GOVERNMENT NOTICE

DEPARTMENT OF ENERGY

No. R. 400 **6 May 2011**

Electricity Regulation Act No.4 of 2006

Electricity Regulations on the Integrated Resource Plan 2010 - 2030

I, Dipuo Peters, Minister of Energy, hereby under the Electricity Regulation Act, 2006 (Act No. 4 of 2006), promulgate IRP 2010 in the Schedule.

SCHEDULE

INTEGRATED RESOURCE PLAN FOR ELECTRICITY 2010-2030

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ABBREVIATIONS

CCGT	Closed Cycle Gas Turbine
CO_2	Carbon Dioxide
COUE	Cost of Unserved Energy
CSIR	Council for Scientific and Industrial Research
CSP	Concentrating Solar Power
DoE	Department of Energy
DSM	Demand Side Management
EEDSM	Energy Efficiency Demand Side Management
EIA	Environmental Impact Assessment
EPRI	Electric Power Research Institute
FBC	Fluidised Bed Combustion
FGD	Flue Gas Desulphurisation
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GJ	Gigajoules
GW	Gigawatt (One thousand Megawatts)
GWh	Gigawatt hour
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
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)
PF	Pulverised Fuel
PV	Present Value; alternatively Photo-Voltaic
PWR	Pressurised Water Reactor
RAB	Regulatory Asset Base
REFIT	Renewable Energy Feed-in Tariff
RTS	Return to Service
SOx	Sulphur Oxide
TW	Terawatt (One million Megawatts)
TWh	Terawatt hour

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.

"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.

"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.

"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.

"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.

"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.

"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 that indicate a set of future circumstances, providing a mechanism to observe outcomes from these circumstances.

"Screening curve" refers to a graph that indicates the levelised cost of technology options relative to potential capacity factors for these technologies. These can be used to screen out clearly inferior technologies from a cost perspective.

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

SUMMARY

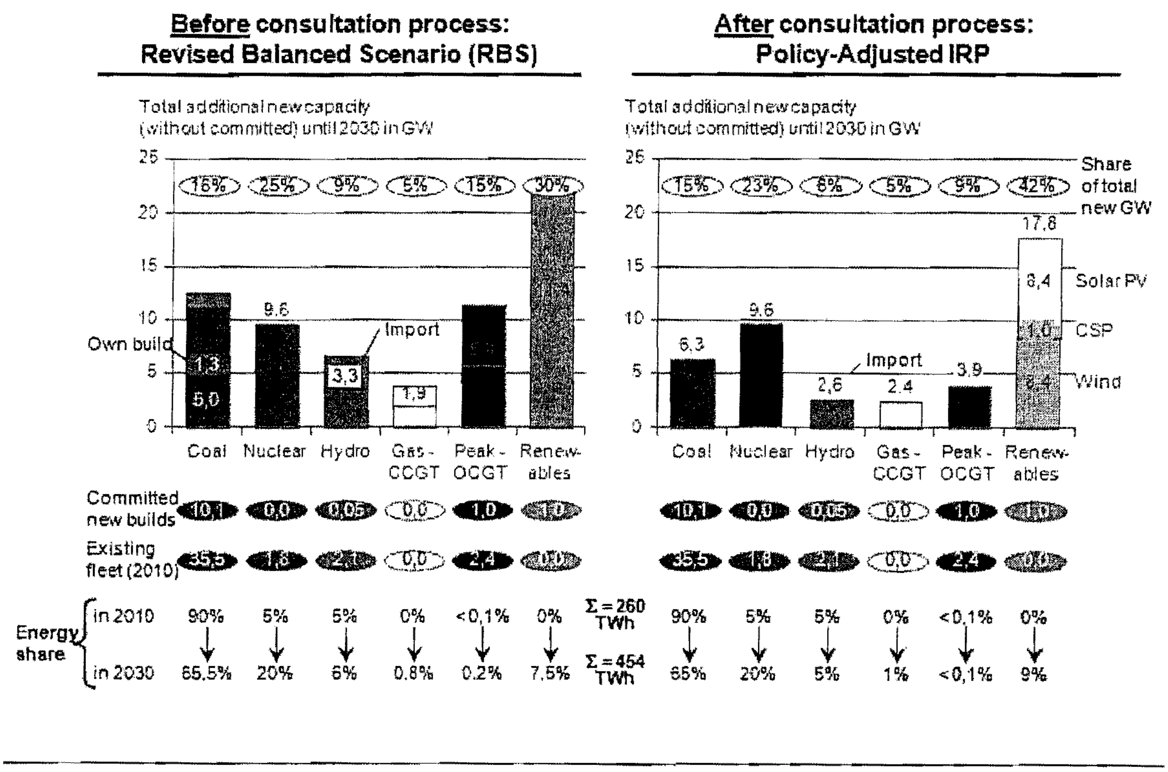
The current iteration of the Integrated Resource Plan (IRP) for South Africa, initiated by the Department of Energy (DoE) after a first round of public participation in June 2010, led to the Revised Balanced Scenario (RBS) that was published in October 2010. It laid out the proposed generation new build fleet for South Africa for the period 2010 to 2030. This scenario was derived based on the cost-optimal solution for new build options (considering the direct costs of new build power plants), which was then "balanced" in accordance with qualitative measures such as local job creation. In addition to all existing and committed power plants, the RBS included a nuclear fleet of 9,6 GW; 6,3 GW of coal; 11,4 GW of renewables; and 11,0 GW of other generation sources.

A second round of public participation was conducted in November/December 2010, which led to several changes to the IRP model assumptions. The main changes were the disaggregation of renewable energy technologies to explicitly display solar photovoltaic (PV), concentrated solar power (CSP) and wind options; the inclusion of learning rates, which mainly affected renewables; and the adjustment of investment costs for nuclear units by increase of 40% based on recent construction experience.

Additional cost-optimal scenarios were generated based on the changes. The outcomes of these scenarios, in conjunction with the following policy considerations, led to the Policy-Adjusted IRP:

- The installation of renewables (solar PV, CSP and wind) have been brought forward in order to accelerate a local industry;
- To account for the uncertainties associated with the costs of renewables and fuels, a nuclear fleet of 9,6 GW is included in the IRP;
- The emission constraint of the RBS (275 million tons of carbon dioxide per year after 2024) is maintained;
- Energy efficiency demand-side management (EEDSM) measures are maintained at the level of the RBS.

This Policy-Adjusted IRP is recommended for adoption by Cabinet and for subsequent promulgation as the final IRP. This proposal is a confirmation of the RBS in that it ensures security of supply. It is a major step towards building local industry clusters and assists in fulfilling South Africa's commitments to mitigating climate change as expressed at the Copenhagen climate change summit. The Policy-Adjusted IRP includes the same amount of coal and nuclear new builds as the RBS, while reflecting recent developments with respect to prices for renewables. In addition to all existing and committed power plants (including 10 GW committed coal), the plan includes 9,6 GW of nuclear; 6,3 GW of coal; 17,8 GW of renewables; and 8,9 GW of other generation sources.



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1 IRP IN CONTEXT

1.1 The Integrated Resource Plan (IRP) is a living plan that is expected to be continuously revised and updated as necessitated by changing circumstances. At the very least, it is expected that the IRP should be revised by the Department of Energy (DoE) every two years, resulting in a revision in 2012.

1.2 The DoE initiated the current iteration of the IRP following the completion of the first draft iteration in January 2010. The first iteration covered a limited period for new capacity development (2010-2013), with the intention of conducting a more inclusive process to develop the full plan covering the period 2010 to 2030.

1.3 The first round of public participation was conducted in June 2010 and focussed on the input parameters for the IRP modelling. The final inputs for the IRP were published along with the comments submitted on each parameter and responses by the DoE. Following this, the IRP modelling was undertaken including scenarios for different outcomes, policy options and technology choices. The Revised Balanced Scenario (RBS) was developed in discussion with other departments, incorporating different policy objectives and the cost optimisation was undertaken as part of the modelling process.

1.4 The Inter-Ministerial Committee (IMC) approved the RBS for publication in order to elicit public comment on the plan. A draft IRP report (with the RBS as a draft IRP) was published for public comment alongside the Executive Summary (used for the IMC deliberations) and the Medium Term Risk Mitigation Project (MTRMP) which focussed on the next six years and the potential shortfall of generation in the medium term.

1.5 The public participation process included the opportunity for interested parties and individuals to submit written comments (either through the provided questionnaire, as a preferred option, or in any other form) and to make a presentation at one of three workshops held in Durban (26 November 2010), Cape Town (29 November 2010) or Johannesburg (2 and 3 December 2010).

1.6 The public consultation and subsequent independent international consultant input resulted in changes to the IRP modelling as well as new scenarios to test additional policy options and outcomes. This process led to refinements, and to the proposed Policy-Adjusted IRP presented herein.

2 BALANCING GOVERNMENT OBJECTIVES IN THE IRP

2.1 The RBS was developed in consultation with government departments represented in Working Group 2 (as part of the inter-departmental task team process). The multi-criteria decision-making process confirmed that this RBS represented an appropriate balance between the expectations of different stakeholder considering a number of key constraints and risks, for example:

a) Reducing carbon emissions;
b) New technology uncertainties such as costs, operability, lead time to build etc;
c) Water usage;
d) Localisation and job creation;
e) Southern African regional development and integration; and
f) Security of supply.

2.2 The RBS was adjusted from a cost-optimised scenario developed under a carbon emission constraint of 275 million tons per year from 2025, incorporating localisation objectives and bringing forward the renewable roll-out. By bringing the construction programme for renewable technologies forward and maintaining a stable roll-out programme, an opportunity was provided for localisation, not only in the construction of the equipment, but in the development of skills to support the renewable energy programme. By not specifically categorising the renewable technologies after 2020, a window was provided for government to direct alternative renewable technology development to meet government objectives.

2.3 As part of the medium-term risk mitigation project, a number of own generation or co-generation options were identified for implementation before 2016. These options were included in the RBS as additional capacity, forced in as per the medium-term schedule, in order to maintain some continuity between the plans. However these options were not included in the calculations on water, prices or emissions.

Table 1. Revised Balanced Scenario

	Committed build											New build options												
	RTS Capacity (coal)	Medupi (coal)	Kusile (coal)	Ingula (pumped storage)	DOE OCGT IPP (diesel)	Co-generation, own build	Wind	CSP	Landfill, hydro	Sere (wind)	Decommissioning	Coal (PF, FBC, Imports)	Co-generation, own build	Gas CCGT (natural gas)	OCGT (diesel)	Import Hydro	Wind	Solar PV, CSP	Renewables (Wind, Solar CSP, Solar PV, Landfill, Biomass, etc.)	Nuclear Fleet	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Demand Side Management
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
2010	380	0	0	0	0	260	0	0	0	0	0	0	0	0	0	0	0	0	0	0	640	44535	38885	252
2011	679	0	0	0	0	130	200	0	0	0	0	0	103	0	0	0	0	0	0	0	1112	45647	39956	494
2012	303	0	0	0	0	0	200	0	100	100	0	0	0	0	0	0	0	0	0	0	703	46350	40995	809
2013	101	722	0	333	1020	0	300	0	25	0	0	0	124	0	0	0	0	0	0	0	2625	48975	42416	1310
2014	0	722	0	999	0	0	0	100	0	0	0	0	426	0	0	0	200	0	0	0	2447	51422	43436	1966
2015	0	1444	0	0	0	0	0	100	0	0	-180	0	600	0	0	0	400	0	0	0	2364	53786	44865	2594
2016	0	722	0	0	0	0	0	0	0	0	-90	0	0	0	0	0	800	100	0	0	1532	55318	45786	3007
2017	0	722	1446	0	0	0	0	0	0	0	0	0	0	0	0	0	800	100	0	0	3068	58386	47870	3420
2018	0	0	723	0	0	0	0	0	0	0	0	0	0	0	0	0	800	100	0	0	1623	60009	49516	3420
2019	0	0	1446	0	0	0	0	0	0	0	0	0	0	474	0	0	800	100	0	0	2820	62829	51233	3420
2020	0	0	723	0	0	0	0	0	0	0	0	0	0	711	0	360	0	0	800	0	2594	65423	52719	3420
2021	0	0	0	0	0	0	0	0	0	0	-75	0	0	711	0	750	0	0	800	0	2186	67609	54326	3420
2022	0	0	0	0	0	0	0	0	0	0	-1870	0	0	0	805	1110	0	0	800	0	845	68454	55734	3420
2023	0	0	0	0	0	0	0	0	0	0	-2280	0	0	0	805	1129	0	0	800	1600	2054	70508	57097	3420
2024	0	0	0	0	0	0	0	0	0	0	-909	0	0	0	575	0	0	0	800	1600	2066	72574	58340	3420
2025	0	0	0	0	0	0	0	0	0	0	-1520	0	0	0	805	0	0	0	1400	1600	2285	74859	60150	3420
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	600	1600	2200	77059	61770	3420
2027	0	0	0	0	0	0	0	0	0	0	0	750	0	0	805	0	0	0	1200	0	2755	79814	63404	3420
2028	0	0	0	0	0	0	0	0	0	0	-2850	2000	0	0	805	0	0	0	0	1600	1555	81369	64867	3420
2029	0	0	0	0	0	0	0	0	0	0	-1128	750	0	0	805	0	0	0	0	1600	2027	83396	66460	3420
2030	0	0	0	0	0	0	0	0	0	0	0	1500	0	0	345	0	0	0	0	0	1845	85241	67809	3420
TOTAL	1463	4332	4338	1332	1020	390	700	200	125	100	-10902	5000	1253	1896	5750	3349	3800	400	7200	9600	41346			

Table 2. Revised Balanced scenario capacity

	Total generating capacity in 2030		Capacity added (including committed) from 2010 to 2030		New (uncommitted) capacity options from 2010 to 2030	
	MW	%	MW	%	MW	%
Coal	41074	48.2	16386	31.4	6253	16.3
OCGT	9170	10.8	6770	13.0	5750	15.0
CCGT	1896	2.2	1896	3.6	1896	5.0
Pumped Storage	2912	3.4	1332	2.5	0	0.0
Nuclear	11400	13.4	9600	18.4	9600	25.1
Hydro	5499	6.5	3399	6.5	3349	8.8
Wind[1]	11800	13.8	11800	22.6	11000	28.8
CSP	600	0.7	600	1.1	400	1.0
PV	0	0.0	0	0.0	0	0.0
Other	890	1.0	465	0.8	0	0.0
Total	85241		52248		38248	

Notes: (1) Wind includes the "Renewables" bucket identified in the RBS after 2019

(2) Committed generation capacity includes projects approved prior to IRP 2010 (refer to Table1)

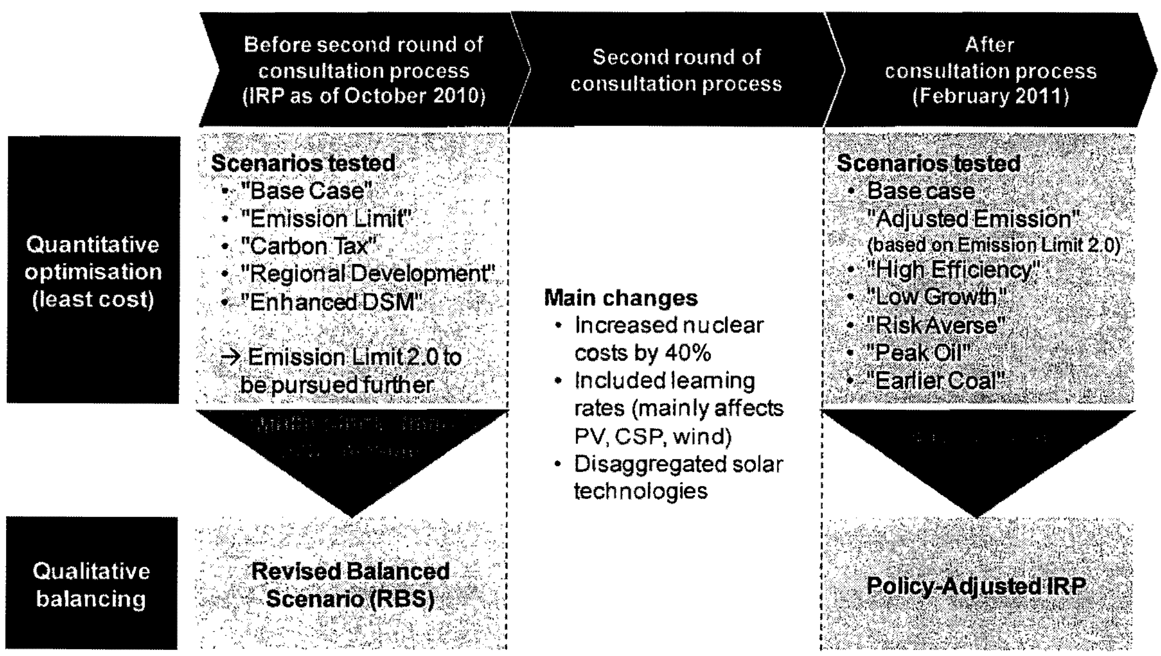
3 CONSULTATION PROCESS AND LEARNINGS

3.1 In total, 479 submissions were received from organisations, companies and individuals, resulting in 5090 specific comments. Specific issues raised included the need to reduce carbon emissions further than proposed in the RBS, by increasing renewable energy, improving energy efficiency initiatives and considering a lower growth in electricity demand. Opposition to nuclear generation was raised, suggesting that renewable generation could replace nuclear generation in the plan. The impact of the additional capacity on the future electricity price path was a key consideration, with concerns raised regarding the impact on the poor as well as on the competitiveness of the South African economy. The lack of a socio-economic impact study was a concern, as was the exclusion of the impact of network costs on the choice of technologies.

3.2 As a consequence of these comments, additional research was conducted (in particular on technology learning rates and the cost evolution of solar PV technology). The results of this research were included in the modelling along with modified assumptions on nuclear capital costs and biomass modelling. Additional scenarios were also included to test specific policy choices and potential outcomes (specifically on future fuel prices and demand projections).

3.3 An overview of the IRP process is provided in Figure 1, indicating the original scenarios covered in the draft IRP report which culminated (through the multi-criteria decision-making process) in the RBS. The second round of public participation resulted in modelling changes, leading to a further set of scenarios developed as part of the cost-optimisation. The policy choices highlighted in this report informed the development of the Policy-Adjusted IRP.

Figure 1. Overview of IRP process



4 POLICY CLARIFICATION

4.1 The changes brought about by the public consultation and the scenarios required a review of the policy parameters established for the RBS.

Policy Issue 1: Nuclear options

4.2 The scenarios indicated that the future capacity requirement could, in theory, be met without nuclear, but that this would increase the risk to security of supply (from a dispatch point of view and being subject to future fuel uncertainty).

4.3 Three policy choice options were identified:

a) Commit to the nuclear fleet as indicated in the RBS;
b) Delay the decision on the nuclear fleet indefinitely (and allow alternatives to be considered in the interim);
c) Commit to the construction of one or two nuclear units in 2022-4, but delay a decision on the full nuclear fleet until higher certainty is reached on future cost evolution and risk exposure both for nuclear and renewables.

4.4 The Department accepted option 4.3a, committing to a full nuclear fleet of 9600 MW. This should provide acceptable assurance of security of supply in the event of a peak oil-type increase in fuel prices and ensure that sufficient dispatchable base-load capacity is constructed to meet demand in peak hours each year.

Policy Issue 2: Emission constraints

4.5 The scenarios indicated that a requirement for future coal-fired generation could only be met by increasing the emission target from that imposed in the RBS.

4.6 Two policy choice options were identified:

a) Commit to the emission constraint as reflected in the RBS;
b) Allow an increase in the emission constraint to a new unspecified target.

4.7 The Department accepted option 4.6a, retaining the emission constraint as reflected in the RBS. The RBS allowed for coal-fired generation after 2026. The policy requirement for continuing a coal programme could result in this coal-fired generation being brought forward to 2019-2025, thus by 2030 the emission outcome should not be affected, only the timing of the constraint. Existing coal-fired generation is run at lower load factors to accommodate the new coal options while the target applies.

Policy Issue 3: Import options

4.8 The scenarios assumed that all identified import options could be utilised (with the exception of the Namibian gas option). This includes 3349 MW of import hydro (from Mozambique, Lesotho and Zambia) and the coal options identified in Mozambique and Botswana. The additional capacity to the RBS is the Botswana coal option.

4.9 Four policy choice options were identified:

a) Limit the coal import options (or exclude completely); or
b) Limit the hydro import options (to 2500 MW); or
c) Limit both options to 0 MW for coal and 2500 MW for hydro; or
d) Allow import options to the extent identified in the RBS, inclusive of import coal options.

4.10 The Department accepted option 4.9d, allowing for import options, with the exception that import coal options will not be separately identified but considered as part of the domestic coal fleet (with emissions counting towards South Africa's carbon inventory as with domestic coal).

Policy Issue 4: Energy efficiency

4.11 The extent to which Energy Efficiency Demand-Side Management (EEDSM) impacts on future generation options was an important consideration. In the RBS, the Eskom Demand Side Management programme, as reflected in the multi-year price determination application to NERSA, was assumed as the EEDSM base. During the public participation process, it was suggested that this under-estimated the potential of EEDSM. By increasing EEDSM in one of the scenarios it was possible to reduce carbon emissions while reducing the need for additional capacity. However, there is a risk, which cannot be ignored, that the EEDSM programme may under-achieve.

4.12 Two policy choice options were identified:

a) Increase the assumed EEDSM programme to the 6298 MW capacity option; or
b) Continue with the EEDSM[1] as in the RBS.

4.13 The Department accepted option 4.12b. While aware of the benefits of increased EEDSM, the Department believes that the risk to the security of supply, if relying on this option, negates the assumed benefits.

5 THE POLICY-ADJUSTED IRP

5.1 The public consultation provided useful feedback to the planning process, including additional information and alternative views that assisted in the development of the Policy-Adjusted IRP.

5.2 Following the policy recommendations highlighted above, and the modelling changes undertaken as a result of the public participation process, the following changes were made to the RBS, resulting in the Policy-Adjusted IRP:

5.2.1 Inclusion of solar PV as a separate technology option with an assumed roll-out of 300 MW per year from 2012 (since solar PV can be rolled out early if procurement processes are initiated immediately);

5.2.2 Bringing forward the coal generation, originally expected only after 2026, and allowing for imported coal options;

5.2.3 Securing a minimum 711 MW from combined cycle gas turbines (CCGT) – possibly using liquefied natural gas (LNG) – between 2019 and 2021 (to improve security of supply by providing back-up to the renewable energy roll-out) as well as additional CCGT later in the IRP period;

5.2.4 Consolidating the co-generation and own build category of the RBS into the coal options identified in the Policy-Adjusted IRP and treating the co-generation as part of the expected demand;

5.2.5 Allowing for cost optimisation on import hydro options leading to a reduction compared to the RBS (due to the increased renewable roll-out and bringing coal generation forward); and

5.2.6 Modifications to the roll-out of wind and concentrated solar power (CSP) to accommodate the solar PV options, with a complete disaggregation of the previous renewable grouping into

[1] The EEDSM programme includes a contribution of 1617 MW of renewable energy from solar water heating.

constituent technologies: wind, solar CSP, and solar PV. Due to delays in the renewable energy feed-in tariff (REFIT), the committed wind capacity from REFIT has been delayed to 2012.

5.3 These changes reflect government policy on the future of different technologies and requirements from different sectors of the economy.

5.4 The Policy-Adjusted IRP continues to indicate a balance between different government objectives, specifically economic growth, job creation, security of supply and sustainable development.

5.5 The Department believes that security of supply should not be compromised. The Policy-Adjusted IRP has been tested for adequacy in all years of the IRP period. The CCGT options have been introduced earlier than the optimised plan required in order to deal with security of supply concerns arising between 2022 and 2028. To further support security of supply, decommissioning of existing plant should take place toward the end of the year in which it is assumed to be decommissioned.

5.6 Affordability is a key consideration and, as reflected in the discussion in Appendix C, the Policy-Adjusted IRP results in a price path similar to that of the RBS.

5.7 Additional coal options would be undermined by a carbon tax regime, which would render South African industries less competitive and put economic value, jobs and country growth at risk.

5.8 Unacceptable planning uncertainty and economic growth risk will be created if further demand forecast reductions or more rapid energy intensity reductions are assumed.

Figure 2. Changes to the Revised Balanced Scenario that informed the Policy-Adjusted IRP

Adjustment	Resulting change to RBS
Disaggregation of solar technologies	Solar PV now included
Inclusion of learning rates	More renewables due to their increasing competitiveness
Roll-out of coal new builds in a more steady manner	End-2020s-planned coal new builds brought forward

Table 3. Policy-Adjusted IRP

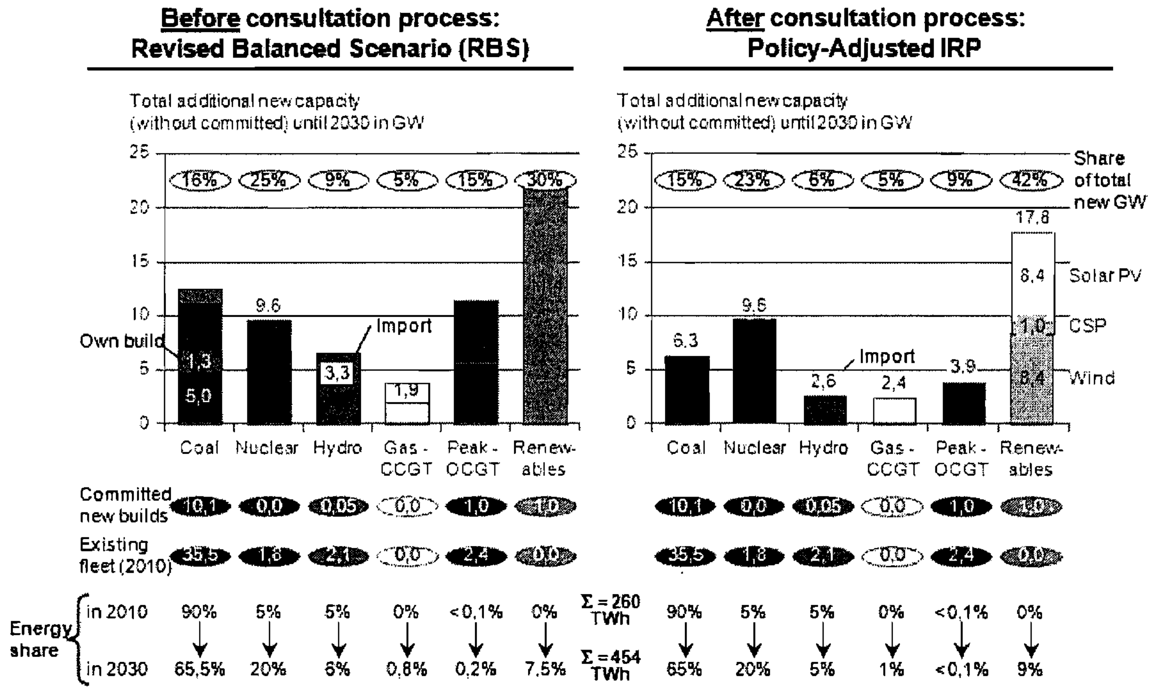
	Committed build											New build options											
	RTS Capacity (coal)	Medupi (coal)	Kusile (coal)	Ingula (pumped storage)	DOE OCGT IPP (diesel)	Co-generation, own build	Wind	CSP	Landfill, hydro	Sere (wind)	Decommissioning	Coal (PF, FBC, Imports)	Gas CCGT (natural gas)	OCGT (diesel)	Import Hydro	Wind	Solar PV	CSP	Nuclear	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Demand Side Management
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
2010	380	0	0	0	0	260	0	0	0	0	0	0	0	0	0	0	0	0	0	640	44535	38885	252
2011	679	0	0	0	0	130	0	0	0	0	0	0	0	0	0	0	0	0	0	809	45344	39956	494
2012	303	0	0	0	0	0	300	0	100	100	0	0	0	0	0	0	300	0	0	1103	46447	40995	809
2013	101	722	0	333	1020	0	400	0	25	0	0	0	0	0	0	0	300	0	0	2901	49348	42416	1310
2014	0	722	0	999	0	0	0	100	0	0	0	500	0	0	0	400	300	0	0	3021	52369	43436	1966
2015	0	1444	0	0	0	0	0	100	0	0	-180	500	0	0	0	400	300	0	0	2564	54933	44865	2594
2016	0	722	0	0	0	0	0	0	0	0	-90	0	0	0	0	400	300	100	0	1432	56365	45786	3007
2017	0	722	1446	0	0	0	0	0	0	0	0	0	0	0	0	400	300	100	0	2968	59333	47870	3420
2018	0	0	723	0	0	0	0	0	0	0	0	0	0	0	0	400	300	100	0	1523	60856	49516	3420
2019	0	0	1446	0	0	0	0	0	0	0	0	250	237	0	0	400	300	100	0	2733	63589	51233	3420
2020	0	0	723	0	0	0	0	0	0	0	0	250	237	0	0	400	300	100	0	2010	65599	52719	3420
2021	0	0	0	0	0	0	0	0	0	0	-75	250	237	0	0	400	300	100	0	1212	66811	54326	3420
2022	0	0	0	0	0	0	0	0	0	0	-1870	250	0	805	1143	400	300	100	0	1128	67939	55734	3420
2023	0	0	0	0	0	0	0	0	0	0	-2280	250	0	805	1183	400	300	100	1600	2358	70297	57097	3420
2024	0	0	0	0	0	0	0	0	0	0	-909	250	0	0	283	800	300	100	1600	2424	72721	58340	3420
2025	0	0	0	0	0	0	0	0	0	0	-1520	250	0	805	0	1600	1000	100	1600	3835	76556	60150	3420
2026	0	0	0	0	0	0	0	0	0	0	0	1000	0	0	0	400	500	0	1600	3500	80056	61770	3420
2027	0	0	0	0	0	0	0	0	0	0	0	250	0	0	0	1600	500	0	0	2350	82406	63404	3420
2028	0	0	0	0	0	0	0	0	0	0	-2850	1000	474	690	0	0	500	0	1600	1414	83820	64867	3420
2029	0	0	0	0	0	0	0	0	0	0	-1128	250	237	805	0	0	1000	0	1600	2764	86584	66460	3420
2030	0	0	0	0	0	0	0	0	0	0	0	1000	948	0	0	0	1000	0	0	2948	89532	67809	3420
TOTAL	1463	4332	4338	1332	1020	390	700	200	125	100	-10902	6250	2370	3910	2609	8400	8400	1000	9600	45637			

Table 4. Policy-Adjusted IRP capacity

	Total capacity		Capacity added (including committed) from 2010 to 2030		New (uncommitted) capacity options from 2010 to 2030	
	MW	%	MW	%	MW	%
Coal	41071	45.9	16383	29.0	6250	14.7
OCGT	7330	8.2	4930	8.7	3910	9.2
CCGT	2370	2.6	2370	4.2	2370	5.6
Pumped Storage	2912	3.3	1332	2.4	0	0.0
Nuclear	11400	12.7	9600	17.0	9600	22.6
Hydro	4759	5.3	2659	4.7	2609	6.1
Wind	9200	10.3	9200	16.3	8400	19.7
CSP	1200	1.3	1200	2.1	1000	2.4
PV	8400	9.4	8400	14.9	8400	19.7
Other	890	1.0	465	0.8	0	0.0
Total	89532		56539		42539	

Notes: (1) Committed generation capacity includes projects approved prior to IRP 2010 (refer to Table 3).

Figure 3. Comparison of scenarios before and after consultation process



Note: The 42% of new capacity allocated to renewables is dependent on the assumed learning rates and resulting cost reductions for renewable options.

6 IMPLEMENTING THE POLICY-ADJUSTED IRP

Decision points

6.1 The New Generation Regulations require a feasibility study on the potential capacity identified in the IRP to provide input to the Ministerial determination between Eskom build and procurement from Independent Power Producers (IPPs). This feasibility study needs to be undertaken as soon as the IRP is promulgated to give impetus to the decisions.

6.2 Table 5 indicates the new capacities of the Policy-Adjusted IRP that are recommended for firm commitment. All dates indicate the latest that the capacity is required in order to avoid security of supply concerns. Projects could be concluded earlier than indicated. The reasons for these firm decisions before the next round of the IRP are laid out in the following.

Table 5. Commitments before next IRP

	New build options							
	Coal (PF, FBC, imports, own build)	Nuclear	Import hydro	Gas – CCGT	Peak – OCGT	Wind	CSP	Solar PV
	MW	MW	MW	MW	MW	MW	MW	MW
2010	0	0	0	0	0	0	0	0
2011	0	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0	300
2013	0	0	0	0	0	0	0	300
2014	500[1]	0	0	0	0	400	0	300
2015	500[1]	0	0	0	0	400	0	300
2016	0	0	0	0	0	400	100	300
2017	0	0	0	0	0	400	100	300
2018	0	0	0	0	0	400[4]	100[4]	300[4]
2019	250	0	0	237[3]	0	400[4]	100[4]	300[4]
2020	250	0	0	237[3]	0	400	100	300
2021	250	0	0	237[3]	0	400	100	300
2022	250	0	1 143[2]	0	805	400	100	300
2023	250	1 600	1 183[2]	0	805	400	100	300
2024	250	1 600	283[2]	0	0	800	100	300
2025	250	1 600	0	0	805	1 600	100	1 000
2026	1 000	1 600	0	0	0	400	0	500
2027	250	0	0	0	0	1 600	0	500
2028	1 000	1 600	0	474	690	0	0	500
2029	250	1 600	0	237	805	0	0	1 000
2030	1 000	0	0	948	0	0	0	1 000
Total	6 250	9 600	2 609	2 370	3 910	8 400	1 000	8 400

Firm commitment necessary now

Final commitment in IRP 2012

1. Built, owned & operated by IPPs 2. Commitment necessary due to required high-voltage infrastructure, which has long lead time 3. Commitment necessary due to required gas infrastructure, which has long lead time 4. Possibly required grid upgrade has long lead time and thus makes commitment to power capacity necessary

6.3 The dark shaded projects need to be decided before the next IRP iteration, with the identified capacities thereafter assumed as "committed" projects:

6.3.1 Coal fluidised bed combustion (FBC) 2014/15: These coal units will be built, owned and operated by IPPs. They need to be firmly committed to by the private investors, in a timely manner, to ensure that this expected capacity will be met. From a central planning perspective, an alternative will be required to replace this capacity by 2019 if it does not materialise.

6.3.2 Nuclear fleet: Long lead times for new nuclear power stations require immediate, firm commitment to the first 3,0 GW, but government policy is to pursue the full nuclear fleet.

6.3.3 Import hydro 2022 to 2024: The import hydro new build options require cross-border negotiations and a time-consuming upgrade in transmission infrastructure. To enable the connection of this capacity to the South African grid by 2022, a firm commitment is required immediately.

6.3.4 CCGT 2019 to 2021: Building gas-driven CCGT power plants requires the creation of gas infrastructure. In addition to the CCGT power plants, a LNG terminal needs to be decided on unless a suitable domestic supply is developed, and built together with the associated gas infrastructure. To trigger these decisions and investments and to ensure that the first CCGT capacity is available by 2019, a firm commitment to building the CCGT power plants is required, which will create the necessary demand to ensure appropriate utilisation of the new gas infrastructure. In the absence of domestic gas supply, it could be highly beneficial to develop an anchor industrial customer (for example petro-chemical) for the LNG terminal in order to facilitate the volumes required to justify the LNG terminal itself as well as provide gas supply flexibility to the CCGT plant, which would otherwise be required to run base-load (or with very high load factors) to warrant the LNG terminal expense.

6.3.5 Solar PV programme 2012-2015: In order to facilitate the connection of the first solar PV units to the grid in 2012 a firm commitment to this capacity is necessary. Furthermore, to provide the security of investment to ramp up a sustainable local industry cluster, the first four years from 2012 to 2015 require firm commitment.

6.3.6 Wind 2014/15: As is the case with solar PV, it is necessary to make a firm commitment to the first post-REFIT wind installations in order to connect the wind farms to the grid by 2014. Furthermore, to provide the security of investment to ramp up a sustainable local industry cluster, the first two years from 2014 to 2015 need commitment.

6.3.7 CSP 2016: The 100 MW of CSP power, planned for 2016, needs firm commitment because of the long lead time of these projects.

6.4 The light shaded options should be confirmed in the next IRP iteration:

6.4.1 Coal FBC 2019/20: There is sufficient time for these coal power stations to be firmly committed to in the next round of the IRP. If all underlying assumptions do not radically change, a firm commitment to these coal units will then be required to ensure timely grid connection by 2019.

6.4.2 Wind 2016 to 2019: For the first wind installations until 2015, extensive grid extension is not necessary. For the additional units to come in 2016 to 2019, these extensions might become necessary. To trigger the associated feasibility studies, planning, and investments in a timely manner, the additional wind units added from 2016 to 2019 should be decided on in the next round of the IRP at the latest.

6.4.3 CSP 2017 to 2019: Because of the long lead time for CSP plants, a commitment to the capacity planned for 2017 to 2019 is necessary in the next round of the IRP at the latest. By then, the cost and technical assumptions for CSP plants will also be grounded on more solid empirical data.

6.4.4 Solar PV 2016 to 2019: As with wind, grid upgrades might become necessary for the second round of solar PV installations from 2016 to 2019, depending on their location. To trigger the associated tasks in a timely manner, a firm commitment to these capacities is necessary in the next round of the IRP at the latest. By then, the assumed cost decreases for solar PV will be confirmed.

6.5 All non-shaded options could be replaced during the next, and subsequent, IRP iterations if IRP assumptions change and thus impact on the quantitative model results.

6.5.1 Open Cycle Gas Turbine (OCGT) and Combined Cycle Gas Turbine (CCGT) options could be replaced by gas engines for peaking and quick response operations which have technical efficiency and cost benefits relative to the turbines assumed in the modelling. Further work on this option is required. Continued assessment of the viability of demand response and pumped storage options as alternatives to OCGT capacity will be undertaken.

Risks

6.6 In general, diversification mitigates the set of risks associated with an expanding power-supply system.

6.7 Diversification does introduce a risk in moving from dependence on a historically certain fuel supply, specifically coal in South Africa's case, to different commodities and technologies which are less certain (from a historical perspective). The Policy-Adjusted IRP increases the exposure to imported commodities (uranium and gas) and electricity imports (regional hydro), but reduces the risk to price increases in the single commodity, coal. The current average coal price reflects the historic cost-plus pricing for the local power market, whereas in the future a stronger link to global coal prices is expected.

6.8 By 2030, electrical energy will be supplied by a wide range of very different technologies, whose individual risks are not or only weakly correlated. In so doing, the Policy-Adjusted IRP reduces South Africa's exposure to the risks associated with individual technologies and commodities.

6.9 The following risks have been identified in relation to the Policy-Adjusted IRP

6.9.1 Demand forecast: The forecast demand is at the higher end of the anticipated spectrum. The risk is thus that the actual demand turns out to be lower than forecast. In this case, the effect would be limited to over-investment in capacity. Security of supply is not jeopardised because of the conservative assumptions regarding energy efficiency and thus demand-reducing measures.

6.9.2 Nuclear costs: Figure 4 shows that the costs of nuclear build account for a large portion of the overall price between 2020 and 2030. If the nuclear costs should turn out to be higher than assumed, this could increase the expected price of electricity. This can be mitigated with a firm commitment to 3,0 GW of nuclear.

6.9.3 IPP-operated coal FBC units: If the coal units expected to be commissioned in 2014 and 2015 are not built, or are not built in a timely manner, the reserve margin from these years on will be roughly 1,0 GW lower. Until 2020, the reserve margin is substantial (approximately 20%) and a cancellation or delay of these coal FBC units is unlikely to jeopardise security of supply before 2020. This provides sufficient time to implement mitigation measures.

6.9.4 Plant performance of new generation: If new renewable generation capacities should fail to reach their forecast performance in terms of full-load hours, this will increase total costs. It will, however, not affect other dimensions like security of supply, since solar PV is completely backed up with conventional, dispatchable generation and wind power is backed up to a large extent. Regarding conventional power plant, it is very unlikely that these, once built, will not reach their originally designed name-plate capacity, efficiency, and full-load hours.

6.9.5 Variable capacity impacting on system security and stability: At low levels of penetration there is only a marginal impact on the system from fluctuating renewable capacity. However there is a point at which an isolated system, with the South African generation mix and demand profile, would have to make adjustments to system and network operations (if not configuration) to cater for the variability of this capacity. This level is as yet unknown for South Africa and additional research will be required to identify this for the next IRP iteration. The Policy-Adjusted IRP proposes 10% penetration for wind and PV capacity as a share of total installed capacity in 2020 and 20% in 2030. The benefits of flexible dispatch generation should be considered as back-up for this capacity to ameliorate the impact on the system.

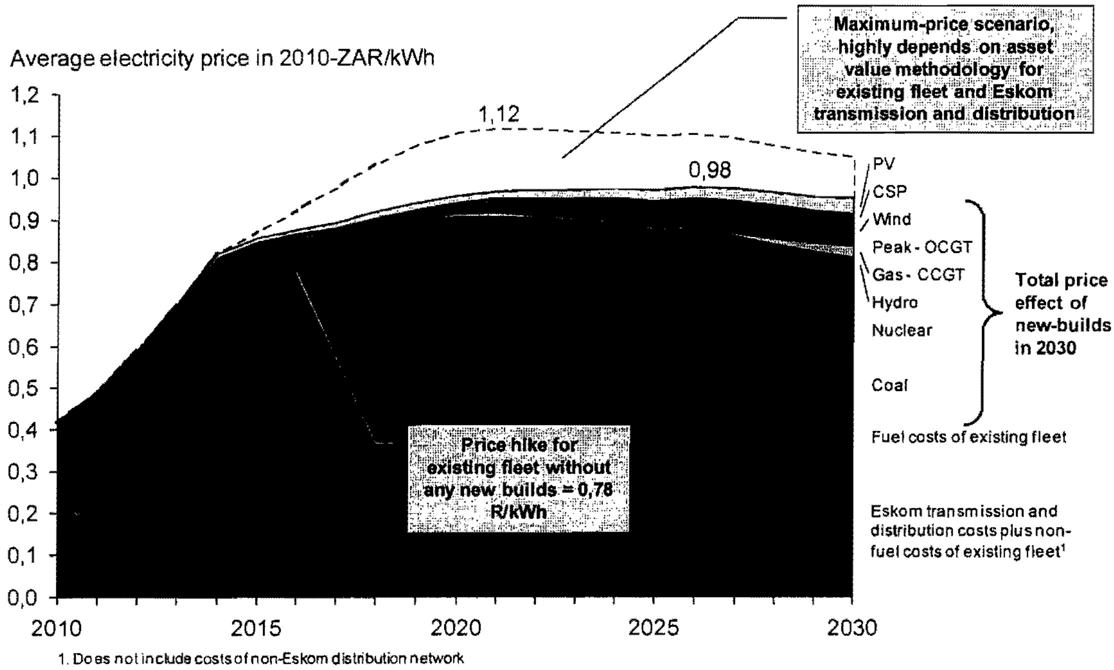
6.9.6 Learning rates not being realised: These assumptions hinge on assumed international roll-out for these technologies, with a dependence on interventions by governments on a significant scale (in terms of feed-in tariffs and other incentives). If the expected capacity does not materialise (either due to reduced government incentives – following the government finance crunch in many developed economies – or similar constraints) then the learning rates will be applied to a less rapidly increasing installed base and technology costs will decrease more gradually. Given the relatively optimistic assumptions made, there is a greater risk of not achieving the expectation than of exceeding it. These risks are predominantly outside the control of local authorities as South Africa's potential capacity is a small component of the global capacity (except perhaps in the case of solar options). However, one can infer from Figure 4 that if the cost decreases do not materialise to the full extent, especially for solar PV, this will have a relatively small impact on the electricity price development.

6.9.7 Fuel costs: Figure 4 shows that by far the greatest risk with respect to fuel prices lies in the coal fuel cost. Spending on coal (new build coal power plants and existing fleet) represents approximately 20% of total costs of the entire energy system in 2020. Today, South Africa is 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. If, however, these contracts expire and are open to renegotiation (especially the older existing contracts), it is uncertain whether the new negotiated price will remain favourable, especially if selling on the global market would be more attractive. Other than the risks associated with the fuel prices of other technologies, the risk associated with the coal price, due to its current low price point, is mostly a downside risk. The risk associated with increasing gas and diesel prices is limited, because the fuel costs of diesel-driven OCGTs and gas-driven CCGTs account for only a very small fraction of the overall system costs (approximately 0.3% in 2030, as indicated in Figure 4).

6.9.8 Import hydro options: The main risks associated with the import hydro options are a delay in the construction of both the necessary grid extension and the power plants themselves, and severe, long-lasting droughts. In both cases, other dispatchable sources of generation would have to make up for the missing hydro capacity There is also a cost risk in that the assumptions used in the IRP are based on estimates from the SAPP pool plan and do not reflect any commitment on the part of potential developers.

6.9.9 EEDSM assumptions: The current assumptions with respect to energy efficiency measures are conservative. Only existing planned programmes were considered, and new options to increase energy efficiency further were not taken into account. Thus, the risk that the modelled amount of energy efficiency does not materialise is relatively small. If it should nevertheless happen, more mid-load capacity (like CCGT) will have to be built, which can be achieved with short lead times.

Figure 4. Breakdown of anticipated average electricity price path[2]



Mitigation

6.10 Chronological dispatch runs: An adequate system is one that provides for contingencies regarding future demand and generation performance. The adequacy of a system or plan can be measured in a number of ways, of which reserve margin is but one (although generally a weak indicator of general adequacy). A number of adequacy tests were conducted on the Policy-Adjusted IRP (using chronological production runs), testing for variability in demand, wind and solar profiles, each indicating that there is sufficient dispatchable capacity to counter the impact of the variations.

6.11 Bringing forward new capacity: The Policy-Adjusted IRP brings forward the roll-out of renewable options to enhance the localisation impact. In so doing, this creates surplus capacity and is not off-setting alternative options. At the same time some of the CCGT and coal options are forced in to ensure dispatchable capacity when renewable capacity starts impacting on system security.

6.12 Life extension: The Policy-Adjusted IRP assumes that the older Eskom coal-fired power stations are decommissioned at the end of 50 year lifespan. It is possible that these power stations could have the economic life extended with some capital investment and continue to operate for another ten years in case the proposed new build options are delayed or demand projections prove insufficient. This would have to be traded off against the higher emissions and low efficiencies of the generators.

Policy and Facilitation

6.13 REFIT tariffs need to consider the impact of learning rates and adjust accordingly, otherwise price impact will be more extreme than assumed.

6.14 The energy cost for the earlier solar PV capacity (specifically 2012 and 2013) is not currently included in the multi-year price determination for Eskom. Due to the delay in the REFIT

[2] The price expectation is a comparative analysis based on the existing price regulation methodology. The comparative analysis should not be used to suggest an absolute price path.

programme, approved funding can be re-allocated to this capacity, but additional funding may be required depending on the final REFIT tariffs for solar PV.

6.15 Net metering, which allows for consumers to feed energy they produce into the grid and offset this energy against consumed energy, should be considered for all consumers (including residential and commercial consumers) in order to realise the benefits of distributed generation. The impact of such a policy on subsidies needs to be considered.

6.16 The IRP should not limit activities behind the meter where consumers take up energy efficiency and other measures to improve their demand exposure, inclusive of co-generation and residential/commercial PV. Similarly the IRP should not be restrictive in terms of own generation.

6.17 The required capital injection for the IRP is assumed to be apportioned between the private sector in the form of IPPs (for 30% of the capacity) and the public sector. The public sector portion will depend on debt or fiscal allocations to Eskom as and when required.

7 RESEARCH AGENDA FOR NEXT IRP

Distributed generation, smart grids and off-grid generation

7.1 An independent study on solar PV technologies suggests that before 2015 the levelised cost of the PV installation (without storage) would be the same, if not cheaper, than residential prices (especially at municipal retail tariffs). This possibility suggests that distributed generation should be seriously considered in future iterations of the IRP with additional research into the technology options for distributed generation and the impact on networks, pricing and residual demand on centrally planned generation.

7.2 The growth of distributed generation has a bearing on the development and operations of the network (predominantly the distribution network), especially if some, if not most, of the distributed generation is variable technology. The development opportunity of smart(er) grids and storage solutions – which can help in integrating variable renewable technologies – should also be considered, alongside the system's balancing capability (and ancillary services). There could be an initial focus on smart metering and the ability to manage demand.

7.3 Off-grid activities should be considered especially as there is an impact on the potential future demand (through "suppressed demand" which has occurred as a result of lack of grid access for a number of potential consumers).

Harnessing South Africa's coal resource

7.4 Research into Underground Coal Gasification (UCG) should have a priority in the research agenda as there is a potential for this option to be used in place of natural gas.

7.5 Carbon Capture and Storage (CCS) would allow coal generation to continue to have a large presence even in a carbon-constrained world. This is still a priority for future research.

Uncertainties in decision-making

7.6 Further research is required to investigate more appropriate options of incorporating uncertainty and risk in the IRP process. The current process assigns an uncertainty factor to scenarios but does not fully incorporate these risks in the optimisation process within each scenario.

7.7 The possibility of different discount rates for technology to factor in different risk profiles for the technologies should also be investigated.

Longer term outlook

7.8 Further integration is required with the Integrated Energy Plan and government's long term vision for emissions and the energy industry. It is proposed that a "Vision for 2050" be developed in order to feed into the IRP 2012.

7.9 The impact of extensive decommissioning of existing coal fleet between 2030 and 2040 should be considered. The impact of extending the horizon should be considered, alongside a need for stronger policy objectives and guidance from government on long term objectives which the IRP should be meeting.

7.10 Further analysis on price sensitivity of demand should be a priority for IRP 2012, as well as the possibility of substitutes to electricity (heating technologies, natural gas supply, other gas options).

Decommissioning and waste management

7.11 Further research is required on the full costs relating to specific technologies (coal and nuclear) around the costs of decommissioning and managing waste (in the case of nuclear specifically spent fuel).

Technology options

7.12 Further research is required on a number of potential technology options, including:

7.12.1 Small hydro

7.12.2 Regional hydro options (specifically Inga)

7.12.3 Biomass (including municipal solid waste and bagasse)

7.12.4 Storage; and

7.12.5 Energy efficiency demand side management

8 CONCLUSION

8.1 This Policy-Adjusted IRP is recommended for adoption by Cabinet and subsequent promulgation as the final IRP.

8.2 A commitment to the construction of the nuclear fleet is made based on government policy and reduced risk exposure to future fuel and renewable costs.

8.3 A solar PV programme as envisaged in the Policy-Adjusted IRP should be pursued (including decentralised generation).

8.4 The acceleration of the coal options in the Policy-Adjusted IRP should be allowed with an understanding of the impact on emission targets and the carbon tax policy.

8.5 An accelerated roll-out of renewable energy options should be allowed in order to derive the benefits of localisation in these technologies.

8.6 A commitment to the construction of the CCGT options in 2019-2021 and the resulting import infrastructure to support this option should be made in order to improve security of supply from a flexible, dispatchable generation perspective.

APPENDIX A – SCENARIOS INFORMING THE REVISED BALANCED SCENARIO

Table 6. Scenarios for the RBS

Scenario	Constraints
Base Case 0.0	Limited regional development options No externalities (incl. carbon tax) or climate change targets
Emission Limit 1.0 (EM1)	Annual limit imposed on CO_2 emissions from electricity industry of 275 MT CO_2-eq
Emission Limit 2.0 (EM2)	Annual limit imposed on CO_2 emissions from electricity industry of 275 MT CO_2-eq, imposed only from 2025
Emission Limit 3.0 (EM3)	Annual limit imposed on CO_2 emissions from electricity industry 220 MT CO_2-eq, imposed from 2020
Carbon Tax 0.0 (CT)	Imposing carbon tax as per Long Term Mitigation Strategy (LTMS) values (escalated to 2010 ZAR)
Regional Development 0.0 (RD)	Inclusion of additional regional projects as options
Enhanced DSM 0.0 (EDSM)	Additional DSM committed to extent of 6 TWh energy equivalent in 2015
Balanced Scenario	Emission constraints as with EM 2.0, Coal costs at R200/ton; LNG cost at R80/GJ, Import Coal with FGD, forced in Wind earlier with a ramp-up (200 MW in 2014; 400 MW in 2015; 800 MW from 2016 to 2023; 1600 MW annual limit on options throughout)
Revised Balanced Scenario	As with Balanced Scenario, with the additional requirement of a solar programme of 100 MW in each year from 2016 to 2019 (and a delay in the REFIT solar capacity to 100 MW in each of 2014 and 2015). CCGT forced in from 2019 to 2021 to provide backup options. Additional import hydro as per the Regional Development scenario

Note: All scenarios (except Balanced and Revised Balanced) were tested with a case of Kusile not being committed.

Initial scenarios

A.1. The Base Case (with Kusile and Medupi as per the original committed schedule) provides for imported hydro as the first base-load capacity in 2020 (after the committed programmes), followed by combined cycle gas turbines (CCGT) (fuelled by liquefied natural gas, or LNG), then imported coal and fluidised bed combustion (FBC) coal, before pulverised coal which forms the basis of all further base-load capacity. Additional peaking capacity is exclusively provided by open-cycle gas turbines (OCGT), fuelled by diesel. CO_2 emissions continue to grow (albeit at a lower rate due to more efficient power stations replacing decommissioned older ones) to a level of 381 million tons at the end of the period (2030). Water usage drops from 336 420 million litres in 2010 to 266 721 million litres in 2030 (due to replacing older wet-cooled coal power stations with newer dry-cooled ones). The cancellation of the Kusile project would require alternative capacity to be built in 2017, in this case FBC coal and CCGT, with additional projects brought on at least a year earlier in each case. This increases the cost to the economy from R789bn to R840bn (in present value terms), *but does not include* the net impact of the cost saving on the cancelled project and penalties relating to this cancellation. The present value costs indicated do not include capital costs for committed projects.

A.2. Imposing a limit on emissions (at 275 million tons of CO_2 throughout the period) in the Emissions 1 scenario shifts the base-load alternatives away from coal (in particular pulverised coal) to nuclear and gas. Wind capacity is also favoured to meet the energy requirements over the period, especially as the emission constraint starts to bite in 2018. As the nuclear programme is restricted in terms of its build rate (one unit every 18 months starting in 2022) wind is required to reduce emissions in the interim. CCGT provides a strong mid-merit alternative until nuclear is commissioned, especially providing higher load factors than wind, with some dispatchability. The total cost to the economy (excluding capital costs of committed projects) is R860bn, compared with R789bn for the Base Case, but with significantly lower water consumption (241 785 million litres in 2030).

A.3. The emission limit is retained at 275 million tons for the Emission 2 scenario but is only imposed from 2025. Under these conditions the nuclear and wind build are delayed (nuclear by one year, wind by five years). The other capacity is similar to the Base Case until 2022, when low carbon capacity is required to ensure that the constraint can be met in 2025. Decommissioning of older power stations (6654 MW by 2025) provides an opportunity to return to the constrained level of emissions. The cost to the economy is lower than the Emission Limit 1 scenario at R835bn with a slightly higher average annual emission of 275 million tons (as opposed to 266 million tons).

A.4. In the Emissions 3 scenario a tighter emission limit of 220 million tons is imposed from 2020. This requires a significant amount of wind capacity (17600 MW starting in 2015) and solar capacity (11250 MW commissioned between 2017 and 2021) to meet the constraint. In total 17,6 GW of wind, 11,3 GW of solar and 9,6 GW of nuclear are built, with no coal capacity included. CCGT is constructed as a lower emission mid-merit capacity along with 6,5 GW of OCGT peakers. The cost to the economy is significantly higher at R1250bn with much lower average annual emissions (235 million tons) and water consumption (218 970 million litres in 2030).

A.5. The carbon tax scenario includes a carbon tax at the level of that discussed in the Long Term Mitigation Strategy (LTMS) document, starting at R165/MWh in 2010 rands, escalating to R332/MWh in 2020 until the end of the period (2030) before escalating again to R995/MWh in 2040. This level of carbon tax causes a switch in generation technology to low carbon emitting technologies, in particular the nuclear fleet (starting in 2022) and wind capacity of 17,6 GW starting in 2020. The remainder is provided by imported hydro (1959 MW), OCGT (4255 MW) and CCGT (4266 MW) with some FBC coal after 2028 (1750 MW). The cost to the economy (excluding the tax itself, which would be a transfer to the fiscus) arising from the changed generation portfolio is R852bn, with average annual emissions at 269 million tons and water consumption declining to 238 561 million litres in 2030.

A.6. While the Base Case only includes some import options (limited import hydro (Mozambique) and import coal (Botswana)), the Regional Development scenario considers all listed projects from the Imports parameter input sheet. These additional options provide good alternatives to local supply options at lower generation costs (but require additional transmission capacity to transport the energy). Including these options brings the total cost to the economy (excluding the transmission backbone requirement for these projects) to R783bn (R6bn cheaper than the Base Case). The import coal and hydro options are preferred to local options, but imported gas is not preferred to local gas options.

A.7. The Enhanced DSM scenario was run to see what the impact of additional DSM would be on the IRP. For this scenario an additional 6 TWh of DSM energy was forced by 2015. The resulting reduction in cost was R12,8bn (R789,5bn of the Base Case less R776,7bn for the Enhanced DSM scenario) on a PV basis, indicating that if a 6 TWh programme could be run for less than this cost it would be beneficial to the economy.

A.8. Two balanced scenarios were created considering divergent stakeholder expectations and key constraints and risks. The balanced scenarios represent the best trade-off between least-investment cost, climate change mitigation, diversity of supply, localisation and regional development. The CO_2 emission targets are similar to those in the Emissions 2 scenario. The balanced scenarios include the Eskom committed build programme plus the MTPPP and REFIT commitments. A significant amount of wind is built, as this is the cheapest renewable energy option. Care is taken to ensure a steady and consistent build up in wind capacity in order to stimulate localisation of manufacturing and job creation. A consistent, although more modest, commitment is given to the more expensive concentrated solar power (CSP) option in order to develop local experience with this technology as well as costs. The renewable energy options continue after 2020, but are not specified according to technology type at this stage. These choices will be made when there is more local knowledge and experience with both wind and solar energy. Nuclear energy comes in as a base-load option from 2023 – but because this is 13 years away, this decision does not yet have to be made. The scenario also provides for substantial diversity with gas, regional hydro, and coal options also included. In addition, allowance is made for some short- to medium-term co-generation and self-build options to bolster security of supply concerns.

Multi-criteria decision-making

A.9. The scenarios provided a platform to consider the impact of identified policy uncertainties. Having considered each of the resulting cost-optimised plans a mechanism was required to bring together the desirable elements from these outcomes into a synthesised "balanced" plan. A set of criteria was proposed and discussed at a series of inter-departmental workshops against which to assess these plans. These include:

A.9.1. Water: The usage of water is quantified for each technology, according to the independent EPRI report and information from existing Eskom plant. The cost of water for existing plant and approved future plant is known and quantified. For plant that is recommended to be built in the proposed IRP 2010 only the usage of water is quantified, given that the location of the plant is not known at this stage of the IRP.

A.9.2. Cost: Each scenario involves the construction of new generation capacity over the study period. For the current and approved projects the costs from the existing owner (Eskom, municipality or private supplier) is used. For potential new projects the approved data set of option costs will be used. The criteria applied for this dimension should cover the direct costs associated with new generation capacity built under each scenario (including capital, operating and fuel costs) as well as existing plant (but excluding capital costs for committed plant) and summed to determine the total cost of the plan. This will be discounted to determine the present value of the plan and used as a comparator between the different scenarios. An alternative approach is to look at the future electricity price curves required to meet the generation costs incurred by the scenario portfolio. This model, similar to that applied in the Eskom MYPD decision by NERSA, provides an indicator of future costs to consumers for the electricity industry from each scenario portfolio.

Table 7. Score for each criteria

Plans	CO_2 emissions	Price	Water	Uncertainty	Localisation potential	Regional development	TOTAL
Base Case 0.0	-	21.74	-	2.73	-	6.08	30.54
Emission 1.0	12.41	18.61	5.24	16.14	6.47	6.08	64.94
Emission 2.0	9.43	20.61	2.53	16.14	6.47	6.08	61.25
Emission 3.0	21.74	-	10.87	19.57	6.47	-	58.65
Carbon Tax 0.0	11.50	18.41	3.50	19.26	6.47	2.77	61.91
Region Development 0.0	0.67	21.53	0.37	-	-	10.87	33.44
Enhanced DSM	1.54	20.85	0.94	3.04	-	6.08	32.45
Balanced	10.46	20.24	2.74	16.71	11.02	1.85	63.01
Revised Balance	11.01	19.33	2.92	16.32	15.22	8.85	**73.66**
Swing Weighting (/100)	21.74	21.74	10.87	19.57	15.22	10.87	100.00

A.9.3. Climate change mitigation: The Department of Environmental Affairs "Long Term Mitigation Strategy" (LTMS) provides guidance on the extent to which greenhouse gas (GHG) emissions should be restricted over time. For the purposes of the IRP the GHG emissions from existing and planned generation capacity can be quantified in the model and compared between scenarios. While certain scenarios may impose a specific limit to emissions, this criterion compares the actual emissions between all scenarios.

A.9.4. Portfolio risk or uncertainty: An approach has been developed to identify and model the risks associated with each of the scenario portfolios. There are different dimensions or sources of risk between the scenario portfolios, including (but not limited to): the validity of the cost assumptions for each technology; the validity of the lead time assumptions for each technology; the maturity of each technology; the security of fuel supplies for each technology; and operational risks associated with each technology (including secondary life cycle effects), such as waste management, pollution and contamination. Ideally these risks would carry cost elements which would enable incorporation into the IRP optimisation (through monetisation of the risk elements). However given the time constraints and dearth of data to support this process, this is not feasible at present. The second best approach would be to identify a probability distribution associated with the risks, use the standard deviation as a measure of risk, and apply these across the identified dimensions. While this can be done for some of the risk dimensions, there is again a lack of information and time to produce such measures for every dimension. The third approach is to apply subjective expert judgement to each technology for every dimension and derive a risk factor for each technology (and consequently a capacity weighting for each scenario portfolio). This methodology was used for the IRP 2010, with the resulting risk factor compared between the different scenarios.

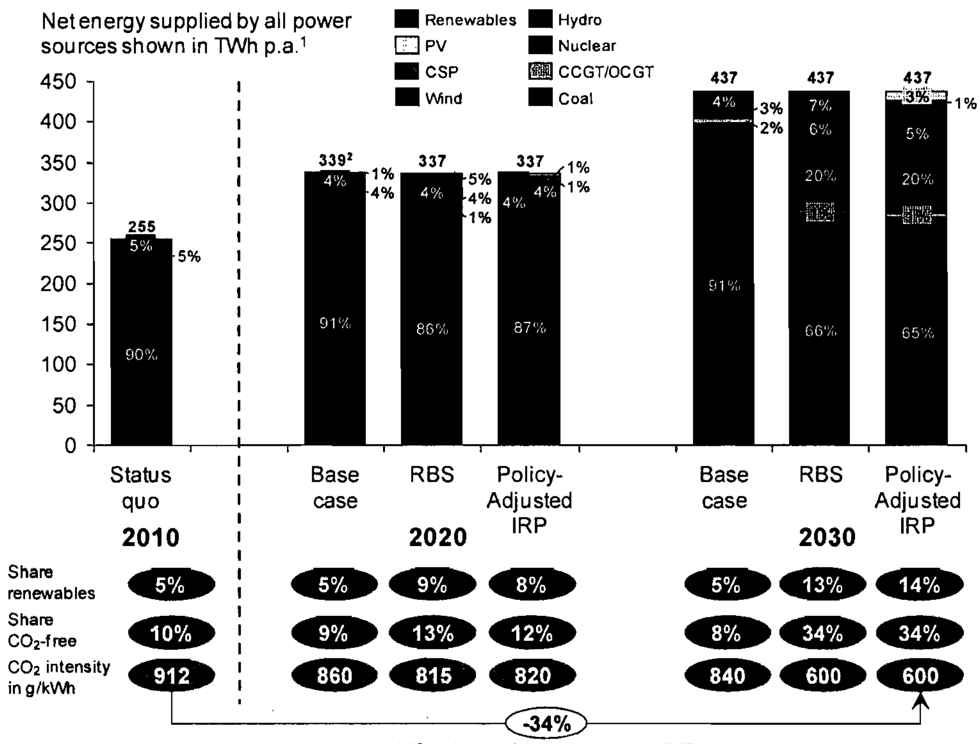
A.9.5. Localisation benefit: A rating has been given to each scenario portfolio to indicate the extent to which this portfolio supports localisation of specific technologies and supporting industries. It is expected that the earlier a technology construction programme is triggered, and the more steadily such technology capacity is added, the higher the potential to localise the technology industry. Thus a wind industry is supported by a regular build profile, starting earlier, and consequently a portfolio that incorporates such a build profile would have a higher score in this criterion. The application is however subjective.

A.9.6. Regional development: Workshops with government departments indicated that this is an important criterion for the portfolios and that those portfolios that support increased import from regional options should receive a higher score. Thus the portfolio with the higher percentage of imports (to the total capacity) scores higher on the regional development criterion. Technically speaking the total capacity is replaced in this calculation by the demand that must be met, so as not to penalise portfolios that build significant wind (which requires more capacity for each unit of demand due to the capacity credits applied to wind).

A.10. For the first three criteria (emissions, cost of plan and water) and the regional development criterion the measurement is provided by the optimisation results. The average domestic emissions figure is determined based on the emission contribution of each of the proposed projects and its expected output in each year. Similarly the cost of the plan is determined based on the capital, operating and fuel costs of each project (discounted to 2010 rands), but specifically excludes the capital costs associated with existing power stations and the committed Eskom build. The water criterion is measured by summating the water requirements for the scenario portfolio for the entire study period.

A.11. The uncertainty factor criterion is measured using uncertainty factors for each technology, which is then applied based on the relative capacity of each technology in the portfolio. The localisation criterion is based on a subjective score applied to the portfolios based on their perceived potential for localisation.

Figure 5. Impact of RBS and Policy-Adjusted IRP on net energy supply



1. "Other" generation sources not shown 2. "Base case" scenario contains slightly more pumped energy in 2020 than RBS and Policy-Adjusted IRP and thus requires more total energy being generated

Table 8. Base Case scenario

	Committed	Coal FBC	Import Coal	Gas CCGT	OCGT	Import Hydro	Coal PF + FGD	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Demand Side Management	Reserve Margin	Reliable capacity Reserve Margin	Unserved energy	Annual energy (net sent-out) forecast	PV Total cost (cumulative)	Water	Total CO_2 emissions	Capital expenditure (at date of commercial operation)
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	%	GWh	GWh	Rm	ML	MT	Rbn
2010	640	0	0	0	0	0	0	640	44535	38885	252	15.28	15.18	-	259,685	44,138	336,420	237	-
2011	1009	0	0	0	0	0	0	1009	45544	39956	494	15.41	14.74	-	266,681	87,467	349,613	243	-
2012	1425	0	0	0	0	0	0	1425	46969	40995	809	16.88	15.25	-	274,403	128,921	350,510	250	-
2013	2601	0	0	0	0	0	0	2601	49570	42416	1310	20.59	17.84	-	283,914	168,689	347,830	252	-
2014	2543	0	0	0	0	0	0	2543	52113	43436	1966	25.66	23.52	-	290,540	206,850	341,505	252	-
2015	1988	0	0	0	0	0	0	1988	54101	44865	2594	27.98	23.48	-	300,425	244,060	327,011	259	-
2016	1355	0	0	0	0	0	0	1355	55456	45786	3007	29.63	24.52	-	310,243	280,709	326,392	264	-
2017	1446	0	0	0	0	0	0	1446	56902	47870	3420	28.01	22.54	-	320,751	314,878	330,861	272	-
2018	723	0	0	0	0	0	0	723	57625	49516	3420	25.01	19.82	-	332,381	346,282	341,701	286	-
2019	0	0	0	0	460	0	0	460	58085	51233	3420	21.48	16.57	-	344,726	378,543	346,415	297	1.95
2020	0	0	0	0	805	653	0	1458	59543	52719	3420	20.78	16.03	-	355,694	413,756	360,214	306	12.64
2021	-75	0	0	474	805	1023	0	2227	61770	54326	3420	21.34	16.72	-	365,826	451,476	368,262	313	22.47
2022	-1870	750	600	948	805	283	0	1516	63286	55734	3420	20.97	16.49	-	375,033	493,152	359,495	319	37.39
2023	-2280	750	600	711	0	0	1500	1281	64567	57097	3420	20.29	15.93	-	383,914	542,245	333,078	323	61.91
2024	-909	250	0	474	0	0	1500	1315	65882	58340	3420	19.96	15.70	-	392,880	581,161	321,490	330	39.47
2025	-1520	0	0	0	345	0	3000	1825	67707	60150	3420	19.35	15.24	-	404,358	625,387	300,861	337	65.21
2026	0	0	0	0	0	0	1500	1500	69207	61770	3420	18.61	14.63	-	415,281	657,853	303,450	348	31.87
2027	0	0	0	0	0	0	1500	1500	70707	63404	3420	17.88	14.02	-	426,196	688,775	306,068	359	31.87
2028	-2850	0	0	237	460	0	3750	1597	72304	64867	3420	17.67	13.91	-	436,761	730,641	277,801	365	83.15
2029	-1128	0	0	237	0	0	2250	1359	73663	66460	3420	16.85	13.20	-	445,888	762,702	266,200	372	49.32
2030	0	0	0	237	0	0	1500	1737	75400	67809	3420	17.10	13.52	-	454,357	789,481	266,721	381	33.39

No emission constraints; committed programme includes Medupi, Kusile, Ingula, Sere and Return to Service capacity (all from Eskom), 1025MW from REFIT, 1020MW OCGT IPP; 390MW from MTPPP; maximum wind 1600MW per year; EEDSM as per Eskom MYPD2 application, max 3420MW

Table 9. Emissions 1 scenario

	Committed	Coal FBC	Import Coal	Gas CCGT	OCGT	Import Hydro	Wind	Nuclear Fleet	Coal PF + FGD	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Demand Side Management	Reserve Margin	Reliable capacity Reserve Margin	Unserved energy	Annual energy (net sent-out) forecast	PV Total cost (cumulative)	Water	Total CO_2 emissions	Capital expenditure (at date of commercial operation)
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	%	GWh	GWh	Rm	ML	MT	Rbn
2010	640	0	0	0	0	0	0	0	0	640	44535	38885	252	15.28	15.18	-	259,685	44,138	336,420	237	-
2011	1009	0	0	0	0	0	0	0	0	1009	45544	39956	494	15.41	14.74	-	266,681	87,467	349,613	243	-
2012	1425	0	0	0	0	0	0	0	0	1425	46969	40995	809	16.88	15.25	-	274,403	128,921	350,510	250	-
2013	2601	0	0	0	0	0	0	0	0	2601	49570	42416	1310	20.59	17.84	-	283,914	168,689	347,830	252	-
2014	2543	0	0	0	0	0	0	0	0	2543	52113	43436	1966	25.66	23.52	-	290,540	206,850	341,505	252	-
2015	1988	0	0	0	0	0	0	0	0	1988	54101	44865	2594	27.98	23.48	-	300,425	244,060	327,011	259	-
2016	1355	0	0	0	0	0	0	0	0	1355	55456	45786	3007	29.63	24.52	-	310,243	280,709	326,392	264	-
2017	1446	0	0	0	0	0	1200	0	0	2646	58102	47870	3420	30.71	23.40	-	320,751	325,028	330,424	268	17.95
2018	723	0	0	948	0	0	1600	0	0	3271	61373	49516	3420	33.14	23.76	-	332,381	372,475	331,897	275	30.00
2019	0	0	0	948	0	740	1600	0	0	3288	64661	51233	3420	35.24	23.94	-	344,726	425,196	319,036	275	43.60
2020	0	0	0	948	0	370	1600	0	0	2918	67579	52719	3420	37.08	23.95	-	355,694	472,514	317,333	275	36.80
2021	-75	0	0	948	0	0	1600	0	0	2473	70052	54326	3420	37.61	22.82	-	365,826	516,670	317,085	275	30.00
2022	-1870	0	0	0	0	0	1400	1600	0	1130	71182	55734	3420	36.07	19.96	-	375,033	573,594	308,548	275	78.17
2023	-2280	0	0	0	805	0	0	1600	0	125	71307	57097	3420	32.85	17.22	-	383,914	620,892	303,971	274	60.63
2024	-909	0	0	0	805	283	1200	0	0	1379	72686	58340	3420	32.35	15.65	-	392,880	653,285	295,954	275	23.80
2025	-1520	0	0	0	805	283	0	1600	0	1168	73854	60150	3420	30.19	14.06	-	404,358	695,121	289,791	275	63.07
2026	0	0	0	0	230	0	0	1600	0	1830	75684	61770	3420	29.71	14.03	-	415,281	733,015	287,851	273	58.20
2027	0	250	0	474	690	0	800	0	0	2214	77898	63404	3420	29.86	13.73	-	426,196	760,364	283,339	275	22.49
2028	-2850	750	1200	0	0	0	0	1600	750	1450	79348	64867	3420	29.13	13.39	-	436,761	806,411	256,206	275	109.23
2029	-1128	750	0	0	115	0	0	1600	0	1337	80685	66460	3420	27.99	12.66	0	445,888	841,096	241,365	271	71.41
2030	0	0	0	0	690	283	0	0	0	973	81658	67809	3420	26.82	11.83	-	454,357	860,504	241,785	275	5.36

Emission constraint of 275 million tons per year applicable throughout the period; committed programme as per Base Case scenario; maximum wind 1600MW per year; EEDSM as per Eskom MYPD2 application, max 3420MW