Towards a New Power Plan

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For the National Planning Commission

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Executive Summary

Many of the assumptions in the 2010 Integrated Resource Plan (IRP) are now out of date and no longer valid. These include the anticipated demand growth, and data on technology and fuel availabilities and costs. If the 2010 IRP continues to be used as a basis for investment decisions, it will result in a sub-optimal mix of generation plants, and higher electricity prices. It is therefore critical that the IRP assumptions are revised and that a new plan is developed.

This report was commissioned by the National Planning Commission as part of its on-going mandate to provide independent research and advice. President Zuma stated on 11 May 2010:

> *The mandate of the commission is to take a broad, cross-cutting, independent and critical view of South Africa, to help define the South Africa we seek to achieve in 20 years time and to map out a path to achieve those objectives. The commission is expected to put forward solid research, sound evidence and clear recommendations for government.*

This report should not be seen as an alternative power plan. Rather it is an input to the public debate around our electricity future. The Ministry of Energy has legislative responsibility to produce IRPs for the sector. This report looks at key assumptions in the IRP 2010-2030 and the impact that updating some of these assumptions will have on a new power plan. The new assumptions considered are lower demand, updated investment costs of renewable and nuclear technologies and the availability of natural gas from LNG, shale, West Coast Ibhubezi and a pipeline from Northern Mozambique.

The modelling assumes that carbon emissions will follow the 2025 peak, plateau and decline trajectory implied by our Copenhagen pledges . The limit for the power sector is set to 275Mton/annum in 2025, and starts to decline from 2035 to 225Mton in 2040 and 150Mton in 2050.

Electricity demand growth has been much lower than forecast; it is still below 2007 levels, and future growth is expected to be lower than projected in the IRP 2010 (base assumption). Contributing factors to this lower projected growth include demand responses to higher electricity prices, structural changes in the economy and, perhaps in the future, increased investment in distributed generation as alternative supply options become economic. In 2030, demand is expected to reach 341 TWh (50 GW peak) compared to the 454 TWh (67.8 GW peak) of the IRP. Nuclear costs are higher at 7000$/kW, compared to the 5000$/kW used in the IRP. Renewable costs reflect those of the REIPPP programme. The cost of natural gas starts lower than in the IRP but is escalated with an index to the oil price, and several options for gas supply are allowed.

The New Power Plan, based on updated assumptions, has an installed capacity in 2030 of around 61GW instead of 89GW anticipated in the 2010 IRP. Due to the lower demand growth and the committed investment plans (Medupi, Kusile, Ingula and the 2011 renewable energy ministerial determinations) very little further investment is needed before 2025. New capacity between 2025 and 2030 is dominated by gas with solar thermal, wind and imported electricity meeting the remaining requirements. No new nuclear comes online before 2040 and it is economical to bring imported hydro online as soon as possible. Even if much lower costs are assumed for nuclear, plus much higher demand growth, the earliest that nuclear might be required is 2029.

However, many of the low emission alternatives to nuclear capacity (imported hydro, wind and natural gas) can be installed at lower cost, with shorter lead times, in smaller increments, thus reducing the risk of overbuild. The consideration given to flexible options allows rigorous testing of a proposed plan against various outcomes rather than just planning doggedly for one outcome. This approach has a great deal of merit especially in the context of economic and demand uncertainty.

The New Power Plan presented in this report is work in progress. It is not a definitive alternative to the IRP2010. The preferred power generation options shown are outputs of the TIMES model and are obviously highly dependent on input parameters and assumptions. We have accordingly also modelled alternative scenarios with higher demand, lower nuclear costs, more optimistic renewable costs, and competitive shale gas options. It is possible that after five years of stagnation in demand growth, that there might be a sharp rebound. South Africa's growth and development aspirations, as spelt out in the National Development Plan, would imply higher electricity demand growth. A number of scenarios are thus presented with higher growth assumptions.

One area not adequately dealt with in this modelling is the need for a steady stream of renewable energy investments in order to sustain a local RE industry. The model includes renewables over the 30-year period – but there are years where no renewable investments are required, which might make it difficult for local manufacturing and local developers to survive, unless they can grow export markets.

The modelling also does not examine in detail immediate supply security issues. Eskom's current fleet of coal plants (and the Koeberg nuclear plant) are experiencing high levels of unplanned outages (i.e. they are breaking down more and more). As a result current reserve margins are thin. Further plant breakdowns, plus delays in the commissioning of the Medupi and Kusile coal-fired power stations, as well as the Ingula pumped storage scheme, will almost certainly result in rolling black-outs. It is thus urgent to commission new generation capacity that can be built quickly. Gas is one the few options available to us that can provide substantial base and mid-merit power within a 3-year period. That might result in short-term, nominal over-capacity but will provide a window for Eskom to catch up on much needed maintenance on its existing generators.

In brief, this report is intended to stimulate debate around our future power sources. The results suggest that nuclear investments are not necessary (at least not in the next 15 to 25 years), nor are they cost-effective based on latest cost data. Gas options should be explored more intensively and hydro projects from the region should be fast-tracked.

Towards a New Power Plan?

Many of the IRP 2010 assumptions no longer apply and as a result the recommended investment decisions are sub-optimal. If followed, the existing plan would result in surplus, stranded and expensive generation capacity. Electricity demand growth has been much lower than forecast; it is still below 2007 levels, and future growth is expected to be considerably lower than projected in the IRP 2010 (base assumption). Nuclear costs are higher, new information on RE costs is now available through the REIPPP program and new options are expected to become available to supply natural gas to South Africa. Many of the existing coal power plants are getting old and are due to retire between 2030 and 2040, and it is therefore important to start looking at investment requirements beyond 2030.

Figure 1 shows new capacity requirements as stipulated in the Policy Adjusted Scenario of the IRP 2010 and the resulting total installed capacity (grouped in 5-year periods). Overlaid onto the "Total Installed Capacity" is the peak demand. The original peak demand projection of the IRP 2010 net of DSM is shown as the dotted line. The peak demand shown here as a solid line is the peak observed in 2011 and projected at the same growth rate as the original peak demand projection of the IRP 2010.

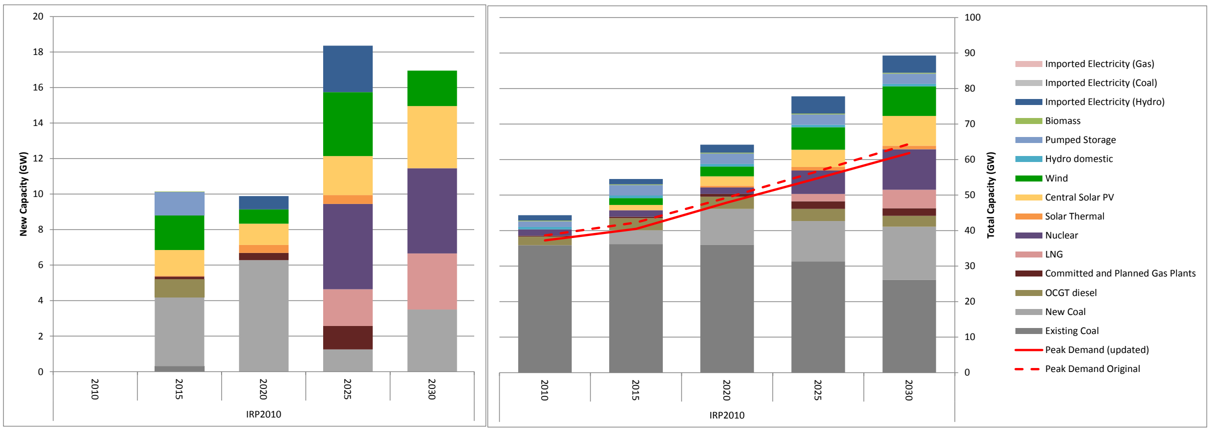

Figure 1 IRP 2010 Policy Adjusted Scenario – New and Total Installed Capacity with Peak Demand

Figure 2 shows what a possible New Power Plan could look like if we were to update some of the assumptions based on new data that has become available and enforce the 2011 ministerial determinations. The most noticeable difference is that by 2030 we end up with around 61GW instead of 89GW due to the lower demand projection. We also notice that due to overinvestment in the period before 2020, there is very little investment in new capacity required in the period 2021-2025. Using IRP assumptions for imported hydro, it is economical to bring those options online as soon as possible despite there being excess capacity because of their very attractive costs ranging between 13.6c/kWh to 38.2 c/kWh. The assumption used was that they would be available from 2020 onward.

The new capacity that comes online in the period 2026-2030 is dominated by investment in gas power plants: the upgrades of Ankerlig (Ibhubezi gas) and Gourikwa (Petro SA gas), the balance coming from new LNG. There is also 1 GW of new Solar Thermal Electric Power with storage, 500MW of wind and about 2.3 GW of imported electricity, which is a mixture of coal, gas and imported hydro. Beyond 2030, we see 10 GW of new Solar Thermal, 8.3 GW of Wind, 3.1 GW of Gas, 600 MW of Solar PV, 500 MW of biomass and 15 GW of new coal. Another important observation is that there is no new nuclear power coming online before 2040, meaning that South Africa could actually still meet the Copenhagen commitments without having to install nuclear plants.

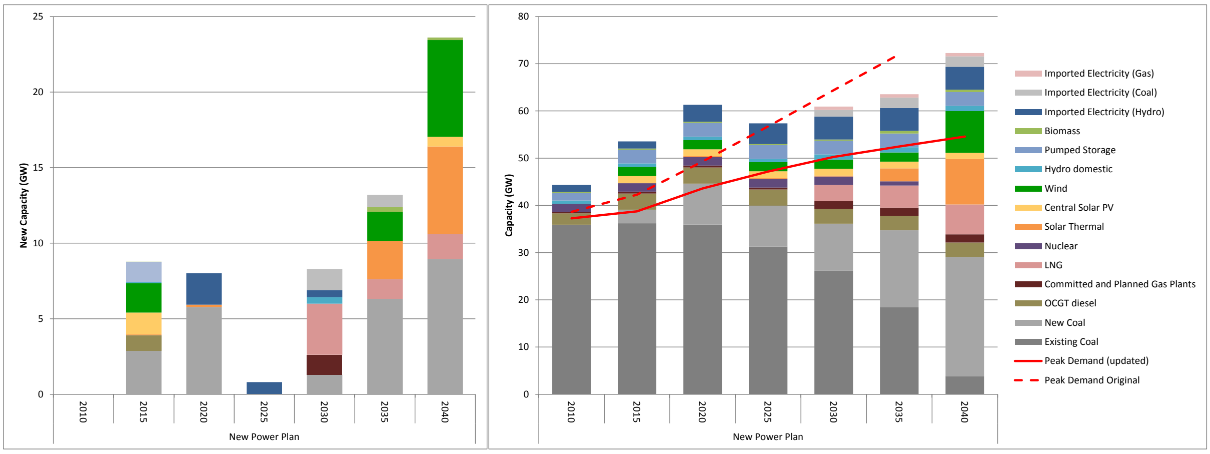

Figure 2 New Power Plan: New and Total Installed Capacity with Peak Demand

Basis for the New Power Plan

This section describes in some detail the different assumptions that have been used to develop a New Power Plan. Assumptions used in the TIMES model presented here which are different to those of the IRP are: a lower demand projection; higher nuclear costs, although a sensitivity with lower nuclear costs is included; higher costs for renewable technologies, in line with the REIPPPP programme; and changes to fuel prices, in particular the gas price.

The Planning Horizon and the Retirement Schedule

In order to accommodate the investment required to replace the retiring coal fired plants, the planning horizon has been extended to 2040. The assumed retirement schedule for existing coal plants is shown in Figure 3. The retirement schedule is based on the installation year of the power plants and an assumed plant life as well as communication with Eskom planners. Most coal plants are also assumed to have a lifetime of 50 years. By 2040, 32GW of existing coal capacity will have retired. Many of the plants, 22 GW in total, retire between 2030 and 2040. The Koeberg nuclear power plant is assumed to retire in 2035 based on its installation year and an assumed life of 50 years.

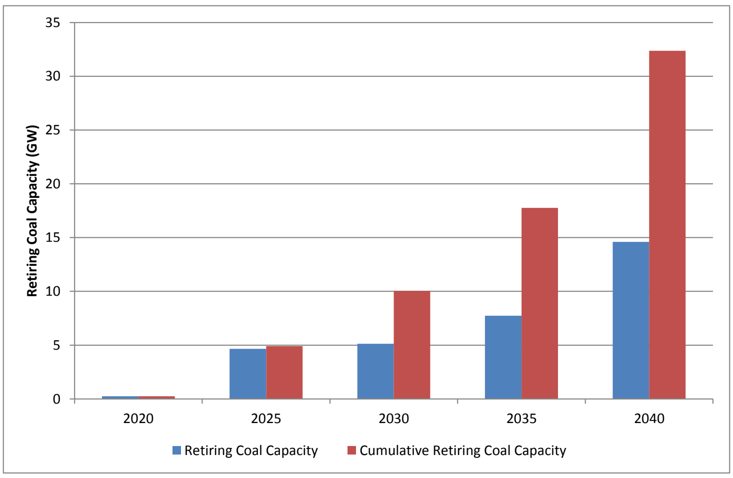

Figure 3 Retirement Schedule for Existing Coal Plants

The 2011 Ministerial Determinations

The 2011 ministerial determinations shown in Figure 4 are included in all the scenarios considered in this report. The 2012 Ministerial Determinations are included as part of a sensitivity analysis.

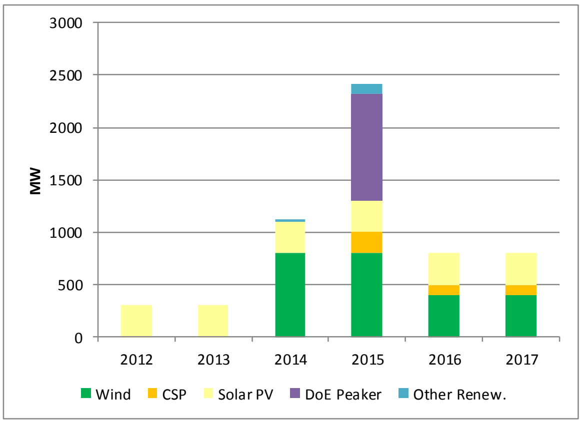

Figure 4 2011 Ministerial Determinations

The Demand Projection

Figure 5 shows the set of assumptions governing the growth in energy demand over the planning horizon and the resulting electricity demand projection after subtracting the demand side management (DSM) assumed in the IRP2010[1]. The "IRP2010 Mod" growth rate shown in Figure 5 is the growth rate assumed in the "Policy Adjusted Scenario" of the IRP2010; the "MYPD3" growth rate is the growth rate that was assumed in the MYPD3 application (Eskom 2012).

Demand growth in the New Power Plan presented here on the right hand side of Figure 5 begins with the demand seen in 2011 and follows the MYPD3 projected growth rates until 2017. After 2017 demand growth matches the growth rates of the "IRP2010 Low" growth scenario until 2035. From 2035 to 2040, a constant growth of 0.78% was assumed. The New Power Plan shown in Figure 2 uses this "Extended" MYPD3 growth projection.

A higher demand growth was adopted as a sensitivity analysis (discussed later in this report). The higher demand growth - called "MYPD3 adj" - starts by tracking the MYPD3 growth to 2017 then rises to 2.75% in 2019 and then drops down to 2% in 2021 and stays at that level until 2040. This scenario results in a demand that is roughly halfway between the IRP2010 "Moderate" scenario and the IRP2010 "Low" Scenario.

[1] Total in table 26 of the IRP document

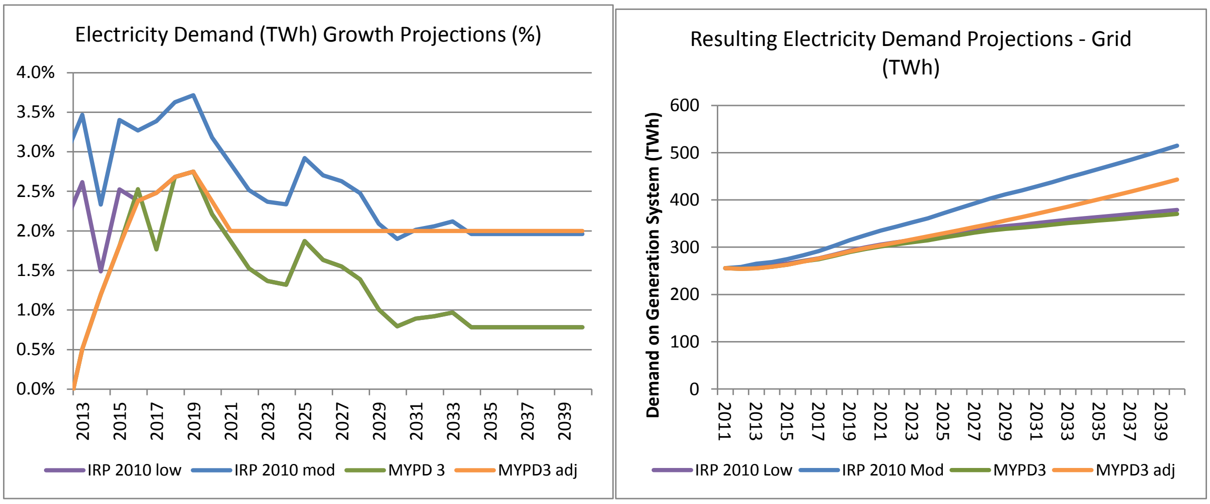

Figure 5 Electricity Demand Projections

Reliability Criteria and Reserve Margin

A reserve margin constraint of 15% of firm capacity is imposed in all scenarios, which falls within the 14%-19% range recommended in the Electricity Master Plan (DOE2007). The firm capacity (capacity credit) of all thermal (including solar thermal with storage), pump storage and hydro units are assumed to be 1. The firm capacity of wind is conservatively set to 0.15. The firm capacity of solar thermal without storage and solar PV are set also conservatively, to zero.

Investment Costs

Investment Costs for coal and gas, biomass and hydro technologies remain as they were in the IRP2010. The investment costs for Nuclear and Renewable Technologies have been updated to reflect current experience in the Renewable Energy IPP Programme.

Nuclear

The initial assumption for the overnight cost of nuclear plants in the IRP2010 was around $3500/kW. After stakeholder consultation this figure was adjusted upwards by 40% and an overnight cost of $5000/kW was used in the IRP2010 despite the fact that Eskom had been quoted in the region of $6000/kW by Areva in 2008 bidding process. More recent publications of the cost estimates put the overnight cost in the region of $7000/kW (Harris et al 2012). An overnight cost of $7000/kW has been adopted for this study in the base case with a sensitivity analysis at $5000/kW. Other parameters for nuclear remain at the IRP2010 values.

Renewable Technologies

The recent REIPPP windows one and two have helped to uncover what some of the renewable technologies would actually cost in South Africa. Table 1 shows the project costs and total capacity for the second window of the REIPPP of 2012 (DOE 2012). Given this data we can estimate what this means in terms of the overnight costs in 2010 Rands, which we can use in the planning model.

Table 1 REIPPP window 2 cost data on Renewable Technologies

		Wind	PV	CSP
Total Project cost	mR(2012)	10,897	12,048	4,483
Capacity	MW	563	417	50
Project Cost	2012 R/kW	19,355	28,892	89,660
Project Cost[2]	2010 R/kW	16,592	24,768	76,861
Lead Time	years	2	1	3
IDC[3]		0.12	0.08	0.17
Overnight Cost	2010 R/kW	14,772	22,933	65,766
Overnight Cost[4]	2010 $/kW	1,996	3,099	8,887

Costs for these technologies are still coming down and are projected to continue to do so as the global installed capacity rapidly increases from a relatively low base. As per the modelling in the IRP2010, we assume that South Africa is a price taker on technology costs and that the learning would continue to depend on what happens globally rather than locally and therefore investment cost reductions due to technology learning are specified exogenously.

Three scenarios which reflect global technology learning were considered in this analysis, namely an “optimistic”, “conservative” and “pessimistic” cost reduction scenario. The “optimistic” annual cost reductions for PV and CSP are based on the IRP2010 and are shown on the left hand side of Figure 6 and Figure 7. For wind the “conservative” cost reduction scenario was based on IRP2010 as shown in Figure 8. In all three cases, the annual cost improvement for the “conservative” case is half that of the “optimistic” case, and the “pessimistic” case is half the “conservative” case. The resulting impact on the overnight cost, using a 2012 value that is based on the REIPPP window 2 (as per Table 1), is shown on the right hand side of the figures. For PV we see that the “optimistic” case tracks the assumptions in the International Energy Agency’s Energy Technology Perspectives (IEA-ETP 2012) quite well. For CSP with 3 hours of storage we see a similar pattern. The Sunshot and NREL figures fall somewhere in between our “conservative” and “pessimistic” cases for the CSP with 6 hours of storage, and similarly for CSP with 12 hours of storage. For the New Power Plan scenario we have assumed the conservative, mid-range, learning curves. Later we run sensitivity analyses that asume more optimistic learning curves.

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[2] Using GDP deflator downloaded from http://search.worldbank.org/data?qterm=gdp%20deflator%20%22south%20africa%22&language=EN

[3] Using a real discount rate of 8% as per IRP2010 – IDC (Interest During Construction) here is shown as a fraction of overnight costs.

[4] Using the IRP2010 exchange rate of 7.4 2010 Rands per 2010 US$

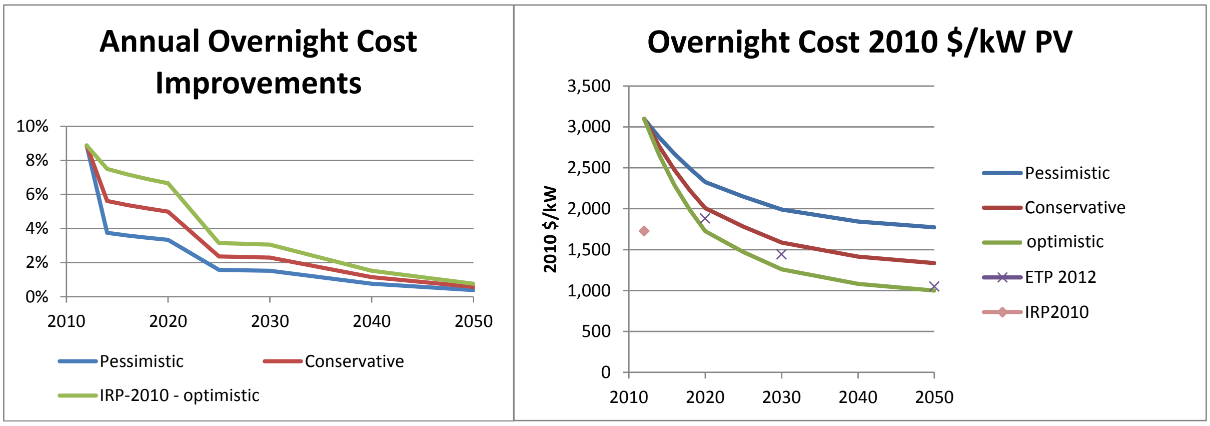

Figure 6 Annual Cost Reductions for PV

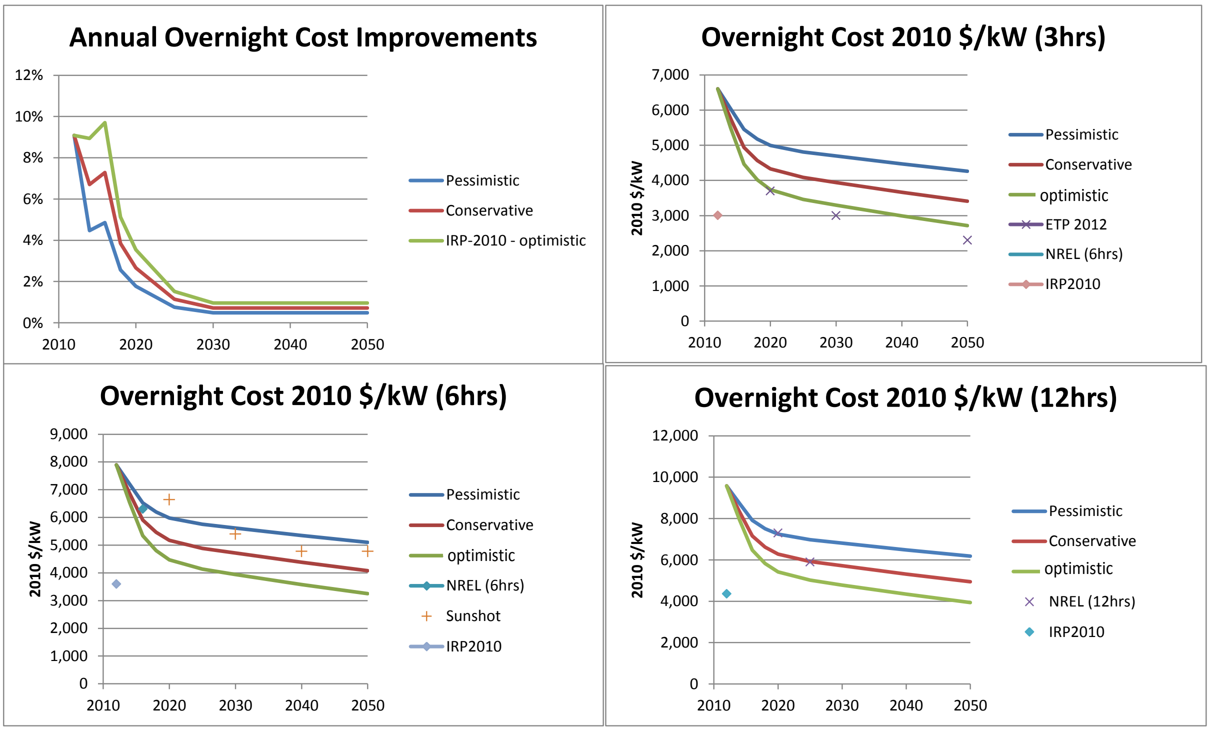

Figure 7 Annual Cost Reductions for CSP

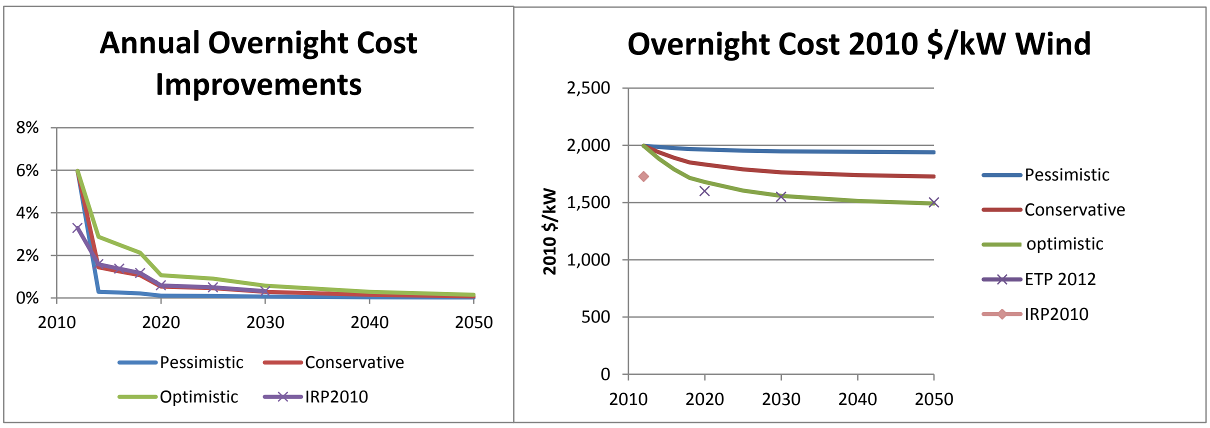

Figure 8 Annual Cost Reductions for Wind

Fuel Price Assumptions

The "Base" assumptions for fuel prices seen by power plants are shown in Figure 9. Table 2 and Table 3 show the assumed gas prices and delivery infrastructure costs seen by the model. The Fuel price assumptions were kept as they were in IRP2010 except for the coal price and the gas price. The coal price was updated according to the recent MYPD3 application. The price of imported or domestically produced gas is indexed to the price of oil and thus rises as the oil price rises. The oil price is assumed to rise from around 80$/bbl in 2010 to just over 150$/bbl in 2040 as per an early release of the American Energy Outlook (US-EIA 2013). The gas price seen by power plants includes supply infrastructure costs assuming a 90% utilisation factor. The detailed assumptions for the gas infrastructure costs and the oil indices for the different gas supply options are given in Table 2 and Table 3 respectively as per (Dynamic Energy 2013).

Shale-gas and Mozambique piped gas are not included in the base New Power Plan scenario runs because of uncertainties in cost projections – but later sensitivity analyses are undertaken on these options.

Table 2 Gas Infrastructure Cost Assumptions

Gas Project		Ibhubezi/Shale	Northern Mozambique	LNG Terminal	FSRU
Range	km	500	2,500		
ODC	$m	100	501	110	41
EPC	$m	1,037[5]	4,517[5]	845[6]	315[7]
Total Overnight Cost	$m	1,137	5,017	955	356
Lead Time	years	4	4	4	2
Capacity (size of minimum investment)	PJ/a	45.4	45.4	172.8	48

Table 3 Assumed Gas Costs

Source of Gas		Ibhubezi	Domestic Shale	Northern Mozambique	LNG
Crude Oil Index	$/Mbtu/ $/bbl	0.10	0.08	0.06	0.12
Gas Price at 100$/bbl	$/Mbtu	10.0	8.0	6.0	12.0

[5] Assuming $70k/km/inch of pipeline, and a 22 inch pipeline with compression
[6] Assuming a 1xLNGC berth (3.6 mtons) with 2x165000 m3 tanks
[7] Based on the 400m$ quoted in the media for a 1mton FSRU unit for the Petro SA GTL plant

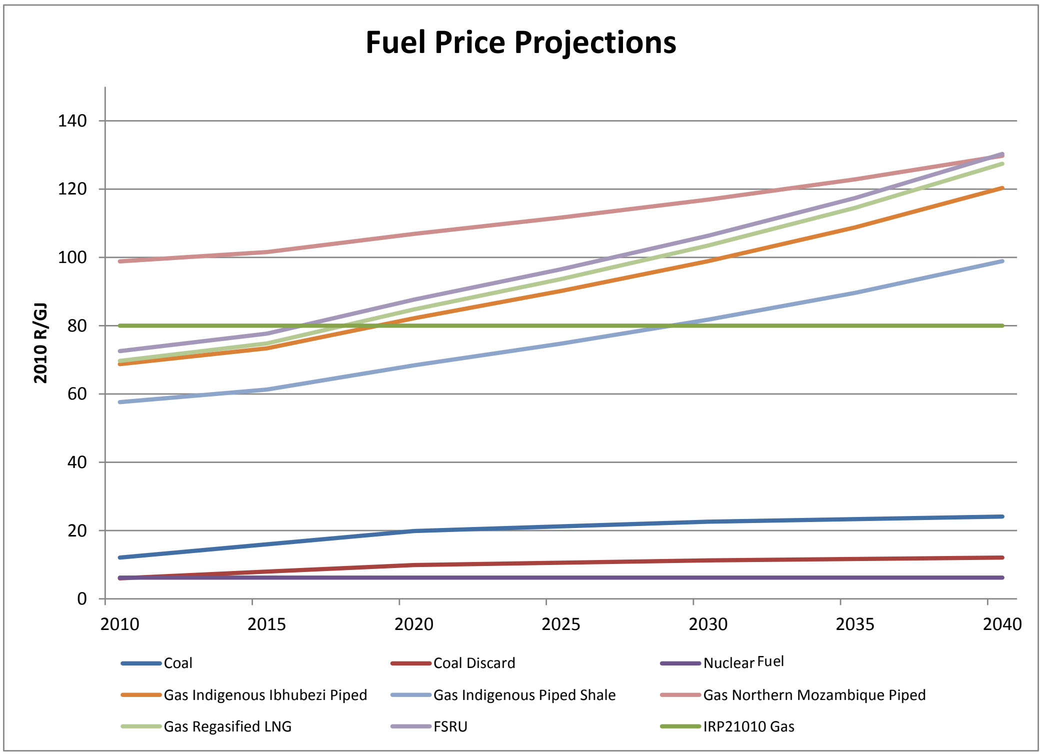

Figure 9 Fuel Price Projection for "Base" assumptions on Oil Price

CO_2 Emission Constraints

CO_2 emissions from the power sector are constrained from 2025 onwards following a “Plateau and Decline” trajectory. The limit is set to 275Mton/annum in 2025, and starts to decline from 2035 to 225Mton in 2040 and 150Mton in 2050.

Levelised Cost of Electricity

The levelised cost of electricity (LCOE) shown in Figure 10 and Figure 11 reflects the cost of producing electricity at different load factors over the life of the plant. The levelised cost are given in real terms and includes the capital cost of the plant, fuel costs and operation and maintenance costs and is calculated at a real discount rate of 8%. Expenditure is assumed to be at the beginning of the year and corporate taxes are not included.

Figure 10 shows the LCOE’s for plants which run at low capacity factors. Costs for PV and wind are shown at the capacity factors of 19% and 29% respectively.

Figure 11 shows the LCOE’s for plants which run at higher capacity factors in 2030. All the import hydro options are very attractive. Without CO_2 considerations, coal is the domestic technology with the lowest LCOE at high capacity factors. Nuclear at \$5000/kW and at \$7000/kW crosses the LNG and Shale LCOE’s around the 80% capacity factor. The range for the solar thermal plant shown in the chart (14hr storage) is very close to the nuclear range.

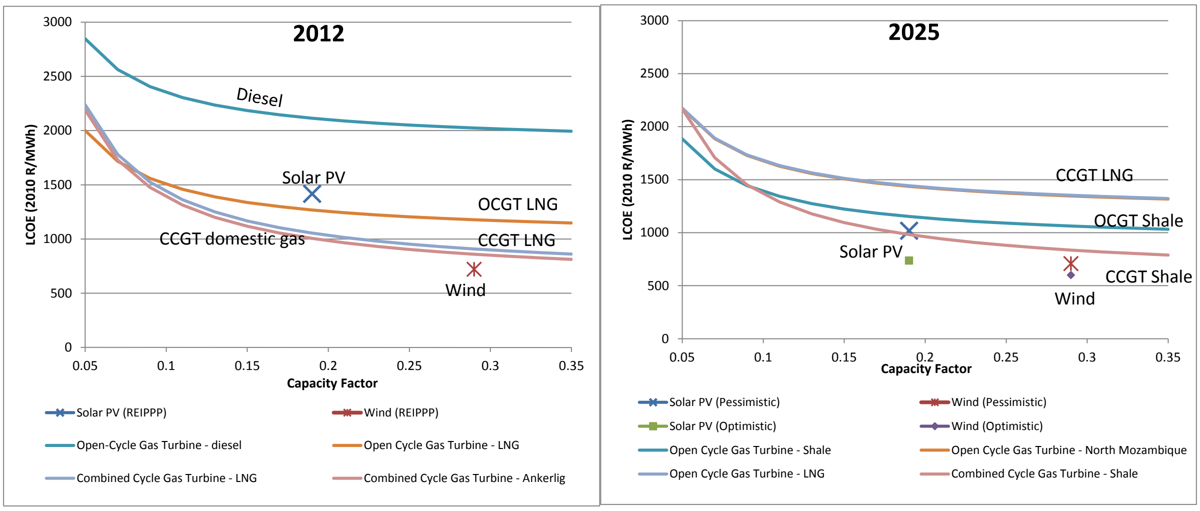

Figure 10 LCOE Analysis for Low Capacity Factor Technologies in 2012 and 2025

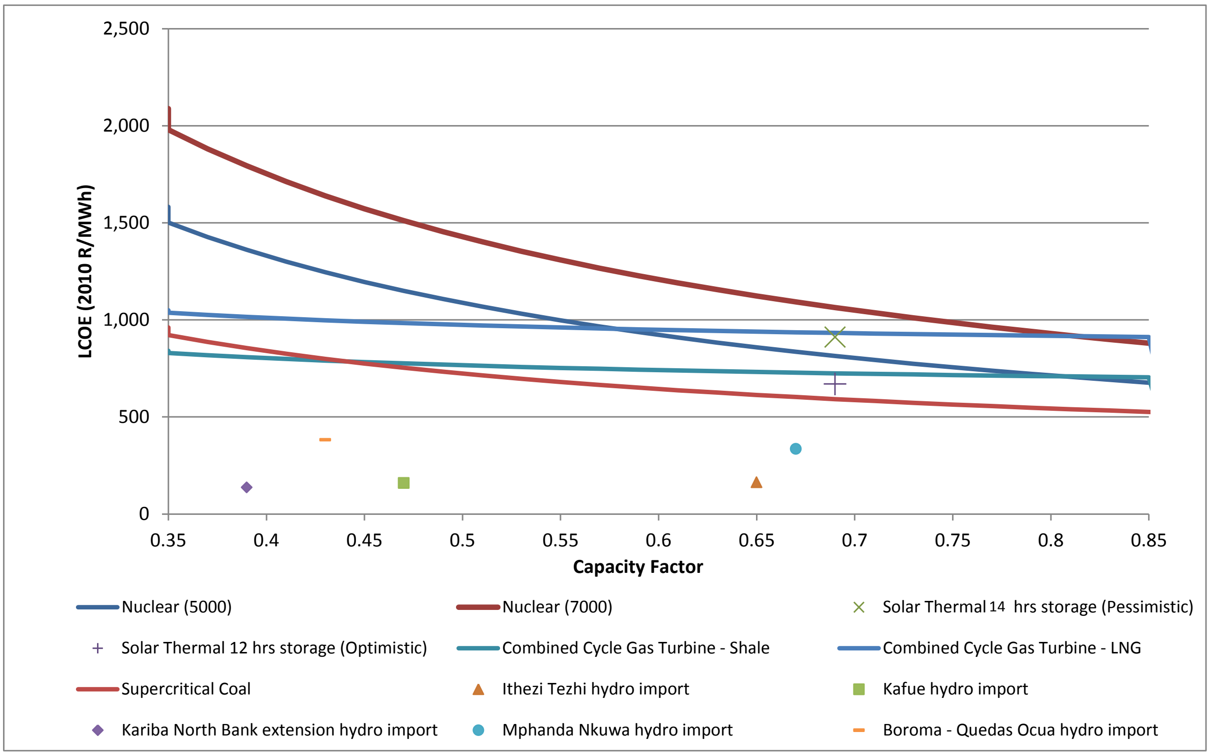

Figure 11 LCOE Analysis for high Capacity Factor Technologies in 2030

Sensitivity Scenarios

The extent to which the New Power Plan is sensitive to changes in technology, fuel costs and a higher energy demand projection is explored in this section. For each sensitivity, the new capacity requirements and the implications for generation price are shown and discussed. The generation price includes the fuel costs, operation and maintenance costs (including water and the environmental levy) and the capital costs of power plants as per the RAB methodology. The capital cost of plants built before 2009 is set to the valuation of the existing generation asset base as per the MYPD3 application.

Demand

The increase in demand from 370 TWh 2040 in the new power plan to 514 TWh in 2040 in the higher demand scenario increases the capacity built from 72.3 to 92.6 GW. Capacity additions are largely from gas and renewables as additions of coal are subject to the CO_2 emissions limits imposed. Notable is that even in the higher demand scenario, nuclear capacity remains limited, with only 1.6 GW of new nuclear built before 2040, the additional nuclear capacity coming online in 2038.

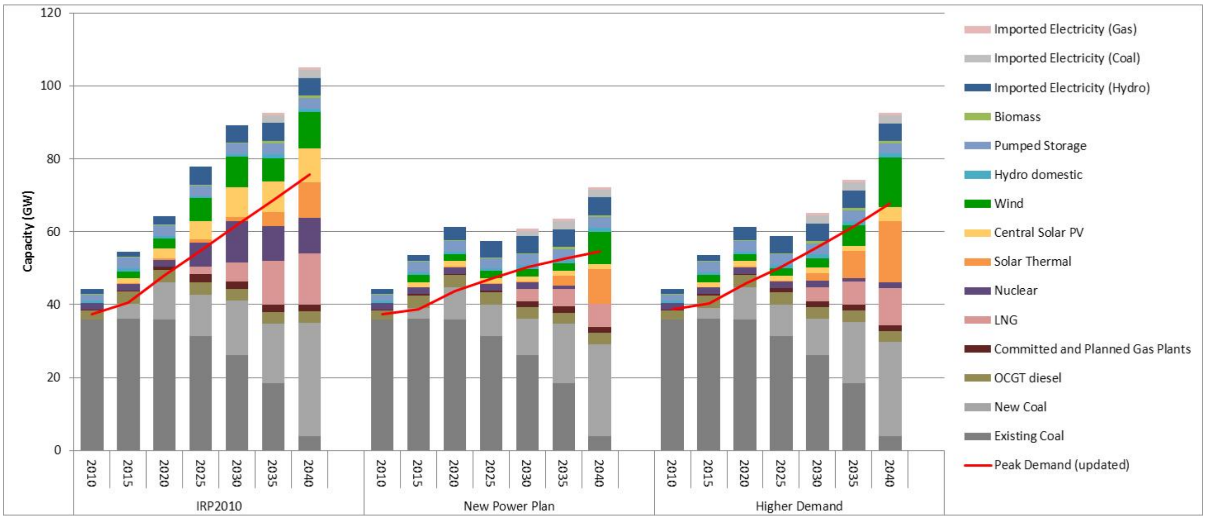

Figure 12 Total Installed Capacity for IRP2010, New Power Plan and Higher Demand Scenario

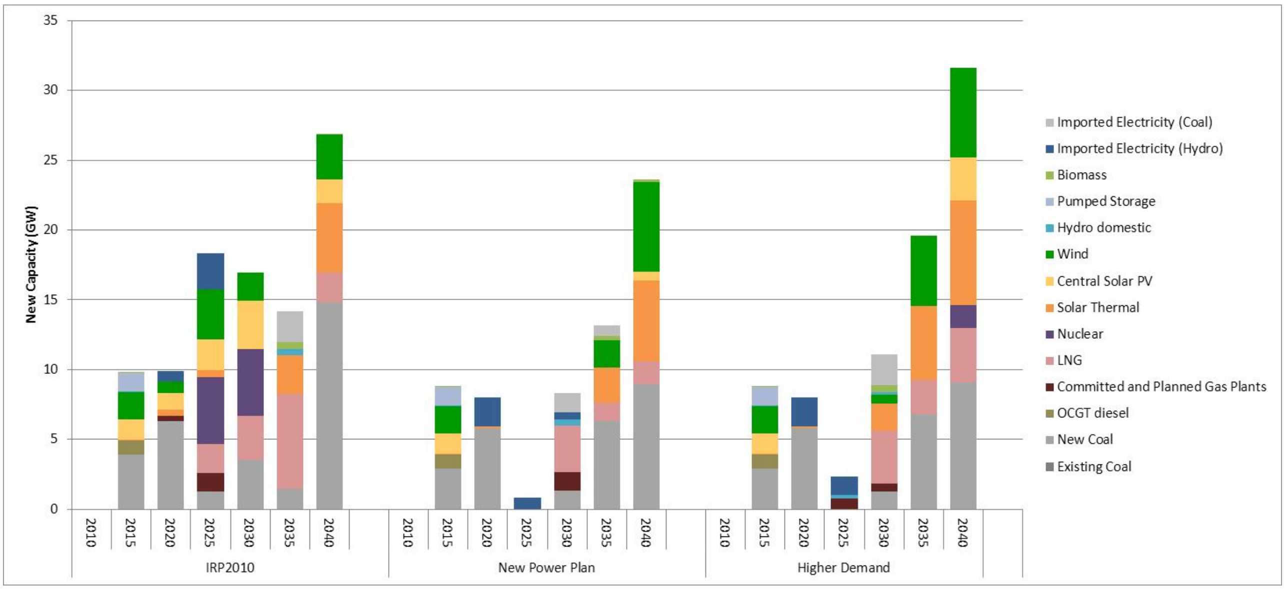

Figure 13 New Capacity for IRP2010, New Power Plan and Higher Demand Scenario

Figure 14 shows the generation component of the electricity price. The initial rise in price between 2012 and 2016 reflects the expenditure on the power plants under construction and is the same for all three scenarios. The drop in price of the New Power Plan and Higher demand scenario until 2026 is due to the initial overbuild relative to the demand expected, and the very small capacity additions between 2021 and 2025. Costs rise after 2025 as it becomes necessary to replace the retiring coal fired plants and meet the increasing demand. The CO_2 limit is the same in all scenarios and with the higher demand, there is a higher share of non-coal options which drives the electricity price up. The high cost of electricity in the IRP2010 is higher due to the sustained high level of investment resulting in significant levels of overcapacity if the SO moderate growth is applied to the actual 2011 demand levels. The two dotted lines show the impact on the electricity price if we fix the nuclear component of the IRP 2010 and assume the two demand levels considered in this study. They show that in both cases, this commitment would cause the price of electricity to be 11-12% higher than it would be in the New Power Plan in 2023.

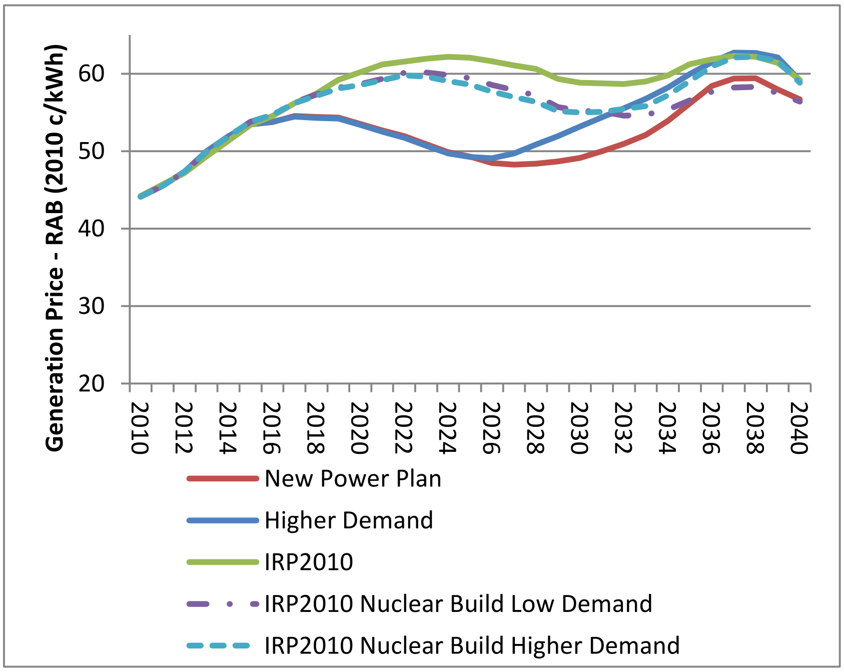

Figure 14 Generation price for IRP2010, New Power Plan, Higher Demand Scenario, and with the Nuclear Plan fixed

Ministerial determinations

The 2012 ministerial determinations include the additional capacity shown in Table 4. The ministerial determinations have the effect of shifting capacity in gas and RE built in the New Power Plan forward and lowering the new capacity needed between 2016 and 2025.

Table 4 2012 Ministerial Determinations

Technology/Fuel Group	Target Capacity (MW)	Target Year
Coal PF/FBC	2500	2014-2024
Gas	2652	2021-2025
Imported Hydro	2609	2022-2024
Other Renewables	3200	2017-2020

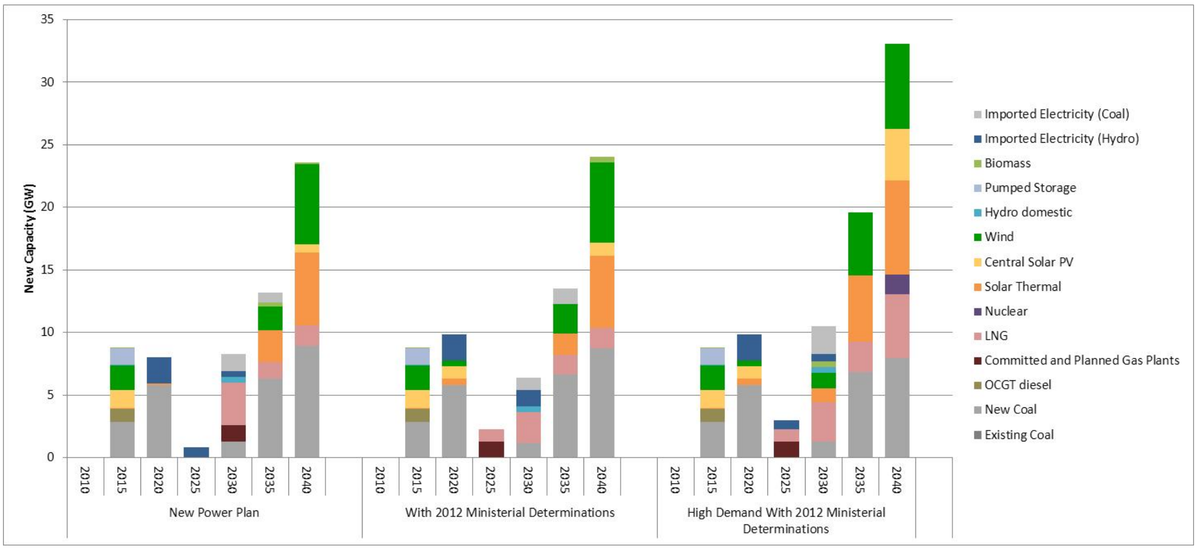

Figure 15 New Capacity for New Power Plan with the 2012 Ministerial Determinations and Higher Demand with Ministerial Determinations

The cost of generating electricity is raised slightly when the ministerial determinations are included. The increase peaks at plus 2.4% in 2025. Even in the high demand case, there is also an increase in price if 2012 ministerial determinations are included, which peaks at plus 2% in 2025.

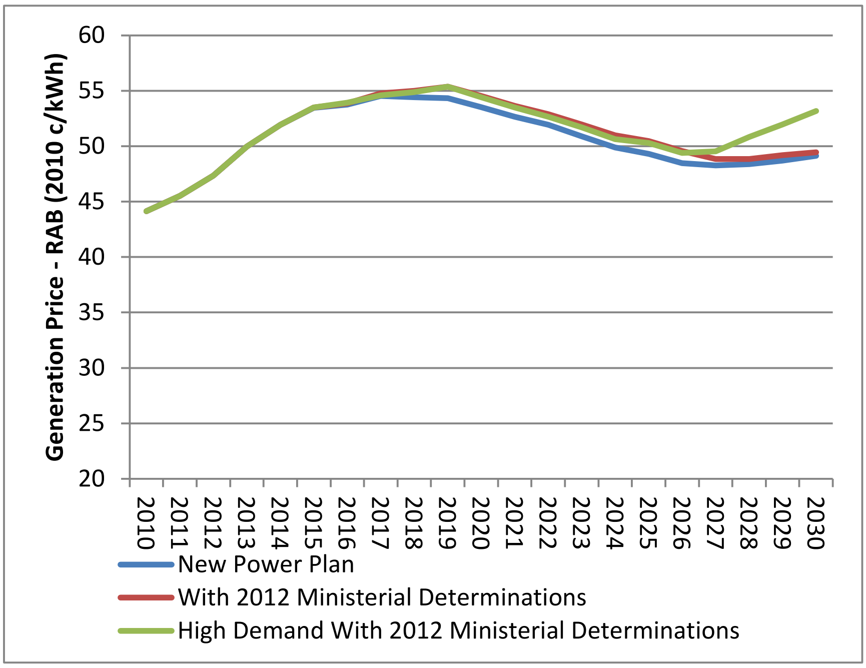

Figure 16 Generation Price for New Power Plan with the 2012 Ministerial Determinations and Higher Demand with Ministerial Determinations Generation Price

Cheaper Nuclear

When the overnight cost of nuclear plants is dropped from \$7000/kW to \$5000/kW, nuclear plants replace much of the renewable capacity in the New Power Plan. Nuclear plants are incorporated in units of 1.6GW. In the lower demand case the first unit only comes online in 2035 when Koeberg is due to retire, and by 2040, 5 units (8GW) are built. In the higher demand scenario the investment in nuclear capacity increases, and the first unit comes online in 2029 and by 2040, 10 units are built (16GW). Noticeable in these scenarios is the absence of PV and the lower addition of solar thermal capacity, and some new pump storage in the high demand case.

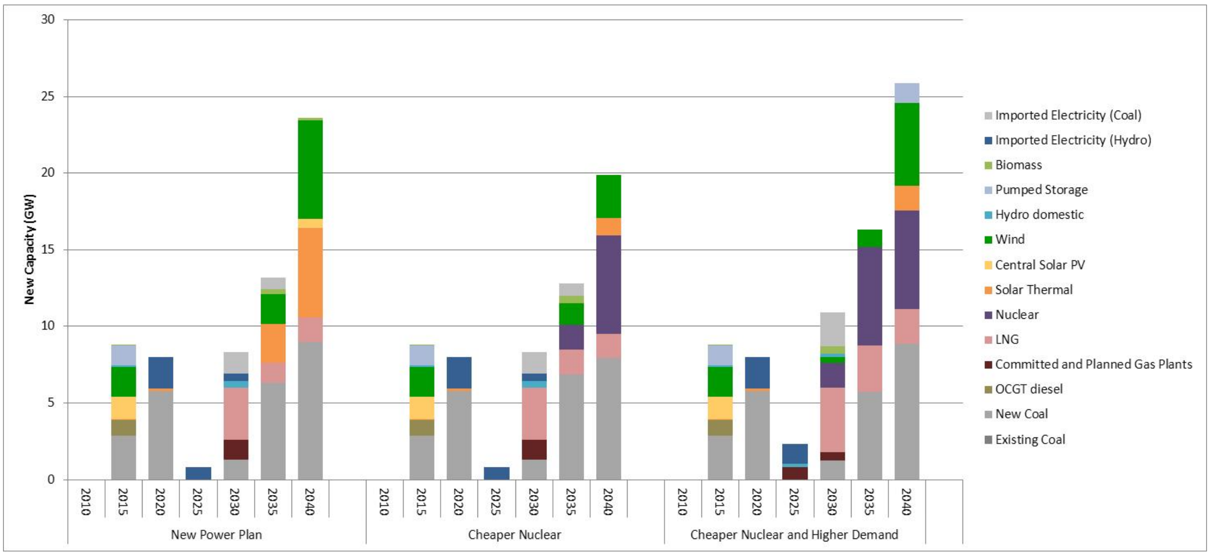

Figure 17 New Capacity for New Power Plan, Cheaper Nuclear and Cheaper Nuclear with Higher Demand

Figure 18 shows the impact on the generation price. In the cheaper nuclear case, the price is initially higher than the NPP but then ends up lower towards the end of the horizon. In the higher demand case, the price increase begins earlier around 2021 when the expenditure on the first unit begins.

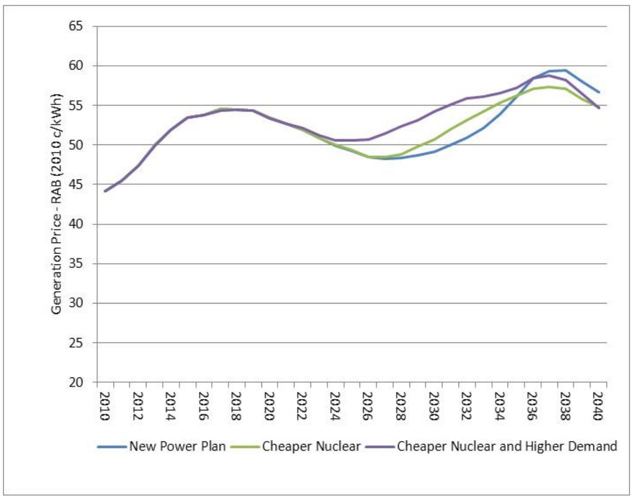

Figure 18 Generation Price of New Power Plan, Cheaper Nuclear and Cheaper Nuclear with Higher Demand

Combined Cases

Figure 19 and Figure 20 compares the higher demand scenario with cheaper nuclear ($5000/kW) against a combined scenario which includes cheaper nuclear, shale gas and optimistic costs for RE, and one with the same combination except with high nuclear costs. The cost and size of the shale gas resource in South Africa is very uncertain however; if the shale gas and infrastructure costs shown in Table 2 and Table 3 are used, shale replaces LNG. The lower RE costs cause nuclear at the lower cost to be replaced by renewable generation capacity, largely from Solar Thermal power plants. There is still some investment in nuclear capacity, 8 GW by 2040 with the first unit coming in 2035, when Koeberg retires. If the high cost of nuclear is assumed then we no longer see any nuclear before 2040, but instead, large amounts of shale gas and RE in form of wind solar thermal and solar PV.

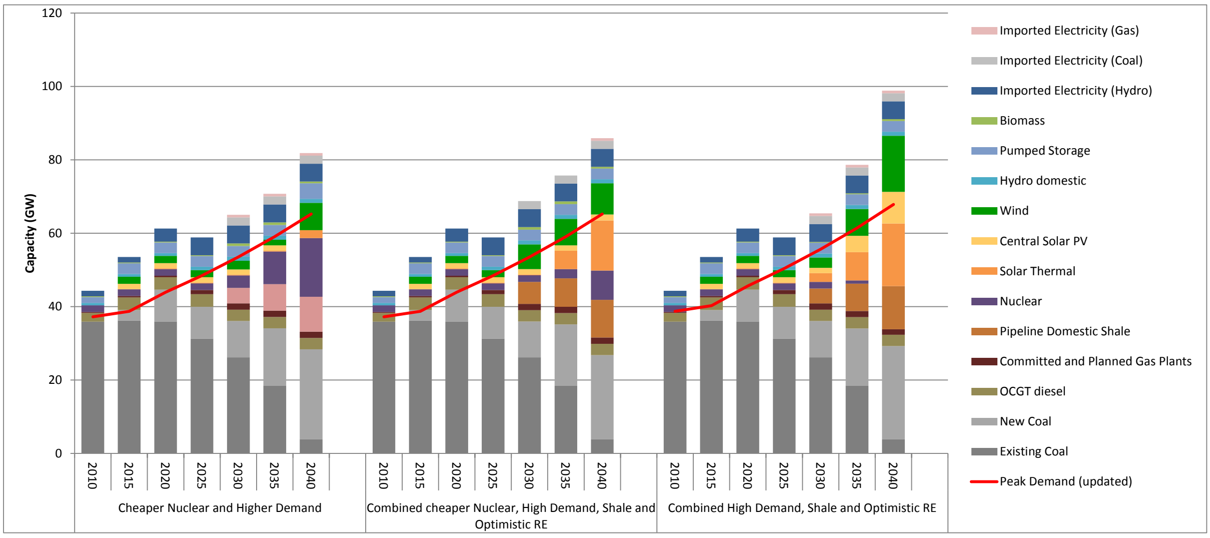

Figure 19 Total Capacity for Cheaper Nuclear with Higher Demand and two other combined cases with cheap and expensive nuclear

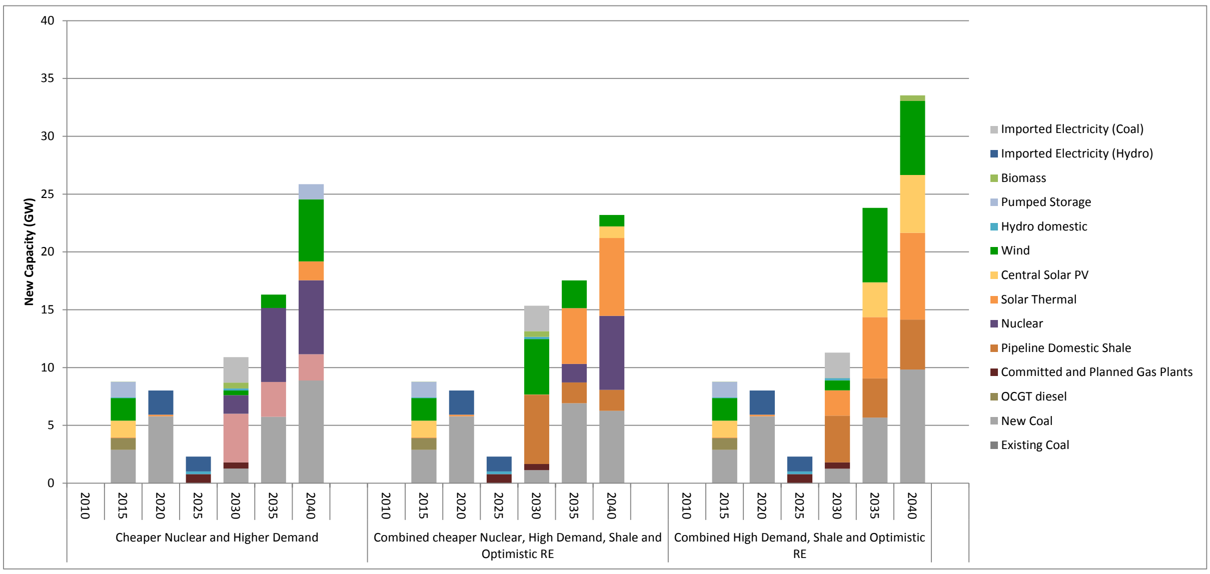

Figure 20 New Capacity for Cheaper Nuclear with Higher Demand and two other combined cases with cheap and expensive nuclear

Interestingly, the price difference between the scenarios is relatively small, as shown in Figure 21, but should we commit to a nuclear program expecting a low cost but end up with high one then the impact on the price is much more significant as shown by the dotted lines.

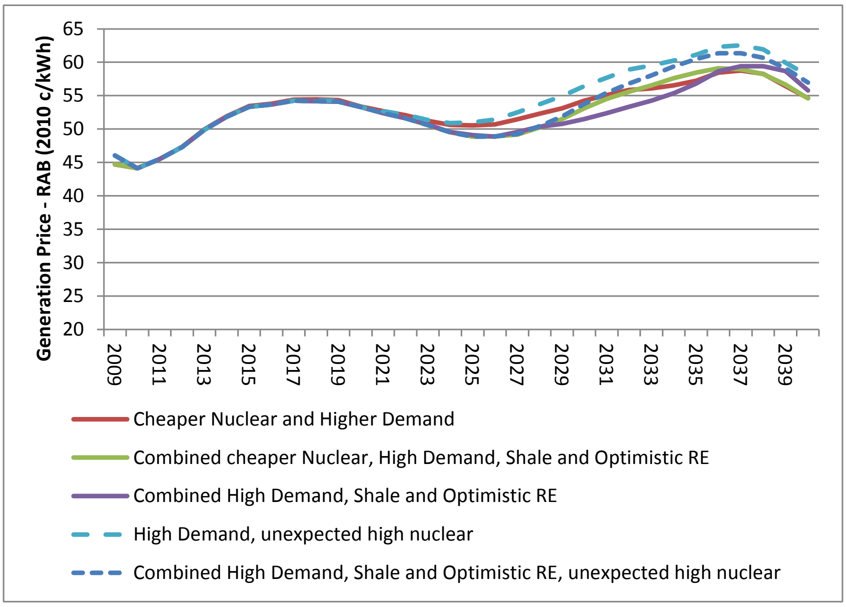

Figure 21 Generation Price for Cheaper Nuclear with Higher Demand and two other combined cases with cheap and expensive nuclear

RE programme

Due to overinvestment before 2020, there isn't much room for new investment in RE before 2030. However, in order to expand the renewable capacity at the scale and rate required at that time, it could be argued that the renewable program that has begun through REIPPP should be kept alive by maintaining a steady stream of investment over the planning period. This was modelled as an extra sensitivity where a minimum investment in each of those three technology was imposed as well has an upper limit on the annual increase in new capacity as shown in Table 5. The impact of these constraints in terms of new investment is shown in Figure 22. We see the minimum investment level in the period 2015-2020 and then a gradual increase in the subsequent periods. The impact on the generation price is shown in Figure 23. The increase is of the same order as of that of enforcing the 2012 ministerial determinations.

Table 5 Limits imposed on Investment in RE Technologies for Renewable Program

Technology	Minimum Annual Investment (MW/yr)	Upper limit on annual increase on new capacity
Wind	50	20%
Solar PV	25	10%
Solar Thermal	50	20%

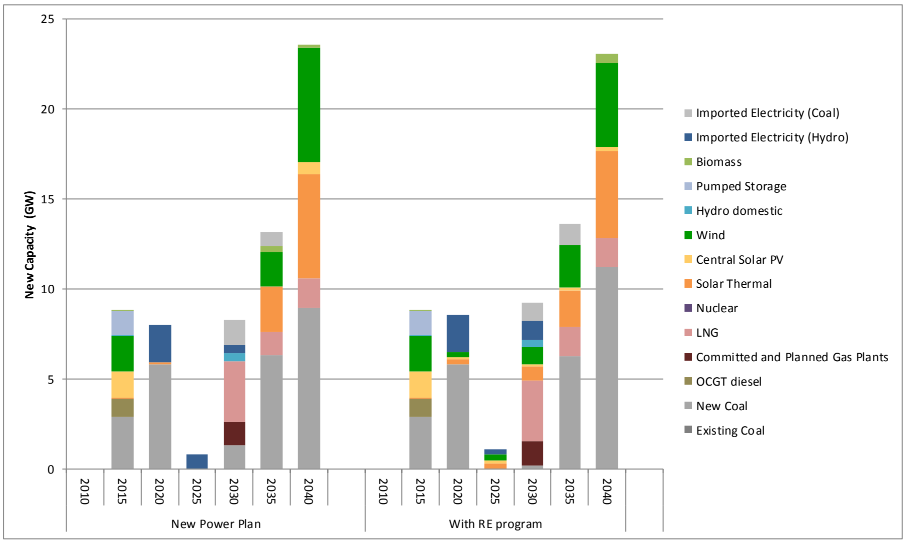

Figure 22 New Capacity for New Power Plan and Optimistic RE Programme

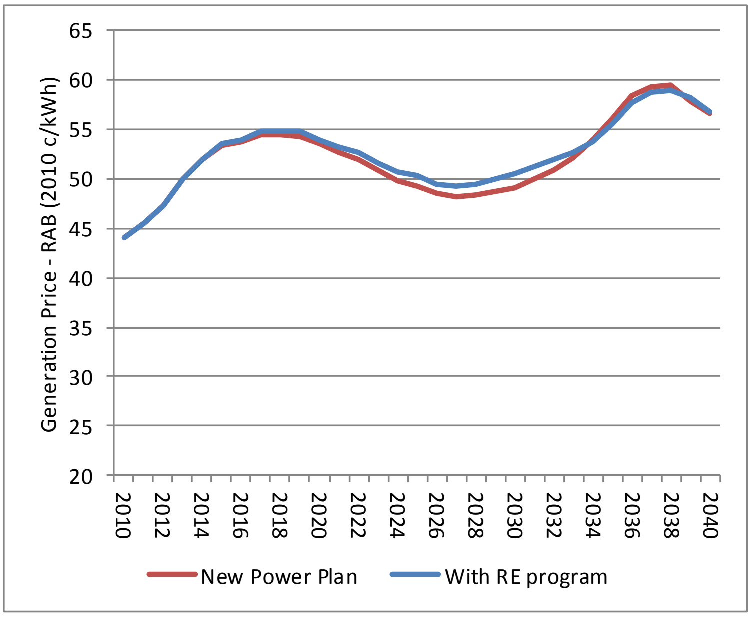

Figure 23 Generation Price of New Power Plan RE programme

Conclusions and Future work

The New Power Plan presented in this report is work in progress. It is not a definitive alternative to the IRP2010. The preferred power generation options shown are outputs of the TIMES model and are obviously highly dependent on input parameters and assumptions. We have accordingly also modelled alternative scenarios with higher demand, lower nuclear costs, more optimistic cost improvements of renewables, with and without shale gas, and with/without the 2012 ministerial determinations and an RE program with sustained annual investments.

The New Power Plan presented in this analysis shows the impact of changing demand assumptions in accordance with the lower demand seen today compared to that of the IRP2010. New information on the costs and electricity generating options are becoming available and indicate that RE costs and nuclear costs are higher, and the role which shale gas could play should it become available at costs competitive with LNG.

The analysis performed clearly shows the importance of updating the IRP2010. Ignoring this new information and fixing decisions, including a large nuclear roll-out of large units, on an out-dated plan is going to be very costly to the economy. The analysis also shows that even with a higher demand, and lower nuclear costs, new capacity in nuclear is only required in 2029 and not in 2023 as per IRP2010. This means that there is more time for South Africa to make this decision about nuclear – and it is by no means a matter of urgency, by which time more information would become available on:

- The availability and cost of shale gas in South Africa
- The costs of a gas via pipeline from Northern Mozambique
- The LNG price, given the growth in global LNG markets
- The projected cost and capabilities for long storage solar thermal technologies
- More information on the feasibility of further hydro imports, including the Inga Dam, which was excluded from this analysis but could provide South Africa with further low CO_2 electricity
- A better understanding of demand and the role that distributed generation (e.g. rooftop PV) could play, which was also not properly considered in this analysis
- A better understanding of the transmission constraint on large RE program
- A better assimilation of existing uncertainties in the modelling framework (e.g. with scenario-wise decomposition)
- A more integrated approach to analysis to include the interactions between the power sector and the rest of the energy/water sectors and the rest of the economy
- More information on costs and capabilities of more flexible smaller modular nuclear reactors, which would be far more suitable for South Africa given the large uncertainties in demand and the large RE resource.

Acknowledgements

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