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Technology Selection
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EXECUTIVE SUMMARY

Eskom Limited is under a government mandate to install and operate flue gas desulphurization (FGD) technology on the Medupi Power Station units. This study includes a technical suitability assessment of commercially available FGD technologies to identify leading FGD technologies for implementation at Medupi Power Station, the cost implications associated with the leading FGD technologies, and the raw resources required for the operation with the leading FGD technologies and their availability at the Medupi Power Station.

Commercially available FGD technologies were considered for the Medupi plant. Based on the outcome of technology studies, the leading FGD technologies evaluated in the report are the Wet FGD and Dry FGD – Circulating Fluidized Bed (CFB) technologies.

The Wet FGD has a long history of application to fossil fuelled power plants in units of all sizes, and remains the predominant process utilized today. It has high removal efficiency on high sulphur coals and only requires a single absorber vessel per boiler. The gypsum created by this process can be used in concrete and wall board manufacturing or be landfilled. There may be a waste water stream created that will require further processing. The amount of water used in Wet FGD is higher than a Dry FGD-CFB, however a flue gas cooler may be installed to reduce this water requirement to that of the Dry FGD-CFB.

The Dry FGD-CFB has been used extensively around the world and mixes lime, water, and fly ash-laden flue gas in a reactor to remove the sulphur dioxides from the boiler flue gas stream. There is no waste water stream created by this process. The fly ash created in the process will need to be landfilled. This process works best with low to medium sulphur coals and has a current reactor size maximum of 450 MW, so two reactors would be required for each boiler for Medupi.

While the implementation of WFGD with flue gas cooling has the potential to reduce the WFGD water consumption the practical challenges cannot be ignored as this is expected to have a significant impact on the maintainability and availability of the power plant and the cost of electricity to the consumer. Furthermore all three power stations from Europe visited by Eskom during a benchmarking exercise advised against the installation of the system due to the problematic operation that it provides. WFGD with flue gas cooling is therefore not considered as a feasible option for Medupi.

The implementation of the WFGD technology has the potential to contribute to the broader socio-economic development of Lephalale and its surrounding areas because the WFGD has the flexibility of using lower quality limestones that can be sourced from areas closer to the power station which is not the case with the DFGD systems. Furthermore the water supply for the WFGD at Medupi is part of the Phase 2A water augmentation project which is being developed to maximise the potential use of the natural water resource in the Crocodile catchment for industrial use in Lephalale and the surrounding areas. The development of Phase 2A therefore creates an opportunity for economic development in the area which cannot take place without it.

The DFGD technology resulted in a 9% higher capital cost for implementation due to modifications required for existing ductwork design and the addition of a new fabric filter system to the existing FFP in order to retrofit this technology. Although the DFGD processes use slightly

less water for the Medupi site, the estimated operating expense for the DFGD is 53% higher than the WFGD system, mostly due to the significantly higher cost of the lime reagent.

It is therefore recommended that Eskom continue with its plan to construct the WFGD technology without the inclusion of a flue gas cooler as this is still the best long term option for SO₂ removal at Medupi Power Station. Based on the information presented in this report it is evident that this is the most efficient, sustainable and broadly (i.e. technical, social, cost) responsible solution for both Eskom and South Africa going forward.

1. INTRODUCTION

1.1 Background

The Medupi Power Station will consist of six 800 Megawatt (MW) coal fired steam electric generating units located in Limpopo Province, approximately 15 kilometres (km) west of the town of Lephalale, South Africa. The Medupi Power Station Flue Gas Desulphurisation (FGD) Project will result in the retrofitting of an FGD system to each of the operating units. The FGD units are planned to enter commercial operation sequentially post the first general overhaul outage of the respective units.

Eskom previously conducted a technology review of FGD technologies [9] available to achieve the level of SO₂ reduction required by law. This was applicable to new as well as existing power stations. The Wet Flue Gas Desulphurisation technology was selected for Kusile and Medupi Power Station based, amongst other reasons, on its technology maturity and high level of commercialised industrial application worldwide.

As a result, the design of Medupi Power Station included considerations and provisions for the future retrofit of a WFGD plant for SO₂ emission abatement. The WFGD plant engineering design for the retrofit therefore commenced in 2011.

Recent questions arose on the applicability of this technology selection based on the maturity that other technologies have gained in the past few years. A reassessment of the technology selection at Medupi was therefore initiated and the findings are reported herein¹.

Eskom traditionally makes project related decisions based on a techno-economic basis. This implies that the chosen technology is cost effective and technically proven. For the Medupi FGD project specifically additional considerations need to be made with regards to raw resource availability. This suggests that there needs to be a strategic look at specifically water and sorbent availability and quality in South Africa.

Furthermore, Eskom recognises the significance of considering the technology selection within the current socio-economic climate of South Africa. In this, the chosen technology for implementation must be efficient, sustainable and a broadly (i.e. cost, social, technical) responsible solution for emission abatement. This required finding the balance between the cost of implementation and the environmental and social impacts relating thereto. These factors are highly interdependent and cannot be evaluated in isolation. The basis for comparison of the technologies were mainly on the legislative requirements, impact to the electricity tariff and the utilisation of the raw resources (i.e. water and sorbent).

1.2 Study Objectives

The study is broken down into three evaluation steps. Firstly the technical suitability of a technology will be assessed and compared for implementation at Medupi Power Station. Secondly the cost associated with each of the technologies respectively will be discussed, and finally the raw resource availability will be evaluated.

¹ The costs developed in this study should be analysed only on a comparative basis for the respective technologies and should not be taken as absolute values.

The FGD Technology Selection Study Design Basis [3] serves as the basis for all calculations, analysis and estimates.

In particular, the objectives of the study can be summarised as follows:

a) Technical suitability assessment

- i) Understand the requirement for SO₂ reduction and the implications of non-compliance.
- ii) Identify the technologies available to achieve the level of SO₂ reduction required. Factors for consideration include: degree of commercialisation, unit size, reliability and availability.
- iii) Understand the requirements for the magnitude of waste produced in the FGD to serve as input to waste management planning.
- iv) Discussion on water reduction strategies that can be employed for each alternative (if applicable) and the degree of implementation for each alternative.
- v) Consider the infrastructure requirements in relation to the existing power plant configuration and arrangement.
- vi) Short term measures for emission abatement.

b) Cost Implications

- i) Determine the capital expenditure requirement for each alternative.
- ii) Discussion on the operational expenditure for each alternative.
- iii) Evaluation of the implication to the electricity tariff for each alternative.

c) Raw Resource Availability

- i) Fundamental raw resource definition.
- ii) Understand the requirements for the magnitude of sorbent usage.
- iii) Understand the requirements for the magnitude of water usage.

2. SUPPORTING CLAUSES

2.1 Scope

The scope of this document is limited to the study objectives as described in Section 1.2 and is related to Medupi Power Station only. Any technical recommendations are therefore limited to Medupi Power Station.

2.1.1 Purpose

The purpose of this document is to capture the technical position for flue gas desulphurisation at Medupi Power Station and the sharing of the considerations to relevant stakeholders (including the public).

2.1.2 Applicability

This document shall apply throughout Eskom Holdings Limited Divisions with specific reference to the Medupi Power Station.

2.2 Normative/Informative References

Parties using this document shall apply the most recent edition of the documents listed in the following paragraphs.

2.2.1 Normative

- [1] Design Base Standard – Doc no: 474-190.
- [2] Design Review Procedure – Doc no: 240-5311 3685.
- [3] Technology Selection Study Design Basis – Doc no: 348-11281 (B&V file no.: 195700.41.0108).

2.2.2 Informative

- [4] Medupi User Requirements (URS) Rev. 4 – Doc no: NC/001.
- [5] Medupi FGD Retrofit Project Design Manual (PDM) – Doc no: 200-61989.
- [6] Eskom Air Quality Strategy – Doc no: ESG32-1143.
- [7] National Environmental Management Act 2004 (Act 39 2004).
- [8] Listed Activities and Associated Minimum Emission Standards Identified in Terms of Section 21 of the National Environmental Management: Air Quality Act, 2004 (Act 39 2004).
- [9] FGD Technology Review – Doc no: RES/RR/04/24115.
- [10] Medupi FGD Retrofit Basic Design Report (BDR) – Doc no: 200-61771 Rev 2.
- [11] Pre-screening of flue gas cooling options based on techno-economic assessment for Medupi Power Station WFGD Retrofit Project –Doc no: 200-2211635 (June 2016).

- [12] Fleet SO_x Project – Majuba Power Station Cost Estimation and Life Cycle Cost Analysis – Doc no: 363-SO_x-ACCA-D00160-2 (Steinmueller Doc no: 062104-T-KAL-101).
- [13] Fleet SO_x Emissions Reduction Report - Majuba Power Station Concept Design Report – Doc no: 363-SO_x-BDDD-D00185-7.
- [14] Post-combustion Flue Gas Desulphurization (FGD) Plant Technology Strategy.
- [15] Dry Sorbent Injection for Medupi Power Station - Doc no:1788771.41.0053.

2.3 Definitions

2.3.1 Classification

Public domain: Published in any public forum without constraints (either enforced by law, or discretionary).

2.4 Abbreviations

Abbreviations	Description
BDR	Medupi FGD Retrofit Basic Design Report [10]
BOP	Balance-of-Plant
°C	Centigrade
CaCO ₃	Calcium Carbonate (limestone)
CaO	Calcium Oxide (lime or quick lime)
Ca(OH) ₂	Calcium Hydroxide (hydrated lime)
CFB	Circulating Fluidized Bed (FGD)
DFGD	Dry or Semi-Dry Flue Gas Desulphurisation
FFP	Fabric Filter Plant
FGD	Flue Gas Desulphurisation
ID	Induced Draught
Km	Kilometres
kPa	Kilopascal
µm	Micron (micrometre)
LSFO	Limestone Forced Oxidation
m ³	Cubic Metres
Mbar	Millibar
mg/Nm ³	Milligram per Normal Cubic Metre (0° C and 1 atmosphere, dry basis at 6% O ₂)
MW	Megawatt
O ₂	Oxygen
PDM	Project Design Manual
SDA	Spray Dryer Absorber (semi-dry flue gas desulphurisation)
SO ₂	Sulphur Dioxide

Abbreviations	Description
URS	User Requirements Specification
WFGD	Wet (limestone) Flue Gas Desulphurisation
ZLD	Zero Liquid Discharge

2.5 Roles and Responsibilities

This document was compiled under instruction from Eskom with input from three parties; Black and Veatch, Steinmüller Engineering and Eskom.

Individual	Company	Role and Responsibility
Candice Stephen	Eskom Boiler Lead Discipline Engineer	Input
Christian Unger	Steinmüller Project Manager/Lead Process Engineer	Input
Daniel Chang	Black & Veatch Project Manager	Compile
Leon van Wyk	Eskom Boiler Auxiliaries CoE Manager (Acting)	Review
Muhammad Bagus	Eskom Engineering Design Work Lead	Review

2.6 Process for Monitoring

Not Applicable.

2.7 Related Supporting Documents

Not Applicable.

3. TECHNICAL SUITABILITY ASSESSMENT

3.1 Requirement for SO₂ reduction

According to the United States Environmental Protection Agency and also referenced by the World Health Organisation, the leading concern with SO₂ is short-term exposure to airborne SO₂ as this has been associated with various adverse health effects, particularly respiratory health. Secondary other environmental effects include contributions to acidic deposition, reduced visibility and negative impact to vegetation growth.

South Africa has therefore created and issued Minimum Source Emission Standards for Listed Activities published in terms of Section 21 of the National Environmental Management: Air Quality Act (Act No 39 of 2004). This Act stipulates that the SO₂ emission limits for new and existing coal fired power stations shall not exceed 500 mg/Nm³ and 3500 mg/Nm³ (10% referenced oxygen content) respectively with an associated compliance timeframe for each.

Medupi Power Station is included in this requirement and will need to operate the power generation facility with a maximum SO₂ outlet emission concentration of 500 mg/Nm³. This cannot be achieved through any other means than FGD technology.

Typical operating emission levels for Medupi without FGD are approximately 4000mg/Nm³. The nominal SO₂ removal efficiency required is therefore approximately 87.5%². All technologies considered should therefore be able to at least meet this removal efficiency.

As SO₂ emissions is a function of the coal sulphur content being combusted, the outlet emissions cannot be manipulated with load reductions at the power generation facility. Non-compliance to the emission limit therefore implies a shutdown of the generation facility.

3.2 Identification of the technologies available to achieve the level of SO₂ reduction required

The identification of suitable FGD technology begins with evaluating commercially available and applicable technologies for SO₂ reduction in flue gas from coal power generation activities. SO₂ can be reduced using FGD technologies identified in Figure 1 before combustion, during combustion, and post-combustion of coal.

² The quoted removal efficiency is not the designed removal efficiency required for the project as the design includes various transient conditions, fuel dynamics and safety factors. The quoted removal efficiency is only used as a guideline for initial technology screening purposes.

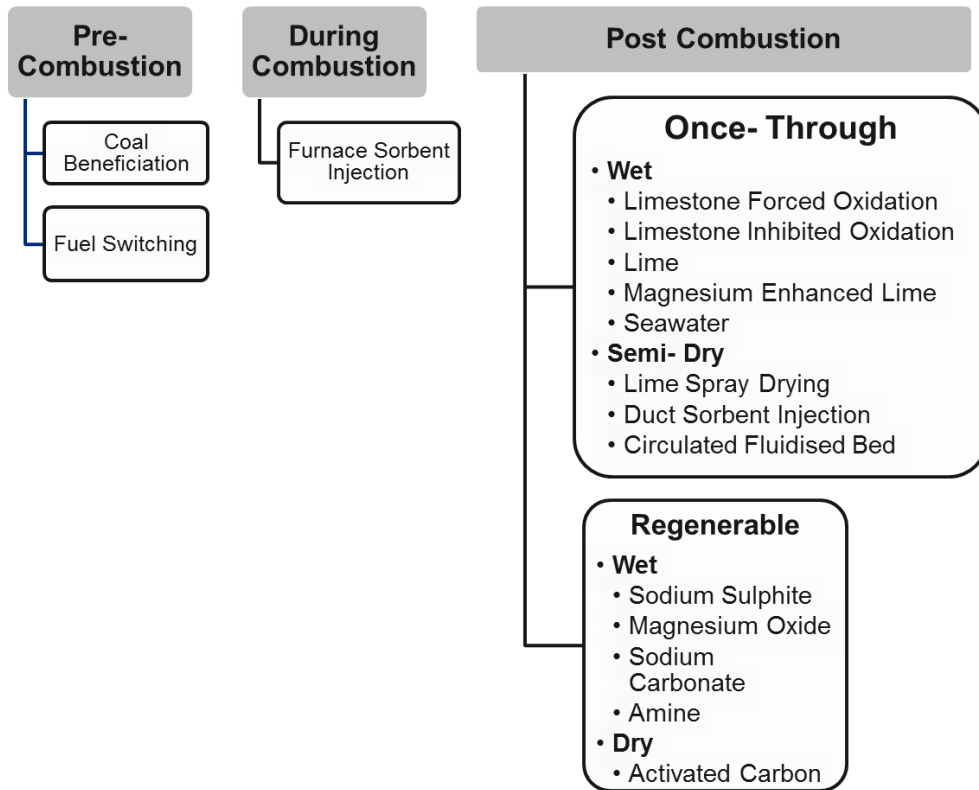


Figure 1: Summary of conventional technologies to reduce SO₂ emissions as a result of the combustion of coal, adapted from (Srivastava, 2000).

The majority of FGD technology alternatives employed for SO₂ reduction from flue gas includes Wet FGD and variants of Dry FGD (spray drying absorber, circulated fluidised bed, and duct injection system). A summary of the worldwide installed capacity and SO₂ and water consumption performance metrics of the Wet and Dry FGD is presented in Table 1.

Table 1: Summary of main FGD technologies installed worldwide and associated performance specification (Carpenter, 2012).

FGD technology	SO ₂ removal efficiency achievable (%)	Worldwide installed capacity (%)	Water consumption (l/kWh)
WFGD	98	80	0.21
SDA/CFB	90-95	10	0.14
DSI	30-60	2	Negligible

A study was completed by Eskom that reviewed the commercially available SO₂ control technologies that could be employed to meet the requirements of controlling the SO₂ emissions

from the Medupi generating units to the statutory emissions level of 500 mg/Nm³ @ 10% O₂ [14]. The technologies considered are found in Table 2 below.

Table 2: Technology Comparison Overview

Criteria	Wet FGD	Dry FGD		
	Limestone Forced Oxidation	Spray Drying Absorber (SDA)	Circulated Fluidised Bed (CFB)	Duct Injection System
Coal Sulphur Type	Low, Medium and High (This parameter is critical when selecting the FGD technology)			
SO ₂ Removal Efficiency %	>98%	>90%	>95%	30% - 60%
Potential Reagents	Limestone, Lime	Hydrated Lime, Calcium Oxide	Hydrated Lime	Lime, Sodium Base
Ca/S mole ratio	1.1 - 1.3	1.4 - 2.0	1.4 - 2.0	2 - 4
By-product Disposal Alternatives	Landfill, saleable gypsum	Landfill, reclamation	Landfill, reclamation	Landfill, reclamation
Fly Ash Disposal Alternatives	No Effect on Fly Ash Quality	Fly ash co-disposed with by-product or new pre-filter	Fly ash co-disposed with by-product or new pre-filter	Fly ash co-disposed with by-product
Pressure Drop Impact	2-2.5 kPa	1-1.2 kPa (with an additional 1.7-2 kPa due to new fabric filter)	2-2.5 kPa Due to reactor and fabric filter	No impact
Effect on Stack Liner	Potential for corrosion due to acid mist in saturated flue gas	Standard Carbon Steel	Standard Carbon Steel	Standard Carbon Steel
Power consumption of plant utilities	1.2-1.6% increase in auxiliary power consumption	0.5% increase in auxiliary power consumption	0.3-1% energy consumption of the electric capacity of the plant	<1% increase in auxiliary power consumption
Effects on Waste Water Treatment System	To make saleable gypsum, a chloride blow-down is required	None	None	None
Water Usage (% of Base Case)	High water consumption to quench flue gas to saturation (100%)	Hydration of Lime (60 – 65%)	Low Water consumption (60% less than LSFO)	N/A (hydrated lime)

Based on the results of these studies, the Dry FGD (SDA and CFB) and Wet FGD technologies were identified as being capable of meeting the new regulations at the Medupi plant.

3.2.1 Dry FGD Technology

DFGD processes, including the spray dryer absorber (SDA) process and circulating fluidized bed (CFB) process have been extensively used around the world for SO₂ control. The DFGD technology uses less water than typical WFGD systems because the flue gas is not saturated

with water and the technology uses hydrated lime instead of limestone as the reagent for SO₂ capture. The system mixes the water, lime, and fly ash-laden flue gas in a reactor, which then passes to a fabric filter to remove all the by-products of desulphurisation and the fly ash from the flue gas stream. This technology is evaluated in this report as representative of all semi-dry FGD technologies.

Utilities have installed numerous dry and semi-dry FGD systems on boilers using low sulphur fuels. These installations generally have DFGD systems designed for a maximum fuel sulphur content of less than 2 percent. The CFB process uses calcium hydroxide [Ca(OH)₂] produced from the lime (CaO or "quick lime") reagent, as a dry powder to the flue gas in a reactor designed to provide good gas-reagent contact. SDA systems use Ca(OH)₂ injected as a liquid slurry. The SO₂ in the flue gas reacts with the calcium in the reagent to produce primarily a mix CaSO₃•1/2H₂O and CaSO₄•2H₂O.

An evaluation of the SDA, CFB, and other semi-dry modular technologies based on experience, fuel flexibility, SO₂ emissions control, site layout, operability, capital cost, and operating costs indicates that these systems are fairly comparable in most areas as considered in the 2005 FGD Technology Review [9]. Increased utilisation of these technologies and some process developments are now resulting in higher SO₂ removal guarantees with a lower corresponding risk as to lime consumption.

SDA technology has an experience advantage over CFB and modular technologies. SDA systems have been designed for units in excess of 900 MW using multiple absorber vessels, with each vessel handling the flow equivalent to 450 MW. The range of experience for the CFB and modular systems indicates that these technologies have sufficient range of operational and design experience to be considered applicable; however as with the SDA, multiple CFB reactors would be required for each unit.

SO₂ removal efficiency of the SDA technology has been enhanced by hydrated lime injection into the SDA inlet by at least one manufacturer to allow it to now quote 96 to 98 percent SO₂ removal, which is similar to CFB technologies for low to medium sulphur coals.

The main difference between the SDA and CFB processes is the preparation of the lime into calcium hydroxide. Slakers produce a paste with approximately 10 to 13 percent lime mixed with water and are typically used with the SDA technology. This can limit the amount of lime (and, as such, SO₂ removed) added to the process due to the transport water causing the flue gas to approach dew point.

Since one of the features of the CFB is the ability to control the amount of lime independent of water, CFB systems are supplied with lime hydrators that convert the pebble lime to calcium hydroxide. The hydrated lime is stored in a separate hydrated lime silo for application to the scrubbing absorber module, as required. This allows for a spare lime hydrator to be incorporated and the product to be stored to allow for maintenance and redundancy in the reagent preparation systems similar to the operation of the WFGD.

There are DFGD technologies where a group of small flash dry modules are clustered together for parallel operation. Modules are removed from service to facilitate partial load operation. This is in lieu of the recirculation duct used in the CFB to keep adequate gas velocities in the absorber, to keep the CFB absorber bed fluidised.

Another consideration for the DFGD technologies is the elimination of the potential to produce a saleable by-product such as that produced from the WFGD systems. There is no known commercial use for the by-product of the DFGD processes, which is captured as a mixture with the fly ash in the fabric filter downstream of the absorber. This requires the by-product from the DFGD to be disposed of, typically in a landfill.

No wastewater is produced with the DFGD technology as all water is evaporated or contained as waters of hydration in the dry by-product mixture. This eliminates the capital and operating costs of an additional wastewater treatment system when considering the application of this technology. Other water streams at the plant may require treatment for reuse, but they are not associated with the scrubbing process and are, therefore, not included in the cost analysis.

3.2.2 Wet FGD Technologies

WFGD technology has a long history of application to fossil fired generating facilities in units of all sizes. WFGD remains the predominant process utilised today, particularly in retrofit applications, due to its high SO₂ removal capability, high inlet sulphur capability, and retrofit suitability. Wet limestone-based FGD processes are most frequently applied to pulverised coal fired boilers that combust medium-to-high sulphur coals. Typically, the WFGD processes on a coal facility are characterised by high removal efficiency (greater than 98 percent) and high reagent utilisation (95 to 97 percent) when combined with a high sulphur fuel. The ability to realise high removal efficiencies on higher sulphur fuels is a major difference between wet scrubbers and semi-dry/dry FGD processes.

In a WFGD system, the absorber module is located downstream of the ID fans (or booster fans, if required), placing the retrofit WFGD downstream of any existing particulate control device. This location typically eliminates the need for the addition of another particulate control device and the WFGD usually provides some additional particulate control itself. Flue gas exiting the fans enters the module and is contacted with slurry containing reagent and by-product solids. The SO₂ is absorbed into the slurry and reacts with the calcium to form calcium sulphite hemi-hydrate (CaSO₃• ½H₂O) and calcium sulphate di-hydrate (CaSO₄•2H₂O, also called “gypsum”). On most new WFGD systems, oxidation air is blown into the absorber tank to push the chemical reactions to create gypsum and very little CaSO₃• ½H₂O. This helps in the process chemistry to virtually eliminate scaling and plugging of the absorber and can allow for the sale of by-product for wallboard production or other industry purposes, if a suitable market exists in the nearby region. To create a marketable by-product, most times a wastewater stream is necessary to purge impurities such as chlorides from the system. Such a wastewater stream may be avoided if a wetter by-product is sent to waste.

3.3 Understanding the requirements for the magnitude of by-product produced in the FGD

Each FGD technology will create waste by-product streams that will need to be disposed of while the plants are in operation. The by-products created by each technology are shown below in Table 3 below:

Table 3: By Product Quantities Generated

By-product Quantities Generated	Wet FGD	Dry FGD
Gypsum (tonnes/tonne of SO ₂)	5.62	

By-product + Ash (tonnes / tonne of SO ₂)		7.43
Crystallizer Salts (tonnes / tonne of SO ₂)	0.48	0
Pre-treatment Solids (tonnes / tonne of SO ₂)	0.92	0

The DFGD waste does not produce a currently marketable product and would require that all the ash and scrubber by-product be disposed of by landfilling. For the purposes of this study, only the differential cost of landfilling the additional by-product has been calculated to allow equal comparison of all technologies.

The WFGD waste will consist of the gypsum produced by the FGD process, pre-treatment solids from the ZLD Pre-treatment plant, and the salt produced by the ZLD Crystallizer plant. As noted previously, the gypsum produced by the FGD process can be a marketable by-product if a good quality limestone is used and, if necessary, the chlorides contained in the gypsum are removed by washing the gypsum during the dewatering process. Otherwise, the gypsum and pre-treatment solids should be able to be landfilled together. The crystallizer salts may require a separate landfill depending on how the South African Department of Environmental Affairs determines to classify this waste.

The ash from the existing FFP plant is currently landfilled on the plant site.

Both the wet and semi-dry technologies produce wastes that must be managed and disposed in compliance with the national legislation. The legislation provides guidelines for the waste classification and corresponding type of waste management applied (i.e. re-use, recycling, recovery, treatment, and disposal). The wastes are classified based on the quantity, physical, chemical and leachability properties depending on laboratory testing of actual samples. The FGD wastes are classified as hazardous and vary in type with Type 0 being the most hazardous and Type 3 being the least hazardous. The disposal of all these wastes require a liner protection with Class A being the most conservative (and most expensive) and Class D being the least conservative (and least expensive). Please see below a summary of the waste management requirements in terms of the legislation.

Table 4: Waste Management Requirements

	Hazardous Classification	Waste Management Applied	Landfill Liner Class
WFGD Wastes			
Gypsum	Type 3	Re-use, recovery, disposal	Class C
Chemical Sludge from ZLED Plant	Type 1	Disposal	Class A
Chemical Salts from ZLED Plant	Type 1	Disposal	Class A

	Hazardous Classification	Waste Management Applied	Landfill Liner Class
CDS Waste exiting the particulate abatement system.	Type 3	Disposal	Class C

It is also important to note that implementation of CDS implies that the entire mixture of the fly ash and the CDS by-product removed from the particulate abatement system will need to be landfilled. This implies a larger footprint equipped with a Class C liner to cater for the fly ash and CDS by-product mixture. Currently the fly ash is landfilled in a designated area equipped with a Class C liner because fly ash alone is classified as a Type C waste. Implementation of the CDS technologies also eliminates the potential for commercial exploitation of the fly ash since it will be removed as a mixture.

3.4 Water reduction strategies that can be employed

The WFGD technology is the only of the FGD technologies that has the potential for reduction in its water consumption.

Eskom is a strategic water user in the country and based on its commitment to water conservation it has already taken various measures to reduce the plant's water consumption and ensure that water is utilised responsibly within the plant. The implementation of **dry cooling technology** and the adoption of the **zero liquid effluent discharge policy (ZLED)** are notably Eskom's most significant water-saving initiatives. Once completed Medupi will be the largest dry-cooled power plant in the world. The implementation of dry cooling reduces the water consumption from approximately 2 l/kWh to 0.14 l/kWh and came with an energy penalty of roughly 1.75% on the overall thermal efficiency of the plant. If retrofitted the WFGD plant will be a consumer of water in the power plant however due to the implementation of the various water reduction measures the water requirement of the power plant with WFGD (power plant with WFGD≈ 0.35 l/kWh) is still expected to be lower when compared to the conventional wet-cooled power plants (power plant without WFGD≈ 2 l/kWh) within Eskom's fleet.

The various streams in which water enters and leaves the WFGD process are summarised below.

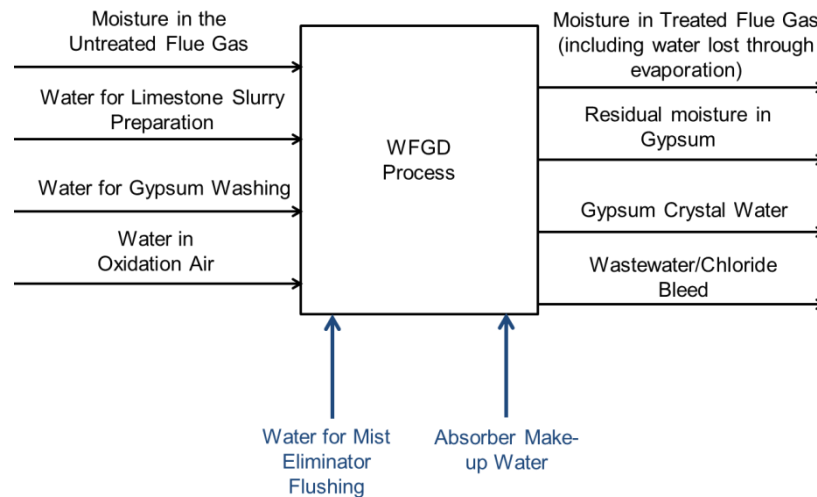


Figure 2: Overview of the water users and losses in the WFGD system.

Water is lost through the treated flue gas, gypsum and wastewater bleed outlet streams.

The biggest water consumption in the WFGD LSFO process is due to the evaporative cooling of the flue gas as it is cooled from the inlet flue gas temperature to the saturation temperature. The higher the flue gas temperature entering the WFGD, more water would be required to reach saturation. Therefore water savings can be realised through the reduction of the flue gas temperature entering the WFGD process.

Several technologies have been developed in order to facilitate temperature reduction prior to a WFGD plant. Two main technologies commonly utilised in the power generation industry include; regenerative rotary type heat exchangers and tubular shell-and-tube cross flow heat exchangers.

Regenerative rotary type heat exchange is not a new technology in the power industry. These types of heat exchangers are traditionally used to heat combustion air through the cooling of flue gas. An adaptation of the traditional use can be employed to further cool down the flue gas to a point closer to saturation temperature. Traditionally the treated flue gas leaving the absorber is used as the cooling medium; in this way the temperature of the untreated flue gas is reduced closer to the saturation temperature before entering the absorber and the treated flue gas is heated before exiting via the stack. The reheat of the treated flue gas before it exits via the stack also reduces the visibility of the plume and improves the buoyancy of both the plume and the residual pollutants. Another benefit of reheating the treated flue gas before it enters the stack is that the stack can be operated in a dry environment negating the need for special liners required for traditional wet stacks. While the implementation of regenerative rotary type heat exchange may result in the benefits described above it is important to consider the practical application with respect to construction, operation and maintenance. These types of heat exchangers require large surface area and are expensive to install and maintain. Advances in the technology have improved the choice of these heat exchangers as leakage rates have now been improved to the point that they no longer pose a risk to non-compliance due to clean flue gas contamination through re-entrainment. The biggest drawback of this technology is the spatial requirements due to the large surface area required.

Indirect flue gas tubular shell-and-tube crossflow heat exchangers have been implemented at several power stations. The advantage of this technology is that the heating and cooling elements can be separated to reduce the overall size. In this technology the cooling media is mostly liquid-gas. The biggest drawback of this technology is the material selection. A plastic perfluoroalkoxy (PFA) material is most commonly used in the cooling section as the flue gas enters at the sulphur dew point. Acid corrosion therefore is a significant consideration. The cooling elements are made up of thousands of small diameter PFA tubes suspended from a tube plate with the cooling liquid (usually water) circulated through them. Several bundles of these PFA tubes are required with some installations having the PFA tube surface area exceeding that of the heating elements within the boiler. In the event that the flue gas needs to be reheated, chloride becomes the main consideration from a material selection perspective. Most installations utilise stainless steel alloys. The PFA bundles need to be cleaned periodically due to ash contamination. Ash contamination causes clogging and reduced heat transfer even with an efficient fabric filter plant or electrostatic precipitator (dust concentration to be less than 20 mg/Nm³). A water washing system is introduced to facilitate this process. It is recommended to manually clean these systems at least every 15,000 operational hours to maintain efficient functionality of the heat exchanger. Due to the close packed bundle spacing, maintenance provisions outside of the duct are required to ensure proper cleaning and maintenance. Two further considerations are required; firstly PFA tubes undergo diffusion of sulphur and the cooling liquid pH needs to be managed accordingly. Secondly, the PFA tubes leak over time which requires manual intervention to plug the holes of the leaking tubes. The management of the flue gas cooler is critical and poor maintenance can cause significantly increased plant down-time. The PFA bundles are also expensive items and add to the operating cost of the unit. Ducts leading to the WFGD from the cooler further need to be lined with a plastic material (PFA or glass-reinforced (GRP)) in order to withstand the sulphur corrosion. Water can be reclaimed from the washing process by a having duct design recline into the absorber. There is therefore no additional water requirement needed for the washing system over and above the water requirement for the FGD process.

Eskom benchmarked a few flue gas cooler installations in order to establish its feasibility for application within the Eskom fleet. Three power stations in Europe (hereafter referred to as Power Station A, B and C) were selected as example stations utilising the flue gas cooler after the particulate abatement plant and two power stations in China (hereafter referred to as Power Station D and E) for application before the particulate abatement plant.

The three power stations in Europe had varying degrees of success for the application of the flue gas coolers installed. Power Station A utilised PFA tube material. Water washing is introduced 4-6 times per day. The experience of Power Station A suggests that 20% of the tubes are plugged at any given point in time of their operation due to leaking. This would require a design consideration to increase the actual surface area requirement with a significant margin in order to maintain appropriate heat transfer rates. Furthermore, Power Station A has been required to replace all the heat transfer bundles within a 6 year period.

Due to the problems experienced with the PFA tubes, an innovative improvement has been developed in which an increased diameter steel tube arrangement is used. The tube is coated in enamel and jacketed with PFA material. The PFA and enamel is able to protect the steel tube from corrosion and the heat transfer characteristics are not significantly reduced through this improvement.

Power Station B utilised the mild steel, enamel and PFA material-arrangement with increased success (increase in plant availability and reduction in maintenance cost) to Power Station A.

The system also utilises a water washing system which introduces purge air to keep the nozzles of the washing system clean and reduce plugging. Power Station B noted that the handling and cleaning of the enamel based material is critical and the enamel can easily damage; a sentiment which was shared by Power Station C, although not using the same application.

Power Station C utilised an application similar to that of Power Station A, but with a higher degree of maintenance and operating care is able to operate with only 10% of tubes plugged at any given point of operation. Power Station C noted that a few aspects are important to manage to improve the operability of the cooler. The distribution of the washing system needs to be such that more water is available higher in the bundle than lower down. Power Station C furthermore reduced the frequency of washing the cooler to reduce the moisture in the cooler that in their experience contributed to clogging. It is also important to have the flue gas distribution over the cooler equal to ensure proper heat transfer. Power Station C further noted that the cleaning pressure of the system needs to be maintained between 200-300 kPa, but higher pressure manual cleaning is also needed every 15,000 operational hours, which requires the plant to be on outage for approximately 5 days' worth of cleaning time (subject to maintenance provisions being made such as out-of-duct bundle suspension cleaning).

All three power stations in Europe advised against the installation of the system due to the problematic operation that it provides. The installations at these power stations were not due to water conservation considerations, but due to various other reasons that included increased plant efficiencies (through feed-water heating integration) and visible plume reduction out of the stack as legislatively prescribed in their countries. This technology has also mostly been implemented on lignite coal fired power plants where the benefits of the improved power plant efficiency through heat recovery are significant due to the higher back-end flue gas temperatures.

The applications in China for Power Stations D and E were both recent installations and maintenance experience has not been fully established. The installations both have the flue gas cooler installed before the particulate abatement plant (ESP for both applications). The operating fundamental is that the cooler is operating in a finned-tube arrangement with a soot blower rather than a water washing system to clean the heat transfer elements. The application is subject to the ash being able to neutralise the sulphur concentration being formed through the interaction of calcium and magnesium within the ash.

Images taken from reference power plants during the benchmarking exercise are shown below.



Figure 3: Side view of a tubular flue gas cooler.

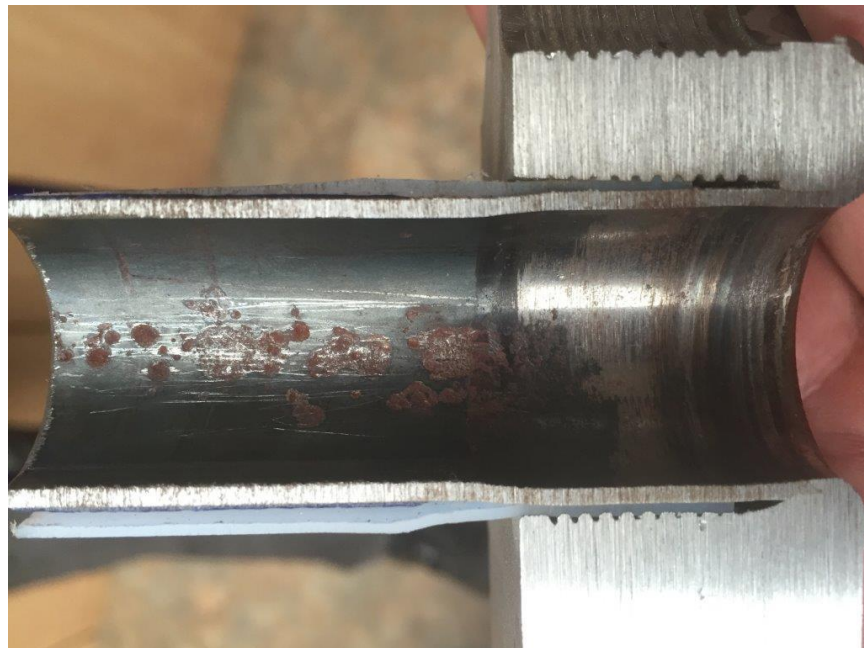


Figure 4: Corrosion of a carbon steel tube.



Figure 5: Water washing system cracking due to corrosion.



Figure 6: Corrosion of carbon steel bolt.



Figure 7: Corrosion of the stainless steel tube sheet.



Figure 8: Fly Ash build-up retrieved from the tubes during maintenance.



Figure 9: Wear damage of carbon steel tube.



Figure 10: Discolouration of the PFA tubes due to fly ash contamination.

The installation of a regenerative type heat exchanger at Medupi is not possible due to the established layout and space constraints at the plant and is therefore not considered further.

Conclusions on WFGD with flue gas cooling for Medupi

The installation of a regenerative type heat exchanger at Medupi is not possible due to the established layout and space constraints at the plant and is therefore not considered further.

Elements of concern for the installation of the flue gas cooler at Medupi Power Station are the following:

- For applications before the FFP:

A flue gas cooler before the particulate abatement plant is not possible due to the ash characteristics. It has been found through the operation of the FFP that the ash does not have a neutralisation effect to the formed sulphur and therefore will not be successful in reducing the acid corrosion that will take place.

The ash characteristics at Medupi are such that it is highly abrasive. This will erode the finned tube material easily if the velocity is not kept sufficiently low enough. The velocity reduction in a high ash environment although good for wear protection, will incur both dust fall-out and plugging problems. It is therefore not advisable to install a flue gas cooler before the FFP at Medupi.

- For applications after the FFP:

Although the ash loading is low, wear protection should still be considered for ash as aggressive as the Medupi fly ash.

The availability of space on the already established footprint and plant layout will cause a significant constraint to the installation of a flue gas cooler. Although the real estate may be found to install the cooler itself, space is conceptually not available to install all the maintenance provisions that is required to service the plant appropriately. Without the increased maintenance provisions, complexity in maintenance and plant downtime will be experienced.

The cost of the material selection for the flue gas cooler is high. Elements such as the cooler's weight contributes to the overall cost and considerations such as deep piling for founding conditions which may require blasting at Medupi on an already generating unit.

- Use of the recovered heat needs to be considered. Feed-water integration although possible will be complex with increased piping lengths that need to be considered.

Installation of the flue gas cooler will also reduce the power output of the unit due to increased pressure drop and pumping for water recirculation. This will increase the relative CO₂ per megawatt sent out from the generating unit.

- Plant downtime to periodically clean the flue gas cooler will decrease the plant availability which is contradicting to the objective of the plant.

While the implementation of flue gas cooling has the potential to reduce the WFGD water consumption the practical challenges discussed above cannot be ignored as this is expected to have a significant impact on the maintainability and availability of the power plant and the cost of electricity to the consumer. WFGD with flue gas cooling is therefore not considered to be a feasible option at Medupi and was not considered further however the costs associated with this option has been included in this report for the purpose of information only.

3.5 Infrastructure requirements in relation to the existing power plant configuration and arrangement.

The infrastructure additions and changes that are required to the existing power plant arrangement to install each of the technologies are discussed below. The equipment required to implement each technology is reviewed, including the core equipment to treat the flue gas and the balance of plant equipment required to support the core equipment.

3.5.1 WFGD – Limestone Reagent

This technology was recommended in the Medupi FGD Retrofit BDR [10], which is the basis for this technology evaluation. The BDR WFGD system design includes an absorber system with five spray levels in the absorber tower that allows for a design emission rate of 400 mg/Nm³ at full load on the worst anticipated coal. A bypass arrangement around the existing duct to the stack was designed to allow the untreated flue gas to go to the absorber tower for SO₂ removal, and then return the clean flue gas back to the stack. There is a significant number of balance of plant systems required to support the absorber system, including limestone handling, limestone preparation, makeup water, by-product separation and disposal, liquid recycling, and chemical processing of the process bleed stream that produces a solids by-product to be landfilled and a water stream that can be reused in the plant.

The BDR WFGD system design includes all balance-of-plant (BOP) equipment required for the successful integration of the new equipment into the existing plant.

The process flow diagram for the technology case study design basis is shown on drawing 006265-R-PFD-005.

3.5.2 Dry CFB Technology

The application of a semi-dry CFB technology to the Medupi Power Station would result in significant changes to the equipment as compared to the BDR WFGD design [10]. The limestone handling would be replaced by lime handling systems for receiving pebble lime deliveries and for processing the pebble lime into hydrated lime for use in the DFGD absorbers. This modification to the process design is reflected in process flow diagram 006265-R-PFD-010 (attached).

The makeup water system supply may be marginally impacted with the requirement for filtration of all the water through a 100 µm filter. In addition, there are some limitations for the hardness and chloride content for the makeup water used to hydrate the pebble lime and therefore may require some softening upstream of the slaking process; however, the majority of the water required by the semi-dry absorber process would be directed to a makeup water tank for direct injection into the absorber flue gas stream.

The CFB technology would require relocation of the existing FFP or construction of a new FFP as well as the relocation of the ID fans. An increase in the size, height and location of the flue gas duct work after the CFB and the addition of a recirculation duct for low load operation would also be required. The time requirement for the relocation of the existing FFP into the new elevated CFB configuration is not feasible during the planned outage schedule of 6 weeks. The FFP is elevated so that the captured lime / fly ash / scrubber by-product can be returned to the CFB absorber by gravity and recycled. This requires that the FFP is elevated to have the hopper outlet flanges 20 to 25 metres above grade and in close proximity to the CFB absorber.

The Medupi Plant would be required to have two installed CFB absorbers per 800 MW unit. One CFB absorber per boiler unit may be possible; however, operations at part-load conditions are reduced and no absorber of this size currently exists in operation.

The Process Area Arrangement Dry/CFB Drawings (006265-Z4050-001-00 and 006265-Z4050-002-00), in conjunction with Process Flow Diagram (PFD) Dry/CFB Cluster 1 (attached), reflect the general arrangement requirements of the CFB and FFP combination required for the Medupi Plant. The existing FFP would be abandoned and ducted through, and a new FFP constructed after the CFB absorber. The existing ductwork that feeds directly to the chimneys would be abandoned. The PFD shows the relocated ID fans and a recirculation duct, which is used during periods of low load operation to recirculate clean flue gas back to the inlet of the CFB absorber to keep the bed fluidised with adequate air flow during periods of low-load operation. Standard designs of the dry CFB technology do not include a bypass of the CFB absorber to the FFP. The risk of no bypass is mitigated by the use of two 50 percent absorber vessels that would be installed in parallel. This will allow the plant to remain on line at 50 to 60 percent load if equipment failure occurred on one of the absorbers that required its removal from service for repair or maintenance. The CFB absorber design should address the air flow requirements of the units operating at this reduced load.

The CFB also uses recirculation of the material captured in the FFP back to the inlet to the CFB. Significant portions of hydrated lime are not consumed by the reaction with SO₂ during a single pass through the CFB and are still available in the captured material. This material, with the addition of water that is added at the inlet to the CFB, can enhance the lime for additional SO₂ capture, to minimise the cost of the process sorbent.

The reagent demand for lime and limestone are similar, however, the pebble lime delivered to the site cannot be stored outdoors and will need to be unloaded into silos versus open air piles used for limestone. Based on the design coal specifications, approximately 17,640 tons per week of pebble lime sorbent will be required. The design, as shown in the redundancy sizing criteria, indicates two quicklime silos, which will supply all of the hydrators, and six hydrated lime silos will be required to receive the product from the 18 anticipated quick lime hydrators (two required for each unit with one spare).

An additional ash silo will be required to receive the increased ash from the FFP/FGD system compared with the WFGD. A conveyor will be required to move the ash to the existing ash disposal system. Details of this installation are not included in this study. However, the supply and installation of the new silos and pneumatic conveying system from the FFP product silo to the existing ash silo is included in the estimated costs of the system.

4. COST IMPLICATIONS

Capital and annual operating cost estimates were prepared for the WFGD and CFB technologies that were identified in the FGD Technology Review [9].

The cost estimates for each FGD technology have a conceptual-level accuracy (±30 percent) in 2017 ZAR and were based on information obtained from the following sources:

- Steinmüller in-house database.
- Black & Veatch in-house database.

- Publicly available cost data.

The cost estimates include allowances for auxiliary electric, control system upgrades, and other required BOP system upgrades. The operating cost estimates were based on operation at full-load conditions. The annual operating costs also account for increases in auxiliary power requirements, additional labour requirements, water costs, and additional costs for consumables.

4.1 Capital Cost Estimates

Capital costs were developed for this study for the two FGD retrofit technologies and the one modification to a proposed technology that were identified in the Medupi FGD Retrofit BDR [11] and are shown in Table 5. The capital cost estimates were based on adjustments to the Basic Design cost estimate as noted in this report, and escalated to 2017 cost basis. The cost estimate is developed based on the Technology Selection Study Design Basis [3]. The capital cost estimates include direct and indirect costs as an overnight price, but excludes Owner's costs. The purpose of these estimates is to provide sufficient confidence in the Phase 1 design study to support the selection of a FGD technology.

Table 5: Capital Cost Estimate Summary (1,000,000 ZAR)

Description	Option 1 Wet FGD	Option 2 Wet FGD + Gas Cooler	Option 3 Dry FGD
Environmental Purchase Contracts	2,657,484	2,657,488	1,694,784
Mechanical Purchase Contracts	350,301	645,101	515,701
Civil / Structural Purchase Contracts	723,714	746,214	2,269,816
Electrical / C&I Purchase Contracts	258,532	260,532	200,232
Subtotal Purchase Contracts	3,990,031	4,309,331	4,680,531
Mechanical / Chemical Construction Contracts	3,940,802	3,961,302	4,900,802
Civil / Structural Construction Contracts	2,655,178	2,706,478	2,719,978
Electrical/C&I Construction Contracts	1,731,287	1,745,587	1,522,287
Construction Service Contracts	1,318,018	1,318,018	1,318,018
Subtotal Construction Contracts	9,645,284	9,731,384	10,461,085
Total Direct Costs (purchase and construction)	13,635,315	14,040,715	15,141,615
Indirect Costs	2,326,516	2,348,916	2,335,616
Contingency	1,715,900	1,732,800	1,800,400
Escalation	Included	Included	Included
Total Capital Requirements	17,677,732,	18,122,432	19,277,632

Direct costs (total of the purchase and construction contracts) consist of purchased equipment and its installation, as well as miscellaneous costs. Purchased equipment costs include the cost for purchasing the FGD technology equipment from an equipment vendor (including taxes and freight). The construction costs also consider retrofit-related issues, based on the existing site configuration. Finally, miscellaneous costs account for the costs for additional items such as site preparation, buildings, and other structures. The direct cost estimates were based on the following assumptions:

- A regular supply of construction craft labour and equipment is available.
- Normal lead times for equipment deliveries.
- Construction utilities (power, water, air) would be readily available.

Indirect costs are those costs that are not related to the equipment purchased, but are associated with any engineering project, such as the retrofit of a new control technology. Indirect costs include the following:

- Engineering.
- Construction Management.
- Project Insurance.
- Performance Bond.

- Contractor Overhead and Profit.

4.1.1 Contingency

Contingency accounts for unpredictable events and costs that could not be anticipated during the normal cost of development for a project. The contingency cost category includes items such as possible redesign and equipment modifications, errors in estimation, unforeseen weather-related delays, strikes and labour shortages, escalation increases in equipment costs, increases in labour costs, delays encountered in start-up/commissioning, etc.

4.1.2 Estimate Exclusions

The capital cost estimates do not include the following:

- Testing for environmental hazards, including remediation, and removal or disposal of (but not limited to) asbestos, lead paint, underground contamination, and polychlorinated biphenyls.
- Labour and material costs resulting from underground interferences.
- Salvaging or storage of equipment or structures.
- Scrap values.
- Upgrade or repairs to off-site roads, bridges, and foundations, if required.
- Owner's costs.
- Operational spares.

4.2 Operations and maintenance cost

Operations and maintenance costs typically consist of the following categories:

- Reagent costs.
- By-product disposal costs, which is a combination of the gypsum, pre-treatment solids, and crystallizer salts disposal costs.
- Auxiliary power costs.
- Steam costs.
- Water costs.
- Wastewater disposal costs.
- Operating labour costs.
- Maintenance materials and labour costs.

The costs for reagent, electric power, by-product disposal, wastewater disposal, and water are variable annual costs that are dependent on the amount of pollutant removed. Operations and maintenance materials and labour are fixed annual costs that do not vary with these factors. Table 6 lists the annual consumption rates, Table 7 the Unit Costs for Input and Outputs for the FGD Process, and Table 8 the estimated operating costs. The Technology Selection Study Design Basis [3] lists this data and the major economic evaluation criteria used to obtain the operations costs.

Table 6: Consumption Rates

Description	Option 1 Wet FGD	Option 2 Wet FGD + Gas Cooler	Option 3 Dry FGD
Reagent	Limestone	Limestone	Lime
Hourly consumption, kg / hr	125,735	125,735	105,300
Consumption per year*, tonnes	991,295	991,295	830,185
By-product for Disposal	Gypsum	Gypsum	By-product+Ash
Hourly generation, kg / hr	233,250,	233,250,	308,000
Total generation per year*, tonnes	1,838,940	1,838,940	2,428,272
Steam			
Hourly consumption, kg / hr	21,000	21,000	0
Total consumption per year*, kg	124,173,000	124,173,000	0
Water			
Hourly consumption, 1,000 L / hr	1,179.5	818.1	748.2
Total consumption per year*, 1,000 L	9,299,178	6,449,900	5,898,809
Wastewater Disposal (ZLD)			
Hourly generation, 1,000 L / hr	75.2	73.8	0
Total generation per year*, 1,000 L	444,658	436,379	0
Auxiliary Power			
Hourly consumption, MWh / hr	54.45	61.20	54.18
Total consumption per year*,MWh	357,406	409,393	388,132
Operating Labour			
Number of operation staff	89	89	64
Total man-hours per year	185,120	185,120	133,120
<i>* Based on a capacity factor of 90 percent or 8,760 hours of equivalent full load operation per year.</i>			

Table 7: Unit Costs for Inputs and Outputs for FGD

	Limestone	Lime
Reagent/Sorbent (R/tonne)	475	1800
By-product for Disposal (R/tonne)	30	30
Steam (R/1000 kg)	91	
Water (R/m3)	21.16	21.16
Wastewater Disposal (ZLD) (R/m3)	477.32	
ZLD Pretreatment Solids Disposal (R/tonne)	680	
ZLD Crystallizer Salts Disposal (R/tonne)	1000	
Auxiliary Power (R/MWhr)	421	421
Operating Labour (R/hr)	240	240

Table 8: Annual Operating Costs (ZAR)

	Limestone (w/o gas cooler)	Limestone (w/gas cooler)	Lime
Reagent/Sorbent	470,865,125	470,865,125	1,494,333,000
By-product for Disposal	55,168,200	55,168,200	72,848,160
Steam	11,299,743	11,299,743	
Water	196,770,606	136,479,884	124,818,798
Wastewater Disposal (ZLD)	212,244,157	208,292,424	
ZLD Pretreatment Solids Disposal	40,739,480	40,739,480	
ZLD Crystallizer Salts Disposal	31,351,000	31,351,000	
Auxiliary Power	150,467,926	172,354,453	163,403,572
Operating Labour	44,428,800	44,428,800	31,948,800
Total Operating Costs	1,213,335,037	1,170,979,109	1,887,352,330

4.2.1 Reagent Costs

Reagent costs include the cost of the material and delivery of the reagent to the facility. Additional costs associated with reagent preparation processes are included in the energy and water costs. Reagent costs are a function of the quantity of the reagent used and the price of the reagent. The quantity of reagent used will vary with the reagent purity and quantity of pollutant that must be removed, as well as the reagent utilisation. The WFGD technology utilises limestone as a reagent. The CFB technology utilises lime as a reagent, which has a typical cost multiplier of three to four times that of limestone on a per ton basis.

4.2.2 Auxiliary Power Costs

Additional auxiliary power will be required to run the new control technology systems applied to the facility. The power requirements of each system vary, depending on the type of technology

and the complexity of the system. The report considers the power costs associated with the process energy requirements which includes the FGD process electrical consumption, FGD common electrical consumption, differential power of the ID fans and ZLD equipment electrical consumption.

The difference in the fan differential pressure requirement was considered for electrical costs to operate the FGD technologies evaluated in this report. The cost for changes in the ID fan power requirements were added for the WFGD. The additional pressure drop for the flue gas water-cooled heat exchanger (WFGD with cooler option) was used to determine additional ID fan power consumption in addition to the WFGD increase. For the CFB option, only the differential pressure of the CFB module was considered as additional system pressure drop, since the FFP currently exists in the system and will be replaced with similar equipment.

Predicted pressure drops for the components are 14.7 mbar for the WFGD, 8 mbar for the flue gas cooler, and 15 mbar for the absorber portion of the CFB.

Auxiliary power costs for the ZLD system were only included for the WFGD systems, since no waste water is produced for the DFGD system.

4.2.3 Water Costs

Water would be required for all of the FGD technologies considered.

4.2.4 Steam Costs

Steam would be required for the zero liquid discharge (ZLD) plant operations for heating the waste water to evaporate the water to be reused and crystallise the brine for disposal as required.

4.2.5 Water Disposal Costs

This estimate assumes that the typical WFGD by-product is dewatered to an average of 10 percent moisture content, which is then landfilled. Although the by-product gypsum could be washed to attain acceptable chloride content and be utilised for the production of wallboard, this estimate assumes all of the by-product will be landfilled. The extracted water from the by-product can then be returned to the process, reducing the overall water requirements. This process requires the control of contaminants, primarily chlorides, in the scrubber slurry. To limit chloride levels, a liquid stream is bled from the process. This liquid stream is distilled in the planned ZLD system, with salts and sludge containing about 15 to 20 percent moisture being landfilled. The remaining high quality water will be returned to the plant for reuse in the FGD system. The costs of ZLD system chemicals and the waste landfill disposal are included.

Note that this study only considers the WFGD wastewater and not any other waste streams as included in the BDR [11]. The DFGD system produces no FGD wastewater stream.

4.2.6 By-product Disposal Costs

The DFGD waste does not produce a currently marketable product and would require that all the ash and scrubber by-product be disposed of by landfilling. For the purposes of this study, only the differential cost of landfilling the additional by-product has been calculated to allow equal comparison of all technologies.

The WFGD waste will consist of the gypsum produced by the FGD process, pre-treatment solids from the ZLD Pre-treatment plant, and then salt produced by the ZLD Crystallizer plant. The gypsum and pre-treatment solids should be able to be landfilled together. The crystallizer salts may require a separate landfill depending on how the South African Department of Environmental Affairs determines to classify this waste.

The ash from the existing FFP plant is currently landfilled on the plant site and is not impacted by the installation of either of the WFGD technologies.

4.2.7 Operating Labour Costs

Operating labour costs are determined by estimating the number of employees required to operate the new equipment. This estimate was based on common industry practice and is only a suggested quantity. After the control technology has been added, a final determination of the staffing levels will be required. The WFGD labour costs were based upon 89 operations, maintenance, and supervisory personnel. Since the CFB absorber has no wastewater to be disposed of as a result of the scrubbing process, the operating labour for this option was reduced by 25 personnel that are not required for the operation of a ZLD system.

4.2.8 Maintenance Material and Labour Costs

The annual maintenance materials and labour costs are typically estimated as a percentage of the total equipment costs of the system. Based on typical electrical utility industry experience, maintenance materials and labour are estimated to be approximately 1.25 percent (approximately 0.75 percent for materials and 0.50 percent for additional contract labour) of the total direct capital costs according to the retrofit technology. Some initial recommended spare parts are included in the capital costs.

4.2.9 Cooler Operation and Maintenance Costs

The operating and maintenance costs for the WFGD Cooler option would be greater than the base WFGD option due to additional activities such as washing, repair of erosion and corrosion within the gas cooler, and maintaining additional rotating equipment. The electricity costs would also increase due to the increased pressure drop from the cooler. The by-product disposal costs would also increase minimally, while the wastewater disposal costs would decrease slightly. The raw water consumption would be reduced by 20-30%.

4.3 Implication to the electricity tariff (Eskom)

The incremental difference in terms of the “tariff increase” between the wet and CFB-FGD technologies is expected to be approximately 0.45%.

Eg. Baseline “Tariff Increase” including WFGD is X% therefore “Tariff Increase” with CFB-FGD would be X% + 0.45 %.

5. RAW RESOURCE AVAILABILITY

5.1 Fundamental raw resource definition

The raw resources required to operate a WFGD system are water and limestone, whereas the resources required to operate a CFB are lime and water. Lower quality limestones can effectively be utilised in the WFGD process however higher quality limestones are required to produce the lime products required for the CFB-FGD technology.

5.1.1 Sorbent Usage

The application of a semi-dry CFB technology to the Medupi Power Station would result in significant changes to the equipment as compared to the BDR WFGD design [11]. The limestone handling would be replaced by lime handling systems for receiving pebble lime deliveries and for processing the pebble lime into the required hydrated lime necessary for use in the DFGD absorbers. The makeup water system supply may be marginally impacted with the requirement for filtration of all the water through a 100 µm filter. In addition, there are some limitations for the hardness and chloride content for the makeup water used to hydrate the pebble lime that may require some softening of this process stream; however, the majority of the water required by the semi-dry absorber process would be directed to a makeup water tank for direct injection into the absorber flue gas stream.

As stated earlier, the reagent demand for lime and limestone are similar; however, the pebble lime delivered to the site cannot be stored outdoors and will need to be unloaded into silos versus open air piles for limestone. Based on the demand, approximately 17,640 tons per week of pebble lime sorbent will be required. The design, as shown in the redundancy sizing criteria, indicates two quicklime silos, which will supply all of the hydrators, and six hydrated lime silos will be required to receive the product from the 18 anticipated quick lime hydrators (two required for each unit with one spare).

An additional ash silo will be required to receive the increased ash from the FFP/FGD system compared with the WFGD. A conveyor will be required to move the ash to the existing ash disposal system. Details of this installation are not included in this study. However, consideration of the new silos and pneumatic conveying system from the FFP product silo to the existing ash silo is included in the estimated costs of the system.

5.1.2 Energy and Water Usage

The pros and cons of wet versus dry flue gas desulphurisation (technologies have been well documented for quite some time and the important points have been highlighted in this report. The complete value chain of each technology is however dependent on the characteristics unique to the region of implementation. The benefit of lower water consumption with semi-dry technologies when compared to wet technologies is widely known however most comparisons are based on the sorbent delivery to the power plant without consideration given for the processing of the sorbent before delivery. The processing of the sorbent before delivery includes both water and energy requirements. It is also important to note that energy requirements include an inferred water requirement inherent to the power generation process. A desktop study was conducted to compare these requirements for the conventional wet and circulated fluidized bed FGD technologies for Medupi Power Station.

Both technologies are considered to be energy and water intensive. The figure below gives an indication of the processing steps that require energy and water in the value chain.

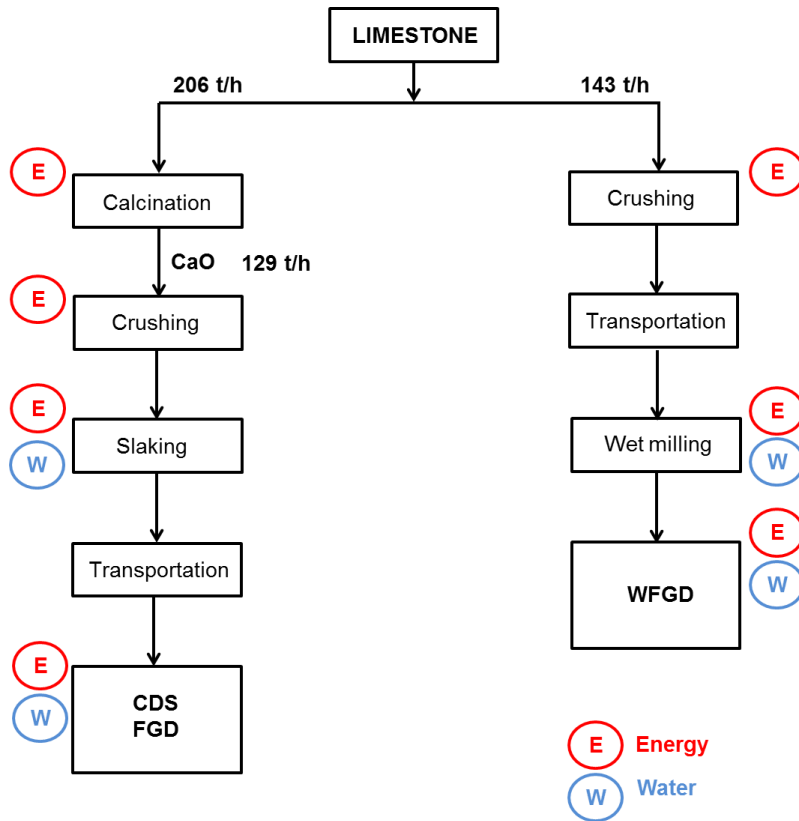


Figure 11: Overview of water and energy requirements for the WFGD and CFB-FGD technologies.

A breakdown of the energy and water requirements associated with both the WFGD and CFB-FGD technologies are indicated below.

Table 9: Breakdown of Water and Energy Requirements for the WFGD and CFB-FGD Technology (per annum).

		Delivery to site	Reagent Preparation	Reactor and other processes	Pressure drop
WFGD		no processing required	Milling + Suspension		
	Water [m ³]		3 613 669	2 884 733	
	Power [MW]		24 125	211 080	12 437

		Delivery to site	Reagent Preparation	Reactor and other processes	Pressure drop
WFGD with Cooler (100°C)		no processing required	Milling + Suspension		
	Water [m ³]		3 583 940	1 054 160	
	Power [MW]		24 125	211 080	19 328
WFGD with Cooler (90°C)		no processing required	Milling + Suspension		
	Water [m ³]		3 583 940	551 943	
	Power [MW]		24 125	211 080	19 328
CFB-FGD		Calcination & Crushing	Slaking		
	Water [m ³]		438 869	3 268 677	
	Power [MW]	860 375	19 402	104 497	31 093

As mentioned above the energy requirements include an inferred water requirement inherent to the power generation process. The energy and water requirements associated with each technology are given in Table 10 below.

Table 10: Total Water and Energy Requirements for the WFGD and CFB-FGD Technology (per annum).

	WFGD	WFGD (with Cooler 100°C)	WFGD (with Cooler 90°C)	CFB-FGD
Total Water (m ³ /annum)	6 498 402	4 638 100	4 135 883	3 707 546
Total Power (MW/annum)	247 642	254 533	254 533	1 015 367
Power to Water (m ³ /annum)	49 450	50 826	50 826	202 752
Total Water (m³/annum)	<u>6 547 852</u>	<u>4 688 927</u>	<u>4 186 709</u>	<u>3 910 298</u>
Percent of Base Case	100%	72%	64%	60%

Both the wet and semi-dry technologies require water. The CFB-FGD technology requires about 60% of the WFGD water requirement. The WFGD water requirement could be reduced through the introduction of upstream flue gas cooling. However based on the experiences of international power plants equipped with flue gas coolers accounted in this report suggest that the use of the coolers for the purposes of achieving water savings may result in significant operation and maintenance drawbacks that may ultimately lead to plant downtime.

5.2 Sorbent usage (non-quantitative)

The WFGD process uses finely ground limestone and the CDS technologies use dry hydrated lime. Lime is produced from limestone through a process called calcination and hydrated lime is produced by mixing lime with water under controlled conditions. The use of characteristically different sorbents therefore means different plant designs, plant configurations, and plant operating requirements.

Limestone is an abundant naturally occurring material consisting mainly of calcium carbonate. A brief study of literature on the material reveals that its chemical composition, mineralogical characteristics and chemical reactivity differs considerably from region to region and sometimes from seam to seam in the same mine. It is this variability that renders some limestones more useful than others depending on the application. In South Africa, limestone deposits can be found along the northern – western coastal line with inland deposits in the Northern Cape, North-West and Limpopo. Gauteng has mostly what is classified as dolomite (i.e. less reactive calcites) deposits.

Calcination is a process of converting limestone (CaCO_3) into lime (CaO) by thermal decomposition. The temperature required for the reaction to take place is typically between 850 °C and 1 340 °C subject to the dissociation temperature of the carbonates in the limestone. The degree of 'burning' (soft burn, medium burn and hard burn) is often used to characterise the lime produced. 'Soft burn' lime is preferred for CDS since it is more reactive but the production of this requires a more delicate balance of the calcination process parameters and is therefore difficult to produce.

The production of good quality lime is not only product function of the calcination process parameters but also the intrinsic properties of the parent material. The limestone's crystal structure, shape and behaviour during the calcination process in addition to its quality affects the results, meaning that not all limestones are suitable for calcinations or are able to produce a suitable product especially for CDS. Furthermore, the conversion of roughly 1 tonne lime from limestone requires about 2 tons of pure limestone.

During operation, the WFGD is fed with about 1.02 – 1.05 mols of limestones per mol of captured SO_2 depending on process design and limestone quality. The process can operate with CaCO_3 content in the limestone of between 85% - 98%. The CDS requires hydrated lime quality of above 90% with stoichiometric ratio (SR) of between 1.4% and 2% for every mol of SO_2 in the raw gas to achieve comparable SO_2 removal efficiency. The higher SR requirement of the CDS means that the process uses relatively larger amounts of sorbent compared to the WFGD for comparable performance. Since burnt lime is produced from limestone, this implies that the CDS process requires more limestone than the WFGD process.

The CDS process also requires higher quality lime. As discussed above, not all limestones are suitable for this purpose. While some regions in South Africa have limestone deposits that can

potentially be used for this purpose, other regions notably lack such. This situation is most true in the South African context since the country's power plants are concentrated inland with potential sustainable limestone sources situated over 700 km away. Interactions with lime suppliers in the country indicate that the limestone deposits in the regions surrounding the power stations are not conducive for calcination and the production of a good quality lime product as would be required for the CDS. The cost drivers for desulphurisation technology selection in terms of the sorbent include the quality, and transportation of sorbent which can be significant depending on the distance between the sorbent source and the end-user.

One needs to consider the broader socio-economic environment in context of the technical challenges related to the calcination of limestone to produce high quality hydrated lime. The intention is to utilise limestone sources that are available within the areas closer to the power station in an effort to stimulate mining development and the creation of jobs leading to further economic growth and development in an economically stagnant region (i.e. Lephalale, Marble Hall and Thabazimbi). The lower quality limestones in this region can be utilised in the WFGD process however these available limestones cannot be used to produce hydrated lime in the qualities that are required for the CDS technologies and will therefore have to be sourced in from the Northern Cape. Implementation of any CDS technology therefore eliminates the potential for the socio-economic growth and development envisaged for the region in and surrounding the power station. Sourcing of hydrated lime from the Northern Cape will also have a negative impact on the cost to consumer due to the transportation costs.

5.3 Water usage (non-quantitative)

The Integrated Vaal River System is the most important bulk water supply system in the country, supplying water to 60% of the country's economy and 45% of the population. This covers the whole of Gauteng, but also to important areas in Mpumalanga, North West, Free State, Northern Cape and soon to the all-important developments near Lephalale in Limpopo. The system receives water from KwaZulu-Natal via the Tugela-Vaal water transfer scheme and Orange River via the Lesotho Highlands Water Project and many other catchments.

Rand Water supplies approximately 1600 million m³/a of potable water to users in the area (see figure 12 below) of which approximately 50% (800 million m³/a) is supplied to users located in the Crocodile River Catchment. Of this, approximately 60% (480 million m³/a) of this water is treated by Waste Water Treatment Works in the Crocodile Catchment and released as return flows. These return flows make up an artificial resource which is growing over time due to increasing demand for potable water supplied from the Vaal System. Whilst some of the return flows are being utilised there is currently a surplus which results in high dam levels in the Crocodile Catchment of which Hartbeespoort Dam is a prime example.

Dams were constructed in the Crocodile Catchment to maximise the potential use of the natural water resource. The additional artificial water resource means that the dams are spilling more frequently and the water flowing into the ocean. The Department of Water and Sanitation has identified this surplus resource (return flows) for use for industrial purposes in the Lephalale area in the Waterberg (Mokolo Catchment).

The full yield of Mokolo Dam (43.8 million m³/a) has been allocated for: provision for the reserve; irrigation; Lephalale Municipality; Eskom and Exxaro. Phase 1 of the Mokolo and Crocodile Water Augmentation Project (MCWAP) supplies water to Eskom, Exxaro and the Lephalale Municipality which has been allocated a maximum of 7.2 million m³/a for its current

needs. The Mokolo Dam via Phase 1 is currently the only source of water to the area. A drought in the Mokolo Catchment would thus result in a water shortage in the Lephalale area affecting irrigators, the Lephalale the community and potentially the supply of electricity to the country at large. The development of Phase 2A will mitigate all these risks and it will present an opportunity for economic development in the area which cannot take place without it. Phase 2A is thus required to supplement existing allocations for both existing and future developments.

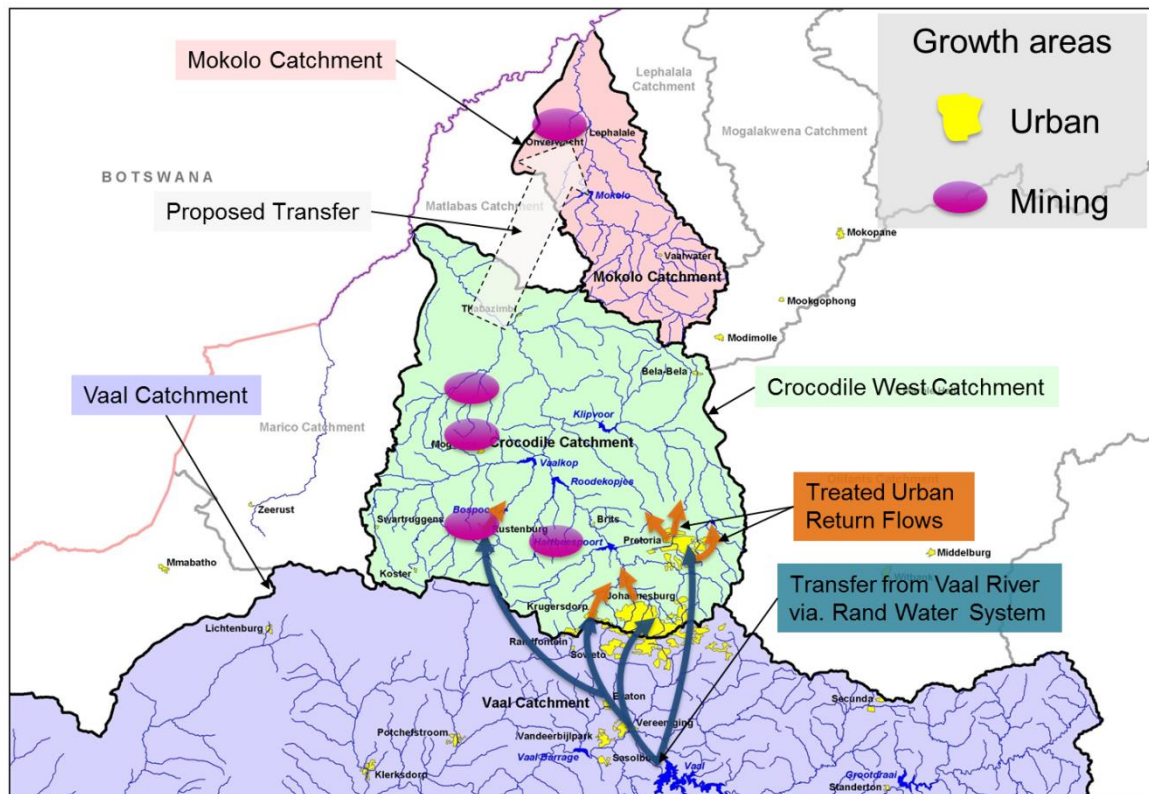


Figure 12: Water Resource Systems

6. CONCLUSION AND RECOMMENDATION

The FGD technology study evaluated available FGD technologies to identify applicable FGD technologies and specific approaches that can be implemented at the Medupi Power Station. The applicable FGD technologies were evaluated and compared on performance, operational requirements, and impacts to the Medupi Power Station when considering a retrofit. The technologies that were evaluated are WFGD, WFGD with cooler, and Dry FGD using CFB.

The impacts to the long term operation of the Medupi Power Station were reviewed in Section 5.0 of this report. The raw resource required for the operation of each type of FGD technology such as sorbent usage, parasitic energy consumption, and water requirements for the operation of the technology was reviewed and compared between technologies. Additionally, considerations from current operation of commercially available flue gas cooling technologies were considered for the alternative of utilising WFGD with flue gas cooler.

While the implementation of WFGD with flue gas cooling has the potential to reduce the WFGD water consumption the practical challenges cannot be ignored as this is expected to have a significant impact on the maintainability and availability of the power plant and the cost of electricity to the consumer. Furthermore all three power stations from Europe visited by Eskom during the benchmarking exercise advised against the installation of the system due to the problematic operation that it provides. WFGD with flue gas cooling is therefore not considered as a feasible option for Medupi.

The implementation of the WFGD technology has the potential to contribute to the broader socio-economic development of Lephalale and its surrounding areas because the WFGD has the flexibility of using lower quality limestones that can be sourced from areas closer to the power station. Furthermore the water supply for the WFGD at Medupi is part of the Phase 2A water augmentation project which is being developed to maximise the potential use of the natural water resource in the Crocodile catchment for industrial use in Lephalale and the surrounding areas. The development of Phase 2A therefore creates an opportunity for economic development in the area which cannot take place without it.

The DFGD technology resulted in a 9% higher capital cost for implementation due to modifications required for existing ductwork design and the addition of a new fabric filter system to the existing FFP in order to retrofit this technology. Although the DFGD processes use slightly less water for the Medupi site, the estimated operating expense for the DFGD is 53% higher than the WFGD system, mostly due to the significantly higher cost of the lime reagent.

It is therefore recommended that Eskom continue with its plan to construct the WFGD technology without the inclusion of a flue gas cooler as this is still the best long term option for SO₂ removal at Medupi Power Station. Based on the information presented in this report it is evident that this is the most efficient, sustainable and broadly (i.e. technical, social, cost) responsible solution for both Eskom and South Africa going forward.

7. AUTHORISATION

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8. REVISIONS

Date	Rev.	Compiler	Remarks
September 2013	0	David Harris Project Manager Black & Veatch	
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October 2017	1.2	Daniel Chang Project Manager Black & Veatch	
December 2017	1.3	Daniel Chang Project Manager Black & Veatch	Updated final document for authorisation and publication

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10. ACKNOWLEDGEMENTS

- None

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List of Attachments

(The following listed set of Documents is available under separate cover)

Process Flow Diagrams

P06259-R-PFD-005 Wet FGD without Cooler – Worst Coal LS; 96% CaCO₃
006265-R-PFD-021 Wet FGD with Cooler – Worst Coal 96% CaCO₃
006265-R-PFD-010 Dry / CFB Cluster 1 – Worst Coal 93.07% CaO

Process Area Arrangement Drawings

P06259-Z4010-501-09 Wet FGD without Cooler
006265-Z4010-XXX Wet FGD with Cooler
006265-Z4050-001-00 Dry / CFB
006265-Z4050-002-00 Dry / CFB Single Unit Overview

Data Sheets

P06259-S-TAB-0xx-DRAFT Wet FGD / CBF Comparison Overall Data Sheet