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DEPARTMENT OF ENERGY

NO. 897 **27 AUGUST 2018**

REQUEST FOR COMMENTS: DRAFT INTEGRATED RESOURCE PLAN 2018

I, Jeff Radebe, Minister of Energy, under section 4 (1) of the Electricity Regulations on New Generation Capacity, hereby publish the draft Integrated Resource Plan 2018 for public comments.

Interested persons and organisations are invited to submit within 60 days of this publication, written comments on the draft Integrated Resource Plan 2018 to the Director-General of the Department of Energy for the attention of Mr Tshepo Madingoane:

By Post:

Private Bag X 96, Pretoria, 0001

Or by hand:

Matimba House, 192 Corner Visagie and Paul Kruger Street, Pretoria

Or by email:

IRP.Queries@energy.gov.za

Kindly provide the name, address, telephone number, fax number and e-mail address of the person or organisation submitting the comment. Please note that comments received after the closing date may be disregarded.

J. Radebe

JEFF RADEBE, MP
Minister of Energy

energy
Department:
Energy
REPUBLIC OF SOUTH AFRICA

INTEGRATED RESOURCE PLAN 2018

AUGUST 2018

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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	Gigajoules
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	Megaton

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.

"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.

"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.

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

EXECUTIVE SUMMARY

The National Development Plan identifies the need for South Africa to invest in a strong network of economic infrastructure designed to support the country's medium- and long-term economic and social objectives. Energy infrastructure is a critical component that underpins economic activity and growth across the country; it needs to be robust and extensive enough to meet industrial, commercial and household needs.

The National Development Plan 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 environmentally sustainable through reduced pollution.

The Integrated Resource Plan 2010–2030 was promulgated in March 2011. At the time, it was envisaged that it should be a "living plan" to be revised by the Department of Energy frequently.

The National Development Plan requires the development of additional electricity capacity. It provides a path to meet electricity needs over a 20-year planning horizon to 2030 and is being used to roll out electricity infrastructure development in line with Ministerial Determinations issued in terms of Section 34 of the Electricity Regulation Act No. 4 of 2006. The Plan, together with Ministerial Determinations, are policy signals investors use to plan their investments in the country's energy sector.

A number of assumptions used in the Integrated Resource Plan 2010–2030 has since changed, which necessitated its review. Key assumptions that have changed include electricity demand projection that did not increase as envisaged, existing Eskom plant performance that is way below the 80% availability factor, additional capacity committed to and commissioned, as well as technology costs that have declined significantly.

The Integrated Resource Plan Update process, as was the case in the Integrated Resource Plan 2010–2030 development process, aimed to balance a number of objectives, namely to ensure security of supply, to minimize cost of electricity, to minimize negative environmental impact (emissions) and to minimize water usage.

The Update process consisted of four key milestones that included the development of input assumptions; the development of a credible base-case and scenario analysis; the production of a balanced plan; and policy adjustment. Whereas the Integrated Resource Plan 2010–2030 covers a study period up to 2030, the Integrated Resource Plan Update study period was extended to the year 2050.

Following the finalisation of the assumptions, various scenarios as outlined below were modelled and analysed using the PLEXOS Integrated Energy Model, which is commercial power system modelling tool/simulation software used for electricity supply demand optimisation studies based on a least-cost path.

The scenarios studied included demand-growth scenarios where the impact of projected load demand on the energy mix was tested. Other key scenarios were based on varying the key input assumptions. These included the use of carbon budget instead of peak-plateau-decline as a strategy to reduce greenhouse gas emissions in electricity, the removal of annual build limits on renewable energy (unconstrained renewables) and varying the price of gas for power.

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

- The committed Renewable Energy Independent Power Producers Programme, 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 approximately 2025.
- The installed capacity and energy mix for scenarios tested for the period up to 2030 will not differ materially. That will be driven mainly by the decommissioning of about 12GW of Eskom coal plants.
- Imposing annual build limits on renewable energy will not affect the total cumulative installed capacity and the energy mix for the period up to 2030.
- Applying carbon budget as a constraint to reduce greenhouse gas emissions or maintaining the peak-plateau-decline constraint as in IRP 2010 – 2030 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, in the case of which a market-linked increase in gas prices was assumed instead of an inflation-based increase.
- The scenario without renewable energy annual build limits provides the least-cost option by 2030.

For the period post 2030 the following were observed:

- The decommissioning of coal plants (total 28GW by 2040 and 35GW by 2050), together with emission constraints imposed, imply that coal will contribute less than 30% of the energy supplied by 2040 and less than 20% by 2050.
- Imposing annual build limits on renewable energy 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 strategy to reduce greenhouse gas emissions 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 significantly affect the projected cost.
- The scenario without renewable energy 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 differ significantly for all scenarios and are highly impacted/influenced by the assumptions used.

In conclusion, the review and outcome of the Integrated Resource Plan Update imply the following:

- That the pace and scale of new capacity developments needed up to 2030 must be curtailed compared with that in the Integrated Resource Plan 2010–2030.
- Ministerial Determinations for capacity beyond Bid Window 4 (27 signed projects) issued under the Integrated Resource Plan 2010–2030 must be reviewed and revised in line with the new projected system requirements for the period ending 2030.

The significant change in energy mix post 2030 indicates the sensitivity of the results observed to the assumptions made. A slight change concerning 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.

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 is 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 identified in the Plan.

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 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 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. The promulgated IRP 2010–2030 incorporated government objectives such as affordable electricity, reduced greenhouse gas (GHG), reduced water consumption, diversified electricity generation sources, localisation and regional development.

Following the promulgation of the IRP 2010–2030, the DoE implemented the IRP by issuing Ministerial Determinations in line with Section 34 of the Electricity Regulation Act No. 4 of 2006. These Ministerial Determinations give 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 6422MW under the Renewable Energy Independent Power Producers Programme (REIPPP) has been procured, with 3272MW operational and made available to the grid.

- Under the Eskom build programme, the following capacity has been commissioned: 1332MW of Ingula pumped storage, 1588MW of Medupi, 800MW of Kusile and 100MW of Sere Wind Farm.
- Commissioning of the 1005MW Open Cycle Gas Turbine (OCGT) peaking plant.

In total, 18000MW of new generation capacity has been committed to.

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

These changes necessitated the review and update of the IRP.

2. THE IRP UPDATE PROCESS

The IRP Update process undertaken consisted of four key milestones as depicted in Figure 1 below. These were the development of input assumptions; the development of a credible base case (reference case) and scenario analysis; the production of a balanced plan; and policy adjustments.

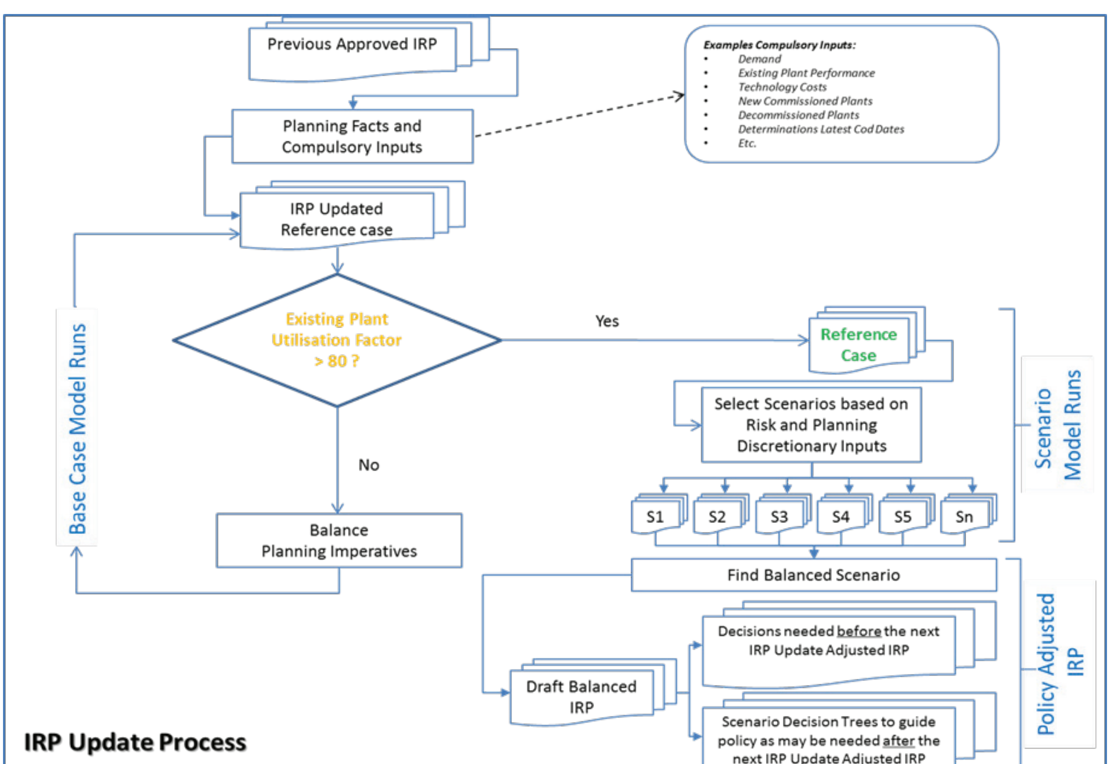


Figure 1: IRP Update Review Process

3. INPUT PARAMETER ASSUMPTIONS

Key input assumptions that changed from the promulgated IRP 2010–2030 include, among others, technology costs, electricity demand projection, fuel costs and Eskom's existing fleet performance and additional commissioned capacity. These key input assumptions are dealt with in detail below.

The assumptions below were updated, taking into account comments from the public consultation process undertaken between December 2016 and March 2017. Submissions received from the public varied from opinion statements to substantive inputs with supporting data. The comments were mostly advocating for a least-cost plan, mainly based on renewable energy (RE) and gas in accordance with the scenario presented by the Council for Scientific and Industrial Research (CSIR) at the time.

Other issues covered in the submissions included, among others, policy and process issues; assumptions published (demand forecast, technology costs, exchange rate, and demand-side options); and preliminary base case (constraints on RE, technologies missing in the preliminary base case, treatment of determinations already issued by the Minister of Energy, practicality of the plan and the price path). A detailed report on comments received and how they were addressed is included as **Appendix D**.

3.1 ELECTRICITY DEMAND

Electricity demand as projected in the promulgated IRP 2010–2030 did not realise. A number of factors 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 smelters.

3.1.1 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.

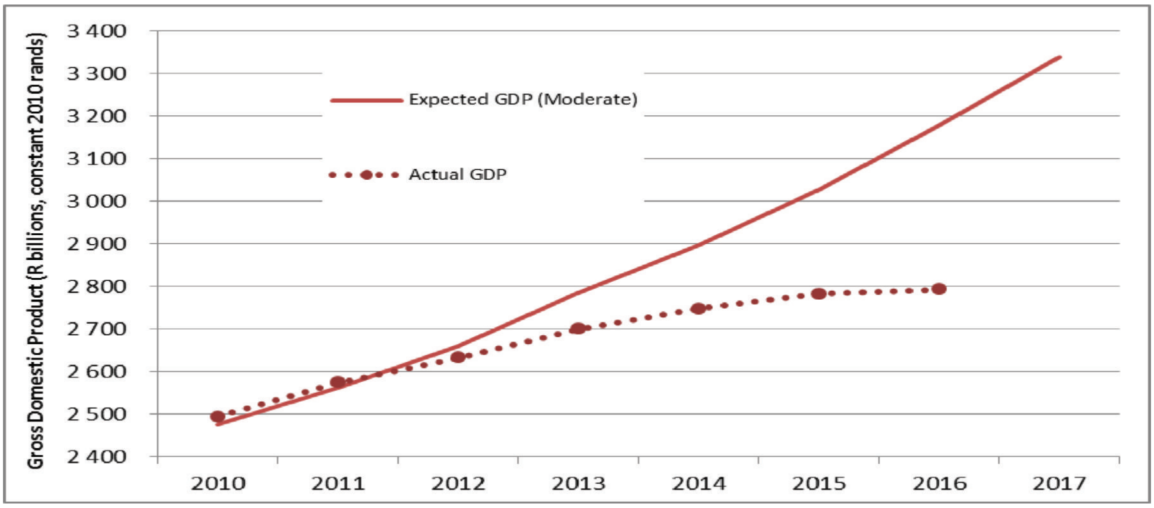


Figure 2: Expected GDP Growth from IRP 2010 *vs* Actual (Sources: Statistics SA & Promulgated IRP 2010–2030)

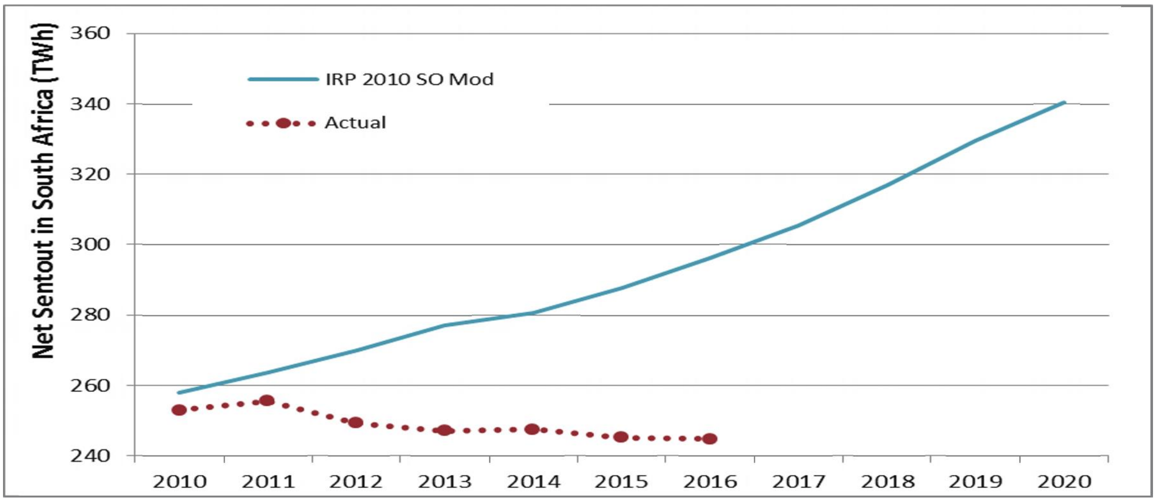


Figure 3: Expected Electricity Sent-out from IRP 2010–2030 *vs* Actual (Sources: Statistics SA & Promulgated IRP 2010–2030)

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.

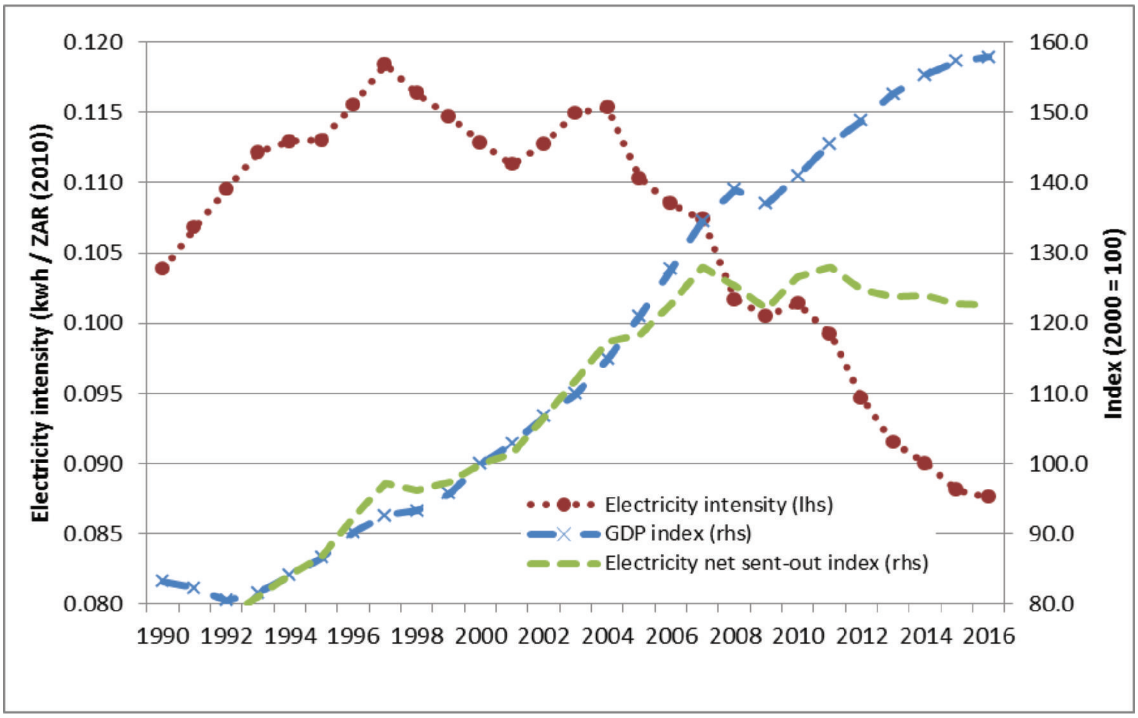


Figure 4: Electricity Intensity History 1990–2016 (Source: Own Calculations based on Statistics SA Data)

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.

3.1.2 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.

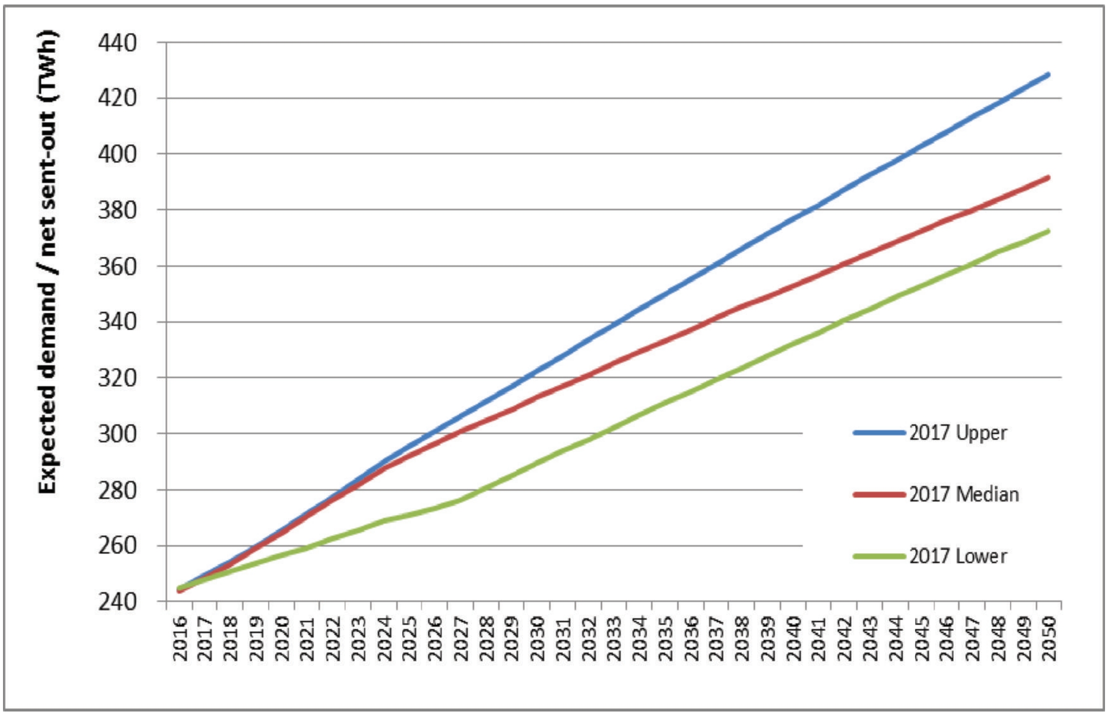


Figure 5: Expected Electricity Demand Forecast to 2050

The upper forecast[1] was based on an average 3,18% annual GDP growth, but assuming 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[2] 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 average electricity growth forecast associated with the upper forecast was relatively lower than the average electricity growth forecast for the median forecast.

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

The lower forecast[3] 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).

3.1.3 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 also 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 on building, new developments are installing solar water heaters instead of full 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 modelled as standalone scenarios, but considered to be

[3] The CSIR junk status forecast in its detailed forecast report

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.

3.2 TECHNOLOGY, FUEL AND EXTERNALITY COSTS

The IRP analyses mainly entailed balancing supply and demand at least-possible cost. Costs of technology, fuel and externalities[4] 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[5] (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 IRP Update assumptions, the above report was updated again to show the costs based on the January 2017 ZAR/US dollar exchange rate. For this IRP Update, 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.

The EPRI report incorporates cost and performance data for a number of power-generation technologies applicable to South African conditions and environments. 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 costs assumptions report can be downloaded from the DoE website (http://www.energy.gov.za/files/irp_frame.html).

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

[5] EPRI is an independent, non-profit organisation 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.

This IRP Update includes the costs as contained in the EPRI report, except for the following technologies: PV, wind, coal and sugar bagasse for which average actual costs achieved by the South African REIPPP were used.

The nuclear technology costs were based on the DoE-commissioned study aimed at updating the cost of nuclear power based on available public and private information. The study expanded the analysis by EPRI to include a technology cost analysis from projects in the East (Asia). A detailed technology costs assumptions report (Ingerop Report) can be downloaded from the DoE website (http://www.energy.gov.za/files/irp_frame.html).

The pumped storage costs were based on the recently commissioned Eskom Ingula pumped storage scheme.

The new combined cycle gas engine costs were based on information provided by Wartsila as part of public inputs. A copy of the technology costs submission by Wartsila can be downloaded from the DoE website (http://www.energy.gov.za/files/irp_frame.html).

3.2.1 Economic Parameters

For economic parameters, the following assumptions were 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.

3.2.2 Technology, Learning and Fuel Costs

The overnight capital costs[6] associated with the technologies are summarised in Figure 6.

Some of the technology costs, such as coal, nuclear and concentrating solar power (CSP), showed much higher costs in 2017 relative to the assumed values in the promulgated IRP 2010–2030. That was mainly due to the higher exchange rate in 2017, which impacted all technologies with the exception of some of the RE technologies as a result of learning-related reduction in costs experienced over the last few years.

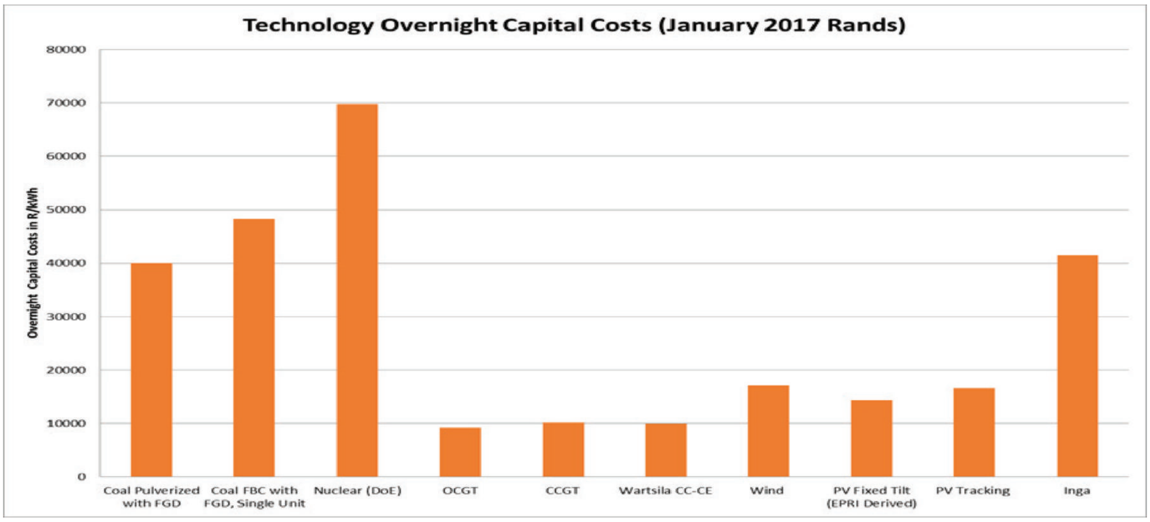


Figure 6: Technology Overnight Capital Costs in January 2017 (Rands)

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 steep decline in prices experienced in South Africa. These are reflected in Table 1.

Table 1: Technology Learning Rates

Technology	**Overnight Costs**	
	Year 2015 (R/kW)	Year 2050 (R/kW)
PV (fixed tilt)	16860.6	13425.0
PV (tracking)	17860.6	14221.4
Wind	19208.1	17287.4
Nuclear	55260.0	53768.8

Table 2 below shows assumed fuel costs as contained in the EPRI report.

Table 2: Fuel Cost Assumptions

[6] Overnight cost is the cost of a construction project if no interest was incurred during construction, as if the project was completed 'overnight'.

Parameter	Value used in the Model	
Fuel cost (R/GJ)	Coal pulverised	31 (~R558/t)
	Coal FBC (discard coal)	15.5 (~R279/t)
	LNG	135.70
	Nuclear fuel cost	9.10

3.2.3 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 in Table 3. The costs associated with carbon dioxide (CO2) are not included as the CO2 emissions constraint imposed during the technical modelling indirectly imposes the costs to CO2 from electricity generation.

Table 3: 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

3.3 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 B**.

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 39730MW of new generation capacity must be developed. A list of Ministerial Determinations is included in **Appendix B.**

Of the 39730MW determined, about 18000MW has been committed[7] to date. This new capacity is made up of 6422MW under the REIPPP with a total of 3772MW operational on the grid. Under the committed Eskom build, the following capacity has been commissioned: 1332MW of Ingula pumped storage, 2172MW of Medupi (out of the 4800MW planned), 800MW of Kusile (out of the 4800MW planned) and 100MW of Sere Wind Farm. 1005MW 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 4.

Table 4: CODs for Eskom New Build

Medupi		**Kusile**	
Unit 6	Commercial operation	Unit 1	Commercial operation
Unit 5	Commercial operation	Unit 2	2019, Apr
Unit 4	2017, Dec	Unit 3	2020, May
Unit 3	2019, Jun	Unit 4	2021, Mar
Unit 2	2019, Dec	Unit 5	2021, Nov
Unit 1	2020, May	Unit 6	2022, Sep

3.3.1 Existing Eskom Plant Performance

The existing Eskom plant availability was assumed to be 86% in the promulgated IRP 2010–2030. The actual plant availability at the time was 85%. Since then, Eskom plant availability declined steadily to a low of 71% in the 2015/16 financial year before recovering to over 77.3% in the 2016/17 financial year. This drop in availability was a major contributor to the constrained capacity situation between 2011 and 2015. For the foreseeable future, the existing Eskom fleet remains the

[7] Committed refers to the capacity commissioned or contracted for development.

bulk of the South African electricity supply mix. The performance of these plants is therefore critical for electricity supply planning and security.

Medium plant performance projection is assumed for the IRP Update as it is in line with Eskom's Shareholder Compact of 2017 and Corporate Plan targets. Figure 7 shows the plant performance projection scenarios compiled by Eskom.

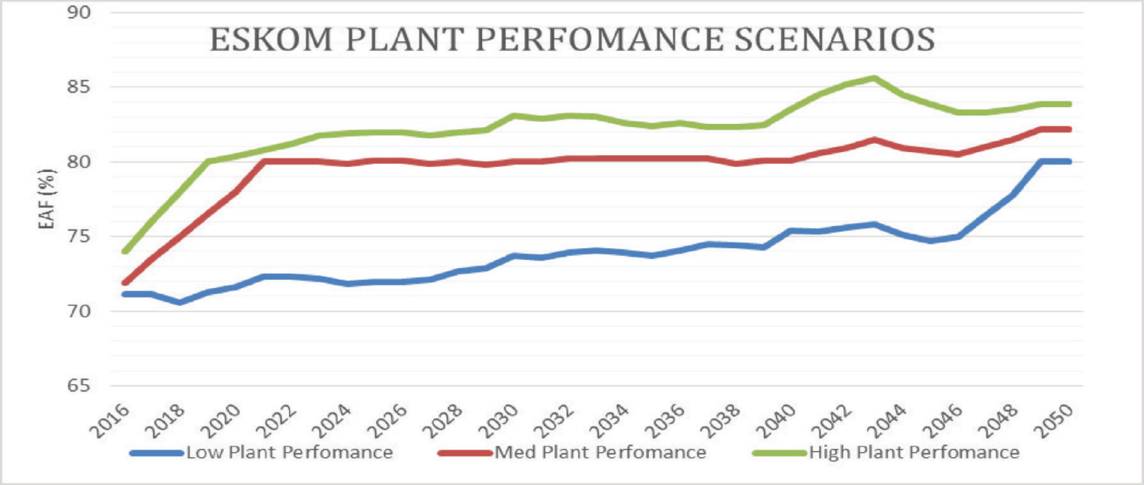


Figure 7: Eskom Plant Performance (Source: Eskom)

3.3.2 Existing Eskom Plant Life (Decommissioning)

Decommissioning of plants is a major consideration in the IRP Update. Eskom coal plants were designed and built for 50-year life, which falls within the 2050 study period of the IRP Update. The full impact of decommissioning the existing Eskom fleet was not studied fully as part of the IRP Update. That included the full costs related to coal and nuclear decommissioning, rehabilitation and waste management. The socio-economic impact of the decommissioning of these plants on the communities who depend on them for economic activity was also not quantified.

In line with the decommissioning schedule in **Appendix B**, Figure 8 shows that about 12600MW of electricity from coal generation by Eskom will be decommissioned cumulatively by 2030. That will increase to 34400MW by 2050. It is also expected that 1800MW of nuclear power generation (Koeberg) will reach end-of-life between 2045 and 2047.

The decommissioning schedule is linked to Eskom complying with the minimum emission standards in the Air Quality Act No. 39 of 2004 in line with the postponements granted to them by the Department of Environmental Affairs (DEA). A number of Eskom power plants (Majuba, Tutuka, Duvha, Matla, Kriel and Grootvlei) requires extensive emission abatement retrofits to ensure compliance with the law. Failure to comply is likely to result in these plants becoming unavailable for production, which could lead to the early retirement of some of the units at these plants.

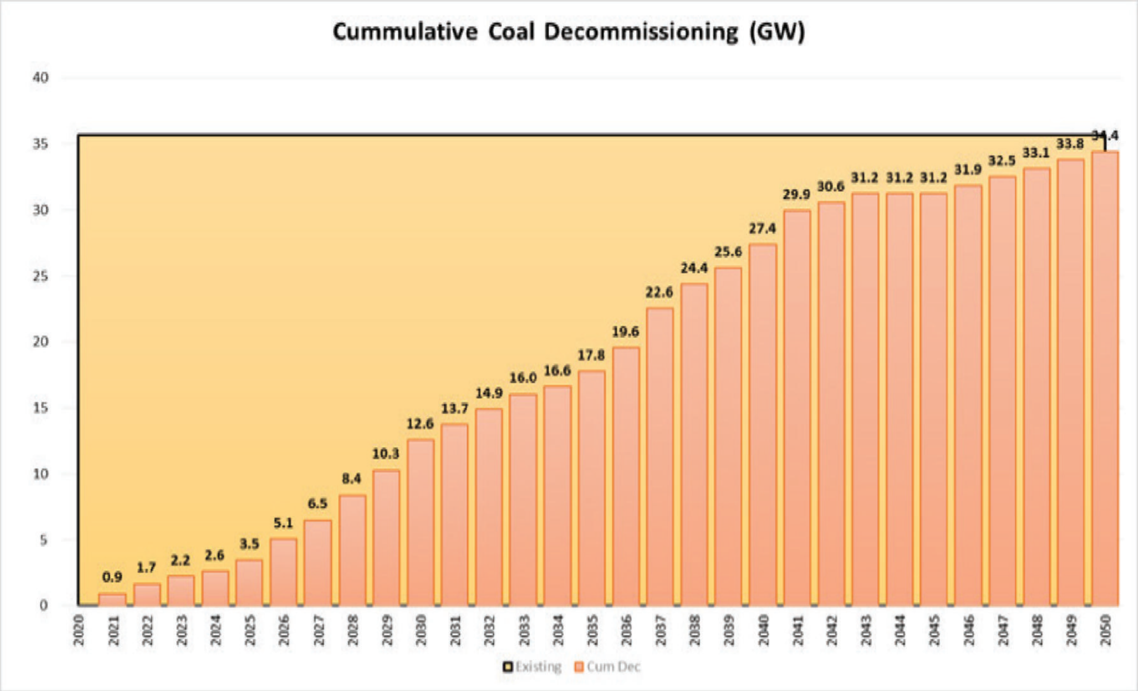


Figure 8: Cumulative Eskom Coal Generation Plants Decommissioning

3.4 CO_2 EMISSION CONSTRAINTS

In line with South Africa's commitments to reduce emissions, the promulgated IRP 2010–2030 imposed CO_2 emission limits on the electricity generation plan. The Plan assum9ed that emissions would peak between 2020 and 2025, plateau for approximately a decade and decline in absolute terms thereafter.

Figure 9 shows the emission reduction trajectory in line with the peak-plateau-decline (PPD) constraints for electricity generation adopted in the promulgated IRP 2010–2030.

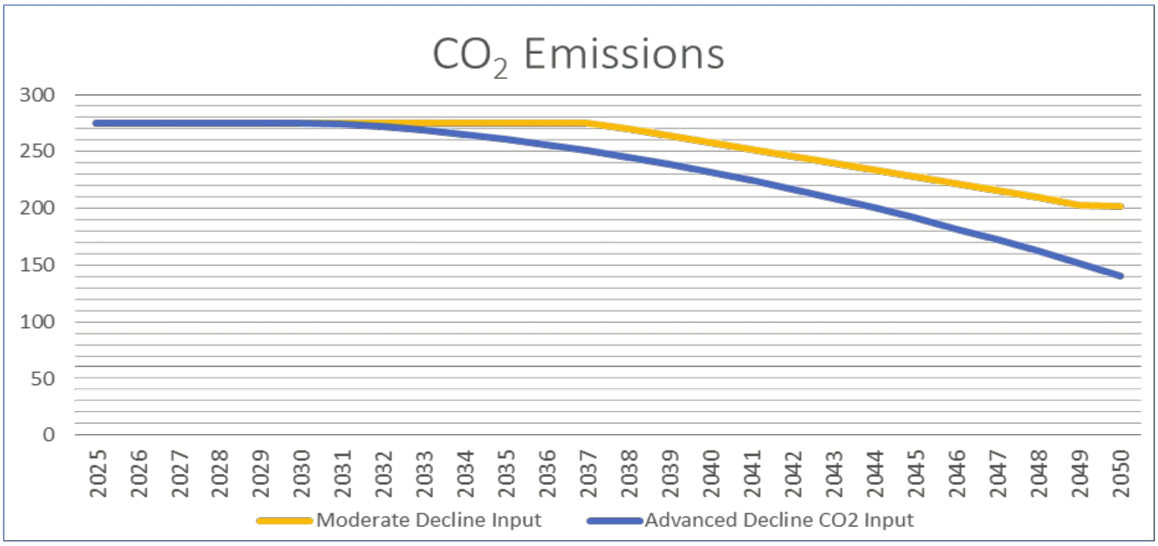


Figure 9: Emission Reduction Trajectory (PPD)

The other emission constraint approach is to impose carbon budget target for a specified period. A carbon budget is generally defined as a tolerable quantity of GHG emissions that can be emitted in total over a specified time.

Carbon budget targets approach as proposed for the electricity sector divided into 10-year intervals, are contained in Table 5. The proposal suggests that the total emission reduction budget for the entire electricity sector up to 2050 must be 5470Mt CO_2 cumulatively.

Table 5: Emission-reduction Constraints (Carbon Budget)

Decade	Budget in Mt CO_2 Equivalent
2021–2030	2750
2031–2040	1800
2041–2050	920

While the reference case for the IRP Update applied PPD as an emission constraint, as was the case in the promulgated IRP 2010–2030, applying carbon budget as a constraint instead of PPD was tested as a scenario.

3.5 TRANSMISSION NETWORK COSTS

The technical models in the promulgated IRP 2010–2030 did not explicitly include the cost of the transmission network in their analyses. The IRP Update does include the cost of the transmission network for scenario comparison.

The transmission network was 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 average costs for transmission infrastructure.

For RE technologies (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 CSP transmission costs were treated the same as conventional technology costs.

The transmission infrastructure costs considered different capacity increments/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).

4. SCENARIO ANALYSIS RESULTS

Table 6 below outlines the seven scenarios considered and the key assumptions for each scenario. These assumptions can be grouped into projected demand growth scenarios and key input scenarios, which look at some of the key considerations, such as using carbon budget for a GHG reduction strategy, variation in assumed gas prices to analyse the impact of high gas prices on the energy mix and the removal of annual build limits imposed on RE.

Table 6: Key Scenarios

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 studied 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 GHG emission reductions constraint using the PPD mitigation strategy, except for one scenario that tested the carbon budget mitigation strategy;
- 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 analysed.

Technical modelling of the reference case and scenarios was performed using PLEXOS. The objective function of PLEXOS is to minimize 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.

The constraints that can be applied in the model 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.

4.1 RESULTS OF THE SCENARIOS

Because of the extent of the IRP Update study period and the level of certainty of the assumptions into the future, the reference case and the scenarios were analysed in three periods, namely 2017–2030, 2031–2040 and 2041–2050. Figure 10 below depicts these periods.

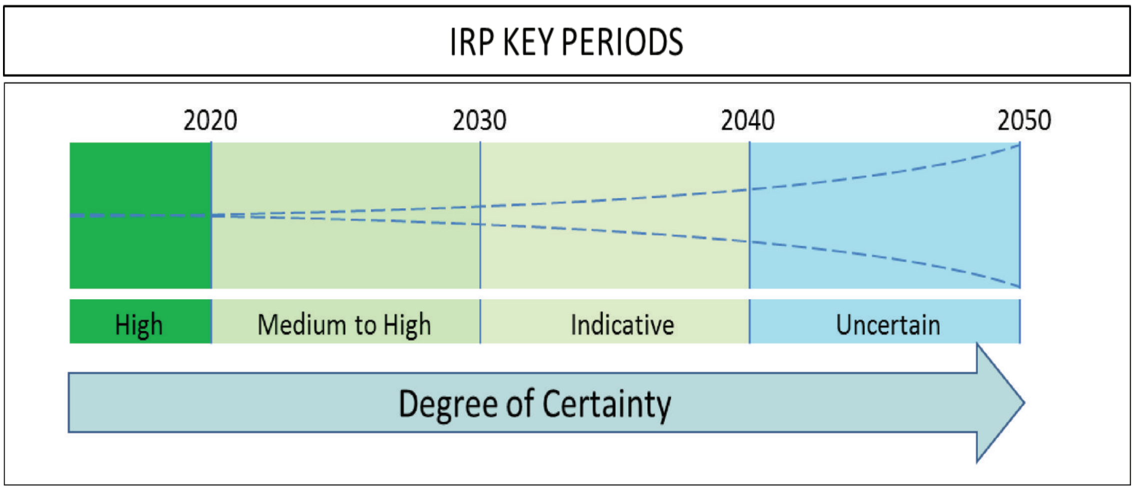


Figure 10: IRP Study Key Periods

The period up to 2020 is mainly covered through the Medium-term System Adequacy Outlook compiled annually by Eskom and published by NERSA in line with the Grid Code requirements.

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. Detailed results from the technical analysis are contained in **Appendix A**.

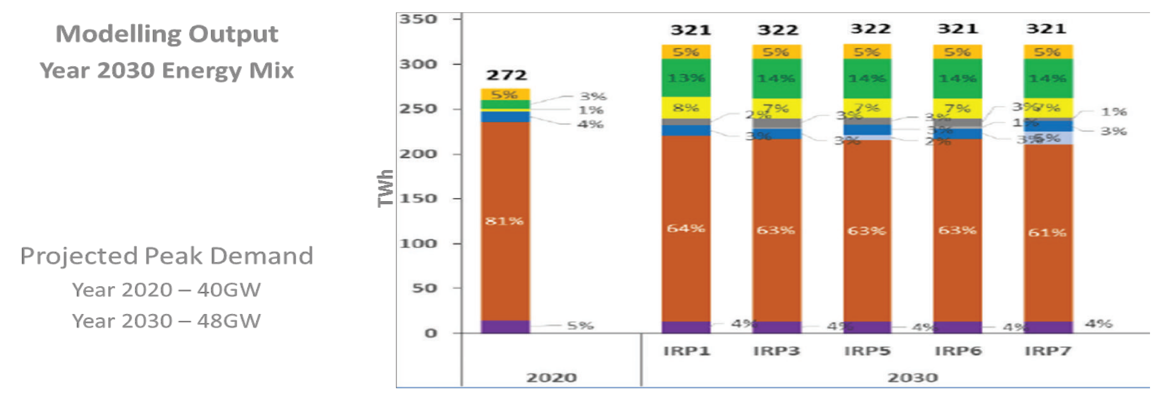
The results of the scenario analyses for the period ending 2030 are as contained in Figure 11. From the results of the scenario analyses, the following are observed for the period ending 2030:

- 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 GHG 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.

The results of the scenario analyses for the period post 2030 are as contained in Figure 12 and Figure 13. 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 GHG 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.



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.					

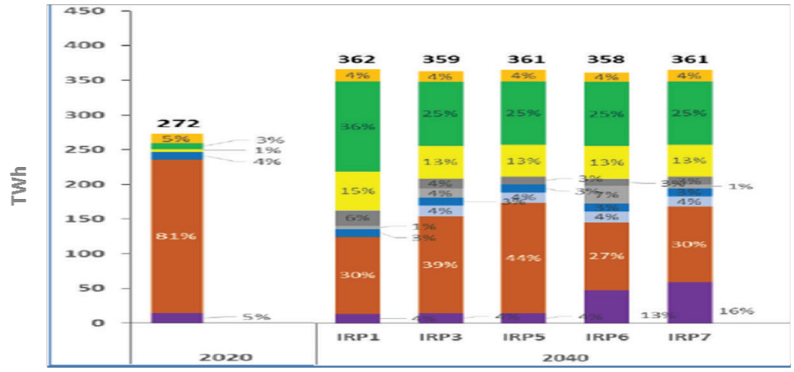
* Year 2017 Rands

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

Figure 11: 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



		2020	IRP1	IRP3	IRP5	IRP6	IRP7
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					

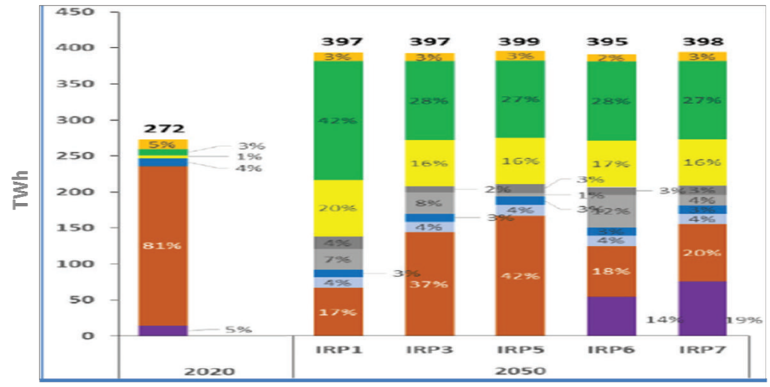
Nuclear Coal Hydro Import Hydro CCGT CC-GE OCGT PV Wind Others

*** Year 2017 Rands**

Figure 12: 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.					

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

*** Year 2017 Rands**

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

4.2 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. This is the case on the back of assumed electricity demand and or existing Eskom plant performance.
- 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 (updated plan).
- 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, cease to 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. This considered with the low degree of certainty of the assumptions post 2030 requires an in-depth analysis of the assumptions, technical and the economic implications of the electricity infrastructure development path choices for the period post 2030.

5. RECOMMENDED PLAN

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 is 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 are 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.

Applied policy adjustment and considerations in the final proposed plan are as follows:

- 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.
- Inclusion of 1000MW of coal-to-power in 2023–2024, based on two already procured and announced 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.
- Inclusion of 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 to partner with regional neighbours, The Project has the potential to energise and unlock regional industrialisation.

- Renewable energy technologies identified and endorsed for localisation and promotion will be enabled through Ministerial Determinations utilising the existing PV, Wind and Gas allocations in the IRP Update Table 7. Technologies reflected in Table 7 are therefore a proxy for technologies that provide similar technical characteristics at similar or less cost to the system. 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, is expected to consider the cost of new capacity, risks (technical, financial and operational) and value for money (economic benefits).
- Made annual allocations of 200MW for generation-for-own-use between 1MW to 10MW, starting in 2018. These allocations will not be discounted off the capacity allocations in the Table 7 initially, but will be considered during the issuing of Ministerial Determinations taking into account generation for own use filed with NERSA. See **Appendix E** for categories of plants included in these allocations.

With these adopted policy adjustments, the recommended updated Plan is as depicted in the table below. Associated price paths are discussed under **Appendix A**.

	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)
Embedded Generation Capacity (Generation for own use allocation)

Table 7: Proposed Updated Plan for the Period Ending 2030

The following must be noted with regard to the plan in Table 7 above:

- 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 earlier than previously assumed.
- Total installed generation for own use regardless of installed capacity is unknown as these installations were exempted from holding a generation license or were not required to be registered.
- The timing of new additional capacity as indicated in Table 7 can change (move back or forward) depending on what happens with the projected electricity demand and or Eskom's existing plant performance.

6. APPENDICES

6.1 APPENDIX A – DETAILED TECHNICAL AND COST ANALYSIS RESULTS

6.1.1 IRP Update Approach and Methodology

In accordance with assumptions discussed earlier in this IRP Update, there has been a number of developments and changes in the electricity sector since the promulgation of IRP 2010–2030, both domestically and in the international energy sector. These have impacted not only on the starting position of the IRP Update, but also on the expectation of future demand and supply options. These key changes can be summarised as follows:

- Additional generation capacity in the form of RE (REIPPP), baseload coal (Medupi and Kusile), pumped storage (Ingula) and gas peaking plants (Avon and Dedisa), has come on line.
- Domestic electricity demand is significantly lower than the expectation in 2010 because of the reduction in energy demand and a significant reduction in electricity intensity. The expectation of future demand has had to shift to account for these changes.
- The cost of some technology options has followed the trends expected in 2010 (especially the learning rates assumed) while others have not, requiring an update of the outlook concerning technology costs, as well as potential for new technologies and fuel.

The promulgated IRP 2010–2030 considered PPD as a GHG emission mitigation strategy, but there is now a proposal to apply carbon budget as a GHG mitigation strategy. PPD is based on annual celling for emissions whilst carbon budget is based on a periodic target.

The development of the reference case followed the process outlined in the Figure 1.

Following the 01 September 2017 announcement of the Minister of Energy regarding the signing of procured Independent Power Producer (IPP) projects, the consideration of Determinations was adjusted to include only procured projects up to Bid Window 4.

Following the development of the reference case, a number of scenarios was studied to understand the impact of key technical and policy inputs, specifically the low- and high-demand trajectories; the climate change mitigation strategies; the renewable build rate; and market-based gas prices.

Scenario analyses and observations were then used as input into the finalisation of the IRP Update.

6.1.2 Treatment of Ministerial Determinations issued in line with the Promulgated IRP 2010–2030

Taking into account changes in other key assumptions such as demand, the impact of Ministerial Determinations issued in line with the promulgated IRP 2010–2030 was tested with the utilisation of existing assets as an indicator of over- or under-capacity. Figure 14 depicts the process followed in the evaluation of the impact of Ministerial Determinations as contained in **Appendix B**.

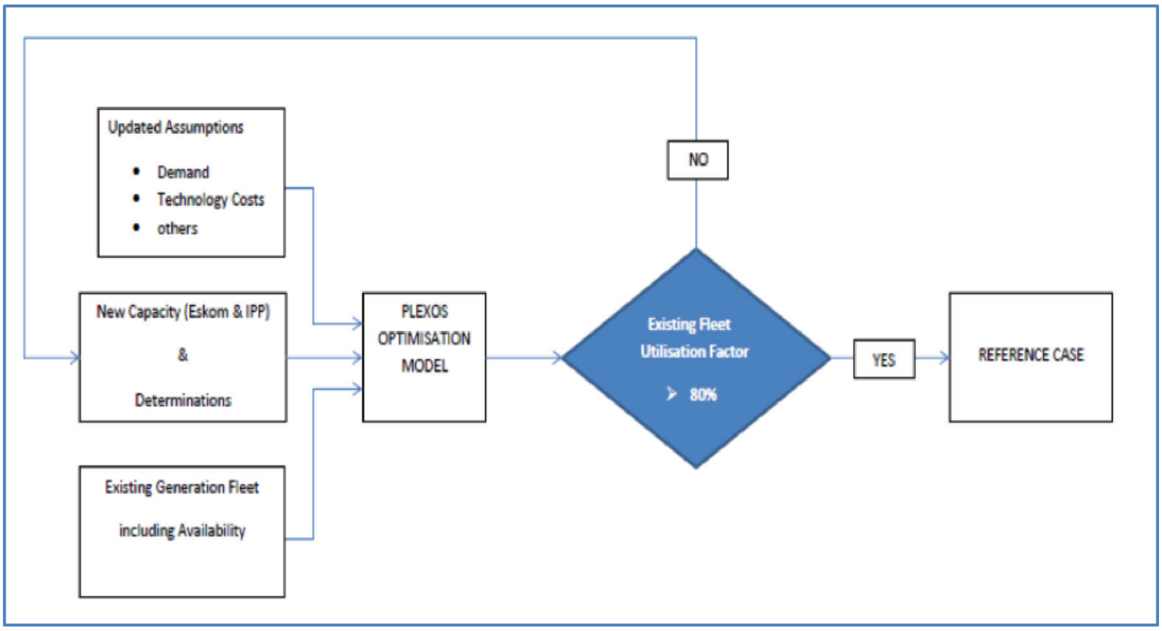


Figure 14: Ministerial Determinations Testing Process for the IRP Update Reference Case

To arrive at an acceptable utilisation factor and taking into account the latest demand forecast, the following scenarios relating to Ministerial Determinations issued under the promulgated IRP 2010–2030 were tested.

- The inclusion of all Ministerial Determinations with commissioning dates in line with the promulgated IRP 2010–2030.
- The inclusion of all Ministerial Determinations with commissioning dates updated to reflect the likely realistic date for commissioning.
- The inclusion of all Ministerial Determinations where requests for proposals had been issued or binding commercial process had commenced.

The test case with Ministerial Determinations where a request for proposal had been issued showed acceptable existing plant utilisation levels, which was an indication of reasonable supply-and-demand balance. This consideration regarding Determinations was then adopted for the reference case and subsequent scenario analyses.

Following the 01 September 2017 announcement of the Minister of Energy regarding the signing of procured IPP projects for Bid Windows 3.5 and 4, the consideration of Determinations was adjusted to include only procured projects up to Bid Window 4.

This was not a decision on Ministerial Determinations but a reference point. Full consideration of and decisions on issued Ministerial Determinations are included in the section on the policy adjustment stage later on in this document.

6.1.3 Scenario Analysis Results

The comparison of the scenarios in this section must be understood in the context of the drivers of the energy system and capacity requirements discussed later on in this document in sub-section 6.1.5.

Comparison of the results from the analysis of scenarios looks at the energy share, capacity share and the projected price path.

- **Observations from the Growth Scenarios**

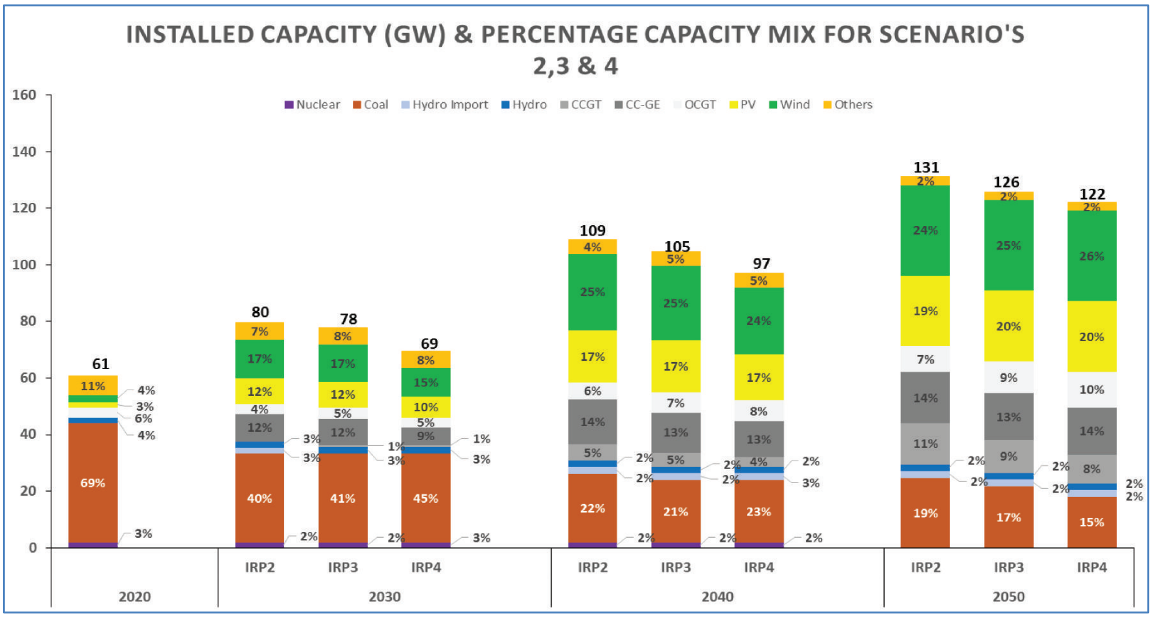


Figure 15: Installed Capacity (GW) for the High- (IRP2), Median- (IRP3) and Low-growth (IRP4) Scenarios

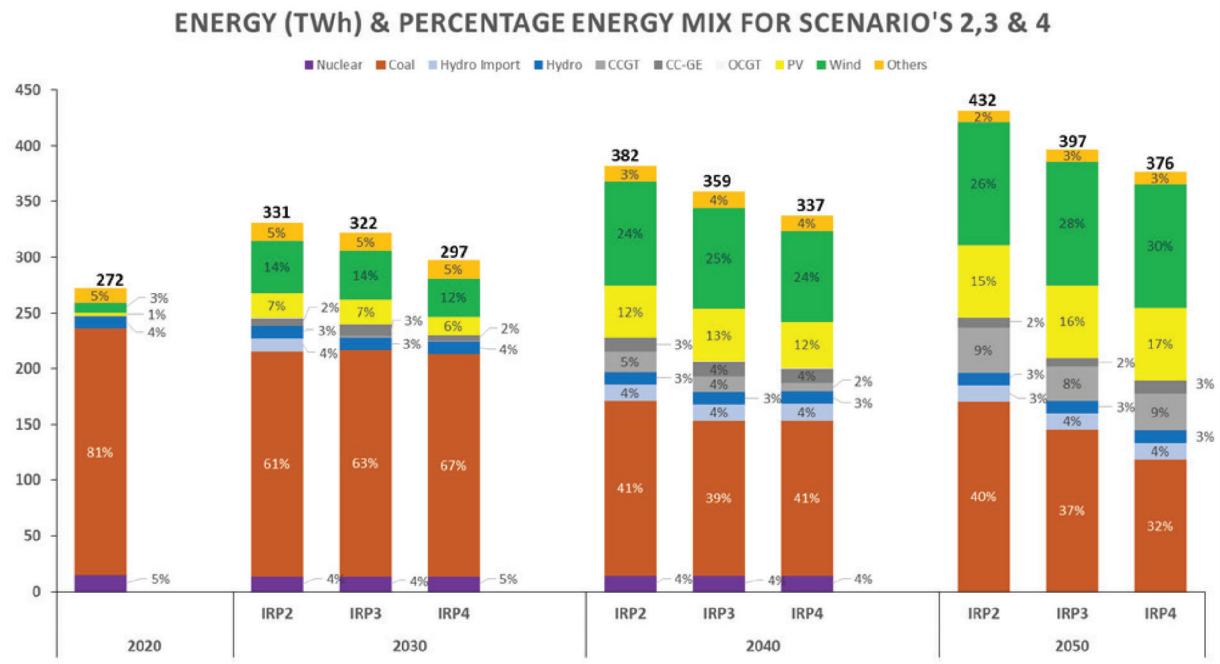


Figure 16: Consumed Energy (TWh) for the High- (IRP2), Median- (IRP3) and Low-growth (IRP4) Scenarios

Observations from the growth scenarios in line with Figure 15 and 16 can be summarised as follows:

- Period 2021–2030

  The energy and capacity mix between the three load-growth scenarios is fairly comparable for the period up to 2030. The share of coal reduces as power plants are decommissioned, with the share of renewables and gas increasing while maintaining the GHG emission constraints imposed.

  The high-growth scenario sees the full import of hydro capacity (2500 MW) coming on line earlier than 2030, compared with 1000 MW for the median-growth and nothing for the low-growth scenarios.

- Period 2031–2040

  The energy and capacity mix remains fairly comparable for the three load-growth scenarios.

  The new capacity continues to be dominated by RE and gas.

- Period 2041–2050

  For this period, the energy and capacity mix also remains similar for the three load-growth scenarios.

  The new capacity continues to be dominated by RE and gas.

  A significant change in this period, which is applicable to all scenarios, is the assumed decommissioning of the Koeberg nuclear plant. Renewables and gas are now the dominant energy suppliers in the mix, with 25% of energy coming from wind power.

- **Observations from Key Input Scenarios**

Figure 17 provides a graphical representation of the key input energy (TWh) scenarios and capacity outputs (GW).

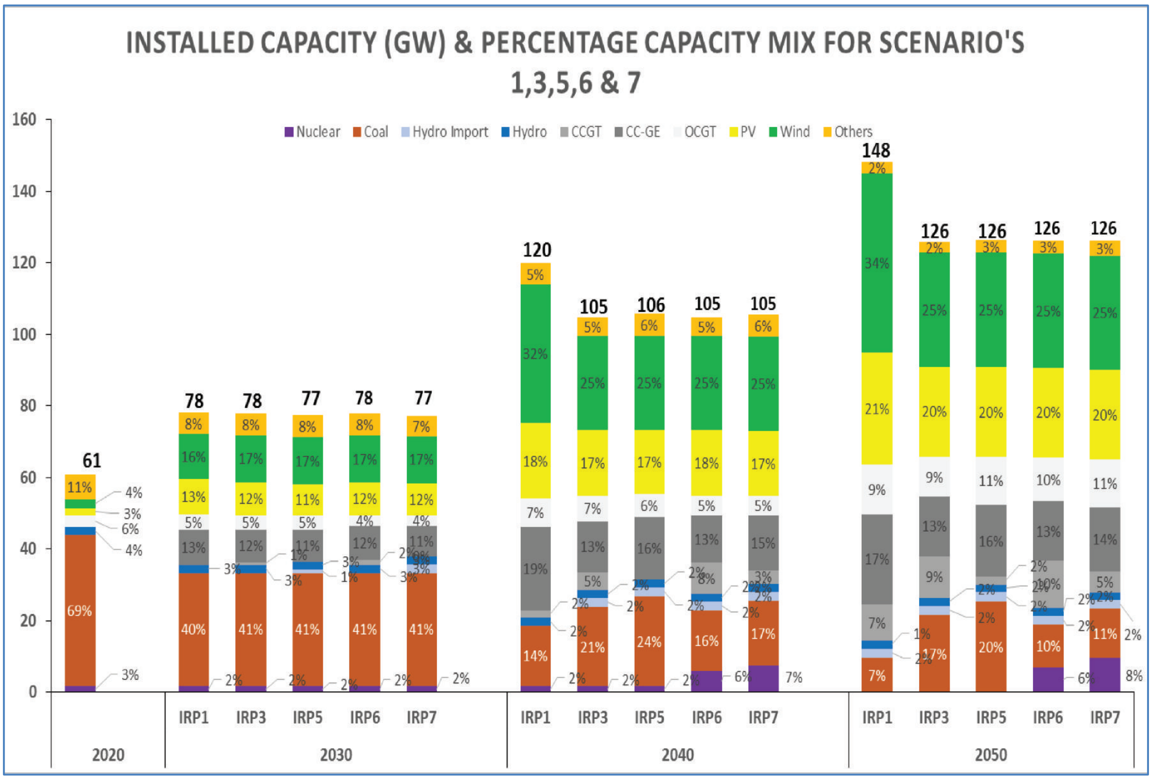


Figure 17: Installed Capacity (GW) for the No RE Annual Build Rate (IRP1), Median-growth (IRP3), Market-linked Gas Price (IRP5), Carbon Budget (IRP6) and Carbon Budget plus Market-linked Gas Price (IRP7) Scenarios

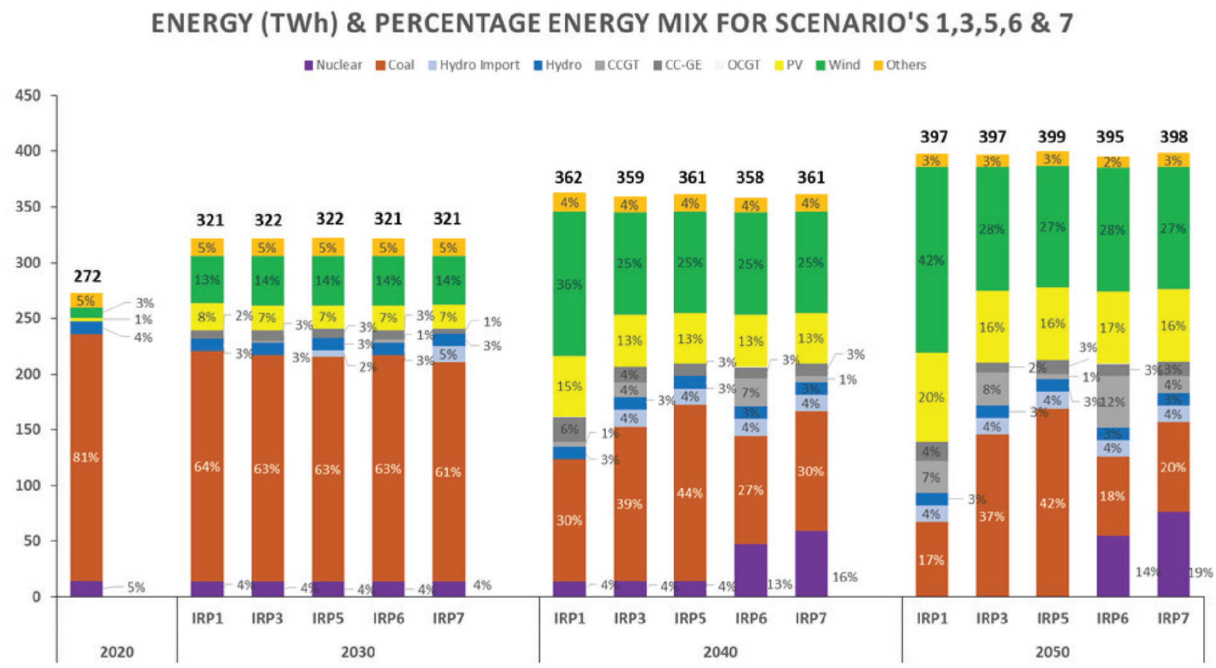


Figure 18: Consumed Energy (TWh) for the No RE Annual Build Rate (IRP1), Median-growth (IRP3), Market-linked Gas Price (IRP5), Carbon Budget (IRP6) and Carbon Budget plus Market-linked Gas Price (IRP7) Scenarios

Observations from the key input scenarios from Figure 17 and 18 can be summarised as follows:

- Period 2021–2030

  The energy and capacity mix between the three load-growth scenarios is fairly comparable for the period up to 2030. The share of coal reduces as power plants are decommissioned, with the share of renewables and gas increasing in adherence to the GHG emission constraints imposed.

  The application of the market-linked gas price scenario combined with carbon budget as a GHG emission constraint (IRP7) sees the full import of hydro capacity (2500 MW) coming on line earlier than 2030 compared with 1000 MW for the market-linked gas price scenario (IRP5). Higher gas prices and stringent carbon emission limits could be the reason for full hydro capacity and the slight increase in renewables.

The share of renewables and gas in the energy mix is fairly similar among all options, including the scenario without annual build limits, the reason being that a combination of these technologies is best suited for load following.

Imposing annual build limits does not disadvantage renewables for the period ending 2030. It can therefore be concluded that varying input assumptions do not materially alter the energy mix for this period.

- Period 2031–2040

This period sees the installed capacity from renewables and gas increasing to just over double that of the period up to 2030. The scenario comprising removal of annual build limits on renewables sees renewables and gas capacity tripling.

The reference case (IRP3), the market-linked gas price (IRP5) and the carbon budget plus market-linked gas price (IRP7) scenarios commission new coal capacity of about 5250 MW, 8250 MW and 1500 MW, respectively. The carbon budget GHG emission mitigation strategy and the removal of annual build limits on renewables imply that no new coal units will be commissioned up to 2040.

The carbon budget (IRP6) and carbon budget plus market-linked gas price (IRP7) scenarios commission additional nuclear capacity of about 4200 MW and 5600 MW, respectively.

From an energy-production perspective, the contribution of coal to energy produced is significantly reduced compared with the reference case (IRP3) – from about 60% in the 2021–2030 period to about 30% in this period, with corresponding installed capacity sitting at about 18% *versus* 40% in the previous study period.

- Period 2040–2050

All scenarios indicate a complete transition from the capacity and energy mix of today. Installed capacity will be mainly from renewables and gas with coal and nuclear making up less than 50% of the mix.

The no RE annual build rate (IRP1) scenario leads to a path where more than 90% of installed capacity will be from renewables and gas by 2050, with coal under 10%. More than 80% of the energy produced will be from renewables and gas.

The carbon budget (IRP6) and carbon budget plus market-linked gas price (IRP7) scenarios are the only scenarios with a higher share of coal and nuclear in energy produced.

6.1.4 Least Cost Plan Capacity by year 2030

Table 7 and Table 8 below show Least Cost Plan capacities by year 2030.

Year	PV	Wind	Gas (CCGT/CC-GE/OCGT)	Landfill Gas
2020				
2021				
2022				
2023				
2024				
2025			2380	
2026			750	250
2027	2290		1480	
2028	1640	2500	2200	
2029	2180	2800	2200	
2030	1710	3700	1930	
TOTAL	7820	9000	10940	250

Table 7: Capacities for Least Cost Plan (IRP1) by Year 2030

Year	PV	Wind	Gas (CCGT/CC-GE/OCGT)	Landfill Gas
2020				
2021				
2022				
2023				
2024	1000			
2025	1000	1600		
2026	1000	1600	2380	
2027	1000	1600	1650	
2028	1000	1600	1950	
2029	1000	1600	3000	250
2030	1000	1600	1800	
TOTAL	7000	9600	10780	250

Table 8: Capacities for Least Cost Plan by Year 2030 with Annual Build Limits on RE (IRP3)

6.1.5 Scenario Analysis of 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.

Figure 19 below shows the comparative tariff projections for each of the five input scenarios and Figure 0 shows the cumulative difference between the scenarios[8] by 2030.

[8] 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.

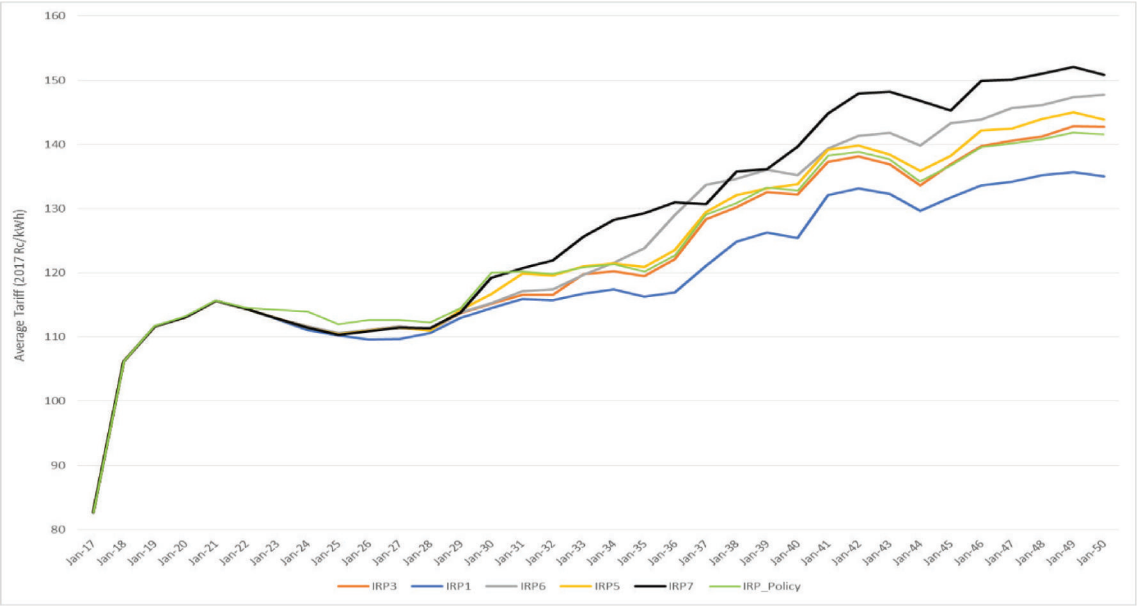


Figure 19: Comparison of Tariffs for the Scenarios in 2017 (Cents per Kilowatt Hour)

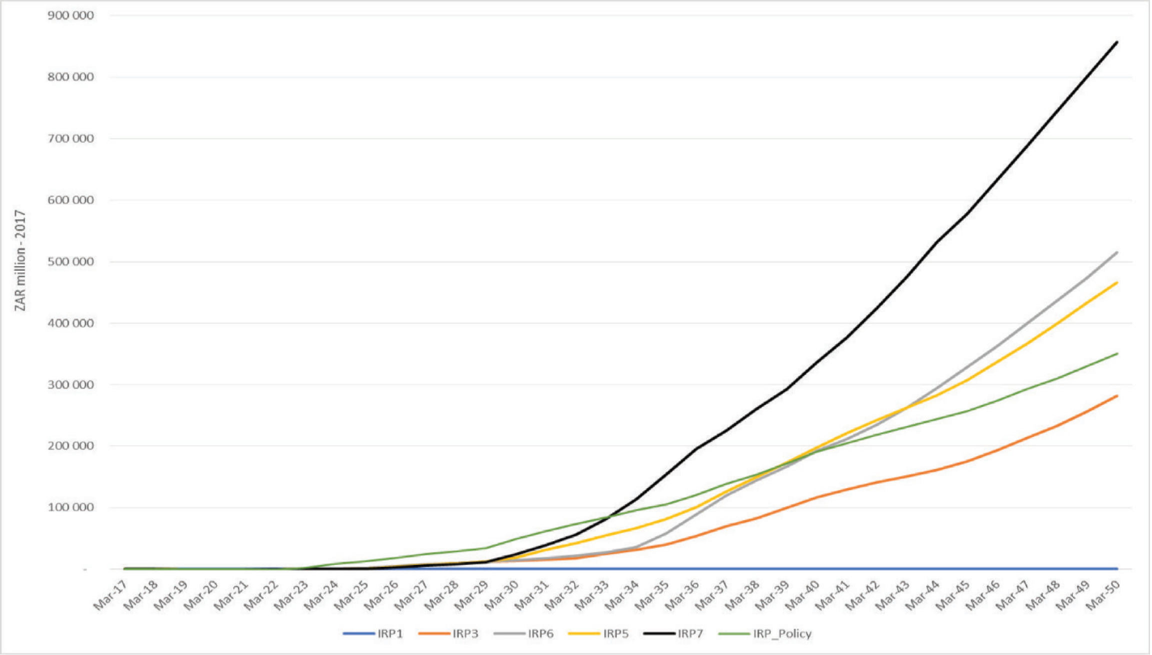


Figure 20: Cumulative Comparison of Tariff Paths for the Scenarios

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.

6.1.6 Additional Analysis of and Observations concerning the Scenarios

- **Drivers of new capacity**

The capacity potentially installed by 2020 is used as a departure point. The capacity step change from 2020 to 2030 is mainly as a result of increasing load growth, new capacity resulting from Ministerial Determinations and Eskom new build and decommissioning of existing plants, as illustrated in Figure . Different technology types provide different requirements for the system.

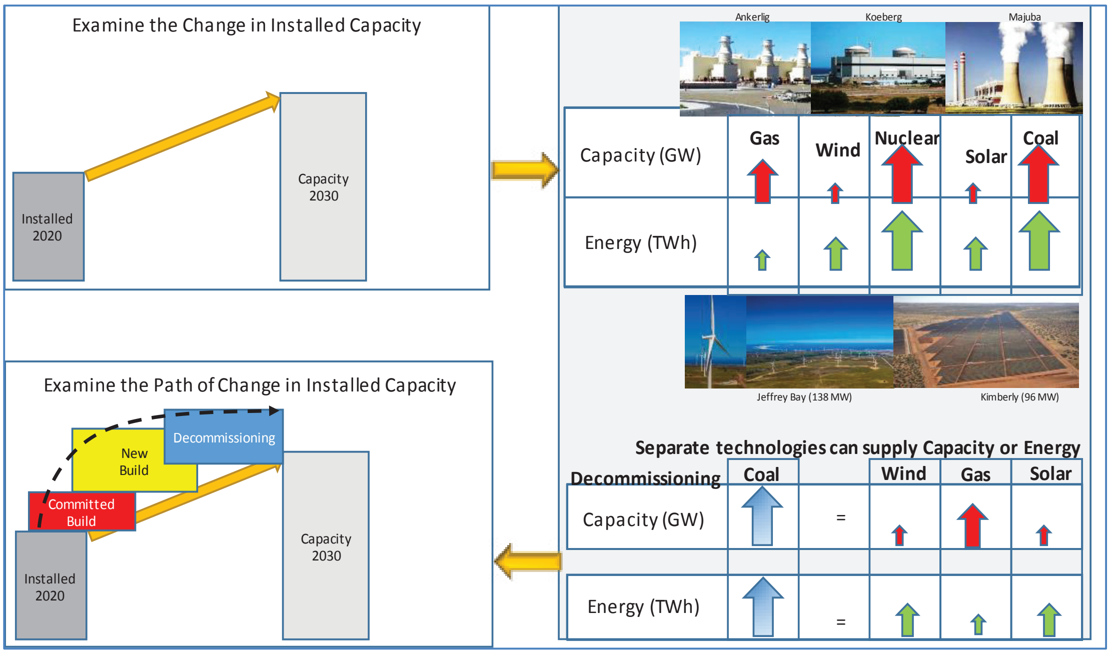


Figure 21: Change in Installed Capacity

Figure below is an illustration of both system-generic capacity and energy requirement drivers. The additional capacity and energy requirements are contrasted against increase in demand *versus* decommissioning of the existing fleet. Up to the end of the first decade (2030), the new capacity requirement is driven primarily by the decommissioning of existing coal-fired plants. The total installed capacity around 2020 will be about 50 GW. Assuming there will be no commissioning of new plants or decommissioning of existing plants, the earliest need for new capacity will be post 2030, based on high load growth. With decommissioning in line with the information in **Appendix B,** the earliest need for new capacity will be around 2025. This is a clear indication that the new capacity requirement driver in this decade will be decommissioning.

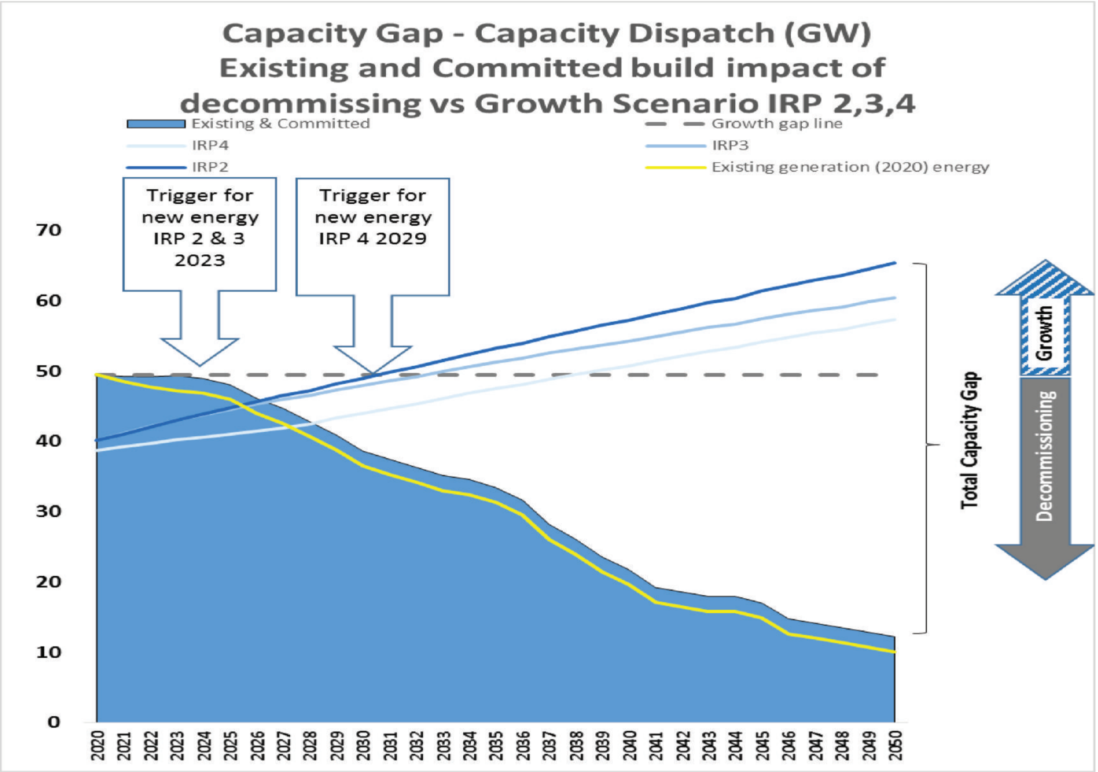


Figure 22: Illustration of Capacity and Energy Driver

- **New Build Capacity per Decade**

  Figure 19 to 25 show new build capacity across the five scenarios during the study period. Only the market-linked gas price and the combination of carbon budget and market-linked gas price scenarios introduce imported hydro capacity by 2030.

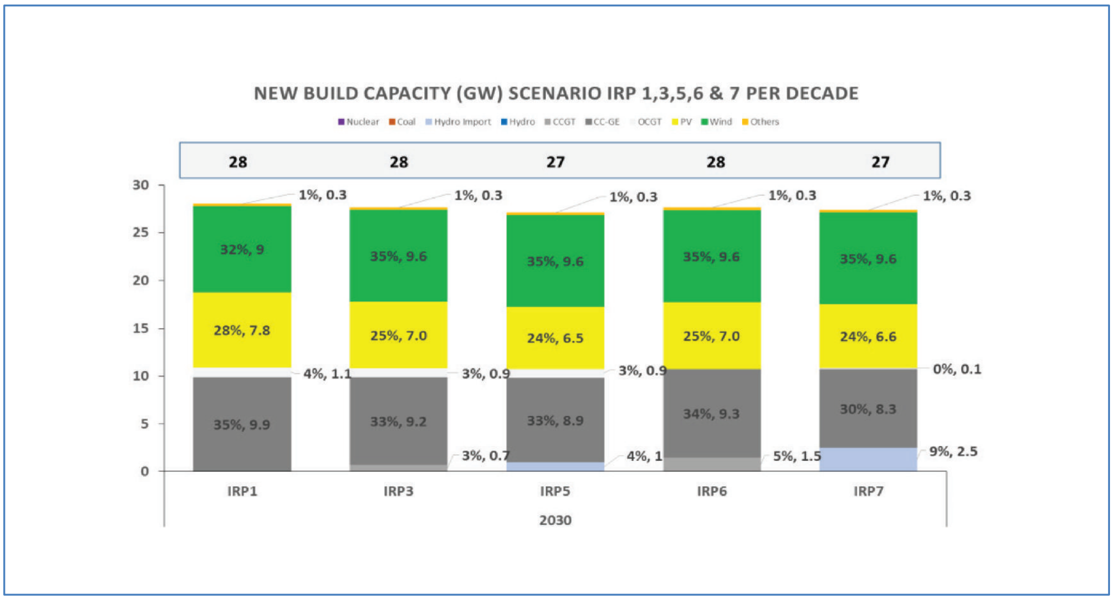


Figure 19: New Build Capacity for the Period Ending 2030

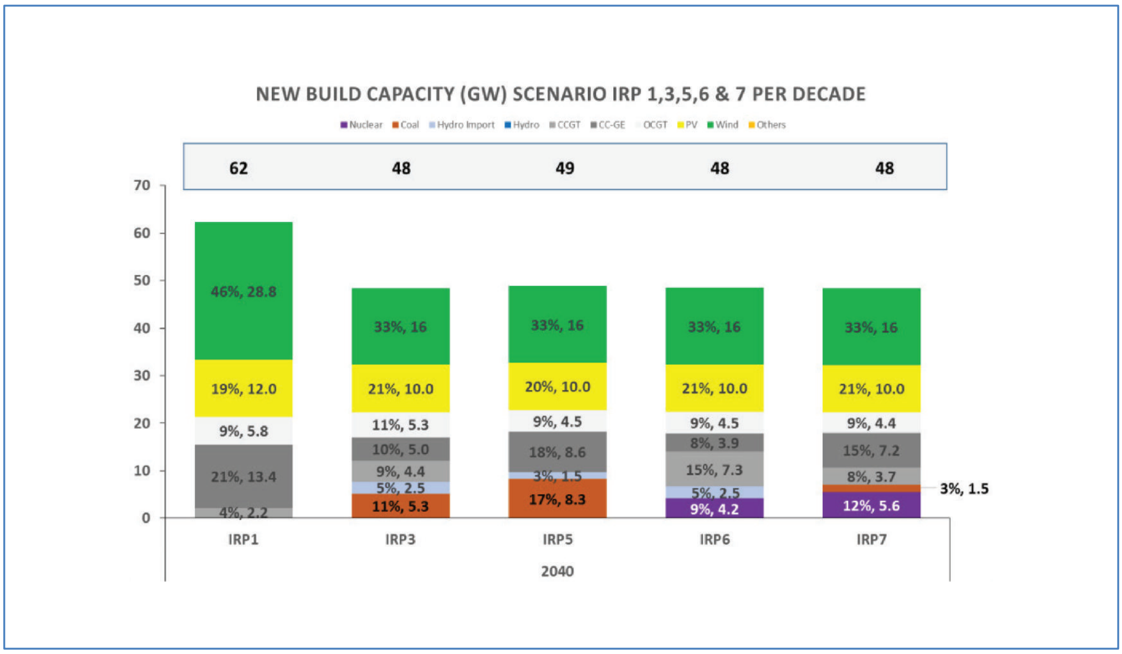


Figure 24: New Build Capacity for the Period 2031–2040

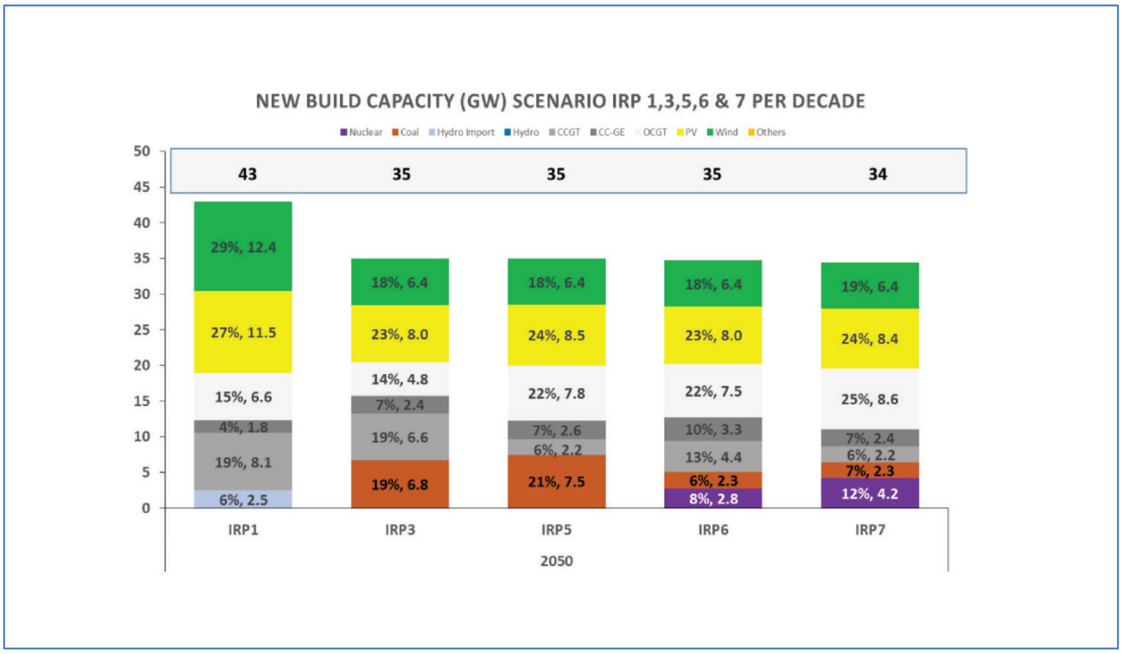


Figure 25: New Build Capacity for the Period 2041–2050

6.2 APPENDIX B – INSTALLED CAPACITY, MINISTERIAL DETERMINATIONS AND DECOMISSIONING SCHEDULE

6.2.1 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	Dec 2018	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

6.2.2 Eskom Generators

Table 9: Eskom Generators as at 01 September 2017

Power station capacities at 01 September 2017

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
Generation Group power stations					
Base-load stations					
Coal-fired (14)				**40 141**	**37 878**
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 [6]	Emalahleni	Aug 1980 to Feb 1984	6x600	3 600	3 450
Grootvlei [1]	Balfour	Apr 2008 to Mar 2011	4x200; 2x190	1 180	1 120
Hendrina [2]	Middelburg	May 1970 to Dec 1976	4x200; 3x195; 2x170; 1x168	1 893	1 793
Kendal [3]	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
Lethabo	Vereeniging	Dec 1985 to Dec 1990	6x618	3 708	3 558
Majuba [3]	Volksrust	Apr 1996 to Apr 2001	3x657; 3x713	4 110	3 843
Matimba [3]	Lephalale	Dec 1987 to Oct 1991	6x665	3 990	3 690
Matla	Bethal	Sep 1979 to Jul 1983	6x600	3 600	3 450
Tutuka	Standerton	Jun 1985 to Jun 1990	6x609	3 654	3 510
Kusile [3]	Ogies	Aug 2017 to	*6x800*	799	720
Medupi [3]	Lephalale	Aug 2015 to	*6x794*	1 588	1 437
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) [4]				**2 732**	**2 724**
Drakensberg	Bergville	Jun 1981 to Apr 1982	4x250	1 000	1 000
Palmiet	Grabouw	Apr 1988 to May 1988	2x200	400	400
Ingula	Ladysmith	June 2016 to Feb 2017	4x333	1 332	1 324
Hydroelectric stations (2) [5]				**600**	**600**
Gariep	Norvalspont	Sep 1971 to Mar 1976	4x90	360	360
Vanderkloof	Petrusville	Jan 1977 to Feb 1977	2x120	240	240
Total Generation Group power station capacities (24)				**47 839**	**45 471**
					45 471
Renewables power stations					
Wind energy (1)					
Sere	Vredenburg	Mar 2015	46x2.2	**100**	**100**
Solar energy					
Concentrating solar power	*Upington*	*Under construction*	*100*	–	–
Other hydroelectric stations (4)				**61**	**61**
Colley Wobbles	Mbashe River		3x14	42	42
First Falls	Umtata River		2x3	6	6
Ncora	Ncora River		2x0.4; 1x1.3	2	2
Second Falls	Umtata River		2x5.5	11	11
Total Renewables power station capacities (5)				**161**	**161**
Total Eskom power station capacities (29)				**48 000**	**45 632**
Available nominal capacity - Eskom owned					**95.07%**
IPP capacity					
Hydroelectric energy					
Wind energy					
Solar energy					
Gas/liquid fuel energy					
Total nominal capacity available to the grid - Eskom and IPPs					**45 632**

1. Former moth-balled power stations that have been returned to service. The original commissioning dates were:
   Komati was originally commissioned between Nov 1961 and Mar 1966.
   Camden was originally commissioned between Aug 1967 and Sep 1969.
   Grootvlei was originally commissioned between Jun 1969 and Nov 1977.
2. Due to technical constraints, some coal-fired units at these stations have been de-rated.
3. Dry-cooled unit specifications based on design back-pressure and ambient air temperature.
4. Pumped storage facilities are net users of electricity. Water is pumped during off-peak periods so that electricity can be generated during peak periods.
5. Use restricted to periods of peak demand, dependant on the availability of water in the Gariep and Vanderkloof dams.
6. Duvha unit 3 is under extended temporary inoperability.

6.2.3 Ministerial Determinations issued in line with the IRP 2010–2030

The table below outlines Ministerial Determinations together with their status as at 30 September 2016.

Table 10: Summary of Ministerial Determinations issued in line with the IRP 2010–2030

Programme	**Applicable S 34 Ministerial Determination**	**Status (as at 30 Sep 2017)**
RE	Determination dated 11 August 2011 – **3725 MW** (including 100 MW for small projects)	**3772.04 MW** in commercial operation.
RE	Determination dated 19 December 2012 – **3200 W** (including 100 MW for small projects)	
RE	Determination dated 18 August 2015 – **6300 MW** (including 200 MW for small projects)	
Co-generation	Determination dated 19 December 2012 - **800 MW** Determination dated 18 August 2015 – **1000 MW**	**11.5 MW** procured No contracts signed
Nuclear	Determination dated 17 December 2013 and Revised Determination dated 05 December 2016 – **9600 MW**	Not yet implemented
Gas/Diesel peaking plants	Determination dated 25 May 2012 – **1020 MW**	**1005 MW** in commercial operation.
Coal Baseload IPP Programme (domestic)	Determination dated 19 December 2012 - **2500 MW**	**900 MW** procured No contracts signed
Coal Baseload IPP Programme (cross border)	Determination dated 20 April 2016 – **3750 MW**	Not yet implemented
Gas (including CCGT/natural gas) and OCGT/diesel	Determination dated 18 August 2015 – **3126 MW**	Not yet implemented
Additional gas	Determination dated 27 May 2016 – **600 MW**	Not yet implemented
Hydro (imported hydro)	Determination dated 19 December 2012 – **2609 MW**	Treaty signed with DRC for **2500 MW**
Solar park	Determination dated 27 May 2016 – **1500 MW**	Not yet implemented
Ankerlig Diesel (Eskom backup for Koeberg)	Determination dated 27 May 2016 – **100 MW**	Construction not started

6.2.4 Emission Abatement Retrofit Programme and 50-year Life Decommissioning

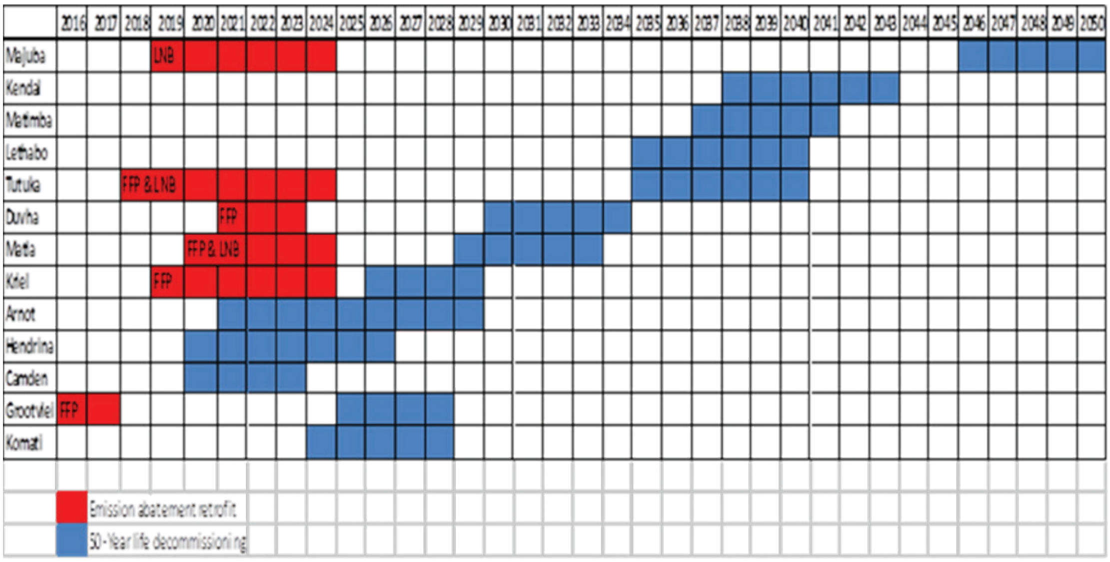


Figure 26: Emission Abatement Retrofit Programme and 50-year Life Decommissioning

6.2.5 Detailed Decommissioning Analysis

- **Coal Decommissioning**

The full impact of decommissioning the existing Eskom fleet was not fully studied in the IRP Update. This includes the full costs related to coal and nuclear decommissioning and waste management. The impact of security of supply *versus* de-carbonization of the economy is something that must be understood fully and requires comprehensive investigation.

Figure 27 below depicts decommissioning of coal-fired plants over the IRP Update planning period.

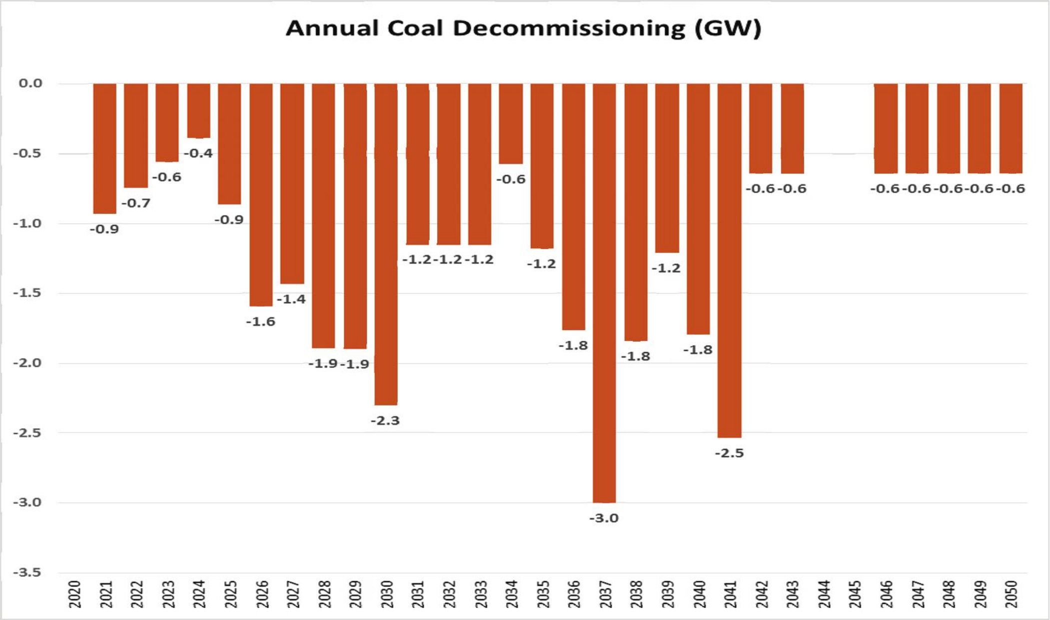


Figure 27: Annual Existing Coal Decommissioning

It is evident that close to 75% (just under 30 GW) of the current Eskom coal fleet would have reached end-of-life by 2040.

- **Nuclear Decommissioning**

Eskom's existing nuclear power station (Koeberg) is expected to reach end-of-life by mid- to late 2040, based on a normal 60-year lifespan. This is discounting the envisaged steam generator replacement that is expected to extend Koeberg's life by an additional 20 years. Figure 28 below reflects Koeberg's annual decommissioning.

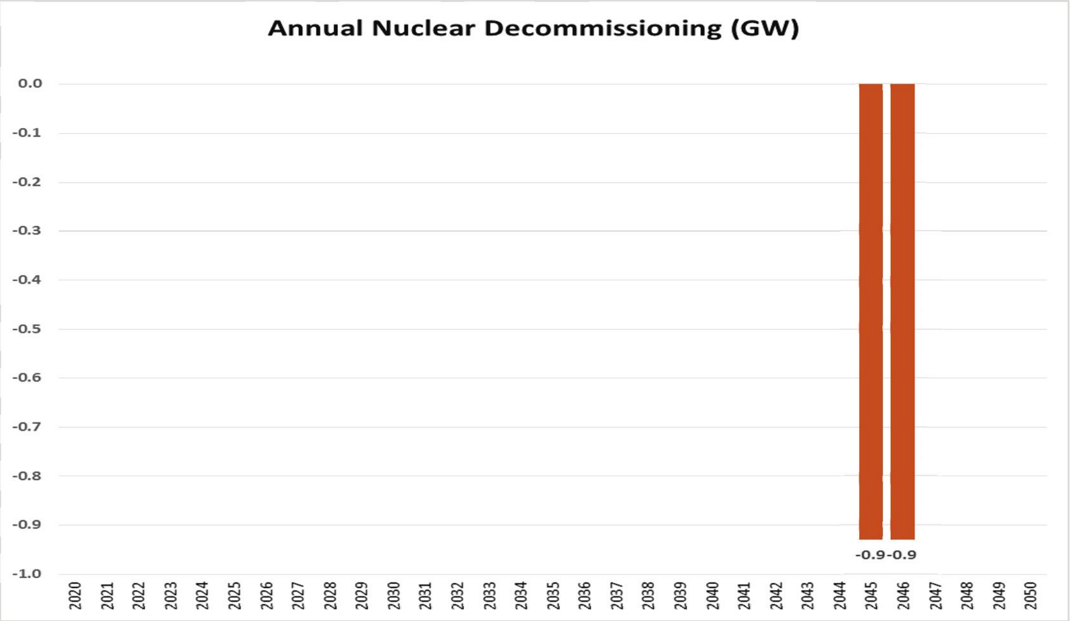


Figure 28: Annual Nuclear Decommissioning

Fifty per cent of Eskom's nuclear power plant will reach end-of-life by 2045 and the balance by 2047.

- **OCGT Decommissioning**

  Current OCGT plants in South Africa are operating on diesel and about 3GW is expected to be decommissioned by 2025 as depicted in Figure 29.

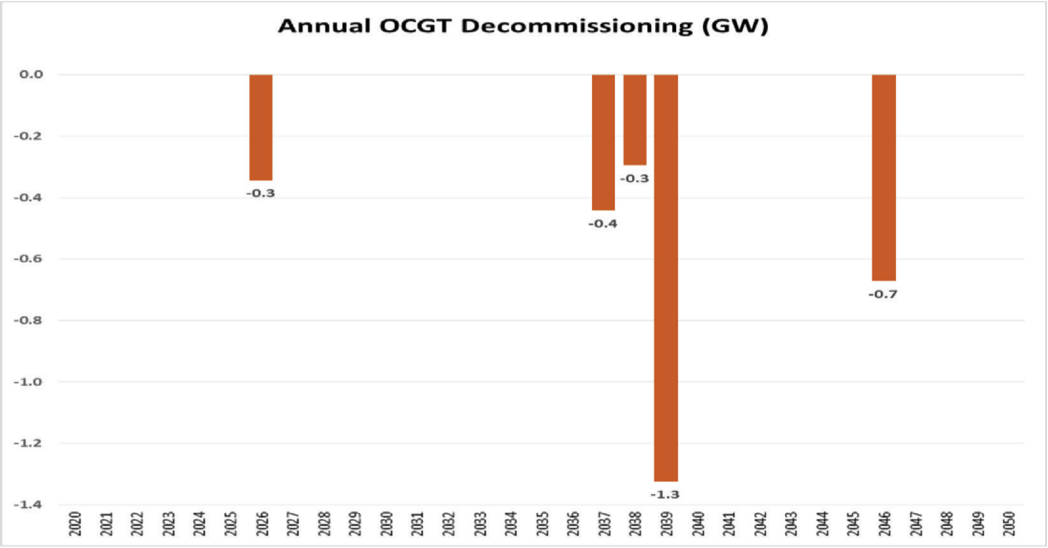


Figure 29: Annual OCGT Decommissioning

- **Wind Decommissioning**

Figure 30 reflects annual wind capacity decommissioning. Wind capacity signed under REIPP Bid Window 1 will be decommissioned by 2035.

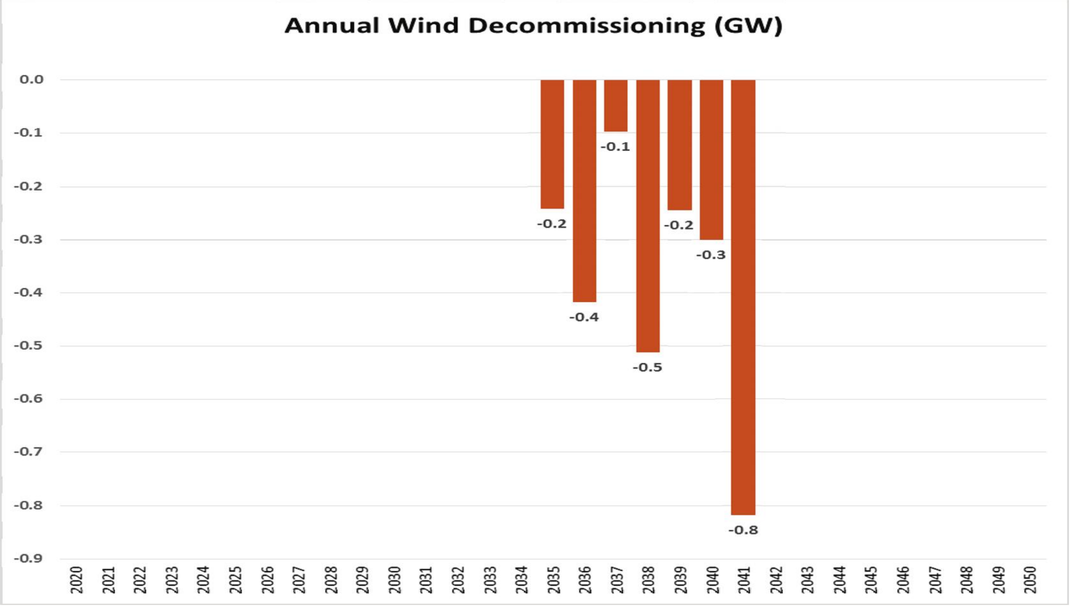


Figure 30: Annual Wind Capacity Decommissioning (GW)

- **PV Decommissioning**

Figure 31 shows solar PV capacity decommissioning. Close to 1GW of PV capacity will be decommissioned by 2040.

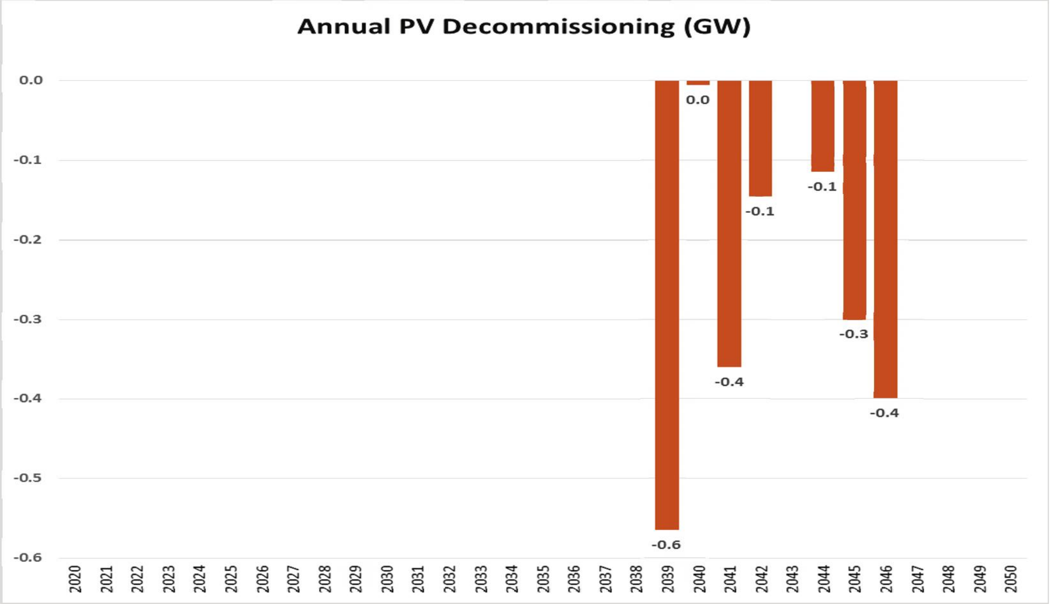


Figure 31: Annual PV Capacity Decommissioning (GW)

- **Total Generation Decommissioning**

Figure 32 depicts the total annual capacity decommissioning by plant type up to 2050. It is important to take note of the total capacity that will be decommissioned by 2041.

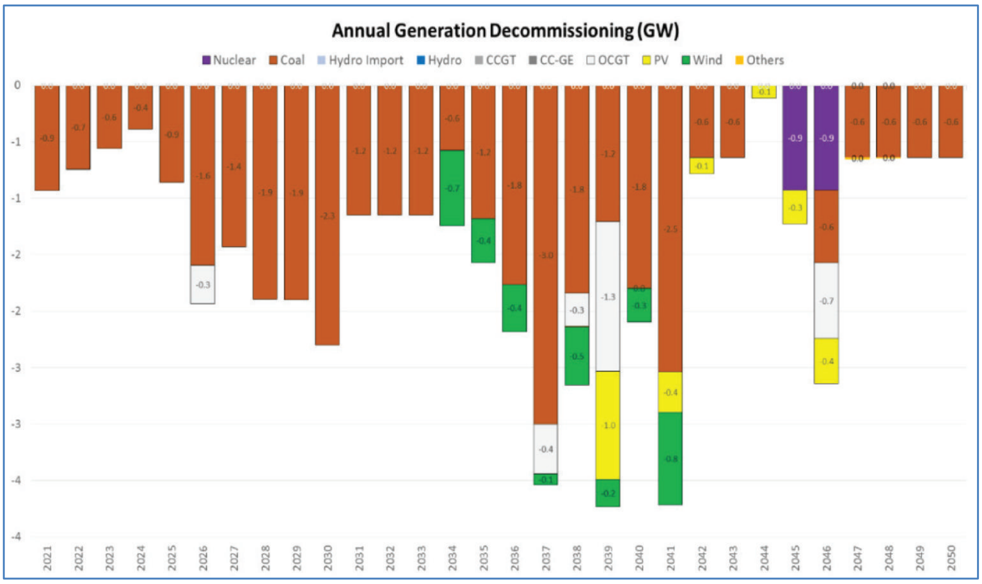


Figure 32: Annual Total Capacity Decommissioning (GW)

Figure 33 depicts the total cumulative capacity decommissioned by 2050 and the total cumulative capacity decommissioned per decade.

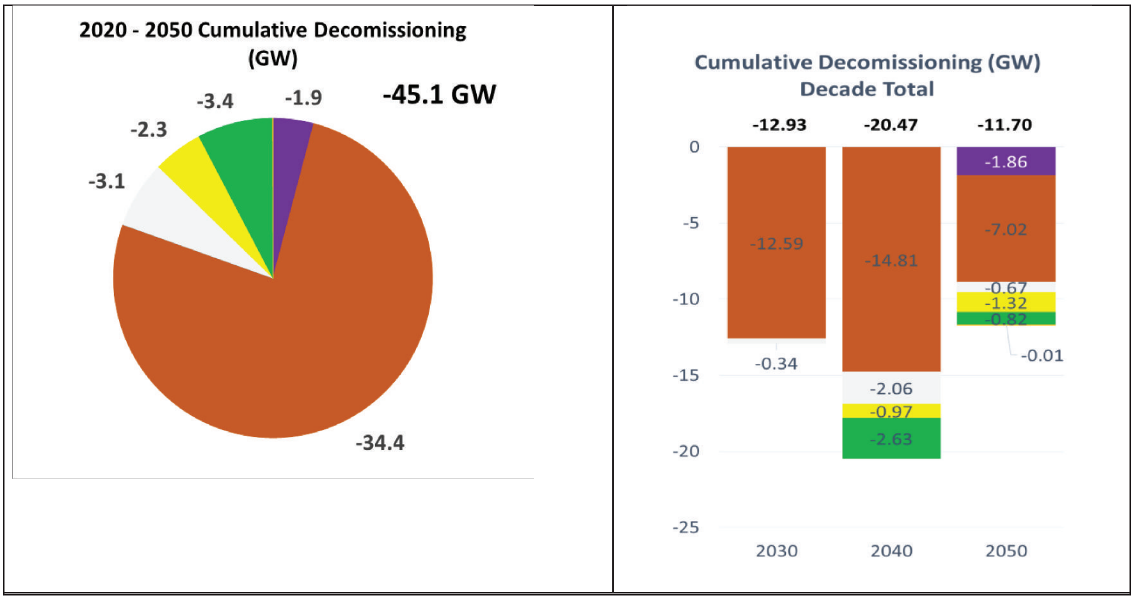


Figure 33: Annual Wind Capacity Decommissioning (GW)

6.3 APPENDIX C – RISKS

The IRP Update increases the exposure to imported commodities (gas) and electricity (regional hydro), but reduces the risk of coal price increases. The current average coal price reflects the historic cost-plus pricing for the local power market, whereas a stronger link to global coal prices is expected in future.

The following risks have been identified in relation to the IRP Update:

- **Demand Forecast**
  The risk is that actual demand may turn out to be lower or higher than forecasted. Current indications are that demand is more likely to be lower than forecasted as a result of increasing grid electricity prices, grid deflections and a move to substitutes such as LPG. It is therefore safe to assume the effect would be limited to over-investment in capacity, without any risk concerning general security of supply. This can be mitigated by managing the pace and scale of new capacity implementation through regular reviews of the IRP.

- **Technology Costs**
  If any of the assumed technology costs should turn out to be higher than assumed, the expected price of electricity could increase. Similarly, should the costs of some of the technologies be lower than assumed, the plan will not be the least-cost plan. As in the case of demand, this risk can be mitigated by managing the pace and scale of new capacity implementation through regular reviews of the IRP. Instituting feasibility studies to inform any procurement in line with New Generations Regulations will also help mitigate against this risk.

- **Existing Plant Performance**
  If the performance of existing Eskom coal plants does not improve to the levels assumed, there will be an increase in the total costs because other plants such as diesel or gas plants will have to be run to make up for the shortfall. This can be mitigated by implementing a threshold and monitoring plant performance trends for decisions. In the short term, emergency power will have to be

procured, as was the case in the past. In the long run this will imply accelerating or bringing forward capacity proposed in the plan.

- **Variable Capacity from Renewable Sources impacting on System Security and Stability**
  At low levels of penetration, fluctuating renewable capacity will have only marginal impact on the system. However, considering the South African energy generation mix and demand profile, there is a point at which an isolated system would have to make adjustments to system and network operations if not configured to cater for the variability of this capacity. The level at which this will become necessary is still being debated and additional research will be required before it can be identified for inclusion in the next IRP version.

- **Fuel Costs**
  - South Africa has generally been in the very privileged position of having access to coal that is priced well below world-market prices and locked in via long-term contracts. Based on Eskom's coal procurement, indications are that this is no longer the case. However, the coal IPP procurement prices indicate that Eskom's current situation is not necessarily a trend and therefore there is still space for Power Purchase Agreements based on long-term coal price certainty.
  - The risk associated with increasing gas volumes to support RE is real unless gas becomes available locally. Exposure to currency fluctuations and the impact of that on electricity prices must be assessed and understood prior to any commitment. The importation of gas and the impact of that on the balance of payments must also be assessed.

- **Import hydro options**
  The main risks associated with import hydro options are delays in the construction of both the necessary grid extension and the power plants themselves. There is also a cost risk in that the assumptions used in the IRP Update are based on a 'desktop study' and do not reflect any commitment on the part of potential developers.

6.4 APPENDIX D – INPUT FROM PUBLIC CONSULTATIONS ON THE ASSUMPTIONS

The DoE undertook public consultations on input assumptions from 07 December 2016 to 31 March 2017. Consultations included presentations as well as written submissions. Bilateral discussions at the request of organisations such as Business Unity South Africa and the South African Banking Association also took place.

The consultation statistics can be summarised as follows:

- From December 2016 to February 2017, nine public workshops were held in nine provinces.
- In total, 63 public presentations were made during the workshops.
- In total, 640 people attended the workshops.
- In total, 190 comments were received via 115 submissions. These comprised:
  - 89 submissions from companies, including government departments and entities; and
  - 26 submissions from private individuals.

Addressing Public Comments

Comments received from the public varied from opinion statements to substantive inputs with supporting data. Most opinion statements were in support of a least-cost plan, which is mainly based on RE as presented by the CSIR.

Substantive comments received during the workshops, as well as written submissions, can be grouped into the following categories:

- Policy and process
- Assumptions
  - Demand forecast
  - Technology costs
  - Exchange rate
  - Demand-side options
- Preliminary base case

- Constraints on RE
- Missing technologies
- Treatment of Determinations already issued by the Minister of Energy
- Price path

The following issues were raised under each category:

- **Policy and process**

  - The start of the consultation process, namely December 2016, was critisised. This was resolved by the DoE agreeing to extend the closing date for written comments from 26 February 2017 to 31 March 2017.
  - The link between the IRP and Integrated Energy Plan (IEP) and which one comes first. It was explained to the pubic that the IEP does not necessarily come first and that the two plans feed into each other.

- **Assumptions**

  - Demand forecast

    Concerns and comments raised about the electricity demand forecast were that the forecast was outdated and that it did not take into account current GDP projections and declining electricity consumption. The critism was correctly placed, since the forecast had been developed in March 2015, while the consultations started in December 2016.

    The demand forecast has since been revised to reflect actual 2016 electricity consumption as a starting point. The relationship between GDP, electricity growth and electricity intensity has also been detailed in the detailed demand-forecast report.

  - Technology costs

    Concerns and comments on technology costs were mainly around the publication of the cost-assumptions report used to come up with the nuclear overnight capital costs and the DoE's use of average cost from Bid

Window 1 to Bid Window 3.5 instead of the average cost from Bid Window 4 expedited.

The Ingerop Report to determine nuclear costs has since been published.

With regard to costs relevant to RE, revised costs based on average costs from Bid Window 4 expedited are now being used.

The EPRI report, which forms the basis for all other costs, was revised with the latest costs and the exchange rate has been pegged at January 2017.

- Exchange rate

  During the first public workshop in December 2016, there was general outcry about the use of R11.55 to $1(USD), instead of the prevailing December 2016 rate of R16 to a $1.

  The Update uses R13.57 to $1, which is the January 2017 average exchange rate.

  Scenario analysis is a comparative excersice and the exchange rate affects all scenarios almost equally. The impact of exchange rate comes in when developing the final price path, which may be used as an indication of future tariffs, especially in the short term.

- Demand-side options

  Issues raised on the demand side included energy efficiency, embedded generation and fuel switching. The general comments were around the need to incorporate these into future plans and to test them as scenarios.

  Because of limited or lack of data to develop credible assumptions, the issues above were considered as potential drivers for low demand in the IRP Update. The assumption was that the impact of these would be lower demand with reference to the median forecast demand projection.

- **Preliminary Base Case**

  In planning studies, a base case can be defined as a reference case or starting point. In the case of the IRP Update, a preliminary base case was developed, based on the assumptions the DoE had compiled. It was called a preliminary base case because the assumptions were still subject to public comment and adjusment. While the preliminary base case was published to provide context to the assumptions, the general public focused more on the reference case than on the assumptions.

  The main issues raised in relation to the preliminary base case included the following:

  - Constraints on RE

    As this is an IRP Update, certain considerations from the IRP 2010 were maintained in the preliminary base case, with the understanding that they may have to be reviewed during scenario analysis. The promulgated IRP 2010–2030 imposed 1000 MW and 1600 MW annual build limits on PV and wind power, respectively. These limits were imposed to minimize the exposure to risk associated with delays in these projects resulting from circumstances unknown at the time of planning or implementation, as well as technology glitches, since the technology was new in South Africa.

    The concern was that the DoE, in taking this approach, was trying to make a case for nuclear and it was suggested that the limits should be completely removed.

    As explained in the IRP Update, detailed studies indicated that that concern was unfounded, since there is a marginal difference in the amount of RE and gas required when annual build limits are imposed or relaxed.

- Missing technologies

  A number of associations and project developers raised concern about the fact that the technologies they were developing or investing in did not appear on the preliminary base case results. These include CSP, biomass, fuel cells and others.

  This concern is addressed through a policy position in the IRP Update. The position is that all new technologies identified and endorsed for localisation will be enabled through determinations utilising existing allocations.

- Treatment of Determinations already issued by the Minister of Energy

  Questions were raised about the Ministerial Determinations issued based on the promulgated IRP 2010–2030. These were the first considerations when the IRP Update process started. A number of test cases were run to consider these determinations.

  Future demand forecast indicated that the projected demand up to 2030 was below that of the promulgated IRP 2010–2030. When policy is adjusted, the Determinations will be revised to reflect the changed assumptions and capacity resquirements.

- Price path

  Following on the CSIR's cost comparison between its own scenario and the DoE preliminary base case, the DoE was critisised for not publishing the price path for the preliminary base case. However, it was put forward that, since it was a preliminary base case, and because there was no other scenario that could be used for comparison, there was no need to publish the price path.

  This Update contains price path analysis for the scenarios tested.

6.5 APPENDIX E – EMBEDDED GENERATION CATEGORIES

The following activities constitute the embedded generation allocation for own use reflected in table 7 of 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.