Energy Consultant to Provide Preparatory Assistance

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MUSINA MAKHADO SPECIAL ECONOMIC ZONE (MMSEZ)

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Global hands Africa (Pty) Ltd
Reg No: 2011/119409/07
Block D Portion, First floor
Menlynwoods Office Park
291 Sprite Avenue
Faerie Glen
Pretoria
0081
T +27 12 844 7809
E Info@globalhands.co.za
W globalhands.co.za

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Approver signature	RDM
Name	R Matshidze
Title	Project Director

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Nomenclature

CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Sequestration
CFB	Circulating Fluidised Bed
EIA	Environmental Impact Assessment
EPC	Engineer, Procure and Construct
FGD	Flue Gas Desulphurization
HELE	High Efficiency, Low Emissions
IFC	International Finance Corporation
IGCC	Integrated Gasification Combined Cycle
IPP	Independent Power Producer
IRP	Integrated Resource Plan
NERSA	National Energy Regulator of South Africa
MMSEZ	Musina-Makhado Special Economic Zone
$MtCO_{2e}$	Million tons CO_2 emitted
MW	Mega Watt
OPEX	Operational Expenditure
PPA	Power Purchase Agreement
SAPP	Southern Africa Power Pool

Assumptions

The following technical assumptions are considered:

- Baseload power is required (i.e. 24/7 continuous supply)
- Relatively cheap tariff required (i.e. close to the cost of current Eskom tariffs or less)
- Specific power consumption of the metallurgical cluster is about 3 - 4 MWh / tonne product
- Grid cost:
  - Average Eskom Mega-Flex tariff of 80c / kWh – this is the current Eskom tariff; our assumption is rather the rate of increase of this tariff beyond 2021 for which we do not have data
  - Eskom will recoup the cost of new generation through increased tariffs (higher than inflation) over the coming years
  - The IPP will connect to the Eskom grid. Additional grid connection and transmission costs are not included in the LCOE.
- The MMSEZ has secured an investment for the energy and metallurgical complex, which will be located on Site 1 – South Side. The secured investors are planning to build a coal fired power plant for the South Side. With regards to a coal fired power plant generation, our assumption is that only Ultra-supercritical will be considered, as per lessons learnt from cases around the world. This has been addressed in the document. CCS is not considered due to the additional high CAPEX, rendering the option to be not economically feasible (a review is still provided though)
- The full set of assumptions used and recommendations for further studies for the client's considerations can be found in the Inception Report, issued in April 2020, as well as the terms of reference provided by MMSEZ.

EXECUTIVE SUMMARY

The Musina Makhado Special Economic Zone (MMSEZ) has been earmarked for accelerating the economic growth, development and job opportunities in Limpopo. The SEZ is a nationally designated zone where special benefits and incentives are provided to encourage investment and trade in the region. The targeted sectors for investment are Energy, Metallurgical, Agro-Processing, Logistics and General Manufacturing.

Despite a difficult global investment climate, funding for the MMSEZ metallurgical cluster has been secured. As a result, there is a need for the energy demands of the cluster to be assessed. It is imperative for a cheap, reliable and consistent power to be available to meet the operational requirements of the metallurgical off-takers, which require a large amount of base-load power supply. Such power would typically be provided via the national grid. However, the current electricity challenges in South Africa makes it difficult for this sector to be connected to the grid. Furthermore, the latest national Integrated Resource Plan (IRP) does not take the MMSEZ's energy requirements into consideration.

The MMSEZ is therefore considering procuring its own generation from an Independent Power Producer (IPP).

The MMSEZ Power project has the potential to increase the provincial GDP growth from 0.2% at the end of 2019 to an average of over 5% per year over the next number of years, which would be a significant boost to the people of Limpopo and to South Africa in general. The MMSEZ has many developmental benefits and inspires hope to the people of Limpopo. The success of the power project is critical as an enabler to the overall MMSEZ project and critical to the sustainable development of Limpopo Province

Of critical importance to the procurement of power from IPPs is the overarching policy and legislative environment governing the framework within which such transactions must take place. As such, it not only impacts on the type of energy generation allowed, but also the procurement framework in terms of which it is procured and the governance and licensing framework within which it must function. Key policy and legislation that affect this are the Integrated Resource Plan, the Environmental Management Act the Electricity Regulation Act, water use permits, and atmospheric emissions read together with associated regulations.

Baseload power for the metallurgical sector is generally sourced from either coal, gas, and/or nuclear technologies. The report highlights the lack of gas infrastructure in Limpopo, limited availability of natural gas, the price and regulatory impact of sourcing nuclear power does not make it an attractive option either. Renewable energy technologies were not extensively considered as part of this study as these are intermittent sources of energy and can only be used effectively as baseload generation when combined with storage, which is currently not economically feasible. Accordingly, various "clean coal technologies" were investigated as potential options for a continuous base load power supply, to comply with environmental

imperatives. Ultra-supercritical coal technology proved most favourable (preferably with CFB combustion technology or post combustion SO_2 removal)

This study therefore concluded, based on the baseload requirement, that the development of a new Ultra-supercritical technology coal power plant as an IPP to the MMSEZ should be investigated further as part of future energy options studies.

In this development, it will be imperative that the correct procedures are followed in the development and procurement of all contracts, including the development of a new coal mine to supply fuel to the power plant. The proposed correct procedures are discussed in more detail in this report.

1 INTRODUCTION

1.1 PROJECT DESCRIPTION

Musina-Makhado Special Economic Zone (SOC) appointed Global Hands Africa and their subcontractors, Aurecon and Kügel Legal Consulting as Energy Consultant to provide project preparatory assistance, technical support, compliance with legislation, policy and regulatory frameworks, as well as provide guidance regarding licensing requirements in respect of power generation for own consumption. This document does not assess the impact of the technologies considered but is rather a concept level advisory report, that provides information and direction to the MMSEZ and its associates. A full Environmental Impact Assessment (EIA) and detailed feasibility study would be required to progress the project further.

The MMSEZ has four (4) targeted sectors namely:

- Energy and Metallurgy
- Agri Processing
- Logistics
- General Manufacturing

The energy and metallurgical complex will be located on Site 1 – South Side. The EIA process for this area is currently underway.. The SEZ master plan was completed end of October 2019 and had limited Energy inputs.

During the development of the Integrated Resource Plan (IRP) that guides national energy planning and investment, a coal fired power plant for the metallurgical cluster was not specifically taken into consideration, as is evidenced by the allocations made under the IRP towards different technologies[1].

A roadmap for investor occupancy in the north side of the SEZ exists, and a similar roadmap should be developed for the south side (i.e. Bokmakierie)

Typical off-takers from the MMSEZ Power Project will include:

- Steel / Stainless Steel Plant
- Coking Plant
- Pig Iron Plant
- Ferro Manganese Plant

[1] The IRP does not mention specific projects, but it is evident from the allocation of capacity in Table 5 of the IRP that the cluster was not specifically considered.

- Ferro Chrome Plant
- Chrome Plating Plant
- Lime Plant

All these metallurgical cluster consumers will be producing commodities that are sensitive to cost of production. With the current global industrial climate, the development of a metallurgical cluster and industrial zone will only be commercially viable if large scale, reliable continuous power can be supplied to these off-takers at very competitive prices. The cost of production for the identified metallurgical commodities are mostly linked to cost of energy, with the specific power consumption in the production of ferro-chromium as high as 3.8MWh/tonne of hot metal, and sometimes even exceeding 4MWh/tonne. To put that into perspective, a blended Eskom Mega-flex tariff will cost approximately ZAR0.80/kWh (yearly average rate), so at a specific power consumption of 4MWh/tonne, the energy cost alone to produce 1 tonne of ferro-chromium would be approximately R3,200.00 (which is high). It is imperative that the power supply to these consumers be of a high quality and environmentally acceptable whilst also as cheap as possible.

Further to the issue of cost of energy, these manufacturing processes are all highly sensitive to the interruption of power supply and would require an uninterrupted, continuous (baseload) power supply. In order to identify the most viable and applicable power generation option to supply baseload power to the metallurgical zone, these factors must be taken into consideration.

1.2 PROJECT OBJECTIVES

The energy project is an enabler to the MMSEZ Project and thus unlocks many economic benefits for the province.

Limpopo is the second poorest province in South Africa. Besides government efforts over the past 5 years through the Limpopo Development Plan (LDP 2016-2019), the challenges of low provincial GDP growth, high unemployment, inequality, poverty and youth inactivity persist. COVID-19 has worsened the socioeconomic landscape adding to the already over 14 000 jobs lost in the mining sector to now over 30 000 total projected job losses in the province.

The MMSEZ project is the hope of the Limpopo, expected to be the main contributor to Limpopo's Development Plan (LDP 2020-2025) and a catalyst to a new growth trajectory for the Province. This hope is not without justification given that it is accepted the world over that infrastructure investments have a catalytic effect on economic growth. This is also affirmed by South Africa's focus on infrastructure as an integral part of its economic recovery plan as emphasised in the recent Sustainable Infrastructure Development Symposium SA (SIDSSA) 2020.

A cheap, reliable and consistent supply of electricity is required for the MMSEZ to succeed. The MMSEZ will therefore have the option to either buy electricity from the national grid or procure its own generation via an Independent Power Producer (IPP). This report aims to identify the most suitable power generation option for the cluster at a high level, outline the legislation that must be complied with and advise on the associated procedures that should be followed.

One of the most important considerations while investing in a Metallurgical cluster is the security of supply and cost of electricity. As part of the scope of this project, the Energy Consultant shall identify sector opportunities and challenges, as well as analyse current and projected energy tariffs. It shall also identify and recommend on latest technological developments in terms of clean coal and other alternatives that would best suit the MMSEZ's ideal.

1.2.1 THE PROJECT CONTRIBUTION TO LIMPOPO'S SUSTAINABLE GROWTH AND DEVELOPMENT

Selected areas of the MMSEZ project's potential contribution to the sustainable growth and development of Limpopo Province are highlighted below.

a. Contribution to Limpopo's Economic Growth

The estimated project value of over R400 billion including the proposed energy project is more than the GDP of Limpopo of nearly R350 billion. The project has the potential to lift the provincial GDP from 0.2% annual growth at the end 2019 to an average of over 5% per year over the next number of years, which would be a much-needed boost to the people of Limpopo and to South Africa in general.

b. Poverty Reduction

The local communities are expected to participate in the ownership structure of the Energy project in line with the national regulations for IPPs. Given the magnitude of the energy project and its sustainable revenue, this can amount to considerable amounts of money annually for the communities which could contribute in many ways towards alleviating poverty including enabling them to have access to education and basic services, among others.

c. Development of Sustainable Communities

The sheer size of the project promises unprecedented economic activity in Musina and Makhado Municipalities. Several infrastructure developments are required to enable the project which will also unlock various business developments and demand for integrated housing developments. This is an opportunity for the development of a new post democratic South African City in Limpopo. Unlike the positioning of Limpopo's last mega project (Medupi project in Lephalale) which stimulated much economic activity, the MMSEZ is located at the busiest land border in South Africa and is host to precious minerals and a vibrant agricultural sector. This creates an enabling environment for sustainable local economies beyond the MMSEZ project.

d. Spatial Transformation of Township and Rural Economies

The project's geographic landscape in rural Limpopo offers an opportunity for spatial transformation by integrating the project with the surrounding rural and township economies. Such integration paves the way for sustainable rural and township economies and inclusive growth, which is necessary to reduce the huge inequalities in South Africa. This could help reduce the migration patterns reflective of the past structural injustices where Limpopo people leave their comfortable homes to live in squatter camps in Gauteng Province which in turn contributes to the uncontrollable urban sprout in the major cities.

e. Employment Creation

The MMSEZ project is expected to create over 21 000 jobs which will greatly contribute to the reduction of unemployment, especially youth unemployment. The contribution is almost equivalent to the official number of unemployed people in Musina Municipality estimated at 23 000. When combined with the secondary and tertiary economic opportunities unlocked by the project, unemployment rates are expected to drop below 20% in the two municipalities compared to the national average of over 30%.

f. Youth Inactivity and Skills Development

Limpopo has one of the highest rates of youth inactivity in the country, many of which have low skills with minimal education. The MMSEZ offers an opportunity for a massive skills development programme that could see many of the youth's skills and having access to decent jobs. This will enable the province to enjoy the benefits of its demographic dividend of having a young population.

1.3 SUMMARY OF THE ENERGY CONSULTANT'S SERVICES

Details of scope of services includes:

a. Sector opportunities and challenges

b. Cost of Own Generation compared to Cost of Grid

c. New Generation technology selection and options study

d. Legislative compliance requirements

e. Market options and advice on Power Purchase Agreement / negotiations

f. Green building code developments for MMSEZ specific investors

g. Guidance and advice on carbon capture / off-set system

h. South Africa & the Paris Agreement

i. Engineering Energy Master Plan for the MMSEZ

2 ELECTRICITY SUPPLY IN SOUTH AFRICA

Electricity in South Africa is mostly supplied by the parastatal utility, Eskom. About 90% of the electricity is produced by Eskom's coal fired power station fleet. However, many of these power plants are aging and inefficient and have been partly responsible for the rolling black-outs experienced by the country.

South Africa's power system remains highly constrained with Eskom currently implementing rotational load shedding and will be for some years. Keeping the lights on is currently the most pressing challenge for South Africa's electricity supply industry for the next few years. It is also key to the longer-term prospects for the economy.

During his February 2020 State of the Nation address, President Ramaphosa said "Our economy has not grown at any meaningful rate for a decade" and its recovery has stalled "as persistent energy shortages have disrupted businesses and people's lives". On commenting how this will be addressed by Government, Mr Ramaphosa said: "We will put in place measures to enable municipalities in good financial standing to procure their own power from independent power producers". "Over the next few months, as Eskom works to restore its operational capabilities, we will be implementing measures that will fundamentally change the trajectory of energy generation in our country," Ramaphosa said. As part of the government's planned steps for the state to become less reliant on the troubled power utility, the president said that the Integrated Resource Plan of 2019 will be given effect to allow for the development of additional grid capacity from renewable energy, natural gas, hydro power, battery storage and coal.

Diversifying the energy mix is also important for the country to fulfil on its obligations and commitments to reduce GHG emissions and limits climate change under the Paris Agreement.

A secure supply of electricity, at a cost which South Africa can afford, is essential for the economy to recover as well as to provide equitable access to electricity.

One of the biggest challenges then for the industry and for the policymakers, is to find the right balance between secure supply of electricity, lowering GHG emissions and decarbonization of the industry, and all at a cost which is affordable for the country and attractive to new investment in infrastructure.

2.1 GRID POWER COST PREDICTION

If the Eskom Mega-Flex tariff of average 59c/kWh in 2016 increased with CPI, the 2020 average mega-flex tariff would have been only 72c/kWh. Instead, Eskom tariffs increased by a total of 35% over the past 4 years, and today the average Mega-Flex tariff is 80c/kWh.

In 2018, Eskom applied to NERSA for an 18.91% increase, but only a 5.23% increase was granted. In April 2020, a South African court ruled in favour of Eskom appealing the NERSA 2018 decision. This now allows Eskom to do a supplementary tariff increase application to NERSA. If approved, it is expected that Eskom will claw back these increases over the next couple of years. It is also anticipated that Eskom will continue to apply for higher than CPI tariff increases going forward in order to pay back debt from its new Kusile and Medupi power plants.

Figure 1 indicates the difference in the estimated Eskom tariffs (in c/kWh) over the next 20 years versus that of a 2016 Eskom tariff should it have escalated with CPI and a dollar indexed IPP tariff based on 2020 cost of generation calculations and a hypothetical new-build Ultra-supercritical coal technology.

It is conservatively assumed that Eskom tariffs will settle to escalate with CPI from 2026 onwards.

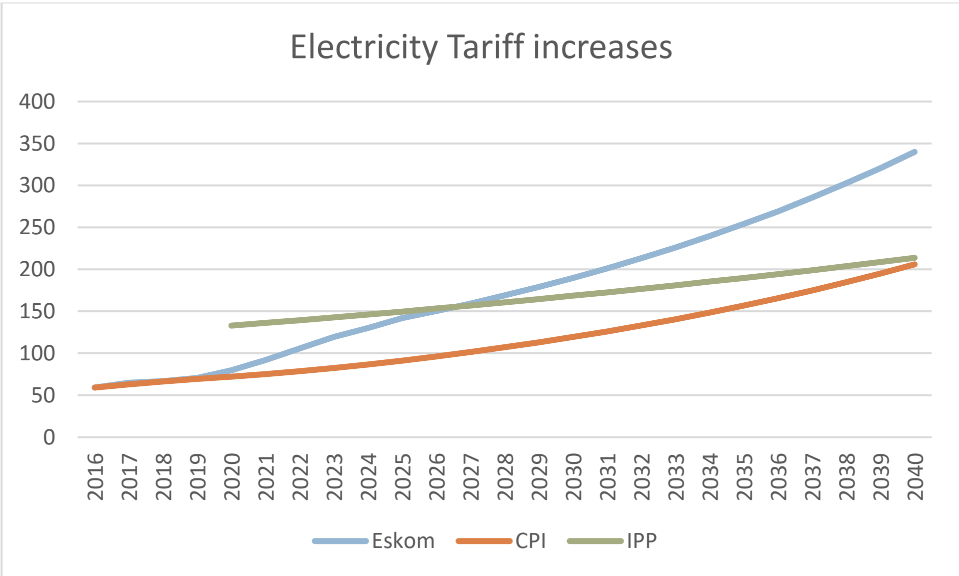

FIGURE 1: ESKOM VS CPI TARIFF INCREASES

As most of the cost of generation is related to CAPEX, and the CAPEX of an Ultra-supercritical coal power plant of approximately 1320MW is most likely to be US Dollar denominated, the tariff increase of an IPP is US Dollar indexed.

2.1.1 RISKS ASSOCIATED WITH GRID SUPPLY

The two primary risks associated with grid supply is reliability and cost. Eskom's aging infrastructure combined with congestion on the network has resulted in increasing power cuts and is expected to worsen over time. Planned or unplanned power cuts will be detrimental to the MMSEZ as it poses a risk to the industrial consumers that require a continuous and affordable power supply for operations.

In addition to the unreliable grid supply, **Figure 1** (and section above) shows that Eskom's tariffs are likely to escalate extensively in the coming years. The uncertainty around Eskom's financial stability and its proposed tariff increases is a major risk to the success of the MMSEZ if the cost of electricity becomes unfeasible for industrial operations.

The current status of Eskom (financially and technically) leads to several large power users considering own generation in order to provide security of supply as well as tariff (input cost) stability.

For the past few years, Eskom proved to be the single biggest risk to the South African economy due to interruption of supply as well as unstable electricity tariffs. Despite several government bail-outs and obtaining international loans, Eskom is still experiencing many technical and commercial difficulties.

The cost of loss of operation by the MMSEZ off-takers (what it will cost in terms of production losses, process downtime and additional re-start costs) should also be included in the consideration of the cost of own generation.

This means that the cost of own generation should not only include the IPP Tariff, but also the upside or benefit of security of supply vs the cost of not having a supply or not having a secure supply (cost of loss of operation).

3 POWER GENERATION OPTIONS

A first order and high-level power generation options analysis was compiled for the MMSEZ power supply. The technologies considered include:

- Advanced Nuclear
- Solar PV (tracking utility scale) with Storage
- Bio-Mass
- CCGT Plant
- Clean Coal Technologies

Note: Supercritical Coal, Subcritical Coal and CFB with limestone injection were not included in this analysis based on the outcome of the reflection on the Paris Agreement, South African new coal case studies (Khanyisa and Thabametsi) and environmental legislation which all discard the above options as non-clean coal.

3.1 ADVANCED NUCLEAR

Advance Nuclear Technologies are at the forefront of clean energy development. Nine different advanced nuclear technologies are being developed globally, some in more advanced stages than other. These technologies are suitable to generate clean, safe, baseload power with a continuous focus on reducing cost. Advanced nuclear technologies are inherently safer by design, emits no CO_2 or other Greenhouse Gasses, can act as load following (similar to OCGT technology) in order to support a high penetration of renewable generation and comes in a wide range of sizes which can be expanded modularly. Installed capacity of 1600MW as required for phase 1 of the MMSEZ power demand is therefore achievable with Advanced Nuclear and can be increased via a phased approach.

In many first world countries, developing and deployment of advanced nuclear power generation is key to reduce climate change impact whilst providing reliable baseload power. In the UK, nuclear contributes to 20% of the total domestic electricity supply, and 40% of the low-carbon electricity generated. Advanced Nuclear Technologies (defined as Small Modular Reactors (SMRs) which are smaller versions of today's technology, and Advanced Modular Reactors (AMRs) which adopt next generation technologies) could work alongside other low-carbon sources in a hybrid energy system to offer cost-effective solutions to a range of energy needs.

However, over many years the policy framework in these countries have been specifically adapted to allow for the stringent regulation of such developments. Nuclear regulation and the licensing and permitting processes are crucial enablers in any country's nuclear policy framework. The regulatory system for new reactors must be robust, provide public confidence and enable innovation. Addressing the regulatory framework in South Africa will add a significant time requirement and would not fit with the MMSEZ's timeframe for own generation. The UK started on this journey in 2014 and are still not at a point of readiness on advance nuclear regulation. Apart from National Nuclear Regulatory framework in South Africa, any new-build nuclear facility would require approval from the International Atomic Energy Agency.

The Capital Cost required to develop new Nuclear Power Plants is a key factor dominating the economics of the technology. Advanced Nuclear development in a country that does not yet have an established regulatory framework, and where limited number of projects will be developed, will lay in the high range of overnight cost and estimated LCOE, making the cost of energy at approximately USD192/MWh from a new build nuclear project too high for metallurgical commodity production.

Technology	**Overnight Cost (USD/kW)**		**Estimated LCOE (USD/MWh) 2020 over 30years**	
	Low	High	Low	High
Advanced Nuclear	6,000	12,200	110	192

From this, it was concluded that the timeline for the development and regulatory and licencing of an advanced nuclear power plant, as well as the cost of generation outweighs environmental benefits, and Nuclear power generation should not be considered economical viable for the MMSEZ.

3.2 SOLAR PV WITH STORAGE

South Africa has exceptionally good solar resource, especially in the Northern Cape region. Most of the country's utility scale PV plants are located in the Northern Cape, and very cheap renewable energy cost of generation can be achieved in these areas, where the yearly global horizontal irradiation (GHI) is in excess of 2200kWh/m^2. In the MMSEZ area, GHI is approximately 2000kWh/m^2 which is still considered a good solar resource for PV generation.

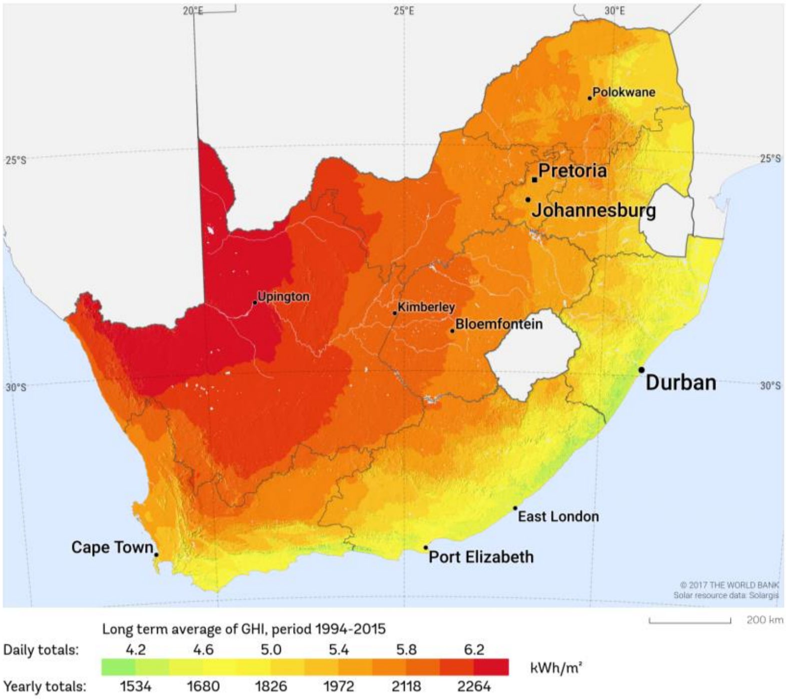

Figure 2: South Africa Global Horizontal Irradiation (GHI)

With this level of GHI, a solar field covering 1ha of PV panels could generate approximately 1MW of AC power during peak irradiation levels. A PV Solar farm capable of generating 1320MW (MMSEZ first phase demand) during most of daylight hours (not only at peak) would need to be in approximately 2000ha of PV panels. At the end of 2019, utility scale solar projects in operation in South Africa had a combined installed capacity of 1500MW. To date, the world's largest solar park is the Longyangxia Dam Solar Park in the Qinghai province of China, totalling 850MW installed capacity and spread over more than 25km^2 and consists of 4 million solar panels.

In addition to severe space constrains, mega solar alone is still non-dispatchable power (meaning it is only available when the resource(sunshine) is available and cannot provide power on demand). In order to provide baseload dispatchable power to the Metallurgical offtakers, solar PLUS storage solution would be required. This could be implemented with different technologies for storage, such as:

- Lithium Ion batteries
- Lead-acid batteries
- Thermal (such as molten salt) storage
- Flow batteries
- Hydrogen

In all of these cases, excess solar generation would be required during daytime / peak hours to charge battery storage which could be deployed at night or when solar resource is unavailable (cloud cover) in order to provide baseload power to the Metallurgical offtakers. That would add significantly to the installed capacity of the solar plant.

The world's largest thermal storage (molten salt) is part of the Solana Generating Station in the USA, capable of delivering 280MW for 6hours. The Dalian Vanadium Redox Flow Battery system in China is capable of delivering 200MW for 4hours. The Hornsdale Lithium-ion battery system in Australia is the largest of its kind at 150MW for just over 1 hour.

The KaXu Solar One Thermal Solar farm in Northern Cape South Africa is the world's 3rd largest Thermal Storage solar facility with storage. A 100MW parabolic trough plant with 3 hours storage capacity.

As with the rest of solar power generation technology and equipment, the price of battery storage is improving with further development of technology. In 2018, the National Renewable Energy Laboratory (NREL) of the USA estimated that the capital cost of Lithium Ion battery systems could decrease to 1/5th of its 2018 cost in the next 30 years, and a cost reduction of 10 – 50% by 2025 (depending on technology development.

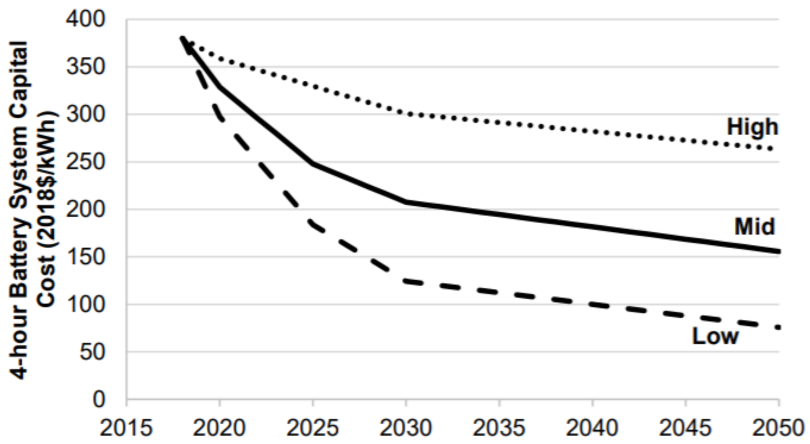

FIGURE 3: BATTERY COST PROJECTIONS FOR 4-HOUR LITHIUM ION SYSTEMS

Current capital cost of a utility scale battery system capable of providing 4hours of energy ranges between 400– 800 USD/kWh. In order to provide baseload power to the metallurgical offtakers, the MMSEZ's application would require at least 8 – 10 hours of battery storage. That scale of battery storage system is physically constrained and requires excessive capex.

Technology	**Overnight Cost (USD/kW)**		**Estimated LCOE (USD/MWh) 2020 over 30years**	
	Low	High	Low	High
Solar PV (tracking utility scale) -No storage	900	1,100	36	44
Solar PV (tracking utility scale) + Lithium Ion Storage 12hrs	5,000	9,100	110	156
Solar Thermal + Storage	6,000	9,100	126	156

Based on the above, it is clear that large scale baseload power generation from Solar plus storage, is not yet feasible or economically viable for the MMSEZ's purposes.

It is however crucial to consider augmenting other baseload generation with Solar PV, and other applications for PV should be considered in the MMSEZ's energy masterplan. Solar PV plus storage could be considered for the Agri-Processing, logistics and other manufacturing and processing clusters which will be developed alongside the metallurgical zone.

3.3 BIO-MASS

Bio-mass to power plants in general are medium scale facilities of approximately 200MW installed capacity. This is generally limited by the availability of feedstock. Ironbridge in the UK is a 740MW wood pellet fired biomass power plant and was converted from coal-fired to biomass in 2013 and decommissioned completely in 2015.

Operations and maintenance (O&M) costs can make a significant contribution to the levelised cost of electricity (LCOE) and typically account for between 9% and 20% of the LCOE for biomass power plants. It can be lower than this in the case of co-firing and greater for plants with extensive fuel preparation, handling and conversion needs. Cost of fuel and cost of transportation of fuel is another operating cost that contribute to the LCOE.

Secure, long-term supplies of low-cost, sustainably sourced feedstocks are critical to the economics of biomass power plants. Feedstock costs can be zero for wastes which would otherwise have disposal costs or that are produced onsite at an industrial installation (e.g. black liquor at pulp and paper mills or bagasse at sugar mills). Feedstock costs may be modest where agricultural residues can be collected and transported over short distances. However, feedstock costs can be high where significant transport distances are involved due to the low energy density of biomass (e.g. the trade in wood chips and pellets). The LCOE of biomass-fired power plants ranges from USD95 to USD290/MWh depending on capital costs and feedstock costs. Where low-cost feedstocks are available and capital costs are modest, biomass can be a very competitive power generation option.

The main reason for typical biomass power plant sizes to be limited below 200MW, is the low energy content of biomass. 1600ha of typical pine plantations would produce 1MW of baseload power for one year. Or another way of expressing the immense amount of biomass required for large scale baseload power generation, is that 1tonne of dry woody biomass is consumed for each 1MWh produced. A 1320MW plant, operating at an 90% Load Factor would consume 10,400,000 tonnes of dry woody biomass per year.

To fire a 1320MW baseload power plant with woody biomass, would require 2,500,000ha or 25,000km² of pine plantations

FIGURE 4: AREA REQUIRED AS PINE PLANTATIONS TO PROVIDE SUFFICIENT BIOMASS FOR 1320MW

Woody biomass is by far not the only biomass option, and other options such as miscanthus and sugar cane provide much higher yields under wet and tropical conditions. Given the arid conditions in the Musina/Makhado area, such high yields and tropical cultivars cannot be considered. The above serves as an illustration of the extensive land and biomass production required for large scale baseload power generation. Even if a crop with three times the biomass yield (typical miscanthus yield is 12tonnes/ha/year or 3 times that of pine plantations) could be cultivated in this arid region, it would still require almost 1million hectares of feedstock.

Technology	Overnight Cost (USD/kW)		Estimated LCOE (USD/MWh) 2020 over 30years	
	Low	High	Low	High
Bio-Mass	5,000	7,000	95	210

3.4 NATURAL GAS AND CCGT TECHNOLOGY

Existing natural gas supply and pipeline networks in South Africa are limited to:

- **ROMPCO pipeline:** An 865 km pipeline between Temane in Mozambique and Secunda in South Africa, jointly owned by Sasol and the two respective Governments. This pipeline is currently capacity constrained, with the majority of gas consumed at Sasol's facilities for power generation and fuel production.
- **Sasol pipeline network:** A natural gas distribution network delivering gas from the ROMPCO line to users (industrial and residential) in Gauteng.
- **Mossgas (PetroSA):** PetroSA announced in October 2019, that the Mossel Bay plant will run out of natural gas (obtained from the offshore field about 89km from Mossel Bay) by December 2020. Although this day-zero is currently somewhat delayed, the company is considering importing LNG in order to continue production at the Mossgas plant. No additional gas and infrastructure are available for 3rd party use.
- **Lilly pipeline:** A small capacity line between Durban and Johannesburg, mainly transporting Methane-rich gas (not natural gas) from Secunda to Richards Bay. This line is owned by Transnet and operated by SASOL under a lease agreement until 2022 and can be repurposed to handle natural gas. It is not clear what Transnet's plans are for the pipeline once the Sasol lease comes to an end. However, the pipeline is only 16 inch in diameter for the majority of the pipeline length and throughput capacity will be limited. The line has off-take points at Newcastle, Empangeni/Richards Bay and the Durban area. The maximum capacity of this pipeline is 23 million GJ per year, operating at 40 – 53 Bar. The majority of its current off-takers are located on the section between Secunda and New CastleIt is expected that industrial demand in this section will exceed the line's capacity in the early 2020s (according to Transnet's 2017 long term planning framework report), but availability still remain in the section between Richardsbay and Durban for the long term. In repurposing this line to receive LNG at Richards Bay, operating pressure could be increased to closer to the design limit of 80bar, which will allow continued supply to current Gauteng based offtakers.
- **Expansion:** Transnet is planning several expansions and new pipelines, on a phased approach as illustrated in Figure 5 below. There is no indication on timeline of any of these phases.

FIGURE 5: CEF GROUP-ESKOM-TRANSNET STRATEGICALLY ALIGNED PHASED GAS PIPELINE NETWORK

There are thus no natural gas reserves, new explorations, pipelines or LNG import facilities in the MMSEZ or surrounding areas. With the ROMPCO line and Temane and Pande gas fields already under capacity constraints, it will also not be possible to receive sufficient gas from the ROMPCO line for the generation of 1320MW baseload power at MMSEZ.

The nearest port to the MMSEZ for LNG imports would be Maputo, Mozambique. With the current ROMPCO line already operating at design capacity, it would be required to install a dedicated gas line from Maputo to MMSEZ for gas supply. This would require the construction of approximately 450km of pipeline in addition to an LNG receiving terminal and regasification facility at Maputo.

Approximately 1,500,000tonnes/annum of natural gas will be required to fuel a 1320MW CCGT power plant. A pipeline of this magnitude will add significantly to the capex of a power project, but the benefit of importing LNG into the region and possible energy supply to the metallurgical zone, in addition to the environmental benefit of CCGT technology is worth investigating.

Technology	Overnight Cost (USD/kW)		Estimated LCOE (USD/MWh) 2020 over 30years	
	Low	High	Low	High
Gas in CCGT (no pipeline)	700	1,300	44	68
Pipeline cost (1.5MT/annum over 450km) @ $2m/km	USD 900,000,000			
Power plant + Pipeline cost	1,400	2000	85	120

3.5 CLEAN COAL TECHNOLOGIES

A desktop study and high-level literature review was done for the following clean coal technologies in Sections 10 and 11:

- Integrated Gasification Combined Cycle (IGCC)
- Ultra-Supercritical Coal
- Supercritical coal plus Flue Gas Desulphurisation
- Underground Coal Gasification and Combined Cycle Gas Turbine (CCGT)
- Shale Gas via Fracking plus CCGT
- Circulating Fluidised Bed (CFB) plus limestone injection
- Carbon Capture and Storage (CCS)

Costs for ultra-supercritical coal, with and without CCS, are provided in the cost of electricity comparison in the following section.

4 INDEPENDENT POWER PRODUCER SUPPLY

Independent Power Producers (IPPs) are private entities which own, build and/or operate power generation facilities in accordance with different ownership and operating models[2]. IPPs are typically procured through a formal procurement process whereby bidders tender for the proposed project and are selected based on a predetermined set of criteria. The most well-known example of this process in South Africa is the Renewable Energy Independent Power Producer Program (REIPPP), as deployed by the Department of Energy's IPP Office in 2011. As a result of such a programme, the preferred bidder enters into a Power Purchase Agreement (PPA) with the end-user or off-taker, whereby the cost of power is agreed over the tenure of the PPA. The IPP may offer various technologies depending on the size and demands of the end-user, as well as the legislative requirements in the region.

4.1 OWN GENERATION (IPP GENERATION) COST

Typical overnight CAPEX costs for different generation technologies over the past 5 years in the global market and associated Levelised Cost of Electricity (LCoE) are depicted in Table 4.1 below:

TABLE 4.1 HIGH-LEVEL COST COMPARISON FOR OWN GENERATION TECHNOLOGIES

Technology	Overnight Cost (USD/kW)		Estimated LCOE (USD/MWh) 2020 over 30years	
	Low	High	Low	High
Advanced Nuclear	6,000	12,200	110	192
Solar PV (tracking utility scale)	900	1,100	36	44
Solar PV (tracking utility scale) + Lithium Ion Storage 12hrs	5,000	9,100	110	156
Solar Thermal + Storage	6,000	9,100	126	156
Bio-Mass	5,000	7,000	95	210
Gas in CCGT	700	1,300	44	68
Ultra-Supercritical Coal	3,000	6,000	66	100

[2] E.g. BOO (Build, own operate), BOOT (build, own, operate, transfer) or BTO (build, transfer, operate) models.

Technology	Overnight Cost (USD/kW)		Estimated LCOE (USD/MWh) 2020 over 30years	
Ultra-Supercritical Coal with CCS	6,000	10,000	127	155

Ideally, a Combined Cycle Gas Turbine (CCGT) arrangement would be most cost effective and with a relatively limited environmental impact and contribution to Greenhouse Gas Emissions. Without readily available Natural Gas resources, this option is unfortunately not viable. The most viable case to procure cost effective, baseload power supply to the metallurgical industrial park is evidently through the development of a Clean Coal IPP project. Cost of generation of a 2 x 660MW Ultra Supercritical Coal power plant without CCS were investigated further as part of this study. The following cost estimation and assumptions were used as basis, as obtained from recent coal projects in the SADC region.

TABLE 4.2 CLEAN COAL COST OF GENERATION

Parameter	Assumption and estimated costs (all costs in 2020 USD)
Technology	Ultra-supercritical Coal with dry cooling
Gross Installed Capacity	2 x 660MW
Net Annual Power Output	10,150 GWh/year
Term of PPA /generation	30 years
Coal calorific Value	20.5 kJ/kWh (HHV) (Waterberg Coal average)
Average annual coal consumption	5,336,500 tonnes per year (including degradation over 20years)
Coal Price	$25/tonne [Department of Mineral Resources (DMR) 2018 report]
CAPEX	$4,800,000,000
Inflation assumption	4%/annum for 30 years
NPV Cost (Pre-TAX and Finance)	$6,224,000,000
Nett Cost of Generation	$86.10/MWh

This net cost of generation is mainly made up by CAPEX (65%) Fuel cost (20%) and variable and fixed O&M costs (7% and 8% respectively).

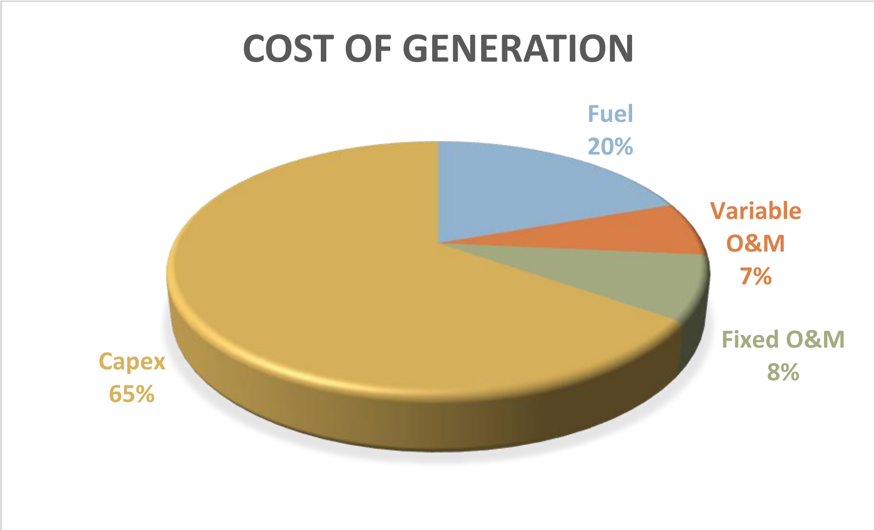

FIGURE 6: COST OF GENERATION – ULTRA-SUPERCRITICAL COAL TECHNOLOGY

4.1.1 RISKS ASSOCIATED WITH IPP GENERATION

The risks allocated to the MMSEZ associated with IPP generation will be determined by the PPA and associated agreements. Depending on how the PPA and related agreements[3] are drafted and negotiated, the majority of the development risk should reside with the IPP. Offtake and payment risks will be allocated to the MMSEZ and/or its off-takers. Off-taker risk often require supportive mechanisms such as escrow account arrangements, Government guarantees and other supportive mechanisms to mitigate. Various options can be designed and implemented to mitigate MMSEZ's risks, depending on the legal and financial structuring of the project

It is imperative that the PPA properly allocates risk to the Contractor and Operations and Maintenance (O&M) operator and ensure that all risks are accounted for.

The IPP will be responsible for obtaining all licensing and permits. As indicated in the lessons learned from Thabametsi and Khanyisa below, acquiring the necessary documents can be delayed by years if the correct approach is not taken. This also adds to the MMSEZ and industries' risk of securing an own generation supply.

[3] Such as Implementation Agreements, Fuel Supply Agreements, Direct Agreements with Lenders and Operations and Maintenance Agremeents.

5 SECTOR CHALLENGES AND OPPORTUNITIES

The security of supply and cost of Electricity is one of the most important considerations while investing in a Metallurgical cluster. With the current commodity markets, the success of this large investment and job creation initiative by the MMSEZ will greatly depend on its ability to supply cheap, secure baseload energy to the off-takers.

Globally, the main source of power supply to the metallurgical sector is base load power generation from either Coal, Gas and/or Nuclear technologies.

With very little Gas Infrastructure in South Africa, and nothing at all in the Limpopo Province, and the price and regulatory impact of nuclear power, the MMSEZ is forced to consider other means of “clean power generation” to supply uninterrupted power to the Metallurgical cluster.

An alternative is the use of “clean coal technology” which is defined as “a set of technologies that either reduce or optimize the use of natural resources, whilst simultaneously reducing the negative effects it has on the planet and its ecosystems.” However, baseload coal, in any form, is still a contentious topic, and although it presents opportunities for growth and development, the technology also comes with its own set of challenges.

5.1 CHALLENGES

The 1000 MW of new coal build published in the August 2018 draft IRP was expected to come from two IPPs – Thabametsi (537 MW developed by Marubeni and Exxaro consortium) and Khanyisa (306 MW developed by an ACWA led consortium). Both these plants were planned to reach Commercial Operation Date (COD) in December 2021. However environmental activists and the Life After Coal Campaign (Earthlife Africa, the Centre for Environmental Rights (CER) and groundwork), lobbied against the roll out of the new power stations, arguing that the impact on climate change was not properly accounted for. The case against Thabametsi was taken to court where the High Court ruled in favour of the environmentalist groups. The same group has also filed numerous objections against Khanyisa and commencement of construction of the two plants have since been on hold. Figure 7 below shows a timeline of the major events leading up to this point.

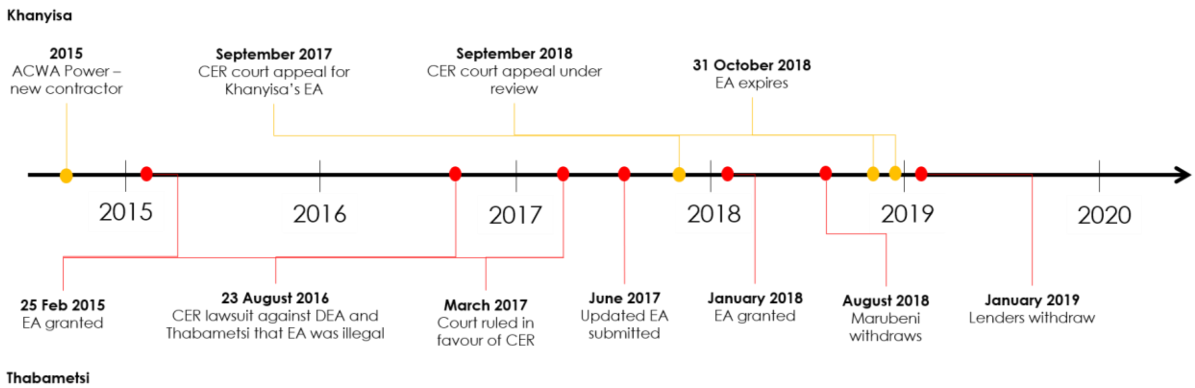

FIGURE 7: KHANYISA AND THABAMETSI EA DEVELOPMENT TIMELINE

Environmental authorisation and approval prove to be very difficult and a sensitive topic in the development of Coal Power Plants globally, with no exception in South Africa. The legal challenges around licensing and permitting involves granting Environmental Authorisation, and Atmospheric Emission, Water Use and Generation Licenses. These permits are governed by the National Environment Management Act 1998, the National Water Act 1998 and the Electricity Regulation Act 2006 respectively. The CER has opposed the construction of the two plants in line with this legislation, as well as the 2015 Paris Agreement commitments which South Africa has pledged to.

5.1.1 THABAMETSI – LESSONS LEARNT

The key findings in favour of CER in the case against Thabametsi included the following:

- Climate change and other environmental impacts must be individually assessed, and the environmental authority must independently make the decision to allow the project to go ahead
- The EIA must include a comprehensive assessment of climate change impacts before authorisation is allowed. Previously it was not a requirement to include specific climate change impacts in an EIA
- The EIA should not be limited to the quantification of greenhouse gases and must also include an assessment of the broader climate change impacts including water scarcity and the long-term health of the surrounding communities
- The environmental authority must determine measures (if applicable) to reduce the carbon emissions and ensure that the surrounding environment is resilient to the impacts of the project. – this is where "Clean Coal Technologies" have an advantage and could still be granted environmental authorisation, provided it is carefully approached and very well defined as per above guidelines

The table shows the status of the hurdles which Thabametsi is required to resolve in order to reach financial close.

TABLE 5.1 THABAMETSI EA CHALLENGES

Regulatory Hurdle	Status	Appeal Action	Current Status
Environmental Authorisation (EA)	Issued in January 2018 after revised EA was submitted	CER challenge court proceedings on 26/03/2018	EA granted (activities must commence 3 years from date of issue)

Regulatory Hurdle	Status	Appeal Action	Current Status	
Atmospheric Emission License (AEL)	Provisional AEL issued on 14/2/2019	Appeal issued by CER in Oct 19	Provisional AEL granted (valid for 5 years)	
Water Use License (WUL)	Revised application submitted in Feb 18	CER objected to the application based on a study by Savannah Environmental	Awaiting license. CER ready to appeal if issued.	
NERSA Generation License	Application submitted	CER objections Dec 17 - Feb 20	Awaiting license	

In addition to the regulatory challenges shown above, Thabametsi has also not reached financial close due to key funders withdrawing, including primary shareholders Marubeni and lenders First Rand, Nedbank and Standard Bank. South African lenders have been withdrawing support for coal power producers in favour of responsible lending and support of sustainability initiatives and "green" funding. Currently, none of the big commercial banks are supporting any coal (Clean or other technology) as funders. Funding for Clean Coal Technology will have to be sourced from markets which still support such technology, typically Chinese and other BRICS countries.

5.1.2 KHANYISA – LESSONS LEARNT

The regulatory challenges faced by Khanyisa are similar to that of Thabametsi, with the exception that the initial Environmental Authorisation (EA) for this plant has now expired. The initial EA was granted in October 2013. The primary hurdles which Khanyisa is required to resolve, are listed below.

TABLE 5.2 KHANYISA EIA CHALLENGES

Regulatory Hurdle	Status	Appeal Action	Current Status	
Environmental Authorisation (EA)	EA expired on 31/10/2018	Contractor opposes ruling CER requests confirmation of DEFF's ruling on 5/2/2020	EA expired	
Atmospheric Emission License (AEL)	Still pending (as at Oct 2019)	CER appeal	Awaiting license	
Water Use License (WUL)	Application submitted	CER appeal – license was initially suspended but	Awaiting license	

Regulatory Hurdle	Status	Appeal Action	Current Status
		contractor application to lift the suspension was successful	
NERSA Generation License	Application submitted	CER objected to the application	Awaiting license

5.2 OPPORTUNITIES

On the other hand, Clean Coal technology and the independent generation by a utility scale power plant such as this project, brings several good opportunities to the country, the MMSEZ, the independent developers and potential off-takers.

A clean coal technology power plant of an estimated 1600MW net output will bring approximately USD 6 billion dollars in foreign investment directly related to the power plant. That is excluding the additional foreign investment that it will enable through the Metallurgical Zone.

The MMSEZ should also specifically investigate the number of direct and secondary jobs created through such a development that will greatly benefit the community.

If the development timeline is planned well, this can provide great relief to the unemployment issue related to end of construction at Medupi and Kusile Eskom power plants. In a report prepared by Hill and Associates, Inc. from the USA, the economic benefits of the development of a coal fired power plant is highlighted, even for an established economy such as that of the USA. The benefits to the South African economy should be further investigated to aid in the support of such a development. In this report, it is stated that the development and construction of a 1500MW ultra-supercritical coal fired power plant with associated new coal mine will generate over 20,000 job-years of employment in the region. During the operation of such a power plant and mine over 40 – 50 years, an additional 2,300 permanent jobs will be sustained. Much of the economic activity and many of the new jobs will be created indirectly as a result of the expenditures made directly at the power plant and mine.

Furthermore, clean coal technology has the potential to overcome the stigma around coal and can benefit Southern African developing countries in delivering cheap baseload clean energy. It also has the potential to offset the current carbon emissions produced by the old and inefficient technology used by Eskom's coal fleet. These new technologies should be further investigated to replace decommissioned Eskom plants.

From the South African Department of Energy's White Paper on Energy Policy, released in December 1998, the current policy objectives for clean coal utilisation and the entire energy sector, are to increase access to affordable energy services, improve energy governance, stimulate economic development, manage energy-related environmental impacts and secure energy supplies through diversity. "Restructuring aims to improve the quality of life of all South Africans and to increase economic growth and redeploy assets. To ensure non-discriminatory and open access to transmission lines, and taking into consideration the financial stability of Eskom, government, in the medium term, is to establish a separate state-owned transmission company. [http://www.energy.gov.za/files/coal_frame.html]

From the 2019 IRP:

- Coal: Beyond Medupi and Kusile coal will continue to play a significant role in electricity generation in South Africa in the foreseeable future as it is the largest base of the installed generation capacity and it makes up the largest share of energy generated. Due to the design life of the existing coal fleet and the abundance of coal resources, new investments will need to be made in more efficient coal technologies (HELE technology, including supercritical and ultra-supercritical power plants with CCUS) to comply with climate and environmental requirements. The stance adopted by the Organization for Economic Cooperation and Development and financial institutions in regard to financing coal power plants, is a consideration upon which the support of HELE technology is predicated. This ensures that South African coal still plays an integral part of the energy mix. Given the significant investments required for CCS and CCUS1 technology, South Africa could benefit from establishing strategic partnerships with international organisations and countries that have made advancements in the development of CCS, CCUS and other HELE technologies.
- Carbon capture and storage, underground coal gasification, and other clean coal technologies are critical considerations that will enable us to continue using our coal resources in an environmentally responsible way into the future.
- Eskom's role as a Buyer under section 34 of the Electricity Regulation Act will have to be reviewed, taking the ramifications of its unbundling into account.
- More funding should be targeted at long-term research into clean coal technologies such as CCUS and UCG as these will be essential in ensuring that South Africa continues to exploit its vast, indigenous minerals responsibly and sustainably.
- HELE coal technologies including underground coal gasification, integrated gasification combined cycle, carbon capture utilization and storage, ultra-supercritical, super-critical and similar technologies are preferred for the exploitation of our coal resources. Due consideration must be given to the financing constraints imposed by lenders and the Organization of Economic Cooperation and Development (OECD) countries, insofar as coal power plant development. Due consideration must also be given to the pace and scale of the coal-to-power programme taking into account the lessons from Medupi and Kusile mega projects. Procurement under the IPP programme has shown that there is a business case for modular and smaller power plants (300MW and 600MW).

- **Decision 6 of the IRP:** South Africa should not sterilise the development of its coal resources for purposes of power generation, instead all new coal power projects must be based on high efficiency, low emission technologies and other cleaner coal technologies.
- **Risk mitigation (new Coal Development):** The Department is monitoring the legal challenge on the environmental approvals issued by DEA and will be guided by the outcome of this process as applicable. The assumption in the IRP is that all new coal to power capacity beyond the already procured 900 MW will be in the form of clean coal technology, which is still generally financed. As proposed in the draft IRP update, work to enable implementation and investments in flexible HELE will be undertaken following finalisation of the IRP

It is evident that affordable baseload power in terms of clean coal technologies are still part of the South African energy mix. In an interview with Chris Yelland in February 2020, the minister of Minerals and Energy, Mr Gwede Mantashe noted in his closing remarks: "So, I subscribe to an energy mix – clean coal, CCS, gas-to-power, hydro, renewables, battery storage and even nuclear, because that also gives us time to study the trends as we move ahead. I am one of the those who think that a balanced approach to the energy transition would help us. The energy transition is not just about jobs and training, but about establishing serious alternative opportunities and economic activities."

6 PROPOSED OWNERSHIP MODEL

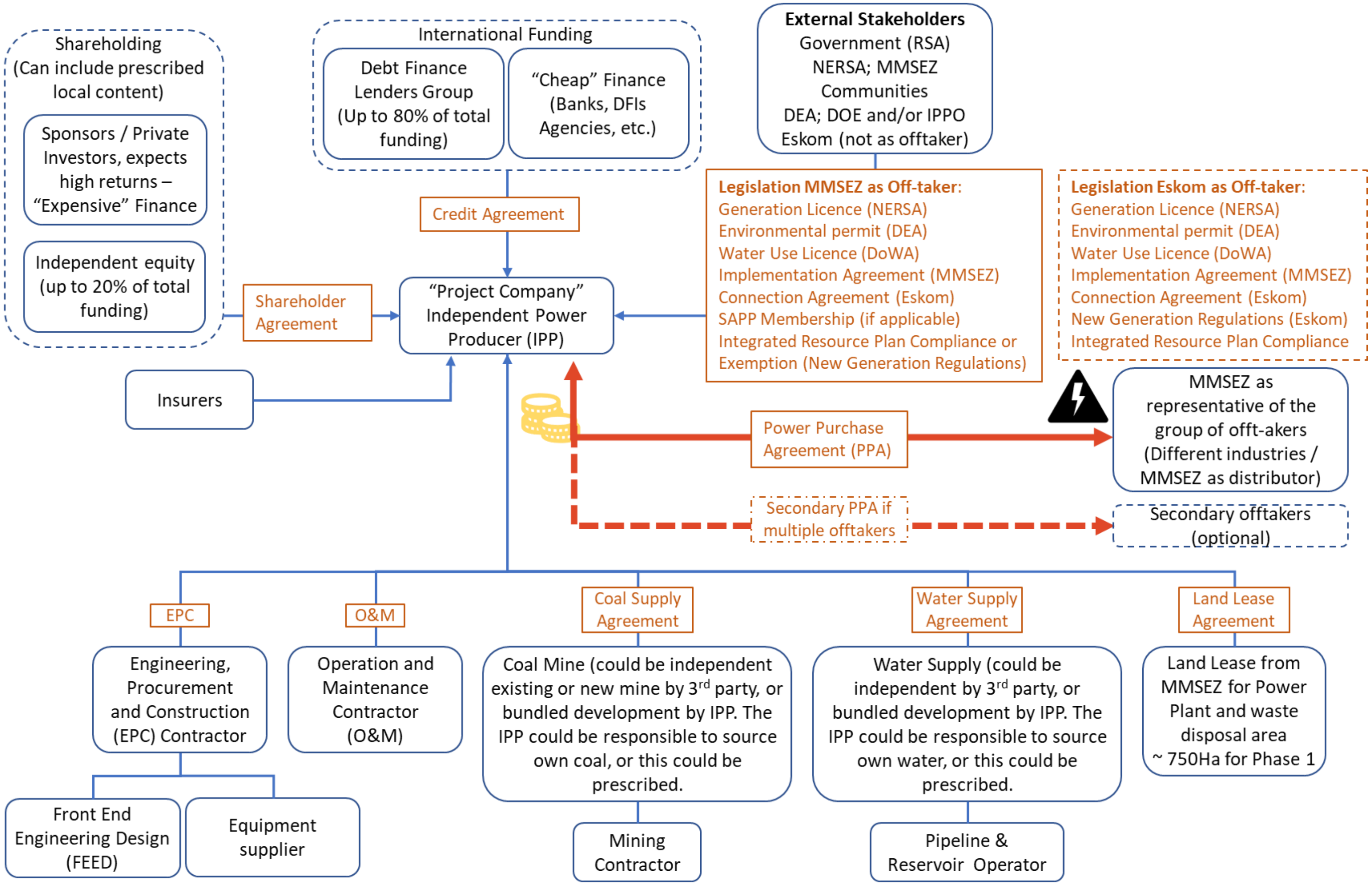

FIGURE 8: IPP OWNERSHIP MODEL STAKEHOLDERS AND CONTRACTS

7 PROPOSED PLANT SIZE

According to the MMSEZ master planning, the power requirement of the metallurgical cluster will be divided into two phases – construction and operation phases. This master plan states that during construction of the metallurgical zone, maximum power demand will be approximately 10MVA. This does not make sense, as construction power required for large metallurgical cluster development and the construction of the power plant will have to happen simultaneously and will require much larger supply than 10MVA. The Master Plan is also not clear on final power demand of the cluster, and sizing of the power plant.

From discussion with the MMSEZ and understanding of the initial developments planned at the metallurgical cluster, the power plant size will be based on a phased approach.

Phase 1: installation of first 2 x 660MW units

Phase 2: installation of additional 2 x 660MW units (depending on local, Eskom and Regional demand)

This study is focusing on the first 2x660MW power plant development, to supply "Own Generation" to the MMSEZ.

It is currently advised to limit the development to this phased approached and initial size to 1320MW installed capacity. This will allow for approximately 1175MW to be available for supply to off-takers (11% auxiliary load) within the MMSEZ area.

This initial size selection is based on the following considerations:

- Currently the South African Government's Integrated Resource Plan (IRP) allows for 2 x 750MW (2023 and 2027 respectively) new additional capacity coal generation (not yet finally allocated according to our knowledge) and 5732MW committed/ already contracted additional coal generation (Kusile and Medupi completion). In addition, the IRP includes a further amount of 2000MW (2019-2022) under "other" for "Distributed Generation, Co-gen, Bio mass and Landfill". While it was thought that this would primarily relate to small-scale technologies to produce electricity close to the end users of power, NERSA recently approved a section 34 Ministerial determination that this power would now be procured by the Department of Minerals Resources and Energy (DMRE) from various sources and that Eskom would be the off-taker. Accordingly, this is no longer available for use by MMSEZ or other developers.
- Licensing – Given the proposed installed capacity of the facility, a generation licence is required from NERSA under the Electricity Regulation Act, 2006 (small generation facilities <1MW that are grid connected do not need a licence but may be registered). Such a licence *inter alia* requires compliance to the IRP, or if not compliant, requires Ministerial approval to deviate therefrom. Whilst a draft determination has been made by the Minister in March 2020 to allocate the 2x750 MW available coal generation in the IRP to be procured

by DMRE with Eskom as the off-taker, our current understanding is that pending NERSA;s concurrence with the Minister that the facility could effectively fall within the "allowed" allocation for coal generation(i.e. the allocated 2x750MW in the IRP). The proposed 2x660MW units could be seen to be within the broader parameters of the IRP and it may hence not be necessary to request Ministerial deviation if NERSA shares this view (and of course if the "available" IRP capacity is not otherwise finally allocated to Eskom in terms of the draft Ministerial determination to this effect). It should be noted that given the intent and purposes of the IRP (i.e. to pre-determine South Africa's new generation capacity and technologies for the periods set out therein), deviation is not impossible, but is not given lightly either.

- While sales to Eskom may seem inherently attractive from a developer's perspective, there are various aspects that need careful consideration. These include:
  - All Eskom procurement for new generation is subject to the New Generation Regulations (published under the Electricity Regulation Act) that requires a Ministerial determination under section 34 of that Act. All procurement under a section 34 Ministerial determination is done in a competitive manner, i.e. unsolicited bids (which this project would be) are not catered for.
  - Eskom's current financial position is not as potentially attractive nor as secure as potential large industrial off-takers. Eskom sits with a large debt burden, aging and failing infrastructure, tariffs that are by their own admission not cost reflective and struggles with management and governance issues. It is also uncertain to what extent Government would be willing or even able to guarantee Eskom PPA obligations given its recent track history with other state-owned organisations and Governments own fiscal challenges. As such it is thus unlikely that a bankable PPA would be able to be concluded on a normal project financing basis and even if a PPA is concluded, what its longer-term viability would be.
- Impact on environment
- Economies of scale vs bankability
- Available coal reserve (approximately 165,434,000 tonnes of coal will be required to fuel a 1320MW power plant for 30 years)

8 NATIONAL LEGISLATIVE COMPLIANCE REQUIREMENTS

8.1 THE INTEGRATED RESOURCE PLAN

The Integrated Resource Plan is an electricity infrastructure development plan for South Africa based on a least-cost electricity supply and demand balance, considering security of supply and environmental considerations.

In essence, it aims to provide an indication of the country's electricity demand, how and when this demand will be supplied, and what it will cost.

In principle, all new generation capacity in South Africa is subject to the Integrated Resource Plan (IRP), which is amended from time to time. Some smaller exemptions are allowed (i.e. smaller own generation between 1MW and 10MW was allowed in the past from IRP compliance), and the Minister may also allow deviations on a case to case basis, although this seldom happens.

Compliance is *de facto* enforced via the requirement that applicants have to show adherence to the IRP before a generation licence is issued by the National Energy Regulator (NERSA).

	Coal	Coal (Decom)	Nuclear	Hydro	Storage	PV	Wind	CSP	Gas/ Diesel	Other
Base	37149.0		1860.0	2100.0	2912.0	1474.0	1980.0	300.0	3830.0	499.0
2019	2155.0	-2373.0					244.0	300.0		Allocation to the extent of the short term capacity and energy gap
2020	1433.0	-557.0				114.0	300.0			
2021	1433.0	-1403.0				300.0	818.0			
2022	711.0	-844.0			513.0	1400.0	1600.0			
2023	750.0	-555.0				1000.0	1600.0			500.0
2024			1860.0				1600.0		1000.0	500.0
2025						1000.0	1600.0			500.0
2026		-1219.0					1600.0			500.0
2027	750.0	-847.0					1600.0		2000.0	500.0
2028		-475.0				1000.0	1600.0			500.0
2029		-1694.0			1575.0	1000.0	1600.0			500.0
2030		-1050.0		2500.0		1000.0	1600.0			500.0
Total Installed Capacity by 2030 (MW)	33364.0		1860.0	4600.0	5000.0	8288.0	17742.0	600.0	6380.0	
% Total Installed Capacity by 2030 (% of MWh)	43.0%		2.4%	5.8%	6.4%	10.5%	22.5%	0.8%	8.1%	
% Annual Energy Contribution (% of MWh)	58.8%		4.5%	8.4%	1.2%*	6.3%	17.8%	0.6%	1.3%	

- Installed Capacity
- Committed/Already Contracted Capacity
- New Additional Capacity
- Capacity Decommissioned
- Extension of Koeberg Plant Design Life
- Includes Distributed Generation Capacity for own use

FIGURE 9: INTEGRATED RESOURCE PLAN (2019)

8.2 THE NEW GENERATION REGULATIONS

The New Generation Regulations govern the procurement of new generation by "organs of state", which includes entities such as Eskom. A recent proposed amendment to the regulations will also make the regulations applicable to Municipalities. Both Eskom and Municipalities would thus need to comply to the regulations in the procurement of any new generation.

The regulations are directly linked to section 34 of the Electricity Regulation Act, as it requires that the Minister makes a Ministerial determination setting out exactly how such new generation should be procured through a competitive procurement process[4].

In the case of the recent Renewable Energy Independent Power Producer Program (REIPP), procurement was channelled through the IPP Office under the auspices of the Department of Energy and the resultant agreements assigned to Eskom. Direct procurement (e.g. between Eskom and an IPP) is also possible, but in all cases section 34 clearly requires a competitive procurement process.

An issue that considers serious consideration is if MMSEZ also qualifies as an "organ of state". Should this be the case, procurement of an IPP for MMSEZ would automatically require compliance to the New Generation Regulations, which in turn means that a Ministerial determination under section 34 of the Electricity Regulation Act is a prerequisite that will in turn set out in detail how such procurement must be done.

8.3 SECTION 34 DETERMINATIONS

Under section 34 of the Energy Regulation Act, the Minister of Energy, in consultation with NERSA, by notice in the *Gazette* determines when new generation is needed in order to ensure the continued uninterrupted supply of electricity in the country.

In terms of such a notice, the Minister may *inter alia* –

(a) determine the types of energy sources from which the electricity must be generated;

(c) determine that electricity may only be sold to the persons or in the manner set out in the notice;

(d) determine that electricity produced must be purchased by the persons set out in the notice;

(e) require that new generation capacity must-

[4] Typically via the Department of Mineral Resources and Energy and its associated offices, e.g. the IPP Office.

(i) be established through a tendering procedure which is fair, equitable, transparent, competitive and cost-effective; and

(ii) provide for private sector participation.

It should be noted that NERSA has to concur with section 34 determinations, i.e. such a determination is not binding until such time as NERSA agrees thereto.

Whilst section 34 is closely linked to the New Generation Regulations and purchases of new generation by "organs of state" such as Eskom, it is not so clear if a Ministerial determination would also be needed for the generation and sale of electricity between non-state (private) enterprises, for example between an IPP and a large private sector customer.

It is our view that this is not the case as the Energy Regulation Act does not require section 34 determinations as a pre-requisite for the issuing of a generation licence – it only refers to compliance to the IRP.

However, once a Ministerial determination is made and NERSA agrees with it, the determination becomes binding for the type and quantum of generation set out in the determination (section 34) notice and the related available capacity in the IRP is thus also allocated or "taken up".

As an example, the IRP 2019 does not in itself specify how the 2x750MW coal allocation should be procured and who should be involved as seller or buyer. In theory the IRP allocation could thus be "claimed" by MMSEZ in the absence of a Ministerial determination (and assuming MMSEZ is not an "organ of state"). In turn, as soon as a Ministerial determination is made that specifies otherwise the opportunity for own generation by MMSEZ would fall away.

On 18 February 2020 the Minister of Energy indeed published a section 34 determination that *inter alia* states that the 2x750MW allocation for coal for the years 2023 to 2027 should be procured by DMRE and that Eskom should be the buyer of the power under a competitive procurement process. NERSA has requested stakeholders to comment on the draft determination and it is expected that its final views should be forthcoming towards the end of July – beginning of August 2020.

Accordingly, the opportunity for and MMSEZ IPP would fall away should NERSA concur with the determination, and consequently a deviation from the IRP would then be required to obtain a generation licence(Unless the IPP would want to partake in the competitive procurement process and sell to Eskom – but that would imply that the capacity is no longer available directly for sale to large industrial customers within the MMEZ area, but only to Eskom – which is not the purpose of the exercise).

As noted, if MMSEZ or its agents are deemed "organs of state", the binding nature of the New Generation Regulations would also require a Ministerial section 34 determination that would then set out how the power should be procured as part of a competitive procurement process.

8.4 LICENSING

In many jurisdictions, own generation does not require licensing or allows for a simplified process such as registration. This used to be case in South Africa, but since 2017 all own generation that are grid connected also requires a licence. The latest amendments to Schedule 2 of the Electricity Regulation Act now determine that –

(a) fully autonomous own generation (i.e. not connected to transmission or distribution at all) does not need to be licensed or registered;

(b) small generation (<1MW) connected to distribution may sell to third parties (with or without wheeling) if it is registered with NERSA (i.e. does not need a generation licence but must be registered) – these also *de facto* do not need to comply to the IRP as no licence is issued for which IRP compliance needs to be shown;

(c) co-generation may wheel to a related customer ("related" as defined in the Companies Act)

Following from the above, MMSEZ would not fall into any of these categories and hence any generation in MMSEZ would need to be licensed, be it for distributed generation (e.g. sales to MMSEZ for on-selling to industrial customers and/or direct sales to industrial customers), or for sales to third parties (e.g. PPA with Eskom).

The licensing process covers generation, transmission, distribution, sales, import and exports and is set out in the Electricity Regulation Act, read with the licence application regulations published thereunder. Key to the licensing process is that the applicant needs to show compliance to the IRP, or Ministerial approval to deviate.[5]

Prospective applicants are encouraged to discuss proposed applications with NERSA prior to formally applying for a licence.

For a generation licence (IPP), the following shows a broad oversight of the licensing process and documentary requirements that have to be met before a licence will be issued.

[5] Should the draft Ministerial determination be accepted that allocate 2x750MW to Eskom, the MMSEZ IPP would thus need a formal Ministerial deviation from compliance to the IRP.

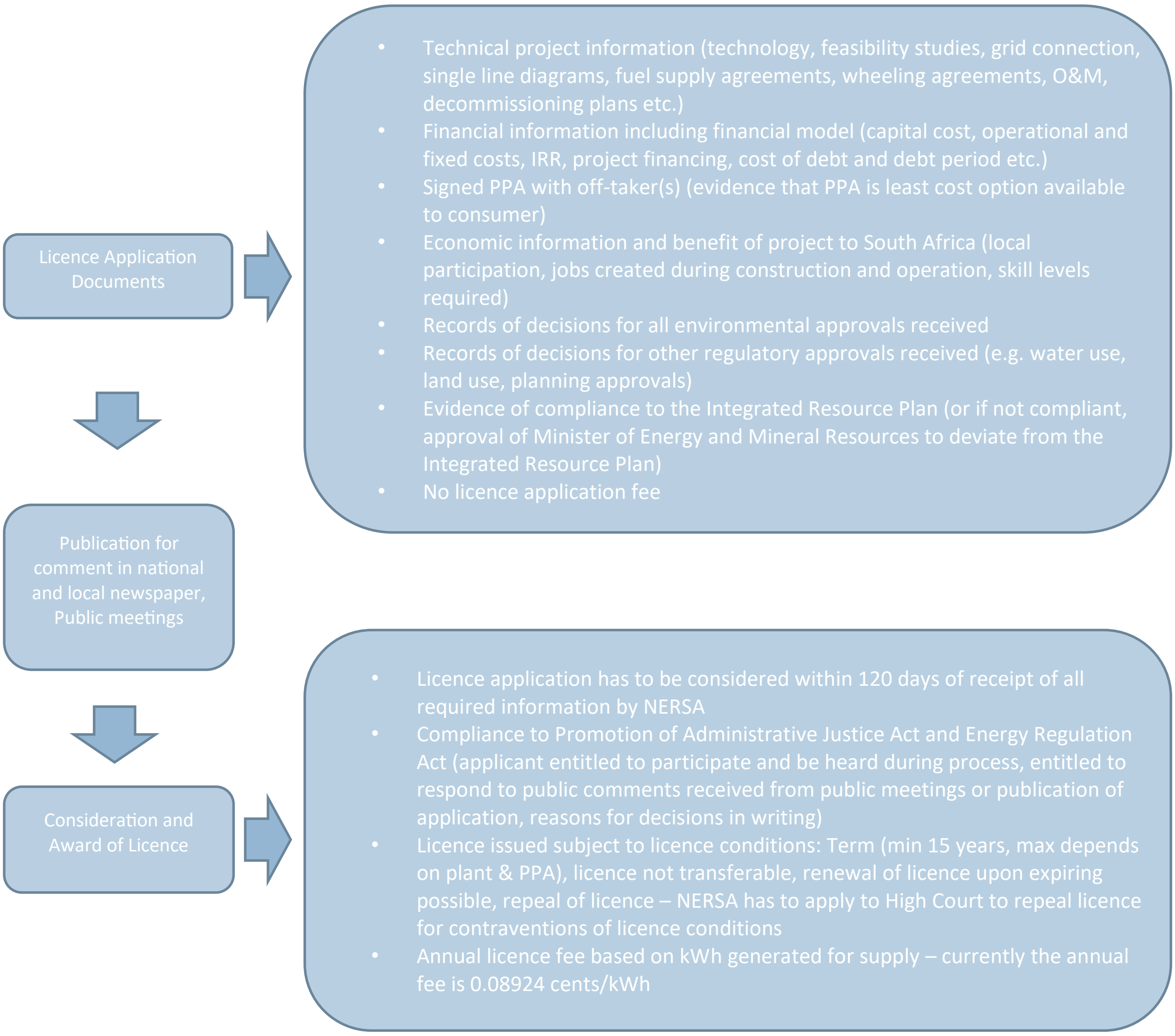

FIGURE 10: NERSA LICENSING

8.5 INTERRELATION BETWEEN IRP, SECTION 34 AND LICENSING

The interaction between the IRP, New Generation Regulation Regulations, section 34 determinations and licensing may seem complicated and must be viewed holistically. Each of these are addressed in the above sections, but to summarise the most important aspects[6], the following observations can be made:

1. All generation requires licences under the Electricity Regulation Act, except for

[6] There are further activities in terms of Schedule 2 of the Electricity Regulation Act that may escape licensing but these are not relevant for MMSEZ.

- autonomous (not connected to the grid at all) own generation that does not need a licence;
- very small generation (<1MW) can be registered instead of licensed; and
- co-generation can be registered (with or without wheeling of electricity) and supply of electricity to a related company

In effect it means that all other IPPs (whether for own use or not) must hold a generation licence. Accordingly, the MMSEZ IPP will need a generation licence.

2. All new generation must comply to the IRP in order to be issued with a license, or otherwise needs an exemption from IRP compliance from the Minister of Energy. This is a legal requirement under the Electricity Regulation Act. Whilst it is possible to get such exemptions in theory, in practice this has not often happened.
3. All "organs of state" must procure new generation in accordance with the New Generation Regulations. These regulations also determine that the Minister may make a section 34 determination as to how such new generation will be procured. If MMSEZ or its agents are viewed as "organs of state", it will be bound to these regulations and the subsequent section 34 Ministerial determination which will prescribe how the new generation is to be procured via a competitive procurement process.
4. Section 34 determinations set out the type of new generation to be procured, the quantum to be procured, the time periods in which this must happen, the buyers and the sellers, and the competitive process to be followed. Whilst these determinations do not apply to private (i.e. non-state) procurement *per se*, it does affect private transactions as determinations are linked to the IRP and hence "takes up" the relevant allocated generation (be it for own generation or otherwise). The Minister has made a determination in February 2020 that allocates the 2x750MW "available" in the IRP 2019 via a competitive process to Eskom as the off-taker. Should NERSA concur, this 2x750MW would hence no longer be available for use by MMSEZ.
5. MMSEZ is closely linked to Government and hence in the Consultant's view would need to take heed of the New Generation Regulations and its potential impact. If these regulations indeed apply to MMSEZ, it would require a section 34 Ministerial determination, a Ministerial exemption from complying to the IRP (assuming NERSA concurs with the current Ministerial determination that already allocates the available 2x750MW to another process as mentioned), and a resultant competitive procurement process in order for MMSEZ to procure new generation.

This interrelation/interdependence between the different instruments is illustrated below.

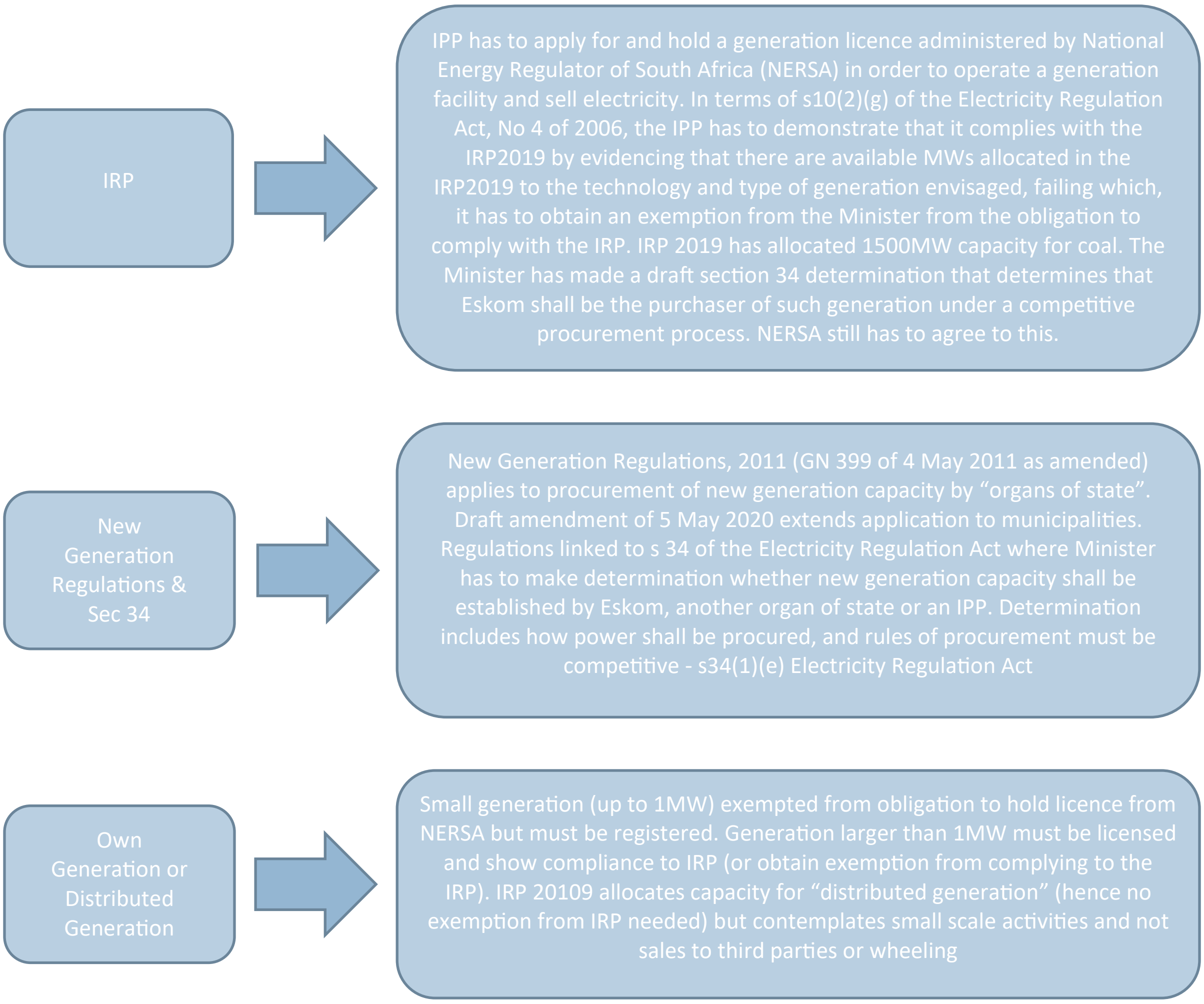

FIGURE 11 IRP, LICENSING, SEC 34

8.6 ENVIRONMENTAL REQUIREMENTS AND LEGISLATION

The key South African environmental legislation to which a coal-fired power station will have to comply is summarised in Table 8.1.

TABLE 8.1 KEY SOUTH AFRICAN ENVIRONMENTAL LEGAL REQUIREMENTS

Act and/ or Regulations	Requirements	Required authorisations
6. National Environmental Management Act, 1998 (Act no. 107 of 1998) *Environmental Impact*	The National Environmental Management Act, 1998 (NEMA), through the EIA regulations (GN Numbers R 983 to 985 of 2014) require the undertaking of Environmental Impact Assessment or Basic Assessments for a range of different activities identified in the listing notices. The applicable listed activities depend on the nature of the affected environment and the nature of the activity. An	Environmental Authorisation

Act and/ or Regulations	Requirements	Required authorisations
Assessment (EIA) regulations, 2014	Environmental Authorisation (EA) has to be obtained before the commencement of construction of such an activity. The legislated time frame for a Scoping and EIA process is 300 to 350 calendar days (excluding specialist studies, which can be started before the official start of the EIA process). In the case of a coal-fired power station, the required Scoping and EIA process can be expected to be long, due to the controversial nature of coal-fired power. Refer in this regard to the challenges such as appeals experienced with the EIAs for the Thabametsi and Khanyisa coal-fired power stations (Section5.1). In a case brought by Earthlife Africa Johannesburg against the Minister of Environment and others, regarding the Environmental Authorization for Thabametsi, the court found in favour of the plaintiff and required the following as part of its EIA: a. "A climate change impact assessment is necessary and relevant to ensuring that the proposed coal-fired power station fits South Africa's peak, plateau and decline trajectory as outlined in the [nationally determined contribution] and its commitment to build cleaner and more efficient than existing power stations" b. "A climate change impact assessment in relation to the construction of a coal fire *(sic)* power station ordinarily would comprise an assessment of: i. the extent to which a proposed coal-fired power station will contribute to climate change over its lifetime, by quantifying its GHG emissions during construction, operation and decommissioning; ii. the resilience of the coal-fired power station to climate change, taking into account how climate change will impact on its operation, through factors such as rising temperatures, diminishing water supply, and extreme weather patterns; and iii. how these impacts may be avoided, mitigated, or remedied"	

Act and/ or Regulations	Requirements	Required authorisations
7. National Environmental Management: Air Quality Act, 2004 (Act No. 39 of 2004). *Notices 710 & 712 of 2017: Declaration of Greenhouse Gases as Priority Air Pollutants and National Pollution prevention plans regulations.* *National Greenhouse Gases emission reporting regulations: Notice No. 275 of 2017.*	The National Environmental Management: Air Quality Act, 2004 (NEM: AQA) requires obtaining Atmospheric Emission Licenses (AELs) for any of several different processes identified in Regulation 983 of 2013). This regulation lists 10 categories of listed activities that require AEL's including Category 1 (Combustion Installations), which would apply to a coal-fired power station. Any person conducting a process defined in Annexure A to Declaration of Greenhouse Gases as Priority Air Pollutants must prepare a Pollution Prevention Plan (PPP) for any process that emits more than the 0.1 Megatonnes (Mt) of greenhouse gases annually (reported as carbon dioxide equivalents (CO_2-eq)). PPPs mush cover periods of five calendar years. Progress reports of PPPs must be submitted annually. Annexure A includes Electricity Production as such a process. Any person in control of or conducting an activity specified in Annexure 1 to the regulations above the specified threshold must register all facilities where the activities exceed the threshold within 30 days after commencing such an activity. Annually, by 31 March of each year, such a person must submit the greenhouse gas emissions and activity data as set out in the Technical Guidelines for Monitoring, Reporting and Verification of Greenhouse Gas Emissions by Industry for each of the relevant greenhouse gases emitted in all of its facilities. Electricity production from installations with total capacity of 10 MW(thermal) is one of the activities included in Annexure 1 of the regulations.	a. Atmospheric Emission License b. Approval of a Pollution Prevention Plan
8. National Environmental Management: Waste Act, 2008 (Act No. 59 of 2008) *Waste Management Activities (Notice no. R 921 of 2014)*	The National Environmental Management: Waste Act, 2008 (Act No. 59 of 2008) (NEM:WA) requires the licensing of various waste management and disposal facilities through Waste Management Licenses (WMLs). The Waste Management Activities for which WML are required are defined in the List of Waste Management Activities that have, or are likely to have, a Detrimental Effect on the Environment (Notice no. R 921 of 2014). The assessment of the environmental impacts of these activities can be integrated with the EIA process above. Depending on the applicable licensing authority, an integrated EA, including Management Activities, can be obtained.	a. Waste Management License b. Waste classification c. Waste assessment d. Classification of ash dams

Act and/ or Regulations	Requirements	Required authorisations
Waste Classification and Management Regulations, 2013 (Notice No. R 634 of 2013) *Norms and Standards for Assessment of Waste for Landfill Disposal (Notice No. R. 635 of 2013)* *National Norms and Standards for Disposal of Waste to landfill (Notice No. R. 636 of 2013)*	Three categories (A, B and C) of activities are defined. Category A and B activities respectively require Basic Assessments and Scoping and EIA processes in terms of the EIA regulations. Category C activities do not require any form of licensing but must comply with defined norms and standards. The ash dams for the power station will require the following authorisations: ▪ Waste Management License in terms of NEM:WA ▪ Waste classification in terms of the Waste Classification and Management Regulations (WCMR) GN R. 634 of 2013 ▪ A waste assessment in terms of the Norms and Standards for Assessment of Waste for Landfill Disposal (GN R.635 of 2013) ▪ Classification of the ash dams in terms of the National Norms and Standards for Disposal of Waste to landfill (GN R. 636 of 2013) Furthermore, the ash dam design also needs to comply with the last-mentioned regulations.	
National Water Act, 1998 (Act No. 36 of 1998)	Section 21 of the National Water Act, 1998 (NWA) identifies several activities that affect water resources as Water Uses, for which Water Use Licenses or General Authorisations are required. The Water Uses that may apply depend of the location of the proposed power station relative to wetlands, watercourse and other freshwater features on the site. It is likely that the Department of Water and Sanitation will require the preparation of an Integrated Water and Waste Management Plan (IWWMP) for the power station and its associated infrastructure, including the ash dams, coal stockpiles, etc.	a. Water Use License or General Authorisation b. IWWMP
National Forests Act, 1998 (Act No. 84 of 1998) Notice 908 of 2014	Notice no. 908 of 2014 (List of Protected Tree Species) under the National Forests Act (NFA) lists 47 trees species that are protected in South Africa. Such trees may not be removed or damaged in any way without a permit issued by the	Tree removal permit

Act and/ or Regulations	Requirements	Required authorisations
(Protected Tree Species)	Department of Environment, Forestry and Fisheries (DEFF). Even fairly common trees like Marula *Sclerocarya birrea* subsp. *caffra* are listed, and a number of other species on the list are likely to occur on the site e.g: • Baobab *Adansonia digitata* • Shepherd's Tree *Boscia albitrunca*. • Leadwood *Combretum imberbe*. Thus, the power plant will need to comply with this act to be allowed to clear / prepare land for construction.	
National Heritage Resource Act, 1999 (Act No. 25 of 1999) The National Heritage Act Regulations (Notice No. R 548 of 2000)	According to Section 38(1)(Heritage Resources Management) of the National Heritage Resources Act, 1999 (NHRA) certain specified activities require a Heritage Impact Assessment (HIA), which must comply with specified standards and be submitted to the relevant provincial heritage management authority and / or the SA National Heritage Resource Agency (SAHRA). Section 38(8) of the NHRA provides for the integration of an HIA in the EIA process. The activities that require an HIA include those such as changing the character of a site larger than 5,000 m2 (0.5 ha) or re-zoning of a site larger than 10,000 m2 (1 ha). Depending on the risk of the occurrence of fossils, as defined by SAHRA's "PalaeoSensitivity Map", the HIA must include a desktop or site-based Palaeontological Impact Assessment. The National Heritage Act Regulations (Notice No. R 548 of 2000) specifies procedures for the permitting of certain activities e.g. excavations and demolitions of historical buildings. In this respect, it must be noted that all buildings older than 60 years are protected by the NHRA. If graves are found on the site and they need to be relocated, the grave relocation process must be conducted in terms of the "Procedure for consultation regarding burial	SAHRA approval of HIA Permit (as necessary)

Act and/ or Regulations	Requirements	Required authorisations
	grounds and graves" (Chapter XI of the National Heritage Act Regulations).[7]	
Limpopo Environmental Management Act, 2003 (Act No. 7 of 2003)	The Limpopo Environmental Management Act (LEMA) provides for the protected of several classes of animals and plants that are indigenous to the province, including Specially Protected Wild Animals (Schedule 2), (Protected Wild Animals (Schedule 3), Specially Protected Plants (Schedule 11) and Protected Plants (Schedule 12). In general, if any such plants need to be relocated or destroyed to accommodate the proposed power station, permits will need to be obtained from the provincial nature conservation authority.	Permits for destruction or relocation of protected species
Rezoning	Zoning of land is local government competence under the South African Constitution and each local government is required to have its own zoning plans. In parallel to environmental authorisations named above, the applicable local government must approve the rezoning of the land from its current use (probably Agriculture) to an appropriate zoning.	Zoning certificate

The key environmental and social requirements of the International Finance Corporation (IFC) to which a coal-fired power station will have to comply, as outlined in the IFC Performance Standards, are summarised in Table 8.2. World Bank requirements would apply if a loan is provided to the South African government.

TABLE 8.2 KEY IFC PERFORMANCE STANDARD (PS) REQUIREMENTS

PS	Requirement	Applicability
PS1: Assessment and Management of Environmental	This PS relates to integrating and managing environmental and social performance throughout the life of a project in line with national regulations and international standards. The standard requires the undertaking of an Environmental and Social Impact Assessment (ESIA) and the development of an Environmental and Social Management System (ESMS) which	Applicable – the client will need to undertake an ESIA and develop an ESMS.

[7] Regulations Relating to the Management of Human Remains (Regulation NO. R 363 of 2013) under the National Health Act, 2013 would also apply to re-internment of human remains.

PS	Requirement	Applicability
and Social Risks and Impacts	requires a structured approach to managing environmental and social risks and impacts.	
PS2: Labour and Working Conditions	This PS aims to ensure that developers establish, maintain and improve worker-management relationships that promote fair treatment, non-discrimination and equal opportunity of workers, and compliance with national labour and employment laws and international standards (as defined by the International Labour Organisation, ILO). Specifically, PS2 addresses child labour and forced labour, and promotes safe and healthy working conditions, and protecting and promoting the health of workers.	Applicable, particularly for a large construction project such as a power station.
PS 3: Resource Efficiency and Pollution Prevention	This PS aims to abate pollution to air, water, and land that may threaten people and the environment at the local, regional, and global levels. This PS requires project developers to consider and implement feasible resource efficiency and pollution prevention principles and initiatives that avoid or minimize, as far as possible, adverse impacts on human health and the environment. The resource efficiency requirements in this PS deal specifically with greenhouse gas emissions. They require that for any new project, direct annual GHG emissions from the physical boundary of the project (Scope 1) as well as any indirect GHG emissions from purchased power and heat (Scope 2) be determined, and if the sum of these emissions exceed 25,000 tCO_2-equivalent per annum, annual GHG emissions must be determined during the operation of the project and be publicly disclosed. It also requires that options to reduce project-related GHG emissions be assessed and adopted during the design and operation of the project.	Applicable: 1. A GHG emissions and mitigation assessment required. 2. Annual GHG reporting required if the project's GHG emissions exceed 25,000 tCO_2-e per annum
PS 4: Community, Health, Safety and Security	The aim of this PS is to anticipate and avoid adverse impacts on the health and safety of the affected communities throughout the life of the project because of routine and none routine events of the project. The PS also requires an assessment of how the use of security by the project, to safeguard personnel and property, could impact on community security, with consideration of human rights.	Applicable to any project such as this where the health and safety of communities around the project may be affected.
PS5: Land Acquisition and	PS5 aims to anticipate and avoid physical and economic resettlement or, where avoidance is not possible, to minimise	Applicable particularly if involuntary

PS	Requirement	Applicability
Involuntary Resettlement	adverse social and economic impacts of economic and physical displacement.	resettlement will apply to the project.
PS6: Biodiversity Conservation and Sustainable Management of Living Natural Resources	This PS aims to protect and conserve biodiversity based on the Convention on Biological Diversity. It divides habitat into three categories: modified, natural, and critical. For projects in natural habitat, mitigation measures should be designed to achieve no net loss of biodiversity where feasible. Critical habitats should be avoided, but projects impacting critical habitats must have mitigation strategy described in a Biodiversity Action Plan, which is designed to achieve net gains of those biodiversity values for which the critical habitat was designated. Projects impacting protected areas must demonstrate that they are legally permitted there, consult protected area sponsors and implement plans according to government recognized management plans that enhance the local conservation aims.	If the project will be undertaken on natural habitat, an appropriate biodiversity impact assessment needs to form part of the EIA.
PS7: Cultural Heritage	Cultural heritage, according to this PS, refers to tangible forms of cultural heritage, such as tangible movable or immovable objects, property, sites, structures, or groups of structures, having archaeological (prehistoric), paleontological, historical, cultural, artistic, and religious values; unique natural features or tangible objects that embody cultural values, such as sacred groves, rocks, lakes, and waterfalls; and certain instances of intangible forms of culture that are proposed to be used for commercial purposes, such as cultural knowledge, innovations, and practices of communities embodying traditional lifestyles.	The applicability of this PS will depend on the findings of the Heritage Impact Assessment, to be undertaken as part of the EIA.

9 INTERNATIONAL LEGISLATIVE REQUIREMENTS

9.1 IMPLICATIONS OF PARIS AGREEMENT FOR SOUTH AFRICA

In 2015, 194 countries that are Party to the United Nations Framework Convention on Climate Change (UNFCCC) agreed on a historic global climate agreement. In this agreement, known as the Paris Agreement, the parties committed to limiting average global temperature increase to "well below 2°C above pre-industrial levels", and to pursue efforts to keep the increase to no more than 1.5°C. With the publication of the Special Report on the impacts of global warming of 1.5°C above pre-industrial levels by the Intergovernmental Panel on Climate Change(IPCC) in 2018, which showed that a 1.5°C increase gives the world a much better chance of adaptation compared to 2°C increase, 1.5°C has become the global focus for climate mitigation efforts.

Articles 3 and 4 of the Paris agreement require countries to undertake and communicate ambitious efforts to contribute to towards the achievement of the 1.5°C target, and these efforts need to represent progression overtime (UNFCCC, 2015). The efforts are to be packaged in the form of nationally determined (UNFCCC, 2015) (DEA, 2019) (DoE, 2019) contributions (NDCs), which are to be submitted every five years. Each successive NDC needs reflect the country's highest possible ambition, while also reflective of each country's national circumstances.

As a party to the Paris Agreement, South Africa submitted its first NDC in August 2015, reiterating the country's intention to have its emissions following a peak, plateau and decline trajectory, peaking between 2025 and 2030 within the range of 398 and 614 MtCO2e. Under the Paris Agreement, South Africa is required to submit its second NDC that is more ambitious than the current one by the end of 2020.

In 2019 the World Resources Institute (WRI) published a report showing that the combined impact of all the first NDCs submitted under the Paris Agreement falls significantly short of limiting global warming to 1.5°C, hence there is global pressure on all countries to significantly increase ambition in their second NDCs. There is also a growing view among climate researchers that including new coal-fired capacity in new NDCs undermines the credibility of those new NDCs (Edenhofer, Steckel, Jakob, & Bertram, 2018). This is also likely to put pressure on countries like South Africa to minimize as far as possible, if not avoid, inclusion of new coal capacity in the second NDCs.

9.2 THIS PROJECT AND SOUTH AFRICA'S NEED TO COMPLY WITH THE PARIS AGREEMENT

South Africa's latest GHG inventory shows that the country's net GHG emissions were 512 MtCO2e in 2015. South Africa's GHG emissions have not grown since 2007. Over the period 2007 – 2015 the emissions have plateaued in the 516 MtCO2e region, ranging between a minimum of 509 MtCO2e in 2009 and a maximum of 527 MtCO2e 2013 (DEA, 2019). This has been due to a combination of factors including very low economic growth and implementation of various GHG mitigation within that period. The country's 3rd Biennial Update Report (BUR) to the UNFCCC shows that in 2015 alone an estimated 119 MtCO2e of GHG emissions were avoided through implementation of GHG reduction programmes (DEA, 2019).

According to the country's latest Integrated Resources Plan (IRP 2019) two other coal-fired power plants of 750 MW (2023 and 2027) in addition to Kusile and Medupi are to be commissioned between 2019 and 2030 (DoE, 2019). These will add an additional 76 MtCO2e of GHG emissions to the country's GHG inventory on annual basis. The bulk of these can, however, be offset by the decommissioning of Eskom's old power plants as per the IRP.

The decommissioning of Eskom's old power plants, however, has been somewhat of a moving target. It was planned that by the end of 2019 at least five coal power plants (Camden, Hendrina, Komati, Grootvlei and Kriel) would have been decommissioned, but as of May 2020 none have been decommissioned and no clear plans are in place for the decommissioning of these power plants. The recently experienced load-shedding and the "continued underperformance of Medupi and Kusile" will also likely contribute to the delay in decommissioning of the old power stations.

With the absence or delay in the decommissioning of Eskom's old power plants, even minimal average growth in the economy between 2021 and 2030 will certainly result in the country's emissions exceeding the 614 MtCO2e NDC target by 2030.

Table 9.1 below shows that, depending on the selected technology, the envisaged MMSEZ project will add between 6.7 and 10.9 MtCO2e to South Africa's annual GHG emission, with CFB technology plus limestone injection leading to the biggest contribution. Should Ultra-supercritical technology be utilised, this value will be to the lower range of approximately 6.8 MtCO2e per annum.

TABLE 9.1 ESTIMATED ANNUAL GHG EMISSIONS OF THE PROJECT

Technology used for self-generation	Typical efficiencies	GHG emissions	
		Emissions Intensity (tCO_2e/MWh)	Annual ($MtCO_2e$)
Integrated Gasification Combined Cycle	46%	0.75	6.7
Ultra-Supercritical Coal	45%	0.77	6.8
Supercritical coal plus FGD	41%	0.84	7.5
Underground Coal Gasification and CCGT	43%	0.81	7.2

Technology used for self-generation	Typical efficiencies	GHG emissions	
		Emissions Intensity (tCO_2e/MWh)	Annual ($MtCO_2e$)
CFB technology plus limestone injection	34%	1.23	10.9

As noted previously, South Africa's 2nd NDC, focusing on post 2030 will have to be even more ambitious than the current NDC. It therefore goes without saying that the emission target will be significantly lower than 614 MtCO2e and will most likely be based on IRP2019 while also aligned with the National Climate Change Response White Paper's requirement for the country's emissions to decline in absolute terms by 2035 at the latest.

Thus, any new coal generation capacity added to the grid from now on has the potential to compromise South Africa's chances to meet its mitigation target in the current or the next NDC.

10 NEW COAL GENERATION OPTIONS STUDY

In order to comply with environmental legislation, the following clean coal technologies were investigated:

- Integrated Gasification Combined Cycle (IGCC)
- Ultra-Supercritical Coal
- Supercritical coal plus Flue Gas Desulphurisation
- Underground Coal Gasification and Combined Cycle Gas Turbine (CCGT)
- Shale Gas via Fracking plus CCGT
- Circulating Fluidised Bed (CFB) plus limestone injection

In addition, Carbon Capture and Storage (CCS) was also investigated.

10.1 RESOURCES AVAILABLE TO NEW GENERATION

For a 2 x 660MW Clean Coal, Dry cooled power plant, the following resources are required, of which typical quantities and qualities are depicted in Table 10.1

TABLE 10.1 CLEAN COAL INPUT RESOURCES

Resource	Quality	Quantity	Availability
Coal	Average CV = 20.45 MJ/kg (HHV)	5,500,000 T/annum for 1320 MW [165,000,000 tonnes of coal over 30 years]	Mine to be developed by others. Typical Coal CV for Waterberg coal, and Heat rate for USC used
	Max Sulphur = 1.5%	This is typical Waterberg coal parameters, but exact coal specification is required for any further studies and for higher accuracy. This will prescribe sulphur treatment requirements as described in "Clean Coal Technology" sections of this report	
	Max Ash = 26%	This is typical Waterberg coal parameters, but exact coal specification is required for any further studies and for higher accuracy.	
Water	Indirect cooling Technology	4,000 - 6,000m3/day	Dry cooling technology assumed
	Direct Cooling Technology	8,000 - 12,000 m3/day	
Ash Disposal site	Wet / dry ash disposal, depending on EIA and technology	Approximately 1,400,000Tonne of ash to be stored per annum [total of 42,000,000tonnes of ash] would require approximately 180Ha of land for ash disposal	

10.2 CLEAN COAL TECHNOLOGIES

10.2.1 OVERVIEW

Around 70% of South Africa's energy demand is met by coal fired power plants. The latest revision of the Integrated Resource Plan (IRP 2019) shows that while there is an ambition for a more diversified energy mix, coal will continue to be a large contributor to the power pool going forward (~ 40% by 2030). Figure 12 below shows the expected evolution of generation sources over the next 10 years.

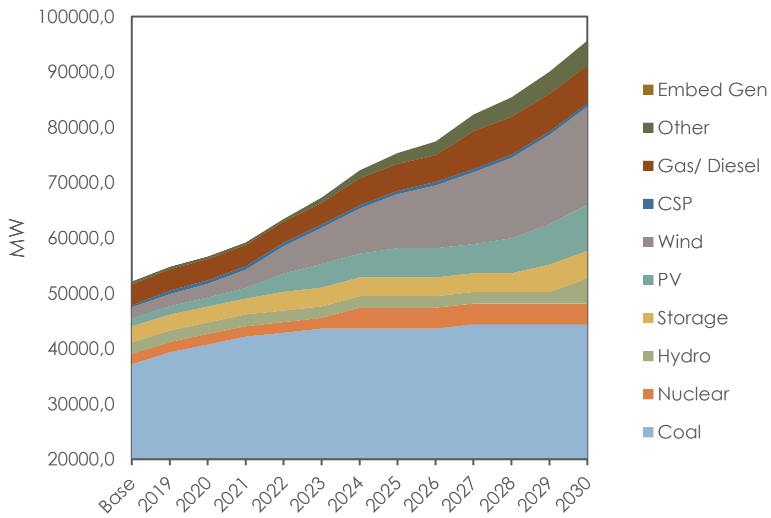

FIGURE 12: SOUTH AFRICAN ENERGY MIX TO 2030 (IRP 2019)

Although traditional coal-based power generation meets the need for cheap, continuous, "base load" power, the pollutants associated with burning coal is known to contribute to a large portion of the country's total emissions.

The development of new "clean coal" technologies allows for higher efficiencies and lower emissions and therefore reduces the overall impact on the environment. The figure below is a high-level overview of the more established clean coal combustion technologies used in industry, and how it compares to traditional subcritical pulverised coal combustion (technology used in majority of Eskom fleet). Note that data may differ depending on the data source and assumptions used.

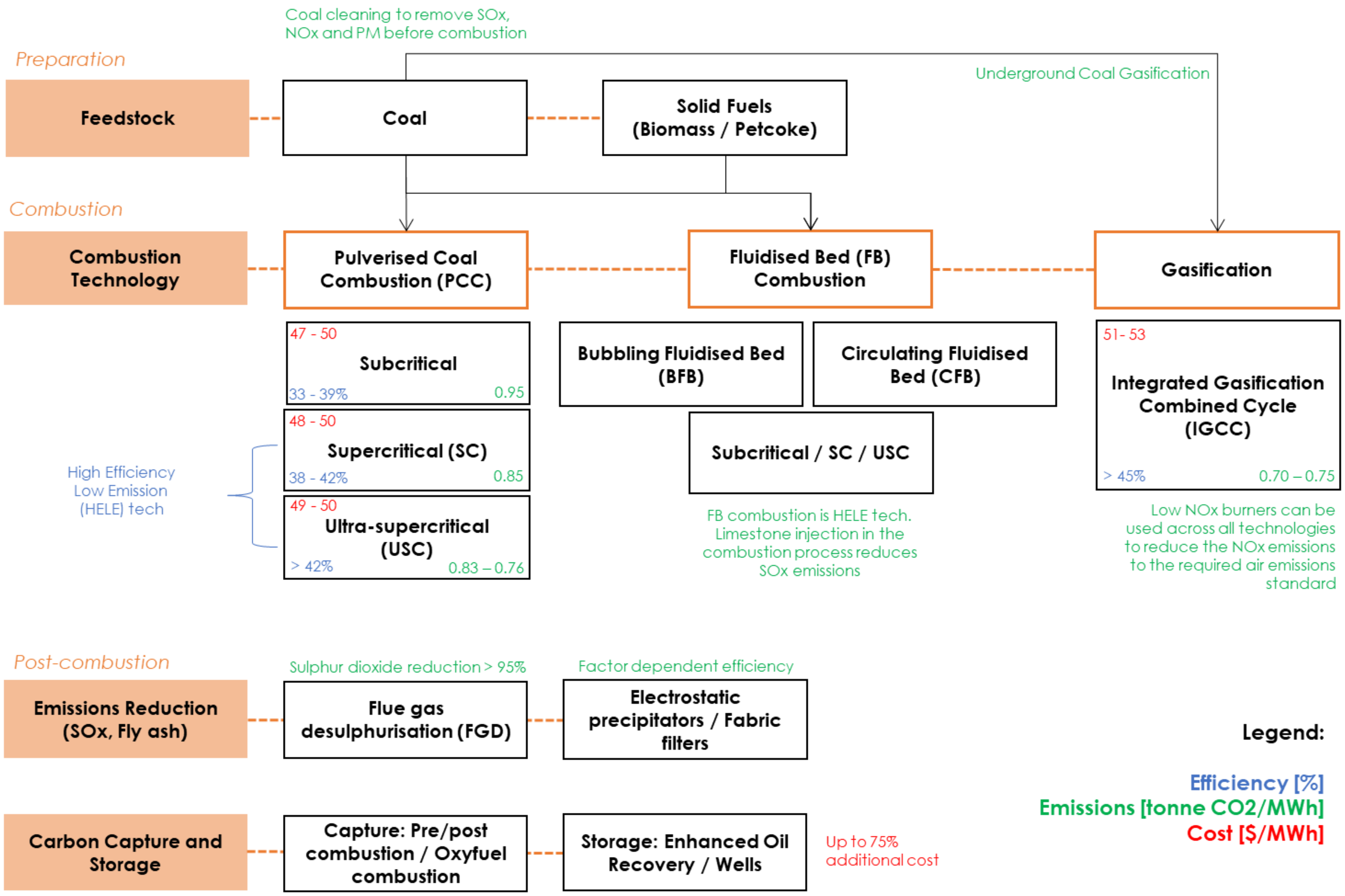

FIGURE 13: OVERVIEW OF CLEAN COAL TECHNOLOGIES

Figure 14 shows how emissions are reduced with an increasing efficiency with more refined clean coal technology (and higher CAPEX) applications. Carbon Capture and Storage (CCS) can reduce CO2 emissions by up to 90%, however the efficiency of the overall plant is reduced, and the total capital cost can increase by up to 50%, depending on the technology used.

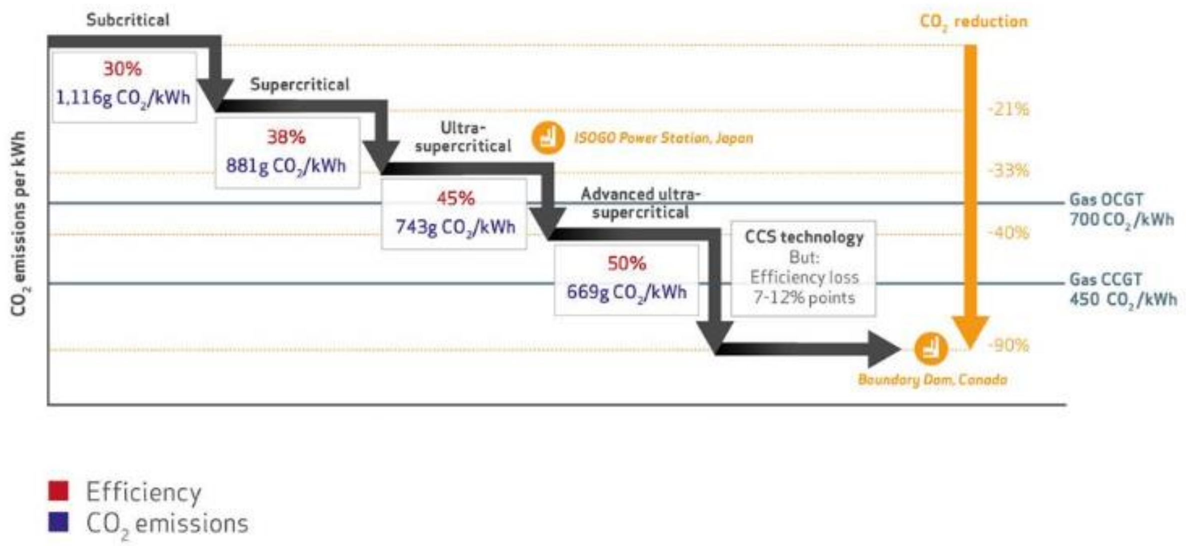

FIGURE 14:CO_2 REDUCTION POTENTIAL OF COAL-FIRED POWER PLANTS BY INCREASED EFFICIENCY (VGB POWERTECH 2013)

Unfortunately, with advancement in technology, the CAPEX and OPEX are significantly increased.

10.2.2 PULVERISED COAL COMBUSTION

Most of South Africa's ESKOM coal fleet uses sub-critical PC combustion technology. Developments over the past few years have predominantly involved increasing the plant thermal efficiencies by raising the steam pressure and temperature. The combustion can be categorised into three tiers, based on the differences in pressure and temperature. This is shown in the table below:

TABLE 10.2 OPERATING CONDITIONS OF A PC POWER PLANT

PC Power Plant	Steam pressure [MPa]	Steam temperature [°C]
Subcritical	< 22.1	< 565
Supercritical	22.1 – 25.0	540 – 580
Ultra-supercritical	> 25.0	> 580

Subcritical power plants operate at conditions below the critical point of water, which means that both the liquid and gas phases are present. These plants therefore require a steam drum at the top of the boiler to separate the phases such that only the gas phase remains. This gas is then heated further before it is sent to the turbine. The economizer's function is to pre-heat the feed water using the hot flue gas which exits the furnace.

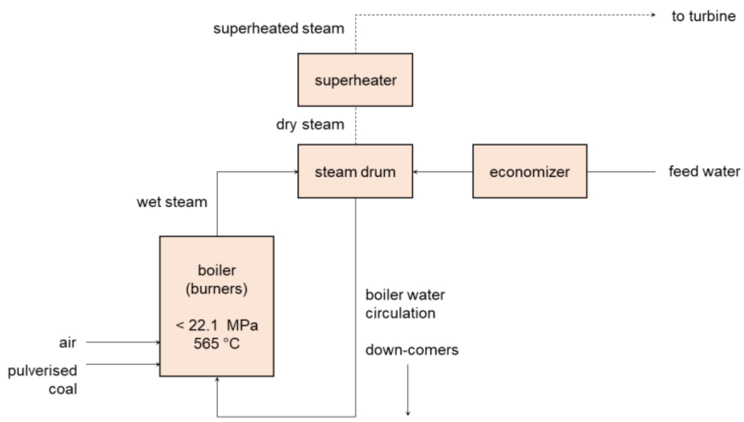

FIGURE 15: SIMPLIFIED SUBCRITICAL UNIT SHOWING STEAM CYCLE (ADAPTED: JAPAN COAL CENTER)

Supercritical (SC) and Ultra-supercritical (USC) plants operate at conditions above the critical point of water. Only the gas phase exits the boiler, so there is no need for a steam drum. SC and USC achieve higher efficiencies due to the high pressure and temperature operating conditions. As a result, these plants use less coal which result in lower CO2 emissions. The figure below shows a simplified diagram of how SC and USC units differ from subcritical units.

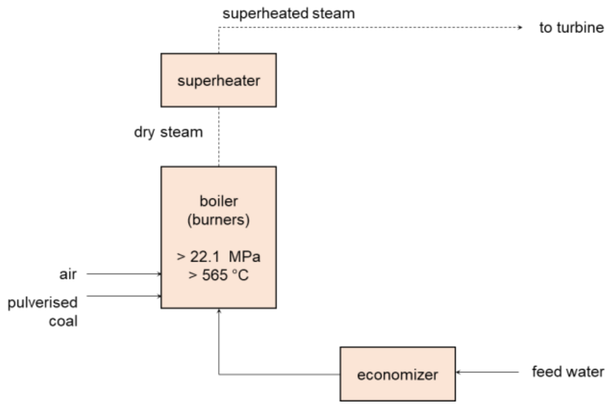

FIGURE 16: SIMPLIFIED SC/USC UNIT SHOWING STEAM CYCLE (ADAPTED: JAPAN COAL CENTER)

10.2.3 FLUIDISED BED COMBUSTION

Fluidised bed combustion (FBC) technology involves blowing air below a bed of solid fuel particles, which results in the fuel behaving like a fluid. There are primarily two types of FBC technologies used in industry – Bubbling Fluidised Beds (BFB) and Circulating Fluidised Beds (CFB). BFBs use low air speeds to keep the particles within the bed while CFBs use higher air speeds which distributes the fuel particles throughout the boiler. In a CFB, a recycle loop allows unburnt fuel particles to return to the lowest area of the burner which results in a longer fuel residence time. Higher combustion efficiencies are therefore achieved at lower operating temperatures. CFBs are also better suited to burning a wider range of solid fuels including low grade coal, petcoke and biomass.

The injection of limestone with the coal particles can reduce the sulphur dioxide emissions by up to 98%[8]. The figure below shows a simplified schematic of a CFB power plant.

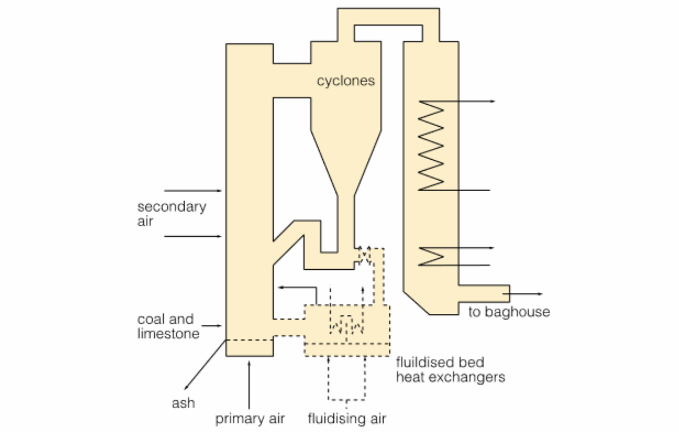

FIGURE 17: SIMPLIFIED CFB POWER PLANT(IEA)

10.2.4 INTEGRATED GASIFICATION AND COMBINED CYCLE

Integrated Gasification and Combined Cycle (IGCC) plants are a next-generation thermal power system with higher plant efficiencies and lower emissions. Synthetic gas (syngas) is produced from coal and stream and is primarily composed of carbon monoxide, hydrogen, carbon dioxide, natural gas and water vapour. The gas is cooled and cleaned before being fed to the gas turbine. Combined Cycle plants are more efficient as the process also includes a Heat Recovery Steam Generator (HRSG) which produces steam to operate a steam turbine.

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[8] GE USCFB boilers

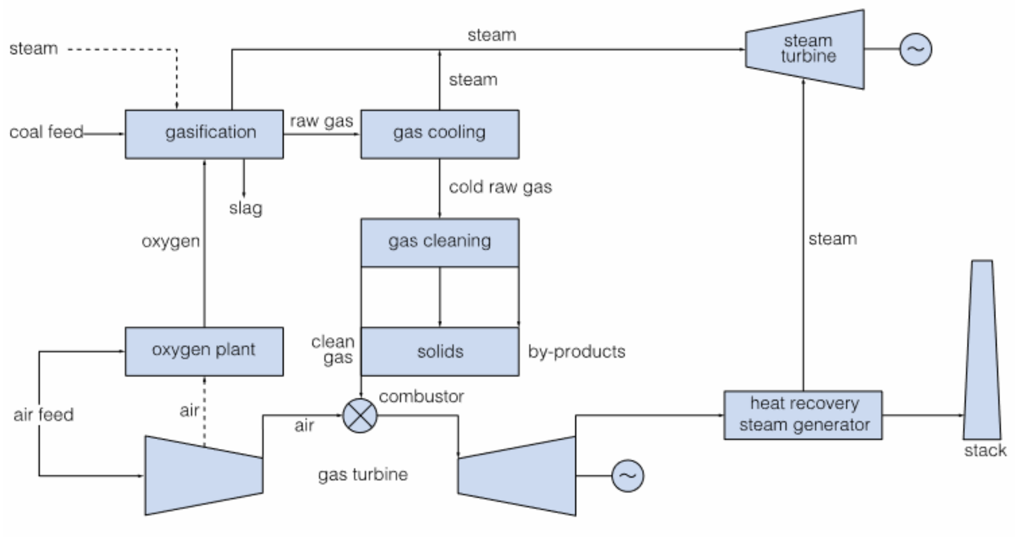


FIGURE 18: SIMPLIFIED IGCC POWER PLANT(IEA)

10.2.5 UNDERGROUND COAL GASIFICATION AND CCGT

Underground Coal Gasification (UCG) is a clean coal technology where the coal is gasified in-situ, as opposed to coal processing within the plant shown in the section above. Steam and air are injected into a drilled well leading to a coal seam, resulting in direct gasification. An underground cavity is created as the coal burns and synthetic gas is formed. The resulting gas is collected above surface, to be processed and used in a gas-fired power plant. The process avoids the need for coal mining, transport, processing, specialised equipment and the disposal of residual ash. The additional benefit is that if the gas-fired plant is equipped with CCS, the carbon dioxide can be reinjected into the wells to fill the cavity created.

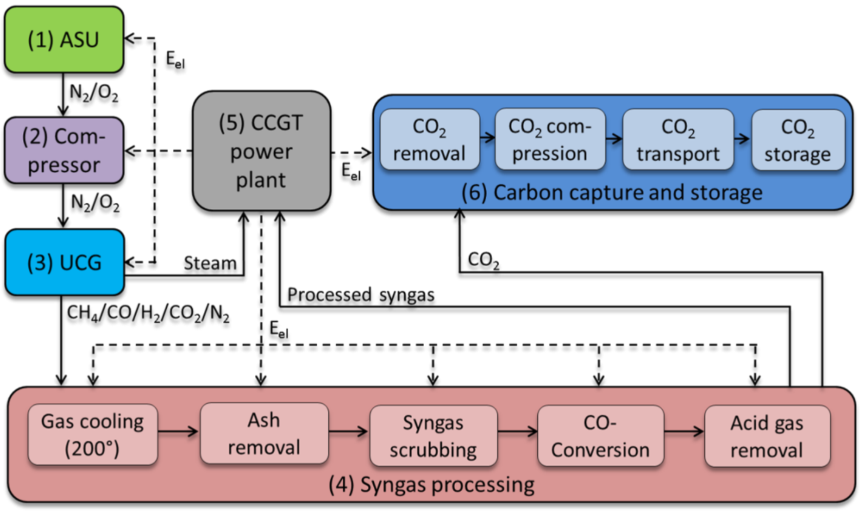


FIGURE 19: SIMPLIFIED UCG + POWER PLANT (GFZ)

10.2.6 COMPARISON OF EMISSIONS OF OLD ESKOM COAL PLANTS

Power Plant/ Technology	Capacity (MW)	Power generated / annum (MWh)	% Load Factor / Availability	Coal consumption / annum (T)	Coal efficiency (T/MWh)	kg CO2 /MWh	Annual CO2 emissions (tonne)
Eskom Grootvlei (Sub-Critical) (actual 2018 data)	1,200	3,295,218	31%	2,322,971	0.7	1,265	3,954,262
Proposed MMSEZ Ultra-supercritical proposed annual data	1,320	10,638,144	92%	4,830,000	0.45	800	8,510,515

10.4 GRID CONNECTION COMPLIANCE REQUIREMENTS

All changes or additions to the National Transmission System (TS) should follow the guidance, requirements and regulations set out in the South African Grid Code (SAGC). The SAGC establishes the reciprocal obligations for all industry participants around the use of the TS and the operation of the Interconnected Power System (IPS). The Grid Code is further enforced through the licencing requirements of the transmission service providers and participants.

The SAGC is intended to provide:

- To the NERSA, that service providers operate according to the relevant parts of their licence,
- To customers, that service providers operate transparently and provide open access to their defined services, and
- To service providers, that customers will honour their mutual Grid Code obligations and that there is industry agreement on these.

The Grid Code further consist of a Governance Code, Network Code, System Operations Code, Metering Code, Transmission Tariff Code and Information Exchange Code.

The applications for Transmission Connection is governed by The Network Code, Version 10.0, August 2019. The integration of Power Stations into the TS is governed by Section 7.6.5 of The Network Code which defines the steady-state and transient stability network redundancy requirements for integration.

The Grid Connection Application and process for ultimate connection is managed by the Eskom Grid Access Unit which facilitates grid access/connection for IPPs & generators and manages the overall process consisting of a Consultation and Application Phase, followed by a formal Quotation and Contracting Phase through to the Connection, Testing and Synchronization of the facility.

Changes to the SAGC or requests for deviations are handled via a Grid Code Advisory Committee under the auspices of NERSA

11 CARBON CAPTURE AND / OR OFF-SET SYSTEMS

11.1 CARBON SEQUESTRATION IN SOUTH AFRICA

Carbon sequestration refers to processes that remove carbon from the atmosphere in order to store it. In Carbon Sequestration terminology, there are two important concepts:

1. Carbon Capture: Prevents the release of carbon dioxide emissions into the atmosphere from power generation
2. Carbon Storage: Stores the captured carbon dioxide indefinitely preventing the release of the captured carbon dioxide into the atmosphere.

South Africa has joined the "Carbon Sequestration Leadership Forum" that investigates technologies to sequestrate carbon.

In addition, South Africa has acceded to the Kyoto Protocol as a non-Annex I country, and its participation is scheduled to be through the "Clean Development Mechanism" once the Protocol comes into force".

A regulation under Section 25 of the National Environmental Management Act establishing the Designated National Authority (DNA) was gazetted on 24 December 2004 by Martinus van Schalkwyk, the minister of the Department of Environmental Affairs and Tourism. The regulation established the DNA within the Department of Minerals and Energy and provides the DNA with its legal mandate to oversee the Clean Development Mechanism (CDM) in South Africa.

The CDM was established in December 1997 by the Third Conference of Parties to the United Nations Framework Convention on Climate Change (UNFCCC). The CDM allows industrialised countries with emission-reduction commitments to meet part of their commitments by investing in projects in developing countries that reduce greenhouse-gas emissions while contributing to the local sustainable development needs of the host country. To allow CDM projects to occur, host countries need to designate national authorities to evaluate and approve the operation of CDM projects in their country.

South Africa has established a Designated National Authority (DNA) to fulfil this function as well as other functions related to the successful implementation of the CDM in South Africa, including the promotion of investment in CDM projects.

From the developing country perspective, the CDM offers the following opportunities:

- It can attract capital for projects that assist in the shift to a more prosperous but less carbon-intensive economy
- It encourages and permits the active participation of private and public sectors

- It can be an effective tool of technology transfer if investment is channelled into projects that replace old and inefficient fossil fuel technology or create new industries in environmentally sustainable technologies
- It can help developing countries define investment priorities I projects that meet their sustainable development goals

In South Africa, the CDM may provide additional investment for the development of activities that reduce the combustion of fossil fuels (particularly coal, oil, gas and paraffin), reduce methane emissions (from landfill sites for example) and improve land use patterns (such as reforestation). This investment, which is directly related to the extent to which emissions are reduced could make some businesses in South Africa more viable.

To date, there are 360 CDM projects submitted to the DNA – 220 Project Idea Notes (PINs) and 140 Project Design Documents (PDDs). Out of 140 PDDs, 90 have been registered (35 Programme of Activities) by the CDM Executive Board as CDM projects (15 Issued with CER's), and 48 are at different stages of the project cycle – DNA approval, validation stage and/or request for review. The projects submitted to the DNA for initial review and approval cover the following types, bio-fuels, energy efficiency, waste management, cogeneration, fuel switching and hydro-power, and cover sectors like manufacturing, mining, agriculture, energy, waste management, housing, transport and residential.

[http://www.energy.gov.za/files/coal_frame.html]

11.2 CARBON CAPTURE TECHNOLOGIES

There are three main methods of capturing carbon dioxide in coal-fuelled power plants. These three methods are characterised by the point in the power generation process, relative to combustion, during which the carbon dioxide is removed. These methods are: pre-combustion capture, during combustion capture (better known as oxy-fuel combustion), and post-combustion capture. There are various processes of removing CO_2 that fall within the generic methods listed. This review will primarily discuss the most commonly accepted process as recognised by industry. The methods are at various stages of adoption in industry. Some technologies have been adopted in an appreciable scale, whilst some remain routes of interest for industry. Carbon capture can noticeable reduce CO_2 emissions, as much as 90%, but not without cost to capital and efficiency. There are five primary technologies for removing CO_2 from the gas stream. The technologies are: Chemical Solvents, Physical Solvents, Adsorption/Desorption, Membrane Separation, and Cryogenic Separation. The nature of the gas stream determines which technology is most apt; The pressure, temperature, CO_2 concentration in the gas stream govern which technology is best suited.

11.2.1 PRE-COMBUSTION CARBON CAPTURE

Pre-combustion CO_2 capture is linked to the IGCC process mentioned previously. Pre-combustion carbon capture involves the removal of carbon from the syngas produced in standard IGCC. In the standard IGCC process, coal fuel is converted into a gas called 'syngas'. IGCC alone offers a reduction of CO_2, NOx, SO_2 and Particulate Matter emissions over solid fuel combustion; without the aid of carbon capture. The syngas primarily is comprised of hydrogen (H_2) and carbon monoxide (CO). Coal comprises mainly carbon, hydrogen, sulphur and other impurities. The coal is crushed to create Pulverised Coal (PC), which has the consistency of a fine powder. The PC is heated in an oxygen-rich environment. The oxygen is extracted from air by an air separation unit (ASU). This produces syngas. The syngas is sent through filtering and scrubbing units to remove sulphur and particulates from the syngas. This 'clean' syngas can be sent through a turbine for power generation as for the case of standard IGCC, however CO_2 emissions are still present. The syngas can also have the carbon removed. The syngas is sent through a shift reactor to capture the carbon. A shift reactor comprises of a catalyst and high temperature steam. The catalyst induces a reaction between the carbon monoxide in the syngas and the high temperature steam. This reaction produces more hydrogen gas and carbon dioxide, CO_2. The CO_2 can be separated from the hydrogen gas using physical solvent (most commonly Selexol). The resultant, almost CO_2-free, gas is hydrogen-rich. The hydrogen-rich gas combusted in a gas turbine to generate power.

Approximately 80% - 90% of CO_2 can be removed in pre-combustion carbon capture. However, this improvement is not without cost to capital and efficiency. The energy penalty when comparing standard IGCC to carbon capture IGCC is typically between 15% - 20%, but new plants have improved upon this. This is the energy required to operate the carbon capture equipment, and thus the thermal efficiency is reduced from approximately 40% to 30%. This energy deficit can be overcome by designing a larger facility and consuming more coal. Carbon capture also increases the capital cost of the facility by approximately 20% - 30%, operation and maintenance costs by 10% - 20% and fuel costs by as much as 15% - 25%. Despite the drawbacks of this process, numerous test projects have been developed, usually on the order of 250 MW. Even without carbon capture, IGCC is an expensive process to produce power, being 20% more expensive than non-carbon captured supercritical power plant.

11.2.2 DURING COMBUSTION / OXY-FUEL COMBUSTION

Oxy-fuel Combustion involves the combustion of coal in the presence of nearly pure oxygen (approximately 95% oxygen) instead of ordinary air (with oxygen content of approximately 21%). This results in flue gases that is principally comprised of water vapour and a high concentration of carbon dioxide. The water vapour can be condensed to liquid form, leaving a CO_2 rich gas stream. Once the impurities, from the coal, in the gas are filtered and scrubbed out of the gas, the CO_2 gas can be sent for storage. Oxy-fuel methods have the potential to remove up to 100% of CO_2 from the flue gas.

The main problem is however, that obtaining pure oxygen has a large energy penalty, producing pure oxygen with air separating units remains energy intensive. When compared to standard combustion of Pulverised Coal in air, an 8% - 10% more energy is required – so an 8% - 10% impact on efficiency and fuel consumption. Oxy-fuel combustion also incurs a large capital premium due to its additional complexity; and while Oxy-fuel combustion is established in the processing industry, it is not yet deemed viable in the energy generation sector as of the time of writing.

11.2.3 POST-COMBUSTION CARBON CAPTURE

Post-combustion carbon capture is the most available and proven capture technology. Most industrial applications use a chemical absorption process using amines (specifically monoethanolamine or MEA). Post-combustion carbon capture is also called flue gas scrubbing, as it involves the removal of CO_2 from the flue gas (the exhaust gases of combustion). Flue Gas Scrubbing should not be confused with Flue Gas Desulphurisation (FGD), which only removes harmful SOx from the flue gas, and does not address CO2 and greenhouse gas emissions.

Flue Gas Scrubbing's popularity is in part due to its ability to be considered an independent subsystem. In order to introduce post-combustion capture, no extensive alterations to an existing/established coal fired power station is required. This allows it to be retrofit to existing facilities. The established combustion technology of supercritical, ultra-supercritical and subcritical boilers is kept mostly unchanged. The coal is burnt in a conventional combustion chamber. The flue gases are then passed through the following emission control systems;

Flue Gas Desulphurisation to remove SO_2, Fabric Filters to remove Particulate Matter and Selective Catalytic Reduction to remove NO_X. After the emissions have passed through the emissions controls, it is moved to a CO_2 absorption unit. Emission Control of Ash, sulphur dioxide and NO_X is vital to the efficient operation of the carbon absorption process. In the CO_2 absorption unit, a solution of aqueous MEA, a chemical solvent, is used to remove 90% of the CO_2 in the flue gas. The CO_2-rich MEA is heated in a CO_2 stripper, the MEA releases the pure CO_2. The MEA can then be recycled to absorb more CO_2. The CO_2 that is collected by the stripper is compressed and stored for transportation to long-term storage.

The most common and established post-combustion CO_2 capture process is chemical absorption with amine solvents. Other post-combustion CO_2 capture technologies are membranes, the Pressure Swing Adsorption process, and mineral carbonation process. While promising, they are yet to be adopted in considerable scale in industrial power generation.

A problem lies in the heating of the CO_2-rich MEA in order to strip the CO_2 and reactivate the MEA. Either a large amount of electricity is required to heat it or, more commonly, low-pressure steam is syphoned from the turbine in order to heat the carbon-rich solvent. This has a considerable impact on the energy output and efficiency of the plant, as well as water consumption. The solvent once stripped also requires cooling. Again, an energy penalty of around 15% to 20% applies for carbon capture. This results in a thermal efficiency (%) drop of 10% (e.g. from 40% to 30%). Therefore, requiring more coal to be burnt for the same output and therefor more capex and opex. A post-combustion system also must process a greater volume of gas. Due to this scale they increase the initial capital cost by 40% - 50%, as well as increasing operations and maintenance costs. However, post-combustion carbon capture can be retrofitted to an existing facility should it be demanded in the future.

11.3 CARBON TRANSPORT AND STORAGE

Once captured, the CO2 needs to be stored somehow. In order to successfully store carbon, it must first be delivered to the storage location which is most often not close to the generation facility. This brings with it the well understood problems of moving large volumes of gas. Unlike many industrial use gases CO_2 poses no threat of fire or combustion, but it is an asphyxiant. In order to transport CO_2 efficiently, the gas is compressed. The compression of CO_2 is energy intensive. The compressed CO_2 is transported by high-pressure pipeline, truck, rail or ship. The cost of CO_2 transport is another stumbling block to successful carbon storage. On the low end, a 200km onshore-to-onshore pipeline will have a unit cost of $2.50 per ton of CO_2. On the high end, a ship with a loading and unloading pipeline has a unit cost of $20.50 per ton of CO_2.

Carbon (CO_2) storage is defined as the placement of CO_2 into a repository where it is intended to stay indefinitely. It is the final step of carbon management. CO_2 is captured, compressed and transported and finally sequestrated. It is believed that the world's storage potential is considerable. There are a few options for long term storage of CO_2 available. These options are: storage in geological formations, in the ocean, terrestrially and through mineral sequestration.

It would be best if captured CO_2 could be used in industry. Unfortunately, the production of CO_2 far outstrips industry demand. Industry also requires chemically pure CO_2, which requires additional cleaning of the captured CO_2. Captured CO_2 is treated as a waste that must be disposed without releasing it into the atmosphere.

Geological Storage

Underground storage of CO_2 in geological formations is the most developed disposal option of captured CO_2. This is due to experience gained in industry. Geological sequestration involves the injection of CO_2 into underground reservoirs that have the ability to securely store CO_2 for a sufficiently long period of time. The geological formation of interest are saline aquifers, depleted oil and gas reservoirs (not applicable to Southern Africa), or unmineable coal seams.

Better than simple storage of a waste product, is the potential to make the waste product economically useful. This is done in two ways Enhance Oil Recovery (EOR) and Enhance Gas Recovery (EGR). In EOR, CO_2 is injected into an oil well; the CO_2 reduces the viscosity of oil easing oil recovery. The CO_2 is separated and reinjected. EOR is well established and in commercial use in the USA. The limited amount of oil and gas fields in Southern Africa does limit the viability of EOR. EGR is the use of high-pressure CO_2 to displace the methane of unmineable coal fields. There is often methane trapped in coal beds, it is ordinarily difficult to obtain. The methane can then be extracted and used. The CO_2 is trapped by the coal or absorbed by the coal. More research is required to fully understand this displacement of methane by CO_2 in coal seams. It is a double-edged sword. CO_2 can displace methane, but the absorption of CO_2 by coal forces the coal to expand. This expansion restricts the permeability of the coal, this restricts the flow of CO_2 and restricting the recovery of the methane.

The major risks in Geological Storage are not the technical but geological. The effect of acid on carbonated rock. The creation of fissures due to the injection of high pressure CO_2 that may result in leakage. The leakage through unknown faults or broken seals or exiting drill holes. The exact geology is difficult to know. And it must be ensured that the stored CO_2 poses no threat to potable water supplies. Carbon Dioxide in high concentrations is an asphyxiant and cannot be allowed to leak. Geological storage remains the most viable CO_2 storage option.

11.3.1 OCEAN STORAGE

A potential CO_2 storage option is to inject captured CO_2 at the seafloor in deep oceans (depths of greater than 1000 m). This option has massive CO_2 storage potential. However, there are concerns about the environmental and ecological impact. When CO_2 dissolves in water it forms weak carbonic acid. This acid will have to neutralised by a base (e.g. NaOH) which will also have to be injected at the ocean floor. However, this will produce long lasting effects by altering ocean chemistry. It could endanger oceanic plant and animal life. The ocean is an open system, so the effect of any alterations is almost impossible to predict. This ecological concern is the main reason that ocean storage of CO_2 will not be a genuine option for the foreseeable future.

11.3.2 TERRESTRIAL STORAGE

Nature has spent billions of years operating in balance with CO_2. Photosynthesis, the absorption of CO_2 into the ground and aquatic environments all remove CO_2 from the atmosphere. Restoring terrestrial ecosystems such as forests, wetlands and marshes will aid in the decrease of CO_2 in the atmosphere, as well as improve air- and water-quality and habitat restoration. Natural terrestrial CO_2 uptake is suspected to offset as much as one third of one third of manmade carbon emissions. Natural carbon capture must not be overlooked.

11.3.3 MINERAL CARBONATION

Mineral carbonation is the fixation of CO_2 into naturally occurring rock. Alkaline and alkaline-earth oxides such as magnesium oxide and calcium oxide can be used. The chemical reactions with these minerals and dissolved CO_2 results in CO_2 removal by producing carbonates of magnesium and calcium. The carbonates can be used in industry. The reactions are however, slow and the mineral processing required is energy intensive. Power plants would need to increase their capacity by 60% or as much as 180% to offset the energy demands of mineral processing. Currently mineral carbonation is not viable.

11.4 CONCLUSION ON CARBON CAPTURE AND SEQUESTRATION

Carbon Capture and Sequestration is very expensive technology, with a significant impact on energy efficiency of the power plant, resulting in almost twice the CAPEX and OPEX compared to a power project without CCS. Although the requirement to implement SSC may become necessary to meet emission standards in future, that is not yet applicable to South Africa and other developing countries. Future Carbon Tax laws may make the capturing of CO_2 a requirement but is not yet commercially viable in the South African electricity market.

Currently, viable storage technology is a major stumbling block for carbon capture and sequestration. Capturing CO_2 is somewhat established but before that is possible a location to store the captured carbon must be found. This is difficult and highly location specific. Improvements of terrestrial carbon capture and 'storage' systems, such as reinstituting forests and aquatic habitats, is the simplest and most proven way to actively reduce CO_2 in the atmosphere. Geological storage is promising but again, is highly site specific.

Although the South African Government is committed to clean development under the Kyoto protocol, being recognised as a developing economy implies that:

- It can attract capital for projects that assist in the shift to a more prosperous but less carbon-intensive economy – such as replacing conventional coal generation capacity with new clean coal technology with almost 50% savings on CO2 emissions.
- It can be an effective tool of technology transfer if investment is channelled into projects that replace old and inefficient fossil fuel technology or create new industries in environmentally sustainable technologies
- It can help developing countries define investment priorities in projects that meet their sustainable development goals

12 SENSITIVITY TO A BIGGER PLANT SIZE

Several factors impact the decision of power plant size, and will have to be considered in following phases of the development of the energy master plan of the MMSEZ

- Direct demand and off-take allowed under legislation
- Environmental permits for even clean coal technologies will be more difficult with increasing size
- Coal and water supply limitations
- IRP determination for new generation and technology specific additional clean coal generation
- Generation licence application
- CAPEX vs off-take demand
- Economies of scale is not considerable above 1000MW installed capacity
- Increase investment risk

13 MARKET OPTIONS AND PPA ADVICE

13.1 HEADS OF TERMS OF A TYPICAL PPA

The Power Purchase agreement is the long-term agreement signed by the Off-taker(s) and the power producer and stipulated the contractual arrangements under which electricity is sold to the off-taker. Key considerations in a PPA includes stipulating when the project will begin commercial operation, schedule for delivery of electricity, penalties for under delivery, payment terms, and termination. A PPA is the principal agreement that defines the revenue and credit quality of a generating project and is thus a key instrument of project finance.

The form of PPAs vastly differs, depending on the generation technology, dispatch regime, legislation and regulatory regime surrounding the particular project.

Because of the significant capital expenditure associated with the development and construction of an Ultra-Supercritical Coal Fired Power Plant, the tenure of the PPA will typically be 20 – 30years.

The PPA should as a minimum address the following points (in addition to boilerplate conditions) in either the main sections of the PPA or as technical Schedules to the PPA

1. Term of the PPA
2. Development and construction requirements /specifications
3. Testing and commissioning, Performance guarantees
4. Sale, Purchase and delivery conditions (availability, deemed energy etc.)
5. Pricing / Tariff
6. Invoicing and Payment
7. Operation and Maintenance specifications and requirements
8. Stop/Starts and dispatching requirements or stipulations
9. Coal Supply (impact of CSA on PPA if linked)
10. Metering
11. Force Majeure
12. Events of Default
13. Transfer events
14. Representations and Warranties
15. Construction and commissioning programme
16. Technical description and specification

14 GREEN BUILDING CODE DEVELOPMENT

Public Sector regulations should apply to the green building code development, considering that the owner of the power plant will be classified as an "organ of state". All occupiable buildings or parts of buildings meant to be occupied are required to adhere to the following regulations as a minimum:

- SANS 10400 National Building Regulations.

In addition, the occupiable buildings, at the discretion of the Client, may be designed, constructed and operated in accordance with guidance published by the Green Building Council of South Africa.

Note that the green building codes will only apply to the ancillary buildings of the power plant which will be occupied by the site staff. This may include buildings such as:

- Operations and Maintenance building
- Warehouse
- Boardrooms and offices

These buildings can obtain "Green Star Certification" by the Green Buildings Council of South Africa (GBCSA) through the use of their "Green Star" tools. These tools are based on the following categories, each with a range of credits which address the environmental and sustainability aspects of designing, constructing and operating a building:

- Management
- Indoor Environment Quality (IEQ)
- Energy
- Transport
- Water
- Materials
- Land Use and Ecology
- Emissions
- Innovation
- Socio-Economic

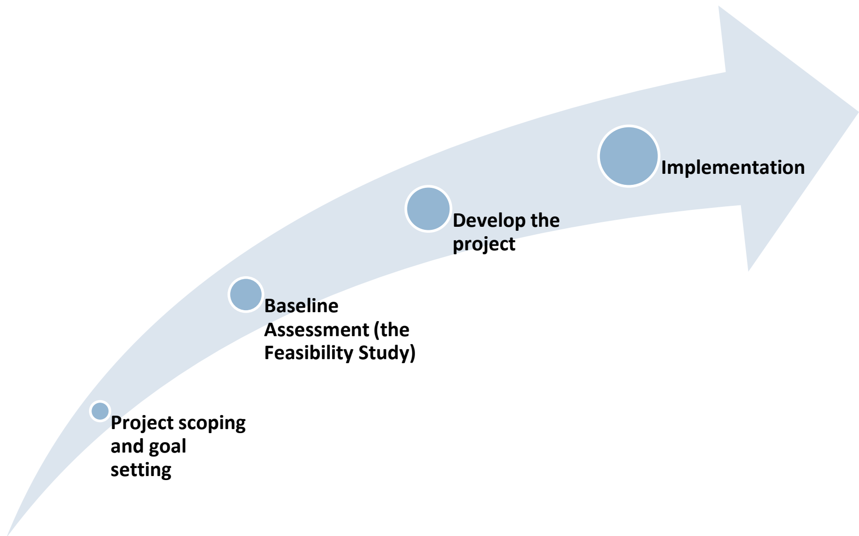
An independent Green Star Assessment Professional should be appointed to assist in developing the design of the buildings to the correct standards.

15 ENERGY MASTER PLAN (CONCLUSIONS AND NEXT STEPS)

An Energy Master Plan is required to look holistically across the MMSEZ and potential off-takers to identify a strategy to implement the supply of affordable, reliable industrial power over a long-term investment.

After careful attention of all the aspects of this study, it can be concluded that the MMSEZ has to consider several energy supply options in its approach to provide cost efficient, reliable power to the large industrial clients within the metallurgical zone. This may include the development of an Ultra-supercritical Coal Fired power plant through an independent power producer (IPP) to provide cost effective baseload power to an industry which will support investment and social-economic growth of the Limpopo region. This technology is considered "Clean Coal" and limits carbon and other GHG emissions to well under local legislation, World Bank and IFC standards. Such a power plant and its associated coal mine can be developed in a phased approach to allow for continued investment into the power industry as well as the metallurgical zone.

The following illustration depicts the proposed energy master plan steps for the MMSEZ:



15.1 PROJECT SCOPING

This study can be defined as the Project Scoping and Goal Setting phase. Based on the information gathered, it is foreseen that the MMSEZ will proceed in the develop of an Ultra-supercritical Coal Fired Power Plant in a phased approach through an IPP to deliver power to the MMSEZ's cluster of off-takers (Goal).

15.2 BASELINE ASSESSMENT (THE FEASIBILITY STUDY)

The next step in the energy master plan will be to form a sound baseline of the project information and inputs. This baseline can be formed through conducting a feasibility study, which will gather data such as:

- Accurate forecast of Power Demand
- Consider all renewable power options that could alleviate carbon impact and cost of energy
- Clearly define GHG emission standards that will apply to the project
- Stipulate community involvement requirements
- Define (quantify) community benefit from the programme
- Investigate coal supply options
- Determine accurate water requirements and supply options
- Land and infrastructure requirements and options
- Renewable energy augmentation options
- Investment and funding options
- Environmental legislation requirements
- Ministerial determination
- Indicative cost estimates

15.3 DEVELOP THE PROJECT

- Identify interested funders and developers via EOI and/or MOU
- IPP selection through an independent and open tendering programme
- Select preferred bidder
- The MMSEZ will **Support** the preferred bidder to Financial Close (responsibility remain that of the developer):

– Generation licence

– Off-take agreements

– Land-lease agreementsp

– Joint development

– EIA

16 REFERENCES

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