MODELLING SOUTH AFRICA'S 2050 ENERGY MIX

Will South Africa be able to create a JET (Just Energy Transition)?

By: Dr DF Rodda; AM Balusik

ACRONYMS

ACE	Agent-based Computational Economics
ACEGES	Agent-based Computational Economics of the Global Energy System
ASSA	Actuarial Society of South Africa
BESS	Battery Energy Storage Systems
CCGT	Closed Cycle Gas Turbine
CCS	Carbon Capture Storage
CGE	Computable General Equilibrium
CSIR	Council for Scientific and Industrial Research
CSP	Concentrated Solar Power
CTA	Carbon Tax Act
DME[1]	Department of Minerals and Energy
DMRE[1]	Department of Minerals, Resources and Energy
DOE[1]	Department of Energy
DPE	Department of Public Enterprises
DSM	Demand Side Management
DSR	Demand Side Response
EAF	Energy Availability Factor
EESI	Environmental and Energy Study Institute
EIA	Energy Information Administration
EPP	Electricity Pricing Policy
EPRI	Electric Power Research Institute
ERA	Energy Regulator Act
ETSAP	Energy Technology Systems Analysis Programme
GHG	Greenhouse Gases
GW [2]	Gigawatt
IEA	International Energy Agency
IEP	Integrated Energy Plan
IGA	Intergovernmental Agreement
ILS	Interruptible Load Supply
IOS	Interruption of Supply
IPP	Independent Power Producer
ISMO	Independent System and Market Operator
J[2]	Joules
JET	Just Energy Transition
kW[2]	Kilowatt
kWh	Kilowatt hours
LCOE	Levelised Cost of Electricity
LPG	Liquified Petroleum Gas
MARKAL	MARKet ALlocation Model
MLR	Manual Load Reduction
MW[2]	Megawatt
MWh	Megawatt hours
MYPD	Multi-Year Price Determination
NDC	Nationally Determined Contribution
NDP	National Development Plan

[1] The Department of Minerals and Energy was established in 1997 and was separated into the Ministry of Mineral Resources and the Ministry [Department] of Energy (DOE). These were again recombined in 2019 to create the Department of Mineral Resources and Energy

[2] Useful unit conversions:1W = 1J; 1kW = 1000W; 1MW = 1000kW; 1GW = 1000MW; 1TW = 1000GW

NEMS	National Energy Modelling System
NERSA	National Energy Regulator of South Africa
NPC	National Planning Commission
NTCSA	National Transmission Company South Africa SOC Limited
O&M	Operation and Management
OCGT	Open-Cycle Gas Turbine
OSeMOSYS	Open Source energy MOdelling SYStem
PCLF	Planned Capability Loss Factor
PE	Partial Equilibrium
POLES	Prospective Outlook on Long-term Energy Systems
PS	Pumped Storage
PV	Photovoltaic
RE	Renewable Energy
REIPPPP	Renewable Energy Independent Power Producers Procurement Programme
RES	Reference Energy System
RMIPPPP	Risk Mitigation Independent Power Producers Procurement Programme
RSA	Republic of South Africa
SADC	South African Development Community
SOE	State Owned Entity
TPES	Total Primary Energy Supply
TW[2]	Terawatt
TWh	Terawatt hour
UCLF	Unplanned Capability Loss Factor
UNFCCC	United Nations Framework Convention on Climate Change
VRE	Variable Renewable Energy
W[2]	Watt

1. INTRODUCTION

March 2023 marks the 100 year anniversary of Eskom providing electricity to South Africa (Eskom, 2022a). From being awarded Power Company of the Year at the Global Energy Awards in 2001 (Eskom, 2022a) to 2007 marking the start of load-shedding and the beginning of the country's electricity crisis, and finally to present day which sees 2023 having the worst load-shedding in South Africa's history - Figure 1: Load-shedding Over Time (2007-2022)shows the large increase in load-shedding during 2022. However, load-shedding in 2023 is expected to be worse as Eskom's CEO announced that load-shedding will likely continue throughout until the end of the year as Eskom tries to meet the 4000MW-6000MW generation capacity shortfall currently experienced (Daniels, 2023; Nene, 2023) . The present energy crisis in South Africa is multi-faceted and complex and, while not experts in energy, actuaries are experienced in long-term thinking, finance, risk management, and modelling, all of which are relevant in the energy planning. We want to avoid the current situation happening in the future and hope to contribute to forward-looking energy policy and public debate through the provision of a simple excel model and useful context for those looking to gain deeper understanding of the current electricity crisis. The objective of the paper is to create an independent model which allows the modelling of future electricity scenarios while identifying key risks and providing independent insight into what might be the optimal 2050 energy mix. The publication of the excel model with this report should enable anyone to better understand the impact of various options for our electricity mix.

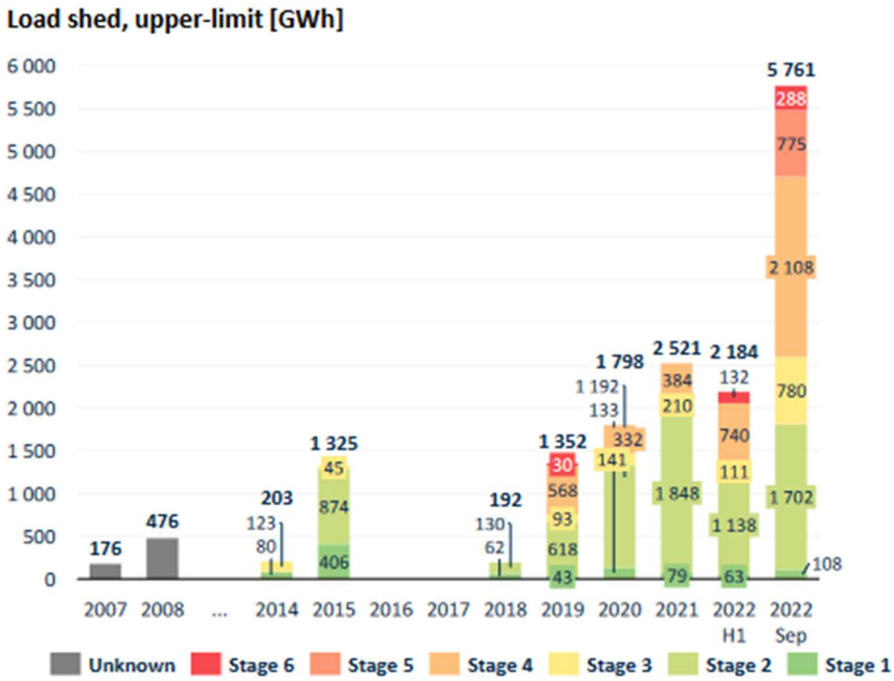

Figure 1: Load-shedding Over Time (2007-2022)

This research aims to provide insight into how the energy crisis in South Africa evolved, what is being done about it currently and what the future of electricity generation in South Africa may look like. A mnemonic – the 4 P's - has been employed in the paper to help summarise the main points considered. In doing so it aims to answer the following research questions:

- What is the background of the current energy crisis in South Africa - How have **P**olicies, **P**olitics, and **P**ractical considerations (3P's) affected the situation?
- The fourth P: **P**redicting. What are the current predictions about the future of energy in South Africa and what can a forecasting model tell us about the future energy mix of South Africa presently?
- What does the potential energy mix of South Africa that will be used to generate electricity look like? How does the fourth P relating to the Prediction of a forecasted energy mix relate to the 3P'S in question 1 – what risk areas are associated with the suggested forecasts?

In attempting to answer these questions, this paper also aims to inform the reader of important concepts, jargon, entities, experts, and issues related to the South African energy. In doing that, the paper aims to equip the reader with this information so that they will be able to meaningfully engage with news and public discourse around the energy crisis.

As Pouris (2008) discusses, South Africa has relatively low levels of academic publications relating to energy and fuel relative to other academic disciplines in the country and relative to other nations like Australia, Canada, Malaysia and New Zealand. As such, additional independent research into the area is useful in providing new insights into the energy crisis faced by the country. This paper intends to add onto the existing body of research and provide independent thought on the issue of the energy crisis. This paper looks through an actuarial lens and as such aims to provide insight into how the broader energy environment in South Africa works, the variety of different and sometimes conflicting needs of relevant stakeholders, and the potential risk areas that may need to be managed. The results of this independent modelling may be translated into actionable recommendations to provide commentary and enable more public participation on the long-term solutions for South Africa's energy mix.

1.1 BREAKDOWN OF THE PAPER

The structure of the paper centres around the 4P's mentioned above with background context and conclusions framing the central issues. As such the paper is structured in the following way:

- Section 2 provides an introduction into how energy and electricity work and what the difference between them is (Section 2.1), provides a breakdown of key concepts and terms related to electricity systems (Section 2.2), and provides an overview of how electricity is produced in South Africa (Section **Error! Reference source not found.**). In doing so, the paper aims to equip the reader with information that will enable them to meaningfully engage with news and public discourse around the energy crisis;
- Section 3 looks to provide a background on the current energy situation by addressing the 3P's: Section 3.1 (**P**olicies) provides a summary of critical reports, legislation and government plans that have shaped the energy sector in the country; Section 3.2 (**P**olitics) discusses the people- and process-related elements that contribute to the crisis; and Section 3.3 (**P**ractical considerations) looks at elements in the broader landscape (changes in the local and international energy landscape and Eskom's financial situation) that have played a role in the current crisis and should be considered in future planning.
- Section 0 and 5 address the fourth P (**P**rediction) and provides insight into what the current outlook on South Africa's future energy mix is. Section 0 provides a summary of commonly used energy system models. Section 4.2 summarises other research that provides commentary around the future of South Africa's energy mix. Section 5 outlines the workings and results of our independent model which allows scenario testing of future energy mixes for South Africa.
- Section **Error! Reference source not found.** presents the results of our findings in the context of the 3P's. In doing so the paper aims to provide commentary on what the future of electricity in South Africa may look like

2. UNDERSTANDING ELECTRICITY CONCEPTS

Before delving into the background of the electricity crisis, a discussion and explanation around key concepts related to energy science is provided.

2.1 WHAT IS ENERGY AND ELECTRICITY?

Joules (J) is most commonly used when referring to the amount of energy that can be extracted from raw sources of fuels (Cullen, 2009). It is often used to express the amount of energy that can theoretically be extracted from primary energy sources (International Energy Agency, 2004). The International Energy Agency's (IEA) Energy Statistics Manual provides a breakdown of these sources as shown in Figure 2 **Error! Reference source not found.**. These sources can be renewable (e.g., solar and wind) or non-renewable (e.g., coal and gas). The figure also depicts 'Heat and Electricity' as a country importing either would see that as an energy source. However, heat and electricity are also products that can be generated from utilising the other energy sources. For example, combustible sources (e.g., oil and coal) are burnt to produce heat which can be used to power steam which is used to drive turbines that generate electricity. Non-combustible sources (e.g., wind and nuclear) use other methods – wind converts kinetic energy from the wind into electricity and nuclear uses the heat generated from nuclear Processes to drive steam turbines.

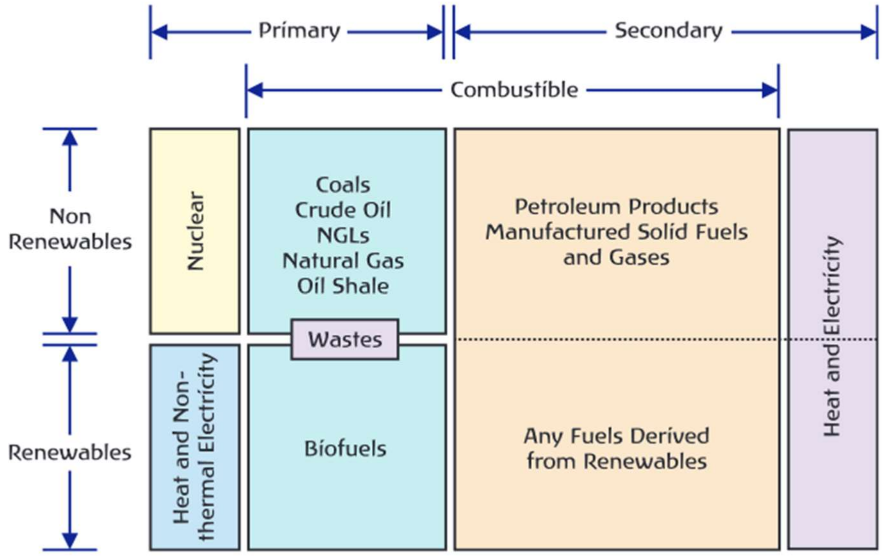

Figure 2: Breakdown of Primary and Secondary Energy Sources (International Energy Agency, 2004)

Given that this paper aims to ultimately consider South Africa's energy mix (i.e., what are the sources South Africa will use to meet its electricity demand in the future), the distinction between energy and electricity should be made. When discussing the broader energy sector – energy can be thought of as the work and heat available from all the primary and secondary energy sources as described above. This would include the energy that can be utilised by the transport industry's use of gas and the industrial sector's use of coal and oil for industrial purposes. Electricity is one of these sources and as such is part of the picture when discussing the energy sector. Given that load-shedding and the generation of electricity to meet the country's needs to the country is the issue at top of mind, a focus on the sources of energy that can be used to meet this demand is what is predominantly considered in the scope of this paper. However, it is useful to keep in mind that it is just a part of the broader energy sector in South Africa.

When discussing electricity, the basic unit of measurement discussed is the watt (W), where 1 Watt is equivalent to 1 Joule per second. When discussing electricity on the national scale more common measures are those related to the kilowatt (1kW=1000W), megawatt (1MW=1000kW), and gigawatt (1GW=1000MW). Electricity prices are usually quoted with reference to a time element, for example in Rand or cents per kWh (kilowatt hours). A kilowatt-hour is equivalent to 3.6 million Joules of energy (1kW = 1000 Watts = 1000 Joules/s which comes to 1000*60*60 Joules after one hour). For example, a 1kW petrol generator running at 100% capacity for one hour will have produced 1 kilowatt-hour (kWh) of electricity during that hour.

The total electricity sent out to the South African grid in the period 1 April 2021 to 31 March 2022 was 226,226 GWh (Eskom, 2022c, p. 7) , i.e. 226 terawatt-hours (TWh where 1TWh=1000GWh).

2.2 USEFUL ELECTRICITY GENERATION CONCEPTS

While section 2.1 above describes useful concepts that assist in understanding metrics provided around electricity supply and generation. This section provides explanation of concepts associated with the generation of electricity.

The installed (or nameplate) capacity is the theoretical maximum output that a generator can produce (NMPP Energy, 2021a). However, the installed capacity is not the same as the nominal capacity. The nominal capacity is the theoretical maximum output that a generator can send out; after allowing for any auxiliary power consumption and the decreasing ability of generators to produce energy as they age (Eskom, 2022c, p. 150) . For example Koeberg, the nuclear power station in Cape Town, has a nominal capacity of 1854MW while the coal power station Medupi has an installed (or nameplate) capacity of 4764MW, made up of six 794MW generators (Eskom, 2022c, p. 78).

However, this nominal capacity is not necessarily an achievable or sustainable output onto the grid at any point for a generation facility. Facilities may have net electricity output (the output achievable after allowing for the auxiliary power consumption needed to run the plant itself that differs throughout the seasons (U.S. EIA, 2023). The nominal capacity is the maximum output when a generation facility is running at optimal conditions.

In the practical sense, power stations cannot run continuously – there are planned outages (such as for maintenance) and unplanned losses to electricity generation. To account for this loss of generation, Eskom reports on the energy availability factor (EAF) of its generation facilities. The EAF reflects the ratio of the energy that was actually produced and available over a period to the output that could have been theoretically produced if a generation facility was running according to its nominal capacity with no outages (See the equation below outlining the calculation of an EAF for a generation facility (Eskom, 2022c, p. 93; IAEA, n.d.)):

$$EAF = \frac{REG - PCLF - UCLF - OCLF}{REG}$$

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Where:

REG: Reference Energy Generation for the period. This is what could theoretically be available were generators running at their nominal capacity full time

PCLF: Planned Capability Loss Factor. Planned energy loss such as during planned maintenance.

UCLF: Unplanned Capability Loss Factor. Energy loss that is due to unplanned issues that are still in the plant management's control

OCLF: Energy losses that are unplanned and outside of plant management's control

Figure 3 below shows Eskom's actual and targeted EAF's for 2020-2022 as well as the target amounts for 2022, 2023, and 2025:

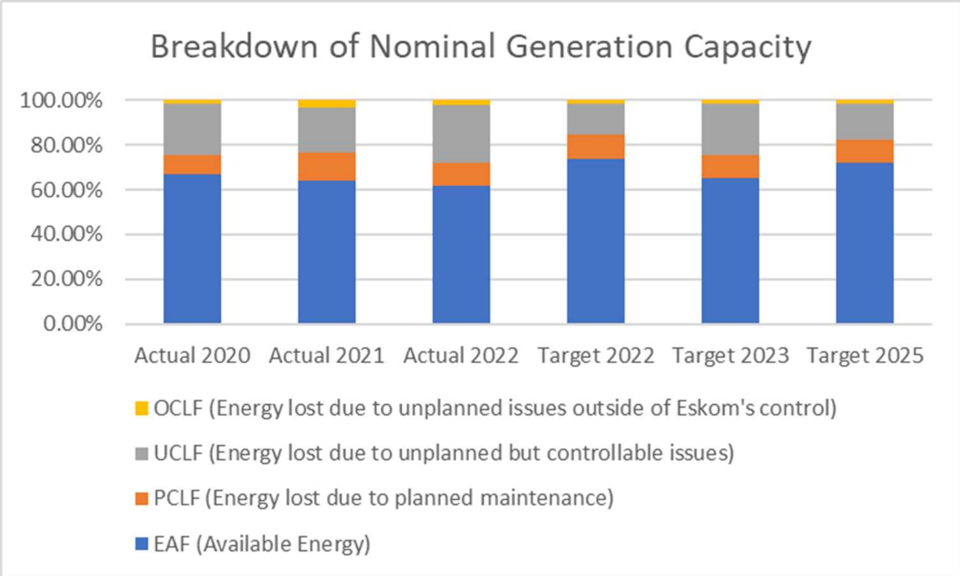


Figure 3: Split of Nominal Generation Capacity between available energy; energy lost to planned and unplanned issues under Eskom's control; and uncontrollable issues (Eskom, 2022b, p. 93)

Whereas the EAF gives an idea of how well maintained generation plants are. This represents the maximum amount of time that a generator could theoretically be run at maximum output. Since it is unlikely that a generator will be able to be run at maximum capacity, the capacity or load factor reflects the actual energy produced by a generation facility relative to its nominal capacity over the same time period (Pedraza, 2019; Pierce and Le Roux, 2022, p. 13). Hence, the capacity factor of a generator multiplied by its nominal capacity multiplied by the number of hours in a year (8760 hours) is an estimation of how much electricity the generator can be expected to produce.

The figure below comes from a report from the CSIR shows the annual capacity factors per supply source in the first half of 2022 (Pierce and Le Roux, 2022, p. 14):

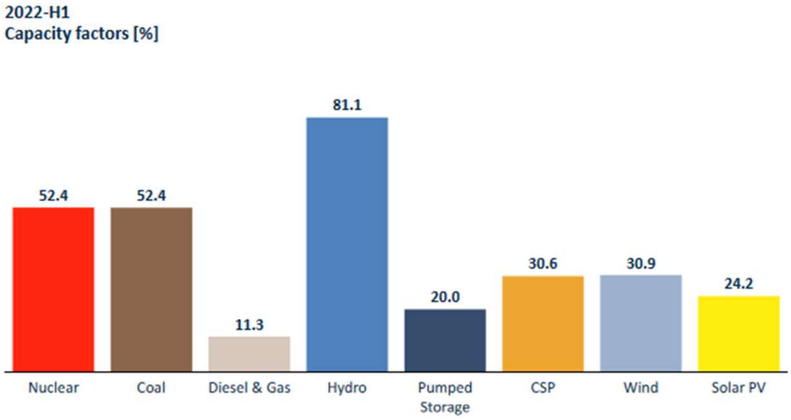


Figure 4: Capacity factor per energy source in South Africa 2022H1 (Pierce and Le Roux, 2022, p. 14)

Given that generators are not able to produce electricity at full capacity continuously, the management of energy supply needs to ensure that the mix of energy generation capacity from various sources matches supply at any point in time.

Base load energy plants are power stations (mostly coal and nuclear in South Africa) that are designed to operate continuously (Eskom, 2022c, p. 71) and provide a consistent source or 'base' energy for a country. While renewable energy (RE) provides a more climate friendly source of energy, it represents non-dispatchable energy. This type of energy is not able to be generated continuously as sources of the energy (e.g. sun or wind) is not always readily available depending on the time of day or year (NMPP Energy, 2021b). The figure below shows the average daily supply from various sources across the months of 2021 (Pierce and Ferreira, 2022, p. 65). As seen in Figure 5 below, energy from solar photovoltaics (PV) and concentrated solar power (CSP) peak during the day and provide more electricity during sunnier months (September – March) whereas wind provides complementary electricity during the night.

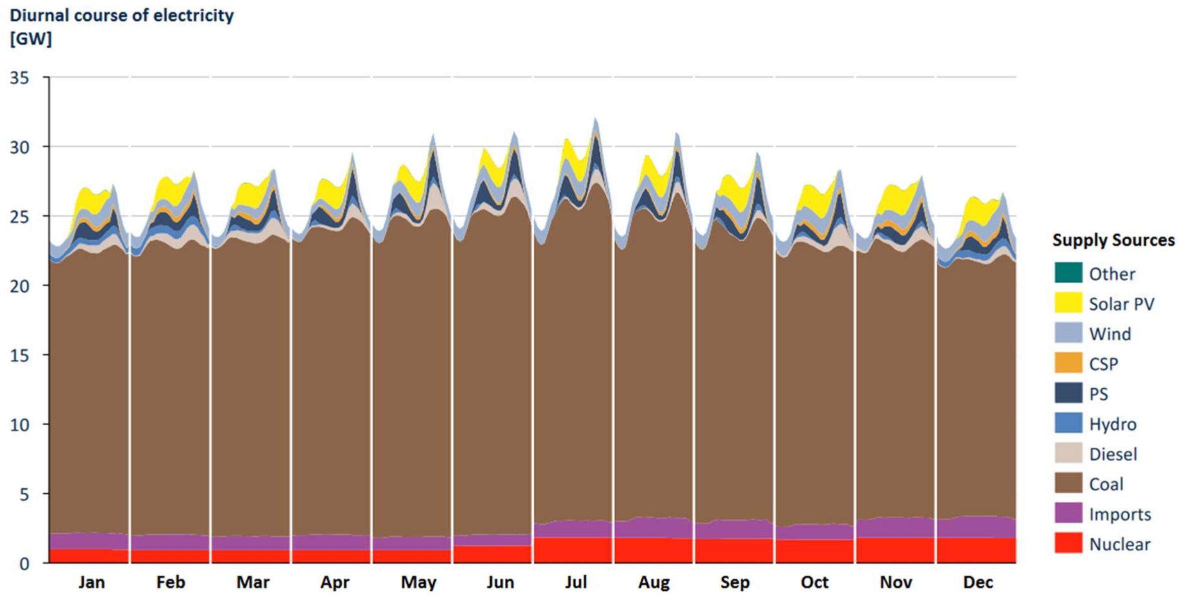


Figure 5: Average daily electricity production and source across 2021 (Pierce and Ferreira, 2022, p. 65)

The non-dispatchable and base load energy sources discussed above are able, at times, to produce more than the required energy. This additional energy can be stored to be used in times where demand is greater than available supply. This currently is in the form of pumped storage (PS) in South Africa. However, storage can also be in the form of battery energy storage systems (BESS). This includes lithium phosphate, nickel manganese cobalt, flow, sodium ion and liquid metal batteries (Madiba, 2022). Key considerations on selecting a BESS include its energy density (the amount of energy a battery contains relative to its size), lifespan, cost, and speed of discharge (Madiba, 2022).

Where the combination of base load plants, non-dispatchable renewable plants and insufficient to meet demand, peak-load plants are needed. These are plants that are used during periods of peak demand and include gas turbines, hydroelectric, PS (Eskom, 2022c, p. 71), and in the future BESS. These are electricity generation sources that can be turned on and their generation added to the energy system more flexibly than baseload plants and are usually run for shorter durations.

The difference between the two types of plants (peak-load and base load) are also usually noted in their capacity factors. As seen in Figure 4, as base load plants usually have higher capacity factors relative to peaking plants. The exception being energy derived from hydroelectric in 2022H1 (81.1% for hydro compared with capacity factors of approximately 52% for coal and nuclear). However this is not the standard as can be seen from the fact that hydro had an average monthly capacity factor of 30.3% in 2021 whereas coal and nuclear had average monthly capacity factors of 54.4% and 74.5% in 2021 respectively (Pierce and Ferreira, 2022, pp. 26–27).

The above shows the usefulness of a diversified energy mix in order to be able to better supply energy on-demand and to improve the security of the energy sector as reliance on a single source for supplying electricity is reduced. This is a common theme across many of the energy policies for South Africa discussed in section 3.1.

Now that the reader should be more familiar with the various concepts required to parse documents related to the energy section, the next section examines each of the main processes involved in the energy system (namely generation, transmission and distribution) of South Africa in more detail.

2.3 HOW ELECTRICITY IN SOUTH AFRICA WORKS

Figure 6 below shows a useful diagrammatic visual for how the electricity sector in South African functions (Pierce and Le Roux, 2022, p. 7). These sort of diagrammatic expressions of an energy system (or an electricity system) that capture the generation, conversion, and use of energy are often referred to as a reference energy system (RES) (Bhattacharyya and Timilsina, 2010, p. 6).

In the case of the figure below, this reflects a single component of the broader RES of the country as it focuses mainly on how electricity flows in the country. From generation (by Eskom and independent power producers (IPPs)) to transmission (by Eskom), and then distribution (either directly from Eskom or via municipalities). The electricity is ultimately demanded and consumed by end-users for Domestic (Dom), Commercial (Com), Agricultural (Agri), Industrial (Ind) and Mining (Min) purposes. It is at this demand stage that the network is managed through demand side responses (DSR) that ensure that supply equals demand.

DSR responses that result in reduced power include "load-shedding" or manual load reduction (MLR), Interruption of Supply (IOS), and interruptible load supply (ILS) (Pierce and Le Roux, 2022, p. 7):

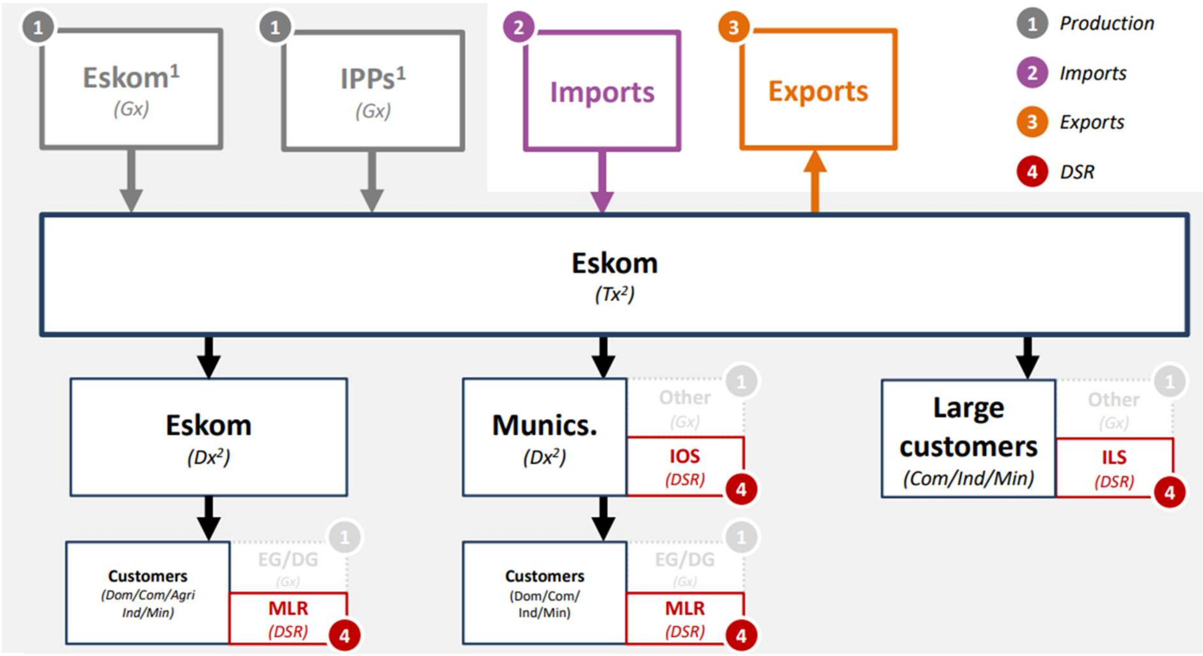


Figure 6: Diagram showing how energy is generated, transmitted and consumed in South Africa (Pierce and Le Roux, 2022, p. 7)

This three stage system of generation, transmission and distribution provides a useful summary of how to think about the electricity industry in South Africa. It also reflects how electricity planning thinks as is reflected in current efforts to separate Eskom into these three divisions. The most recent impetus in the separation of Eskom comes from the State of Nation Address in February 2019, where President Cyril Ramaphosa announced the restructuring of Eskom into three separate entities (Department of Public Enterprises (DPE), 2019). Namely, separate entities for the generation, transmission and distribution of electricity. With the transmission entity, a wholly-owned subsidiary of Eskom named the National Transmission Company South Africa SOC Limited (NTCSA) to be the first division unbundled as of December 2021 (Eskom, 2022g).

The sections below provide commentary on each of these three elements of the electricity industry in South Africa.

2.3.1 Supply and Energy Generation

Electricity is generated via the conversion of the energy from primary and secondary sources through some generation process. The Total Primary Energy Supply (TPES) is the amount of energy that could theoretically be produced from the conversion of these primary energy sources. Figure 7, provides the TPES breakdown for South Africa in 2018[3].

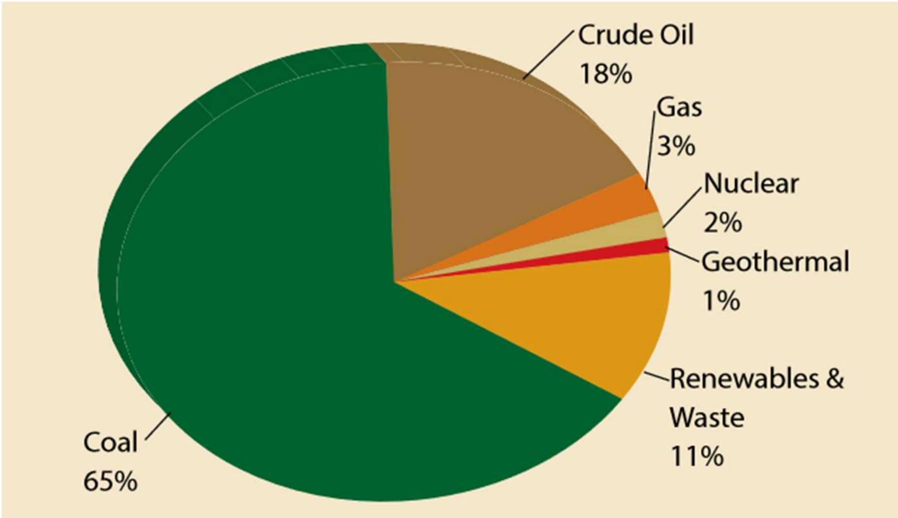


*Figure 7: Breakdown of TPES by Source. Figure from (*The South African Energy Sector Report 2021*, 2021), original data from 2018 Energy Balances from the DMRE website (DMRE, n.d.)*

As discussed above in section 2.1, energy is converted into electricity via a generation facility. Electricity generation in South Africa is split between Eskom which owns 30 generation facilities and independent power producers (Eskom, 2022c, p. 150). A short description of each of South Africa's primary energy sources are provided below:

<u>*Coal*</u>

South Africa is resource rich in terms of coal deposits – In 2012, South Africa was the fifth largest coal producing country in the world and the country relied on it to produce around 90% of its electricity (NPC, 2012b, pp. 163–164). Coal reliance is declining as older stations are gradually decommissioned, around 24GW will be decommissioned between 2030 and 2050 (DMRE, 2019, p. 44). However, Kusile and Medupi, the largest and most recent additions to the coal fleet will still play a part in providing energy to 2050 for the country (DMRE, 2019, p. 12).

<u>*Gas*</u>

As South Africa moves away from coal and its large base load capacity, a need for flexible peaking generation capacity will be needed in order to meet demand at any point in time. Gas could be used for this role and could help move the country towards electricity generation which is centred around demand, where energy is supplied less passively and deterministically and move actively and stochastically (DMRE, 2021, p. 28). This is particularly important given the country's plan to incorporate intermittent renewable energy sources which would be complemented by the flexible generation capacity of gas (DMRE, 2019, p. 13).

[3] Note that the breakdown provides a general indication of the TPES. However, the raw data shows petroleum products making up 3.7% of the TPES which is not shown here. Geothermal is also grouped with solar energy in the raw energy balance data.

The South African Gas Master Plan: Basecase Report (the 'Gas Master Plan') was published in September 2021 and aims to lay out a roadmap for future gas production in South Africa (DMRE, 2021). The plan points out that gas is set to expand as a proportion of South Africa's energy mix, according to the 2019 IRP, from 2.6% to 15.7% by 2030 (DMRE, 2021, p. 1). In order to do so, supplies of gas need to be considered. The 2019 Integrated Resource Plan (discussed in more detail in the policy section below) mentions two options: in the short-term imports from regional Southern Africa Development Community (SADC) members (e.g. Mozambique's Rovuma Basin) and in the medium-term domestic sources (e.g. the Brulpadda gas field in the Outeniqua basin) could be considered (DMRE, 2019, p. 13).

The other consideration would be that of electricity generation from gas. Currently there are four Open-Cycle Gas Turbine (OCGT) stations connected to the grid with a combined capacity over 3000MW- Eskom owned Ankerlig and Gourikwa and independent plants Avon and Dedisa (DMRE, 2019, p. 150). Currently, three of these four receive their diesel by road tankers which slows provision of electricity through these generators. When these plants operate at maximum output they consume more fuel than it can be delivered (DMRE, 2019, p. 91). Eskom also has two smaller gas peaking generating stations, Acacia and Port Rex, with capacity of 171MW each, which run on Kerosene (DMRE, 2019, p. 150). Given the supply constraints, in order for gas to become viable, gas transmission infrastructure also needs further consideration. As noted in the Gas Master Plan, given the large volumes that can be extracted from gas fields, direct distribution pipelines to each of these facilities would provide the most economically viable plan (DMRE, 2021, p. 22,27).

While improved transmission of gas supply will help for lower costs and improved generation capabilities, additional generation capacity will need to be generated in order meet the 15.7% energy mix target mentioned above. Converting decommissioned (mothballed) coal fired plants to gas generation facilities is a possibility as it would reduce the capital expenditure as well as help to prevent job losses from these coal stations being decommissioned (DMRE, 2021, p. 28). Additionally, the four existing OCGT stations (Ankerlig, Gourikwa, Avon, Dedisa) could be converted to more efficient gas-powered combined cycle gas turbines (CCGT) if sufficient gas is available and sufficient utilisation is expected (DMRE, 2019, p. 13). According to the 2017 Electric Power Research Institute (EPRI) report commissioned for setting the assumptions in the IRP, the net plant efficiency of OCGTs is 31.3% while CCGT with and without carbon capture storage (CCS) is 50.5% and 48.7% respectively, meaning more of the heat produced from the fuel can be converted to electrical energy with CCGT; CCGTs can also run for longer, with a typical capacity factor of 50% (compared to 10% for OCGT) (EPRI, 2017).

While not 100% green in the sense that the burning of gas does produce greenhouse gas (GHG) emissions, it has also been argued that gas generation can coexist with 2050 net-zero targets, for example through carbon capture and storage, green hydrogen, and synthetic natural gas (St John, 2020). Such synthetic gasses can be carbon neutral due to the fact that the carbon emitted during burning is stored and converted back into a gas to be used as fuel, through combination with hydrogen that is produced using renewable energy from water using electrolysis (Nature Research Custom Media and Tokyo Gas, n.d.).

Renewable Energy

South Africa has the ability and some of the best sunshine and wind resources in the world and could provide more than the demand needed by the country (Knorr *et al.*, 2016). As such these resources provide an opportunity to diversify and secure South Africa's while providing distributed generation (DMRE, 2019, p. 13). The contribution of renewables as an energy source to the country has increased over time (currently sitting at 6.75% of the total demand in 2022), as seen in Figure 8 below (Eskom, 2022c, p. 92).

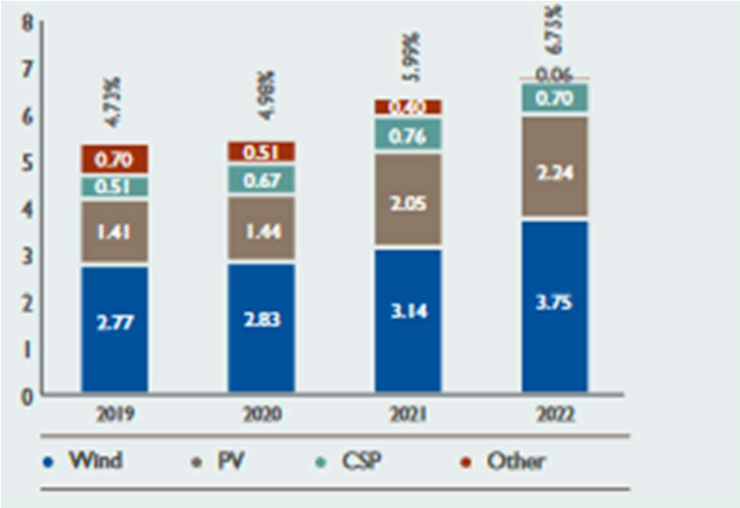


Figure 8: Contribution of renewables to South Africa's energy demand (Eskom, 2022c, p. 92)

While solar and wind are noted as the main sources of renewable energy above, generation capacity from renewable sources such as small scale hydro (<100MW) and biomass are also used in South Africa. In order to generate additional capacity, IPPs have been awarded generation contracts via: the REIPPPP (Renewable Energy Independent Power Producer Procurement Programme) intended to secure private renewable energy generation capacity which can be added to the grid through a competitive bidding process (DOE, 2018a; RSA, n.d.) and the RMIPPPP (Risk Mitigation Independent Power Producer Procurement Programme) intended to help deal with current supply constraints and reduce reliance on diesel OCGT electricity generation by securing 2000MW of generation capacity (DMRE, 2020).

Local hydroelectric generation options (other than a few small scale hydro capabilities) are limited as 90% of the hydroelectric potential in South Africa (around 14000GWh per year) has already been developed (AG, no date). As such, following the 2012 National Development Plan's emphasis on the need for enhanced regional cooperation and integration (NPC, 2012b, p. 70), there is potential to partner with SADC members and to develop hydropower generation capacity which we would then import. This would be initially from Mozambique and Zambia and in the future the Democratic Republic of Congo (The Grand 'Inga' Hydro Power Project could potentially provide 2500MW) (NPC, 2012b, p. 206).

<u>Nuclear</u>

Nuclear energy is another form of renewable energy generation that has the benefit of providing consistent baseload energy unlike the other intermittent sources like wind and solar. Currently, South Africa only has the Koeberg nuclear generation facility which reaches its end of design life in 2024 but has had its end of life extended (DMRE, 2019, p. 12).

Regarding new nuclear power, original plans for nuclear in the 2010 Integrated Resource Plan included building generation capacity from 2023 (DOE, 2010b). The 2012 National Development Plan expressed caution on pursing this option due to the unprecedented investment costs involved; it acknowledged that nuclear could provide a low-carbon baseload energy path that additional investigation on the effects of nuclear energy's inclusion in the country's energy mix would be needed (NPC, 2012b, p. 92). Other nuclear options such as the development of a nuclear pebble bed modular reactor in Koeberg and a nuclear deal with the Russian Federation; the United States; and South Korea were considered but were hindered by legal rulings (the cases leading to the rulings are discussed further in section 3.2.3). While there is potential for future nuclear energy generation, it has seen a reduction in focus with developing Integrated Resource Plans (from the 2010 to the 2019 reports).

Apart from the above energy sources that are currently being used and are focused upon when considering the future energy mix in South Africa, there is always the potential that new generation technologies are developed or that the international and local energy landscape changes in such ways as to make certain unviable. These practical considerations (the third P) are further discussed in section 3.3.

2.3.2 Energy Transmission

As discussed above, the first entity to have been spun out from Eskom is that of transmission. The NTSCA plays the role of system operator whose job it is to balance the supply and demand of electricity in the country (Eskom, 2022c, p. 41), the system operator determines at what stage of load-shedding is required in order to prevent a blackout of the entire system (Eskom Hld SOC Ltd [@Eskom_SA], 2023). Transmission takes the electricity generated and distributes it across the country to the ultimate end users. The 2023-2032 Transmission Development Plan provides details of how Eskom plans to develop infrastructure that will support the planned increased generation capacity in the country (Eskom, 2022e).

2.3.3 Energy Distribution and Demand

Electricity, after it has been generated, needs to be transmitted for use in many aspects of the country and economy (residential or household use, industry, commerce, mining, transport and agriculture) (DME, 1998, p. 6). Figure 9 shows the breakdown of the main energy demand of the country as at 2018. While not every sector requires electricity (the transport industry, for example, relies heavily on gas), the breakdown shows that industry is the largest consumer of electricity in the country (it accounts for 52% of demand whereas the residential sector accounts for 20% (Enerdata, n.d.)). As such, embedded generation (electricity production from small-scale facilities that fall outside the scope of projects like the REIPPPP (DBSA, n.d.)) provides a way for large industrial users of electricity (e.g. mines) to generate electricity from renewable sources locally and reduce the demand on the grid (Africa, 2022).

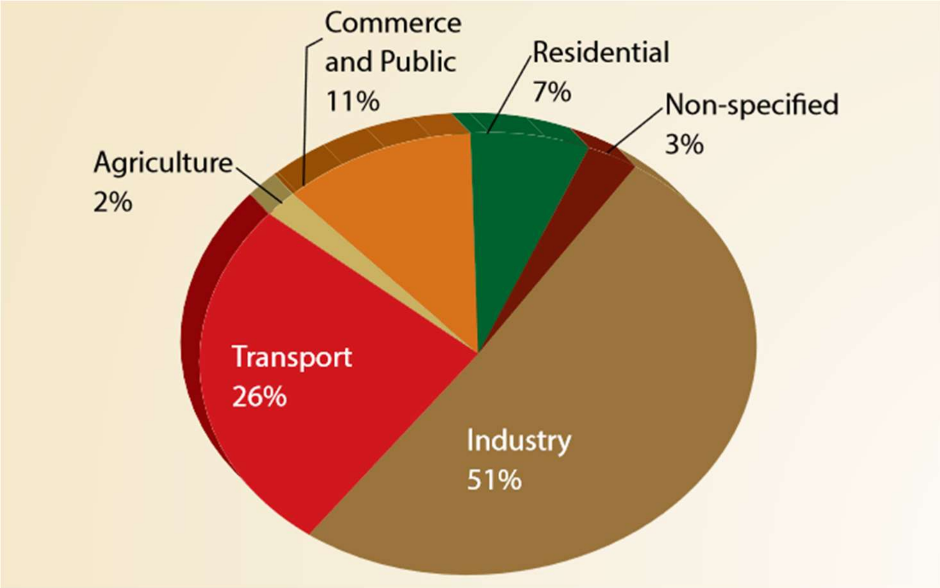


*Figure 9: South African Energy Demand per Sector (2018) (*The South African Energy Sector Report 2021*, 2021, p. 21)*

Note that distribution is not done solely through Eskom, it also sells to municipalities, ultimately around 40% of the distribution of electricity comes from municipalities and 60% from Eskom (DME, 2008, p. 10).

3. THE BACKGROUND TO THE ENERGY CRISIS IN SOUTH AFRICA

The development of the South African energy sector and the future of electricity generation in the country is influenced by the 3P's: Policy, Politics, and Practical considerations. These are all items which are constantly evolving. As mentioned in the 2023 Budget speech, in order to solve the current energy crisis a just transition towards a low carbon economy is needed (National Treasury, 2022, p. 11). This concept of a just transition to a low carbon economy, is clearly incorporated into Eskom's strategy as they have proposed a Just Energy Transition (JET) plan (Eskom, 2022c, p. 112). This plan aims to simultaneously grow the economy and create jobs ('Just') by restructuring generation capabilities away from coal ('Energy') towards more sustainable sources which have reduced GHG emissions ('Transition') (Eskom, 2022c, p. 116). 'A focus on a JET of the energy sector' is a tagline which summarises the aim of the majority of the public policy, plans and legislation that is described below. Valuable sources for additional information on the below and how they influence the energy sector include Spalding-Fecher (2002), Glazewski (1999), and Murombo (2016).

3.1 ENERGY PUBLIC POLICY IN SOUTH AFRICA

3.1.1 1998 White Paper

The 1998 White Paper (DME, 1998), the "White Paper", was one of the first documents that outlined potential energy concerns for the country. The paper outlined five main objectives for the energy sector of the country under which a short commentary on the objectives relevance to South Africa's current and future energy mix are provided:

- Access to affordable energy services

Providing all South Africans with affordable electricity is echoed in the NDP which aims to have more than 90% of population to have grid access by 2030 (NPC, 2012b, p. 163). The National Electrification Programme has been largely successful and has seen access to electricity rise from around two-thirds of people in the 1990s (NPC, 2012b, p. 165) to 83% in 2012 (Eskom, 2022a, p. ESKOM 2003-2012). Further improving this number further comes at increasing marginal costs as those without electricity access reside in more remote and rural areas. However, improving local regional generation and distribution may help to ensure that electricity is more uniformly distributed throughout the country and assist in this objective.

- Improving energy governance

South Africa's energy governance has improved over the years as multiple Acts have been passed (see section 3.1.2 below). This is also a key concern in other planning documents – the NDP notes that the electricity crisis in 2008 exposed institutional weaknesses of state-owned entities (NPC, 2012b, p. 45). Reducing delays in generation facility construction, licence issuing are resulting from poor governance structures and are key items that need to be addressed to tackle the energy crisis.

- Stimulating economic development

This aim is echoed in the National Development Plan which aims for the energy sector to be able to provide reliable and efficient energy service at competitive rates that supports economic growth and job creation (NPC, 2012b, p. 163). As mentioned in the White Paper, increased economic development through lowering costs can be done via government encouraging competition in the energy sector (DME, 1998, p. 26). Increased participation of IPPs in electricity generation is part of this increased generation.

- Managing energy-related environmental impacts

The energy sector's impact on the climate is considered throughout various pieces of government policy (see Section 3.1.7 for more detail) and heavily influences plans for South Africa's future energy mix.

- securing energy supply through diversity

The White Paper's goals to implement integrated resource planning to help inform future energy mix and to introduce energy supplies other than coal (DME, 1998, p. 29) are echoed throughout the National Development Plan and the various Integrated Resource Plans and play a large part in the planned increase of gas and renewable energy in South Africa's future energy mix.

3.1.2 Energy Regulation

Modern regulation of energy in South Africa starts in 1994 with the replacement of the Electricity Control Board with the National Energy Regulator as established in the Electricity Amendment Act of 1994 (RSA, 1994) which gave the body additional powers to regulate the electricity industry (Eskom, 2022a, p. ESKOM 1993-2002).

The National Energy Regulator was then used to establish a broader authority (extending to gas and petroleum pipelines) (Eskom, 2022a, p. ESKOM 2003-2012) of the National Energy Regulator of South Africa (NERSA) which was established under the National Energy

Regulator Act in 2004 (RSA, 2005). It takes the role of the piped-gas regulator under the Gas Act, 2001 (RSA, 2002); the petroleum pipelines regulator under the Petroleum Pipelines Act, 2003 (RSA, 2003); and electricity regulator under the Electricity Regulation Act (ERA), 2006.

3.1.3 National Energy Act

The National Energy Act (2008) has helped in the creation of the regular Integrated Resource Plans put out by the Department of Mineral Resources and Energy (DMRE) across various years (See Section 3.1.4 for the various IRPs). The Act aims to ensure that an affordable, sustainable, and uninterrupted supply of energy can be sourced from a diverse supply of energy sources to provide South Africa's electricity. It aims to do this through energy planning, improving energy conservation, promoting energy research and innovation (through the creation of the South African National Energy Development Institute), ensuring energy data collection, investment in infrastructure, and the holding of strategic energy feedstocks and carriers. (RSA, 2008)

3.1.4 Integrated Resource Plans (IRPs)

The first IRP (the '2010 IRP') was disseminated in March 2011 with its primary objective to create a plan for managing long term electricity demand and supply for the 2010-2030 period in South Africa (DOE, 2010b). An update to the 2010 IRP was produced in 2016 (the '2016 IRP Update') and provides updates to certain assumptions, the base case and the scenarios considered (DOE, 2016). A draft IRP was put out for comment in 2018 (the '2018 Draft IRP') but was not officially published (DOE, 2018b). The most recent IRP (the '2019 IRP') was released to the public in October 2019 (DMRE, 2019) and is the current basis for which much of the country's energy management policy is based off of.

2010 IRP

The first IRP consisted of three main stages: input parameters (demand forecasts, price assumptions, nominal generation capacity, learning curves for generation technology), scenario modelling and analysis and developing the IRP off a base (the 'Revised Balanced Scenario') which was developed on the most likely inputs and outputs following revision by an interdepartmental task team (DOE, 2010a, p. 5). The goal in producing a base scenario was to determine the optimal least-cost energy mix to meet demand while considering climate mitigation, job creation and localised energy generation, development in the SADC region, diversity of energy supplies, energy efficiency, and demand side management (DSM) (DOE, 2010a).

For its assumptions, the IRP considers a range of forecasted annual energy demands as displayed in Figure 10 below. The 'SO' scenarios are generated using an inhouse model (the Sectoral Model) that uses Eskom sale by customer type to generate the forecast. An independent model developed by the CSIR was also used. This model used a multiple regression model to forecast demand by linking it to demand drivers relevant to each sector consuming energy (DOE, 2010b, pp. 29–30).

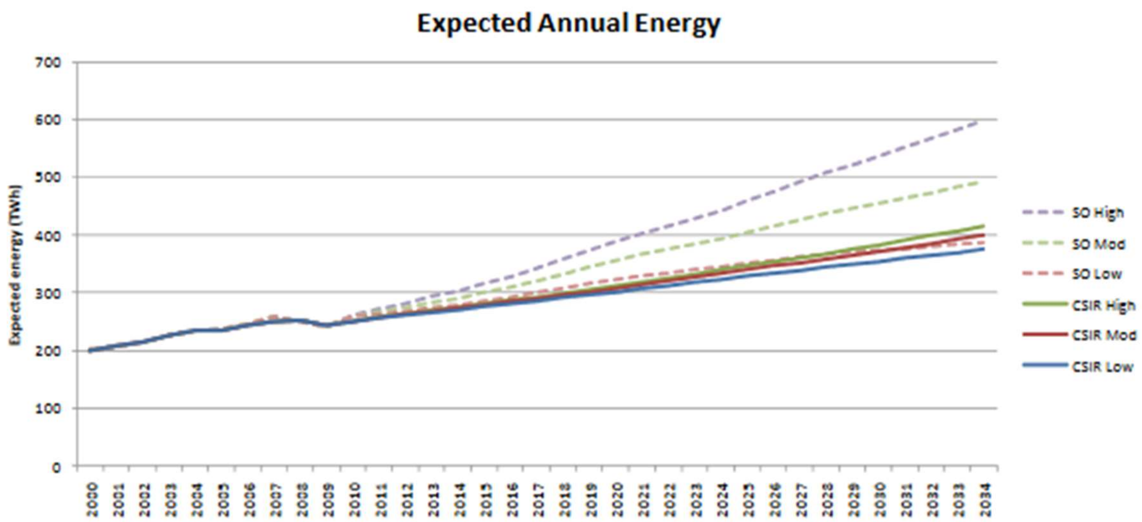


Figure 10: IRP 2010 Forecasted Annual Energy Demand Scenarios (DOE, 2010b, pp. 30–31)

A total of 17 scenarios were considered, the broad categories of scenario are discussed here:

- Base Case (3 models): Scenarios only considering direct costs and investigating the impact of Kusile and Medupi coal stations;
- Emission Limit (6 models): Scenarios considering various version of CO_2 emission levels;
- Carbon Tax (2 models): Scenarios investigating the impact of implementing a carbon tax;
- Regional development (2 models): Scenarios considering localised energy production;
- Enhanced DSM (2 models): Scenarios considering the impact of implementing DSM programmes; and
- Balanced scenario: As is and the revised version which was ultimately used as the scenario the IRP is based off of. As discussed above, scenarios aim to find the cheapest energy mix given a set of socio-economics constraints with the revised version incorporating feedback from an interdepartmental task team. (DOE, 2010a, pp. 8–9)

Notable results from the IRP include the forecasted real price of electricity (R/kWh) until 2030 (Figure 11 below) – the Revised Balanced Scenario estimates the 2023 kWh price of electricity at around R1.10 and the range of prices in 2023 as approximately between R1.00 (Balanced scenario) and R1.70 (The most stringent emission (EM) limit scenario) (DOE, 2010a, p. 16).

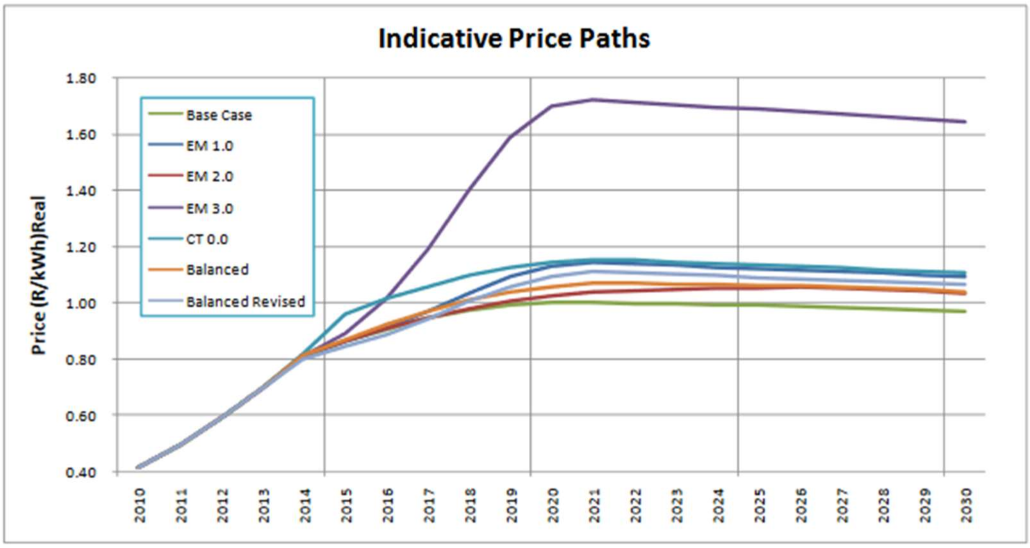


Figure 11: 2010 IRP Forecasted Real Price of Electricity (R/kWh) until 2030 (DOE, 2010a, p. 16)

The results of the Revised Balanced Scenario would see the 2030 energy mix (see Figure 12 below) incorporate a base load comprised of predominantly nuclear energy which would see new generation being added from 2023 until nominal capacity of at least 9.6GW is created by 2030, a large portion of the supply comprising of renewable energies with majority of that being wind, and gas used as the main form of peaking production in the form of IPP OCGT production (DOE, 2010b, p. 25).

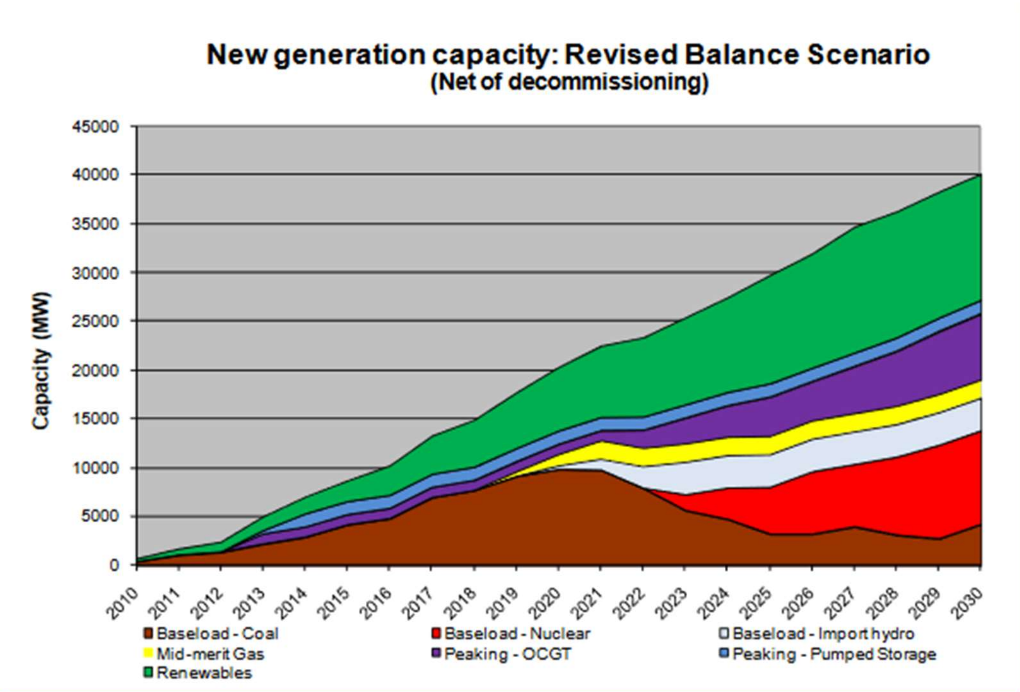


Figure 12: 2010 IRP Revised Balanced Scenario Energy Mix 2010-2030 (DOE, 2010b, p. 9)

2016 IRP Update

The 2016 update to the 2010 IRP update saw adjustments to the plan (which was extended to 2050) to incorporate additional socio-economic considerations including affordable electricity; carbon mitigation, water consumption reduction, and the decarbonisation of the energy sector; diversifying electricity generation; and localised energy generation (DOE, 2016, p. 6). Figure 13 reflects the update to a lower demand forecast – the ‘High (less energy intense)’ forecast is used in the updated plan - than the original IRP 2010 forecast (DOE, 2016, p. 9).

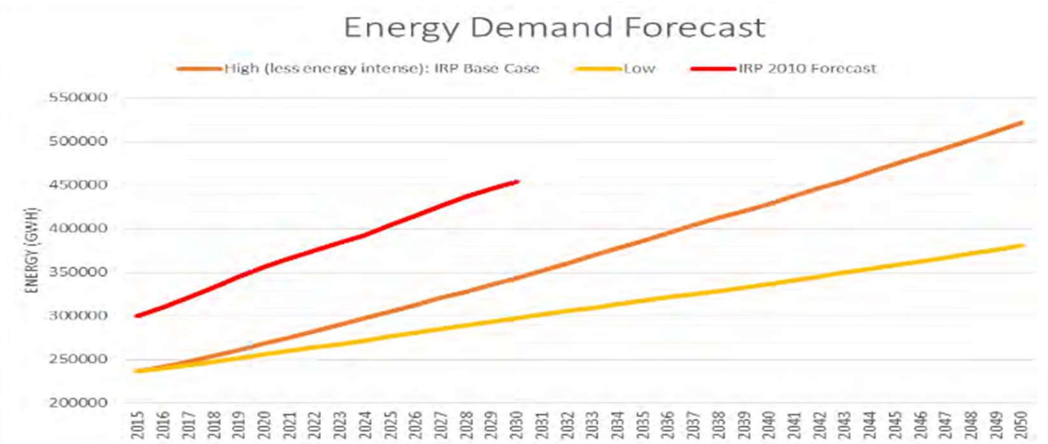


Figure 13: 2016 Update to the 2010 IRP Demand Forecast (DOE, 2016, p. 9)

The plan also includes the forecasts of plant EAFs (the moderate and low plant performance scenarios were ultimately used) – see Figure 14 (DOE, 2016, p. 11).

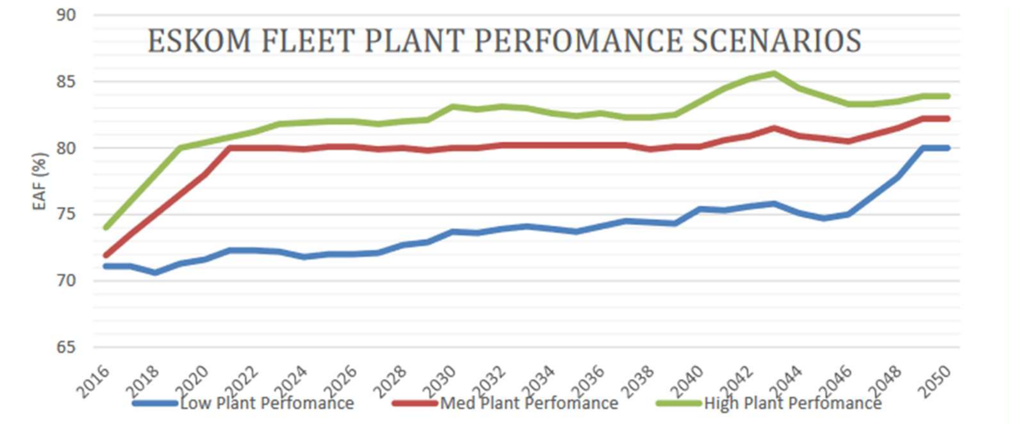


Figure 14: 2016 IRP Update EAF Forecasts (DOE, 2016, p. 11)

The 2016 Integrated Energy Plan (IEP) incorporates elements of the 2016 Updated IRP but aims to provide a higher level roadmap of the entire energy landscape than compared with the IRP (DOE, 2017, p. 11). In terms of the updated energy mix, the development of additional nuclear capacity deferred to 2030, with gas and renewables forming the largest share of the energy supply, and coal having a larger share of supply than in the 2010 IRP (DOE, 2017, pp. 17–19). The ‘Base Case’ scenario presented in Figure 15 reflects these updates to planned energy mix.

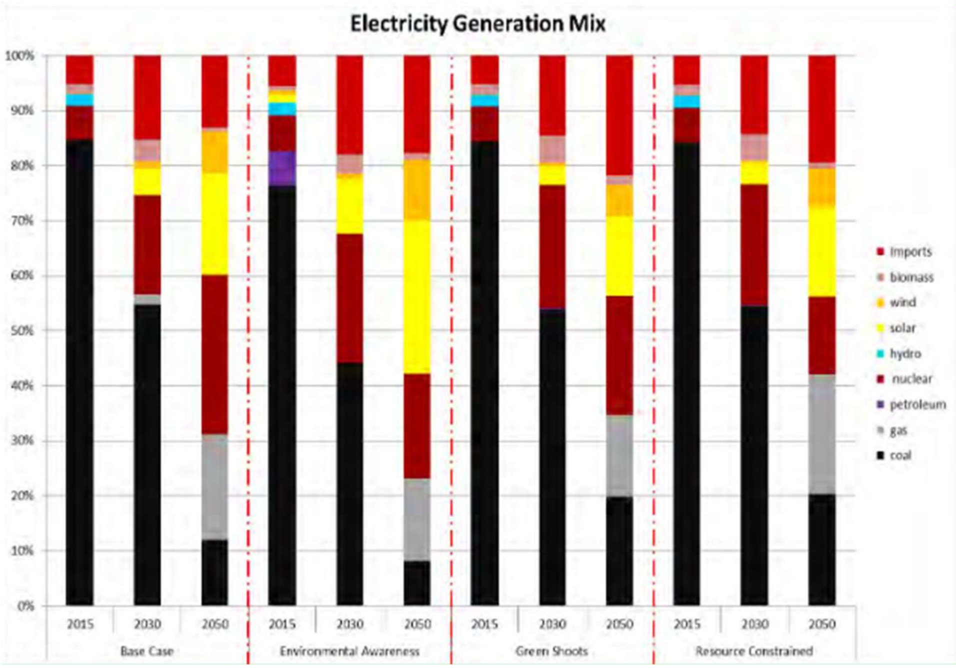


Figure 15: 2016 IEP 2015,2030,2050 Energy Mix (DOE, 2017, p. 142)

<u>*2018 Draft IRP*</u>

A proposed IRP was put out for comment in 2018 but never officially published. As such, the results are only briefly mentioned here. Interesting to note is that the PLEXOS Integrated Energy Model is used to forecast scenarios and to determine the least-cost energy mix. The main items in the plan include coals contribution making up less than 20% of the energy mix by 2050, a delay in new capacity developments as compared with the 2010 IRP, and energy from the REIPPP Programme being used to offset the decline in coal generation capacity (DOE, 2018b, p. 11,12). While the forecasted energy mix is dependent on the scenario considered, all scenarios reflect significant contribution of wind and solar (PV) to the energy supply and decreased generation of electricity from coal – see Figure 16(DOE, 2018b, p. 36).

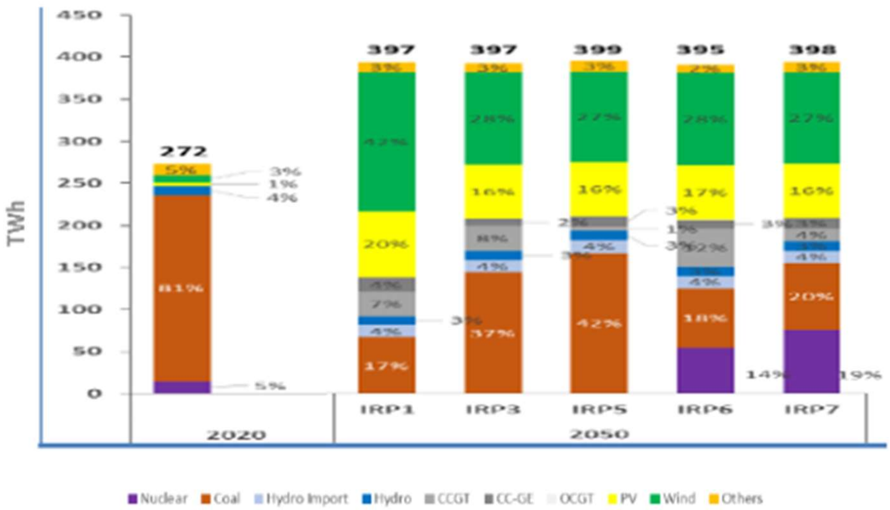


Figure 16: 2018 Draft IRP 2050 Energy Mix Under Various Scenarios(DOE, 2018b, p. 36)

<u>*2019 IRP*</u>

The 2019 IRP informs much of the country's energy system planning strategy and notes the following about the future energy mix of South Africa:

- Kusile and Medupi coal plants playing a large part in supplying base load energy to the country;
- Koeberg nuclear power station having to have its life extended by 20 years past its 2024 end of design life with the potential for additional nuclear capacity to be created in the future;
- Natural gas being used in conjunction with renewable energies to ensure reliable energy supply. Over the short-term, gas imports could help meet energy demands and over the medium- to long-term, local and regional gas resources should be investigated. See Section 2.3.1 for additional commentary on the gas sector in South Africa;
- Renewable energy sources will play a role in helping to diversify the nation's energy supplies. Particular mention is made to the potential of biomass generation to provide an opportunity for regional generation;
- Similarly, to biomass, hydro electricity generation could provide for additional regional development and a source of potential international trade with neighbouring nations;
- Storage technology as a complement to renewable energy sources needs to be investigated (DMRE, 2019, pp. 11–15); and
- Eskom's unbundling into three divisions will help to align to the proposed new generation capacities as more competition will be allowed in generation with the transmission entity acting as a single buyer (DMRE, 2019, p. 17).

The plan notes that the original demand forecasts in the 2010 IRP did not materialise due to lower than expected GDP growth, demand side reduction (load-shedding), improved energy efficiency, increased embedded generation (e.g. rooftop PV), and switching from electricity to Liquified Petroleum Gas (LPG) for cooking and heating (DMRE, 2019, pp. 25–26). Figure 17 below shows the updated demand forecast scenarios were generated using a statistical regression model per sector (DMRE, 2019, p. 27).

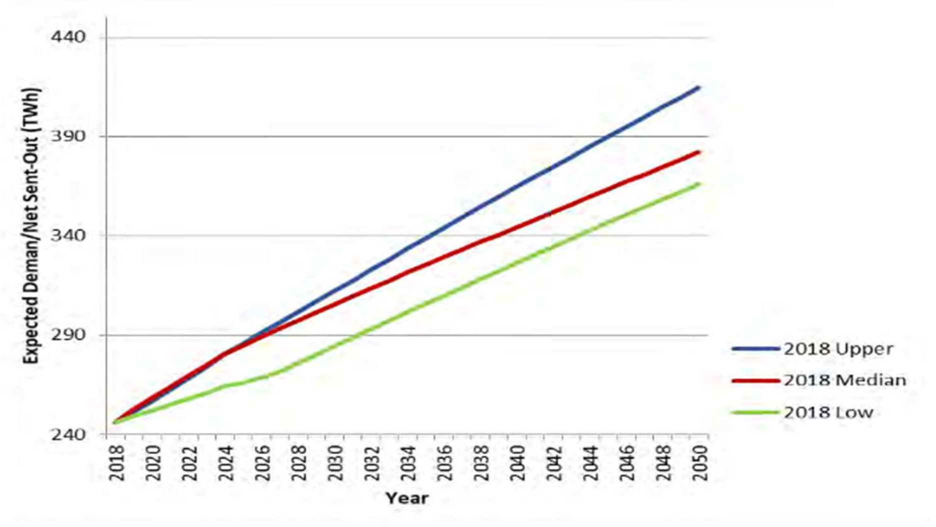


Figure 17: 2019 IRP Forecasted Energy Demand Scenarios (DMRE, 2019, p. 27)

In line with the 2010 IRP, it is determined that 39,730MW of additional generation capacity will need to be generated, with 18,459MW already being committed at the time of the 2019 IRP – this includes:

1) 6,422MW from the REIPPPP;
2) 1,322MW from the Ingula pumped storage facility;
3) 4,800MW coming from both Medupi and Kusile respectively;
4) 100MW from the Sere Wind farm; and
5) 1,005MW from OCGT generation. (DMRE, 2019, p. 33)

As discussed in previous IRPs, the assumed EAF of the Eskom fleet was overpredicted. The final 2019 plan assumes an EAF of 71% in 2020 and thereafter increasing to 75% by 2030 (DMRE, 2019, p. 34).

Serious energy supply predictions made in the plan have come to pass. Due to underperforming generation (lower than expected EAFs) and a lack of emergency margin reserves of generation capacity there has been a resultant increase in load-shedding. The plan aims to capture the cost of mitigation of this supply shortfall via additional diesel generation in a higher, than prior IRPs forecasted, electricity prices (DMRE, 2019, p. 40).Figure 18 shows the forecasted electricity tariffs under the various scenarios in the 2018 Draft IRP and the 2019 IRP (DMRE, 2019, p. 43) . It should be noted that actual prices for 2023 are higher than those forecasted across both IRPs.

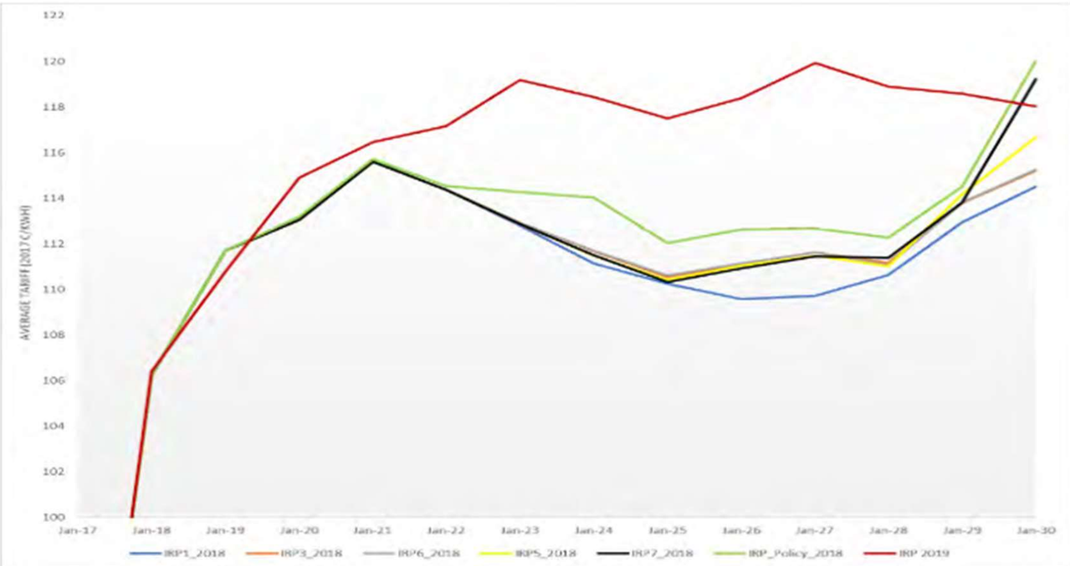


Figure 18: Comparison of 2019 IRP and 2018 Draft IRP Electricity Price (c/kWh) Forecasts over Time (DMRE, 2019, p. 43)

The initially proposed 2030 energy generation mix based off the 2018 Draft IRP is presented in the 2019 plan and is provided in Figure 19 below - of the roughly expected 77.8GW of installed capacity in 2030, the plan sees an increase proportion of supply (one-third of the 2030 total installed capacity) coming from wind and PV sources contracted out to IPPs while coal still makes up approximately 43% of the supply installed capacity (DMRE, 2019, p. 42).

	Coal	Coal (Decommissioning)	Nuclear	Hydro	Storage	PV	Wind	CSP	Gas & Diesel	Other (Distributed Generation, CoGen, Biomass, Landfill)
Current Base	37 149		1 860	2 100	2 912	1 474	1 980	300	3 830	499
2019	2 155	2373					244	300		Allocation to the extent of the short term capacity and energy gap.
2020	1 433	557				114	300			
2021	1 433	-1403				300	818			
2022	711	-844			513	400 1000	1600			
2023	750	-555				1000	1600			500
2024			1860				1600		1000	500
2025						1000	1600			500
2026		1219					1600			500
2027	750	-847					1 600		2000	500
2028		-475				1000	1 600			500
2029		-1694			1575	1000	1 600			500
2030		-1050		2 500		1 000	1 600			500
TOTAL INSTALLED CAPACITY by 2030 (MW)	33364		1860	4600	5000	8288	17742	600	6380	
% Total Installed Capacity (% of MW)	43		2.36	5.84	6.35	10.52	22.53	0.76	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
- Capacity Decommissioned
- New Additional Capacity
- Extension of Koeberg Plant Design Life
- Includes Distributed Generation Capacity for own use

Figure 19: 2019 IRP 2030 Planned Energy Mix (DMRE, 2019, p. 42)

In order to ensure the plan is practical, the 2019 IRP presents an updated 2030 mix as shown in Figure 20 below. This updated plan sees the 2030 mix being comprised of more coal and gas than previously and a slightly smaller proportion arising from wind and PV; additionally, it assumes that embedded generation can be used to help make up supply shortfall (DMRE, 2019, p. 95)

	Coal	Nuclear	Hydro	Storage (Pumped Storage)	PV	Wind	CSP	Gas / Diesel	Other (CoGen, Biomass, Landfill)	Embedded Generation
2018	39 126	1 860	2 196	2 912	1 474	1 980	300	3 830	499	Unknown
2019	2 155					244	300			200
2020	1 433				114	300				200
2021	1 433				300	818				200
2022	711				400					200
2023	500									200
2024	500									200
2025					670	200				200
2026					1 000	1 500		2 250		200
2027					1 000	1 600		1 200		200
2028					1 000	1 600		1 800		200
2029					1 000	1 600		2 850		200
2030			2 500		1 000	1 600				200
TOTAL INSTALLED	33 847	1 860	4 696	2 912	7 958	11 442	600	11 930	499	2600
Installed Capacity Mix (%)	44.6	2.5	6.2	3.8	10.5	15.1	0.9	15.7	0.7	

- Installed Capacity
- Committed / Already Contracted Capacity
- New Additional Capacity (IRP Update)

Figure 20: 2019 IRP Updated 2030 Generation Mix (DMRE, 2019, p. 95)

3.1.5 NATIONAL DEVELOPMENT PLAN (NDP)

The NDP was published in 2012 as the long-term national development plan for the country to reduce poverty, unemployment and inequality by 2030 (NPC, 2012a) and used the 2010 IRP as a main point of reference . It touches on planning for many socio-economic issues including (Education, employment, environmental sustainability, infrastructure and international trade) (NPC, 2012b). While many of these issues intersect with the energy sector, the summary of the NDP below focuses on the sections of the plan primarily focused on South Africa's energy sector.

The main concepts addressed in the NDP related to energy include resolving issues in the coal sector, investigating gas, nuclear and renewable energies as alternatives to coal, improving the diversity of the energy sector, improving the distribution of electricity, and improving national electrification and affordable electricity distribution.

South Africa has abundant coal deposits – that have historically allowed South Africa to rely on it as a fuel source. However, several issues around coal are noted in the NDP, namely: the need to improve rail infrastructure to key coal areas (e.g. the Waterberg coal field in Limpopo where two-thirds of the country's coal reserves are located), managing the security of local supply while improving coal exports, and implementing cleaner coal technologies to mitigate climate effects of coal use in the medium term until plants are decommissioned (NPC, 2012b, pp. 165–167).

Given the NDPs aim to improve the environmental sustainability of the energy sector (NPC, 2012b, p. 163), the plan provides areas of investigation of alternative energy sources. Given the country's resources, gas is presented as a potential transition fuel to meet energy demands while partially reducing environmental impact. South Africa has the fifth largest shale gas reserve globally and there are several other gas areas that the plan highlights for investigation (natural gas off the West coast, natural gas imports from Namibia and Mozambique, coal-bed methane gas, and liquified natural gas) (NPC, 2012b, pp. 167–168).

Nuclear is another possible option outlined as mentioned in the 2010 IRP that would provide a low-carbon baseload energy source. High investment costs are noted as a potential limitation with additional investigation into the economic, environmental and sourcing implications needed by the National Nuclear Energy Executive Coordinating Committee (NNEECC) (NPC, 2012b, p. 172).

While gas and nuclear may play a role in diversifying South Africa's energy mix and improving the country's energy security, the inclusion of renewable energies (wind, solar and hydroelectric) to reduce the nations greenhouse gas emissions is also needed (NPC, 2012b, p. 168).

Part of the diversification of South Africa's energy includes improving energy generation competition in the market by establishing an independent system and market operator (ISMO) and allowing for IPPs to contract and supply energy to this entity responsible for transmission of electricity (NPC, 2012b, p. 169).

In addition to the ISMO, the NDP notes that municipal distribution of electricity needs to be improved as they distribute around half of the country's electricity although little progress has been made to invest in infrastructure which coincides with increasing local supply failures (NPC, 2012b, p. 170).

All of the above are items that need to be investigated while considering that the country aims to achieve wide-spread electrification (more than 90% of households by 2030) with electricity that is affordable (NPC, 2012b, p. 169) and sourced from a cleaner and more diversified resource base.

3.1.6 Splitting Up Eskom

The Eskom Conversion Act of 2001 saw Eskom become a public company wholly owned by the state and would see the state-owned entity (SOE) needing to pay tax (RSA, 2001). The Independent System and Market Operator Act was proposed in 2012 but has subsequently been withdrawn in March 2014 (Parliamentary Monitoring Group (PMG), n.d.). The bill would have seen the establishment of an independent entity that would be responsible for procuring, purchasing and transmitting electricity through the South African grid (NPC, 2012b, p. 175). Given that the bill has been withdrawn, the new transmission entity (NTCSA) will fill many of the roles envisaged for the Independent System and Market Operator. The State of the Nation Address in February 2019 put into action the separation of Eskom into Generation, Transmission, and Distribution (Department of Public Enterprises (DPE), 2019).

This separation allows additional competition as IPPs can then be enabled to enter the generation market (Spalding-Fecher, 2002, p. 7). More details on how the three entities are planned to function is found in Section 2.3.

3.1.7 Climate Change Policies

The NDP focusses throughout on the need for environmental sustainability via pollution reduction in order to mitigate the effects of climate change (NPC, 2012a, p. 163). It also notes the fact that South Africa needs to transition away from non-renewable energy resources (coal) and utilise its solar, wind and hydropower resources (NPC, 2012a, p. 198) . The plan acknowledges a main challenge of this strategy in that the transition to these resources needs to be done in a way that of de-links economic productivity, environmental damage and carbon-intensive energy while remaining competitive and meeting the needs of society (NPC, 2012a, pp. 198–199). This is especially challenging as much of South Africa’s economic production comes from manufacturing and mining sectors contribute around 20% of the country’s GDP (see Figure 21 below) which are very energy intensive, and this energy demand is difficult to meet if emission levels need to go down to keep in line with international environmental commitments. While there is a local need for a JET, consideration also needs to be given to South Africa’s role in climate change reduction as part of a global society.

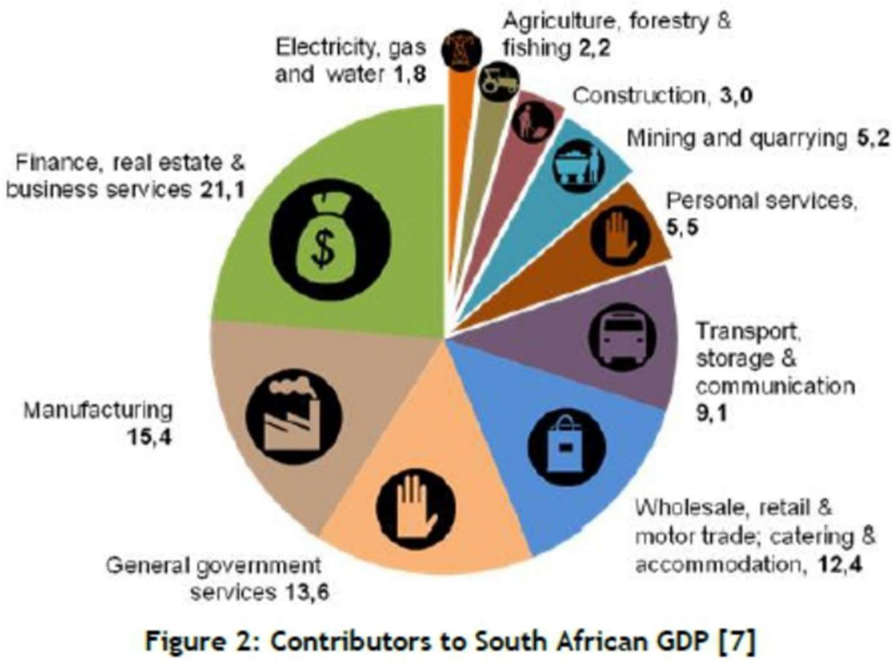


Figure 21: Breakdown of South Africa's GDP (2013) (Dewa, van der Merwe and Matope, 2020, p. 112)

In April 2016, South Africa became a signatory to the Paris Agreement on Climate change which requires governments to cooperate and to limit GHG emissions in an effort to limit global temperature increase to below 2°C (with efforts to limit the increase to 1.5°C) relative to pre-industrial levels (RSA, 2016). As part of this cooperation, countries need to submit Nationally Determined Contributions (NDCs) to the United Nations Framework Convention on Climate Change (UNFCCC). South Africa's first NDC in 2016 included a target range between 398-614Mt CO_2e[4] in both 2025 and 2030 as part of a 'peak, plateau and decline' trajectory to 2050 (Republic of South Africa, 2021). In September 2021 South Africa submitted its updated NDC to the UNFCCC indicating an updated target range between 398-510Mt CO_2e in 2025, and between 350-420Mt CO_2e in 2030 (Republic of South Africa, 2021). This conveys a significantly more ambitious mitigation target that allows South Africa to remain on a pathway well below 2°C, and to continue to strive for a 1.5°C pathway.

These commitments are reflected in the legislative space as various Acts have been put into legislation. Most recently, the Climate Change Bill [B9- 2022] (the 'Climate Bill') was presented to parliament in February 2022 having the express purpose in developing a sustainable response to climate change which develops a long-term, just transition to a climate-resilient and low-carbon economy (RSA, 2021). The preamble in the Climate Bill points to a predecessor document, the 2011 National Climate Change Response White Paper (RSA, 2011), as a source for the need to implement an effective climate change response.

Given the above local and international policies, the actual implementation of achieving reduced emission standards must be considered. The NDP suggests that given South Africa's dependence on coal, carbon capture and storage (low emission coal generation technology) be investigated (NPC, 2012a, p. 207). It also points out that in order to encourage a transition

[4] CO_2 equivalent

to a low-carbon economy that GHG emitters must be encouraged to internalise their environmental costs through methods such as a carbon budget, and pricing carbon through and carbon pricing (e.g. a carbon tax) (NPC, 2012a, p. 207).

Section 24 of the Climate Bill concerns the establishment of carbon budgets limiting the amount of emissions that can be made by particular emitters in specified given 5-year periods. As described in Eskom's 2022 Integrated Report, included in the first phase of the Climate Bill will be prescribed mandatory carbon budgets for January 2023 to December 2027 (Eskom, 2022c, p. 116). In the same section, Eskom's report summarises the 2019 Carbon Tax Act (CTA) (RSA, 2019) and explains some near-term implications and risks, some related to the planned unbundling of Eskom, as follows:

The CTA was introduced to help meet South Africa's NDC under the Paris Agreement and aims to encourage a reduction in carbon-intensive product usage by levying a carbon tax on GHG emissions (Eskom, 2022c, p. 116). Following the National Budget Speech in February 2022, this tax was sitting at R144 per 1MT CO_2e as of January 2022 with an aim to reach USD20 and USD30 per tonne in 2025 and 2030 respectively (National Treasury, 2022, p. 15).

The carbon tax is an example of a Pigouvian tax[5] which forces market participants to internalise climate externalities. This affects electricity producers and its influence can be seen in Eskom's 2022 Integrated report in which they allude to the financial ramifications of the tax and their ability to offset their tax liability through renewable IPP purchases (Eskom, 2022c, p. 116). Apart from the carbon tax, the country's future energy mix is heavily influenced by the above climate policies and legislation and their aim to move towards a decarbonised economy. Eskom, for example, incorporates the sentiment of reducing emissions in their JET strategy which aims to reach net zero emissions by 2050 while promoting job growth (Eskom, 2022c, p. 38).

3.2 POLITICS IN SOUTH AFRICA

Whereas the above sections details policies, plans, and legislation that creates the framework in which the energy sector in South Africa should ideally act, this section provides some examples of where the people element (or 'politics') that has prevented the above being enacted as expected.

3.2.1 POOR GOVERNANCE LEADING TO DELAYS

As mentioned in the NDP, the beginning of the electricity crisis in 2008 exposed institutional weaknesses of state-owned entities (NPC, 2012b, p. 45). These weaknesses form part of a broader governance issue that manifests itself in the form of delays which slow down any progress that can be made in solving the energy supply issue. Examples of such delays include the delay in operationalisation of the Medupi and Kusile coal fire stations (Business Tech, 2022) , the separation of Eskom into its three main functions (Eskom, 2022c, p. 41), the continuation of the REIPPPP process between 2015 and 2019 and general delays in REIPP approval and addition to the grid (Evans and Ngcuka, 2023), producing consistent IRPs

[5] A Pigouvian tax, named after 1920 British economist Arthur C. Pigou, is a tax on a market transaction that creates a negative externality, or an additional cost, borne by individuals not directly involved in the transaction. (Tax Foundation, n.d.)

which are recommended to be published every two years (Portfolio Committee on Energy, 2018).

Stronger governance structures are required to ensure adherence to the NDPs goal of having sound policy making and to have accountability and transparency in South Africa's JET to a low-carbon economy(NPC, 2012b, p. 200).

3.2.2 Power Plays

Apart from institutional inefficiencies, there are cases where political motives have driven decisions regarding the energy sector that have at times worsened the energy crisis. The manipulation of energy sector governance frameworks, by individuals in in the past, has had significant impacts which are still being felt in the present. As part of the investigation of State Capture[6], a report of the Portfolio Committee on Public Enterprise was published in 2018 and looks into the governance, procurement and the financial sustainability of Eskom given its role in State Capture (Portfolio Committee on Public Enterprises, 2018). While political commentary is not in the scope of this paper, the ultimate effects of the findings in the report show how political interests can be at odds with an electricity sector in crisis and be a source of operational risk[7]. The report details how irregular procurement processes, a lack of independent oversight, and the inappropriate dismissal of highly skilled workers cost Eskom billions of Rands (Portfolio Committee on Public Enterprises, 2018, pp. 4–5). The harm caused to Eskom by State Capture in terms of increased unexplained expenditure, procurement of unbeneficial services and supply agreement, and reduction in skilled workers makes the country's main electricity work of solving the energy crisis even harder.

Operational risk still needs to be a consideration when thinking about potential barriers that may prevent the JET future as laid out in public policy from being achieved. Andre de Ruyter (Eskom's outgoing CEO that was appointed in 2019) has alleged that high-level officials may be involved in the misappropriation of funds and put forward allegations of criminal syndicates in Mpumalanga stealing around R1bn from Eskom each month (Masilela, 2023). Again, commentary on the political involvement is not in the scope of this paper. However, the large risk that corruption poses to a successful JET of the South African energy sector should be noted as it poses a large operational risk.

3.2.3 Competing Interests

Given that electricity is intricately incorporated into all facets of South Africa's economy, any electricity plan needs to consider a wide range of stakeholders. This consideration often means needing to adjust plans to incorporate different and conflicting interests. In the extreme case, corruption arises due to the interests of a handful of individuals wanting to enrich themselves being in conflict with the ability of a country to generate widespread, affordable and sustainable electricity. The State Capture of Eskom described in the section above is not the only (nor is it the most recent) example of situations arising in the energy sector where key stakeholders have conflicting interests.

[6] When individuals (or a group of them) acting in the public and private sector influence legislation and policy making for their own gain (Martin and Solomon, no date, p. 22)

[7] Operational risk being the risk of loss resulting from failed or inadequate internal processes, people and systems (Auditboard, 2023)

Another example involving Eskom is that of the issue of cost-reflective tariffs. Over the past several financial years, Eskom has been unable to increase the price of electricity towards a 'cost-reflective tariff' in order to produce additional revenue to improve its financial position (Eskom, 2022c, p. 82). Given that electricity supply is constrained, economics would then argue that the economic cost of providing electricity and the price charged (given that demand stays the same) would have to increase. However, Eskom's executive reports in Eskom's 2022 Integrated Report express the challenges they've experienced in getting NERSA to agree with the price increases they have proposed in the past (Eskom, 2022c, pp. 20–26). Table 1 below shows the Eskom proposed vs NERSA approved tariff charges for the coming and the past Eskom financial year.

Table 1: Eskom-proposed vs NERSA approved energy tariff increases

Eskom Financial Year	**2022/2023**	**2023/2024**
Proposed Price Increase	20.50%	32.00%
Actual Price Increase approved by NERSA[8]	9.61%	18.65%
Source	(Eskom, 2022c, p. 34)	(Mntambo, 2023)

In determining tariff increases for consumers of electricity, NERSA employs a multi-year price determination (MYPD) methodology which is reviewed when needed (NERSA, 2021, p. 34). The MYPD 4 methodology is currently in place, with MYPD being discussed for the 2023-2025 period. This methodology aims to meet the objectives set out in the DME's Electricity Pricing Policy (EPP) document – objectives which align to the ERA's principle that pricing should enable "an efficient licensee to recover the full cost of its licensed activities, including a reasonable margin of return" (DME, 2008, p. 14).

In the above circumstance, it can be argued that both parties are acting in the favour of the economy. In order to combat the energy crisis and to help facilitate a transition to a low-carbon economy, Eskom requires additional money to improve its plant performance through much needed maintenance (Eskom, 2022c, p. 25) and it also comments on additional immediate tariff increases of 20% to remove its dependence on government support and a 10% increase to cover costs from the CTA and the RMIPPPP (Eskom, 2022c, p. 33). On the other hand, NERSA - under the ERA (RSA, 2006, p. 6) - has on objective to ensure that the needs of current and future electricity customers are met efficiently, effectively and in a long-term sustainable manner. In determining the MYPD for 2023/24, comments from the public were noted and there are numerous comments from groups pointing out that Eskom's current situation is due to inefficiencies and corruption and that the general public should not have to pay higher electricity prices to make up for Eskom's errors as that encourages inefficiencies in the electricity sector (NERSA, 2021). Additionally, current electricity customers have the need for affordable electricity which is put in jeopardy as the historic cost of electricity has outpaced inflation (see Figure 22 below).

[8] Note that different types of consumers of electricity are charged different electricity prices. The prices in the table represent the overall average increase.

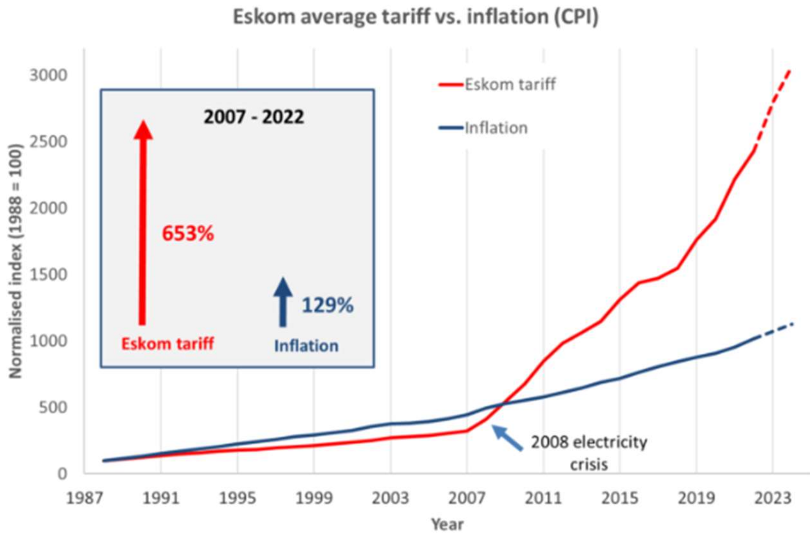


Figure 22: Eskom Average Tariff vs. CPI Increases (Moolman, 2021)

The difference in NERSA's and Eskom's opinion has resulted in legal action as Eskom argues that the energy regulator did not correctly allow for Eskom's regulatory asset base when deciding upon the 9.61% increase for 2022/23 (Creamer, no date) . This is not the only time that Eskom's policies and plans have conflicted with the interests of others and resulted in legal action being levied against the SOE. In *Earthlife Africa (Cape Town) v Director General Department of Environmental Affairs and Tourism and Another (7653/03) [2005] ZAWCHC 7; 2005 (3) SA 156 (C); [2006] 2 All SA 44 (C); 2006 (10) BCLR 1179 (C) (26 January 2005)* , the non-profit (Earthlife Africa) applied to the High Court of South Africa in an attempt to prevent the construction of a nuclear pebble bed modular reactor in Koeberg on the grounds that the construction of the facility was approved by the Department without considering independent comment correctly. The decision was in favour of Earthlife Africa and, citing cost reasons, the project was ultimately shelved in 2010 (POWER, 2010).

Other court cases which have seen climate interests clashing with the generation interests of the energy sector are *Earthlife Africa Johannesburg and Another v Minister of Energy and Others (19529/2015) [2017] ZAWCHC 50; [2017] 3 All SA 187 (WCC); 2017 (5) SA 227 (WCC) (26 April 2017)* ("Earthlife Johannesburg v Minister of Energy") and *Normandien Farms (Pty) Limited v South African Agency for Promotion of Petroleum and Exploitation SOC Limited (24294/2016) [2017] ZAWCHC 53 (3 May 2017)* ("Normandien Farms v South African Petroleum Agency").

Earthlife Johannesburg challenges steps by the government to further nuclear procurement from the Russian Federation. The case argued that NERSA's approval of the nuclear procurement was not done considering the public's best interest and a lack of transparency in the Minister of Energy's tabling of three intergovernmental agreements (IGAs) for nuclear procurement from the Russian Federation, United States, and the Republic of Korea resulted in the decision that the tabling of these IGAs to Parliament was unconstitutional. This case halted a R1-trillion nuclear dela with Russia and steer South Africa away from a large base load coming from nuclear power (Lekalakala, 2022).

Normandien Farms v South African Agency for Promotion of Petroleum Exploitation prevented the awarding of an exploration right to Rhino Oil and Gas Exploration SA given that the Petroleum Association of South Africa did not comply with certain requirements under the Mineral and Petroleum Resources Development Act 28 of 2002 (Glazewski, 2017, pp. 12–18).

While the forecasting of South Africa's energy mix seems like a technical and quantitative exercise, a "politics" or people element exists which influences the actual ability of the country's electricity sector to follow the policies and plans laid out in section 3.1 and presents a source of operational risk for the energy sector.

Poor governance and planning results in delays in enacting energy plans, power plays by individuals in an effort to enhance their own wealth results in additional costs borne by the energy sector, and the competing interests of various stakeholders can at times hinder the ability of energy sector stakeholders to implement plans and at other times completely prevent energy plans from being acted upon.

While the above two sections have elaborated on 2 P's (namely **P**olicy and **P**olitics) which are related to how the government and various stakeholders have influenced the energy sector's future plans, the third P (**P**ractical considerations) discussed below aims to also provide insights into uncertain areas that have the potential to significantly shape the energy landscape of the country.

3.3 PRACTICAL CONSIDERATIONS

3.3.1 CHANGING LOCAL & INTERNATIONAL ENERGY LANDSCAPE

Any electricity forecast require assumptions around the availability, cost and range of different technologies that can be used to generate electricity. However, changes to both the local and international energy landscape have the ability to significantly influence these forecasts.

An example of recent international developments that have impacted the energy sector are increases in global oil prices as a result of decreased supply following from the Russia-Ukraine war (S. Business Tech, 2022). Given the recent additional reliance on OCGT electricity generation to stem load-shedding, increased fuel prices caused an increase of the budgeted primary energy costs for their 2023 financial year of around 5% or R6.8bn (Eskom, 2022c, p. 78). As such, considerations around things affecting our current supply of energy sources needs to be considered in addition to considering future sources of energy that are currently untapped.

The 2050 infrastructure plan makes mention of local production of green hydrogen and the creation of a Green Hydrogen Valley in South Africa as a source for economic development and a source of green energy (Department of Public Works and Infrastructure, 2022). Green hydrogen is hydrogen produced using renewable energy resources with zero emissions via processes such as water electrolysis (Department of Science and Innovation, 2021). As the South African Hydrogen Society Roadmap notes, given the country's ability to access large amounts of renewable energy in the form of wind and solar, the production of hydrogen could help reduce carbon emissions in the country by providing a source of green energy for OCGT and CCGT electricity generation, being used to help decarbonise the transport industry through hydrogen powered vehicles, and providing a green source of hydrogen for industrial applications (Department of Science and Innovation, 2021).

New technologies such as green hydrogen have the potential to impact the cost, GHG emissions and broader economic value assumptions that are used when producing forecasted future energy mixes that influence energy planning. However, given that these technologies are new, assumptions around the costs and generation capacity of these technologies is likely to vary as time progresses and technology improves. Examples include renewable energy technologies like solar and wind which have seen significant decreasing costs over time. As costs decrease over time (see Figure 23 below), it incentivises energy mix forecasts to include a larger share of renewables when generating options for a least cost energy mix (Creamer, no date) .

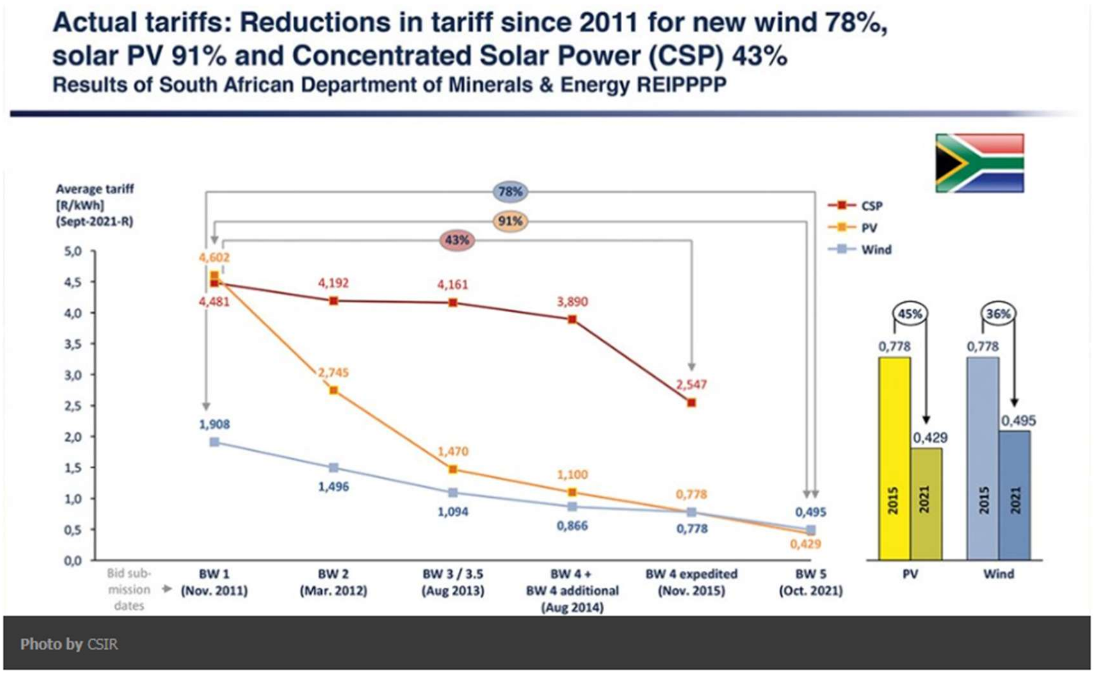


Figure 23: Decreasing Costs of Renewable Energy in South Africa

As the local and international energy landscape changes, energy mix forecasts need to be updated regularly to allow for new technologies when determining scenarios that reflect a least-cost and secure energy supply.

3.3.2 Eskom's Balance Sheet

As mentioned in the IRP of the same year, as of 2019, Eskom's debt burden was over R13.5bn with non-payment of municipalities not helping in Eskom's ability to meet these obligations (DMRE, 2019, p. 18). Looking at Eskom's 2022 annual integrated report: Municipal debt has increased to R44.8bn as of their integrated report (Eskom, 2022c, p. 85).

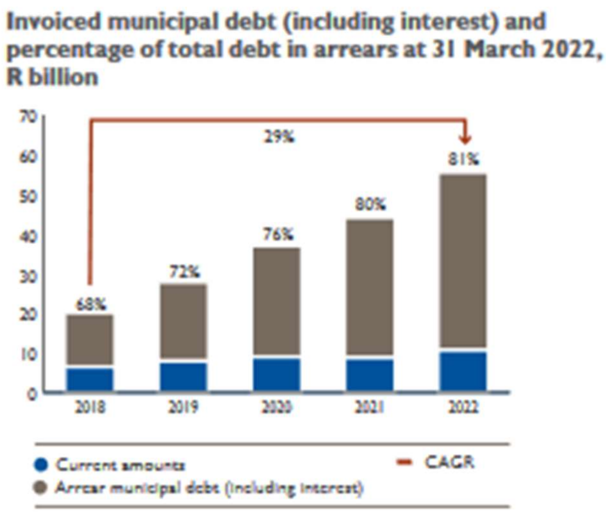


Figure 24: Municipal Debt Owed to Eskom (2018-2022) (Eskom, 2022c, p. 85)

The issues above are further exacerbated by the fact that the SOE has seen around a 1% decrease each year in sales volumes. While raising prices to be cost-reflective may on one hand help increase income, it may also result in many people being unable to afford and pay for electricity. Both Masike and Vermeulen (2022) and Inglesi and Pouris (2010) note the elasticity of consumer demand as electricity prices increase. This would mean that Eskom's sales volumes could decrease further reducing the expected increase in revenue from prices.

Without a stable balance sheet and financial liquidity, Eskom is unable to undertake much needed maintenance for generators which is needed to meet targeted capacity factors in the 2019 IRP. In the 2023 Budget Speech, the government announced that they would take over R254bn of Eskom's debt (Godonngwana, 2023, p. 8). In order for a JET to occur in the country, Eskom's financial stability needs to be improved as Eskom still provides around 90% of the country's energy (NPC, 2012b, pp. 163–164). Energy mix plans would be hindered were Eskom's financial position to result in its inability to operate.

Professor Roula Inglesi-Lotz and Associate Professor Heinrich Bohlmann in the Department of Economics at the University of Pretoria note many of the considerations and issues that we have pointed out above such as the provide delays in the REIPPPP process and building of Medupi and Kusile, the financial effects of state capture, the issues resulting from NERSA and Eskom's conflicting interests (Inglesi-Lotz and Bohlmann, 2022). In the same article, Inglesi-Lotz and Bohlmann note that any fixes are not likely to be in the short-term, the next section provides information on how plans around the future of the energy mix in South Africa may be generated as a basis for decision making. It includes discussion on the models used to generate such forecasts (Section 0) as well as a review of the views of other research on what South Africa's future energy mix may look like (Section 4.2).

4. THE CURRENT VIEW OF THE FUTURE ENERGY MIX IN SOUTH AFRICA

The 3P's considered in the section above (Policy, Politics, and Practical considerations) provide the context why our energy mix is what it is currently and how our lack of supply, leading to lead shedding, has resulted in the current state of the energy crisis. This section considers the current outlook on the future of South Africa's energy mix is. Prior to that, a description of existing energy system models commonly used is provided to give insight into how entities (like the DMRE when setting the IRP) determine potential future paths, policies, and plans related to the energy sector.

4.1 EXISTING ENERGY SYSTEM MODELS IN THE LITERATURE

Energy systems models can broadly be classified into bottom-up and top-down models (Herbst *et al.*, 2012, p. 5). The main differentiating factor being that bottom-up models usually contain a higher-degree of technical specification whereas top-down models they allow for interaction with broader economic influences (welfare from the state, employment and economic growth) (Herbst *et al.*, 2012, p. 8). Top-down models include input-output models, econometric models, computable general equilibrium (CGE) models, and system dynamics models (Herbst *et al.*, 2012, p. 4). Bottom-up models include: partial equilibrium (PE) models; optimisation models; and simulation, multi-agent models, and accounting models. (Herbst *et al.*, 2012, pp. 8–14).

As Herbst *et al.* (2012, p. 15) notes, the incorporation of technological detail (e.g. inclusion of granular nominal generation capacity and capacity factors) into bottom-up models allows them to provide useful insight into forecasted energy demand and supply. Given that the model in this paper is focused on forecasting South Africa's energy mix, a bottom-up approach has been employed. To provide additional context, expansion on the types of bottom-up models is provided below.

PE models are related to the top-down CGE models in that both involve using multiple equations serving as representations of the behaviour of a particular system (Scottish Government, 2016). Where they differ is that PE models look at a particular sector in the economy (Herbst *et al.*, 2012, p. 9), in this case the energy sector. CGE models aim to capture the entire economy (Scottish Government, 2016). Examples of a PE model include the POLES model described below.

Optimisation models use granular accounting energy data and optimise the mix of energy for a given level of demand according to a provided optimisation criteria (e.g. minimised unit cost of electricity or a target metric for CO^2 (Bhattacharyya and Timilsina, 2010, p. 6; Herbst *et al.*, 2012, p. 10). Examples include the MARKAL model described below.

Simulation models aim to use a base accounting framework to determine relationships between all the elements in the energy system (e.g. energy prices, generation technologies, climate standards) (Herbst *et al.*, 2012, pp. 11–12). They can then be used for scenario testing in which various future outcomes (e.g. decreasing costs of renewable energies) may influence elements of the energy system; this provides a useful narrative within which to interpret the results from the model (Bhattacharyya and Timilsina, 2010, p. 23).

Multi-agent models aim to build upon simulation models by incorporating game theory elements through Agent-based Computational Economics (ACE) (Herbst *et al.*, 2012, p. 13). These agents then act as goal-orientated entities that through interaction with other agents provide non-linear emergent properties that aim to model real world interactions (Voudouris and Di Maio, 2010). The ACEGES model described below is an example.

Energy accounting models are simple simulation models in that they model the ins and outs of an energy system (tracking how energy moves through the energy system) (Herbst *et al.*, 2012, p. 12). Accounting models (such as LEAP described below) aim to account for supply and demands elements of a system and model their interactions,

The example models discussed above along with several other notable existing energy system models are discussed below.

4.1.1 POLES (PROSPECTIVE OUTLOOK ON LONG-TERM ENERGY SYSTEM)

A partial equilibrium model, POLES was developed by Enerdata and aims to model international energy markets and captures both supply and demand (Bhattacharyya and Timilsina, 2010, pp. 27–28).It forecasts both global and regional supply, demand and greenhouse gas emissions (Enerdata, 2015). The model is run year-by-year recursively and models regional demand and supply which adjusts for lagged international prices (Herbst *et al.*, 2012, p. 9). The figure below shows a diagrammatic depiction of the model's workings.

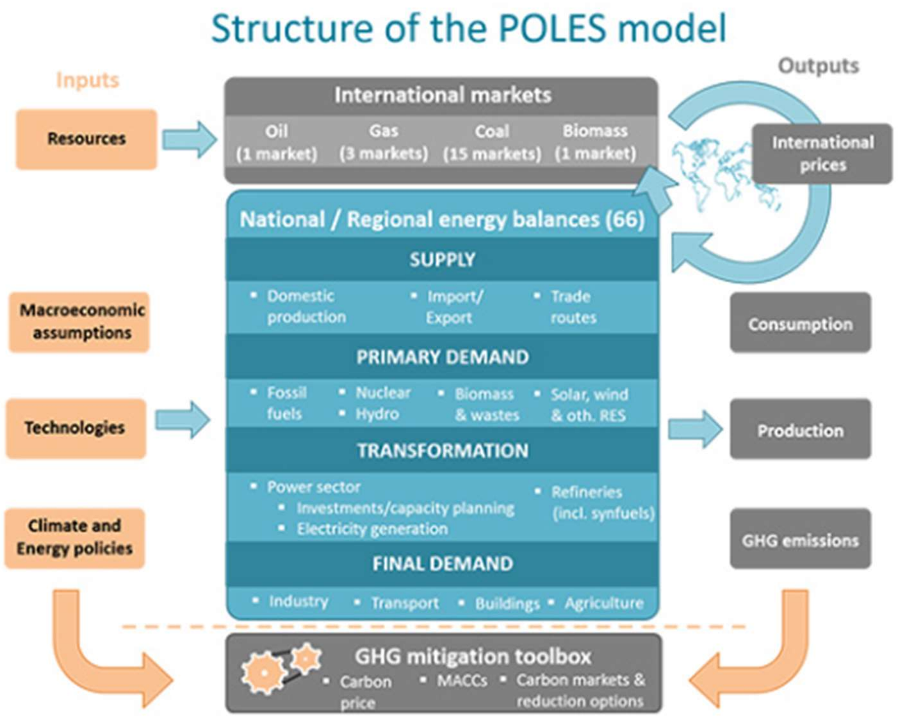


Figure 25: POLES Model (Enerdata, 2015)

4.1.2 MARKAL (MARKET ALLOCATION)

The original MARKAL model was developed under the IEA's Energy Technology Systems Analysis Programme (ETSAP) in the 1980's (EnergyPLAN, 2013a). It was originally developed as a bottom-up model that aimed to optimise energy supply according to a least-cost method with restraints on emission levels (Herbst *et al.*, 2012, p. 10). The model has since then been extended in different ways to produce a family of models (Bhattacharyya and Timilsina, 2010, p. 21). The most notable being the TIMES model originally developed in 2000 (Enerdata, 2015). The extended MARKAL/TIMES model still performs linear optimisation to produce the least-cost energy solution, however, it now also allows for features such as: flexible-time periods (year/season/week/time-of-day segmenting); commodity flows; and data decoupling (Loulou *et al.*, 2016, p. 133). In capturing both technical and economic links into the model, this is an example of a hybrid model. A figure below depicts the main inputs and outputs in the MARKAL/TIMES model, it shows the level of granularity, interconnectedness and consideration of the broader macroeconomic environment that is employed.

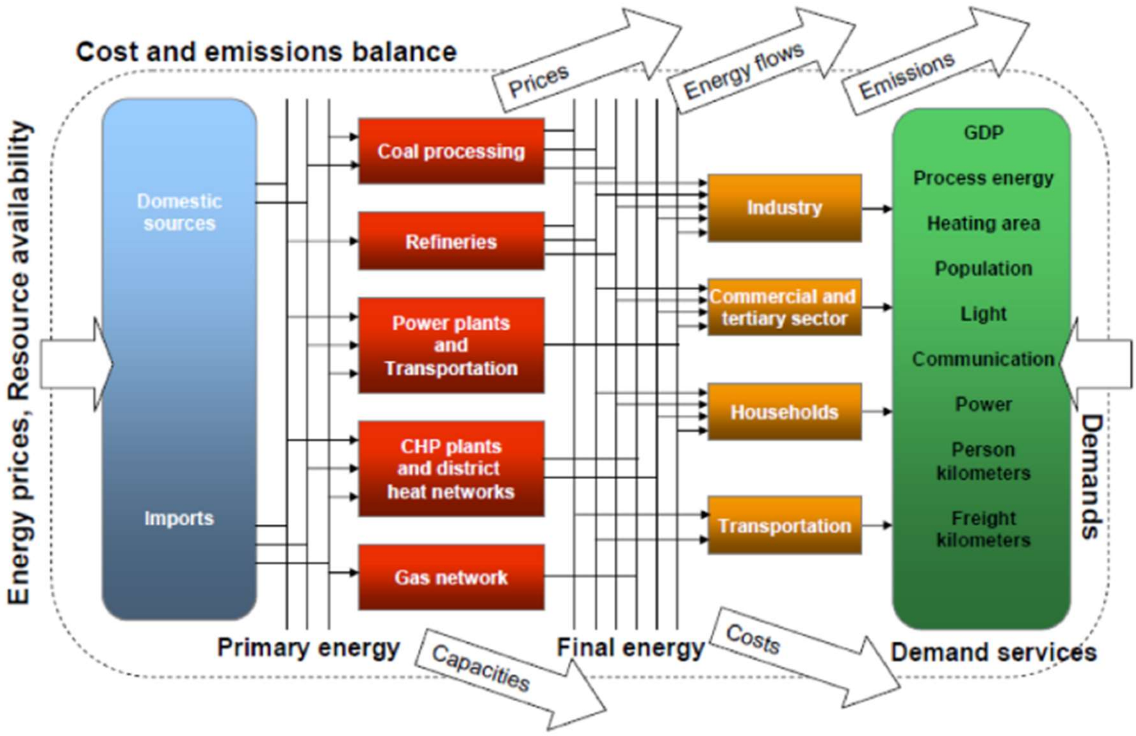


Figure 26: Diagram of MARKAL/TIMES main inputs and outputs. Schematic from (Energy Techonology Systems Analysis Programme (ETSAP), nd) based off of the source (Loulou et al.*, 2016).*

4.1.3 LEAP (Low Emissions Analysis Platform)

LEAP is a modelling software developed by the Stockholm Environment Institute designed to allow users to model energy systems - the models calculation structure is provided below (Stockholm Environment Institute (SEI), n.d.). The model allows for scenario generation is enabled through modelling demand (either via a top-down or bottom-up approach) and supply (via accounting or simulation techniques) (Bhattacharyya and Timilsina, 2010, p. 23). The newer versions of the LEAP model allows for least-cost energy supply optimisation (Stockholm Environment Institute (SEI), n.d.) whereas earlier versions were able of only simulating various user led simulations.

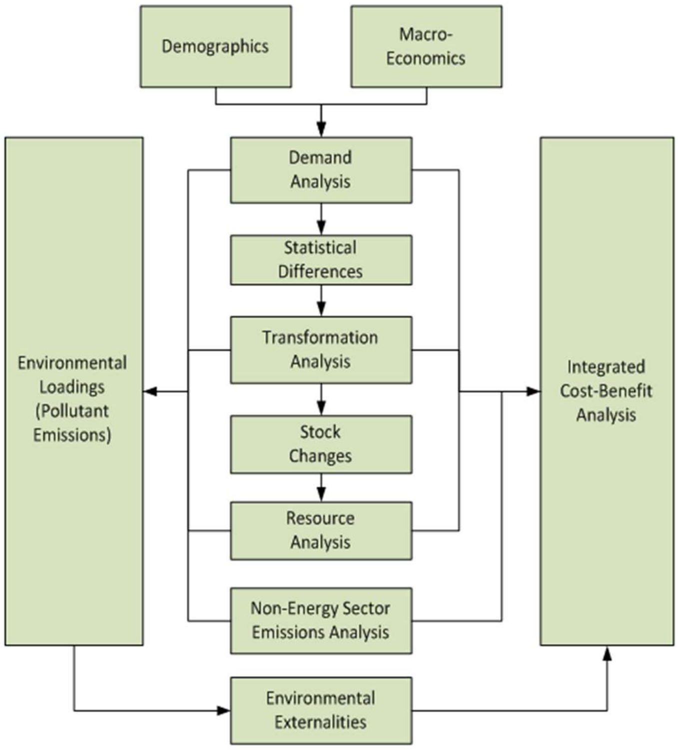


Figure 27: LEAP's calculation structure (Stockholm Environment Institute (SEI), n.d.)

4.1.4 ACEGES (Agent-based Computational Economics of the Global Energy System)

(Voudouris and Di Maio, 2010) provides documentation for V1.0 of the model initially used to model oil production for 93 countries. Being an 'agent-based' model means that the model aims to create autonomous goal-seeking agents that interact with one another and in doing so allow for the emergence of economic interactions (Voudouris and Di Maio, 2010, p. 3). The ACEGES model focuses specifically on regional and international oil production (Voudouris and Di Maio, 2010) but the agent-based methodology can be extended to other regions of element systems (Herbst *et al.*, 2012, p. 24)

4.1.5 NEMS (National Energy Modelling System)

Developed in 1973 by the Energy Information Administration (EIA), NEMS models the US energy system until 2030 (EnergyPLAN, 2013b). The model uses system dynamics to model the supply and demand in the energy system and then calculates the price of each energy type that will balance the two (EnergyPLAN, 2013b). The figure below shows how the model works by considering four separate areas and then combining them: supply; demand; conversion; and macroeconomic and international trading activities (Bhattacharyya and Timilsina, 2010, p. 26).

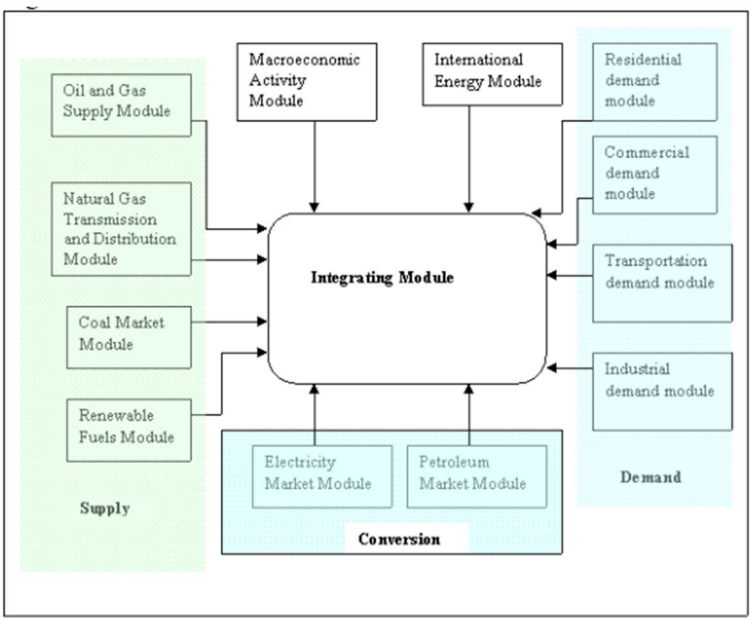


Figure 28: Structure of NEMS model (EIA, 2009, p. 15)

4.1.6 PLEXOS

Originally released in 2000, PLEXOS is an optimisation model that allows for short-, medium-, and long-term energy market planning (Energy Exemplar, n.d.; University of Victoria, n.d). It is mentioned here since it is the model used to generate forecasts in the 2018 Draft IRP and the 2019 IRP (Section 3.1.4) (Eberhard and Lovins, 2018).

4.1.7 OPEN SOURCE MODELS

While the above provide examples of models where there is a paid element, there are several open source energy models. Openmod is an example of a collection of bottom-up models that are published under open source licenses (Openmod, n.d.). An example of this is OSeMOSYS (Open Source energy MOdelling SYStem) which is used for long run integrated energy planning with over 60 national models and data kits that are free to use (OSeMOSYS, n.d).

4.2 REVIEW OF OTHER 2050 ENERGY MIX PROJECTIONS IN THE LITERATURE

While the above are potential models that could be used to inform plans around South Africa's future energy mix, there are various pieces of literature from independent energy analysts that use alternative methods to produce projections and commentary on South Africa's future optimal energy mix. They include:

- Meridian economics published a two-part study in June 2022 on insights from 2021 which was the worst year of load-shedding up to that time, and a game on plan how to end load-shedding (Meridian Economic, 2022). A remarkable outcome from part A is that an additional 5,000MW of wind and solar capacity (which could have been procured in two annual REIPPPP bidding rounds) would have enabled Eskom to eliminate 96.5% of the load-shedding in 2021 (Meridian Economic, 2022). They made use of the hourly Eskom Data portal data and included hourly fluctuations in their modelling.

- In the book *South Africa's Energy Transition: A Roadmap to a Decarbonised, Low-cost and Job-rich Future*, authors Tobias Bischof-Niemz, Terence Creamer introduce how the cost of Solar PV and Wind per MWh became lower than the cost of coal in the past decade, and how a mix of variable renewable energy and gas peaking plants could result in a prosperous future for South Africa (Bischof-Niemz and Creamer, 2018).
- More recently, in 2021, Tobias Bischof-Niemz presented on the opportunity of green hydrogen for South African exports. He shows a future with 300GW of Solar PV plus 300GW of wind generation in 2050, creating over 500,000 jobs just for that part of energy generation, and high scale production of green hydrogen and various other products for export. A suggested path for this is to add 12-14GW of Solar PV and 12-14GW of Wind generation each year to perpetuity (Bischof-Niemz, 2021).
- The CSIR has submitted and published formal public comments on the IRPs, an example being those for the 2016 IRP (Wright *et al.*, 2017). These comments provide insightful summaries of the IRP scenarios as well as providing improvements to the IRP scenarios, and technical details and discussions on risks.
- As mentioned in the transmission portion of section 2.3, the annual Transmission Development Plan is in some ways like an annually updated IRP, incorporating the latest data on expected demand, new generation, and decommissioning (Eskom, 2022e).

While these projections help to develop the body of knowledge and provide independent thought, it should not be taken for granted the difficulty in accurately projecting the future. Section 3.1.4 outlines several forecasts related to South Africa's energy generation and demand in the various IRPs available to the public (2010 IRP, 2016 IRP Update, 2018 Draft IRP, and the 2019 IRP). These IRPs are key drivers in South Africa's energy policy but even they are not always accurate. Comparing the forecasted figures to the present state of the nation's energy sector show the complexity of energy system forecasting. For example, the 2010 IRP reflects a 2023 energy mix comprising of significantly more renewable energy generation capacity than what is currently available (DOE, 2010b), Figure 14 which shows forecasted Eskom fleet EAFs in the 2016 IRP update shows that even the 'Low Plant Performance' scenario significantly overestimates the generation ability of the fleet currently (DOE, 2016). The lowest scenario assumes an EAF of around 73% in 2022 compared with an actual EAF of around 62% in 2022 (See **Error! Reference source not found.**which reflects the actual EAF of Eskom's fleet for 2020-2022) (Eskom, 2022c). This reflects an 18% overprediction.

The most recent 2019 IRP has detailed pathways for South Africa's 2050 energy mix, which has had a lot of input from public consultations and various consultants. The least cost-mix from those consultations is discussed and replicated as one of the scenarios for our Simple Energy Model built in Excel. That least cost mix has approximately 70% of its annual energy production coming from renewable sources (~42% Wind, ~20% Solar PV, and ~7% Hydro), and 11% supplied by gas.

5. CREATED SIMPLE ENERGY MODEL (SEM) USED TO FORECAST SOUTH AFRICA'S ENERGY MIX

This section explains how our SEM works in Excel and what the results of various scenarios are.

5.1 MODEL CONSIDERATIONS

This section discusses the considerations in choosing what characteristics and capabilities the Excel model should have, and what has been descoped becoming limitations of the model. These limitations include the lack of economic and demand forecasting as well as factoring in energy prices' effect on demand.

The particular choice of Excel model structure was informed by these considerations:

- That biggest demand for energy in the country, both in the industrial and residential sectors, comes from electricity (including renewables) (*The South African Energy Sector Report 2021*, 2021). Electricity has the potential to become an even higher proportion of energy needs going forward with the move away from fossil fuels, the ability to use electricity as energy source in other sectors such as transport (e.g. electric vehicles), and as due to more of the population getting access to electricity. Hence out SEM used to forecast South Africa's 2050 energy mix is limited to only consider electricity and not the broader energy environment. This matches the IRP as South Africa's long term energy planning which also focusses on electrical generation requirements.
- Proponents of renewable energy cite that its costs have, in recent years, declined to below the cost of electricity from coal per kWh (Bischof-Niemz and Creamer, 2018). Hence, the lowest carbon mix is now also the lowest cost mix and thus the obvious choice given the need for a JET towards a low-carbon economy to tackle climate change.
- Proponents of nuclear and coal often refer to the variability of solar and wind as the reason a majority renewable mix cannot work since, "the wind does not always blow and the sun does not always shine." (Eberhard and Lovins, 2018). As examples of this, in the first half of 2022, electricity demand fluctuated between 18.7 and 34.6 GW, i.e. minimum demand being 54% of maximum demand, whereas solar PV, CSP and wind total output had a much larger fluctuation of between 0.6% and 17.9% of the total RSA demand on an hourly level, 96% variance with the current levels of installed renewables (Pierce and Le Roux, 2022). Proponents of renewables argue that during times when renewable energy is not producing enough to meet demand, the need can be filled by expensive peaking stations (gas/diesel) and that due to them being run for only a short amount of time, per day, the overall cost of such as system will be less than one with higher levels of coal and nuclear baseload.
- While generation characteristics such as hourly variation vs baseload capability can be analysed independently, there is a need to actually calculate the total system cost and simultaneously check that it is adequate, i.e. that there will be no need for load-shedding.
- Apart from this there is also the consideration of to what degree battery and other bulk energy storage is necessary or able to enable a high-renewables future (Lovins, 2017).

The above points are what has been considered in how we determine the mix. Regarding the form of the model, we have determined that there is a need for the current model to be in excel, simple, and reliably accurate. This is so that the general public of South Africa has the ability to test scenarios for investigating how a proposed mix would fare if certain risks were to materialize and in doing so encourages public participation in the discourse around the energy crisis and its potential solutions.

The helpful simplification that the model explores only South Africa's 2050 energy mix means that the model is much simpler than either 1) proposing a pathway up of energy for each point in time up to 2050, or 2) solving for a precise mathematically optimum mix in terms of price or carbon emissions.

Hence the developed model was chosen to meet these requirements and be able to:

1. Model actual hourly electricity demand, with its morning and evening peaks;
2. Model actual hourly sunshine and wind availability (reflecting the actual "weather" in the country);
3. Model risk-reflective capacity factors of coal and nuclear, reflecting maintenance periods and possible down-time rather than ideal scenarios;
4. Take into account winter and summer seasonality, hence a whole year should be modelled rather than a single example day;
5. Output the number of hours of load-shedding and MWh of load-shedding in the hypothetical year scenario, so that load-shedding-free scenarios can be sought;
6. Output overall annual costs of a given inputted energy mix – for example to see whether peaking plants together with renewables (at the level that will meet national demand) is in fact cheaper than options with heavier reliance on coal/nuclear for baseload generation;
7. Reflect costs relating to operating costs (such as maintenance), fuel costs, and the capital costs in constructing the generating capacity. These capital costs must be expressed in a present value levelized cost per MWh considering the expected lifetime production of the plant for plants to be developed by Eskom.

The below is the limitations of the model that has been developed:

- Although the model caters for fixed grid level energy storage such as PS and batteries, it does not take into account possible efficient alterations to demand by "grid flexibility resources" including higher efficiency, and flexible demand to match renewable output more closely, such as matching the time of most intensive industry to the time when the most sun is shining (Lovins, 2017).
- There is increasingly a belief that hydrogen production using renewable energy is the key to enabling a green future, since it can be produced with excess daytime renewable energy, stored, used in production of other green fuels, and exported for big economic benefits (Bischof-Niemz, 2021; Department of Science and Innovation, 2021). The model does not explicitly cater for an additional form of energy storage such as hydrogen (though the battery parameters could potentially be changed to effectively represent hydrogen stored for future electricity production).
- The model has scenario inputs for only one amount of installed capacity for the year, so it will not necessarily match an actual year's experience where the installed capacity changes. Similarly, the coal capacities are fixed for the year whereas, in reality, there would be more scope to increase or decrease the coal generation at certain times to more closely match demand. For this reason, a small amount of load-shedding should not necessarily be indicative of actual load-shedding with the mix, as coal could be ramped up for some hours. Additionally, the curtailment of renewables

may not actually imply that supply would have to be higher than the demand at a point in time - coal generation could be managed to be reduced at that time.

- The model does not take into account that, with greater installed capacities of wind or solar spread out over the country, the hourly variation in overall renewable capacity factors will be less. This is due to the fact that with diversification of geographical renewable generation that the variance in country wide output could be reduced. This calculation is more involved, and has already been conducted with favourable results in the Wind and Solar PV Resource Aggregation Study for South Africa by the CSIR Energy Centre and Fraunhofer IWES. It showed that fluctuations in wind and solar will be manageable in South Africa even with high proportion renewable penetration, that wind generation is least when solar is most (thus complementing each other), and that the changes in generation over 15-minute intervals get more stable as the penetration of wind gets more widespread (CSIR, 2016).
- the Excel model does not calculate monthly gradients, and may imply higher than realistic fluctuations at higher RE penetration levels since the gradients will be based off the approximately 5GW installed capacity in 2020, which will not be as spatially diversified as a larger renewable installed capacity would likely be.
- We have not conducted detailed electricity demand forecasting, or cost forecasting, but allow other's overall forecast values to be supplied as inputs.

5.2 DATA AND INPUT ASSUMPTIONS INTO THE MODEL AND YEAR 2050 SCENARIOS

Our model will require four main inputs that determine how much energy is produced, curtailed (if supply is higher than demand) or falling short of demand (load-shedding). These four are: 1) annual demand in TWh, 2) Annual shape of hourly demand, 3) nominal generation capacity, and 4) capacity factors (representative of the weather and coal/nuclear fleet performance). Then there are cost and emissions assumptions per generation output which can give the costs and GHG emissions of an inputted energy mix. Before describing each of these inputs, we have a note explaining the Eskom data portal data from which input scenarios are derived.

5.2.1 NOTE ON ESKOM DATA PORTAL DATA

Detailed hourly data on electricity generation is available through data request at https://www.eskom.co.za/dataportal/data-request-form/. This includes all generation resources that can be dispatched by Eskom National Control or that Eskom has contracts with (i.e. IPPs), including imported energy, and renewable energy. Data is available from 1 April 2018, the start of the 2019 Eskom Financial year. Hence the public participation and comments made on the Draft 2018 IRP did not have the benefit of a full year of this data available at that time. The data portal also contains a glossary which provides a useful resource to help understand terms used – this may be consulted in conjunction with some important concepts being detailed in section 2. Below is a list of a selection of the fields available on an hourly basis, a description of the field and, in the case of aggregation fields, the subcomponents used in their calculation:

Eskom data portal data - summary of fields used in this research – own analysis

Field number	Field name	Description and calculation
5	Dispatchable Generation	All energy generation other than the renewable energy included under "Total RE", i.e. imports, coal, nuclear, gas, Eskom and IPP OCGT, Hydro, pumped storage less energy used in Synchronous Condenser Operation to stabilise the grid and energy used in pumping water to the upper reservoirs for pumped storage. Calculation: The fields highlighted in orange: sum of fields (9) through (15) and fields (19) through (23).
6	Residual Demand	Is the total demand for energy left after RE has supplied some of the demand, i.e. the demand that needs to be met by dispatchable generation (and load-shedding if needed). Calculation: Dispatchable generation (5) + ILS usage (16) + Manual Load Reduction (17) + Other IOS (18)
7	RSA Contracted Demand	Total amount of Energy demanded from South Africa, it includes all South African electricity generation plus load-shedding or other interruption of supply. Calculation: Residual demand (6) + renewable generation (31).
9	International Imports	MWh of energy imported from the other countries in the region each hour.
10	Thermal Generation	Coal MWh of energy generated for the grid.
11	Nuclear Generation	Nuclear MWh of energy generated for the grid.
12	Eskom Gas Generation	Gas MWh of energy generated for the grid.
13	Eskom OCGT Generation	Eskom OCGT MWh of energy generated (currently all diesel) - excludes IPP OCGT generation which has its own field.
14	Hydro Water Generation	Hydroelectric MWh of energy generated for the grid (excluding PS generation).
15	Pumped Water Generation	Pumped storage MWh of energy generated for the grid.
16	ILS Usage	Interruptible load shed - where Eskom has contracts enabling them to interrupt the supply of certain institutions.
17	Manual Load Reduction(MLR)	Load-shedding.
18	IOS Excl. ILS and MLR	Other Interruption of supply, such as due to transmission network faults.
19	Dispatchable IPP OCGT	IPP OCGT MWh of energy generated (currently all diesel).
20	Eskom Gas SCO	Synchronous Condenser Operation - negative in value, it is MWh used in stabilising the grid by Gas generation stations.
21	Eskom OCGT SCO	Synchronous Condenser Operation by Eskom OCGT.
22	Hydro Water SCO	Synchronous Condenser Operation by Hydroelectric generation stations.
23	Pumped Water SCO Pumping	Energy used in pumping wated back up to the top reservoirs for storage to be let down later for energy generation.
24	Drakensberg Gen Unit Hours	A measure of water is stored in Drakensburg's upper reservoir: the number of hours it would take for one (of the four) 250MW generating units to deplete the upper reservoir.
25	Palmiet Gen Unit Hours	A measure of water is stored in Palmiet's upper reservoir: the number of hours it would take for one (of the two) 200MW generating units to deplete the upper reservoir.
26	Ingula Gen Unit Hours	A measure of water is stored in Ingula's upper reservoir: the number of hours it would take for one (of the four) 333MW generating units to deplete the upper reservoir.
27	Wind	Wind MWh of energy generated for the grid.
28	PV	Solar PV MWh of energy generated for the grid.
29	CSP	Concentrated solar power MWh of energy generated for the grid.
30	Other RE	Other renewable energy generated from the grid, such as biomass, landfill gas, and small hydro.
31	Total RE	Total renewable energy produced for the grid. Calculation: The sum of the previous 4 fields (27)+(28)+(29)+(30).
32	Wind Installed Capacity	The total Wind Installed Capacity in MW at that hour.
33	PV Installed Capacity	The total PV Installed Capacity in MW at that hour.
34	CSP Installed Capacity	The total CSP Installed Capacity in MW at that hour.
35	Other RE Installed Capacity	The total Other RE Installed Capacity in MW at that hour.
36	Total RE Installed Capacity	The total RE Installed Capacity in MW at that hour.
37	Installed Eskom Capacity	The total Installed Eskom Capacity in MW at that hour.

5.2.2 ANNUAL DEMAND IN TWH

As shown in Figure 17, annual demand assumptions are sourced from the 2019 IRP.

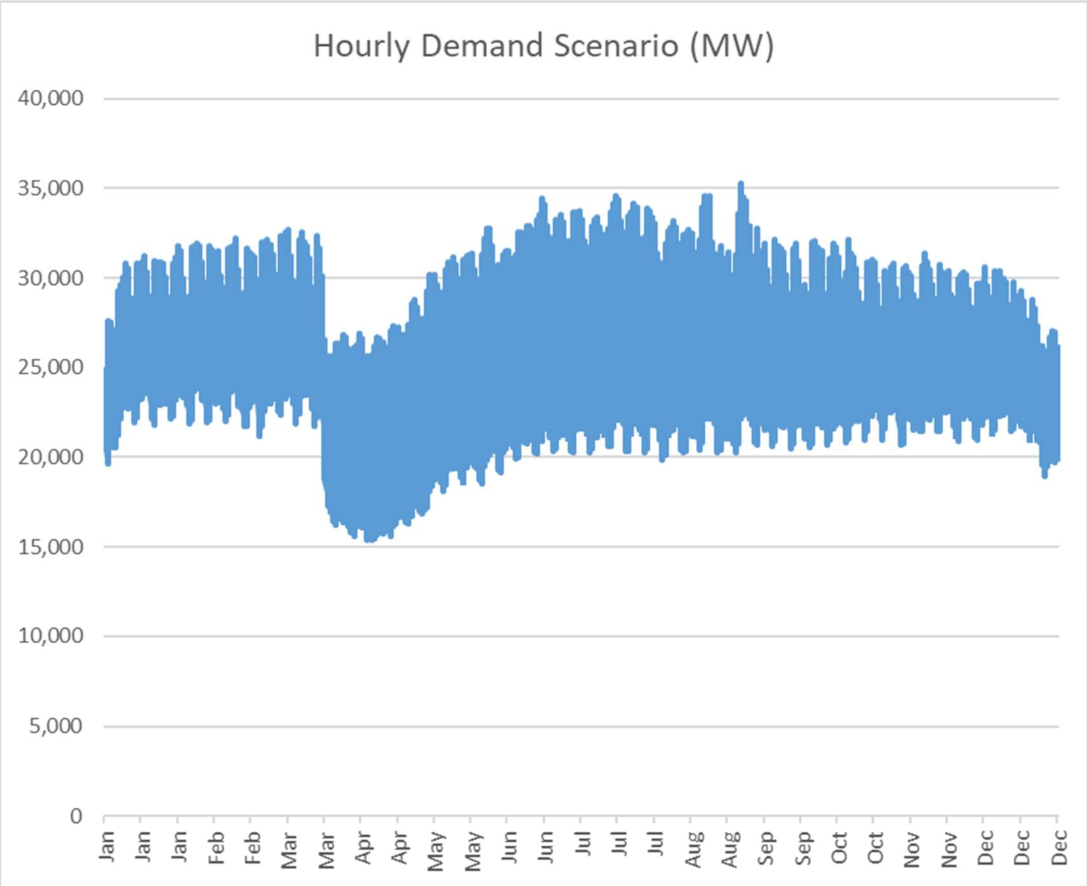
Our model has flexibility to input any annual energy demand amount as a scenario, but the following, in annual TWh, have been included as scenarios that can be selected in the input sheet:

IRP Median	IRP low	IRP high	2022 Actual	2021 Actual	2020 Actual	2019 Actual	2030 IRP	2030 median IRP
380	365	415	227	227	220	233	315	302.5

5.2.3 HOURLY DEMAND SHAPE

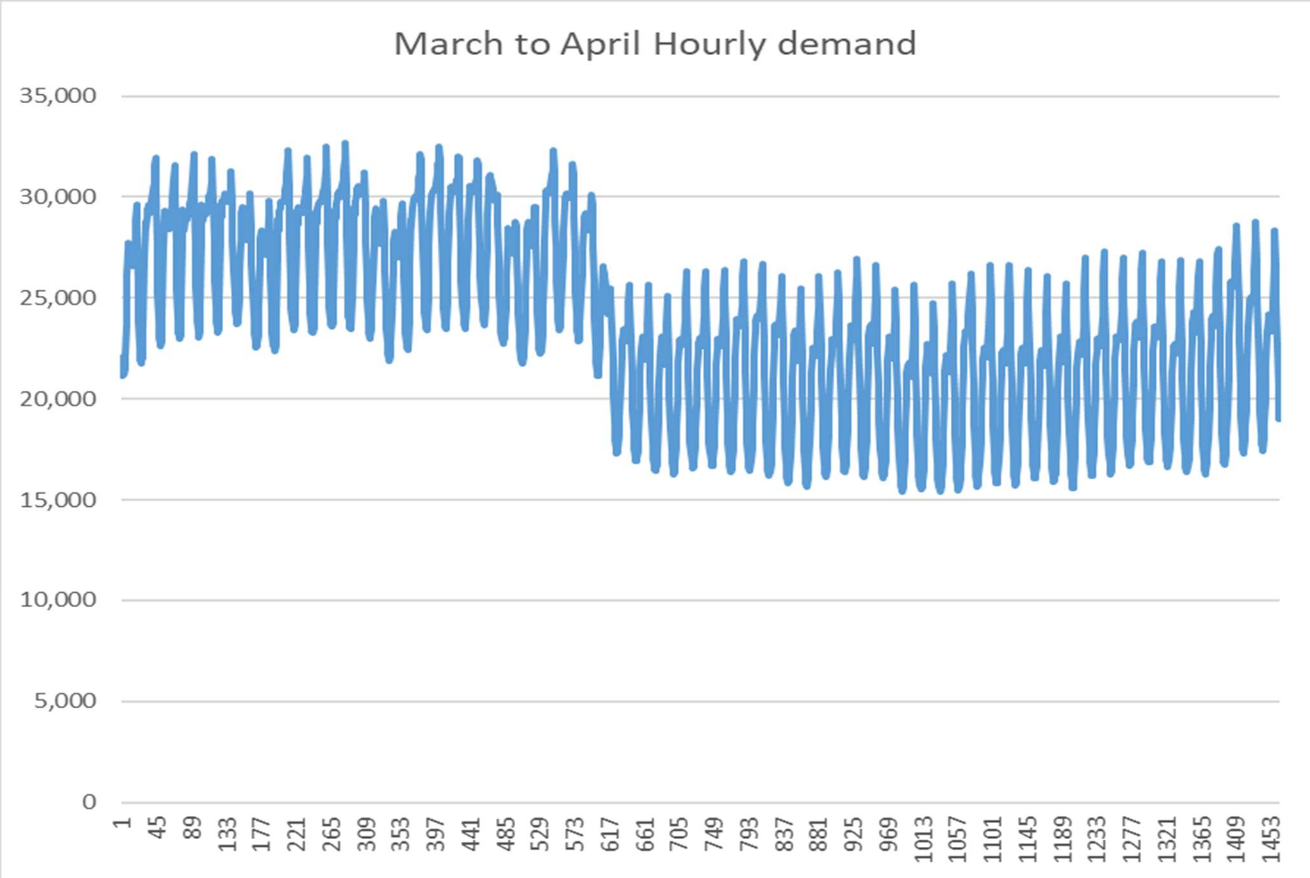
To improve the accuracy of our future projections, we thought it prudent to have the option of inputting actual demand shapes from any of the recent actual years (2019-2022). This takes into account daily, weekly, and annual seasonality in demand. Using a period shorter than a year would make the model susceptible to criticism of cherry-picking hours, days, weeks or months where demand is at a certain high or low level which may make the results unrepresentative of reality.

Below is a graph of the 2020 hourly electricity demand as extracted from the Eskom Data portal column "RSA Contracted Demand", where the sudden decrease in energy demand when lockdown started is visible:



Above it is also clear that winter peak demand, around June to August, was higher than the rest of the year.

Zooming in to the 1464 hours of March and April 2020, one can see the weekday morning and evening peaks (evenings are higher peaks), the lower demand on the weekends, and how the demand suddenly dopped with the commencement of the hard lockdown at the end of March 2020.



While 2020 is shown as an example year for illustration, the 2019, 2021, and 2022 will be more representative of an average year's hourly demand shape for use if forward projections.

5.2.4 Nominal Capacity

The nominal capacity of electricity generation is the input this research is most interested in optimising, as it represents the energy mix of the scenario.

While any hypothetical future nominal capacity can be inputted, accurate historical nominal capacity of electricity generation is useful for three reasons in the model:

1) To set supply scenarios based on history to validate the model through backtesting;

2) To provide a base for short-term future projections, which then allows us to see the impact of adding additional renewables in coming years for example. It is also important to know what is already installed so that the capital costs portion of a future scenario only takes into account the amount of generation that is relatively newly built (for example, extending Koeberg's operational lifetime will result in only operations, management and fuel costs for future generation as the capital will have already been spent and those costs potentially written off already); and

3) To determine the actual historical capacity factors based off of what was generated divided by the nominal capacity in that hour, so that historical capacity factors can be incorporated in future projections with different nominal capacities.

Nominal capacity for each of Eskom's generation sources is provided in Eskom's integrated annual reports as at their financial year end on 31 March of each year, and in the period 2018-2022 the most significant changes have been to coal. The figure below shows the power station capacities as at 31 March 2022 (Eskom, 2022c).

Power station capacities

at 31 March 2022

The difference between installed and nominal capacity reflects auxiliary power consumption and reduced capacity caused by the age of the plant.

Name of station	Location	Years commissioned, first to last unit	Number and installed capacity of generator sets MW	Total installed capacity MW	Total nominal capacity MW
Base-load stations					
Coal-fired (15)				**44 013**	**39 456**
Arnot	Middelburg	Sep 1971 to Aug 1975	6x370	2 220	2 100
Camden[1,3]	Ermelo	Mar 2005 to Jun 2008	3x200; 1x196; 2x195; 1x190; 1x185	1 561	1 481
Duvha[2]	Emalahleni	Aug 1980 to Feb 1984	5x600	3 000	2 875
Grootvlei[1,3]	Balfour	Apr 2008 to Mar 2011	4x200; 2x190	1 180	570
Hendrina[3]	Middelburg	May 1970 to Dec 1976	5x200; 1x195; 1x191; 1x170; 1x167	1 723	1 098
Kendal[4]	Emalahleni	Oct 1988 to Dec 1992	6x686	4 116	3 840
Komati[1,3]	Middelburg	Mar 2009 to Oct 2013	4x100; 4x125; 1x90	990	114
Kriel	Bethal	May 1976 to Mar 1979	6x500	3 000	2 850
Kusile[4]	Ogies	Aug 2017 to Mar 2021	3x799	2 397	2 160
		Under construction	3x800	–	–
Lethabo	Vereeniging	Dec 1985 to Dec 1990	6x618	3 708	3 558
Majuba[4]	Volksrust	Apr 1996 to Apr 2001	3x657; 3x713	4 110	3 843
Matimba[4]	Lephalale	Dec 1987 to Oct 1991	6x665	3 990	3 690
Matla	Bethal	Sep 1979 to Jul 1983	6x600	3 600	3 450
Medupi[4]	Lephalale	Aug 2015 to Jul 2021	6x794	4 764	4 317
Tutuka	Standerton	Jun 1985 to Jun 1990	6x609	3 654	3 510
Nuclear (1)					
Koeberg	Cape Town	Jul 1984 to Nov 1985	1x970; 1x964	**1 934**	**1 854**
Peaking stations					
Gas/liquid fuel turbine stations (4)				**2 426**	**2 409**
Acacia	Cape Town	May 1976 to Jul 1976	3x57	171	171
Ankerlig	Atlantis	Mar 2007 to Mar 2009	4x149.2; 5x148.3	1 338	1 327
Gourikwa	Mossel Bay	Jul 2007 to Nov 2008	5x149.2	746	740
Port Rex	East London	Sep 1976 to Oct 1976	3x57	171	171
Pumped storage schemes (3)[5]				**2 732**	**2 724**
Drakensberg	Bergville	Jun 1981 to Apr 1982	4x250	1 000	1 000
Ingula	Ladysmith	Jun 2016 to Feb 2017	4x333	1 332	1 324
Palmiet	Grabouw	Apr 1988 to May 1988	2x200	400	400
Hydroelectric stations (2)[6]				600	600
Gariep	Norvalspont	Sep 1971 to Mar 1976	4x90	360	360
Vanderkloof	Petrusville	Jan 1977 to Feb 1977	2x120	240	240
Total used for capacity management purposes				**51 705**	**47 043**

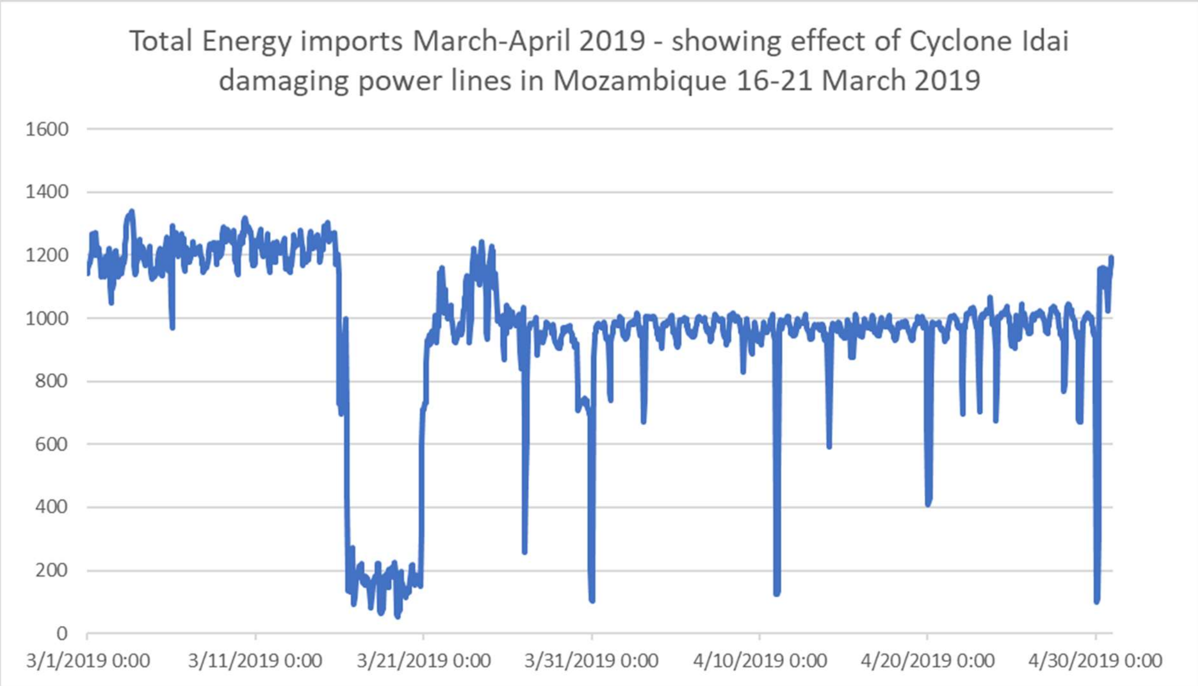
RE nominal capacity (for each of solar PV, wind, CSP, and other RE - all mainly from IPPs) is available on an hourly level from the Eskom data portal, but for coal, we approximate the hourly installed capacity using linear interpolation between coal nominal capacity at financial year ends.

Linear interpolation was done to estimate hourly coal nominal capacity because: 1) it's difficult to tell exactly the date on which certain units were decommissioned or "removed from the base due to technical constraints" and economic reasons (Eskom, 2022c, p. 157), and 2) new units start producing power to the grid sometime before reaching commercial operation[9]. Dates of first synchronisation to the grid, commissioning, and finally official status are shown for some coal generating units in the sheet "Coal capacity changes" in the Excel ("ESK_Supply_capacity_and_EAFs.xlsx") file. Since March 2023, coal capacity is not available yet. It was estimated as the March 2022 capacity plus 800MW and minus 121MW because the 800MW unit 4 of Kusile entered commercial operation at the end of May 2022 (Eskom, 2022f), and Komati's last 121KW was decommissioned in October 2022 (Steyn, 2022).

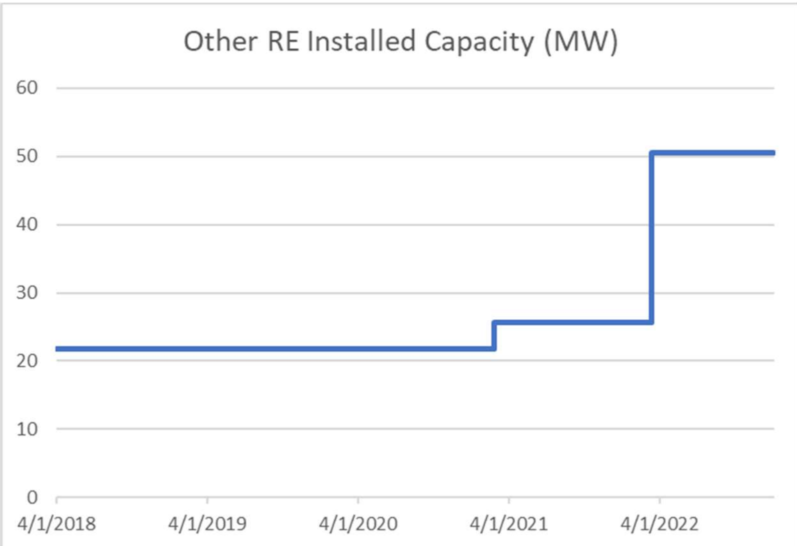
Nuclear nominal capacity consists only of Koeberg's approximately 1860MW throughout the past years. There have been no changes to Eskom's Hydro 2018 generation summing to 600MW. The PS schemes have also been unchanged from the March 2018 value and have a nominal capacity of 2724MW. The gas/liquid fuel nominal capacity consists of 2409MW from four Eskom stations, plus 1005MW from IPP capacity (Eskom, 2022c, p. 151), making a total of 3414MW.

The nominal capacity of energy imports was set as the maximum MW supplied in any given hour in the history of the Eskom Data portal data of 1765MW (which was generated in the hour 14:00-15:00 on 21 November 2021). Much of this comes from the Cahorra Bassa Hydroelectric Generation Station in Mozambique from which there is theoretically capacity to import up to 1800MW(Cigre Southern Africa, 2019). Other imports include 200MW hydro power available from the Ruacana hydropower plant on the Kunene River in Namibia(News24, 2015). By looking at the historical hourly energy imports, one can make some deductions as to what the energy comes from. The cyclone and floods in Idai in Mozambique in March 2019 damaged transmission lines, caused a sudden drop in capacity and prompted increased load-shedding in South Africa (Reuters, 2019). Plotting the total MWh imports around that time, there is a visible 1000MW drop in the energy imports for a few days, corresponding to interruption of power coming from Cahora Bassa, leaving 200MW which could be the 200MW of hydro from Namibia. Hence it seems that the vast majority of our imports are of hydroelectric source.

[9] The Eskom Data portal does have a field " Installed Eskom Capacity" which could potentially serve as an accurate hourly representation of what coal capacity is if the more stable nuclear, Hydro, OCGT, and gas capacity is accurately removed. This has not been explored here. The data portal glossary mentioned a term "Available Dispatchable Capacity (Incl. Non-Comm Units)" – which "includes non-commercial generation, as it is dispatchable energy available to support the system" (Eskom, 2020).



A small note on what the Eskom data portal data calls "Other RE": the average "Other RE Installed Capacity" in 2022 is only 46MW, so practically negligible compared to other sources of electricity, but it may be useful to know where that is coming from. The Eskom data portal glossary states that "Other RE" is renewable generation from smaller contracted RE sources(small hydro, biomass, landfill gas, etc.). A graph of installed capacity over time shows that there 21.78MW installed from the start of the data (April 2018) until 25 Feb 2021 where an extra 3.8MW was added, and a final addition was made on 12 March 2022 of 25MW.



The 25MW capacity added in March 2022 corresponds to the start of operations of the Ngodwana energy biomass power plant, partially owned by Sappi south Africa(Sappi, n.d.). Included in the Other RE must also be the 7.5MW landfill gas to electricity project in Durban (eThekwini Municipality, 2022) and various small hydro facilities (Hendriks, 2021). These have been grouped as "renewable baseload" in the model.

The final grouping of the 2022 calendar year average hourly nominal capacity grouped by source is therefore as follows:

Baseload	**2022 Average nominal generation capacity (MW)**
Coal	39,628
Nuclear	1,860
Renewable baseload (e.g. LFG, biomass)	46
Non-dispatchable Renewable Energy and Hydro	
Solar PV	2,228
Wind	3,277
CSP	500
Hydroelectric in SA	600
Imports (mostly Hydro)	1,765
Storage (pumped or battery)	
Pumped Storage	2,724
Battery	-
Peaking plants	
Gas/Diesel	3,414

Related to generation capacity are the assumptions related to efficiency of storage, whether pumped storage or battery.

For pumped storage, the calculations and assumptions are in the Excel workbook "ESK_Supply_capacity_and_EAFs.xlsx" in the first sheet in range AP1:AT27.

The pumped storage consists of 1,000MW from Drakensburg, 400MW from Palmiet, and 1,332MW from Ingula pumped storage scheme (a total "installed capacity" of 2,732MW but slightly lower overall "nominal capacity" of 2,724MW). According to the Eskom data portal data, the maximum historical number of generator hours of storage for the three stations – fields "Drakensberg Gen Unit Hours", "Palmiet Gen Unit Hours" and "Ingula Gen Unit Hours" – are 102; 58.81 and 65.57 respectively, implying a historical maximum storage, 11,762MWh, and 21,835MWh respectively, summing to 59,097MWh total storage available in the scheme. As a reasonability check, this is within 1% of the storage capacity number of 58,600MWh obtainable through technical brochures and articles on the stations (made up of 27,600MWh for Drakensburg (Eskom, 2022b), 10,000MWh for Palmiet (Eskom, 2022d) plus 21,000MWh for Ingula (Sawyer and Du Plessis, 2010)). Hence 59,097MWh is a reasonable estimate for the current total storage capacity in South Africa's pumped storage schemes.

Two more assumptions are required in order to model the hourly charging and discharging of energy storage: the cycle efficiency of storage charging/refilling, and the maximum amount of energy that be used per hour for charging/refilling.

Relating to cycle efficiency, the empirical overall efficiency of PS charging can be calculated as 74% from the Eskom data portal (a total of 4.9TWh generated with 6.6TWh used in refilling the reservoirs between 1 April 2018 and 2 January 2023). This is reasonably close to the 73.7% efficiency stated for the Drakensburg scheme: "Losses during pumping and generation mean that the scheme requires about 1,36 units of pumping energy for each unit generated" (Eskom, 2022b) (the inverse of 73.7% being 1.36). The other two pumped storage schemes are said to have an efficiency of 78% (Ingula) and 77.9% (Palmiet). Hence the empirical value of 74% seems reasonable.

The maximum hourly amount of energy that has been used in refilling the pumped storage reservoirs is the average of 2,848MW (from 10-11PM on Wednesday 18 September 2019, per Eskom Data portal data). At such a rate, with 74% efficiency, there would have been 2,107.52MWh of stored energy added to the top reservoirs per hour, and an equivalent rate would be 28.04 hours to fill a 59,097MWh total capacity. This is 29.6% longer than the 21.63 hours it would take for a total capacity of 59,097MWh to be depleted at a rate of 2,732MW (the combined nominal capacity of the three pumped storage stations). As a reasonability check on this ratio of 29.6% longer to refill than to deplete, the time to fill Palmiet is said to be 33 hours (12.23% longer than the 29.41 hours it would take to discharge its capacity of 10,000MWh at a rate of 400MW) and the time to refill the Drakensburg Reservoir is said to be 39 hours (41.3% longer than the 27.6 hours it would take to discharge its capacity of 27,600MWh at a rate of 1000MW) (Eskom, 2022b). Hence 29.6% seems to be a reasonable ratio for the entire system, being close to halfway between 12.23% and 41.3%. Thus, approximating the time to refill pumped storage at 28.04 hours seems reasonable.

As for BESS, December 2022 marked the beginning of construction of Eskom's first BESS project. The first facility will have a capacity of 8MW with 32MWh of storage (so 4 hours of storage at full discharge rate). The plan for phase 1 of the project is to add a total of 199MW of capacity and 833MWh of storage by 30 June 2023. For phase 2 an additional 144MW capacity with 616MWh is to be added by the end of 2024 (Eskom, 2022b). Such battery storage has many benefits: it provides ancillary services, helping stabilize the grid frequency and voltage at the places where it is situated; it lessens the need of other power during peak load times between 17:00-21:00 and 06:00-10:00; it lessens the need to curtail renewable energy generation as any power from wind or solar can go into the batteries, and enables the ramping up of the share of renewable energy in the energy mix, as power can be provided by the batteries in times when there is not as much wind or sun to meet the demand (Eskom, 2023). Typically, such batteries are recharged during the off-peak hours of 00:00-06:00, or during the midday hours where the generation from Solar is highest, such as between 10:00 and 15:00 (Eskom, 2023). Using these numbers, we will assume that it takes about 5 hours to recharge these 4-hour grid batteries, 25% longer to charge than to discharge, which is not far off from the ratio observed in pumped storage.

Battery discharge/charge efficiency was assumed to be 80%, which is conservatively low for lithium-ion batteries' range of 85 – 95%, yet within the range of lead-acid batteries' 80 –

90% and flow batteries' 60 – 85% as per a 2019 fact sheet from the Environmental and Energy Study Institute (EESI) (EESI, 2019).

Hence the assumptions for storage capacity in South Africa is as in the following table, where the storage capacity in MWh is set as a multiple of the nominal generation capacity, including 8MW battery storage for illustrative purposes:

Energy Storage Capacity (MWh) and Efficiency			
Pumped MWh	59,097		
Pumped Efficiency	74%	max charge/hour	2,108
Pumped recharge hours	28	charge use/hour	2,848
Battery MWh	32		
Battery Efficiency	80%	max charge/hour	6
Battery recharge hours	5	charge use/hour	8

As a default, the MWh available for storage will vary in proportion to how the generation capacity in MW varies. The multiple for pumped storage is 59,097MWh/2,724MW (around 21.69) and the multiple for batteries is 4 hours (4 times the battery installed MW capacity). In the above table, the max charge/hour is the highest amount of energy that can be added to the storage in one hour, which is the total potential MWh divided by the hours it takes to recharge. The "charge use/hour" is the amount of energy needed to spend to result in the "max charge/hour" being added to the storage, which is the "max charge/hour" divided by the efficiency.

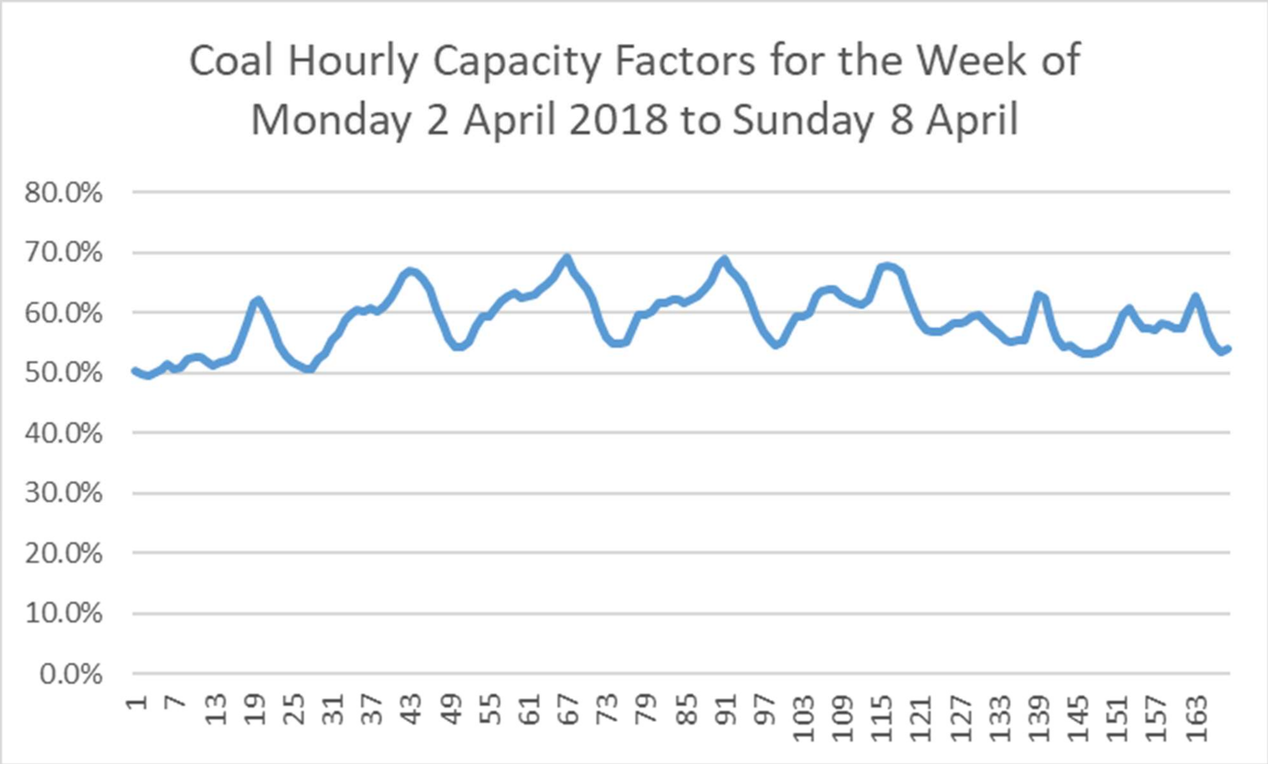
For consideration regarding medium-term future, a report from the world bank indicates that there is a potential for domestic demand of 10-15GWh for battery energy storage by 2030 making it a potentially key player in the international battery value chain; the country would have the ability to localise production of both lithium-ion batteries and vanadium redox flow batteries (VRFB) (Murray, 2023b). In addition to the 343MW already been procured, Eskom has made a request for proposals for another 36MW in December 2022 (Murray, 2022) and is planning to procure at least another 1,200MW by the end of 2023 (Murray, 2023a).

5.2.5 Hourly capacity factors by source

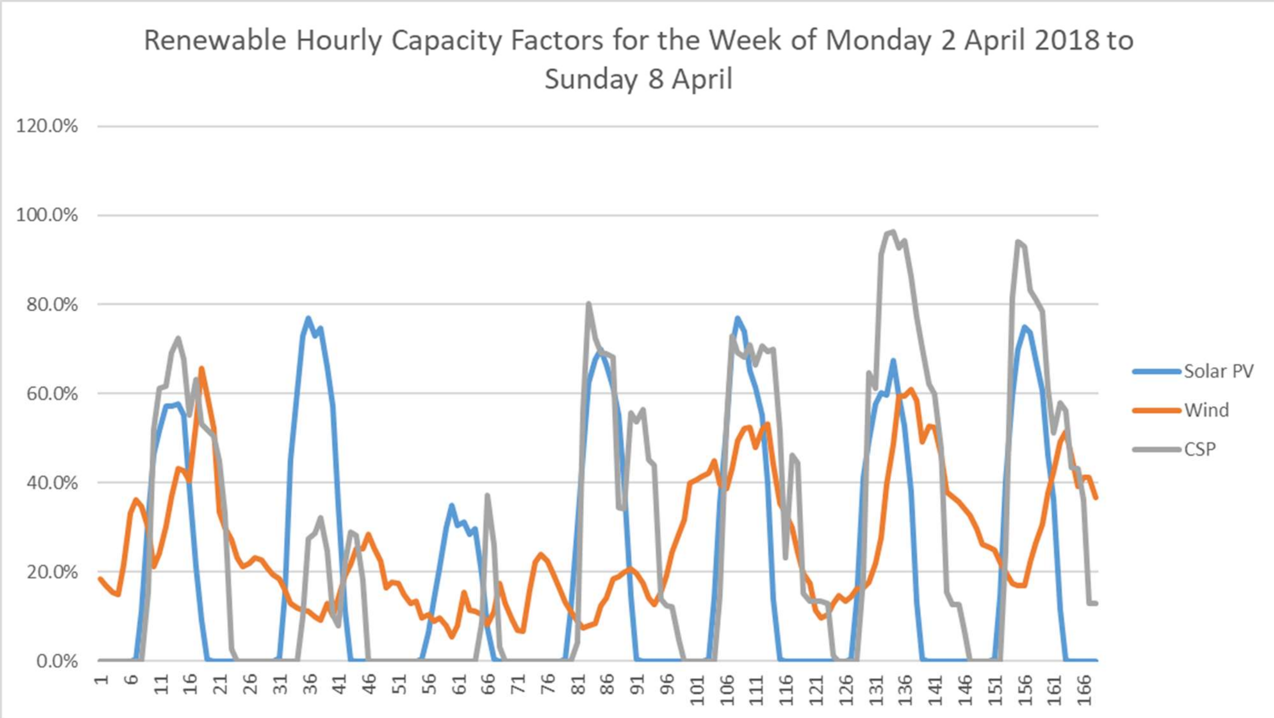
Hourly capacity factors were calculated per each energy source by taking the MWh generated in that hour (From the Eskom Data portal data) and dividing by the nominal capacity at that hour (determined as per section 5.2.4 above).

Nominal capacity was not lowered in the event of shutdowns of plants or units due to maintenance or accidents, hence the capacity factor will naturally be lowered during such periods. This is considered a prudent approach, taking into account operational risks in running or installing a specified capacity of something like coal or nuclear

The coal capacity factors will vary based on both the availability of the coal fleet and daily fluctuations in demand, where more coal is burned at hours of higher demand, see the graph below showing the coal actual capacity factors first Monday to Sunday week of April 2018.



The solar PV, wind and CSP capacity factors are indicative of the wind and sunshine (the weather) over time. Below is an example during the same 2-9April period. Note that solar is highest at the middle of the day, and that wind shows a minimum at noon, making wind and solar a good combination (CSIR, 2016, p. 2). As the amount of wind and solar installed increases, the smoother the variation in capacity factor becomes due to the geographical dispersion. It can also be seen from the figure below that CSP lasts longer into the evenings than compared with solar PV.



Historical hourly capacity factors were calculated in this way in columns BH to BQ in sheet "ESK3269_SUPPLY and EAFs" in the Excel workbook "ESK_Supply_capacity_and_EAFs.xlsx", where gas and OCGTs were combined, and SCO was ignored (being a very small percentage of the output).

5.2.6 Cost and environmental impact assumptions

Regarding cost assumptions, the 2019 IRP points out that since future energy planning often targets a least-cost mix, cost assumptions are crucial and play a big role in the modelling (DMRE, 2019, p. 2). There are three main sources of costs used in the 2019 IRP (DMRE, 2019, pp. 30–31).

One major source of cost information in the 2019 IRP was the 2017 update to the EPRI report commissioned specifically for use South Africa's 2018 and 2019 IRPs, which contains costs for various generation technologies as at January 2017 (EPRI, 2017). For each technology, capital costs, operational and management costs (O&M), and fuel costs are provided and aggregated to form one levelized cost of electricity amount (LCOE) in terms of Rands per MWh. LCOE is calculated as the present value of the costs incurred to obtain power divided by the present value of energy generation over the lifetime of the plant obtained by those costs, thus providing a reasonably equitable way to compare the costs of generation of different power generation technologies (DOE, 2014). The LCOE does depend on assumptions about the capacity factor of the plant (higher capacity factor means more generation for the same capital costs thus lower LCOE) and the discount rate (higher discount rate making capital intensive long-term projects such as nuclear less attractive[10]). In the EPRI's 2017 update, baseline costs from the EPRI's 2015 study (EPRI, 2015)were adjusted to January 2017 USD using an annual escalation rate of 2.5% and converted to Rands based on the 1 January 2017 exchange rate (EPRI, 2017, p. VII). The 2015 EPRI study was itself an

[10] For nuclear, a doubling of discount rate from 5% to 10% would approximately double the LCOE per MWh of nuclear energy.

update to the results published by the EPRI in April 2012 and had much higher prices for renewables than what South Africa was actually awarding bids for in the REIPPPP process (DMRE, 2019, p. 30).

Costs for renewables such as solar PV and wind in the 2019 IRP were sourced from the South African REIPPPP actual tariffs obtained, a second source of costs.

Costs for nuclear in the 2019 IRP were from the 2013 Ingerop study commissioned by the DMRE (DOE, 2014).

In order for the model to consider some of the system as already paid off (not incurring extra capital costs) there is the need for assumptions about what proportion of each energy source is available and paid off in a given scenario. For example a Koeberg life-extension should provide cheaper power than new nuclear build, since infrastructure is already in place and capex has already been incurred, hence in a short term power mix scenario, nuclear is more likely to be included than in 2050 when Koeberg will be beyond its life extension and any nuclear in the 2050 mix will have to come from new build. Since a coal station lifetime is generally considered no more than 50 years, only coal stations built after 2000 will be available in 2050. Hence only Kusile and Medupi are considered still available and having their capex paid off in 2050. The only other Eskom stations considered to still be available in 2050 are the hydroelectric and PS stations. The currently installed renewable capacity is mainly from IPPs, so instead of considering the LCOE as an aggregation of capital and O&M and fuel, just the tariffs are used (the bidder is expected to have already incorporated capital and lifetime operations costs in that tariff). In any case, the lifetime of variable renewables is less than 30 years. The lifetime of gas/diesel plants is also expected to be 30 years or less(Sargent & Lundy, 2017), and Eskom's newest gas/diesel stations came online in 2008 and 2009 so are unlikely to still be used in 2050. The EPRI 2017 study states that the book life for fossil fuel, nuclear, biomass and solar thermal generation facilities is 30 years, 25 years for solar PV facilities and 20 years for wind (EPRI, 2017, pp. 3–5)"the book life for fossil, nuclear, solar thermal, and biomass plants in this study is 30 years, for PV plants is 25 years, and for wind plants is 20 years.

The assumptions for costs in the model, as a base case, use the same three sources of costs as the 2019 IRP, just the REIPPPP tariffs are sourced from the more recent September 2021 bids (Bid window 5) (Creamer, 2021). The Ingerop study is used for nuclear, IEA projections are used for hydroelectric, Eskom's report was used to infer the cost of imported hydro, and EPRI was used for coal, renewable baseload, battery and gas/diesel as a default. The details are in sheet "Cost scenarios" of the simple excel model, from column L to the right. As a first step all prices sourced are taken to December 2022 prices (using an escalation factor of 2.5% per year for the Ingerop study's nuclear dollar costs and the hydro costs), and then converted to ZAR. Other rand prices are taken to December 2022 as per CPI inflation. Coal cost assumptions as a base case include flue-gas desulfurization (FSD), as was included in Kusile, but do not include Carbon capture storage, which would make the costs more expensive.

Note, these costs are at assumed capacity factors, technically if the actual capacity factor is lower than assumed above (obtainable rom EPRI reports for example), then then capital and O&M costs should probably increase in proportion inverse to the proportion reduction in capacity factor, since the rand per year stays approximately the same but the denominator, the energy produced will go down because of the newer capacity factor (DOE, 2016, p. 17).

Of special interest is the effect of the diesel price on OCGT generation. The 2019 IRP included a scenario "IRP5" with higher expected costs for natural gas as fuel, (which resulted in new coal build being included as part of the optimal trajectory) so is an important potential scenario. To better match and model the diesel expense of Eskom's higher than previous years' running of OCGT's in 2022 , there is a mechanism to change the diesel price which changes the expected cost of generation. Historical diesel prices are in sheet "Diesel prices" and the cost per litre is converted to a cost of fuel per MWh by assuming 38MJ or heat from burning one litre of diesel (where 3.6MJ=1kWh of raw heat), an efficiency of 35% in converting to electricity for OCGT's(Eskom, 2021), resulting in an assumption of 3.694kWh of electricity per litre of diesel which is 35%*38MJ/(3.6MJ/kWh).

Emissions costs in terms of CO_2, NO_3 and water use are included in the same sheet "Cost scenarios" in the Excel model which are based off of the assumptions used in the Draft 2016 IRP.

With a Diesel price of R22.035, the cost assumptions are then as follows:

Costs scenario			Base scenario			
	Old build usable (MW)		Diesel price:	R22.035		
			Rand generation costs			
	2022 installed		MWh/ZAR			
Baseload	2	% new build	Capital	O&M (operations and maintenance)	Fuel	**Overall**
Coal	**38,964**	0%	R1,042.62	R305.06	R403.92	**R708.98**
Nuclear	**1,860**	0%	R1,543.03	R551.86	R84.40	**R636.26**
Renewable baseload	**25**	0%	R843.84	R568.16	R54.53	**R622.69**
Variable Renewable Energy and Hydro						
Solar PV	**2,194**	0%				**R465.95**
Wind	**2,662**	0%				**R537.63**
CSP	**500**	0%				**R2,766.35**
Hydroelectric in SA	**600**	0%				**R1,305.46**
Imports (mostly Hydro)	**1,765**	0%				**R600.08**
Storage (pumped or battery)						
Pumped Storage	**2,724**	0%				**R1,305.46**
Battery	**0**	100%	R5,267.89	R1,029.78	R0.00	**R6,297.67**

Peaking plants						
Gas/Diesel	**3,414**	0%	R1,513.90	R210.20	R5,964.40	**R6,174.60**

The emission assumptions sourced from the Draft 2016 IRP are as follows, where the water use for coal is sourced from other research (Sparks *et al.*, 2014) and is provided in the table below. Note that nuclear generation using sea water for cooling has negligible impact on South Africa's fresh water reserves.

	Environmental costs		
	kg/MWh	**kg/MWh**	**l/MWh**
Baseload	**CO2**	**NO3**	**Water use**
Coal	947.30	1.90	1,646
Nuclear	-	-	
Renewable baseload	806.00	0.60	
Variable Renewable Energy and Hydro			
Solar PV	-	-	
Wind	-	-	
CSP	-	-	
Hydroelectric in SA	-	-	
Imports (mostly Hydro)	-	-	
Storage (pumped or battery)			
Pumped Storage	-	-	
Battery	-	-	
Peaking plants			
Gas/Diesel	574.00	0.30	

The model currently does not make any assumptions about other externalities, such as jobs/MWh, mortality/MWh, or use of tonnes of material or land needed per MWh for different technologies. Such could be added in future versions of the model.

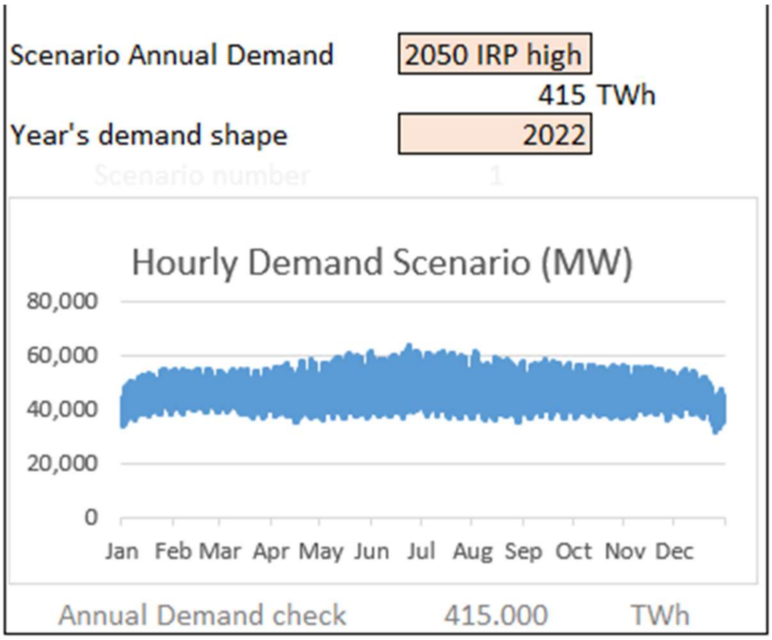
5.3 METHODOLOGY: MECHANISM OF THE MODEL AND HOW TO USE IT

Based on the inputs mentioned under 5.2 above, the model applies calculations to output: 1) the hourly demand for the specific scenario, 2) the hourly electricity generation per source, and the power used in charging PS reservoirs or batteries, 3) any curtailment needed if extra supply cannot go into storage, 4) load-shedding required if the demand cannot be met. The hourly supply and demand can be graphed such as the instructive graph of choosing exemplary weeks to graph. Hourly values are also aggregated to annual values per source, which then also translate into capacity factors per source. This is the first level of output.

The annual outputted energy per source can then be multiplied with the relevant costs and emissions per source to get an annual cost (including emissions) for the inputted energy mix.

5.3.1 CALCULATIONS OF DEMAND

The two demand inputs are: 1) the scenario annual demand in TWh (which can be chosen per dropdown), and 2) the year's demand shape (either of 2019, 2020, 2021, or 2022 can be chosen). The hourly demand in the scenario is simply calculated as the actual demand in the chosen year each hour, multiplied by a factor of [the inputted annual demand in TWh]/[the actual demand in TWh of the year of the chosen demand shape]. This results in a scenario with total annual demand as inputted. For example, the actual 2022 demand reached a maximum of around 35GW, and a total annual demand of 227TWh. If the 2022 demand shape is chosen together with the "2050 IRP high" scenario, the peak load becomes around 63MW and the annual demand (sum of each of the hourly demand values) is 415TWh:



5.3.2 CALCULATIONS OF GENERATION, STORAGE, CURTAILMENT AND LOAD-SHEDDING

For baseload and variable renewable energy and hydro, the hourly generation is calculated as the nominal capacity as inputted for the scenario multiplied by the capacity factor of the relevant historical hour, potentially adjusted by multiplication with an adjustment factor to increase or decrease the capacity factors of each hour by an equal ratio. The nominal capacity scenario can be changed by choosing from the dropdown in cell H10, which updates the values in range I12:I25, but the values used in the scenario are those in cells H12:H25, which may reference column I (the chosen scenario) but can also be edited individually to make any adjustments to each of the nominal capacity individually, for example to see what would happen if an extra 6GW of solar had been installed in 2021, or to customised each aspect of a proposed 2050 energy mix.

Supply scenario			
		Copy scenario to the left to activate that scenario, manual adjustments allowed in the inputs.	
Nominal power capacities (MW)			
Supply scenario	2021 Average	Scenario number	1
Baseload	**Nominal generation capacity**		
Coal	38,964	38,964	
Nuclear	1,860	1,860	
Renewable baseload (e	25	25	
Variable Renewable Energy and Hydro			
Solar PV	2,194	2,194	
Wind	2,662	2,662	
CSP	500	500	
Hydroelectric in SA	600	600	
Imports (mostly Hydro)	1,765	1,765	
Storage (pumped or battery)			
Pumped Storage	2,724	2,724	
Battery	8	-	
Peaking plants			
Gas/Diesel	3,414	3,414	
Total (MW)	**54,716**	**54,708**	
Weekly Diesel limit (Ml)	31.00	expressed in MWh:	114,528
Energy Storage Capacity (MWh) and Efficiency			
Pumped MWh	59,097		
Pumped Efficiency	74%	max charge/hour	2,108
Pumped recharge hours	28	charge use/hour	2,848
Battery MWh	32		
Battery Efficiency	80%	max charge/hour	6
Battery recharge hours	5	charge use/hour	8
Energy Availability Factors per hour scenario:		(other RE uses dates as per solar)	
historical start date (max 1 Jan 2022)		**Factor (multiply)**	**Resulting Load Factor**
Solar EAF scenario	1-Jan-21	100%	26.38%
Wind EAF scenario	1-Jan-21	100%	35.73%
Hydro EAF scenario	1-Jan-21	100%	29.95%
coal EAF scenario	1-Jan-21	100%	54.17%
Nuclear EAF scenario	1-Jan-21	100%	75%

From row 8,816 down in sheet “Simple Energy Model” the 8,760 hourly capacity factors are pulled from sheet “Supply scenarios” where the first capacity factor is that relating to the date inputted in H37 to H41 of sheet “Simple Energy Model”. So any 365 day period can be chosen for, say solar, and any other 365 day period can be chosen for other generation. When pulling through the historical capacity factors, they are multiplied by the relevant adjustment factor in I37-I41. The adjustment factors can be used, for example, to see what would change if the overall performance of solar PV matched a different assumption (such as an overall capacity factor of 28% instead of the historical 26%, which could be attained by a multiplicative factor of around 28/26=107%). The hourly generation by these sources is then simply the single assumed amount of nominal capacity in MW multiplied by the capacity factor, where the capacity factor is capped to not go above 100% (which may be necessary due to application of the multiplicative adjustment factors).

In this way, the hourly electricity supplied by coal, nuclear, renewable baseload, solar PV, wind, CSP, hydroelectric and imports is determined for one year of 8760 hours. Hence it is assumed that the supply (capacity factors, also known as load factors) from these sources will continue as it did historically, with historical fluctuations, rather than responding in any way to the demand. Although technically hydroelectric stations can be used as peaking plants and respond to demand, it was grouped together with non-peaking plants because historically they have not always been used during load-shedding, which may indicate that they are more constrained by other factors such as the water levels. In any case, the ability to ramp up hydro power in South Africa to a large degree seems unrealistic based on our limited water resources, so will not be considered as peaking in the model. More reasons are in sheet "Why not consider Hydro as Peaking".

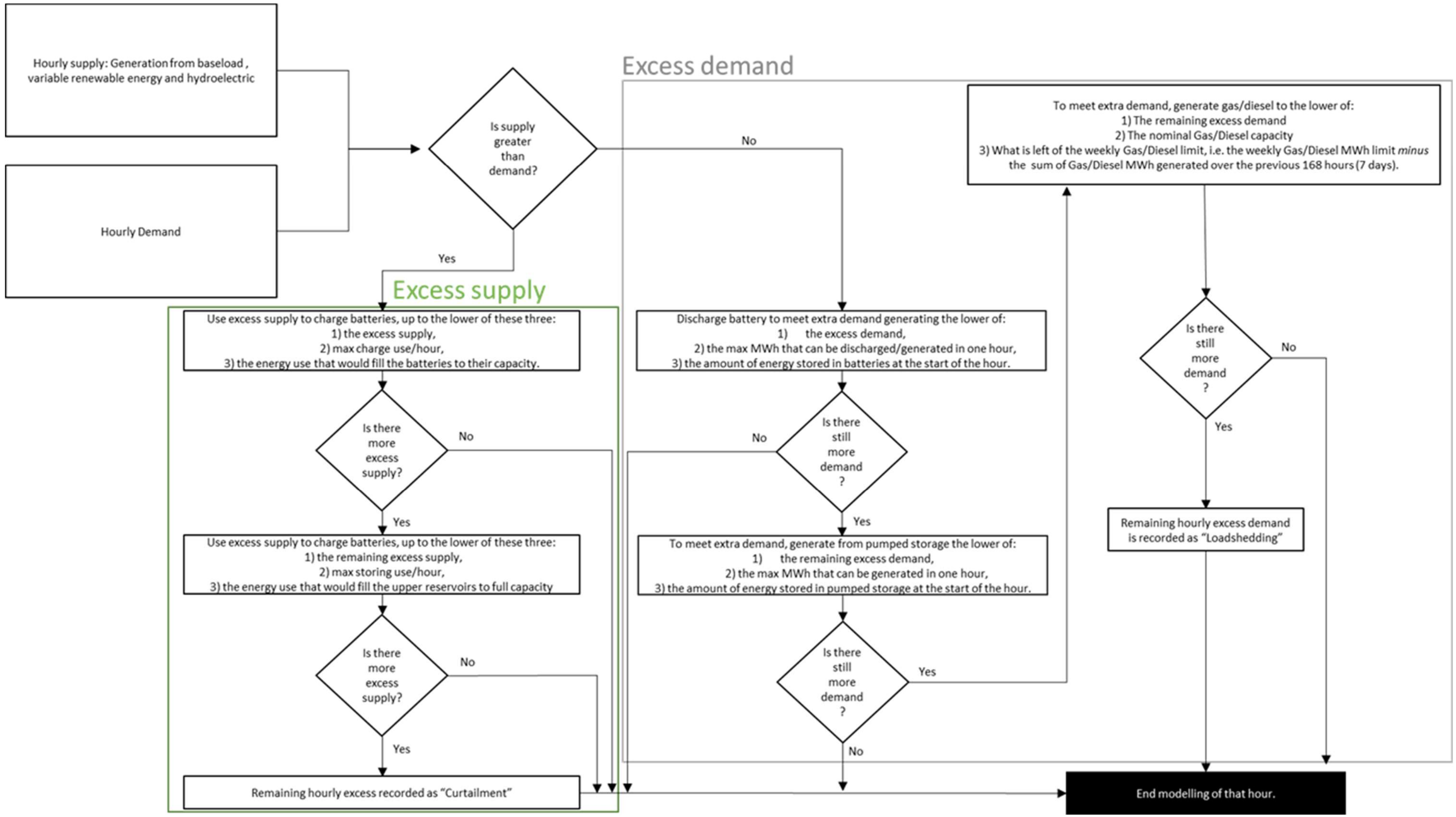
For hourly use related to PS, battery storage, curtailment, gas/diesel generation, and load-shedding, the model applies formulae considering the hourly demand compared to the baseload and renewable energy supply, as well as charging capacity and hourly limits related to the installed technology.

A weekly diesel limit in millions of litres is an input to make the model more realistic to the actual situation in South Africa where the majority of diesel burned comes from overseas on tankers and is delivered to the peaking plants by truck (Hawker, 2022), hence there being logistical and budget constraints on the usage of peaking plants.

The conversion of a litre limit to a kWh limit is 3.694kWh of electricity per litre of diesel or equivalently 3.694MWh per million litres (Ml) of diesel.

The mechanism of the model is described on the flow chart on the following page. The process is as follows: first check if the supply that hour is greater than the demand that hour, and if it is charging the batteries as much as possible, if there is more supply after charging the batteries, let the pumped storage pump water back to the upper reservoirs as much as possible, if there is still more supply, then that needs to be curtailed. If on the other hand, the supply is less than the demand, first try to meet the demand from batteries, then if the batteries cannot fully meet the demand generate power from the pumped storage, and if there is still insufficient supply then generate using the Gas/Diesel generators as much as possible, within the limits of the nominal capacity and the weekly diesel limit. Any remaining demand needs to be reduced through load-shedding. The beginning % of storage capacity stored at the first hour modelled is per input in cell Q40 for batteries (set at ~0%) and cell Q41 for pumped storage (set at 50%).

Note, the reason the model charges/discharges batteries first before pumped storage is because batteries have higher cycle efficiency. Batteries are also expected to charge and discharge more frequently since they have a lower maximum storage capacity. If it is desired to swap the order of the two storage types, the input characteristics of the two storage types could be swapped in the model (storage capacity in MWh, efficiency, recharge hours, and starting charge).



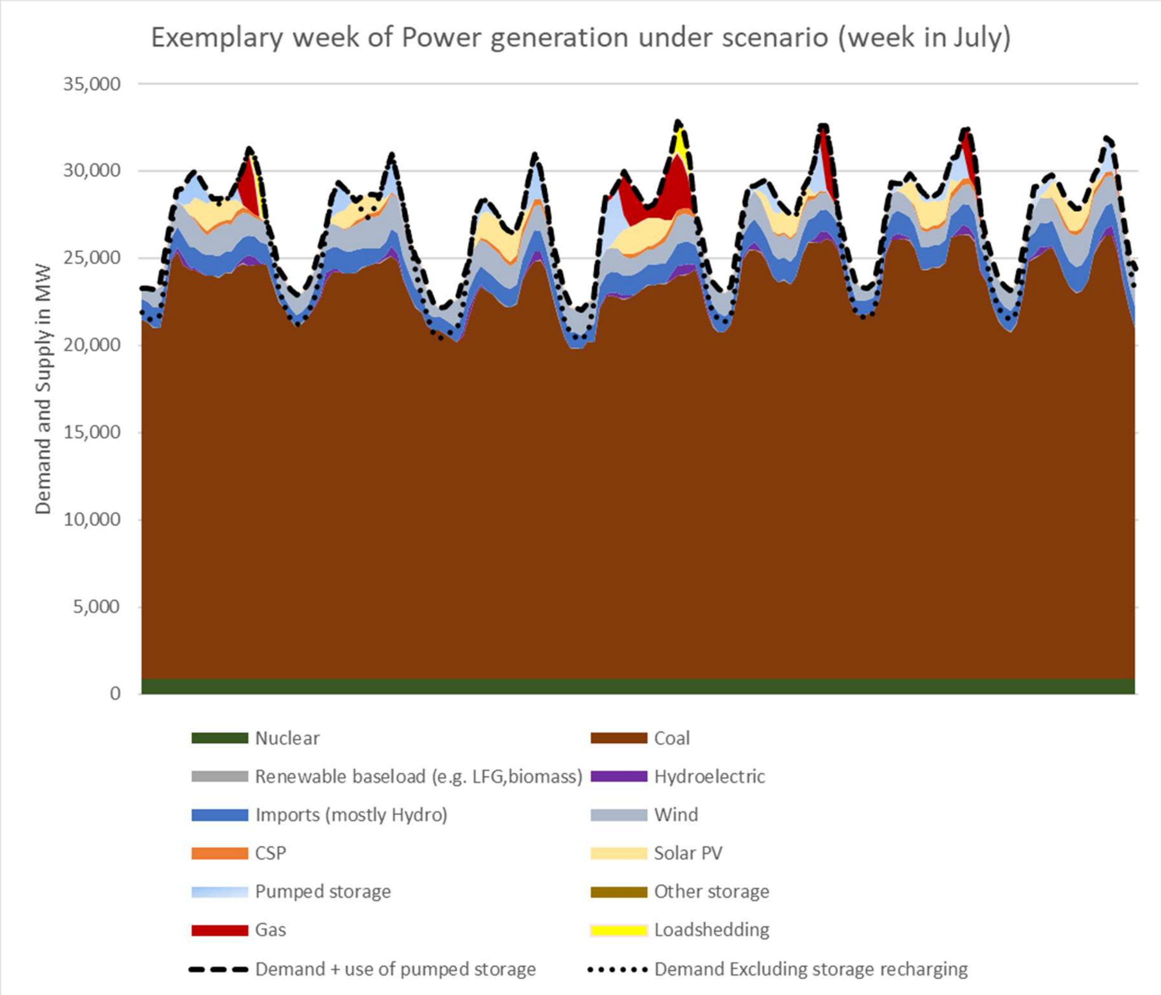
Hourly supply: Generation from baseload , variable renewable energy and hydroelectric
Hourly Demand
Is supply greater than demand?
Yes
No
Excess supply
Excess demand
Use excess supply to charge batteries, up to the lower of these three: 1) the excess supply, 2) max charge use/hour, 3) the energy use that would fill the batteries to their capacity.
Is there more excess supply?
No
Yes
Use excess supply to charge batteries, up to the lower of these three: 1) the remaining excess supply, 2) max storing use/hour, 3) the energy use that would fill the upper reservoirs to full capacity
Is there more excess supply?
No
Yes
Remaining hourly excess recorded as "Curtailment"
Discharge battery to meet extra demand generating the lower of: 1) the excess demand, 2) the max MWh that can be discharged/generated in one hour, 3) the amount of energy stored in batteries at the start of the hour.
Is there still more demand ?
No
Yes
To meet extra demand, generate from pumped storage the lower of: 1) the remaining excess demand, 2) the max MWh that can be generated in one hour, 3) the amount of energy stored in pumped storage at the start of the hour.
Is there still more demand ?
Yes
No
To meet extra demand, generate gas/diesel to the lower of: 1) The remaining excess demand 2) The nominal Gas/Diesel capacity 3) What is left of the weekly Gas/Diesel limit, i.e. the weekly Gas/Diesel MWh limit minus the sum of Gas/Diesel MWh generated over the previous 168 hours (7 days).
Is there still more demand ?
No
Yes
Remaining hourly excess demand is recorded as "Loadshedding"
End modelling of that hour.

Below under the purple heading is example output from the above 2021 supply input scenario. On the right, two columns of actuals for 2021 are included to compare as a preliminary validation check[11]. This output is based on inputs of 1) 2021 demand TWh amount, 2) 2021 demand shape, 3) 2021 average nominal generation capacity and 4) 2021 hourly capacity factors for each generation source. The capacity factors are annual generation are very close to the actuals except that the scenario makes less use of pumped storage, less use of gas/diesel, and incurs some curtailment, with the net result being less load-shedding.

% of total annual MWh	Annual Power Output	Annual MWh	Capacity factor	2021 Actual	CSIR 2021 load factors
	Baseload				
82%	Coal	184,894,255	54.2%	184,682,586	54.2%
5%	Nuclear	12,161,423	74.6%	12,161,423	74.6%
0%	Renewable baseload	123,923	56.6%	123,941	NA
0%	**Variable Renewable Energy and Hydro**				
2%	Solar PV	5,070,569	26.4%	5,069,146	26.4%
4%	Wind	8,330,491	35.7%	8,359,224	35.8%
1%	CSP	1,655,648	37.8%	1,656,017	37.8%
1%	Hydroelectric in SA	1,574,202	30.0%	1,578,334	30.0%
5%	Imports (mostly Hydro	10,151,824	65.7%	10,151,824	NA
0%	Curtailment	-24,019			
0%	**Storage (Net users of electricity)**				
		Output			
2%	Pumped Storage	4,182,586	17.5%	4,902,032	20.4%
0%	Battery	-			
		Charging utilisation			
	Pumped Storage	-5,612,631		-6,629,076	
	Battery	0			
	Peaking plants				
1%	Gas/Diesel	3,044,701	10%	3,174,472	10.7%
	Net sent out (MWh)	**225,552,972**			
	Loadshedding	1,613,123	0.7%	1,936,172	
	Send out + load shed	*227,166,094*		227,166,094	
	Demand (MWh)	**227,166,094**			

Here is an example of the model's output of an example week in July, winter, in this case for a 2022 scenario, which gives a picture of the adequacy of the mix of generation capacity, where need for load-shedding is highlighted in yellow:

[11] the actual annual generation is from the Eskom Data portal data, checked to be the same as the results for the CSIR in 2021 in the next section. The CSIR2021 load factors are from slide 15 from Pierce and Ferreira (2022)



An example of the costs output are included in the next section on model validation, but it is noted here that the full cost of generation is included, including the cost of curtailed energy.

5.4 MODEL VALIDATION CHECKS

In order to give assurance that the Excel model accurately models the causal relationship between the electricity scenario inputs and outputs, the model was back tested. In order to do this backtesting we first extracted actual calendar data from the Eskom Data portal – and the accuracy of our extraction of the actuals was checked by comparing to CSIR reports. Having confidence in the actuals being correctly sourced, we then compare the model output to the actuals to see if it is suitable for making high-level approximations.

5.4.1 ACTUAL HISTORICAL ANNUAL GENERATION PER SOURCE

The below table shows the historical MWh generated per source per year, including load-shedding, based off formulae from the Data Eskom portal (Range CV10:CZ56 in sheet "ESK3269_SUPPLY and EAFs" in "ESK_Supply_capacity_and_EAFs.xlsx")

Table 2:

	Annual MWh generated

	2019	2020	2021	2022
Baseload				
Coal	194,913,095	184,407,540	184,682,586	176,630,344
Nuclear	13,585,801	11,514,614	12,161,423	10,075,242
Renewable baseload	80,163	86,612	123,941	220,790
Non-dispatchable Renewable Energy and Hydro				
Solar PV	3,324,989	4,140,212	5,069,146	4,831,964
Wind	6,624,642	6,625,830	8,359,224	9,660,641
CSP	1,557,151	1,626,049	1,656,017	1,440,230
Hydroelectric in SA	676,384	761,772	1,578,334	3,138,768
Imports (mostly Hydro)	9,829,822	9,888,997	10,151,824	10,829,347
Curtailment	0	0	0	0
Storage (Net users of electricity)				
Pumped Storage *Output*	4,939,254	5,124,207	4,902,032	4,451,453
Pumped Storage *Charging utilisation*	-6,495,315	-6,846,806	-6,629,076	-5,853,406
Peaking plants				
Gas/Diesel	2,113,788	1,875,012	3,174,472	3,576,718
Net sent out (MWh)	**231,149,774**	**219,204,040**	**225,229,922**	**219,002,093**
Load-shedding (MLR+ILS) and interruption of supply	1,361,514	1,425,624	1,936,172	8,244,514
Sum of above	*232,511,289*	*220,629,664*	*227,166,094*	*227,246,607*
Breakdown of load-shedding into MLR, ILS and OLS				
MLR	1,090,432	1,269,139	1,774,892	8,073,976
IOS	221,844	111,267	104,454	101,906
ILS	49,239	45,218	56,826	68,633

The green shaded cells above match the CSIR's numbers in their 2021 statistics and the sum of blue shaded cells match their number for renewable energy output:

> **The electricity mix is still dominated by coal-fired power generation which contributed over 80% to system demand in 2021**
> - Coal energy contributed 81.4% (184.7 TWh)
> - Nuclear energy contributed 5.4% (12.2 TWh)
> - Renewable energy contributed 11.9% (27.0 TWh)
> - Renewable energy contributed 6.7% (15.2 TWh) - excluding hydro
> - The remaining 1.4% came from diesel (3.2 TWh)

The other years should also be accurate since they use the same extraction methodology.

5.4.2 CALENDAR YEAR 2022 BACKTESTING – SENSE CHECKING ANNUAL GENERATION

Slight discrepancies may appear between actual and modelled historical generation for baseload and variable renewables. This is due to there being a single input per source of nominal capacity, whereas the true capacity may have changed throughout the year e.g. with new installations. Hourly and annual demand should be exactly the same as the historical experience as those are inputs. However, the utilisation of pumped storage, gas/diesel and load-shedding are outputted based on the mechanics of the model and provide a useful model reasonability check. Costs and emission output values can also be sense checked against actuals as those assumptions are made independently of the actuals. Eskom's financial year data containing such information runs from April to March rather than in calendar years but should offer good reasonability checks and insights. Comparing outputted implied capacity factors to that published independently by the CSIR also gives us comfort that our assumed installed capacities are reasonable.

If all inputs are set to 2022 actuals, with a 26 million litre weekly diesel budget, the output looks like the below, compared to actuals in the rightmost column:

% of total annual MWh	Annual Power Output	Annual MWh	Capacity factor	Actual 2022
	Baseload			
81%	Coal	176,675,870	50.9%	176,630,344
5%	Nuclear	10,075,242	61.8%	10,075,242
0%	Renewable baseload	217,869	54.3%	220,790
0%	**Variable Renewable Energy and Hydro**			
2%	Solar PV	4,828,073	24.7%	4,831,964
4%	Wind	9,631,467	33.6%	9,660,641
1%	CSP	1,439,947	32.9%	1,440,230
1%	Hydroelectric in SA	3,126,993	59.5%	3,138,768
5%	Imports (mostly Hydro)	10,829,347	70.0%	10,829,347
0%	Curtailment	-49,048		0
0%	**Storage (Net users of electricity)**			
		Output		
1%	Pumped Storage	2,836,307	11.9%	4,451,453
0%	Battery	-		
		Charging utilisation		
	Pumped Storage	-3,792,917		-5,853,406
	Battery	0		
	Peaking plants			
2%	Gas/Diesel	3,568,047	12%	3,576,718
	Net sent out (MWh)	**219,387,197**		
	Loadshedding	7,859,411	3.5%	8,244,514
	Send out + load shed	*227,246,608*		227,246,607
	Demand (MWh)	**227,246,608**		

This scenario is quite close to the actual 2022. The actual use of pumped storage (and the resulting net energy loss) was more than modelled, resulting in higher overall load-shedding than modelled. It seems that Eskom is using OCGT's or load-shedding at night time to refill the pumped storage schemes so that they can be used to alleviate higher stages of load-shedding during the day(Clyde Mallinson [@ClydeMallinson], 2023).

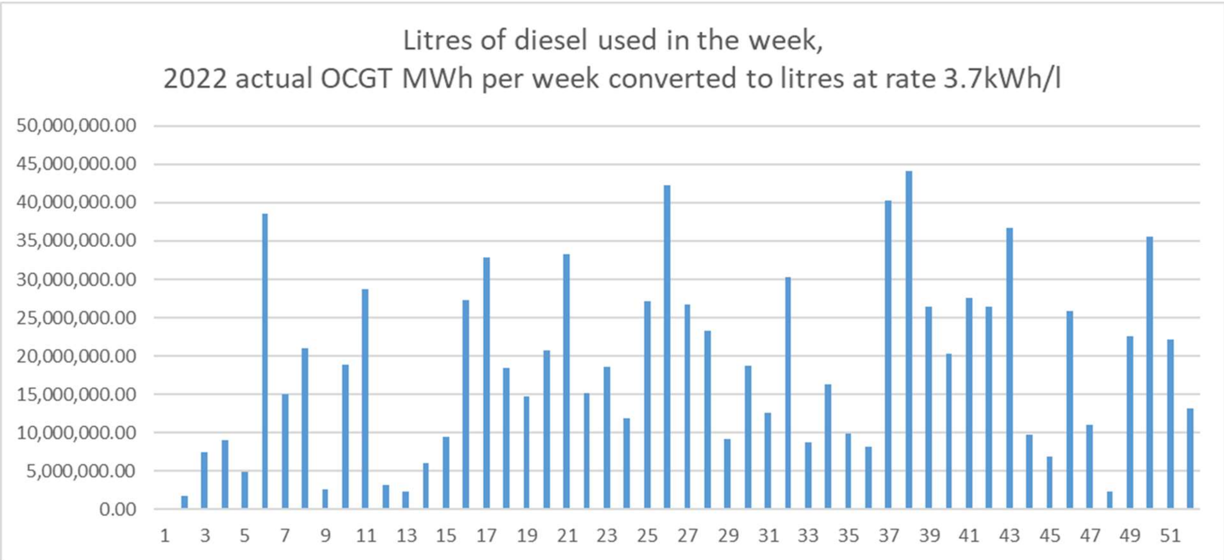
5.4.3 ANALYSIS OF THE PRACTICAL WEEKLY DIESEL LIMIT

With a 31 million litre weekly diesel the part above “Gas/Diesel” remains unchanged, but would have implied significantly more gas/diesel usage than the 3.58TWh actually produced in 2022. Hence the limitations in real life were more restrictive than 31 million litres per week, a budget that resulted in quite a close match for 2021. A lower weekly diesel budget in 2022 is understandable since 1) there was much more overall use of Diesel in 2022 compared to 2021, and 2) the price of diesel went up significantly in 2022 (average unweighted price of R21.71 per litre) compared to 2021(average unweighted price of R14.53 per litre) - both these points resulting in much higher annual diesel spend by Eskom in 2022.

% of total annual	Annual Power Output	Annual MWh	Capacity factor	Actual 2022
	Peaking plants			
2%	Gas/Diesel	4,109,526	14%	3,576,718
	Net sent out (MWh)	**219,928,676**		
	Loadshedding	7,317,932	3.2%	8,244,514
	Send out + load shed	*227,246,608*		227,246,607
	Demand (MWh)	**227,246,608**		

At Jan 2023 consumer prices for diesel was around R21.10 (*Fuel Pricing*, no date), thus the cost of 60 million litres comes to nearly R1.3bn; however based on the Megawatt-hours we have seen being generated, there have been on average 87m litres per month consumed by OCGT in the second half of 2022.

Plotting the implied diesel use per week in 2022, there is an implicit maximum of around 35million litres per week (which was exceeded in only 6 of the 52 weeks). But every time a week exceeded 35m litres, the following week is under 30m litres, implying that the practical sustainable logistical weekly limit is a bit lower.



5.4.4 Calendar year 2022 Backtesting – sense checking annual costs and emissions

A scenario was set up to estimate 2022 electricity generation costs. It has a 26 million litre weekly diesel limit, and a diesel price of R22.73 (expected roughly weighted average cost of diesel in 2022, see sheet "Monthly use of diesel" in the simple Excel model). It assumes the only capital costs related to Eskom's generation are for Kusile and Medupi (19% of the coal generation). The output for annual costs in 2022 (for 219.4TWh generated) looks as follows:

Costs scenario						8
	Old build usable (MW)		**Gas/Diesel price:**	CCGT Sept 2021	R9.57	
			Rand generation costs			
	from 2022 working in 2050		**ZAR/MWh**			
Baseload	3	**% new**	**Capital if new**	**O&M**	**Fuel**	**Overall**
Coal	**8,640**	0%	R1,042.62	R305.06	R403.92	**R709.01**
Nuclear	**0**	100%	R1,543.03	R551.86	R84.40	**R2,179.29**
Renewable baseload	**0**	100%	R843.84	R568.16	R54.53	**R1,466.52**
Variable Renewable Energy and Hydro						
Solar PV	**0**	100%				**R465.95**
Wind	**0**	100%				**R537.63**
CSP	**0**	100%				**R2,766.35**
Hydroelectric in SA	**600**	0%				**R1,305.46**
Imports (mostly Hydro)	**1,765**	59%				**R600.08**
Storage (pumped or battery)						
Pumped Storage	**2,724**	0%				**R1,305.46**
Battery	**0**	0%	R5,267.89	R1,029.78	R0.00	**R1,029.78**
Peaking plants						
Gas/Diesel	**0**	100%	R1,513.90	R210.20	R2,590.70	**R4,314.80**

The total cost of R981.55/MWh (including a R184.40/MWh portion towards the capital costs) is very close to Eskom Group's "Electricity operating costs" in the 2022 financial year of R979.45.

The carbon dioxide emissions modelled come to 170Mt, which is 18% less than the actual 207.2Mt of CO_2 emitted per Eskom's annual integrated report(Eskom, 2022c, p. 146). Similarly, the NOx emissions modelled are 337kt, much less than the 822 NOx emitted per the annual report. This may indicate that either the assumptions in the model for emissions are low, or the current fleet is more "dirty" than the assumed emissions of new coal stations.

The total water use in the model (with only water use assumptions for coal) is 290,808 million litres for the 2022 calendar year, which is very close to the 283,610 million litres used in Eskom's 2022 financial year.

5.5 NEW SIMPLE EXCEL MODEL SCENARIOS

In constructing a base case scenario, and seeing the model outputs from such a scenario, we aim to 1) identify whether the suggested IRP least cost mix is feasible, and whether it would enable security of supply at the stated costs, 2) consider risks and mitigation, and 3) compare it to other scenarios to get more confidence based on the simple model that such a strategy is indeed the least-cost.

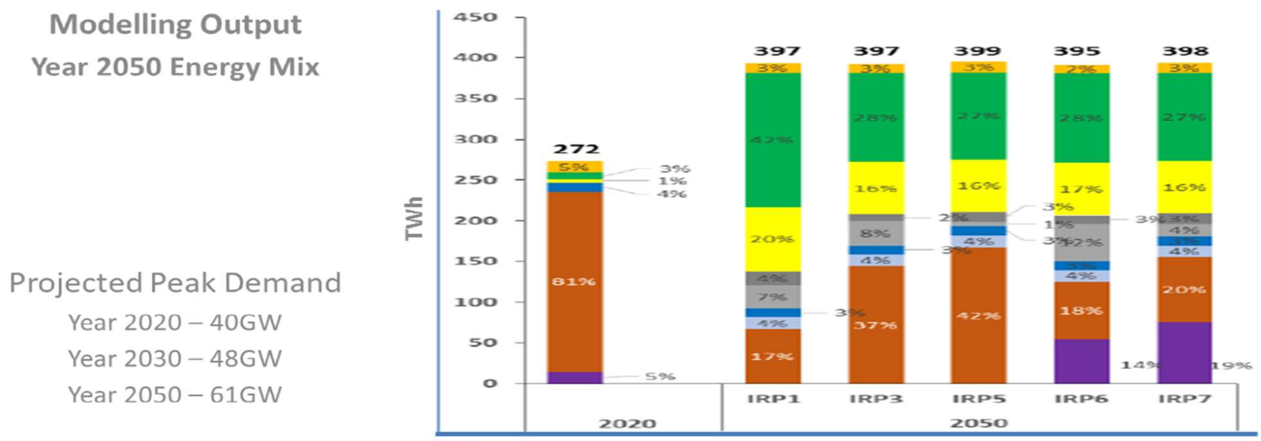
We will consider 6 scenarios for 2050, inputs, outputted generation, prices and emissions. These scenarios include:

- The lowest-cost scenario according to the 2019 IRP, called IRP1.
- An adjustment of IRP1 needing zero load-shedding, called the new base case.
- A 2050 mix including higher diesel/gas prices.
- A 2050 mix including significant nuclear build.
- A 2050 mix with battery storage instead of gas.
- A 2025 mix with the coming online of already procured power of 2000MW dispatchable (will be lower cost than OCGT's) through RMIPP; Bid window 5 procurement of 785MW of onshore wind and 975MW from solar PV, and Bid Window 6 procurement of 1000MW of solar. Additionally, it also includes the coming online of remaining Kusile units, and the decommissioning of 3500MW of coal.

5.5.1 REPLICATING THE 2019 IRP'S LOWEST COST 2050 MIX, WITH COMMENTS

We will create a baseline 2050 scenario for the simple Excel model based on the scenario "IRP1" from the 2019 IRP, "the scenario of RE without annual build limits" and which is advocated as providing "the least-cost path up to 2050." This is the only case considered in the IRPs since 2016 where there are no artificial limitations places on the amount of renewable's added to the energy mix in a given year. According to the CSIR the annual limits are unjustified, and while up to 2030 it does not have much effect on the least-cost mix, it does influence the proposed 2050 mix and the choice of whether or not ever to build new nuclear or new coal (which are included in the mix if the 1000MW PV and 1600MW for wind RE annual build limits are imposed).

The IRP1's 2050 installed mix is presented in the Draft 2018 IRP in terms of total installed capacity and percentages of that coming from various sources, as well as the electrical energy produced in total (TWh) in the 2050 year and split by source. There is also an image in the 2018 Draft IRP showing energy production, costs, emissions and water use values for 2050 for the IRP1 scenario (and other scenarios), and the same image is used in the final 2019 IRP, which used the same assumptions:



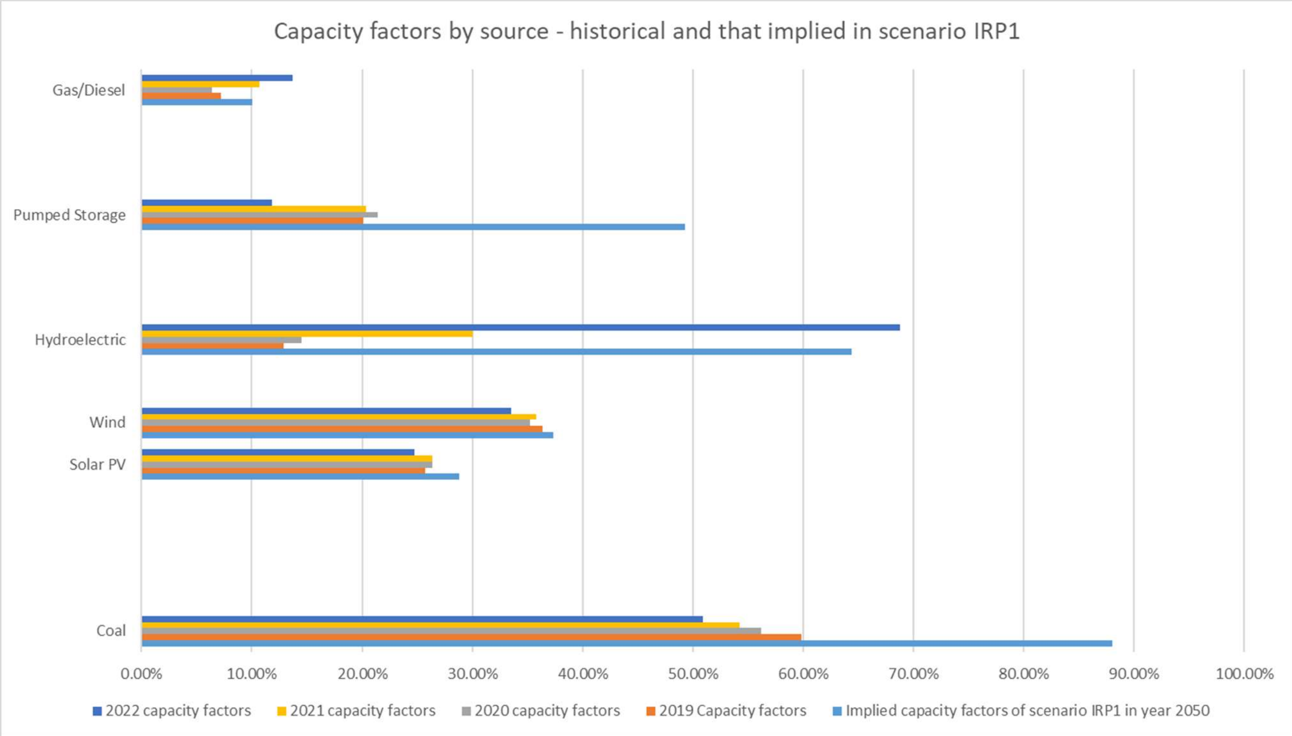
		2020	IRP1	IRP3	IRP5	IRP6	IRP7
Installed Capacity	GW	61	148	126	126	126	126
Environment	CO2 (Mt / year)	236	82	160	178	92	90
	Water Usage (bn Ltr / year)	260	36	54	51	36	38
Cost*	Unit Cost (c/kwh)		135	143	144	148	151
	Cumulative Cost Difference (R'million)		0	282 315	466 286	515 081	857 073
Security of Supply	Grid Stability and Fuel Supply Exposure	Reliance on coal continues significantly decline to around 30% from between 60% and 80% pre year 2030. Significant reliance on renewables and gas. Depending on source of gas, there is potential price and supply risk. Grid stability at high levels of renewable energy will need to be studied in detail and confirmed before a path is decided.					

* Year 2017 Rands

Figure 13: Scenario Analysis Results for the Period 2041–2050

The 2018 CSIR comments on the draft 2018 IRP recommended that there is a need for future IRPs to have full transparency around all elements of the models used to generate the forecasts which would make replicating scenarios like this easier (Wright *et al.*, 2017). It is unclear what the 3% orange "others" consists of, but we follow the CSIR in considering it as consisting of renewables such as biomass/biogas. According to the CSIR, the least-cost IRP1 scenario is around R30-60bn cheaper per year than all other scenarios by 2050. This scenario also exhibits the least CO_2 emissions and least water usage by 2050. The IRP1 has approximately 70% of its annual energy production coming from renewable sources (~42% Wind, ~20% Solar PV, and ~7% Hydro), and 11% supplied by gas. Note that unlike the Draft 2016 IRP and the previous 2010 IRP version, there is no nuclear build included in the least cost IRP1 scenario. This is since from 2018, the IRP cost assumptions included the much lower prices per kWh actually obtained in bids in South Africa's REIPPPP programme, lower than the prices assumed in the earlier IRPs based on the EPRI study. This is despite also including lower nuclear costs based on the Ingerop study of nuclear costs which include Asian nuclear projects which the EPRI had excluded. In sheet "IRP 1 installed capacity" of the simple excel model we have formulated an approximate version of the 2050 installed capacity of the IRP1 to serve as our first scenario.

Before showing the simple model's output, we note that the implied capacity factors in the IRP 1 are higher than the recent experience. When comparing the annual energy output in IRP 1 to the installed capacity in IRP1, we can calculate capacity factors implied in the IRP for each source of generation in 2050. We can also calculate the capacity factors for each source historically in South Africa (see same sheet "IRP 1 installed capacity" in the excel model). Capacity factor = (annual production in MWh)/(installed capacity in MW*8760), where 8760 is the number of hours in a year. The below graphs shows the IRP1 implied capacity factors compared to the actual 2019-2022 experience.



The implied IRP1 has an implied coal capacity factor of around 15-90% which is 28-37% higher than that experience in either of the 2019-2022 years, for Solar PV their capacity factor is 2.4%-4% higher, and for wind the IRP1's is 0.95%-3.8% higher for wind. While not big in absolute numbers, when the mix has as much as 80,000MW installed solar and wind generation as in the case of IRP1, a 4% lowering in capacity factor results in a significant percentage of the overall generation being lost, which could result in significant need of load-shedding. (4% of 80,000 over 8760 hours comes to 28TWh, or 7% of the 2050 annual supply of 392Twh. To put this in perspective, the 2022 calendar year experienced load-shedding amounting to 7TWh, or 3.2% of the annual production). The much higher expected capacity factor attributed to the coal plants is similarly likely unrealistic (though being applicable to the newer Medupi and Kusile power stations, the only stations of the current coal fleet that will still be within their 50 year lifetime in 2050, those stations will be at a similar age in 2050 to the current fleet now, and have not had great performance to date). This further indicates that if the IRP1 scenario is followed without additional capacity, there is risk of seriously high levels of load-shedding due to the possibility of lower than expected capacity factors, ceteris paribus.

The capacity factor assumption for hydro is high, but such factors are being reached currently with consistent supply from Cahorra Bassa in Mozambique. However, such capacity factors can only be reached when there is plenty of rain and the dams are full (compare ~69% capacity factor in 2022 to ~12.9% in 2019). Also, since the imported hydro comes from very far, such supply is more prone to interruption (through natural disasters such as Cyclone Idai referenced above or political risks).

A final point of mention is that the IRP1 scenario does not explicitly have a line showing how much curtailment is expected for wind or solar. However, such curtailment may be necessary at times when the capacity factors of wind and solar are high. Curtailment should either be modelled through lower capacity factors (capacity factors in IRP1 are however higher than current) or through explicit reduction in the generated electricity, since that generated electricity does not go towards meeting demand.

What follows are the IRP1 inputs and outputs based on the simple excel model:

Input for IRP1 replication scenario:

Annual Demand: 2050 IRP Median (380TWh)

Year's demand shape: 2022

Supply scenario:

Baseload	**Nominal generation capacity (MW)**
Coal	8,640
Nuclear	-
Renewable baseload (e.g. LFG,biomass)	2,960
Variable Renewable Energy and Hydro	
Solar PV	31,080
Wind	50,320
CSP	-
Hydroelectric in SA	600
Imports (mostly Hydro)	4,265
Storage (pumped or battery)	
Pumped Storage	2,724
Battery	-
Peaking plants	
Gas/Diesel	48,840
Total (MW)	**146,705MW excluding pumped storage, 149,429 with**

No diesel/gas limit (since the 2050 gas/diesel mix will likely include a higher proportion of CCGTs which can operate at higher capacity factors than OCGTs)

Capacity factors:

Factors were applied to the 2022 actual capacity factors to approximate the implied capacity factors in the IRP1:

Capacity Factors per hour scenario: historical start date (max 1 Jan 2022)		Factor (multiply)	Resulting load factor
Solar capacity factors	1-Jan-22	116%	28.78%
Wind capacity factors	1-Jan-22	111%	37.35%
Other RE capacity factors	1-Jan-22	84%	45.4%
Hydro capacity factors	1-Jan-22	94%	64.42%
coal capacity factors	1-Jan-22	173%	87.83%
Nuclear capacity factors	1-Jan-22	100%	

Costs:

In 2050, the gas/diesel production will likely be much more from CCGTs rather than OCGTs which are more efficient. The 2016 draft IRP used a heat rate of 7,395kW/kWh for CCGT, and 11,519 for OCGT and had the cost of GJ of fuel for both sources equal at R115.5/GJ. If the cost per GJ of fuel (diesel vs gas) is the same, then to incorporate the efficiency gain of CCGTs over OCGTs in the model, a factor of 0.6419=7,395/11,519 (the ratio of the heat rates) will be applied to the diesel price scenarios. The result is a "stress" scenario of a maximum CCGT fuel cost equivalent to OCGT R16.36 per litre (0.64* December 2022 diesel price of R25.48). The equivalent average 2022 scenario for CCGT is R14.01 per litre of diesel, and for September 2021, it is equivalent to R9.57 per litre diesel in OCGTs (actual diesel price being R14.91 in September 2021). However, prices for natural gas are lower now than in September 2021 and more work could be done to estimate 2050 fuel prices more accurately. In addition, future versions of the simple model could split out OCGT and CCGT to model them more accurately or have more intuitive inputs rather than converting diesel prices to equivalent diesel prices given improved efficiency of CCGTs.

For the 2050 scenarios, considering capital costs, it will be assumed that everything is new except the existing coal, hydroelectric and pumped storage and Cahorra Bassa hydroelectric imports from Mozambique, thus the below costs (in December 2022 Rands):

Costs scenario						8
	Old build usable (MW)		Gas/Diesel price:	CCGT Sept 2021	R9.57	
from 2022 working in 2050			Rand generation costs ZAR/MWh			
Baseload	3	**% new**	**Capital if new**	**O&M**	**Fuel**	**Overall**
Coal	**8,640**	0%	R1,042.62	R305.06	R403.92	**R709.01**
Nuclear	**0**	100%	R1,543.03	R551.86	R84.40	**R2,179.29**
Renewable baseload	**0**	100%	R843.84	R568.16	R54.53	**R1,466.52**
Variable Renewable Energy and Hydro						
Solar PV	**0**	100%				**R465.95**
Wind	**0**	100%				**R537.63**

CSP	**0**	100%				**R2,766.35**
Hydroelectric in SA	**600**	0%				**R1,305.46**
Imports (mostly Hydro)	**1,765**	59%				**R600.08**
Storage (pumped or battery)						
Pumped Storage	**2,724**	0%				**R1,305.46**
Battery	**0**	0%	R5,267.89	R1,029.78	R0.00	**R1,029.78**
Peaking plants						
Gas/Diesel	**0**	100%	R1,513.90	R210.20	R2,590.70	**R4,314.80**

Emissions are as assumed in the assumption in section 5.2.6 above.

Output from IRP1 replication scenario:

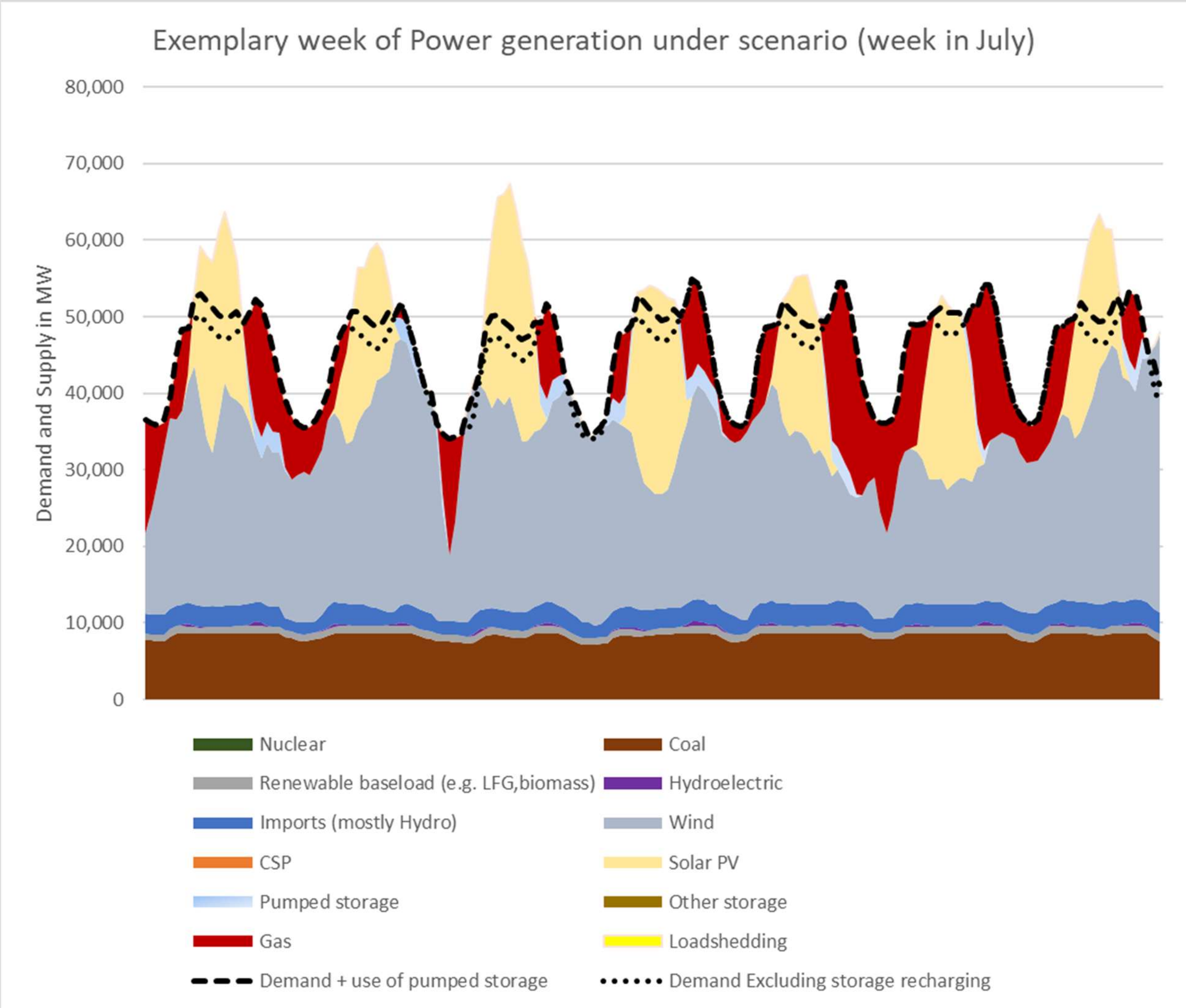
Annual generation is as shown in the below table:

	Output			
	Annual Power Output			
% of total annual MWh	**Baseload**	**Annual MWh**	**Capacity factor**	**Actual IRP1**
17%	Coal	66,477,883	87.8%	66,640,000
0%	Nuclear	0		
3%	Renewable baseload	11,763,501	45.4%	11,760,000
0%	**Variable Renewable Energy and Hydro**			
21%	Solar PV	78,355,942	28.8%	78,400,000
43%	Wind	164,651,736	37.4%	164,640,000
0%	CSP	0		
1%	Hydroelectric in SA	2,940,141	55.9%	11,760,000
6%	Imports (mostly Hydro)	24,512,381	65.6%	15,680,000
-6%	Curtailment	-23,742,902		0
0%	**Storage (Net users of electricity)**			
		Output		
1%	Pumped Storage	5,433,287	22.8%	
0%	Battery	-		
		Charging utilisation		
	Pumped Storage	-7,365,157		0

	Battery	0		
	Peaking plants			
15%	Gas/Diesel	56,973,190	13%	43,120,000
	Net sent out (MWh)	**380,000,000**		
	Load-shedding	0	0.0%	
	Send out + load shed	*380,000,000*		392,000,000
	Demand (MWh)	**380,000,000**		

Since the capacity factors were adjusted to approximate that implied in the IRP1, the output for most generation sources is similar to the actual IRP, with these notable exceptions: The simple model replication includes 23.7TWh of curtailment that reduces the RE output; loses 1.9TWh through net energy usage by pumped storage; and has significantly higher gas generation as a result – with gas making up 15% of the energy mix (vs the IRP1's 11% per their graph). Like the IRP1, the replication does not predict load-shedding if capacity factors are as high as implied in the IRP1.

The curtailment in simple Excel model can be seen in the graph of an exemplary week, where energy above the striped line is in excess of what is consumed both by RSA demand and pumped storage use. The extent solar and wind curtailment on the third day, 24 July at noon is almost 19GW. Such curtailment is hard to avoid without battery storage, since at such high levels of VRE in the mix, even if all coal and gas and hydropower generation were turned off there would still be more supply than the demand (27,815MW from solar PV and 28,079MW from wind alone giving 55,894MW compared to 48,641MW of demand and pumped storage charging at that hour):



The projected costs, in December 2022 Rands, are as follows:

Cost outputs			LCOE Rand	ZAR/MWh
Total annual cost	**R460,884,679,645**	Capital portion:	R96,180,557,357	R711.32
		Fuel portion	R175,093,484,499	R1,294.93
Total CO2 (Mt)	**105**	O&M:	R38,938,844,644	R287.98
		REIPPP	R125,031,159,706	R514.52
total Nox (kt)	**150**	Hydro	R18,547,702,099	R675.63
water use (Mℓ)	109,423	Pumped storage	R7,092,931,340	
Diesel/gas cost	R147,600,382,195	**Total**	**R460,884,679,645**	**R1,212.85**

The R1,201285/kWh outputted is close to the R1.00-R1.20/kWh ballpark in the IRP tariff graphs in figures Figure 11and Figure 18 above. The total system cost of R461bn is less than the R529bn assumed for the IRP1 scenario by the CSIR in their 2018 formal comments, but if the capital portion scenario is changed to "All new (100% capital costs)" then the simple model outputs R530.2bn as the total system cost, aligning well with the CSIR. Our assumed water consumption is much higher, at 109Mℓ compared to the CSIR's assumed 36Mℓ for the year, as are our assumed CO_2 emissions of 105Mt compared to the CSIR's 82Mt, due to different emissions assumptions per source, but the low difference in output overall from the IRP1 indicates reasonableness of the outputs given the input assumptions. Removing all capital costs (case ”all usable, i.e. no capital costs” for old build usable (MW) would result in a cost excluding any capital portion of R364bn, or R0.95975/kWh.

However, as noted, this scenario seems to have used higher capacity factors than recent actual experience for solar, wind and coal generation, and the gas use contributed 15% of the year’s energy use, significantly more than the 11% assumed in the IRP1. However, as noted, this scenario seems to have used higher capacity factors than recent actual experience for solar, wind and coal generation, and the gas use contributed 15% of the year’s energy use, significantly more than the 11% assumed in the IRP1.

If we change the capacity factor multiples to 100% to match 2022 experience, there is still not load-shedding in the 2050 IRP median demand scenario, but gas generation contributes 24% of the annual electricity output with an annual load factor of 21% and the cost goes up to R1.523/kWh as a result. Then changing the annual demand to the 2050 IRP high scenario results in the gas running at a 29% load factor, a cost of R1,71/kWh, and a very small amount of load-shedding – however the load-shedding could increase dramatically if there were shortages of gas, for example if the load factor were limited to 18% through a weekly limit (a weekly gas limit of 1.586TWh), the 2050 IRP high demand scenario would result in load-shedding equivalent to 11% of annual demand (with an electricity price of R1.39/kWh), and the 2050 IRP median scenario would have load-shedding of 5.5% of annual demand (with energy prices at R1.36/kWh). This would also leave South Africa very vulnerable to changing gas prices.

These sensitivities indicate that it may be worthwhile to adjust the IRP1 to form a new least-cost base case that is less reliant on gas, ideally limiting gas generation to 10-15% of the annual mix (as the IRP1 scenario had suggested) even in a high demand scenario and using capacity factors as experienced in 2022. This is considered next.

5.5.2 NEW APPROXIMATE LEAST-COST BASE CASE

We adjust the projected solar and wind by different factors with the goal of 1) reducing overall cost (to be expected as reliance on expensive gas reduces), and 2) to reduce the proportion of annual generation from gas to 10-15%, thus reducing the susceptibility of South Africa to changes in gas prices or supply. This should be the case even in a 2050 IRP high demand scenario to have sufficient “reserve” energy. The below are the results from testing various scenarios of demand and multiplicative factor of the amount of solar PV and wind that was used as input for the IRP1 scenario above. These outputs are all using 2022 demand shape, 2022 capacity factors for all generation types (lower than the IRP1), assuming all new build (except coal), and approximate and September 2021 CCGT fuel prices:

Demand Scenario (2050 IRP high or median)	% of IRP 1 solar PV and wind capacity	Overall system cost (still paying for curtailed energy)	Cost per kWh	Gas generation as a % of the annual generation
High (415TWh)	100%	R710bn	R1.711	30%
Median (380TWh)	100%	R579bn	R1.524	24%
Median (380TWh)	150%	R415bn	R1.091	10%
Median (380TWh)	175%	R389bn	R1.025	7%

Median (380TWh)	200%	R385bn	R1.013	5%
Median (380TWh)	225%	R391bn	R1.030	4%
Median (380TWh)	250%	R404bn	R1.064	3%
Median (380TWh)	300%	R440bn	R1.159	2%
High (415TWh)	200%	R428bn	R1.031	7%

In this simple manual optimisation exercise, the lowest overall cost for energy generation is to install approximately double (200%) the amount of solar PV and Wind suggested by the IRP1, i.e. to install a nominal generation capacity of 62,160MW of solar and 100,640MW of wind to supply an median annual demand of 380TWh in 2050. In this case it is expected than only 5% of annual generation will come from gas, which only increases to 7% in a high demand scenario.

The suggested gas generation capacity in the IRP of 48,840MW is still prudent even in a case of procuring double the generation capacity for renewables, since there are times when the weather precludes generation (e.g. lack of wind or dense cloud cover blocking the sun) and a big proportion of the hourly demand needs to be met by flexible generation. Using 2022 capacity factors, the time of greatest gas generation need was from 19:00-20:00 on 21 July where the sun was not shining, and the South Africa's wind generation had a capacity factor for that hour of only 3.7%. In the new base case scenario of double the IRP1 renewables, gas generation at that hour is still needed to the extent of 44,814MW in the 2050 high IRP demand scenario (415TWh annual demand), so installing anything less than that would have led to load-shedding in the scenario. Since a large wind fleet would be more diversified than the 2022 wind fleet, it is likely that the wind capacity factor would not drop so low, and South Africa might be fine with less gas generation, but we will leave it at 44,000 for the new base case, resulting in 814MWh of load-shedding in the year, just for that single hour, in the high demand case.

The load factor of gas in this case will be at 8% on average, a bit lower than the 13% experienced in 2022 or the 11% implied in the IRP1, which means less is generated for the same capital costs, so a more detailed model might have a higher capital cost per MWh than the simplified model, but 8% is not so different and it is not thought necessary to change in this model.

Input for new base case scenario:

The annual demand is 380TWh (2050 IRP Median), the year's demand shape is 2022, the nominal generation is per the below table:

Supply scenario	
Nominal power capacities (MW)	
Supply scenario	2050 - IRP 1
Baseload	**Nominal generation capacity**
Coal	8,640
Nuclear	-
Renewable baseload (e.g. LFG,biomass)	2,960

Variable Renewable Energy and Hydro	
Solar PV	62,160
Wind	100,640
CSP	-
Hydroelectric in SA	600
Imports (mostly Hydro)	4,265
Storage (pumped or battery)	
Pumped Storage	2,724
Battery	-
Peaking plants	
Gas/Diesel	44,000
Total (MW)	**225,989**

There is no diesel/gas limit.

The capacity factors are as 2022 actuals:

Capacity Factors per hour scenario: historical start date (max 1 Jan 2022)		**Factor (multiply)**	**Resulting load factor**
Solar capacity factors	1-Jan-22	100%	24.73%
Wind capacity factors	1-Jan-22	100%	33.55%
Other RE capacity factors	1-Jan-22	100%	54.3%
Hydro capacity factors	1-Jan-22	100%	68.74%
coal capacity factors	1-Jan-22	100%	50.89%

Output for new base case scenario:

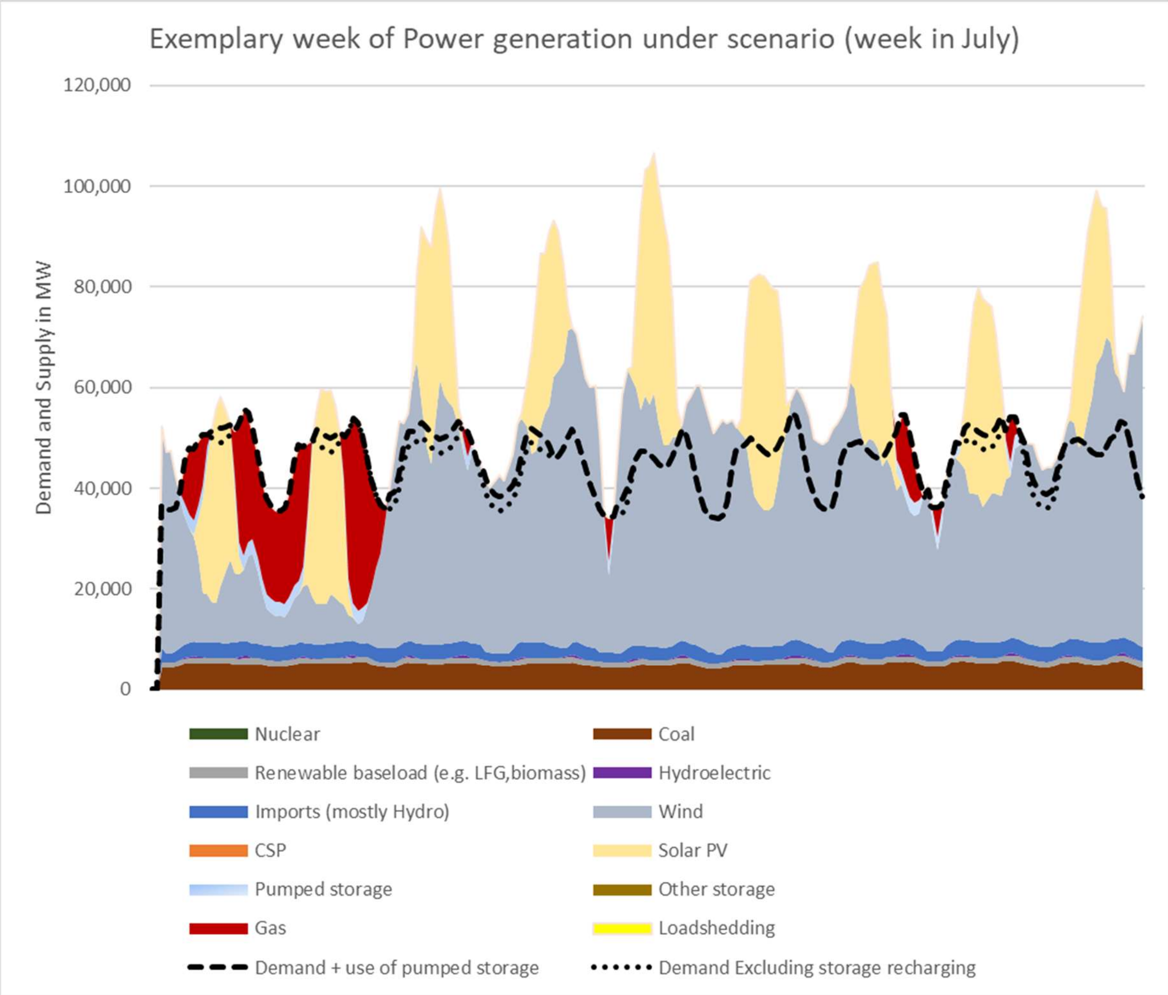
Annual generation per source is outputted per the table below (including MWh generated per year, % of total generation, and capacity factors, and a comparison to the IRP1).

	Output			
	Annual Power Output			
% of total annual MWh	**Baseload**	**Annual MWh**	**Capacity factor**	**IRP1**
10%	Coal	38,520,309	50.9%	66,640,000
0%	Nuclear	0		
4%	Renewable baseload	14,085,074	54.3%	11,760,000
0%	**Variable Renewable Energy and Hydro**			
35%	Solar PV	134,681,108	24.7%	78,400,000
78%	Wind	295,800,039	33.6%	164,640,000

0%	CSP	0		
1%	Hydroelectric in SA	3,126,993	59.5%	11,760,000
7%	Imports (mostly Hydro)	26,168,365	70.0%	15,680,000
-40%	Curtailment	-150,951,005		0
0%	**Storage (Net users of electricity)**			
		Output		
1%	Pumped Storage	5,448,308	22.8%	
0%	Battery	-		
		Charging utilisation		
	Pumped Storage	-7,402,509		0
	Battery	0		
	Peaking plants			
5%	Gas/Diesel	20,523,318	5%	43,120,000
	Net sent out (MWh)	**380,000,000**		
	Load-shedding	0	0.0%	
	Send out + load shed	*380,000,000*		392,000,000
	Demand (MWh)	**380,000,000**		

Note that there despite significant curtailment of Solar PV and Wind (of 430TWh generated in the year, 150TWh is curtailed), this is still a cheaper mix than the IRP1. As a sense check, the most expensive preferred bidder in bid window 6 of the REIPPPP offers a tariff of 54c/kWh for solar PV, at which price 430TWh could be generated for R232bn, and even though only 280TWh of the 430TWh can be used by the demand, the effective price per used kWh is still very economical, at 83c/kWh. The 280TWh at this low price makes up 74% of the annual demand (35% from solar, 78% from wind minus 40% curtailment), and as such causes the overall price to be low, even if the remaining 22% of annual demand is supplied by much more expensive flexible gas power.

An exemplary week and two days starting on the 20th of July (the day before the lowest renewable output on 21 July at 19:00) looks as follows:



The cost and emissions output are as follows:

Cost outputs			LCOE Rand	ZAR/MWh
Total annual cost	**R385,204,071,723**	Capital portion:	R42,957,122,290	R587.42
		Fuel portion	R69,496,830,777	R950.34
Total CO2 (Mt)	**60**	O&M:	R24,067,458,675	R329.11
		REIPPP	R221,784,759,973	R515.20
total Nox (kt)	**88**	Hydro	R19,785,358,808	R675.38
water use (Mℓ)	63,404	Pumped storage	R7,112,541,202	
Diesel/gas cost	R53,169,737,050	**Total**	**R385,204,071,723**	**R1,013.69**

This scenario is cheaper and emits less CO_2 than any of the IRP scenarios (which had a cheapest systems cost of R529bn per year and CO_2 of 82Mt). It could be that the reason for the possibility for such an improvement on the IRP scenarios is that in 2018 the average solar PV and wind tariff observed in Bid window 4 (in 2014 and 2015) were significantly higher than those seen later in Bid windows 5 and 6 (in 2021 and 2022). The more recent tariffs are less than 50c/kWh, whereas the Bid window 4 tariffs were at around 78c/kWh (all in Sept-2021 Rands)

Two important comments are to emphasize that in a 2050 scenario, excess energy may be used for green-hydrogen production and may not necessarily be curtailed. Similarly, instead of the flexible generation burning natural gas, it may be possible to burn hydrogen for power, thus having a net-zero emissions mix.

The following two cases will be based off this base case and consider how the base case might be influenced by a shock on the diesel price, and how a nuclear option would look.

5.5.3 HIGH GAS PRICE SCENARIO

Taking the new base case above and increasing the gas price from coastal September 2021 prices (equivalent to R9.57/l of diesel with OCGT efficiency, calculated as R14.90* 7395/11519 the heat rate of CCGT over the heat rate of CCGT) to the month with the highest yet seen diesel price of Gauteng November 2022 (R25.48 per litre of diesel with CCGT equivalent to R16.36/l with OCGT efficiency) results in the following costs output:

Costs scenario				9	
	Old build usable (MW)	Gas/Diesel price:	CCGT Nov 2022	R16.36	
		Rand generation costs			
	from 2022 working in 2050			ZAR/MWh	
Cost outputs				LCOE Rand	ZAR/MWh
Total annual cost	R422,904,485,191	Capital portion:		R42,957,122,290	R587.42
		Fuel portion		R107,197,244,245	R1,465.87
Total CO2 (Mt)	60	O&M:		R24,067,458,675	R329.11
		REIPPP		R221,784,759,973	R515.20
total Nox (kt)	88	Hydro		R19,785,358,808	R675.38
water use (Mℓ)	63,404	Pumped storage		R7,112,541,202	
Diesel/gas cost	R90,870,150,518	**Total**		**R422,904,485,191**	**R1,112.91**

In this scenario, the 71% increase in the fuel price (not unrealistic as this is what happened in the Diesel price from September 2021 to November 2022) translates to a system cost increase of 10% from R385bn to R423bn.

If there were a further increase of 56%in the diesel price (i.e., as if the diesel price would reach R39.69, with a similar increase in CCGT fuel costs to an equivalent of R25.48) then the output would look as follows:

Costs scenario				1	
	Old build usable (MW)	Gas/Diesel price:	November 2023	R25.48	
	from 2022 working in 2050	Rand generation costs			
				ZAR/MWh	
Cost outputs				LCOE Rand	ZAR/MWh
Total annual cost	R473,580,414,973	Capital portion:		R42,957,122,290	R587.42
		Fuel portion		R157,873,174,026	R2,158.84
Total CO2 (Mt)	60	O&M:		R24,067,458,675	R329.11
		REIPPP		R221,784,759,973	R515.20
total Nox (kt)	88	Hydro		R19,785,358,808	R675.38
water use (Mℓ)	63,404	Pumped storage		R7,112,541,202	

Diesel/gas cost	R141,546,080,300	**Total**	**R473,580,414,973**	**R1,246.26**

This represents a 23% increase in the overall systems cost (a further 12% increase on top of the first 10% increase), emanating from a 266% increase in the fuel price from September 2021. Due to the low proportion of gas in the total mix with the new base case, the overall effect on the price is not excessive (reaching up to R1.24626/kWh), and still roughly in the R1.00 to R1.20/kWh range that the IRP scenarios projected. Another implication is that even using OCGT's, and a price shock like seen in November 2022, the price of electricity is still manageable in the short term with price per kWh not exceeding R1.25/kWh.

5.5.4 Base case with Nuclear replacing some gas capacity

In this case we will slowly lower gas nominal capacity and replace it with nuclear to see if that can improve costs or keep costs the same but bring in the benefit of additional diversification to the energy mix (less reliance on gas as fuel). The previous IRPs have not included nuclear as part of a least cost mix, perhaps due to its high costs, but the high recent costs of fuel may make nuclear more attractive than it was in the 2019 IRP.

As established in the new base case (section 5.5.2), at least 44,000MW of flexible generation or baseload plus flexible generation would be needed in the 2050 IRP median demand case with 2022 capacity factors to avoid load-shedding. Additionally, in constructing a nuclear scenario, there is a need to adjust the nuclear capacity factors to that assumed in the pricing of the capital costs per MWh to be realistic.in order to be reflective. The assumptions for the Draft 2016 IRP, which also got their values from the Ingerop study for nuclear as we have assumed as well, have a typical capacity factor for nuclear at 90%. For this nuclear scenario we change the adjustment factor for nuclear capacity factors from 100% to 177%, which changes the resulting annual effective load factor from 62% (the actual 2022 experience with Koeberg) to 90%.[12]

Capacity Factors per hour scenario: historical start date (max 1 Jan 2022)			
		Factor (multiply)	**Resulting load factor**
Solar capacity factors	1-Jan-22	100%	24.73%
Wind capacity factors	1-Jan-22	100%	33.55%
Other RE capacity factors	1-Jan-22	100%	54.3%
Hydro capacity factors	1-Jan-22	100%	68.74%
coal capacity factors	1-Jan-22	100%	50.89%
Nuclear capacity factors	1-Jan-22	177%	90%

With such a capacity factor, for every lowering in flexible generation of 900MW from the base case, there is a need to install an additional 1000MW of nuclear. This is to ensure that

[12] The reason a factor greater than 145%=90/62 is needed because Koeberg already has some days on which the load factor gets as high as 98.9%, to which the adjustment factor doesn't make much of a difference to get up to the 100% it is capped at, so a bigger adjustment factor is needed to affect the other days (where historical factors were lower) to get the overall average annual load factor to 90%.

the same amount of energy can be generated on that day and hour with maximum residual demand (demand after VRE of solar and wind).

Below are the changes to total systems cost and gas generation as a percentage of the mix as we add successive 1600MW units of nuclear, each time reducing the installed gas capacity by 90% of that (1440MW). The new least cost base case row is highlighted green.

Demand Scenario (2050 IRP high or median)	# of 1600MW nuclear units installed	Overall system cost (still paying for curtailed energy)	Cost per kWh	Gas generation as a % of the annual generation
Median (380TWh)	0	R385bn	R1.013	5%
Median (380TWh)	1	R400bn	R1.052	5%
Median (380TWh)	2	R416bn R404bn	R1.094	4%
Median (380TWh)	4	R451bn R440bn	R1.188	3%
Median (380TWh)	6	R491bn R428bn	R1.293	7%
High (415TWh)	0	R428bn	R1.031	7%
High (415TWh)	1	R439bn	R1.057	6%
High (415TWh)	2	R451bn	R1.087	6%
High (415TWh)	4	R480bn	R1.156	4%
High (415TWh)	6	R514bn	R1.238	3%

The overall costs are always higher when adding nuclear instead of gas, despite the benefits of nuclear, the costs outweigh them. Some of the benefits of nuclear include nuclear cost/MWh being about half that of gas (R2179/MWh vs R4315/MWh for gas), nuclear providing continuous and consistent baseload energy thus reducing the need to use PS (about 300GWh for one unit of nuclear, saving the associated pumped storage cost of R1305/MWh in the high demand scenario), and removing the need for load-shedding in the 2050 high demand scenario for that 1 hour (if renewables were reduced to 198% from 200% of IRP1 levels, then the load-shedding would come back though, so the one unit of nuclear is taking the place of 2% of renewables). However, since nuclear is not flexible as gas, there is the need to pay high R2/kWh all year through, rather than only when it is needed. A conclusion from this simple scenario analysis is that nuclear does not work well with a renewable mix, it is either nuclear *or* renewables, and even at very high levels of nuclear due to it being so much more expensive than renewables, the renewable option seems better.

A conclusion from this simple scenario analysis is that new nuclear does not synergise well with a renewable mix, it should be either nuclear *or* renewables. This supports what is stated by others that the choice of renewables vs nuclear are mutually exclusive, since the development of one creates long term lock-ins to the exclusion of the other (Overy, 2011).

However, a primarily nuclear mix would be much more expensive than renewables. For example, if the nuclear was supplied to meet the minimum 29,000MW demand, less the average 4,400MW coal supply (so 24,600/0.9=27,333MW installed nuclear), and renewables and gas for the rest (choosing the renewables so as to minimise system cost), the supply and cost would result in the following below with 57% the suggested IRP amount of renewables:

Generation capacity with a primarily nuclear mix after reducing renewables such as to minimise the overall systems cost at R635.5bn:

Supply scenario	
Nominal power capacities (MW)	
Supply scenario	2050 Primarily nuclear
Baseload	**Nominal generation capacity**
Coal	8,640
Nuclear	27,333
Renewable baseload (e.g. LFG,biomass)	2,960
Variable Renewable Energy and Hydro	
Solar PV	17,716
Wind	28,682
CSP	-
Hydroelectric in SA	600
Imports (mostly Hydro)	4,265
Storage (pumped or battery)	
Pumped Storage	2,724
Battery	-
Peaking plants	
Gas/Diesel	35,360
Total (MW)	**128,280**

Energy output with a primarily nuclear mix:

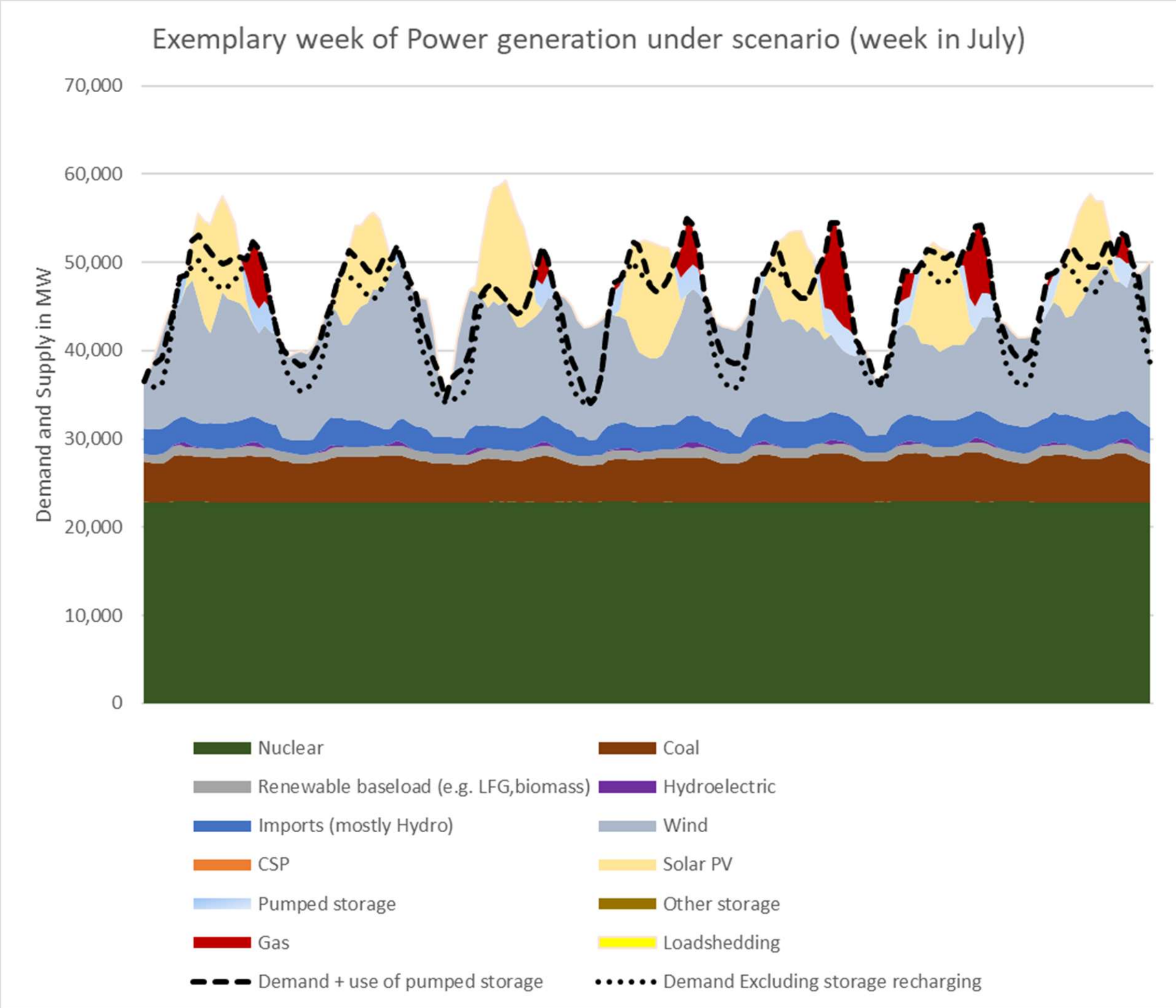
	Output			
	Annual Power Output			
% of total annual MWh	**Baseload**	**Annual MWh**	**Capacity factor**	**IRP1**
10%	Coal	38,520,309	50.9%	66,640,000
57%	Nuclear	215,283,132	89.9%	
4%	Renewable baseload	14,085,074	54.3%	11,760,000
0%	**Variable Renewable Energy and Hydro**			
10%	Solar PV	38,384,116	24.7%	78,400,000
22%	Wind	84,303,011	33.6%	164,640,000
0%	CSP	0		
1%	Hydroelectric in SA	3,126,993	59.5%	11,760,000
7%	Imports (mostly Hydro)	26,168,365	70.0%	15,680,000

-12%	Curtailment	-45,540,281		0
0%	**Storage (Net users of electricity)**			
		Output		
1%	Pumped Storage	3,809,046	16.0%	
0%	Battery	-		
		Charging utilisation		
	Pumped Storage	-5,187,290		0
	Battery	0		
	Peaking plants			
2%	Gas/Diesel	7,047,525	2%	43,120,000
	Net sent out (MWh)	**380,000,000**		
	Load-shedding	0	0.0%	
	Send out + load shed	*380,000,000*		392,000,000
	Demand (MWh)	**380,000,000**		

Costs of a primarily nuclear mix:

Cost outputs			LCOE Rand	ZAR/MWh
Total annual cost	**R635,506,436,523**	Capital portion:	R354,744,585,046	R1,290.28
		Fuel portion	R52,755,305,620	R191.88
Total CO2 (Mt)	**52**	O&M:	R140,039,978,374	R509.35
		REIPPP	R63,208,656,592	R515.20
total Nox (kt)	**84**	Hydro	R19,785,358,808	R675.38
water use (Mℓ)	63,404	Pumped storage	R4,972,552,083	
Diesel/gas cost	R18,258,015,341	**Total**	**R635,506,436,523**	**R1,672.39**

Exemplary week with a primarily nuclear mix:



The nuclear case does seem to have the additional benefit of lower CO_2 emissions (52Mt of CO_2 vs the least-cost mix of 60Mt), and a lower dependence on the gas price (gas would make up 2% of the mix rather than 5% of the mix). However, a case could be made that nuclear results in more emissions than renewables and gas (our emissions assumptions assumed zero for nuclear, which may be incorrect) (Overy, 2011). Moreover, the price would be significantly more expensive per MWh (60% more) and there are other concerns about nuclear such as risks associated with accidents, lower jobs per MWh and susceptibility to water cooling issues, as well as the fact that 90% seems to be an optimistic capacity factor compared to what has been attained on average by Koeberg over recent years.

5.5.5 BATTERIES REPLACING SOME GAS CAPACITY

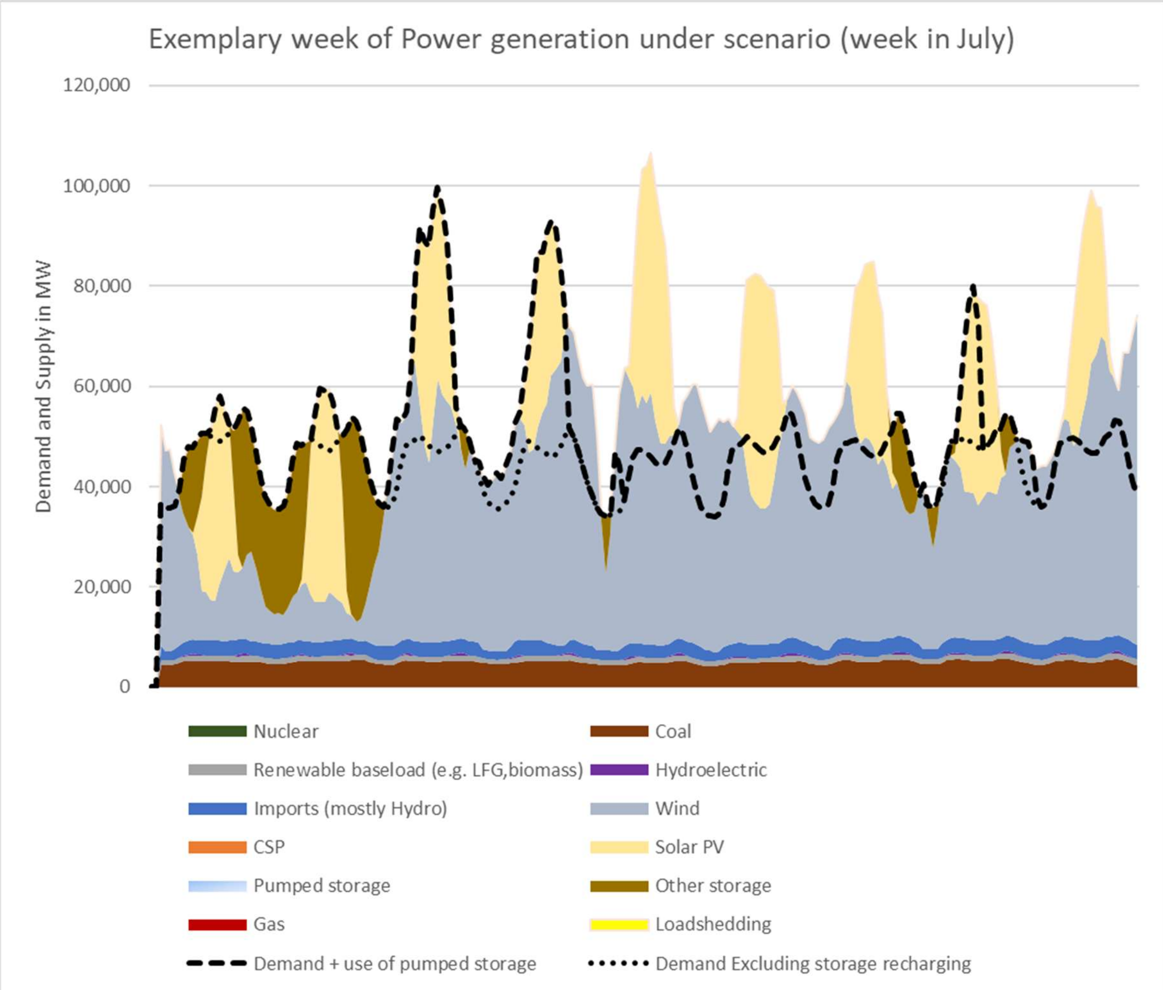
To get to a net-zero 2050 energy mix, one could use battery storage instead of gas - adding 44,000MW of battery storage would only increase the cost of electricity generation 15%, from R1.013/kWh to R1.153/kWh, and result in 51Mt of CO_2 emissions and only 1% of the energy mix coming from gas.

To eliminate the need of gas completely, one would need to set the battery storage at 216,000MW according to the excel model and the new base case scenario, with a cost of R1.18/kWh. In that case the only emissions are from the coal stations, producing 41Mt of CO_2.

This is using battery storage costs of R6.297 per kWh sourced from the EPRI report of 2017. Current battery prices are likely to be less, and 2050 battery prices significantly less according to learning curves, which may make batteries less than the CCGT fuel price of R4314.80/MWh (incorporating fuel price as per September 2021 and CCGT efficiency of R2599/MWh for fuel alone).

If OCGTs were used instead, and diesel prices go to prices seen in November 2022 (R25.48 per litre of diesel) the price per MWh generation from OCGT would be R8620.94/MWh (including a R6,897/MWh fuel cost) in which case the battery set-up would be cheaper overall. A battery capacity of 216,000MW instead of 44MW of OCGT generation would result in zero emissions from gas, zero load-shedding, and a cheaper overall cost of electricity of R1192/MWh for the year compared to R1246.26/MWh if 44,000MW of OCGTs were used. It is hence worthwhile investing heavily in batteries to 1) reduce susceptibility on gas prices, and 2) potentially benefit from battery prices going lower than gas generation (even at normal gas prices) by the year 2050.

Below is an output of an exemplary week in this scenario:



With these inputs:

Supply scenario	2050 - IRP 1
Baseload	**Nominal generation capacity**

Coal	8,640
Nuclear	-
Renewable baseload (e.g. LFG,biomass)	2,960
Variable Renewable Energy and Hydro	
Solar PV	62,160
Wind	100,640
CSP	-
Hydroelectric in SA	600
Imports (mostly Hydro)	4,265
Storage (pumped or battery)	
Pumped Storage	2,724
Battery	216,000
Peaking plants	
Gas/Diesel	-
Total (MW)	**397,989**

And these outputs:

	Output			
	Annual Power Output			
% of total annual MWh		**Annual MWh**	**Capacity factor**	**IRP1**
	Baseload			
10%	Coal	38,520,309	50.9%	66,640,000
0%	Nuclear	0		
4%	Renewable baseload	14,085,074	54.3%	11,760,000
0%	**Variable Renewable Energy and Hydro**			
35%	Solar PV	134,681,108	24.7%	78,400,000
78%	Wind	295,800,039	33.6%	164,640,000
0%	CSP	0		
1%	Hydroelectric in SA	3,126,993	59.5%	11,760,000
7%	Imports (mostly Hydro)	26,168,365	70.0%	15,680,000
-33%	Curtailment	-124,768,467		0
0%	**Storage (Net users of electricity)**			
		Output		
0%	Pumped Storage	5,761	0.0%	
7%	Battery	25,965,865	0.0%	
		Charging utilisation		
	Pumped Storage	-47,715		0
	Battery	-33,537,331		
	Peaking plants			

0%	Gas/Diesel	0	#DIV/0!	43,120,000
	Net sent out (MWh)	**380,000,000**		
	Load-shedding	0	0.0%	
	Send out + load shed	*380,000,000*		392,000,000
	Demand (MWh)	**380,000,000**		

Cost outputs			LCOE Rand	ZAR/MWh
Total annual cost	**R453,069,486,859**	Capital portion:	R148,672,123,454	R3,301.34
		Fuel portion	R16,327,093,726	R362.55
Total CO2 (Mt)	**48**	O&M:	R46,492,630,338	R1,032.39
		REIPPP	R221,784,759,973	R515.20
total Nox (kt)	**82**	Hydro	R19,785,358,808	R675.38
water use (Mℓ)	63,404	Pumped storage	R7,520,560	
Diesel/gas cost	R0	**Total**	**R453,069,486,859**	**R1,192.29**

Note if the renewables are reduced from 200% the level of the IRP1 to 199% the level of the IRP1, load-shedding starts to be required in this scenario.

Also note that with a 2050 IRP High demand scenario load-shedding will be completely avoided with the same installed amount of RE only if battery capacity reaches 340,000MW or more.

5.5.6 Modelling the likely 2025 mix

Though this research is intended mainly to give insight on the optimal long term 2050 energy mix, we can also use it to estimate how load-shedding will look two to three years from now. Here are some main changes which are likely to happen between now and 2025:

Coal:

- According to page 29 of Transmission development plan (TDP) 2022-2032, there will be a cumulative 2621MW of coal generation capacity decommissioned in the three years 2023, 2024 and 2025.
- Units 5 and 6 of Kusile, with nominal capacity of 720MW each, are expected to come online by the end of 2024.
- Unit 4 of Medupi (about 720MW nominal capacity), which was damaged in an explosion in August 2021, may possibly be fixed by the end of 2024. This would improve the EAF and hence capacity factor of coal generation if nothing else goes wrong.
- Units 1, 2, and 3 of Kusile (nominal capacity of 720MW each) are expected to come back online during 2023, after all three were put out of service in October 2022 due to a chimney failure in unit 1. Units 2 and 3 were kept temporarily out of service as a precaution. This would improve the EAF and hence capacity factor of coal generation if nothing else goes wrong.

RMIPPPP

- Of the 2000MW of projects selected in March 2021 under the RMIPPPP, nearly 800MW have a high likelihood of being implemented (the three Karpowership projects making up 1220MW are facing legal uncertainty). The RMIPPPP call for bids for electricity that can be dispatched any time between 5h00 and 21h30, and in this way the supply they provide can be modelled using OCGT gas/diesel generation as proxy with lower costs.

REIPPPP

- Up to 1608MW of Wind and 975MW of solar PV from preferred bidders selected in October 2021 under Bid Window 5 of the REIPPPP.
- About 1000MW of Solar PV procured from REIPPPP bid window 6 is likely to come online in 2025.

Embedded generation (especially mining-related)

- About 3000 MW of embedded generation (renewable energy projects) within the mining industry is expected to come online by the end of 2024.

Municipal procurement

- On 20 February 2023, the Gauteng premier announced the development of 800MW of solar for the province.
- There may be up to a total of 1500MW procured by municipalities by 2024 according to presidency's January 2023 update on the Energy Action plan. Such municipal generation may perhaps include something like Cape Town's planned 200MW of renewables and 500MW of dispatchable power. The sum of these comes to 1500MW.

The January 2023 update on the Energy Action plan lists a number of other potential increases in capacity or reduction in demand for the next few years, such as through the BESS project, increased rooftop solar (for which incentives were announced for both residential and commercial installation in the 2023 budget speech), demand response and energy efficiency, an emergency generation procurement programme, additional embedded generation and much more procurement from 2024 and beyond (including 3000MW of gas facilities in Richard's bay or Mossel Bay, 4000MW of pumped storage, further REIPPPP bid windows to be carried out on an expedited basis and more.

For our simple scenario for 2025, we first only consider some of these improvements, and assume a scenario with no improvement to the coal capacity factor, yet no increase in demand from 2022 levels. This equates to the following adjustments to the end December 2022 nominal generation capacity:

Supply scenario	**31-Dec-22**	**New up and running**	**Old decommissioned**	**2025 Scenario**	
Baseload					**Comment**
Coal	40,062	1440	-2621	38,881	**Kusile units 4 and 5 coming online, and 2621 being decommissioned according to the 2023-2032 TDP**
Nuclear	1,854			1,854	**No change assumed**
Renewable baseload (e.g. LFG,biomass)	51			51	**No change assumed**

Variable Renewable Energy and Hydro					
Solar PV	2,287	4075		6,362	**975MW BW 5, 1000MW BW6, 1200MW of embedded generation in mines (40% of the 3000MW renewables), 900MW for Gauteng**
Wind	3,443	3408		6,851	**1608MW from BW5, 1800MW from embedded mining generation (60% of 3000MW)**
CSP	500			500	**No change assumed**
Hydroelectric in SA	600			600	**No change assumed**
Imports (mostly Hydro)	1,765			1,765	**No change assumed**
Storage (pumped or battery)					
Pumped Storage	2,724			2,724	**No change assumed**
Battery				0	**No change assumed**
Peaking plants					
Gas/Diesel	**3,414**	1700		5,114	**800MW from RMIPPPP, 500MW non-renewable for City of Cape Town, 200MW battery dispatchable for City of Cape Town, 200 battery dispatchable from BESS phase 1**
Total (MW)	**56,699**		**Total (MW)**	**64,701**	

The diesel limit will be a blended limit of 120Ml per week for the new dispatchable capacity (effectively no limit, as such a high limit does not influence the gas/diesel use) and 26 litres for the existing 3414MW of OCGT's (as per 2022 experience). In this case the gas/diesel limit is 55.59=26*3414/5114+120*(5114-3414)/5114Ml per week. With such an input scenario, and 2022 demand and demand shape and 2022 capacity factors, the output is as such:

	Annual Power Output		
% of total annual MWh	**Baseload**	**Annual MWh**	**Capacity factor**
77%	Coal	173,345,848	50.9%
4%	Nuclear	10,042,741	61.8%
0%	Renewable baseload	240,683	54.3%
0%	**Variable Renewable Energy and Hydro**		
6%	Solar PV	13,784,642	24.7%
9%	Wind	20,135,124	33.6%
1%	CSP	1,439,947	32.9%
1%	Hydroelectric in SA	3,126,993	59.5%
5%	Imports (mostly Hydro)	10,829,347	70.0%

-4%	Curtailment	-7,989,090	
0%	**Storage (Net users of electricity)**		
		Output	
1%	Pumped Storage	3,036,903	12.7%
0%	Battery	-	
		Charging utilisation	
	Pumped Storage	-4,079,959	
	Battery	0	
	Peaking plants		
1%	Gas/Diesel	2,518,508	6%
	Net sent out (MWh)	**226,431,687**	
	Load-shedding	814,920	0.4%
	Send out + load shed	*227,246,608*	
	Demand (MWh)	**227,246,608**	

This very nearly solves load-shedding, with on average only 93MW of load-shedding per hour throughout the year. If 720MW nominal capacity is added for coal, to represent the fixing of unit 4 of Medupi, the load-shedding drops again to 456GWh, or 0.2% of the annual demand. At such small levels of lack in meeting the demand, it is unclear whether load-shedding will actually need to be implemented for significant periods during the year.

As an example, the model indicates load-shedding at times such as 29 June at 19:00 where in 2022 the wind capacity factor had been under 10% for four hours straight, solar generation was zero, and international imports were about half the amount they usually were due to a line fault in Mozambique's Cahorra Bassa, over 15GW of coal was offline due to breakdowns and a further 4GW was at risk due to illegal strike action. In 2022 this necessitated stage 6 load-shedding with the model showing a 5434-5992MW insufficient supply for the two hours 18:00-20:00 on 29 June 2022 assuming average 2022 capacity.

Changing the supply to the 2025 expected scenario there is still a 4.4GW lack of supply to meet the demand from 18:00 to 19:00 on 29 June (necessitating stage 5 load-shedding), and a 3.8GW lack of supply to meet the demand from 19:00-20:00. As a result, even doubling the solar and wind capacity would not remove the load-shedding completely. Adding 1200MW of Karpowership capacity (with effectively unlimited limit on added portion of capacity) would only reduce one stage of load-shedding in those hours. Instead adding 3000MW of gas as proposed for Richard's Bay/Mossel Bay would still leave a necessary 2 stages of the 5. Adding 3000MW plus 1200MW of dispatchable generation could have reduced the lack to 200MW during that hour, perhaps avoiding load-shedding (if extra diesel was burned for example, or if a wider distribution of wind generation would have resulted in higher average capacity factors in those hours).

The highest time of load-shedding simulated is forecasted to be in September, where on 19 September at around 18:00, the simulated load-shedding with 2022 nominal capacity reached nearly 9GW (stage 9), and with expected 2025 capacity the load-shedding reached about 6GW (stage 6). The actual reasons in September 2022 were that 5 generating units had broken down and OCGTs had been running a long time, and the diesel reserves ran out. The model also shows diesel use is limited at those hours due to very high usage in the previous week.

If we take the installed 2022 capacity scenario, which had 9GW load-shedding modelled for 19 September, and make only one change, to change the coal capacity factors from 2022 levels (~50%) to 2019 levels (~60%), that would have completed removed all load-shedding for the entire year.

The highest MLR per Eskom Data Portal data occurred on 9 December 2019 between 19:00 and 21:00, with nearly 9GW shed per hour. Stage 6 was implemented at that time, the cause being a technical issue with Medupi as well as heavy rains causing operational problems and problems related to coal handling. In the simple model, using 2022 actual demand, 2022 demand shape, and 2022 capacity factors for all generation types except coal which uses 2019 capacity factors, and average 2019 installed capacity for all sources, we see an output of 1.6TWh of load-shedding for the year (0.6% of annual demand) and stage 6 being needed for those days in December 2019. However, as mentioned in the previous paragraph, merely changing to 2022 installed capacity completely removes the load-shedding to zero for the year, if using 2019 capacity factors for coal. To repeat, the 2022 mix would have had no load-shedding if the coal fleet was performing as it did in 2019.

Below are some conclusions from this exercise of looking at 2025 and considering what risks materialised in the past, and recommendations for the short-term planning:

- Increasing renewables is useful in combatting load-shedding, but unless diversification significantly flattens out the wind load shape, there will be times when there is insufficient output from renewables. This necessitates very large peaking capacity but deployed at very low annual load factors. In other words it requires almost enough to provide electricity to the whole country by gas and coal alone for those rare occasions where there is a widespread lack of wind.
- Since the coal fleet still contributes such a large percentage of our electricity, making a small improvement in the capacity factor (say, 50% to 60%) would have an enormous effect on reducing load-shedding. So Eskom and the National Energy Crisis Committee are right to consider increasing the availability of the existing fleet as the number 1 key initiative in the Energy Action Plan (RSA, 2023).
- We may need significantly more peaking capacity by 2025 in order to completely remove load-shedding if the coal fleet capacity does not improve as hoped. The amount of capacity needed would be 9904MW in total if there were no diesel or fuel storage constraints constraining the weekly use.
- If only the expected 2025 scenario amount of dispatchable generation is available (i.e. 5114MW, the current OCGTs of 3414MW plus 1700MW in the table above), then in order to completely remove the need for load-shedding one would need to add 26.5GW of wind before 2025, in addition to the expected 3408MW of wind to be added by then. It is unlikely that additional geographical diversification of wind farms would significantly increase the minimum hourly capacity factor from the ~1% observed in 2022. According to CSIR (2016), even if as much as 76GW of wind capacity is installed, there will be instances where the output is as low as 0.08GW (0.1% capacity factor at that instant). If that happens at night when the sun is not shining, then there is the need for either batteries or flexible peaking generation to

supply the entire countries' need. In the short term, coal and gas may meet the need, but in 2050, a net zero alternative, perhaps green hydrogen and battery storage and pumped storage could meet that need.

5.6 MODEL IMPROVEMENTS

The model could be extended in future work by detailed calculation of costs per MW incorporating the capacity factor's impact on capital costs/MWh, as well as discount rates. Incorporating learning curves for prices of renewables and batteries could also greatly improve the cost projections.

The demand projections could also be improved, by, for example demand side efficiency and incorporating embedded generation.

The emissions and water use assumptions could also be refined, for example adding on more detail on CCS technology, and separating OCGT peaking stations from CCGT mid-merit stations which were considered together in the current model.

Additionally, further refinement could involve incorporating macroeconomic factors and feedback loops between the price of electricity and the demand for electricity. The model could also be improved by adding an automatic cost optimising algorithm.

All this would still be a simplification as it does not consider the path up to 2050 but rather just the costs related to a specific hypothetical 8760 hour year.

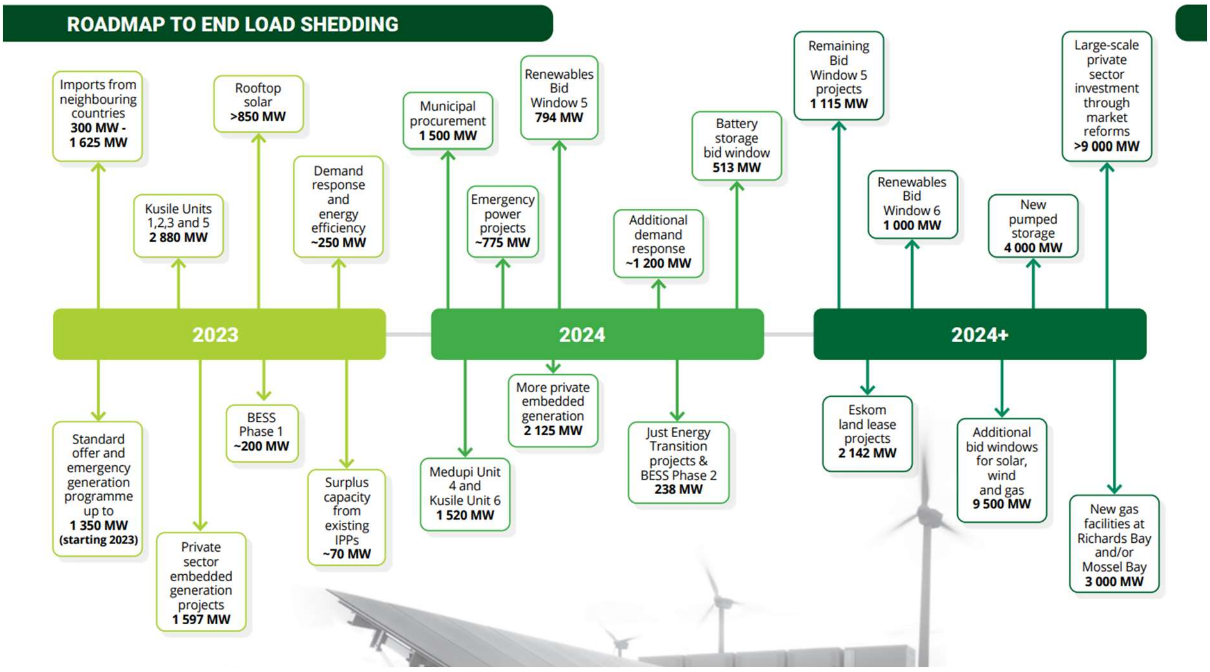
Further scenarios that could be added include decommissioning the coal stations early or excluding the grand inga development or imports.

The model could also be used for medium-term planning (such for 2030, as done for 2025 above) and setting expectations on load-shedding levels in the coming years.

6. RECOMMENDATIONS AND CONCLUSION

Regarding in finding an optimal 2050 energy mix (i.e. the 4th P of **P**rediction) that aims to adhere to the JET set out in much of the first P (**P**olicy considered), RE is the cheapest option and can be complemented well with gas peaking-generation. Having the 2050 mix comprise of 5% gas also helps to reduce the volatility of the electricity price as there is less reliance on diesel. Nuclear does not complement RE generation and is likely to be an expensive option if pursued. It is worth investing in batteries as they may be cheaper than gas by 2050 and have the added benefit of producing zero emissions.

Many of these points are echoed in the most recent Transmission Development Plan (see the Figure below outlining how the plan sees load-shedding decreasing in time). Given the similarities, it is worth noting that there is a plan for the effective reduction in load-shedding being enacted.



While our forecasts and those of government in plans like the 2019 IRP and the Transmission Development Plan are useful in helping the country to plan on how to solve the current energy crisis. It is important to note the potential barriers to effective implementation, namely the other two P's (**P**olitics and **P**ractical considerations). Given historic planning and governance issues, delays in the deployment of renewable energies need to be minimised. Operational risks arising from corruption has the potential to add on unexpected costs. A changing local and international energy landscape (for example developing green hydrogen) has the potential to significantly change the future energy mix. As such, this research much like the aim of the IRP is to be a living document where developments in the electricity crisis are incorporated and their impacts on our future energy mix assessed.

ACKNOWLEDGEMENTS
The authors would like to thank ASSA for the funding provided to complete this research. Additionally, thanks are given to Sandy Govender and Lusani Mulaudzi for facilitating the research done.

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APPENDIX A