INTEGRATED RESOURCE PLAN FOR ELECTRICITY (IRP) 2017

NOVEMBER 2017

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ABBREVIATIONS

CCGT	Closed Cycle Gas Turbine
CO_2	Carbon Dioxide
COD	Commercial Operation Date
Cogen	Co-generation
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
DMP	Demand Market Participant
DSM	Demand Side Management
EAF	Energy Availability Factor
EEDSM	Energy Efficiency Demand Side Management
EBLS	Expensive Base Load Station
EPRI	Electric Power Research Institute
EUF	Energy Utilisation Factor
FBC	Fluidised Bed Combustion
FGD	Flue Gas Desulphurisation
FOR	Forced Outage Rate
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GJ	Gigajoules
GLF	Gross Load Factor
GW	Gigawatt (One thousand Megawatts)
GWh	Gigawatt hour
ICE	Internal Combustion Engine
IGCC	Integrated Gasification Combined Cycle
IMC	Inter-Ministerial Committee on energy
IPP	Independent Power Producer
IRP	Integrated Resource Plan
kW	Kilowatt (One thousandth of a Megawatt)
kWp	Kilowatt-Peak (for Photovoltaic options)
LNG	Liquefied Natural Gas
LTMS	Long Term Mitigation Strategy
MCDM	Multi-criteria Decision Making
MTO	Medium Term Outlook
MTPPP	Medium Term Power Purchase Programme
MW	Megawatt
MWh	Megawatt hour
MYPD	Multi-Year Price Determination
NERSA	National Energy Regulator of South Africa; alternatively the Regulator
NOx	Nitrogen Oxide
OCGT	Open Cycle Gas Turbine
O&M	Operating and Maintenance (cost)
PDD	Project Development Department
PF	Pulverised Fuel
POR	Planned Outage Rate
PPA	Power Purchase Agreement
PPD	Peak-Plateau-Decline
PV	Present Value; alternatively Photo-Voltaic
RAB	Regulatory Asset Base
RTS	Return to Service
SOx	Sulphur Oxide
TW	Terawatt (One million Megawatts)
TWh	Terawatt hour
UE	Unserved Energy

GLOSSARY

"Base-load plant" refers to energy plant 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" 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" 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 Operating and Maintenance (O&M) costs"

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

"Heat Rate"

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

"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.

"Lead time" ….

"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.

"Overnight Capital Cost" …., expressed in R/MW.

"Peaking plant" refers to energy plant 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"

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

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

"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.

"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" refers 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 specific objectives will be achieved.

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

"Test case" refers to a mechanism to test the impact of certain input assumptions or forced output requirements on the model outcomes.

"Unplanned Outage Rate"

"Variable Operating and Maintenance (O&M) costs"

1 BACKGROUND

1.1 The Integrated Resource Plan (IRP) 2010-30 was promulgated in March 2011. It was indicated at the time that the IRP should be a "living plan" which would be revised by the Department of Energy (DoE) every two years.

1.2 The Integrated Energy Plan (IEP) is the over-arching energy plan for the country of which the IRP forms an integral part. The publication of the IEP in November 2016 provides the framework for the interaction between different energy carriers and informs the technology potential for the IRP as well as potential energy sources and the costs associated with both.

1.3 The IRP 2010 identified the preferred generation technology (and assumed energy efficiency demand side management) required to meet expected demand growth up to 2030. The policy-adjusted IRP incorporated a number of government objectives, including affordable electricity, carbon mitigation, reduced water consumption, localisation and regional development, producing a balanced strategy toward diversified electricity generation sources and gradual decarbonisation of the electricity sector in South Africa.

1.4 Following the promulgation of the IRP 2010 the DoE developed plans for the implementation of the IRP, starting with Ministerial Determinations (as per Section 34 of the Electricity Regulation Act). These determinations give effect to the proposed capacity plan by facilitating the procurement of capacity through programmes run by the DoE. Table 1 below provides a summary of the Ministerial Determinations, Programmes, allocated capacities and contracted capacities to date.

Table 1 – Summary of Procurement programmes and facilitating Determinations

Programme/ Phase of Programme	Applicable S 34 Ministerial Determination and MW allocation	No of Preferred Bidders (where applicable)	Allocated Capacity (MW)	Capacity signed (MW)	Status (as at 30 September 2017)
REIPP First Bid (BW1) Submission	Determination dated 11 August 2011 – **3725MW** (including 100MW for small projects)	28	1 430	1 425.34	All 28 PPAs signed **1414.51MW** in commercial operation.
REIPP Second Bid (BW2) Submission	Determination dated 19 December 2012 – **3200MW** (including 100MW for small projects)	19	1 040	1 040.42	All 19 PPAs signed **1033.35MW** in commercial operation.
REIPP Third Bid (BW3) Submission	Determination dated 18 August 2015 – **6300MW** (including 200MW for small projects)	17	1 457	1 435.06	16 out of 17 PPAs **(1 440.5 MW)** signed. **814.18MW** in commercial operation.
REIPP Three point Five Bid (BW 3.5) Submission		2	200	100	1 out of 2 PPAs **(100 MW)** signed
REIPP Fourth Bid (BW4) Submission	Total MWs allocated for Renewables: **13 225MW**	13	1 122	n/a	No contracts signed

Programme/ Phase of Programme	Applicable S 34 Ministerial Determination and MW allocation	No of Preferred Bidders (where applicable)	Allocated Capacity (MW)	Capacity signed (MW)	Status (as at 30 September 2017)
REIPP Four point Five Bid (BW 4.5) Submission		13	1 084	n/a	No contracts signed
Small REIPP Smalls BW1		10	49		No contracts signed
CIPP Bid Window 1(a)	Determination dated 19 December 2012 (initially calling for 800MW) later updated by Determination dated 18 August 2015 –**1 800MW**	1	11.5		No contracts signed
DoE Peakers	Determination dated 25 May 2012 - **1020MW**	2	1 005	1 005	Both contracts signed. **1005 MW** in commercial operation.
Coal Baseload IPP Programme (domestic)	Determination dated 19 December 2012 - **2500MW**	2	863		No contracts signed
Coal Baseload IPP Programme (cross border)	Determination dated 20 April 2016 – **3750MW**	unknown	-		RFP not yet released to market.
Gas (including CCGT/ natural gas) and OCGT/diesel	Determination dated 18 August 2015 – **3126MW**	unknown	-		RFP not yet released to market
Additional Gas	Determination dated 27 May 2016 – **600MW**	unknown	-		RFP not yet released to market
Hydro (Imported Hydro)	Determination dated 19 December 2012 – **2609MW**	unknown	-		RFP not yet released to market
Nuclear	Determination dated 14 December 2016 – 9600 MW	unknown	-		Subject to court action
Solar Park	Determination dated 27 May 2016 – **1500MW**	unknown	-		RFP not yet released to market

Programme/ Phase of Programme	Applicable S 34 Ministerial Determination and MW allocation	No of Preferred Bidders (where applicable)	Allocated Capacity (MW)	Capacity signed (MW)	Status (as at 30 September 2017)
TOTAL	30 130MW	107	8 261.5	5 005	

1.5 Eskom has also embarked on the New Build Programme for the capacity that was committed in the IRP 2010, specifically:

1.5.1 Finalising the full return to service of Komati, Camden and Grootvlei power stations;

1.5.2 Fully commissioning the Ingula pumped storage station;

1.5.3 Fully commissioning the Sere wind farm; and

1.5.4 The continued construction and commissioning of the Medupi and Kusile coal-fired power stations. The expected commercial operation dates for future units are indicated in Table 1Table 2 below.

Table 2 – Commercial operation dates for Eskom new build

MEDUPI		KUSILE	
Unit 6	Commercial	Unit 1	Commercial
Unit 5	Commercial	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

1.5.5 The Eskom Concentrating Solar Power project, which was seen as a demonstration plant in IRP 2010 and not included in the total capacity, has not yet been constructed.

1.5.6 The Minister issued a determination on 27 May 2016 for an additional 100 MW diesel capacity at Ankerlig for dedicated backup supply to Koeberg. This also has not been constructed.

Table 3 – IRP2010 Policy Adjusted Plan with Ministerial Determinations

	New build options								Committed					Non IRP
	Coal (PF, FBC, imports, own build	Nuclear	Import hydro	Gas – CCGT	Peak – OCGT[1]	Wind	CSP	Solar PV	Coal	Other	DoE Peaker	Wind[2]	Other Renew.	Co-generation
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
2010	0	0	0	0	0	0	0	0	380	260	0	0	0	0
2011	0	0	0	0	0	0	0	0	679	130	0	0	0	0
2012	0	0	0	0	0	0	0	300	303	0	0	400	100	0
2013	0	0	0	0	0	0	0	300	823	333	1020	400	25	0

2014	500	0	0	0	0	400	0	300	722	999	0	0	100	0
2015	500	0	0	0	0	400	0	300	1444	0	0	0	100	200
2016	0	0	0	0	0	400	100	300	722	0	0	0	0	200
2017	0	0	0	0	0	400	100	300	2168	0	0	0	0	200
2018	0	0	0	0	0	400	100	300	723	0	0	0	0	200
2019	250	0	0	237	0	400	100	300	1446	0	0	0	0	0
2020	250	0	0	237	0	400	100	300	723	0	0	0	0	0
2021	250	0	0	237	0	400	100	300	0	0	0	0	0	0
2022	250	0	1 143	0	805	400	100	300	0	0	0	0	0	0
2023	250	1 600	1 183	0	805	400	100	300	0	0	0	0	0	0
2024	250	1 600	283	0	0	800	100	300	0	0	0	0	0	0
2025	250	1 600	0	0	805	1 600	100	1 000	0	0	0	0	0	0
2026	1 000	1 600	0	0	0	400	0	500	0	0	0	0	0	0
2027	250	0	0	0	0	1 600	0	500	0	0	0	0	0	0
2028	1 000	1 600	0	474	690	0	0	500	0	0	0	0	0	0
2029	250	1 600	0	237	805	0	0	1 000	0	0	0	0	0	0
2030	1 000	0	0	948	0	0	0	1 000	0	0	0	0	0	0
Total	6 250	9 600	2 609	2 370	3 910	8 400	1 000	8 400	10133	1722	1020	800	325	800

2011 Determinations | 2012 Determinations | Eskom commitments (pre IRP) | 2015/6 Determinations

Notes: 1. OCGT is seen as natural gas in the determination
2. Includes Sere (100MW)

2 UPDATE PROCESS AND APPROACH

2.1 There have been a number of developments and changes in the electricity sector since the promulgation of the Integrated Resource Plan (IRP 2010) both domestically and in the international energy sector. These have impacted not only on the starting position of the IRP update but also the expectation of future demand and supply options.

2.1.1 Domestic electricity demand is significantly lower from the expectation in 2010. The reduction in energy demand is due to a lower GDP growth and a significant reduction in energy intensity (units of energy consumed per unit of GDP). The expectation of future demand has had to shift to account for these changes.

2.1.2 The cost of some technology options have followed the trends expected in 2010 (especially the learning rates assumed) but others have not requiring an update to the outlook for technology costs, as well as potential for new technologies and fuel.

2.1.3 The IRP 2010 considered only carbon caps as a mitigation strategy but alternatives, such as carbon taxes and carbon budgets are being investigated as to their impact on electricity supply beyond 2020.

2.1.4 Affordability of electricity, and customer response to electricity prices since 2010, has clearly had an impact on demand and the actual experience of (and further potential for) self-supply beyond 2020.

2.2 In 2013 the DoE published the IRP 2010 Update report which provided an indication of the shifts in the industry from 2011 to 2013. This Update report informs the process followed in this iteration of the IRP, especially the incorporation of decision trees (taking into consideration uncertainty in the policy development process) and the potential for self-supply through embedded generation (especially rooftop PV).

2.3 A draft IRP 2016 report was released for public comment in November 2016. This was based on updates to the electricity demand outlook and supply costs. The public participation process is detailed in Appendix D and some of the outcomes of this process have been used to inform this final report.

2.4 The approach adopted for this final report has been:

2.4.1 The development of a Reference Case that incorporates:

2.4.1.1 Fixed capacity and timelines for outstanding procurement processes arising from the Ministerial determinations. In particular the expected capacity from Bid Windows 3.5, 4 (and the extension) have been fixed (as indicated in Table 4);

2.4.1.2 A median electricity demand forecast based on revised economic projections (further discussed below);

2.4.1.3 The maintenance of "artificial" limits of annual renewable capacity additions, as used in the IRP 2010, now capped at 1000 MW for PV and 1800 MW for wind;

2.4.1.4 An accommodation for Transmission infrastructure costs by including costs for collector stations for all technologies in the optimisation model. This has an impact on renewable energy technologies given their remote locations where there is limited network capacity;

2.4.1.5 While allowance is made for embedded generators (especially rooftop PV) these have not been modelled explicitly, however it is expected that procurement process for capacity would accommodate that which is self-supplied before procuring the same capacity again.

2.4.2 A number of scenarios and test cases were modelled in the process of developing the IRP 2017 but the key scenarios discussed in detail were chosen to highlight possible outcomes and policy alternatives:

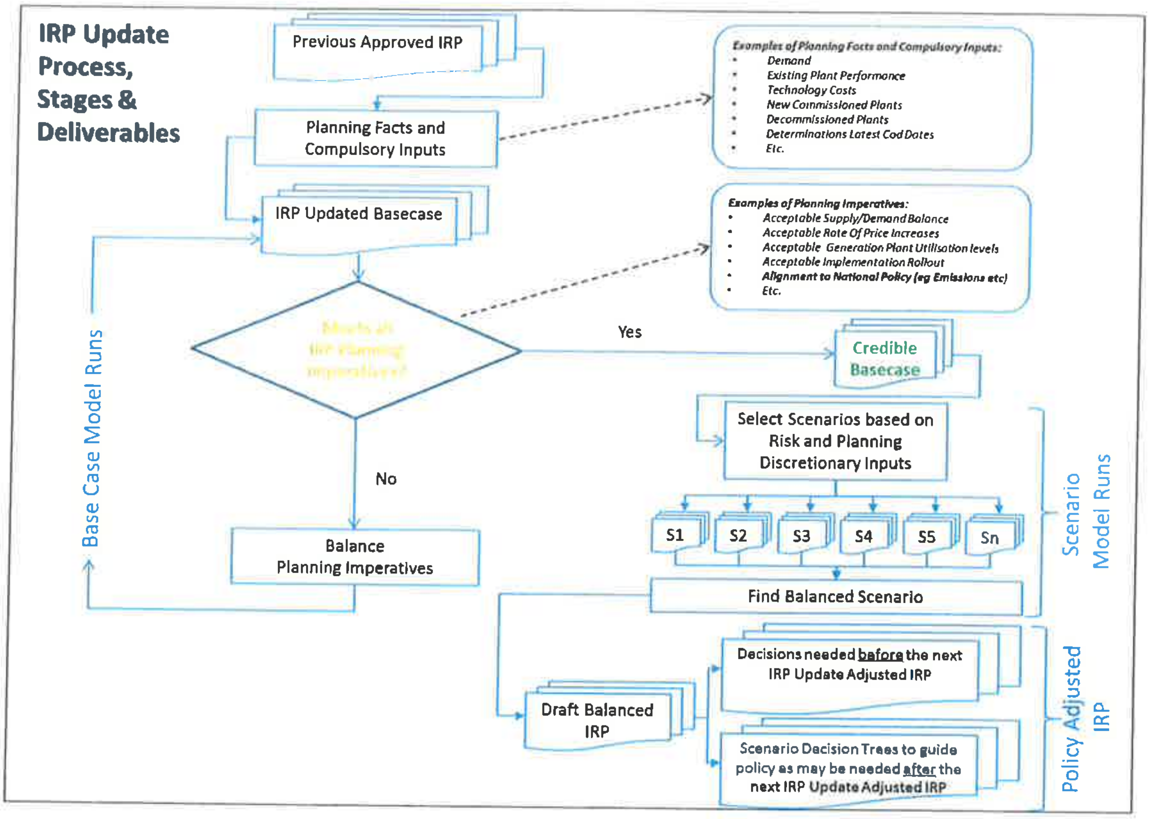
2.4.2.1 Optimum Plan – releasing the renewable capacity limits, but maintaining the Median forecast and Moderate Mitigation strategy

2.4.2.2 Low Growth Scenario – shifting to a lower growth trajectory but maintaining the other Reference case constraints and assumptions

2.4.2.3 Carbon Budget Plan – using the Median forecast and other Reference case constraints and assumptions but replacing the Moderate Mitigation strategy with the Carbon Budget approach

2.4.2.4 Forced Nuclear – as with the Reference Case but forcing in 9600 MW of nuclear capacity

Figure 1 – IRP update process and expected deliverables



3 CHANGED CONDITIONS FROM 2010

Technology options and costs

3.1 Technology costs for the IRP 2010 and 2017 have been derived from the EPRI reports that provide generic costs for potential generation options.

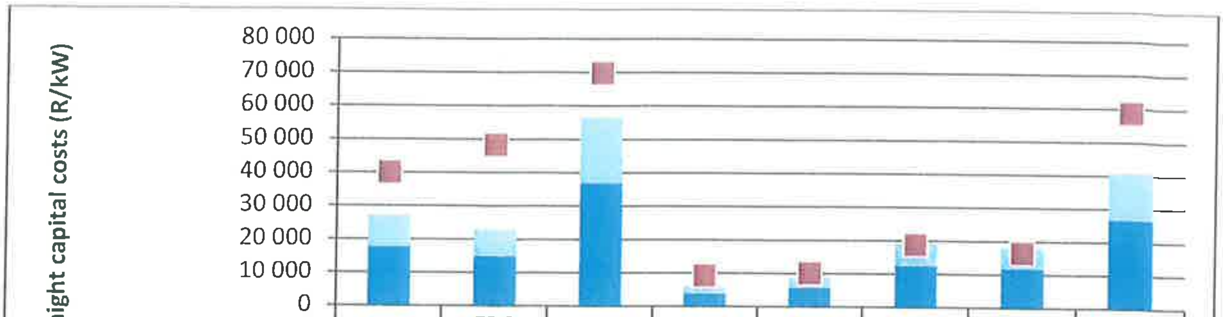
3.1.1 The costs for generic technologies used in the IRP 2010 were based on the July 2010 EPRI report ("Power Generation Technology Data for Integrated Resource Plan of South Africa"). The generic technology data was used for all options, except for solar photovoltaic generation which was provided by the Boston Consulting Group in their report ("Outlook on Solar PV"); sugar bagasse generation (provided by the sugar industry as part of the public hearings); pumped storage costs (provided by Eskom) and the regional hydro, gas and coal options (which were based on data compiled in previous Southern African Power Pool plans).

3.1.2 EPRI developed an updated 2017 report on the generic technology costs based on more recent data (latest technology costs and exchange rate). This review utilises the updates provided by EPRI for the same technologies except for photovoltaic, wind, coal and sugar bagasse for which actual costs achieved by the IPP programme, and nuclear costs which were provided to the DoE through the Ingerop report. For wind, PV and CSP costs the RE IPP Bid Window 4 expedited data for overnight costs was used (based on the median of all successful projects for each technology). Eskom provided an updated view of the pumped storage costs.

3.1.3 The overnight costs associated with key technologies are indicated in Figure 2, showing the IRP 2010 costs and the adjustment for South African inflation. Some of the options, such as Coal, Nuclear and CSP, show much higher costs in 2017 relative to the inflation-adjusted

2010 values. This is mainly due to the higher exchange rate in 2017 which impacts all technologies, but the learning in some renewable energy options has mitigated this impact.

Figure 2 – Comparison of overnight capital costs between IRP 2010 and IRP 2017

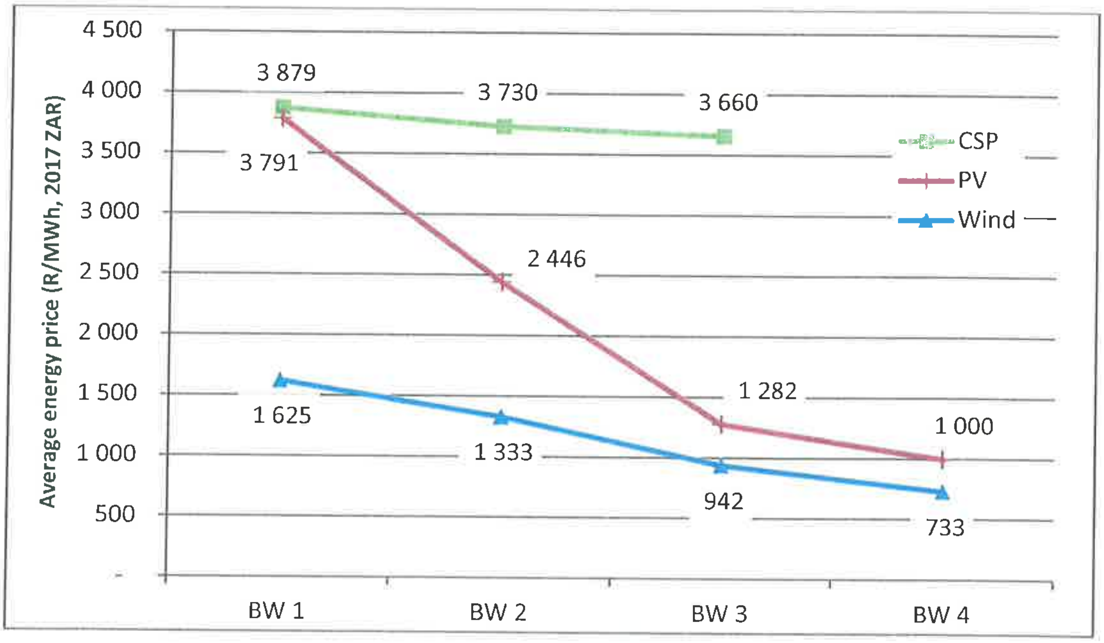


	PF Coal (with FGD)	FBC Coal (with FGD)	Nuclear	OCGT	CCGT	Wind	PV (fixed tilt)	CSP (trough , 9hrs)
Adjusted for Inflation	9 525	8 015	19 770	2 118	3 095	6 729	6 361	14 325
2010 IRP (incl learning)	17 785	14 965	36 915	3 955	5 780	12 564	11 877	26 748
2017 IRP	40 031	48 319	69 764	9 226	10 131	18 847	16 555	58 833

Note: The IRP 2010 capital costs are those adopted following the consultation process (PV and nuclear were revised) and all adjusted for learning rates to 2017

3.1.4 The experience of the REIPPP procurement programme has supported the assumed learning curve for some renewable options used in 2010. The average costs of each technology under the four bid windows are shown in Figure 3. In particular the PV and wind prices have fallen beyond the expectation of the learning rates in 2010 but the CSP prices have not achieved the same learning.

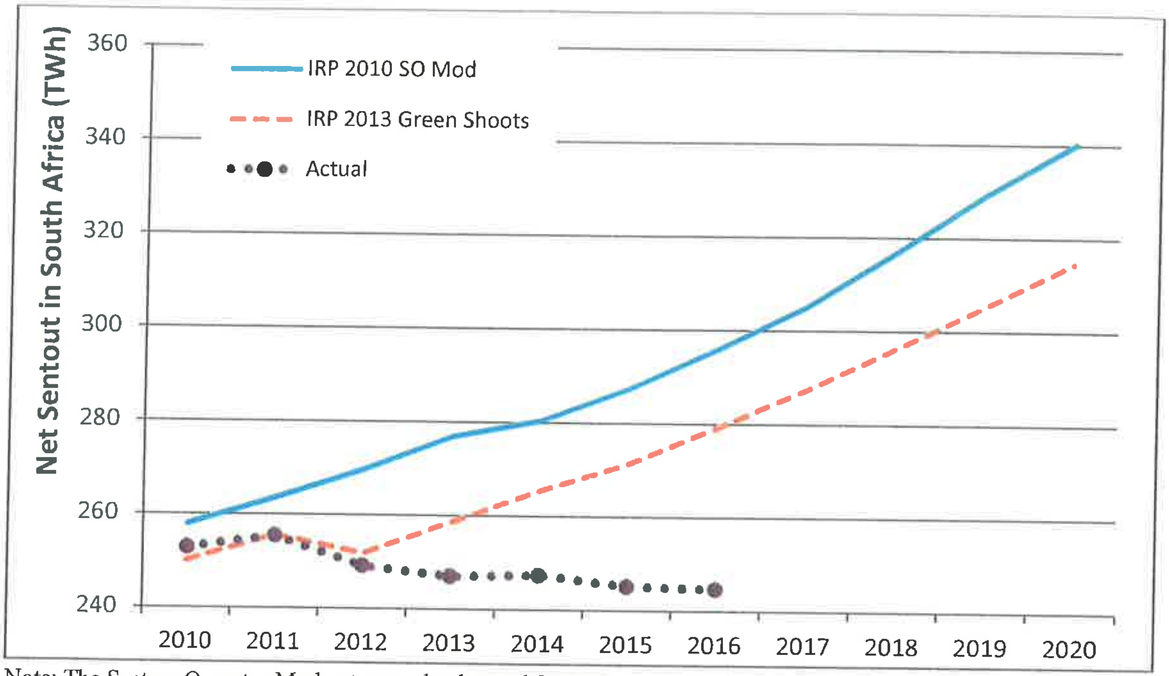
Figure 3 – Reduction in renewable purchase prices through REIPPP programme



Expected Demand

3.2 The actual net sent-out for the country has been declining marginally over the past six years (at an average compound rate of -0,6% from 2010 to 2016). This is in stark contrast to the expectation in the IRP 2010 of an average growth rate of 3,0% (for the SO Moderate). The result is that in 2016 the net sent-out is at 244 TWh relative to expected 296 TWh.

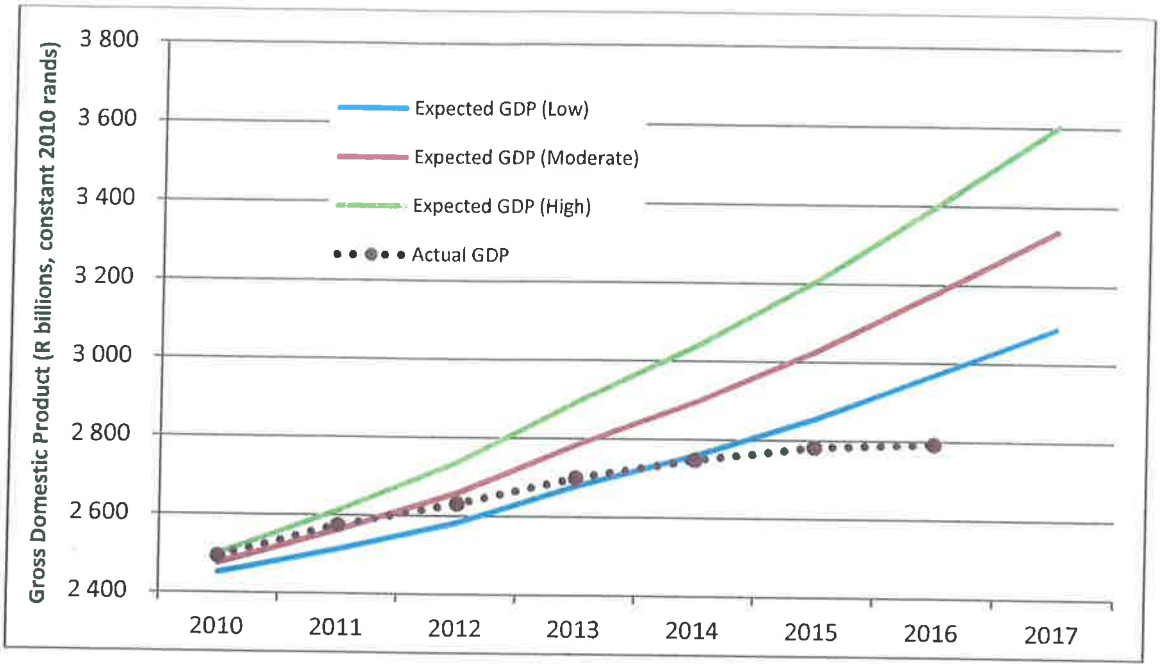
Figure 4 – Expected RSA sent-out from IRP 2010 vs actual



Note: The System Operator Moderate was the demand forecast used in the policy-adjusted IRP
Sources: StatsSA (for actual), IRP 2010 and IRP 2010 Update Reports (forecasts)

3.3 Economic activity has been significantly lower than the GDP forecasts in the IRP 2010. The compound average growth rate for the years 2010 to 2016 was 2,05% against an expectation of 2,95% for the Low growth forecast, 3,95% for the Moderate forecast and 4,95% for the High. This lower growth compared to the expectation in 2010 has a large impact on the resulting electricity demand. In particular the recession in 2016 has severely impacted electricity demand.

Figure 5 – Expected GDP growth from IRP 2010 vs actual



Source: StatsSA, IRP 2010 assumptions

3.4 The underlying causes of the reduced demand are many-fold, including:

3.4.1 General economic conditions as shown in Figure 5 above, which have specifically impacted energy intensive sectors. [redacted]

3.4.2 The constraints imposed by the supply situation between 2011 and 2015 with the strong potential for suppressed demand, by industrial consumers as well as domestic consumers. It was expected that suppressed demand would return once the supply situation had been resolved, but electricity pricing (and commodity price issues) may have delayed, or permanently removed, this potential.

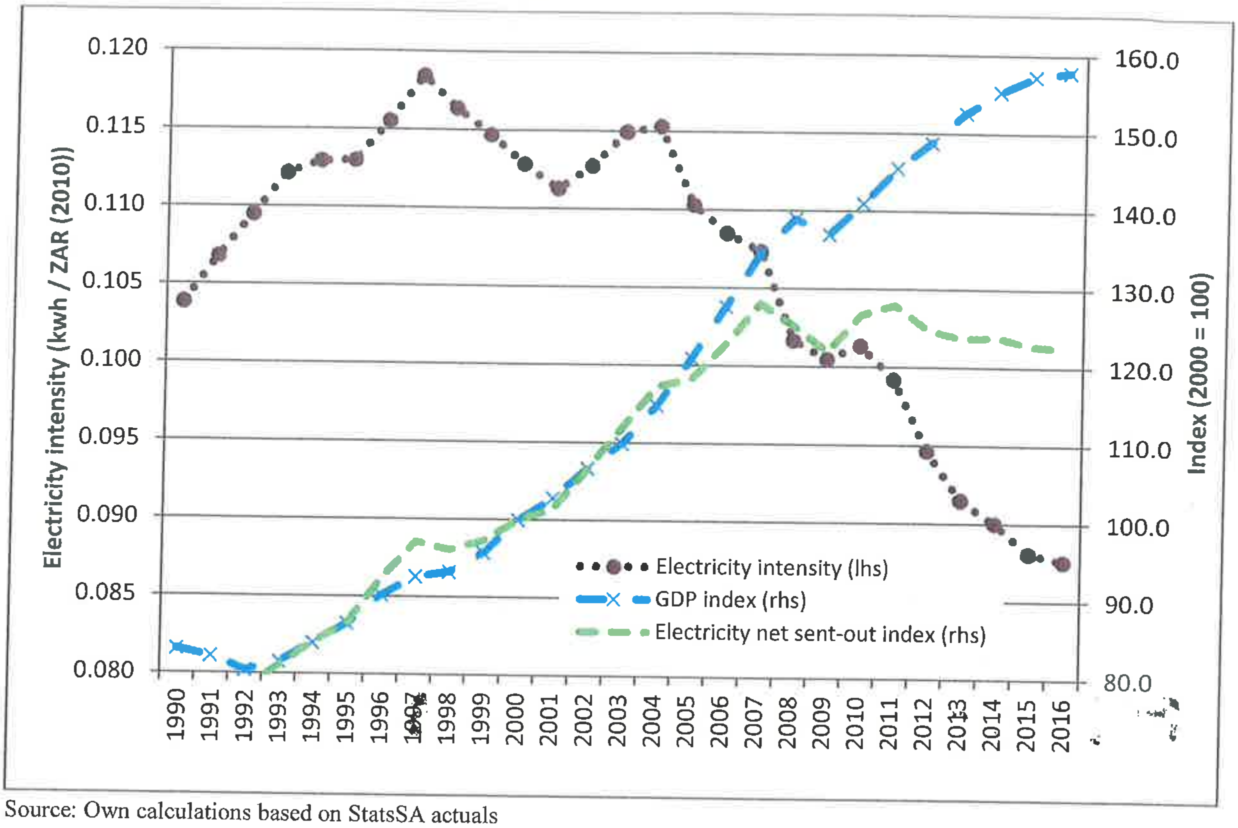
3.4.3 The price increases over the past five years which have led to large adjustments in consumer demand. There was criticism regarding the IRP 2010 approach that insufficient attention was paid to price elasticity in demand forecasting, and there is a strong case that the price increases are a major contributor to a contraction in demand, especially from energy intensive electricity consumers. There is evidence to suggest that current electricity prices are causing some energy intensive users to relocate smelting operation to countries with more competitive electricity prices. From an industrial consumer perspective then there is a strong indication that electricity prices have reached the threshold for a more price-elastic demand. Quantifying the impact of prices on electricity demand into the future is almost impossible, but the impact is reflected by assuming a progressive decline in electricity intensity of GDP. This is further discussed in Appendix A.

3.4.4 Improved energy efficiency, partly as a response to the price increases which would greatly improve the payback for many efficiency investments, and partly as a response to concerted efforts by municipalities, Eskom and the Department of Energy.

3.4.5 Increasing embedded generation. There is evidence of growth in rooftop PV but this capacity is still very small, however this is likely to increase in the medium term and further impact on the reported net sent-out for the country, especially in the absence of a reporting or licensing regime for these facilities.

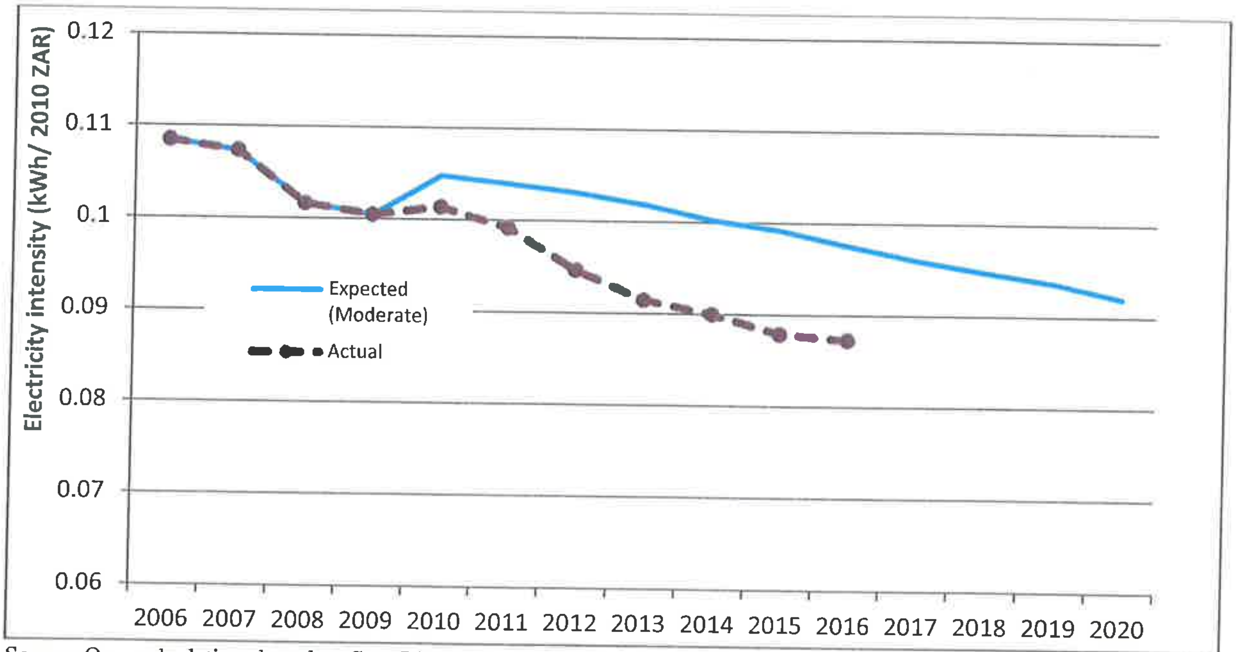
3.5 The electricity intensity (as measured by the electricity sent-out in kWh required to produce one rand of total gross value added (in constant 2010 rands) in the South African economy) has continued to decline over the past six years, exceeding the expectation in the IRP 2010 SO Moderate forecast.

Figure 6 – Electricity intensity history 1990 to 2016



Source: Own calculations based on StatsSA actuals

Figure 7 – Actual electricity intensity relative to IRP2010 expectations



Source: Own calculations based on StatsSA actuals, IRP 2010 assumptions

Performance of the Eskom fleet

3.6 In the IRP 2010 there was an expectation of 86% availability for Eskom's existing fleet. At the time the availability was 85%. Since then the availability declined steadily to a low of 71% in the 2015/16 financial year before recovering to over 80%. This drop in availability was a major contributor to the capacity situation between 2011 and 2015. For the foreseeable future the existing Eskom fleet will remain the bulk of the South African electricity supply and maintenance thereof needs to be a priority especially as the average age of the plant increases.

3.7 The performance figures generally reflect the capacity situation in the country. In the presence of excess capacity it is possible for availability to be overstated as the generating plant is not put under the same strain and plant failures are less visible. As the capacity becomes strained with a tighter system these plant failures become more evident and availability statistics reflect the true state of affairs. Attention should be paid to ensure that these statistics are correctly captured and reported to facilitate more effective planning.

4 REFERENCE CASE

4.1 The Reference Case is produced by incorporating the following assumptions:

4.1.1 The median forecast for the purposes of the Reference Case is the CSIR High Less Intense (HLI) forecast (detailed in Appendix A) selected from the three trajectories identified (detailed in Section 5 below). A revised economic and electricity sector outlook has been developed to inform decisions required in this new iteration of the IRP. The projected energy demand by 2030 is now estimated to be around 312 TWh (for the Reference Case) as compared to the 454 TWh forecast of IRP 2010. The anticipated peak demand by 2030 has reduced from 67 809 MW to 48 030 MW.

4.1.2 The Ministerial Determinations (identified in Table 1 above) are committed as follows:

Table 4 – Assumed capacity under REIPPP (forced in the Reference Case)

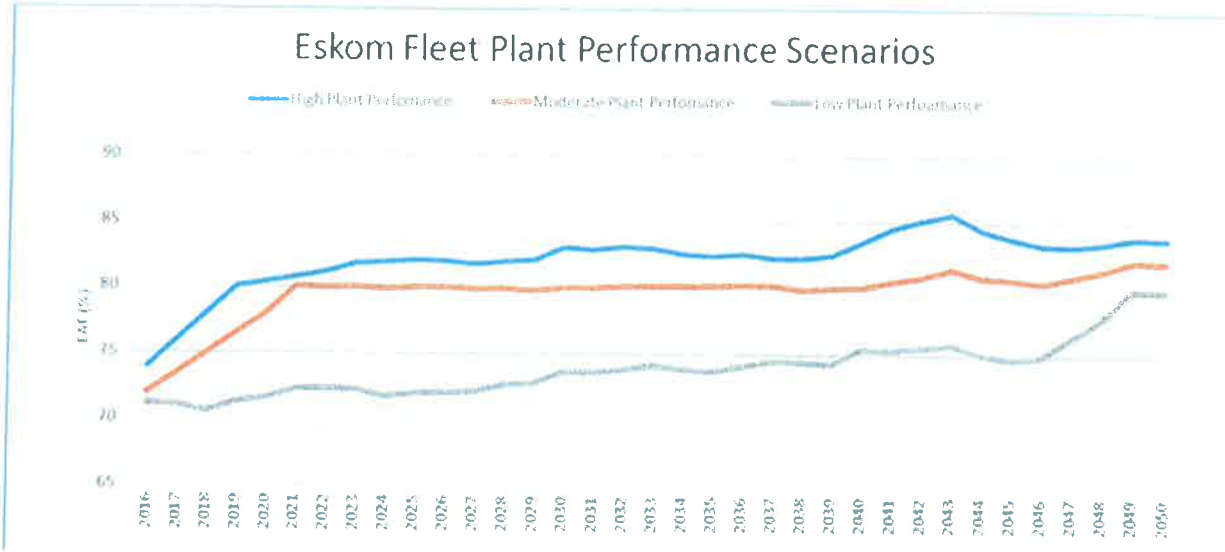
	PV	Wind	CSP	Landfill	Hydro	Biomass
2013	7	0	0	0	0	0
2014	964	569	0	0	0	0
2015	969	956	100	0	10	0
2016	1329	1373	200	0	14	0
2017	1474	1470	200	11	14	0
2018	1474	1982	300	13	14	17
2019	1588	2226	600	13	14	17
2020	1888	2526	600	13	19	42
2021	2287	3344	600	13	19	42
2022	2287	3344	600	13	19	42
2023	2287	3344	600	13	19	42

4.1.3 Similarly the Eskom new build is committed as per Table 2.

4.1.4 An additional gas technology was added to the IRP 2017 Reference Case, including for the first time a specific indication of gas engine costs. Previously it was assumed that gas engines and open cycle turbines would be interchangeable but with recent developments in engine technology it was decided to include these as a separate option for the model. The costs associated with engines were sourced from specific suppliers and used as indicated in Appendix B.

4.1.5 The performance of the Eskom fleet is updated to 80% availability as per the Eskom performance undertakings. [redacted] shows the Eskom Energy Availability Factor (EAF) scenarios. Performance of new generic options is assumed as per the EPRI availability assumptions.

Figure 8 – Eskom Energy Availability Factor (EAF) scenarios

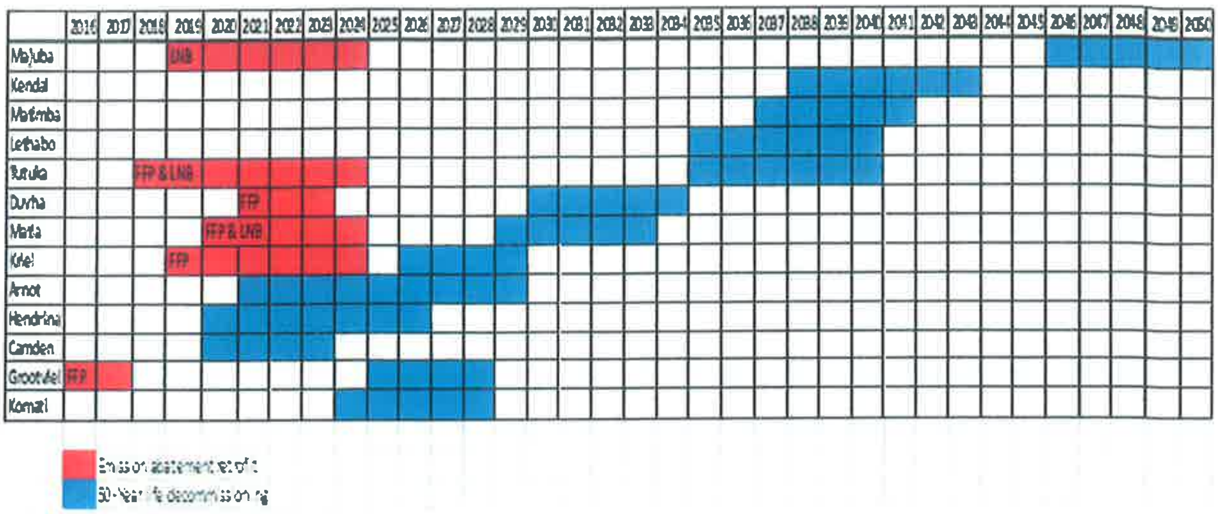


4.1.6 Extensive emission abatement retrofits are required at Eskom existing coal power stations to ensure compliance with the Minimum Emission Standards which were published in terms of section 21 of the National Environmental Management Act (NEMA): Air Quality Act (Act no 39 of 2004) on April 2010. This means existing plant standards need to be compliant by 1 April 2015 and the more stringent 'new plant' standards need to be complied with immediately and for existing power stations by 1 April 2020. These limits are concentration limits that are applicable per unit (or per stack in case of combined stacks) and the primary objective is to reduce emissions associated with:

- Particulate matter (PM)
- Sulphur dioxide (SO_2)
- Oxides of nitrogen (NO_x)

4.1.7 However, Eskom is still expected to execute the emission abatement retrofit programme that was committed to as shown in Table 5 to implement air quality offsets to reduce levels of particulate matter in the ambient environment.

Table 5 – Emission abatement retrofit programme



4.1.8 The Reference Case includes externality costs for pollutants associated with coal-fired generation. These externality costs reflect the cost to society due to the activities of a third party resulting in social, health, environmental, degradation or other costs. The IRP 2017, as is the case with the IEP, considers negative externalities related air pollution cause by pollutants such as nitrogen oxide (NO_x), sulphur oxide (SO_x), particulate matter (PM) and mercury (Hg). 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 6. Costs associated with carbon dioxide are not included as the mitigation strategy covers the reduction in CO_2 emissions.

Table 6 – Local emission and particulate matter costs

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

4.1.9 The assumed exchange rate, discount rate, cost of unserved energy and fuel costs for the Reference Case are also indicated in Table 7.

Table 7 – Other assumptions for the Reference Case

Parameter	Value used in the model	
Discount rate, real post-tax	8.20%	
Exchange Rate (1 Jan 2017)	R13.57/USD	
Cost of unserved energy	R87.85/kWh as per NERSA update	
Fuel cost (R/GJ) (data from EPRI 2017)	Coal pulverised	31 (~R558/t)
	Coal FBC (discard coal)	15.5 (~R279/t)
	Liquefied natural gas	135.70
	Nuclear fuel cost	9.10

4.1.10 The policy adjusted IRP only allowed for 2609 MW of regional hydroelectric generation projects, even though it considered an additional 740 MW. Since the promulgation of the IRP 2010 the outlook for regional options has changed with Mpanda Nkuwa and other hydro options seemingly less likely but with the clear addition of the Inga III project in the Democratic Republic of Congo (DRC), for which a treaty between South Africa and the DRC has been concluded. Thus Inga III is included as an option for the Reference Case using costs as provided by Eskom's Southern African Energy department. Although there are other projects in the region, supported by the Southern African Power Pool (SAPP) pool plan, these are not included as options for the Reference Case as there is no commitment from South Africa to procure these.

4.2 The preferred technology options for 2030 arising from the Reference Case are indicated in Table 8. In comparison to the IRP 2010 capacity for the same period it is clear that the reduction in the expected peak demand (67809MW in IRP 2010 to 48030MW in the Reference Case) leads to a large reduction in total capacity, especially from less flexible dispatchable generation such as Coal, Nuclear, and Hydro, whereas the more flexible options supplied by gas engines and open cycle gas turbines increases in order to support higher renewable capacity.

Table 8 – Technology options arising from IRP 2010 and the IRP 2017 Reference Case in 2030

Technology option	IRP 2010 (MW)	IRP 2017 Reference Case (MW)
Existing Coal	34746	31616
New Coal	6250	0
CCGT	2370	732
OCGT	7330	3855
Gas Engines		9150
Hydro Imports	4109	1500
Hydro Domestic	700	696
PS (incl Imports)	2912	2912
Nuclear	11400	1860
PV	8400	8977
CSP	1200	600
Wind	9200	13349
Other	915	2284
TOTAL	**89532**	**77631**
Peak demand	**67809**	**48030**

Notes:

(1) Demand Response options added to IRP 2010 to ensure comparability (previously not considered in IRP)

(2) "Existing" coal includes Medupi and Kusile

5 DEMAND FORECAST TRAJECTORIES

5.1 A number of updated demand forecasts were developed during 2017 based on the latest economic indicators and measured electricity demand. The CSIR prepared five electricity demand forecasts based on the five economic projections developed by the IRP team. These details are also included in Appendix A.

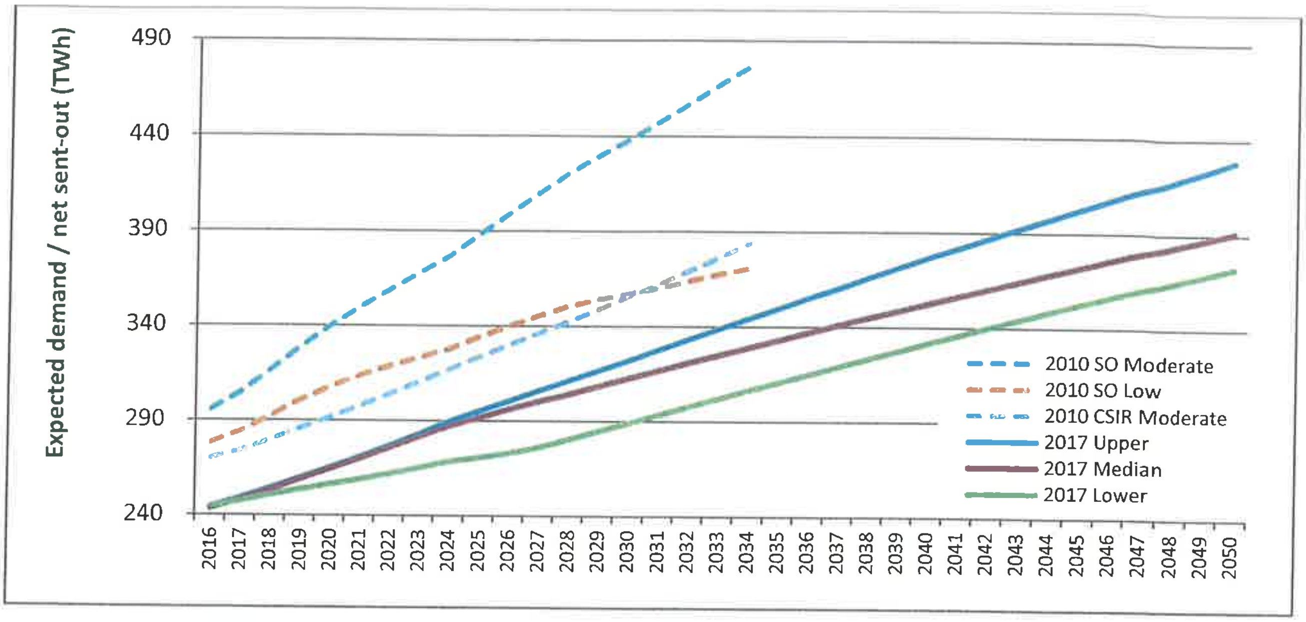
5.2 For the purposes of the IRP 2017 cases only three of the trajectories are used (shown in Figure 9, compared to the IRP 2010 forecasts):

5.2.1 The Upper forecast (which is the CSIR Moderate forecast), is based on an average 3,18% annual GDP growth but assuming the current economic sectoral structure persists, and results in an average annual electricity demand growth of 2,0% to 2030 (and only 1,66% to 2050);

5.2.2 The Median forecast (the CSIR High Less Intense forecast), is based on an average 4,26% GDP growth to 2030 but with a significant restructuring of the economy, results in an average annual electricity demand growth of 1,8% to 2030 (and 1,4% to 2050), and is used for the Reference Case;

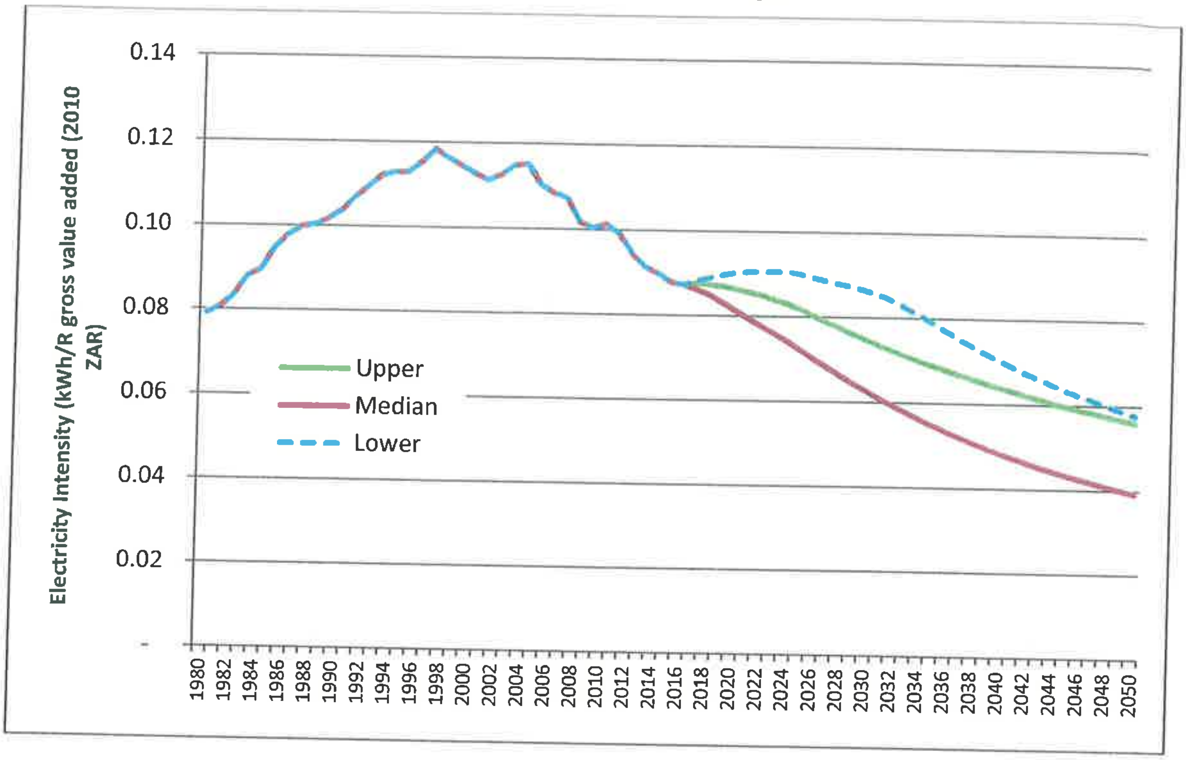
5.2.3 The Lower forecast (the CSIR Junk status forecast) has a 1,33% GDP growth to 2030 results in a 1,21% average annual electricity demand growth to 2030 (and 1,24 % to 2050).

Figure 9 – Expected electricity demand trajectories to 2050



5.3 Combining the electricity demand and economic growth forecasts results in declining electricity intensity expectations over the next forty years as indicated in Figure 10. Whereas the Lower intensity climbs initially (assuming that mining output continues to grow while other sectors of the economy suffer from the impact of the junk status decision by rating agencies) before dropping extensively to meet the Upper intensity in 2050, the Median intensity drops extensively during the period from the current 0,088 to 0,04 in 2050. This reflects the impact of the assumed sector shift in the economy as energy intensive industries make way for less intensive industries.

Figure 10 – Electricity Intensity for each of the demand trajectories



5.4 The optimisation model produced outputs for each of the three trajectories indicated above. The results from the optimisation (reflected in Table 9) indicate that the annual limits imposed on renewable technology create a binding constraint on all three cases by 2050 such that the installed wind and PV capacity is common to all three cases, while the peaking gas backup requirement (for OCGT and Gas Engines) is similar. None of the cases requires nuclear capacity, whereas all three require new coal-fired generation, 6750 MW for the Lower, 8250 MW for the median case and 12750MW for the Upper. All these are required after 2030. The CCGT gas requirement also increases from the Reference Case to the Upper.

5.5 Before 2030 all three cases have a similar requirement for renewable capacity and gas and no requirement for new coal or nuclear capacity.

Table 9 – Technology options arising from the three demand trajectories in 2030 and 2050

Technology option	2030			2050		
	IRP 2017 Reference Case (MW)	IRP 2017 Lower (MW)	IRP 2017 Upper (MW)	IRP 2017 Reference Case (MW)	IRP 2017 Lower (MW)	IRP 2017 Upper (MW)
Existing Coal	31616	31616	31616	9791	9791	9791
New Coal	0	0	0	8250	6750	12750
CCGT	732	0	1464	12444	11712	16104
OCGT	3855	3459	3459	12743	13139	10763
Gas Engines	9150	7050	9900	17550	15900	16650
Hydro Imports	1500	1500	1500	4000	4000	4000
Hydro Domestic	696	696	696	696	696	696
PS (incl Imports)	2912	2912	2912	1512	1512	1512
Nuclear	1860	1860	1860	0	0	0
PV	8977	7057	9287	25000	24770	25000
CSP	600	700	700	100	100	100
Wind	13349	10149	14249	36000	36000	36000

Other	2284	2284	2284	1229	1229	1229
TOTAL	**77631**	**69283**	**79927**	**129315**	**125598**	**134594**
Peak demand	**48030**	**44062**	**49028**	**60516**	**57355**	**65385**

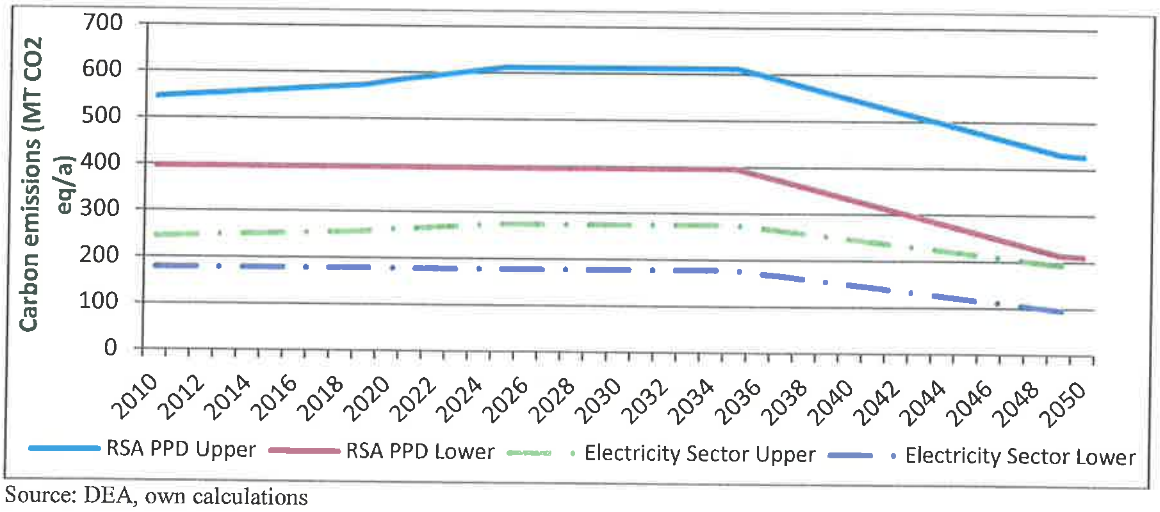
Notes: "Existing" coal includes Medupi and Kusile

6 CLIMATE CHANGE MITIGATION

6.1 A key issue for extending the study period for the IRP 2017 was to consider other strategies to reduce carbon emissions in the period following 2030. By excluding the period after 2030 there is a risk of building coal-fired generation in the period leading up to 2030 on the assumption that the carbon emission caps would continue at the same level, but this would lead to a constraint in reducing the emissions or under-utilisation of generation capacity if the cap needed to be reduced over time as indicated by the government's peak-plateau-decline (PPD) objective.

6.2 The peak-plateau-decline objective suggests that emissions would be allowed to peak in 2025 (originally indicated at 550 million tons per annum for South Africa as a whole), then plateau for some period before declining. In August 2011 the Department of Environmental Affairs (DEA) published an explanatory note titled 'Defining South Africa's Peak, Plateau and Decline Greenhouse Gas Emission Trajectory" which indicated the range of expected carbon dioxide emissions up to 2050. Under the PPD range, South Africa's upper limit is expected at 428 MT/a in 2050 and the lower limit at 212 MT/a. The Long Term Mitigation Scenarios (LTMS) (October 2007) indicated that the electricity sector greenhouse gas contribution was 45% in 2003. The IRP 2010 assumed a 50% contribution, but this was seen by some observers at the time as an indulgence. Assuming the less indulgent 45% contribution, the upper limit for the electricity would be 193 MT/a in 2050 and the lower limit would be 95 MT/a.

Figure 11 – DEA Peak, Plateau and Decline range with assumed electricity industry contribution



Source: DEA, own calculations

6.3 The Reference case assumes a "Moderate Decline" target based on the PPD starting at 275 MT/a before 2037, declining at a moderate pace to reach 210 MT/a in 2050.

Carbon budget

6.4 An alternative approach investigated in this report to induce the appropriate climate mitigation path is to set total emissions allowance for the electricity sector over a period of time and impose that as a constraint rather than an annual limit.

6.5 The DEA is investigating a carbon budget approach for all sectors in the economy, and has proposed a more ambitious target (relative to the Moderate Decline above) for the electricity sector as indicted in Table 10 below. The budget provides adequate emission space for existing fleet including allowances for generation from Medupi, Kusile and potential independent coal-fired generators. The total budget for the entire electricity sector must not exceed cumulative 5470 Mt CO_2 equivalent from 2021 to 2050.

Table 10 – DEA Proposed Emission Budget

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

Source: DEA

Scenario comparison: Carbon budget and Moderate Decline

6.6 A comparison between the two approaches is shown in Table 11. As with the demand trajectories the annual limits on renewable capacity results in a common renewable capacity between the two options before 2050. However the carbon budget, being a tighter overall emission target, reduces the new coal-fired generation capacity and replaces this with more nuclear capacity.

Table 11 – Technology options arising from different mitigation strategies

Technology option	2030		2050	
	IRP 2017 Reference Case Moderate Decline (MW)	IRP 2017 Carbon Budget (MW)	IRP 2017 Reference Case Moderate Decline (MW)	IRP 2017 Carbon Budget (MW)
Existing Coal	31616	31616	9791	9791
New Coal	0	0	8250	1500
CCGT	732	0	12444	13176
OCGT	3855	4251	12743	13535
Gas Engines	9150	9450	17550	16500
Hydro Imports	1500	1500	4000	4000
Hydro Domestic	696	696	696	696
PS (incl Imports)	2912	2912	1512	1512
Nuclear	1860	1860	0	5600
PV	8977	9287	25000	25000
CSP	600	700	100	0
Wind	13349	13849	36000	36000
Other	2284	2284	1229	1729
TOTAL	**77631**	**78405**	**129315**	**129138**
Peak demand	**48030**	**48030**	**60516**	**60516**

7 SCENARIO COMPARISON

7.1 Five scenarios have been identified to indicate the impact of key inputs, specifically the growth trajectories, the mitigation strategies and the renewable build rate (whether including the annual build rates or not).

Table 12 – Key inputs to the five scenarios

Model Key Input	Reference Case	Optimum Plan	Low Growth	Carbon Budget	Forced Nuclear
Growth	Median	Median	Lower	Median	Median
Renewable Build Rate	Constrained	Unconstrained	Constrained	Constrained	Constrained
CO2 Mitigation	Moderate	Moderate	Moderate	Carbon Budget	Carbon Budget
Nuclear	Model Chooses	Model Chooses	Model Chooses	Model Chooses	Forced In

7.2 Full Transmission plans for extreme scenarios (high renewable penetration vs high nuclear vs high coal) were developed to indicate the costs associated with these plans. The variation between these extreme cases was no more than 10% of the total transmission cost, indicating that the total quantum involved from a Transmission perspective is minimal compared to the total Generation cost. For the purposes of the optimisation model it was decided that collector station costs would be included for all technologies (including an accounting for the long transmission connections required for international projects). The costs associated with the collector stations are included in Appendix E.

Table 13 – Total capacity for technology options arising from the five scenarios

Technology option	2030				
	IRP 2017 Reference Case (MW)	IRP 2017 Optimum Plan (MW)	IRP 2017 Low Growth (MW)	IRP 2017 Carbon Budget (MW)	IRP 2017 Forced Nuclear (MW)
Existing Coal	31616	31616	31616	31616	31616
New Coal	0	0	0	0	0
CCGT	732	0	0	0	0
OCGT	3855	4119	3459	4251	3591
Gas Engines	9150	9900	7050	9450	9150
Hydro Imports	1500	1500	1500	1500	1500
Hydro Domestic	696	696	696	696	696
PS (incl Imports)	2912	2912	2912	2912	2912
Nuclear	1860	1860	1860	1860	3260
PV	8977	10127	7057	9287	8287
CSP	700	700	700	700	700
Wind	13349	12449	10149	13849	11649
Other	2284	2284	2284	2284	2284
TOTAL	**77631**	**78163**	**69283**	**78405**	**75645**
Peak demand	**48030**	**48030**	**44062**	**48030**	**48030**

Technology option	2050				
	IRP 2017 Reference Case (MW)	IRP 2017 Optimum Plan (MW)	IRP 2017 Low Growth (MW)	IRP 2017 Carbon Budget (MW)	IRP 2017 Forced Nuclear (MW)
Existing Coal	9791	9791	9791	9791	9791
New Coal	8250	0	6750	1500	1500
CCGT	12444	10248	11712	13176	8052

OCGT	12743	13799	13139	13535	13931
Gas Engines	17550	25050	15900	16500	17400
Hydro Imports	4000	4000	4000	4000	4000
Hydro Domestic	696	696	696	696	696
PS (incl Imports)	1512	1512	1512	1512	1512
Nuclear	0	0	0	5600	9800
PV	25000	31420	24770	25000	25000
CSP	100	100	100	0	100
Wind	36000	50200	36000	36000	35100
Other	1229	1229	1229	1729	1229
TOTAL	**129315**	**148044**	**125598**	**129138**	**128110**
Peak demand	**60516**	**60516**	**57355**	**60516**	**60516**

7.3 Results from the model indicate that:

7.3.1 Releasing the annual limits for renewable capacity will increase total PV capacity in 2050 from 25000 MW to 31420 MW and total wind capacity from 36000 MW to 50200 MW while negating any new coal-fired generation or nuclear capacity. The supporting gas capacity is increased, especially from gas engines.

7.3.2 The three gas generation options fulfil specific roles to support the system. Firstly gas engines provide fast response backup for renewable options as well as sufficiently efficient peaking generation (mostly operating in a 6-12% capacity factor range); secondly the open cycle gas turbines provide traditional peaking capacity (with a very low capacity factor range (less than 5%), and thirdly, combined cycle gas turbines provide mid-merit capability (with a capacity factor in the 20-40% range). This suggests that import infrastructure to support gas generation would require significant storage capability and allow for very low utilisation. This requirement is common across all five scenarios, and none of the scenarios support base-load gas generation.

7.3.3 In all five cases "dispatchable" generation capacity (including coal-fired, gas-fired, nuclear capacity as well as Hydro Import and pumped storage capacity) exceed the peak demand with some reserve available for unplanned outages.

7.3.4 The Inga generation option is supported in all cases, provided a relatively cheap base-load supply option, based on the information provided regarding costs of production and transport.

7.3.5 Landfill gas is supported in each case (included under "Other" in Table 13) to a maximum of 250 MW.

7.3.6 The current price assumptions for Concentrating Solar Power generation do not support further development of this technology. In the absence of a significant reduction in prices (perhaps from further rounds of the REIPPP) no new CSP capacity can be justified.

7.3.7 Storage options, including batteries and pumped storage, are not selected in any case, with gas generation playing the supporting role for renewable energy. The combination of gas (through engines and turbines) and renewable energy provides a suitable replacement for traditional base-load generation.

7.3.8 Nuclear generation is only selected in the Carbon Budget case with four units each operational in 2039, 2040, 2045 and 2046. This only occurs because the renewable capacity is constrained by the annual limits – a test case releasing the annual limits and enforcing the carbon budget does not build nuclear capacity and relies on the renewable capacity and gas to meet the carbon budget. The Forced Nuclear case includes a constraint that the model must construct at least 9600 MW as per the IRP 2010 over the full study period. The first unit is planned for operation in 2030 with subsequent units becoming operational in 2033, 2035, 2037, 2039, 2041 and 2045. The tariff path model, which provides the expected tariff path for each case, suggests that this constraint (requiring 9600 MW of nuclear capacity) leads to a price path significantly higher than the Optimum Case and still higher than the Reference Case and Carbon Budget case.

Tariff path

7.4 An expected electricity price path for each of the key scenarios has been developed. The methodology adopted assumes all new capacity, with the exception of nuclear, is owned and operated by an independent power producer (thus costs are associated with levelised cost over the life of the plant), while existing Eskom capacity and nuclear costs (as well as Transmission and Distribution costs) are subject to the South African regulatory pricing methodology (which allows for cost recovery for work under construction thus the price path will allow for higher prices earlier in the life of the plant but level out in real terms over the life of the plant).

7.5 The price paths are indicated in Figure 12 for the key scenarios (with the exception of the Low Growth scenario). Initially all scenarios show a large escalation in electricity prices to indicate the "cost reflective" tariff associated with a debt-service ratio greater than 1 for the utility (i.e. that it has sufficient cash flow to cover debt-service obligations). This allows for more effective comparison between the scenarios as contemporary considerations regarding the appropriate price level are eliminated.

7.6 The Optimum Case provides the lower price path over the full period, with the Reference Case higher after 2035 by approximately 8c/kWh. The Forced Nuclear case has the highest price path over the period with prices approximately 15c/kWh higher than the Optimum Case.

The cumulative revenue difference over the period (between the Optimum Case as the lowest and each of the Reference Case, Carbon Budget scenario and Forced Nuclear scenario) is shown in

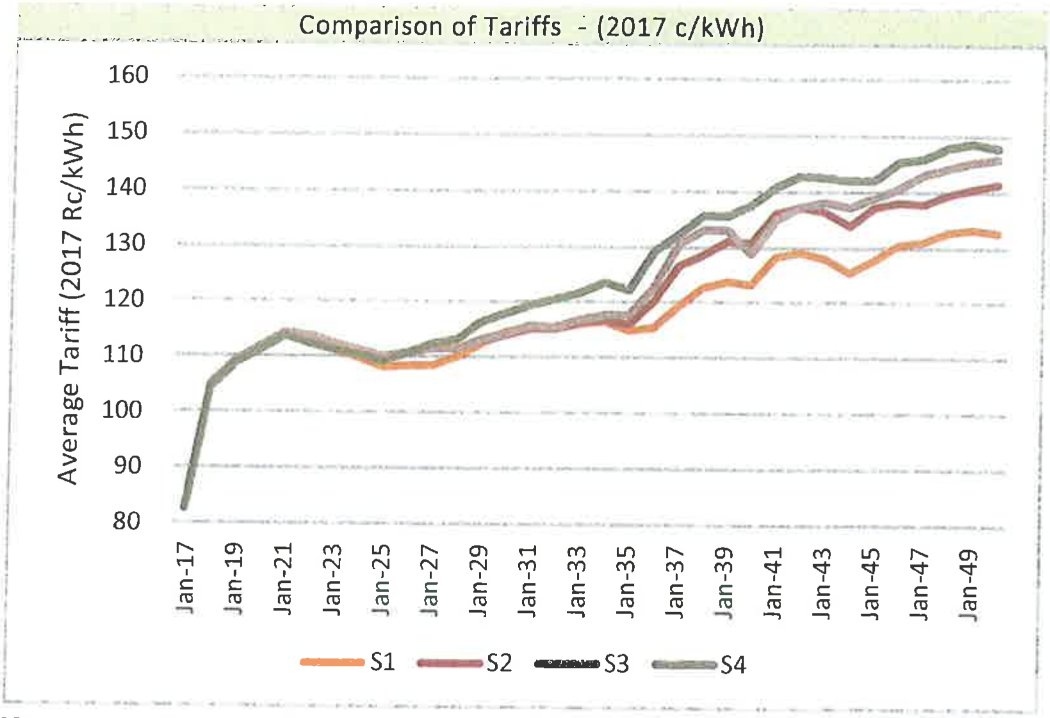
7.7 Figure 13. This reflects the long term effect of the higher prices associated with the other cases. After 2030 the effect increases, especially in the case of the Forced Nuclear and suggests that over the following twenty years the total revenue difference would amount to R800 billion (in real 2017 terms).

Utilisation of existing fleet

7.8 The Eskom coal fleet is currently under-utilised due to reducing demand over the recent past as new capacity is reaching commercially operation. It is expected that as demand increases the utilisation will return to an optimal range of 85-90%. Figure 14 shows how the different scenarios result in different utilisation patterns for the coal fleet. The Lower Growth scenario shows how the delayed growth keeps the utilisation at lower levels for longer before reaching the preferred range. The introduction of a carbon budget drives utilisation lower after 2035 in order to meet stricter targets. The Forced Nuclear case also reduces utilisation, partly due to the carbon budget, but also due to the forced additional capacity (especially in 2031) from large base-load nuclear capacity.

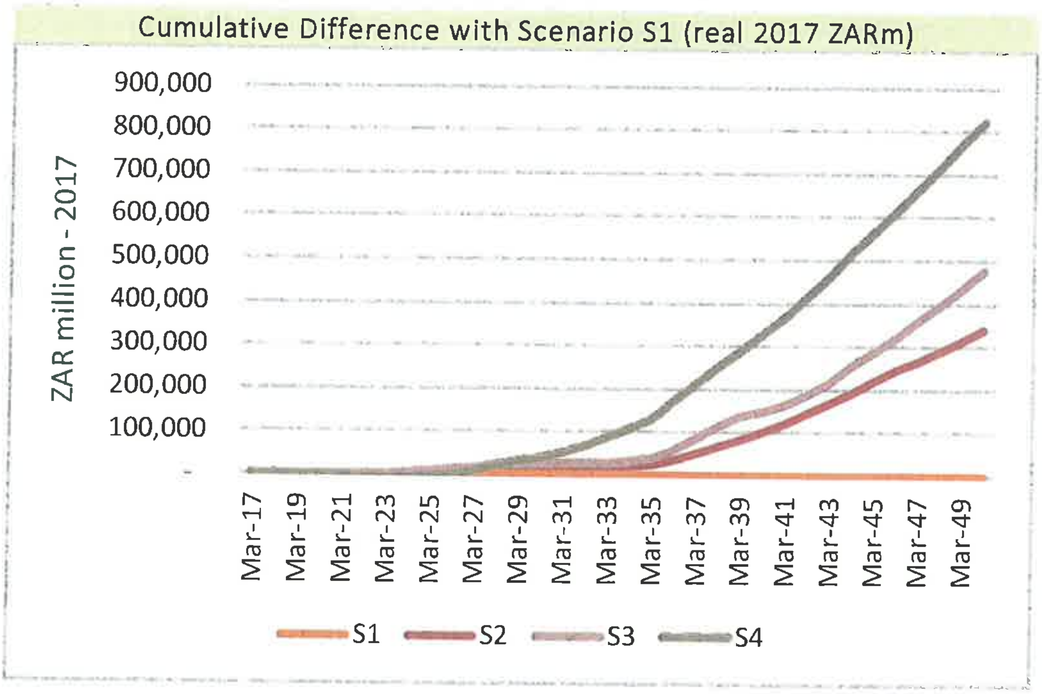
7.9 While a shortage of capacity has clear ramifications to the South African economy (as experienced in the 2014-15 period), under-utilisation of capacity has an impact on electricity tariffs since large capital costs are recovered via the regulatory tariff process from a reduced customer base leading to higher tariffs (and potentially a negative spiral of continuously declining demand and ever increasing tariffs).

Figure 12 – Price paths indicated for the key scenarios



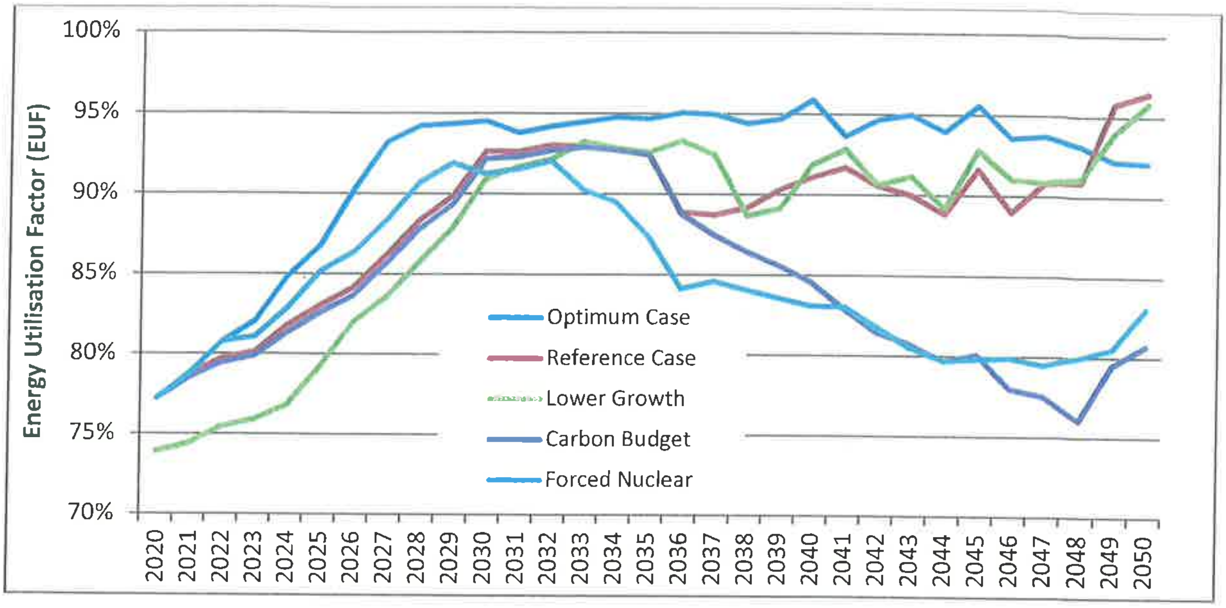
Notes: S1 = Optimum Case; S2 = Reference Case; S3 = Carbon Budget; S4 = Forced Nuclear

Figure 13 – Cumulative revenue difference between Optimum Case and other scenarios



Notes: S1 = Optimum Case; S2 = Reference Case; S3 = Carbon Budget; S4 = Forced Nuclear

Figure 14 – Energy utilization of Eskom coal fleet



8 COMMITMENTS BEFORE 2030 (COMMON ELEMENTS)

8.1 Whereas the IRP 2010 provided a final plan outlining specific annual capacity for each preferred technology from 2010 to 2030, it is proposed that the IRP 2017 provide guidance for the period ending 2030 and indicate broad decision trees for the period between 2031 and 2050.

8.2 Using the key scenarios identified above it is possible to identify commitments that are common to the scenarios and make a proposal for the period to 2030. Table 14 provides an overview of the technology options before 2030.

Table 14 – Common technology options before 2030 (excluding landfill gas)

	Reference Case				Optimal Plan				Low Growth				Carbon Budget				Forced Nuclear				
	PV	Wind	CC-GE	OCGT	PV	Wind	CC-GE	OCGT	PV	Wind	CC-GE	OCGT	PV	Wind	CC-GE	OCGT	PV	Wind	CC-GE	OCGT	Nuclear
2020	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2024	690	0	0	0	0	0	0	0	0	0	0	0	1000	0	0	0	0	0	0	0	0
2025	1000	900	300	0	20	0	2250	132	0	0	0	0	1000	1400	150	0	1000	0	900	0	0
2026	1000	1800	2250	0	0	0	750	0	770	0	0	0	1000	1800	2100	0	1000	1100	2550	0	0
2027	1000	1800	1500	0	2290	0	1350	132	1000	1300	750	0	1000	1800	1650	0	1000	1700	900	0	0
2028	1000	1800	1800	0	1640	2500	1800	396	1000	1800	1650	0	1000	1800	1950	0	1000	1800	1650	0	0
2029	1000	1800	3150	0	2180	2800	1950	264	1000	1800	2400	132	1000	1800	3000	0	1000	1800	3150	0	0
2030	1000	1800	150	792	1710	3700	1800	132	1000	1800	2250	264	1000	1800	600	1188	1000	1800	0	528	1400

8.3 Before 2030 the five main scenarios produce similar results with PV, Wind, CC-GE and OCGT being preferred options before 2030 (and the Forced Nuclear case requiring the first nuclear units in 2030). The variation between the five scenarios indicates the combination of growth rates and application of the carbon budget. Landfill gas is also a common element with each building the expected maximum of 250 MW before 2030.

8.4 By 2030 the five scenarios require new capacity from each technology as per Table 15.

Table 15 – Total new capacity required from each technology before 2030

	Reference Case	Optimal Plan	Low Growth	Carbon Budget	Forced Nuclear
PV	6690	7840	4770	7000	*8010*
Wind	9900	9000	6700	10400	*9900*
CC-GE	9150	9900	7050	9450	*8550*
OCGT	792	1056	396	1188	*1056*

Note: New capacity excludes capacity committed under existing procurement (as per Table 4) and existing capacity at 2017

8.5 In the case of each technology the minimum requirement is represented by the Low Growth scenario. As either expected growth increases or the carbon budget requirement becomes applicable the capacity from each technology increases. In particular the Optimal Plan requires that more PV is built as demand increases relative to Wind, reflecting the tighter annual limits imposed in the Reference Case.

8.6 For the purposes of a final IRP plan it is recommended that the following be adopted:

8.6.1 Annual procurement under continued Renewable Energy IPP programme, initially at 1000 MW PV, 1800 MW Wind, and for the maximum landfill gas that can be procured starting in 2019 (with expected financial close before 2021 and commercial operation starting in 2023), with a revision of the capacity in 2025 to ensure that continued annual procurement met the total capacity required in each case;

8.6.2 Development of the import infrastructure for LNG to meet the need of CC-GE and OCGT capacity by 2025;

8.6.3 Finalisation of the Gas procurement programme to accommodate competing generators for the capacity required under CC-GE and OCGT;

8.6.4 Continued development of energy efficiency programmes to ensure continued improvement of energy efficiency (and resulting electricity intensity).

8.7 As mentioned above the IRP did not analyse the impact of extending the life of existing Eskom (and non-utility) generators. Considering that the IRP has indicated the preferred capacity in the absence of life extension, any decision to extend life would require an analysis of the mitigation, air quality and water consumption impacts as well as the increase likelihood of under-utilisation of the capacity of Eskom generators if procurement of the above capacity continues at the pace proposed.

9 DECISION OPTIONS BEYOND 2030

9.1 The IRP 2010 indicated preferred options for the period 2010-30 but did recommend the need to be flexible considering inherent high uncertainty and changing circumstances. Beyond 2030 there is significant uncertainty regarding:

9.1.1 Expected demand

9.1.2 Policy regarding greenhouse gas mitigation strategy

9.1.3 Technology costs and potential disruptive technologies

9.2 For reference purposes, an additional case is indicated in the figures below to indicate the preferred technology without annual limits and lower growth trajectory. This case (the Lower Unconstrained Case) informs the extent to which the limits could be over-ridden through procurement when demand growth is low. The Lower Unconstrained Case suggests that the optimal PV capacity in 2050 is 30330 MW and optimal wind capacity is 45400 MW assuming the Lower demand growth.

Figure 15 – Total PV capacity under different scenarios

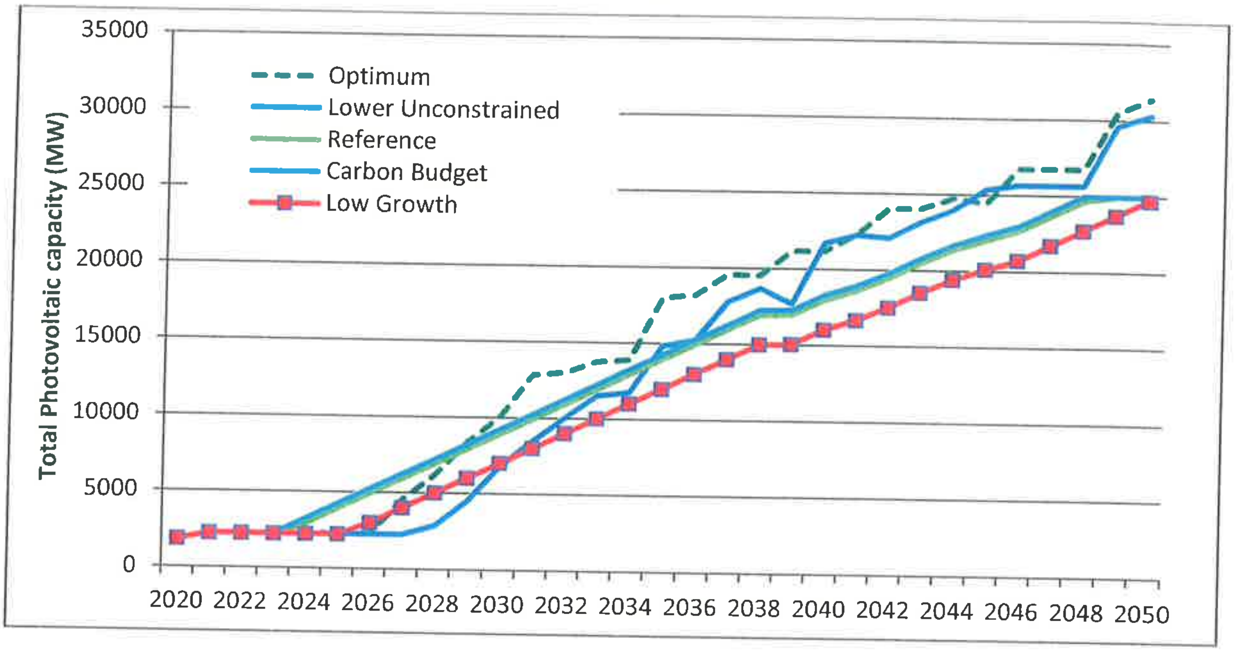


Figure 16 – Total Wind capacity under different scenarios

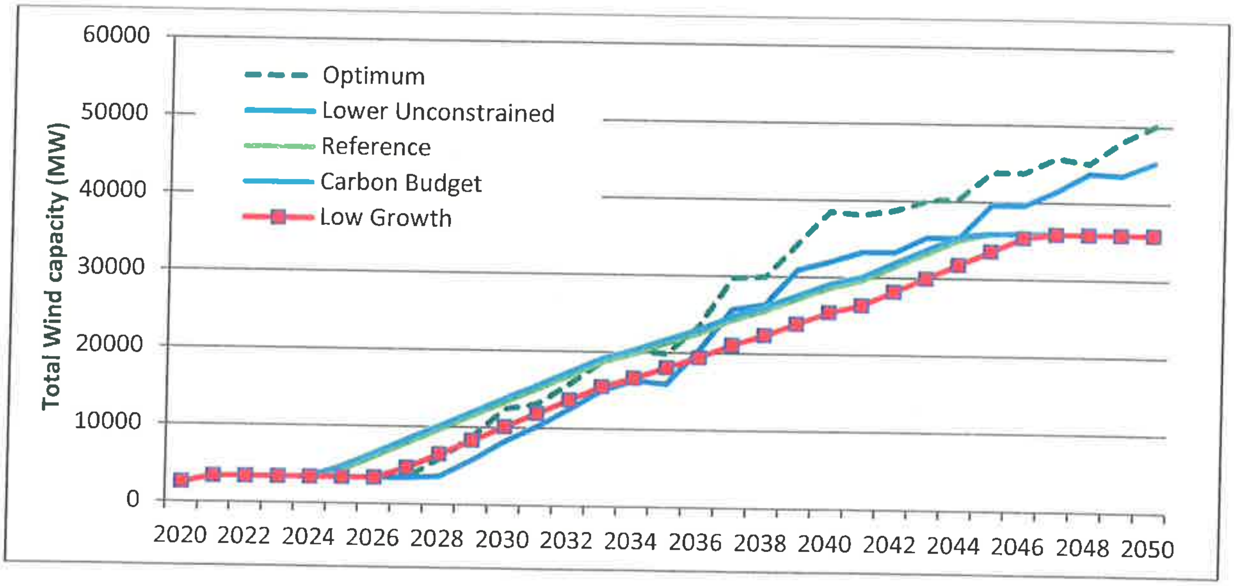


Figure 17 – Total CCGT capacity under different scenarios

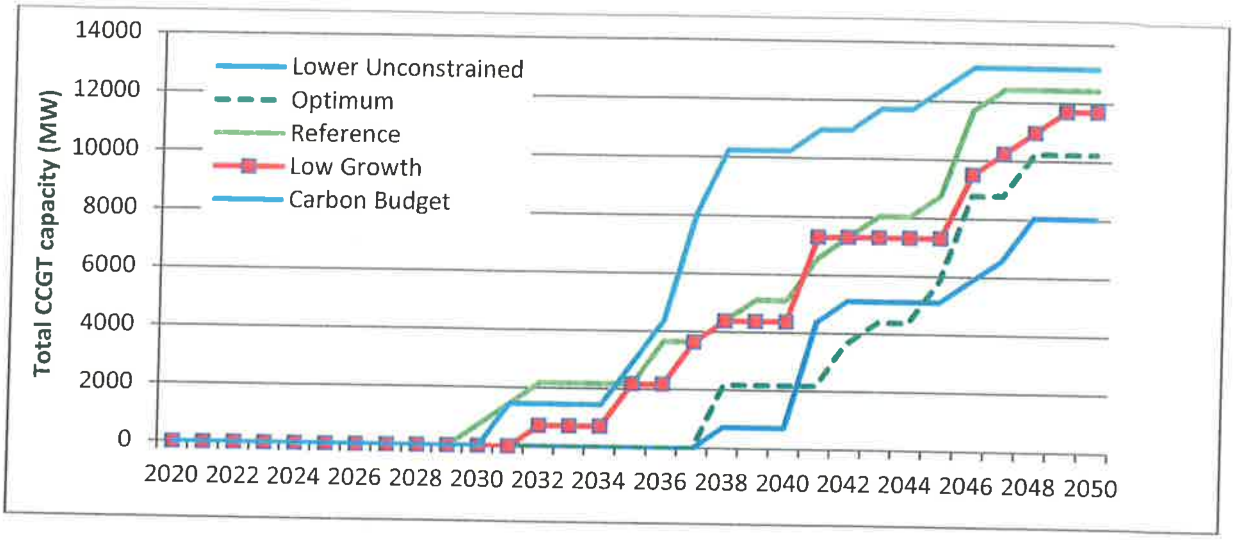


Figure 18 – Total OCGT capacity under different scenarios

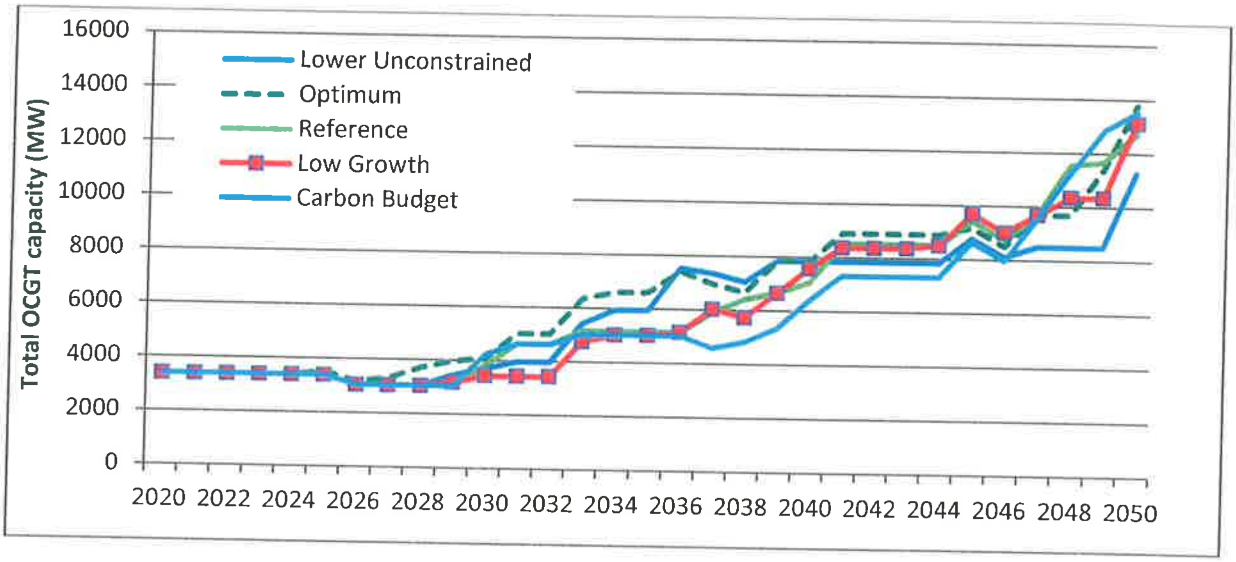


Figure 19 – Total Gas Engine capacity under different scenarios

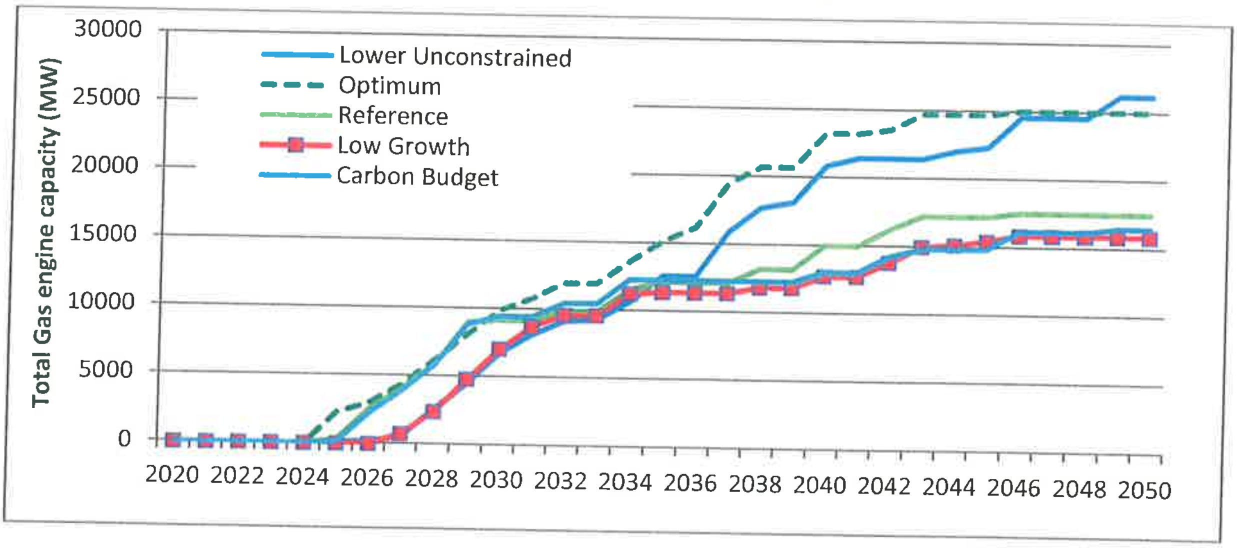
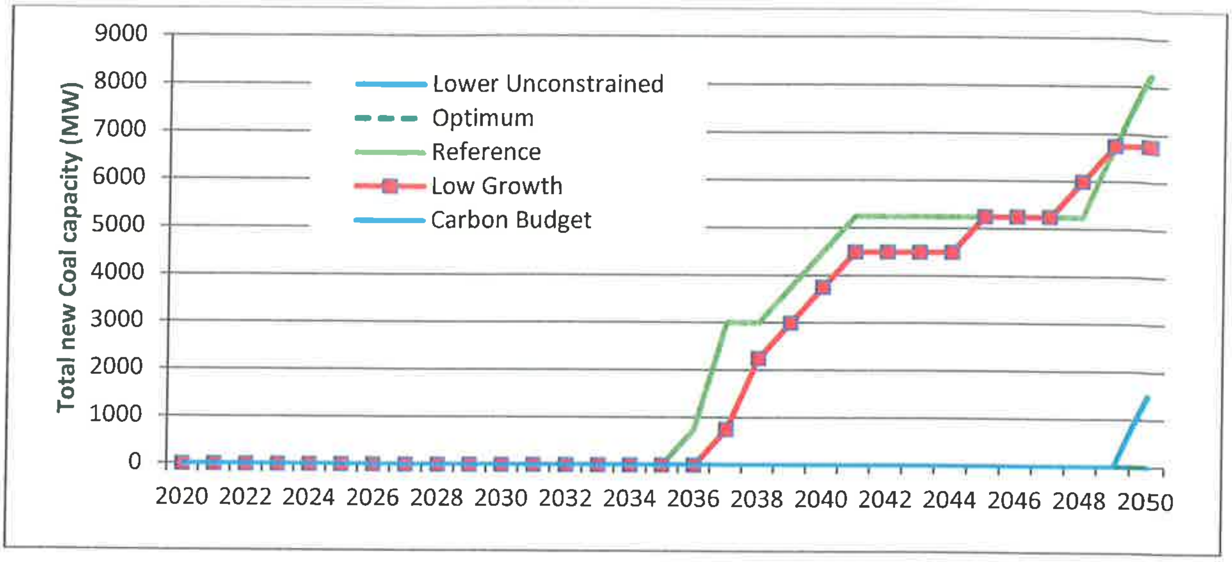


Figure 20 – Total new coal capacity under different scenarios



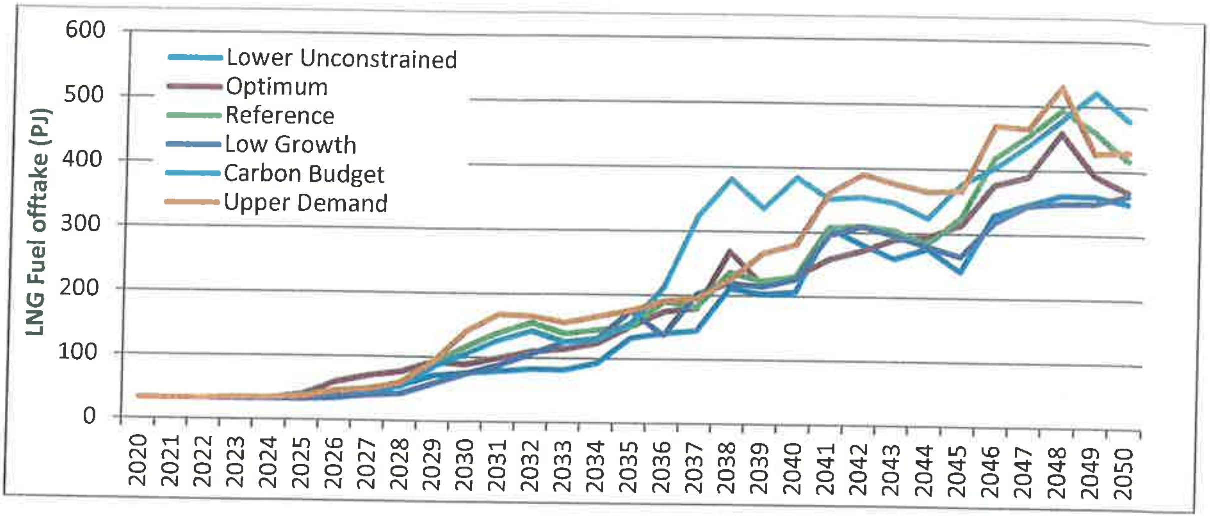
9.3 The clear lessons from the modelling of scenarios beyond 2030 are:

9.3.1 There is a limited requirement for nuclear capacity as this only occurs when the carbon budget constraint is applied at the same time as annual renewable capacity limits. In the absence of one of these then alternatives such as renewable energy or coal-fired generation are preferred by the model. It is thus recommended that no action is taken regarding nuclear capacity until the next iteration where the demand outlook and the system's ability to integrate renewable capacity are re-assessed.

9.3.2 New coal-fired generation is only required where the annual limits on renewable capacity are applied. In the absence of these limits the model prefers to build renewable capacity and gas backup (especially gas engines). From a future procurement perspective, there is time before the new capacity is proposed (in 2035 under the Reference Case) to assess the system's ability to integrate renewable capacity and determine whether this constraint is valid.

9.3.3 The period leading up to 2030 would likely see the establishment of at least one significant import terminal for LNG. The requirement for additional storage or import facilities is evident from the total annual gas import as indicated in Figure 21. A final decision regarding the new infrastructure will depend strongly on whether battery technology (or other backup technologies) progresses to the point of disrupting the need for gas. There is sufficient time before committing to this infrastructure.

Figure 21 – Annual gas offtake under different scenarios



9.3.4 In terms of the procurement of additional renewable energy capacity it is Figure 15 and Figure 16 show the tight band of annual capacity addition, driven predominantly by the annual limits but also the general requirement from the unconstrained optimisation over the period.

9.3.4.1 The IRP model applies the annual limits as a maximum for additional capacity in each year. These limits though also provide a minimum that should apply for the procurement of wind and PV capacity. It can be seen from the capacity graphs above that, except for the initial period before 2030, these limits provide the effective floor for new capacity, always below the optimal level for the Lower and Median forecasts. By procuring this capacity annually, even before the optimal position requires, the system will allow for consistent and sustainable development of the technology domestically, supporting the potential for localisation of ancillary technologies.

9.3.4.2 Every year the procuring authority should determine the registered capacity for self-supply PV (assuming that NERSA has completed regulations for such a registration mechanism, in the absence of this annual surveys to determine self-supply should be considered). The annual procurement window should only require new PV capacity for the shortfall (the required capacity less that already self-supplied) in to avoid over-capacity for this particular technology.

9.3.4.3 Given the short lead times for renewable capacity it is proposed that adjustments to the annual procurement be allowed three to five years in advance but always maintaining some minimum in order to ensure the viability of downstream industries and avoiding an intermittent procurement process that provides limited certainty to developers.

9.3.5 The costs for production and transport for the Inga power project in the DRC should be confirmed before commitment to the project. At the submitted costs for the project it is an attractive option for base-load renewable generation for South Africa. The requirement for the capacity in the early 2030s requires that a final decision should be reached by 2022 in order to ensure alternatives are developed should the project not be viable.

9.3.6 There is a clear need for continued Demand Response programmes that support the system's ability to integrate renewable energy as well as maintain system security. DR plays a role in reducing the need for additional peaking capacity and is currently limited by the expectation of consumer appetite for this service. By managing regular auctions for DR it is possible that the expected capacity could be increased and displace the need for more peaking generation.

10 PROPOSED INTEGRATED RESOURCE PLAN

10.1 Arising from the discussion above it is proposed that there is a "Base Plan" that caters for the minimum expected demand. Capacity additions according to this "Base Plan" will meet the requirements of the Moderate Decline and Carbon Budget mitigation options. This plan is provided in Table 16.

Table 16 – Proposed Base Plan for IRP 2017

	Base Plan – Annual Capacity added (MW)					
	PV	Wind	Landfill	Gas - Peaking (OCGT)	Gas - Fast response (Engines)	Gas - Mid Merit (CCGT)
2020				0	0	0
2021				0	0	0
2022	1000			0	0	0
2023	1000	1800		0	0	0
2024	1000	1800		0	0	0
2025	1000	1800	125	0	300	0
2026	1000	1800	125	0	400	0
2027	1000	1800		792	1500	0
2028	1000	1800		792	1500	0
2029	1000	1800		0	1500	0
2030	1000	1800		0	2250	732
2031	1000	1800		0	2000	732
2032	1000	1800		0	1000	732
2033	1000	1800		528	500	0
2034	1000	1800		0	500	732
2035	1000	1800		0	500	1464
2036	1000	1800		0	500	1464
2037	1000	1800		1188	500	2196
2038	1000	1800		792	500	2196
2039	1000	1800		1584	500	0
2040	1000	1800		396	500	732
2041	1000	1800		1452	500	732
2042	1000	1800		0	500	0
2043	1000	1800		0	500	0
2044	1000	1800		0	500	0
2045	1000	1800		924	500	732
2046	1000	1800		0	450	732
2047	1000	1800		924	0	0
2048	1000	1800		1848	0	0
2049	1000	1800		132	0	0
2050	1000	1800		1056	0	0

10.2 In addition, should demand increase faster than the lower demand trajectory then a "Supplemental Plan" would contribute additional capacity. If the latest projections of country net-sentout exceed that in the plan for the specific year then the additional capacity for that year should be procured or constructed.

	Supplemental Plan – Annual capacity added (MW)				
	Expected Annual Net Sent-out (GWh)	PV	Wind	Gas - Fast response (Engines)	Gas - Mid Merit (CCGT)
2028	304 517				
2029	308 754				
2030	312 936				732
2031	317 113	600			
2032	321 162				

2033	325 204				
2034	329 280	500			
2035	333 290	1000	1000	800	
2036	337 343		1000	1000	
2037	341 413		1000	1000	
2038	345 279		1000	1000	
2039	348 905			1000	
2040	352 745		1400		

11 REFERENCES

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