to the GPSS database at a resolution of one hour. Laboratory data for coal parameters and carbon in refuse was acquired via site personnel, which is typically stored on another database (LIMS[®]) with a minimum reporting resolution of one day.

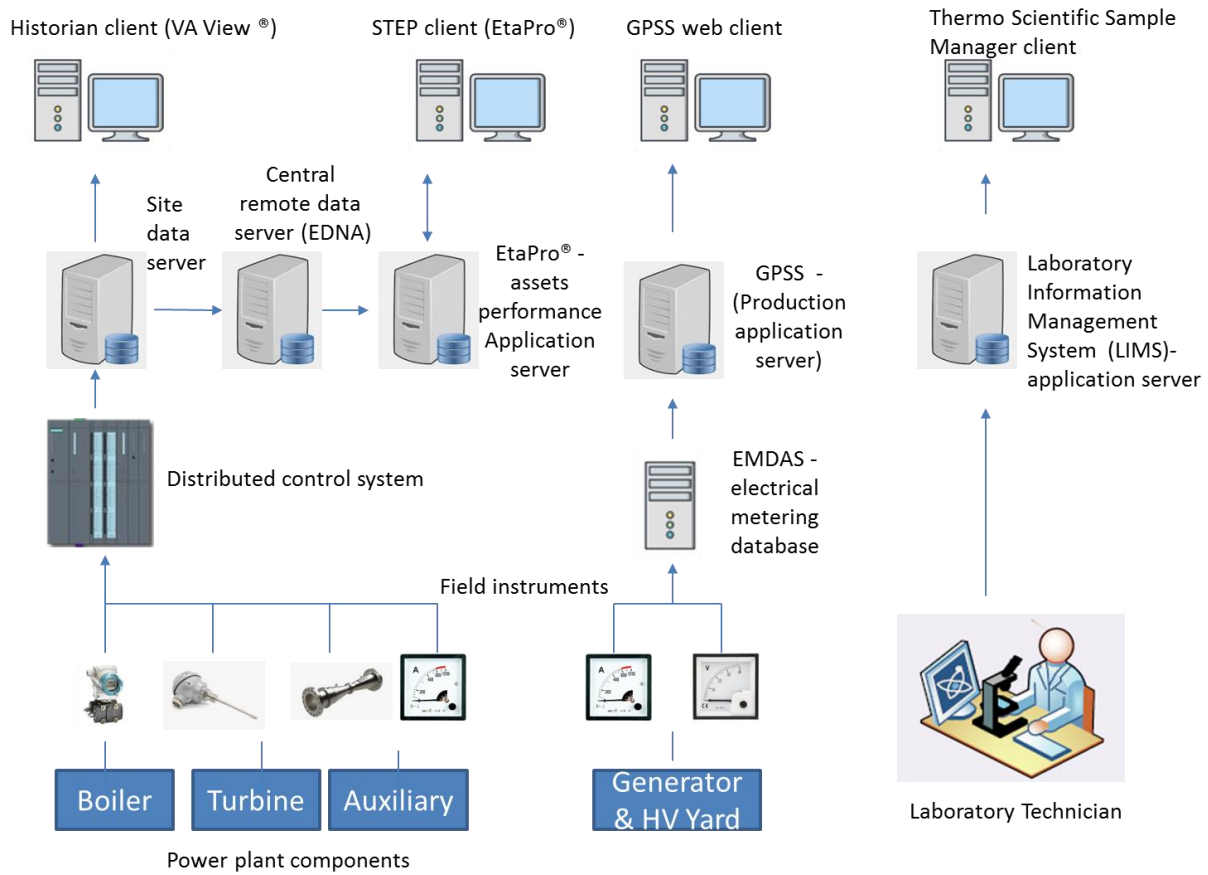


Figure 4-7: Power plant data flow

4.2.2. Data screening

It was intended to process raw data and use typical instrument uncertainties found from literature without exploring the detailed elements of each variable's systematic uncertainty (this scope has been included in a different study that was to run concurrently with this study). It would be nonsensical to include instrumentation drift when the unit is not producing power, hence data during off-load conditions were disregarded from the analysis.

4.2.3. Data pre-processing

Plant process data is converted to measurement units that are required in STEP, e.g.:

See point 2 in Figure 4-8, $m_{FW,1min} = \dot{m}_{FW,avg} \frac{kg}{s} \times \frac{60s}{1} \times \frac{1Gg}{10^6 kg}$

A significant amount of the STEP input parameters are not directly measured and had to be derived. This is particularly in the case of component running hours, where time is accumulated by the summation of the time step where the motor current signals are filtered to be above the

assigned off-load drift tolerance. In the very same manner power (MW) is converted to energy totals (GWh) for electric power, e.g.:

See point 1 in Figure 4-8, $RT_{Boil.for1min} = If(\dot{m}_{Main_Steam} > 20 \frac{kg}{s}, \frac{1min}{60min/hour}, 0)$

STEP has two types of input data, namely average input parameters and cumulative input parameters. The STEP computer model internally segments the data into specified chunk sizes. For each segment analysed, the average input parameters are weighted by the electrical units generated, e.g.:

see range 4 in Figure 4-8 : $P_{Condenser.Act_Segment} = \frac{\sum_{i=1}^{N_{segment_size}} (P_{Condenser.Act_i} \times Pow_{Generated_i})}{\sum_{i=1}^{N_{segment_size}} Pow_{Generated_i}}$

For cumulative input parameters, the entries are summed and extrapolated for a month as the STEP program is designed for monthly inputs, e.g.:

See range 3 on Figure 4-8 : $RT_{Boil.segment} = \sum_{i=1}^{N_{segment_size}} RT_{Boil.1min_i} \times \frac{44640}{N_{segment_size}}$

The average input parameters include temperature, pressure, the carbon in refuse (CIR), and specific mass flow rates. The data processing is further demonstrated in Section 4.3.5.

In certain cases, data had to be up-scaled to a minute resolution i.e. coal flow rates were discretized to a minute resolution by calibrating the mill feeder mass flow signals to the summed monthly conveyor belt mass meter indications. Although some unquantifiable uncertainties would be introduced as feeders degrade over time and mill configurations change within the month, this was thought to be relatively insignificant and necessary to compare the direct and indirect efficiency computation.

Figure 4-8 is an example of the CSV file produced from the processed signals. This file is read in as input data to the STEP model. The data file had consisted of 112 tags per unit x 44640 temporal entries.

Time	MILL_A_Run_Hrs[1]	Boil_Run_hrs[1]	Gen_LV_Main_J[1]	Cond_Act_P[1]	FW_Tot_Mass[1]	AH_RH_Gas_Out_T[1]
2019/05/01 00:00	0.0167	0.0167	0.00783932	7.317	0.02155896	105.06
2019/05/01 00:01	0.0167	0.0167	0.00789300	7.348	0.02124258	105.12
2019/05/01 00:02	0.0167	0.0167	0.00786253	7.382	0.02107866	105.12
2019/05/01 00:03	0.0167	0.0167	0.00784443	7.402	0.02095568	105.12
2019/05/01 00:04	0.0167	0.0167	0.00779852	7.402	0.02120022	105.36
2019/05/01 00:05	0.0167	0.0167	0.00779305	7.341	0.02156064	105.36
2019/05/01 00:06	0.0167	0.0167	0.00782863	7.301	0.02182680	105.36
2019/05/01 00:07	0.0167	0.0167	0.00782213	7.317	0.02221224	105.36
2019/05/01 00:08	0.0167	0.0167	0.00783272	7.310	0.02214366	105.36
2019/05/01 00:09	0.0167	0.0167	0.00783272	7.326	0.02195772	105.36
2019/05/01 00:10	0.0167	0.0167	0.00784023	7.355	0.02165418	105.36
2019/05/01 00:11	0.0167	0.0167	0.00784585	7.340	0.02148222	105.24
2019/05/01 00:12	0.0167	0.0167	0.00782837	7.319	0.02159286	105.42
2019/05/01 00:13	0.0167	0.0167	0.00782318	7.308	0.02161452	105.30
2019/05/01 00:14	0.0167	0.0167	0.00778387	7.320	0.02153670	105.30
2019/05/01 00:15	0.0167	0.0167	0.00779732	7.310	0.02160492	105.36
2019/05/01 00:16	0.0167	0.0167	0.00781665	7.270	0.02161440	105.54
2019/05/01 00:17	0.0167	0.0167	0.00784173	7.346	0.02171598	105.42
2019/05/01 00:18	0.0167	0.0167	0.00782875	7.357	0.02162220	105.42
2019/05/01 00:19	0.0167	0.0167	0.00784590	7.375	0.02164104	105.42
2019/05/01 00:20	0.0167	0.0167	0.00784590	7.375	0.02170464	105.30
2019/05/01 00:21	0.0167	0.0167	0.0078	7.384	0.02161626	105.30
2019/05/01 00:22	0.0167	0.0167	0.00785	7.384	0.02172996	105.18
2019/05/01 00:23	0.0167	0.0167	0.00785018	7.375	0.02192298	105.18
2019/05/01 00:24	0.0167	0.0167	0.00783932	7.357	0.02184108	105.18
2019/05/01 00:25	0.0167	0.0167	0.00783932	7.378	0.02192406	105.18
2019/05/01 00:26	0.0167	0.0167	0.00783155	7.378	0.02197272	105.18
2019/05/01 00:27	0.0167	0.0167	0.00783155	7.406	0.02195556	105.18
2019/05/01 00:28	0.0167	0.0167	0.00783155	7.357	0.02194650	105.36
2019/05/01 00:29	0.0167	0.0167	0.00782973	7.357	0.02195778	105.36
2019/05/01 00:30	0.0167	0.0167	0.00782695	7.371	0.02196246	105.36
...						
2019/05/31 23:59	0.0167	0.0167	0.00781880	7.379	0.02160720	105.48

Figure 4-8: Example of processed signals/tags

4.3. Modelling for uncertainty analysis

The sequential perturbation method was chosen due to its calculation traceability and controllability (as opposed to random variations), low computational expense and the ability to propagate through a model of multiple functions including discontinuous functions such as those contained in the STEP program. These attributes were specifically desired with the intent of analysing temporal uncertainties based on actual plant data and typical systematic uncertainties as per literature (without trying to determine uncertainties by statistical methods). Actual derivatives of the STEP calculations would be impractical based on the complexity of the functions. It was envisaged that the sequential perturbation method would be the least computationally expensive, would require the least effort in scripting when compared to the other methods explored and would produce exactly the same results.

4.3.1. Principles of sequential perturbation

The sequential perturbation method is illustrated by equations 4.6 to 4.12:

$$R_0 = f(x_1, x_2, \dots, x_L) \quad (4.6)$$

$$R_1^+ = f(x_1 + u_{x1}, x_2, \dots, x_L) \quad (4.7)$$

$$R_1^- = f(x_1 - u_{x1}, x_2, \dots, x_L) \quad (4.8)$$

$$\delta R_i^+ = R_i^+ - R_0 \quad (4.9)$$

$$\delta R_i^- = R_i^- - R_0 \quad (4.10)$$

$$\delta R_i = \frac{\delta R_i^+ - \delta R_i^-}{2} \approx \left(\frac{\partial R}{\partial x_i} \right)_{x_i = \bar{x}_i} u_{\bar{x}_i} \quad (4.11)$$

$$u_R = \sqrt{\sum_{i=1}^L \left(\left(\frac{\partial R_i}{\partial x_i} \right)_{x_i = \bar{x}} u_{\bar{x}_i} \right)^2} \quad \text{or} \quad u_R = RSS(\delta R_i) \quad (4.12)$$

The above method is detailed by Fiogiola and Beasley [48]. The significance or impact of each variable relative to the total uncertainty can be derived as follows:

$$Significance_{u_i} = \frac{\left(\left(\frac{\partial R_i}{\partial x_i} \right)_{x_i = \bar{x}} u_{\bar{x}_i} \right)^2}{\sum_{i=1}^L \left(\left(\frac{\partial R_i}{\partial x_i} \right)_{x_i = \bar{x}} u_{\bar{x}_i} \right)^2} \times 100\% \quad (4.13)$$

or

$$Significance_{u_i} = \frac{u_{R_i}^2}{u_R^2} \times 100\% \quad (4.14)$$

where:

R_0 -evaluation of the function with the inputs being the mean of each variable

R_i^+ -is the result of the function where the absolute uncertainty for each variable is added to the mean sequentially

R_i^- - is the result of the function where the absolute uncertainty for each variable is subtracted from its mean sequentially

u_R - Propagated combined uncertainty to the result of a function at the mean of each input variable

u_i - Propagated individual uncertainty to the result of a function at the mean of each input variable

4.3.2. Statistic & probability theory

The term error is used in various texts to describe the deviation from an individual measurement to that of the true underlying mean of the collective sample. The error or deviations from the true mean can be attributed to various elements. The elements are typically classified as random (temporal) or systematic errors.

Figure 4-9 and Figure 4-10 demonstrate the difference between random and systematic errors where the systematic error is fixed in time which is a result of some static influence such as measurement equipment calibration. On the other hand random errors change due to a temporal influence on repeatability. An example of where the random error could occur is human subjectivity when a measure resolution is too low, variations in operating and environmental conditions.

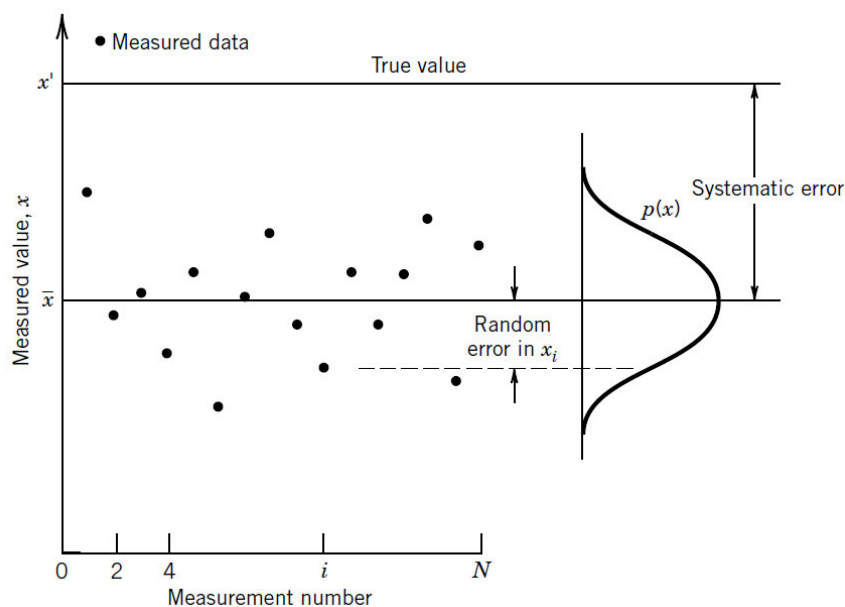


Figure 4-9: Distribution of error on repeated measurement [48]

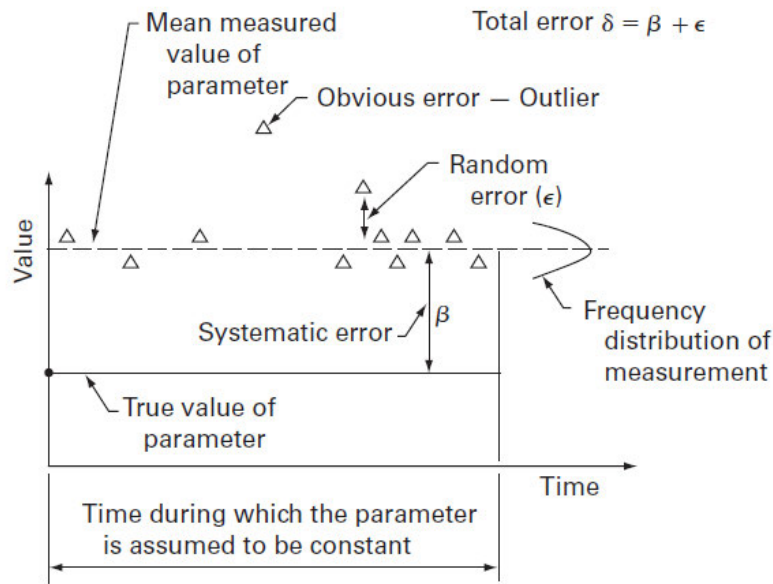


Figure 4-10: Distribution of error as a function of time [17]

For repeated measurements, the calculated statistical parameters are given below [66]:

Mean of the measured value:

$$\bar{x} = \frac{1}{N} \sum_{i=1}^N x_i \quad (4.15)$$

where:

N = number of measurements

x_i = individual measurement in a set of measurements

The standard deviation for a sample:

$$S_x = \sqrt{\frac{1}{N-1} \sum_{i=1}^N (x_i - \bar{x})^2} \quad (4.16)$$

The standard deviation of means or standard error for a sample is given by:

$$S_{\bar{x}} = \frac{S_x}{\sqrt{N}} \quad (4.17)$$

For $N > 30$, S_x is approximated to σ_x [67]. An expected or true value based on a set of measurements is generally represented by its mean and uncertainty as a function of the confidence level or percentage probability ($P\%$). The form as per probability theory is given below:

$$x' = \bar{x} \pm u_x(P\%) \quad (4.18)$$

where:

$P\%$ = probability percentage

u_x = uncertainty associated with a set of measurements from a single point of measurement.

In the case of multiple, independent and similar measurements points to acquire the same measurand such as in the case of two thermocouples measuring the same parameter, the combined uncertainty is given by [47]:

$$u_c = \frac{u_x}{\sqrt{N_{MP}}} \quad (4.19)$$

where:

u_c - combined uncertainty for a variable

N_{MP} - number of measurement points

The above equation is derived from the equation (4.17) where the numerator remains unchanged for additional measurements but the denominator becomes $\sqrt{N \times N_{MP}}$.

In probability theory, repeated observations or repeated measurements will generate a typical distribution profile when the histograms are plotted. When the data is normalized in terms of S_x and expressed in percentage of frequency, it would likely fit a standard probability density function. The typical distributions for engineering data are normal distribution, log-normal, rectangular, triangular, Poisson and binomial. Refer to [48] for more detailed descriptions of the standard distributions used in engineering sciences. Figure 4-11 is the most common distribution profile in engineering data. It is also known as Gaussian distribution. For this type of distribution, the normal and t-probability tables indicate the probability of an observation based on the deviation from the mean and the standard deviation of the data set.

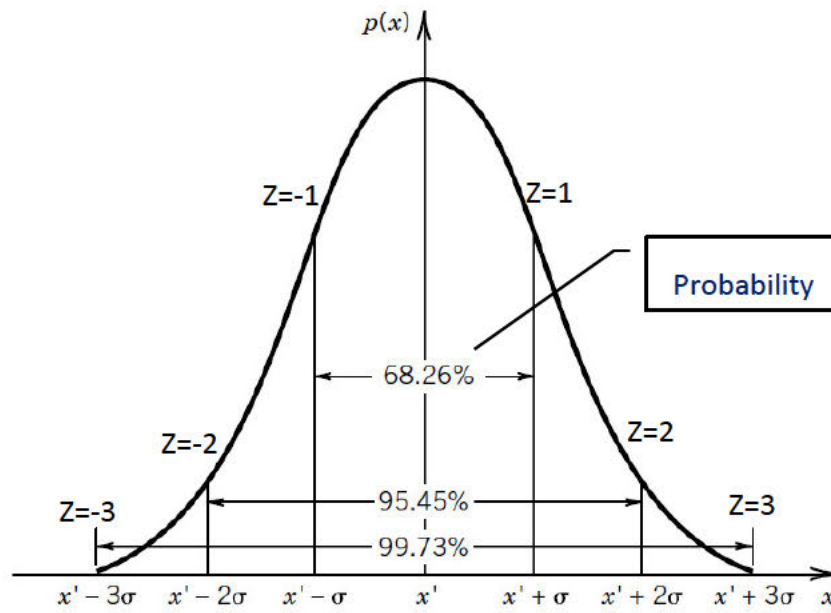


Figure 4-11: Gaussian distribution probability density function [48]

$$t = Z = \frac{x_i - \bar{x}}{\sigma_x} \quad \text{for } N > 30 \quad (4.20)$$

Where:

t - statistical term, t-score also referred to as the coverage factor

Z - statistical term, Z-score

The 95% confidence interval is typically used in the indication of the uncertainty of parameters used in power plant thermal performance calculations [47],[15],[18]. More accurately at the 95% confidence interval $Z = 1.96$. Now uncertainty can be described relative to probability or confidence interval by the equation below:

$$u_x(P\%) = ZS_{\bar{x}} \quad (4.21)$$

Now equation (4.18) becomes:

$$x' = \bar{x} \pm ZS_{\bar{x}} \quad (4.22)$$

4.3.3. Simplifications and assumption

The largest benefit of the sequential perturbation method is the ability to propagate uncertainty through discrete and highly non-linear functions such as the entire STEP calculation method. However, this method assumes that all variables are non-correlated and treated as such. It is also

assumed that all STEP inputs are non-correlated therefore the covariance had not been analysed in this study.

The uncertainty model has been limited to the first layer or primary uncertainty propagation, meaning that a derived variable that may have additional uncertainties from the method of derivation is omitted in the propagation to the result. A typical example to demonstrate this point is that, in thermodynamics, the enthalpy is looked up from steam tables using steam pressure and temperature. The uncertainty in the steam temperature and pressure measurement may be considered as primary uncertainties. The uncertainty associated with the development of the steam tables can be considered as secondary uncertainty and is a function of the temperature and pressure. From literature [68], uncertainty estimates are provided for steam tables, however, it would require significant effort in coding and introduce additional computational expense. The processing of the 2nd tier of calculations is of limited value to the objectives of this study. The second tier would be a consideration for the analysis using STEP models specific to dry cooled sliding pressure power plants as Eskom employs the direct method in the turbine performance analysis due to the thermal performance being more sensitive to the load factor and ambient conditions. The model used in the case study was that of a wet-cooled static pressure power plant hence did not require any look-ups from steam tables.

The STEP program utilizes coefficients for polynomial performance curves derived from regression fitting of the acceptance test data. Seeing that these tests were only performed once (not repeated), there are no estimates in the uncertainty of this data. Similarly, all other parameters derived from single plant tests have no uncertainty estimates and therefore could not be modelled at this stage of the study.

For the current study, all parallel or series measurements used in the variable averaging are assumed to be measuring a homogeneous stream i.e. the uncertainty pertaining to spatial non-uniformity of the measurement is ignored. Even though in some cases stratification in flue gas ducting could cause large deviations between points of measurement and consequentially introduce significant uncertainty of the measured temperature, more detailed practical studies are required to estimate the impact of these cases which may be very specific to the physical layout of the plant. The spatial uncertainty can be easily incorporated into the uncertainty model for future work.

4.3.4. The computer program of the STEP calculation procedure

To evaluate the temporal uncertainty at a minimum of 30-minute intervals (1488 intervals per month) and perturb 538 of the input variables by the positive and negative uncertainties per

interval, would require significant computational resources, seeing as the STEP model would have to be run ≈ 1.6 M times.

Due to the significant number of calculated variables in STEP (approx. 1700) and the operation sequence required in the processing of the uncertainties, it had been anticipated that significant computational processing would be required, especially in the handling of large data sets. This had necessitated that the modelling be moved to a platform more capable for large data analytics. Python® with the Pandas library was chosen due to availability (open source), online support/training, and the experience and recommendation of fellow scholars, academics and peers in the industry.

4.3.5. Model architecture

Figure 4-12 illustrates the computer program process flow sequence covering the high-level steps in the modelling architecture. The steps illustrated in the mentioned figure are further elaborated with illustrations. Based on the acquired data as per 4.2.1, it would be statistically inaccurate to consider a sample size of less than or equal to 30 observations (30 x 1minute intervals) as the sample standard deviated is no longer representative of the population standard deviation, which is a significant parameter in the uncertainty quantification.

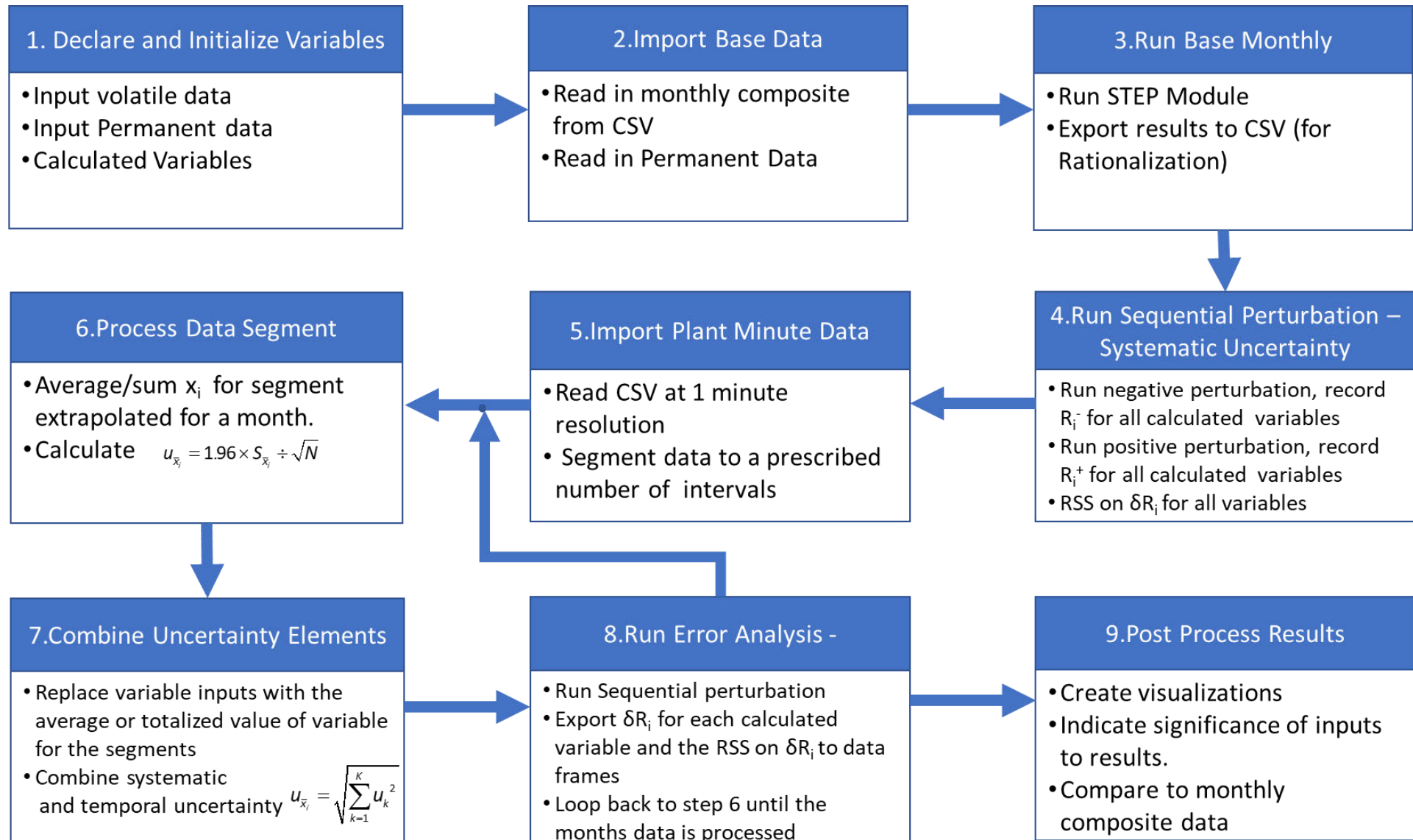


Figure 4-12: Uncertainty propagation model architecture

Herewith follows a brief discussion of the computer program functions.

Step 1: All variables are declared and set to a value of zero.

Step 2: The base input variables are read in from a CSV file to the input data frame in the STEP computer program. The CSV file is generated from an MS Excel workbook where data is manually copied in from the EtaPro database client. The data is thereafter automatically processed for input to the developed STEP computer program so that various monthly composite datasets can be easily imported to the model as per Figure 4-13.

Step 3: The STEP module is run and the results are exported for verification (see also Appendix G). Figure 4-14 is a truncated view of the calculated variables. These values had been compared with the MathCAD calculation sheet mentioned in section 4.1 to verify the model and have proven to be extremely useful in eradicating errors such as unit conversions and code debugging e.g. divide by zeros or empty entries and syntax errors for the STEP module of the program. Refer to Appendix E for the description of the calculated variables.

Step 4: The uncertainty model is run with only the systematic uncertainties read in. The results are exported to an MS Excel file (refer to Figure 4-15).

Step 5: The plant operational data on a 1-minute resolution is read into a data frame from a CSV file.

Step 6: Each segment/chunk is processed to acquire the average or sum of the variables (refer to Figure 4-16). The standard deviation for each segment and each variable is computed to determine the temporal uncertainty at a 95% confidence interval. The associated uncertainty of each input variable (rows) to the calculated variable (columns) is reported per segment run. The table as shown in Figure 4-15 is produced for each segment run. The overall impact of each input variable on a calculated variable is the weighted average value of all segments by the USO.

Step 7: The temporal uncertainty for each segment is combined with the systematic uncertainty as shown in Figure 4-12.

Step 8: Recall equations (4.6) to (4.12). The δRi for each calculated variable is exported for each segment run. The RSS of the δRi is the combined impact of all input uncertainties per calculated variable. Each row entry in Figure 4-17 represents the results of a segment run. The overall uncertainty of each calculated variable is the weighted average of the RSS values by the USO for all segment runs.

Step 9: The results are fed into post-processing tools to generate visuals, see section 5.

Input Variable	Unit(Cycle) Number							Unit of measure	Step Code
	Station	1	2	3	4	5	6		
AH_LH_Gas_Out_T	0.000	113.824	113.824	129.384	129.384	125.661	125.661	°C	IDB001
AH_RH_Gas_Out_T	0.000	115.843	115.843	129.468	129.468	126.529	126.529	°C	IDB002
FD_LH_AIR_In_T	0.000	29.303	29.303	32.741	32.741	29.455	29.455	°C	IDB004
FD_RH_AIR_In_T	0.000	31.447	31.447	30.268	30.268	31.544	31.544	°C	IDB005
AH_LH_Gas_In_O2_x	0.000	3.677	3.677	3.712	3.712	3.892	3.892	%	IDB007
AH_RH_Gas_In_O2_x	0.000	3.623	3.623	3.350	3.350	4.169	4.169	%	IDB008
Boil_Run_hrs	0.000	744.000	744.000	627.800	627.800	727.970	727.970	h	IDB010
FW_Tot_Mass	0.000	1 144.900	1 144.900	1 003.250	1 003.250	864.360	864.360	Gg	IDB011
BD_Tot_Mass	0.000	0.000	0.000	0.000	0.000	0.000	0.000	t	IDB012
AH_LH_Gas_Out_O2_x	0.000	5.677	5.677	5.712	5.712	5.892	5.892	%	IDB013
AH_RH_Gas_Out_O2_x	0.000	5.623	5.623	5.350	5.350	6.169	6.169	%	IDB014
Boil_Starts_0to7hrs	0.000	0.000	0.000	0.000	0.000	0.000	0.000		IDB022
Boil_Starts_7to15hrs	0.000	0.000	0.000	0.000	0.000	0.000	0.000		IDB023
Boil_Starts_15to24hrs	0.000	0.000	0.000	1.000	1.000	1.000	1.000		IDB024
Boil_Starts_24to168hrs	0.000	0.000	0.000	1.000	1.000	0.000	0.000		IDB025
Boil_DownTime_0to7hrs	0.000	0.000	0.000	0.000	0.000	0.000	0.000	h	IDB026
Boil_DownTime_7to15hrs	0.000	0.000	0.000	19.450	19.450	0.000	0.000	h	IDB027
Boil_DownTime_15to24hrs	0.000	0.000	0.000	0.000	0.000	18.220	18.220	h	IDB028
Boil_DownTime_24to168hrs	0.000	0.000	0.000	96.750	96.750	0.000	0.000	h	IDB029
HotSby_Time	0.000	0.000	0.000	0.000	0.000	0.000	0.000	h	IDB030
Boil_ColdStarts	0.000	0.000	0.000	0.000	0.000	0.000	0.000		IDB031
Mill_Reject_Mass	0.000	0.000	0.000	0.000	0.000	0.000	0.000	ton	IDB070
Mill_Reject_CV	0.000	15.000	15.000	15.000	15.000	15.000	15.000	MJ/kg	IDB071
AH_Gas_In_CIR	0.000	3.043	3.043	3.105	3.105	3.793	3.793	%	IDB076
CoarseAsh_CIR	0.000	0.761	0.761	0.777	0.777	0.947	0.947	%	IDB077
MILL_A_Run_Hrs	0.000	641.830	641.830	573.330	573.330	556.070	556.070	Hrs	IDB091
MILL_B_Run_Hrs	0.000	676.270	676.270	617.390	617.390	665.890	665.890	Hrs	IDB092
MILL_C_Run_Hrs	0.000	289.170	289.170	442.030	442.030	357.510	357.510	Hrs	IDB093
MILL_D_Run_Hrs	0.000	706.260	706.260	460.380	460.380	118.770	118.770	Hrs	IDB094
MILL_E_Run_Hrs	0.000	597.400	597.400	445.860	445.860	657.570	657.570	Hrs	IDB095
MILL_F_Run_Hrs	0.000	742.280	742.280	529.430	529.430	677.540	677.540	Hrs	IDB096
Gen_LV_Main_J	0.000	375.157	375.157	340.861	340.861	316.510	316.510	GWh	IDT012
Gen_LV_Check_J	0.000	375.157	375.157	340.861	340.861	316.510	316.510	GWh	IDT013
AuxPower_Main_J	0.000	19.295	19.295	23.511	23.511	26.116	26.116	GWh	IDT014
AuxPower_Check_J	0.000	19.295	19.295	23.511	23.511	26.116	26.116	GWh	IDT015
Gen_AboveNER_J	0.000	0.000	0.000	0.000	0.000	0.000	0.000	GWh	IDT019
Gen_AboveNER_RT	0.000	0.000	0.000	0.000	0.000	0.000	0.000	h	IDT025
Gen_Reactive_J	0.000	-42.369	-42.369	-17.357	-17.357	4.281	4.281	GVARh	IDT020
Gen_RT	0.000	744.000	744.000	622.060	622.060	716.040	716.040	h	IDT024
AuxPower_Import_Trip_J	0.000	0.000	0.000	1 256.840	1 256.840	1 239.740	1 239.740	MWH	IDT100
AuxPower_SB_J	0.000	20.470	20.470	25.820	25.820	28.680	28.680	GWh	IDT089
A_EFP_RT	0.000	0.000	0.000	632.790	632.790	742.990	742.990	h	IDT085
B_EFP_RT	0.000	0.000	0.000	628.420	628.420	619.870	619.870	h	IDT100
C_EFP_RT	0.000	0.000	0.000	0.000	0.000	0.000	0.000	h	IDT110
...	0.000	0.000	0.000	0.000	0.000	0.000	0.000		

Figure 4-13: Step 2 - Example of monthly composite input data

Calculated Variable	Unit No.	Base Result	Unit of Measure
AH_GAS_OUT_T	[0]	0.000	°C
AH_GAS_OUT_T	[1]	125.610	°C
AH_GAS_OUT_T	[2]	125.610	°C
AH_GAS_OUT_T	[3]	129.385	°C
AH_GAS_OUT_T	[4]	129.385	°C
AH_GAS_OUT_T	[5]	124.055	°C
AH_GAS_OUT_T	[6]	124.055	°C
FD_In_T	[0]	0.000	°C
FD_In_T	[1]	30.330	°C
FD_In_T	[2]	30.330	°C
FD_In_T	[3]	31.575	°C
FD_In_T	[4]	31.575	°C
FD_In_T	[5]	32.065	°C
FD_In_T	[6]	32.065	°C
AH_Gas_In_O2_x	[0]	3.898	%
AH_Gas_In_O2_x	[1]	3.705	%
AH_Gas_In_O2_x	[2]	3.705	%
AH_Gas_In_O2_x	[3]	3.845	%
AH_Gas_In_O2_x	[4]	3.845	%
AH_Gas_In_O2_x	[5]	4.215	%
AH_Gas_In_O2_x	[6]	4.215	%
Stm_Mass	[0]	6025.020	Gg
Stm_Mass	[1]	1144.900	Gg
Stm_Mass	[2]	1144.900	Gg
Stm_Mass	[3]	1003.250	Gg
Stm_Mass	[4]	1003.250	Gg
Stm_Mass	[5]	864.360	Gg
Stm_Mass	[6]	864.360	Gg
Boil_LF	[0]	0.000	%
Boil_LF	[1]	84.311	%
Boil_LF	[2]	84.311	%
Boil_LF	[3]	87.554	%
Boil_LF	[4]	87.554	%
Boil_LF	[5]	65.054	%
Boil_LF	[6]	65.054	%
Boil_LF_CF	[0]	1.003	
Boil_LF_CF	[1]	1.003	
Boil_LF_CF	[2]	1.003	
Boil_LF_CF	[3]	1.003	
Boil_LF_CF	[4]	1.003	
Boil_LF_CF	[5]	1.002	
Boil_LF_CF	[6]	1.002	
CIR_Targ_CF	[0]	0.000	%
...			

Figure 4-14: Step 3 - Example of base results

	AH_GAS_OUT_T[2]	FD_In_T[2]	AH_Gas_In_O2_x[2]	AH_LH_Leak[2]	AH_RH_Leak[2]	Stm_Mass[2]	Boil_LF[2]	Boil_LF_CF[2]	Boil_Fuel_CF[0]	CIR[2]	...
Base	0	0	0	0	0	0	0	0	0	0	0
AH_LH_Gas_Out_T[2]	0.650	0	0	0	0	0	0	0	0	0	0
FD_LH_AIR_In_T[2]	0	0.175	0	0	0	0	0	0	0	0	0
FD_RH_AIR_In_T[2]	0	0.180	0	0	0	0	0	0	0	0	0
AH_LH_Gas_In_O2_x[2]	0	0	0.023	-0.288	0	0	0	0	0	0	0
AH_RH_Gas_In_O2_x[2]	0	0	0.021	0	-0.259	0	0	0	0	0	0
AH_LH_GAS_Out_O2_x[2]	0	0	0	0.366	0	0	0	0	0	0	0
AH_RH_GAS_Out_O2_x[2]	0	0	0	0	0.307	0	0	0	0	0	0
Boil_Run_hrs[2]	0	0	0	0	0	0	-0.929	0.000	0	0	0
FW_Tot_Mass[2]	0	0	0	0	0	14.5	0.929	0.000	0.000	0	0
BD_Tot_Mass[2]	0	0	0	0	0	0	0	0	0	0	0
Mill_Reject_Mass[2]	0	0	0	0	0	0	0	0	0	0	0
Mill_Reject_CV[2]	0	0	0	0	0	0	0	0	0	0	0
AH_Gas_In_CIR[2]	0	0	0	0	0	0	0	0	0	0.015	0
CoarseAsh_CIR[2]	0	0	0	0	0	0	0	0	0	0.001	0
MILL_A_Run_Hrs[2]	0	0	0	0	0	0	0	0	0	0	0
Gen_LV_Main_J[2]	0	0	0	0	0	0	0	0	0	0	0
Gen_LV_Check_J[2]	0	0	0	0	0	0	0	0	0	0	0
AuxPower_Main_J[2]	0	0	0	0	0	0	0	0	0	0	0
AuxPower_Check_J[2]	0	0	0	0	0	0	0	0	0	0	0
Gen_AboveNER_J[2]	0	0	0	0	0	0	0	0	0	0	0
Gen_AboveNER_RT[2]	0	0	0	0	0	0	0	0	0	0	0
...											

Figure 4-15: Step 4 -Uncertainty propagation to calculated variable per segment run for each input variable

	MILL_A_Run_Hrs[2]	...	Boil_Run_hrs[4]	...	Gen_LV_Main_J[2]	...	Gen_LV_Main_J[4]	...	IPT_RH_Stm_in_T[2]	...	AH_RH_Gas_Out_T[2]	...
2019/05/01 00:00	0.0167		0.0167		0.00783932		0.0080586		538.2		105.06	
2019/05/01 00:01	0.0167		0.0167		0.0078893		0.00816605		537		105.12	
2019/05/01 00:02	0.0167		0.0167		0.00786253		0.0080586		533.7		105.12	
2019/05/01 00:03	0.0167		0.0167		0.00784443		0.007931617		530.88		105.12	
2019/05/01 00:04	0.0167		0.0167		0.0078853		0.0078853		530.04		105.36	
2019/05/01 00:05	0.0167		0.0167		0.00778305		0.0095417		531.66		105.36	
2019/05/01 00:06	0.0167		0.0167		0.00781363		0.00934033		533.16		105.36	
2019/05/01 00:07	0.0167		0.0167		0.00782213		0.00800325		535.98		105.36	
2019/05/01 00:08	0.0167		0.0167		0.00783272		0.007934883		536.34		105.36	
2019/05/01 00:09	0.0167		0.0167		0.00783272		0.007873017		535.2		105.36	
2019/05/01 00:10	0.0167		0.0167		0.00784023		0.0078893		533.04		105.36	
2019/05/01 00:11	0.0167		0.0167		0.00784585		0.007957667		531.9		105.24	
2019/05/01 00:12	0.0167		0.0167		0.00782837		0.007986983		530.88		105.42	
2019/05/01 00:13	0.0167		0.0167		0.00782318		0.0079772		530.04		105.3	
2019/05/01 00:14	0.0167		0.0167		0.0078300		0.0079205		529.38		105.3	
2019/05/01 00:15	0.0167		0.0167		0.00777732		0.0086767		529.38		105.36	
2019/05/01 00:16	0.0167		0.0167		0.00781665		0.00815017		531.06		105.54	
2019/05/01 00:17	0.0167		0.0167		0.00784173		0.007934883		533.64		105.42	
2019/05/01 00:18	0.0167		0.0167		0.00782875		0.007850217		534.18		105.42	
2019/05/01 00:19	0.0167		0.0167		0.0078459		0.007902317		533.58		105.42	
2019/05/01 00:20	0.0167		0.0167		0.0078459		0.00794465		533.58		105.3	
2019/05/01 00:21	0.0167		0.0167		0.00786333		0.007983717		533.28		105.3	
2019/05/01 00:22	0.0167		0.0167		0.00785018		0.008061867		533.28		105.18	
2019/05/01 00:23	0.0167		0.0167		0.00785018		0.008013017		533.28		105.18	
2019/05/01 00:24	0.0167		0.0167		0.00782695		0.00795403		533.04		105.18	
2019/05/01 00:25	0.0167		0.0167		0.00781932		0.00803883		532.32		105.18	
2019/05/01 00:26	0.0167		0.0167		0.00783155		0.0079100		532.32		105.18	
2019/05/01 00:27	0.0167		0.0167		0.00783155		0.007846967		532.08		105.18	
2019/05/01 00:28	0.0167		0.0167		0.00783155		0.0079414		532.38		105.36	
2019/05/01 00:29	0.0167		0.0167		0.00782973		0.008013017		532.38		105.36	
2019/05/01 00:30	0.0167		0.0167		0.00782695		0.008123733		532.38		105.36	
2019/05/01 00:31	0.0167		0.0167		0.0078188		0.00800325		533.46		105.48	
2019/05/01 00:32	0.0167		0.0167		0.0078188		0.0079707		533.46		105.48	
2019/05/01 00:33	0.0167		0.0167		0.00783478		0.0079479		533.46		105.48	
2019/05/01 00:34	0.0167		0.0167		0.00783478		0.00790133		532.5		105.48	
2019/05/01 00:35	0.0167		0.0167		0.00783515		0.00794417		531.42		105.42	
2019/05/01 00:36	0.0167		0.0167		0.00783573		0.007967433		530.34		105.42	
2019/05/01 00:37	0.0167		0.0167		0.00783573		0.0079186		529.56		105.24	
2019/05/01 00:38	0.0167		0.0167		0.00782832		0.007980467		530.52		105.24	
2019/05/01 00:39	0.0167		0.0167		0.00782683		0.008016283		531.72		105.24	

Figure 4-16: Step 6 - Illustration of segmented operational data

	AH_GAS_OUT_T[0]	AH_GAS_OUT_T[1]	AH_GAS_OUT_T[2]	AH_GAS_OUT_T[3]	AH_GAS_OUT_T[4]	AH_GAS_OUT_T[5]	AH_GAS_OUT_T[6]	...
Systematic	0	5.024937811	0.707106781	0.707106781	0.707106781	0.707106781	0.707106781	
RSS	0	5.032899573	2.084726672	0.707106781	3.560308546	3 223841703	0.707106781	
RSS	0	5.025765818	1.472842196	0.707106781	1.392738594	2.151293904	0.707106781	
RSS	0	5.026524906	2.83563277	0.707106781	4.703723519	2.37324494	0.707106781	
RSS	0	5.026084669	1.06587837	0.707106781	1.156305313	1 037540841	0.707106781	
RSS	0	5.049999961	0.959689442	0.707106781	1.15288757	1.16643581	0.707106781	
RSS	0	5.049373475	1.602211387	0.707106781	1.041553388	1 029528412	0.707106781	
RSS	0	5.025789483	1.956804872	0.707106781	1.263126888	0 982108146	0.707106781	
RSS	0	5.028715952	1.670217565	0.707106781	1.208252706	1.665883187	0.707106781	
RSS	0	5.026666392	1.027063943	0.707106781	1.400642445	0 859778209	0.707106781	
RSS	0	5.027752136	0.970189789	0.707106781	1.689729181	1.173250192	0.707106781	
RSS	0	5.027576158	0.8129707	0.707106781	1.212563435	0 938796495	0.707106781	
RSS	0	5.025562183	0.882086764	0.707106781	0.903267328	1.124062103	0.707106781	
RSS	0	5.025635933	0.858340378	0.707106781	2.694344468	2 897349003	0.707106781	
RSS	0	5.027408529	0.945148627	0.707106781	1.524432005	0 924474577	0.707106781	
RSS	0	5.025796259	0.866217942	0.707106781	2.010073418	0 983406335	0.707106781	
RSS	0	5.025768914	0.821017242	0.707106781	11.61855408	0.730042311	0.707106781	
RSS	0	5.026349504	0.828206233	0.707106781	2.73457951	0.782894435	0.707106781	
RSS	0	5.025436179	0.836239513	0.707106781	17.77619234	0 881203098	0.707106781	
RSS	0	5.042984907	0.82350228	0.707106781	6.38205624	2.115300198	0.707106781	
RSS	0	5.049843416	2.132214134	0.707106781	6.898385759	0 914492033	0.707106781	
RSS	0	5.035788783	1.887947292	0.707106781	15.49715185	0 953875703	0.707106781	
RSS	0	5.037867608	1.979184128	0.707106781	4.381363057	0 948808566	0.707106781	
RSS	0	5.026077206	1.572599673	0.707106781	1.080280393	2.148516144	0.707106781	
RSS	0	5.025937698	1.200461683	0.707106781	2.93480708	1.453197476	0.707106781	
RSS	0	5.026834389	0.848329487	0.707106781	1.264197507	1 350386547	0.707106781	
RSS	0	5.025949977	1.021542622	0.707106781	1.358757236	0.772267363	0.707106781	
RSS	0	5.026712682	2.097274151	0.707106781	1.471749487	1 345109652	0.707106781	
RSS	0	5.025910009	1.267933714	0.707106781	0.779716012	0 902858395	0.707106781	
RSS	0	5.025864606	0.99091987	0.707106781	0.71152324	1.620624455	0.707106781	
...								

Figure 4-17: Step 8 - Example of combined uncertainty of calculated variables per segment run

5. Results and discussion

5.1. Model uncertainty

In the section the model uncertainty had been studied by comparing the STEP loss computations to that of the standard performance codes listed in Table 5-1. The table below is a summary of the results further explained in this section.

Table 5-1: Summary of loss review

Losses	STEP %	Standard %	Deviation %	Code
Carbon in refuse	0.940	1.097	0.157	BS EN 12952-15: 2003
Carbon monoxide		0.170	0.170	BS EN 12952-15:2003
Dry flue gas	4.797	4.660	-0.182	BS EN 12952-15: 2003
Dry flue gas	4.797	4.843	0.046	BS 2885: 1974
Hydrogen & moisture	4.897	5.007	0.110	BS EN 12952-15: 2003
Make-up	2.657	2.261	-0.396	66.7% vs. 50% steam fraction
Radiation	0.568	0.289	-0.279	BS EN 12952-15: 2003
Turbine deterioration	0.850	3.264	2.414	IEC 60953-0/Ed1: 1996
Turbine deterioration	0.850	1.402	0.552	ASME PTC 6 Report -1985

5.1.1. Carbon in Refuse

From equations (A.8) and (B.42), it can be deduced that STEP calculation does not account for the sensible heat of the ash leaving the boiler. The impact on the loss due to the difference in methodology was demonstrated to be +0.157% (or +0.029 MJ/kg coal-fired) for the case evaluated as per calculations (C.4) and (C.10) in Appendix C. A sensitivity study was further conducted by changing the fly ash in flue gas efficiency to 90% and 85% which yielded a difference in thermal loss of 0.246% and 0.335% respectively which is significant in the indirect determination of the boiler efficiency.

5.1.2. Dry Flue Gas loss

Both the BS 2885 [5] and BS EN 12952-15 [15] do not give any means to calculate the combustion products in flue gas as it would be measured during an acceptance test or if the flue stacks are fitted with gas analysers. The STEP methodology attempts to approximate the gas composition from an oxygen balance calculation and assuming that the gas products will comprise only of N₂,

CO₂ and O₂. Typical gas analysers measure these gases on a dry volumetric basis which suits the calculation of the Dry Flue Gas loss. It is observed that the heat capacity of the flue gas ($c_{p,FG}$) is static as per STEP calculations and the BS 2885 [5]. The approach is different as per the BS EN 12952 -15 as the $c_{p,FG}$ is calculated based on the CO₂ mass fraction and temperature of the flue gas.

For the case demonstrated, the STEP calculation and the BS 2885 [5] yielded very similar results as the same gas composition was used in the calculation. The loss as per STEP was calculated to be 4.797% or 0.901 MJ/kg coal (refer to Appendix C.4) versus 4.843% or 0.909 MJ/kg coal using the BS 2885 approach (refer to Appendix C.5). The difference between the two methods is that STEP calculates the mass ratio of dry flue gas to a kg of coal-fired and BS 2885 [5] leaves it on a molar basis. They both calculate the relative gas flows based on the CO₂ concentration in the flue gas. The principle is based on 1 mol C → 1 mol CO₂. The method employed in STEP to calculate the CO₂ concentration in the flue gas is not referenced but appears to be based on some empirical relationships of the coal composition (some parameters being on a proximate analysis base).

The BS EN 12952-15 [15] calculates the mass ratios of gas products through stoichiometric reactions of the elements within the coal, hence the ultimate analysis of the constituents is required. The excess air is determined by the oxygen depletion method (see Appendix C.6 – calculation (C.31)). In this case, the result is marginally different yielding a loss of 4.660% or 0.875 MJ/kg Coal (see Appendix C.6 - calculations (C.42) and (C.43)).

5.1.3. Carbon Monoxide (CO) loss

Carbon monoxide loss is the loss of energy release due to incomplete combustion due to insufficient mixing or residence time in the combustion chamber i.e. the formation of CO instead of the full reaction of carbon with oxygen to produce CO₂. This loss is omitted from the STEP calculation possibly due to low levels normally generated in the fleet. The Fossil Fuel Firing Regulations (FFFR) [69] ensures a sufficiently adequate oxidising environment to prevent the significant formation of CO. The threshold for CO at the economiser outlet is 200ppm (V/V). In the case evaluated, with a CO concentration of 50ppm (V/V) the loss yielded is only 0.043% and reaches 0.426 % (or 0.08 MJ/kg coal-fired) at 500ppm (see Appendix C.3 for the methodology [15] and assumptions).

5.1.4. Make-up Water loss

The make-up water loss is used to quantify the energy lost due to the efflux of water from the Rankine cycle through losses such as leakage from passing valves, boiler blowdowns, soot blowing and venting/draining. There is limited information on these losses in literature as the performance

test codes assume that these defects are resolved before acceptance testing. These flows are typically not measured at a power plant. The make-up water loss is one of the highest losses experienced in South African power plants as per the STEP program and hence had been identified for critical review.

The calculation methodology is demonstrated by calculations in Appendix C.9. The methodology was deemed to be fundamentally satisfactory. However, STEP makes approximations of these flows by assuming that a 3rd of the make-up water is lost at the boiler feed water conditions and 2/3rd is lost at main steam conditions (see Appendix C.9 calculation (C.54)). The approximation is not referenced in the STEP manuals [34][42] nor could be found in the literature. For the case evaluated the make-up loss was determined to be 2.657%. See Table 5-2 for the results of the sensitivity study.

Table 5-2: Sensitivity analysis on the fraction of make-up water lost at main steam conditions

The fraction of make-up lost at MS conditions	The fraction of make-up lost at FW conditions	Thermal Loss (%)
0.10	0.90	1.317
0.20	0.80	1.552
0.33	0.67	1.866
0.50	0.50	2.261
0.67	0.33	2.657
0.80	0.20	2.976

From the above table is it quite obvious that the fraction of make-up water lost at main steam (MS) conditions has a significant impact on the thermal loss determination. The spread or range would become even wider when conditions of high make-up are experienced.

From calculation (C.59) in Appendix C.9, It can be seen that demineralized water flows that are external to the Rankine cycle are included in the hot make-up volume. It becomes difficult to standardize these calculations done in STEP as the various plant metering configurations are different. It is incorrect to include the water losses in the thermal loss calculations e.g. the water supplied to the hydrogen plant for electrolysis or cooling water to the compressed air systems cannot be considered to be lost at main steam condition neither at feed water conditions.

Another major risk to the accuracy of the make-up determination is the method to distinguish between hot make-up and cold make-up flow especially if this is done manually. Manual methods

of recording the integrated volume of make-up may not be synchronized to the unit synchronization and uncoupling from the grid. Hot make-up is the demineralized water top-up to the Rankine cycle when the unit is synchronized to the electricity grid. The make-up used during commissioning should also be discounted as the input energy to the cycle (coal & oil-fired) during commissioning is discounted in the calculation of the running plant heat rate. Make-up flow during cold conditions (unit offload and cooled) has negligible thermal energy value. In many cases where power plants are equipped with modern data systems, the quantification of the make-up volume can be determined through the integration of the instantaneous flow meter signals and can be filtered directly by the plant data systems. In this case calculation (C.59) in Appendix C.9 may be circumvented to a direct input.

5.1.5. Boiler Radiation loss

Generally, during acceptance testing of a boiler, a full-scale radiation test is omitted due to the vast number of measurement points required across the boiler skin casing and piping, it is preferred to agree on a figure based on a similar design implemented elsewhere. Both ASME [17] and BSI [5] recommend sampling surface temperatures and ambient temperatures measurement at various points and applying related heat transfer coefficient to calculate heat loss per area. The STEP calculation methodology uses the former principles for its loss calculations, where previous test results for similar designs are available in the form of manufacturer's curves. The boiler radiation loss is estimated by BSI [15] as a function of the boiler output in MWs. It is assumed that the ash hopper losses are inclusive as the revision does not specifically mention. The losses calculated in STEP yielded a value of 0.568 % versus a value of 0.289% calculated as per the method prescribed by BSI (see Appendix C.10 and C.11 respectively).

5.1.6. Turbine Deterioration loss

The turbine deterioration in STEP is 0.1% abs/year which is applied monthly by multiplying by an availability factor i.e. the percentage of time on-load. The IEC's correlation [16] yields a much higher deterioration as demonstrated in Appendix C.13 calculations (C.68) - (C.70). Whilst ASME's PTC 6-1996 [32] does not recommend corrections for ageing when carrying out the acceptance test, however, the related report [47] does provide a method. The deterioration had been calculated over ten years. The calculations as per STEP yielded a deterioration of 1.0 % compared to the IEC's method yielding a deterioration of 1.76%. It should also be noted that the quoted loss constants of 0.1% abs/month and 0.06% abs/month are applicable for the first and second year of operation relatively. The BCEGB formerly stated 0.117% abs/month for the first year, 0.0417% abs/month for the 2nd and 0.0083% abs/month for the balance of years [34]. In Figure 5-1: Turbine deterioration loss comparison below, the dashed lines are linearized extrapolations for the ASME

PTC 6 report 1985 method based on the last year's deterioration was extrapolated forward after the 48th month. 0.1%/year was also applied to the BSEN 60953-2-1996 method after the 2nd year to aligning with BCEGB and Eskom (as per the excel STEP versions). With the assumptions applied, it would appear that the ASME PTC 6 Report -1985 provides the best fit to the actual plant data provided [34].

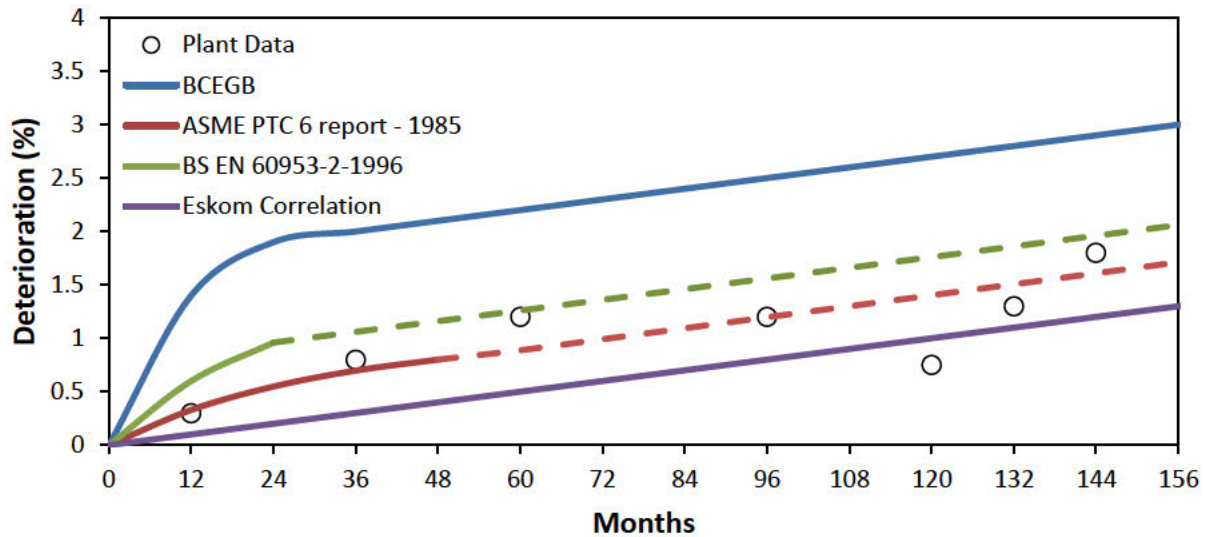


Figure 5-1: Turbine deterioration loss comparison

5.1.7. Hydrogen and Fuel Moisture loss

STEP had been developed at a time where automated queries from steam tables were not available, which possibly would justify the assumption of a simplification made in the methodology applied in Appendix C.8. STEP also does not compute the sensible heat loss of the combustion air moisture. The impact of 0.112% on the boiler efficiency had been demonstrated in the case analysed as per calculation (C.49) in Appendix C.7 due to this omission.

The BS-EN 12952 does address the deficiencies above, however, it does not differentiate for solid/liquid to gaseous fuels as was done in the BS 2885-1974 [5], and hence the reference enthalpy used in the loss determination, is for moisture in the gaseous phase as applied to moisture in the air (see notes made at the calculation (C.47) in Appendix C.7). An adaptation was applied to assess the fuel losses individually (see calculation (C.50)) which yielded results that were comparable to STEP having a 0.110% difference. The adaptation is based on the moisture in air initially being treated as superheated steam as per the BS EN 12952-15 [15] and ASHRAE handbook 2005 [23], and the moisture of fuel initially being treated as a liquid. STEP should be adjusted to conform to 1st principles.

5.1.8. Unitized cycle efficiency - direct method

The STEP model apportions the coal flow to each unit based on its fraction of total electrical units generated applied to the station's total coal consumption. The methodology adopted is due to very high uncertainty associated with mill feeder calibration repeatability, drift as a function of time (wear on spiral feeders and ploughs on table feeders) and inconsistency of the coal density, hence the lack of cycle efficiency calculation at a unit level by the "direct method".

5.2. Instrument uncertainty

The instrument uncertainty of each of 545 input variables had been propagated to each of the 1785 calculated variables via the Python computer program of the STEP calculation method. Refer to Appendix D for the details of each input variable uncertainty assumption. See Table F- 1 in Appendix F for the full results of the instrument uncertainty propagation. It is recommended that this section be read with the review of terminologies explained in sections 4.1 and 1.4.

Table 5-3: Truncated results greater 5% – instrument uncertainty propagation

Calculated Variable	Unit Level			Station Level		
	Base Result	u (abs)	u (%)	Base Result	u (abs)	u (%)
MS_L_Cost	14 767.224	30 984.097	209.817	150 304.440	68 109.383	45.314
MS_SF_T_L	0.038	0.079	209.716	0.070	0.032	45.312
HPT_Diff_In_T	-1.405	2.800	199.322			
IPT_Diff_In_T	-4.102	2.800	68.253			
ReH_Stm_L_Cost	46 573.048	31 505.089	67.647	286 757.185	69 619.781	24.278
ReH_SF_T_L	0.119	0.080	67.504	0.134	0.033	24.275
BP_L_Cost	674 718.199	419 453.943	62.167	5 593 366.533	927 751.450	16.587
BP_SF_L	1.720	1.068	62.113	2.614	0.433	16.582
CW_Rise_T	14.170	7.920	55.891			
MU_SF_L	-0.339	0.087	25.755	0.640	0.063	9.782
MU_L_Cost	-132 936.388	34 233.172	25.752	1 369 881.210	134 120.223	9.791
Radiation_L	0.005	0.001	25.397	0.006	0.000	7.584
AuxPower_L_Cost	-325 313.576	78 290.221	24.066	-670 246.404	133 849.399	19.970
BP_Targ	5.416	1.270	23.441	5.322	0.514	9.651
AuxPower_SF_L	-0.829	0.192	23.142	-0.313	0.063	19.966
DFG_L_Cost	224 778.035	49 812.081	22.161	2 169 978.309	116 838.251	5.384
DFG_SF_L	0.573	0.125	21.825	1.014	0.054	5.369
MU_Act_L	0.516	0.107	20.685	1.780	0.076	4.283
MU_Hot_F	0.516	0.107	20.684	0.000	0.000	0.000
FW_L_Cost	1 490 785.753	302 380.180	20.283	14 302 061.830	743 058.851	5.195
Radiation_L_Coeff	0.408	0.082	20.100			
AH_LH_Leak	13.043	2.609	20.006	13.070	1.072	8.200
AH_RH_Leak	12.999	2.600	20.000	13.018	1.067	8.193
Boil_L_Cost	322 772.480	63 325.683	19.619	3 068 035.665	196 518.510	6.405
FW_SF_L	3.800	0.732	19.257	6.685	0.346	5.179
Boil_SF_L	0.823	0.154	18.728	1.434	0.092	6.388
Cycle_L_Cost	2 910 659.322	539 693.164	18.542	28 459 290.381	1 227 700.769	4.314
Cycle_SF_L	7.420	1.326	17.877	13.302	0.571	4.294
Turb_L_Cost	3 046 136.806	530 535.547	17.417	24 691 619.910	1 191 696.155	4.826
Turb_SF_HR	718.825	124.034	17.255			
Turb_SF_L	7.765	1.297	16.708	11.541	0.555	4.809
L_Corr_H2andMoist	1.384	0.229	16.575	0.000	0.000	0.000
CIR_L_Cost	199 713.018	28 531.468	14.286	1 381 066.295	142 917.428	10.348
L_Corr_Ash	0.361	0.049	13.510			
FW_Diff_T	-44.326	5.661	12.772			
CIR_SF_L	0.509	0.065	12.724	0.645	0.067	10.334
Cond_DepresT	38.075	3.960	10.400			
MR_SF_L	0.000	0.000	7.370			
MR_Act_L	0.000	0.000	7.370	0.000	0.000	3.180

AH_Out_CO2_Coeff	1.942	0.132	6.779			
H2_Moist_L_Cost	-101 718.572	5 807.997	5.710	-483 008.940	12 108.292	2.507
AuxPower_Act_Frac	3.806	0.214	5.635	8.310	0.072	0.871
FD_In_T	30.374	1.617	5.322			
Boil_LF	81.869	4.175	5.099			
H2_Moist_SF_L	-0.259	0.013	5.055	-0.226	0.006	2.473
Stm_Mass	1 113.935	55.697	5.000	6 019.247	123.377	2.050

The Table 5-3 is a truncated form of the stated table where the variables with uncertainties greater than 5% are shown at a unit level. The results above are valuable to understand the uncertainty of each calculated variable but it must be emphasized that even though the uncertainty of the calculated variable may be extremely high, it may be relatively insignificant to the final result of STEP i.e. cycle efficiency, turbine efficiency, boiler efficiency and associated STEP Factors (% of targets achieved). The above information, however, may be vitally important for specific business case sensitivity analysis, where an individual parameter may be of high importance e.g. the cost of feed water temperature loss may be a significant input parameter in a feasibility study to replace the feedwater heaters.

It is observed that the parameter uncertainty at a station level is lower than that of a unit level by the typical factor, $\sqrt{N_{units}}$, where the station parameters are a mere composite of unit parameters. This is not the case where the unit parameters are influenced by some common input parameters e.g. coal quality parameters, common plant auxiliary power consumption, common plant demineralized water consumption.

From the results above is already noticeable that some significant contributors to the uncertainty of the listed variables are temperature measurement (thermocouples), make-up water flow (orifice plates), condenser pressure transducer, coal quality parameters (total moisture) and electrical metering. The method of flagging the items in the table by the percentage uncertainty is very sensitive to the base run conditions, hence a more holistic and in-depth analysis was performed on the parameters of specific interest with consideration for the absolute uncertainty with a drill-down approach.

It is interesting to observe from Table 5-4 (highlighted in blue), there is quite a large difference between the direct and indirect STEP Factor uncertainty i.e. 0.571% vs 2.210%. It is vastly accepted that the indirect method should yield lower uncertainties due to the fact it is not directly dependent on the coal flow rate measurement, which is prone to significant measurement noise.

Table 5-4: Truncated results drill-down approach – instrument uncertainty propagation

Calculated Variable	Unit Level			Station Level		
	Base Result	u (abs)	u (%)	Base Result	u (abs)	u (%)
Cycle_Act_Eff	0.000	0.000	0.000	31.911	0.756	2.370
Cycle_Indirect_SF	73.479	1.683	2.291	86.698	0.571	0.659
Cycle_Direct_SF	0.000	0.000	0.000	90.487	2.210	2.443
Cycle_Unacc_L	0.000	0.000	0.000	-3.788	2.230	58.878
Cycle_Acc_L	0.000	0.000	0.000	13.302	0.571	4.294
Cycle_Act_HR	0.000	0.000	0.000	3.134	0.074	2.369
Cycle_HR_Targ	2.872	0.034	1.179	2.836	0.015	0.516
Cycle_SF_L	26.521	1.683	6.346	13.302	0.571	4.294
Cycle_Unacc_L_Cost	0.000	0.000	0.000	-8 105 289.618	4 767 717.845	58.822
Incr_NLtoNER_Act_HR	3.313	0.051	1.532	2.970	0.015	0.520
AuxPower_Act_Frac	11.676	0.398	3.411	8.310	0.072	0.871
AuxPower_CF	1.008	0.001	0.067	1.004	0.000	0.018
AuxPower_SF_L	1.675	0.332	19.801	-0.313	0.063	19.966
AuxPower_Targ_Frac	10.001	0.086	0.863	7.879	0.027	0.340
Boil_Act_Indirect_Eff	88.201	0.281	0.318	88.735	0.246	0.277
Est_MU_F	1.486	0.032	2.187	0.000	0.000	0.000
MU_Targ_L	1.192	0.026	2.208	0.996	0.008	0.811
MU_Targ_CF	1.003	0.000	0.021	0.000	0.000	0.000
MU_Hot_F	3.694	0.284	7.693	0.000	0.000	0.000
MU_Act_L	3.695	0.284	7.695	1.780	0.076	4.283
MU_SF_L	2.045	0.233	11.371	0.640	0.063	9.782
Turb_Est_Det_L	2.046	0.000	0.004	2.037	0.000	0.014
Boil_Act_L	11.799	0.281	2.380	11.265	0.246	2.183
Boil_Eff	0.000	0.000	0.000	88.735	0.246	0.277
Boil_SF_L	2.117	0.175	8.252	1.434	0.092	6.388
MS_SF_T_L	0.047	0.079	167.343	0.070	0.032	45.312
ReH_SF_T_L	0.138	0.079	57.333	0.134	0.033	24.275
BP_Targ	4.875	1.170	23.995	5.322	0.514	9.651
BP_Act_CF	103.643	0.148	0.143	0.000	0.000	0.000
BP_Targ_CF	0.996	0.011	1.122	0.000	0.000	0.000
BP_SF_L	4.048	1.127	27.836	2.614	0.433	16.582
Turb_SF_L	20.684	1.615	7.809	11.541	0.555	4.809
FW_SF_L	14.405	1.164	8.078	6.685	0.346	5.179
FW_Targ_T	233.103	0.833	0.357	238.775	0.338	0.142
FW_Diff_T	-97.852	5.662	5.786	0.000	0.000	0.000
CIR_Act_L	1.880	0.079	4.190	1.615	0.066	4.086
CIR_SF_L	0.980	0.089	9.125	0.645	0.067	10.334
DFG_Act_L	5.223	0.131	2.506	4.971	0.056	1.132
DFG_SF_L	1.342	0.130	9.721	1.014	0.054	5.369
Gen_HV_LF	73.910	1.280	1.732	81.166	0.616	0.759

H2_Moist_Act_L	4.686	0.230	4.909	4.672	0.229	4.902
H2_Moist_SF_L	-0.204	0.016	7.659	-0.226	0.006	2.473
MR_SF_L	0.000	0.000	7.495	0.000	0.000	0.000
Radiation_L	0.011	0.002	15.740	0.006	0.000	7.584

A negative unaccounted cycle loss as indicated in the table above (In blue text) would indicate either that the direct-method cycle efficiency is overstated or that the losses are overstated, or both. The unaccounted SF loss (3.788%) is the difference between the direct STEP Factor and the indirect STEP Factor, and is used as an indication of the uncertainty of either of the stated metrics. If one combines the systematic uncertainty of both parameters (0.571% + 2.210%), it could only justify a maximum deviation of 2.781%, which would be only 73 % of the unaccounted loss, hence it can be deduced that other significant uncertainties affect these computations, which will be re-examined in Section 5.5 of this document.

From Figure 5-2, the backpressure loss and final feed water loss have the highest instrument uncertainty for the case analysed. The other loss uncertainties are significant but relatively much lower.

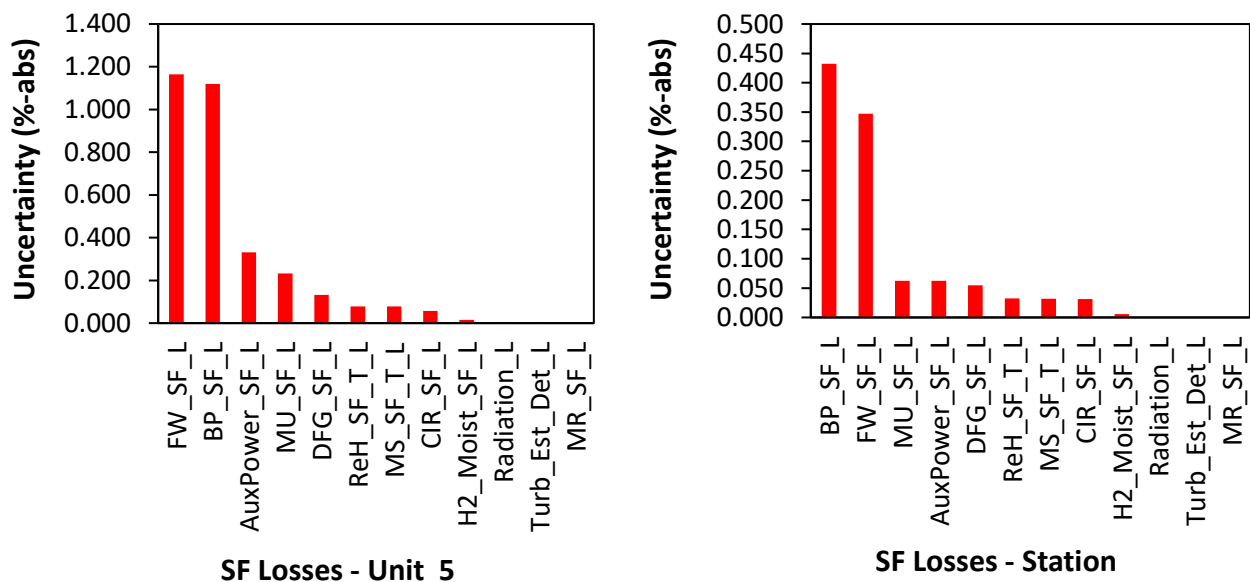


Figure 5-2: Instrument uncertainty on SF losses

5.2.1. Indirect STEP Factor uncertainties

Recall, the variable significance has been defined as the percentage contribution of an individual input variable to the total uncertainty of a calculated parameter (refer to the equation (4.13) for the mathematical operation).

From Figure 5-3 it is observed that the cooling water inlet temperature measurement has the highest contribution (57%) to the indirect STEP Factor uncertainty as the uncertainty had been derived from a thermocouple at a single measurement point. The economizer inlet feed water temperature contributes to 36% of the STEP Factor uncertainty. It is observed from the above that the parameters with relatively average input uncertainties can have a significant impact on a result

due to the sensitivity ratio, $\left(\frac{\partial R}{\partial x_i}\right)_{x_i=\bar{x}}$ portion of the uncertainty equation (3.5). It is important to

note that the y-axis in Figure 5-3 is log scale.

In STEP it would mean that input parameters would become more significant as the plant operation moves toward the steeper sections of their associated polynomial performance curve i.e. the feedwater temperature will have a higher impact on the uncertainty at point B than at point A as indicated in Figure 5-4, hence it can be deduced the most significant parameters can be unique to a particular plant and its respective deficiencies.

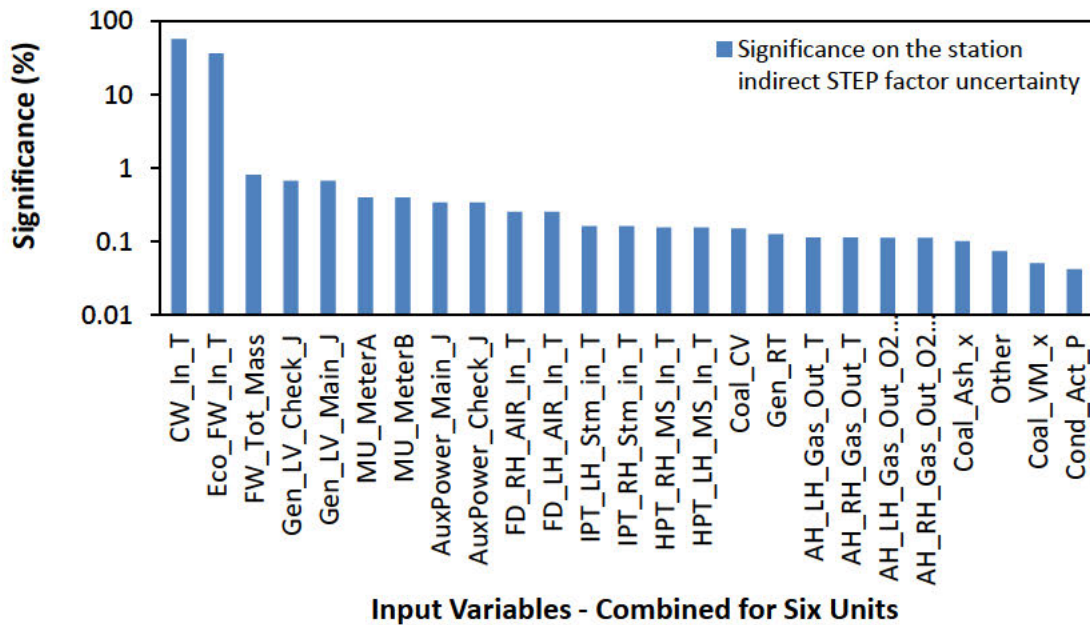


Figure 5-3: Variable significance on station cycle indirect STEP Factor uncertainty

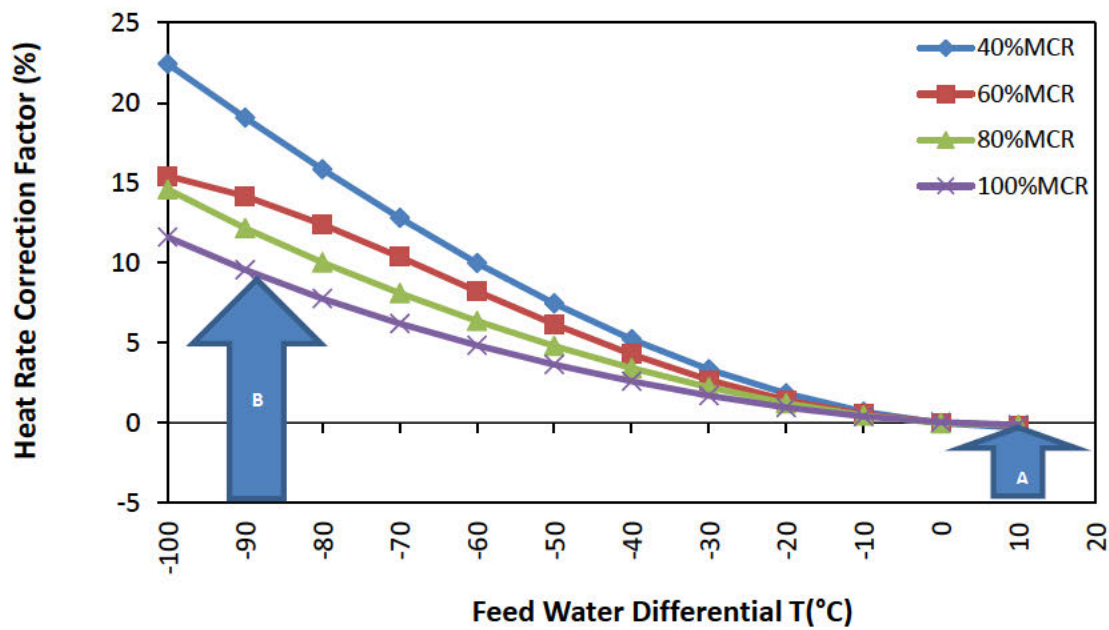


Figure 5-4: Final feed water - original heat rate correction factor curves

5.2.2. Direct STEP Factor uncertainties

The direct STEP Factor uncertainty of 2.210% (abs) translates to a 0.756% (abs) on the cycle efficiency. The coal CV (74.756%), CW inlet temperature (6.393%), coal mass (5.718%), units generated (5.355%), coal moisture (2.230%) has the greatest significance in the order of magnitude on the direct STEP Factor, the other variables seem to have a negligible impact.

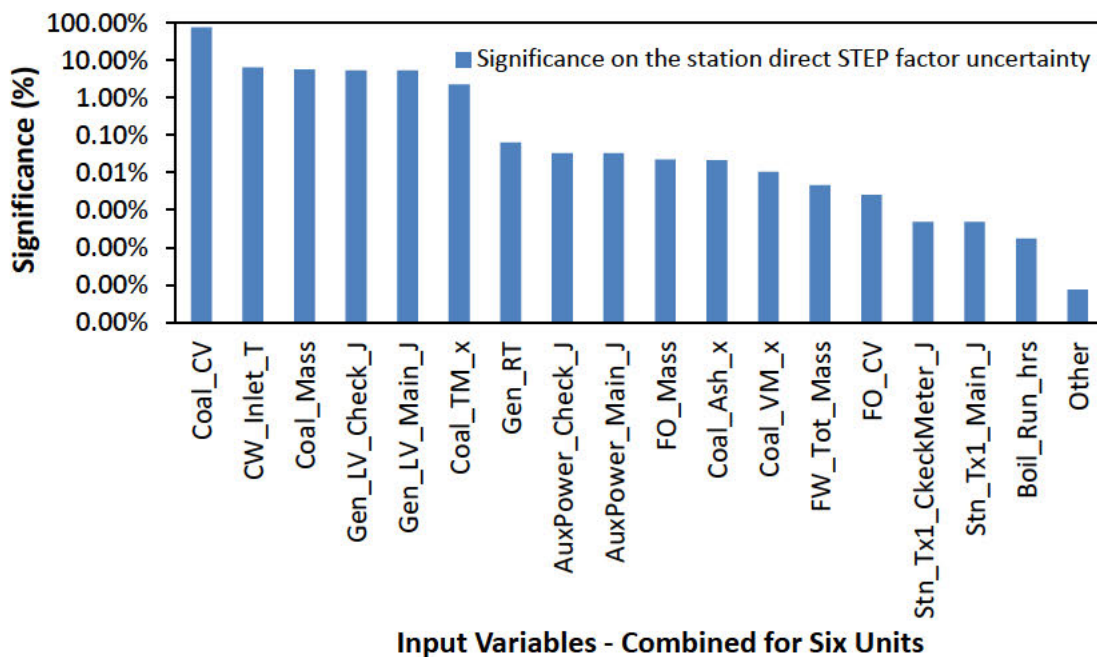


Figure 5-5: Variable significance on station cycle direct STEP Factor loss uncertainty

The coal CV is a significant parameter only direct STEP Factor as is used in calculating the actual cycle heat input as per equations (B.252) to (B.255) in Appendix B. The coal CV is used differently in the indirect method mostly to normalize the losses to the 1kg of coal burnt, which is used in target and actual loss calculation. The uncertainty impact is canceled out in the STEP loss calculation. The CW inlet temperature affects the target back pressure loss and not actual for the indirect method. In the case of the direct STEP Factor it affects the target heat rate and not the calculation of the actual heat rate, hence the canceling effect is minimal for both methods. The CW Temperature is a significant parameter specific to case evaluated.

5.2.3. Cycle and turbine losses

The turbine plant SF loss uncertainty was determined to be 0.555% abs for the case evaluated, of which cooling water inlet temperature contributed 60.078% and the economizer feedwater inlet temperature contributed 38.52% of the uncertainty. These two parameters are almost the sole contributors to the condenser backpressure loss uncertainty and feed water temperature loss uncertainty respectively. The turbine deterioration can only be influenced by the turbine running hours but we see that uncertainty of the generating units introduces a significantly greater uncertainty when composited for the 6 units (compare with Figure F- 1 in Appendix F). The other loss uncertainties are significantly lower, and their contributions are as expected where: the main steam temperature SF loss uncertainty is equally split between the LH & RH HPT inlet temperature and the Reheater SF temperature loss uncertainty is split between the IPT LH & RH temperatures.

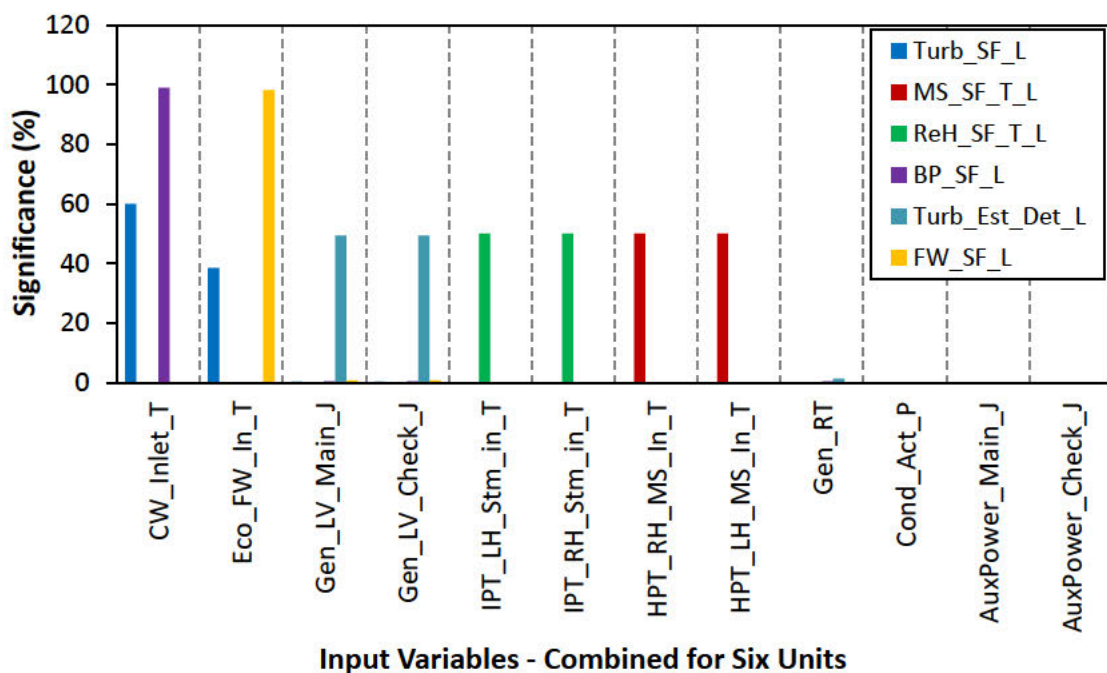


Figure 5-6: Variable significance on uncertainty on the station cycle and turbine plant SF losses

5.2.4. Boiler losses

Even though the boiler SF loss uncertainty is relatively low at 0.092% abs, the significant parameters that influence the uncertainty for the case evaluated were identified to be the: forced draught fan inlet temperature, coal CV, mass of feed water supplied to the boiler, air heater gas outlet temperature, air heater gas outlet oxygen content, the ash content of coal and the volatile matter content of coal. Their contribution to the boiler SF loss uncertainty as well as the individual loss uncertainties are reflected in Figure 5-7 (refer to Figure F- 2 in Appendix F for results at a unit level). A critical phenomenon observed is that parameters that affect either the target loss or actual losses will have an impact on the SF losses, but parameters that affect both the target and actual has minimal effect on the SF loss, as the variable uncertainty impact is cancelled out in the generic calculation of SF losses (recall equation (4.4)). The phenomenon is demonstrated by the comparison of Figure 5-7 to Figure F- 3 in Appendix F.

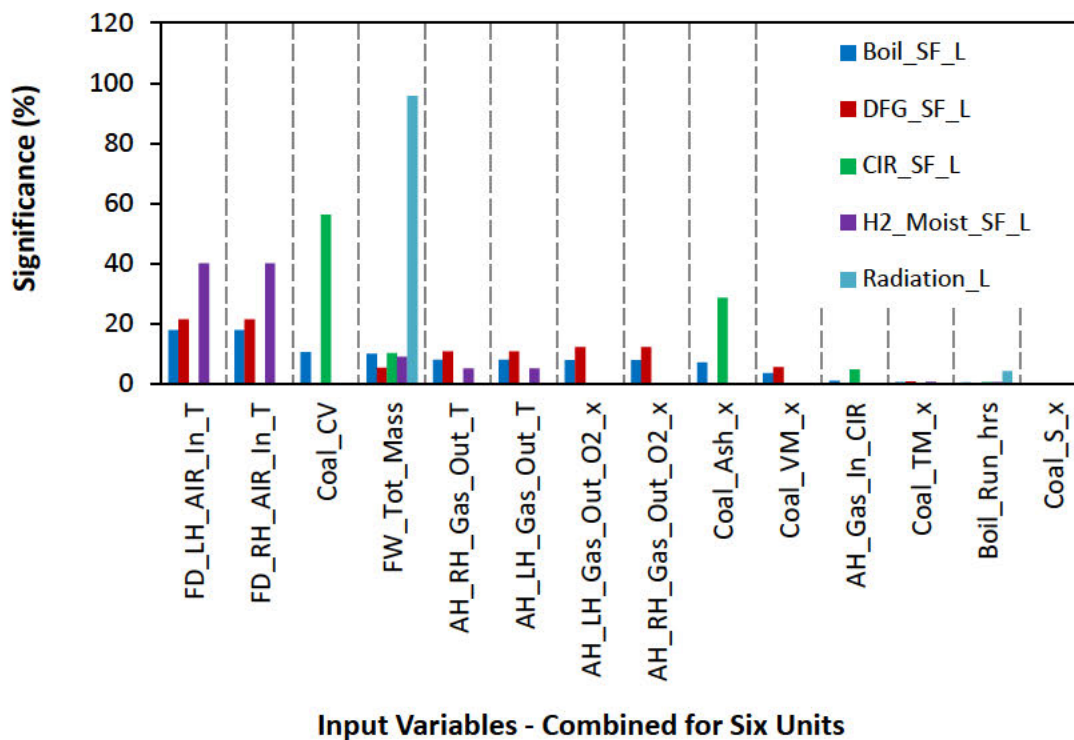


Figure 5-7: Variable significance on uncertainty on the station boiler SF losses

5.4. Temporal uncertainty

In this section, the impact of input parameter variability as a function of input resolution on the total uncertainty on specific STEP results is evaluated. The temporal uncertainty model has been programmed to evaluate the thermal performance indicator taking into consideration the unit and station load profile as well as the key input variables in the computation of each loss.

From Figure 5-8: Generated power profile by resolution, it can be seen that the inputs to STEP can have a significant variability when viewed at different resolutions. The generated power, when converted into a load factor is the most common variable that is used in almost all the STEP loss calculations. The objective of this section of the study was to investigate if there would be a significant difference in discretizing the inputs into multiple segments of different sizes and then carry out the thermal performance calculations on each segment. The monthly composite results being the weighted average of the segment results by the USO of each segment was compare to a single STEP run with monthly averages as inputs. The segment sizes that were analysed were: 1 month, semi-monthly, 1 week, 1 day, 12h, 3h, 1h and 30 minutes.

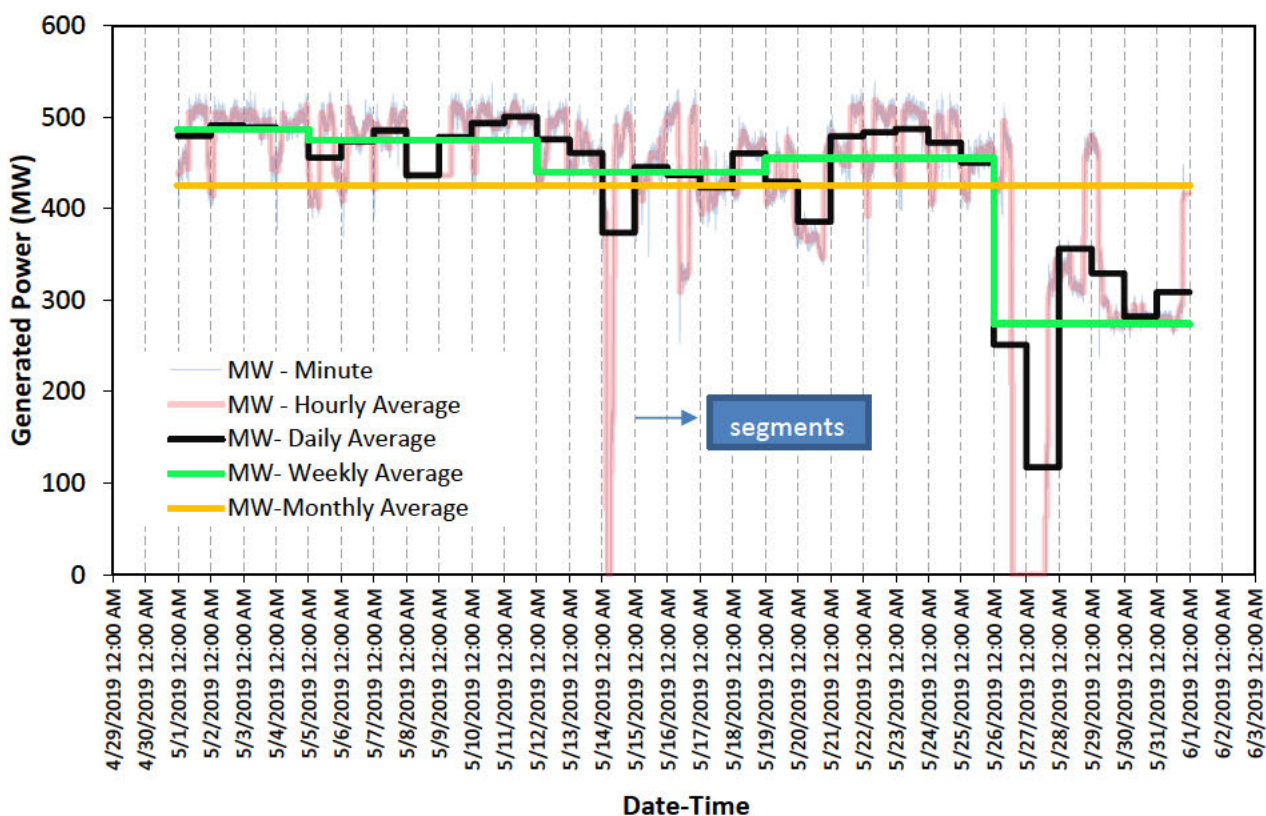


Figure 5-8: Generated power profile by resolution

The aim was to find the segment size that would yield the highest number of stable load segments and lowest number of transition segments by a statistical method. Naturally one would expect this to be achieved by discretizing to the highest possible resolution at which the data is available, however, the temporal uncertainty within each segment had to be quantified with the reduction in the sample data size i.e. the segment size. The minimum sample size of 30 minutes or 30 observations was set to conform to the principles of statistics, where the sample standard deviation can be approximated to the population standard deviation as per equation (4.17). It is important to note that, it is a requirement that the load remains stable for 4 hours to deem an acceptance test to be successful, hence the baseline performance data is very specific to the unit loads rather than the average of transient conditions [14] and therefore should only be applied to actual stable loads rather than averages.

Each loss has a significant parameter e.g. condenser backpressure loss is a function of the LP exhaust pressure, final feedwater temperature loss is a function of the economizer inlet temperature, etc. These significant parameters also have some degree of variability relative to time or resolution. If one examines Figure A- 1 in Appendix A.2.2, it can be deduced that large deviations in either the load or the significant parameter (in this case LP-turbine condenser pressure) from the design point will result in a significant change in the heat rate which is used to determine the losses, especially when the deviated points are in the exponential zones of the curves.

Figure 5-9 compares the STEP Factors when run at various resolutions. As expected, the direct STEP Factor appears to be fairly static due to the simple calculation of the actual direct efficiency (see Appendix B equations (B.255) & (B.256)) which is not affected by plant process parameters. The most significant parameter: coal CV, is weighted by the coal mass within and across all segments. The coal mass and USO are summative parameters hence does not vary with the time resolution analysis. The target efficiency is derived through the application of correction factors, but these are normally small adjustments to the heat rate to compensate for external conditions and not as significant as plant deficiencies.

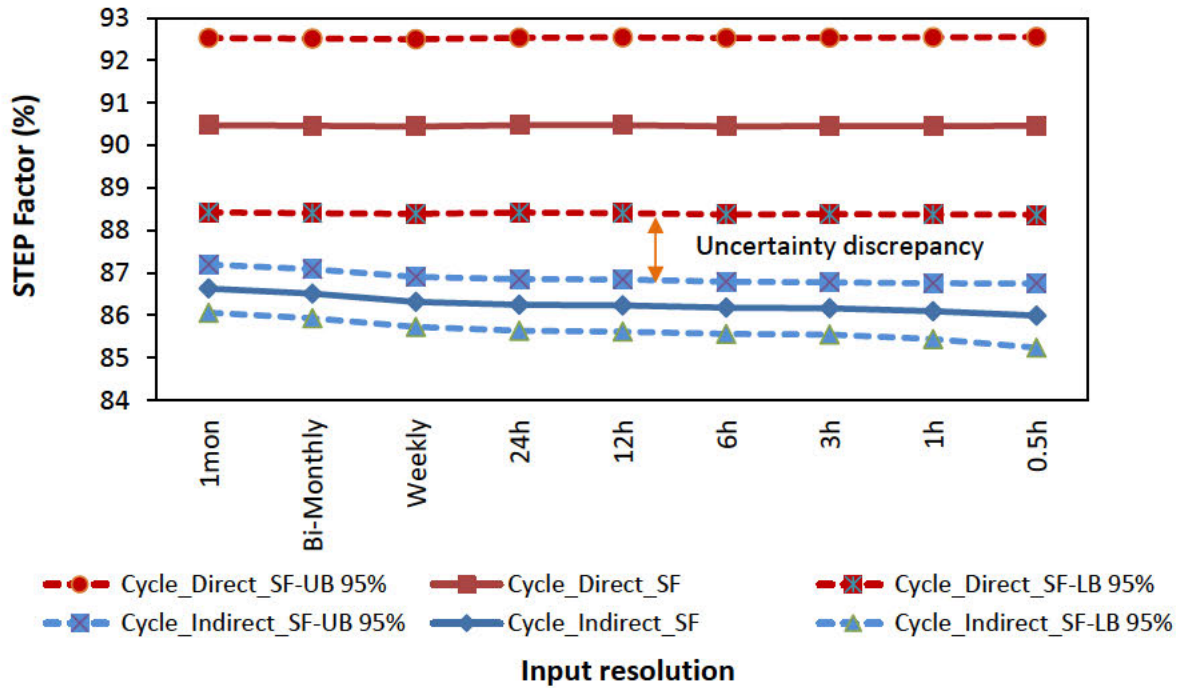


Figure 5-9: Station STEP Factor results with uncertainty bounds

In theory, both STEP Factors should be the same but in the case of this analysis, the uncertainty bounds do not even overlap. This would indicate that uncertainties are higher than that quantified. The possibility of underestimating the input uncertainties was considered and reviewed with experienced plant performance engineers. Since the systematic and the temporal uncertainty have been estimated as per conventional methods, it can be deduced that the gap between the two bands is an indication of the combined model and baseline data uncertainty. In this case, an example would be the underestimation of the auxiliary power STEP Factor loss and possible overestimations of the final feed water STEP Factor loss which will be discussed in more detail when examined at a unit level.

The indirect STEP Factor moved from 86.698% to 86.163% (0.189% abs change in overall efficiency) by increasing the input resolution to a 3-hour segment size. The discretised runs now differentiate with regards to the load factors and significant parameters per segment, thus proving that there is merit in running STEP at a higher resolution. In the case studied, there is a significant step-change at the weekly resolutions which correlates with the data in Figure 5-8 showing a reduction of load during the last week of operation which indicates that the segmented runs are sensitive to such changes. At a 6-hour resolution there seems to be a further change that is differentiating between peak and off-peak operations.

From Figure 5-10, it can be noted that the direct SF accrued an uncertainty of 2.210% abs when only considering the systematic uncertainty propagation and a combined uncertainty of 2.239% at a 3-hour resolution. It can be deduced that there is minimal temporal uncertainty contribution and

minimal movement of the mean for the direct SF. The indirect SF accrued an uncertainty of 0.571% abs when only considering the systematic uncertainty propagation and a combined uncertainty of 0.617% abs at a 3-hour resolution. Here the findings suggest that the temporal uncertainty contribution is significant and the movement of the mean is also significant when compared to a monthly composite run. The above phenomenon is also expected as previously explained. When zooming into the uncertainty profile as per Figure 5-10, it would suggest that there is a limit to the resolution at which STEP should be run, as the temporal uncertainty sharply increases from a time resolution of 3-hour. The phenomenon is due to the reduction of the sample size for each segment which makes the temporal uncertainty higher, recall $S_{\bar{x}} = \frac{S_x}{\sqrt{N}}$ equation (4.17).

One of the objectives of STEP is to accurately quantify the losses at a unit level so that maintenance work or defect resolution can be prioritized especially in a capital-constrained environment. Figure 5-11 reveals that the final feed water temperature loss could be perceived to be 2.378% when evaluated at a month resolution, however, increases to 3.188 % when evaluated by a 3-hour segment run which is significant. The turbine back-pressure loss moved from 3.511% to 3.164%. The auxiliary power consumption is baselined with the boiler steam feed pumps (BFPTs – pumps driven by a steam turbine) in service. When the BFPTs are unavailable the energy consumed for the operations of the electric motor driven boiler feed pumps (EFPs) are estimated by the power vs load curve as indicated in equations (B.106) and (B.107) in Appendix B. The target auxiliary power is adjusted by the estimated power consumption, which in principle gives a zero nett effect on the STEP Factor loss. For the data used in this study, it is not the case, which indicates that there is a possible deviation with the power vs load curve (i.e. it overestimates the power consumption of the EFPs).

Unit 5 results indicate that the unit suffers from the same deficiencies as Unit 4 however the magnitude is much higher. The weighted average final feed water temperature deviation from the design is 99 °C, which is typical of operating the unit without both banks of HP heaters. The operating condition translates to a STEP Factor loss of approximately 14.8% as indicated in Figure 5-12. The uncertainty in this value is expected to be extremely high as the operating point will fall in the extrapolated zone of Figure 5-4 with the largest distance from actual performance data.

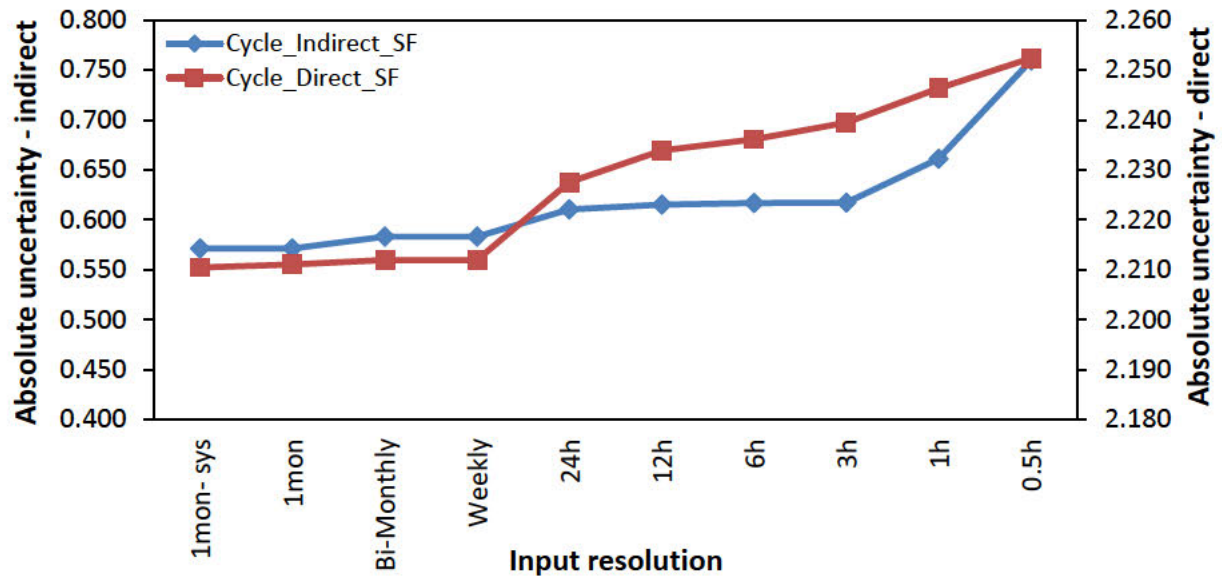


Figure 5-10: Station STEP Factor uncertainty by resolution

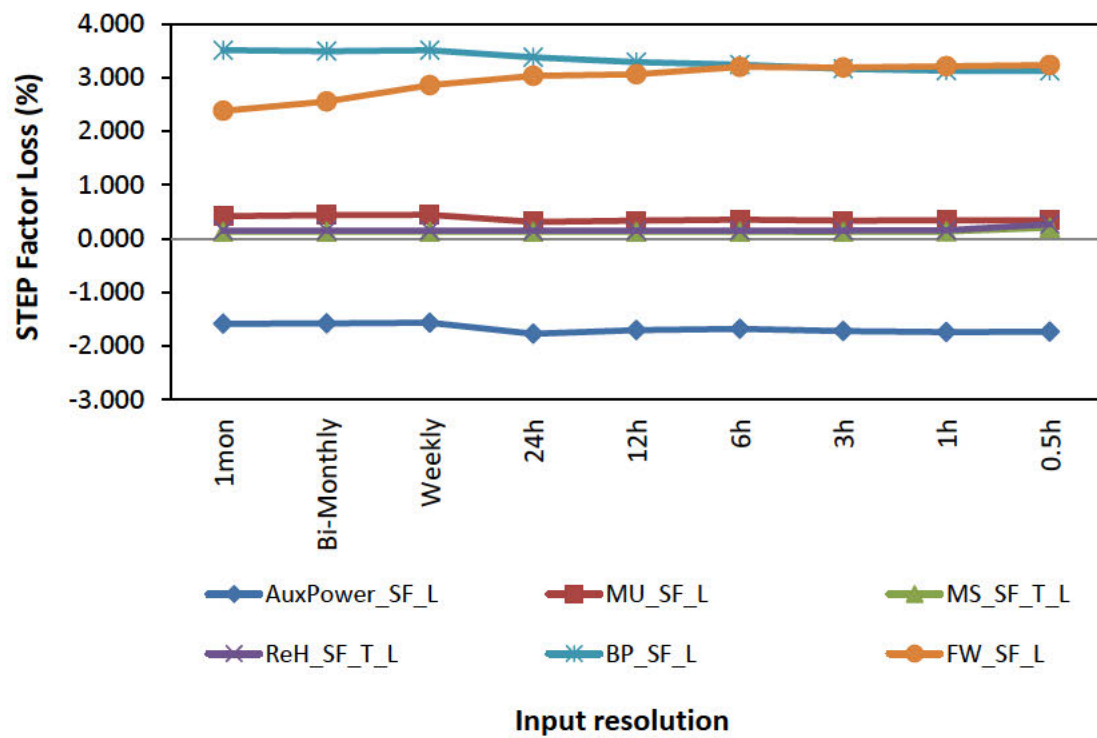


Figure 5-11: Unit 4 segmented SF loss evaluation

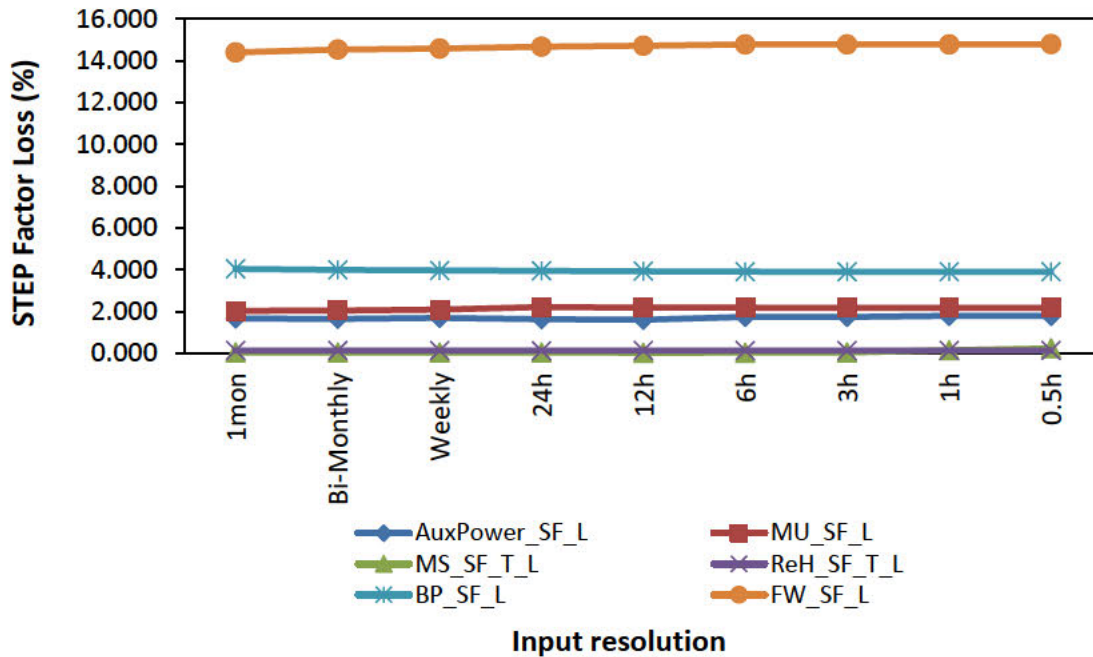


Figure 5-12: Unit 5 segmented SF loss evaluation

5.5. Baseline data uncertainty

As alluded to in the previous sections, an attempt was made to investigate the possibility of erroneous baseline data because of the wide gap between the direct and indirect STEP Factor illustrated in Figure 5-9. The final feed water and condenser backpressure heat rate correction curves were reproduced by modelling the Rankine cycle on thermodynamic tools, namely EtaPro® - Virtual Plant and STEAM PRO®. The models were verified and validated through other initiatives undertaken by Eskom.

The above exercise yielded a significant improvement in the agreement of the Direct SF to the Indirect SF as shown in Figure 5-13. As expected, there was no change to the direct SF of 90.487%, but the indirect SF had moved from 86.698% to 90.418% (1.312% abs change in overall efficiency) at a monthly resolution. Further, the Indirect SF mean value had minimal variance as a function of time resolution, hence would mean that the sensitivity ratios at the operating points of the loss curve have significantly reduced. The exercise has provided some insight into potential uncertainty in the baseline data and some means of detecting anomalies in the performance data. It is suspected that data is extrapolated from OEM sensitivity curves produced for a lower range of deviations from the design and then incorrectly extrapolated for severe deviation as experienced during operations.

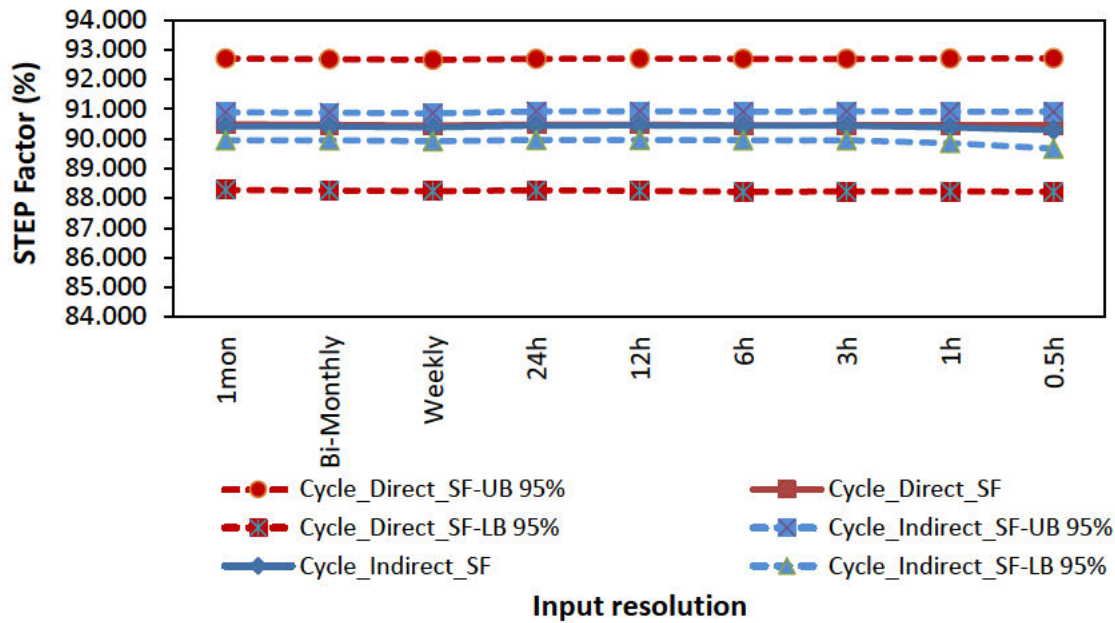


Figure 5-13: Station STEP Factor results with uncertainty bounds – corrected

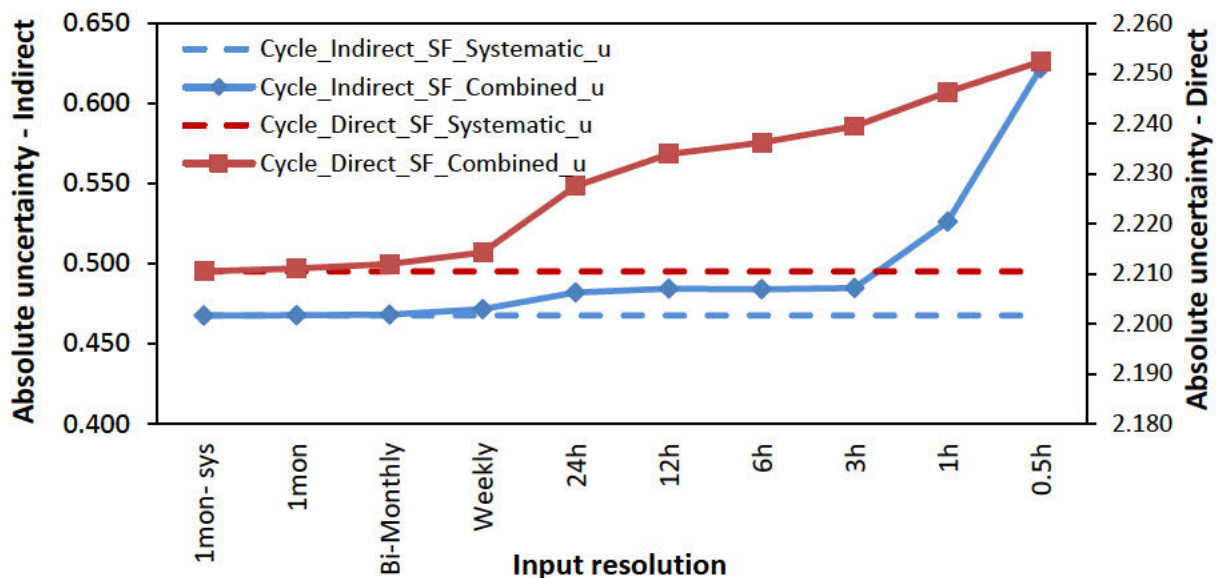


Figure 5-14: Station STEP Factor systematic vs combined uncertainty - corrected

After correction of the baseline data, the propagation study yielded a station Direct SF systematic uncertainty of 2.210 % abs and a combined uncertainty at a 3-hour resolution of 2.239% abs. The station Indirect SF accrued a systematic uncertainty of 0.468% abs, and a 0.485% abs combined uncertainty at a 3-hour resolution. Now both the systematic uncertainty and the temporal uncertainty contribution are much smaller when compared to the uncorrected results. The economizer feed water temperature contributions to the direct STEP factor, has reduced from 36.806% to 5.457% (see Figure F- 4 & 5 in Appendix F) with no impact to the direct STEP factor.

6. Conclusions and summary of recommendations

6.1. Conclusion

The program used in Eskom for thermal efficiency and loss quantification was reviewed with a focus on 4 facets pertaining to the accuracy of the system employed:

- model uncertainty (the method used in quantifying the losses),
- instrument uncertainty (systematic uncertainty),
- temporal uncertainty (as a function of input resolution),
- baseline performance uncertainty (heat rate correction curves)

A semi-quantitative/qualitative approach was used to appreciate the potential uncertainty of the STEP model by studying the difference between performance standards and STEP. A quantitative assessment was carried out for the case studied, however, it was not intended to establish which standard is superior and should be used as a generalized ultimate reference for the expression of model uncertainties. The models produced during the study, provide a means of quantifying the accuracy of STEP relative to a specific case, and the expected parameter uncertainties. From the analysis of the case studied, it was deduced that the systematic uncertainty is much more dominant than the temporal uncertainty, and has highlighted key parameters/measurements that should be maintained or enhanced to reduce the overall impact on the STEP results. Whilst the temporal uncertainty may be of a lower magnitude, it may have a significant impact on the losses at a unit level, this could be crucial for investment consideration. The study has yielded that the optimal period (segment size) that STEP should be run to negate the impact of the temporal uncertainty is three hours. The input data processing methodology can be considered as a pilot study, however, can be improved further with the implementation on existing data systems. The baseline performance data (heat rate correction curves) was compared to that produced via commercial modelling software. The review had led to the conception that significant uncertainties are introduced with erroneous baseline performance data. The recommendations below, speak to the conclusions made above and the findings made in Section 5.

6.2. Recommendations

6.2.1. Model Uncertainty

STEP intends to apportion cycle heat loss as accurately to the lowest possible level. The following recommendations will drive lower unaccounted losses calculated by STEP:

- The calculation of the sensible heat loss in ash that is emitted by the boiler is to be accounted for in the STEP calculations.
- The hydrogen and fuel moisture losses should be updated as per BS 2885-1974 [5] or the sample the calculation performed in Appendix C.7.
- The losses associated with partial combustion or CO production are to be expressed in STEP.
- The demineralized water loss appropriation assumption is to be reviewed through a practical study (the assumption that a 3rd of make-up water is lost is at feed water condition and the balance at the main steam condition). A practical study using a calibrated instrument is to be carried out. The existing water balance model should be configured in the future to estimate this ratio based on plant data, which then could become a volatile input to STEP. In the case of input errors then default values being based on some proven principle from baseline tests be used.
- All empirical correlations derived from losses as a function of load factor to be re-based lined over time. STEP baseline testing should include sensitivities at extreme operating condition so that the polynomial regression fitting is done with a data scatter over the entire operating range, e.g. heat rate test and modelling should be done with both banks of HP heaters offload or with the LP turbines operated at maximum allowable backpressure as per the operating philosophy.
- Throttle losses are included in overall turbine losses as a function of load. Deviations from expected to be identified and quantified in STEP. The mentioned loss could be beneficial in identifying issues with final steam pressure control such as defects with emergency shut-off valves, governor valves and strainers.
- The direct unitized cycle efficiency calculation should be performed for power stations fitted with new technology coal feeders such as the gravimetric belt feeders. The calculation could be carried through to stations with spiral and table feeders for trending purposes only (identify feeder calibration issues). The uncertainty in the latter would be too high in the case of volumetric coal flows as the density of coal can vary significantly with mineral composition, moisture content and size grading.
- Coal quality is considered for Carbon in Refuse losses and Hydrogen and Moisture losses, but, the ash impact on Dry Flue Gas loss (radiation impact) and Auxiliary Power loss are to be further studied and incorporated into STEP.
- The unitized Auxiliary Power STEP Factor losses are erroneous, based on the treatment of off-load auxiliary power that is equally shared by all units. The unit that supplies the loop

supply (interconnected auxiliary power reticulation between units and common plant) is not credited for its contributions to the common auxiliaries and other units.

- The auxiliary power STEP Factor loss is baselined with the boiler steam feed pumps (BFPTs – pumps driven by a steam turbine) in service, when the BFPTs are unavailable the energy consumed for the operations of the electric motor driven boiler feed pumps (EFPs) are estimated by the power vs load curve as indicated in equations (B.106) and (B.107) in Appendix B. The target auxiliary power is adjusted by the estimated power consumption, which in principle should give a zero nett effect on the STEP Factor loss. STEP does not account for the cycle heat rate gains by running the EFPs instead of the BFPTs. The above philosophy could have adapted due to the number of tests that would have to be done to cover all possible configurations. It is therefore recommended that validated thermodynamic models be used to generate the load sensitivity correlations as done in software such as Virtual Plant or Steam Pro and be expressed as a separate loss. The target auxiliary power should be adjusted by the measured actual EFPs electric energy consumption rather than using a correlation to determine.
- A study to determine the turbine deterioration factors should be initiated to consider the local history of turbine cylinder efficiency test or enthalpy drop test for specific turbine designs and sizes.

6.2.2. Input data

In some cases, totalized values such as mass flows were averaged and multiplied by the duration of a period. This practice should be avoided as there can be a considerable difference when compared with an integrated value at the lowest possible resolution (dt).

A system should be designed/configured and proved to process data to enable the running of STEP at a higher resolution. Section 4.2.3 can be considered a pilot exercise in determining the methodology. Future work could entail the automation and integration with existing plant data systems.

6.2.3. Baseline performance data

Polynomial correlated data based on an acceptance test to be refitted with credible regression fitting tools that can be extrapolated to worse case operational data. Once-off repeated testing should be done to establish the typical uncertainty of the acceptance test data. In the world of power generation, this would be very difficult to justify based on both resource and plant availability costs. A similar desktop study as discussed in section 5.5 should be performed for all STEP applications within Eskom and the industry.

6.2.4. Instrument uncertainty

The study intended to determine the typical uncertainty of performance metrics in the South African power industry. Whilst it has been proven that it is very dependent on a specific case, a tool has been developed to compute the uncertainty of these performance metrics for any power plant that employs STEP, for a specific condition. Instrument uncertainty can be reduced by increasing the number of transmitters, increasing the calibration frequency and choosing measurement devices of a higher measurement class.

Key parameters for improvement include the:

- cooling water inlet temperature,
- economizer inlet feed water temperature,
- coal CV,
- coal mass,
- units generated,
- coal moisture,
- mass of feed water supplied to the boiler,
- air heater gas outlet temperature,
- air heater gas outlet oxygen content,
- ash content of coal, and
- volatile matter content of coal.

6.2.5. Temporal uncertainty

The optimal resolution is 3 hours as there could be a significant change of the resultant means, particularly for the losses at a unit level, with minimal increase in the temporal uncertainty.

The STEP input or segment resolution should be kept a minimum of 3-hours, even though 6 hours would be adequate the segmenting windows would have to be aligned to separate the peaks for off-peak data. The 3-hour segment size is the size up to overcome alignment issues and also the next size down from the 1-hour segment size, where an increased temporal uncertainty at this resolution is observed.

6.2.6. Future work

Coal quality parameters were limited to daily composites as per the station laboratory analysis. During the study, some work had commenced at other sites to correlate online coal scanner data to real-time burn conditions. Each power plant has a specific coal flow and storage configuration based on conveyor belt layout, measurement points and storage capacities. A time duration sensitivity/uncertainty study should be carried out to determine the duration of coal movement from the measurement point (location of the coal scanner) to the boiler, taking into account belt loading, silo storage, bunker storage, mill configuration and confirmation of the assumption of plug flow (no mixing). Should an uncertainty in the time lag be considerably low translating into a relatively low temporal parameter uncertainty, the data can then be processed through the existing models developed, however, configured for the specific power plant.

The water balance models developed should be integrated or linked to the STEP program to ensure the improvement of the method by reasonably appropriating the losses based on the enthalpy of the water at its point of release.

STEP intends to provide a thermal performance effectiveness assessment. Exergy efficiency analysis is deemed to provide a more realistic measure of effectiveness; it would be an interesting study to include exergy computations to the STEP baseline/ acceptance test data and produce exergy STEP factors for comparison with the current method.

The spatial uncertainties associated with the location of the measurement points and sampling methods were omitted from this study as practical case-specific studies would be required to determine these uncertainties. It would be interesting to carry out a study that investigates the temperature, oxygen content, and unburned carbon in ash by traversing the flue gas ducting at various points.

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Appendix A. Equations and correlations from literature

A.1. Boiler performance principles [15]

A.1.1. Boiler efficiency

$$\begin{aligned}\dot{Q}_{Boil.Out} = & \dot{m}_{LS}(h_{LS} - h_{FW}) + \dot{m}_{SW}(h_{FW} - h_{SW}) \\ & + \dot{m}_{ReH1.In}(h_{ReH1.Out} - h_{ReH1.In}) + \dot{m}_{SW.ReH1}(h_{ReH1.Out} - h_{SW.ReH1}) \\ & + \dot{m}_{ReH2.In}(h_{ReH2.Out} - h_{ReH2.In}) + \dot{m}_{SW.ReH2}(h_{ReH2.Out} - h_{SW.ReH2}) \\ & + \dot{m}_{BD}(h_{BD} - h_{FW}) + \dot{m}_{SAH}(h_{SAH.Out} - h_{tapoff})\end{aligned}\quad (A.1)$$

$$\dot{Q}_{Boil.In} = \dot{m}_{Fuel} \left[\frac{(CV_{Fuel} + h_{Fuel.sensible})}{1 - Cu} + \mu_{AS} h_{AS} + J_{Air} \right] \quad (A.2)$$

$$\eta_{Direct} = \frac{\dot{Q}_{Boil.Out}}{\dot{Q}_{Boil.In} + \dot{Q}_{Credits}} \quad (A.3)$$

$$\eta_{Indirect} = 1 - \frac{\dot{Q}_{Boil.Losses}}{\dot{Q}_{Boil.In} + \dot{Q}_{Credits}} \quad (A.4)$$

Where:

LS – Live Steam

FW – Feedwater

SW - Spray Water

ReH – Reheater

BD – blowdown

SAH-Steam Air Heater

AS – Atomizing Steam

μ -Mass flow ratio to that of the coal mass flow rate

A.1.2. Flue gas / chimney loss

$$\dot{Q}_{Loss.FG} = \dot{m}_{Fuel} [\mu_{DFG} C_{p.DFG} (T_{DFG} - T_{ref}) + \mu_{H_2O} (h_{H_2O.FG} - h_{H_2O.ref})] \quad (A.5)$$

$$\mu_{H_2O} = x_{TM.Coal} + 8.937 x_{H.Coal} + \mu_{DA} w + \mu_{AS} \quad (A.6)$$

w - Absolute humidity

DA – Dry air

A.1.3. Unburned CO loss

$$\dot{Q}_{Loss.CO} = \dot{m}_{Fuel.burned} V_{DFG} y_{CO.MF} H_{CO.n} \quad (A.7)$$

Where:

$H_{CO.n}$ - heat value of a normal cube of CO

$y_{CO.MF}$ - Mass fraction of CO on moisture free basis

A.1.4. Ash sensible and unburned combustible heat loss

$$\dot{Q}_{Loss.Refuse} = \dot{m}_{Fuel.burned} \left\{ \frac{x_{Ash.Coal} (1 - x_{VM.Ash})}{(1 - lu)} \left[\frac{\eta_{BA}}{1 - x_{UC.BA}} h_{BA} + \frac{\eta_{FA}}{1 - x_{UC.FA}} h_{FA} \right] \right\} \quad (A.8)$$

$$\eta_{FA} = 1 - \eta_{BA} \quad (A.9)$$

$$h_{BA} = C_{BA} (T_{BA} - T_{ref}) + \mu_{BA} H_{UC} \quad (A.10)$$

$$h_{FA} = C_{FA} (T_{FA} - T_{ref}) + \mu_{FA} H_{UC} \quad (A.11)$$

Where:

H_{UC} - Heating value of unburned carbon

η_{BA} - Efficiency of bottom ash recovery

η_{FA} - Efficiency of fly ash recovery

$x_{UC.BA}$, $x_{UC.FA}$ - mass fractions unburned combustibles in ash (Carbon in Refuse)

$x_{VM.Ash}$ - Volatile matter of ash, is assumed to be 5% for burner firing (correlation's with the grade of coal has not yet been determined)

lu - Ratio of unburned coal (including associated ash and moisture)

A.1.5. Radiation and convection losses

$$\dot{Q}_{Loss.RC} = k\dot{Q}_{Boil.Out}^{0.7} \quad (A.12)$$

Where:

$k = 0.0315$ for brown coal (lignite)

$k = 0.0220$ for hard coal (anthracite)

$\dot{Q}_{Boil.Out}$ = Boiler heat output (MW)

A.2. Turbine plant performance principles [16]

A.2.1. Turbine deterioration Loss [16]

Turbine cylinder efficiency tests are performed on the HP and IP turbine sections by the enthalpy drop method to assess the actual performance or condition of the turbine cylinders. The stated method is preferred as per the IEC [16] to determine the turbine loss due to ageing, however, a theoretical method to estimate the target turbine efficiency degradation as a function of age for the cylinder efficiencies is given by:

$$Det_{Turbine} = k\sqrt{\frac{150}{P}}f \quad (A.13)$$

Where:

$Det_{Turbine}$ -Target turbine efficiency deterioration [% per month]

P - Power rating of the turbine [MW]

$k = 0.1$ for 2-12 months of operation and 0.06 for 12-24months

$f = 1$ for thermal performance. For power output on reheat cycles $f = 1.45$

Cylinder tests are typically conducted during initial commissioning and thereafter after major plant outages therefore In STEP the actual turbine deterioration is set equal to the target for monthly performance evaluation and baselined after each cylinder efficiency test.

A.2.2. Turbine backpressure Loss

This loss is determined from the heat rate correction curves. For acceptance tests, the correction curves are supplied by the manufacturer based on the process design models (sensitivity analysis). The monthly performance uses the actual as-built plant test sensitivities for correlation of losses as a function of specific operating parameters. The curves indicate the change in the heat rate as a function of turbine back pressure and turbine load (TMCR).

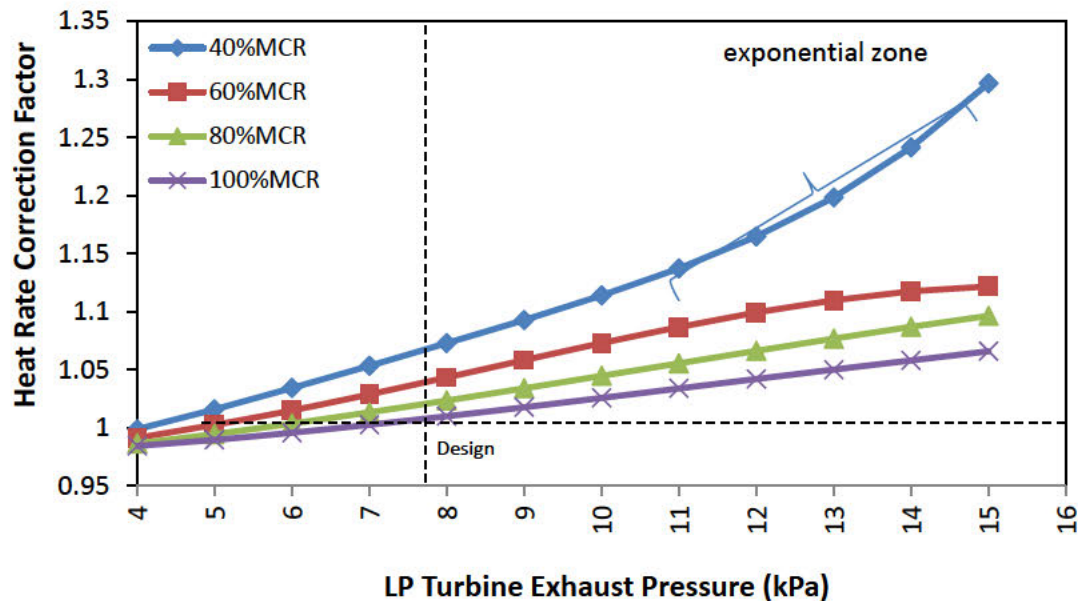


Figure A- 1: Example of turbine backpressure HR correction curve from a 600MWe wet cooled unit

A.2.3. Other turbine plant losses

The final feed water temperature, main steam temperature and reheat steam temperature losses are similarly determined as a function of their respective parameters see examples below.

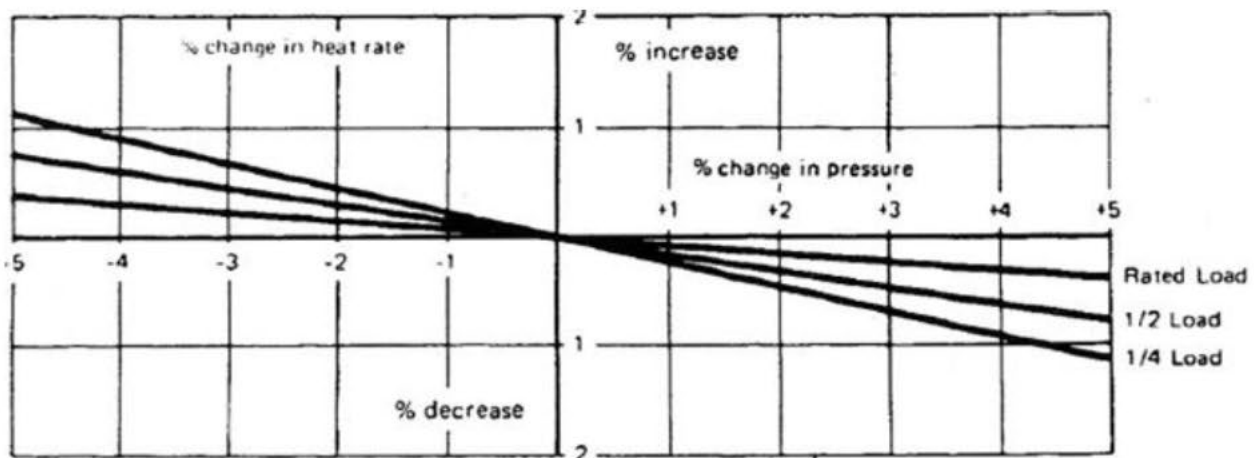


Figure A- 2: Example of turbine throttle pressure HR correction curve [31]

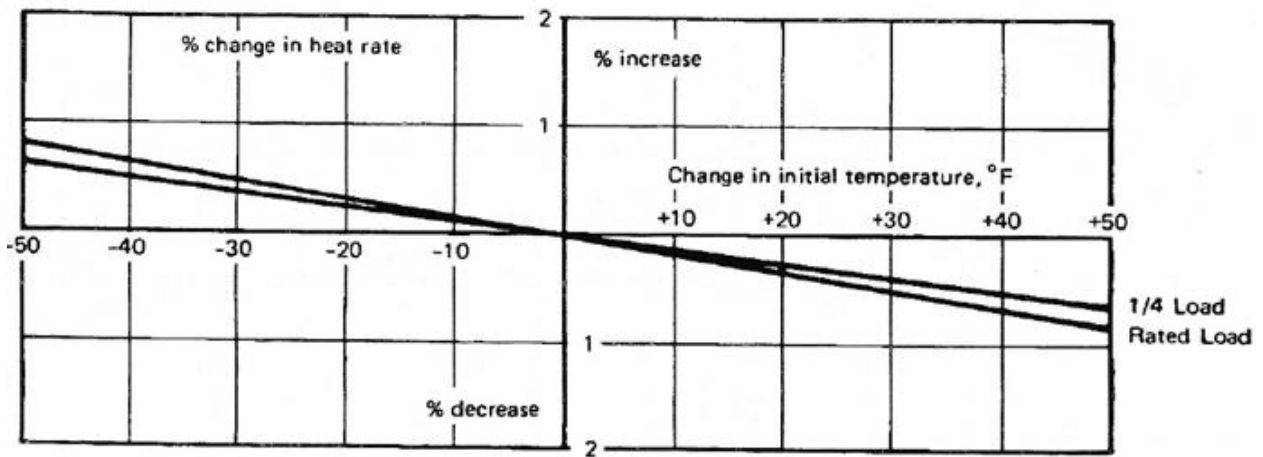


Figure A- 3: Example of turbine throttle temperature HR correction curve [31]

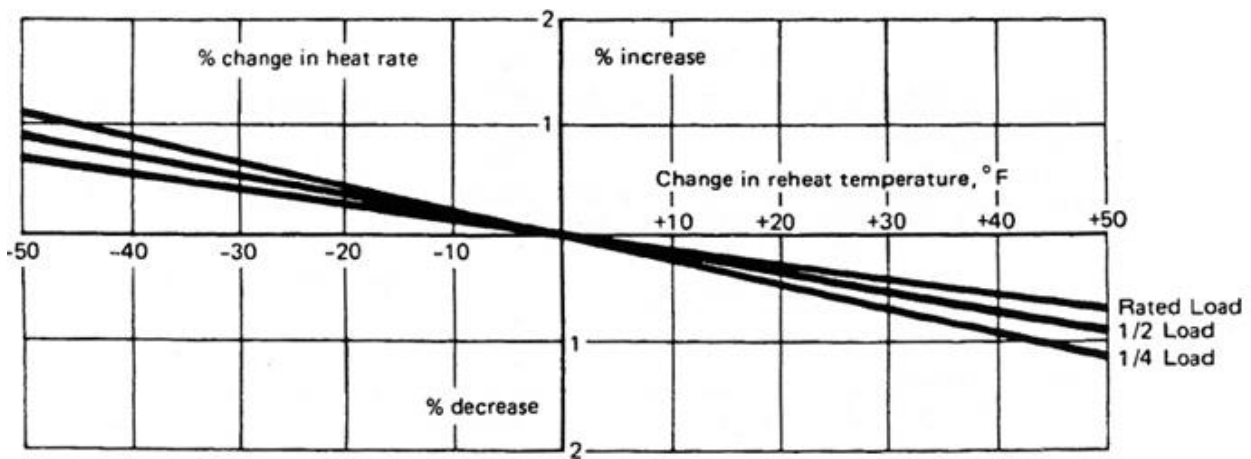


Figure A- 4: Example of reheat temperature HR correction curve [31]

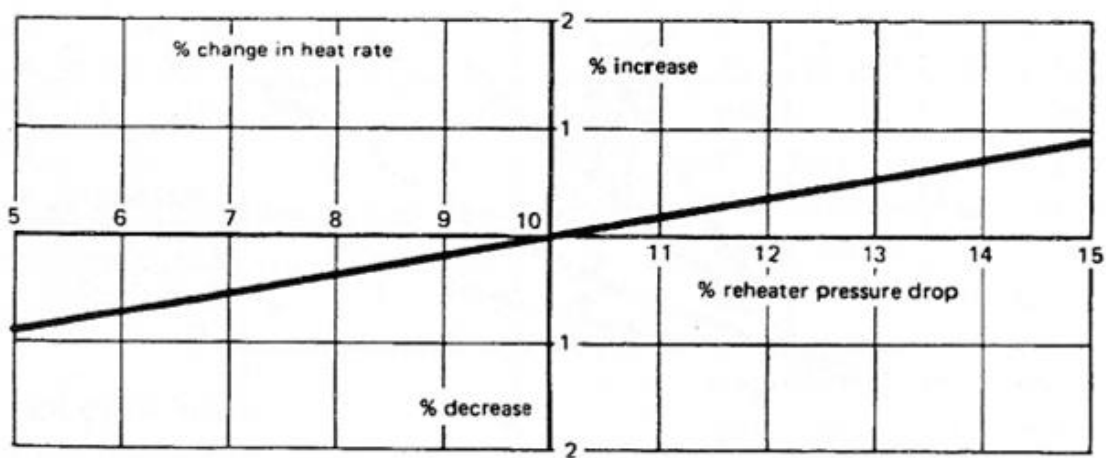


Figure A- 5: Example of reheat pressure drop HR correction curve [31]

A.3. Cycle losses[34]

A.3.1. Make-up water loss

$$\Delta h_{Boil.Abs} = h_{MS} - h_{Eco.In} + \frac{\dot{m}_{ReH.In}}{\dot{m}_{MS}} (h_{ReH.Out} - h_{ReH.In}) \quad (A.14)$$

$$R_{Q.MU} = \frac{0.9 \left(\frac{2}{3} h_{MS} + \frac{1}{3} h_{FW} - h_{RW} \right)}{100 \cdot \Delta h_{Boil.Abs}} \quad (A.15)$$

$$Q_{Loss.MU} = \left[\frac{1 - (R_{Q.MU} Frac_{MU.Targ})}{1 - (R_{Q.MU} Frac_{MU.Act})} \right] \cdot Frac_{MU.Act} \quad (A.16)$$

Where:

$\Delta h_{Boil.Abs}$ - Heat absorbed per kg steam produced in the boiler

$R_{Q.MU}$ - Make-up heat ratio (energy per kg water that is made up to 1kg steam produced)

$Q_{Loss.MU}$ - Make-up heat loss

$Frac_{MU}$ - Fraction of mass of make-up water to mass of steam produced

A.4. Error propagation techniques

A.4.1. Gaussian Quadrature (GQ)

GQ is a numerical method used to determine the mean and variance of an output variable by numerical integration of a function multiplied by its probability density function. The GQ integration technique and one-dimensional integration rule for multivariate functions are applied to achieve the formulas listed below. GQ method is similar to sequential perturbation as described in 4.3.1 when the number of nodes (N) is equal to 3 for GQ integration; however, the perturbed points are weighted as per the GQ rules. GQ uncertainty propagation has been used in robust engineering design and reliability studies. The method is limited to continuous functions and that assumes that a complex simulation can be reduced to polynomial representation or a response surface for complex models to simplify the use of this method. The accuracy of this method is considered to be inconsistent however significantly less demanding computationally when compared with MCS [56].

The generalized expression for computing the mean and variance of a function subjected to input variability can be found below [51],[56]:

$$\bar{y} = E[f(x)] = \int_{-\infty}^{+\infty} f(x) p_x(x) dx \quad (A.17)$$

$$\sigma^2 = \int_{-\infty}^{+\infty} \{f(x) - E[f(x)]\}^2 p_x(x) dx \quad (A.18)$$

p_x is the joint probability function

The above integrals are approximated by applying the GQ integration technique and one-dimensional integration rule for multivariate functions to achieve the formulas below[51].

$$\bar{y}_{GQ} = \sum_{i_1=1}^N w_{i_1} \left(\sum_{i_2=1}^N w_{i_2} \left(\dots \sum_{i_n=1}^N w_{i_n} f(x_{i_1, i_2, \dots, i_n}) \right) \right) \quad (A.19)$$

$$\sigma_{y_{GQ}}^2 = \sum_{i_1=1}^N w_{i_1} \left(\sum_{i_2=1}^N w_{i_2} \left(\dots \sum_{i_n=1}^N w_{i_n} f(x_{i_1, i_2, \dots, i_n}) - \bar{y}_{GQ} \right) \right) \quad (A.20)$$

A.4.2. Method of Moments (MM)

MM is a derivative base technique with a reduced computational expense, however, relies on methods to process the derivatives as per the Taylor Series expansion. MM used in uncertainty propagation is relatively inaccurate for inputs with large variation if the second and higher-order derivatives are eliminated. MM has been significantly used in Robust Design Optimization in the aircraft design [51]

MM is a derivative base technique with a reduced computational expense, however, relies on methods to process the derivatives as per the Taylor Series expansion [51]:

$$\bar{y}_{MM} = \underbrace{f(\bar{x})}_{M_1} + \underbrace{\frac{1}{2} \sum_{p=1}^n \left(\frac{\partial^2 f}{\partial x_p^2} \right) \sigma_{x_p}^2}_{M_2} + \underbrace{\frac{1}{6} \sum_{p=1}^n \left(\frac{\partial^3 f}{\partial x_p^3} \right) \gamma_p \sigma_{x_p}^3}_{M_3} + \underbrace{\frac{1}{24} \sum_{p=1}^n \left(\frac{\partial^4 f}{\partial x_p^4} \right) \gamma_p \sigma_{x_p}^4}_{M_4} \quad (A.21)$$

$$\begin{aligned} \sigma_{y_{MM}}^2 = & \sum_{p=1}^n \left(\frac{\partial f}{\partial x_p} \right) \gamma_p \sigma_{x_p}^2 + \sum_{p=1}^n \left(\frac{\partial^2 f}{\partial x_p^2} \right) \left(\frac{\partial f}{\partial x_p} \right) \gamma_p \sigma_{x_p}^3 + \sum_{p=1}^n \sum_{\substack{q=1 \\ q \neq p}}^n \left(\frac{\partial^3 f}{\partial x_p^2 \partial x_q} \right) \left(\frac{\partial f}{\partial x_q} \right) \sigma_{x_p}^2 \sigma_{x_q}^2 \\ & + \frac{1}{2} \sum_{p=1}^n \sum_{\substack{q=1 \\ q \neq p}}^n \left(\frac{\partial^2 f}{\partial x_p \partial x_q} \right)^2 \sigma_{x_p}^2 \sigma_{x_q}^2 + \frac{1}{3} \sum_{p=1}^n \left(\frac{\partial^3 f}{\partial x_p^3} \right) \left(\frac{\partial f}{\partial x_p} \right) \gamma_p \sigma_{x_p}^4 + \frac{1}{4} \sum_{p=1}^n \left(\frac{\partial^2 f}{\partial x_p^2} \right)^2 (\gamma_p - 1) \sigma_{x_p}^4 \end{aligned} \quad (A.21)$$

The above equations apply to independent input variables and the Taylor series expansion to the 4th order. M = moments. MM used in uncertainty propagation is relatively inaccurate for inputs with large variation if the second and higher-order derivatives are eliminated. MM has been significantly used in Robust Design Optimization in the aircraft design [51]

A.4.3. Sigma Point (SP)

SP methods are synonymous with the sequential perturbation of uncertainties described in section 4.3.1, however, a weight is applied to each variable perturbed (W_p) as a function of its distribution. The SP method is further categorized as Unscented Transformation (UT) and Divided Difference Filter (DDF), where UT only considers the first-order polynomial approximation and DDF creates a second-order polynomial approximation. A significant advantage of this method is the ability to propagate uncertainties through discontinuous functions and relatively lower computational expense ($2n + 1$), n is the number of variables with uncertainties. The DDF has a higher accuracy when compared with UT, however increases the computational expense. SP has been recently demonstrated by Bhonsale et al. [57] to be the most favourable method to be employed to breakage population models in the pharmaceutical design process. The comparison with MCS yielded a good correlation for significantly fewer function evaluations.

The SP method is described by the equations below [51] :

$$\bar{y}_{UT} = W_0 f(x_0) + \sum_{p=1}^n W_p \left[f(x_{p+}) + f(x_{p-}) \right] \quad (A.22)$$

$$\sigma_{y_{UT}}^2 = W_0 \left[f(x_0) - \bar{y}_{UT} \right]^2 + \sum_{p=1}^n W_p \left\{ \left[f(x_{p+}) - \bar{y}_{UT} \right]^2 + \left[f(x_{p-}) - \bar{y}_{UT} \right]^2 \right\} \quad (A.23)$$

$$\sigma_{y_{DDF}}^2 = \frac{1}{2} \sum_{p=1}^n \left\{ W_p \left[f(x_{p+}) - f(x_{p-}) \right]^2 + (W_p - 2W_p^2) \left[f(x_{p+}) + f(x_{p-}) - 2f(x_0) \right]^2 \right\} \quad (A.24)$$

where:

x_{p+} - positive perturbation of each variable by its uncertainty,

$f(x_0)$ - evaluation of the function at its mean input variables

W_p - weight associated with the distribution of each input variable

A.4.4. Polynomial Chaos Expansion (PCE) and Probabilistic Collocation Method (PCM)

PCE is a probabilistic numeral method that was first introduced by mathematician Robert Wiener in 1938. It has since been improved by various authors such as Martin & Cameron, Ghanem & Spanos, Bhabuska, Schwab [38],[58]. There have been various comparative studies to determine the suitability of PCE for various applications; Persio et al. tested PCE for interest rate models [58], Yang et al. [71] and Fenfen et al. [60] for engineering design.

There is very little use of PCE in the application of this method possibly due to its high computational expense especially with a large number of input variables, mathematical complexity and the requirement to express a model as a single function. Some examples of applied uncertainty analysis include software performance estimation by Aleti et al. [61] and robust design of Integrated Circuits (ICs) by Kaintura et al. [62]. PCE makes use of appropriate orthogonal polynomials (Hermite, Legendre, Jacobi, Laguerre, and General Laguerre) relative to probability density functions (Gaussian, Uniform, Beta, Exponential, and Gamma) also known as the Askey Scheme to estimate a function. The properties of orthogonality are used to simplify the calculations of the statistical moments (mean, variance, kurtosis and skewness) of the outputs relative to input distribution properties, see [51],[58],[59],[60],[61],[60],[63] for mathematical detail.

PCM is one of the non-intrusive methods in solving the coefficients of the orthogonal polynomial in the *Estimate Function*. This entails selecting collocation points similar to the GQ integration technique. These points are generally the roots of the next higher-order polynomials in the Askey Scheme [64].

Appendix B. STEP calculations

Note: The number of significant digits is maintained from plant-specific source information. The coefficients used in the polynomial equations below are variables specific to a boiler design.

$$T_{Gas.AH.Out_i} = \frac{T_{Gas.LH.AH.Out_i} + T_{Gas.RH.AH.Out_i}}{2} \quad (B.1)$$

$$T_{Air.FD.In_i} = \frac{T_{Air.RH.FD.In_i} + T_{Air.LH.FD.In_i}}{2} \quad (B.2)$$

$$x_{O2.Eco.Out_i} = \frac{x_{O2.RH.Eco.Out_i} + x_{O2.LH.Eco.Out_i}}{2} \quad (B.3)$$

$$Leak_{AH.LH_i} = \frac{\frac{x_{O2.LH.AH.Out_i}}{\%} - \frac{x_{O2.LH.Eco.Out_i}}{\%}}{21 - \frac{x_{O2.LH.AH.Out_i}}{\%}} \quad (B.4)$$

$$Leak_{AH.RH_i} = \frac{\frac{x_{O2.RH.AH.Out_i}}{\%} - \frac{x_{O2.RH.Eco.Out_i}}{\%}}{21 - \frac{x_{O2.RH.AH.Out_i}}{\%}} \quad (B.5)$$

$$m_{Stm.Boil_i} = m_{FW_i} - m_{BD_i} \quad (B.6)$$

$$LF_{Boil_i} = \begin{cases} 0 & \text{if } t_{RT.boiler_i} = 0 \\ \frac{m_{Stm.Boil_i}}{t_{RT.boiler_i} \cdot MCR_{Boil_i}} & \text{otherwise} \end{cases} \quad (B.7)$$

$$CF_{LF.Boil} = \left[\left(\frac{LF_{Boil}}{\%} \right)^4 + \left(\frac{LF_{Boil}}{\%} \right)^3 + \left(\frac{LF_{Boil}}{\%} \right)^2 + \frac{LF_{Boil}}{\%} + 9.7877377 \times 10^{-1} \right] \quad (B.8)$$

$$CF_{CIR.Targ_i} = \frac{x_{Ash.Coal} CV_{Std.Coal_i}}{CV_{Coal} x_{Ash.Std.Coal_i}} \quad (B.9)$$

$$L_{Corr.Ash_i} = \frac{L_{CIR.std_i}}{\%} \cdot (CF_{CIR.Targ_i} - 1) \cdot \% \quad (B.10)$$

$$F_{ARtoMF} = \frac{100}{100 - \frac{x_{TM.Coal}}{\%}} \quad (B.11)$$

$$x_{H2.Coal} = \frac{\left[\left(\frac{CV_{Coal}}{\frac{MJ}{kg}} + \frac{x_{VM.Coal}}{\%} + \frac{x_{Ash.Coal}}{\%} \right) + F_{ARtoMF} \left(\frac{x_{TM.Coal}}{\%} + 9 \frac{x_{H2.Coal}}{\%} \right) \right]}{F_{ARtoMF}} \% \quad (B.12)$$

$$CF_{Targ.H2_Moist_i} = Q_{L.Moist.Latent} \left[\frac{\frac{x_{TM.Coal}}{\%} + 9 \frac{x_{H2.Coal}}{\%}}{\frac{CV_{Coal}}{\frac{MJ}{kg}}} + \frac{\left(\frac{x_{TM.Std.Coal_i}}{\%} + 9 \frac{x_{H2.Std.Coal_i}}{\%} \right)}{\frac{CV_{Std.Coal_i}}{\frac{MJ}{kg}}} \right] \quad (B.13)$$

$$L_{Corr.H2_Moist} = CF_{Targ.H2_Moist} \% \quad (B.14)$$

$$x_{C.Coal} = \frac{\left[\left[\text{[redacted]} + F_{ARtoMF} \left(\left[\text{[redacted]} \frac{CV_{Coal}}{\frac{MJ}{kg}} \right) + \left(\text{[redacted]} \frac{x_{VM.Coal}}{\%} \right) \dots \right] + \left(\text{[redacted]} \frac{x_{Ash.Coal}}{\%} \right) \right]}{F_{ARtoMF}} \% \quad (B.15)$$

$$L_{Corr.VM.Coal_i} = \frac{CV_{Std.Coal_i} x_{Ash.Coal}}{x_{Ash.Std.Coal_i} CV_{Coal}} \left[e^{\left[\text{[redacted]} \left(\frac{x_{C.Coal}}{x_{H2.Coal}} \right) \right]} \dots \right] \% \quad (B.16)$$

$$\left[+ e^{\left[\text{[redacted]} \left(\frac{x_{C.Std.Coal_i}}{x_{H2.Std.Coal_i}} \right) \right]} \right]$$

$$F(A) = \begin{cases} n \leftarrow 1 \\ \text{while } n < 7 \\ \quad \left| \begin{array}{l} L_{Corr.VM.Coal_n} \leftarrow 0 \text{ if } \frac{x_{VM.Coal}}{\%} > 17 \\ n \leftarrow n + 1 \end{array} \right. \\ L_{Corr.VM.Coal} \end{cases} \quad (B.17)$$

The above function defaults the volatile matter loss correction to zero should the volatile matter be greater than 17%w/w

$$CF_{Fuel.Boil_i} = \frac{\frac{\eta_{Boil.NER_i}}{\%}}{\left(\frac{\eta_{Boil.NER_i}}{\%} - \frac{L_{Corr.Ash_i}}{\%} - \frac{L_{Corr.H2_Moist_i}}{\%} - \frac{L_{Corr.VM.Coal_i}}{\%} \right)} \quad (B.18)$$

$$Q_{Start.0to7hrs_i} = \begin{cases} 0 & \text{if } N_{Starts.0to7hrs_i} = 0 \text{ GWh} \\ Q_{Start.Cold.1_i} \left[1 - e^{-\frac{(-k_{Q.OffLoad})_i \frac{Q_{Start.Cold.1_i}}{GWh}}{N_{Starts.0to7hrs_i}}} \right] & \text{otherwise} \end{cases} \quad (B.19)$$

$$Q_{Start.7to15hrs_i} = \begin{cases} 0 & \text{if } N_{Starts.7to15hrs_i} = 0 \text{ GWh} \\ Q_{Start.Cold.1_i} \left[1 - e^{-\frac{(-k_{Q.OffLoad})_i \frac{Q_{Start.Cold.1_i}}{GWh}}{N_{Starts.7to15hrs_i}}} \right] & \text{otherwise} \end{cases} \quad (B.20)$$

$$Q_{Start.15to24hrs_i} = \begin{cases} 0 & \text{if } N_{Starts.15to24hrs_i} = 0 \text{ GWh} \\ Q_{Start.Cold.1_i} \left[1 - e^{-\frac{(-k_{Q.OffLoad})_i \frac{Q_{Start.Cold.1_i}}{GWh}}{N_{Starts.15to24hrs_i}}} \right] & \text{otherwise} \end{cases} \quad (B.21)$$

$$Q_{Start.24to168hrs_i} = \begin{cases} 0 & \text{if } N_{Starts.24to168hrs_i} = 0 \text{ GWh} \\ Q_{Start.Cold.1_i} \left[1 - e^{-\frac{(-k_{Q.OffLoad})_i \frac{Q_{Start.Cold.1_i}}{GWh}}{N_{Starts.24to168hrs_i}}} \right] & \text{otherwise} \end{cases} \quad (B.22)$$

$$Q_{Start.Hot_i} = Q_{Start.0to7hrs_i} + Q_{Start.7to15hrs_i} \cdots + Q_{Start.15to24hrs_i} + Q_{Start.24to168hrs_i} \quad (B.23)$$

$$Q_{Start.Cold_i} = Q_{Start.Cold.1_i} N_{Starts.Cold_i} \quad (B.24)$$

$$Q_{Sby.Hot_i} = \frac{t_{Sby.Hot_i}}{hr} Q_{Start.Cold.1_i} \left(1 - e^{k_{Q.OffLoad_i} - 1} \right) \quad (B.25)$$

$$Q_{OffLoad.Boil_i} = Q_{Sby.Hot_i} + Q_{Start.Cold_i} + Q_{Start.Hot_i} \quad (B.26)$$

$$x_{CIR_i} = \eta_{FA_i} x_{C.FA_i} + (1 - \eta_{FA_i}) x_{C.BA_i} \quad (B.27)$$

η_{FA} - Fly ash fraction of total as produced

$$k_{CO2.AH.Out} = \text{[Blank]} - \left(\text{[Blank]} \frac{x_{C.Coal}}{\%} \right) + \left(\text{[Blank]} \frac{x_{VM.Coal}}{\%} \right) \quad (B.28)$$

$$Ce_i = \frac{x_{C.Coal}}{\%} - \left(\frac{\frac{x_{CIR_i}}{\%} \frac{CV_{Coal}}{\frac{MJ}{kg}} 10^3}{\text{[Blank]}} \right) + \left(\text{[Blank]} \frac{x_{S.Coal}}{\%} \right) \quad (B.29)$$

$$x_{O2.AH.Out_i} = \frac{x_{O2.LH.AH.Out_i} + x_{O2.RH.AH.Out_i}}{2} \quad (B.30)$$

$$x_{CO2.AH.Out_i} = \frac{\text{[Blank]} - \frac{x_{O2.AH.Out_i}}{\%}}{1 + \frac{\left(2 \text{[Blank]} \frac{x_{H2.Coal}}{\%} \right) + \text{[Blank]} \frac{x_{VM.Coal}}{\%} - k_{CO2.AH.Out}}{Ce_i}} \% \quad (B.31)$$

$$L_{DFG.AT_i} = \begin{cases} 0 & \text{if } LF_{Boil_i} = 0 \\ \left[\begin{aligned} &\text{[Blank]} \times \text{[Blank]} \left(\frac{LF_{Boil_i}}{\%} \right)^4 + \text{[Blank]} \times \text{[Blank]} \left(\frac{LF_{Boil_i}}{\%} \right)^3 \dots \\ &+ \text{[Blank]} \times \text{[Blank]} \left(\frac{LF_{Boil_i}}{\%} \right)^2 + \text{[Blank]} \times \text{[Blank]} \frac{LF_{Boil_i}}{\%} + \text{[Blank]} \end{aligned} \right] \% & \text{otherwise} \end{cases} \quad (B.32)$$

$$x_{Cu.Coal_i} = \frac{x_{Ash.Coal} x_{CIR_i}}{1 - x_{CIR_i}} \quad (B.33)$$

$$L_{CIR.Targ_i} = \begin{cases} 0 & \text{if } LF_{Boil_i} = 0 \\ \left[\begin{aligned} & \left(\frac{LF_{Boil_i}}{\%} \right)^4 \dots \\ & + \left(\frac{LF_{Boil_i}}{\%} \right)^3 \dots \\ & + \left(\frac{LF_{Boil_i}}{\%} \right)^2 \dots \\ & + \frac{LF_{Boil_i}}{\%} + 6.983 \times 10^{-1} \end{aligned} \right] (CF_{CIR.Targ_i} \%) & \text{otherwise} \end{cases} \quad (B.34)$$

$$x_{Cu.Coal.Targ_i} = \frac{L_{CIR.Targ_i} CV_{Std.Coal_i}}{CF_{CIR.Targ_i} CV_C} \quad (B.35)$$

$$L_{DFG.Targ_i} = L_{DFG.AT_i} \frac{\left(x_{C.Coal} - x_{Cu.Coal_i} + \frac{x_{S.Coal}}{2.67} \right) CV_{Std.Coal_i}}{\left(x_{C.Std.Coal_i} - x_{Cu.Coal.Targ_i} + \frac{x_{S.Std.Coal_i}}{2.67} \right) CV_{Coal}} \quad (B.36)$$

$$x_{N2.AH.Out_i} = 1 - x_{CO2.AH.Out_i} - x_{O2.AH.Out_i} \quad (B.37)$$

$$DFC_i = \frac{11 x_{CO2.AH.Out_i} + 8 x_{O2.AH.Out_i} + 7 x_{N2.AH.Out_i}}{3 x_{CO2.AH.Out_i}} \quad (B.38)$$

$$DFG_i = DFC_i \left(x_{C.Coal} - x_{Cu.Coal_i} + \frac{x_{S.Coal}}{2.67} \right) \quad (B.39)$$

$$L_{DFG.Act_i} = \frac{DFG_i Cp_{FG_i} (T_{Gas.AH.Out_i} - T_{Air.FD.In_i})}{CV_{Coal}} \quad (B.40)$$

$$L_{DFG.SF_i} = L_{DFG.Act_i} - L_{DFG.Targ_i} \quad (B.41)$$

$$L_{CIR.Act_i} = \frac{x_{Ash.Coal} x_{CIR_i} CV_C}{(1 - x_{CIR_i}) CV_{Coal}} \quad (B.42)$$

$$L_{CIR.SF_i} = L_{CIR.Act_i} - L_{CIR.Targ_i} \quad (B.43)$$

$$L_{H2_Moist.Targ.LF_i} = \left[\begin{aligned} & \left[\left(\frac{LF_{Boil_i}}{\%} \right)^4 - \left(\frac{LF_{Boil_i}}{\%} \right)^3 \right] \times \left[\frac{L_{H2_Moist.Targ.LF_i}}{\%} \right] \dots \\ & + \left[\left(\frac{LF_{Boil_i}}{\%} \right)^2 - \frac{LF_{Boil_i}}{\%} \right] \times \left[\frac{L_{H2_Moist.Targ.LF_i}}{\%} \right] \dots \\ & + \left[\frac{L_{H2_Moist.Targ.LF_i}}{\%} \right] \end{aligned} \right] \% \quad (B.44)$$

$$L_{H2_Moist.Targ_i} = \begin{cases} 0 & \text{if } LF_{Boil_i} = 0 \\ \left(L_{Corr.H2_Moist_i} + L_{H2_Moist.Targ.LF_i} \right) & \text{otherwise} \end{cases} \quad (B.45)$$

$$L_{H2_Moist.Act_i} = \begin{cases} 0 & \text{if } LF_{Boil_i} = 0 \\ \frac{\frac{x_{TM.Coal}}{\%} + \left(9 \frac{x_{H2.Coal}}{\%} \right)}{\frac{CV_{Coal}}{\frac{MJ}{kg}}} \left[\begin{aligned} & k_{L.H2_Moisture.1_i} \dots \\ & \left(\frac{T_{Gas.AH.Out_i} / ^\circ C}{2} - T_{Air.FD.In_i} / ^\circ C \right) \\ & + \left(\frac{k_{L.H2_Moisture.2_i}}{k_{L.H2_Moisture.1_i}} \right) \end{aligned} \right] \% & \text{otherwise} \end{cases} \quad (B.46)$$

$$L_{H2_Moist.SF_i} = L_{H2_Moist.Act_i} - L_{H2_Moist.Targ_i} \quad (B.47)$$

$$m_{Stm.Stn} = \sum_{i=1}^6 m_{Stm.Boil_i} \quad (B.48)$$

$$m_{Coal.Boil_i} = \frac{m_{Stm.Boil_i}}{m_{Stm.Stn}} m_{Coal.Str} \quad (B.49)$$

$$k_{L.Rad_i} = \begin{cases} 0 & \text{if } LF_{Boil_i} = 0 \\ \left[\begin{aligned} & \left(\frac{1}{100} \times \frac{1}{100} \right) (LF_{Boil_i})^4 - \left(\frac{1}{100} \times \frac{1}{100} \right) (LF_{Boil_i})^3 \dots \\ & + \left(\frac{1}{100} \times \frac{1}{100} \right) (LF_{Boil_i})^2 - \left(\frac{1}{100} \times \frac{1}{100} \right) LF_{Boil_i} + \left(\frac{1}{100} \times \frac{1}{100} \right) \end{aligned} \right] & \text{otherwise} \end{cases} \quad (B.50)$$

$$L_{Rad_i} = \begin{cases} 0 & \text{if } LF_{Boil_i} = 0 \\ \frac{k_{L.Rad_i}}{\frac{LF_{Boil_i}}{100} CF_{LF.Boil_i}} \% & \text{otherwise} \end{cases} \quad (B.51)$$

$$L_{MR.Act_i} = \begin{cases} 0 & \text{if } LF_{Boil_i} = 0 \\ \frac{m_{MR_i} CV_{MR_i}}{m_{Coal.Boil_i} CV_{Coal}} & \text{otherwise} \end{cases} \quad (B.52)$$

$$L_{MR.SF} = L_{MR.Act} \quad (B.53)$$

$$L_{Tot.Boil.Targ_i} = L_{DFG.Targ_i} + L_{CIR.Targ_i} + L_{H2_Moist.Targ_i} + L_{Rad_i} \quad (B.54)$$

$$L_{Tot.Boil.Act_i} = L_{DFG.Act_i} + L_{CIR.Act_i} + L_{H2_Moist.Act_i} + L_{Rad_i} + L_{MR.Act_i} \quad (B.55)$$

$$L_{Tot.Boil.SF_i} = L_{Tot.Boil.Act_i} - L_{Tot.Boil.Targ_i} \quad (B.56)$$

$$Frac_{Tot.Stm_i} = \frac{m_{Stm.Boil_i}}{m_{Stm.Stn}} \quad (B.57)$$

$$L_{CIR.Targ.Stn} = \sum_{i=1}^6 \left(L_{CIR.Targ_i} Frac_{Tot.Stm_i} \right) \quad (B.58)$$

$$L_{CIR.Act.Stn} = \sum_{i=1}^6 \left(L_{CIR.Act_i}^{Frac_{Tot.Stm_i}} \right) \quad (B.59)$$

$$L_{CIR.SF.Stn} = L_{CIR.Act.Stn} - L_{CIR.Targ.Str} \quad (B.60)$$

$$L_{DFG.Targ.Stn} = \sum_{i=1}^6 \left(L_{DFG.Targ_i}^{Frac_{Tot.Stm_i}} \right) \quad (B.61)$$

$$L_{DFG.Act.Stn} = \sum_{i=1}^6 \left(L_{DFG.Act_i}^{Frac_{Tot.Stm_i}} \right) \quad (B.62)$$

$$L_{DFG.SF.Stn} = L_{DFG.Act.Stn} - L_{DFG.Targ.Str} \quad (B.63)$$

$$L_{H2_Moist.Targ.Stn} = \sum_{i=1}^6 \left(L_{H2_Moist.Targ_i}^{Frac_{Tot.Stm_i}} \right) \quad (B.64)$$

$$L_{H2_Moist.Act.Stn} = \sum_{i=1}^6 \left(L_{H2_Moist.Act_i}^{Frac_{Tot.Stm_i}} \right) \quad (B.65)$$

$$L_{H2_Moist.SF.Stn} = L_{H2_Moist.Act.Stn} - L_{H2_Moist.Targ.Str} \quad (B.66)$$

$$L_{Rad.Stn} = \sum_{i=1}^6 \left(L_{Rad_i}^{Frac_{Tot.Stm_i}} \right) \quad (B.67)$$

$$L_{MR.Act.Stn} = \sum_{i=1}^6 \left(L_{MR.Act_i}^{Frac_{Tot.Stm_i}} \right) \quad (B.68)$$

$$L_{Boil.Targ.Stn} = L_{DFG.Targ.Stn} + L_{H2_Moist.Targ.Stn} + L_{CIR.Targ.Stn} + L_{Rad.Str} \quad (B.69)$$

$$L_{Boil.Act.Stn} = L_{DFG.Act.Stn} + L_{H2_Moist.Act.Stn} + L_{CIR.Act.Stn} + L_{Rad.Str} \quad (B.70)$$

$$L_{Boil.SF.Stn} = L_{Boil.Act.Stn} - L_{Boil.Targ.Stn} \quad (B.71)$$

$$Q_{OffLoad.Stn} = \sum_{i=1}^6 \left(Q_{OffLoad.Boil_i} \right) \quad (B.72)$$

$$CF_{LF.Boil.Stn} = \frac{\sum_{i=1}^6 \left(CF_{LF.Boil_i} m_{Stm.Boil_i} \right)}{m_{Stm.Stn}} \quad (B.73)$$

$$CF_{Fuel.Boil.Stn} = \frac{\sum_{i=1}^6 \left(CF_{Fuel.Boil_i} m_{Stm.Boil_i} \right)}{m_{Stm.Stn}} \quad (B.74)$$

$$x_{CIR.Stn} = \sum_{i=1}^6 \left(x_{CIR_i} Frac_{Tot.Stm_i} \right) \quad (B.75)$$

$$x_{O2.AH.Gas.In.Stn} = \sum_{i=1}^6 \left(x_{O2.Eco.Out_i} Frac_{Tot.Stm_i} \right) \quad (B.76)$$

$$Leak_{AH.RH.Stn} = \sum_{i=1}^6 \left(Leak_{AH.RH_i} Frac_{Tot.Stm_i} \right) \quad (B.77)$$

$$Leak_{AH.LH.Stn} = \sum_{i=1}^6 \left(Leak_{AH.LH_i} Frac_{Tot.Stm_i} \right) \quad (B.78)$$

$$J_{Gen.LV_i} = \frac{J_{Gen.LV.Main_i} + J_{Gen.LV.Check_i}}{2} \quad (B.79)$$

$$J_{AuxPower.UB_i} = \frac{J_{AuxPower.Main_i} + J_{AuxPower.Check_i}}{2} \quad (B.80)$$

$$J_{Gen.HV_i} = \left[J_{Gen.LV_i} - \left[(1 - Binary_{MP}) J_{AuxPower.UB_i} \right] \right] \eta_{GT} + J_{AuxPower.UB_i} \quad (B.81)$$

$Binary_{MP} = 1$ For electrical measurement point after the unit transformer

$Binary_{MP} = 0$ For electrical measurement point at generator terminals

$$J_{Gen.HV.Stn} = \sum_{i=1}^6 J_{Gen.HV_i} \quad (B.82)$$

$$J_{Imp.Stn} = \frac{J_{Stn1.Main} + J_{Stn1.Check} + J_{Stn2.Main} + J_{Stn2.Check} + J_{Stn2.Main} + J_{Stn2.Check}}{2} - J_{Exttr} \quad (B.83)$$

$$J_{AuxPower.Stn} = \sum_{i=1}^6 J_{AuxPower.UB_i} + J_{Imp.Stn} \quad (B.84)$$

$$J_{USO.Stn} = J_{Gen.HV.Stn} - J_{AuxPower.Str} \quad (B.85)$$

$$J_{AuxPower.Common.Stn} = J_{Imp.Stn} - J_{AuxPower.Offload.Stn} \cdots \\ + - \sum_{i=1}^6 J_{Unit.AuxPower.SB_i} \quad (B.86)$$

$$Frac_{Gen_i} = \frac{J_{Gen.HV_i}}{J_{Gen.HV.Stn}} \quad (B.87)$$

$$J_{AuxPower_i} = Frac_{Gen_i} J_{AuxPower.Common.Stn} + J_{Unit.AuxPower.SB_i} + J_{AuxPower.UB_i} \quad (B.88)$$

$$J_{USO_i} = J_{Gen.HV_i} - J_{AuxPower_i} \quad (B.89)$$

$$AVL_{NLtoNER_i} = \begin{cases} 0 & \text{if } t_{RT.Gen_i} = 0 \\ \frac{J_{Gen.HV_i} - J_{Gen.>NER_i}}{t_{RT.Gen_i} - t_{Gen.>NER_i}} & \text{otherwise} \end{cases} \quad (B.90)$$

$$Q_{Cons_hr.NLtoNER_i} = \left(\frac{Q_{Incr.NLtoNER_i}}{kW \text{ hr}} \frac{AVL_{NLtoNER_i}}{kW} + \frac{Q_{NL_i}}{kW \text{ hr}} \right) kWt \quad (B.91)$$

$$Q_{AT.NLtoNER_i} = Q_{Cons_hr.NLtoNER_i} \left(\frac{t_{RT.Gen_i}}{hr} - \frac{t_{Gen.>NER_i}}{hr} \right) \quad (B.92)$$

$$Q_{NER_i} = \left(\frac{Q_{Incr.NLtoNER_i}}{kW \text{ hr}} \frac{NER_i}{kW} + \frac{Q_{NL_i}}{kW \text{ hr}} \right) kWt \quad (B.93)$$

$$AVL_{NERTtoMCR_i} = \begin{cases} 0 & \text{if } t_{Gen.>NER_i} = 0 \\ \frac{J_{Gen.>NER_i}}{t_{Gen.>NER_i}} & \text{otherwise} \end{cases} \quad (B.94)$$

$$Q_{Cons_hr.NERTtoMCR_i} = \left(\frac{Q_{Incr.NERTtoMCR_i}}{kWh} \frac{AVL_{NERTtoMCR_i}}{kW} + \frac{Q_{NER_i}}{kWh} \right) kWt \quad (B.95)$$

$$Q_{AT.NERTtoMCR_i} = Q_{Cons_hr.NERTtoMCR_i} \left(\frac{t_{Gen.>NER_i}}{hr} \right) \quad (B.96)$$

$$Q_{Cons.AT_i} = Q_{AT.NERTtoMCR_i} + Q_{AT.NLtoNER_i} \quad (B.97)$$

$$CF_{Amb_i} = \left[\begin{aligned} & \left[\text{[redacted]} \times \text{[redacted]} (T_{ACC.Air.In_i} / ^\circ C)^4 - \text{[redacted]} \times \text{[redacted]} (T_{ACC.Air.In_i} / ^\circ C)^3 \dots \right. \\ & \left. + \text{[redacted]} \times \text{[redacted]} (T_{ACC.Air.In_i} / ^\circ C)^2 + \text{[redacted]} \times \text{[redacted]} T_{ACC.Air.In_i} / ^\circ C \dots \right. \\ & \left. + 1.0011712 \right] \end{aligned} \right] \quad (B.98)$$

$$LF_{Gen_i} = \left| \begin{aligned} & 0 \quad \text{if } t_{RT.Gen_i} = 0 \\ & \frac{J_{Gen.HV_i}}{MCR_{HV_i} CF_{Amb_i} t_{RT.Gen_i}} \quad \text{otherwise} \end{aligned} \right| \quad (B.99)$$

$$PF_i = \left| \begin{aligned} & 1 \quad \text{if } J_{Gen.HV_i} = 0 \\ & \frac{\frac{J_{Gen.HV_i}}{GWh}}{\sqrt{\left(\frac{J_{Reactive.Gen_i}}{GWh} \right)^2 + \left(\frac{J_{Gen.HV_i}}{GWh} \right)^2}} \quad \text{otherwise} \end{aligned} \right| \quad (B.100)$$

$$CF_{PF.40\%_i} = \left[\begin{aligned} & \left[\text{[redacted]} \times \text{[redacted]} (PF_i)^4 + \text{[redacted]} (PF_i)^3 \dots \right. \\ & \left. + \text{[redacted]} (PF_i)^2 + \text{[redacted]} PF_i + \text{[redacted]} \times \text{[redacted]} \right] \end{aligned} \right] \quad (B.101)$$

$$CF_{PF.60\%_i} = \left[\begin{aligned} & \left[-\text{[redacted]} (PF_i)^4 + \text{[redacted]} (PF_i)^3 \dots \right. \\ & \left. + \text{[redacted]} (PF_i)^2 + \text{[redacted]} PF_i - \text{[redacted]} \times \text{[redacted]} \right] \end{aligned} \right] \quad (B.102)$$

$$CF_{PF.80\%_i} = \left[\begin{aligned} & \left[\text{[redacted]} (PF_i)^4 + \text{[redacted]} (PF_i)^3 \dots \right. \\ & \left. + \text{[redacted]} (PF_i)^2 + \text{[redacted]} PF_i + \text{[redacted]} \times \text{[redacted]} \right] \end{aligned} \right] \quad (B.103)$$

$$CF_{PF.100\%_i} = \left[\begin{aligned} & \left[\text{[redacted]} (PF_i)^4 + \text{[redacted]} (PF_i)^3 \dots \right. \\ & \left. + \text{[redacted]} \times \text{[redacted]} (PF_i)^2 + \text{[redacted]} PF_i - \text{[redacted]} \times \text{[redacted]} \right] \end{aligned} \right] \quad (B.104)$$

$$CF_{PF_i} = \begin{cases} CF_{PF.100\%_i} & \text{if } LF_{Gen_i} > 1 \\ \left[\frac{CF_{PF.100\%_i} - CF_{PF.80\%_i}}{100 - 80} \times \left(\frac{LF_{Gen_i}}{\%} - 80 \right) + CF_{PF.80\%_i} \right] & \text{if } 1 \geq LF_{Gen_i} > 0.8 \\ \left[\frac{CF_{PF.80\%_i} - CF_{PF.60\%_i}}{80 - 60} \times \left(\frac{LF_{Gen_i}}{\%} - 60 \right) + CF_{PF.60\%_i} \right] & \text{if } 0.8 \geq LF_{Gen_i} > 0.6 \\ \left[\frac{CF_{PF.60\%_i} - CF_{PF.40\%_i}}{60 - 40} \times \left(\frac{LF_{Gen_i}}{\%} - 40 \right) + CF_{PF.40\%_i} \right] & \text{if } 0.6 \geq LF_{Gen_i} \geq 0.4 \\ CF_{PF.40\%_i} & \text{otherwise} \end{cases} \quad (B.105)$$

$$P'_{EFPs_i} = \left[\begin{aligned} & \left[\text{[redacted]} \times \text{[redacted]} \left(\frac{LF_{Gen_i}}{\%} \right)^4 - \text{[redacted]} \times \text{[redacted]} \left(\frac{LF_{Gen_i}}{\%} \right)^3 \right] \dots \\ & + \left[\text{[redacted]} \times \text{[redacted]} \left(\frac{LF_{Gen_i}}{\%} \right)^2 + \text{[redacted]} \times \text{[redacted]} \frac{LF_{Gen_i}}{\%} - 7.96 \times 10^3 \right] \end{aligned} \right] kW \quad (B.106)$$

$$J_{EFPs.Targ_i} = P'_{EFPs_i} (t_{RT.EFP.B_i} + t_{RT.EFP.B_i} + t_{RT.EFP.C_i}) \quad (B.107)$$

$$CF_{LF.Turb_i} = \begin{cases} 0 & \text{if } J_{Gen.HV_i} = 0 \\ \frac{\frac{Q_{Cons.AT_i}}{J_{Gen.HV_i}} + 100 \left(\frac{HR_{Stm_Feed_i}}{\frac{LF_{Gen_i}}{\%}} \right) \frac{MCR_{Pract_i} CF_{Amb_i}}{MCR_{HV_i} CF_{Amb_i}}}{HR_{MCR.Prac_i} + HR_{Stm_Feed_i}} & \text{otherwise} \end{cases} \quad (B.108)$$

$$Fract_{AuxPower.min.ACC_i} = Fract_{AuxPower.min_i} CF_{Amb_i} \quad (B.109)$$

$$LF_{USO_i} = \begin{cases} 0 & \text{if } t_{RT.Gen_i} = 0 \\ \left[\frac{J_{USO_i}}{t_{RT.Gen_i} MCR_{Pract_i} CF_{Amb_i}} (1 + Fract_{AuxPower.min.ACC_i}) \right] & \text{otherwise} \end{cases} \quad (B.110)$$

$$LF_{USO.Stn} = \sum_{i=1}^6 \left(LF_{USO_i}^{Frac_{Gen_i}} \right) \quad (B.111)$$

$$LF_{USO.Stn} = \sum_{i=1}^6 \left(LF_{USO_i}^{Frac_{Gen_i}} \right) \quad (B.112)$$

$$F_{AuxPower.Est_i} = \left[\begin{aligned} & \left(\frac{LF_{USO_i}}{\%} \right)^4 - \left(\frac{LF_{USO_i}}{\%} \right)^3 \dots \\ & + \left(\frac{LF_{USO_i}}{\%} \right)^2 - \left(\frac{LF_{USO_i}}{\%} \right) + \dots \end{aligned} \right] \quad (B.113)$$

$$Frac_{AuxPower.Targ_i} = \begin{cases} 0 & \text{if } J_{USO_i} = 0 \\ \left(F_{AuxPower.Est_i}^{Fract_{AuxPower.min.ACC_i}} + \frac{J_{EFPs.Targ_i}}{J_{USO_i}} \right) & \text{otherwise} \end{cases} \quad (B.114)$$

$$CF_{AuxPower_i} = \begin{cases} 0 & \text{if } J_{USO_i} = 0 \\ \frac{\left(\frac{Frac_{AuxPower.Targ_i}}{100 + \frac{\%}{\%}} \right) - \frac{J_{EFPs.Targ_i}^{100}}{J_{USO_i}}}{\frac{Fract_{AuxPower.min.ACC_i}}{100 + \frac{\%}{\%}}} & \text{otherwise} \end{cases} \quad (B.115)$$

$$F_{MU.Est_i} = \left[\begin{aligned} & \left[\text{ } \times \text{ } \left(\frac{LF_{USO_i}}{\%} \right)^4 + \text{ } \times \text{ } \left(\frac{LF_{USO_i}}{\%} \right)^3 \dots \right. \\ & \left. + \text{ } \times \text{ } \left(\frac{LF_{USO_i}}{\%} \right)^2 + \text{ } \times \text{ } \frac{LF_{USO_i}}{\%} + \text{ } \right] \end{aligned} \right] \quad (B.116)$$

$$P_{6deg_i} = \left[\begin{aligned} & \left[\text{ } \times \text{ } \left(\frac{LF_{Gen_i}}{\%} \right)^4 - \text{ } \times \text{ } \left(\frac{LF_{Gen_i}}{\%} \right)^3 \dots \right. \\ & \left. + \text{ } \times \text{ } \left(\frac{LF_{Gen_i}}{\%} \right)^2 - \text{ } \times \text{ } \frac{LF_{Gen_i}}{\%} + \text{ } \right] \end{aligned} \right] kPc \quad (B.117)$$

$$P_{10deg_i} = \left[\begin{aligned} & \left[\text{ } \times \text{ } \left(\frac{LF_{Gen_i}}{\%} \right)^4 - \text{ } \times \text{ } \left(\frac{LF_{Gen_i}}{\%} \right)^3 \dots \right. \\ & \left. + \text{ } \times \text{ } \left(\frac{LF_{Gen_i}}{\%} \right)^2 - \text{ } \times \text{ } \frac{LF_{Gen_i}}{\%} + \text{ } \right] \end{aligned} \right] kPc \quad (B.118)$$

$$P_{15deg_i} = \left[\begin{aligned} & \left[\text{ } \times \text{ } \left(\frac{LF_{Gen_i}}{\%} \right)^4 - \text{ } \times \text{ } \left(\frac{LF_{Gen_i}}{\%} \right)^3 \dots \right. \\ & \left. + \text{ } \times \text{ } \left(\frac{LF_{Gen_i}}{\%} \right)^2 - \text{ } \times \text{ } \frac{LF_{Gen_i}}{\%} + \text{ } \right] \end{aligned} \right] kPc \quad (B.119)$$

$$P_{20deg_i} = \left[\begin{aligned} & \left[\text{ } \times \text{ } \left(\frac{LF_{Gen_i}}{\%} \right)^4 - \text{ } \times \text{ } \left(\frac{LF_{Gen_i}}{\%} \right)^3 \dots \right. \\ & \left. + \text{ } \times \text{ } \left(\frac{LF_{Gen_i}}{\%} \right)^2 - \text{ } \times \text{ } \frac{LF_{Gen_i}}{\%} + \text{ } \right] \end{aligned} \right] kPc \quad (B.120)$$

$$P_{25deg_i} = \left[\begin{aligned} & \left[\text{---} \times \text{---} \left(\frac{LF_{Gen_i}}{\%} \right)^4 - \text{---} \times \text{---} \left(\frac{LF_{Gen_i}}{\%} \right)^3 \dots \right] \\ & + \left[\text{---} \times \text{---} \left(\frac{LF_{Gen_i}}{\%} \right)^2 - \text{---} \times \text{---} \frac{LF_{Gen_i}}{\%} + \text{---} \right] \end{aligned} \right] kPc \quad (B.121)$$

$$P_{30deg_i} = \left[\begin{aligned} & \left[\text{---} \times \text{---} \left(\frac{LF_{Gen_i}}{\%} \right)^4 - \text{---} \times \text{---} \left(\frac{LF_{Gen_i}}{\%} \right)^3 \dots \right] \\ & + \left[\text{---} \times \text{---} \left(\frac{LF_{Gen_i}}{\%} \right)^2 - \text{---} \times \text{---} \frac{LF_{Gen_i}}{\%} + \text{---} \right] \end{aligned} \right] kPc \quad (B.122)$$

$$P_{35deg_i} = \left[\begin{aligned} & \left[\text{---} \times \text{---} \left(\frac{LF_{Gen_i}}{\%} \right)^4 - \text{---} \times \text{---} \left(\frac{LF_{Gen_i}}{\%} \right)^3 \dots \right] \\ & + \left[\text{---} \times \text{---} \left(\frac{LF_{Gen_i}}{\%} \right)^2 - \text{---} \frac{LF_{Gen_i}}{\%} + \text{---} \times \text{---} \right] \end{aligned} \right] kPc \quad (B.123)$$

$$P_{40deg_i} = \left[\begin{aligned} & \left[\text{---} \times \text{---} \left(\frac{LF_{Gen_i}}{\%} \right)^4 - \text{---} \times \text{---} \left(\frac{LF_{Gen_i}}{\%} \right)^3 \dots \right] \\ & + \left[\text{---} \times \text{---} \left(\frac{LF_{Gen_i}}{\%} \right)^2 - \text{---} \frac{LF_{Gen_i}}{\%} + \text{---} \times \text{---} \right] \end{aligned} \right] kPc \quad (B.124)$$

$$P_{42deg_i} = \left[\begin{aligned} & \left[\text{---} \times \text{---} \left(\frac{LF_{Gen_i}}{\%} \right)^4 - \text{---} \times \text{---} \left(\frac{LF_{Gen_i}}{\%} \right)^3 \dots \right] \\ & + \left[\text{---} \times \text{---} \left(\frac{LF_{Gen_i}}{\%} \right)^2 - \text{---} \frac{LF_{Gen_i}}{\%} + \text{---} \times \text{---} \right] \end{aligned} \right] kPc \quad (B.125)$$

$$P_{BP.Targ_i} = \begin{cases} P_{6deg_i} & \text{if } T_{ACC.Air.In_i}/^{\circ}C < 6 \\ \left[\frac{P_{10deg_i} - P_{6deg_i}}{10 - 6} (T_{ACC.Air.In_i}/^{\circ}C - 6) + P_{6deg_i} \right] & \text{if } 6 \leq T_{ACC.Air.In_i}/^{\circ}C < 10 \\ \left[\frac{P_{15deg_i} - P_{10deg_i}}{15 - 10} (T_{ACC.Air.In_i}/^{\circ}C - 10) + P_{10deg_i} \right] & \text{if } 10 \leq T_{ACC.Air.In_i}/^{\circ}C < 15 \\ \left[\frac{P_{20deg_i} - P_{15deg_i}}{20 - 15} (T_{ACC.Air.In_i}/^{\circ}C - 15) + P_{15deg_i} \right] & \text{if } 15 \leq T_{ACC.Air.In_i}/^{\circ}C < 20 \\ \left[\frac{P_{25deg_i} - P_{20deg_i}}{25 - 20} (T_{ACC.Air.In_i}/^{\circ}C - 20) + P_{20deg_i} \right] & \text{if } 20 \leq T_{ACC.Air.In_i}/^{\circ}C < 25 \\ \left[\frac{P_{30deg_i} - P_{25deg_i}}{30 - 25} (T_{ACC.Air.In_i}/^{\circ}C - 25) + P_{25deg_i} \right] & \text{if } 25 \leq T_{ACC.Air.In_i}/^{\circ}C < 30 \\ \left[\frac{P_{35deg_i} - P_{30deg_i}}{35 - 30} (T_{ACC.Air.In_i}/^{\circ}C - 30) + P_{30deg_i} \right] & \text{if } 30 \leq T_{ACC.Air.In_i}/^{\circ}C < 35 \\ \left[\frac{P_{40deg_i} - P_{35deg_i}}{40 - 35} (T_{ACC.Air.In_i}/^{\circ}C - 35) + P_{35deg_i} \right] & \text{if } 35 \leq T_{ACC.Air.In_i}/^{\circ}C < 40 \\ \left[\frac{P_{42deg_i} - P_{40deg_i}}{42 - 40} (T_{ACC.Air.In_i}/^{\circ}C - 40) + P_{40deg_i} \right] & \text{if } 40 \leq T_{ACC.Air.In_i}/^{\circ}C < 42 \\ P_{42deg_i} & \text{otherwise} \end{cases} \quad (B.126)$$

$$CF_{BP.Targ.40\%_i} = \left[\begin{aligned} & - \left[\frac{P_{BP.Targ_i}}{kPa} \right]^4 + \left[\frac{P_{BP.Targ_i}}{kPa} \right]^3 \dots \\ & + \left[\frac{P_{BP.Targ_i}}{kPa} \right]^2 + \left[\frac{P_{BP.Targ_i}}{kPa} \right] \dots \\ & + \dots \end{aligned} \right] \quad (B.127)$$

$$CF_{BP.Targ.60\%_i} = \left[\begin{aligned} & - \left[\frac{P_{BP.Targ_i}}{kPa} \right]^4 + \left[\frac{P_{BP.Targ_i}}{kPa} \right]^3 \dots \\ & + \left[\frac{P_{BP.Targ_i}}{kPa} \right]^2 + \left[\frac{P_{BP.Targ_i}}{kPa} \right] \dots \\ & + \dots \end{aligned} \right] \quad (B.128)$$

$$CF_{BP.Targ.80\%_i} = \left[\begin{aligned} & \left[\text{Term}_1 \times \left(\frac{P_{BP.Targ_i}}{kPa} \right)^4 + \text{Term}_2 \times \left(\frac{P_{BP.Targ_i}}{kPa} \right)^3 \right] \dots \\ & + \left[\text{Term}_3 \times \left(\frac{P_{BP.Targ_i}}{kPa} \right)^2 + \text{Term}_4 \times \frac{P_{BP.Targ_i}}{kPa} \right] \dots \\ & + \text{Term}_5 \end{aligned} \right] \quad (B.129)$$

$$CF_{BP.Targ.100\%_i} = \left[\begin{aligned} & \left[\text{Term}_1 \times \left(\frac{P_{BP.Targ_i}}{kPa} \right)^4 + \text{Term}_2 \times \left(\frac{P_{BP.Targ_i}}{kPa} \right)^3 \right] \dots \\ & + \left[\text{Term}_3 \times \left(\frac{P_{BP.Targ_i}}{kPa} \right)^2 + \text{Term}_4 \times \frac{P_{BP.Targ_i}}{kPa} \right] \dots \\ & + \text{Term}_5 \end{aligned} \right] \quad (B.130)$$

$$CF_{BP.Targ_i} = \left[\begin{aligned} & CF_{BP.Targ.100\%_i} \text{ if } LF_{Gen_i} > 1 \\ & \left[\frac{CF_{BP.Targ.100\%_i} - CF_{BP.Targ.80\%_i}}{100 - 80} \left(\frac{LF_{Gen_i}}{\%} - 80 \right) \dots + CF_{BP.Targ.80\%_i} \right] \text{ if } 1 \geq LF_{Gen_i} > 0.8 \\ & \left[\frac{CF_{BP.Targ.80\%_i} - CF_{BP.Targ.60\%_i}}{80 - 60} \left(\frac{LF_{Gen_i}}{\%} - 60 \right) \dots + CF_{BP.Targ.60\%_i} \right] \text{ if } 0.8 \geq LF_{Gen_i} > 0.6 \\ & \left[\frac{CF_{BP.Targ.60\%_i} - CF_{BP.Targ.40\%_i}}{60 - 40} \left(\frac{LF_{Gen_i}}{\%} - 40 \right) \dots + CF_{BP.Targ.40\%_i} \right] \text{ if } 0.6 \geq LF_{Gen_i} \geq 0.4 \\ & CF_{BP.Targ.40\%_i} \text{ otherwise} \end{aligned} \right] \quad (B.131)$$

$$CF_{MU.Targ_i} = \frac{1 - \left(R_{Q.MU_i} \frac{Frac_{MU.Targ_i}}{\%} \right)}{1 - \left(R_{Q.MU_i} \frac{Frac_{MU.Targ_i}}{\%} F_{MU.Est_i} \right)} \quad (B.132)$$

$$HR_{Targ_i} = HR_{SO.Opt_i} CF_{BP.Targ_i} CF_{MU.Targ_i} CF_{AuxPower_i} CF_{LF.Turb_i} CF_{LF.Boil_i} CF_{Fuel.Boil_i} CF_{PF_i} \quad (B.133)$$

$$Q_{OnLoad.Targ.Turb_i} = HR_{Targ_i} J_{USO_i} \quad (B.134)$$

$$Q_{Start.RangeTurb_i} = \left(\frac{Q_{NL_i}}{kW\ hr} \dots \frac{Q_{Incr.NLtoNER_i}}{kW\ hr} + \frac{10^6}{10^6} \right) \left(\frac{N_{Start.Hot.Turb_i}}{2} \dots + N_{Start.Cold.Turb_i} \right) \frac{100.6}{\eta_{Std.Boil_i} \%} GWh \quad (B.135)$$

$$Q_{Tot.Targ_i} = Q_{OnLoad.Targ.Turb_i} + Q_{Start.RangeTurb_i} + Q_{OffLoad.Boil_i} \quad (B.136)$$

$$T_{HPT.Act.In_i} = \frac{T_{LH.HPT.In_i} + T_{RH.HPT.In_i}}{2} \quad (B.137)$$

$$T_{IPT.Act.In_i} = \frac{T_{LH.IPT.In_i} + T_{RH.IPT.In_i}}{2} \quad (B.138)$$

$$L_{Det.Turb_i} = Det_{Turb.Previous_i} + \frac{t_{RT.Gen_i}}{hr8760} 0.1\% \quad (B.139)$$

$$T_{FW.Targ_i} = \left[\begin{aligned} & \left[\dots \times \left(\frac{LF_{Gen_i}}{\%} \right)^4 - \dots \times \left(\frac{LF_{Gen_i}}{\%} \right)^3 \dots \right. \\ & \left. + \dots \times \left(\frac{LF_{Gen_i}}{\%} \right)^2 - \dots \times \frac{LF_{Gen_i}}{\%} + \dots \times \right] \quad ^\circ C \end{aligned} \right] \quad (B.140)$$

$$Fract_{AuxPower.Act_i} = \begin{cases} 0 & \text{if } J_{USO_i} = 0 \\ \frac{J_{AuxPower_i}}{J_{USO_i}} & \text{otherwise} \end{cases} \quad (B.141)$$

$$L_{AuxPower.SF_i} = Fract_{AuxPower.Act_i} - Fract_{AuxPower.Targ_i} \quad (B.142)$$

$$T_{FW.Diff_i} = T_{FW.Act_i} - T_{FW.Targ_i} \quad (B.143)$$

$$L_{FW.SF_i} = \begin{cases} 0 & \text{if } L_{FGen_i} = 0 \\ \left[\begin{aligned} & \left[\frac{T_{FW.Diff_i}}{K} \right]^4 - \left[\frac{T_{FW.Diff_i}}{K} \right]^3 \dots \% \\ & + \left[\frac{T_{FW.Diff_i}}{K} \right]^2 - \frac{T_{FW.Diff_i}}{K} \dots \\ & + \dots \end{aligned} \right] & \text{otherwise} \end{cases} \quad (B.144)$$

$$T_{HPT.In.Diff_i} = T_{HPT.Act.In_i} - T_{HPT.Targ.In_i} \quad (B.145)$$

$$L_{MS.SF_i} = \begin{cases} 0 & \text{if } L_{FGen_i} = 0 \\ \left[\begin{aligned} & \left[\frac{T_{HPT.In.Diff_i}}{K} \right]^4 \dots \% \\ & + \left[\frac{T_{HPT.In.Diff_i}}{K} \right]^3 \dots \\ & + \left[\frac{T_{HPT.In.Diff_i}}{K} \right]^2 \dots \\ & + \frac{T_{HPT.In.Diff_i}}{K} - 0 \end{aligned} \right] & \text{otherwise} \end{cases} \quad (B.146)$$

$$T_{IPT.In.Diff_i} = T_{IPT.Act.In_i} - T_{IPT.Targ.In_i} \quad (B.147)$$

$$L_{ReH.SF_i} = \begin{cases} 0 & \text{if } LF_{Gen_i} = 0 \\ \left[\begin{aligned} & \left(\frac{T_{IPT.In.Diff_i}}{K} \right)^4 \dots \\ & + \left(\frac{T_{IPT.In.Diff_i}}{K} \right)^3 \dots \\ & + \left(\frac{T_{IPT.In.Diff_i}}{K} \right)^2 \dots \\ & + \frac{T_{IPT.In.Diff_i}}{K} - 0 \end{aligned} \right] \% \text{ otherwise} \end{cases} \quad (B.148)$$

$$CF_{BP.40\%_i} = \left[\begin{aligned} & \left(\frac{P_{Cond_i}}{kPa} \right)^4 + \left(\frac{P_{Cond_i}}{kPa} \right)^3 \dots \\ & + \left(\frac{P_{Cond_i}}{kPa} \right)^2 + \frac{P_{Cond_i}}{kPa} + \end{aligned} \right] \quad (B.149)$$

$$CF_{BP.60\%_i} = \left[\begin{aligned} & \left(\frac{P_{Cond_i}}{kPa} \right)^4 + \left(\frac{P_{Cond_i}}{kPa} \right)^3 \dots \\ & + \left(\frac{P_{Cond_i}}{kPa} \right)^2 + \frac{P_{Cond_i}}{kPa} + \end{aligned} \right] \quad (B.150)$$

$$CF_{BP.80\%_i} = \left[\begin{aligned} & \left(\frac{P_{Cond_i}}{kPa} \right)^4 + \left(\frac{P_{Cond_i}}{kPa} \right)^3 \dots \\ & + \left(\frac{P_{Cond_i}}{kPa} \right)^2 + \frac{P_{Cond_i}}{kPa} + \end{aligned} \right] \quad (B.151)$$

$$CF_{BP.100\%_i} = \left[\begin{aligned} & \left[\text{Coefficient}_1 \times \left(\frac{P_{Cond_i}}{kPa} \right)^4 + \text{Coefficient}_2 \times \left(\frac{P_{Cond_i}}{kPa} \right)^3 + \dots \right. \\ & \left. + \text{Coefficient}_3 \times \left(\frac{P_{Cond_i}}{kPa} \right)^2 + \text{Coefficient}_4 \times \frac{P_{Cond_i}}{kPa} + \text{Coefficient}_5 \times 1 \right] \end{aligned} \right] \quad (B.152)$$

$$CF_{BP.Act_i} = \begin{cases} CF_{BP.100\%_i} & \text{if } LF_{Gen_i} > 1 \\ \left[\frac{CF_{BP.100\%_i} - CF_{BP.80\%_i}}{100 - 80} \left(\frac{LF_{Gen_i}}{\%} - 80 \right) + CF_{BP.80\%_i} \right] & \text{if } 1 \geq LF_{Gen_i} > 0.8 \\ \left[\frac{CF_{BP.80\%_i} - CF_{BP.60\%_i}}{80 - 60} \left(\frac{LF_{Gen_i}}{\%} - 60 \right) + CF_{BP.60\%_i} \right] & \text{if } 0.8 \geq LF_{Gen_i} > 0.6 \\ \left[\frac{CF_{BP.60\%_i} - CF_{BP.40\%_i}}{60 - 40} \left(\frac{LF_{Gen_i}}{\%} - 40 \right) + CF_{BP.40\%_i} \right] & \text{if } 0.6 \geq LF_{Gen_i} \geq 0.4 \\ CF_{BP.40\%_i} & \text{otherwise} \end{cases} \quad (B.153)$$

$$L_{BP.SF_i} = \begin{cases} 0 & \text{if } LF_{Gen_i} = 0 \\ (CF_{BP.Act_i} - CF_{BP.Targ_i}) & \text{otherwise} \end{cases} \quad (B.154)$$

$$L_{Turb.SF_i} = L_{MS.SF_i} + L_{ReH.SF_i} + L_{Det.Turb_i} + L_{FW.SF_i} + L_{BP.SF_i} \quad (B.155)$$

$$L_{MU.Targ_i} = Frac_{MU.Targ_i} F_{MU.Est_i} CF_{MU.Targ_i} \quad (B.156)$$

$$V_{MU.Stn} = V_{MU.MeterB.Stn} + V_{MU.MeterA.Stn} \quad (B.157)$$

$$V_{MU_USO.St} = \frac{V_{MU.Stn}}{J_{USO.Stn}} \quad (B.158)$$

$$V_{MU.Other} = V_{MU.MeterA.Stn} + V_{MU.MeterB.Stn} - \sum_{i=1}^6 V_{MU_i} \quad (B.159)$$

$$F_{MU.Hot_i} = \begin{cases} 0 & \text{if } m_{Stm.Boil_i} = 0 \\ \frac{V_{MU_i} + \left(\text{Frac}_{Gen_i} V_{MU.Other} \right) - V_{MU.Cold_i}}{m_{Stm.Boil_i}} & \text{otherwise} \end{cases} \quad (B.160)$$

$$L_{MU.Act_i} = \frac{\frac{F_{MU.Hot_i}}{\frac{ML}{Gg}} \left(1 - R_{Q.MU_i} \text{Frac}_{MU.Targ_i} \right)}{\left(1 - R_{Q.MU_i} \frac{F_{MU.Hot_i}}{\frac{ML}{Gg}} \right)} \quad (B.161)$$

$$V_{MU.ExclU} = V_{MU.Stn} - \sum_{i=1}^6 V_{MU_i} \quad (B.162)$$

$$L_{MU.SF_i} = \begin{cases} 0 & \text{if } L_{FGen_i} = 0 \\ \left[\left(L_{MU.Act_i} - L_{MU.Targ_i} \right) R_{Q.MU_i} 100 \right] & \text{otherwise} \end{cases} \quad (B.163)$$

$$L_{U.SF_i} = L_{Turb.SF_i} + L_{MU.SF_i} + L_{AuxPower.SF_i} + L_{Tot.Boil.SF_i} \quad (B.164)$$

$$L_{U.SF.derived_i} = 1 - L_{U.SF_i} \quad (B.165)$$

$$MCR_{LV_i} = \text{ } MW \quad (B.166)$$

$$L_{FGen.LV_i} = \begin{cases} 0 & \text{if } t_{RT.Gen_i} = 0 \\ \frac{J_{Gen.LV_i}}{CF_{Amb_i} t_{RT.Gen_i} MCR_{LV_i}} & \text{otherwise} \end{cases} \quad (B.167)$$

$$HR_{15deg_i} = \left[\begin{aligned} & \left[\text{ } \times \text{ } \left(\frac{LF_{Gen.LV_i}}{\%} \right)^4 - \text{ } \times \text{ } \left(\frac{LF_{Gen.LV_i}}{\%} \right)^3 \right] \dots \frac{kJ}{kWh} \\ & + \left[\text{ } \times \text{ } \left(\frac{LF_{Gen.LV_i}}{\%} \right)^2 - \text{ } \frac{LF_{Gen.LV_i}}{\%} + \text{ } \times \text{ } \right] \end{aligned} \right] \quad (B.168)$$

$$HR_{18deg_i} = \left[\begin{aligned} & \left[\text{ } \times \text{ } \left(\frac{LF_{Gen.LV_i}}{\%} \right)^4 - \text{ } \times \text{ } \left(\frac{LF_{Gen.LV_i}}{\%} \right)^3 \right] \dots \frac{kJ}{kWh} \\ & + \left[\text{ } \times \text{ } \left(\frac{LF_{Gen.LV_i}}{\%} \right)^2 - \text{ } \frac{LF_{Gen.LV_i}}{\%} \right] \dots \\ & + \left[\text{ } \times \text{ } \right] \end{aligned} \right] \quad (B.169)$$

$$HR_{23deg_i} = \left[\begin{aligned} & \left[\text{ } \times \text{ } \left(\frac{LF_{Gen.LV_i}}{\%} \right)^4 - \text{ } \times \text{ } \left(\frac{LF_{Gen.LV_i}}{\%} \right)^3 \right] \dots \frac{kJ}{kWh} \\ & + \left[\text{ } \times \text{ } \left(\frac{LF_{Gen.LV_i}}{\%} \right)^2 - \text{ } \times \text{ } \frac{LF_{Gen.LV_i}}{\%} \right] \dots \\ & + \left[\text{ } \times \text{ } \right] \end{aligned} \right] \quad (B.170)$$

$$HR_{28deg_i} = \left[\begin{aligned} & \left[- \text{ } \times \text{ } \left(\frac{LF_{Gen.LV_i}}{\%} \right)^4 + \text{ } \times \text{ } \left(\frac{LF_{Gen.LV_i}}{\%} \right)^3 \right] \dots \frac{kJ}{kWh} \\ & + \left[\text{ } \times \text{ } \left(\frac{LF_{Gen.LV_i}}{\%} \right)^2 - \text{ } \times \text{ } \frac{LF_{Gen.LV_i}}{\%} \right] \dots \\ & + \left[\text{ } \times \text{ } \right] \end{aligned} \right] \quad (B.171)$$

$$HR_{33deg_i} = \left[\begin{aligned} & \left[\text{ } \times \text{ } \left(\frac{LF_{Gen.LV_i}}{\%} \right)^4 - \text{ } \times \text{ } \left(\frac{LF_{Gen.LV_i}}{\%} \right)^3 \right] \dots \frac{kJ}{kWh} \\ & + \left[\text{ } \times \text{ } \left(\frac{LF_{Gen.LV_i}}{\%} \right)^2 - \text{ } \times \text{ } \frac{LF_{Gen.LV_i}}{\%} \right] \dots \\ & + \left[\text{ } \times \text{ } \right] \end{aligned} \right] \quad (B.172)$$

$$HR_{Turb.Targ_i} = \begin{cases} HR_{15deg_i} & \text{if } T_{ACC.Air.In_i} / ^\circ C < 15 \\ \left[\frac{HR_{18deg_i} - HR_{15deg_i}}{18 - 15} (T_{ACC.Air.In_i} / ^\circ C - 15) \dots + HR_{15deg_i} \right] & \text{if } 15 \leq T_{ACC.Air.In_i} / ^\circ C < 18 \\ \left[\frac{HR_{23deg_i} - HR_{18deg_i}}{23 - 18} (T_{ACC.Air.In_i} / ^\circ C - 18) \dots + HR_{18deg_i} \right] & \text{if } 18 \leq T_{ACC.Air.In_i} / ^\circ C < 23 \\ \left[\frac{HR_{28deg_i} - HR_{23deg_i}}{28 - 23} (T_{ACC.Air.In_i} / ^\circ C - 23) \dots + HR_{23deg_i} \right] & \text{if } 23 \leq T_{ACC.Air.In_i} / ^\circ C < 28 \\ \left[\frac{HR_{33deg_i} - HR_{28deg_i}}{33 - 28} (T_{ACC.Air.In_i} / ^\circ C - 28) \dots + HR_{28deg_i} \right] & \text{if } 28 \leq T_{ACC.Air.In_i} / ^\circ C < 33 \\ HR_{33deg_i} & \text{otherwise} \end{cases} \quad (B.173)$$

$$Q_{15deg_i} = \left[\begin{aligned} & - \left(\frac{LF_{Gen.LV_i}}{\%} \right)^4 + \frac{LF_{Gen.LV_i}}{\%}^3 \dots \\ & + \frac{LF_{Gen.LV_i}}{\%}^2 + \frac{LF_{Gen.LV_i}}{\%} - \dots \end{aligned} \right] \quad (B.174)$$

$$Q_{18deg_i} = \left[\begin{aligned} & \frac{LF_{Gen.LV_i}}{\%}^4 + \frac{LF_{Gen.LV_i}}{\%}^3 \dots \\ & + \frac{LF_{Gen.LV_i}}{\%}^2 + \frac{LF_{Gen.LV_i}}{\%} - \dots \end{aligned} \right] \quad (B.175)$$

$$Q_{23deg_i} = \left[\begin{aligned} & \left(\frac{LF_{Gen.LV_i}}{\%} \right)^4 + \frac{LF_{Gen.LV_i}}{\%}^3 \dots \\ & + \frac{LF_{Gen.LV_i}}{\%}^2 + \frac{LF_{Gen.LV_i}}{\%} - \dots \end{aligned} \right] \quad (B.176)$$

$$Q_{28deg_i} = \left[\begin{aligned} & \left(\frac{LF_{Gen.LV_i}}{\%} \right)^4 + \left(\frac{LF_{Gen.LV_i}}{\%} \right)^3 \dots \\ & + \left(\frac{LF_{Gen.LV_i}}{\%} \right)^2 + \frac{LF_{Gen.LV_i}}{\%} - \dots \end{aligned} \right] \quad (B.177)$$

$$Q_{33deg_i} = \left[\begin{aligned} & \left(\frac{LF_{Gen.LV_i}}{\%} \right)^4 + \left(\frac{LF_{Gen.LV_i}}{\%} \right)^3 \dots \\ & + \left(\frac{LF_{Gen.LV_i}}{\%} \right)^2 + \frac{LF_{Gen.LV_i}}{\%} - \dots \end{aligned} \right] \quad (B.178)$$

$$CF_{MS_i} = \begin{cases} Q_{15deg_i} & \text{if } T_{ACC.Air.In_i} / ^\circ C < 15 \\ \left[\frac{Q_{18deg_i} - Q_{15deg_i}}{18 - 15} (T_{ACC.Air.In_i} / ^\circ C - 15) + Q_{15deg_i} \right] & \text{if } 15 \leq T_{ACC.Air.In_i} / ^\circ C < 18 \\ \left[\frac{Q_{23deg_i} - Q_{18deg_i}}{23 - 18} (T_{ACC.Air.In_i} / ^\circ C - 18) + Q_{18deg_i} \right] & \text{if } 18 \leq T_{ACC.Air.In_i} / ^\circ C < 23 \\ \left[\frac{Q_{28deg_i} - Q_{23deg_i}}{28 - 23} (T_{ACC.Air.In_i} / ^\circ C - 23) + Q_{23deg_i} \right] & \text{if } 23 \leq T_{ACC.Air.In_i} / ^\circ C < 28 \\ \left[\frac{Q_{33deg_i} - Q_{28deg_i}}{33 - 28} (T_{ACC.Air.In_i} / ^\circ C - 28) + Q_{28deg_i} \right] & \text{if } 28 \leq T_{ACC.Air.In_i} / ^\circ C < 33 \\ Q_{33deg_i} & \text{otherwise} \end{cases} \quad (B.179)$$

$$h_{Targ.MS_i} = \left[\begin{aligned} & \left(\frac{LF_{Gen.LV_i}}{\%} \right)^4 + \left(\frac{LF_{Gen.LV_i}}{\%} \right)^3 \dots \\ & + \left(\frac{LF_{Gen.LV_i}}{\%} \right)^2 - \frac{LF_{Gen.LV_i}}{\%} + \dots \end{aligned} \right] \frac{kJ}{kg} \quad (B.180)$$

$$h_{Targ.ReH.Out_i} = \left[\begin{aligned} & \left[\text{[redacted]} \times \text{[redacted]} \left(\frac{LF_{Gen.LV_i}}{\%} \right)^4 + \text{[redacted]} \times \text{[redacted]} \left(\frac{LF_{Gen.LV_i}}{\%} \right)^3 \right] \dots \frac{kJ}{kg} \\ & + \left[\text{[redacted]} \times \text{[redacted]} \left(\frac{LF_{Gen.LV_i}}{\%} \right)^2 + \text{[redacted]} \frac{LF_{Gen.LV_i}}{\%} \right] \dots \\ & + \left[\text{[redacted]} \times \text{[redacted]} \right] \end{aligned} \right] \quad (B.181)$$

$$h_{Targ.FW_i} = \left[\begin{aligned} & \left[\text{[redacted]} \times \text{[redacted]} \left(\frac{LF_{Gen.LV_i}}{\%} \right)^4 - \text{[redacted]} \times \text{[redacted]} \left(\frac{LF_{Gen.LV_i}}{\%} \right)^3 \right] \dots \frac{kJ}{kg} \\ & + \left[\text{[redacted]} \times \text{[redacted]} \left(\frac{LF_{Gen.LV_i}}{\%} \right)^2 - 2.0284 \frac{LF_{Gen.LV_i}}{\%} + 8.5133 \times 10^2 \right] \end{aligned} \right] \quad (B.182)$$

$$P_{Targ.HPT.Out_i} = \left[\begin{aligned} & - \left[\text{[redacted]} \left(\frac{LF_{Gen.LV_i}}{\%} \right)^4 \right] \dots \\ & + \left[\text{[redacted]} \left(\frac{LF_{Gen.LV_i}}{\%} \right)^3 \right] \dots \\ & + \left[\text{[redacted]} \left(\frac{LF_{Gen.LV_i}}{\%} \right)^2 \right] \dots \\ & + \left[\text{[redacted]} \frac{LF_{Gen.LV_i}}{\%} - \text{[redacted]} \right] \end{aligned} \right] bar \quad (B.183)$$

$$T_{Targ.HPT.Out_i} = \left[\begin{aligned} & - \left[\text{[redacted]} \left(\frac{LF_{Gen.LV_i}}{\%} \right)^4 + \text{[redacted]} \left(\frac{LF_{Gen.LV_i}}{\%} \right)^3 \right] \dots ^\circ C \\ & + \left[\text{[redacted]} \left(\frac{LF_{Gen.LV_i}}{\%} \right)^2 + \text{[redacted]} \frac{LF_{Gen.LV_i}}{\%} \right] \dots \\ & + \left[\text{[redacted]} \right] \end{aligned} \right] \quad (B.184)$$

$$h_{Targ.HPT.Out_i} = \left[\begin{aligned} & \left[\text{[redacted]} \times \text{[redacted]} \left(\frac{LF_{Gen.LV_i}}{\%} \right)^4 \right] \dots \frac{kJ}{kg} \\ & + \left[\text{[redacted]} \times \text{[redacted]} \left(\frac{LF_{Gen.LV_i}}{\%} \right)^3 \right] \dots \\ & + \left[\text{[redacted]} \times \text{[redacted]} \left(\frac{LF_{Gen.LV_i}}{\%} \right)^2 \right] \dots \\ & + \left[\text{[redacted]} \frac{LF_{Gen.LV_i}}{\%} + \text{[redacted]} \times \text{[redacted]} \right] \end{aligned} \right] \quad (B.185)$$

$$T_{Targ.SW_i} = \left[\begin{aligned} & \left[\text{[redacted]} \times \text{[redacted]} \left(\frac{LF_{Gen.LV_i}}{\%} \right)^4 + \text{[redacted]} \times \text{[redacted]} \left(\frac{LF_{Gen.LV_i}}{\%} \right)^3 \right] \dots \\ & + \left[\text{[redacted]} \times \text{[redacted]} \left(\frac{LF_{Gen.LV_i}}{\%} \right)^2 + \text{[redacted]} \frac{LF_{Gen.LV_i}}{\%} + \text{[redacted]} \times \text{[redacted]} \right] \end{aligned} \right] ^\circ C \quad (B.186)$$

$$h_{Targ.SW_i} = \left[\begin{aligned} & \left[\text{[redacted]} \times \text{[redacted]} \left(\frac{LF_{Gen.LV_i}}{\%} \right)^4 + \text{[redacted]} \times \text{[redacted]} \left(\frac{LF_{Gen.LV_i}}{\%} \right)^3 \right] \dots \frac{kJ}{kg} \\ & + \left[\text{[redacted]} \times \text{[redacted]} \left(\frac{LF_{Gen.LV_i}}{\%} \right)^2 + \text{[redacted]} \frac{LF_{Gen.LV_i}}{\%} + \text{[redacted]} \times \text{[redacted]} \right] \end{aligned} \right] \quad (B.187)$$

$$P'_{Est.CEPs_i} = \left[\begin{aligned} & \left[\text{[redacted]} \times \text{[redacted]} \left(\frac{LF_{Gen_i}}{\%} \right)^4 + \text{[redacted]} \times \text{[redacted]} \left(\frac{LF_{Gen_i}}{\%} \right)^3 \right] \dots \frac{GW}{10^6} \\ & + \left[\text{[redacted]} \times \text{[redacted]} \left(\frac{LF_{Gen_i}}{\%} \right)^2 + \text{[redacted]} \times \text{[redacted]} \frac{LF_{Gen_i}}{\%} + \text{[redacted]} \times \text{[redacted]} \right] \end{aligned} \right] \quad (B.188)$$

$$J'_{Est.CEPs_i} = P'_{Est.CEPs_i} (t_{RT.CEP.A_i} + t_{RT.CEP.B_i}) \quad (B.189)$$

$$J_{Pumps_i} = J_{EFPs.Targ_i} + J'_{Est.CEPs_i} \quad (B.190)$$

$$HR_{Turb.Act_i} = \begin{cases} 0 & \text{if } J_{Gen.LV_i} = 0 \\ \frac{\left[m_{HPT.In_i} (h_{Targ.MS_i} - h_{Targ.FW_i}) \dots \right.}{\left(\frac{J_{Gen.LV_i} - J_{Pumps_i}}{t_{RT.Gen_i}} \right)} & \text{otherwise} \end{cases} \quad (B.191)$$

$$+ \left(m_{IPT.In_i} h_{Targ.ReH.Out_i} \right) - \left(m_{ReH.In_i} h_{Targ.HPT.Out_i} \right) \dots$$

$$+ - \left(m_{ReH.SW_i} h_{Targ.SW_i} \right)$$

$$HR_{Turb.SF_i} = HR_{Turb.Act_i} - HR_{Turb.Targ_i} \quad (B.192)$$

$$\eta_{Turb.Targ_i} = \frac{1}{HR_{Turb.Targ_i}} \quad (B.193)$$

$$\eta_{Turb.Act_i} = \begin{cases} 0 & \text{if } HR_{Turb.Act_i} = 0 \\ \frac{1}{HR_{Turb.Act_i}} & \text{otherwise} \end{cases} \quad (B.194)$$

$$\eta_{Turb.SF_i} = \eta_{Turb.Act_i} - \eta_{Turb.Targ_i} \quad (B.195)$$

$$Q_{Rej.15deg_i} = \left[\begin{aligned} & \left[\dots \times \left(\frac{LF_{Gen_i}}{\%} \right)^4 + \dots \times \left(\frac{LF_{Gen_i}}{\%} \right)^3 \dots \right] MW \\ & + \left[\dots \times \left(\frac{LF_{Gen_i}}{\%} \right)^2 + \dots \times \frac{LF_{Gen_i}}{\%} \dots \right] \\ & + \left[\dots \times \dots \right] \end{aligned} \right] \quad (B.196)$$

$$Q_{Rej.18deg_i} = \left[\begin{aligned} & \left[\dots \times \left(\frac{LF_{Gen_i}}{\%} \right)^4 + \dots \times \left(\frac{LF_{Gen_i}}{\%} \right)^3 \dots \right] MW \\ & + \left[\dots \times \left(\frac{LF_{Gen_i}}{\%} \right)^2 + \dots \times \frac{LF_{Gen_i}}{\%} + \dots \times \dots \right] \end{aligned} \right] \quad (B.197)$$

$$Q_{Rej.23deg_i} = \left[\begin{aligned} & \left[\text{ } \times \text{ } \left(\frac{LF_{Gen_i}}{\%} \right)^4 + \text{ } \times \text{ } \left(\frac{LF_{Gen_i}}{\%} \right)^3 \dots \right. \\ & \left. + \text{ } \times \text{ } \left(\frac{LF_{Gen_i}}{\%} \right)^2 + \text{ } \frac{LF_{Gen_i}}{\%} + \text{ } \times \text{ } \right] \end{aligned} \right] MW \quad (B.198)$$

$$Q_{Rej.28deg_i} = \left[\begin{aligned} & \left[\text{ } \times \text{ } \left(\frac{LF_{Gen_i}}{\%} \right)^4 + - \left(\text{ } \times \text{ } \right) \left(\frac{LF_{Gen_i}}{\%} \right)^3 \dots \right. \\ & \left. + \text{ } \times \text{ } \left(\frac{LF_{Gen_i}}{\%} \right)^2 + \text{ } \frac{LF_{Gen_i}}{\%} + \text{ } \times \text{ } \right] \end{aligned} \right] MW \quad (B.199)$$

$$Q_{Rej.33deg_i} = \left[\begin{aligned} & \left[\text{ } \times \text{ } \left(\frac{LF_{Gen_i}}{\%} \right)^4 + \text{ } \times \text{ } \left(\frac{LF_{Gen_i}}{\%} \right)^3 \dots \right. \\ & \left. + \text{ } \times \text{ } \left(\frac{LF_{Gen_i}}{\%} \right)^2 + \text{ } \frac{LF_{Gen_i}}{\%} + \text{ } \times \text{ } \right] \end{aligned} \right] MW \quad (B.200)$$

$$Q_{Rej_i} = \left[\begin{aligned} & Q_{Rej.15deg_i} \quad \text{if } T_{ACC.Air.In_i} / ^\circ C < 15 \\ & \left[\begin{aligned} & \frac{Q_{Rej.18deg_i} - Q_{Rej.15deg_i}}{18 - 15} (T_{ACC.Air.In_i} / ^\circ C - 15) \dots \\ & + Q_{Rej.15deg_i} \end{aligned} \right] \quad \text{if } 15 \leq T_{ACC.Air.In_i} / ^\circ C < 18 \\ & \left[\begin{aligned} & \frac{Q_{Rej.23deg_i} - Q_{Rej.18deg_i}}{23 - 18} (T_{ACC.Air.In_i} / ^\circ C - 18) \dots \\ & + Q_{Rej.18deg_i} \end{aligned} \right] \quad \text{if } 18 \leq T_{ACC.Air.In_i} / ^\circ C < 23 \\ & \left[\begin{aligned} & \frac{Q_{Rej.28deg_i} - Q_{Rej.23deg_i}}{28 - 23} (T_{ACC.Air.In_i} / ^\circ C - 23) \dots \\ & + Q_{Rej.23deg_i} \end{aligned} \right] \quad \text{if } 23 \leq T_{ACC.Air.In_i} / ^\circ C < 28 \\ & \left[\begin{aligned} & \frac{Q_{Rej.33deg_i} - Q_{Rej.28deg_i}}{33 - 28} (T_{ACC.Air.In_i} / ^\circ C - 28) \dots \\ & + Q_{Rej.28deg_i} \end{aligned} \right] \quad \text{if } 28 \leq T_{ACC.Air.In_i} / ^\circ C < 33 \\ & Q_{Rej.33deg_i} \quad \text{otherwise} \end{aligned} \right] \quad (B.201)$$

$$HR_{Incr.Act_i} = \begin{cases} 0 & \text{if } LF_{Gen_i} = 0 \\ \frac{HR_{Incr.AT_i} CF_{BP.Targ_i} 10^6}{\left(100 - \frac{L_{Turb.SF_i}}{\%}\right) \left(100 - \frac{L_{Tot.Boil.Act_i}}{\%}\right) \left(100 - \frac{Fract_{AuxPower.min.ACC_i}}{\%}\right)} & \text{otherwise} \end{cases} \quad (B.202)$$

$$HR_{Incr.MCR.Act_i} = \begin{cases} 0 & \text{if } LF_{Gen_i} = 0 \\ \frac{HR_{Incr.MCR.AT_i} CF_{BP.Targ_i} 10^6}{\left(100 - \frac{L_{Turb.SF_i}}{\%}\right) \left(100 - \frac{L_{Tot.Boil.Act_i}}{\%}\right) \left(100 - \frac{Fract_{AuxPower.min.ACC_i}}{\%}\right)} & \text{otherwise} \end{cases} \quad (B.203)$$

$$T_{MS.Targ.Stn} = \sum_{i=1}^6 \left(T_{HPT.Targ.In_i} Frac_{Gen_i} \right) \quad (B.204)$$

$$T_{IPT.Targ.In} = \sum_{i=1}^6 \left(T_{IPT.Targ.In_i} Frac_{Gen_i} \right) \quad (B.205)$$

$$T_{MS.Act.Stn} = \sum_{i=1}^6 \left(T_{HPT.Act.In_i} Frac_{Gen_i} \right) \quad (B.206)$$

$$T_{IPT.Act.Stn.In} = \sum_{i=1}^6 \left(T_{IPT.Act.In_i} Frac_{Gen_i} \right) \quad (B.207)$$

$$L_{MS.SF.Stn} = \sum_{i=1}^6 \left(L_{MS.SF_i} Frac_{Gen_i} \right) \quad (B.208)$$

$$L_{ReH.SF.Stn} = \sum_{i=1}^6 \left(L_{ReH.SF_i} Frac_{Gen_i} \right) \quad (B.209)$$

$$P_{BP.Targ.Stn} = \sum_{i=1}^6 \left(P_{BP.Targ_i}^{FracGen_i} \right) \quad (B.210)$$

$$P_{BP.Act.Stn} = \sum_{i=1}^6 \left(P_{Cond_i}^{FracGen_i} \right) \quad (B.211)$$

$$L_{BP.SF.Stn} = \sum_{i=1}^6 \left(L_{BP.SF_i}^{FracGen_i} \right) \quad (B.212)$$

$$L_{Turb.Det.Stn} = \sum_{i=1}^6 \left(L_{Det.Turb_i}^{FracGen_i} \right) \quad (B.213)$$

$$T_{FW.Targ.Stn} = \sum_{i=1}^6 \left(T_{FW.Targ_i}^{FracGen_i} \right) \quad (B.214)$$

$$T_{FW.Act.Stn} = \sum_{i=1}^6 \left(T_{FW.Act_i}^{FracGen_i} \right) \quad (B.215)$$

$$L_{FW.SF.Stn} = \sum_{i=1}^6 \left(L_{FW.SF_i}^{FracGen_i} \right) \quad (B.216)$$

$$L_{Tot.Turb.SF.Stn} = L_{ReH.SF.Stn} + L_{MS.SF.Stn} + L_{BP.SF.Stn} + L_{Turb.Det.Stn} + L_{FW.SF.Stn} \quad (B.217)$$

$$L_{MU.Targ.Stn} = \sum_{i=1}^6 \left(L_{MU.Targ_i}^{FracGen_i} \right) \quad (B.218)$$

$$L_{MU.Act.Stn} = \sum_{i=1}^6 \left(L_{MU.Act_i}^{Frac_{Gen_i}} \right) \quad (B.219)$$

$$R_{Q.MU.Stn} = \sum_{i=1}^6 \left(R_{Q.MU_i}^{Frac_{Gen_i}} \right) \quad (B.220)$$

$$L_{MU.SF.Stn} = \left(L_{MU.Act.Stn} - L_{MU.Targ.Stn} \right) R_{Q.MU.Stn}^{100} \quad (B.221)$$

$$Fract_{AuxPower.Act.Stn} = \sum_{i=1}^6 \left(Fract_{AuxPower.Act_i}^{Frac_{Gen_i}} \right) \quad (B.222)$$

$$Fract_{AuxPower.Targ.Stn} = \sum_{i=1}^6 \left(Fract_{AuxPower.Targ_i}^{Frac_{Gen_i}} \right) \quad (B.223)$$

$$L_{AuxPower.SF.Stn} = Fract_{AuxPower.Act.Stn} - Fract_{AuxPower.Targ.Stn} \quad (B.224)$$

$$HR_{Incr.Act.Stn} = \sum_{i=1}^6 \left(HR_{Incr.Act_i}^{Frac_{Gen_i}} \right) \quad (B.225)$$

$$HR_{Incr.MCR.Act.Stn} = \sum_{i=1}^6 \left(HR_{Incr.MCR.Act_i}^{Frac_{Gen_i}} \right) \quad (B.226)$$

$$Cost_{Q.Incr} = \frac{Cost_{Coal.Incremental}}{CV_{Coal}} \quad (B.227)$$

$$Cost_{L_i} = \frac{\frac{Q_{Tot.Targ_i}}{GWh} \frac{Cost_{Q.Incr}}{\frac{c}{kWh}}}{\frac{L_{U.SF.derived_i}}{\%}} 100 \quad (B.228)$$

$$Cost_{L.MS_i} = \frac{L_{MS.SF_i}}{\%} Cost_{L_i} Frac_{Gen_i} \quad (B.229)$$

$$Cost_{L.ReH_i} = \frac{L_{ReH.SF_i}}{\%} Cost_{L_i} Frac_{Gen_i} \quad (B.230)$$

$$Cost_{L.BP_i} = \frac{L_{BP.SF_i}}{\%} Cost_{L_i} Frac_{Gen_i} \quad (B.231)$$

$$Cost_{L.Det.Turb_i} = \frac{L_{Det.Turb_i}}{\%} Cost_{L_i} Frac_{Gen_i} \quad (B.232)$$

$$Cost_{L.FW_i} = \frac{L_{FW.SF_i}}{\%} Cost_{L_i} Frac_{Gen_i} \quad (B.233)$$

$$Cost_{L.Turb_i} = Cost_{L.FW_i} + Cost_{L.Det.Turb_i} + Cost_{L.BP_i} + Cost_{L.MS_i} + Cost_{L.ReH_i} \quad (B.234)$$

$$Cost_{L.MU_i} = \frac{L_{MU.SF_i}}{\%} Cost_{L_i} Frac_{Gen_i} \quad (B.235)$$

$$Cost_{L.AuxPower_i} = \frac{L_{AuxPower.SF_i}}{\%} Cost_{L_i} Frac_{Gen_i} \quad (B.236)$$

$$Cost_{L.CIR_i} = \frac{L_{CIR.SF_i}}{\%} Cost_{L_i} Frac_{Tot.Stm_i} \quad (B.237)$$

$$Cost_{L.DFL_i} = \frac{L_{DFG.SF_i}}{\%} Cost_{L_i} Frac_{Tot.Stm_i} \quad (B.238)$$

$$Cost_{L.H2_Moist_i} = \frac{L_{H2_Moist.SF_i}}{\%} Cost_{L_i} Frac_{Tot.Stm_i} \quad (B.239)$$

$$Cost_{L.Boil_i} = Cost_{L.H2_Moist_i} + Cost_{L.DFL_i} + Cost_{L.CIR_i} \quad (B.240)$$

$$\eta_{Indirect.Act.Boil_i} = 1 - L_{Tot.Boil.Act_i} \quad (B.241)$$

$$\eta_{Indirect.Targ.Boil_i} = 1 - L_{Tot.Boil.Targ_i} \quad (B.242)$$

$$\eta_{Indirect.Var..Boil_i} = \eta_{Indirect.Act.Boil_i} - \eta_{Indirect.Targ.Boil_i} \quad (B.243)$$

$$\begin{aligned} \eta_{Load.AT.Boil_i} = & \left[\frac{L_{Boil_i}}{\%} \right]^4 - \left[\frac{L_{Boil_i}}{\%} \right]^3 \dots \\ & + \left[\frac{L_{Boil_i}}{\%} \right]^2 \dots \\ & + \frac{L_{Boil_i}}{\%} + \dots \end{aligned} \quad (B.244)$$

$$Cost_{L.Tot_i} = Cost_{L.AuxPower_i} + Cost_{L.MU_i} + Cost_{L.Turb_i} + Cost_{L.Boil_i} \quad (B.245)$$

$$J_{EFPs.Targ.Stn} = \sum_{i=1}^6 J_{EFPs.Targ_i} \quad (B.246)$$

$$Q_{Tot.Targ.Stn} = \sum_{i=1}^6 Q_{Tot.Targ_i} + Q_{Comm.Str} \quad (B.247)$$

$$T_{Sat.Cond_i} = \left[\begin{aligned} & \left(\frac{P_{Cond_i}}{kPa} \right)^4 + \left(\frac{P_{Cond_i}}{kPa} \right)^3 + \left(\frac{P_{Cond_i}}{kPa} \right)^2 \dots \\ & + \frac{P_{Cond_i}}{kPa} + \end{aligned} \right] ^\circ C \quad (B.248)$$

$$T_{Depres.Cond_i} = T_{Cond_i} - T_{Sat.Cond_i} \quad (B.249)$$

$$T_{rise.ACC_i} = T_{ACC.Air.Out_i} - T_{ACC.Air.In_i} \quad (B.250)$$

$$J_{Cap.Stn} = \sum_{i=1}^6 \left(Pow_{Cap.LV_i}^{CF_{Amb_i}} t_{RT.Gen_i} \right) \quad (B.251)$$

$$Q_{Coal} = \frac{\frac{m_{Coal.Stn}}{tonne} \frac{CV_{Coal}}{\frac{MJ}{kg}}}{36 \left(100 - \frac{x_{EM.Coal}}{\%} \right)} GWh \quad (B.252)$$

$$Q_{FO} = m_{FO.Stn} CV_{FO.Std} \quad (B.253)$$

$$Q_{FO} = \text{ } \times \text{ } GWh \quad (B.254)$$

$$HR_{Act.Stn} = \frac{Q_{Stn.In}}{J_{USO.Stn} + J_{AuxPower.Offload.Str}} \quad (B.255)$$

$$\eta_{overall} = \frac{1}{HR_{Act.Stn}} \quad (B.256)$$

$$HR_{Targ.Stn} = \frac{Q_{Tot.Targ.Stn}}{J_{USO.Stn} + J_{AuxPower.Offload.Str}} \quad (B.257)$$

$$SF_{Direct.Stn} = \frac{HR_{Targ.Stn}}{HR_{Act.Stn}} \quad (B.258)$$

$$L_{Acc.Stn} = L_{Boil.SF.Stn} + L_{Tot.Turb.SF.Stn} + L_{MU.SF.Stn} + L_{AuxPower.SF.Stn} \quad (B.259)$$

$$SF_{Indirect.Stn} = 1 - L_{Acc.Stn} \quad (B.260)$$

$$L_{SF.equiv.Stn} = 1 - SF_{Direct.Stn} \quad (B.261)$$

$$L_{Unacc.Stn} = L_{SF.equiv.Stn} - L_{Acc.Stn} \quad (B.262)$$

$$Cost_{Coal_USO} = \frac{m_{Coal.Stn} Cost_{Coal_Ton}}{J_{USO.Stn}} \quad (B.263)$$

$$Cost_{FO_USO} = \frac{m_{FO.Stn} Cost_{FO_ton}}{J_{USO.Stn}} \quad (B.264)$$

$$Cost_{Fuel_USO} = Cost_{Coal_USO} + Cost_{FO_USC} \quad (B.265)$$

$$Cost_{Q.Incr} = \frac{Cost_{Coal.Incremental}}{CV_{Coal}} \quad (B.266)$$

$$Cost_{Q.Incr_USO} = Cost_{Q.Incr}^{HR} Incr.Act.Stn \quad (B.267)$$

$$P'_{Cap.Installed.USO.Stn} = \sum_{i=1}^6 P'_{Cap.Installed.USO}_i \quad (B.268)$$

$$m'_{Coal.Stn} = \frac{m_{Coal.Stn}^{SF_{Direct.Stn}}}{J_{USO.Stn}(1 - L_{Acc.Stn} - L_{Unacc.prev.month.Stn})} \quad (B.269)$$

$$L_{FStd.USO.Stn} = \frac{J_{USO.Stn} + J_{AuxPower.Offload.Str}}{P'_{Cap.Installed.USO.Stn} \uparrow hr_month} \quad (B.270)$$

$$Fract_{AuxPower.min.ACC.Stn} = \sum_{i=1}^6 \left(Fract_{AuxPower.min.ACC}_i^{Fract_{Gen}_i} \right) \quad (B.271)$$

$$CF_{AuxPower.Stn} = \frac{\left(1 + Fract_{AuxPower.Targ.Stn} \right) - \frac{J_{EFPs.Targ.Stn}}{J_{USO.Stn}}}{1 + Fract_{AuxPower.min.ACC.Stn}} \quad (B.272)$$

$$L_{FSby.Stn} = \frac{J_{USO.Stn}}{J_{Sby.Stn}} \quad (B.273)$$

$$L_{FAP.SO.Stn} = \frac{J_{USO.Stn} + J_{AuxPower.Offload.Str}}{P'_{Cap.Installed.USO.Stn} \uparrow Gen.Stn} \quad (B.274)$$

$$Litre_USO_{RW} = \frac{V_{RW.Stn}}{J_{USO.Stn}} \quad (B.275)$$

$$Litre_USO_{WW} = \frac{V_{WW.Stn}}{J_{USO.Stn}} \quad (B.276)$$

$$Cost_{L.Stn} = \frac{Q_{Tot.Targ.Stn} Cost_{Q.Incr}}{SF_{Direct.Stn}} \quad (B.277)$$

$$Cost_{CIR.Stn} = L_{CIR.SF.Stn} Cost_{L.Stn} \quad (B.278)$$

$$Cost_{CIR.Stn} = L_{CIR.SF.Stn} Cost_{L.Stn} \quad (B.279)$$

$$Cost_{H2_Moist.Stn} = L_{H2_Moist.SF.Stn} Cost_{L.Stn} \quad (B.280)$$

$$Cost_{Boil.Stn} = Cost_{H2_Moist.Stn} + Cost_{DFG.Stn} + Cost_{CIR.Stn} \quad (B.281)$$

$$Cost_{MSt.Stn} = L_{MS.SF.Stn} Cost_{L.Stn} \quad (B.282)$$

$$Cost_{Turb.Det.Stn} = L_{Turb.Det.Stn} Cost_{L.Stn} \quad (B.283)$$

$$Cost_{BP.Stn} = L_{BP.SF.Stn} Cost_{L.Stn} \quad (B.284)$$

$$Cost_{ReH.Stn} = L_{ReH.SF.Stn} Cost_{L.Stn} \quad (B.285)$$

$$Cost_{FW.Stn} = L_{FW.SF.Stn} Cost_{L.Stn} \quad (B.286)$$

$$Cost_{Turb.Stn} = Cost_{FW.Stn} + Cost_{ReH.Stn} + Cost_{BP.Stn} + Cost_{Turb.Det.Stn} + Cost_{MSt.Stn} \quad (B.287)$$

$$Cost_{MU.Stn} = L_{MU.SF.Stn} Cost_{L.Stn} \quad (B.288)$$

$$Cost_{AuxPower.Stn} = L_{AuxPower.SF.Stn} Cost_{L.Stn} \quad (B.289)$$

$$Cost_{Acc.L.Stn} = Cost_{AuxPower.Stn} + Cost_{MU.Stn} + Cost_{Turb.Stn} + Cost_{Boil.Stn} \quad (B.290)$$

$$Cost_{SF.Equiv.Stn} = L_{SF.equiv.Stn} Cost_{L.Stn} \quad (B.291)$$

$$Cost_{Unnacc.L.Stn} = Cost_{SF.Equiv.Stn} - Cost_{Acc.L.Stn} \quad (B.292)$$

$$F_{AuxPower.Offload.Stn} = \frac{J_{AuxPower.Offload.Stn}}{J_{USO.Stn} + J_{AuxPower.Offload.Stn}} \quad (B.293)$$

$$CV_{Adj.EM} = \frac{CV_{Coal}}{1 - x_{EM.Coal}} \quad (B.294)$$

$$CV_{MF} = \frac{CV_{Coal}}{1 - x_{TM.Coal}} \quad (B.295)$$

$$Q_{Adj.Gen.Stn} = CV_{Adj.EM} m_{Coal.Stn} + m_{FO.Stn} CV_{FO.Stn} \quad (B.296)$$

$$HR_{Stn} = \frac{Q_{Adj.Gen.Stn}}{J_{USO.Stn}} \quad (B.297)$$

$$\eta_{Stn} = \frac{1}{HR_{Stn}} \quad (B.298)$$

$$\eta_{Boil.Stn} = 1 - L_{Boil.Act.Stn} \quad (B.299)$$

$$L_{Boil.SF.Stn} = L_{Boil.SF.Str} \quad (B.300)$$

$$BR_{Stn} = \frac{m_{Coal.Stn}}{J_{USO.Stn}} \quad (B.301)$$

$$Q_{Tot.TurbTarg.Stn} = \sum_{i=1}^6 \left(Q_{Cons.AT_i}^{CF_{PF_i}} CF_{BP.Targ_i} \right) \quad (B.302)$$

$$\eta_{Turb.Stn} = \frac{J_{Gen.HV.Stn}}{Q_{Tot.TurbTarg.Stn}} (1 - L_{Tot.Turb.SF.Stn}) \quad (B.303)$$

$$Ratio_{MU_Stm.Stn} = \frac{\frac{V_{MU.Stn}}{I}}{\frac{m_{Stm.Stn}}{kg}} \quad (B.304)$$

$$Fract_{AuxPower.Stn} = \frac{J_{AuxPower.Stn}}{J_{USO.Stn}} \quad (B.305)$$

$$LF_{Sby} = \frac{J_{USO.Stn}}{J_{Sby.Stn}} \quad (B.306)$$

$$LF_{Max.Demand} = \frac{J_{USO.Stn}}{t_{hr_month}^{USO_{Max.Stn}}} \quad (B.307)$$

$$LF_{Running.Stn} = \frac{J_{Gen.HV.Stn}}{J_{Cap.Stn}} \quad (B.308)$$

$$LF_{USO.Stn} = \frac{J_{USO.Stn}}{P'_{Cap.Installed.USO.Stn} t_{hr_month}} \quad (B.309)$$

$$EUF_{Stn} = \frac{L^{FUSO.Stn}}{EAF_{Stn}} \quad (B.310)$$

Appendix C. Model uncertainty analysis

Note: For most of this section STEP is compared with the BSEN12952-15:2003 [15]. Even though the total boiler heat input includes the energy of the combustion air and atomizing steam, it is omitted when calculating the heat loss percentages so that the comparison is done on the same base as STEP so that key differences can be appreciated and attributed to the methodology. Hence the losses in MJ per kg coal-fired are divided only by the CV of coal.

C.1. Carbon in refuse as per STEP [34]

$$\text{Case: } CV_{Coal} = 18.780 \frac{MJ}{kg} \quad CV_C = 33.820 \frac{MJ}{kg} \quad x_{Ash.Coal} = 0.309 \quad \eta_{FA} = 0.950 \quad x_{C.FA} = 0.016$$

$$x_{C.BA} = 0.028$$

From equation (B.27)

$$x_{CIR} = \eta_{FA} x_{C.FA} + (1 - \eta_{FA}) x_{C.BA} = 0.017 \quad (C.1)$$

The equation below is also derived from 1st principles mass balance at a higher level.

$$x_{CIR} = \frac{x_{Cu}}{x_{Cu} + x_{Ash.Coal}} \quad (C.2)$$

Then solving for x_{Cu} , we derive equation (B.33):

$$x_{Cu} = \frac{x_{CIR} x_{Ash.Coal}}{(1 - x_{CIR})} = 0.005 \quad (C.3)$$

Simplifying equation (B.42), we get:

$$L_{CIR.Act} = \frac{x_{Cu} CV_C}{CV_{Coal}} = 0.940 \% \quad (C.4)$$

or in energy per kg coal-fired:

$$L_{CIR.Act} = x_{Cu} CV_C = 0.177 \frac{MJ}{kg \text{ Coal}_{fired}} \quad (C.5)$$

C.2. Carbon in refuse as per BS EN standard [15]

Case: $x_{TM.Coal} = 0.07$ $x_{VM.Ash} = 0.05$ $\eta_{BA} = 0.050$ $T_{ref} = 25\text{ }^{\circ}\text{C}$ $C_{p.FA} = 0.840 \frac{\text{kJ}}{\text{kg K}}$ $T_{FA} = 130\text{ }^{\circ}\text{C}$

$$T_{BA} = 790\text{ }^{\circ}\text{C} \quad C_{p.BA} = 1.000 \frac{\text{kJ}}{\text{kg K}} \quad C_{p.FA} = 0.840 \frac{\text{kJ}}{\text{kg K}}$$

$$h_{BA} = C_{p.BA} (T_{BA} - T_{ref}) + x_{C.BA} CV_C = 1.712 \frac{\text{MJ}}{\text{kg}} \quad (\text{C.6})$$

$$h_{FA} = C_{p.FA} (T_{FA} - T_{ref}) + x_{C.FA} CV_C = 0.629 \frac{\text{MJ}}{\text{kg}} \quad (\text{C.7})$$

$$x_{Cu} = \frac{x_{Ash.Coal} (1 - x_{VM.Ash})}{1 - x_{Ash.Coal} - x_{TM.Coal}} \left(\frac{x_{C.BA}}{1 - x_{C.BA}} \eta_{BA} + \frac{x_{C.FA}}{1 - x_{C.FA}} \eta_{FA} \right) = 0.008 \quad (\text{C.8})$$

$$L_{CIR.Act} = \frac{x_{Ash.Coal} (1 - x_{VM.Ash})}{1 - x_{Cu}} \left(\frac{\eta_{BA}}{1 - x_{C.BA}} h_{BA} + \frac{\eta_{FA}}{1 - x_{C.FA}} h_{FA} \right) = 0.206 \frac{\text{MJ}}{\text{kg Coal}_{fired}} \quad (\text{C.9})$$

or as the percentage of the energy fired:

$$L_{CIR.Act} = \frac{\frac{x_{Ash.Coal} (1 - x_{VM.Ash})}{1 - x_{Cu}} \left(\frac{\eta_{BA}}{1 - x_{C.BA}} h_{BA} + \frac{\eta_{FA}}{1 - x_{C.FA}} h_{FA} \right)}{CV_{Coal}} = 1.097\% \quad (\text{C.10})$$

C.3. Carbon monoxide loss as per BS EN 12952-15 [15]

Case: $CV_{CO} = 12.633 \frac{\text{MJ}}{\text{m}^3}$ $y_{CO.DFG} = \frac{200}{1000000} \frac{\text{m}^3}{\text{m}^3}$ $\rho_{DFG} = 0.747 \frac{\text{kg}}{\text{m}^3}$ $DFG = 9.455 \frac{\text{kg}}{\text{kg Coal}_{fired}}$

$$V_{DFG} = \frac{DFG}{\rho_{DFG}} = 12.657 \frac{\text{m}^3}{\text{kg Coal}_{fired}} \quad (\text{C.11})$$

$$L_{CO.Act} = V_{DFG} y_{CO.DFG} CV_{CO} = 0.032 \frac{\text{MJ}}{\text{kg Coal}_{fired}} \quad (\text{C.12})$$

Or

$$L_{CO.Act} = \frac{V_{DFG} y_{CO.DFG} CV_{CO}}{CV_{Coal}} = 0.170\% \quad (\text{C.13})$$

C.4. Dry Flue Gas (DFG) loss as per STEP [34]

Case: $x_{H.Coal} = 0.031$ $x_{C.Coal} = 0.4682$ $x_{S.Coal} = 0.005$ $y_{O2.AH.Out} = 0.051$ $T_{Gas.AH.Out} = 403.65K$

$$T_{Air.FD.In} = 308.65K \quad C_{p.DFG} = 1.009 \frac{kJ}{kg \cdot K}$$

$$Ce = \frac{x_{C.Coal}}{\%} - \left(\frac{\frac{x_{CIR}}{\%} CV_{Coal}}{33820 \frac{kJ}{kg}} \right) + \left(0.375 \frac{x_{S.Coal}}{\%} \right) = 46.236 \quad (C.13)$$

$$k = \blacksquare - \left(\blacksquare \frac{x_{C.Coal}}{\%} \right) + \left(\blacksquare \frac{x_{VM.Coal}}{\%} \right) = 2.586 \quad (C.14)$$

$$y_{CO2.AH.Out} = \frac{21 - \frac{y_{O2.AH.Out}}{\%}}{1 + \frac{\left(2.37 \frac{x_{H.Coal}}{\%} \right) + 0.375 \frac{x_{VM.Coal}}{\%} - k}{Ce}} \% = 0.124 \quad (C.15)$$

$$y_{N2.AH.Out} = 1 - y_{CO2.AH.Out} - y_{O2.AH.Out} = 0.825 \quad (C.16)$$

The calculations above aim to estimate the volume fraction of CO₂ and N₂ on a dry basis, by an approximated molar balance relative to the O₂ depleted from the air, where:

Ce - Carbon Equivalent

k - Empirical constant relating to N₂ and O₂ content in coal (not referenced in [34]). It is assumed that this term is synonymous with the $x_{N,O.Coal}$ as mentioned on page 42 [15].

$$DFC = \frac{11 y_{CO2.AH.Out} + 8 y_{O2.AH.Out} + 7 y_{N2.AH.Out}}{3 y_{CO2.AH.Out}} = 20.275 \frac{kg}{kg C_{fired}} \quad (C.17)$$

DFC - Flue gas mass ratio to 1kg of carbon burned

$$DFG = DFC \left(x_{C.Coal} - x_{Cu} + \frac{x_{S.Coal}}{2.67} \right) = 9.399 \frac{kg}{kg Coal_{fired}} \quad (C.18)$$

DFG - Flue gas mass ratio to 1kg of coal-fired

$$L_{DFG.Act} = \frac{DFG \ C_{p,DFG} (T_{Gas.AH.Out} - T_{Air.FD.In})}{CV_{Coal}} = 4.797 \% \quad (C.19)$$

$$L_{DFG.Act} = DFG \ C_{p,DFG} (T_{Gas.AH.Out} - T_{Air.FD.In}) = 0.901 \frac{MJ}{kg \ Coal_{fired}} \quad (C.20)$$

C.5. Dry Flue Gas (DFG) loss as per BS 2885 [5]

The dry flue gas loss calculation in STEP is very similar to the method detailed in [5], however, the calculation (C.18) is limited to $y_{CO2.AH.Out}$ being measure by an Orsat apparatus, which typically includes the SO₂ content, otherwise, the term $\frac{x_{S.Coal}}{2.67}$ should be dropped.

Now DFG is calculated differently in molar form, see below:

$$C_{p,FG.mol} = 30.6 \frac{kJ}{kmol \ K} \quad [5] \quad x_{Cu} = 0.005$$

$$DFG = \frac{\left(x_{C.Coal} - x_{Cu} + \frac{x_{S.Coal}}{2.67} \right) \frac{kg}{kg \ Coal_{fired}} 100}{12 \frac{kg}{kmol} \left(\frac{y_{CO2.AH.Out}}{\%} + \frac{y_{CO.DFG}}{\%} \right)} = 0.313 \frac{kmol}{kg \ Coal_{fired}} \quad (C.21)$$

$$L_{DFG.Act} = DFG \ C_{p,FG.mol} (T_{Gas.AH.Out} - T_{Air.FD.In}) = 0.909 \frac{MJ}{kg \ Coal_{fired}} \quad (C.22)$$

$$L_{DFG.Act} = \frac{DFG \ C_{p,FG.mol} (T_{Gas.AH.Out} - T_{Air.FD.In})}{CV_{Coal}} = 4.843 \% \quad (C.23)$$

C.6. Dry Flue Gas (DFG) loss as per BS EN 12952-15 [15]

$$\text{Case: } x_{VM.Ash} = 0.05 \quad y_{CO2.DA} = 0.0003\% \quad y_{O2.DA} = 0.2093\% \quad \rho_{DA.STP} = 1.293 \frac{kg}{m^3}$$

$$x_{CO2.DA} = 0.00050\% \quad y_{O2.AH.Out} = 0.051 \quad x_{N2.DA} = 0.75\% \quad x_{O2.DA} = 0.231 \quad x_{C.Coal} = 0.468$$

$$x_{H.Coal} = 0.031 \quad x_{S.Coal} = 0.009 \quad M_{NO2} = 46.010 \frac{kg}{kmol} \quad M_{SO2} = 64.065 \frac{kg}{kmol} \quad M_{CO2} = 44.0098 \frac{kg}{kmol}$$

$$M_{O2} = 32.000 \frac{kg}{kmol} \quad M_N = 14.010 \frac{kg}{kmol} \quad M_S = 32.065 \frac{kg}{kmol} \quad \eta_N = 0.192 \quad \eta_S = 1$$

The BS EN 12952-15 [15] and provides an alternative method of calculating the gas products and heat coefficients i.e. calculating the boiler excess air through an O₂ balance. Stoichiometric

quantities are derived from elemental balances. Properties of air are acquired from DIN 1871 as referenced in [15]. Other chemical properties not stated were acquired from [72].

$$x_{N.Coal} = 0.015(1 - x_{Ash.Coal} - x_{TM.Coal}) = 0.009 \quad (C.24)$$

The nitrogen content of coal is assumed to be 1.5 % on a dry-ash-free basis as per [15]. The calculation above converts to as received/fired basis. The combined nitrogen and oxygen, $x_{N,O.Coal}$ is required. In this case, it is set to be equal to $k = 0.026$ as computed in the STEP dry flue gas loss calculation above.

$$x_{O.Coal} = x_{N,O.Coal} - x_{N.Coal} = 0.017 \quad (C.25)$$

$$\mu_{DA.Stoich} = 11.5122 x_{C.Coal} + 34.2974 x_{H.Coal} \dots = 6.421 \frac{kg}{kg \text{ Coal}_{fired}} + 4.3129 x_{S.Coal} - 4.3212 x_{O.Coal} \quad (C.26)$$

$$V_{DFG.Stoich} = \left(\begin{array}{l} 8.8930 x_{C.Coal} + 20.9724 x_{H.Coal} \dots \\ + 3.319 x_{S.Coal} - 2.6424 x_{O.Coal} \dots \\ + 0.7997 x_{N.Coal} \end{array} \right) \frac{m^3}{kg} = 4.807 \frac{m^3}{kg \text{ Coal}_{fired}} \quad (C.27)$$

$$\mu_{CO2.Stoich} = 3.6699 x_{C.Coal} + 0.0173 x_{H.Coal} \dots = 1.719 \frac{kg}{kg \text{ Coal}_{fired}} + 0.0022 x_{S.Coal} - 0.0022 x_{O.Coal} \quad (C.28)$$

$$\mu_{CO2} = \mu_{CO2.Stoich} \dots = 1.720 \frac{kg}{kg \text{ Coal}_{fired}} + \rho_{DA.STP} V_{DFG.Stoich} \frac{y_{O2.AH.Out}}{y_{O2.DA} - y_{O2.AH.Out}} x_{CO2.DA} \quad (C.29)$$

$$\mu_{DA} = \mu_{DA.Stoich} \dots = 8.422 \frac{kg}{kg \text{ Coal}_{fired}} + \rho_{DA.STP} V_{DFG.Stoich} \frac{y_{O2.AH.Out}}{y_{O2.DA} - y_{O2.AH.Out}} \quad (C.30)$$

$$\mu_{DA} = \mu_{DA.Stoich} \dots = 8.422 \frac{kg}{kg \text{ Coal}_{fired}} + \rho_{DA.STP} V_{DFG.Stoich} \frac{y_{O2.AH.Out}}{y_{O2.DA} - y_{O2.AH.Out}} \quad (C.31)$$

$$\mu_{N2} = \mu_{DA.Stoich} x_{N2.DA} \dots = 6.367 \frac{kg}{kg \text{ Coal}_{fired}} + \rho_{DA.STP} V_{DFG.Stoich} \frac{y_{O2.AH.Out}}{y_{O2.DA} - y_{O2.AH.Out}} x_{N2.DA} \quad (C.32)$$

$$\mu_{O2} = \rho_{DA.STP} V_{DFG.Stoich} \frac{y_{O2.AH.Out}}{y_{O2.DA} - y_{O2.AH.Out}} x_{O2.DA} = 0.462 \frac{kg}{kg \text{ Coal_fired}} \quad (C.33)$$

$$\mu_{NO2} = x_{N.Coal} \eta_N \frac{M_{NO2}}{M_N} = 0.006 \frac{kg}{kg \text{ Coal_fired}} \quad (C.34)$$

$$\mu_{SO2} = x_{S.Coal} \eta_S \frac{M_{SO2}}{M_S} = 0.018 \frac{kg}{kg \text{ Coal_fired}} \quad (C.35)$$

η_N , η_S - Nitrogen and sulphur conversions are assumed for wall-fired boilers. The nitrogen converted is approximated to 100% nitrogen dioxide and sulphur to 100% sulphur dioxide.

$$\mu_{DFG} = \mu_{SO2} + \mu_{NO2} + \mu_{N2} + \mu_{CO2} + \mu_{O2} = 8.573 \frac{kg}{kg \text{ Coal_fired}} \quad (C.36)$$

For coal-fired boilers, other combustion products are negligible, then:

$$y_{CO2} = \frac{\frac{\mu_{CO2}}{M_{CO2}}}{\frac{\mu_{CO2}}{M_{CO2}} + \frac{\mu_{SO2}}{M_{SO2}} + \frac{\mu_{N2}}{M_{N2}} + \frac{\mu_{O2}}{M_{O2}} + \frac{\mu_{NO2}}{M_{NO2}}} = 0.139 \quad (C.37)$$

$$x_{CO2} = \frac{\mu_{CO2}}{\mu_{DFG}} = 0.201 \quad (C.38)$$

$$C_{p.DA.0}(T) = 1.004173 + \frac{0.1919210 \cdot 10^{-4}}{2} T + \frac{0.5883483 \cdot 10^{-6}}{3} T^2 \dots \quad (C.39)$$

$$+ \frac{-0.7011184 \cdot 10^{-9}}{4} T^3 + \frac{0.3309525 \cdot 10^{-12}}{5} T^4 \dots$$

$$+ \frac{-0.5673876 \cdot 10^{-16}}{6} T^5$$

The integral heat capacity of dry air relative to 0°C is given by the function above.

$$P_{2m}(T) = -0.1002311 + \frac{0.7661864 \cdot 10^{-3}}{2} T + \frac{-0.9259622 \cdot 10^{-06}}{3} T^2 + \dots$$

$$+ \frac{0.5293496 \cdot 10^{-9}}{4} T^3 + \frac{-0.1093573 \cdot 10^{-12}}{5} T^4$$
(C.40)

The above polynomial function is given in [15] to calculate the heat capacity of flue gas. See below:

$$C_{p.DFG.0}(T) = C_{p.DA.0}(T) + P_{2m}(T) \cdot x_{CO2}$$
(C.41)

$$C_{p.DFG} = \frac{C_{p.DFG.0}\left(\frac{T_{Gas.AH.Out}}{K}\right) \frac{T_{Gas.AH.Out}}{K} - \left(C_{p.DFG.0}\left(\frac{T_{Air.FD.In}}{K}\right) \frac{T_{Air.FD.In}}{K}\right)}{\frac{T_{Gas.AH.Out}}{K} - \frac{T_{Air.FD.In}}{K}} \frac{kJ}{kg \cdot K} = 1.074 \frac{kJ}{kg \cdot K}$$
(C.41)

$$L_{DFG.Act} = \mu_{DFG} C_{p.DFG} (T_{Gas.AH.Out} - T_{Air.FD.In}) = 0.875 \frac{MJ}{kg \text{ Coal}_{fired}}$$
(C.42)

$$L_{DFG.Act} = \frac{\mu_{DFG} C_{p.DFG} (T_{Gas.AH.Out} - T_{Air.FD.In})}{CV_{Coal}} = 4.660 \%$$
(C.43)

C.7. Hydrogen and moisture loss as per BS EN 12952-15 [15]

$$\text{Case: } x_{H2O.Coal} = 0.08 \quad x_{H.Coal} = 0.031 \quad \mu_{DA} = 8.422 \quad w = 0.013 \quad \mu_{AS} = 0$$

$$T_{Gas.AH.Out} = 403.650K \quad T_{Air.FD.In} = 298K$$

$$\mu_{H2O.Fuel} = x_{H2O.Coal} + 8.937 x_{H.Coal} = 0.357$$
(C.44)

$$\mu_{H2O} = \mu_{H2O.Fuel} + \mu_{DA} w + \mu_{AS} = 0.357$$
(C.45)

$$h_{H2O.FG} = h_{steam}(1bar, T_{Gas.AH.Out}, "", "", "") = 2737.718 \frac{kJ}{kg}$$
... from steam tables

$$h_{H2O.Tref.liquid} = h_{steam}(1.bar, T_{Air.FD.In}, "", "", "") = 104.301 \frac{kJ}{kg}$$
...from steam tables

$$h_{H2O.Tref.Gas} = h_{steam}("", T_{Air.FD.In}, "", 1, "") = 2546.272 \frac{kJ}{kg}$$
... from steam tables

$$L_{H2O} = \mu_{H2O} (h_{H2O.FG} - h_{H2O.Tref.Gas}) = 0.089 \frac{MJ}{kg \text{ Coal}_{fired}}$$
(C.46)

$$L_{H2O} = \frac{\mu_{H2O} (h_{H2O.FG} - h_{H2O.Tref.Gas})}{CV_{Coal}} = 0.476\%$$
(C.47)

It can be deduced from the term μ_{H_2O} , the fuel moisture is assumed to be in a gaseous phase hence combined with the moisture in combustion air and atomizing steam to determine only the sensible heat losses. This would not apply to solid fuels. The calculations below will individually compute the moisture in fuel loss and the moisture in combustion air which is congruent with BS 2885-19974 [5]. The reference enthalpy for moisture in fuel loss will be considered in the liquid phase.

$$L_{H_2O.Moist_Air} = \mu_{DA} w (h_{H_2O.FG} - h_{H_2O.Tref.Gas}) = 0.021 \frac{MJ}{kg \text{ Coal_fired}} \quad (C.48)$$

$$L_{H_2O.Moist_Air} = \frac{\mu_{DA} w (h_{H_2O.FG} - h_{H_2O.Tref.Gas})}{CV_{Coal}} = 0.112\% \quad (C.49)$$

$$L_{H_2O.Fuel} = \mu_{H_2O.Fuel} (h_{H_2O.FG} - h_{H_2O.Tref.liquid}) = 0.940 \frac{MJ}{kg \text{ Coal_fired}} \quad (C.50)$$

$$L_{H_2O.Fuel} = \frac{\mu_{H_2O.Fuel} (h_{H_2O.FG} - h_{H_2O.Tref.liquid})}{CV_{Coal}} = 5.007\% \quad (C.51)$$

C.8. Hydrogen and moisture loss as per STEP [34]

$$\text{Case: } x_{H_2O.Coal} = 0.08 \quad x_{H.Coal} = 0.031 \quad T_{Gas.AH.Out} = 403.650K \quad T_{Air.FD.In} = 298K$$

$$k_{L.H_Moisture.1} = \blacksquare \quad k_{L.H_Moisture.2} = \blacksquare$$

$$L_{H_Moist.Act} = \frac{\frac{x_{TM.Coal}}{\%} + \left(9 \frac{x_{H.Coal}}{\%}\right)}{\frac{CV_{Coal}}{\frac{MJ}{kg}}} \left[\frac{k_{L.H_Moisture.1} \dots}{\left(\frac{T_{Gas.AH.Out}/^{\circ}C}{2} - T_{Air.FD.In}/^{\circ}C \right)} + \left(\frac{1}{k_{L.H_Moisture.2}} \right) \right] \% = 4.897\% \quad (C.52)$$

The origins of the above equation cannot be traced back to the BS 2885 [5], however $K_{L.H_Moist1}$ is the latent heat of water (MJ/kg) and $K_{L.H_Moist2}$ is the inverse of the heat capacity of liquid water (K.kg/MJ). So it is simplified that the fuel moisture would absorb sensible heat in the liquid phase to the midpoint between $T_{Gas.AH.Out}$ and $T_{Air.Fd.In}$, thereafter in the form of latent. The sensible heat absorbed in the gas phase is ignored.

C.9. Make-Up Water [34]

Case: $V_{MU.Stn} = 108128000 \text{ L}$ $J_{USO.Stn} = 477.966 \text{ GWh}$ $V_{MU.Other} = 103.518 \text{ ML}$ $V_{MU} = 4610 \text{ ML}$
 $V_{MU.Cold} = 20 \text{ ML}$ $Frac_{MU.Targ} = 1\%$ $m_{Stm.Boil} = 145000000000 \text{ kg}$ $LF_{USO} = 70\%$ $\eta_{Boil} = 0.9$
 $Frac_{Gen} = 1$ $m'_{ReH.in} = 626 \frac{\text{kg}}{\text{s}}$ $m'_{MS} = 630 \frac{\text{kg}}{\text{s}}$ $h_{RW} = 104.913 \frac{\text{kJ}}{\text{kg}}$ $h_{MS} = 3381.453 \frac{\text{kJ}}{\text{kg}}$
 $h_{FW} = 1148.252 \frac{\text{kJ}}{\text{kg}}$ $h_{ReH.Out} = 3601.370 \frac{\text{kJ}}{\text{kg}}$ $h_{ReH.in} = 3003.550 \frac{\text{kJ}}{\text{kg}}$

$$\Delta h_{Boil} = h_{MS} - h_{FW} + \frac{m'_{ReH.in}}{m'_{MS}} (h_{ReH.Out} - h_{ReH.in}) = 2827.225 \frac{\text{kJ}}{\text{kg}} \quad (C.53)$$

In the above calculation, Δh_{Boil} is the total heat absorbed per kg steam produced by the boiler.

$$R_{Q.MU} = \frac{\frac{2}{3} h_{MS} + \frac{1}{3} h_{FW} - h_{RW}}{\frac{\Delta h_{Boil}}{\eta_{Boil}} \cdot 100} = 0.008 \quad (C.54)$$

where $R_{Q.MU}$ is the make-up heat ratio which can also be expressed as:

$$R_{Q.MU} = \frac{\text{Heat of 1kg water lost}}{\text{Energy required for 1kg steam produced}} \times \frac{1}{100}$$

Therefore in generalized form:

$$L_{MU} = \left(\frac{\text{Heat of 1kg water lost}}{\text{Energy required for 1kg steam produced}} \times \frac{1}{100} \right) \times \underbrace{\left(\frac{m_{MU}}{m_{Steam}} \times \frac{100}{1} \right)}_{Frac_{MU} (\%)}$$

Then:

$$L_{MU.design} = R_{Q.MU} \frac{Frac_{MU.Targ}}{\%} = 0.806 \% \quad (C.55)$$

$$F_{MU.Est} = -3.4643 \cdot 10^{-8} \left(\frac{LF_{USO}}{\%} \right)^4 + 8.231 \cdot 10^{-6} \left(\frac{LF_{USO}}{\%} \right)^3 \dots = 1.107 \quad (C.56)$$

$$+ -6.1239 \cdot 10^{-4} \left(\frac{LF_{USO}}{\%} \right)^2 + 8.0326 \cdot 10^{-3} \frac{LF_{USO}}{\%} + 1.554$$

The above factor calculated is a polynomial function to estimate the make-up water to steam raised, mass fraction relative to design conditions at MCR, as a function of the sent out load factor and is specific to a Unit design.

$$CF_{MU.Targ} = \frac{1 - R_{Q.MU} \frac{Frac_{MU.MCR}}{\%}}{1 - R_{Q.MU} \frac{Frac_{MU.MCR}}{\%} F_{MU.Est}} = 1.001 \quad (C.57)$$

The target cycle heat rate correction factor relative to the sent-out load factor is expressed above.

$$L_{MU.Targ} = \frac{Frac_{MU.MCR}}{\%} F_{MU.Est} CF_{MU.Targ} R_{Q.MU} = 0.893 \% \quad (C.58)$$

It can be seen that there is now compensation for changes in efficiency specific to the deviation in the make-up water fraction, $CF_{MU.Targ}$. Initially, the energy input to the cycle was calculated by setting the boiler efficiency to 90% as in calculation(C.49). The correction factor is necessary, for the thermal loss to be normalized to one unit of energy input to the cycle.

$$F_{MU.Hot} = \frac{V_{MU} + (Frac_{Gen} V_{MU.Other}) - V_{MU.Cold}}{m_{Stm.Boil}} = 0.032 \frac{ML}{Gg} \quad (C.59)$$

From the above calculation, it is observed that make-up when the unit is off-load or before synchronization, $V_{MU.Cold}$ is deducted from the total make-up accounted for. This is sensible as this heat is accounted for in the heat for commissioning and should be included in the running unit heat rate calculation. $Frac_{Gen} V_{MU.Other}$ is the means to apportion all other demineralized water flow that is not directly fed to the unit Rankine cycle to an individual unit. This would typically include water used in the auxiliaries cooling loops, hydrogen production and other common plant areas.

In most cases it is difficult to split this flow further into what is recovered to the Rankine cycle typically via the condenser cleans drains tank and what would be lost externally to the Rankine cycle such as the flows to the hydrogen production plant or compressed air supply plants. Each power plant's metering configuration should be carefully analysed to establish if this flow should be considered for thermal losses or a factor should be applied which station-specific is. It is noted that the density of water in the calculation (C.54) is approximated to 1kg/m^3 and is therefore

$F_{MU.Hot}$ approximated to a mass fraction. A sensitivity calculation with a density of 0.997 kg/m³ proved to have a negligible impact on subsequent loss calculations.

$$L_{MU.Act} = \frac{F_{MU.Hot}}{\frac{ML}{Gg} \%} \frac{\left(1 - R_{Q.MU} \frac{Frac_{MU.MCR}}{\%}\right)}{\left(1 - R_{Q.MU} \frac{F_{MU.Hot}}{\frac{ML}{Gg} \%}\right)} R_{Q.MU} = 2.657 \% \quad (C.60)$$

$$L_{MU.SF} = (L_{MU.Act} - L_{MU.Targ}) = 1.764 \% \quad (C.61)$$

Note: In STEP, the term $R_{Q.MU}$ is dropped from calculations (C.54) and (C.55), but added to the calculation (C.56) to give the same effect as the above.

C.10. Radiation and convection loss as per BS EN 12952-15 [15]

$$C = 0.02675 \text{ for bituminous coal} \quad CV_{Coal} = 20.466 \frac{MJ}{kg} \quad m'_{Coal} = 70.665 \frac{kg}{s}$$

$$Q'_{Boil.Out} = 1.363 \times 10^3 \text{ MW@ 97\% MCR design}$$

$$L_{RC} = C \left(\frac{Q'_{Boil.Out}}{MW} \right)^{0.7} \quad MW = 4.183 \text{ MW} \quad (C.62)$$

$$L_{RC} = \frac{L_{RC}}{m'_{Coal} CV_{Coal}} = 0.289\% \quad (C.63)$$

C.11. Radiation loss as per STEP [15]

$$L_{FBoil} = 97\%$$

$$CF_{LF.Boil} = \left[\left(\frac{L_{FBoil}}{\%} \right)^4 + \left(\frac{L_{FBoil}}{\%} \right)^3 + \left(\frac{L_{FBoil}}{\%} \right)^2 + \frac{L_{FBoil}}{\%} + 1 \right] \quad (C.64)$$

$$k_{L.Rad} = \left[\left(\frac{LF_{Boil}}{\%} \right)^4 - \left(\frac{LF_{Boil}}{\%} \right)^3 \right] \dots = 0.551 \quad (C.65)$$

$$+ \left[\left(\frac{LF_{Boil}}{\%} \right)^2 - \frac{LF_{Boil}}{\%} \right] + \dots$$

$$L_{Rad} = \frac{k_{L.Rad}}{\frac{LF_{Boil}}{\%} C_{LF.Boil}} = 0.568\% \quad (C.66)$$

C.12. Turbine deterioration loss as per STEP

$$Det_{Turb.Previous} = 0 \quad F_{Availability} = 0.85 \quad N_{yr} = 10yr$$

$$L_{Det.Turb} = Det_{Turb.Previous} + 0.1 \frac{\%}{yr} N_{yr} F_{Availability} = 0.85\% \quad (C.67)$$

C.13. Turbine deterioration loss as per the IEC [73]

$$k_{1st_year} = 0.1 \quad P = 600MW \quad f = 1 \quad k_{2nd_year} = 0.06 \quad F_{Availability} = 0.85$$

$$Det_{Turb.1st_Year} = k_{1st_year} \sqrt{\frac{150}{\frac{P}{MW}}} f \left(\frac{\%}{month} \right) = 0.05 \frac{\%}{month} \quad (C.68)$$

$$Det_{Turb.2nd_Year} = k_{2nd_year} \sqrt{\frac{150}{\frac{P}{MW}}} f \left(\frac{\%}{month} \right) = 0.03 \frac{\%}{month} \quad (C.69)$$

$$Det_{Turb.120_Month} = (12 Det_{Turb.1st_Year} + 108 Det_{Turb.2nd_Year}) F_{Availability} = 3.264\% \quad (C.70)$$

C.14. Turbine deterioration loss as per ASME PTC 6 Report-1985 [47]

$$BF_{10yrs} = 3.95 \quad \text{Base Factor ...linearly extrapolated from Fig 3.3 [47]}$$

$$Pow = 600MW \quad P = 16.1MPa \quad f = 1.000 \quad \text{for fossil fuels}$$

$$Det_{Turb.10_yrs} = \frac{BF_{10yrs}}{\log\left(\frac{Pow}{MW}\right)} \sqrt{\frac{\frac{P}{psi}}{2400}} f \% = 1.402\% \quad (C.71)$$

Appendix D. STEP program inputs details

Table D- 1: Input variable instrument uncertainty

List no.	Variable	Python Tag reference	Variable Description	Unit	u_i^i	$u_{Literature}$	Function	N_{tx}	Source ⁱⁱ
0	$T_{GAS.LH.AH.OUT_i}$ ⁱⁱⁱ	AH_LH_Gas_Out_T[i]	Left hand air heater outlet temperature	°C	1.604	5.6	Abs	12	[47]
1	$T_{GAS.RH.AH.OUT_i}$	AH_RH_Gas_Out_T[i]	Right hand air heater outlet temperature	°C	1.604	5.6	Abs	12	[47]
2	$T_{Air.LH.FD.In_i}$	FD_LH_AIR_In_T[i]	Left hand forced draught fan air inlet temperature	°C	2.268	5.6	Abs	6	[47]
3	$T_{Air.RH.FD.In_i}$	FD_RH_AIR_In_T[i]	Right hand forced draught fan air inlet temperature	°C	2.268	5.6	Abs	6	[47]
4	$x_{O2.LH.Eco.Out_i}$	AH_LH_Gas_In_O2_x[i]	Left hand air heater inlet oxygen content	% (V/V)	0.212	0.3	Abs	2	[74]
5	$x_{O2.RH.Eco.Out_i}$	AH_RH_Gas_In_O2_x[i]	Right hand air heater inlet oxygen content	% (V/V)	0.212	0.3	Abs	2	[69]
6	$x_{O2.LH.AH.OUT_i}$	AH_LH_Gas_Out_O2_x[i]	Left hand air heater outlet oxygen content	% (V/V)	0.300	0.3	Abs	1	[69]
7	$x_{O2.LH.AH.OUT_i}$	AH_RH_Gas_Out_O2_x[i]	Right hand air heater outlet oxygen content	% (V/V)	0.300	0.3	Abs	1	[69]
8	$t_{RT.boiler_i}$	Boil_Run_hrs[i]	Boiler running hours	hrs	5.000	5.0	%	1	default
9	m_{FW_i}	FW_Tot_Mass[i]	Total feed water delivered to the boiler	Gg	3.200	3.2	%	1	[47]
10	m_{BD_i}	BD_Tot_Mass[i]	Total mass of water blown down	ton	3.200	3.2	%	1	[47]
11	$N_{Starts.0to7hrs_i}$	Boil_Starts_0to7hrs[i]	Number of boiler starts after being offload for 0-7 hours	-	5.000	5.0	%	1	default
12	$t_{Offload 0to7hrs_i}$	Boil_DownTime_0to7hrs[i]	Boiler offload time for periods 0-7 hours	hrs	5.000	5.0	%	1	default
13	$N_{Starts 7to15hrs_i}$	Boil_Starts_7to15hrs[i]	Number of boiler starts after being offload for 7-15 hours	-	5.000	5.0	%	1	default
14	$t_{Offload 7to15hrs_i}$	Boil_DownTime_7to15hrs[i]	Boiler offload time for periods 7-15 hours	hrs	5.000	5.0	%	1	default
15	$N_{Starts 15to24hrs_i}$	Boil_Starts_15to24hrs[i]	Number of boiler starts after being offload for 15-24 hours	-	5.000	5.0	%	1	default
16	$t_{Offload 15to24hrs_i}$	Boil_DownTime_15to24hrs[i]	Boiler offload time for periods 15-24 hours	hrs	5.000	5.0	%	1	default
17	$N_{Starts 24to168hrs_i}$	Boil_Starts_24to168hrs[i]	Number of boiler starts after being offload for 24-168 hours	-	5.000	5.0	%	1	default
18	$t_{Offload 24to168hrs_i}$	Boil_DownTime_24to168hrs[i]	Boiler offload time for periods 24-168 hours	hrs	5.000	5.0	%	1	default

		i]							
19	$t_{Sby.Hot_i}$	HotSby_Time[i]	Period where the boiler is kept on hot standby	hrs	5.000	5.0	%	1	default
20	$N_{Starts.Cold_i}$	Boil_ColdStarts[i]	Boiler cold starts (RTS after being offload for >168 hours)	-	5.000	5.0	%	1	default
21	m_{MR_i}	Mill_Reject_Mass[i]	Mass of mill rejects	ton	5.000	5.0	%	1	default
22	CV_{MR_i}	Mill_Reject_CV[i]	Calorific value of mill rejects	MJ/kg	0.300	0.3	abs	1	[75]
23	$x_{C.FA_i}$	AH_Gas_In_CIR[i]	Air heater gas inlet carbon in ash	% (m/m)	1.000	1.0	%	5	[17]
24	$x_{C.BA_i}$	CoarseAsh_CIR[i]	Boiler bottom carbon in ash	% (m/m)	1.000	1.0	%	200	[17]
25	$t_{RT.Mill.A_i}$	MILL_A_Run_Hrs[i]	Mill “A” running hours	hrs	5.000	5.0	%	1	default
26	$t_{RT.Mill.B_i}$	MILL_B_Run_Hrs[i]	Mill “B” running hours	hrs	5.000	5.0	%	1	default
27	$t_{RT.Mill.C_i}$	MILL_C_Run_Hrs[i]	Mill “C” running hours	hrs	5.000	5.0	%	1	default
28	$t_{RT.Mill.D_i}$	MILL_D_Run_Hrs[i]	Mill “D” running hours	hrs	5.000	5.0	%	1	default
29	$t_{RT.Mill.E_i}$	MILL_E_Run_Hrs[i]	Mill “E” running hours	hrs	5.000	5.0	%	1	default
30	$t_{RT.Mill.F_i}$	MILL_F_Run_Hrs[i]	Mill “F” running hours	hrs	5.000	5.0	%	1	default
31	$J_{Gen.LV.Main_i}$	Gen_LV_Main_J[i]	Energy measured at the generator terminals main meter	GWH	5.000	5.0	%	1	[47] ^{iv}
32	$J_{Gen.LV.Check_i}$	Gen_LV_Check_J[i]	Energy measured at the generator terminals check meter	GWH	5.000	5.0	%	1	[47]
33	$J_{AuxPower.Main_i}$	AuxPower_Main_J[i]	Energy measures at auxiliary power tap-off point main meter	GWH	5.000	5.0	%	1	[47]
34	$J_{AuxPower.Check_i}$	AuxPower_Check_J[i]	Energy measures at auxiliary power tap-off point check meter	GWH	5.000	5.0	%	1	[47]
35	$J_{Gen.>NER_i}$	Gen_AboveNER_J[i]	Energy measured at generator terminals when generating above NER	GWH	5.000	5.0	%	1	[47]
36	$t_{Gen.>NER_i}$	Gen_AboveNER_RT[i]	Time that generator operates above NER	hrs	5.000	5.0	%	1	default
37	$J_{Reactive.Gen_i}$	Gen_Reactive_J[i]	Generator reactive energy	GVARs	5.000	5.0	%	1	[47]
38	$t_{RT.Gen_i}$	Gen_RT[i]	Generator run time (synchronization to separation from the power grid)	Hrs	5.000	5.0	%	1	[47]
39	$J_{Unit.AuxPower.Trip_i}$	AuxPower_Offload_J[i]	Auxiliary power measured when generator not synchronized	GWH	5.000	5.0	%	1	[47]
40	$J_{Unit.AuxPower.SB_i}$	AuxPower_SB_J[i]	Auxiliary power supplied from the station	GWH	5.000	5.0	%	1	[47]

			board						
41	$t_{RT.EFP.A_i}$	A_EFP_RT[i]	Electric feed water pump “A” run time	hrs	5.000	5.0	%	1	default
42	$t_{RT.EFP.B_i}$	B_EFP_RT[i]	Electric feed water pump “B” run time	hrs	5.000	5.0	%	1	default
43	$t_{RT.EFP.C_i}$	C_EFP_RT[i]	Electric feed water pump “C” run time	hrs	5.000	5.0	%	1	default
44	$T_{FW.Act_i}$	Eco_FW_In_T[i]	Economizer feedwater inlet temperature	°C	5.556	5.6	abs	1	[47]
45	$T_{LH.HPT.In_i}$	HPT_LH_MS_In_T[i]	High-pressure turbine left hand inlet temperature	°C	3.928	5.6	abs	2	[47]
46	$T_{RH.HPT.In_i}$	HPT_RH_MS_In_T[i]	High-pressure turbine right hand inlet temperature	°C	3.928	5.6	abs	2	[47]
47	$T_{LH.IPT.In_i}$	IPT_LH_Stm_in_T[i]	Intermediate-pressure turbine left hand inlet temperature	°C	3.928	5.6	abs	2	[47]
48	$T_{RH.IPT.In_i}$	IPT_RH_Stm_in_T[i]	Intermediate-pressure turbine right hand inlet temperature	°C	3.928	5.6	abs	2	[47]
49	$\dot{m}_{HPT.In_i}$	HPT_Stm_In_MFR[i]	High-pressure turbine inlet mass flow rate	kg/s	1.000	1.0	%	1	[47]
50	$P_{HPT.In_i}$	HPT_Stm_In_P[i]	High-pressure turbine inlet pressure	bar	0.250	0.5	%	4	[47]
51	$\dot{m}_{IPT.In_i}$	IPT_Stm_In_MFR[i]	Intermediate-pressure turbine inlet mass flow rate	kg/s	1.000	1.0	%	1	[47]
52	$P_{IPT.In_i}$	IPT_Stm_In_P[i]	Intermediate-pressure turbine inlet pressure	bar	0.250	0.5	%	4	[47]
53	$\dot{m}_{ReH.In_i}$	ReH_Stm_In_MFR[i]	Re-heater inlet mass flow rate	kg/s	1.000	1.0	%	1	[47]
54	$P_{HPT.Out_i}$	HPT_Stm_Out_P[i]	High-pressure turbine outlet pressure	bar	0.354	0.5	%	2	[47]
55	$T_{HPT.Out_i}$	HPT_Stm_Out_T[i]	High-pressure turbine outlet temperature	°C	3.928	5.6	abs	2	[47]
56	$\dot{m}_{ReH.SW_i}$	ReH_SW_MFR[i]	Re-heater spray water mass flow rate	kg/s	1.000	1.0	%	1	[47]
57	$T_{ReH.SW.In_i}$	ReH_SW_T[i]	Re-heater spray water supply temperature	°C	5.556	5.6	abs	1	[47]
58	$t_{RT.CEP.A_i}$	CEP_A_RT[i]	Condensate extraction pump “A” run time	hrs	5.000	5.0	%	1	default
59	$t_{RT.CEP.B_i}$	CEP_B_RT[i]	Condensate extraction pump “B” run time	hrs	5.000	5.0	%	1	default
60	$T_{ACC.Air.In_i}$	ACC_Fan_In_T[i]	Air cooled condenser air inlet temperature	°C	2.778	2.8	abs	1	[47]
61	$T_{ACC.Air.Out_i}$	ACC_Out_T[i]	Air cooled condenser air outlet temperature	°C	2.778	2.8	abs	1	[47]
62	P_{Cond_i}	Cond_Act_P[i]	Condenser actual pressure	kPa	0.354	0.5	%	2	[47]
63	$N_{Start.Hot.Turb_i}$	Turb_HotStart_Num[i]	Number of turbine hot starts	-	5.000	5.0	%	1	default
64	$N_{Start.Cold.Turb_i}$	Turb_ColdStart_Num[i]	Number of turbine cold starts	-	5.000	5.0	%	1	default

65	V_{MU_i}	MU_V[i]	Make up water volume	ML	1.000	1.0	%	1	[47]
66	$V_{MU.Cold_i}$	MU_Cold_V[i]	Make up water volume consumed when unit not synchronized	ML	1.000	1.0	%	1	[47]
67	$Det_{Turb.Previous_i}$	Turb_Previous_Det[i]	Turbine deterioration from previous period	%	0.000	0.0	%	1	n/a
68	T_{Cond_i}	Condensate_T[i]	Condensate temperature	°C	3.928	5.6	abs	2	[47]
69	$Pow_{Cap.Installed.USO_i}$	Capacity_USO_Pow[i]	Unit sent out capacity	MW	0.000	0.0	%	1	n/a
70	$Pow_{Cap.LV_i}$	Capacity_LV_Pow[i]	Unit generating capacity	MW	0.000	0.0	%	1	n/a
71	$J_{Stn1.Main}$	Stn_Tx1_Main_J	Station transformer “1” energy imported measured by the main meter	GWH	5.000	5.0	%	1	[47]
72	$J_{Stn1.Check}$	Stn_Tx1_CheckMeter_J	Station transformer “1” energy imported measured by the check meter	GHW	5.000	5.0	%	1	[47]
73	$J_{Stn2.Main}$	Stn_Tx2_Main_J	Station transformer “2” energy imported measured by the main meter	GWH	5.000	5.0	%	1	[47]
74	$J_{Stn2.Check}$	Stn_Tx2_Check_J	Station transformer “2” energy imported measured by the check meter	GHW	5.000	5.0	%	1	[47]
75	$J_{Stn3.Main}$	Stn_Tx3_Main_J	Station transformer “3” energy imported measured by the main meter	GWH	5.000	5.0	%	1	[47]
76	$J_{Stn3.Check}$	Stn_Tx3_Check_J	Station transformer “3” energy imported measured by the check meter	GHW	5.000	5.0	%	1	[47]
77	J_{Extr}	Extr_WP_J	Extraneous works power	MWH	5.000	5.0	%	1	[47]
78	m_{Coal_i}	Coal_Mass[i]	Mass of coal fired	ton	0.500	0.5	%	1	[76]
79	CV_{Coal}	Coal_CV	Calorific value of coal	MJ/kg	0.464	0.5 ^v	abs	1	[77],[78]
80	$x_{Ash.Coal}$	Coal_Ash_x	Ash content in coal (as received)	% (m/m)	0.300	0.3	abs	1	[79]
81	$x_{TM.Coal}$	Coal_TM_x	Total moisture of coal	% (m/m)	1.500	1.5	abs	1	[80]
82	$x_{SM.Coal}$	Coal_SurfMoist_x	Surface moisture of coal	% (m/m)	1.500	1.5	abs	1	[80]
83	$x_{VM.Coal}$	Coal_VM_x	Volatile matter content of coal	% (m/m)	0.500	0.5	abs	1	[81]
84	$x_{FC.Coal}$	Coal_FC_x	Fixed carbon content of coal	% (m/m)	0.300	0.3	%	1	IM
85	$x_{S.Coal}$	Coal_S_x	Sulphur content of coal	% (m/m)	0.150	0.2	abs	1	[82]

86	AI_{Coal}	Coal_Abrassiveness	Abrasive index of coal	mgFe/kg	15.000	15.0	%	1	[83]
87	HGI_{Coal}	Coal_HGI	Coal Hardgrove index	-	5.000	5.0	abs	1	[84]
88	$Cost_{Coal.Incremental}$	Coal_Incr_Cost	Coal incremental cost	R/ton	0.000	0.0	%	1	n/a
89	$Cost_{Coal_ton}$	Coal_PerTon_Cost	Coal cost per ton	R/ton	0.000	0.0	%	1	n/a
90	$m_{FO.Stn}$	FO_Mass	Mass of fuel oil burned for all units	ton	5.000	5.0	%	1	
91	CV_{FO}	FO_CV	Calorific value of fuel oil	MJ/kg	0.300	0.3	abs	1	Typical certificate vi
92	$Q_{Comm.Stn}$	Heat_Comm	Heat for commissioning	GWH	5.000	5.0	%	1	default
93	$V_{MU.MeterA.Stn}$	MU_MeterA	Make-up water through measuring point "A"	ML	1.000	1.0	%	1	[47]
94	$V_{MU.MeterB.Stn}$	MU_MeterB	Make-up water through measuring point "B"	ML	1.000	1.0	%	1	[47]
95	$V_{RW.Stn}$	RW_V	Raw Water intake volume	ML	1.000	1.0	%	1	[47]
96	$V_{WW.Stn}$	WW_V	Wastewater recovered volume	ML	1.000	1.0	%	1	[47]
97	$L_{Unacc.prev.month.Stn}$	Unacc_Previous_L	Previous unaccounted loss	%	0.000	0.0	%	1	n/a
98	$USO_{Max.Stn}$	USO_Max_Stn	Maximum electrical units sent out (power)	MW	0.000	0.0	%	1	n/a
99	UCF_{Stn}	UCF_Stn	Station unit capability factor	%	0.000	0.0	%	1	n/a
100	$x_{EM.Coal}$	Coal_EM_x	Coal excess moisture content	%	1.500	1.5	abs	1	[80]
101	$J_{Sby.Stn}$	Tot_Sby_Load_J	Total standby load	GWH	5.000	5.0	%	1	[47]
102	$t_{Gen.Stn}$	Stn_Run_Time	Station running hours	hrs	5.000	5.0	%	1	default
103	$Cost_{FO_ton}$	FO_Cost	Fuel oil cost	R/ton	0.000	0.0	%	1	n/a
104	$t_{hr.month}$	Month_Hrs	Hours for the specific month	hrs	5.000	5.0	%	1	default
105	EAF_{Stn}	Stn_EAF	Station availability factor	%	0.000	0.0	%	1	n/a

ⁱ The uncertainty, $U_i = \frac{U_{Literature}}{\sqrt{N_{transmitters}}}$, where $U_{Literature}$ is transformed to a % form by dividing by the typical variable value x 100 if given in units.

ⁱⁱ The word “default” in the reference column indicates that a quantitative assessment had not been determined, a chosen default value to test the sensitivity of the variable. Used typically for manual human errors however these should be neglected when the estimation of running hours is done through an automated electronic process.

ⁱⁱⁱ The subscript “i” or “[i]” = 1-6 (for each unit number). If omitted from the variable name, then the property refers to a composite value for the entire station.

^{iv} Even though the referenced text indicates that the uncertainty for uncalibrated electrical metering can be in excess of 5% a more conservative figure of 2.5% has been evaluated based on the authors experience.

^v ISO [78] indicates that mechanical sampling systems should be design to a 1% uncertainty on ash content which was translated to the CV using the South African ash/CV correlation[85] to achieve an uncertainty of 0.37 MJ/kg on an as received basis. ISO [77] suggests an uncertainty of 0.3 MJ/kg on an air dried basis. The uncertainties were combined by the RSS method.

^{vi} ISO [86] indicates a 0.1% uncertainty, however typical supplier test certification indicate 7.5% uncertainty in the measured CV

Appendix E. STEP program output tag list

Table E- 1: STEP program output list

Python Tag	STEP tag	Description	Unit
A_EFP_RT	IDT085	(A) Electric Feed Pump On Load Hours	h
Cond_CW_In_T	IDT003	Mean CW Inlet Temperature	°C
AH_Gas_In_CIR	IDB076	Carbon in Dust	%
AH_Gas_In_O2_x	IDB009	Mean Economiser Gas Outlet O2	%
AH_Gas_Out_CO2_x	IDB079	Mean Air heater Gas Outlet CO2	%
AH_GAS_OUT_T	IDB003	Mean Air Heater Gas Outlet Temperature	°C
AH_LH_Gas_In_O2_x	IDB007	L/H Economiser Gas Outlet O2	%
AH_LH_Gas_Out_T	IDB001	L/H Air Heater Gas Outlet Temperature	°C
AH_RH_Gas_In_O2_x	IDB008	R/H Economiser Gas Outlet O2	%
AH_RH_Gas_Out_T	IDB002	R/H Air Heater Gas Outlet Temperature	°C
AT_Heat	IDT053	Test Heat Consumption	GWh
AT_NLToNER_Heat	IDT051	Fixed Heat Consumption	GWh
AuxPower_Act_Frac	IDT073	Actual Works Unit On-Load	%
AuxPower_CF	IDT064	Works Power Correction Factor	NA
AuxPower_Check_J	IDT015	Actual Unit Aux Power (Check Meter)	GWh
AuxPower_F	IDT062	Factor for Estimating Works Power	NA
B_EFP_RT	IDT100	(B) Electric Feed Pump On Load Hours	h
AuxPower_J	IDT022	Total Works Units Used	GWh
AuxPower_L_Cost	IDT076	Cost of Works Units Loss	R
AuxPower_Main_J	IDT014	Actual Unit Aux Power (Main Meter)	GWh
Auxpower_OffLoad_F	IDS109	Works Units Not On-load	%
AuxPower_OffLoad_J	IDS156	Works Units While Not Generating	MWh
AuxPower_SB_J	IDT089	Works Power from Station Board	GWh
AuxPower_SF_L	IDT074	STEP Factor Works Units Loss	%
AuxPower_Targ_Frac	IDT063	Target Works Units On-Load	%
AuxPower_UB_J	IDT017	Mean Auxiliary Units From Unit Board	GWh
C_EFP_RT	IDT110	(C) Electric Feed Pump On Load Hours	h
BD_Tot_Mass	IDB012	Water Blowdown	(SI)t
Boil_Act_L	IDB054	Total Actual Boiler Loss	%
Boil_ColdStarts	IDB031	No. of Cold Starts	NA
Boil_DownTime_0to7hrs	IDB026	Total Time Off Load Type 1 Start	h
Boil_DownTime_15to24hrs	IDB028	Total Time Off Load Type 3 Start	h
Boil_DownTime_24to168hrs	IDB029	Total Time Off Load Type 4 Start	h
Boil_DownTime_7to15hrs	IDB027	Total Time Off Load Type 2 Start	h
Boil_Fuel_CF	IDB065	Boiler Fuel Correction Factor	NA
Boil_L_Cost	IDB057	Total Cost of Boiler Losses	R
Boil_LF	IDB061	Average % Load of Practical MCR Capacity	%
Boil_LF_CF	IDB062	Boiler Load Correction Factor	NA
Boil_OffLoad_Heat_GWH	IDB069	Total Off-Load Heat	GWh

Boil_Run_hrs	IDB010	Steaming Hours	h
Boil_SF_L	IDB055	Total Boiler STEP Factor Loss	%
Boil_Starts_0to7hrs	IDB022	No. of Hot Starts Type 1	NA
Boil_Starts_15to24hrs	IDB024	No. of Hot Starts Type 3	NA
Boil_Starts_24to168hrs	IDB025	No. of Hot Starts Type 4	NA
Boil_Starts_7to15hrs	IDB023	No. of Hot Starts Type 2	NA
Boil_Targ_L	IDB053	Total Target Boiler Loss	%
BP_L_Cost	IDT042	Cost of Backpressure Loss	R
BP_SF_L	IDT040	STEP Factor Backpressure Loss	%
BP_Targ	IDT031	Target Condenser Backpressure	kPa
BP_Targ_CF	IDT058	Backpressure Correction Factor	NA
Capacity_LV_Pow	IPT029	Specified Turbine MCR Capacity	MW
Capacity_USO_Pow	IDT158	Standard Output Capacity	MW
CarbonEquiv	CE.U01	Carbon Equivalent of Fuel	%
CIR	IDB035	Mean Carbon in Ash	%
CIR_Act_L	IDB038	Actual Carbon in Refuse Loss	%
CIR_L_Cost	IDB041	Cost of Carbon in Refuse Loss	R
CIR_SF_L	IDB039	STEP Factor Carbon in Refuse Loss	%
CIR_Targ_CF	IDS151	Target Carbon in Refuse Correction Factor	%
CIR_Targ_L	IDB037	Target Carbon in Refuse Loss	%
Coal_Abrassiveness	IDS188	Abrasiveness	NA
Coal_Ash_x	IDS140	Ash in Coal	%
Coal_BurnRate	IDS173	Estimated Firing Rate	kg/USO
Coal_C_x	IDS148	Carbon in Coal (total)	%
Coal_CV	IDS146	CV of Coal as Fired (Received)	MJ/kg
Coal_EM_x	IDS066	Excess Moisture in Coal	%
Coal_FC_x	IDS142	Fixed Carbon in Coal	%
Coal_H_x	IDS139	Hydrogen in Coal	%
Coal_Heat	IDS036	Heat in Coal	GWh
Coal_HGI	IDS185	Hardgrove Index	NA
Coal_Incr_Cost	IDS144	Cost of Coal (Incremental)	c/ton
Coal_Incr_PerUSO_Cost	IDS157	Incremental Cost per Unit Sent Out	c/kWh
Coal_Mass	IDS014	Total Station Coal Burnt	(SI)t
Coal_PerTon_Cost	IDS169	Total Cost of Coal	c/ton
Coal_PerUSO_Cost	IDS160	Station Total Cost per USO	c/kWh
Coal_S_x	IDS143	Sulphur in Coal	%
Coal_TM_x	IDS138	Total Moisture in Coal	%
Coal_VM_x	IDS141	Volatiles in Coal	%
CoarseAsh_CIR	IDB077	Carbon in Rough Ash	%
Cond_Act_P	IDT010	Actual Condenser Backpressure	kPa
Cond_TSat	IDT043	Backpressure Equivalent Saturation Temperature	°C
Condensate_T	IDT071	Condenser Hot well Condensate Temperature	°C
Cu_Targ_x	TCU.U0	Target Unburnt Carbon in Refuse	%
Cu_x	CU.U01	Unburnt Carbon in Refuse	%

Cycle_Act_Eff	IDS041	Station Overall Thermal Efficiency	%
Cycle_Act_HR	IDS047	Actual Station Heat Rate	kWh/kWh
Cycle_Direct_SF	IDS042	Direct STEP Factor	%
Cycle_HR_Targ	IDS046	Target Station Heat Rate	kWh/kWh
Cycle_Indirect_SF	IDT077	Derived Unit STEP Factor	%
Cycle_L_Cost	IDT084	Cost of Total STEP Factor Loss	R
Cycle_SF_L	IDT080	Total Unit STEP Factor Loss	%
Cycle_Unacc_L	IDS119	Unaccounted STEP Losses	%
Cycle_Unacc_L_Cost	IDS121	Cost of Unaccounted Losses	R
DFC	DFC.U0	Dry Flue Gas per kg of Carbon Burnt	NA
Dfg	DFG.U0	Dry Flue Gas per kg of Fuel Burnt	NA
DFG_Act_L	IDB043	Actual Dry Flue Gas Loss	%
DFG_L_Cost	IDB046	Cost of Dry Flue Gas Loss	R
DFG_SF_L	IDB044	STEP Factor Dry Flue Gas Loss	%
DFG_Targ_L	IDB042	Target Dry Flue Gas Loss	%
Eco_FW_In_T	IDT011	Actual Final Feedwater Temperature	°C
EFPs_Targ_J	IDT087	Estimated Target Units Used by EFP, SFP O/C	GWh
Equiv_SF_L	IDS116	Station STEP Factor Loss Equivalent	%
Equiv_SF_L_Cost	IDS118	Cost of STEP Loss Equivalent	R
Est_MU_F	IDT060	Factor for Estimating Make-up	NA
Extr_WP_J	IDS155	Total Extraneous Supply	MWh
FD_In_T	IDB006	Mean FD Fan Air Inlet Temperature	°C
FD_LH_AIR_In_T	IDB004	L/H FD Fan Air Inlet Temperature	°C
FD_RH_AIR_In_T	IDB005	R/H FD Fan Air Inlet Temperature	°C
FO_Cost	IDS176	Cost of Fuel Oil	R/ton
FO_Heat	IDS037	Heat in Fuel Oil	GWh
FO_Mass	IDS015	Total Station Fuel Oil Burnt	(SI)t
FO_PerUSO_Cost	IDS177	Fuel Oil Cost per USO	c/kWh
Frac_Tot_Stm	IDB036	Fraction of Total Steam Raised	NA
Fuel_PerUSO_Cost	IDS178	Total Fuel Cost per USO	c/kWh
FW_L_Cost	IDT047	Cost of Final Feedwater Temperature Loss	R
FW_SF_L	IDT045	STEP Factor Feedwater Temperature Loss	%
FW_Targ_T	IDS091	Average Target Final Feedwater Temperature	°C
FW_Tot_Mass	IDB011	Total Feed Water To Boiler	Gg
Gen_Frac	IDT067	Unit Load fraction of Total Units Generated	NA
Gen_HV_J	IDT018	Total Units Generated (HV)	GWh
Gen_HV_J[0]	IDS029	Station Total Units Generated - L.V.	GWh
Gen_HV_LF	IDT054	Average Load Generated % of Specified MCR Capacity	%
Gen_LV_Check_J	IDT013	Actual Units Generated (Check Meter)	GWh
Gen_LV_J	IDT016	Mean Units Generated - L.V.	GWh
Gen_LV_Main_J	IDT012	Actual Units Generated (Main Meter)	GWh
Gen_Reactive_J	IDT020	Reactive Load Generated	GVARh

Gen_RT	IDT024	Time Generating	h
Generating_Heat	IDS038	Heat for Generation	GWh
H2_Moist_Act_L	IDB048	Actual H2 and Fuel moisture Loss	%
H2_Moist_L_Cost	IDB051	Cost of H2 and Fuel Moisture Loss	R
H2_Moist_SF_L	IDB049	STEP Factor H2 and Fuel Moisture Loss	%
H2_Moist_Targ_L	IDB047	Target H2 and Fuel Moisture Loss	%
H2andMoist_Targ_CF	IDS137	Target H2 Fuel and Moisture Correction Factor	NA
Heat_Boil_Cold_Starts	IDB067	Heat for Unit Cold Starts	GWh
Heat_Boil_Hot_Starts	IDB066	Heat for Unit Hot starts	GWh
Heat_Boil_HotSby	IDB068	Heat for Unit Hot Standby	GWh
Heat_Comm	IDS020	Heat for I.C. Sets Calculated	GWh
HotSby_Time	IDB030	Time for Hot Standby	h
HPT_LH_MS_In_T	IDT004	Main Steam Turbine Inlet L/H Side Temperature	°C
HPT_RH_MS_In_T	IDT005	Main Steam Turbine Inlet R/H Side Temperature	°C
HPT_Targ_In_T	IDT029	Target Main Steam Temperature	°C
HR_Targ	IDT065	Running Sent Out Heat Rate	kWh/kWh
Incr_Heat_Cost	IDS147	Cost of Heat (incremental)	c/kWh
Incr_NLtoNER_Act_HR	IDT094	Actual Incremental Heat Rate	kWh/kWh
IPT_Act_In_T	IDT009	Actual Mean Reheat Steam Temperature	°C
IPT_LH_Stm_in_T	IDT007	Reheat Steam Turbine Inlet L/H Side Temperature	°C
IPT_RH_Stm_in_T	IDT008	Reheat Steam Turbine Inlet R/H Side Temperature	°C
IPT_Targ_In_T	IDT030	Target Reheat Steam Temperature	°C
L_Corr_Ash	IDB063	Correction for Fuel Ash Content	NA
L_Corr_H2andMoist	IDB064	Correction for H2 and Moisture Content	NA
L_Corr_VM	IDB078	Correction for Volatiles in Coal	NA
L_Cost	IDB016	Cost of Loss Factor	R/%
MILL_A_Run_Hrs	IDB091	Total (A) Mill On Load Hours	h
MILL_B_Run_Hrs	IDB092	Total (B) Mill On Load Hours	h
MILL_C_Run_Hrs	IDB093	Total (C) Mill On Load Hours	h
MILL_D_Run_Hrs	IDB094	Total (D) Mill On Load Hours	h
MILL_E_Run_Hrs	IDB095	Total (E) Mill On Load Hours	h
MILL_F_Run_Hrs	IDB096	Total (F) Mill On Load Hours	h
Mill_Reject_CV	IDB071	Mean CV of Mill Rejects	MJ/kg
Mill_Reject_Mass	IDB070	Weight of Mill Rejects	(SI)t
Month_Hrs	ISS001	Hours in Period	h
MR_Act_L	IDB058	Actual Mill Reject Loss	%
MR_L_Cost	IDB075	Cost of Mill Reject Loss	R
MR_SF_L	IDB073	STEP Factor Mill Reject Loss	%
MS_Act_T	IDT006	Actual Main Live Steam Temperature	°C
MS_L_Cost	IDT036	Cost of Main Steam Temperature Loss	R
MS_SF_T_L	IDT034	STEP Factor Main Steam Temperature Loss	%

MS_Targ_T	IDS072	Average Target Main Steam Temperature	°C
MU_Act_L	IDT069	Actual Make-up loss	%
MU_CF	IDT061	Make-up Correction Factor	NA
MU_Cold_V	IDT096	Cold Make Up Used	ML
MU_Hot_F	MU.U01	Unit of Make-up as a Fraction of Total Steam Raised	NA
MU_L_Cost	IDT072	Cost of Make-up water Loss	R
MU_MeterA	IDS001	Make-Up Water Meter (A)	MI
MU_MeterB	IDS002	Make-Up Water Meter (B)	MI
MU_Other_V	IDS175	Station Make-Up Excluding Unit Make-Up	ML
MU_PerUSO_V	IDS135	Demin Water Used	L/USO
MU_SF_L	IDT070	STEP Factor Make-up Water Loss	%
MU_Targ_L	IDT068	Target Make-up Loss	%
MU_V	IDT079	Unit Make-Up Water Used	ML
MU_V[0]	IDS003	Station Meter Make-up Water Used	ML
OnLoad_Targ_Heat	IDT066	Target Turbine On-Load Heat Consumption	GWh
PF	IDT056	Average Power Factor	NA
PF_CF	IDT057	Power Factor Correction Factor	NA
Radiation_L	IDB052	Radiation Loss	%
Range_Start_Heat	IDT028	Heat for Turbine Starting	GWh
ReH_SF_T_L	IDT037	STEP Factor Reheat Steam Temperature Loss	%
ReH_Stm_L_Cost	IDT039	Cost of Reheat Steam Temperature Loss	R
Reh_Targ_T	IDS077	Station Target Reheat Steam Temperature	°C
RW_PerUSO_V	IDS134	Raw Water Used	litres/USO
RW_V	IDS025	Total Raw Water Used	ML
Sby_LF	IDS133	Standby Load Factor	%
StdCoal_Ash_x	IPS027	Ash in coal (Standard)	%
StdCoal_C_x	IPS029	Carbon in coal (Standard)	%
StdCoal_CV	IPS025	CV of coal (Standard)	MJ/kg
StdCoal_H2_x	IPS030	Hydrogen in coal (Standard)	%
StdCoal_S_x	IPS031	Sulphur in coal (Standard)	%
StdCoal_TM_x	IPS026	Moisture in coal (Standard)	%
StdCoal_VM_x	IPS028	Volatiles in coal (Standard)	%
Stm_Mass	IDB017	Total Steam Raised	Gg
Stm_Mass[0]	IDS044	Station Total Steam Raised	Gg
Stn_AuxPower_CommonPlant_J	IDS174	Station Common Aux Power Consumption	GWh
Stn_Run_Time	IDS034	Station Time Generating	h
Stn_Tx1_CheckMeter_J	IDS005	Station Tx.1 Check Meter	GWh
Stn_Tx1_Main_J	IDS004	Station Tx1 Main Meter	GWh
Stn_Tx2_Check_J	IDS007	Station Tx 2 Check Meter	GWh
Stn_Tx2_Main_J	IDS006	Station Tx 2 Main Meter	GWh
Stn_Tx3_Check_J	IDS009	Station Tx 3 Check Meter	GWh
Stn_Tx3_Main_J	IDS008	Station Tx 3 Main Meter	GWh
StnTx_Imp_J	IDS010	Station Transformers Works Units	GWh

Tot_Sby_Load_J	IDS021	Total Standby load	GWh
Tot_Targ_Heat	IDT081	Total Target Heat Consumption	GWh
Turb_ColdStart_Above30Hrs	IDT027	Number of Turbine Cold Starts (Offload > 30 Hours)	NA
Turb_Det_L_Cost	IDT044	Cost of Turbine Deterioration Loss	R
Turb_Est_Det_L	IDT032	STEP Factor Turbine Deterioration Loss	%
Turb_HotStart_Below30Hrs	IDT026	Number of Turbine Hot Starts (Offload < 30 Hours)	NA
Turb_L_Cost	IDT050	Cost of Total Turbine Losses	R
Turb_LF_CF	IDT055	IDT055 Correction Factor	NA
Turb_SF_L	IDT048	Total Turbine STEP Factor Loss	%
UCF_Stn	IDS024	Generation Load Factor	NA
Unacc_Previous_L	IDS172	Previous Months Unaccounted STEP Loss	%
USO_AP_LF	IDS132	Installed Sent-out Load Factor	%
USO_J	IDT023	Units Sent Out - L.V.	GWh
USO_LF	IDT059	Average Running Load % of Max Output Capacity	%
USO_Max_Stn	IDS131	Max Sustained Load Sent Out in a Specific Hour of a Day	MW
USO_Std_LF	IDS179	Standard Installed Sent Out Load Factor	%
WW_PerUSO_V	IDS136	Station Total Waste Water	L/USO
WW_V	IDS027	Waste Water	ML

Appendix F. Results

Table F- 1: Systematic uncertainty propagation full results

Calculated Variable	Unit Level			Station Level		
	Base Result	u (abs)	u (%)	Base Result	u (abs)	u (%)
MS_L_Cost	14 767.224	30 984.097	209.817	150 304.440	68 109.383	45.314
MS_SF_T_L	0.038	0.079	209.716	0.070	0.032	45.312
ReH_Stm_L_Cost	46 573.048	31 505.089	67.647	286 757.185	69 619.781	24.278
ReH_SF_T_L	0.119	0.080	67.504	0.134	0.033	24.275
BP_L_Cost	674 718.199	419 453.943	62.167	5 593 366.533	927 751.450	16.587
BP_SF_L	1.720	1.068	62.113	2.614	0.433	16.582
CW_Rise_T	14.170	7.920	55.891			
MU_SF_L	-0.339	0.087	25.755	0.640	0.063	9.782
MU_L_Cost	-132 936.388	34 233.172	25.752	1 369 881.210	134 120.223	9.791
Radiation_L	0.005	0.001	25.397	0.006	0.000	7.584
AuxPower_L_Cost	-325 313.576	78 290.221	24.066	-670 246.404	133 849.399	19.970
BP_Targ	5.416	1.270	23.441	5.322	0.514	9.651
AuxPower_SF_L	-0.829	0.192	23.142	-0.313	0.063	19.966
DFG_L_Cost	224 778.035	49 812.081	22.161	2 169 978.309	116 838.251	5.384
DFG_SF_L	0.573	0.125	21.825	1.014	0.054	5.369
MU_Act_L	0.516	0.107	20.685	1.780	0.076	4.283
MU_Hot_F	0.516	0.107	20.684	0.000	0.000	0.000
FW_L_Cost	1 490 785.753	302 380.180	20.283	14 302 061.830	743 058.851	5.195
Boil_L_Cost	322 772.480	63 325.683	19.619	3 068 035.665	196 518.510	6.405
FW_SF_L	3.800	0.732	19.257	6.685	0.346	5.179
Boil_SF_L	0.823	0.154	18.728	1.434	0.092	6.388
Cycle_L_Cost	2 910 659.322	539 693.164	18.542	28 459 290.381	1 227 700.769	4.314
Cycle_SF_L	7.420	1.326	17.877	13.302	0.571	4.294
Turb_L_Cost	3 046 136.806	530 535.547	17.417	24 691 619.910	1 191 696.155	4.826
Turb_SF_L	7.765	1.297	16.708	11.541	0.555	4.809
L_Corr_H2andMoist	1.384	0.229	16.575	0.000	0.000	0.000
CIR_L_Cost	199 713.018	28 531.468	14.286	1 381 066.295	142 917.428	10.348
L_Corr_Ash	0.361	0.049	13.510	0.000	0.000	0.000
CIR_SF_L	0.509	0.065	12.724	0.645	0.067	10.334
MR_SF_L	0.000	0.000	7.370			
MR_Act_L	0.000	0.000	7.370			
H2_Moist_L_Cost	-101 718.572	5 807.997	5.710	-483 008.940	12 108.292	2.507
AuxPower_Act_Frac	3.806	0.214	5.635	8.310	0.072	0.871
FD_In_T	30.374	1.617	5.322			
Boil_LF	81.869	4.175	5.099			
H2_Moist_SF_L	-0.259	0.013	5.055	-0.226	0.006	2.473

Stm_Mass	1 113.935	55.697	5.000	6 019.247	123.377	2.050
H2_Moist_Act_L	4.644	0.228	4.909	4.672	0.229	4.902
H2_Moist_Targ_L	4.904	0.229	4.678	4.898	0.229	4.683
AuxPower_J	13.702	0.622	4.541	157.738	0.880	0.558
Coal_Mass	193 529.322	8 680.859	4.486	1 045 752.689	4 294.749	0.411
Frac_Tot_Stm	0.185	0.008	4.467			
Cu_Targ_x	0.486	0.021	4.395			
CIR_Act_L	1.495	0.063	4.188	1.615	0.066	4.086
AH_Gas_In_O2_x	3.640	0.150	4.121	3.664	0.062	1.681
CIR_Targ_CF	1.429	0.058	4.059			
AH_Gas_Out_O2_x	5.640	0.212	3.761			
Cu_x	0.908	0.032	3.525			
Coal_H2_x	3.293	0.099	3.007	3.293	0.099	3.007
Dfg	10.919	0.323	2.959	0.000	0.000	0.000
Turb_Det_L_Cost	819 292.583	22 857.333	2.790	4 359 129.921	17 867.034	0.410
L_Cost	392 288.889	10 943.851	2.790	2 139 534.043	8 764.325	0.410
DFG_Act_L	4.543	0.124	2.722	4.971	0.056	1.132
CarbonEquiv	52.099	1.402	2.691			
Boil_Act_L	10.687	0.272	2.546	11.265	0.246	2.183
Boil_Targ_L	9.864	0.225	2.277	9.831	0.222	2.262
MU_Targ_L	0.931	0.019	2.083	0.996	0.008	0.811
Est_MU_F	1.162	0.024	2.067			
USO_LF	84.560	1.572	1.859	72.690	0.859	1.181
OnLoad_Targ_Heat	1 017.657	18.331	1.801			
Tot_Targ_Heat	1 017.657	18.331	1.801	5 424.765	41.222	0.760
Gen_LV_LF	84.042	1.456	1.732			
Gen_HV_LF	84.062	1.456	1.732	81.166	0.616	0.759
Turb_Targ_Heat	886.429	15.026	1.695	4 877.733	33.646	0.690
CIR_Targ_L	0.986	0.017	1.679	0.970	0.011	1.084
USO_J	360.040	5.641	1.567	1 898.263	11.929	0.628
AH_Gas_Out_CO2_x	12.218	0.176	1.440			
Cycle_Indirect_SF	92.580	1.326	1.433	86.698	0.571	0.659
AuxPower_UB_J	21.190	0.300	1.414			
Gen_LV_J	375.157	5.306	1.414			
Gen_HV_J	373.741	5.284	1.414	2 056.001	11.896	0.579
DFC	20.585	0.283	1.374			
AT_Heat	890.866	11.767	1.321			
AT_NLToNER_Heat	890.866	11.767	1.321			
Gen_Frac	0.182	0.002	1.268			
Cycle_HR_Targ	2.827	0.032	1.116	2.836	0.015	0.516
HR_Targ	2.827	0.032	1.116			
Targ_Turb_HR	8 538.378	91.766	1.075			
Turb_Targ_Eff	42.163	0.452	1.071			
BP_Targ_CF	0.997	0.011	1.068			
Heat_Boil_HotSby	0.000	0.000	1.000			

Heat_Boil_Cold_Starts	0.000	0.000	1.000			
CIR	3.055	0.031	1.000	3.291	0.015	0.456
AH_GAS_OUT_T	115.029	1.143	0.994			
DFG_Targ_L	3.970	0.037	0.942	3.956	0.031	0.779
Incr_NLtoNER_Act_HR	2.816	0.024	0.864	2.970	0.015	0.520
AuxPower_F	1.048	0.009	0.823			
AuxPower_Targ_Frac	4.635	0.038	0.823	7.879	0.027	0.340
Boil_OffLoad_Heat_GWH	0.000	0.000	0.736	4.983	0.023	0.455
IPT_Act_In_T	530.898	2.800	0.527	530.359	1.146	0.216
MS_Act_T	533.595	2.800	0.525	532.417	1.146	0.215
Heat_Boil_Hot_Starts	0.000	0.000	0.481			
FW_Targ_T	239.365	0.831	0.347	238.775	0.338	0.142
Boil_Act_Indirect_Eff	89.313	0.272	0.305	88.735	0.246	0.277
Boil_Fuel_CF	1.020	0.003	0.271	1.020	0.003	0.271
Boil_Targ_Indirect_Eff	90.136	0.225	0.249			
Turb_LF_CF	1.021	0.001	0.119			
BP_Act_CF	101.432	0.088	0.087			
H2_Moist_LF_Targ_L	3.520	0.001	0.037			
AuxPower_CF	1.002	0.000	0.036	1.004	0.000	0.018
PF	0.994	0.000	0.031			
MU_Targ_CF	1.001	0.000	0.016			
PF_CF	0.998	0.000	0.004			
Turb_Est_Det_L	2.088	0.000	0.004	2.037	0.000	0.014
Boil_LF_CF	1.003	0.000	0.001	1.003	0.000	0.011
AuxPower_Min_Frac	4.421	0.000	0.000			
Cycle_Unacc_L_Cost				-8 105 289.618	4 767 717.845	58.822
Cycle_Adj_HR				11 369.525	269.469	2.370
Auxpower_OffLoad_F				0.776	0.005	0.624
MU_PerUSO_V				0.055	0.002	3.591
Equiv_SF_L				9.513	2.210	23.236
Generating_Heat				5 995.096	137.004	2.285
MS_Targ_T				535.000	0.000	0.000
Equiv_SF_L_Cost				20 354 000.762	4 741 859.072	23.297
EFPs_Targ_J				57.534	0.597	1.037
Fuel_PerUSO_Cost				21.068	0.140	0.665
Coal_BurnRate				0.551	0.004	0.751
USO_AP_LF				0.733	0.009	1.179
Reh_Targ_T				535.000	0.000	0.000
RW_PerUSO_V				1.211	0.061	5.039
Cycle_Adj_Eff				31.664	0.751	2.371
Cycle_Direct_SF				90.487	2.210	2.443
Cycle_Acc_L				13.302	0.571	4.294
FO_Heat				30.781	1.623	5.274
Cycle_Unacc_L				-3.788	2.230	58.878
Cycle_Act_Eff				31.911	0.756	2.370

Coal_Heat	5 964.315	136.995	2.297
Cycle_Act_HR	3.134	0.074	2.369
USO_Std_LF	0.733	0.009	1.179
WW_PerUSO_V	0.000	0.000	5.039
Boil_Eff	88.735	0.246	0.277
Coal_MF_CV	22.156	0.616	2.780
Coal_Incr_PerUSO_Cost	10.599	0.249	2.345

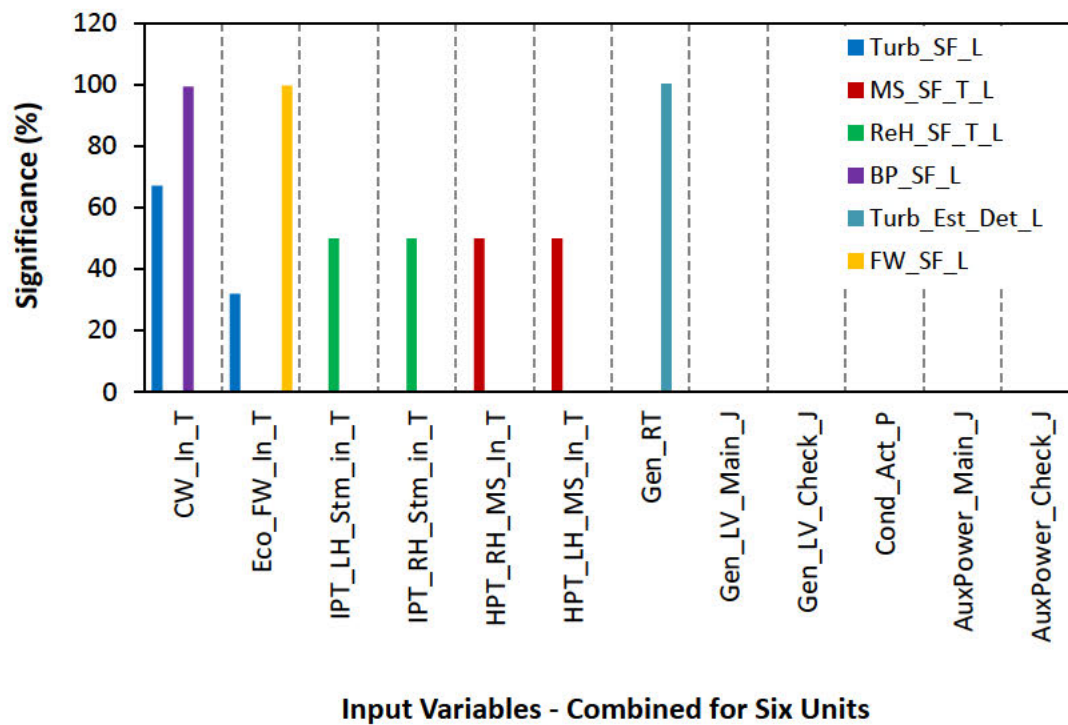


Figure F- 1: Variable significance on uncertainty on Unit 1 cycle and turbine plant SF losses

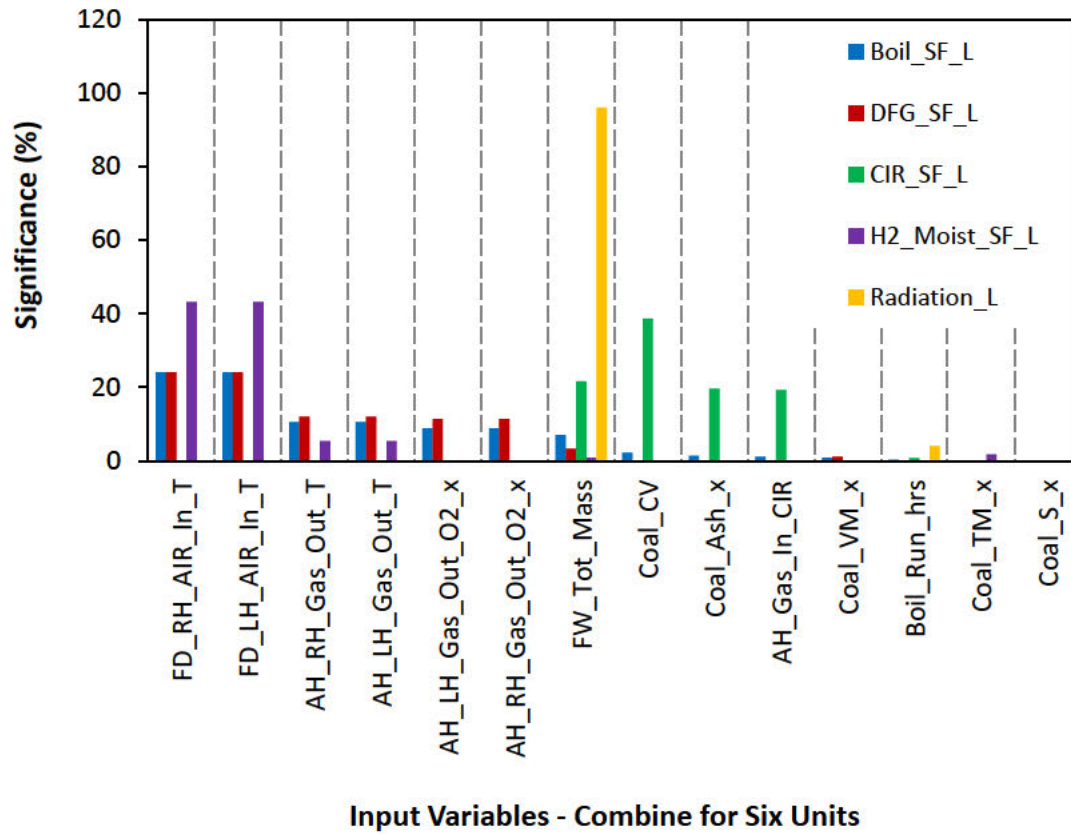


Figure F- 2: Variable significance on uncertainty on Unit 1 boiler SF losses

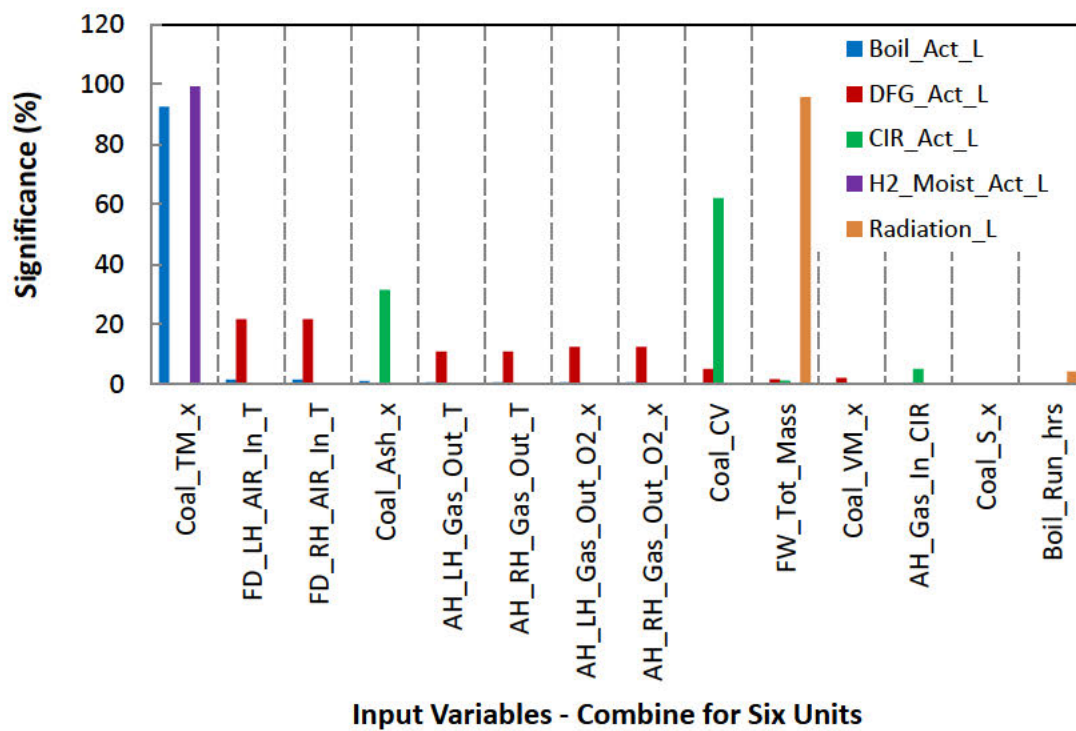


Figure F- 3: Variable significance on uncertainty on station level boiler losses

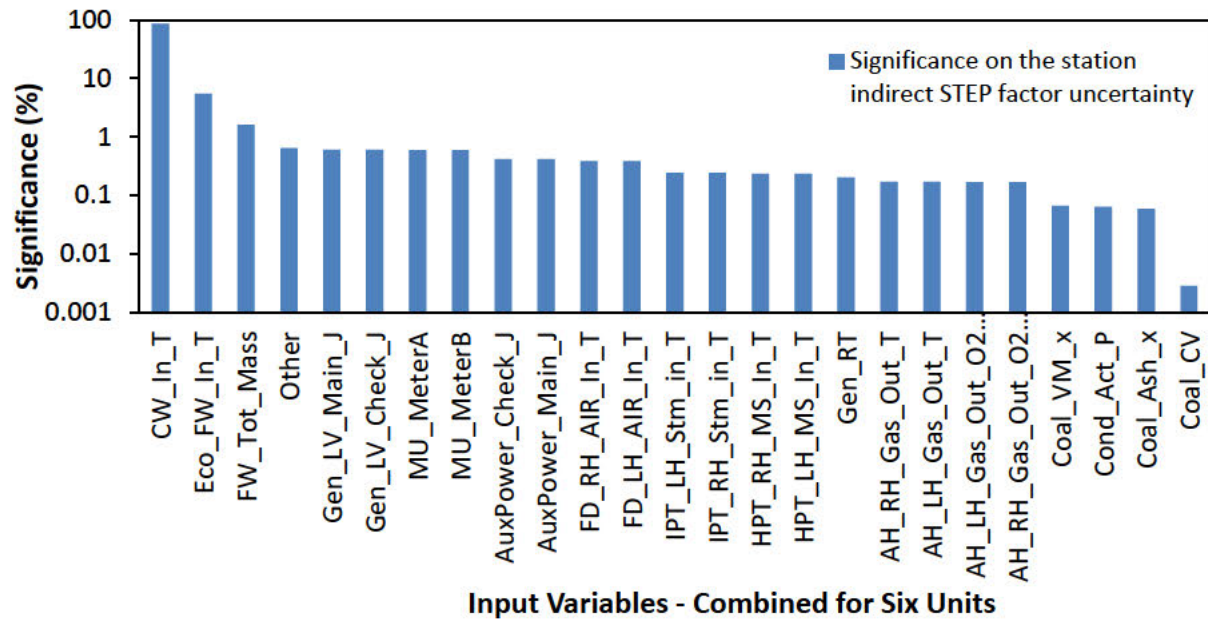


Figure F- 4: Variable significance on the indirect STEP factor with updated FW baseline data

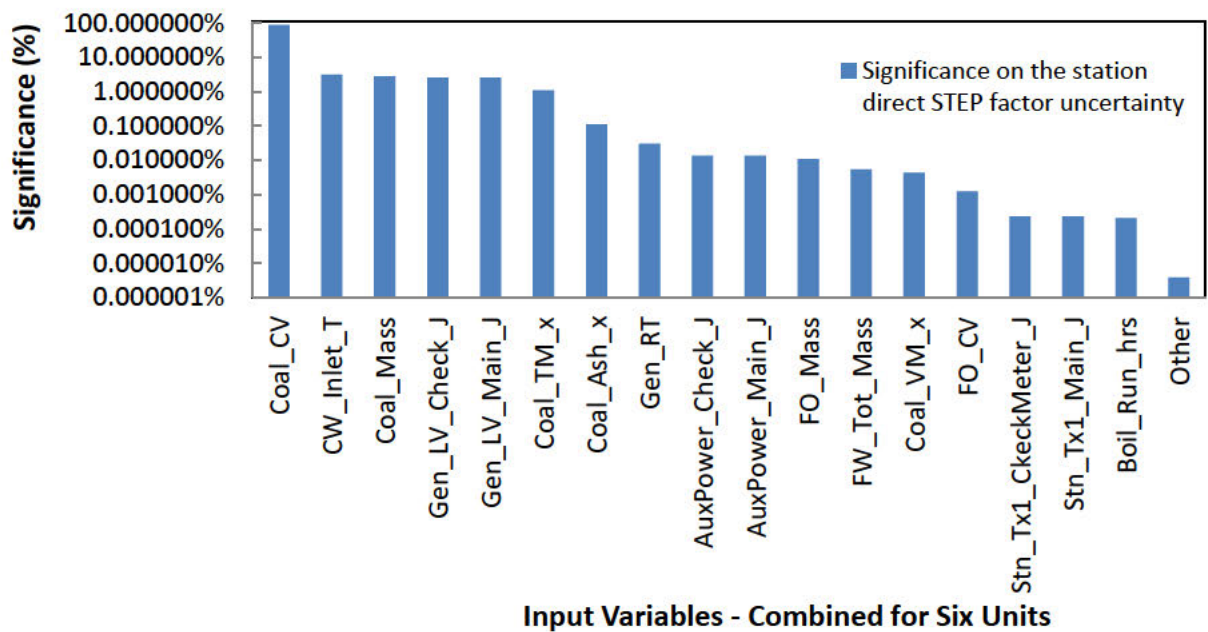


Figure F- 5: Variable significance on the direct STEP factor with updated FW baseline data

Appendix G. Model verification

The table below is a verification of the Python STEP computer model against the Mathcad STEP model. The key deviations in the results can be attributed to the number of significant digits used in the baseline performance data polynomial coefficients. These coefficients were hardcoded into the MathCAD STEP model with up to 5 significant digits. The Python STEP computer model was coded to read in the data as per the source data. The deviations were scrutinized for each calculation to ensure that it indeed stemmed from the polynomial coefficients or carried over from previous calculations. The deviation listed below was considered to be negligible.

Table G- 1: STEP model verification

Calculation No.	Variable [Unit No.]	MathCAD	Python	Difference
1	AH_GAS_OUT_T[1]	130.50000	130.50000	0.00000
2	FD_In_T[1]	35.50000	35.50000	0.00000
3	AH_Gas_In_O2_x[1]	4.35000	4.35000	0.00000
4	AH_LH_Leak[1]	5.76920	5.76923	0.00003
5	AH_RH_Leak[1]	3.70370	3.70370	0.00000
6	Stm_Mass[1]	1 450.00000	1 450.00000	0.00000
7	Boil_LF[1]	92.93206	92.93206	0.00000
8	Boil_LF_CF[1]	1.00050	1.00053	0.00003
9	CIR_Targ_CF[1]	0.96829	0.96829	0.00000
10	L_Corr_Ash[1]	-0.03942	-0.03942	0.00000
12	Coal_H2_x[1]	3.09715	3.09715	0.00000
13	L_Corr_H2andMoist[1]	0.17021	0.17021	0.00000
14	L_Corr_H2andMoist[1]	0.17021	0.17021	0.00000
16	L_Corr_VM[1]	0.00000	0.00000	0.00000
17	L_Corr_VM[1]	0.00000	0.00000	0.00000
18	Boil_Fuel_CF[1]	1.00147	1.00147	0.00000
23	Heat_Boil_Hot_Starts[1]	1.09043	1.09043	0.00000
24	Heat_Boil_Cold_Starts[1]	0.46440	0.46440	0.00000
25	Heat_Boil_HotSby[1]	0.36133	0.36133	0.00000
26	Boil_OffLoad_Heat_GWH[1]	1.91616	1.91616	0.00000
27	CIR[1]	1.65964	1.65964	0.00000
31	AH_Gas_Out_CO2_x[1]	12.41016	12.41016	0.00000
32	DFG_AT_L[1]	4.97287	4.97287	0.00000
33	Cu[1]	0.52199	0.52199	0.00000
34	CIR_Targ_L[1]	1.21408	1.21408	0.00000
35	Tcu[1]	0.69662	0.69662	0.00000
36	DFG_Targ_L[1]	5.04333	5.04333	0.00000
38	DFC[1]	20.27211	20.27211	0.00000
39	Dfg[1]	9.45542	9.45542	0.00000

40	DFG_Act_L[1]	4.82614	4.82614	0.00000
41	DFG_SF_L[1]	-0.21719	-0.21719	0.00000
42	CIR_Act_L[1]	0.94003	0.94003	0.00000
43	CIR_SF_L[1]	-0.27405	-0.27405	0.00000
44	H2_Moist_LF_Targ_L[1]	4.42900	4.42900	0.00000
45	H2_Moist_Targ_L[1]	4.59921	4.59921	0.00000
46	H2_Moist_Act_L[1]	5.01700	5.01700	0.00000
47	H2_Moist_SF_L[1]	0.41779	0.41779	0.00000
48	Stm_Mass[0]	8 700.00000	8 700.00000	0.00000
49	Coal_Mass[1]	282 981.00000	282 981.00000	0.00000
51	Radiation_L[1]	0.34663	0.34663	0.00000
52	MR_Act_L[1]	0.00085	0.00085	0.00000
53	MR_SF_L[1]	0.00085	0.00085	0.00000
54	Boil_Targ_L[1]	10.86098	10.86034	-0.00064
55	Boil_Act_L[1]	10.78838	10.78774	-0.00064
56	Boil_SF_L[1]	-0.07260	-0.07260	0.00000
57	Frac_Tot_Stm[1]	0.16667	0.16667	0.00000
58	CIR_Targ_L[0]	1.21408	1.21408	0.00000
59	CIR_Act_L[0]	0.94003	0.94003	0.00000
60	CIR_SF_L[0]	-0.27405	-0.27405	0.00000
61	DFG_Targ_L[0]	5.04333	5.04333	0.00000
62	DFG_Act_L[0]	4.82614	4.82614	0.00000
63	DFG_SF_L[0]	-0.21719	-0.21719	0.00000
64	H2_Moist_Targ_L[0]	4.59921	4.59921	0.00000
65	H2_Moist_Act_L[0]	5.01700	5.01700	0.00000
66	H2_Moist_SF_L[0]	0.41779	0.41779	0.00000
67	Radiation_L[0]	0.00437	0.00373	-0.00064
68	MR_Act_L[0]	0.00085	0.00085	0.00000
69	Boil_Targ_L[0]	10.86098	10.86034	-0.00064
70	Boil_Act_L[0]	10.78754	10.78774	0.00020
71	Boil_SF_L[0]	-0.07345	-0.07260	0.00085
72	Boil_OffLoad_Heat_GWH[0]	11.49698	11.49698	0.00000
73	Boil_LF_CF[0]	1.00053	1.00053	0.00000
74	Boil_Fuel_CF[0]	1.00147	1.00147	0.00000
75	CIR[0]	1.65960	1.65964	0.00004
76	AH_Gas_In_O2_x[0]	4.35000	4.35000	0.00000
77	AH_RH_Leak[0]	3.70370	3.70370	0.00000
78	AH_LH_Leak[0]	5.76923	5.76923	0.00000
79	Gen_LV_J[1]	510.00000	510.00000	0.00000
80	AuxPower_UB_J[1]	62.00000	62.00000	0.00000
81	Gen_HV_J[1]	508.20800	508.20800	0.00000
82	Gen_HV_J[0]	3 049.24800	3 049.24800	0.00000
84	AuxPower_J[0]	401.99400	401.99400	0.00000
85	USO_J[0]	2 647.25400	2 647.25400	0.00000
87	Gen_Frac[1]	0.16667	0.16667	0.00000

88	AuxPower_J[1]	66.61567	66.61567	0.00000
89	USO_J[1]	441.59233	441.59233	0.00000
92	AT_NLToNER_Heat[1]	1 085.69877	1 085.69877	0.00000
97	AT_Heat[1]	1 091.12323	1 091.12323	0.00000
98	Amb_CF[1]	0.99398	0.99399	0.00001
99	Gen_HV_LF[1]	96.66554	96.66530	-0.00024
100	PF[1]	99.87922	99.87922	0.00000
105	PF_CF[1]	0.99752	0.99752	0.00000
106	EFP_Est_Pow[1]	25 099.40390	25 099.53210	0.12820
107	EFPs_Targ_J[1]	16.66575	16.66584	0.00009
108	Turb_LF_CF[1]	1.00361	1.00361	0.00000
109	AuxPower_ACC_Min_Frac[1]	12.28572	12.28567	-0.00005
110	USO_LF[1]	94.31341	94.31374	0.00033
112	USO_LF[0]	94.31341	94.31374	0.00033
113	AuxPower_F[1]	1.02241	1.02240	-0.00001
114	AuxPower_Targ_Frac[1]	16.33499	16.33495	-0.00004
115	AuxPower_CF[1]	1.00245	1.00245	0.00000
116	Est_MU_F[1]	1.02851	1.02851	0.00000
126	BP_Targ[1]	12.30903	12.30909	0.00006
131	BP_Targ_CF[1]	1.00020	1.00021	0.00001
132	MU_Targ_CF[1]	1.00024	1.00024	0.00000
133	HR_Targ[1]	2.74033	2.74035	0.00002
134	OnLoad_Targ_Heat[1]	1 210.11755	1 210.11773	0.00018
135	Range_Start_Heat[1]	0.42249	0.42249	0.00000
136	Tot_Targ_Heat[1]	1 212.45621	1 212.45638	0.00017
137	MS_Act_T[1]	562.00000	562.00000	0.00000
138	IPT_Act_In_T[1]	572.00000	572.00000	0.00000
139	Turb_Est_Det_L[1]	0.00759	0.00759	0.00000
140	FW_Targ_T[1]	265.53095	265.53116	0.00021
141	AuxPower_Act_Frac[1]	15.08533	15.08533	0.00000
142	AuxPower_SF_L[1]	-1.24966	-1.24962	0.00004
144	FW_SF_L[1]	0.00682	0.00682	0.00000
146	MS_SF_T_L[1]	-0.05571	-0.05571	0.00000
148	ReH_SF_T_L[1]	-0.06003	-0.06003	0.00000
153	BP_Act_CF[1]	99.99388	99.99388	0.00000
154	BP_SF_L[1]	-0.02650	-0.02724	-0.00074
155	Turb_SF_L[1]	-0.12783	-0.12856	-0.00073
156	MU_Targ_L[1]	1.02876	1.02875	-0.00001
158	MU_PerUSO_V[0]	0.04085	0.04085	0.00000
160	MU_Hot_F[1]	0.89802	0.89802	0.00000
161	MU_Act_L[1]	0.89802	0.89802	0.00000
163	MU_SF_L[1]	-0.10982	-0.10982	0.00000
164	Cycle_SF_L[1]	-1.55992	-1.56060	-0.00068
165	Cycle_Indirect_SF[1]	101.55992	101.56060	0.00068
167	Gen_LV_LF[1]	96.61774	96.61811	0.00037

173	Targ_Turb_HR[1]	7 756.92498	7 757.01250	0.08752
179	MS_BP_LF_CF[1]	318 971.27120	318 972.50933	1.23813
180	MS_Act_h[1]	3 380.74358	3 380.78186	0.03828
181	ReH_Act_Out_h[1]	3 596.80526	3 597.15783	0.35257
182	FW_Act_h[1]	1 162.53340	1 162.43766	-0.09574
183	HPT_Targ_Out_P[1]	53.02903	53.03444	0.00541
184	HPT_Targ_Out_T[1]	335.13283	335.16984	0.03701
185	HPT_Act_Out_h[1]	3 020.55539	3 020.55677	0.00138
186	SW_Targ_T[1]	183.98667	183.95927	-0.02740
187	SW_Act_h[1]	779.87254	779.85319	-0.01935
189	CEPs_Est_J[1]	0.64974	0.64974	0.00000
190	Pumps_J[1]	17.31549	17.31558	0.00009
191	Turb_Act_HR[1]	6 717.79854	6 719.22020	1.42166
192	Turb_SF_HR[1]	-1 039.12644	-1 037.79231	1.33413
193	Turb_Targ_Eff[1]	46.41014	46.40962	-0.00052
194	Turb_Act_Eff[1]	53.58898	53.57765	-0.01133
195	Turb_SF_Eff[1]	7.17884	7.16803	-0.01081
201	ACC_HeatRejected[1]	971.58625	971.48644	-0.09981
202	Incr_NLtoNER_Act_HR[1]	2.58083	2.58338	0.00255
203	Incr_NERtoMCR_Act_HR[1]	2.58083	2.58338	0.00255
204	MS_Targ_T[0]	560.00000	560.00000	0.00000
205	Reh_Targ_T[0]	570.00000	570.00000	0.00000
206	MS_Act_T[0]	562.00000	562.00000	0.00000
207	IPT_Act_In_T[0]	572.00000	572.00000	0.00000
208	MS_SF_T_L[0]	-0.05571	-0.05571	0.00000
209	ReH_SF_T_L[0]	-0.06003	-0.06003	0.00000
210	BP_Targ[0]	12.30903	12.30909	0.00006
211	Cond_Act_P[0]	13.50000	13.50000	0.00000
212	BP_SF_L[0]	-0.02724	-0.02724	0.00000
213	Turb_Est_Det_L[0]	0.00759	0.00759	0.00000
214	FW_Targ_T[0]	265.53095	265.53116	0.00021
215	Eco_FW_In_T[0]	263.00000	263.00000	0.00000
216	FW_SF_L[0]	0.00682	0.00682	0.00000
217	Turb_SF_L[0]	-0.12783	-0.12856	-0.00073
218	MU_Targ_L[0]	1.02875	1.02875	0.00000
219	MU_Act_L[0]	0.89802	0.89802	0.00000
221	MU_SF_L[0]	-0.10982	-0.10982	0.00000
222	AuxPower_Act_Frac[0]	15.08533	15.18532	0.09999
223	AuxPower_Targ_Frac[0]	16.33499	16.33495	-0.00004
224	AuxPower_SF_L[0]	-1.24966	-1.24962	0.00004
225	Incr_NLtoNER_Act_HR[0]	2.58083	2.58338	0.00255
226	Incr_NERtoMCR_Act_HR[0]	2.58083	2.58338	0.00255
228	L_Cost[1]	1 052 702.40510	1 052 702.40512	0.00002
229	MS_L_Cost[1]	-58 642.05830	-58 642.08862	-0.03032
230	ReH_Stm_L_Cost[1]	-63 190.21575	-63 190.25988	-0.04413

231	BP_L_Cost[1]	-28 675.61352	-28 674.73422	0.87930
232	Turb_Det_L_Cost[1]	7 989.89553	7 989.84301	-0.05252
233	FW_L_Cost[1]	7 178.20440	7 179.06421	0.85981
234	Turb_L_Cost[1]	-135 339.88734	-135 338.17549	1.71185
235	MU_L_Cost[1]	-115 610.07628	-115 608.12876	1.94752
236	AuxPower_L_Cost[1]	-1 315 530.56778	-1 315 474.33942	56.22836
237	CIR_L_Cost[1]	-288 497.69595	-288 495.79255	1.90340
238	DFG_L_Cost[1]	-228 633.89873	-228 632.39306	1.50567
239	H2_Moist_L_Cost[1]	439 813.90237	439 811.01132	-2.89105
240	Boil_L_Cost[1]	-77 317.68249	-77 317.17430	0.50819
241	Boil_Act_Indirect_Eff[1]	89.21162	89.21226	0.00064
242	Boil_Targ_Indirect_Eff[1]	89.13902	89.13966	0.00064
243	Boil_Var_Indirect_Eff[1]	0.07260	0.07260	0.00000
245	Cycle_L_Cost[1]	-1 643 737.81798	-1 643 737.81798	0.00000
246	EFPS_Targ_J[0]	99.99452	99.99503	0.00051
247	Tot_Targ_Heat[0]	7 274.73724	7 274.73831	0.00107
248	Cond_TSat[1]	52.02536	52.02536	0.00000
249	Cond_DepresT[1]	-1.84536	-1.84536	0.00000
250	ACC_Rise_T[1]	28.00000	28.00000	0.00000
251	Capacity_J[0]	3 167 108.03549	3 167 108.03549	0.00000
252	Coal_Heat[0]	8 992.18812	8 992.18812	0.00000
253	FO_Heat[0]	6.25000	6.25000	0.00000
254	Generating_Heat[0]	8 998.43812	8 998.43812	0.00000
255	Cycle_Act_HR[0]	3.39621	3.39621	0.00000
256	Cycle_Act_Eff[0]	29.44460	29.44460	0.00000
257	Cycle_HR_Targ[0]	2.74565	2.74565	0.00000
258	Cycle_Direct_SF[0]	80.84444	80.84446	0.00002
259	Cycle_SF_L[0]	-1.56076	-1.56060	0.00016
260	Cycle_Indirect_SF[0]	101.56076	101.56060	-0.00016
261	Equiv_SF_L[0]	19.15556	19.15554	-0.00002
262	Cycle_Unacc_L[0]	20.71632	20.71614	-0.00018
265	Fuel_PerUSO_Cost[0]	29.74885	29.74885	0.00000
269	Coal_BurnRate[0]	0.51055	0.51055	0.00000
270	USO_Std_LF[0]	86.24015	86.24015	0.00000
272	AuxPower_CF[0]	1.00242	1.00176	-0.00066
273	Sby_LF[0]	88.24180	88.24180	0.00000
274	USO_AP_LF[0]	2.38819	2.38819	0.00000
275	RW_PerUSO_V[0]	0.07114	0.07114	0.00000
276	WW_PerUSO_V[0]	0.00000	0.00000	0.00000
277	L_Cost[0]	7 934 723.82235	7 934 724.98922	1.16687
278	CIR_L_Cost[0]	-2 174 531.40765	-2 174 531.72265	-0.31500
279	DFG_L_Cost[0]	-1 723 312.19849	-1 723 312.45162	-0.25313
280	H2_Moist_L_Cost[0]	3 315 066.90983	3 315 067.39708	0.48725
281	Boil_L_Cost[0]	-582 776.69631	-582 776.77719	-0.08088
282	MS_L_Cost[0]	-442 013.36932	-442 013.66284	-0.29352

283	Turb_Det_L_Cost[0]	60 223.28571	60 223.29456	0.00885
284	BP_L_Cost[0]	-216 141.87692	-216 135.28100	6.59592
285	ReH_Stm_L_Cost[0]	-476 295.01732	-476 295.41999	-0.40267
286	FW_L_Cost[0]	54 105.21985	54 112.06424	6.84439
287	Turb_L_Cost[0]	-1 020 121.75800	-1 020 109.00503	12.75297
288	MU_L_Cost[0]	-871 401.45957	-871 394.14120	7.31837
289	AuxPower_L_Cost[0]	-9 915 389.58289	-9 915 363.60410	25.97879
290	Cycle_L_Cost[0]	-12 389 689.49677	-12 389 643.52751	45.96926
291	Equiv_SF_L_Cost[0]	151 994 049.23174	151 993 977.24915	-71.98259
292	Cycle_Unacc_L_Cost[0]	164 383 738.72851	164 383 620.77666	-117.95185
293	Auxpower_OffLoad_F[0]	0.08681	0.08681	0.00000
295	Coal_MF_CV[0]	20.52459	20.52459	0.00000
297	Cycle_Adj_HR[0]	12 236.36917	12 236.97357	0.60440
298	Cycle_Adj_Eff[0]	29.42049	29.41904	-0.00145
299	Boil_Act_Indirect_Eff[0]	89.21246	89.21226	-0.00020
300	Boil_SF_L[0]	-0.07345	-0.07260	0.00085
301	Coal_BurnRate[0]	0.64138	0.64138	0.00000
302	Turb_Targ_Heat[0]	6 531.85561	6 531.90338	0.04777
303	Turb_Act_Eff[0]	46.74240	46.74240	0.00000
304	MU_Stm_Ratio[0]	1.24285	1.24285	0.00000
305	AuxPower_Act_Frac[0]	15.18532	15.18532	0.00000
306	Sby_LF[0]	88.24180	88.24180	0.00000
307	Max_Demand_LF[0]	122.55806	122.55806	0.00000
308	Running_LF[0]	96.27825	96.27862	0.00037
309	USO_LF[0]	86.16529	86.16529	0.00000
310	EUF[0]	97.91510	97.91510	0.00000