energy

Department:
Energy
REPUBLIC OF SOUTH AFRICA

DRAFT IRP 2018 UPDATE FOR NEDLAC ENERGY TASK TEAM

DRAFT FOR DISCUSSION

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TABLE OF CONTENTS

Figures

Tables

ABBREVIATIONS AND ACRONYMS

CCGT	Closed Cycle Gas Turbine
CO_2	Carbon Dioxide
COD	Commercial Operation Date
COUE	Cost of Unserved Energy
CSIR	Council for Scientific and Industrial Research
CSP	Concentrating Solar Power
DEA	Department of Environmental Affairs
DoE	Department of Energy
DSM	Demand Side Management
EPRI	Electric Power Research Institute
FBC	Fluidised Bed Combustion
FOR	Forced Outage Rate
GDP	Gross Domestic Product
GHG	Greenhouse Gas
IEP	Integrated Energy Plan
GJ	Gigajoule
GW	Gigawatt (one thousand megawatts)
Hg	Mercury
IPP	Independent Power Producer
IRP	Integrated Resource Plan
kW	Kilowatt (one thousandth of a megawatt)
kWh	Kilowatt hour
kWp	Kilowatt-Peak (for Photo-voltaic options)
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
Mt	Mega ton

MW	Megawatt
NDP	National Development Plan
NERSA	National Energy Regulator of South Africa; alternatively the Regulator
NOx	Nitrogen Oxide
OCGT	Open Cycle Gas Turbine
O&M	Operating and Maintenance (cost)
PM	Particulate Matter
POR	Planned Outage Rate
PPD	Peak-Plateau-Decline
PPM	Price Path Model
PV	Present Value; alternatively Photo-voltaic
RE	Renewable Energy
REIPPP	Renewable Energy Independent Power Producers Programme
SOx	Sulphur Oxide
TW	Terawatt (one million megawatts)
TWh	Terawatt hour

GLOSSARY

"Baseload plant" refers to energy plants or power stations that are able to produce energy at a constant, or near constant, rate, i.e. power stations with high-capacity factors.

"Capacity factor" refers to the expected output of the plant over a specific time period as a ratio of the output if the plant operated at full-rated capacity for the same time period.

"Collector Station" refers to the substation that connects various renewable energy generating plants and or substations together in order to connect these plants to the Transmission network.

"Comparative prices" refer to calculated prices that can be used only to compare outcomes arising from changes to input assumptions, scenarios or test cases. These prices do not indicate what future prices may be (indicative prices).

"Cost of unserved energy (COUE)" refers to the opportunity cost to electricity consumers (and the economy) from electricity supply interruptions.

"Demand side" refers to the demand for, or consumption of, electricity.

"Demand side management (DSM)" refers to interventions to reduce energy consumption.

"Discount rate" refers to the factor used in present value calculations that indicates the time value of money, thereby equating current and future costs.

"Distributed generation" refers to small-scale technologies to produce electricity close to the end users of power.

"Energy efficiency" refers to the effective use of energy to produce a given output (in a production environment) or service (from a consumer point of view), i.e. a more energy-efficient technology is one that produces the same service or output with less energy input.

"Fixed costs" refer to costs not directly relevant to the production of the generation plant.

"Forced outage rate (FOR)" refers to the percentage of scheduled generating time a unit is unable to generate because of unplanned outages resulting from mechanical, electrical or other failure.

"Gross Domestic Product (GDP)" refers to the total value added from all economic activity in the country, i.e. total value of goods and services produced.

"Heat rate" refers to the amount of energy expressed in kilojoules or kilocalories required to produce 1kWh of energy.

"Integrated Energy Plan" refers to the over-arching, co-ordinated energy plan combining the constraints and capabilities of alternative energy carriers to meet the country's energy needs.

"Integrated Resource Plan (IRP)" refers to the co-ordinated schedule for generation expansion and demand-side intervention programmes, taking into consideration multiple criteria to meet electricity demand.

"Lead time" refers to a time period taken to construct an asset from scratch to production of first unit of energy.

"Learning rates" refer to the fractional reduction in cost for each doubling of cumulative production or capacity of a specific technology.

"Levelised cost of energy" refers to the discounted total cost of a technology option or project over its economic life, divided by the total discounted output from the technology option or project over that same period, i.e. the levelised cost of energy provides an indication of the discounted average cost relating to a technology option or project.

"Operating and maintenance (O&M) costs" refer to all non-fuel costs such as direct and indirect costs of labour and supervisory personnel, consumable supplies and equipment and outside support services. These costs are made up of two components, i.e. fixed costs and variable costs.

Outage rate" refers to the proportion of time a generation unit is out of service. The nature of this outage could either be scheduled on unscheduled.

"Overnight capital cost" refers to capital cost (expressed in R/MW) of a construction project if no interest was incurred during construction, assuming instantaneous construction.

"Peaking plant" refers to energy plants or power stations that have very low capacity factors, i.e. generally produce energy for limited periods, specifically during peak-demand periods, with storage that supports energy on demand.

"Planned outage rate (POR)" refers to the period in which a generation unit is out of service because of planned maintenance.

"Policy instrument" refers to an option that when implemented is assured to achieve a particular government objective.

"Present value" refers to the present worth of a stream of expenses appropriately discounted by the discount rate.

"Reference Case (Base Case)" refers to a starting point intended to enable, by means of standardization, meaningful comparisons of scenario analysis results based on sets of assumptions and sets of future circumstances.

"Reserve margin" refers to the excess capacity available to serve load during the annual peak.

"Scenario" refers to a particular set of assumptions and set of future circumstances providing a mechanism to observe outcomes from these circumstances.

"Sent-out capacity" corresponds to electricity output measured at the generating unit outlet terminal having taken out the power consumed by the unit auxiliaries and losses in transformers considered integral parts of the unit.

"Sensitivity" refers to the rate of change in the model output relative to a change in inputs, with sensitivity analysis considering the impact of changes in key assumptions on the model outputs.

"Steps" refer to the gradual change in assumptions, specifically in those adopted in IRP 2010, and the effect these changes have on model outputs.

"Strategy" is used synonymously with policy, referring to decisions that, if implemented, assume that specific objectives will be achieved.

"Supply side" refers to the production, generation or supply of electricity.

"Test case" is a specification of the inputs, execution conditions, testing procedure, and expected results that define a single test to be executed to achieve a particular testing objective.

"Variable costs" refer to costs incurred as a result of the production of the generation plant.

1. INTRODUCTION

South Africa's National Development Plan (NDP) 2030 offers a long-term plan for the country. It defines a desired destination where inequality and unemployment are reduced and poverty is eliminated so that all South Africans can attain a decent standard of living. Electricity is one of the core elements of a decent standard of living.

The NDP envisages that, by 2030, South Africa will have an energy sector that provides reliable and efficient energy service at competitive rates, is socially equitable through expanded access to energy at affordable tariffs and that is environmentally sustainable through reduced pollution.

In formulating its vision for the energy sector, the NDP took as a point of departure the Integrated Resource Plan (IRP) 2010–2030, which was promulgated in March 2011. The IRP is an electricity infrastructure development plan based on least-cost electricity supply and demand balance, taking into account security of supply and the environment (minimize negative emissions and water usage).

At the time of promulgation, it was envisaged that the IRP would be a "living plan" to be revised by the Department of Energy (DoE) frequently.

The promulgated IRP 2010–2030 identified the preferred generation technology required to meet expected demand growth up to 2030. It incorporated government objectives such as affordable electricity, reduced greenhouse gas (GHG) emissions, reduced water consumption, diversified electricity generation sources, localisation and regional development.

Following the promulgation of the IRP 2010–2030, the DoE implemented the IRP through Ministerial Determinations in line with Section 34 of the Electricity Regulation (Act No. 4) of 2006. These Ministerial Determinations gave effect to the planned infrastructure by facilitating the procurement of the required electricity capacity.

Since the promulgated IRP 2010–2030, the following capacity developments have taken place:

A total 6 422 MW under the Renewable Energy Independent Power Producers Programme (REIPPP) has been procured, with 3 876 MW operational and made available to the grid.

In addition IPPs have commissioned 1 005 MW from two Open Cycle Gas Turbine (OCGT) peaking plants.

Under the Eskom build programme, the following capacity has been commissioned: 1 332 MW of Ingula pumped storage, 1 588 MW of Medupi, 800 MW of Kusile and 100 MW of Sere Wind Farm.

In total, 18 000MW of new generation capacity has been committed to.

Besides capacity additions, a number of assumptions have changed since the promulgation of IRP 2010–2030. Key assumptions that changed include the electricity demand projection, Eskom's existing plant performance, as well as new technology costs.

These changes necessitated the review and update of the IRP which resulted in the draft IRP 2018 as per the Table below:

Table 1: Published Draft IRP 2018 (Approved by Cabinet for Consultations)

	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)

2. THE IRP IN CONTEXT

This IRP is developed within a particular context, characterized by very fast changes in energy technologies, and uncertainty with regard to the impact of the technological changes on the future energy provision system. As we plan for the next decade, this technological uncertainty is expected to continue and this call for caution as we make assumptions about the future in a rapidly changing environment. Accordingly, long-range assumptions are to be avoided as much as possible, to eliminate the risk that they might prove costly and ill-advised.

At the same time there is recognition that some of the technology options we have to take, require some level of long-range decisions. We try to harmonize this dichotomy, especially with regards to nuclear, gas and energy storage technologies, which technologies require more consideration of future developments.

The South African power system consists of the generation options, which are 38GW, installed capacity from coal, 1.8GW from nuclear, 2.7GW from pumped storage, 1.7GW from hydro, 3.8GW from diesel and 3.7GW from renewable energy. The electricity generated is transmitted to the various load centres in the country with Eskom and municipalities distributing to various end users. Eskom also supply a number of international customers, including electricity utilities, in the SADC region.

2.1 THE ENERGY MIX

South Africa continues to pursue a diversified energy mix that reduces reliance on a single or a few primary energy sources. The extent of decommissioning of the existing coal fleet due to age and commitment to reduced emissions post-2030, could provide space for a completely different energy mix relative to the current mix. In the period prior to 2030, the system preference is for modular and flexible technology, rather than base load.

Coal: Beyond Medupi and Kusile coal will continue to play a significant role in electricity generation in South Africa in the foreseeable future as it is the largest base of the installed generation capacity and it makes up the largest share of energy

generated. Due to the existing coal fleet age and abundance of coal resources, investments will need to be made in new flexible and more efficient technologies (High Efficiency Low Emission coal technology including new supercritical pulverised fuel power plants with flue-gas desulphurisation) to comply with climate and environmental requirements. The stance adopted by the Organization for Economic Cooperation and Development and financial institutions in regard to financing coal power plants, is a consideration upon which the support of High Efficiency, Low Emissions (HELE) technology is predicated. This ensures that South African coal still plays an integral part of the energy mix.

Given the significant investments required for Carbon Capture and Storage (CCS) and Carbon Capture Utilisation and Storage (CCUS)[1] technology, South Africa could benefit from establishing strategic partnerships with international organisations and countries that have made advancements in the development of CCS, CCUS and other HELE technologies.

Nuclear: Koeberg Power Station reaches end of life in 2024. In order to avoid the demise of the nuclear power programme, South Africa has to make a decision regarding the extension and possibly the expansion of the nuclear power programme.

Additional capacity from any technology deployed should be done at a scale and pace that will not have a negative impact on the economy especially through high tariffs as the user of electricity ultimately pays.

Small nuclear units (300 MW or less) are generally a much more manageable investment than big ones whose cost often rivals the capitalization of the utilities concerned.

The development of such plants elsewhere in the world is therefore particularly interesting for South Africa, and upfront planning with regard to additional nuclear

[1] Carbon capture, utilisation and storage, or CCUS, is an emissions reduction technology that can be applied in the industrial sector and in power generation. This technology involves the capture of carbon dioxide (CO_2) from fuel combustion or industrial processes, the transportation of CO_2 via a ship or pipeline, and either its use as a resource to create valuable products or services or its permanent storage deep underground in geological formations. CCUS technologies also provide the foundation for carbon removal or “negative emissions” when the CO_2 comes from bio-based processes or directly from the atmosphere. **Source**: International Energy Agency

capacity is requisite, given the >10-year lead time, for timely decision making and implementation.

Natural Gas: Gas to power technologies in the form of Combined Cycle Gas Turbines (CCGT), Closed Cycle Gas Engines (CCGE) or Internal Combustion Engines (ICE) provide the flexibility required to complement renewable energy. While in the short term the opportunity is to pursue gas import options, local and regional gas resources will allow for scaling up within manageable risk levels. Exploration to assess the magnitude of local recoverable shale and coastal gas are being pursued.

With the increasing availability of gas in Southern Africa, we might be able to expand electricity generation through the use of gas. There is enormous potential and opportunity in this respect and the Brulpadda gas resource discovery in the Outeniqua Basin of South Africa, piped natural gas from Mozambique (Rovuma Basin), indigenous gas like coal-bed methane and ultimately shale gas, could form a central part of our strategy for regional economic integration within the Southern African Development Community (SADC).

Co-operation with neighbouring countries is being pursued and partnerships are being developed for joint exploitation and beneficiation of natural gas within the SADC region. The SADC is developing a Gas Master Plan, to identify the short- and long-term infrastructure requirements to enable the uptake of a natural gas market.

South Africa continues to run open-cycle gas turbine plants e.g. Ankerlig (Saldanha Bay), Gourikwa (Mossel Bay), Avon (Outside Durban) and Dedisa (Coega IDZ) on diesel, simply because of the unavailability of natural gas, which is cheaper than diesel. The gas-power nexus has not yet been exploited, to the extent that gas plants at Avon and Dedisa could be converted to combined-cycle, provided that natural gas (either pipeline or LNG infrastructure) is developed.

Renewable Energy: Solar PV and CSP with storage present an opportunity to diversify the electricity mix, to produce distributed generation and to provide off-grid electricity. Solar technologies also present huge potential for job creation and localisation across the value chain.

The Wind Atlas developed for South Africa provides a basis for the quantification of the potential that wind holds for power generation elsewhere in the country, over and

above the prevalence of the wind resource around the areas of the coast**.** Most wind projects have been developed in the Western Cape and Eastern Cape, so far.

Imported hydro: South Africa has entered into a Treaty for the development of the Grad Inga Project in the Democratic Republic of Congo (DRC), with some of the power intended for transmission to South Africa across DRC, Zambia, Zimbabwe and Botswana.

In addition to this generation option providing clean energy, the regional development drivers are compelling, especially given that currently there is very little energy trade between these countries, due to the lack of infrastructure. The potential for intra-SADC trade is huge as it could open up economic trade.

Naturally, concerns have to be addressed about the political risk associated with such a project. South Africa does not intend to import power from one source beyond its reserve margin, as a mechanism to de-risk the dependency on this generation option.

Energy Storage: There is a complementary relationship between Smart Grid systems, energy storage, and non-dispatchable renewable energy technologies based on wind and solar PV. The traditional power delivery model is being disrupted by technological developments related to energy storage, and more renewable energy can be harnessed despite the reality that the timing of its production might be during low-demand periods. Storage technologies including battery systems, compressed air energy storage, flywheel energy storage, hydrogen fuel cells etc. are developments which can address this issue, especially in the South African context where over 6 GW of renewable energy has been introduced, yet the power system does not have the requisite storage capacity.

2.2 ENVIRONMENTAL CONSIDERATIONS

The energy sector alone, contributes close to 80% towards total emissions of which 50% are from electricity generation and liquid fuel production alone. Our vast coal deposits cannot be sterilized simply because we have not exploited technological innovations to use them. The timing of the transition to a low carbon economy must

be in a manner that is just and sensitive to the potential impacts on jobs and local economies. It is in this context that engagements at a global forums such as the G20 refer to “Energy Transitions” and not “Energy Transition” as a recognition that countries are different and their energy transition paths will also be different due to varying local conditions.

Carbon capture and storage, underground coal gasification, and other clean coal technologies are critical considerations that will enable us to continue using our coal resources in an environmentally responsible way.

Air quality regulations under the National Environmental Management Act: Air Quality (Act No. 39 of 2004) provide that coal power plants under Eskom’s fleet, amongst others, have to meet the minimum emission standard (MES) by a certain time, or they would be non-compliant and have to shut down.

The timing of the requirement for existing, non-compliant power stations to be decommissioned, must take into account the need to balance energy security, the adverse health impacts of poor air quality and the economic cost associated with the transition.

2.3 PLANT RETIREMENTS DUE TO END-OF-LIFE

Plant closures due to non-compliance with environmental regulations should not be confused with imminent plant retirements due to the plant having reached the so-called ‘turbine stop date”. There are a number of Eskom plants that will reach end of life, and retirements are expected to continue from 2019 onwards due to this reason.

Over and above coal plants reaching end of life, the nuclear plant (Koeberg Power Station) reaches its 40-year lifespan and plans are in place to extend its licence for another 20-years.

2.4 ELECTRICITY TARIFFS

As wholesale and retail electricity tariffs rise, we can expect more electricity users to look for alternatives like rooftop PV systems (residential) or utility scale PV generation (mines and other big industrial users) and migrate away from the grid.

More fuel switching is to be expected, particularly in regard to the thermal load (water heating, cooking and space heating) as electricity tariffs increase and alternatives like LP Gas become available and cost effective.

Non-technical losses (losses due to electricity theft and other problems that are not related to grid technicalities) are increasing at municipal level. At a certain point the willingness to pay (WTP) threshold is breached for more and more municipal customers, and they either actively pursue alternative sources to meet their energy demand, or they stop paying for the electricity service.

We can expect the electricity disruptions (driven by load shedding or poor quality of supply) and high tariffs to drive the WTP threshold even lower.

Requests by industrial and commercial electricity users to deviate from the IRP and to develop their own generation exemplify the trend. While at this stage it is not quantified, most residential estates and shopping malls have installed PV systems.

2.5 WATER ENERGY NEXUS

The possibilities of a recurring drought problem in the country cannot be disregarded. Climatic conditions are changing and over the past 3 years we experienced the worst drought in 30-years due to the El Nino effect covering 5 provinces. This has devastating impact on agricultural output and the local economies of the affected areas.

Coastal areas like Mossel Bay and Cape Town have also suffered from extended drought, despite their proximity to sea water. Consideration should therefore be given to deploying energy technologies for purposes of desalination, provided they have low

variable costs that would not render the desalination process unaffordable. Technologies like wind and solar, or SMR with the requisite heating, are suitable in this regard.

2.6 ROLE OF ESKOM

Eskom has played a crucial role as the dominant vertically integrated utility at all levels of the electricity value chain. With the 2019 decision to unbundle Eskom, their role is expected to change once the generation, transmission and distribution functions are separated.

Eskom's role as a Buyer under section 34 of the Electricity Regulation Act will have to be reviewed, taking the ramifications of unbundling into account.

2.7 MUNICIPALITIES AND RELATED ISSUES

2.7.1 Access

South Africa still has 3-million households without access to grid-based electricity. Electrification through grid connections has been effective in providing lighting and small power, but it is inappropriate for providing thermal energy for cooking and space heating. A significant thermal energy load still needs to be provided for, by providing solutions side by side by with off-grid technologies, particularly in those areas that are too remote to build grid-based infrastructure. In any case, electricity is not the appropriate carrier for meeting the thermal load related to cooking, space and water heating.

The cost of providing a grid connection has increased as the areas being serviced become more remote. There is therefore a need to quantify the off-grid and micro-grid opportunity and put in place the necessary frameworks for accelerated development.

2.7.2 Non-Technical Losses and financial viability

Most municipalities struggle to keep up with the payment for bulk electricity purchases from Eskom, and as at March 2018 Eskom's Chairman indicated that the debt burden stood at over R13.5 billion and continued to rise. The fiscal framework for some municipalities (particularly the rural ones) is unviable, posing a serious risk to their financial sustainability.

The non-payment of electricity, including the theft of distribution infrastructure (copper and cables) and poor credit control systems, needs urgent attention. The Department of Co-operative Government and Traditional Affairs leads an initiative to support municipalities to turn this around.

2.7.3 Distributed Generation and Smart Grids

Distributed generation through biomass, biogas and municipal waste are areas holding great potential for improving municipal revenues. All municipalities have sites for processing waste; they also have sewer outfall sites. Technologies are available for these resources to be added to the generation mix at sub-utility scale. Most small scale generation technologies have low capacity factors, meaning that typically the power is not generated throughout the day and night. For a balanced and safe interconnected power system to be operated sustainably, the intermittent power generators have to be integrated and controlled through smart technologies that allow power to flow bi-directionally between a generator and a load.

The IRP already makes provision for distributed generation. This is intended to allow generation for own use and for municipalities to access small scale generators through alternative generation technologies and to diversify their supply base.

2.8 RESEARCH AND DEVELOPMENT

Research and development should focus on innovative solutions, in particular on those technologies that have the greatest potential to address electricity challenges for energy consumers in a short timeframe.

Solar energy also has the potential to address the need for energy access in remote areas, create semi-skilled jobs and increase localisation.

More funding should be targeted at long-term research into clean coal technologies such as CCS and UCG as these will be essential in ensuring that South Africa continues to exploit its vast, indigenous minerals responsibly and sustainably. Exploration to determine the extent of recoverable shale gas should be pursued and this needs to be supported by an enabling legal and regulatory framework.

South Africa's specific focus on the hydrogen economy and the progress achieved by the hydrogen initiative (or Hy-Sa) based at the University of the Western Cape, should be supported with more research and the chance for practical application within the power system.

Over and above these issues, the research agenda insofar as the power space, needs to be expanded on the basis of the clear evidence of a changing energy paradigm.

2.9 4TH INDUSTRIAL REVOLUTION AND YOUTH

It is inevitable that more and more, the traditional energy delivery system will not be insulated from technological disruptions. The fear about job losses emanating from artificial intelligence-driven robotics, should be regarded as an opportunity to prepare our youth for this future.

We need to recognize that African human capital is a big opportunity, given our demographics as the youngest continent in terms of our median age.

3. THE IRP PROCESS AND CONSULTATIONS

The IRP update process undertaken to date is depicted in Figure 1 below. The update process started with the development and compilation of input assumptions. Following public consultations on the assumptions, various supply and demand balancing scenarios were modelled, simulated and analysed; this process culminated into the production of the draft IRP 2018. In August 2018 and following Cabinet approval, the Draft IRP 2018 report was published for public comment for a period of 60 days.

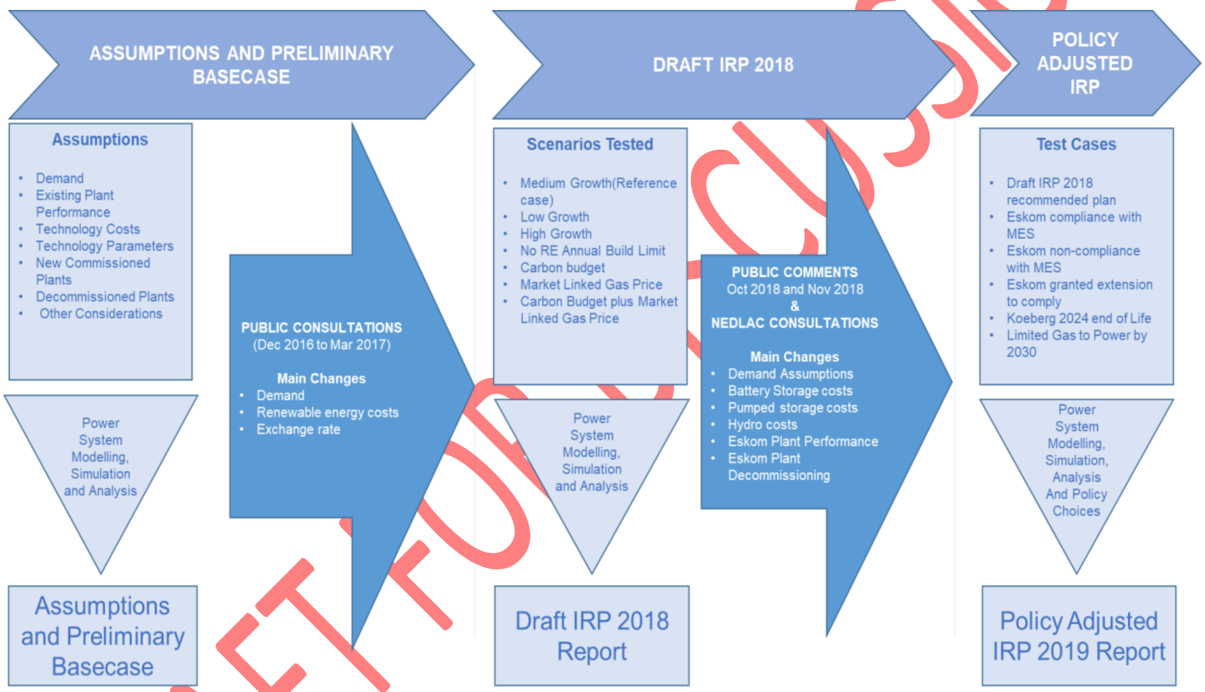


Figure 1: IRP Update Review Process

As with the consultations on the IRP assumptions and the preliminary base case, submissions from the public regarding the draft IRP 2018 public varied from opinion statements to substantive inputs with supporting data. The number of submissions received was 5 929, of which 242 were substantive comments inclusive of discussions and at times supporting facts, data or references.

The public mostly welcomed the recommended least-cost electricity supply plan while advocating for the energy mix in line with the NDP and the IRP 2010–2030.

Key issues raised in the comments included among others, the assumptions regarding demand forecast; a substantial number of the comments questioned the projected growth in demand in the context of declining electricity intensity, low economic growth projections and increasing own generation installations made possible by alternative energy technology advancements. Some submissions made the case for a higher demand projection arguing that demand is supressed by limited generation capacity and that the availability of excess electricity will unlock investment and therefore lead to electricity demand increase.

Cost assumptions for some of the technologies were questioned. While some of the submissions provided alternate costs, the information was project specific and therefore not representative of costs for similar projects or technologies. Where information received was representative of costs from similar projects and technologies, this information was adopted and necessary updates were effected.

Concerns and risks were also raised about the capacity provided for and practicality of gas to power in the recommended plan and the risks it poses since South Africa does not currently have adequate gas infrastructure.

As part of the comments process, Eskom submitted revised system availability projections, a revised plant shutdown schedule and minimum emissions standards compliance schedule as included in **Appendix A**. Eskom's existing generation plant dominates installed capacity. The current and future performance of these generation plants is critical for security of supply and heavily influences the planned capacity in the IRP.

Concerning the recommended published draft IRP 2018, key issues raised include, the extent of the energy mix, the exclusion of new nuclear capacity before year 2030 and deviation from the IRP 2010-2030. Concerns were also raised about the practical implementation aspects and the risks associated with gas to power, taking into account the extent of the capacity recommended in the plan.

The inclusion of coal and hydropower capacity through policy adjustment was criticised on the basis it is a deviation from the least cost path. The inclusion of coal was specifically criticised arguing that in addition to it not being least cost, it contributes

to emissions and will negatively affect the health of communities where the plants will be located.

The annual allocation for distributed generation of between 1MW and 10MW was said to be too low and the proposal was that it should be increased to take into account the requests for deviation from the IRP already received by the Department of Energy.

These comments have been considered and the details are included as part of the summary report on comments and how they are treated (see **Appendix B**).

The next section details the changes to the assumptions after taking into consideration inputs from the public.

4. INPUT PARAMETER ASSUMPTIONS

The assumptions for the recommended plan in this report take into account comments from the public consultation process undertaken between September 2018 and November 2018 as already outlined.

4.1 ELECTRICITY DEMAND

Electricity demand as projected in the promulgated IRP 2010–2030 did not materialise due to a number of factors which resulted in lower demand. These include, among others, lower economic growth; improved energy efficiency by large consumers to cushion against rising tariffs; fuel switching to liquefied petroleum gas (LPG) for cooking and heating; fuel switching for hot water heating by households; and the closing down or relocation to other countries of some of the energy intensive industry.

4.1.1 Electricity Demand from 2010–2016

Reported Gross Domestic Product (GDP) for the period 2010–2016 was significantly lower than the GDP projections assumed in the promulgated IRP 2010–2030. This is depicted in Figure 2.

The compound average growth rate for the years 2010 to 2016 was 2,05%. This lower GDP growth compared with the expectations in 2010 had an impact on the resulting electricity demand as depicted in Figure 3.

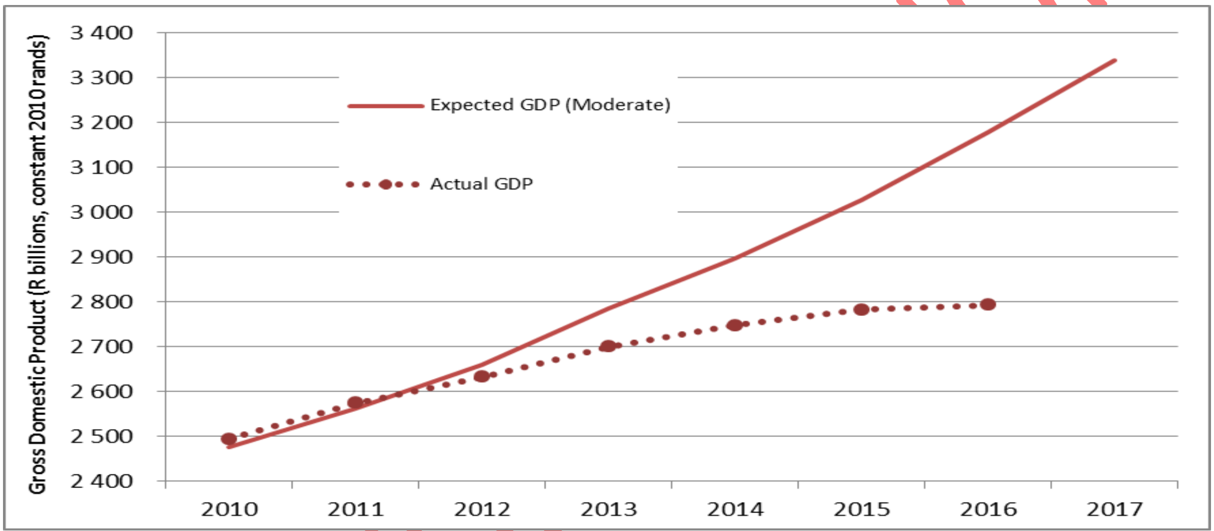


Figure 2: Expected GDP Growth from IRP 2010 *vs* Actual (Sources: Statistics SA & Promulgated IRP 2010–2030)

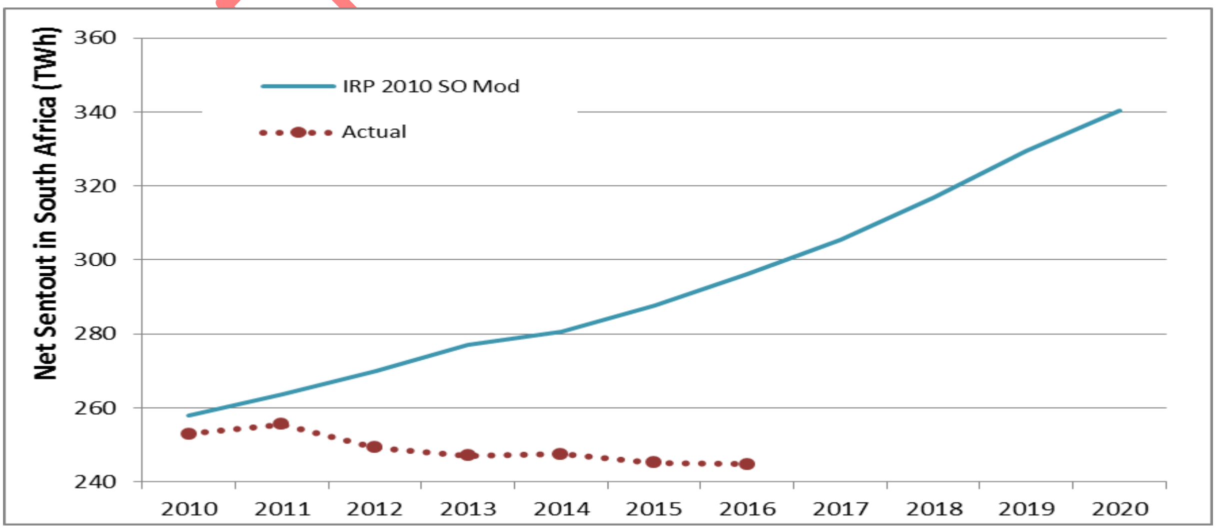


Figure 3: Expected Electricity Sent-out from IRP 2010–2030 *vs* Actual (Sources: Statistics SA & Promulgated IRP 2010–2030)

The actual net electricity energy sent-out for the country declined at an average compound rate of -0,6% over the past years. That was in stark contrast with the expectation of an average growth rate of 3,0% in the promulgated IRP 2010–2030. The result was that the actual net sent-out in 2016 was at 244TWh in comparison with the expected 296TWh (18% difference).

The underlying causes of the reduced electricity demand were many-sided, including:

- General economic conditions as shown in Figure 2 above, which specifically impacted energy-intensive sectors negatively.
- The constraints imposed by the supply situation between 2011 and 2015 with the strong potential for suppressed demand by both industrial and domestic consumers. It was expected that suppressed demand would return once the supply situation had been resolved, but factors attributed to electricity pricing and commodity price issues might have delayed, or permanently removed, that potential.
- Improved energy efficiency, partly as a response to the electricity price increases.
- Increasing embedded generation. There is evidence of growing rooftop photo-voltaic (PV) installations. Current installed capacity is still very small. However, this is likely to increase in the medium to long term.
- Fuel switching from electricity to LPG for cooking and space heating.

Further analysis of the historic electricity intensity trend indicated that electricity intensity also continued to decline over the past years, exceeding the decline expectation in the promulgated IRP 2010–2030 forecast. See Figure 4 below.

Figure 4 also points to possible decoupling of GDP growth from electricity intensity, which generally indicates a change in the structure of the economy.

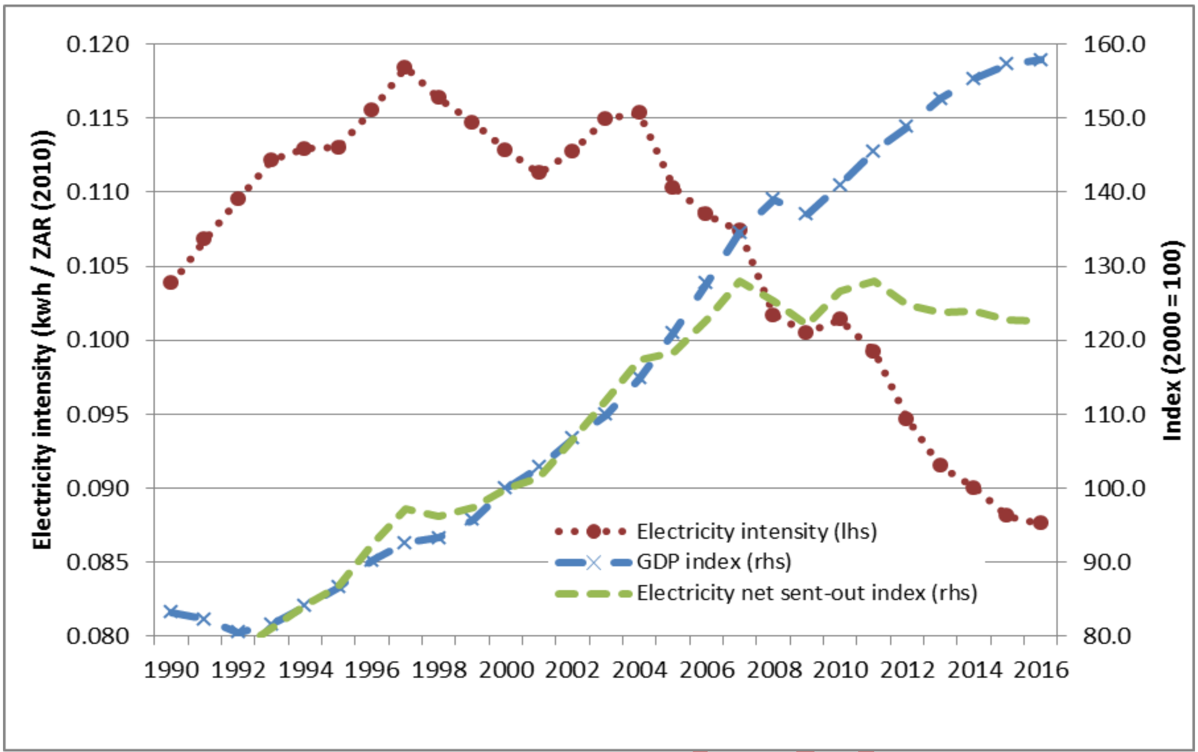


Figure 4: Electricity Intensity History 1990–2016 (Source: Own Calculations based on Statistics SA Data)

The expected electricity demand as forecasted in the promulgated IRP 2010–2030 did therefore not materialise and the forecast was updated accordingly to reflect this.

4.1.2 Electricity Demand Forecast for 2017–2050

The electricity demand forecast was developed using statistical models. The models are data-driven and based on historical quantitative patterns and relationships. Historical data on electricity consumption was key and information in this regard was obtained from various sources in the public domain. Overall consistency between sources was maintained by ensuring sector breakdowns corresponded with totals from Statistics SA data.

Using regression models per sector, sector forecasts were developed using sourced data. Sectoral totals were aggregated and adjusted for losses to obtain total forecasted values. Adjustments were also made to account for electricity energy imports and exports.

Figure 5 below depicts the total energy demand forecast as contained in the demand forecast report but adjusted to reflect the lower actual year-2018 demand as a starting point. The 2018 actual recorded demand is about a 3 percent lower than what was in the draft IRP 2018.

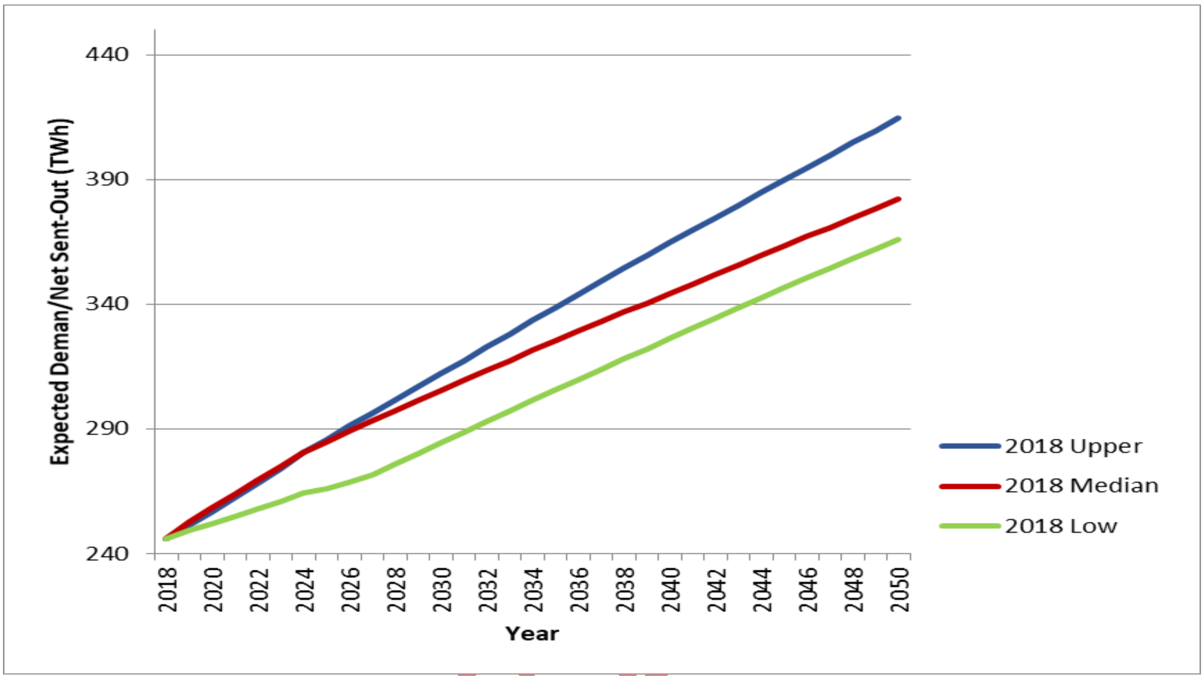


Figure 5: Expected Electricity Demand Forecast to 2050

The upper forecast[2] was based on an average 3.18% annual GDP growth, but assumed the current economic sectoral structure remained. This forecast resulted in an average annual electricity demand growth of 2.0% by 2030 and 1.66% by 2050.

The median forecast[3] was based on an average 4.26% GDP growth by 2030, but with significant change in the structure of the economy. This forecast resulted in an average annual electricity demand growth of 1.8% by 2030 and 1.4% by 2050. The median forecast electricity intensity dropped extensively over the study period (from the current 0.088 to 0.04 in 2050). That reflects the impact of the assumed change in the structure of the economy where energy-intensive industries make way for less intensive industries. The resultant electricity forecasts were such that, even though the median forecast reflected higher average GDP growth than the upper forecast, the

[2] The moderate forecast in its detailed forecast report.
[3] The high less intense forecast in its detailed forecast report.

average electricity growth forecast associated with the upper forecast was relatively lower than the average electricity growth forecast for the median forecast.

The lower forecast[4] had a 1.33% GDP growth to 2030, which resulted in a 1.21% average annual electricity demand growth by 2030 and 1.24% by 2050. The lower forecast assumed electricity intensity initially increased before dropping all the way to 2050. In developing the forecast, the main assumption was that mining output would continue to grow while other sectors of the economy would suffer as a result of low investment. This scenario was developed when the country faced possible downgrading decisions by the rating agencies.

A detailed demand forecast assumptions report, including electricity intensity, can be downloaded from the DoE website (http://www.energy.gov.za/files/irp_frame.html). Comments on the limitations of the forecasting methodology based on historical relationships as used in this IRP have been noted and will be considered for future enhancement of the forecast for IRP updates.

4.1.3 Impact of Embedded Generation, Energy Efficiency and Fuel Switching on Demand

With the changing electricity landscape and advancements in technology, there is an increasing number of own-generation facilities in the form of rooftop PV installations in households. There is also an increasing number of commercial and industrial facilities that are installing PV installations to supplement electricity from the grid.

High electricity prices, as well as technology advancements (improved equipment efficiency), are resulting in increased energy efficiency among consumers.

Equally, there is increasing use of LPG for cooking and space heating that will impact on both energy (kWh) and peak demand (kW). In line with municipal bylaws and building codes, new developments are installing solar water heaters instead of full

[4] The junk status forecast in its detailed forecast report

electric geysers. Voluntarily, consumers are also increasingly replacing electric geysers with solar water geysers to reduce their electricity bills.

These developments impact on overall electricity demand and intensity and must therefore be considered when projecting future demand and supply of electricity.

Due to the limited data at present and for the purpose of this IRP Update, these developments were not simulated as standalone scenarios, but considered to be covered in the low-demand scenario. The assumption was that the impact of these would be lower demand in relation to the median forecast demand projection.

4.2 TECHNOLOGY, FUEL AND EXTERNALITY COSTS

The IRP analyses mainly entailed balancing supply and demand at least-possible cost. Costs of technology, fuel and externalities[5] were therefore major input assumptions during option analyses.

As part of the development of the promulgated IRP 2010–2030, the DoE, through Eskom, engaged the Electric Power Research Institute[6] (EPRI) in 2010 and 2012 to provide technology data for new power plants that would be included in the IRP. That resulted in an EPRI report, which was revised in 2015, taking into account technical updates of the cost and performance of technologies, market-factor influences and additional technology cases.

Following the public consultations on the assumptions, the EPRI report was updated to reflect the costs based on the January 2017 ZAR/US dollar exchange rate. The 2015 baseline cost for each technology was adjusted to January 2017 US dollar, using an annual escalation rate of 2.5%. The baseline costs were then converted to ZAR, based on the currency exchange rate on 01 January 2017.

[5] In economics, an externality is the cost or benefit that affects a party who did not choose to incur that cost or benefit.

[6] EPRI is an independent, non-profit organization that conducts research and development related to the generation, delivery and use of electricity to help address challenges in electricity, including reliability, efficiency, affordability, health, safety and the environment.

The EPRI report incorporates cost and performance data for a number of power-generation technologies applicable to South African conditions and environment. It presents the capital costs; operating and maintenance (O&M) costs; and performance data, as well as a comprehensive discussion and description of each technology.

A detailed EPRI technology cost assumptions report can be downloaded from the DoE website (http://www.energy.gov.za/files/irp_frame.html).

While EPRI provided costs for PV and Wind, the costs adopted in the plan for these technologies were from the South African REIPPP. The nuclear technology costs are based on the DoE-commissioned study (referred to as the Ingerop study). The study expanded the analysis by EPRI to include a technology cost analysis from projects in the East (Asia). A copy of the Ingerop Report can be downloaded from the DoE website (http://www.energy.gov.za/files/irp_frame.html).

Information on combined cycle gas engine cost is based on inputs obtained during the public consultations process. This can be can be downloaded from the DoE website (http://www.energy.gov.za/files/irp_frame.html).

4.2.1 Economic Parameters

For economic parameters, the following assumptions are applied:

- Exchange rate as at the beginning of January 2017, which was R13.57 to $1 (USD);
- the social discount rate of 8.2% net, real and post-tax as calculated by National Treasury; and
- the COUE of R87.85/kWh as per the National Energy Regulator of South Africa (NERSA) study.

4.2.2 Technology Learning

Learning rates used in the promulgated IRP 2010–2030 are maintained in the IRP update, with PV and wind technology learning rates adjusted to reflect the decline in prices experienced in South Africa already. Battery learning rates are obtained from the Lazard's Levelized Cost Of Storage Analysis—Version 3.0.

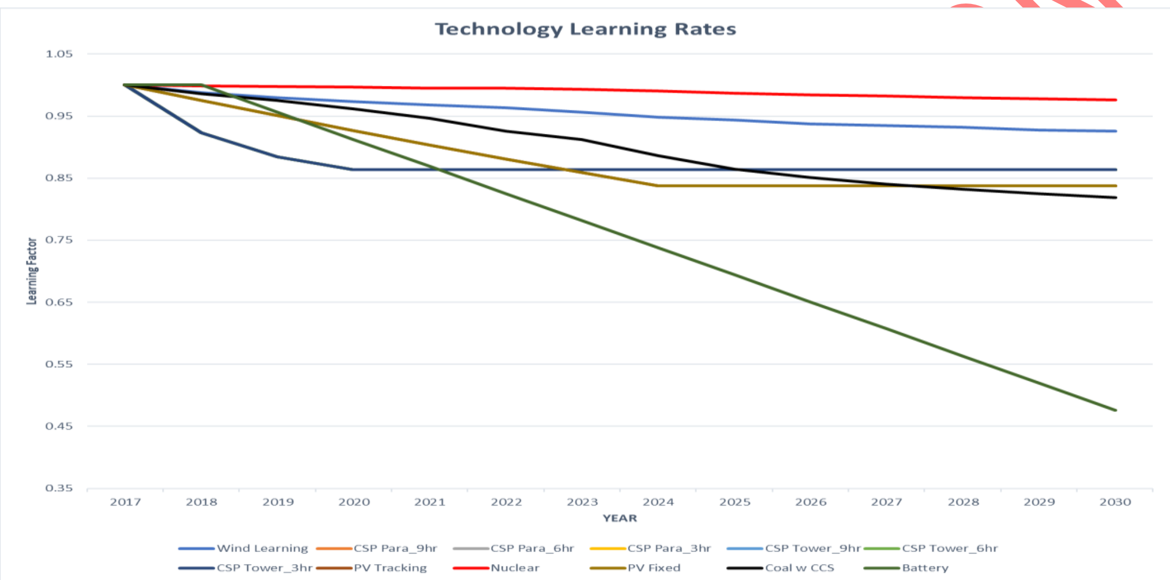


Figure 6: Technology Learning Rates

4.2.3 Emissions Externality Costs

With regard to externality costs associated with GHG emissions, the IRP update considers the negative externalities-related air pollution caused by pollutants such as nitrogen oxide (NOx), sulphur oxide (SOx), particulate matter (PM) and mercury (Hg). These externality costs reflect the cost to society because of the activities of a third party resulting in social, health, environmental, degradation or other costs.

For all these externalities the cost-of-damage approach was used to estimate the externality costs. The overall cost to society is defined as the sum of the imputed monetary value of costs to all parties involved. The costs are indicated Table 2. The costs associated with carbon dioxide (CO2) are not included as the CO2 emissions

constraint imposed already indirectly imposes the penalties or additional costs. The technical model achieves this by applying the CO2 constraints and choosing cleaner electricity generation options even if they are options that are more expensive.

Table 2: Local Emission and PM Costs

	NO_x (R/kg)	SO_x (R/kg)	Hg (Rm/kt)	PM (R/kg)
2015–2050	4.455	7.6	0.041	11.318

4.3 INSTALLED AND COMMITTED CAPACITY

Installed capacity assumed in the IRP Update includes both Eskom and private generation (generation for own use and municipal generation) as filed and licensed with NERSA.

A list of Eskom and private and municipal generators, as licensed with NERSA, is included in **Appendix A.**

In line with the planned capacity in the promulgated IRP 2010–2030 and in accordance with Section 34 of the Electricity Regulation Act No. 4 of 2006, the Minister of Energy has, to date, determined that 39730 MW of new generation capacity must be developed.

Of the 39 730 MW determined, about 18 000 MW has been committed[7] to date. This new capacity is made up of 6 422 MW under the REIPPP with a total of 3 876 MW operational on the grid. Under the committed Eskom build, the following capacity has been commissioned: 1 332 MW of Ingula pumped storage, 2 382 MW of Medupi (out of the 4 800 MW planned), 800 MW of Kusile (out of the 4 800 MW planned) and 100 MW of Sere Wind Farm. 1 005 MW from OCGT for peaking has also been commissioned.

For the IRP Update analysis, the remaining units at Medupi and Kusile were assumed to come on line as indicated in Table 3: CODs for Eskom New Build

[7] Committed refers to the capacity commissioned or procured and officially announced by the Minister of Energy.

Table 3: CODs for Eskom New Build

Medupi		Kusile	
Unit 6	Commercial operation	Unit 1	Commercial operation
Unit 5	Commercial operation	Unit 2	April 2019
Unit 4	Commercial operation	Unit 3	January 2020
Unit 3	June 2019	Unit 4	January 2021
Unit 2	June 2019	Unit 5	September 2021
Unit 1	December 2019	Unit 6	July 2022

4.3.1 Existing Eskom Plant Performance

The existing Eskom's generation plant energy availability factor (EAF) was assumed to be averaging 86% in the promulgated IRP 2010–2030. The actual EAF at the time was averaging 85%. Since then, Eskom's generation plant EAF declined steadily to a low average of 71% in the 2015/16 financial year before recovering to average of around 77.% in the 2016/17 financial year. Information as at January 2018 indicates that EAF has regressed further to the levels below 70%. This low EAF was the reason for constrained capacity early in December 2019 and January 2019 that resulted in load shedding.

Eskom's existing generation plant will still dominate the South African electricity installed capacity for the foreseeable future. The current and future performance of these Eskom plants is critical for security of supply and heavily influences the capacity planned to be introduced under the IRP.

As part of the comments process on the draft IRP 2018 Eskom submitted revised system availability projections per power station. The submission contains two scenarios of which scenario 1 and scenario 2 project an average EAF of 80% by 2030 and 75% by 2030, respectively.

Plant performance projections in the final plan contained in this report are based on scenario EAF of 75% by 2030. In this scenario, EAF starts at 71% in year 2020, and increases to 75.5% by year 2025 and beyond (see **Appendix A**).

4.3.2 Existing Eskom Plant Life

Existing generation plant life is a major consideration in the IRP as it will affect supply and demand balance. The IRP considers both Eskom and non-Eskom plants (municipal and large private sector plants) in this regard.

Eskom coal plants were designed and built for a 50-year life, which falls within the 2050 study period of the IRP 2018 update.

Eskom has also submitted a revised plant shutdown (decommissioning) plan. This submission brings forward the shutdown of some units at Grootvlei, Komati and Hendrina.

Figure 7 shows that about 5 400 MW of electricity from coal generation by Eskom will be decommissioned by year 2022, increasing to 10 500 MW by 2030 and 35 000 MW by 2050. The revised decommissioning schedule is attached in **Appendix A.**

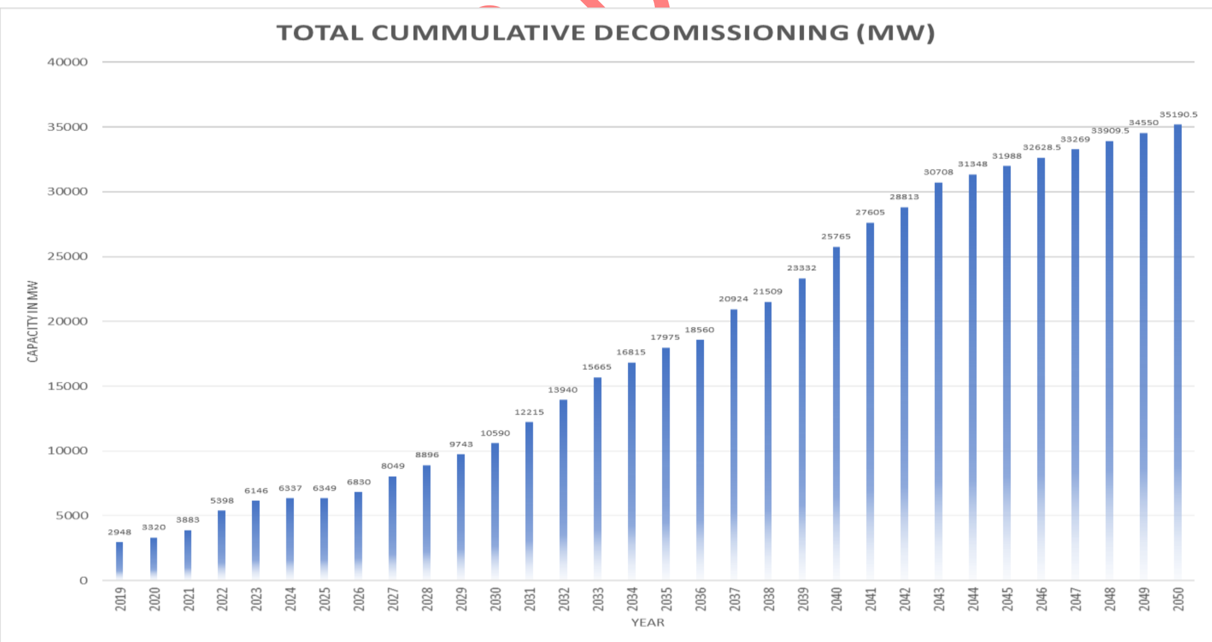


Figure 7: Cumulative Eskom Coal Generation Plants Decommissioning

The socio economic impact of the decommissioning of these Eskom plants has not been quantified or included in this IRP.

It is also expected that by year 2024, 1 800 MW of nuclear power generation (Koeberg) will reach end-of-life. Eskom has initiated preparations and processes to extend the life of this plant to 2044, subject to the necessary regulatory approvals. In light of projected lower EAF for Eskom coal power plants, the IRP plan is based on the assumption that Koeberg plant life would be extended to 2044.

Mitigation of the risks associated with the adopted assumption is included in the risk section of this report.

4.3.3 Compliance to Minimum Emissions Standards (Air Quality Regulations)

A number of Eskom power plants (Majuba, Tutuka, Duvha, Matla, Kriel and Grootvlei) have been retrofitted with emissions abatement technology to ensure compliance with the law (viz. National Environmental Management Act: Air Quality, 2004 or NEMA).

In 2014 Eskom applied for postponement of the date for compliance and permission in this regard was granted for a period not exceeding 5 years. To date, Grootvlei is the only station that has been brought to compliance and this failure to undertake abatement retrofits is likely to result in non-compliant plants becoming unavailable for production from year 2020, unless further postponement is granted. Eskom is in the process of applying for further postponement in line the provisions of the law.

In light of projected lower EAF, the assumption adopted in the IRP is that NEMA-affected Eskom coal plant will remain available for production.

4.4 CO_2 EMISSION CONSTRAINTS

In line with South Africa's commitment to reduce emissions, the promulgated IRP 2010–2030 imposed CO_2 emission limits on the electricity generation plan. IRP 2010-2030 assumed that emissions would peak between 2020 and 2025 as Medupi and Kusile are brought on line, then plateau for approximately a decade and decline in absolute terms thereafter as old coal-fired power plants are decommissioned.

Figure 8 shows the emission reduction trajectory (referred to as the peak-plateau-decline (PPD)) for electricity generation adopted in the promulgated IRP 2010–2030.

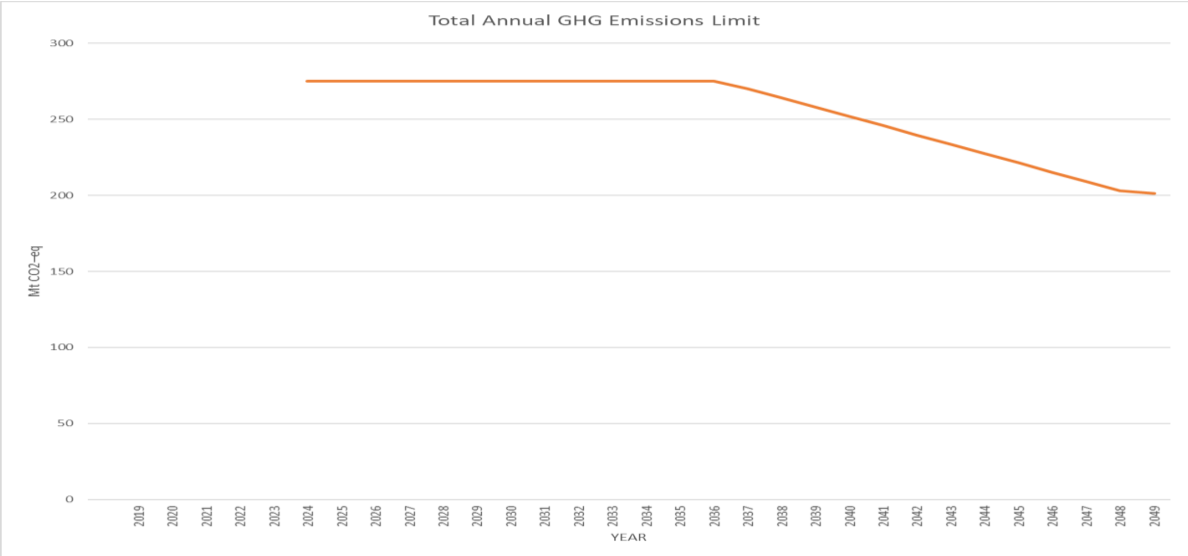


Figure 8: Emission Reduction Trajectory (PPD)

While PPD was applied as the primary assumption, a scenario was tested as part of the draft IRP 2018 where the carbon budget approach was used for emission constraints. A carbon budget is defined as a tolerable quantity of carbon dioxide emissions that can be emitted in total over a specified time. The scenario was based on carbon budget targets divided into 10-year intervals which meant a total emission reduction budget for the entire electricity sector up to 2050 must be 5 470 Mt CO_2 cumulatively.

4.5 TRANSMISSION NETWORK COSTS

The IRP update takes into account the costs of the transmission networks associated with the energy mix.

The transmission network costs have been incorporated by including the estimated, direct transmission infrastructure costs, including collector station and substation costs

in the total overnight generation technology costs. The costing was based on a high-level estimate from recent Eskom average costs for transmission infrastructure.

For renewable energy technologies (like wind and solar PV), the transmission infrastructure costs entailed collector stations and the associated lines connecting to the main transmission substation, as well as the transmission substation costs. For conventional technologies, the costs entailed only the main transmission substation costs. Imported hydro and CSP transmission costs were treated the same as conventional technology costs.

The transmission infrastructure costs considered different capacity increments or penetration per technology in different parts of the country. Transmission corridor costs and ancillary costs required for network stability, particularly inertia, were not included as these are not directly associated with any technology but are part of strengthening the transmission backbone. A detailed transmission network costs report can be downloaded from the DoE website (http://www.energy.gov.za/files/irp_frame.html).

5. UPDATED DRAFT IRP 2018

Inputs from the public and the consideration of all the comments necessitated the updating of planning assumptions, including updated information from Eskom. Modelling work, simulation and analysis of a further set of test cases was completed on the basis of this updated input data. The test cases were developed to assess the following:

- the changed assumptions on the draft 2018 recommended plan,
- the impact of plants shutting down in case of non-compliance with minimum emissions standards (MES),
- the impact of Koeberg plant shutting down in 2024 if its life is not extended,
- the relaxation of policy adjustments adopted in draft IRP 2018, and
- realistic assumptions for gas to power capacity by year 2030.

The details of input parameters for respective test cases are contained in Table 4.

Table 4: Test Case Variable Input Parameters

Parameters	Reference Case	Test Case 1	Test Case 2	Test Case 3	Test Case 4	Test Case 5	Test Case 6
Updated EAF	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Early shutdown	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Actual 2018 energy & demand	Yes	Yes	Yes	Yes	Yes	Yes	Yes
RE Annual Limit	Yes	Yes	Yes	Yes	Yes	Yes	Yes
MES	No MES	MES 1	MES 2	No MES	MES 2	No MES	No MES
Treatment of Inga & IPP Coal	Forced	Forced	Forced	Forced	Optimised	Forced	Forced
Koeberg life (Years)	60	60	60	40	40	60	60
Gas volumes Restrictions	No	No	No	No	No	Yes	Yes

Reference case refers to recommended draft IRP 2018
For implications of MES on Eskom installed capacity, see Appendix D
Test case 6 also adjust down lead times for wind projects from 48 months to 36 months

5.1 OBSERVATIONS FROM THE TEST CASES

The analysis of the results from the simulation of test cases shows (**APPENDIX C**) that in addition to a need for additional capacity in the long-term, there is an immediate risk of energy shortage in the immediate term.

- **Immediate term**
  - Power system simulations show that due to the low EAF of Eskom's generation plants and the early shutdown of non-performing units (Grootvlei, Komati and Hendrina), there is an immediate risk of huge power shortages. This is likely to result in Eskom running diesel peaking plant for an extended duration, or manifesting in load shedding to avoid high expenditure on diesel. It is also clear that there are inadequate capacity reserves in the event of emergency plant breakdowns in the immediate term.
  - This risk plus the associated energy shortages gets worse when considering the non-compliance status of some Eskom plants *vis a vis* NEMA. Eskom is also unlikely to meet the deadline for compliance (postponements granted in year 2015) with the air quality Minimum Emissions Standards (MES) due to constrained finances and project execution delays. Assuming that non-compliant power plants are shut down, the reality of power disruptions manifests significantly from year 2019 onwards.

- Medupi and Kusile are now de-rated at below name-plate rating, meaning that these plants are unable to provide the full complement of energy for their rating. It must be noted that this shortage occurs notwithstanding the already committed capacity from renewable energy projects and the commissioning of the remaining units at Medupi and Kusile. Continued underperformance and late commissioning by Medupi and Kusile units will exacerbate the risk.
- Simulations also indicate that shutting down Koeberg in 2024 in line with its 40-year operating life of plant worsens the situation.

The recently experienced load shedding as well frequent alerts of possible shortages corroborate the observations from the power system simulations.

While the purpose of the IRP is to balance supply and demand on a least-cost basis, implementation lead times for various generation technologies limit the options available for deployment in the short term.

Simulations indicate that the option available to Eskom is to run diesel-fired peaking plant at load factors averaging about 30% for the period 2019 to 2021. Running these plants at higher than contracted load factors creates logistical challenges as there is insufficient infrastructure to support the volumes of diesel required under these circumstances. This arrangement will also worsen the already delicate Eskom financial situation. In addition, electricity users will suffer high tariff increases.

The results from the simulation also show that in the long term, the system uses the combination of renewable energy, gas and storage to balance the system (without regard to whether the gas is readily available).

The following specific observations are made with regard to the long-term:

- **Long Term**
  - The system only builds renewables (wind and PV) and gas if unlimited renewable and gas resources are assumed.
  - Despite decommissioning of old power plants and preference by the system for renewables and gas, coal remains dominant in the energy mix for the planning (up to 2030).
  - The removal of annual build constraints on renewables results in large erratic annual capacity allocations in the plan.

- When annual build limits are imposed on the renewable energy, and realistic gas availability assumptions are applied, the system builds battery storage and coal to close the gap.
- Imposing annual build limits does not affect the volume of wind or solar PV capacity in any significant way by 2030.

5.2 EMERGING LONG TERM PLAN (DRAFT IRP 2018 UPDATE)

Following the observations from the analysis of technical simulations and the adoption of the positions discussed earlier, the following plan emerges.

Table 5: Emerging IRP 2018[8]

	Coal	Nuclear	Hydro	Storage	PV	Wind	CSP	Gas / Diesel	Other (CoGen, Biomass, Landfill)	Distributed Generation
Current Base	37 149	1 860	2 100	2 912	1 474	1 980	300	3 830	499	
2019	2 155					244	300			Allocation to the extent of the short term capacity and energy gap
2020	1 433				114	300				
2021	1 433				300	818				
2022	711			513	400 1000	1600				
2023	750				1000	1600				500
2024		1860				1600		1000		500
2025					1000	1600				500
2026						1600				500
2027	750					1 600		2000		500
2028					1000	1 600				500
2029				1575	1000	1 600				500
2030			2 500		1 000	1 600				500
TOTAL INSTALLED CAPACITY by 2030 (MW)	33691	1680	2600	5000	8288	11342		6380		

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

- 2030 Coal Installed Capacity is less capacity decommissioned between years 2020 and 2030
- Existing Embedded generation for own use installed base is unknown as these installations were exempted from holding a generation license or were not required to be registered.

[8] The plan is subject to policy adjustment by Cabinet.

5.3 EMERGING CONSIDERATIONS

After due consideration of the modelling and simulation outcomes, and taking into account the plan under Table 5 above, the following considerations emerge for practical implementation of the IRP.

5.3.1 Immediate Term Security Supply

In the short-term supply and demand side interventions will have to be deployed to minimise the risk of load shedding and/or extensive usage of diesel peaking plant; the policy and regulatory enablers for these interventions must be identified, developed and enacted.

Eskom's current financial constraints and the economic impact of load shedding will have to be a consideration by the relevant authorities during their assessment of Eskom's application for further postponements regarding Minimum Emissions Standards (MES).

5.3.2 Energy Mix and Just Transition

Due to the expected decommissioning of approximately 24 100 MW of coal power plants in the period beyond 2030 to 2050, attention must be given to the path adopted to give effect to the energy mix and the preparation work necessary to execute the retirement and replacement of these plants. In order to ensure a just transition, the engagement process must commence to put in place the plans and interventions that mitigate against adverse impacts of the plant retirement programme on people and local economies.

5.3.3 Wind and PV

The application of renewable build limits serves to “smooth out” the capacity allocations for wind and solar PV.

Taking into account grid constraints and available South African capacity (engineering, manufacture, supply, construction, financing and project management) the roll out of wind and solar PV capacities at the maximum annual build limits may not be practical.

5.3.4 Coal

High efficiency low emission coal technologies (HELE), including underground coal gasification, integrated gasification combined cycle, carbon capture storage, ultra-supercritical, super-critical and similar technologies are preferred for the exploitation of our coal resources. Due consideration must be given to the financing constraints imposed by lenders and the Organization of Economic Cooperation and Development (OECD) countries, insofar as coal power plant development.

5.3.5 Gas

Whilst we modelled a case for gas that indicates a requirement for 1000 MW in 2023 and 2000 MW in 2027, at a 12% load factor, this is premised on certain constraints that we have imposed on gas, taking into account the locational issues like ports, environment, transmission etc. This represents low gas utilization, which does not justify the development of new gas infrastructure and power plants predicated on such sub-optimal volumes of gas. We also observed that unconstrained gas is a ‘no regret option’ because the model calls for increased gas volumes when there are no constraints imposed.

The development issues of the gas infrastructure necessary for the transportation and storage of the gas supply for the power plant are also dependent on whether this is natural gas (in which case we have to build pipeline infrastructure) or LNG (in which case a regasification terminal is required).

5.3.6 Nuclear

The extension of life of the Koeberg Power Station is critical for continued energy security in the period beyond 2024, when it reaches the end of its 40-year life. Whilst the IRP does not assess system dynamic stability, the relative location of Koeberg at the opposite end of the transmission backbone, when compared to the power stations located around Mpumalanga, poses certain advantages that include improved system stability. Without Koeberg, the Western Cape cannot be supplied from Mpumalanga (when Koeberg is unavailable) without significant transmission capacity upgrades. Local generation in the Western Cape is advantageous.

5.3.7 Hydro

South Africa has entered into a Treaty regarding the Grand Inga Hydropower Project. Whereas the draft IRP 2018 was modelled by forcing the 2 500 MW from Inga, the draft IRP 2019 used the commercial parameters that were submitted by the project developers for Inga, and 2 500 MW (and even more beyond 2030) of hydropower was selected on its own merits.

5.3.8 Energy Storage

When energy storage costs were revised to the latest information, and taking into account the longer gas infrastructure lead time, the model selects more energy storage. This can be expected, given the extent of the wind and solar pv option in the IRP.

It must be noted that Eskom is already preparing to pilot an energy storage-technology project based on batteries. The pilot will enable the assessment and development of the technical applications and benefits, the regulatory matters that relate to a utility-

scale energy storage technology and the enhancement of assumptions for future iterations of the IRP.

5.3.9 Distributed Generation

Public inputs suggested that the allocation for embedded generation needed to be increased, taking into account that the Department of Energy is inundated with requests from companies, municipalities and private individuals for deviation from the IRP in terms of section 10(2)(g) of the Electricity Regulation Act, in order for NERSA to approve their application for a generation licence. Given the observation concerning the energy shortage in the immediate term, increasing the embedded generation allocation could represent the opportunity to address the shortage.

6. APPENDICES

6.1 APPENDIX A – INSTALLED CAPACITY, MINISTERIAL DETERMINATIONS AND DECOMISSIONING SCHEDULE

6.1.1 Municipal, Private and Eskom Generators

Tables 8 and 9 below provide information on installed municipal, private and Eskom generators.

Table 8: Municipal and Private Generators

	Installed Capacity (MW)	Decommissioning Date	Planned Outages (%)	Unplanned Outages (%)
Kelvin	160	Dec 2018	4.8	20
Sasol Infrachem Coal	125	**Post 5050**	4.8	15
Sasol Synfuel Coal	600	Post 2050	4.8	15
Other Non-Eskom Coal	18	Dec 2024	4.8	15
Other NonEskom Gas	16	Dec 2019	6.9	11
Sasol Infrachem Gas	175	Post 2050	6.9	11
Sasol Synfuel Gas	250	Post 2050	6.9	11
DOE IPP	1005	July 2045	7	5
Colley Wobbles	65	Post 2050	6.9	11
Other Non-Eskom Hydro	12	Post 2050	6.9	11
Cahora Bassa	1500	Post 2050	4	4
REBID Hydro	19	Post 2050	4	4
Steenbras	180	Post 2050	4	10
Sappi	144	Post 2050	10	10
Mondi	120	Post 2050	10	10

6.1.2 Eskom Generators

Table 9: Eskom Generators[9]

POWER STATION CAPACITIES

as at 31 March 2018

The difference between installed and nominal capacity reflects auxiliary power consumption and reduced capacity caused by the age of 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)				**40 180**	**37 868**
Arnot	Middelburg	Sep 1971 to Aug 1975	1x370; 1x390; 2x396; 2x400	2 352	2 232
Camden[1,2]	Ermelo	Mar 2005 to Jun 2008	3x200; 1x196; 2x195; 1x190; 1x185	1 561	1 481
Duvha[3]	Emalahleni	Aug 1980 to Feb 1984	5x600	3 000	2 875
Grootvlei[1]	Balfour	Apr 2008 to Mar 2011	4x200; 2x190	1 180	1 120
Hendrina[2,4]	Middelburg	May 1970 to Dec 1976	1x210; 4x200; 2x195; 1x170; 1x168	1 738	1 638
Kendal[5]	Emalahleni	Oct 1988 to Dec 1992	6x686	4 116	3 840
Komati[1,2]	Middelburg	Mar 2009 to Oct 2013	4x100; 4x125; 1x90	990	904
Kriel	Bethal	May 1976 to Mar 1979	6x500	3 000	2 850
Kusile[5,6]	Ogies	Aug 2017	1x799	799	720
		Under construction	5x800		
Lethabo	Vereeniging	Dec 1985 to Dec 1990	6x618	3 708	3 558
Majuba[5]	Volksrust	Apr 1996 to Apr 2001	3x657; 3x713	4 110	3 843
Matimba[5,6]	Lephalale	Dec 1987 to Oct 1991	6x665	3 990	3 690
Matla	Bethal	Sep 1979 to Jul 1983	6x600	3 600	3 450
Medupi[5]	Lephalale	Aug 2015 to Nov 2017	3x794	2 382	2 157
		Under construction	3x794		
Tutuka	Standerton	Jun 1985 to Jun 1990	6x609	3 654	3 510
Nuclear (1)					
Koeberg	Cape Town	Jul 1984 to Nov 1985	2x970	**1 940**	**1 860**
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)[7]				**2 732**	**2 724**
Drakensberg	Bergville	Jun 1981 to Apr 1982	4x250	1 000	1 000
Ingula	Ladysmith	June 2016 to Feb 2017	4x333	1 332	1 324
Palmiet	Grabouw	Apr 1988 to May 1988	2x200	400	400
Hydroelectric stations (2)[8]				**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				**47 878**	**45 461**
Renewable energy					
Wind energy (1)[9]					
Sere	Vredendal	Mar 2015	46x2.2	**100**	**100**
Total capacity including renewable energy				**47 978**	**45 561**
Other hydroelectric stations (4)[9]				**61**	**–**
Colley Wobbles	Mbashe River		3x14	42	–
First Falls	Umtata River		2x3	6	–
Ncora	Ncora River		2x0.4; 1x1.3	2	–
Second Falls	Umtata River		2x5.5	11	–
Total Eskom power station capacities (30)				**48 039**	**45 561**
Available nominal capacity – Eskom-owned					**94.84%**

[9] Source: Eskom 2018 Integrated Report

6.1.3 Emission Abatement Retrofit Programme and 50-year Life Decommissioning

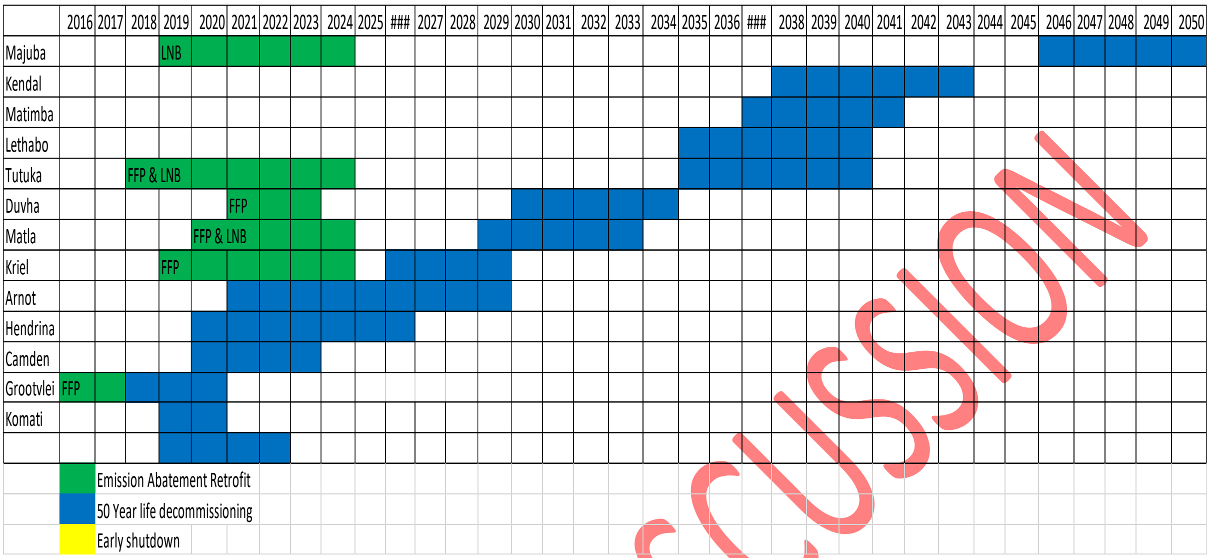


Figure 26: Emission Abatement Retrofit Programme and 50-year Life Decommissioning

6.1.4 Projected Eskom Plant Energy Availability Factor

Table 6: Projected Eskom Plant Energy Availability Factor

IRP 75.5% EAF FY2025 to FY2031 : EAF												
STATION	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
ACACIA	98.40	98.39	82.34	98.39	89.66	96.82	98.63					
ANKERLIG	98.12	94.20	98.13	96.81	97.81	95.16	88.12	98.07	95.89	95.81	95.55	95.70
GOURIKWA	95.88	94.03	97.70	97.44	98.00	91.56	91.63	97.46	96.02	95.52	95.48	95.65
PORT REX	97.71	93.07	92.46	92.62	98.14	96.16	97.91					
GARIEP	98.77	95.96	89.94	98.75	96.95	91.95	96.90	92.94	89.40	94.61	94.15	93.95
VANDERKLOOF	94.73	98.87	88.95	84.44	98.85	97.61	98.45	97.91	95.73	95.05	95.09	94.67
DRAKENSBERG	75.36	84.72	81.29	91.09	90.05	83.22	89.90	85.90	86.07	85.31	86.43	86.53
INGULA	93.28	98.92	94.37	94.71	97.35	90.85	91.39	90.68	90.54	93.56	93.60	93.00
PALMIET	86.05	98.83	94.45	87.89	98.80	88.92	97.50	92.85	92.90	93.11	93.90	93.36
PEAKING	91.79	94.34	92.47	94.31	96.20	91.16	91.88	93.18	92.11	92.96	93.13	92.99
KOEBERG	84.16	82.96	70.32	90.08	86.46	74.93	90.04	89.50	92.11	84.50	84.54	84.72
NUCLEAR	84.16	82.96	70.32	90.08	86.46	74.93	90.04	89.50	92.11	84.50	84.54	84.72
ARNOT	65.08	62.44	65.36	62.27	62.82	65.48	69.37	67.42	60.80	54.54	54.58	
DUVHA	54.48	49.67	60.16	56.92	62.82	61.12	67.22	63.65	59.44	60.91	60.21	59.80
HENDRINA	60.93	55.96	69.35									
KENDAL	69.10	71.34	65.47	73.17	69.03	74.14	75.36	69.41	79.33	73.64	72.94	72.53
KRIEL	54.10	63.42	54.63	51.39	65.20	64.44	65.39	68.89	51.12	60.54	64.15	
LETHABO	73.98	72.38	75.61	71.00	70.41	74.88	68.47	67.91	68.82	74.06	73.36	72.95
MAJUBA	73.05	74.62	75.32	72.62	74.50	77.04	70.13	72.18	71.93	71.63	70.93	70.52
MATIMBA	82.75	80.14	81.64	81.12	81.20	78.37	79.35	78.79	76.45	80.11	79.41	79.00
MATLA	67.30	68.76	70.74	70.97	69.49	70.53	69.66	69.10	75.96	70.37	69.67	69.26
TUTUKA	56.06	56.86	54.05	59.15	54.92	61.15	57.84	57.37	62.55	58.78	58.08	57.67
BIG 10	66.78	67.18	67.69	67.53	68.44	70.41	69.46	68.57	69.48	69.49	69.43	69.20
CAMDEN	60.00	55.81	61.24	64.67	63.05							
GROOTVLEI	89.15											
KOMATI	87.39											
TOTAL RTS	63.21	55.81	61.24	64.67	63.05							
Current Fleet Tota	71.00	71.53	71.40	72.71	73.63	73.85	73.96	73.36	74.23	74.06	74.28	74.31
KUSILE	72.00	76.55	83.72	81.44	81.62	83.16	78.21	82.41	81.67	80.12	79.42	78.94
MEDUPI	76.64	79.23	84.22	83.58	85.20	81.90	85.99	86.66	79.52	81.76	81.06	80.58
NEW BUILD	75.31	78.29	84.00	82.54	83.42	82.53	82.12	84.55	80.59	80.95	80.25	79.77
ESKOM TOTAL	71.5	72.5	73.5	74.5	75.5	75.5	75.5	75.5	75.5	75.5	75.5	75.5

6.2 APPENDIX B – SUMMARY OF INPUT FROM PUBLIC SUBMISSIONS

-	-	- SUMMARY KEY COMMENTS FOR DRAFT IRP 2018 -		-
-	-	- COMMENTS	- RESPONSE	- NO. OF COMMENTS
A. POLICY &PROCESSES -	- 1	- The overall methodology of the draft IRP document was welcomed and deemed to be clear and concise. A proposal for future iterations of the IRP is to include independent experts (organisations and individuals) and international organisations. -	- *The process of future iterations of the IRP will be looked at following the announcement about electricity planning made by the President during the State of the Nation Address.*	- 54
	- 2	- The publication of the IRP in English only and not in other official languages was raised as a concern as it limits participation by other members of the public. -	- *This request is noted. It is proposed that a condensed final approved version of the IRP (possibly in graphics) be developed and published. This will obviously lag the final published IRP.*	
	- 3	- Publication of documents electronically on the Department website and through government gazette was raised as a concern since not everyone has access to the internet. -	- *Noted. A workable solution needs to be found and suggestions are welcome. In the past, the IRP consultation process was expanded to cover all provinces and to include all communities, but this proved to be ineffective for whatever reason*	
	- 4	- It was stressed that the IRP must be revised more regularly, at least every 2-3 years, due to technology advancements and changes in other assumptions.	- *The regulations for planning provide for a timeline regarding IRP updates*	

		-		
	- 5	- The promulgation of this IRP was encouraged to be released soon and articulate the status of the Ministerial determination on gas and how it will be included into the proposed new built program that is planned for 2026. -	- *As stated in the draft IRP, Ministerial Determinations issued will be looked at and revised in line with the latest approved IRP. This will be done in concurrence with NERSA as required by law.*	
	- 7	- There was a concern on the silence of the IRP with regards to cross border coal based power projects. While another view cautioned against the reliance on cross border projects in general. -	- *South Africa still supports the development of strategic regional power resources in support of regional economic development. The strategic merits of each cross-border power opportunity will be weighed in line with government policy*	
	- 8	- Concern was raised about the alignment of the draft IRP to the National Development Plan and other policies such as the Nuclear Energy Policy of 2008 as the plan does not contain additional nuclear capacity. -	- *Each technology option is justified by its merits when considered against other options under a modelling scenario. The draft IRP does not contradict the Nuclear Energy Policy, in fact IRP2010-2030 is proof of that. What is under consideration is whether there is a need for nuclear prior to 2030*	
B. DEMAND	- 9	- Concern is raised regarding the projected electricity demand. • Majority of the comments question the projected growth in demand in the context of falling demand and increasing own generation installations.	- *The drivers of demand are explained in detail in the draft IRP. Projected demand has been re-based to 2017 actual demand as a starting point and we utilize the "cone" in respect of low, medium and high scenarios of demand. This ensures that we take all possible demand scenarios into account, and only have*	- 46

		• There is also an opposing view that says that the projected demand is very low as it ignores suppressed demand and the fact that electricity is a catalyst. Availability of excess electricity will lead to demand increasing and economic growth. -	*to adjust the pace of implementation as the actual demand manifests.* - *The likely impact of distributed generation is acknowledged and the draft IRP states that distributed generation registered or licenced by the NERSA will have to be discounted from the projected demand when Ministerial Determinations are made.* - *Historic trends with regard to electricity intensity, energy switching and levels of energy access suggest that even if the economy turns electricity demand growth will likely not go to the rates seen pre- 2007.* - *As no one has a crystal ball for the future, frequent revision of the IRP will ensure upwards or downwards adjustments to the demand forecast can be incorporated.* -	
- C.MISSING TECHNOLOGIES	- 10	- There are concerns raised about technologies that did not appear on the plan, including CSP, biomass, fuel cells, battery storage, mini-hydro and others. -	- *Most of the technology options relate to utility scale technologies. Technologies that do not appear in the draft IRP could be either due to scale (relatively small) or because of cost and system requirements. Stakeholders have made suggestions that capacity procurement in the future must be based on system requirements and not technology to allow technologies*	- 20

			to compete based on their ability to provide for system requirements at the least possible cost. -	
	- 11	- To encourage flexibility of the plan, it was proposed that the use of technologies and primary energy titles be done away with a rather outline the characteristics of the particular planned generation – base load, mid-merit, renewable etc. -	- *See response to 10*	
	- 12	- The EPRI study does not contain any information cogeneration -	- *See response to 10*	
	- 13	- There is a view that Electric Vehicles will soon form part of the South African transport system and the IRP should include them in its analysis. -	- *The role and impact of EVs on the power system has been taken into consideration. EV influences on the IRP are projected to be minimal in this IRP window up to 2030. Future iterations will include a scenario to test EV penetration*	
- D. GENERAL	- 14	- There was a suggestion that provisions to be made for Local Government to directly arrange for either self-generation or concluding their direct procurement with independent service providers outside of Eskom. -	- *The IRP is about supply and demand balance. It is only at the point where a Ministerial Determination is made that their procurer and buyer are determined.* - *The suggestion is therefore noted.* -	- 26
	- 15	- There is also a proposal by local government that IRP must be done in a	- *The suggestion is noted and could be considered for the next iteration of the IRP. Municipal*	

		bottom up approach with full involvement of local government. -	*capacity to undertake this role varies across the municipalities. Following both approaches (top down and bottom up) has proven to be very useful in other energy planning jurisdictions*	
	- 16	- Concerns were raised about the IRP being silent on the Eskom in the future. Especially in renewable energy. -	- See response to 10. - Further capacity allocations and the role of Eskom will be guided by the work be carried out as part of its reconfiguration and turn around. The policy position does not preclude Eskom from building RE plants; challenge is that the scale Eskom is used to is much larger than for RE-type technologies. -	-
	- 17	- The 3 year procurement gap for renewables was raised as a concern and it was indicated that it is not good for the sector localisation. -	- The concern is noted and will be looked at taking into account costs, system requirements and implications for the energy mix.	
-	-	-	-	-
E. COAL -	- 18	- The inclusion of 1000MW of coal through policy adjustment was raised as a concern. Issues of concern raised include: • The additional costs compared to gas, wind and PV combination, • Emissions and health impact associated with coal fired power plants,	- Noted. All adjustments or deviations from a least cost plan come at additional costs. This must be considered on the basis of cost vs benefit. - Procured projects are expected to comply with all environmental requirements. In so far as the draft IRP is concerned, the inclusion of the coal projects would	- 98

		• The current legal challenges regarding environmental authorisations, • The funding challenges as banks are no longer willing to finance coal to power projects. -	be subject to non- violation or exceedance of emissions constraints limits imposed. - In order not to pre-empt the outcome of the court challenges, the projects are included provided they comply with prevailing environmental legislation. - Funding for these projects is indeed a risk. The Department will have to monitor these projects and decide on the "dead stop date" without compromising security of supply. -	
	- 19	- There are also those who supported the inclusion of 1000MW of coal. While they welcomed this inclusion, they are demanding that the allocation be increased to include: • The full Ministerial determination previously issued for 2500MW of local coal to power, • The Ministerial determination of 3600MW for cross border coal to power. -	- RSA has an abundance of coal; the strategic value of considering imported coal projects under the IRP would have to be evaluated against government policy. As indicated the draft IRP will make reference to coal projects, without indicating that it is for imported coal projects. - Ministerial Determinations issued under the IRP2010 will be reviewed in consultation with NERSA, once the updated IRP is approved.	
	- 20	- Eskom current coal challenges (cost and availability) were raised as a concern. The concern is that the IRP is quiet on this challenge and its impact on Eskom meeting the projected demand.	- Part of IRP technical studies include a "system adequacy" test which takes care of this concern. Eskom is also required as part of their license condition to submit to NERSA	

		-	medium term system adequacy outlook. This report also looks at primary energy projections. - Government is also looking to resolve the coal sector regulatory issues through a revised Mineral and Petroleum Resources Development Act. -	
	- 21	- Clarity was sought regarding the inclusion of " Cleaner Coal" - These include: • High efficiency, low emission (HELE) technologies in the IRP including their costs. One coal generation equipment manufacturer and supplier submitted what is said to be latest costs which are lower than what was used from the EPRI report. • The inclusion of Underground Coal Gasification (UCG). -	- Cleaner coal in the form of HELE is included in the assumptions. For the costs to be revised, this must be based on at least one operational project experience (ideally 3) anywhere in the world, to substantiate claims by manufacturers etc. -	
	- 22	- There is a view that the assumptions around the completion of Medupi and Kusile should be changed. The proposal is for the remainder of Medupi and Kusile units not be considered but to be reviewed against additional capacity from "cheaper" clean energy sources. The cost of energy from these stations, the financial challenges of Eskom and The IPCC	- - Our approach is based on the reality that Medupi/Kusile are already committed. The proposal to stop the completion of Medupi and Kusile has to be looked at in the context of commitments to date and implications of that on Eskom and the national revenue fund, should breakage costs be incurred.	

		report are some of the reasons advanced for the proposal. -	-	
	- 23	- The decommissioning of coal plants that would reach their 50 - year life attracted different views. • There are comments that support the decommissioning of the plants to the extent that there are proposals to fast track the decommissioning of these plants. The concerns raised from these comments are about climate and health impacts of coal. • There are also comments that do not support the decommissioning of coal power plants. The concerns raised from these comments are about potential job losses in affected communities as well as the need for base load power. -	- Accelerated decommissioning has the potential to compromise the security of supply because the capacity has not been discounted prior to scheduled lifespan in the previous energy plan. - Job losses will also have to be considered beyond the energy context. .	
	- 24	- Concerns are raised regarding assumptions used for the Eskom generation Energy Availability Factor (EAF) EAF in the draft IRP. Assumptions are said to be optimistic as current actual EAF is lower than what is projected. The EAF is therefore not improving as per the projections obtained from Eskom with the likelihood that additional capacity	- Eskom EAF (at the aggregate level) is just a useful indicator but individual plant performance projections have been obtained from Eskom and are used to inform the technical studies. Sensitivity analysis will also be conducted to ensure the final proposed plan is robust.	

		maybe required sooner than what the draft IRP indicates. -		
	- 25	- Consideration of the job losses in the coal sector and a reskilling of employees in this sector and a detailed socio-economic impact analysis of communities affected by the decommissioning must be fast-tracked to achieve effective sign-off with all stakeholders and in doing so prevent the creation of ghost towns, unemployment and social upheaval. -	- The solution for potential job losses and economic impact as a result of closing down of power plants must look at options beyond replacing like with like. Job losses will have to be considered beyond the energy context, hence the proposal in the draft IRP for detailed analysis and consultations outside of the IRP process. The reality is that a lot of coal plants will soon reach end of life.	
	- 26	- A proposal is made to address job losses in the coal industry by introducing spatial component into the implementation of the IRP for a just transition. The proposal is that new generation capacity must be closer to where existing power generators will be phased out. -	- See 25 above.	
-	-	-	-	-
- F. GAS	- 27	- The inclusion of gas was critised to be neither least cost option nor clean energy. The extraction of gas was further argued to be harmful to the environment. Moreover it was viewed as an additional greenhouse gas on top of the coal that is reflected in the recommended plan. -	- Gas is considered a transition fuel globally and it provides the flexibility necessary to run a system like we have in a cost effective manner. It is cleaner than other fossil fuels. The extent of the gas contained in the draft IRP is within the imposed emissions reduction trajectory.	- 68

	- 28	- A concern was raised on the source of gas. A request is also made for this information to be reflected in the IRP. -	- Two options are available in the short-medium term, being imported Liquefied Natural Gas, or piped gas from the sub-region (or even domestic)	
	- 29	- Caution was raised about the likely availability of gas infrastructure within the envisaged IRP timelines. Once more, there is a request to reflect implementation details in the IRP. -	- See 28. The IRP will not cover the implementation details because this is not its intended scope. The Gas Infrastructure Plan will address this concern	
	- 30	- The likely volatility of imported gas prices was raised as a point of concern. It was proposed that to mitigate against this, the following should be considered during implementation: • Introduction of 'real time pricing' on a platform similar to that of a day-ahead and a balancing market. This could significantly mitigate the exposure to potentially high import costs of gas. • Customers could be allowed to utilise alternative measures i.e. demand-side management or energy storage in lieu of expensive gas generation etc. -	- The proposal is noted.	
	- 31	- The exchange rate exposure as a result of importing gas and the likely impact on the electricity	- The proposal is noted and will be considered when the gas supply options are weighed.	

		tariff were raised as a concern for the inclusion of gas. • It is proposed that greater consideration is given to those flexible renewable generation and/or energy storage technologies able to mitigate the price and supply risks associated with gas technology • Alternative methods of balancing the renewable energy other than gas were proposed such as CSP, energy storage and small hydro were proposed. -		
	- 32	- There is a request to consider and to include in the IRP additional information regarding the anticipated capacity factors and number of start/stops that would be expected of the gas capacity. -	- This is noted and will be effected.	
	- 33	- The IRP should consider latest information regarding some of the gas technologies compared to that in the EPRI report. Generation equipment supplier submitted “Latest information” for consideration by the technical modelling team. -	- This is noted. Also see 21 above.	
	- 34	- Consultation with gas industry experts was proposed and the idea to conduct more studies on the gas	- This is being done as part of the Gas Infrastructure Plan development.	

		industry was welcomed and a willingness to share information on studies already done was communicated -		
	- 35	-	- Government policy is based on an energy mix that includes nuclear etc. A such rational basis must be advanced as to the exclusion of one technology option or the other, and the same applies to nuclear. Where there is sound basis for the inclusion of nuclear in the energy mix, it will be included.	- 33
	- 36	- Other comments made a case for Nuclear rating high on a security of supply scale as compared to renewable, coal and gas. -	- Noted.	
G. NUCLEAR -	- 37	- It is said that the exclusion of nuclear from the proposed new additional capacity is in contradiction to the NDP and Nuclear policy of 2008. -	- This is not the case. IRP2010-2030 contradicts this assertion. Capacity additions to the system are based on demand and system requirements. The absence of new additional capacity from nuclear is therefore not in contradiction to policy. It is more of a timing issue. It is for this reason that the draft IRP called for detailed analysis to be undertaken to ensure the energy mix is maintained post 2030 when most power plants are being decommissioned.	

			-	
	- 38	- It is recommended that the future cost of decommissioning nuclear power plants should be built into the current price paid for nuclear. -	- The technical model takes into account Life cycle costs for all technologies under consideration.	
	- 39	- It is recommended that the DoE look into the studies that have been conducted over the years by various stakeholders and industry players with regards to nuclear. -	- The technical team has considered all studies made available to the team about nuclear, during the development of the draft report. No additional studies have been submitted as part of the consultation on the draft IRP.	
	- 40	- It is proposed that Policy adjustment must be extended to include nuclear energy given it's a clean source of energy with huge socio-economic advantages including investment with long-term returns to South Africa. -	- Policy adjustment of the IRP is the prerogative of Cabinet, and they will have the opportunity to do so.	
	- 41	- It is proposed that the IRP should include nuclear as the least cost in the long term. Koeberg is referenced as a case in example. It is also indicated that nuclear will create more jobs than the current plan which consist of renewables and gas. -	- Nuclear is included as one of the technologies the technical model should consider. Due to the relative marginal cost of generation, in comparison to other options, no new capacity from nuclear comes through before 2030 but there is a scenario that builds new nuclear capacity post 2030. - This will be looked at in details as part of the post 2030 energy mix.	

			-	
	- 42	- There is a proposal for the Department to nuclear power RFI/RFP like in the case of renewables which is said to be the only way to ascertain the cost of power from nuclear. -	- In 2007 Eskom issued an RFP for nuclear plants and the outcome is well established. There is also plenty of information about the cost of nuclear plants to estimate the marginal cost of generation. This should not be confused with the fully depreciated operational cost of a nuclear plant, like Koeberg.	
-	-	-	-	
- H. CSP	- 43	- A call is made for the inclusion of CSP even though it does not fit least cost criteria. The argument advanced is that CSP is clean and unlike other renewables, it has the ability to provide ancillary services. -	- The proposal is noted. This will be considered under implementation in line with the proposal to procure solutions and not technology.	-
	- 44	- There is a proposal to amend procurement and go beyond procuring a technology but a solution. The proposal is to allow the procurement of CSP in the base load programme, mid merit or peaking demand profiles, with PPAs structured for such operations. -	- See 43	- 16
	- 45	- It is said that the CSP costs used in the draft IRP are high and the Department should consider the learning curves for CSP to date based on SA and international markets. -	- Latest information for CSP is used for the IRP. Some of the information proposed for use could not be verified or supported.	

- I. BATTERY STORAGE	- 46	- It was pointed out that the cost of energy from renewable sources with battery storage technology is becoming cost competitive and comparable to that of renewables with gas. Additional benefits of battery storage for system operations are highlighted as reasons for inclusion of battery storage in the IRP. It is proposed that energy storage be included in the final IRP as the prices are falling at a fast rate. -	- The comment is noted. - This will be considered under implementation in line with the proposal to procure solutions and not technology.	- 41
	- 47	- It is recommended that the Department look at latest cost of batteries together with the learning curve. -	- See 46	
	- 48	- There is a proposal for distributed energy storage allocation to match the allocation for embedded generation. -	- See 46	
-	-	-	-	
- J. EMBEDDED GENERATION/RENEWABLE ENERGY	- 49	- The inclusion of embedded generation was welcomed with the proposal that it be referred to distributed generation which is a common name used. -	- Proposal is noted.	- 84
	- 50	- Clarity is being sought on how the embedded generation cap of 200MW was arrived. The proposal is to increase the annual allocation. There is	- The allocation will be reviewed as proposed.	

		also a proposal to use applications already received by the Department as a starting number. -		
	- 51	- There was a concern that a cap on embedded generation would encourage a noncompliance. Another view proposed that if the cap remains, there should be at least a compounded growth per year. -	- See 50	
	- 52	- It was proposed that the off grid connections not be part of the embedded generation cap. -	- These are exempt from licensing and therefore not part of IRP.	
	- 53	- It was pointed out that microgrids and backfeeding onto the grid for less than 10MW was not addressed. -	- The policy stance is that municipalities have the prerogative whether to allow this or not, in line with the Constitution. The IRP does not prescribe this	
	- 54	- There are concerns regarding the embedded generation installations that are greater than 10MW whether they are included in the IRP allocation or not. -	- These installations will still need a Ministerial deviation in line with the Electricity Regulation Act.	
	- 55	- It is recommended that the annual embedded generation be increased and that provision must also be made for industrial co-generation and self- generation -	- See 50	

	- 56	- It was proposed that work to capture accurate and current information is urgently undertaken reduce uncertainty in the next IRP review in two years. -	- NERSA in the process of finalising the registration process which is in line with this proposal.	
- K. HYDRO POWER	- 57	- A call was made for supporting small hydropower -	- Noted.	- 32
	- 58	- There was a caution against Inga project due to Congo's political instability. -	- Noted. The same applies to any cross-border project, including Cahorra Bassa in Mozambique.	
- L.CLARITY COMMENTS	- 59	- Whether an environmental impact was conducted in line with the legislative framework that governs this requirement.	- Need clarity regarding which environmental impact this question is referring. In any event the scope of the IRP does not extend to EIAs, this is an implementation issue - -	- 16
	- 60	- Community development/benefit - Whether job creation was factored into the development of the IRP, particular in relation to community development, long-term impact on communities and impact on communities upon decommissioning. -	- Job numbers analysis of the final proposed plan for the period up to year 2030 together with potential jobs impact due to decommissioning of old Eskom power plants will be undertaken as part of the proposed work to be undertaken. - -	
	- 61	- Economic outflows of opportunities: Black emerging miners, Mining Charter, -	- Question reads incomplete. Expansion will assist to ensure response is adequate and relevant.	

		-		
	- 62	- IPP contracts and current tariff structure – would want to have sight of this information: proposed a presentation of applications for tariff applications. -	- A presentation in this regard can be arranged for interested members of the Task Team at a suitable time.	
	- 63	- Eskom's financial instability should feature in discussions, particularly its high debt levels, R400billion. Unsustainable business model - it was agreed that while Govt should respond to the points raised, the Secretariat would in addition provide feedback from the work of the Sovereign Ratings Downgrade task team, already engaging on this matter. -	- Eskom issues are being attended to as announced by the President. The proposal for the secretariat to provide feedback from other engagements is supported.	
	- 64	- Future of the electricity industry – any consideration been given? -	- See response to Question 5. IRP at this stage looks at mainly balancing supply and demand irrespective of the market structure. -	
	- 65	- Eskom as a producer of renewables: - - Labour was of the view that Eskom should continue to enjoy its monopoly in the energy sector;	- See response to Question 63.	

		- Eskom should therefore be part of the process of moving towards renewables; and - Also separate issue for noting in the Nedlac report: Eskom's role in producing renewables (not purpose of the IRP to determine who produces what; rather to renounce on the energy generation mix required for security of supply). -		
	- 66	- The proposed retrenchment of 17 000 workers at Eskom were concerning. -	- There is a process dealing with Eskom and as announced in SONA, various stakeholders will be engaged as announced. -	
	- 67	- Decreasing demand on the national grid: How did Government arrive at a conclusion that the demand was decreasing or had decreased, given that many communities are still without electricity? -	- Actual historical data obtained and as measured by Eskom confirms that demand projected in 2010 has not been realised. Data also indicates that the electricity intensity is coming down. This is seen from energy used per unit of GDP. - While historically demand has remained flat, the IRP projects that demand will continue to grow into the future and this makes provision for increasing access. - It should also be noted that the challenges of access are being addressed under the	

				electrification programme, which is a distribution issue (not a generation or IRP issue) -	
	-	68	- Quality control/assurance in respect of models used and research undertaken. -	- The simulation models and data set input used were independently verified by CSIR, NREL as well as PLEXOS developers for quality assurance. Most utilities in the world follow the methodology we are using	
	-	69	- Drafting process – should be shared -	- The request is not clear. An expansion of the request and relevance to the report contents as presented will assist. - The report was compiled by the Department of Energy with support from the technical modelling team. -	
	-	70	- The IRP stated that there was a need for detailed studies on nuclear energy and other forms of energy such as clean coal. The NDP had already called for these in 2012. If the studies were done, they should be shared. -	- The report actually states that due to the significant change in the energy mix post 2030, a number of detailed studies must be undertaken as assumptions made today can significantly alter the energy mix outcome. There are various studies that have been carried out and continue to be carried out by a number of institutions. Future iterations of the IRP always take into account the latest technology developments	

			- -	

6.3 APPENDIX C – RESULTS OF TEST CASES

BASE CASE: Koeberg 60 years; No MES; Coal & Hydro forced in

	Coal	Landfill Gas	Import Hydro	CCGT	CCGE	OCGT	ICE 12MW	PV	Wind
2020									
2021		250					996		
2022					900			1000	
2023	500				900			1000	
2024	500					132		1000	1200
2025								1000	1400
2026					1950			1000	1800
2027					1200			1000	1800
2028								1000	1800
2029					1200			1000	1800
2030			2500					1000	1800

Base Case Gas Load Factors

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Ankerlig	34	18	6	3	5	2	1	2	2	2	2	
DoE_IPP	12	11	3	1	2	1	1	1	1	1	1	1
Gourikwa	42	15	3	2	4	1	2		2	2	2	
CCGT												
OCGT						5	4	4	3	2	2	
CC-CE				41	24	18	17	11	11	8	15	5
ICE-12MW			26	19	14	13	9	5	3	3	3	

TEST CASE 1: Base Case + MES 1

	Coal	Landfill Gas	Import Hydro	CCGT	CCGE	OCGT	ICE 12MW	PV	Wind
2020									
2021		250					6384	70	
2022					3600			1000	
2023	500							1000	
2024	500							1000	1800
2025								1000	1800
2026								1000	1700
2027								1000	1400
2028								1000	400
2029								1000	1800
2030			2500					1000	1800

Test Case 1 Gas Load Factors

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Ankerlig	59	94	6	4	5	1			1		1	
DoE_IPP	24	87	3	1	2	1	1	1	1	1	1	1
Gourikwa	52	94	4	3	5				1		1	
CCGT												
OCGT				5	4	4	3	2	2			
CC-GE		41	24	18	17	11	11	8	15	5	7	8
ICE-12MW	26	19	14	13	9	5	3	3	3		2	2

TEST CASE 2: Base Case + MES 2

	Coal	Landfill Gas	Import Hydro	CCGT	CCGE	OCGT	ICE 12 MW	PV	Wind
2020									
2021		250					8892	1000	
2022					4500			1000	
2023	750			732	450			1000	
2024	7250			1464				1000	1800
2025								1000	1800
2026								1000	1800
2027	2250							1000	1800
2028								1000	1800
2029								1000	1800
2030			2500					1000	1800

Test Case 2 Gas Load Factors

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Ankerlig	62	94	4	4	5							
DoE_IPP	37	88	3	1	2							
Gourikwa	55	94	4	3	4							
CCGT					88	86	82	74	76	70	69	54
CC-CE				95	95	51	47	41	41	39	42	26
ICE-12 MW			77	76	65	8	7	7	6	5	9	5

TEST CASE 3: Base Case + Koeberg 40 years

	Coal	Landfill Gas	Import Hydro	CCGT	CCGE	OCGT	ICE 12MW	PV	Wind
2020									
2021		250					1104		
2022					750			1000	
2023	500				1050			1000	
2024	500							1000	1800
2025								1000	1800
2026					3750			1000	1800
2027					1350			1000	1800
2028								1000	1800
2029					900			1000	1800
2030			2500					1000	1800

Test Case 3 Gas Load Factors

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Ankerlig	41	18	7	8	8	3	1	3	3	3	5	1
DoE_IPP	12	11	3	1	3	1	1	1	1	1	2	1
Gourikwa	29	15	4	4	6	2		2	3	2	3	
CCGT												
ICE-2MW			23	16	19	8	12	10	3	5	16	3
OCGT												
CC-GE				47	23	17	17	16	15	12	30	7
ICE-12MW			27	40	21	14	14	11	8	9	18	4

TEST CASE 4: Base Case +MES 2 +Koeberg 40years + Inga & Coal optimized

	Coal	Landfill Gas	Import Hydro	CCGT	CCGE	OCGT	ICE 12MW	PV	Wind
2020									
2021		250					8892	1000	
2022					5100			1000	
2023				1464				1000	
2024	7500							1000	1800
2025	750							1000	1800
2026	1500							1000	1800
2027	2250							1000	1800
2028								1000	1800
2029								1000	1800
2030			2500					1000	1800

Test Case 4 Gas Load Factors

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Ankerlig		94	4	3	6						1	
DoE_IPP	37	88	3	1	3	1	1	1	1	1	1	1
Gourikwa	55	94	4	2	4						1	
CCGT					**88**	**88**	**87**	**76**	**69**	**70**	**73**	**61**
OCGT												
CC-GE				41	24	18	17	11	11	8	15	5
ICE-12MW			26	19	14	13	9	5	3	3	3	

TEST CASE 5: Base Case + Gas Limit

	Coal	Landfill Gas	Import Hydro	CCGT	CCGE	OCGT	ICE 12MW	PV	Wind	Battery Storage 1 hour
2020										
2021		250					840			
2022					150			1000		162
2023	1250							1000		
2024	500				450				1800	
2025					450			70	1800	
2026					600				1800	
2027	750							820	1800	
2028								1000	1800	252
2029								1000	1800	1821
2030			2500		150			840	1800	

Test Case 5 Gas Load Factor

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Ankerlig	41	18	7	8	8	3	1	3	3	3	5	1
DoE_IPP	12	11	3	1	3	1	1	1	1	1	2	1
Gourikwa	29	15	4	4	6	2		2	3	2	3	
CCGT												
ICE-2MW			23	16	19	8	12	10	3	5	16	3
OCGT												
CC-GE				47	23	17	17	16	15	12	30	7
ICE-12MW			27	40	21	14	14	11	8	9	18	4

TEST CASE 6: Base Case + 30 Months Wind Lead Time + Gas Limit

	Coal	Landfill Gas	Import Hydro	CCGT	CCGE	ICE	OCGT	ICE 12MW	PV	Wind	Battery Storage
2019											
2020											
2021		250									
2022									1000	1800	462
2023	500								1000	1800	
2024	500				450					1700	
2025					450				540	1800	
2026						2		96		1800	
2027	750				1500				490	1600	
2028									1000	1800	66
2029									990	1800	1821
2030			2500		150				1000	800	

Test Case 6 Gas Load Factors

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Ankerlig	41	18	7	8	8	3	1	3	3	3	5	1
DoE_IPP	12	11	3	1	3	1	1	1	1	1	2	1
Gourikwa	29	15	4	4	6	2		2	3	2	3	
CCGT												
ICE-2MW			23	16	19	8	12	10	3	5	16	3
OCGT												
CC-GE				47	23	17	17	16	15	12	30	7
ICE-12MW			27	40	21	14	14	11	8	9	18	4

6.4 APPENDIX D – DISTRIBUTED GENERATION CATEGORIES

The following activities constitute the distributed generationallocation for own use reflected in this IRP Update.

1. The operation of a generation facility with an installed capacity of between 1MW and 10MW that is connected to the national grid when ─
   - the generation facility supplies electricity to a single customer and there is no wheeling of that electricity through the national grid; and
   - the generator or single customer has entered into a connection and user-of-system agreement with, or obtained approval from, the holder of the relevant distribution licence.

2. The operation of a generation facility with an installed capacity of between 1MW and 10MW that is connected to the national grid when ─
   - the generation facility is operated solely to supply a single customer/related customers by wheeling electricity through the national grid; and
   - the generator or single/related customers has/ve entered into a connection and use-of-system agreement with the holder of the distribution or transmission licence in respect of the power system over which the electricity is to be transported.

3. The operation of a generation facility with an installed capacity of between 1MW and 10MW that is **not** connected to the national grid or in the case of which there is no interconnection agreement when ─
   - the generation facility is operated solely to supply electricity to the owner of the generation facility in question;
   - the generation facility is operated solely to supply electricity for consumption by a customer who is related to the generator or owner of the generation facility; or
   - the electricity is supplied to a customer for consumption on the same property on which the generation facility is located.

Notwithstanding the applicable circumstances, all activities listed above must still comply with licensing requirements as regulated and administered by NERSA.

6.5 APPENDIX E1 – SUMMARY OF PUBLISHED DRAFT IRP 2018

This section contain the results of the analysis that resulted into the draft IRP 2018 published plan. These scenarios can be categorised into projected demand growth scenarios and key input scenarios. The scenarios looked at some of the key factors such as the use as carbon budget for carbon dioxide emissions reduction, assumed gas prices variation to analyse the impact of changing gas prices, and the removal of annual build limits imposed on RE.

Key Scenarios Modelled and Simulated in Developing Draft IRP 2018

Test Case	IRP 3	IRP 4	IRP 2	IRP 1	IRP 6	IRP 5	IRP 7
Key Input Change	Demand Forecast	Demand Forecast	Demand Forecast	No Renewables Annual Build Limit	Carbon Budget	Market Linked Gas Price	Carbon Budget And Market Linked Gas Price
Demand Forecast	Median	Lower	Hi	Median	Median	Median	Median
CO_2 Mitigation	Peak Plateau Decline	Peak Plateau Decline	Peak Plateau Decline	Peak Plateau Decline	Carbon Budget	Peak Plateau Decline	Peak Plateau Decline
Renewable Annual Build Limit	Yes	Yes	Yes	No	Yes	Yes	Yes
Fuel Prices	Constant	Constant	Constant	Constant	Constant	Market Linked Gas	Constant
Transmission Grid Collector Stations Costs	Yes	Yes	Yes	Yes	Yes	Yes	Yes

Key assumptions and considerations included in the scenarios modelled and simulated included, among others:

- The demand forecast for various growth trajectories;
- maintenance of the RE annual build rate as previously assumed in the promulgated IRP 2010–2030. The Plan assumed 1000MW for PV and 1600MW for wind per annum;

- the carbon dioxide emission reductions constraint using the PPD , except for one scenario that used carbon budget approach;
- the performance of the Eskom coal plants as per their performance undertakings;
- the decommissioning dates of existing generation plants;
- the cost associated with the dedicated transmission infrastructure costs for that energy and capacity mix; and
- committed, planned generation plants, such as Medupi, Kusile and RE (up to Bid Window 4).

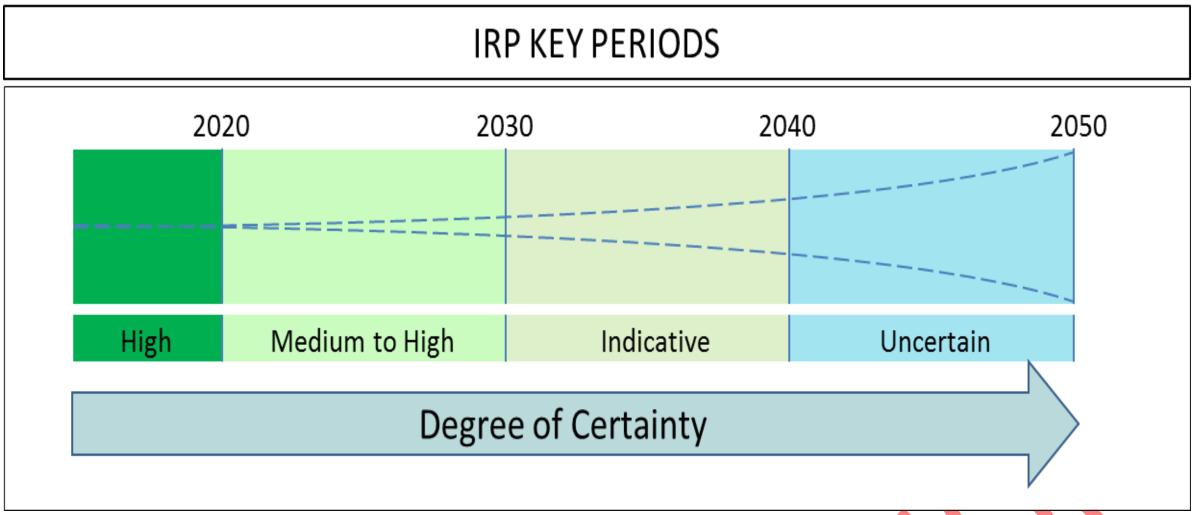
Following the development of the reference case taking into account the assumptions, the scenarios listed were simulated and analysed.

Technical modelling and simulation was performed using PLEXOS software. The objective function of PLEXOS is to minimise the cost of investments and electricity dispatch using complex mathematical models. The cost function is determined by the operational costs, start-up costs, fuels cost and penalty costs for unserved energy or for not meeting the reserve requirements.

Constraints can be applied to the model in the software if necessary. These constraints include, among others: energy balances; emission constraints; operational constraints (limits on generation, reserve provision, up and down times, ramp rates and transmission limits); regional capacity reserve margins and ancillary services; maximum number of units built and retired; fuel availability and maximum fuel usage; minimum energy production; and RE targets.

RESULTS OF THE SCENARIOS

The analysis of the results from the simulations were analysed by looking at the energy mix for three periods (2017–2030, 2031–2040 and 2041–2050). The degree of certainty of the assumptions decreases the longer we project into the future and hence the depiction of the periods in **Error! Reference source not found.**.



IRP Study Key Periods

The assumptions for the period between now and year 2020 are of high certainty as they actually fall within the Eskom operations plan for the year.

The period 2021–2030 is termed a "medium-to-high" period of certainty, with new capacity requirements driven by the decommissioning of old Eskom power plants and marginal demand growth. While demand and technology costs are likely to change, the decommissioning of old plants will definitely result in the requirements for additional capacity.

The period 2031–2040 is termed an "indicative period", as the uncertainty regarding the assumptions begins to increase. The output for this period is relevant to the investment decisions of the 2021–2030 period because it provides information needed to understand various future energy mix paths and how they may be impacted by the decisions made today.

The period 2041–2050 is even more uncertain than the period before 2040.

The results were analysed in line with the objectives of the IRP, which are to balance cost, water usage, emission reduction and security of supply.

From the results of the scenario analyses, the following are observed for the period ending 2030:

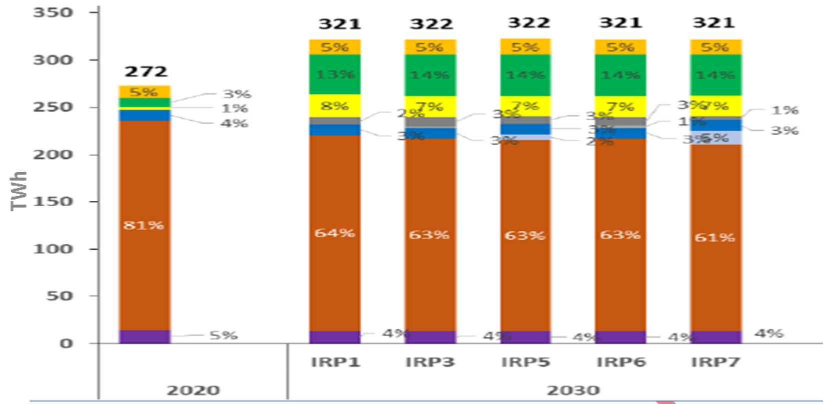
- Committed REIPPP (including the 27 signed projects) and Eskom capacity rollout ending with the last unit of Kusile in 2022 will provide more than sufficient capacity to cover the projected demand and decommissioning of plants up to around 2025.
- The installed capacity and energy mix for scenarios tested for the period up to 2030 does not differ materially. This is driven mainly by the decommissioning of about 12GW of Eskom coal plants.
- Imposing annual build limits on RE will not affect the total cumulative installed capacity and the energy mix for the period up to 2030. See Table 7 and Table 8 for details.
- Imposing carbon budget as a strategy for carbon dioxide emission reduction or maintaining the PPD approach used in 2010 will not alter the energy mix by 2030.
- The projected unit cost of electricity by 2030 is similar for all scenarios, except for market-linked gas prices where market-linked increases in gas prices were assumed rather than inflation-based increases.
- The scenario without RE annual build limits provides the least-cost option by 2030.

For the period post 2030, the following are observed:

- The decommissioning of coal plants (total 28GW by 2040 and 35GW by 2050), together with emission constraints imposed, imply coal will contribute less than 30% of the energy supplied by 2040 and less than 20% by 2050.
- Imposing annual build limits on RE will restrict the cumulative renewable installed capacity and the energy mix for this period.
- Adopting no annual build limits on renewables or imposing a more stringent carbon dioxide emission reduction strategy implies that no new coal power plants will be built in the future unless affordable cleaner forms of coal to power are available.
- The projected unit cost of electricity differs significantly between the scenarios tested. It must be noted that a change in fuel cost (gas, for example) can affect the projected cost significantly.
- The scenario without RE annual build limits provides the least-cost option by 2050.
- Overall, the installed capacity and energy mix for scenarios tested for the period post 2030 differs significantly for all scenarios and is highly impacted / influenced by the assumptions applied.

Modelling Output
Year 2030 Energy Mix

Projected Peak Demand
Year 2020 – 40GW
Year 2030 – 48GW



Installed Capacity	GW	61	78	78	78	78	78
Environment	CO2 (Mt / year)	236	217	215	213	215	207
	Water Usage (bn Ltr / year)	260	199	199	198	199	191
Cost*	Unit Cost (c/kwh)		115	115	117	115	119
	Cumulative Cost Difference (R'million)		0	13 822	19 150	14 265	24 361
Security of Supply	Grid Stability and Fuel Supply Exposure	Envisaged levels of renewable energy supported by flexible gas plants is expected not to affect Grid Stability and Reliability. All scenarios contain similar volumes of Gas to power which is likely to be imported.					

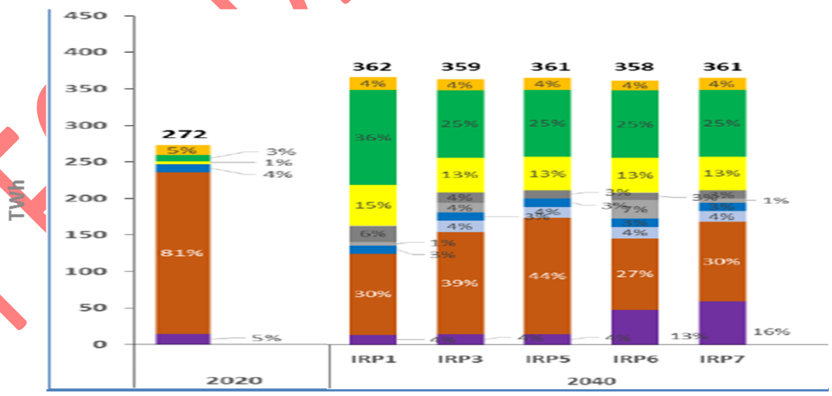
*** Year 2017 Rands**

Nuclear Coal Hydro Import Hydro CCGT CC-GE OCGT PV Wind Others

Scenario Analysis Results for the Period Ending 2030

Modelling Output
Year 2040 Energy Mix

Projected Peak Demand
Year 2020 – 40GW
Year 2030 – 48GW
Year 2040 – 54GW



Installed Capacity	GW	61	120	105	105	105	105
Environment	CO2 (Mt / year)	236	123	153	168	116	119
	Water Usage (bn Ltr / year)	260	59	66	70	56	58
Cost*	Unit Cost (c/kwh)		125	132	134	135	140
	Cumulative Cost Difference (R'million)		0	116 979	198 173	192 673	336 275
Security of Supply	Grid Stability and Fuel Supply Exposure	Reliance on coal significantly reduces 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					

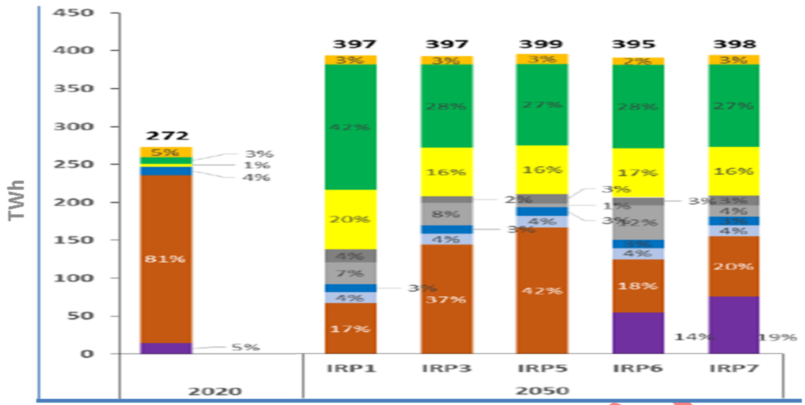
*** Year 2017 Rands**

Nuclear Coal Hydro Import Hydro CCGT CC-GE OCGT PV Wind Others

Scenario Analysis Results for the Period 2031–2040

Modelling Output
Year 2050 Energy Mix

Projected Peak Demand
Year 2020 – 40GW
Year 2030 – 48GW
Year 2050 – 61GW



		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**

Scenario Analysis Results for the Period 2041–2050

CONCLUSIONS FROM ANALYSIS OF THE SCENARIOS

The following conclusions are drawn from the results of the analyses:

- The review of the IRP implies that the pace and scale of new capacity developments needed up to 2030 must be curtailed compared with that in the promulgated IRP 2010–2030 projections.
- Ministerial Determinations for capacity beyond Bid Window 4 (27 signed projects) issued under the promulgated IRP 2010–2030 must be reviewed and revised in line with the projected system requirements.
- The scenario without RE annual build limits provides the least-cost electricity path to 2050.
- Without a policy intervention, all technologies included in the promulgated IRP 2010–2030 where prices have not come down like in the case of PV and wind, will not be deployed because the least-cost option only contains PV, wind and gas.

- The significant change in the energy mix post 2030 indicates the sensitivity of the results observed to the assumptions made. A slight change in the assumptions can therefore change the path chosen. In-depth analysis of the assumptions and the economic implications of the electricity infrastructure development path chosen post 2030 will contribute to the mitigation of this risk.

DRAFT IRP 2018

Drawing from the conclusions of the scenarios analysed, the scenario of RE without annual build limits provides the least-cost path up to 2050. The significant change in the energy mix post 2030 and the sensitivity of the energy mix to the assumptions are key points to note.

It was therefore recommended that the post 2030 path not be confirmed, but that detailed studies be undertaken to inform the future update of the IRP. These studies should, among others, include the following:

- Detailed analysis of gas supply options (international and local) to better understand the technical and financial risks and required mitigations for an RE and gas-dominated electricity generation mix post 2030.
- Detailed analysis of the appropriate level of penetration of RE in the South African national grid to better understand the technical risks and mitigations required to ensure security of supply is maintained during the transition to a low-carbon future. Some work has been done on the impact of increasing shares of variable generation on system operations in South Africa (Flexibility Study). There is a need to expand this work to include an in-depth analysis of technical options such as reduced inertia, reduced synchronizing torque, reduced voltage support and reduced contribution to short-circuit currents to overcome stability issues resulting from non-synchronous generation and distributed generation. There is also a need to determine whether the stability issues will become relevant in the near, mid and long term. The above-mentioned technical options are most suitable to overcome the challenge. This part of work is already under consideration.

- Detailed analysis of other clean energy supply options (coal, hydro, nuclear and others), including their associated costs and economic benefits. The NDP Update acknowledges the potential to increase the efficiency of coal conversion and calls for any new coal-power investments to incorporate the latest technology. The NDP Update calls for cleaner coal technologies to be supported through research and development, and technology transfer agreements in ultra-supercritical coal power plants; fluidised-bed combustion; underground coal gasification; integrated gasification combined cycle plants; and carbon capture and storage, among others. The NDP Update further acknowledges the role of nuclear in the energy mix and calls for a thorough investigation of the implications of nuclear energy, including its costs; financing options; institutional arrangements; safety; environmental costs and benefits; localisation and employment opportunities; and uranium-enrichment and fuel-fabrication possibilities.

  Such an analysis would therefore be in line with and in support of commitments in the NDP Update

  .

- Detailed socio-economic impact analysis of the communities impacted by the decommissioning of old, coal-fired power plants that would have reached their end-of-life. Such an analysis would go a long way in ensuring that communities built on the back of the coal-to-power sector are not left behind during the transition.

For the period ending 2030, a number of policy adjustments is proposed to ensure a practical plan that will be flexible to accommodate new, innovative technologies that are not currently cost competitive, the minimization of the impact of decommissioning of coal power plants and the changing demand profile.

Recommended policy adjustment is as follows:

- Adopt a least-cost plan with the retention of annual build limits (1000MW for PV and 1600MW for wind) for the period up to 2030. This provides for smooth roll out of RE, which will help sustain the industry.
- Make provision for 1000MW of coal-to-power in 2023–2024, based on two already procured projects. Jobs created from the projects will go a long way

towards minimizing the impact of job losses resulting from the decommissioning of Eskom coal power plants and will ensure continued utilisation of skills developed for the Medupi and Kusile projects.

- Make provision for 2500MW of hydro power in 2030 to facilitate the RSA-DRC treaty on the Inga Hydro Power Project in line with South Africa's commitments contained in the NDP Update to partner with regional neighbours, The Project has the potential to unlock regional industrialisation.
- Adopt a position that all new technologies identified and endorsed for localisation and promotion will be enabled through Ministerial Determinations utilising existing allocations in the IRP Update. This approach is supported by existing electricity regulations. The Electricity Regulations on New Generation Capacity enables the Minister of Energy to undertake or commission feasibility studies in respect of new generation capacity taking into account new generation capacity as provided for in the IRP Update. Such feasibility studies are, among others, expected to consider the cost of new capacity, risks (technical, financial and operational) and value for money (economic benefits).
- Adopt a position that makes annual allocations of 200MW for new generation-for-own-use between 1MW to 10MW, starting in 2018. These allocations will not be discounted off the capacity allocations in the IRP Update initially, but will be discounted during the issuing of determinations taking into account generation for own use filed with NERSA.

The recommended updated Plan is as depicted in the table below. Impact on price path is discussed later.

	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 (grey)
Committed / Already Contracted Capacity (yellow)
New Additional Capacity (IRP Update) (green)

Proposed Updated Plan for the Period Ending 2030

- Coal Installed Capacity is less the 12 000 MW capacity to be decommissioned between years 2020 and 2030
- Existing and committed Coal, Nuclear, Hydro and Pumped Storage Capacity is less auxiliary power. Stated numbers are therefore based on sent out capacity not rated capacity.
- Two additional units at Medupi have since been commissioned which is earlier than previously assumed.
- Distributed generationfor own use installed base is unknown as these installations were exempted from holding a generation license or were not required to be registered.

PUBLISHED DRAFT IRP 2018 ELECTRICITY TARIFF PATH COMPARISON

Tariff path analysis was done for the five key input scenarios , namely no RE annual build rate (IRP1), median growth (IRP3), market-linked gas price (IRP5), carbon budget (IRP6) and carbon budget plus market-linked gas price (IRP7).

Data for the Price Path Model (PPM) used for the analysis came from Eskom's Financial Statements and Revenue Application of April 2017, and output of the scenarios from technical models.

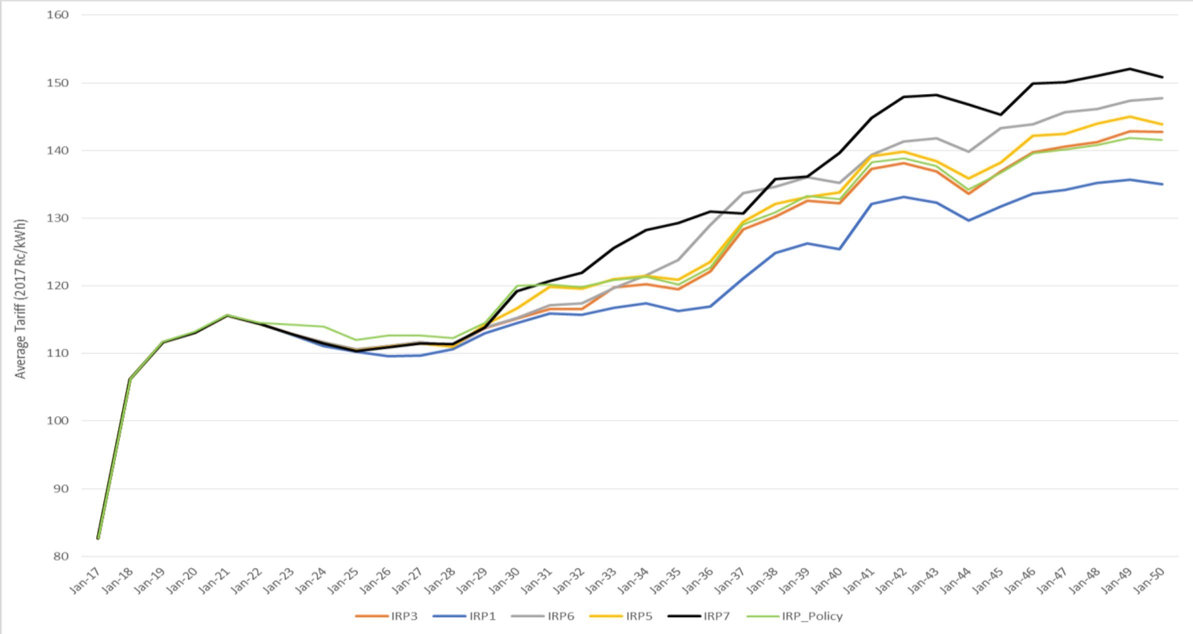
The PPM simulates the regulatory pricing methodology for South Africa. The model forecasts Eskom's total costs, including generation, transmission, purchases and distribution. The PPM does not forecast municipal costs.

Key assumptions in the Model can be summarised as follows:

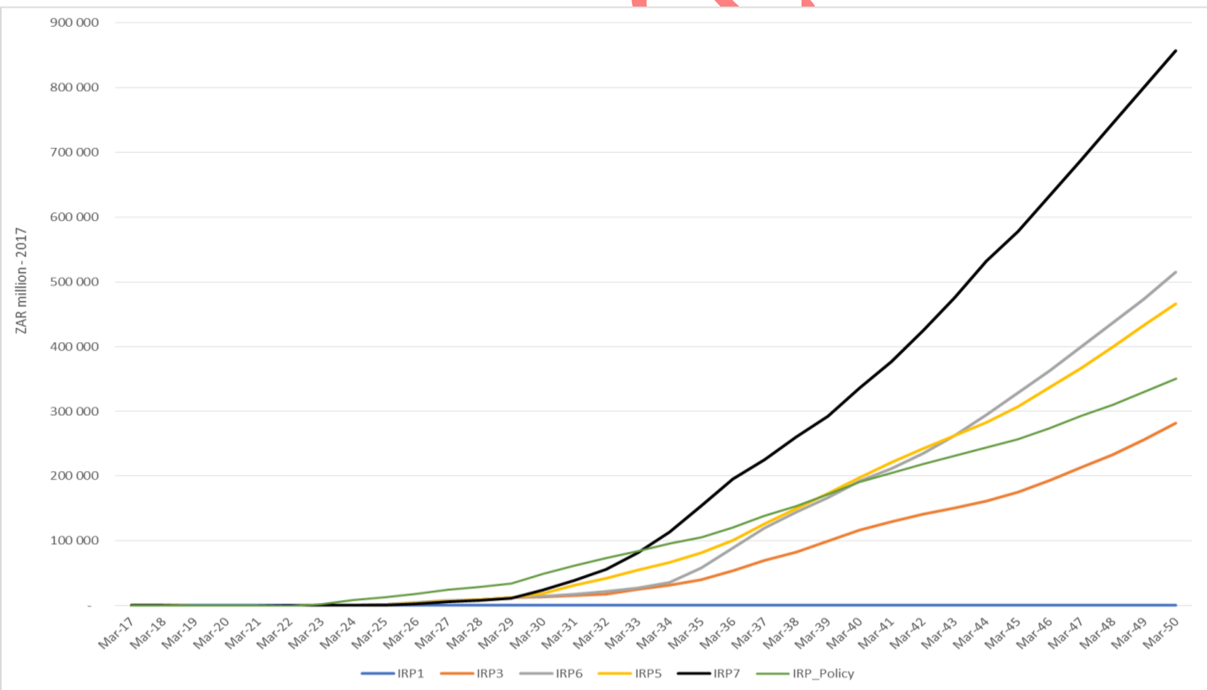
- from financial year 2017/18, the tariffs will immediately move to 'cost-reflective' levels as per the NERSA methodology.
- No change in Eskom's current level of performance and efficiency.
- Eskom will build nuclear and the rest of the capacity will be built by another party.
- Eskom will be responsible for developing new transmission and distribution networks.

Error! Reference source not found. below shows the comparative tariff projections for each of the five input scenarios and **Error! Reference source not found.**0 shows the cumulative difference between the scenarios[10] by 2030.

[10] No RE annual build rate (IRP1), median-growth (IRP3), market-linked gas price (IRP5), carbon budget (IRP6) and carbon budget plus market-linked gas price (IRP7) scenarios.



Comparison of Tariffs for the Scenarios in 2017 (Cents per Kilowatt Hour)



Cumulative Comparison of Tariff Paths for the Scenarios

There is a marginal difference in the projected price path for the period up to 2030. This is to be expected, since technical analysis resulted in the observation that the energy and capacity mix for the period differs marginally between the five scenarios.

Beyond 2030, and driven by the difference in the energy and capacity mix, the price paths are significantly different. The scenario where annual build limits on RE is removed (IRP1) provides the lower-tariff path, with the scenario where carbon budget as emission mitigation strategy is imposed and market-linked gas prices are assumed (IRP7) resulting in the highest tariff path. A further observation was that the adoption of carbon budget as emission mitigation strategy, with the targets as currently suggested, results in the tariff path of this scenario being the second highest by 2050 (see IRP6).

There is therefore no difference in tariff path for the different scenarios up to 2030, while the choice of technologies and their associated costs, taking emission mitigation requirements and capacity building into account, will drive the price path beyond 2030. Cumulative by 2030 deviation from the least cost case (IRP1) will results in additional costs to the consumer.

Hence, it makes no difference for this version of the IRP Update which scenario is adopted up to 2030. The huge difference between scenarios beyond 2030 will, however, make it necessary to undertake a detailed energy path study that will inform a next update of the IRP.

The policy adjusted scenario will result in about 5% higher tariff by year 2030 compared to the least cost scenario. This is the results of the smoothing out RE rollout plan which commissions plants earlier than they are actually required by the system as well as the introduction coal and hydro power. It must be noted this financial analysis does not take into account the economic benefits of a consistent and predictable RE rollout, the likely regional economic benefits of Inga hydropower as well as the economic benefits of continued beneficiation from coal.