PUBLIC NOTICE FOR STAKEHOLDER COMMENT ON ESKOM COAL FLEXIBILISATION STUDIES

Dear stakeholder,

Eskom, South Africa's primary electricity supplier, operates multiple coal-fired power stations that contribute significantly to the country's energy generation. Following Eskom's Minimum Emission Standards (MES) exemption applications, a decision by the Minister of Forestry, Fisheries, and Environment (DFFE), Dr. D.T. George, in respect of the exemption applications submitted by Eskom in terms of Section 59 of the National Environmental Management: Air Quality Act (NEMA: AQA), 2004 (Act No. 39 of 2004) was issued on the 31 March 2025. This decision outlines conditions that Eskom must comply with. In terms of condition Clause 7.49, Eskom is required to submit its coal flexibilisation studies to the Minister within 6 months of the issuance of the exemption decision. Clause 7.50 requires Eskom to publish the studies for Stakeholder comment. As such, a summary of the study and the study is included in this email.

Stakeholders with an interest in the matter are requested to submit their comments to Eskom at EskomMES@eskom.co.za by 28 November 2025.

Further information can also be obtained by contacting the email address above.

Eskom has submitted this information to you based on your previous registration as a stakeholder in an air quality matter. If you do not wish to receive further information, please contact us at EskomMES@eskom.co.za, and we will remove you from our distribution list. Thank you.

Regards,

Eskom Generation team

Generation Division
Generation Head Office
Megawatt Park Maxwell Drive Sunninghill Sandton
PO Box 1091 Johannesburg 2000 SA
Tel +27 11 800 - 2030 www.eskom.co.za
Eskom Holdings SOC Ltd Reg No 2002/015527/30

PUBLIC NOTICE FOR STAKEHOLDER COMMENT ON ESKOM COAL FLEXIBILISATION STUDIES

SUMMARY AND DISCUSSION ON ESKOM COAL FLEXIBILISATION STUDIES

Since 2016, Eskom has undertaken a series of flexibilisation studies of its coal-fired power stations in anticipation of the growth of renewable energy on the national grid. The process followed took into account Eskom's financial constraints and generating capacity constraints.

The flexibilisation studies sought to identify three categories of changes required to improve the operating loads. The categories of changes were broadly defined as:

1. Tier 1 – Changes relating to operational procedures.
2. Tier 2 – Minor equipment changes.
3. Tier 3 - Large capital equipment modification and additions.

Much of the effort to date has focused on consistently achieving and baselining the minimum load performance. The key rationale for this approach has been as follows:

i. Critical maintenance had to be conducted during major outages to restore plant performance across a range of operating loads.
ii. Operating staff needed time to learn to operate units at low loads from short to longer durations.
iii. Coal qualities have changed since the units were first commissioned and require further analysis and plant adjustment.
iv. Minimum load performance gaps were identified during the baseline tests, which needed specialist support from strategic partners such as the Electric Power Research Institute (EPRI), the Danish Energy Agency (DEA) and the German Corporation for International Cooperation (GIZ) (in partnership with VGBe).
v. The support included a holistic assessment of the performance of the units, assessment of operator capabilities at lower loads and identification of further changes required to achieve lower minimum loads.
vi. Specialist support from external parties such as Electric Power Research Institute (EPRI), Danish Energy Agency (DEA) and GIZ was strategic in pursuit of the objective to develop expertise within Eskom for low load operation. This is important as there is an increased risk of production losses at low loads due to a higher risk of flameouts, and the safety risk increases if unburnt coal and fuel oil in the boiler are not carefully monitored.
vii. Donor funding was available to undertake Tier 1 testing from the VGBe energy and Danish Energy Agency, while EPRI support was provided as part of the self-directed funds for supplemental research projects.
viii. Minimum load should be achieved without fuel oil combustion support due to the high cost and increased production and safety risk of secondary airheater and fabric filter bag fires when burning fuel oil. It also causes a significant increase in pollution due to the continuous burning of fuel oil.

PUBLIC NOTICE FOR STAKEHOLDER COMMENT ON
ESKOM COAL FLEXIBILISATION STUDIES

Eskom is in the process of consolidating the in-house minimum generation test results for each of the coal-fired stations, which were conducted during the period from FY2021 to FY2025. It is worth noting that not all units were tested at a station, especially if the minimum load trip risk was deemed too high at the time of the scheduled test.

The results of the baseline/diagnosis tests are contained in the report referenced as RES/TRR/21/1962944 (attached). While the results of the baseline/diagnosis testing indicate favourable conditions for achieving the designed minimum loads, it must be highlighted that, in some cases, this can only be achieved with significant capital investments to restore the ability to operate at low loads.

There have been limited studies, physical testing, and analysis to determine the changes for Tier 2 and Tier 3, mainly because Eskom's Fossil Fuel Firing Regulations limit the minimum load to ensure stable combustion and safe operating conditions. Any deviation lower than this value requires a detailed engineering study to ensure stable combustion conditions. Eskom has embarked on a research programme to apply plasma burners and low fuel burners in coal-fired boilers, with the intention of overcoming the unstable combustion problem at low loads without the need to burn high volumes of fuel oil, which is both expensive and environmentally unfriendly.

Any future Tier 2 and 3 study is expected to target coal stations which will operate beyond 2035. The specific stations and the minimum operating load that will be required will be determined by the prevailing energy market at the time, the merit order of coal plants to be dispatched, the penetration of renewable generating plants and to what extent the remainder of the coal fleet will be required to operate at much reduced load. It is anticipated that this will only be defined during the period 2030 to 2035. Research to model the impact of renewable energy on the national grid began in 2025, but the modelling assumptions require further refinement before they can be used as input for the Tier 2 and 3 studies.

Attached reports provide information regarding the baseline/ diagnosis testing programme conducted. Tier 2 and Tier 3 research studies cannot be provided at this stage based on the reasons provided in the earlier sections of this communiqué.

Eskom remains committed to continuing the minimum load testing programme, considering its financial constraints, by developing models and operating procedures aligned with its operational recovery plans.

ESKOM
RESEARCH, TESTING AND DEVELOPMENT

TECHNICAL REPORT FOR RESEARCH

STAKEHOLDER COMMENT VERSION

REPORT TITLE	:	**GX OPERATIONAL FLEXIBILITY: ENHANCEMENTS, IMPROVEMENTS AND FLEET-WIDE IMPLEMENTATION**

REPORT REF No	:	RES/TRR/21/1962944
PROJECT NAME	:	Gx Operational Flexibility
PROJECT No	:	N.RA30023
STEERING COMMITTEE	:	Long Term Plant Health
AUTHORS	:	
DEPARTMENT	:	Gx Delivery

TECHNICAL REPORT FOR RESEARCH

Gx Operational Flexibility: Enhancements, Improvements and Fleet-Wide Implementation

REPORT REFERENCE NO:	RES/TRR/21/1962944		
DATE:	03 NOVEMBER 2023		
COMPILED BY:			08/12/2023 DATE
ACCEPTED BY:			8/12/2023 DATE
AUTHORISED BY:			08/12/2023 DATE

CONTENTS **PAGE**

EXECUTIVE SUMMARY

Gx Operational Flexibility: Enhancements, Improvements and Fleet-Wide Implementation

BACKGROUND

Flexibility is defined as the ability of the power system to deal with higher degree of uncertainty in the supply demand balance. The variability of supply in renewable energy electricity requires that the coal-fired power stations run on flexible modes of operation. Flexible modes of operation require systematic planning to avoid catastrophic events as well as damage to the plant equipment. These modes of operation require the units to do shorter start-ups, quicker ramp rates and operate at a lower minimum generated load.

Operational flexibility requires a systematic approach to address its different aspects. The requirements for implementation at the power station are not a copy and paste and therefore rigorous assessments on plant design and operational data are necessary per unit/power station. Plant tests therefore need to be conducted to diagnose the plant specific challenges and changes required for successful transition to flexible operation.

DESIGN OBJECTIVES AND ASSUMPTIONS

The objective of this project is to explore the capability of the units to support the minimum generated load as stipulated in the consistent data set (CDS) and identify changes that will support further turndown beyond the CDS minimum load. This was done through testing at the various units where observations were made. In this phase of the study, only diagnosis tests were conducted to baseline and identify limiting factors and opportunities that can further be explored. Where possible, ramp rates were also assessed during the tests.

METHODOLOGY

The operational flexibility assessment methodology follows a systematic approach that consists of six tasks as follows:

1. Initial evaluation, where a desktop study is conducted to review design and operating data as well as interview station personnel to set a basis for testing.
2. Diagnosis testing is conducted onsite and sets a baseline for the unit capabilities – limitations and opportunities.
3. Planning for tier tests, this step produces a test protocol to explore the opportunities identified during the baseline tests and addresses the limiting factors identified.
4. Tier testing is a second onsite test where the envelope to minimum load is pushed further based on the actions identified and presented in the test protocol.
5. Evaluation of risks of lower minimum load with long term considerations
6. Identifying potential future improvements and formalisation of the study.

Only task 1 and task 2 were conducted during this phase of the project and the findings are presented herein.

RESULTS / FINDINGS

All units tested were able to achieve their minimum loads as stipulated in the CDS, except for Medupi's unit 1 which was unable to reach its stipulated minimum load value. With the exclusion of Duvha unit 5 and Kusile unit 3, the rest of the units tested were able to go beyond the CDS load during the tests conducted, actions are required for these units to operate reliably at loads beyond the CDS load.

The areas of plant that posed the most challenges during the tests were the milling plant, inclusive of the reliability of fuel oil burners. The milling plant in most instances limited the ability to go lower in load as well as the stable operation of the minimum load. Most of the milling plants were either overdue for maintenance or out of service for maintenance. Operator confidence was another aspect that contributed to not going lower in load. The operators were mostly not comfortable with going down to the load that required 3 mills, with the concern of not being able to respond adequately to system ops when required to ramp up and bring back a 4th mill.

Another area of concern was the control of the air heater gas outlet temperatures to avoid corrosion in air heaters, and to keep the SO_3 plant in operation. Lethabo was the only power station that experienced high particulate emissions when going beyond the CDS load, where the SO_3 plant goes on standby. Other stations with Electrostatic precipitators were able to stay within the particulate matter limits after the SO_3 plant went on standby.

RECOMMENDATIONS

It is recommended that diagnosis tests be rolled out to the rest of the units at the power stations tested. Different scenarios should be tested when rolling out the diagnosis tests to the rest of the units. This will allow for the development of minimum load procedures catering for different operating conditions. This should include but not limited to different mill combinations, biasing of mills, operation with single feeder and operation with boiler feed pumps and/or electric feed pumps and operating for longer periods at low loads.

Three units are recommended for tier testing, these are Kendal, Kusile and Matimba. The selection criteria for these units considered, remnant life, merit order dispatch, type of boiler and the capability assessment to go lower on load.

CONCLUSIONS

Seven of the eight units were able to operate at their CDS minimum load with no fuel oil support, the CDS stipulates the minimum loads on a net basis. The generated load is not constant as the auxiliary power changes with a change in load:

- Arnot can operate at a minimum load of 230 MWg with four mills. Three mill operation is possible with pressure mills in service.
- Duvha can operate at a minimum load of 350 MWg with three mills. The secondary air circulation is key to maintain the back end temperatures within the required limits.

- Kendal was able to operate at a minimum load of 326 MWg with three mills. Kendal demonstrated operation at 300 MWg with biasing of mills.
- Kriel operated at a minimum load of 305 MWg with four mills. Further investigation into the positive furnace pressure is required.
- Kusile was able to operate at a minimum load of 350 MWg with three mills. Further turndown beyond 350 MWg requires operation with two mills.
- Lethabo operated at a minimum load of 350 MWg with three mills. Further turndown requires attention to the settings of the SO_3 plant in order to remain within the minimum emissions standard on particulate matter. The standby mode should be set on temperature rather than the load.
- Matimba can operate at a minimum load of 350 MWg with three mills. Further turndown at Matimba will require operation at circulation mode with two mills in operation.
- Medupi was tested at a minimum load of 420 MWg with three mills. The major limiting factor to lower load was the evaporator performance. Further turndown to meet CDS minimum load may require circulation mode operation.

KEYWORDS

Operational flexibility, Minimum load, Low load, Ramp rates, CDS, Renewable energy, Grid stability.

ITEM DETAILS

Steering Committee	:	Long Term Plant Health
Report Number	:	RES/TRR/21/1962944
Project No	:	N.RA30023
Project Name	:	Gx Operational Flexibility
Project Manager	:	FULUFHELO MAKANANISE
Contact Number	:	011 629 5722
Customer	:	Generation
Financials		
Actual Cost of this Task	:	R3 671 365
Cost to Implement	:	R4 683 669

RETURN ON INVESTMENT

Operational flexibility alleviates the need to shut-down coal-fired power plants and/or units when the system has over capacity. The benefit of not shutting down the unit/s is seen in the reduction of fuel oil usage.
As an example, Majuba Power Station is designed to consume the following amounts of bunker 150 during start-up as stipulated in the CDS revision 4 document.

80 tons for a cold start-up,
55 tons for a warm start-up,
35 tons for a hot start-up.

The cost of fuel oil is 6 866 R/ton.

Cost of Fuel Oil per start-up	**Cost/unit**	**Cost per 6 units**
Cold Start	R549 280	R3 295 680
Warm Start	R377 630	R2 265 780
Hot Start	R240 310	R1 441 860

Assume that the plant is on “cold reserve” for 1 weekend every month per year. Therefore, the ROI for running the plant at its min-gen instead of “cold reserve” is

$$ROI = \frac{Cost\ Saving\ from\ Investment - Cost\ of\ Investment}{Cost\ of\ Investment} : 1$$

$$ROI = \frac{R\ 39\ 548\ 160 - R4\ 986\ 279}{R\ 4\ 986\ 279} : 1$$

$$ROI = 6.9 : 1$$

ABBREVIATIONS LIST:

Abbreviation	Description
AD	Air Dried
AGC	Automatic Grid Control
AR	As Received
BFPT	Boiler Feed Pump Turbine
BMCR	Boiler Maximum Continuous Rating
CDS	Consistent Data Set
C&I	Control & Instrumentation
CO	Carbon Monoxide
CV	Calorific Value
DCS	Distributed Control System
EFP	Electric Feed Pump
EPRI	Electric Power Research Institute
ESP	Electro Static Precipitator
FFFR	Fossil Fuel Firing Regulations
FGD	Flue Gas Desulphurisation
GAH	Gas Air Heater
GCV	Gross Calorific Value
HRH	Hot Reheat
ID	Induced Draught
IM	Inherent Moisture
LH	Left Hand
LHT	Left Hand Top
MCR	Maximum Continuous Rating
MES	Minimum Emissions Standard
MJ	Mega Joule
MW	Megawatt
MWg	Megawatt generated
MWnet	Megawatt nett – send out
NOx	Oxides of nitrogen
O_2	Oxygen
PA	Primary Air
PM	Particulate Matter
PPM	Parts per Million
RH	Reheat
RH	Right Hand
RT&D	Research, Testing & Development
SH	Superheat
SO_2	Sulphur Dioxide
SO_3	Sulphur Trioxide
SOx	Oxide of sulphur
TM	Total Moisture
TMCR	Turbine Maximum Continuous Rating

LIST OF TABLES

LIST OF FIGURES

GX OPERATIONAL FLEXIBILITY: ENHANCEMENTS, IMPROVEMENTS AND FLEET-WIDE IMPLEMENTATION

1 INTRODUCTION

The ability for a generating unit to operate flexibly depends on its ability to do shorter start-ups, quicker ramp rates and operation at a lower minimum generated load. The shorter the start-up time, the less costly it would be. The changes required to enable operational flexibility are plant specific and therefore site testing is required to diagnose what limitations exist before conclusions can be drawn and modifications implemented. Operation at a minimum load is preferable compared to cycling the unit in on and off modes.

A case study was conducted at Matla and Tutuka Power Stations in 2017 where a methodology to systematically assess the capabilities of the coal units to achieve operational flexibility was developed in collaboration with the Electric Power Research Institute (EPRI). The study was extended to Majuba Power Station to expand its minimum load capabilities. The methodology developed consisted of 6 tasks:

1. Initial evaluation, which involved review of design and operational data of the respective units.
2. Diagnosis tests, where the unit's initial capabilities are assessed.
3. Development of a test protocol in planning for tier testing. The protocol shows a plan on how the unit's further turndown will be explored.
4. Tier testing which explores further turndown and goes beyond the minimum load identified during the diagnosis tests.
5. Evaluation of risks of the new established minimum load.
6. Finalisation of findings

The focus of this phase of research was first to identify changes required to achieve the Eskom documented minimum generated load as stipulated in the consistent data set (CDS), and thereafter explore the unit's ability to go further down in load. The assessment includes the unit's capability to improve ramp rates. The assessments to go lower were in some instances limited due to system constraints where permission to go lower was not granted.

This report summarises the outcomes of tests conducted at eight coal fired power stations [Arnot, Duvha, Kendal, Kriel, Kusile, Lethabo, Medupi and Matimba] in evaluating their ability to achieve their CDS minimum load.

2 DEFINITIONS

Terminology	Definitions
Operational Flexibility	The ability of the power system to deal with higher degree of uncertainty in the supply demand balance.
Minimum Load	The minimum generated unit load in MW that can be achieved under normal operating conditions (Stable combustion without fuel oil support).
CDS Minimum Load	Minimum load as stipulated in the CDS document.
CDS sub-minimum load	Minimum load that is lower than the minimum load stipulated in the CDS document.
Ramp Rate	The change in net power per change in time, it indicates how fast a power station unit can change its net power during operation.
Unit Start-up	The period from starting plant unit operation from light up to synchronisation and from synchronisation to 90% base load. This can be categorised into hot start, warm start and cold start.
Hot Start	Less than 8 hours since plant shutdown.
Warm Start	Between 8 and 48 hours since plant shutdown.
Cold Start	Greater than 48 hours since plant shutdown.
Diagnosis tests	Tests conducted to determine the lowest load that the unit can safely operate at, without fuel oil support and without limits. This test diagnoses the limiting factors to achieve the required minimum load.
Tier tests	Tests conducted at loads lower than the diagnosis test load. Tier tests push the minimum load envelope and identifies further opportunities and risks to minimum load.
System Operator	The legal entity licenced to be responsible for short-term reliability of the interconnected power system, which is in charge of controlling and operating the Transmission system and dispatching generation (or balancing the supply and demand) in real time.

3 OPERATIONAL FLEXIBILITY OBJECTIVES

The operational flexibility methodology requires that 6 tasks be implemented to answer the research questions posed. However, priority was given to assessing the capabilities of the eight stations to meet their CDS stipulated minimum loads and minimise the wind curtailment incidents currently being experienced due to the unit’s inability to ramp down to these loads when required to do so.

Therefore, the main objective of this phase of research was to address task 1 and task 2 of the operational flexibility methodology where design and operational data was reviewed for the eight coal fired power stations and thereafter diagnosis tests conducted, focusing on achieving the CDS stipulated minimum loads. The objective of the tests was to identify and address limiting factors, as well as to assess the different operational strategies to achieve the required CDS minimum load. The following table summarises the CDS min-gen values per unit in each Eskom coal fired power station where AGC is off and with no fuel oil support (option C) as stipulated in revision 4 of the CDS document:

Table 4.1-1: CDS Stipulated Minimum Load (Net)

Power Station	Unit 1	Unit 2	Unit 3	Unit 4	Unit 5	Unit 6	Unit 7	Unit 8	Unit 9	Unit 10	Aux Power
Arnot	220	90	90	90	90	90					20
Camden	100	100	100	100	100	100	100	100			10
Duvha	375	375	-	325	325	325					25
Grootvlei	130	130	130	-	-	-					10
Hendrina	-	120	-	120	120	120	120	-	-	120	10
Kendal	280	280	280	280	280	280					46
Komati	-	-	-	-	-	-	-	-	-		-
Kriel	280	280	280	280	280	280					25
Kusile	319	319	319	319	319	319					80
Lethabo	325	325	325	325	325	325					25
Majuba	405	405	405	446	446	446					(1-3) 51; (4-6) 50
Matimba	330	330	330	330	330	330					50
Matla	300	300	300	300	300	300					25
Medupi	361	361	361	361	361	361					(1-4,6) 74; U5-77
Tutuka	300	300	300	300	300	300					24

The following units were tested at the respective power stations:

- Arnot U2,
- Duvha U5,
- Kendal U2,
- Kriel U6,
- Kusile U3,
- Lethabo U4,
- Matimba U3, and
- Medupi U1.

The study identified risks associated with operational flexibility on grid stability, linked to the unit's ability to respond quickly to load demand as well as the unit's ability to operate at a lower minimum load. Fossil Fuel Firing Regulations (FFFR) limits affecting flexible operation were assessed. Coal quality effects on flexibility and emission performance during low loads were also assessed.

4 COMMON KEY LIMITING FACTORS

Site operating conditions tend to differ even for same technology units, burning the same coal, therefore limiting factors will differ per unit. However, there are some limiting factors that are common when going down in load, and these are summarised below:

4.1 MILL CAPACITY AND FEEDER LIMITS

All coal units are guided by the FFFR mill capacity limits which stipulates that mills should operate between 60% and 90% of their maximum mill rated output. These limits were observed during the tests and were influenced by the quality of coal. The lowest combination of mills used in all tests was 3 mills. Better coal quality limits the ability of the units to go lower without taking out a mill as the mills operate closer to the 60% range. Poor quality coal brings a challenge of operating closer to the 90% FFFR limit.

4.2 STEAM FLOW LIMITS

The objective of the minimum load tests is to determine the lowest safest load that can be operated without fuel oil support. FFFR requires that fuel oil support be brought in, whenever the steam flow drops below 38% of boiler maximum load. This was found not to be a challenge at the loads tested during this phase of research. Fuel oil support was only brought in to stabilise the units and taken off thereafter.

4.3 PYROMETER TEMPERATURE LIMIT

Pyrometer temperatures and flame scanners assist in monitoring the existence and the stability of the flame to avoid furnace explosions. Stable pyrometric temperatures are necessary to maintain the flame. A limit of 800˚C was monitored during the tests. Instances of low pyrometer temperatures were experienced; however, these were intermittent. To mitigate against this risk, the stations were requested to clean the pyrometers every day before the commencement of the tests.

4.4 ECONOMISER INLET WATER FLOW LIMIT

This phase of testing did not intend for the loads to go beyond the Benson point for once-through boilers. A minimum economiser inlet flow is observed for Benson/once-through boilers to maintain stable flow conditions.

4.5 ECONOMISER OUTLET OXYGEN CONCENTRATION LIMIT

The oxygen (O_2) concentrations of the flue gas at the economiser outlets are an indication of the flue gas at the furnace exit. The oxygen concentration at the economiser outlet is expected to increase with a decrease in load. The FFFR stipulates an upper limit of 9% for loads that are above 38% of Boiler Maximum Continuous Rating (BMCR). All stations were within the 9% (O_2) limit during the tests.

4.6 AIR HEATER COMBINED TEMPERATURES

The combined temperatures are monitored due to the risk of corrosion in the air heater cold end plates which results from flue gas temperatures that go below dew point. A cold end or combined temperature limit of 160˚C was observed throughout the tests. In most instances during the tests, these temperatures were controlled by circulating the hot secondary air to improve the incoming air temperature. Steam air preheaters were also used to improve the air heater air inlet temperatures.

5 DATA COLLECTION, OBSERVATIONS AND SAMPLING FOR TESTING

5.1 OPERATING DATA

Key process parameters were monitored during each test. These differed in terms of areas of concern on the respective units.

5.2 COAL SAMPLE ANALYSIS

Hourly coal samples were taken during each test and sent to Research, Testing and Development (RT&D) coal laboratory. These were analysed for ultimate and proximate, total moisture and calorific value (CV). The hourly coal sampling was done to see the change in unit behaviour at low loads as the coal quality changed.

5.3 COMBUSTION MONITORING

Pyrometer temperatures were monitored to ensure flame stability. Hourly physical measurements of O_2 and CO were taken to monitor the FFFR limits. The fly ash samples were taken before the start of the test and after the tests were completed to see how the combustion changed before and after the unit went down in load. Stable combustion requires that at least two pressure mills are in service for a 3 mill combination operation.

5.4 EMISSIONS DETERMINATION

Emissions were also monitored during periods of low load, especially particulate emissions for units with electrostatic precipitator (ESP) where the SO_3 plant tend to go on standby or shut down when going down on load.

6 FINDINGS AND DISCUSSIONS

6.1 DIAGNOSIS TESTING OVERVIEW

All units tested were able to achieve their minimum loads as stipulated in the CDS, except for Medupi’s unit 1 which was unable to reach its stipulated minimum load. With the exclusion of Duvha unit 5 and Kusile unit 3, the rest of the units were able to go beyond the CDS load during the tests conducted. Figure 6.6-1 below shows an overview of the minimum load performance at 11 power stations tested since the inception of the study. The CDS stipulates net minimum load, the tests monitor generated minimum load and therefore the CDS minimum net loads were converted to generated loads utilising the auxiliary power either determined during the tests or auxiliary power stipulated in the CDS (i.e in instances where the auxiliary power changes were minor).

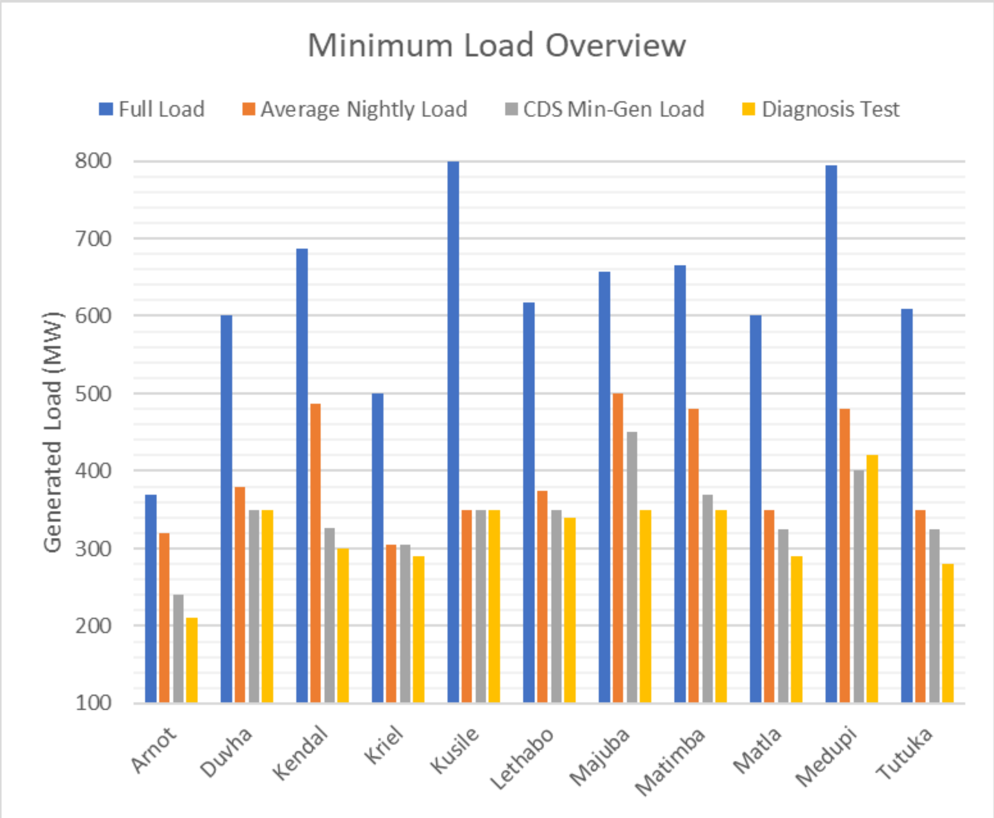


Figure 6.1-1: Minimum Load Overview

The areas of plant that posed the most challenges during the tests were the milling plant, inclusive of the reliability of fuel oil burners. The milling plant in most instances limited the ability to go lower in load as well as the stable operation of the minimum load. Most of the milling plant was either overdue for maintenance or out of service for maintenance. Operator confidence was another aspect that contributed to the inability to go lower in load. The operators were mostly not comfortable with going down to the load that required 3 mills in fear of not being able to respond adequately to system operator when required to ramp up and bring back a 4th mill.

Most of the units can operate at their CDS minimum loads however maintenance of certain systems is required before the operators can operate at these loads comfortably. The detailed findings are shared per station.

6.2 ARNOT POWER STATION

6.2.1 Arnot Unit 2 Test Overview

The diagnosis test was conducted on the evening of the 22^{nd} till the morning of the 23^{rd} of April 2023. Arnot operates its units at a nightly average of 320 MWg whilst the CDS minimum load is 240 MWg [however, Arnot recognises their official minimum load as 210 MWnet (230 MWg) for unit 2 - 6]. During the diagnosis test, a steady load of 210 MWg was achieved with 4 mills in service as shown in figure 6.2-1 below.

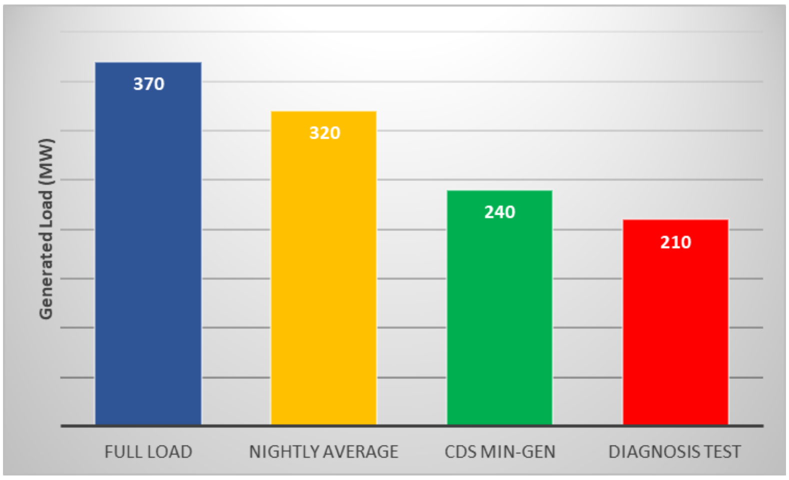


Figure 6.2-1: Arnot Unit Overview

The following program for Arnot's diagnosis testing was adopted.

Table 6.2-1: Arnot Unit 2 Diagnosis Testing Plan

Date	Test Period	Load [% TMCR]
22 April 2023	22:30	320 MWg [87%]
22-23 April 2023	23:40 – 01:15	230 MWg [62%]
23 April 2023	01:25 – 02:50	200 MWg [54%]
23 April 2023	02:50 – 03:40	210 MWg [57%]

The unit operated steadily at 230 MWg with 4 mills in service between 23:30 till 01:10. Mill A was then removed, and load reduced to 200 MWg; from 01:20 till 02:45 the unit operated with 3 mills in service at 200 MWg, however the boiler was not stable for most of this duration. The instability was due to boiler drum level fluctuations as shown in figure 6.2-2.

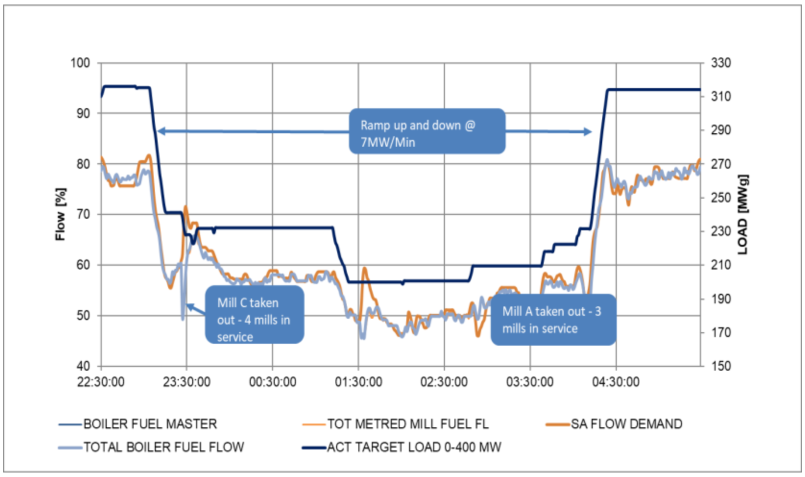


Figure 6.2-2: Arnot Diagnosis Test Overview

The fluctuations in the boiler drum level, which correlates to the fluctuation in the feed water flow, started around 01:55 up until 02:10 as shown in figure 6.2-3 below. This is attributed to the inability of the boiler feed pump turbine (BFPT) to supply the required water flow; the electric feed pump (EFP) was eventually brought in service at 02:00 to support the BFPT up until 02:10 when the BFPT was back to optimal performance.

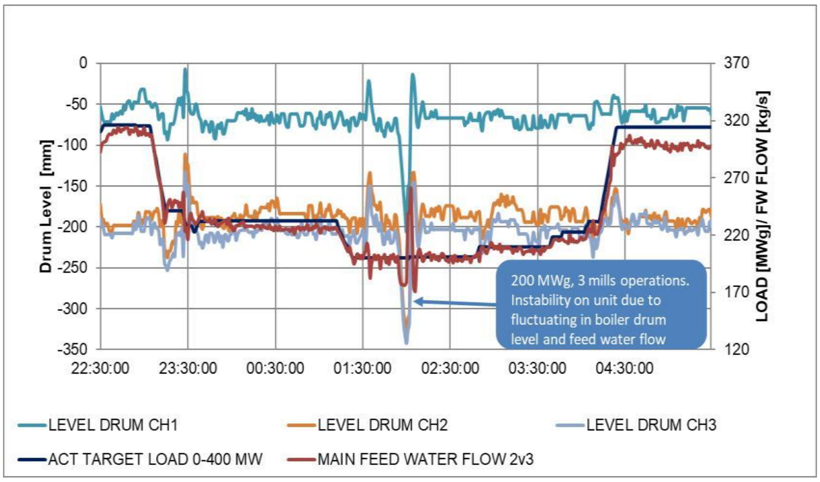


Figure 6.2-3: Arnot Boiler Drum Level Fluctuations

The intention of the diagnosis test was to operate the unit steadily with 3 mills in service. However, operator experience linked to 3 mills operation and the possibility of furnace black-out in the unluckily event that one of the mills trips, alluded to comfortable operation with 4 mills. At 02:45, the load was increased to 210 MWg with the addition of mill A, for a 4-mill operation. Observation of flame stability during the diagnosis test is shown in figure 6.2-4.

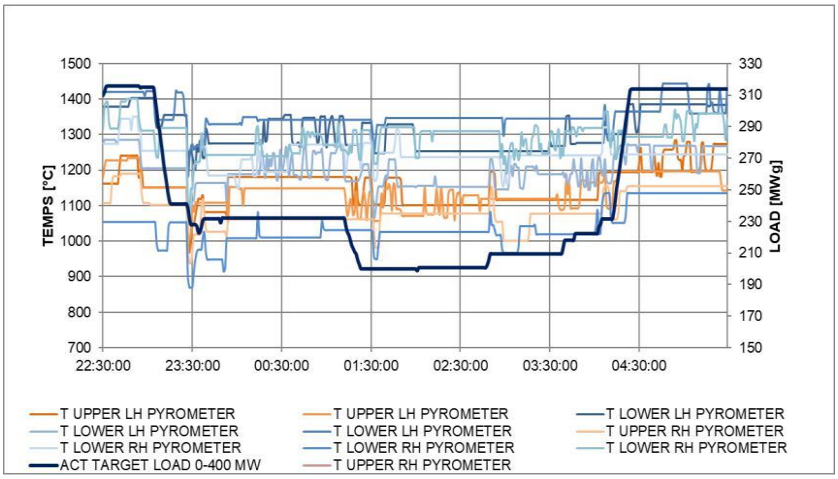


Figure 6.2-4: Arnot Flame Temperatures

There were no issues identified with the flame temperatures, they were on average above 1000°C, except for the conditional dips in flame temperature during the transitions. The lower right-hand pyrometer was found to detect the lowest flame temperature throughout the test duration, however, this prevailed even after the operator's intervention to clean the pyrometers.

The mills were observed in reference to the fossil fuel firing regulations (FFFR) limits, the capacity of the mills was between 60% and 90%. There are also limits on the primary air (PA) flows which are used by the controller to operate the mills; these are 13.2 kg/s for alarms and

12.7 kg/s for a mill trip. Figure 6.2-5 shows the mill capacities and PA flows observed during the diagnosis test.

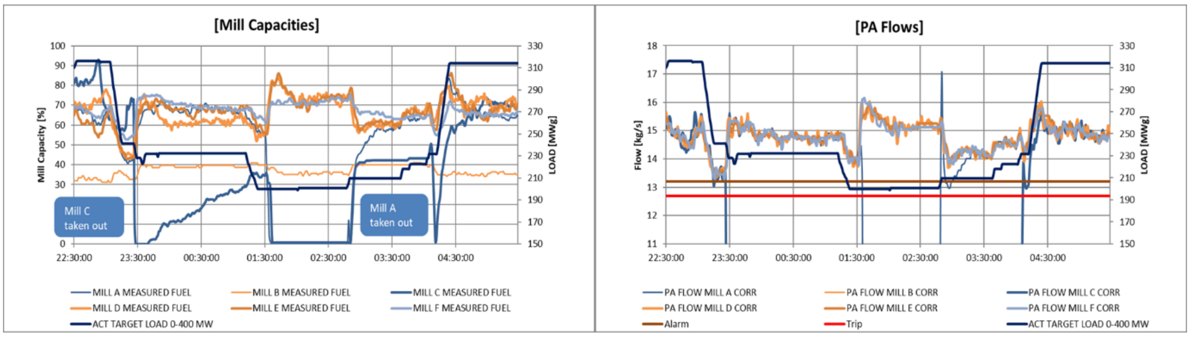


Figure 6.2-5: Arnot Mills Capacity and Primary Air Flows

The PA flows during the 4 mills and 3 mills operations were well within the alarm and trip limits; for the 3 mills operation the PA flows were higher at 200 MWg than for the 4 mills operation at 210 MWg. The high PA flows indicate the ability to operate at a reduced mill capacity before getting closer to the 13.2 kg/s alarm limit, however the 60% FFFR capacity limitation requires attention.

The test coal samples, and fly-ash samples (ce-grit samples) analysis results are tabulated below.

Table 6.2-2: Arnot Unit 2 Coal and Ash Analysis

Proximate Analyses (air dried – ad)	Units	Start of Test	End of Test	Test Average
Analytical Moisture	%	4.60	4.30	4.72
Ash	%	23.60	21.60	22.42
Volatile Matter	%	21.50	22.00	21.58
Fixed Carbon (by difference)	%	50.30	52.10	51.28
Ultimate Analyses (ad)				
Carbon	%	58.28	60.43	59.24
Hydrogen	%	3.04	3.07	3.01
Nitrogen	%	1.32	1.44	1.388
Total Sulphur	%	0.62	0.6	0.614
Carbonate (as CO2)	%	2.92	3.03	2.972
Oxygen (by difference)	%	5.62	5.53	5.638
Gross Calorific Value, ad	MJ/kg	22.70	23.50	23.02
Total Moisture, as received	%	7.70	7.40	7.80
Combustibles in fly ash LH	%	1.20	3.20	-
Combustibles in fly ash RH	%	1.60	1.00	-

Five coal samples were taken during the test. Presented in table 6.2-2 is the coal sample taken at the start of the diagnosis test and that at the end of the test duration; the test average considers all samples taken. The hourly coal qualities did not significantly vary during the diagnosis test, the standard deviations for all paraments in the five samples was below 0.80.

The combustible matter in the fly ash, obtained from the economiser outlet ce-grit samplers on the left-hand side, at the end of test was higher than at the start. However, on the right-hand side the combustible matter in the fly ash was lower at the end than at the start of the diagnosis test.

The oxygen measurements at the economiser outlet, compared to the station's readings are presented below.

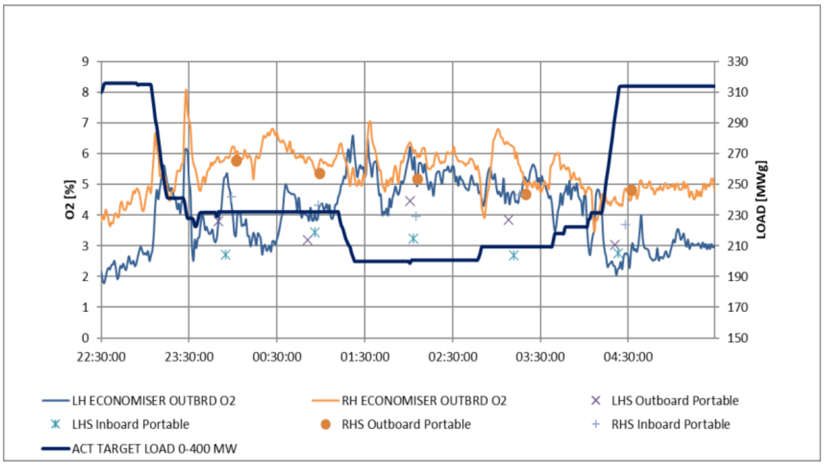


Figure 6.2-6: Arnot Economiser Outlet Oxygen Concentration

The stations outboard O_2 analysers compare with the portable gas analysers reading in the outboard ducts, which illustrate an O_2 split between the left hand and the right hand ducts. The inboards read lower than the outboards on both sides (portable analyser). The split is more noticeable at higher loads.

The flue gas temperature at the exhaust of the air heater and the air at the inlet of the air-heater were observed particularly to assess the possibility of reaching acid dew point. They are presented below.

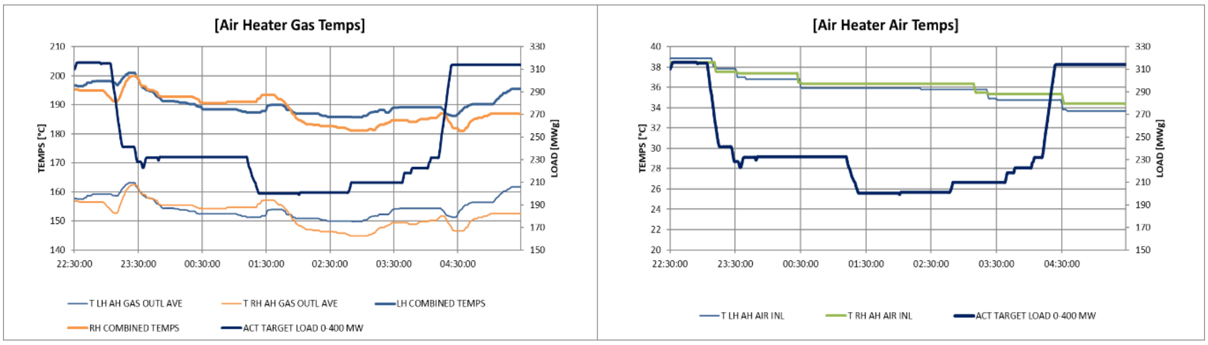


Figure 6.2-7: Arnot Air Heater Combined Temperatures

The combined air heater temperature is shown on the "Gas Temps" graph. The combined temperature was higher than the 160°C due to the higher gas outlet temperatures.

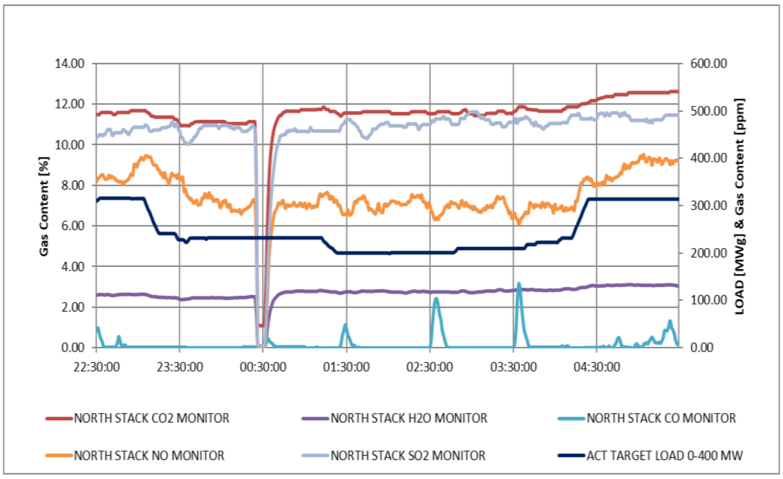


Figure 6.2-8: Arnot Stack Emission

There was no significant change in the overall emissions when the load was being reduced or increased; the NOx emissions however decreased from 400 ppm at 310 MWg to 300 ppm at 220 MWg. Spikes in CO were observed in coordination with taking off and returning of mills.

The steam temperatures trends are shown below.

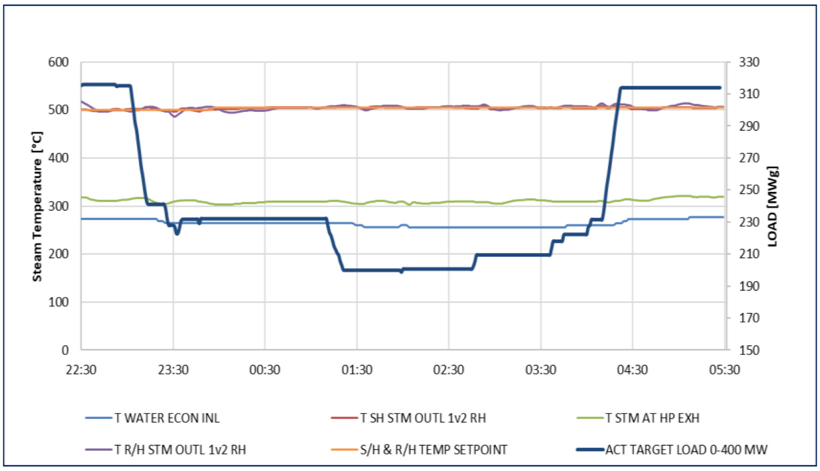


Figure 6.2-9: Arnot Steam Temperatures

The superheater (SH) and reheater (RH) steam temperatures at Arnot are controlled on a moving set-point principle; at full load the set-point is 515°C and reduces with load. During the diagnosis testing the setpoint that was used is 505°C, the SH and RH steam temperatures were controlled well within the setpoint. The figure above shows that there was no deviation from the set-point.

6.2.2 Conclusion And Recommendations

Arnot unit 2 can operate at CDS minimum load of 230 MWg with 4 mills. It was demonstrated that it can operate at 210 MWg reliably with 4 mills, and without fuel oil support. At minimum load with 4 mills the mill capacities were at the lower end of the FFFR limit, at 210 MWg they were literally on 60%.

The oxygen concentration at the economiser outlet was lower than 7% which is below the 9% FFFR limit. The air heater combined temperature was well above the 160°C for acid gas dew point observation. There were no issues with the stack emissions and the turbine inlet (SH and RH) steam temperatures.

Arnot has the potential to operate at an even lower load, however a 3 mills operation must be considered; to mitigate the drum pressure issue that occurred, a pressure mill must be used during the 3 mills operating.

It is recommended that Arnot conduct the min-gen tests at 230 MWg and 210 MWg with 4 mills in service while closely monitoring the mill capacities and the drum pressure.

6.3 DUVHA POWER STATION

6.3.1 Duvha Unit 5 Test Overview

The diagnosis tests were conducted on the night of the 13th and the 14th of June 2022. Duvha's full load is 600 MWg with its nightly average sitting at 380 MWg. The CDS minimum load for unit 1 & 2 is 400 MWg, for unit 4 – 6 it is 350 MWg, and the Benson Point is at 270 MWg.

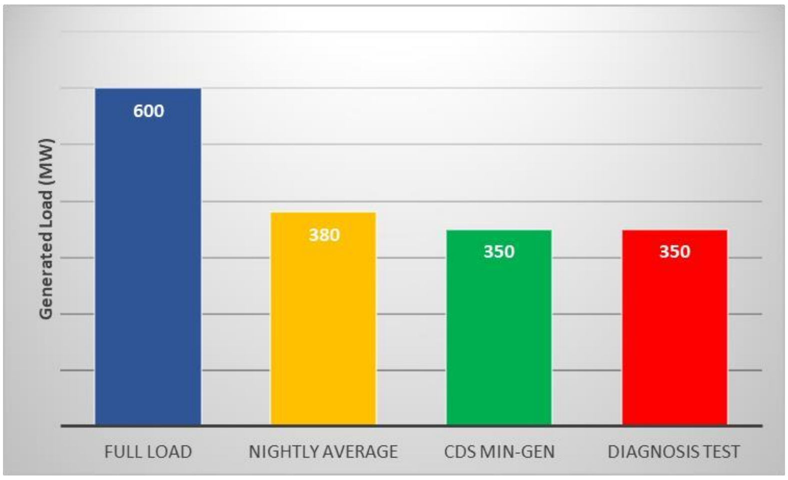


Figure 6.3-1: Duvha Unit 5 Overview

The following program for Duvha's diagnosis testing was adopted.

Table 6.3-1: Duvha Unit 5 Diagnosis Testing Plan

Date	Test Period	Load [% TMCR]
13-14 June 2023	22:00 – 03:00	380 MWg [63%]
14-15 June 2023	22:00 – 04:00	350 MWg [58%]

Duvha's CDS minimum load of 350 MWg was achieved during test 2 with three mills and no fuel oil support.

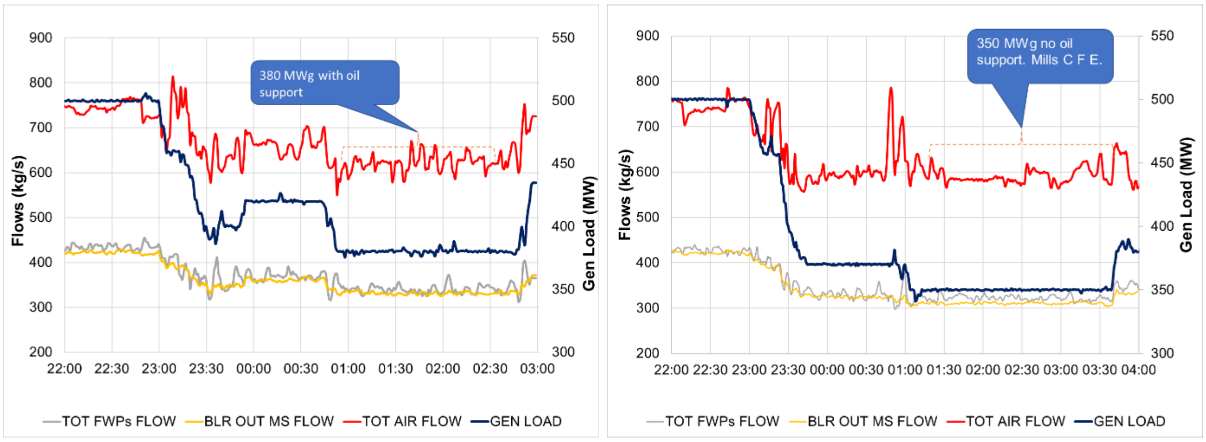


Figure 6.3-2: Duvha Diagnosis Test Overview

During test 1, the unit was unstable at a load of 380 MW with 4 mills and fuel oil support. The main difference between test 1 and test 2 was the mill configuration and unit operator experience; test 1 was operated with mills DCFB at 380 MWg and test 2 with mills CFE as shown below.

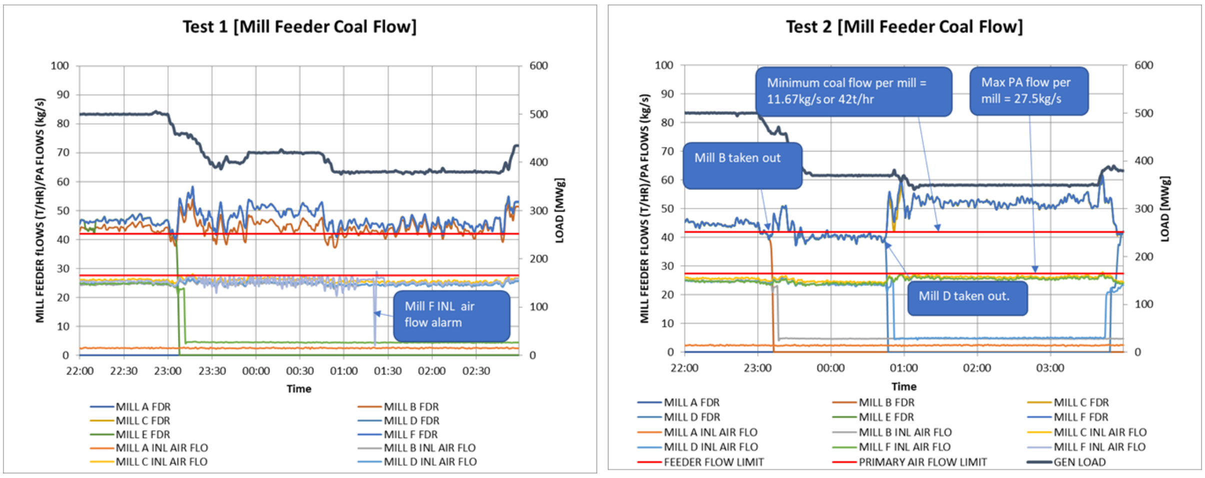


Figure 6.3-3: Duvha Mill Feeder Configurations

To achieve the planned load for test 1, mill E was taken out of service just after 23:00, however the load was maintained above 400 MWg due to national grid limitations. The unit was not stable while the unit was operated at 420 MW, fluctuations in flame temperatures were observed and fuel oil support was initiated. The primary reason for the unit instability was the status of mill B, which was rejecting a lot and therefore not being able to provide the required coal flow. For test 1, at 380 MWg, the unit was operated with fuel oil support.

For test 2 the unit was operated at 350 MWg with three mills and no fuel oil support. At the start of test 2, mill B was taken out of service and the unit operated at 370 MWg with mill DCFE in service and no oil support. At this generated load the mill capacities were sitting on the lower FFFR limit for mill loading, and the flame temperatures were stable. The unit load was further reduced to 350 MWg and operated with mills CFE, after the removal of mill D, the unit was operated with no fuel oil support and flame stability was observed.

The flame temperatures were observed for both tests and are shown below.

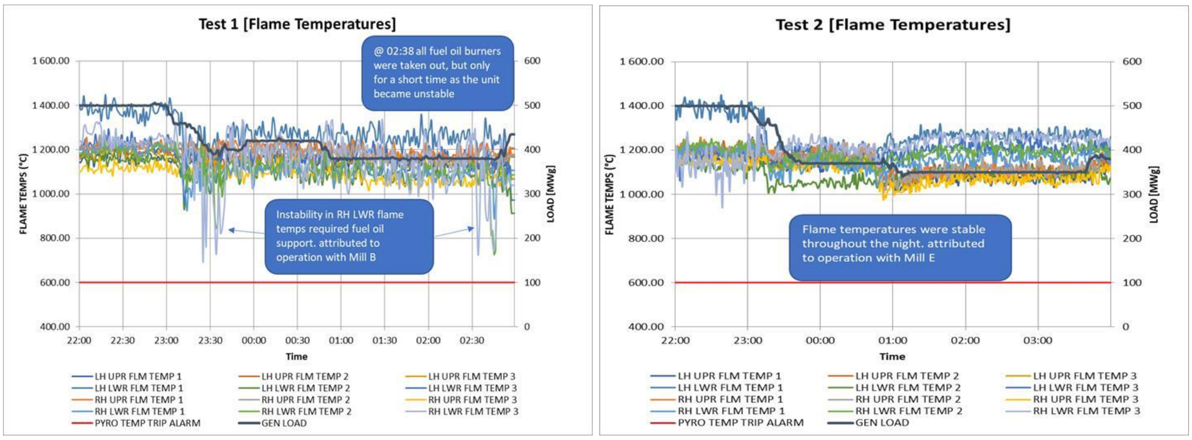


Figure 6.3-4: Duvha Flame Temperatures

The average flame temperatures observed for both tests were above 1000°C, however for test 1 there were a number of temperature drops observed, particularly associated with the removal of mill E and fuel oil support at 02:30. The right-hand lower pyrometer 3 fluctuated throughout test 1 testing period, with the noted drops as mentioned. When fuel oil support was removed, two of the right-hand lower pyrometers dropped below 800°C, i.e., right hand lower pyrometer T2 and T3. Consequently, fuel oil support was returned to prevent unit trip. However, for test 2 there were no flame temperature fluctuations observed when mill B and later mill D were taken out of service to achieve the minimum load.

Coal samples were obtained from the belts feeding the units coal bunkers at different periods on the test days, fly-ash samples were taken at the start and end of each test. The coal analysis results are presented below.

Table 6.3-2: Duvha Unit 5 Coal and Ash Analysis

	Units	Test 1 13/06/'22		Test 2 14/06/'22	
Proximate Analyses (air dried – ad)		*16H30*	*22H00*	*23H00*	*00H30*
Analytical Moisture	%	2.8	2.9	3.1	2.9
Ash	%	26.7	24.8	25.2	27.8
Volatile Matter	%	19	19.6	19.5	19
Fixed Carbon (by difference)	%	51.5	52.7	52.2	50.3
Ultimate Analyses (ad)					
Carbon	%	56.86	58.38	57.5	55.5
Hydrogen	%	3.17	3.08	2.95	2.92
Nitrogen	%	1.06	1.23	1.42	1.48
Total Sulphur	%	0.98	0.69	0.72	0.86
Carbonate (as CO2)	%	2.85	2.94	2.88	2.78
Oxygen (by difference)	%	5.58	6	6.23	5.76
Gross Calorific Value, ad	MJ/kg	22.69	23.36	22.23	22.32
Total Moisture, as received	%	6.4	5	5.8	5.8
		Start	*End*	*Start*	*End*
Combustibles in fly ash LH	%	3.9	2.9	3.9	4.6
Combustibles in fly ash RH	%	3.8	3.2	3.9	3.4

The coal samples taken during the two tests do not differ significantly from each other, indicating that the coal burnt during the tests had a consistent quality. The coal taken at 22:00 during test 1 had the highest calorific value and the lowest ash content compared to the other coal samples.

The combustible matter in fly ash at the start of both tests was found to be, on average, 3.9%. The combustible matter in fly ash at the end of test 1 was lower compared to those analysed for the end of test 2. The combustible matter in fly ash obtained from the LH of the economiser outlet at the end of test 2 was found to be the highest.

The oxygen measurements at the economiser outlet, compared to the station's readings are presented below.

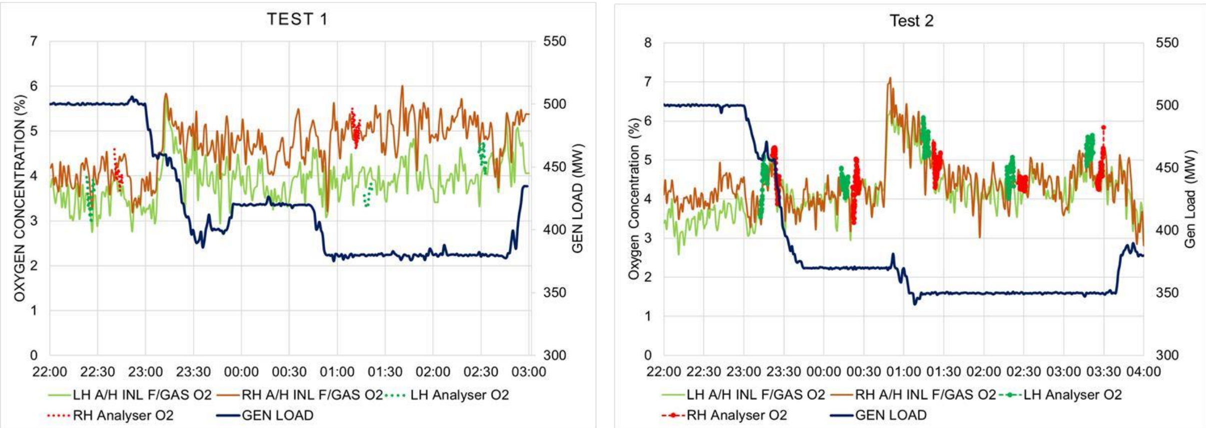


Figure 6.3-5: Duvha Oxygen Concentration

The manual oxygen taken at the air heater inlet ports on both the LH and RH were found to trend well with the station readings on both days. On test 1, an oxygen split was observed in line with the boiler instability mentioned above. However, for test 2 there was minimum deviation between the oxygen readings on the LH and the RH side. On both days the oxygen reading were below the FFFR limit of 9%.

The air heater air inlet and flue gas outlet temperatures were observed during the two nights, regarding keeping SO_3 plant in service, as well as observing the combined temperature. The temperature trends are presented below.

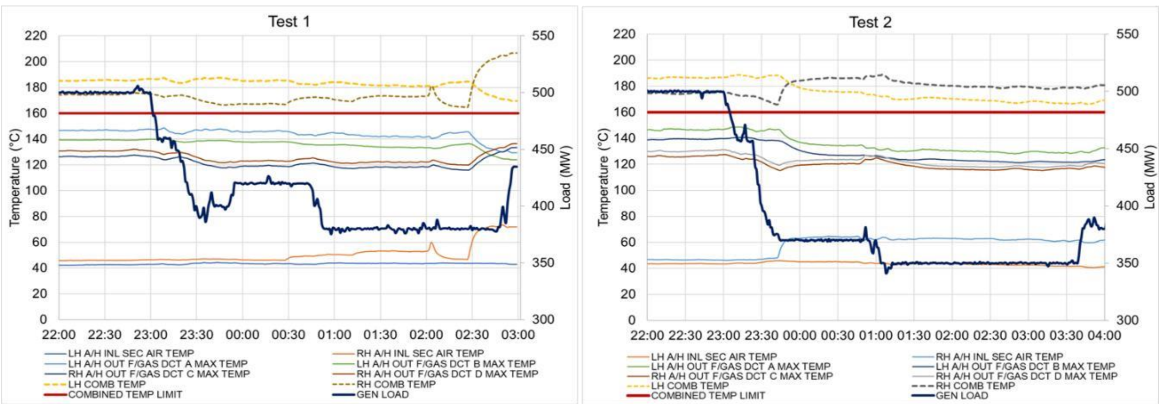


Figure 6.3-6: Duvha Air Heater Combined Temperatures

Duvha aims to maintain the air heater gas outlet temperature above 110°C, this is done by opening the air recirculation dampers when the gas outlet temperature drops below 110°C, as per the station's operating procedure. During test 1, the RH gas outlet temperature was below the limit, the RH air damper was opened around 02:05, however it failed to stay open and returned to close position; this closure of the damper resulted in the RH inlet air temperature dropping sharply. However, for test 2, the RH air recirculation damper was opened and locked at 50% as soon as the load was reduced from 500 MW to 370 MW, this maintained the gas outlet temperature above 110°C, and the SO_3 plant in service. The combined temperatures were consequently above the 160°C limit for both nights.

Gaseous species and particulates trends are presented below.

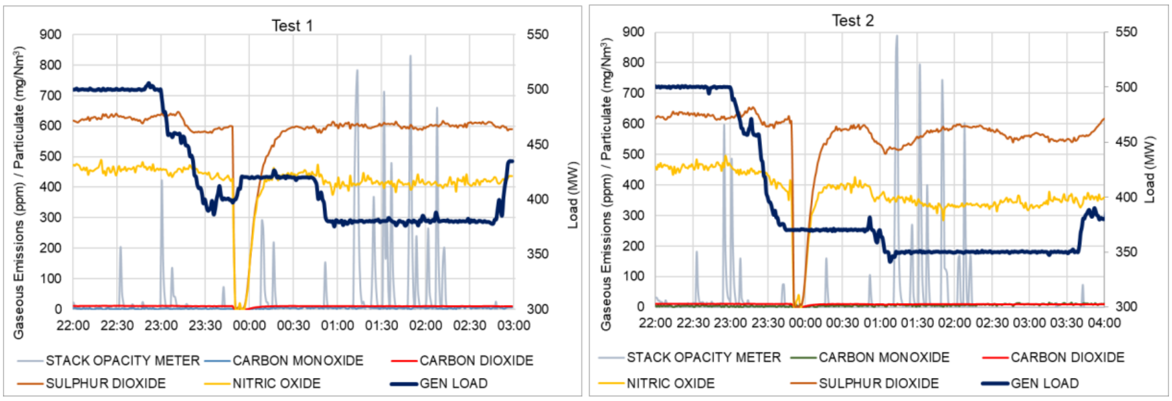


Figure 6.3-7: Duvha Stack Emissions

The emissions were found to reduce with load on both nights. Occasional spikes in particulate emissions were observed for both tests, but on average the particulates were at their minimum even at 350 MWg.

The main steam temperatures and super heater spray water flows were observed for both tests. These trends are presented in figure 6.3-8 below.

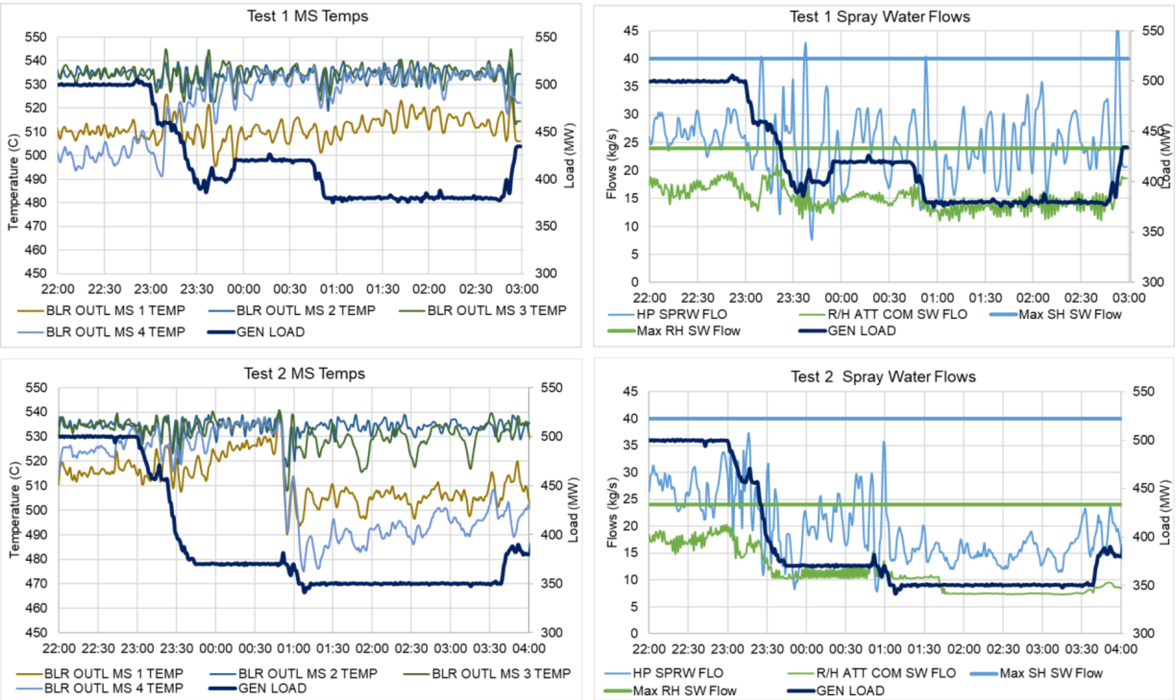


Figure 6.3-8: Duvha Main Steam Temperatures and Super Heater Spray Water

During the diagnosis tests, some of the superheater (SH) spray water valves were either passing or stuck on open as shown in figure 6.3-8 above. Consequently, affecting the main steam temperature, particularly the BLR OUTL MS 1 and BLR OUTL MS 4 legs. This impact was observed for both tests; however, a more significant impact was observed for test 2 when load was reduced to 350 MWg.

The reheater (RH) spray water valves were also defective; however, they can be operated manually; during test 2 the hot RH (HRH) temperature decreased significantly, and the controller had to manually adjust the flows to increase the HRH temperatures as shown below

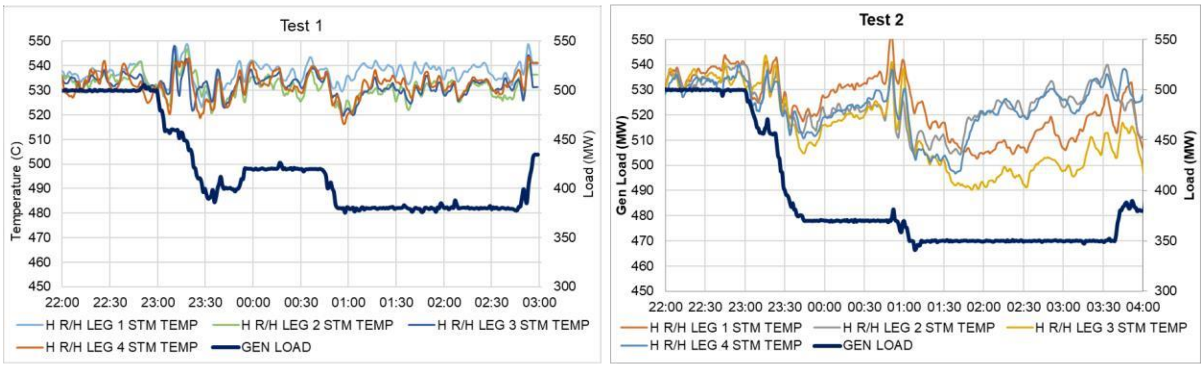


Figure 6.3-9: Duvha Hot Reheat Steam Temperature

The HRH temperature during test 1 were controlled above 520°C, during test 2 they were reduced to temperatures as low as 490°C for HRH leg 3. It is noted that when operating at 380 MW for test 1, fuel oil support was utilised, hence the controlled HRH steam temperature. For test 2, without fuel oil support, controller intervention at around 01:40 improved the HRH steam temperatures immediately in leg 2 and 4, gradual increases were observed for leg 1 and 3 of the HRH legs.

The ramp rates at Duvha were below those stipulated in the CDS document. The CDS stipulates an average of 15MW/min. The highest ramp rate achieved during the tests was 4.4 MW/min, reducing load from 420 MWg to 380 MWg.

6.3.2 Conclusion And Recommendations

Duvha unit 5 can reliably operate at the CDS minimum load of 350 MWg with 3 mills in-service. The conditions of the mills should be considered before choosing a mill combination, any mill that is not up to standard will be the bottle neck for reaching minimum load. Coal flow at minimum load was higher than the feeder lower limit. The economiser flow observed was well above the 228 kg/s limit: indicating potential for further turn down below the CDS minimum load.

The oxygen concentration at the economiser outlet was lower than 6% which is below the 9% FFFR limit. The air heater combined temperature was controlled above the 160°C; however, the unit operators must be thoroughly trained on the use of the recirculation dampers as per the stations low load operation procedure. There were no issues with the stack emissions.

The SH and RH spray water valves availability for auto-control is critical for control of the SH and RH steam temperatures. The main steam and hot reheat temperatures in the 4 legs at low loads had different temperatures due to spray water valve unavailability for auto-control.

Duvha has the potential to operate at an even lower load with 3 mills. However, the availability of the SH and RH spray water, the hot air recirculation dampers, and pressure mills is critical to achieving lower loads.

It is recommended that Duvha conduct the min-gen tests at 350 MWg with 3 mills, while monitoring the air heater back-end temperatures to keep the SO_3 plant in-service during the low load operations.

6.4 KENDAL POWER STATION

6.4.1 Kendal Unit 4 Test Overview

The diagnosis tests were conducted on the night of the 26th and 27th of May 2023. Kendal is rated at 686 MWg as full load, its nightly average is 486 MWg and the CDS minimum load is 326 MWg.

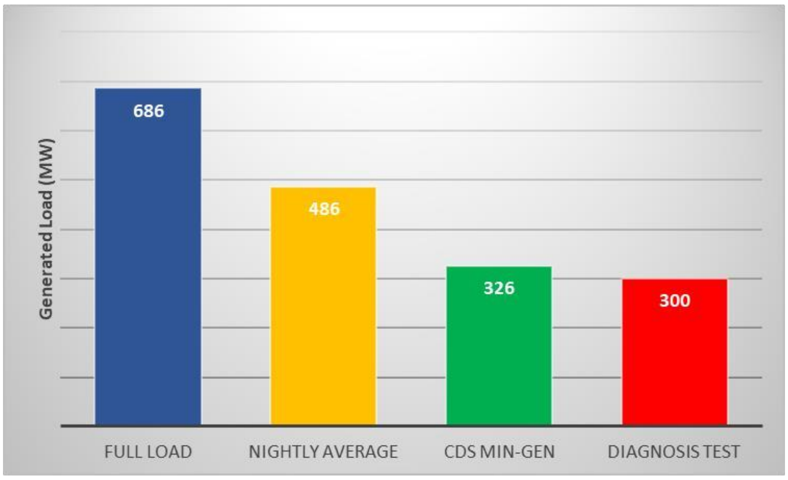


Figure 6.4-1: Kendal Unit Overview

The following program for Kendal's diagnosis testing was adopted.

Table 6.4-1: Kendal Unit 4 Diagnosis Testing Plan

Date	Test Period	Load [% TMCR]
26-27 May 2023	00:00 – 06:10	310 MWSO [45%]
27-28 May 2023	00:25 – 04:00	300 MWSO [44%]

The CDS minimum load was achieved on the first night with a mill configuration of ACD, after a period of 2 and a half hours, the unit was further reduced to 300 MWg for an hour prior to observing the ramping up of unit 4.

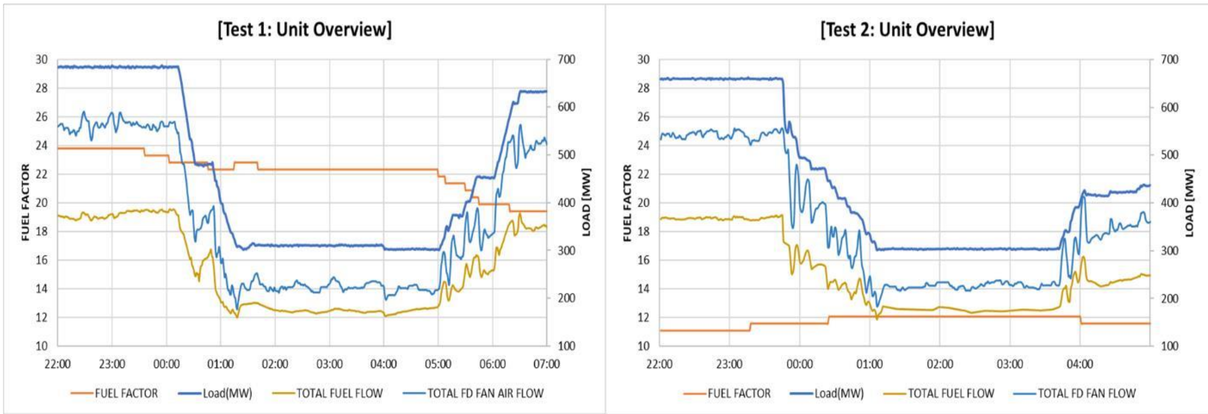


Figure 6.4-2: Kendal Diagnosis Test Overview

On the second night, mill A tripped and a different mill configuration was used; test 2 was conducted with mills BCD. Mill configurations are shown below.

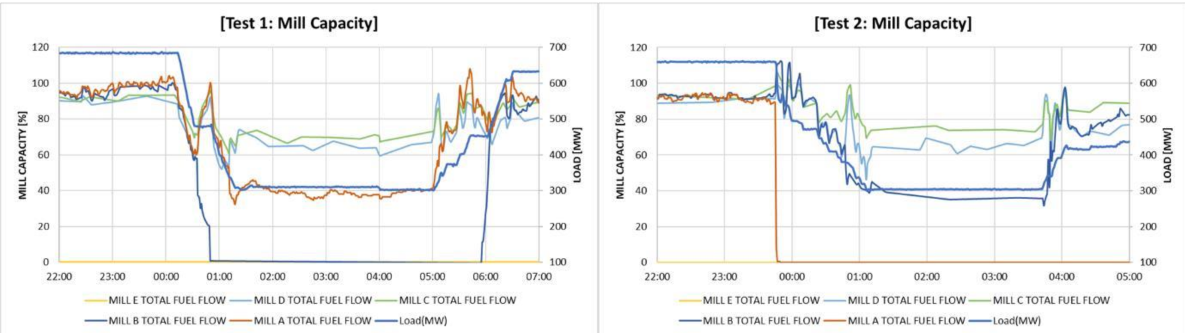


Figure 6.4-3: Kendal Mill Feeder Configurations

Diagnosis testing started after mid-night for both days. For test 1 the load was reduced to 450 MWg and mill B subsequently removed from service, further reduction to the stipulated minimum load was conducted with mills ACD. For test 2, mill A tripped just before mid-night and the load consequently reduced to 450 MWg with mills BCD. Deloading instructions were given around 00:20 and the unit was de-loaded to 300 MWg.

The mill capacity for mill A (test1) and mill B (test 2) were around 40% when the load was at or below 310 MWg, this is because both mills were operated with only single drive end allowing for the other two mills in service to operate above the FFFR lower limit. The limit for a single drive feeder operation at Kendal is 37.5%, for both tests mill A and B operated above the single drive operation limit. The single drive feeder operation can affect the mill outlet temperature as shown below.

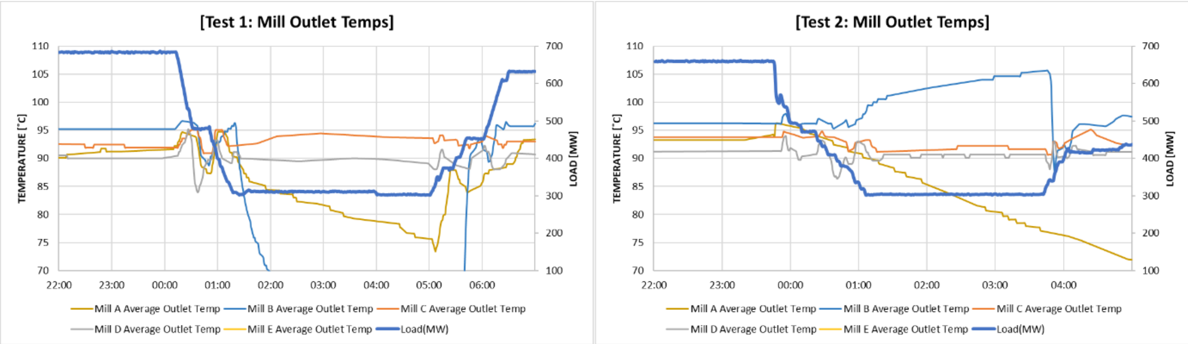


Figure 6.4-4: Kendal Mill Outlet Temperatures

During test 1, mill A outlet temperature decreased as low as 74°C, whereas during test 2 mill B outlet temperature increased to as high as 107°C during the single drive mill operations. These single drive operation impacts should be investigated further to assess why the two scenarios have different outcomes. Consequently, the reduced mill outlet temperature for mill A (test 1) can lead to mill hang up, and the higher mill outlet temperature for mill B (test 2) can lead to mill fires and/or fires in the mill lines. Mill C and D outlet temperatures for the two tests were averaging around 95°C set point.

The analysis results of coal that was burnt during the two diagnosis tests, as well as the fly-ash samples are tabulated below.

Table 6.4-2: Kendal Unit 5 Coal and Ash Analysis

Proximate Analyses (air dried – ad)		Test 1		Test 2	
Analytical Moisture	%	3.3		3.4	
Ash	%	29.2		27.1	
Volatile Matter	%	21.8		23.2	
Fixed Carbon (by difference)	%	45.7		46.3	
Ultimate Analyses (ad)					
Carbon	%	54.45		55.95	
Hydrogen	%	2.97		2.94	
Nitrogen	%	1.35		1.38	
Total Sulphur	%	0.78		0.84	
Carbonate (as CO2)	%	2.73		2.81	
Oxygen (by difference)	%	5.22		5.58	
Gross Calorific Value, ad	MJ/kg	20.97		21.76	
		Start	*End*	*Start*	*End*
Combustibles in fly ash LH	%	2.6	1.0	1	2.1
Combustibles in fly ash RH	%	1.1	0.6	1.8	2.6

The coal samples taken during the two tests do not differ significantly, indicating that the coal burnt during the tests had consistent quality. The coal was found to be within the 240-coal spec for Kendal Power Station. The average coal flow for both tests during the minimum load period averaged around 50 kg/s. The combustible matter in fly-ash for samples obtained at the end was lower for test 1 compared to test 2; this can be attributed to the mill configuration where test 1 utilised mill A which feeds into the last level of top burners and test 2 used mill B which feeds into the second last top burners.

The measured oxygen using a portable gas analyser and the station analysers are compared below.

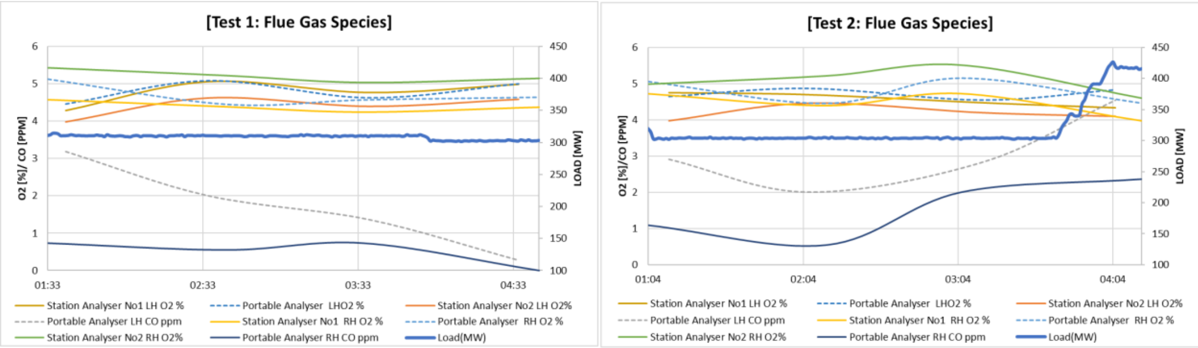


Figure 6.4-5: Kendal Oxygen and Carbon Monoxide Trends

The oxygen readings on both sides of the economiser outlet trend well with each other. The average oxygen concentrations for both days are in proximity. The carbon monoxides (CO) for both days were lower than 5 parts per million (ppm), which infers a good combustion in the boiler.

To monitor acid dew point, as well as the SO_3 plant operations, the air heater gas outlet temperatures were monitored. These are displayed below.

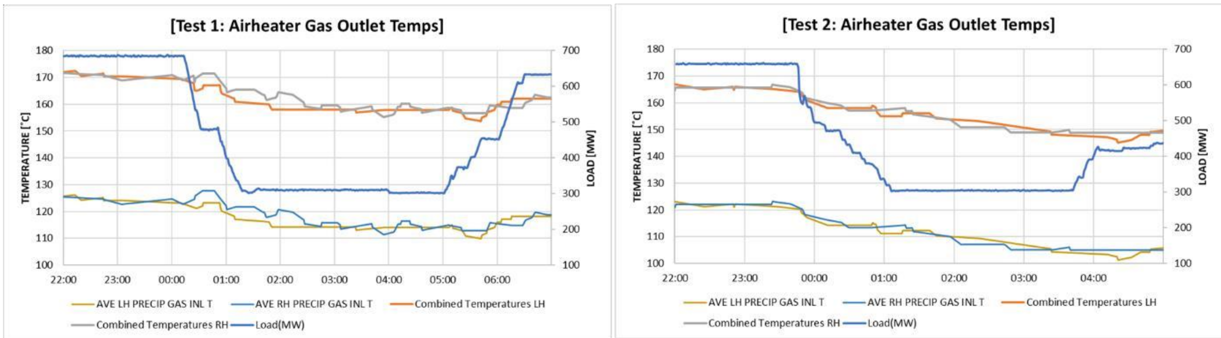


Figure 6.4-6: Kendal Air Heater Gas Outlet Temperatures

The combined temperature (i.e., sum of air inlet temperature and gas outlet temperature) reduced with load as shown above, it reached values below the 160°C combined temperature limit, however it was much lower for test 2. The temperature is maintained using steam air preheaters and hot air recirculation; for Kendal unit 4, both systems were not operational during the diagnosis tests. Operating for prolonged durations below the 160°C can lead to acid dew point corrosions in the air heater back-end packs, the ducts going to the electrostatic precipitators (ESP) as well as the ESP components.

The operation of the SO_3 plant in linked to the ESP inlet gas temperature, the plant goes on standby when the temperature drops below 110°C. The ESP inlet gas temperature for test one stayed above the limit, for test two the temperature went as low as 105°C. The SO_3 plant tripped during test 2, however, it was due to low auxiliary steam temperature used in the SO_3 plant boiler. The SO_3 plant objective is to improve the ESP particulate removal efficiency from flue gas. It can be seen below that this did not alter the emission at min-gen load.

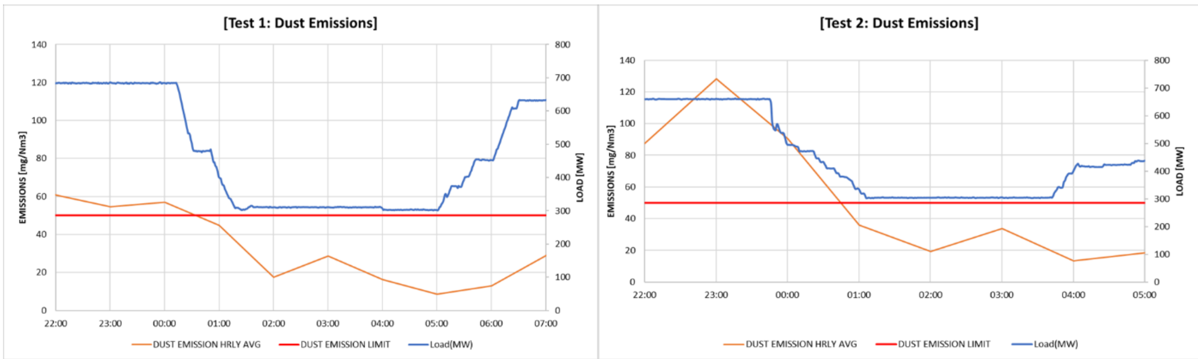


Figure 6.4-7: Kendal Particulate Emission

The particulate emissions were below the limit of 50 mg/Nm^3 while operating at minimum load. The stack gaseous emissions are shown below.

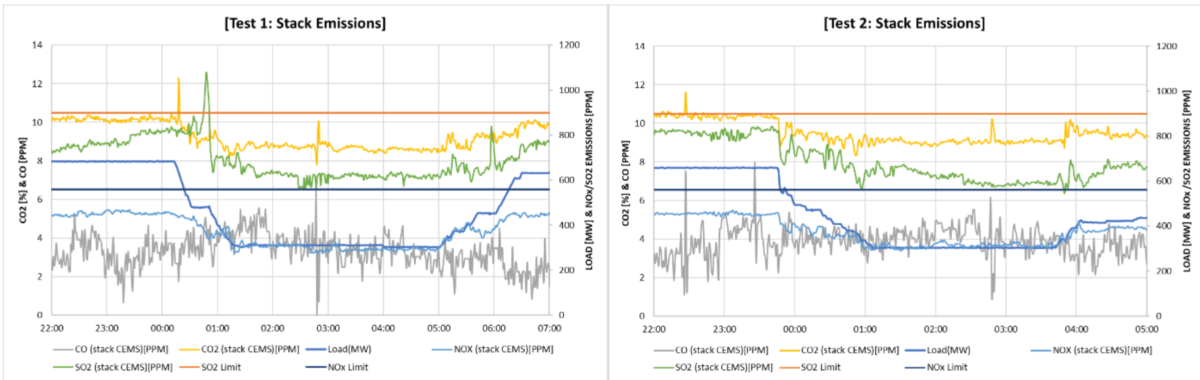


Figure 6.4-8: Kendal Stack Emissions

The emission limits for SO_2 and NO_X as stated in the 240-coal spec are 2600 mg/Nm^3 (909 ppm) and 750 mg/Nm^3 (560 ppm), respectively. It can be seen in the figure above that the SO_2 and NO_X emissions are below the stated limits, except for an SO_2 spike seen during test 1 during ramp down. The SO_2 and NO_X emissions decreased with load, however the CO emission increased with load.

The boiler superheater (SH) and reheater (RH) tubes metal temperatures were observed during the diagnosis tests. The trends are displayed below.

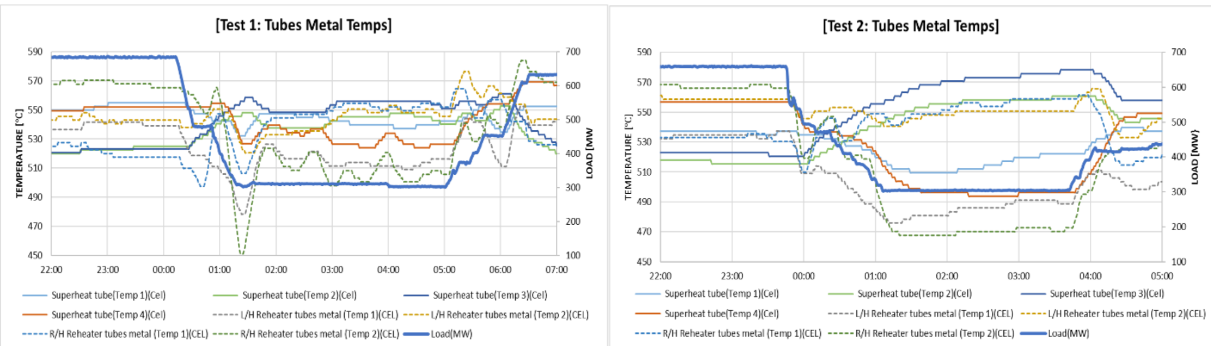


Figure 6.4-9: Kendal SH and RH Tubes Metal Temperatures

At full load a split in the SH and RH tubes temperature was observed for both tests with SH temperature 1 & 4 reading higher and SH temperature 2 & 3 reading lower; for test 1 at 310 MWg the SH temperature starts to propagate at 02:50 and increase when load is reduced to 300 MWg. However, at these low loads SH temperature 2 & 3 are higher than SH 1 & 4, which then switch back to the start of the test upon loading up. Similarly for the RH tubes, at lower loads right hand RH temperature 2 and left hand RH temperature 1 tubes had lower temperatures compared to right hand RH temp 1 and the left hand RH temp 2 tubes, and vice versa at higher loads. This can be attributed to the spray water flows and/or spray water valve conditions on the different legs, as well as mill configuration. Mill configuration has an impact on the split as seen in the figure above; for test 2 (mills BCD) the split at low loads was big compared to test 1 (mills ACD).

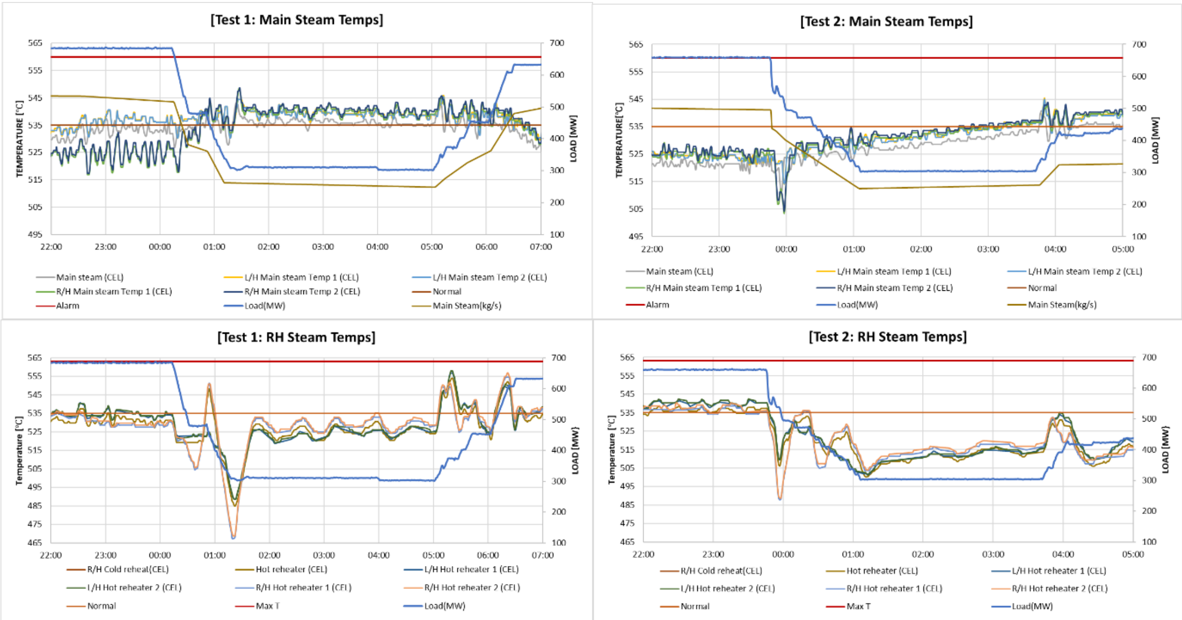


Figure 6.4-10: Kendal Main Steam and Reheater Steam Temperatures

The impact of the SH and RH tube metal temperatures split was also observed in the main steam and reheater steam temperature trends as illustrated in the figure 6.4-10 above. With the smaller split observed for test 1, the average temperatures for the main steam and reheater were higher compared to test 2.

6.4.2 Conclusion And Recommendations

Kendal unit 4 can operate at the CDS minimum load of 326 MWg will 3 mills. It was demonstrated that it can be operated at 300 MWg without fuel oil support. To maintain the FFFR mill capacity limit at low loads, the top mill was operated with a single drive (the mill capacity lower limit for single drive operation is 37.5%), which increased the capacity of the other two to a comfortable capacity above the 60% FFFR limit.

The mill outlet temperature for the single ended driven top mills, displayed conflicting outcomes on the two occasions. With the mill combination ACD, mill A outlet temperature dropped from 95°C at full load to 75°C at minimum load, whereas with mill combination BCD, mill B outlet temperature increased form 94°C at full load to 107°C at minimum load.

The oxygen concentration at the economiser outlet was lower than 6%, and well within the 9% FFFR limit. The air heater back-end temperatures with top mill A stayed above the 110°C required to keep the SO_3 plant in-service; with top mill B, the temperature dropped below the 110°C. The SO_3 plant tripped when operating with mill B, C & D; however, it was attributed to low auxiliary steam temperatures. The air heater combined temperature went below the 160°C with both mill combinations, as an impact of the lower back-end temperatures. It is recommended that the hot air recirculation dampers and the steam pre-heaters be returned to full operation to expand the unit's turndown capability.

The SH and RH spray water valves availability for auto-control is critical for control of the SH and RH steam temperatures. The SH and RH steam temperature at low loads were not controlled effectively around the normal steam temperature set point.
It is recommended that minimum load operation at Kendal be carried out with 3 mills in service, with the top mill on a single end drive operation. Mill outlet temperatures and air heater back-end temperatures must however be closely monitored.

6.5 KRIEL POWER STATION

6.5.1 Kriel Unit 6 Overview

The diagnosis tests at Kriel unit 6 were conducted on the night of the 25th and 26th of November 2022. The full load at Kriel is 500 MWg, the CDS minimum load is 305 MWg (stated as 280 MW sent out in the CDS document).

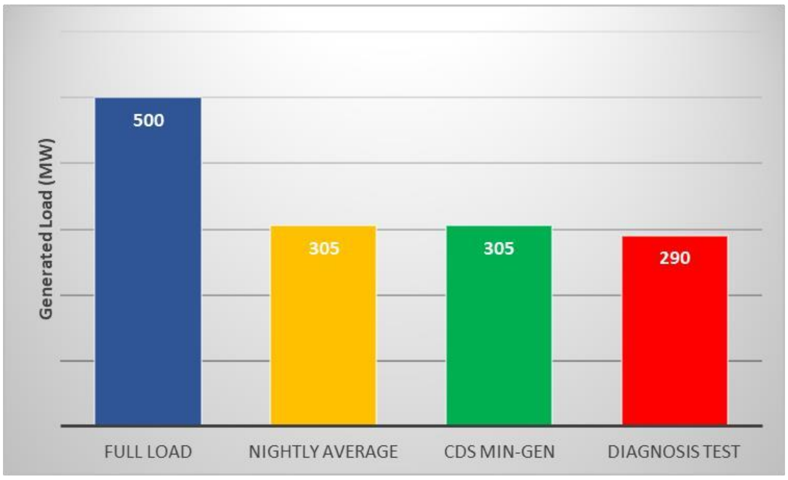


Figure 6.5-1: Kriel Unit Overview

The following program for Kriel's diagnosis testing was adopted.

Table 6.5-1: Kriel Unit 6 Diagnosis Testing Plan

Date	Test Period	Load [% TMCR]
25-26 Nov 2022	22:30 – 04:00	305 MW [61%]
26-27 Nov 2022	21:30 – 02:00	290 MW [58%]

The unit overviews for the 2 tests are shown below. The diagnosis tests were conducted with 4 mills instead of the preferred 3 mills due to unavailability of mill C & F (cross-firing was not possible). The CDS minimum load was achieved on the first night and a lower load of 290 MW was ultimately reached in the last hours of test 1, and during the first hour of the second night of testing.

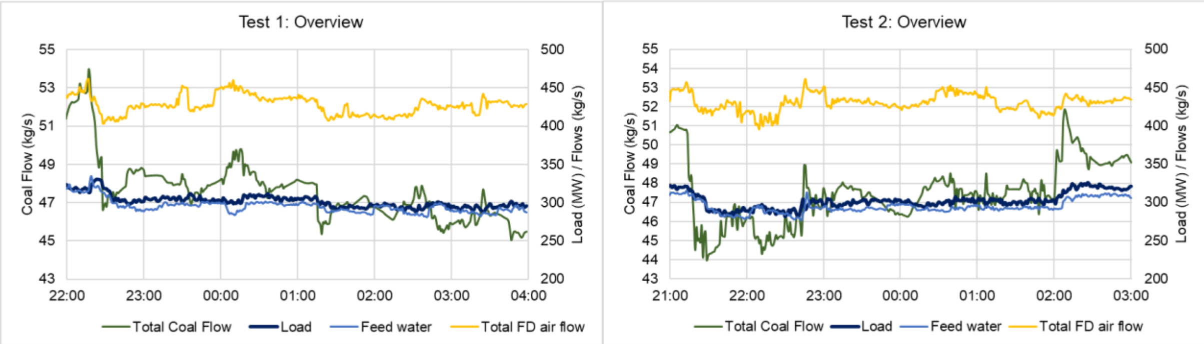


Figure 6.5-2: Kriel Diagnosis Tests Overview

On the second night of testing furnace instabilities were observed with the furnace pressure being more positive; the furnace pressure trend is shown below.

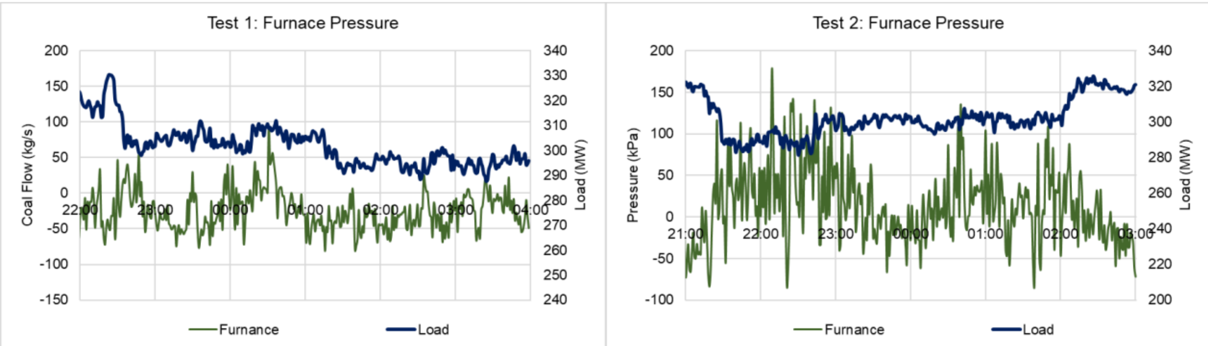


Figure 6.5-3: Kriel Furnace Pressure Behaviour

Furnace pressure was considered as one of the limiting factors for Kriel and during test 2 it was positive when the unit was reduced to 290 MWg for a period of two hours, thereafter the load was increased to control furnace pressure to the preferred negative value. It was however observed to fluctuate more at 305 MWg compared to test 1 where the pressure was more negative and had minimal fluctuations.

The flame temperatures were observed along with the furnace pressure in assessing the stability of the furnace. They are presented below.

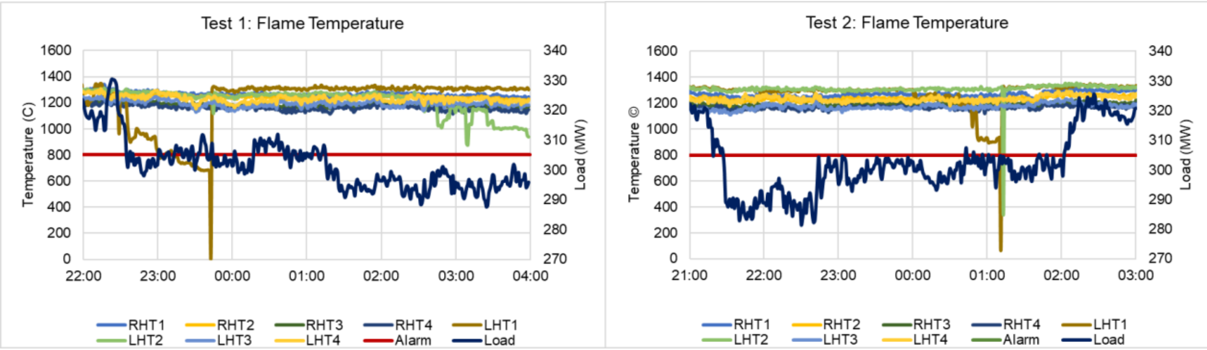


Figure 6.5-4: Kriel Flame Temperatures

As a pre-requirement for diagnosis testing, the pyrometers were cleaned prior to both tests; however, temperature drops in the left hand top (LHT) 1 and 2 pyrometer were observed. The operator intervened by cleaning the pyrometers, it was noted that these were on overall the highest pyrometer temperature readings during both tests. The flame temperatures were found to be above the 800°C limit during the tests.

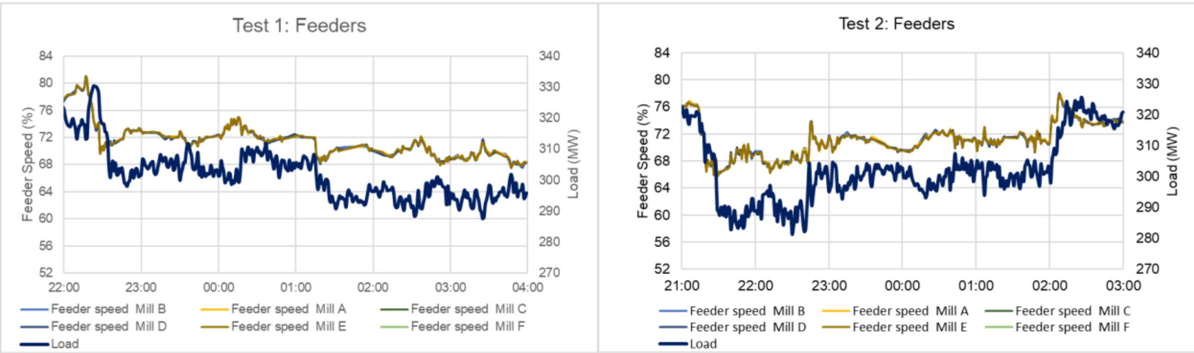


Figure 6.5-5: Kriel Mill Capacities

The feeder speeds when the unit was at 290 MWg were running significantly higher than the FFFR lower limit. The tests were conducted with four mills in service, with the preferred three mills potential for further turndown can be achieved before reaching the FFFR limit.

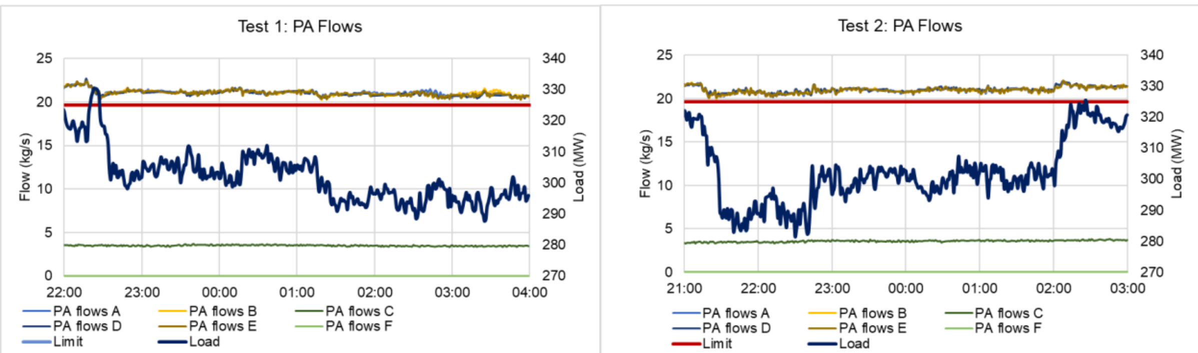


Figure 6.5-6: Kriel Primary Air Flows

The PA flows were also found to be operating above the 19.64 kg/s limit for Kriel as shown above. Tabulated below is the coal and ash analysis results.

Table 6.5-2: Kriel Unit 6 Coal and Ash Analysis

Proximate Analyses (air dried – ad)		Test 1		Test 2	
Analytical Moisture	%	3.8		3.6	
Ash	%	25.4		27.2	
Volatile Matter	%	22		21	
Fixed Carbon (by difference)	%	48.4		48.2	
Ultimate Analyses (ad)					
Carbon	%	54.17		52.99	
Hydrogen	%	2.75		2.98	
Nitrogen	%	1.43		1.34	
Total Sulphur	%	0.57		0.65	
Carbonate (as CO2)	%	2.72		2.66	
Oxygen (by difference)	%	9.25		8.58	
Gross Calorific Value, ad	MJ/kg	21.77		21.4	
Total Moisture	%	7.6		6.4	
		Start	*End*	*Start*	*End*
Combustibles in fly ash LH	%	0.4	0.3	0.5	0.6
Combustibles in fly ash RH	%	0.5	0.3	0.2	0.2

The coal burnt during the diagnosis tests at Kriel was within the stipulated coal specification in the 240-coal spec standard. The coal sampled for test 1 and test 2 did not differ significantly, this can be seen in the insignificantly difference in fuel demand at 290MWg; the fuel demand for test 1 was 890 MJ/s and 882 MJ/s for test 2. The combustibles in the fly-ash ash were low for both nights, indicating that the coal was combusted efficiently.

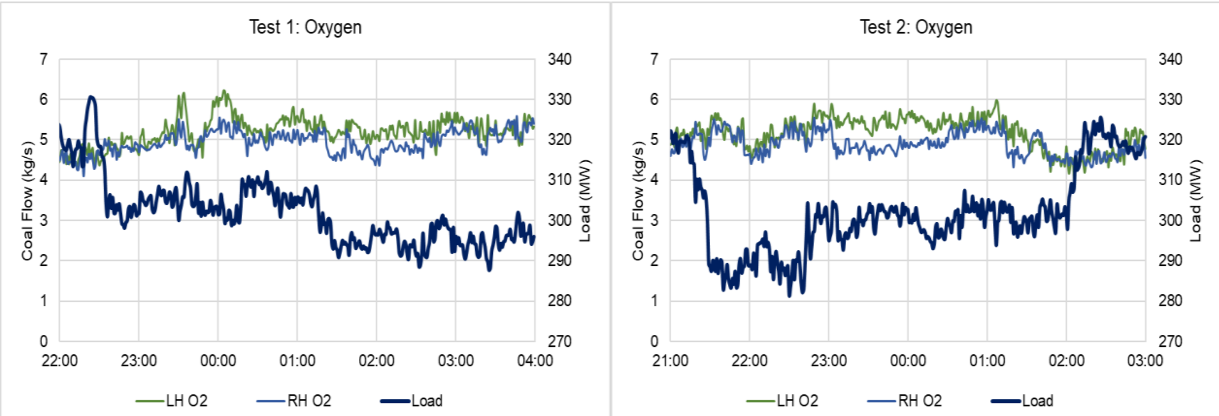


Figure 6.5-7: Kriel Economiser Outlet Oxygen Concentration

The oxygen (O_2) concentrations for both tests were around 5% during the min-gen operations. The left hand O_2 was slightly higher than the right hand O_2, for test 2 a noticeable O_2 split was observed (with the LH O_2 being higher) when the load was increased to bring the furnace pressure to its negative values.

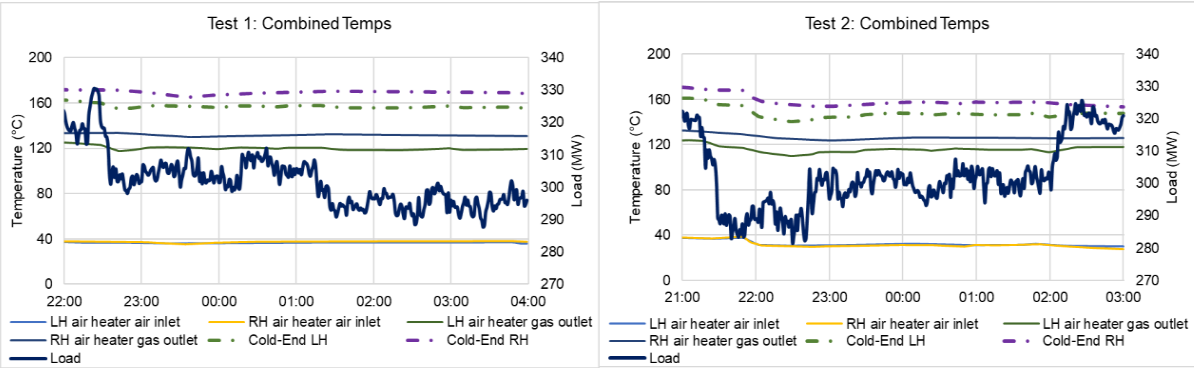


Figure 6.5-8: Kriel Air Heater Combined Temperature Trends

The air heater air inlet temperatures were above 33°C for both tests, the left hand gas outlet temperature was lower than the right hand gas outlet. The combined temperatures for test 1 was higher compared to test 2. Test 2 air heater gas outlet was lower than the required 160°C temperature for acid dew point control; attributed to 7°C – 9°C drop in air inlet temperature just after the start of test 2.

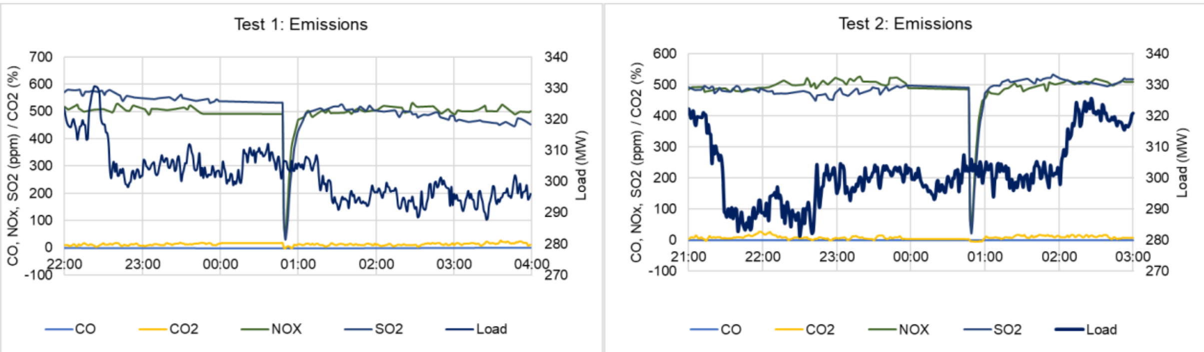


Figure 6.5-9: Kriel Stack Emissions

The emissions displayed similar trends for both tests at 290 MWg, where the SO_2 emissions reduce and the NO_x emissions increase. However, the emissions were found to be below the emission limits.

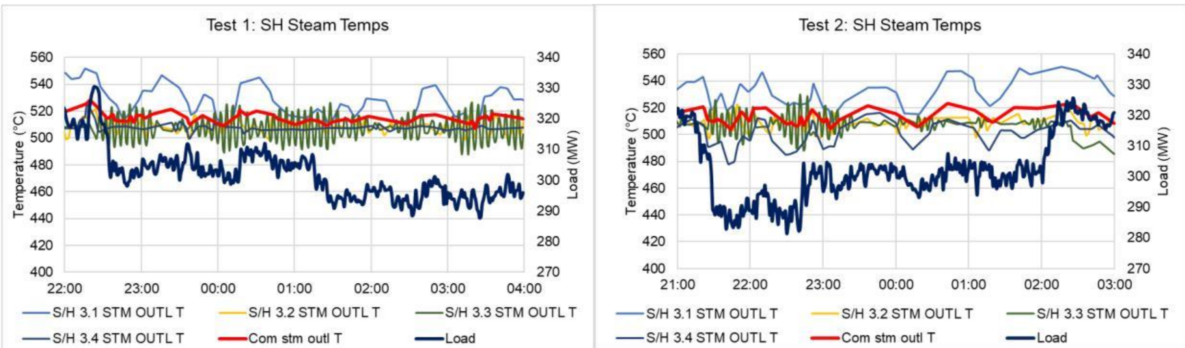


Figure 6.5-10: Kriel Main Steam Temperatures

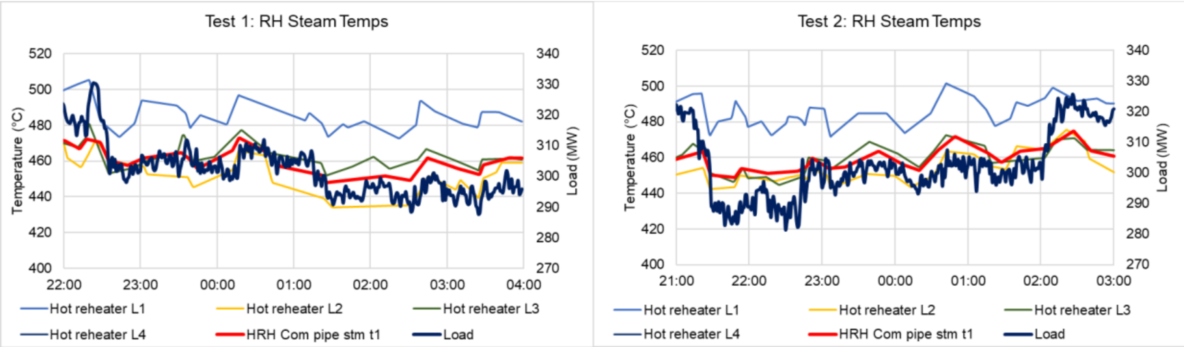


Figure 6.5-11: Kriel Reheater Steam Temperatures

Kriel Power Station main steam temperature (i.e., S/H STM OUTL T) is controlled at 515°C +/- 5°C. The common main steam outlet temperature can be seen to oscillate in the region of the controlled set point; the oscillation was more for test 2 along with the furnace pressure instability. The reheater steam temperature reduced with load, as seen by the hot reheat common steam temperature above; however, reheater leg 1 had the highest temperature compared to the other legs with a difference of approximately 20°C from the common temperature.

6.5.2 Conclusion And Recommendations

Kriel can operate at the CDS minimum load of 305 MWg with 4 mills. It was demonstrated that it can be operated at 290 MWg, however at the time of the test there were furnace pressure issues where pressure got positive with the decrease in load. The mill capacities were above the 60% FFFR limits and the PA flows above the 19.64 kg/s low flow limit observed in the control room.

The oxygen concentration at the economiser outlet was lower than 6% which is below the 9% FFFR limit. The combined temperatures were generally below the required 160°C, because of lower back-end temperatures and lower inlet air temperature. The were no issues with the stack emissions.

Kriel should test at the min-gen with exploration of different mill combinations, this includes operating with three mills using the cross-firing mill combination.

6.6 KUSILE POWER STATION

6.6.1 Kusile Unit 3 Test Overview

Kusile's unit 3 is an 800 MWg unit. At the time of the test Kusile's nightly average was 350 MWg and the CDS minimum load is stipulated as 319 MW Net. Figure 6.6-1 gives an overview of the unit load before and after the diagnosis tests.

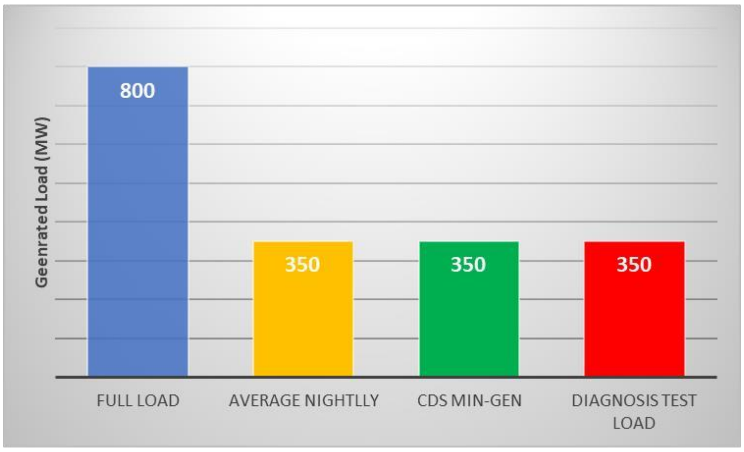


Figure 6.6-1: Kusile Unit Overview

Two sets of diagnosis tests were conducted on the 12th -14th of August 2022 as shown in table 6.6-1 below.

Table 6.6-1: Kusile Diagnosis Testing Plan

Date	Test Period	Load [% TMCR]
12 – 13 August 2023	23:30 – 04:00	350 MWg [44%]
13 – 14 August 2023	00:00 – 05:00	350 MWg [44%]

Both tests were conducted successfully at 350 MWg with two different 3 mill combinations. Test 1 was conducted with mills 10, 20, & 30 and test 2 was conducted with mills 20, 30 & 40. The unit was sootblown before the test. A weekly pyrometer cleaning regime was followed. The mills were in good condition.

The diagnosis tests achieved the CDS minimum load of 319 MW Net (350 MWg). The average steam flows at 350 MWg was 270 kg/s which is about 42.5% of boiler maximum continuous rating (BMCR) of 635.51 kg/s. The average total coal flow was 46 kg/s. The economiser inlet flow was an average of 242 kg/s for test 1 and 240 kg/s for test 2, against a limit of 220 kg/s.

Kusile mills operated at 49% of the mill capacity which is below the FFFR mill capacity limit. This is however allowable as per FFFR 4.2.1.3 a. where power stations with rated mill capacity above 100 tons per hour may operate with mill loading less than 60% provided that stable mill operation and stable combustion has been proven with a defined set of coal qualities.

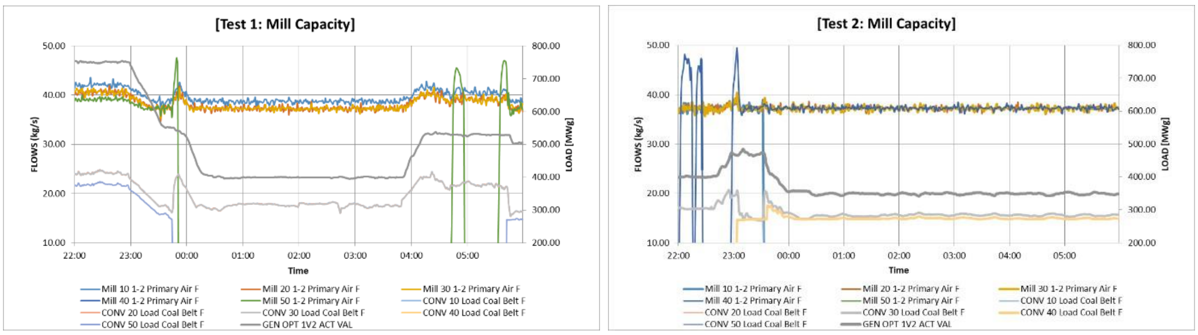


Figure 6.6-2: Kusile Mill Capacities

The coal quality was stable during the two nights of testing, the mill loading was consistent.

Test 1 pyrometer temperatures were lower than test 2 pyrometer temperatures. This was due to the different mill combinations utilised, test 1 had bottom mills while test 2 had middle mill combination.

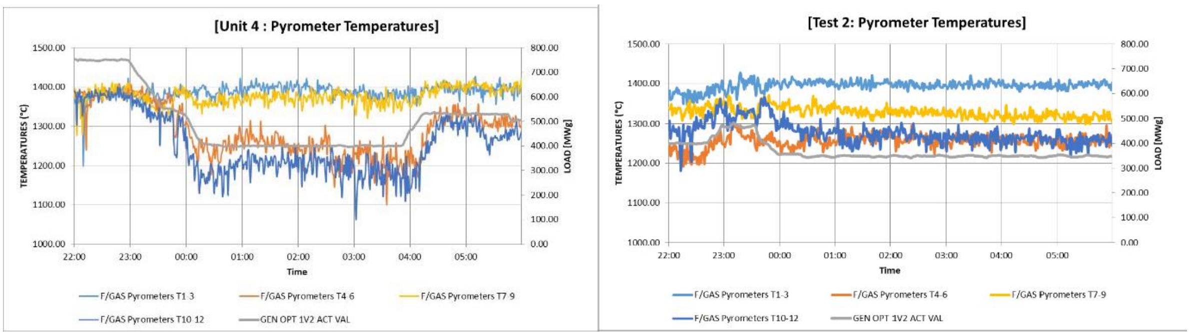


Figure 6.6-3: Kusile Pyrometer Temperatures

Although test 1 temperatures were lower, they were well within the limit of 800˚C. No pyrometer cleaning was done during the tests.

The coal quality was found to be consistent throughout the two nights of testing as seen in table 6.6-2 below. The coal burnt during the tests was within the minimum design specification. According to the minimum coal specification, the Kusile design gross CV (GCV) is 19.4 MJ/kg and the design ash 36.95% on a moisture free basis. The average ash for test 1 and test 2 on moisture free basis was 33.6% and 33.4% respectively.

Table 6.6-2: Kusile Unit 3 Coal and Ash Analysis

Proximate Analyses (AD)		**Test 1**		**Test 2**	
Analytical Moisture	%	4.13		4.12	
Ash	%	32.17		32.31	
Volatile Matter	%	19.63		19.61	
Fixed Carbon (by difference)	%	44.07		43.96	
Ultimate Analysis (AD)					
Carbon	%	49.41		49.22	
Hydrogen	%	2.84		2.84	
Nitrogen	%	1.27		1.29	
Total Sulphur	%	1.03		1.04	
Carbonate	%	2.48		2.47	
Oxygen (by difference)	%	6.67		6.71	
Gross Calorific Value MJ/kg	MJ/kg	19.33		19.28	
		Start	End	Start	End
Combustible Matter LH	%	0.5	0.1	0.4	0.2
Combustible Matter RH	%	0.2	0.3	0.2	0.3

Table 6.6-2 shows the carbon in the ash before the test commenced and after the test was completed. The samples were taken at the gas air heater inlet. For both tests the left hand side (gas air heater 1) showed a decrease in combustible matter from between the start and the end of the test which indicates an improvement in combustion, however the right hand side shows a slight increase in carbon in ash between the start and the end of the test.

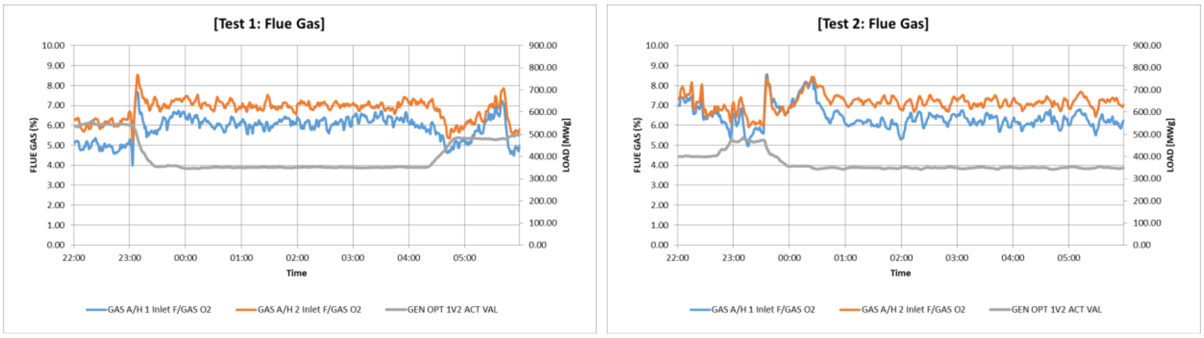


Figure 6.6-4: Kusile Oxygen Concentrations

The oxygen concentrations at the gas air heater inlet were well within the FFFR limit of 9% as shown in figure 6.6-4. Physical measurements of carbon monoxide were conducted, these all showed as zero indicating good combustion.

On average combined temperatures of 160˚C are observed, Kusile's design secondary air inlet temperature and the gas air heater gas outlet temperatures are 32.3˚C and 125˚C respectively. This amounts to a design combined temperature of 157.3˚C.

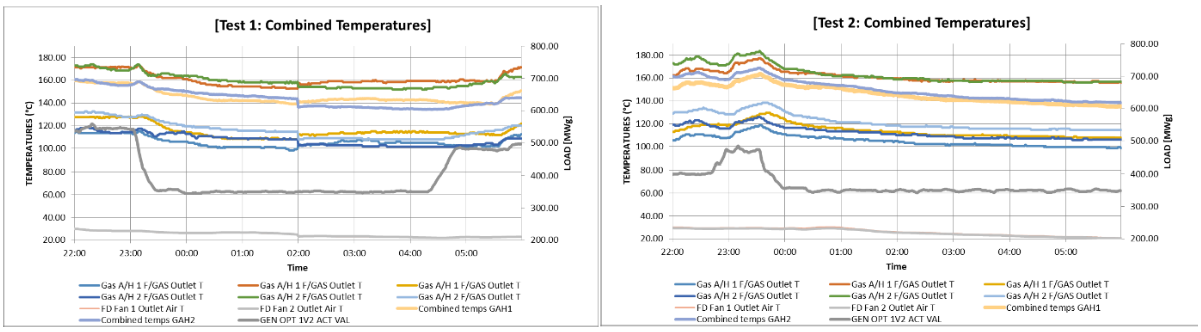


Figure 6.6-5: Kusile Combined Temperatures

As shown in figure 6.6-5, the combined temperatures went below the observed limit of 157˚C. this was due to low inlet temperatures on both the air and the gas side. The operators usually observe an air heater gas outlet temperature of 110˚C to control the pulse jet fabric filter (PJFF) and the flue gas desulphurisation (FGD) inlet temperatures. High back-end temperatures tend to trigger the opening of the attemperating air dampers which leads to an increase in flue gas volume thereby increasing the differential pressure across the FGD plant. The risk of the low flue gas temperatures should be assessed against the risk of sulfuric acid dew point temperatures which may result in corrosion of the gas air heater components.

The SOx and NOx emissions were seen to decrease with a decrease in load and were both within the minimum emission standard of 500 mg/Nm^3 and 750 mg/Nm^3 during the period of the test.

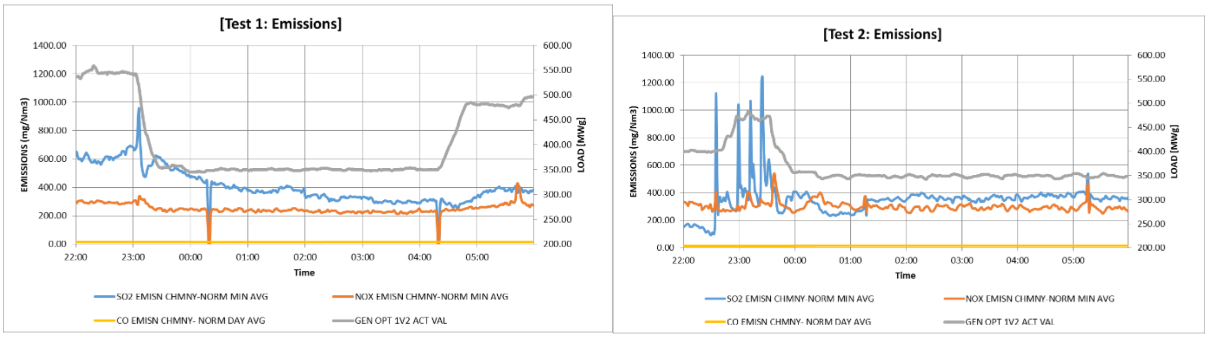


Figure 6.6-6: Kusile Emissions Overview

Dust emissions were also observed to decrease with a decrease in load as shown in figure 6.6-7 below.

Figure 6.6-7: Kusile DCS PM Emissions Overview

The steam temperatures were controlled within the 570˚C alarm limit for super heater temperature and 580˚C alarm limit for reheat temperature. The super heater spray water flows at stable conditions were about 36 kg/s for test 1 and 38 kg/s for test 2. The reheat spray water flows at stable conditions were 18 kg/s for test 1 and 14 kg/s for test 2.

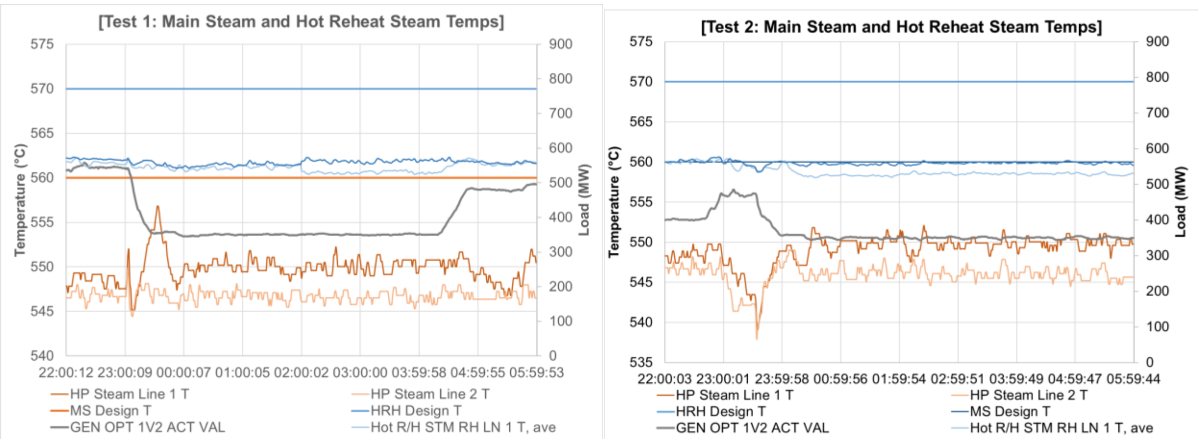


Figure 6.6-8: Kusile Steam Temperatures

Both the super heater and reheat temperatures were lower than their design values due to water over spraying. The spray water valves were stuck on open induce.

Benson operation was sustained through the two nights of testing with both mill combinations. While the evaporator outlet steam conditions were slightly above saturation point, going lower than 350 MWg may result in circulation mode operation. Figure 6.6-9 shows evaporator performance for the two tests.

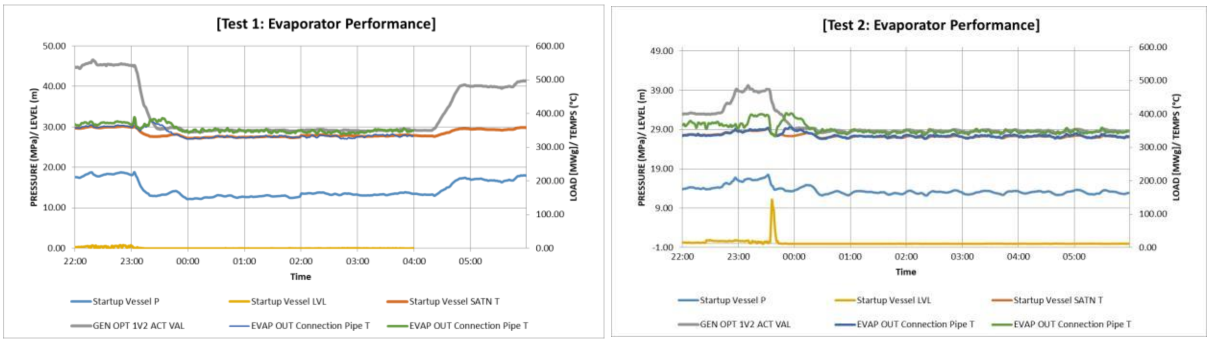


Figure 6.6-9: Kusile Evaporator Performance

A small collection vessel level is seen during the removal of the fourth mill, and no level for the rest of the test duration.

Unit ramp up was not observed, the load was kept low due to high silo levels.

6.6.2 Conclusions And Recommendations

Kusile can operate reliably at the CDS minimum load of 319 MW (Net). The diagnosis tests were able to achieve 350 MWg (approximately 319 MW Net). The unit was sootblown before the tests commenced. The pyrometers cleaning followed a weekly regime. All mills were in good condition. The mill capacity went below the 60% limit; however, this is allowable based on Kusile’s rated mill capacity.

Kusile experienced high flue gas volume at the inlet to the FGD plant due to the attemperating air dampers opening to control the back-end temperatures. This led to operators running the unit at low flue gas temperatures to control and avoid triggering the air dampers to open. This poses a risk of corrosion initiated damage in the gas air heater and therefore this risk should be assessed. The flue gas flows at low loads are expected to reduce and therefore are not expected to pose a challenge to the FGD plant.

Further turndown at Kusile will need to assess the risk of lower back-end temperatures as well as operation with two mills. Kusile has operated with two mills before, however, the operation with two mills is not preferable due to challenges with fuel oil burners when ramping up the unit.

The superheater and reheater spray water valves should be maintained to ensure that the main steam and reheat steam temperatures are maintained at the design temperatures of 565˚C and 570˚C respectively.

6.7 LETHABO POWER STATION

6.7.1 Lethabo Unit 4 Test Overview

Diagnosis tests were conducted at Lethabo's unit 4 on the 23rd to the 25th of June 2023. Two sets of tests were conducted each achieving 340 MWg, which is 10 MW below the CDS minimum load and 55% of turbine maximum continuous rating (TMCR). Sootblowing and pyrometer cleaning were conducted before the commencement of each test. Test 1 was conducted with boiler feed pump turbine (BFPT) and test 2 was conducted with electric feed pumps (EFP). The boiler feed pump turbine was not available during the test 2.

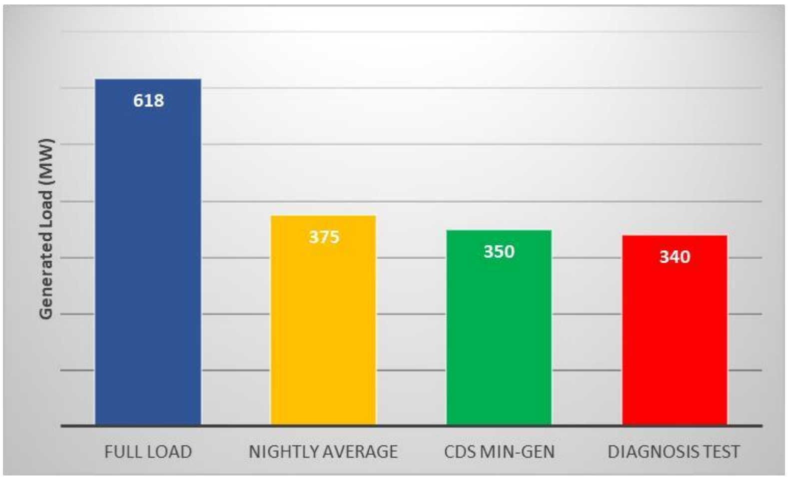


Figure 6.7-1: Lethabo Unit Overview

The test program is shown in table 6.7-1 below. Figure 6.7-1 gives an overview of the unit at the time of the test. The units operate at a nightly average of 375 MWg. The tests were conducted over a period of 7 hours.

Table 6.7-1: Lethabo Diagnosis Testing Plan

Date	Test Period	Load [% TMCR]
23 – 24 June 2023	22:00 – 05:00	340 MWg [55%]
24 – 25 June 2023	22:00 – 05:00	340 MWg [55%]

Test 1 was conducted with 3 mills in service (CDE). Mills C and D are middle mills, while mill E is a bottom mill. Test 2 was conducted with 3.5 mills i.e Mills C, D & E, mill B (bottom mill) was operated with one feeder due to feeder speed control defects. Mill A & F are top mills, mill A tripped before the start of test 1 due to misaligned belt. Platen temperatures had periods where they went above 540˚ C. Spray water valves were on manual.

The primary air flows are used to monitor the mill capacity limits in line with FFFR requirements. The lower mill capacity limit of 60% equates to a minimum primary air flow of 24 kg/s while the upper mill capacity limit of 90% equates to an upper primary air flow of 32 kg/s. Test 1 low load primary air flows averaged at 31 kg/s, while test 2 low load primary air flows averaged at 25.52 kg/s, both of which were within the required limits.

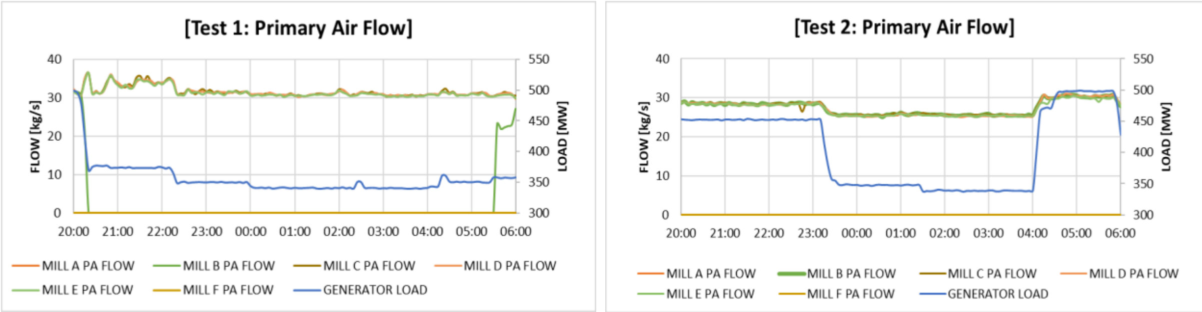


Figure 6.7-2: Lethabo Primary Air Flows

According to the work instruction on limit for unit load to keep mills in safe operating ranges, the unit should not be allowed to drop below 400 MWg with 4 mills in operation. The minimum load operation with 3 mills at Lethabo is not to include either or both top mills (mill A and/or F) as the primary air flows will saturate at 24 kg/s. This can be seen with test 2, where 3.5 mills were operated and almost saturated.

Pyrometers were cleaned before the tests on both test days. The pyrometer temperatures were mostly maintained above 800˚C, however further turndown may have resulted in operation at the limits or lower than the 650˚C limits.

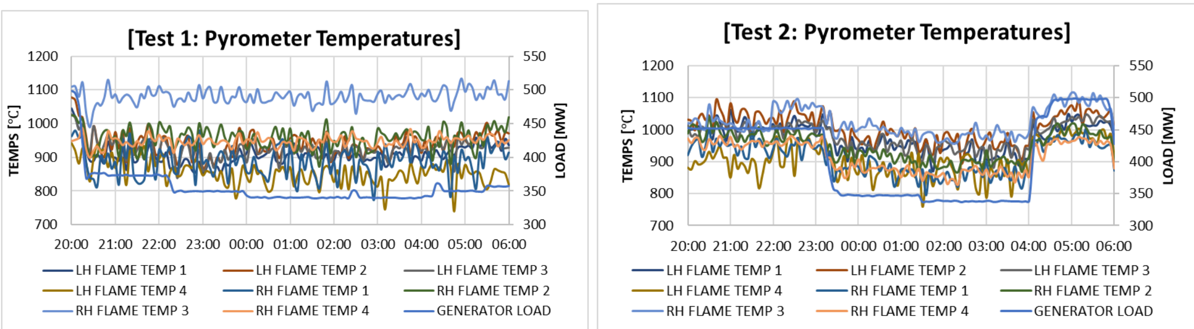


Figure 6.7-3: Lethabo Pyrometer Temperatures

The lowest pyrometer temperature (LH temp 4) at lowest load during test 1 was 745˚C, and 761˚C during test 2.

The quality of coal burnt and the combustible matter analysis over the two nights of testing is shown in table 6.7-2 below.

Table 6.7-2: Lethabo unit 4 Coal and Ash Analysis

Proximate Analyses (AD)		Test 1		Test 2	
Analytical Moisture	%	6.20		6.80	
Ash	%	41.50		38.90	
Volatile Matter	%	19.60		20.00	
Fixed Carbon (by difference)	%	32.70		34.40	
Ultimate Analysis (AD)					
Carbon	%	39.44		41.27	
Hydrogen	%	2.09		2.16	
Nitrogen	%	1.44		1.47	
Total Sulphur	%	0.64		0.64	
Carbonate	%	1.98		2.08	
Oxygen (by difference)	%	6.71		6.68	
Gross Calorific Value MJ/kg	MJ/kg	14.61		15.32	
		Start	End	Start	End
Combustible Matter	%	0.8	0.4	0.4	0.7

The inherent moisture and the ash content were found to be higher than what is stipulated in the 240- coal specification. The coal burnt during the test had a lower CV than the minimum distress limit of 15.38 MJ/kg (as received). Test 1 had better combustion with lower combustibles after the test, however test 2 showed an increase in combustibles after the test indicating a decrease in combustion efficiency. Test 2 operated with 3.5 mills and saw a decrease in primary air flows.

The excess air as seen with the oxygen concentrations at the economiser outlets in Figure 6.7- 4 was higher for test 2 compared to test 1 during the low load operation.

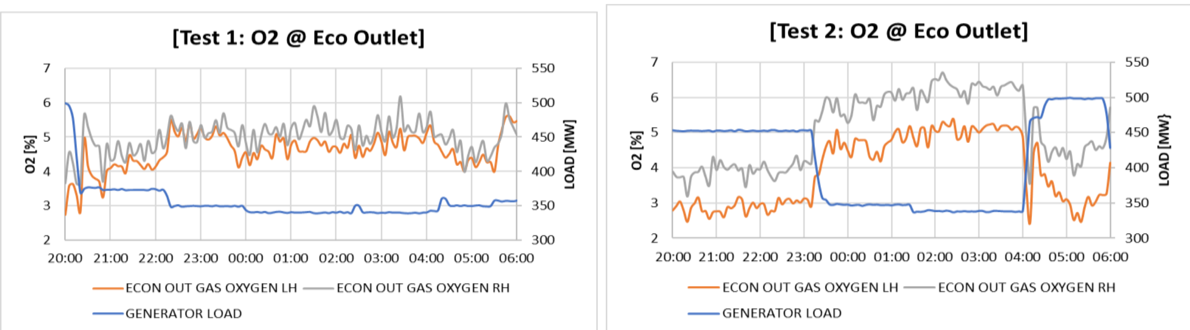


Figure 6.7-4: Lethabo Excess Air

The excess air was within the FFFR limits of 2,5% and 9%. A higher split between the right and left hand was observed for test 2. This is due to the mill combination utilised.

The alarm limit for air heater gas outlet temperatures is 100˚C. The secondary air heater gas outlet temperatures were maintained above the alarm limit. Test 2 gas outlet temperatures were however lower than those of test 1.

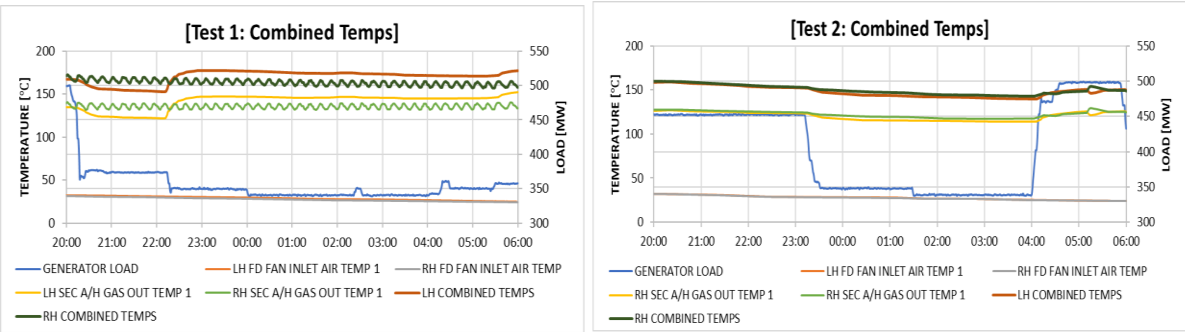


Figure 6.7-5: Lethabo Combined Temperatures

The combined temperatures were maintained above 160˚C for test 1, they however went below 145˚C for test 2. The secondary air heater bypass damper was used for test 1 to maintain high back-end temperatures. The bypass damper was not functional during test 2.

The SO_3 plant went on stand-by at 350 MWg during both tests. This resulted in higher particulate emissions as seen in figure 6.7-6.

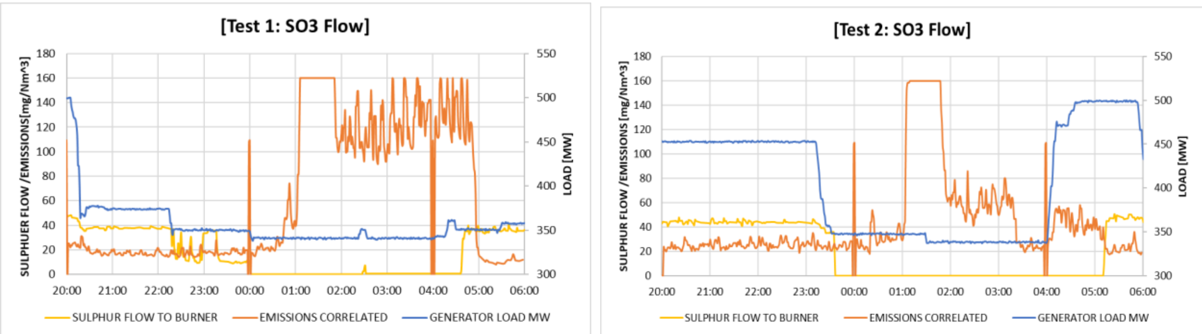


Figure 6.7-6: Lethabo Particulate Emissions

The particulate emissions are seen to increase after about an hour of SO_3 plant going on stand-by. The highest emissions recorded were 160 mg/Nm^3.

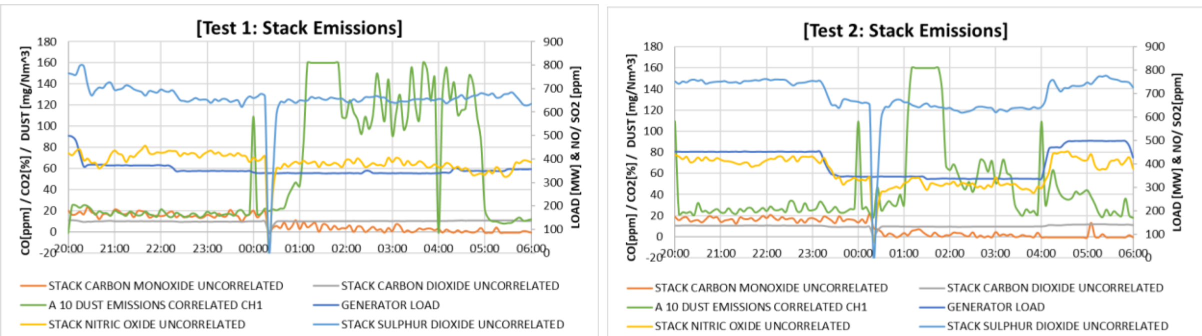


Figure 6.7-7: Lethabo Stack Emissions

All other emissions were seen to decrease with a decrease in load as seen in figure 6.7-7 above. These were also within the required limits.

The superheater and reheater temperatures are designed for normal operation at 535˚C. the superheater temperatures averaged at 525˚C for test 1 and 524˚C for test 2. The reheat temperatures averaged at 508˚C for test 1 and 518˚C for test 2.

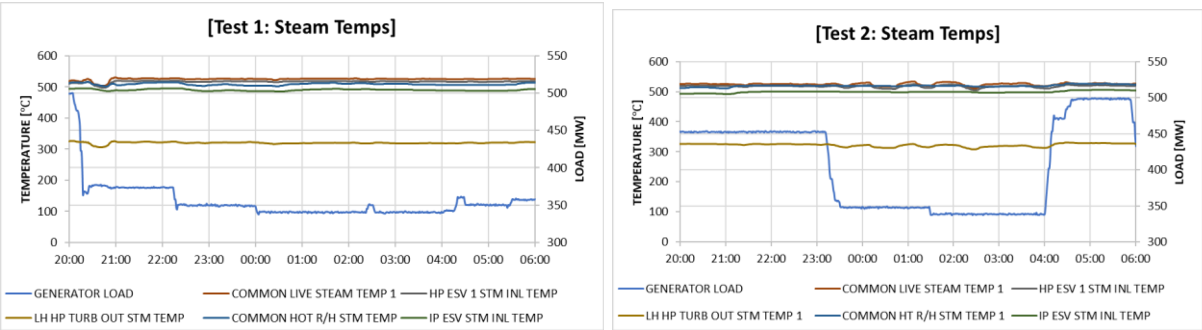


Figure 6.7-8: Lethabo Steam Temperatures

The hot reheat spray water was 1.16 kg/s for test 1 and there was no spray water for test 2.

The unit was de-loaded at a rate of 10 MW/min and ramped up at a rate of 15 MW/min. There were minor upsets during the ramp up as the air flows needed to be adjusted and the metal temperatures went into excursion. However, they were successfully controlled and brought back to normal conditions.

6.7.2 Conclusions And Recommendations

Lethabo can operate at the CDS minimum load of 350 MWg (325 MWnet). Lethabo's main concern is on the thermal excursions linked to platen temperatures which currently requires manual intervention when going down on load. The manual intervention ranges from adjusting spraywater valves, adjusting air flows and biasing of top mills. Some of the manual interventions should be catered for and addressed during the C&I upgrade due to start in 2025. Lethabo's low load procedure covers the aspect of low load and operation with top mills. The procedure will need to be revisited for an update after the completion of all the tests at all units taking into consideration all other concerns that may arise during the tests.

Lethabo burns high ash coal. The coal burnt during the test had higher ash compared to the minimum coal specification requirement. This raise concerns in terms of particulate emissions. The major limiting factors at Lethabo was the high particulate emissions which resulted from the SO_3 plant going on standby at 350 MWg. It is therefore not recommended for Lethabo to operate below the CDS stipulated load until the SO_3 plant can be operated at such low loads. The SO_3 plant standby mode at Lethabo was originally set based on the air heater gas outlet temperatures, which can be controlled by either circulating the secondary air or by utilisation of steam air preheaters to maintain the required temperature for the SO_3 plant to remain in operation. It is recommended that the control of the SO_3 plant be based on back-end temperatures.

6.8 MATIMBA POWER STATION

6.8.1 Matimba Unit 3 Test Overview

Diagnosis testing was conducted on unit 3 at Matimba Power Station. Two sets of tests were conducted on the 10th – 12th of June 2023 as shown in table 6.8-1 below. The unit was sootblown and pyrometers cleaned before the start of the tests. The lowest load achieved was 300 MW sent out which is 49% of TMCR. Figure 6.8-1 shows an overview of the unit loads and what was achieved during the diagnosis tests.

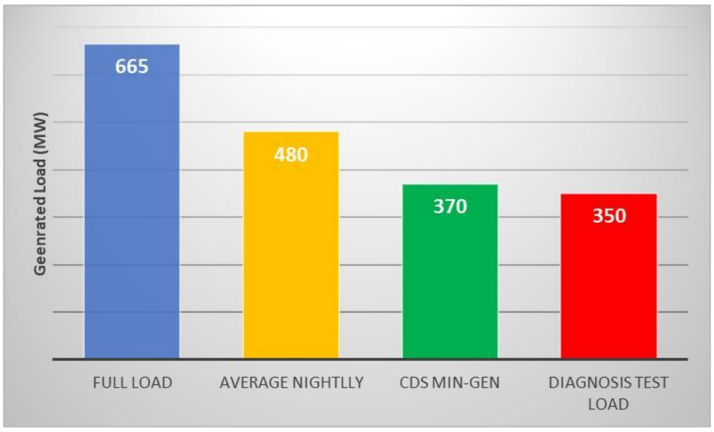


Figure 6.8-1: Matimba Unit Overview

The diagnosis test was conducted with 3 bottom mill combination (CDE), where mill D & E are pressure mills, with mill C being a temperature mill. Mill B is a top mill and is always taken out first when reducing load. Matimba was able to operate at their CDS minimum load of 330 MW sent out. However, they experienced challenges when going further down in load.

Table 6.8-1: Matimba Diagnosis Testing Plan

Date	Test Period	Load [% TMCR]
10 – 11 June 2023	23:50 – 06:10	367 MWg [52%]
11 – 12 June 2023	23:30 – 04:15	350 MWg [49%]

At the start of the tests, ash hopper levels were high due to issues with the collection of the ash. Matimba has a risk of pyrometer blinding resulting from the dislodgement of ash from the reheater tube banks because of excessive ash that accumulates on the reheater tubes during low load operation. The top mill at Matimba has been permanently taken out of service and is used for sweeping air to mitigate against ash falls. Fuel oil burners were regularly checked to ensure their availability to quickly come in when required to support combustion.

Matimba Power Station boilers are Benson boilers and therefore need to maintain a minimum economiser inlet flow limit of 226 kg/s. The lowest economiser inlet flow experienced during the test was 275 kg/s at 336 MWg (306 MW sent out) which was well within the limit but leaves little room to go lower. There were also concerns of the electric feed pump (EFP) leak off – directing some of the water back to the feedwater tank and can result in low economiser inlet flow. The EFP leak off valve was seen to open during test 2, but no issues were experienced as a result of this opening.

The low loads during the two nights of testing were run with the circulation pump on, however the operators are not comfortable with running the circulation pump for longer periods due to concerns with the pump reliability.

Minimum feeder speeds were a concern during the low load operation. The tests were operated with both high pressure (HP) heater banks out of commission (OC), therefore the boiler had to work harder, burning more coal per megawatt output, due to low final feedwater temperatures, to produce the required load. However, operation at the lowest load achieved may not have been possible with 3 mills in service if the HP heaters were in service as the coal burned to produce the same load would have been less, leading to a much lower operation below the FFFR mill capacity lower limit of 60%.

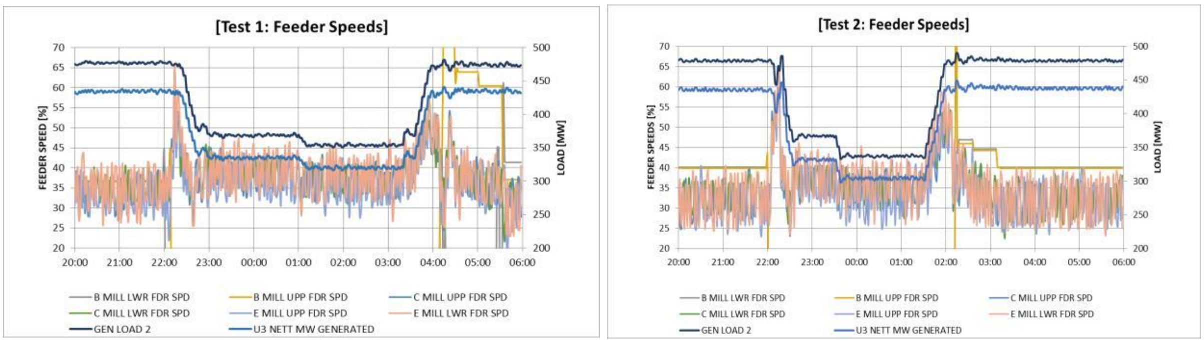


Figure 6.8-2: Matimba Feeder Speeds

The top mill was biased to give preference to the bottom mills to improve feeder speeds, however, these still went below 35% which equates to 60% of mill capacity, 53% of feeder speed equates to 90% of mill capacity. This was one of the limiting factors to going further down in load.

All flame temperatures were well above the alarm limit of 800˚C as shown in figure 6.8-3. The cleaning of the pyrometers before the start of the test assisted with maintaining the flame temperatures within the alarm limits. Test 2 flame temperatures were slightly lower compared to those of test 1.

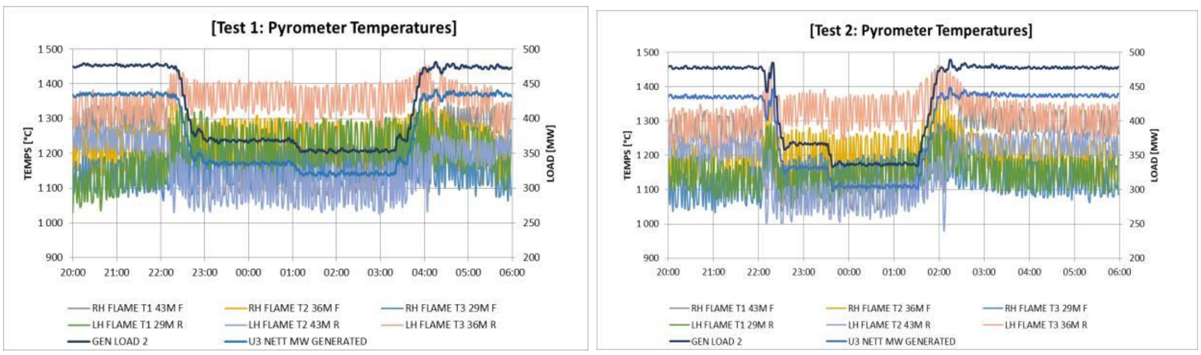


Figure 6.8-3: Matimba Flame Temperatures

In both tests the flame temperatures from pyrometers at 29m and 36m levels increased while those at 43m level decreased when going down in load. This was due to the removal of mill B as a top mill, which shifted the fire ball down in the furnace. No ash fall outs were experienced during the tests.

The coal quality improved from test 1 to test 2. The gross calorific value (GCV) was better during test 2. A slightly more variation was seen during the second test as shown in table 6.8-2 below.

Table 6.8-2: Matimba Unit 3 Coal and Ash Analysis

Proximate Analyses (AD)		Test 1		Test 2	
Analytical Moisture	%	2.27		2.37	
Ash	%	34.93		30.47	
Volatile Matter	%	23.60		24.47	
Fixed Carbon (by difference)	%	39.23		42.70	
Ultimate Analysis (AD)					
Carbon	%	49.04		52.84	
Hydrogen	%	3.18		3.40	
Nitrogen	%	1.42		1.54	
Total Sulphur	%	1.02		1.19	
Carbonate	%	2.47		2.65	
Oxygen (by difference)	%	5.69		5.54	
Gross Calorific Value MJ/kg	MJ/kg	19.58		21.33	
		Start	End	Start	End
Combustible Matter LH	%	0.8	0.8	1.7	1.4

No variations in combustion could be seen from the combustible matter in ash during test 1, however combustion seemed to have improved with reduced combustible matter in ash during test 2. The combustion efficiency during test 2 had dropped compared to test 1, as can be seen by the increased combustible matter during test 2.

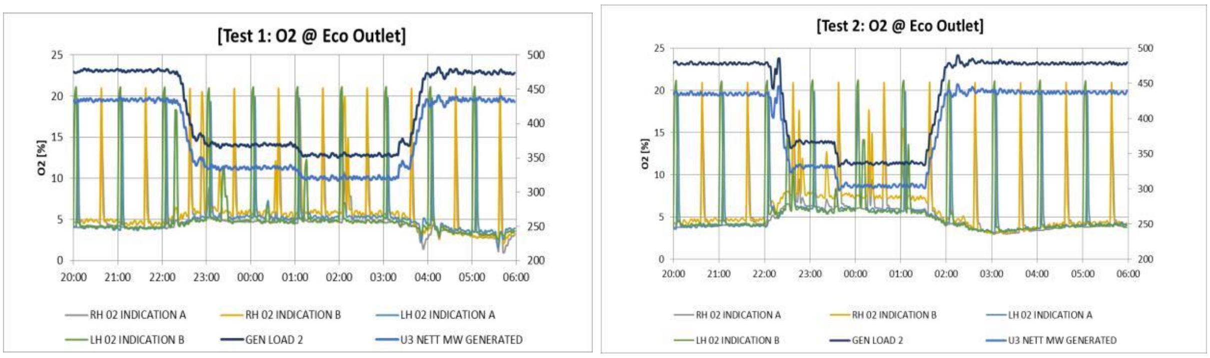


Figure 6.8-4: Matimba Oxygen Concentrations

There were no concerns observed on the oxygen concentration at the economiser outlet which was well within the FFFR limits.

The combined temperatures were well within 160˚C as seen in figure 6.8-5 below, and therefore no concerns regarding dewpoint conditions.

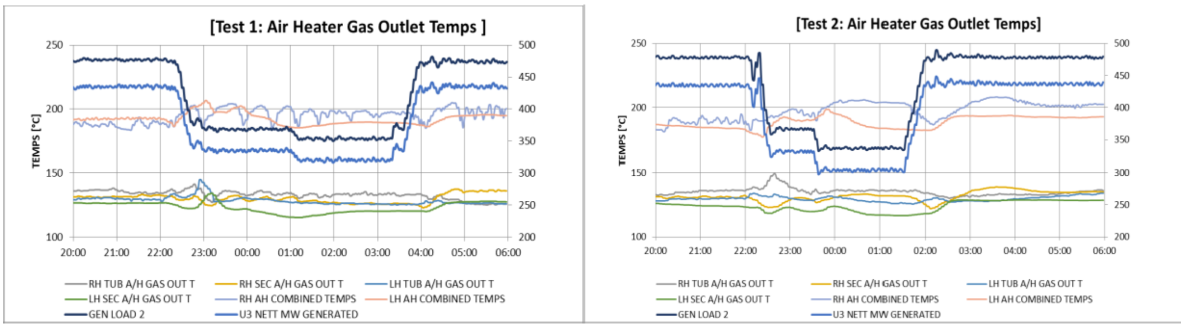


Figure 6.8-5: Matimba Flue Gas Temperatures

A back-end temperature limit of 117˚C is usually observed by the operator. During test 1, the LH air heater gas outlet temperatures reached 117˚C where gas biasing on the Induced Draught (ID) fans was done, so that the left hand ID fan could pull more flue gas to improve the temperature.

Emissions were not a problem during the two nights of testing. Matimba has electrostatic precipitators (ESP) to control the dust emissions. This is preceded by an SO_3 plant which conditions the flue gas before going into the ESP. The SO_3 plant at Matimba has been set to go on stand-by at 350 MWg. The 24hr average for the particulate emissions was below 50 mg/Nm^3 throughout the tests as shown in figure 6.8-6 and well within the minimum emission standard (MES) limit.

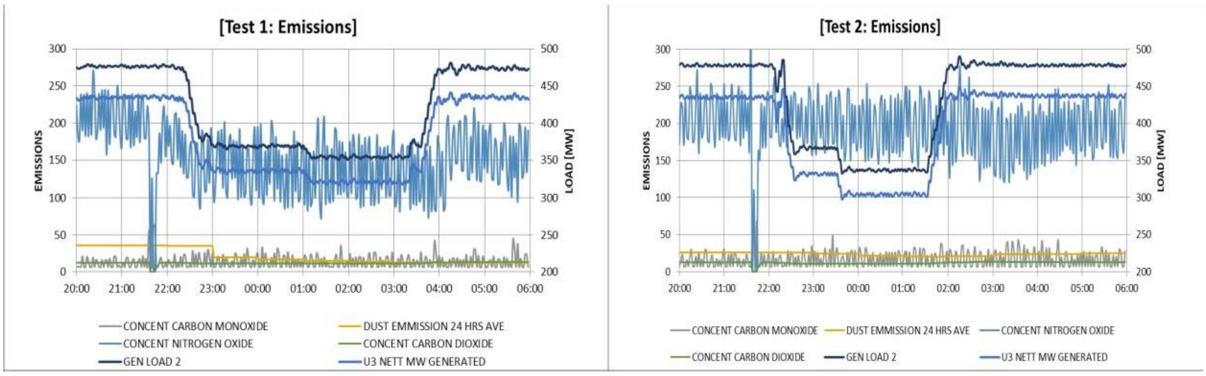


Figure 6.8-6: Matimba PM and NOx emissions at low load

Emissions of SOx and NOx were seen to drop with a decrease in load. The carbon monoxide during test 2 which went to a lower load was slightly higher compared to test 1. This was an indication of a slight drop in combustion efficiency which was also seen on the carbon in ash analysed.

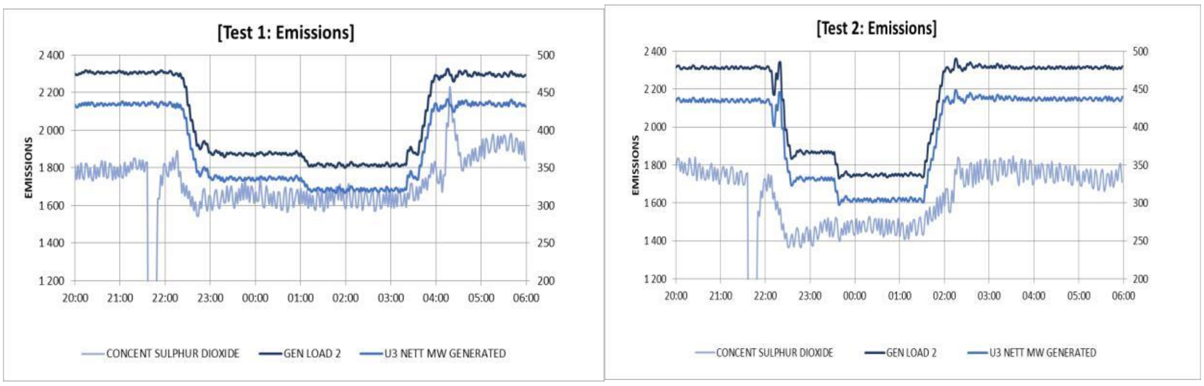


Figure 6.8-7: Matimba SOx Emissions

No emission alarms were observed during the tests.

The alarm limit for both the super heater (SH) and the reheater (RH) temperatures is 545˚C. The SH temperatures were set and maintained at 535˚C for both tests.

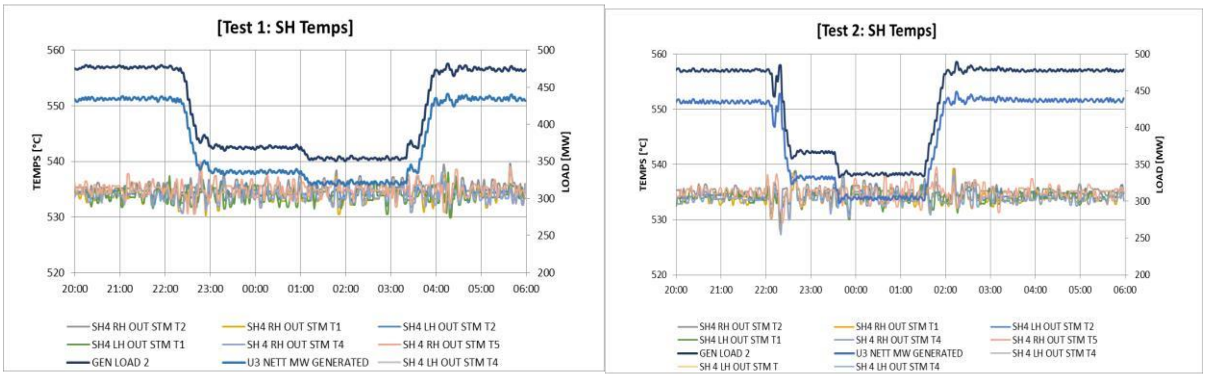


Figure 6.8-8: Matimba Superheater Temperatures

The SH and RH spray water flows were on for the full duration of the test, decreasing with a decrease in load.

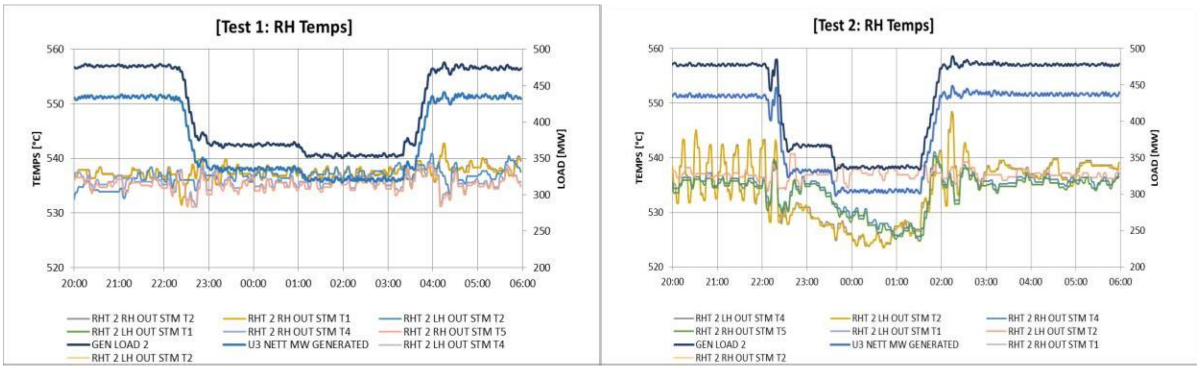


Figure 6.8-9: Matimba Reheater Temperatures

While test 1 reheat temperatures were maintained below 540˚C, test 2 reheat temperatures were unstable and were seen to decrease with a decrease in load. Fluctuations with test 2 reheat temperatures were noticed before the start of the test but got better after the unit was ramped up.

Matimba unit 3 was deloaded at a rate of 5 MW/min until 470 MWg (420 MW sent out), where mill B was taken out of service. Thereafter a 10 MW/min ramp rate was used until the desired load. The CDS stipulates ramp rates of 10 MW/min until 430 MWg and then 15 MW/min from 430 to 665 MWg. The load response on return to full load could not be determined as the unit had high ash hopper levels and could not be loaded up to full load to avoid high particulate emissions. The load was only ramped up to 470 MWg to bring mill B back.

6.8.2 Conclusion And Recommendations

Matimba unit 1 can operate reliably at the CDS minimum load of 330 MW net with 3 mills in service. The main limitation during the tests was the minimum feeder speeds which may necessitate operation with two mills during tier testing to operate within the FFFR mill capacity limit. The EFP leak off was also a concern for low loads as it may reduce the minimum economiser and evaporator flow required for operation above Benson point. Although there are concerns with running the circulation pump over long periods, Matimba has experience on running the circulation pump as this comes on quite often at low loads. The reliability of the circulation pump when running for long periods needs to be investigated.

Matimba is recommended for tier testing. The unit to be tested should be prioritised for address on maintenance defects, including HP heaters.

6.9 MEDUPI POWER STATION

6.9.1 Medupi Unit 1 Test Overview

Diagnosis tests were conducted at Medupi's unit 1 from the 22nd until the 25th of July 2022. Medupi unit 1 has been running at an average nightly load of 450 MWg. The CDS minimum load is 400 MWg (361 MW Net), taking 40 MW as the average low load auxiliary consumption power.

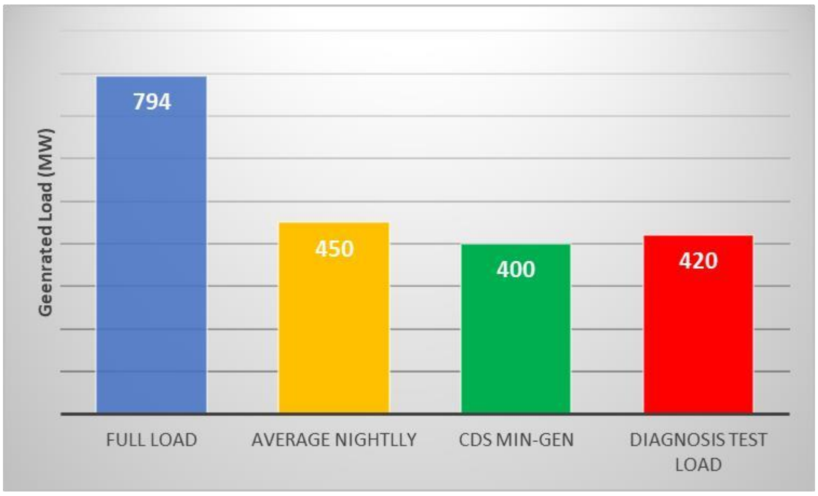


Figure 6.9-1: Medupi Unit Overview

Three sets of tests were conducted with different 3 mill combinations. All three tests were conducted at an average load of 420 MWg. Tests 1 & 3 were conducted with mill 20, 30 & 40, while test 2 was conducted with mills 10, 20, & 30. Test 3 was conducted with sootblowing in progress to assess the possibility of conducting sootblowing at low loads. The major limit to lower load was the evaporator performance. The unit was operated very close to Benson point on all three nights. The collecting vessel had an average level of 25m. The gas air heater temperatures were also a concern, operating at or below the limit of 125˚C. Table 6.9-1 shows the test program over the three nights of testing.

Table 6.9-1: Medupi Diagnosis Testing Plan

Date	Test Period	Load [% TMCR]
22 - 23 July 2023	01:30 – 04:10	420 MWg [53%]
23 – 24 July 2023	23:30 – 04:15	420 MWg [53%]
24 – 25 July 2023	21:30 – 04:00	420 MWg [53%]

All three tests were operated with three mills. A short-term adaptation was obtained from the FFFR committee to allow operation below the mill capacity limit of 60%.

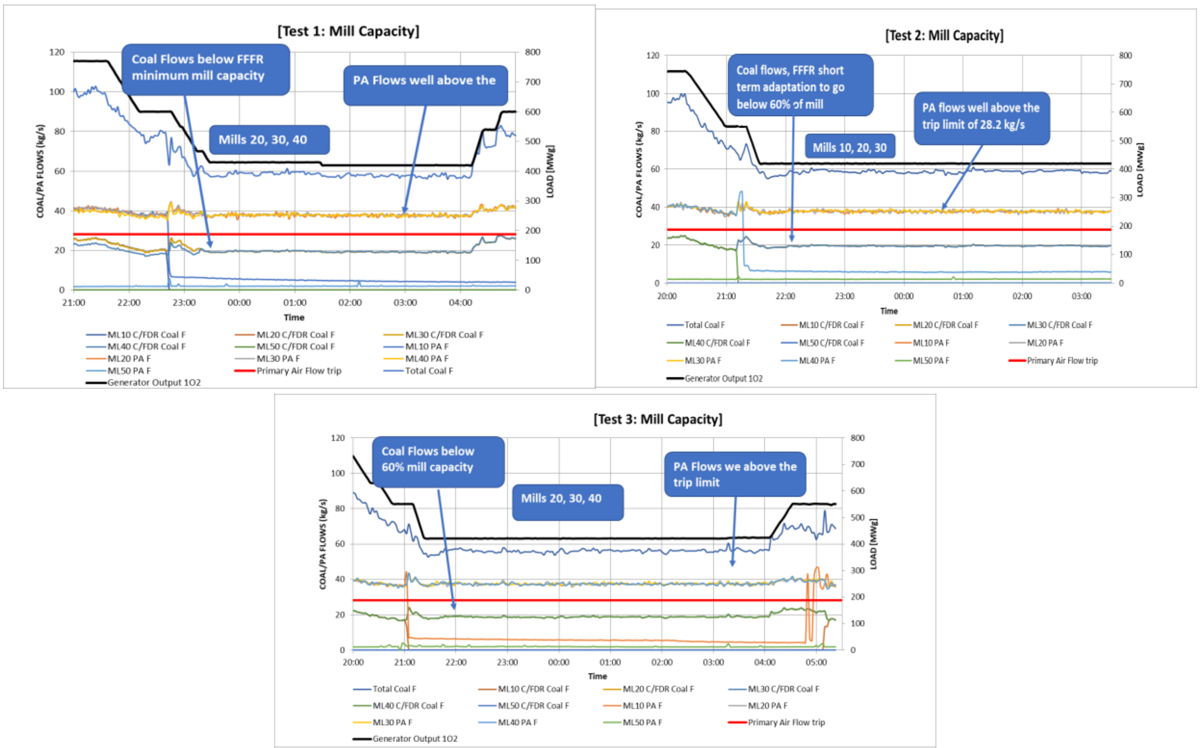


Figure 6.9-2: Medupi Mill Capacities

The mills were operated at an average of 57% of mill capacity. The primary air flows were well within the trip limit of 28.2 kg/s.

Flame temperatures were generally stable indicating a stable flame. They were higher for test 1 and test 3 where middle mills were in service and lower for test 2 where bottom mills were in service. The steep temperature drops were due to pyrometer cleaning.

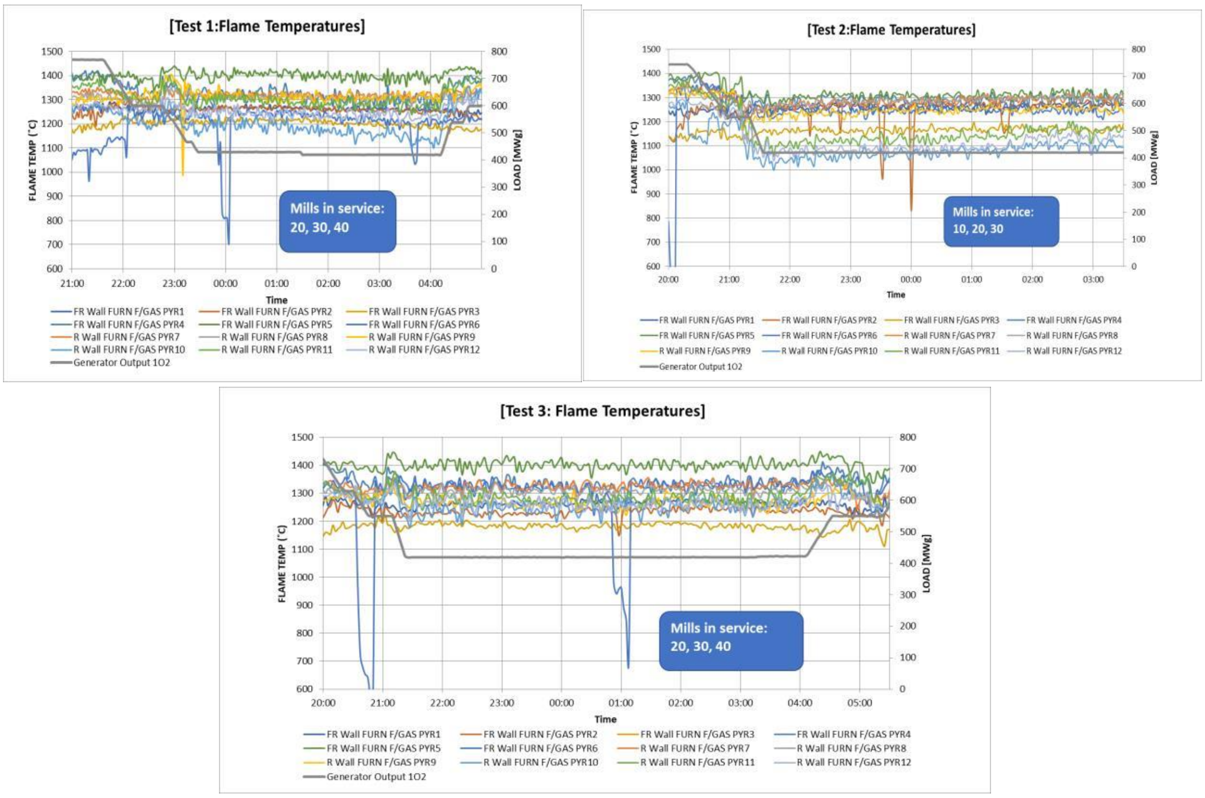


Figure 6.9-3: Medupi Flame Temperatures

Test 2 and test 3 coal quality was better compared to test 1, however in general the quality was consistent over the testing period. The minimum coal specification for Medupi stipulates a GCV of 20.92 MJ/kg on moisture free basis for the original design coal, the current tests had better GCV for all three tests on a moisture free, 20.99 MJ/kg, 21.32 MJ/kg, and 21.37 MJ/kg for test 1, 2 & 3 respectively. In all three tests the ash was less than the design ash of 35.71% on a moisture free basis.

Table 6.9-2: Medupi Unit 1 Coal and Ash Analysis

Proximate Analyses (AD)		**Test 1**		**Test 2**		**Test 3**	
Analytical Moisture	%	2.15		2.20		2.02	
Ash	%	33.25		32.50		32.20	
Volatile Matter	%	26.45		27.60		26.93	
Fixed Carbon (by difference)	%	38.18		37.70		38.88	
Ultimate Analysis (AD)							
Carbon	%	49.95		50.96		51.22	
Hydrogen	%	2.84		2.95		3.14	
Nitrogen	%	1.36		1.34		1.38	
Total Sulphur	%	1.31		1.24		1.25	
Carbonate	%	2.52		2.55		2.57	
Oxygen (by difference)	%	6.63		6.26		6.23	
Gross Calorific Value MJ/kg	MJ/kg	20.58		20.89		20.98	
Surface Moisture	%	8.05		8.10		7.85	
Total Moisture	%	10.03		10.10		9.70	
Inherent Moisture (as recieved)	%	1.98		2.02		1.86	
		Start	End	Start	End	Start	End
Combustible Matter	%	0.1	0.9	0.2	0.2	0.2	0.2

The combustion efficiency for test 1 decreased as seen with an increase in carbon in ash in the table below. No changes were seen in the carbon in ash for test 2 and test 3 before and after the test.

The oxygen concentration at the gas air heater inlet was well within the FFFR upper limit of 9% for all three tests.

Figure 6.9-4: Medupi GAH Inlet Oxygen Concentration

The right hand side gas air heater inlet O_2 was observed to be always higher than the left hand side O_2. The split was minimal during test 3 where sootblowing was conducted during the test and middle mills utilised. The split was highest for test 2, with bottom mills utilised.

Combined temperatures were maintained above 160˚C for test 1 and test 3. For test 2, combined temperatures went below 160˚C but recovered after manual intervention where the steam preheater was brought in.

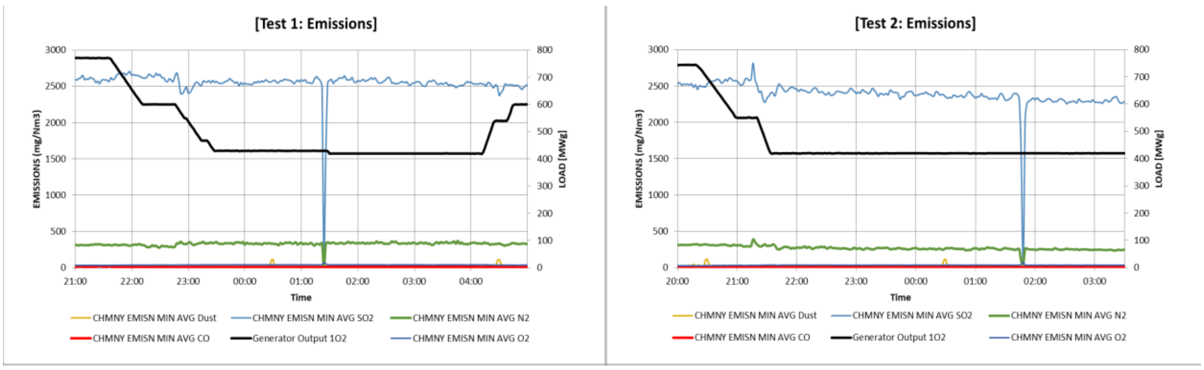
Figure 6.9-5: Medupi Combined Temperatures

The gas air heater gas outlet temperatures were constantly below 125˚C. Stable temperatures were observed for test 3 which was conducted with sootblowing in progress.

Gas air heater gas outlet temperatures were a concern during the test at low loads but were also observed to be low even at high loads. Medupi Power Station burns coal that is high in sulphur and therefore susceptible to high levels of acid formation.

Emissions of SOx, NOx and particulate matter were observed to be within the required limits of 3500 mg/Nm^3, 750 mg/Nm^3 and 50 mg/Nm^3 respectively during the tests.

A slight decrease in SO_2 emissions was observed when going down in load. The bottom mill combination during test 2 yielded lower emissions compared to test 1 and 3 which were operated with middle mills.



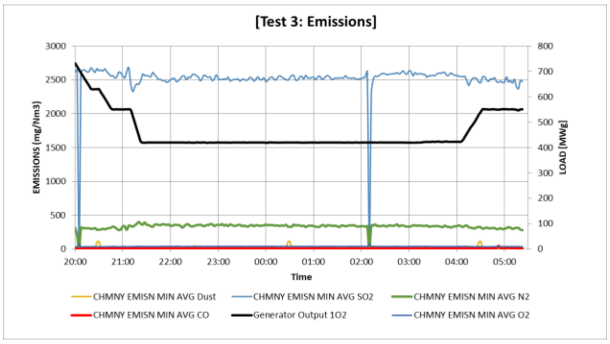


Figure 6.9-6: Medupi SO2 Emissions

The NOx was seen to increase with a decrease in load for test 1 and test 3, however the opposite was the case for test 3 where NOx decreased with a decrease in load. The difference in behaviour is due to the different mill combinations.

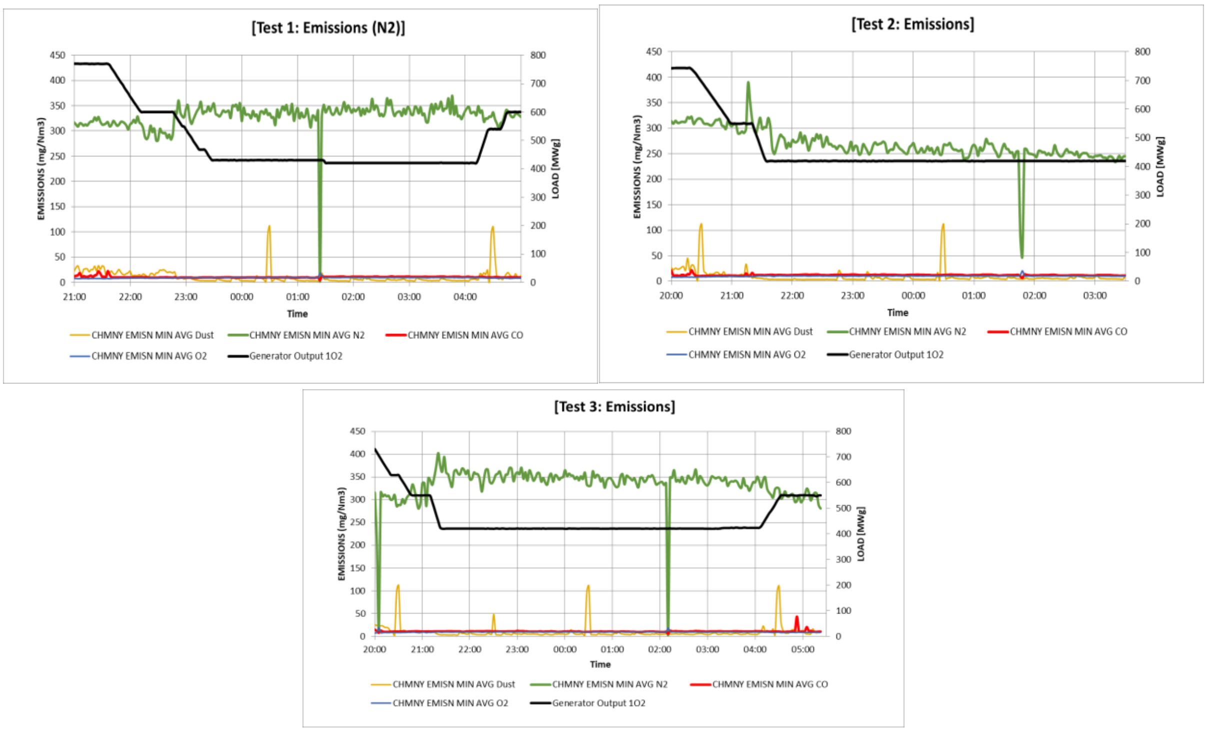


Figure 6.9-7: Medupi NOx Emissions

The average dust emissions decreased with a decrease in load.

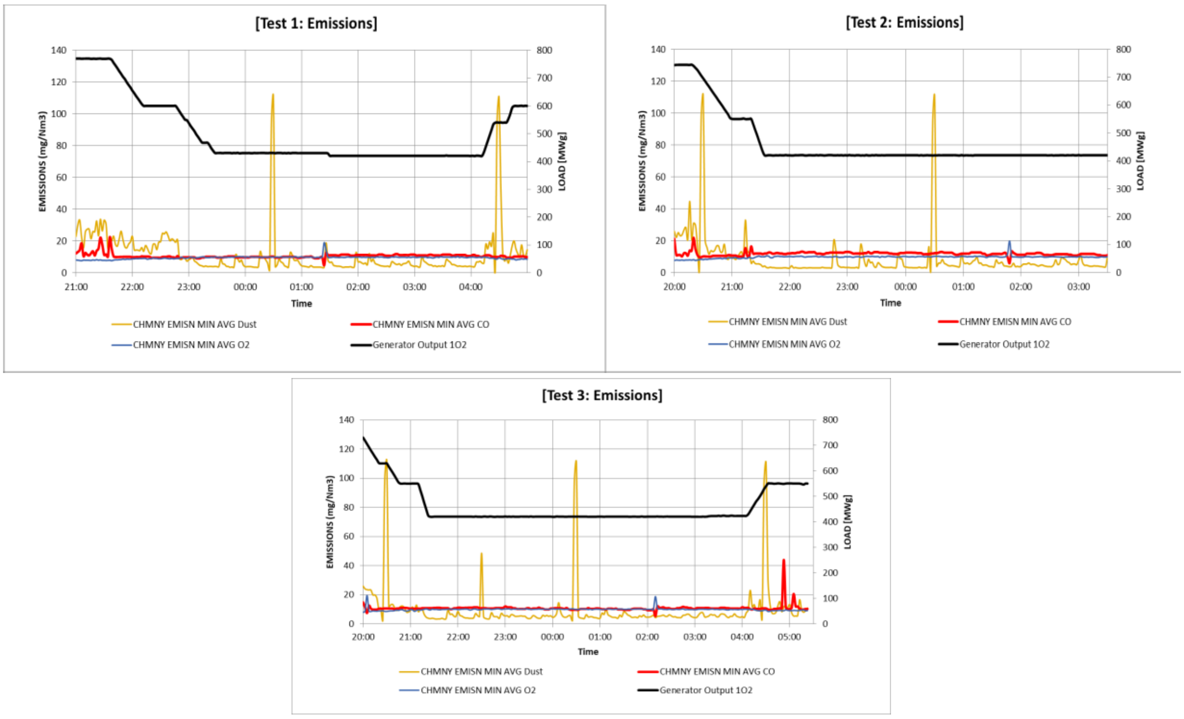


Figure 6.9-8: Medupi Dust Emissions

The superheater and reheater temperatures were maintained below 560˚C and 580˚ C respectively. The spray waters were on throughout the tests and as would be expected, were better with bottom mils operation. Both superheater and reheater spray waters were observed to decrease with a decrease in load while the temperatures remained constant.

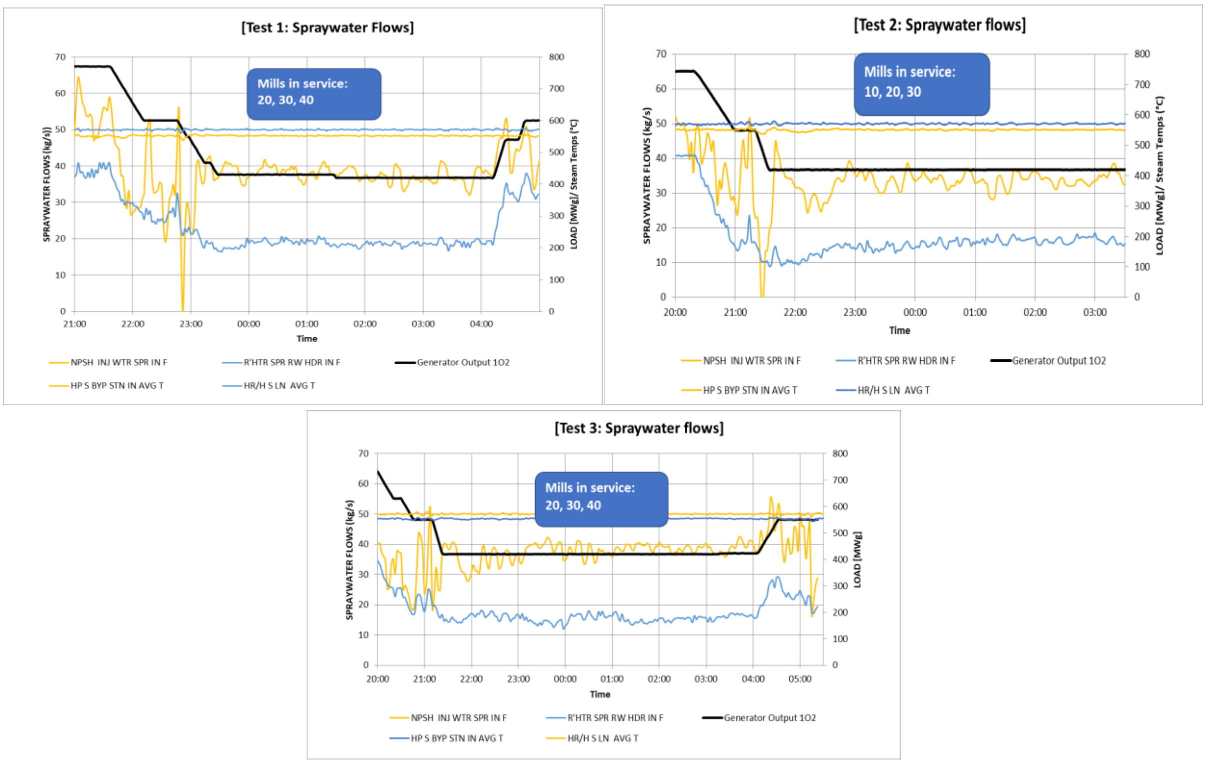


Figure 6.9-9: Medupi Spray Water Flows

The reheater spray water flow for test 3 was better compared to that of test 1 with the same mill combination but no sootblowing. The maximum spray water capacity is 40 kg/s. All three tests operated well below this limit at low load tested.

The evaporator performance was the limiting factor from going lower in load while maintaining Benson operation. The evaporator outlet steam temperatures were close to the steam saturation temperature, which is a function of the evaporator outlet steam pressure.

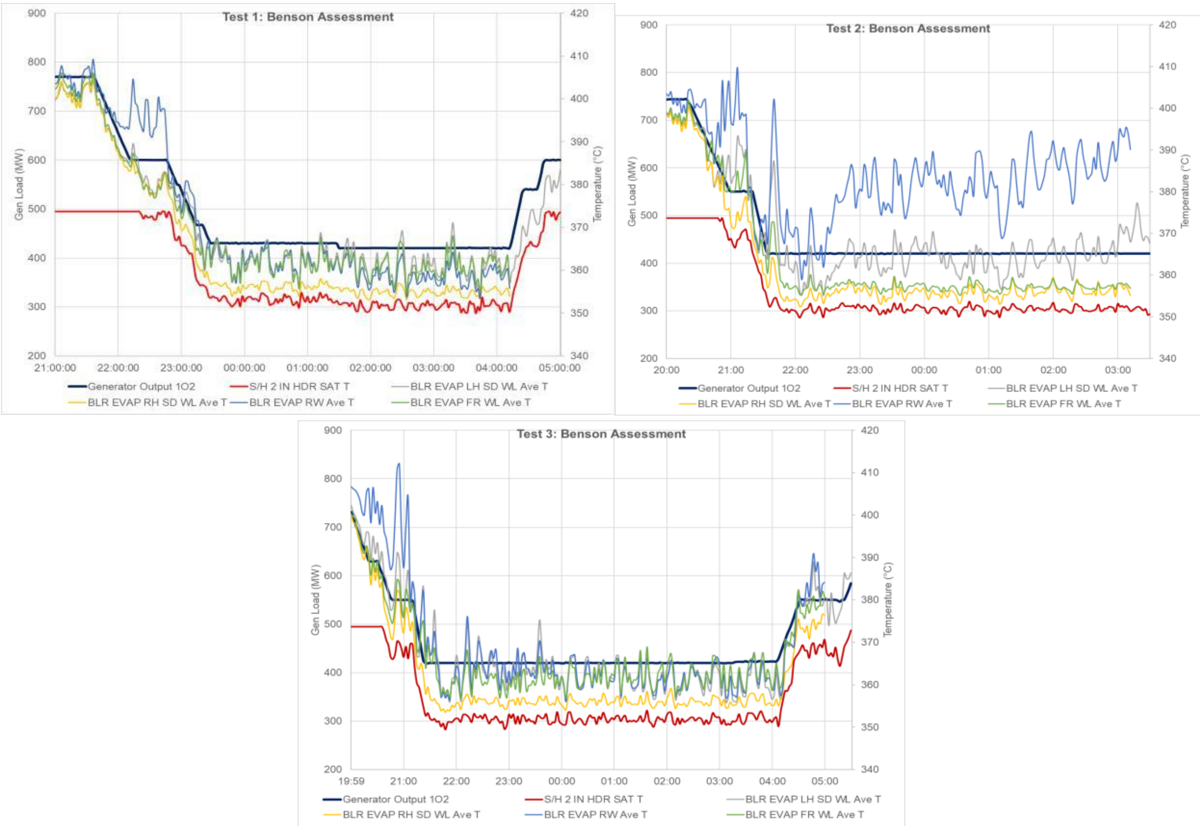


Figure 6.9-10: Medupi Evaporator Performance

The collecting vessel had a level during all three tests. The evaporator heat uptake was found not to be enough to produce dry steam at the outlet. Operating with bottom mills assisted slightly as seen in figure 6.9-10 where the outlet temperatures were better compared to evaporator outlet temperatures in test 1 and 3 operating with middle mill combination. This could get worse with top mill combination as the fire moves up and exacerbates the heat uptake.

The CDS stipulates ramp rates of 10 MW/min for Medupi units. The tests achieved ramp rates of between 5 and 10 MW/min.

6.9.2 Conclusions And Recommendations

Medupi unit 1 was unable to achieve the CDS stipulated min-gen value of 361 MW net, the lowest load achieved during the three nights of testing was 420 MWg (380 MW net). The tests at 420 MWg were conducted with three mills, however this required that a short-term adaptation be requested from the FFFR. The mills at Medupi rated above 100 tons/hr, can go to as low as 40% of mill capacity, however this will require FFFR approval for normal operation at 40%.

The evaporator performance was a major limiting factor to going lower in load without effecting circulation mode. This requires optimisation of the unit coupled with increase in spray water capacity to enable more heat uptake by the evaporator if the unit is to be operated at Benson and lower loads than achieved during the tests. Otherwise, lower loads operation will require operation in circulation mode. Medupi will be replacing their spraywater valves to high capacity valve in 2024.

Medupi has developed a minimum generation operation procedure to address the limiting factors at low loads. More tests are recommended with the new spray water valves. Tests should be rolled out to the rest of the units and the minimum load procedure updated with ensuing conditions.

7 CONCLUSIONS

Seven of the eight units were able to operate at their CDS minimum load with no fuel oil support, the CDS stipulates the minimum loads on a net basis. The generated load is not constant as the auxiliary power changes with a change in load:

- Arnot can operate at a minimum load of 230 MWg with four mills. Three mill operation is possible with pressure mills in service.
- Duvha can operate at a minimum load of 350 MWg with three mills. The secondary air circulation is key to maintain the back end temperatures within the required limits.
- Kendal was able to operate at a minimum load of 326 MWg with three mills. Kendal demonstrated operation at 300 MWg with biasing of mills.
- Kriel operated at a minimum load of 305 MWg with four mills. Further investigation into the positive furnace pressure is required.
- Kusile was able to operate at a minimum load of 350 MWg with three mills. Further turndown beyond 350 MWg requires operation with two mills.
- Lethabo operated at a minimum load of 350 MWg with three mills. Further turndown requires attention to the settings of the SO_3 plant in order to remain within the minimum emissions standard on particulate matter. The standby mode should be set on temperature rather than the load.
- Matimba can operate at a minimum load of 350 MWg with three mills. Further turndown at Matimba will require operation at circulation mode with two mills in operation.
- Medupi was tested at a minimum load of 420 MWg with three mills. The major limiting factor to lower load was the evaporator performance. Further turndown to meet CDS minimum load may require circulation mode operation.

8 RECOMMENDATIONS

It is recommended that diagnosis tests be rolled out to the rest of the units at the power stations tested. Different scenarios should be tested when rolling out the diagnosis tests to the rest of the units. This will allow for the development of minimum load procedures catering for different operating conditions. This should include but not limited to different mill combinations, biasing of mills, operation with single feeder and operation with boiler feed pumps and/or electric feed pumps and operating for longer periods at low loads.

Three units are recommended for tier testing, these are Kendal, Kusile and Matimba. The selection criteria for these units considered, remnant life, merit order dispatch, type of boiler and the capability assessment to go lower on load.

The selection criteria can be seen in appendix 1.

9 REFERENCES

1. Christo Van Wyk. December 2016. Fossil Fuel Firing Regulations Standard. Document Identifier 240-105453648. Eskom Holdings SOC Ltd

2. Kubayi Lebohang. March 2022. Consistent Data Set For Eskom Generating Plant. Unique Identifier 36-623 rev 4. Generation.

3. Priven Rajoo. March 2019. Coal quality Specification for Eskom’s Power Stations rev2. Unique Identifier 240-71273834. Generation

4. Koos Veldman. January 2018. Performance and Capability Proof Testing for Coal Fired Plant Standard rev 2. Unique Identifier 240-84170223. Eskom Technology Generation

5. Du Toit Phillip. December 2022. Medupi Power Station Minimum Generation Optimisation Tests Procedure. Medupi Power Station

10 APPENDICES

10.1 APPENDIX 1: SELECTION CRITERIA

Station	Units	Boiler type	Longest remnant life unit	Gx Cost (R/MWh)	Maximum Continous Rating MWg	Turndown Capability (CDS) MWg	Min. Gen. Tests (MWg)	% Reduction from CDS	Unit tested
Grootvlei	6	unit 1 and 6 Tower , unit 2, 3 and 4 EL PASSO , unit 5 Steinmuller	04-Sep-27		200	140	Not tested		
Kendal	6	Drum	09-Dec-44		686	326	300	8%	2
Hendrina	10	unit 1 Babcock Tower, unit 2-5 Babcock El passo, unit 6-10 Steinmuller tower	31-Dec-25		200	130	Not tested		
Arnot	6	ICAL - Drum boiler	24-Nov-29		370	240	210	13%	2
Majuba	6	Benson Once through	31-Mar-51		657	456	350	23%	2
Camden	8	Double Drum	30-Nov-25		200	110	Not tested		
Tutuka	6	Once through	25-Sep-30		609	324	280	14%	4
Matla	6	Drum	20-Jul-34		600	325	290	11%	3
Kriel	6	Benson Once through	16-Nov-30		500	305	290	5%	6
Duvha	6	Steinmuller Once-through	21-Feb-34		600	400	350	13%	5
Kusile	6	Benson Once through	30-Jun-73		799	399	350	12%	3
Matimba	6	Once through	30-Sep-42		665	380	350	8%	3
Lethabo	6	Babcock two pass	27-Dec-41		618	350	340	3%	4
Medupi	6	Benson Once through	31-Jul-71		794	435	420	3%	1

Notes:

- April 2022 scheduling costs were used.
- The auxiliary power from the CDS was used to convert the net load to generated load.

10.2 APPENDIX 2: OPERATING LOGS

Not included for public distribution due to extensive listing of staff names

11 DISTRIBUTION LIST

PROGRAMME MANAGER:	
CUSTOMER:	
PROJECT OFFICE:	
STEERING COMMITTEE:	
ADDITIONAL COPIES:	