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RESEARCH REPORT

An assessment of new coal plants in South Africa’s electricity future

The cost, emissions, and supply security implications of the coal IPP programme

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Executive summary

South Africa's coal baseload independent power producer (IPP) procurement programme was launched in 2014, in line with the new coal capacity envisaged in the 2010 Integrated Resource Plan for Electricity (IRP 2010) (DoE, 2011). Since the release of the IRP 2010, however, there have been fundamental changes to the South African electricity sector. In particular, rapid changes in the costs of competing supply technologies and fuels globally and in South Africa, coupled with an unprecedented decline in demand for electricity, have rendered the assumptions of the 2010 IRP increasingly out of date. Later iterations of the IRP (2013 and 2016) were not or have not yet been gazetted, and the 2010 IRP thus remains the guiding plan for the construction of new generation capacity, despite these changes in the sector. This has the result of making provision for the addition of new generation capacity that is not necessary to meet demand and ensure security of supply of electricity, provides more costly electricity, and increases greenhouse gas emissions.

Under the coal IPP programme, preferred bidder status has been awarded to two projects: the Thabametsi and Khanyisa coal-fired power plants. Despite opposition from environmental groups, the Minister of Environmental Affairs has stated that, at least in the case of Thabametsi, the environmental authorisation for the station should be upheld. The Minister has argued this on the grounds that the capacity is allocated by the IRP 2010 and the IRP decisions makers "concluded that the harms that would result from the establishment of new coal-fired facilities... were outweighed by the benefit to the country of having the additional energy generation capacity".

Given this context, this study aims to quantify the effects of the inclusion of the coal IPPs in South Africa's electricity system over the period from 2015 to 2052. The modelling framework indirectly allows for an assessment of supply security because the model is required to meet a 15% firm reserve margin of fully dispatchable plant. The relative costs of a system with or without the coal IPPs thus reflects the costs of ensuring an equivalent level of operating supply security and system adequacy. The modelling highlights several key changes in the electricity sector that have not been considered by the Minister of Environmental Affairs in her decision to uphold the environmental authorisation. This includes the substantially lower demand that has materialised since the IRP 2010 (and that is forecast into the future) and which renders the coal IPPs unnecessary for meeting short, medium, or long-term demand growth at lowest cost. We also investigate the cost implications that the inclusion of the coal IPPs imposes on the system relative to cheaper alternatives (comparing total system costs), the GHG emission 'lock-in' from the plants, and the effects this has on South Africa meeting its long-term climate change commitments.

To do this, we model several scenarios using the South African Times Model (SATIM): a reference scenario, a climate change mitigation (CCP) scenario, a best-case sensitivity and a worst-case sensitivity. Each scenario results in a least-cost electricity build plan for South Africa (subject to the assumptions and constraints imposed on the model). A key finding of the study is that in all scenarios, neither new coal nor new nuclear is required to meet demand at lowest cost. Thus, since a least-cost electricity build plan for South Africa does not include new coal plants, after running each scenario we run a comparative scenario (with all assumptions held equal) except that we 'commit' to the coal IPPs – i.e. force them into the model – in order to compare the effects on the system.

The result of the assessment of new coal IPPs has shown that these plants are not necessary to meet demand, and, further, that their inclusion in South Africa's electricity system will substantially raise costs in the electricity sector, and substantially increase GHG emissions over their lifetimes.

The inclusion of the coal IPPs in the electricity build plan increases the total discounted system cost across all of the scenarios analysed. The additional costs range from R16.4 billion (best case coal IPPs) to R27.99 billion (CCP).

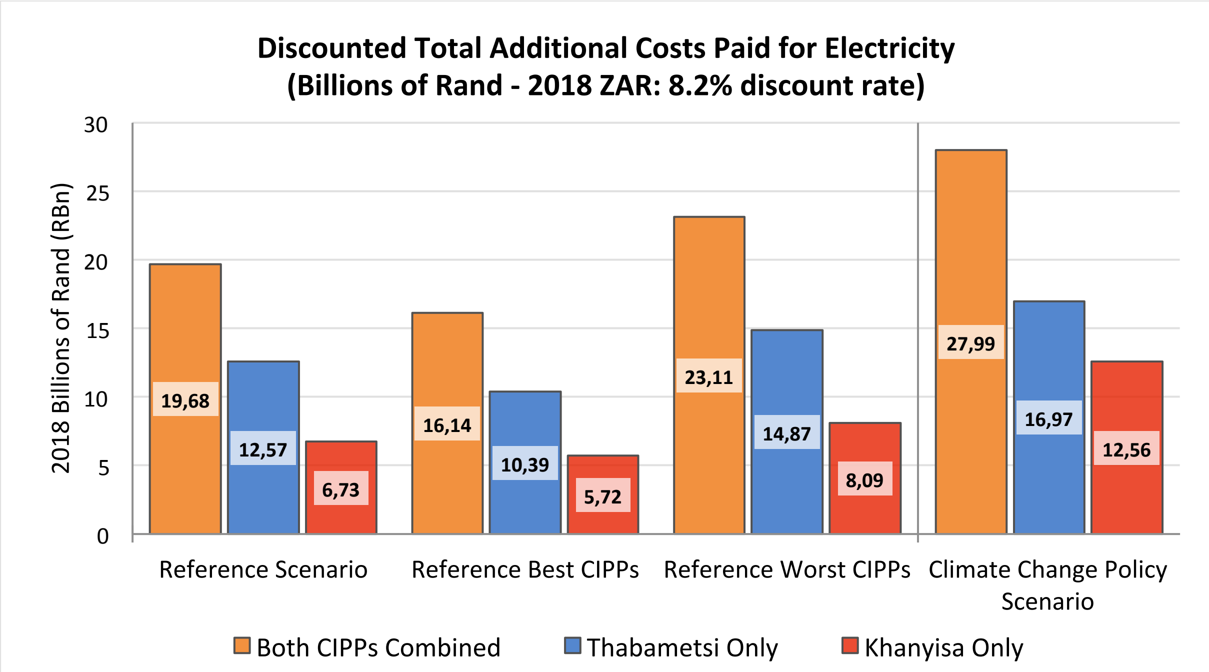

Figure a: Summary of total discounted additional costs for electricity for all scenarios for the individual and combined IPPs[1]

In the reference scenario, the additional present value cost of building the coal IPPs is R19.68 billion. The stations also increase emissions by 205.7Mt CO_2eq over the period. This amounts to a negative carbon price of R96/t CO_2-eq; that is, this is the price per ton that South Africans will pay for the extra emissions if the coal IPPs are built.

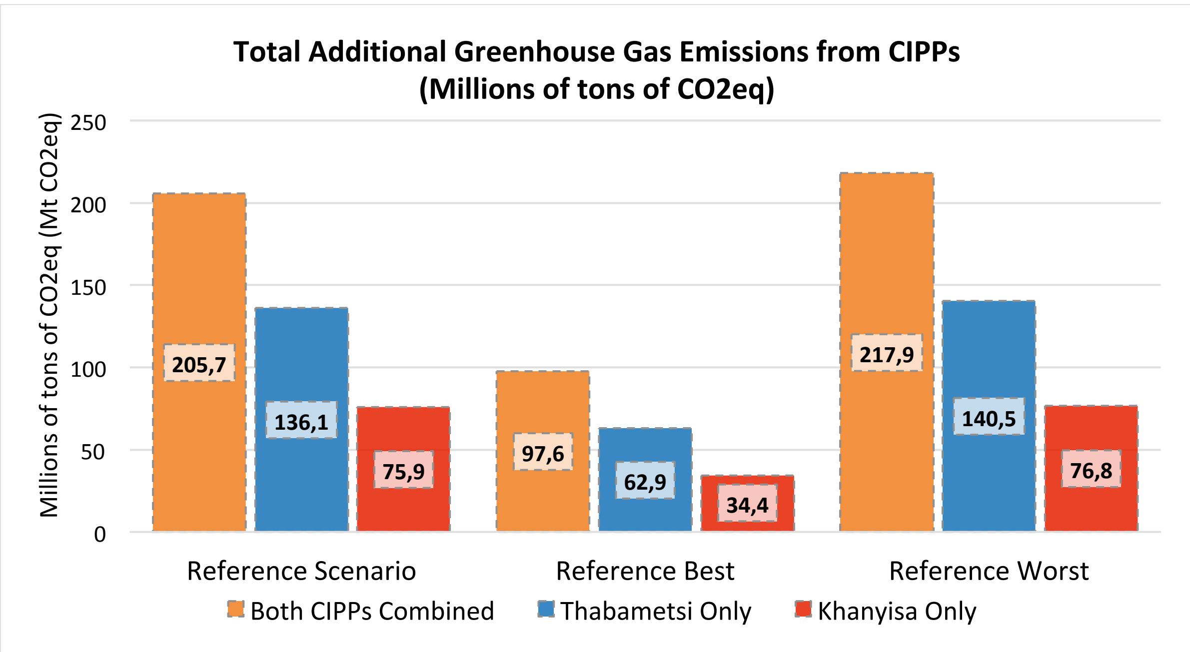

Figure b: Total additional power sector GHG emissions in the reference baseline, best case, and worst case scenarios for the individual and combined COAL IPPs.

[1] In each case, the total additional costs are the difference between the scenario with and without the coal IPPs committed (ie reference compared to reference plus coal, CCP compared to CCP plus coal, best and worse with and without the coal).

The analysis also includes sensitivities on costs and emissions to test whether more pessimistic renewable energy and gas costs could impact the overall findings. We find that even with pessimistic renewable energy cost projections and high gas costs, the coal IPPs still increase the system costs in the electricity sector compared to an optimised electricity build plan. Even in the best case for the coal IPPs, when competing alternatives are expensive and the IPPs are able to mitigate their emissions significantly, the overall increase in system costs is R16.4bn, and the increase in emissions is 97Mt. In the worst case for the coal IPPs, the increase in system costs is R23.11bn and emissions increase by 218Mt.

In comparison, recent modelling on the emissions savings of mitigation policies showed that the emissions savings of the post-2015 National Energy Efficiency Strategy to 2050 will be 214 Mt CO_2-eq (ERC, 2018). The carbon tax is expected to result in reductions of 115 Mt over the period 2020-2050. Thus, the GHG emissions of the coal IPPs in the reference and worst case will almost offset the National Energy Efficiency Strategy. Even under the best-case for coal, the GHG emissions from the coal IPPs will almost offset the entire emission savings of the carbon tax for the South African economy. The coal IPP programme essentially negates key mitigation actions at the disposal of the government.

Finally, we tested the effects of building the coal IPPs in the context of climate change mitigation policy. Should South Africa take its own climate change commitments seriously, building the coal IPPs will dramatically raise the costs of meeting the low-PPD carbon budget as outlined in the National Climate Change Response White Paper. Meeting the low-PPD when the coal IPPs are built requires increased mitigation in the power sector, with the existing fleet run at lower load factors to make room for the coal IPPs, and substantial higher investment required for new generation capacity. Notably, other sectors will also face higher mitigation burdens. In total, the additional discounted system costs to meet the low-PPD trajectory with the coal IPPs is R27.9bn.

The implications of these findings are clear. South Africa is currently facing a large surplus in generation capacity, in particular inflexible base supply capacity. Eskom is facing a financial crisis and rising electricity prices will drive consumers away from the utility. Investments that unnecessarily increase costs in the electricity sector should be avoided

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1. Introduction

South Africa's coal baseload independent power producer (IPP) procurement programme was launched in 2014, in line with the new coal capacity envisaged in the 2010 Integrated Resource Plan for Electricity (IRP 2010) (DoE, 2011). Since the release of the IRP 2010, however, there have been fundamental changes to the South African electricity sector. In particular, rapid changes in the costs of competing supply technologies and fuels globally and in South Africa, coupled with an unprecedented decline in demand for electricity, have rendered the assumptions of the 2010 IRP increasingly out of date. Later iterations of the IRP (2013 and 2016) were not or have not yet been gazetted, and the 2010 IRP thus remains the guiding plan for the construction of new generation capacity, despite these changes in the sector. This has the result of making provision for the additions of new generation capacity that is not necessary to meet demand and ensure security of supply of electricity, provides more costly electricity, and increases greenhouse gas emissions.

Under the coal IPP programme, preferred bidder status has been awarded to two projects: the Thabametsi and Khanyisa coal-fired power plants, with net capacity of 557MW and 306 MW respectively, and both planning to use sub-critical fluidised bed combustion (FBC) technology. Both of these plants have faced considerable opposition from environmental groups and have not yet reached financial close. In the case of Thabametsi, a court ruled that the Department of Environmental Affairs (DEA) had not adequately considered the climate change impacts of the plant before making the decisions to authorise the power station, and a climate change impact assessment was undertaken. The Minister of Environmental Affairs subsequently upheld the environmental authorisation for the plant, on the grounds that the impacts identified in the climate change impact assessment report and supported by the independent review could be justified. The Minister has argued that the justification is based on the capacity allocated to coal in the IRP 2010 because the IRP decisions makers "concluded that the harms that would result from the establishment of new coal-fired facilities... were outweighed by the benefit to the country of having the additional energy generation capacity".

Given this context, this study aims to quantify the effects of the inclusion of the coal IPPs in South Africa's electricity system over the period from 2022 to 2052. The modelling framework indirectly allows for an assessment of supply security because the model is required to meet a 15% firm reserve margin of fully dispatchable plant. The relative costs of a system with or without the coal IPPs thus reflects the costs of ensuring an equivalent level of operating supply security and system adequacy. The modelling highlights several key changes in the electricity sector that have not been considered by the Minister of Environmental Affairs in her decision to uphold the environmental authorisation. This includes the substantially lower demand that has materialised since the IRP 2010 (and that is forecast into the future) and which renders the coal IPPs unnecessary for meeting short, medium-term, or long-term demand growth at lowest cost. We also investigate the cost implications that the inclusion of the coal IPPs imposes on the system relative to cheaper alternatives (comparing total system costs), the GHG emission 'lock-in' from the plants, and the effects this has on South Africa meeting its long-term climate change commitments.

To do this, we model several scenarios using the South African Times Model (SATIM) (see section 2 and appendix) that allows an assessment of the effects of building the stations compared to an optimised future electricity build plan that excludes the coal IPPs. To assess the implications of the inclusion of coal IPPs in the South African electricity system, we model the following scenarios:

- Reference case
- Climate change mitigation policy (CCP) scenario
- Best-case sensitivity for coal IPPs
- Worst-case sensitivity for coal IPPs

Each scenario results in a least-cost electricity build plan for South Africa (subject to the assumptions and constraints imposed on the model). A key finding of the study is that in each scenario, neither new coal nor new nuclear is required to meet demand at lowest cost.[2] Thus, since a least-cost electricity build plan for South Africa does not include new coal plants, after running each scenario we run a comparative scenario (with all assumptions held equal) except that we 'commit' to the coal IPPs – i.e. force them into the model – in order to compare the effects on the system. We then report the deviation in the system between a case without the coal IPPs and the case where the coal IPPs are forced in to the scenario. For example, we report on the difference between the 'reference scenario' and the 'reference scenario plus coal'.

In all scenarios, we find that the inclusion of the coal IPPs in South Africa's electricity build plan raises the total system costs compared to a scenario without the coal IPPs. Similarly, in all scenarios, the coal IPPs increase the GHG emissions of the energy system.[3] The increases in both the system costs and GHG emissions are substantial.

Not only are the coal IPPs not required to meet demand, and not only do they raise costs, and increase emissions, but they also result in increasing pressure on Eskom. Building new coal plants in a situation of low demand means reducing the output of Eskom's fleet, potentially accelerating the 'utility death spiral' in which Eskom already finds itself and putting the electricity supply industry – and thus the South African economy – at risk.

The report is structured as follows: section 2 outlines the modelling framework to be used and explains the functioning of the South African Times Model (SATIM). Section 3 describes the assumptions and scenarios in detail. Section 4 outlines the results for each scenario and section 5 concludes.

[2] The finding that a least-cost optimised energy system excludes new coal in general and the coal IPPs in particular is consistent with other modelling analysis undertaken in South Africa (CSIR, 2017).

[3] Except in the scenario where total GHG emissions are constrained/capped, see section 3 for detail.

2. South African TIMES Model (SATIM)

SATIM is a full South African energy system least-cost optimisation model, which considers not only the demand for electricity and how this is met, but also the demand for liquid fuels and other energy resources and how this demand impacts the choice of fuels used within the electricity sector and vice-versa (for model and documentation: http://energydata.uct.ac.za/organization/erc-satim). In SATIM, the demand for energy services or useful energy (e.g. process heating), which has strong links to demand drivers (e.g. GDP and population), is specified. The final energy demand (e.g. the demand for electricity) is a result of the model, based on the least-cost demand technology mix (e.g. mix of solar and electric geysers, or oil and electric vehicles). This provides a more holistic picture of the energy system and supply-demand interactions, allowing for endogenous fuel switching, and the switch to more efficient technologies. More details can be found in the report appendices and model documentation linked above. We report primarily on the results for the power sector, but note that the modelling framework includes substitution between sectors (e.g. higher electricity demand due to demand for transport services delivered via electric vehicles).

3. Study methodology and scenario description

This study uses the SATIM modelling framework to assess the implications of the coal IPP programme on system costs and GHG emissions for each scenario. Each scenario assesses the difference to the system with or without the plants over the 30-year time horizon of the power purchase agreements (PPA) (2022-2052). The energy system investment is modelled and presented annually from 2015 to 2035 and at 5-year milestone years from 2035 to 2050 (though we run the model to 2052 to capture the effects of the full life times of the stations).

Since an optimised least-cost build plan includes no new coal-fired power plants in the investment horizon to 2050, testing the system implications of the coal IPPs requires the plant or plants to be "forced-in" to the electricity system build plan. Thereafter, when the plants are committed, the deviation from the baseline least-cost system can be quantified and analysed. The study models both coal IPPs as a combined investment, as well as each project committed in isolation. Due to the interconnected combined systems effects of each plant on the rest of the existing system, it is necessary to model the plants both individually and combined, so as to accurately measure the total impacts of each potential investment decision.

The following metrics are reported on and compared for each scenario; in each case comparing that scenario with and without the coal IPPs. The 'deviation' between the reference scenario and the scenario with the coal IPPs committed shows the expected impact of the IPPs on the system.

Primary system metrics measured:

- Annual and total differences in national electricity system cost
- Total difference in discounted system costs
- Difference in the capacity expansion plan or electricity production profile
- Change in annual and cumulative GHG emissions

Metrics excluded from direct analysis:

- Water use and infrastructure requirements
- Environmental impacts such as SO_2, NO_2, or acid mine drainage
- Employment impacts

3.1.1 Representation of the coal IPPs in the model

Both Thabametsi and Khanyisa are modelled as Fluidised Bed Combustion (FBC) coal-fired power plants of 557 MW and 306 MW respectively (DoE, 2015). The total tariffs Eskom pays to Thabametsi and Khanyisa are R1,03/kWh, and R1,04/kWh, respectively (May 2016 Rand). This is calculated by inflating the evaluation price using the CPI index from April 2014 Rand to May 2016 Rand (which includes the shallow grid connection costs), and excluding the carbon tax (included in the evaluation price). This tariff is used as the total cost of the plants in the model (validated by pers. communication, CSIR).

- PPA = Evaluation price (–) Carbon Tax (120 R/t CO_2)

The PPA also includes the requirement for a fixed minimum off-take of electricity by the system operator, totalling 85% of the energy generation capacity of the plant. This offtake is required regardless of the availability of cheaper plants in the system. This would effectively lock the country in to the plants' future emissions and additional costs, while also reducing economic dispatch and system flexibility.

The GHG emissions intensity of Thabametsi is reported to be 1.23 tCO_2eq/MWh (ERM, 2017). We assume the same GHG-intensity for Khanyisa[4], since it also uses FBC technology. Importantly, this GHG-intensity includes both the direct carbon dioxide (CO_2) and the CO_2 equivalent of expected nitrous oxide (N_2O) emissions from the plants (not to be confused with the pollutant nitrogen dioxide (NO_2)). Fluidised bed plants typically emit significantly more N_2O than conventional pulverised fuel coal plants, such as the existing Eskom coal plants, and most of the world's existing plants (Zhu, 2013; Koorneef, 2017). N_2O has a 100-year global warming potential (GWP) 310 times greater per ton than CO_2 (UNFCCC, 2018), therefore even relatively small volumes of N_2O can make a large contribution to overall GHG emissions. As shown in Figure 1, including the N_2O emissions of the coal IPPs increases their GHG-intensity by 20.5%, from 1.02 to 1.23 tCO2-eq/MWh. This makes the GHG-intensity of the coal IPPs much higher than the world average. For comparison, N_2O emissions from Eskom plants only make up 0.4% of total CO2-eq emissions (Eskom, 2017b). The GHG-intensity is approximately 24% higher than the current Eskom fleet average and 58% higher than Medupi & Kusile.

[4] The same emissions intensity of 1.23 tons CO2eq/MWh (ERM, 2017) for both Khanyisa and Thabametsi in the reference scenarios and worst-case scenario, although Aurecon (2012) states an expected GHG emissions intensity of 1.1 tCO2eq/MWh. The ERM report is the most comprehensively investigated and recent figure accounting for GHG emissions of FBC in South Africa which explicitly includes N_2O in a total CO2eq emissions intensity value – N_2O emissions are usually negligible in pulverised fuel coal plants (such as Eskom plants) and have not been explicitly included in the IRP modelling to date. That said, using the 1.1tCO_2-eq/MWh value will not change the core findings, as a best-case sensitivity is modelled with a much lower CO_2-eq intensity of 700g/kWh by assuming ultra-super-critical boilers and negligible N_2O emissions – this best-case scenario still increases overall emissions against the optimal system without the plants if either or both plants are committed, thus the sensitivity analysis includes the 1.1tCO2/MWh figure in its range.

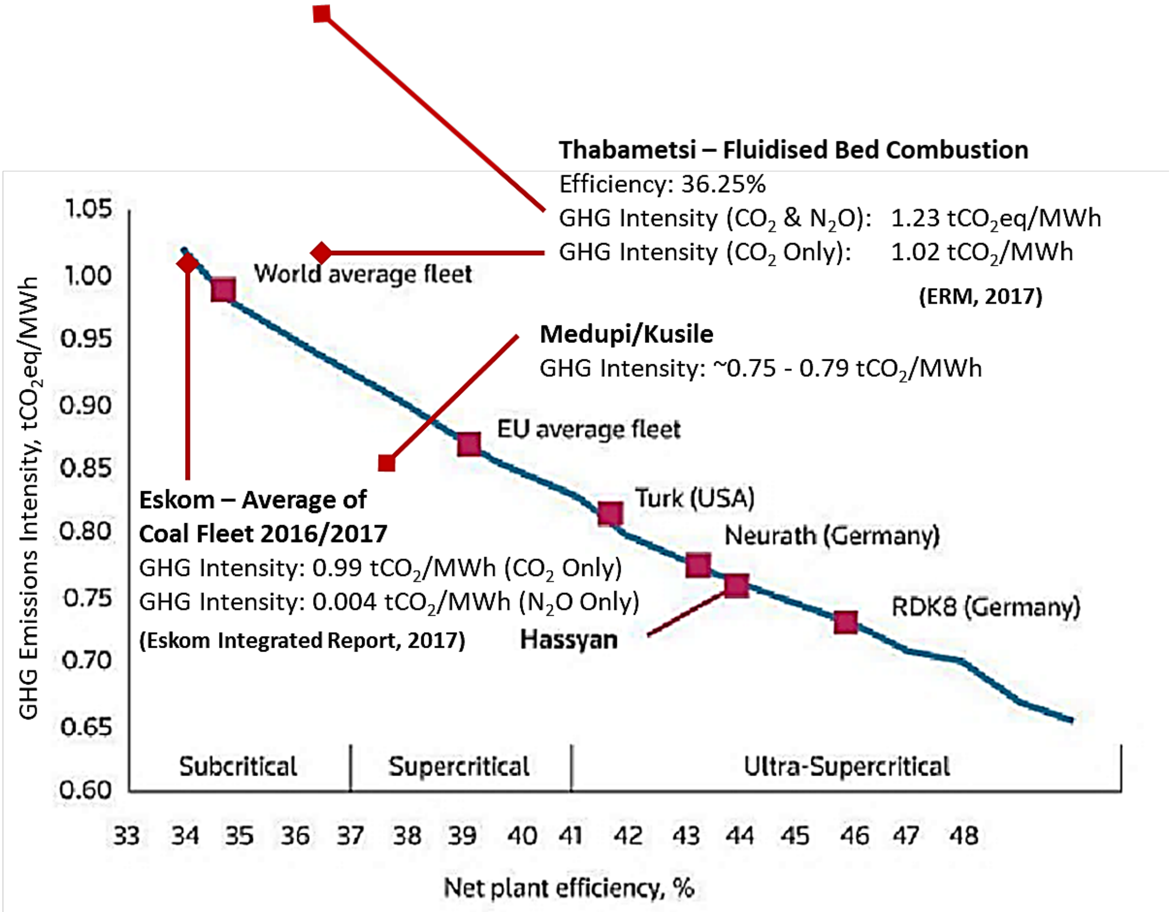

Figure 1: Comparison of various coal power plant efficiencies and emissions intensities. Adapted from PFI Yearbook & ACWA (2017). Sources: Eskom (2017), ERM (2017).

Table 1 shows a summary set of parameters of the coal IPPs.

Parameter	*Thabametsi*	*Khanyisa*
Plant Capacity (net sent out)	557 MW	306 MW
Efficiency (net)	36.25%	35.5%
PPA Tariff (2016 Rands)	1.03 R/kWh	1.04 R/kWh
GHG Emissions Intensity	1.23 tons CO_2-eq /MWh	
Assumed Final Commissioning Date	2022	
Project and PPA Lifetime	30 years	

Table 1: Summary of key input assumptions for coal IPPs (DoE, 2015; ERM, 2017; Aurecon, 2012)

3.2 Reference scenario

The reference scenario is the modelled least-cost energy system pathway without carbon constraints or caps on centralised renewable energy construction. The power sector is modelled in SATIM and provides a future electricity system build plan determining the optimal timing and quantities of new power sector investments, taking into account the existing power system and its integration with the larger South African energy system. An outline of key assumptions relevant to this scenario can be found in the following sections.

3.2.1 Electricity demand projections

Electricity demand forecasts in South Africa for the past 8-10 years have been consistently over-estimated (StatsSA, 2018; DoE 2016; DoE 2011). A combination of factors have impacted electricity demand growth, including: low economic growth rates, structural changes in economic structure, and changes in energy use patterns driven by higher electricity costs and energy efficiency improvements. Distributed and smart energy technologies such as solar photovoltaic (PV), battery storage, and "smart-grids" have not played a significant role yet in the overall South African system, but their wider uptake will have an increasing impact on grid demand.

The demand forecast for this study includes the full South African energy system. For the electricity sector, this projection falls between the IRP 2016 (CSIR High-Low Intensity) and the Energy Intensive Users Group 'EIUG' demand forecast - similar to the CSIR low demand forecast developed for the IRP 2016 (DoE, 2016, CSIR, 2017, EIUG, 2017). The EIUG forecast was used in the Meridian Economics study examining the viability of older Eskom coal plants (Steyn, Burton & Steenkamp, 2017). The ERC demand projection can be seen below, compared to the IRP 2010, IRP 2016, CSIR, and EIUG forecasts. Of interest is the flattened demand since 2010 and the subsequent large difference from the existing IRP 2010 demand forecast.

The current difference between the forecast demand in the IRP 2010 and actual demand is around the equivalent output of both Medupi and Kusile. Both NERSA and Eskom have drawn attention to the large surplus capacity facing Eskom (approximately 5GW), with NERSA disallowing costs in the 2018/19 price determination at two stations because they are surplus to system needs, and Eskom investigating putting older stations into cold reserve (Eskom, 2017a; Eskom 2017b; NERSA 2018).

Furthermore, in the policy-adjusted IRP 2010 (DoE, 2011), the DoE brought the construction of new coal capacity forward to 2014/15; new coal was initially only required from 2026 onwards in the revised balanced scenario (RBS). The IRP states the following in this regard: "*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… Existing coal-fired generation is run at lower load factors to accommodate the new coal options*" (DoE, 2011: 11, section 4.7). Thus the IRP 2010, even with a much higher demand forecast, acknowledges that the coal IPPs were surplus to new generation needs, would result in excess capacity, and would mean running the rest of the coal fleet at lower load factors. Their inclusion in the build plan was moved forward due to a policy commitment to coal. In brief, the allocation for new coal capacity in 2014/15 was not a modelling result and was not driven by energy security concerns.

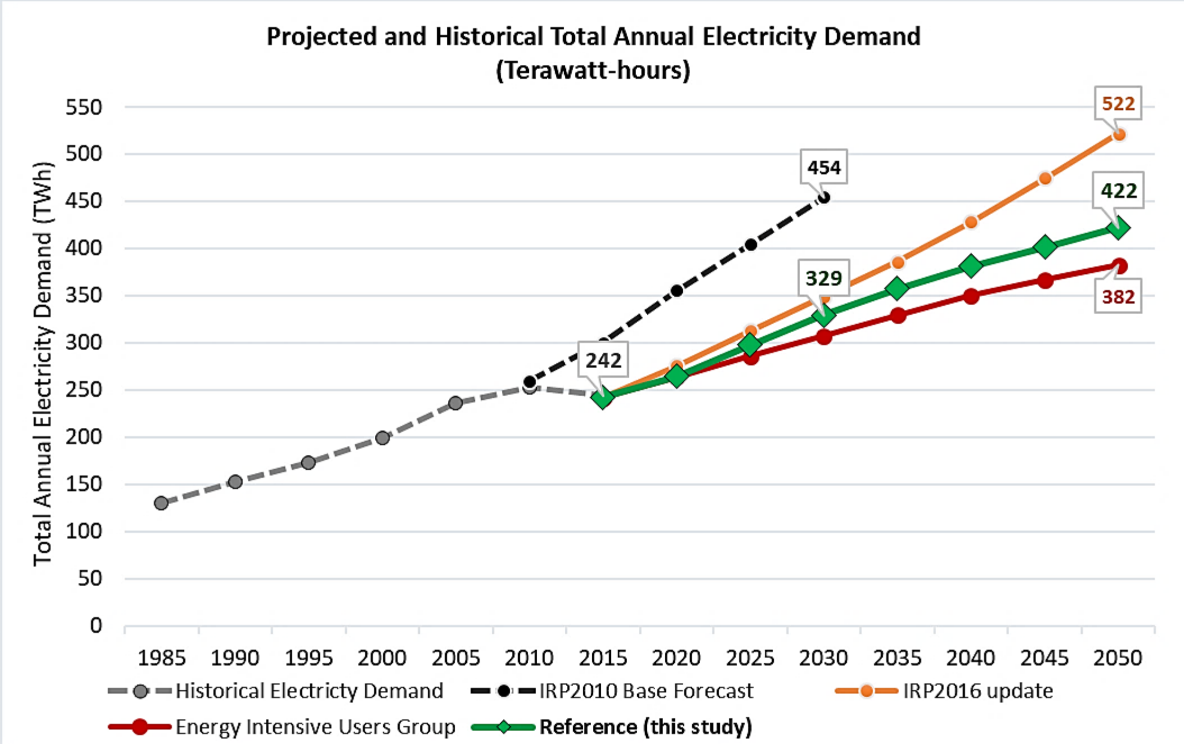

Figure 2: Comparison of historical (StatsSA, 2018) and forecasted annual electricity demands between ERC, CSIR, EIUG, and the IRP 2010 and draft IRP 2016 update.

3.2.1 New Electricity Generation Technologies

All new-build conventional technology costs and performance parameters are aligned with the draft IRP 2016 update (based on the independent EPRI report commissioned for the IRP), other than the parameters on nuclear, which were provided by the Department of Energy (DoE, 2016). Conventional generating technology investment options available for the model to use include: new coal, nuclear, gas turbines and engines, and regional hydro. The cost and performance parameters of conventional technologies all remain fixed throughout the model optimisation horizon to 2050.

Starting technology costs for utility-scale solar PV and onshore wind are aligned with the draft IRP 2016 update and are calculated to align with the recent Renewable Energy Independent Power Producer Procurement Programme (REIPPPP) tariffs, i.e. Bid Window 4.5 (expedited). Between Bid Window 3 and Bid Window 4 (expedited), solar PV and wind prices decreased by 47% and 29% respectively, with both reaching an average of R0.62/kWh (2015 Rand). The evolution of the REIPPPP price and capacity auctions is included below for reference (Figure 3). Only projects with signed PPAs as of May 2018 are included as committed in the baseline build plan.

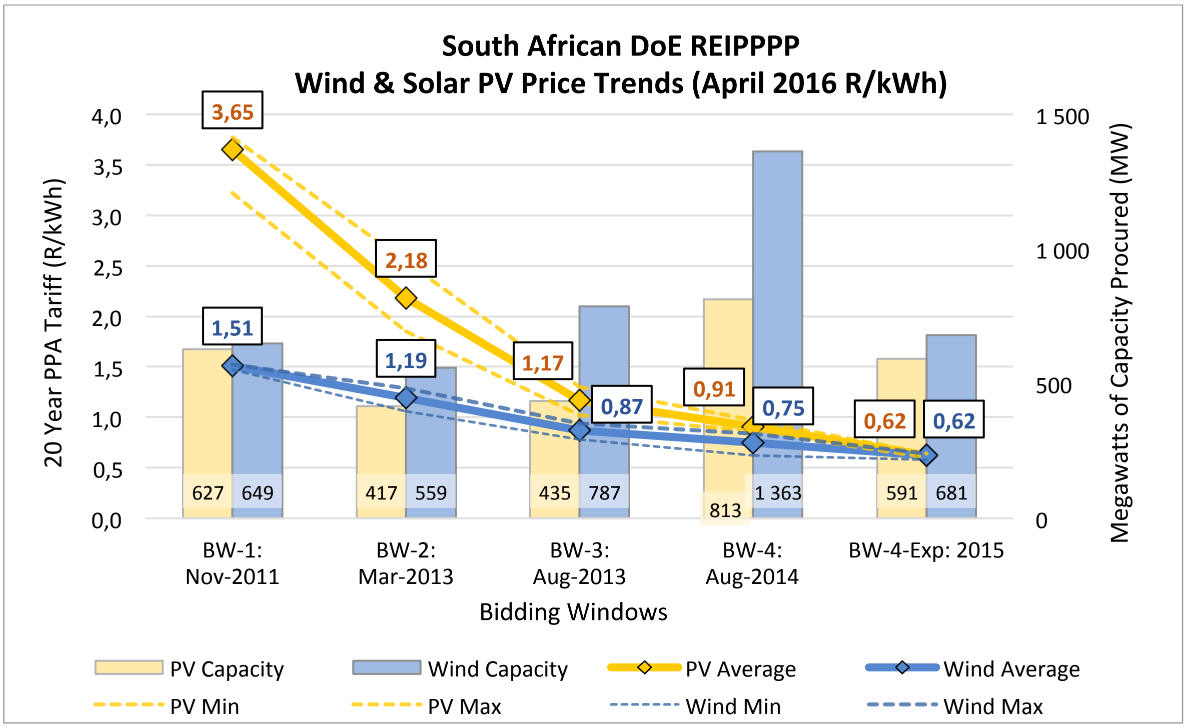

Figure 3: Historical solar PV and onshore wind Renewable Energy Independent Power Producer Procurement Program PPA prices and procured capacity for each round.

Solar PV and wind technology cost reduction projections for the reference scenario ("expected") learning can be seen in Figure 4. We also include optimistic and pessimistic sensitivities on the technology learning for renewables (section 3.4). No total future resource constraints are imposed for PV or wind, and new capacity can be constructed from 2021 onwards. Annual installation limits for PV and wind are set in 2021 to start at the total capacity awarded in round 4 for each technology. Each year thereafter, the annual installation limit increases by the portion of capacity awarded in the final expedited round (590MW for PV and 618MW for wind), until 2030 where the limits are no longer imposed. Wind and PV temporal energy production profiles are based on Fraunhofer (2015) and CSIR (2017).

Solar PV reference scenario technology assumptions:

- Annual capacity factors are assumed to be 28% using single-axis tracking solar PV technology, and 25% for fixed-tilt centralised plants of 75MW+. This is based on existing South African plant performance history, using averaged hourly production data from 2015-2017 (DoE REDIS, 2018).
- Plant life is 25 years, and construction time 1 year. Capacity factors remain fixed.

Onshore wind reference scenario technology assumptions:

- Annual capacity factors for new onshore wind farms are assumed to start at 36% for plants of size 100MW+ (DoE REDIS, 2018)
- Plant life is 20 years, and construction time 2 years.

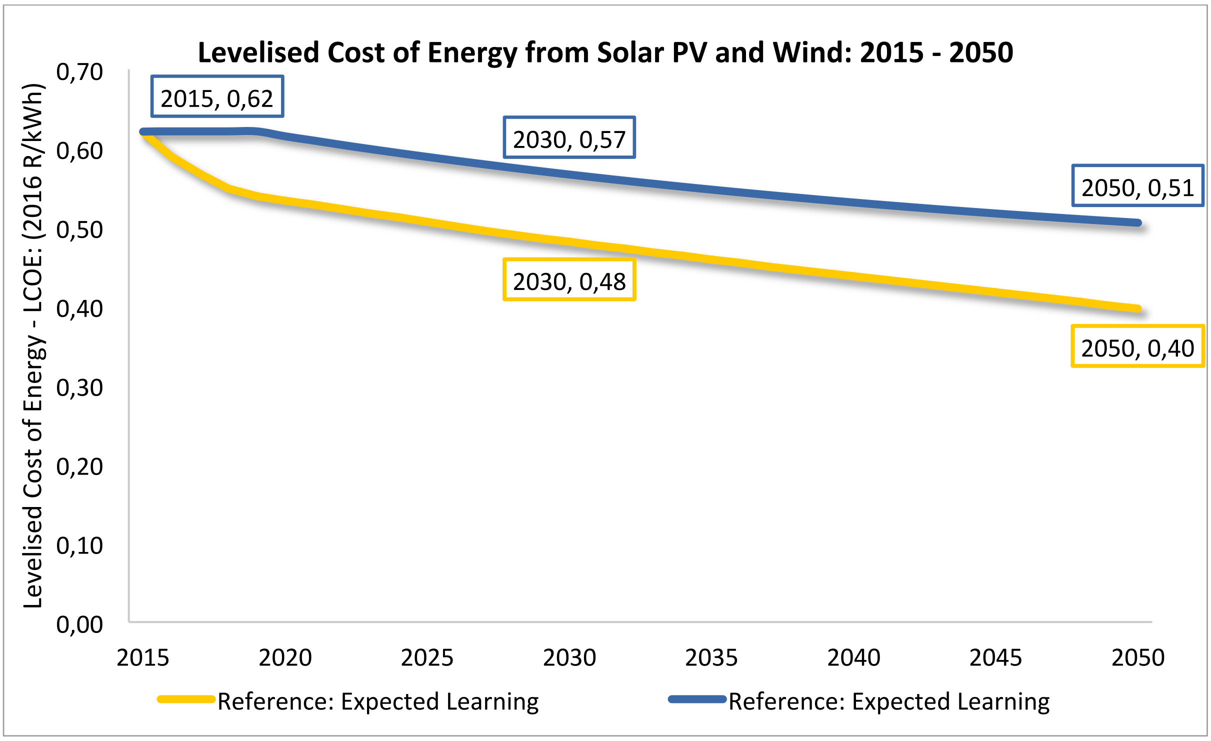

Figure 4: Starting and projected levelised costs of electricity from centralised single-axis tracking solar PV and onshore wind from 2015 to 2050 (April 2016 R/kWh).

The modelling in this study includes the assumption that wind and solar generators are never able to contribute to the peak demand, and are fully backed up by dispatchable firm synchronous generators. Battery storage or flexible demand response are currently not included, but both have a growing future potential to contribute to peak demand reductions and system services if deployed in future. Overall, these technology estimates are considered conservative for the cost and performance of future technologies and optimistic on existing conventional technologies.

3.2.2 Existing South African Electricity System

Existing power plant performance parameters are included in SATIM as per the modelling undertaken in ERC (2018) and the draft IRP 2016 update where data is given (DoE, 2016). These quantify the individual plant capacities, efficiencies, fixed and variable operations and maintenance costs, water use, and GHG and pollutant emissions. The retirement dates of existing plants are aligned to the draft IRP 2016 update (50-year life of plant for all Eskom coal plants). Medupi and Kusile are modelled to come online incrementally, according to the October 2017 Eskom Medium Term System Adequacy Outlook; with 3 units online already and the remainder coming online by end 2022 (Eskom, 2017). The investment and O&M costs related to Eskom's compliance with air quality legislation and station-specific licenses is not included in the modelling.

The existing South African power system (excluding variable renewables) and planned retirement schedule is depicted in Figure 5.

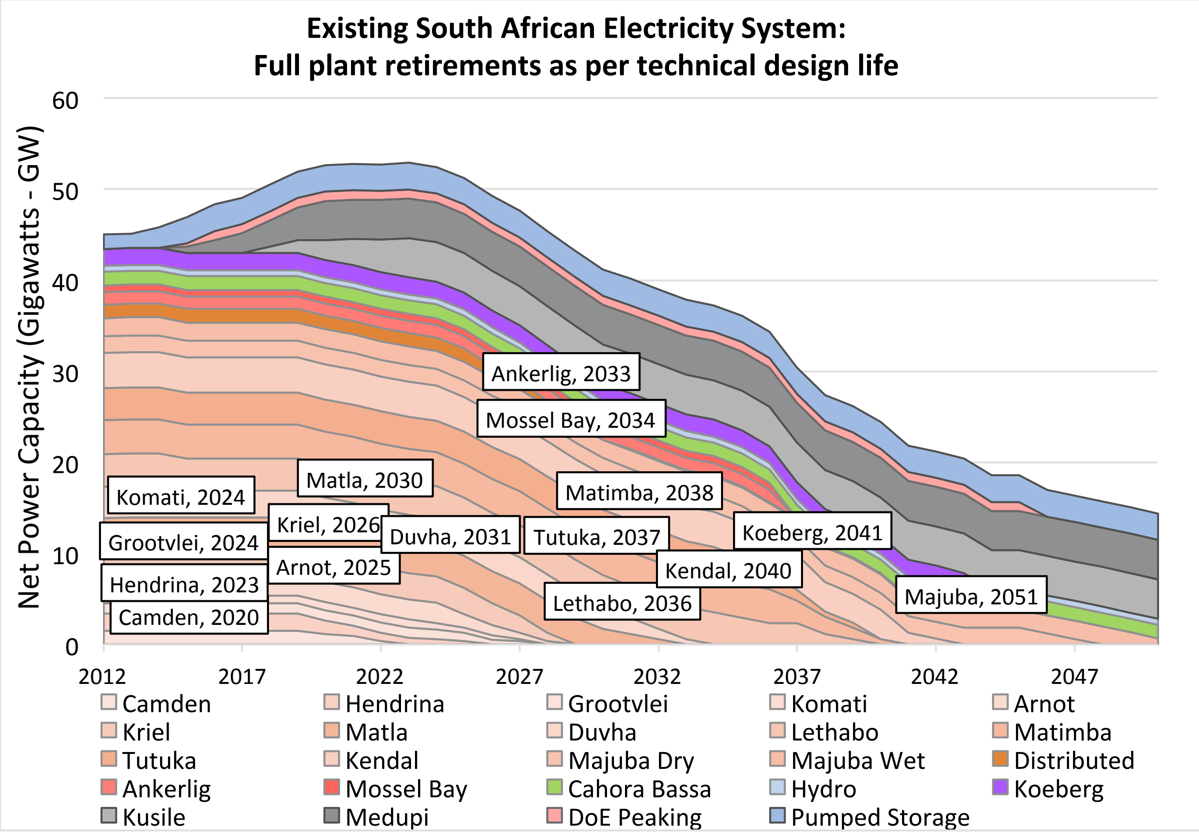

Figure 5: Existing South African power generation capacity with decommissioning schedules as per 50-year life and draft IRP 2016 update retirement dates.

3.3 Climate change mitigation policy (CCP) scenario

With current technology and cost assumptions, the reference scenario described above for the South African energy system is not consistent with meeting the lower range of South Africa's peak, plateau, and decline (PPD) trajectory, as committed to in the National Climate Change Response White Paper (DEA, 2011). The PPD aims to peak emissions in 2025 between 398-614 Mt CO_2-eq, plateau emission for a decade, and then decline to a 2050 range between 212 and 428 Mt CO_2-eq.

While South Africa's nationally determined contribution (NDC) to the Paris Agreement is based on the PPD trajectory range, it currently only includes a quantified emission range of 398-614 Mt CO_2-eq for the years 2025 and 2030. Based on the negotiations, South Africa will likely update its NDC in 2025, for the post-2030 period.

At the same time, globally, NDCs do not yet meet the target of the Paris Agreement to limit warming to 'well below' 2°C. The Paris Agreement 'ratchet mechanism' is designed to encourage increasing ambition from countries over time. In the long-run, keeping temperature well below 2°C and aiming for 1.5°C will require all countries to increase their ambition. If all countries collectively agree to do so, South Africa should reduce emissions further than envisaged in the current NDC for the period after 2030 (or even for the period 2025-2030), or at least commit to meeting the lower range of the PPD. The low PPD aims for 398 Mt CO_2-eq over the period 2025-2035 before declining to 212 Mt by 2050.

Currently, Climate Action Tracker (CAT) deems South Africa's NDC to be an insufficient contribution to meeting 2°C; in particular, the upper range of the trajectory outlined in the PPD and included in the NDC (CAT, 2018). South Africa can meet the upper range of the PPD to 2050 if it implements a least-cost energy system to 2050; that is, one that excludes new coal-fired power plants, achieves high levels of energy efficiency and continues to invest in renewables. However only achieving the upper PPD range would not be an adequate contribution to limiting warming to below 2°C (PRIMAP, 2018). According to both CAT and PRIMAP, the low-PPD range may be considered an adequate contribution to 2°C, but this depends on assumptions about the global carbon budget and the equity approach applied in a given analysis. CAT (2018) considers the low-PPD emission in 2050 as consistent with meeting 2°C, but is not clear on the long-term trajectory implied by this. Given this uncertainty, we model South Africa's low-PPD to 2050 since this already South Africa's own policy commitment, even if in the future meeting 2°C requires reducing emission below the low-PPD trajectory.

More generally, there is considerable literature on energy systems pathways consistent with 2°C and the future of coal within that. UNEP (2017) summarises these studies, which show that unabated coal (without CCS) will have to be phased out globally by mid-century.

We thus include a scenario that assesses the impact of building the coal IPPs in a case where South Africa also meets the low-PPD emissions constraint to 2050 at the lowest system cost. The key assumptions remain the same as in the reference scenario, but also include a CO_2-eq constraint consistent with low-PPD (9.5 Gt CO_2-eq over the period 2020-2050) (ERC, 2018).

The rationale for analysing the implications of such a scenario is as follows. Meeting the PPD range requires reducing emission in the electricity sector. Meeting low-PPD requires even more rapid decarbonisation of the electricity sector, as well as increased mitigation in other sectors. When the coal IPPs are forced into the electricity build plan, this results in decreased use of existing coal plants (which are also cheaper than the coal IPPs), which puts raises costs overall and puts Eskom at risk. As more of the emissions 'budget' is used in the electricity sector, this requires either increased mitigation in the power sector through stranding existing coal assets in the later years of the modelling horizon, or increased mitigation in non-electricity sectors (where mitigation is typically costlier than in the power sector). Understanding this trade-off between the coal IPPs and other coal plants and sectors allows an assessment of the costs of increasing the mitigation burden to other sectors. Essentially, we analyse the effects of "committing" carbon space to the coal IPPs.

3.4 Combined scenarios: best and worst cases for coal IPPs

The "best-case for coal IPPs" and "worst-case for coal IPPs" are scenarios that combine sensitivities on key modelling assumptions, specifically the costs of competing technologies or the GHG emissions intensity of the coal IPPs. This allows us to test and analyse various uncertainties that may materialise regarding future generation costs and the mitigation of GHGs by the stations (which could lower the overall GHG impact of the coal IPPs). We have constructed the scenarios to be weighted towards a future world that, in one scenario, is the "best" case for coal IPPs (for example, expensive renewable energy and gas, and low GHG-intensity from the coal IPPs), and in the other, is the "worst" for the coal IPPs (for example, cheaper renewables and gas and high GHG-intensity). In this way, a broader range of uncertainty can be explored, along with a broader sense of the magnitude of the potential risks and opportunities of committing to the coal IPPs.

3.4.1 Determinants of best and worst cases

3.4.1.1 Renewable energy and gas generation costs

A key power system planning uncertainty is around the future costs of renewable energy technologies. While the overall trend for renewable energy technologies is towards substantially lower costs, the difference in total system costs with and without the coal IPPs could be substantially larger depending on the relative costs of alternative supply options. This represents the cost of a 'missed-opportunity' through the lock-in to the purchase of power from the coal IPPs at a higher cost than other new-build alternatives. We test our cost assumptions through imposing pessimistic and optimistic learning rates for new solar PV and wind (Figure 6 and Figure 7).

Solar PV learning assumptions:

- Learning starts from 2015 for the reference and optimistic scenarios, and 2021 for the pessimistic scenario.
- Plant cost and performance parameters are modelled to start at calculated 2015 Round 4-expedited REIPPPP values, and improve, using adapted projected rates of change in the latest National Renewable Energy Laboratory (NREL) Annual Technology Baseline (NREL ATB, 2017), UNEP (2015) and Fraunhofer (2015).
- Capital cost reductions are applied for all scenarios, and operations and maintenance (O&M) improvements are also applied for the optimistic case. Plant capacity factors remain the same for all projections.

The figure below shows the projected levelised cost of solar PV for the optimistic and pessimistic learning, based on the improvements for the respective technology parameters.

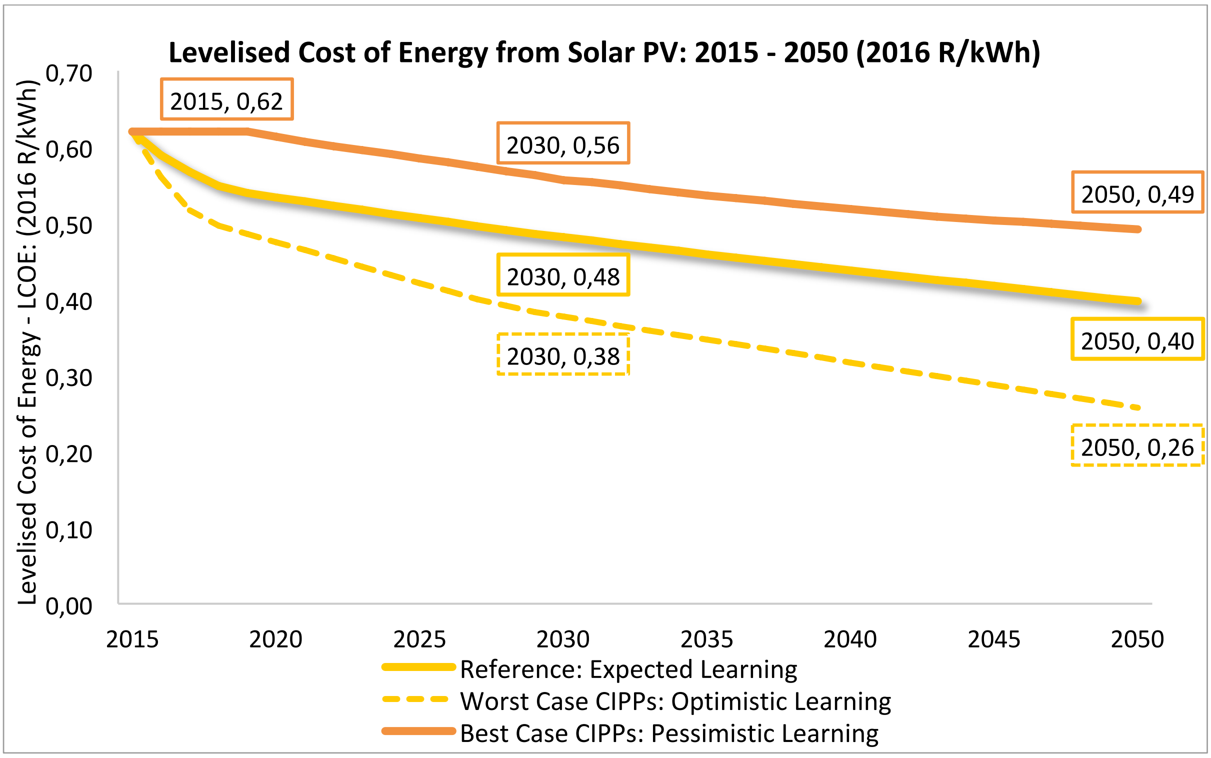

Figure 6: Centralised Solar PV (single-axis tracking) cost assumptions (April 2016 Rand)

Onshore wind learning assumptions:

- Learning starts from 2021 for the reference scenario, and 2015 for the optimistic scenario.
- No technology learning or cost reductions are applied in the pessimistic case.
- Learning is applied to capital costs and annual capacity factors of new plants for the reference and optimistic scenarios (existing plants do not improve), reductions in O&M costs are also applied for the optimistic case.
- Plant cost and performance parameters are modelled to start at calculated 2015 REIPPPP values and change using adjusted projected rates of improvement in the 2017 latest NREL Annual Technology Baseline (NREL ATB, 2017), IEA Wind (2018), and Agora Energiewende (2017).

The figure below shows the projected levelised cost of wind for the optimistic and pessimistic learning based on the improvements for the respective technology parameters.

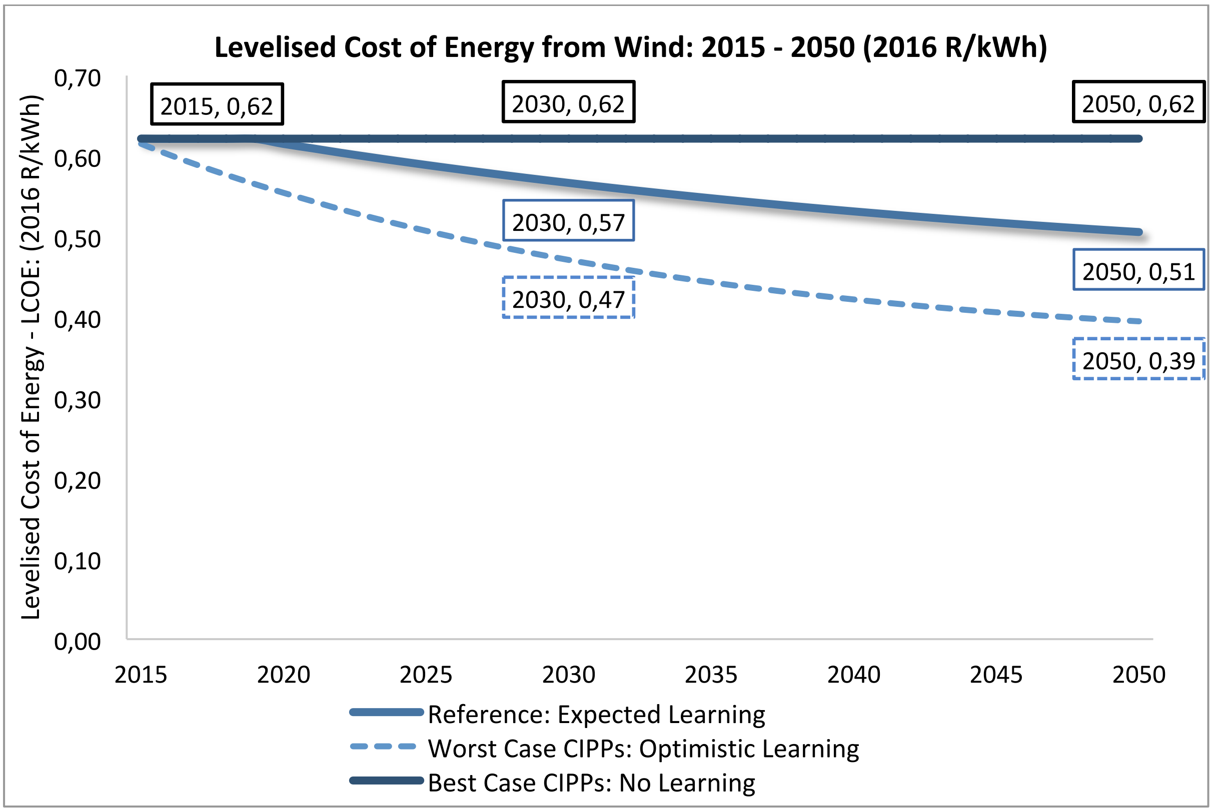

Figure 7: Onshore wind cost assumptions for each scenario (April 2016 Rand)

3.4.1.2 Greenhouse gas emissions-intensity

We include this sensitivity because there are some options that could potentially lower N_2O emissions for the type of plant planned, depending on fuel inputs, possible blending with biomass, or alternative operating conditions such as changing combustion temperature (Koorneef, 2007; Zhu, 2013; Armesto, 2003; Valentim, 2006). These do not seem to have been fully explored or quantified in the measures suggested in ERM (2017). Combined measures could result in reductions in GHGs of up to 25% below many other Eskom plants, and possibly with no resulting impact on the agreed PPAs.

However, even without the high N_2O emissions, the inclusion of the coal IPPs in the build plan results in overall higher emissions over the full period of operation (because the least-cost optimised alternatives – gas plus renewable energy - all have lower GHG emissions). By modelling a reduction in GHG-intensity, this conservatively highlights the additional emissions caused by the plants even under 'best case' outcomes for GHG mitigation by the coal IPPs.

Although carbon capture and storage could be an option for mitigating emissions further (by approximately 90% at existing coal CCS facilities), the technology remains unproven in South Africa, and results in substantially higher costs - currently around US$100/tonne of CO_2 (UNEP, 2017). Even the South African coal roadmap has highlighted the challenge of CCS in the South African context (SACRM, 2011).

3.4.2 "Best-case scenario" for coal IPPs:

- Pessimistic renewable energy costs: no learning for wind (62c/kWh), solar PV learning from 2020 reaches 56c/kWh by 2030, and 49c/kWh by 2050 (all in 2016 Rand).
- Global liquefied natural gas (LNG) price is 25% higher than the reference scenario at US$15/MBTU (R182/GJ in January 2015 Rand[5])
- Low GHG-intensity (assumed low cost abatement of N_2O) and ultra-super-critical coal, as per the proposed KiPower plant (2018)[6]. Greenhouse gas intensity of 0,7 t/MWh CO_2-eq (vs reference case of 1,23t/MWh).

3.4.3 "Worst-case scenario" for coal IPPs:

- Optimistic renewable energy costs: wind learning from 2015, 47c/kWh by 2030, and 39c/kWh by 2050. Solar PV learning from 2015, 38c/kWh by 2030, and 26c/kWh by 2050 (2016 Rand).
- Global LNG price is 25% lower than reference at US$10/MBTU (R122/GJ in January 2015 Rand)
- High GHG-intensity remains unchanged from the reference scenario, as reported in Thabametsi's climate change impact assessment (ERM, 2017). Given the high GHG-intensity of the coal IPPs, as discussed in section Figure 1 and section 3.1.1, we assume that the GHG-intensity of the proposed plants is already 'worst case' without mitigation (approximately 24% higher than the current Eskom fleet average, and 58% higher than Medupi).

[5] Using the draft IRP 2016 update 11.55 R/USD exchange rate from January 2015. The cost of LNG in the IRP 2016 is 115.5 R/GJ (January 2015 Rand)

[6] Though this is not proposed for the coal IPPs under the current tariff structure

3.5 Parameter summary for each scenario

Table 2 summarises the parameters for each scenario.

	Reference Scenario: Base	Reference Scenario: Best case for coal IPPs	Reference Scenario: Worst case for coal IPPs	Climate change mitigation Scenario
GDP Growth	3,2% average annual	3,2% average annual	3,2% average annual	3,2% average annual
RE costs	Expected Reductions	Pessimistic (PV) No Reduction (Wind)	More Optimistic Reductions	Expected Reductions
Global LNG price[7]	12.5 $/MBTU (R152 /GJ)	15.0 $/MBTU (R183/GJ)	10.0 $/MBTU (R122/GJ)	12.5 $/MBTU (R152/GJ)
COAL IPPs GHG intensity	1,23 t CO_2-eq/MWh	0,7 t CO_2-eq/MWh	1,23 t CO_2-eq/MWh	1,23 t CO_2-eq/MWh
GHG emissions constraint	No constraint	No constraint	No constraint	9.5 Gt CO_2-eq total energy emissions budget between 2020 - 2050
Discount rate	8.2%	8.2%	8.2%	8.2%

Table 2: Summary of key parameters per scenario

[7] January 2015 Rand and USD using 11.55 R/USD exchange rate

4. Results

4.1 Reference case

4.1.1 Reference case least-cost electricity system expansion plan

The figures below show the reference case least-cost optimised build plan to 2050 for the electricity sector, depicting the total installed system capacity of each technology in the system, including existing and new-build power plants each year. A least-cost build plan no longer includes new coal or nuclear power plants, which are no longer competitive with alternatives.

South African electricity demand has flattened over the last decade, while large units at Medupi and Kusile are still being added to the grid, resulting in surplus capacity presently and for the medium-term outlook. Thereafter, as demand grows and existing coal plants are decommissioned, the least-cost mix of new centralised generation is a combination of wind, solar PV, and gas.

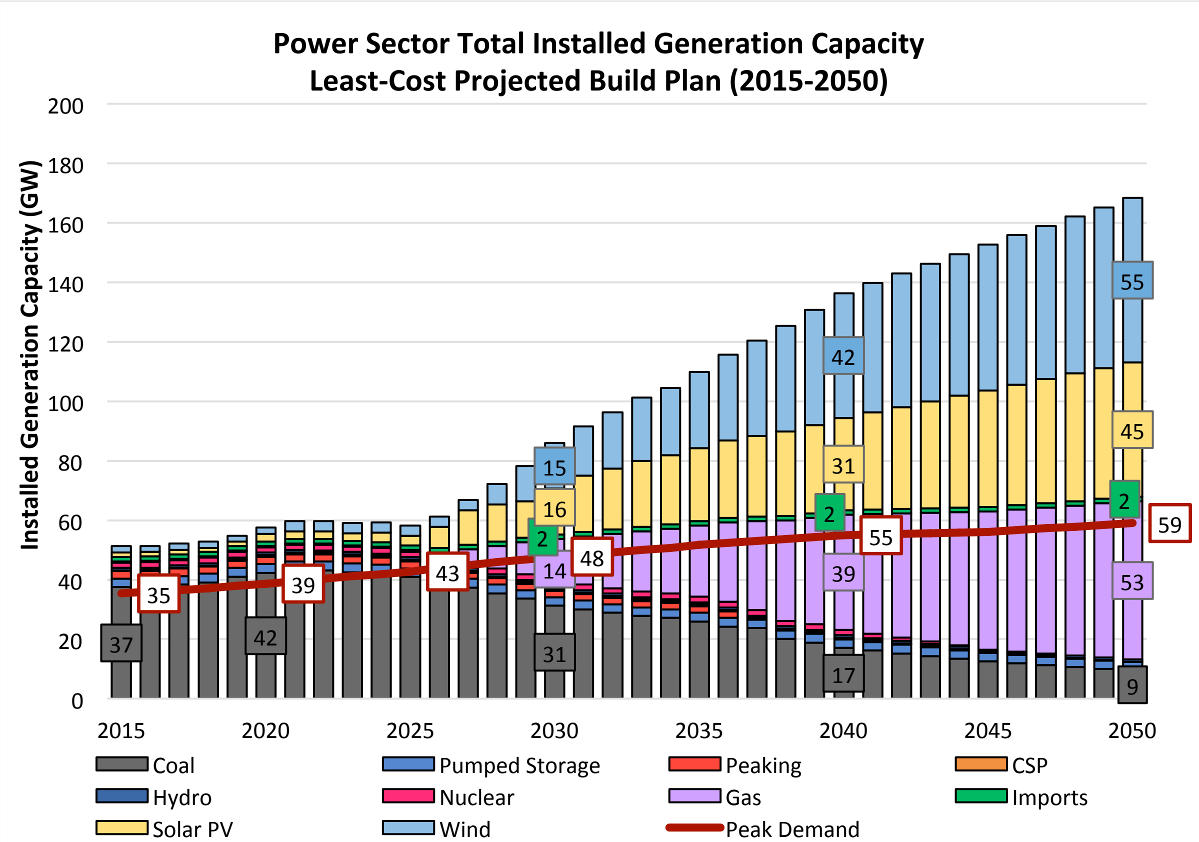

Figure 8: Reference Scenario: installed generation capacity shown and projected peak electricity demand (2015 – 2050)

In the reference scenario, installed capacity reaches 168 GW in 2050, comprising 32% wind, 27% solar, 31.5% gas (Figure 8).

In the reference scenario, installed capacity reaches 168 GW in 2050, comprising 32% wind, 27% solar, and 31.5% gas (Figure 8). Renewable energy makes up 28.5% of electricity generation by 2030 and 74% by 2050, with gas contributing 11%, and coal 15% in 2050. Medupi and Kusile are the only coal plants still running in 2050 (Figure 9). Figure 10 shows the annual capacity additions by generation technology.

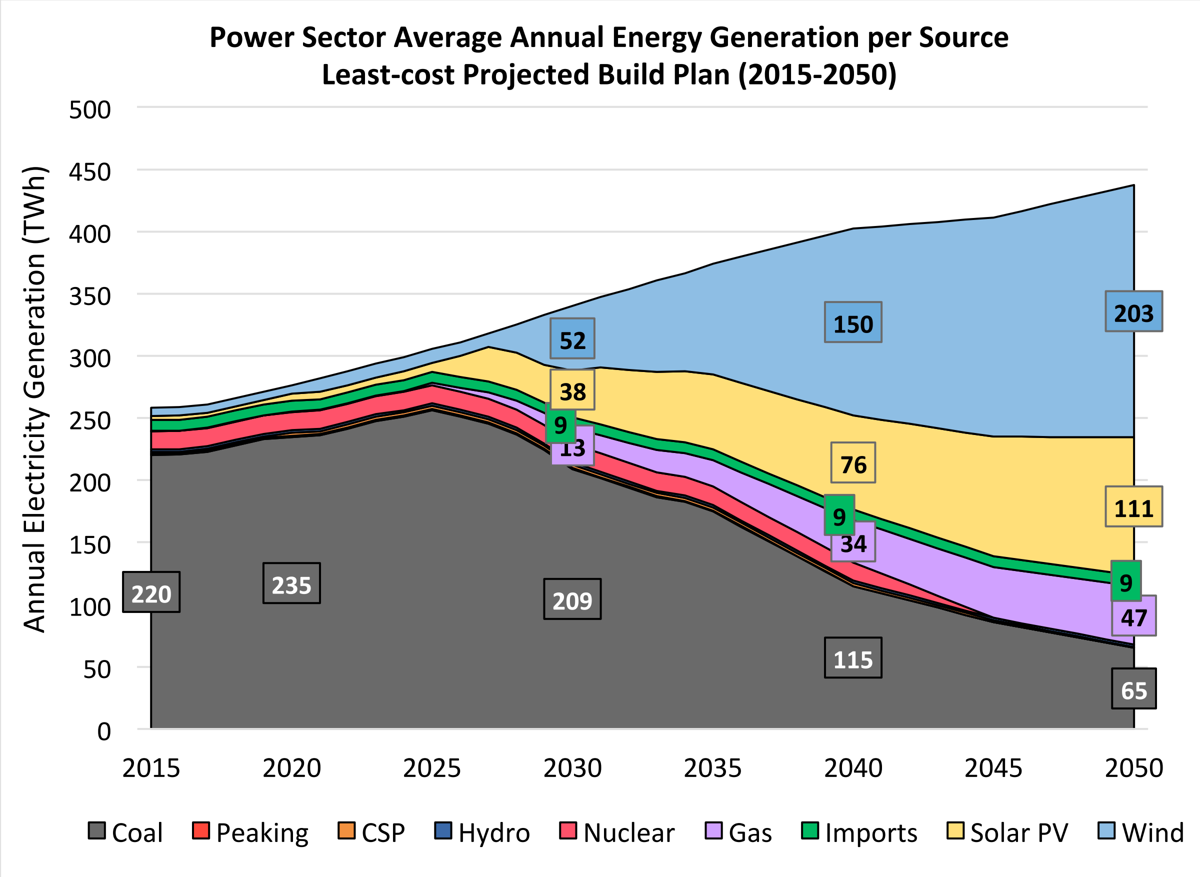

Figure 9: Reference Scenario: annual electricity generation by source (2015-2050)

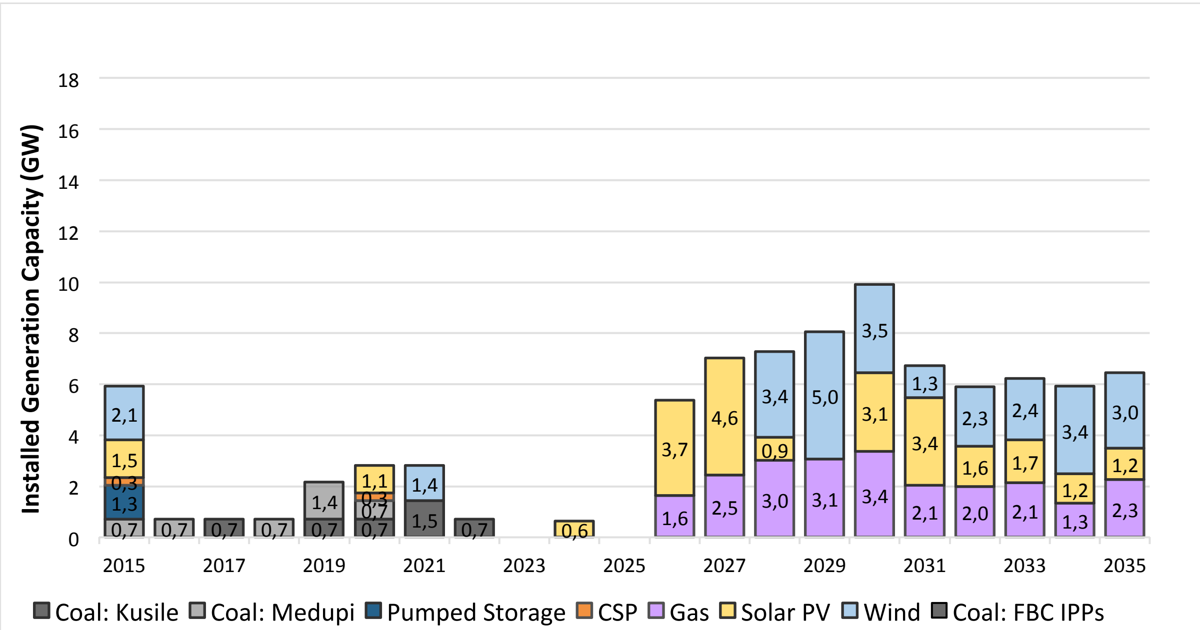

Figure 10: Reference Scenario: annual generation capacity additions (2015-2035)

Greenhouse gas emissions from the energy and industrial sectors can be seen in Figure 11. Emissions peak around 2025 and decline to just over 256Mt CO_2-eq by 2050. A substantial part of these savings come from the electricity sector, where mitigation is achieved at low cost, even as emissions from industry increase substantially. However, as mentioned previously, this emissions trajectory is not consistent with meeting 2°C (CAT, 2018; PRIMAP, 2018). Further mitigation is required to move South Africa towards the low-PPD trajectory. This is explored further in the CCP scenario.

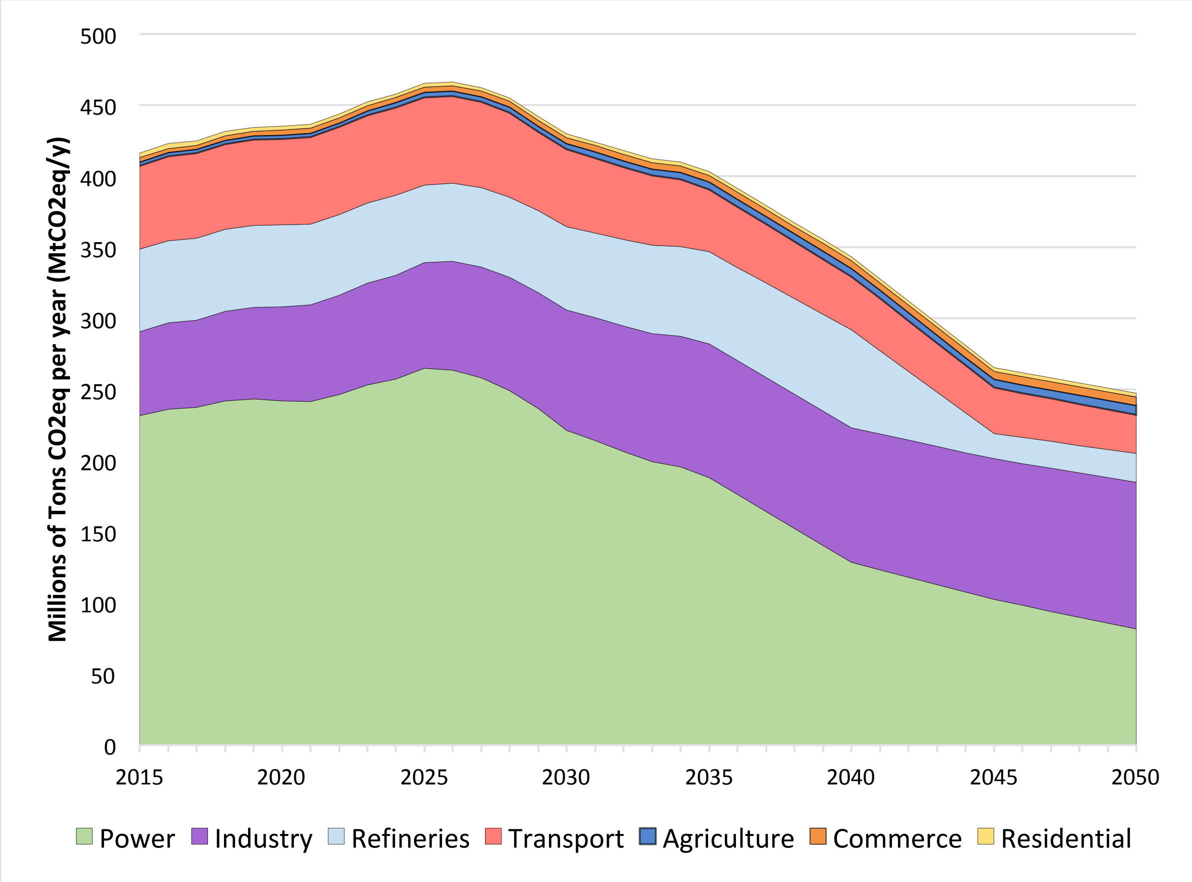

Figure 11: Reference Scenario greenhouse gas emissions by sector 2015 to 2050[8]

The following section outlines the difference between the least-cost reference scenario and the reference scenario with the coal IPPs committed (Reference plus coal IPPs).

4.1.2 Reference case plus coal IPPs

The optimised least-cost build plan includes no new coal-fired power plants in the investment horizon to 2050. Therefore, testing the system implications of signing the 30-year PPAs of the coal IPPs requires the plants to be "forced-in" to the build plan, after which the deviation from the baseline cost optimal system can be directly quantified and analysed.

4.1.2.1 Differences in build-plan and energy generation

Committing to building the coal IPPs changes the power plant investment schedule and energy generation profile compared to the reference scenario described in section 4.1.

Figure 12 shows the deviation in electricity generation from the reference scenario electricity system. From 2022 to 2025, the least-cost system would have used the cheaper existing Eskom coal-fired power plants to meet the demand for electricity. Thereafter the optimised system would have provided this energy with a combination of wind, solar PV, and gas (Figure 12). Most of the energy in the optimised power system comes from wind, with a lesser contribution from solar PV, and existing coal. Gas provides a smaller contribution to energy, but is an important contributor to firm capacity, providing full flexible back-up to the variable renewable energy technologies.

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[8] Shown are only direct energy emissions for each sector (eg. commerce or industry's indirect electricity sector emissions are accounted for in power sector emissions). Non-energy emissions from agriculture, forestry, land-use change, or waste are not included in this total

The energy from the coal IPPs that replaces existing coal totals around 20 TWhs from 2022-2027. For comparison, a unit at Medupi or Kusile produces around 5 TWhs per year. It thus replaces comparable supply capacity in the system (part of the existing fleet), but at a higher cost (discussed below).

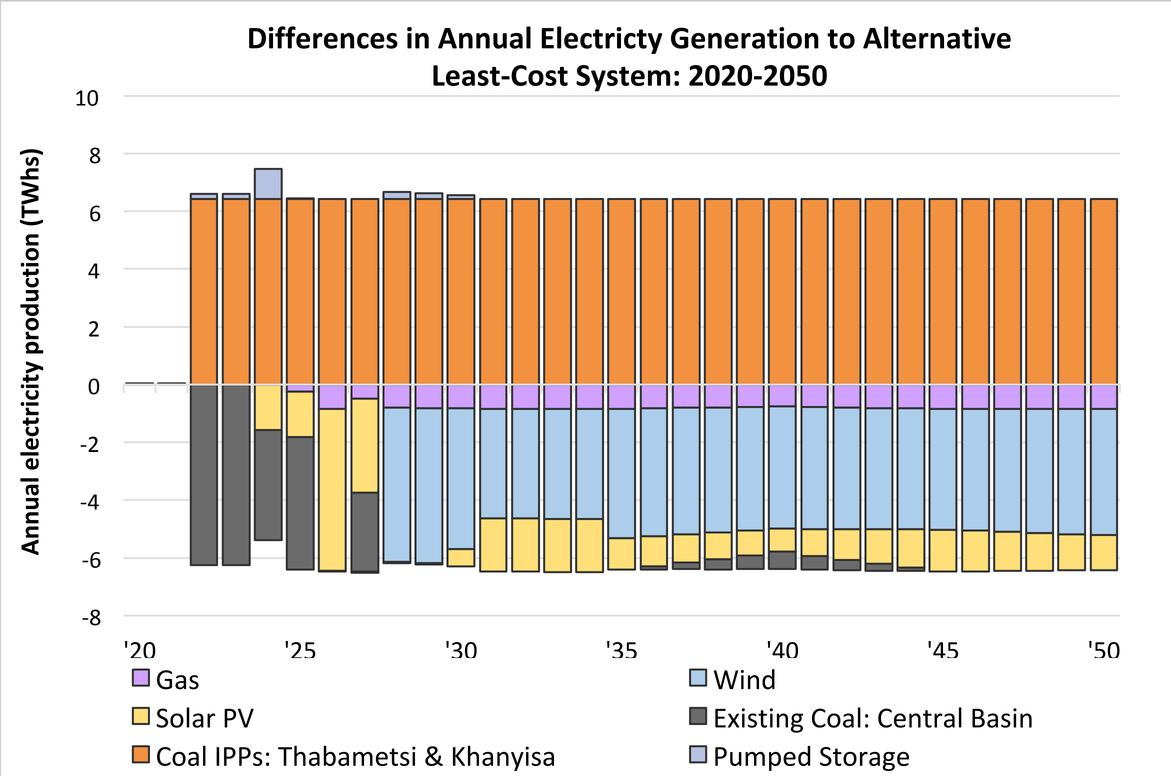

Figure 12: **Difference in annual energy generation profile between the reference scenario and reference scenario plus coal**

The total differences and timing of installed capacity are shown below for the combined coal IPP programme (including both Thabametsi and Khanyisa and totalling 863 MW).[9] Deviations shown as positive values in each year are the amount of additional capacity built or energy generated in that year. As can be seen in Figure 13, the technology mix in the reference scenario to provide the equivalent level of firm capacity and energy is a combination of 863 MW of gas, 440 MW of solar PV, and 1280 MW of wind. Committing to the coal IPPs results in a change in the timing of planned investments, noticeably delaying some solar PV investment by 2-3 years.

[9] The same deviations for each set of results are modelled and measured for each of the individual and combined coal IPPs, but for simplicity only the combination of both plants is shown below. This is necessary to determine the specific individual impacts of each plant on the future South African energy system. In a complex and interconnected system, the impacts of different investment decisions are often non-linear.

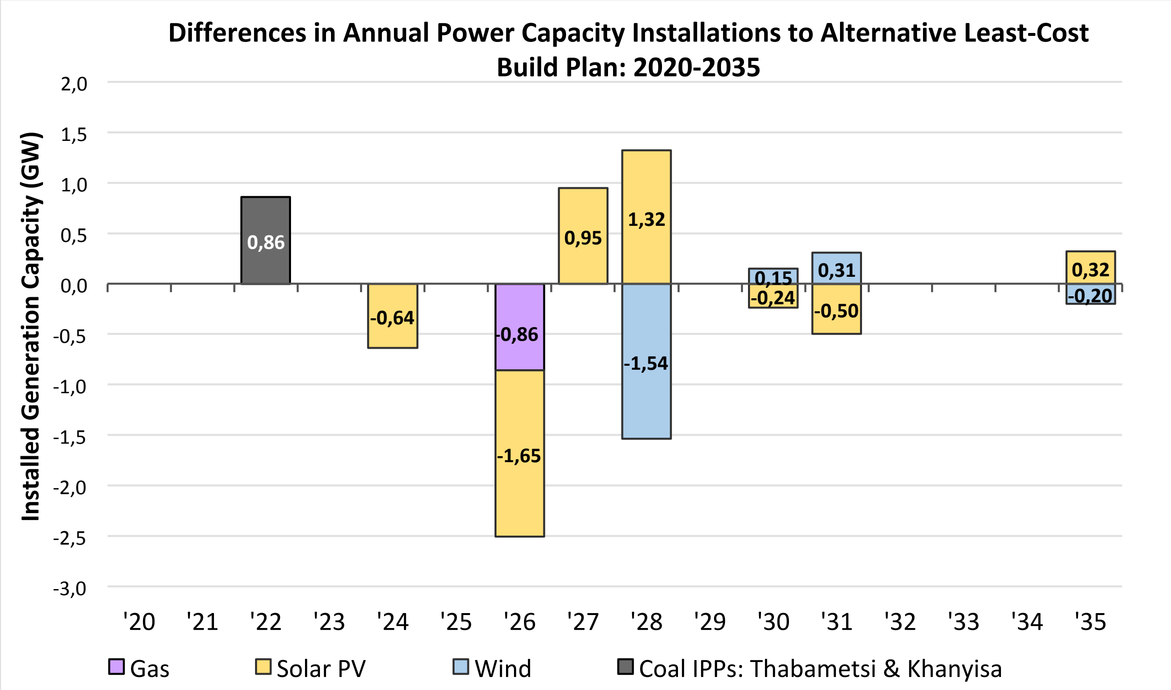

Figure 13: Differences from baseline to power generation capacity additions for combined coal IPPs

Since wind technologies are modelled to have a 20-year life, and solar PV 25 years, the system reinvests in new capacity for these technologies at the end of their lives between 2040 and 2050. The plants are replaced with newer and cheaper capacity later in the period after projected cost reductions are achieved, allowing further reductions in system costs later in the modelling period (Figure 14). The coal IPPs therefore not only replace investments in gas, solar, and wind in the 2020s, but because of their long-lived PPAs, also replace new, much cheaper, generation capacity in the 2040s.

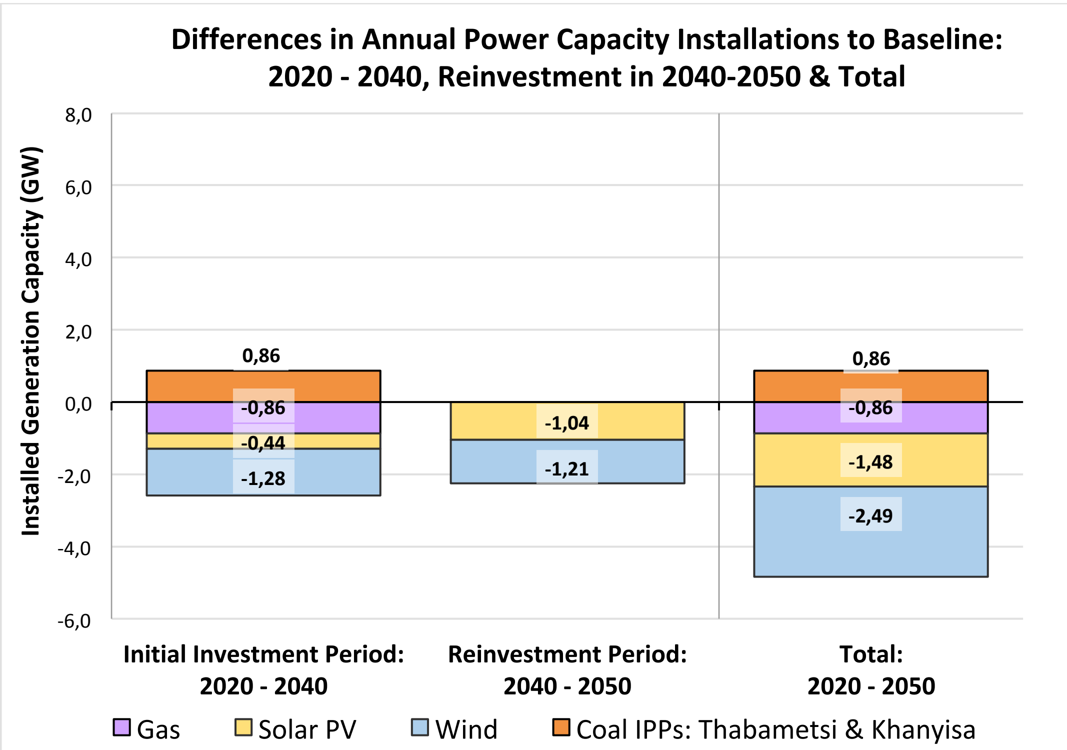

Figure 14: Total differences of alternative electricity generation mix per period (with reinvestment from 2040) and total difference in constructed generation capacity.

4.1.2.2 Power Sector Greenhouse Gas Emissions

As can be seen in Figure 15, the inclusion of the coal IPPs in the build programme results in a net increase in GHG emissions over the modelling period. The additional GHGs for Thabametsi and Khanyisa are 136.1Mt CO_2-eq and 75.9Mt CO_2-eq respectively. If both plants are built, the coal IPPs add 205.7Mt additional GHG emissions over the 30-year period between 2022 and 2052.

In comparison, the Department of Environmental Affairs has recently commissioned modelling that analysed the emissions savings of various mitigation policies and measures (ERC, 2018). Those results show that the emissions savings of the post-2015 National Energy Efficiency Strategy to 2050 will be 214 Mt CO2-eq.

The energy generation profile in Figure 12 shows that the energy generated by the coal IPPs would replace Eskom's existing coal fleet over the period 2022-2027 (and marginally in the late 2030s). Several commentators have argued that replacing this energy with the newer, more efficient IPPs would be better for GHG emissions. However, while the coal IPPs could decrease GHG emissions marginally in the short-term (assuming Eskom runs its most inefficient coal plants to replace the IPPs), in the medium to long-term, the coal IPPs replace zero-carbon or lower-carbon (gas) generation. The combination of wind, solar PV, gas, and existing coal is substantially lower in emissions over the lifetime of the stations, and the IPPs thus always increase GHG emissions when compared to a least-cost electricity system.

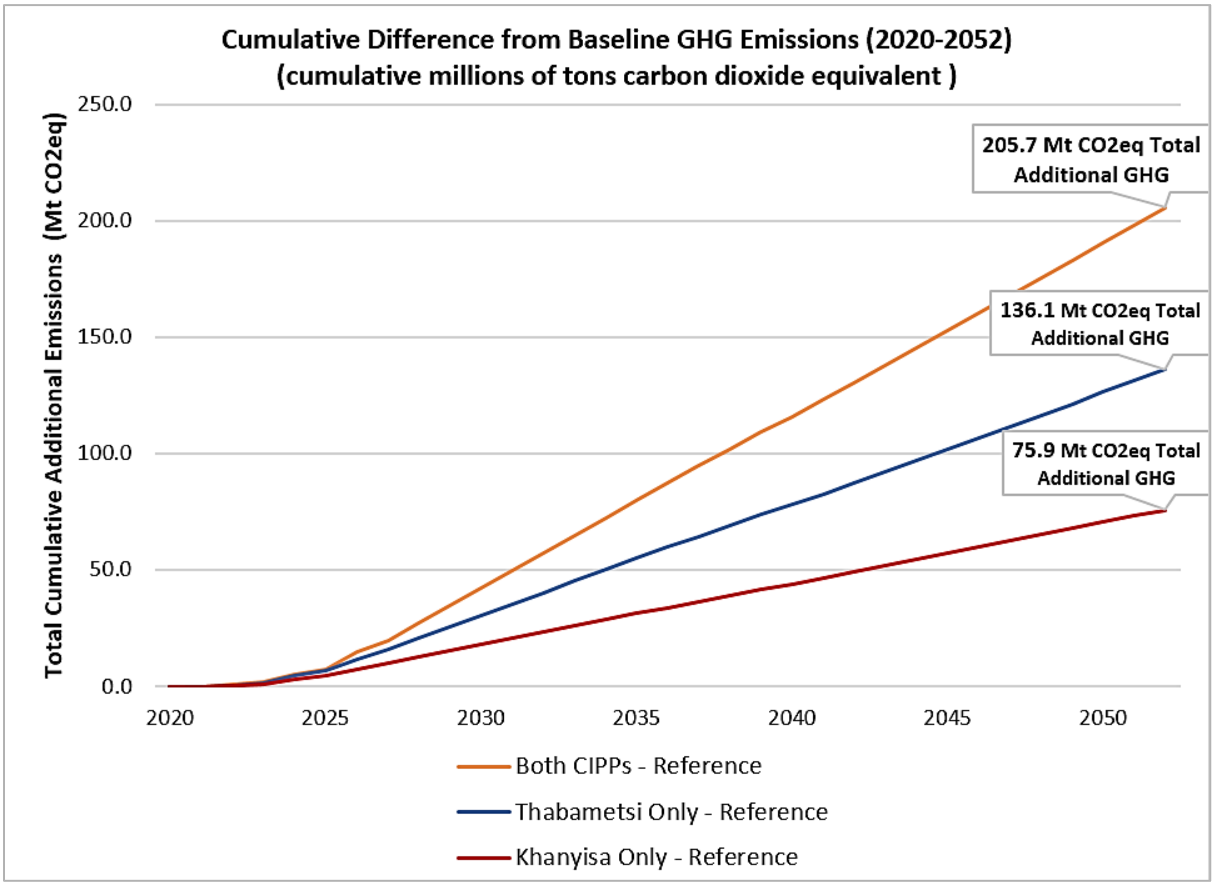

Figure 15: Cumulative total additional power sector greenhouse gas emissions for the combined and individual COAL IPPs

4.1.2.3 Electricity System Cost

Since the cost-optimal reference scenario does not include new coal IPPs, we can expect that their inclusion in the build plan will raise the total system costs for the energy sector. The tariffs that will be paid to the IPPs are currently substantially higher than Eskom's marginal cost of generation and thus the difference in the earlier years between running the existing fleet and building the coal IPPs is large. Over time, as new capacity is built and the cost rises to fund new capacity (compared to plants where capital costs have been paid off), this differential between the cost optimal blend of electricity from renewable energy, gas, and the existing fleet compared to the coal IPPs, starts to fall. Nonetheless, over the modelling period, the coal IPPs result in additional costs in the electricity sector. Figure 16 shows the deviation in billions of Rand between the reference scenario with and without the coal IPPs. The differential peaks between 2022 and 2025 at just less than R3.5bn before falling to between R1.5 and R2bn per year by 2050.

The higher difference in the earlier years is due to the generation surplus currently facing South Africa. The plan to procure the coal IPPs was brought forward by the policy-adjusted IRP 2010, which as noted previously, also overestimated demand considerably. Thus the plants are neither necessary to meet demand, nor are they competitive with alternative supply technologies. In a situation where increased new build is required earlier in the period, the differential would be smaller in the earlier years. However, we have modelled a relatively optimistic demand forecast (higher than the Energy Intensive Users Group (EIUG, 2017)). In the long-term, the coal IPPs are consistently more expensive than the alternative options.

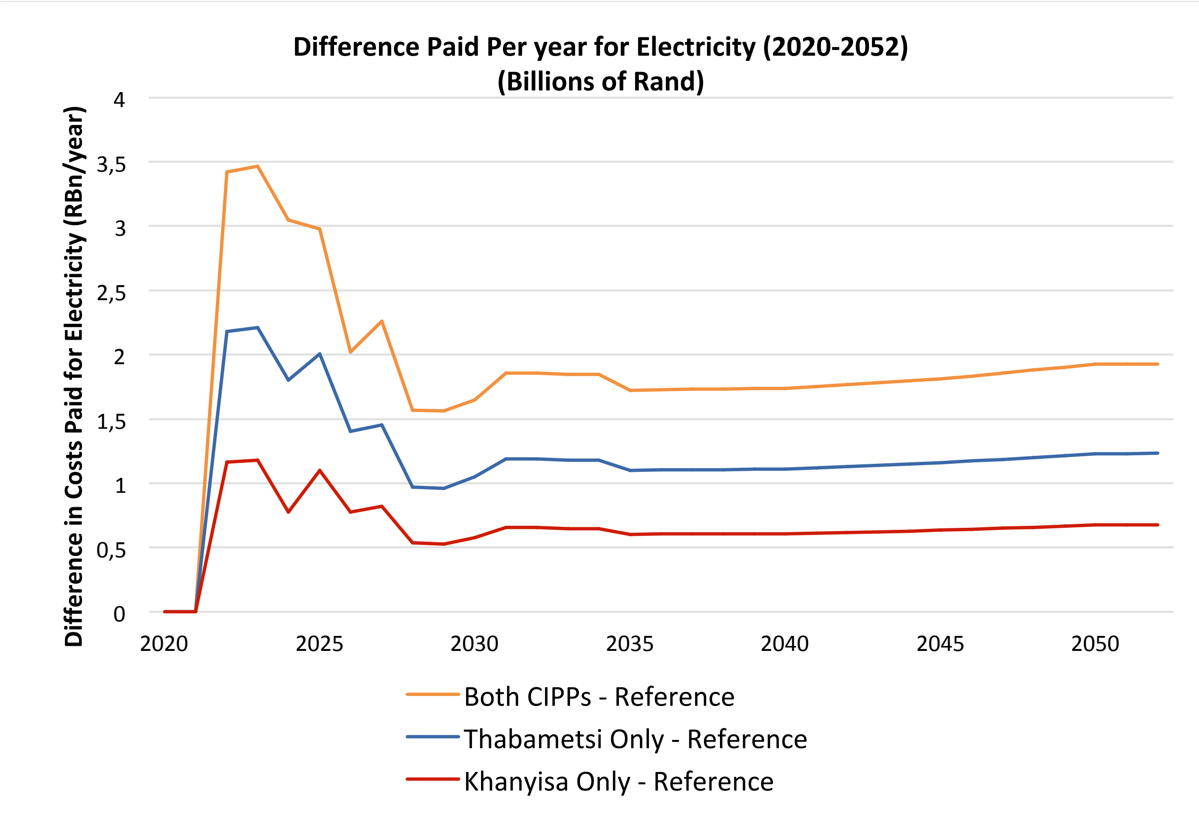

Figure 16: Annual additional cost paid for electricity per year for the combined and individual coal IPPs in nominal terms.

The total discounted system cost difference between the least cost reference and the committed coal can be seen in Figure 17. The combined coal IPPs add an additional system cost of R19,68 billion in present value terms (2018 Rand using a discount rate of 8.2%).

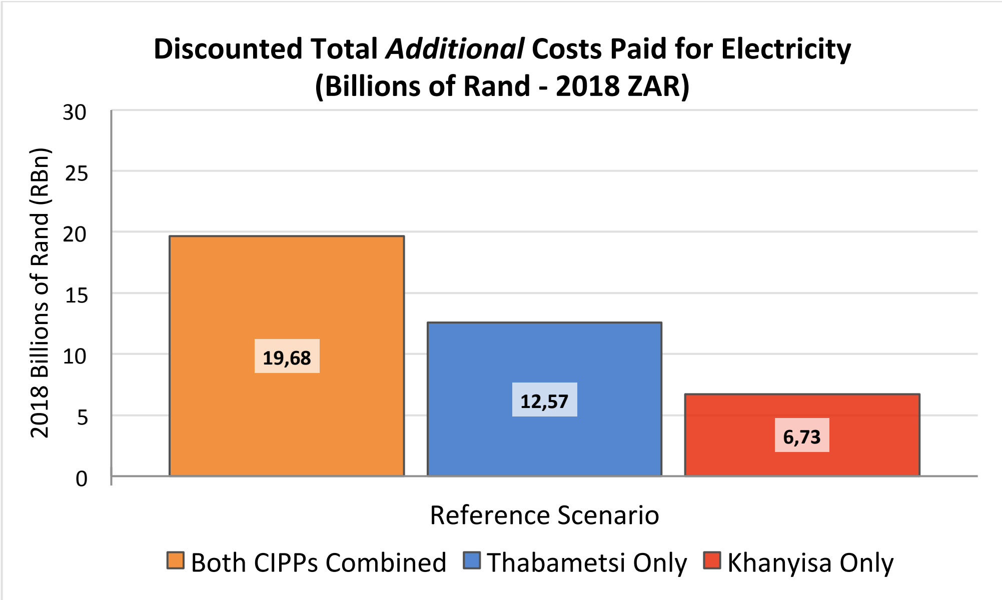

Figure 17: Reference Scenario: Total discounted additional costs paid for electricity for the combined and individual COAL IPPs

4.2 Climate change mitigation policy (CCP) scenario

4.2.1 Least-cost CCP scenario

As discussed in section 3.3, the upper range of South Africa's NDC and PPD trajectory is not considered consistent with limiting warming to below 2°C above industrial levels. While the lower-PPD to 2050 may be considered compatible with 2°C (depending on which equity considerations are applied), South Africa is not currently on track to meet this lower GHG emissions trajectory. Given that all countries are required to raise their ambition over time under the Paris Agreement, we have assessed the implications of meeting the low-PPD trajectory to 2050 in light of the planned increases in coal-fired generation capacity. We have modelled a 9.5 Gt CO_2-eq constraint (i.e. a budget) over the period 2020-2050.

Figure 18 shows the electricity build plan consistent with the 9.5 Gt budget. The higher peak demand than in the reference case is due to increased electrification and fuel switching towards (low-carbon) electricity in various sectors. By 2050, the installed capacity is 180 GW, with renewable energy comprising 59.3%, gas 31.4%, and coal 6.1% (Figure 18).

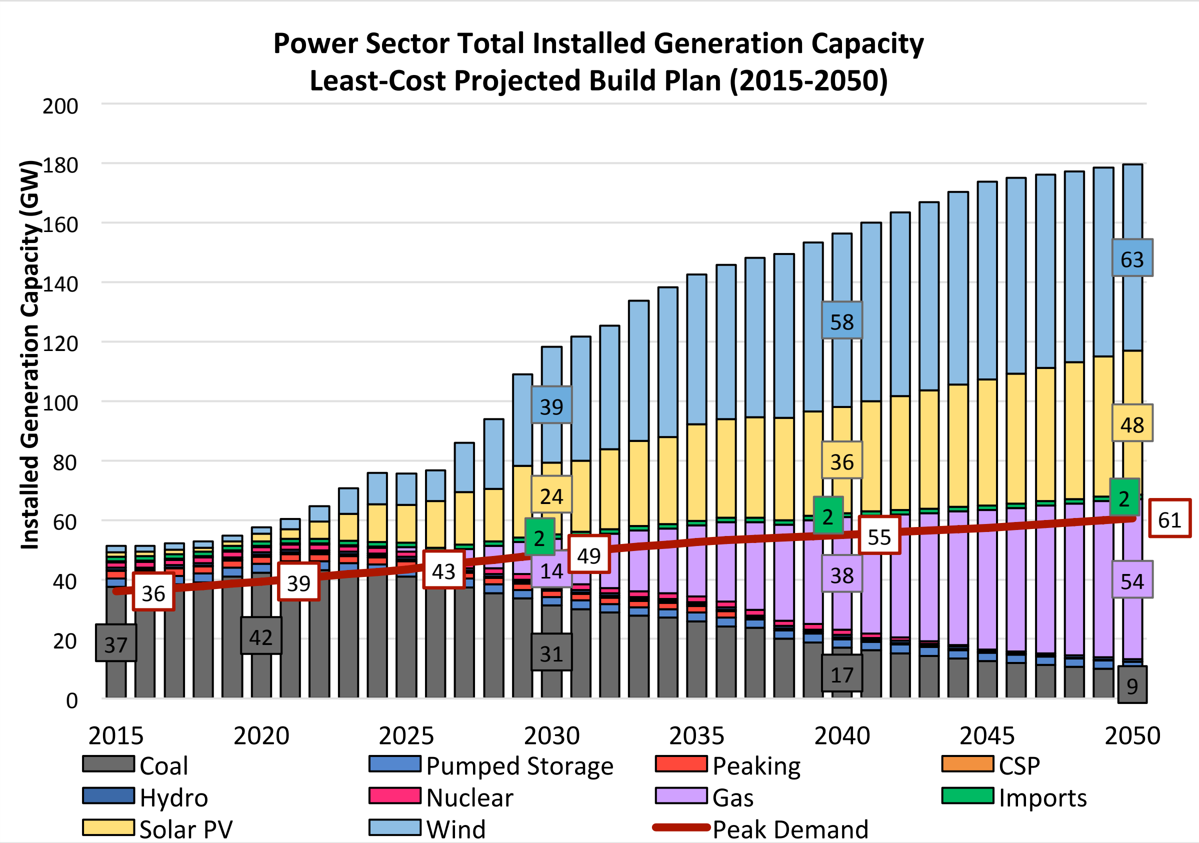

Figure 18: Climate change mitigation policy scenario - Total installed power generation capacity shown per technology for the least-cost build plan and projected peak electricity demand (2015 – 2050)

In energy terms, by 2050, renewable energy provides 79% of electricity, gas 11.8%, and coal 6.7% (Figure 19). Medupi is still running in 2050, though Kusile is stranded and no longer runs, highlighting the risks of stranded assets facing the existing fleet, even without the inclusions of the coal IPPs. Figure 20 shows the energy emissions trajectory consistent with the low-PPD emissions budget. As can be seen, substantial savings come from the electricity sector, which has relatively cheaper mitigation options compared to other sectors (such as industry). It is important to note that, to meet the low-PPD budget with current technology options already requires that the existing coal plants are run at lower load factors to 2050, i.e. there is stranded capacity in the sector.

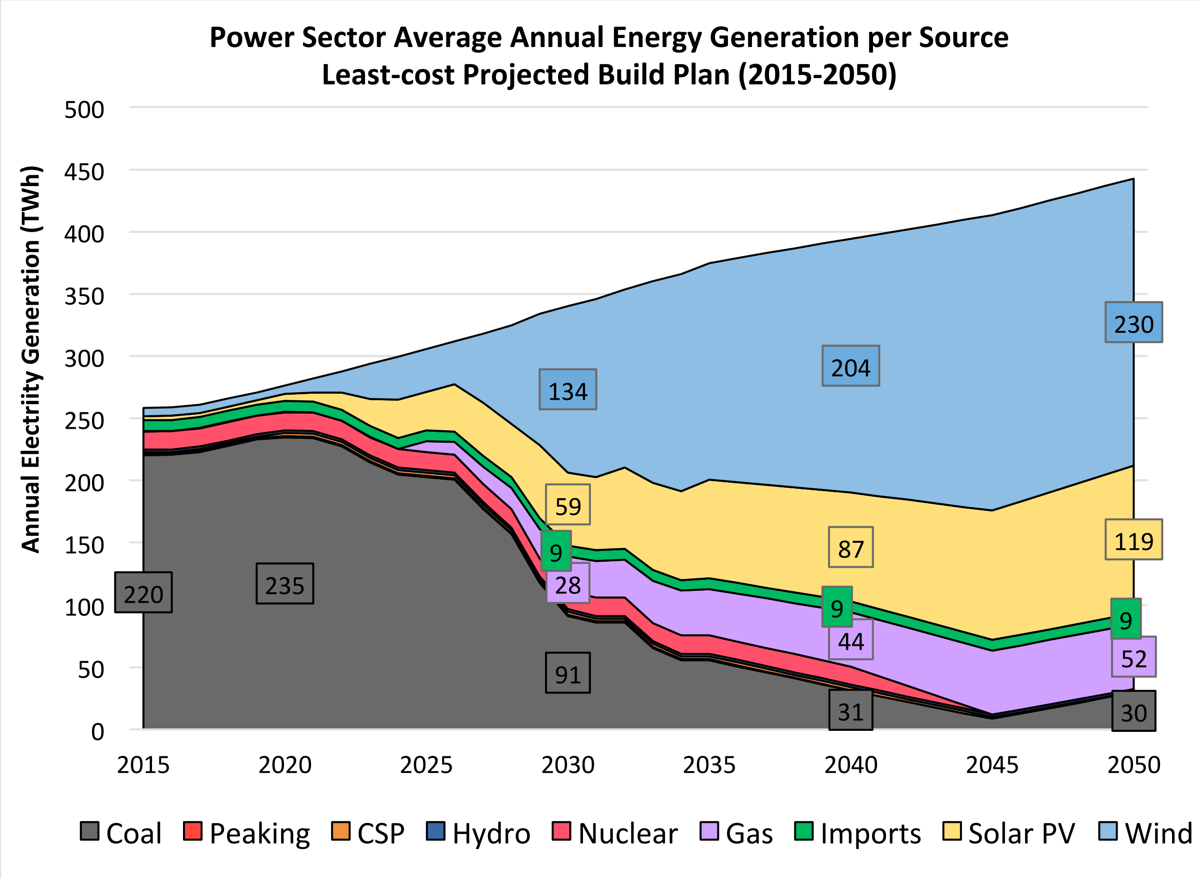

Figure 19: GHG Emissions Budget Scenario Baseline: Average annual energy provided per source in the least-cost baseline system (2015-2050)

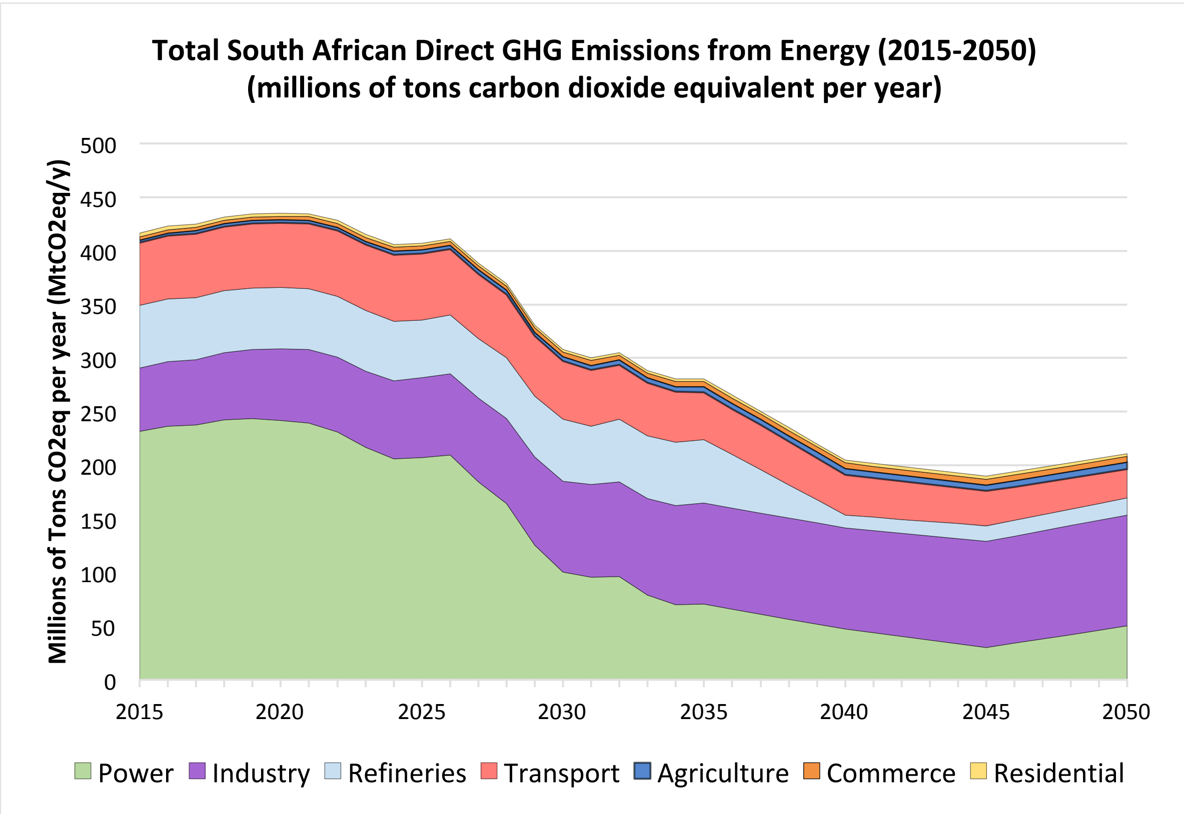

Figure 20: GHG Emissions Budget Scenario Least-cost Baseline System – Total projected energy system CO2 equivalent greenhouse gas emissions per sector from 2015 to 2050.

4.2.2 CCP scenario plus coal

As mentioned above, the CCP scenario requires the existing coal fleet to be run at lower load factors to meet the emission constraint. This requires investment into renewable energy to displace energy from coal plants that are run at lower load factors (as an abatement option). When the IPPs are committed into the system, this investment into renewable energy increases dramatically to make more 'space' for the emissions from the coal IPPs (by further abating emissions from the existing fleet).

4.2.2.1 Differences in build plan

Figure 21 shows the differences in electricity generated between the CCP and CCP plus coal scenario. As can be seen, the CCP scenario primarily uses the existing fleet, plus a combination of wind and solar to meet demand. When the coal IPPs are committed to the system, electricity demand is met by the coal IPPs and by large investments in solar (in the 2020s) and wind (in the 2040s). If South Africa commits to the COAL IPPs and then aims to meet its climate change mitigation targets, this will result in increased stranding of Eskom's assets in the short and long-term. Given Eskom's dire financial position, procuring new coal-fired power that forces out the Eskom plants raises risks for the entire economy.

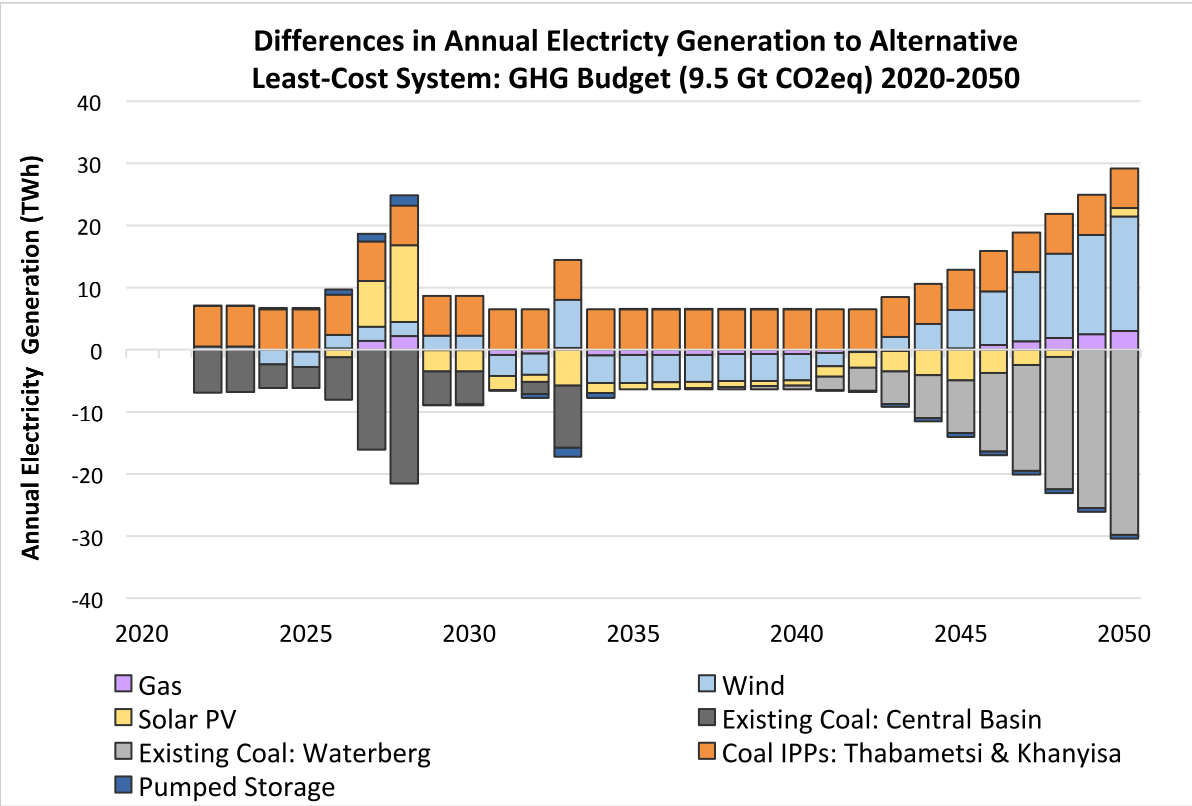

Figure 21: Difference in annual energy generation profile between CCP and CCP plus coal scenarios

Figure 22 shows this large increase in investment into low carbon generation technology in the CCP plus coal scenario. Additional low carbon energy is needed in the case with the COAL IPPs committed compared to a 9.5Gt CO_2-eq budget without the COAL IPPs; the new investment is required to displace energy from existing coal-fired power plants which are no longer run due to the emissions from the COAL IPPs.

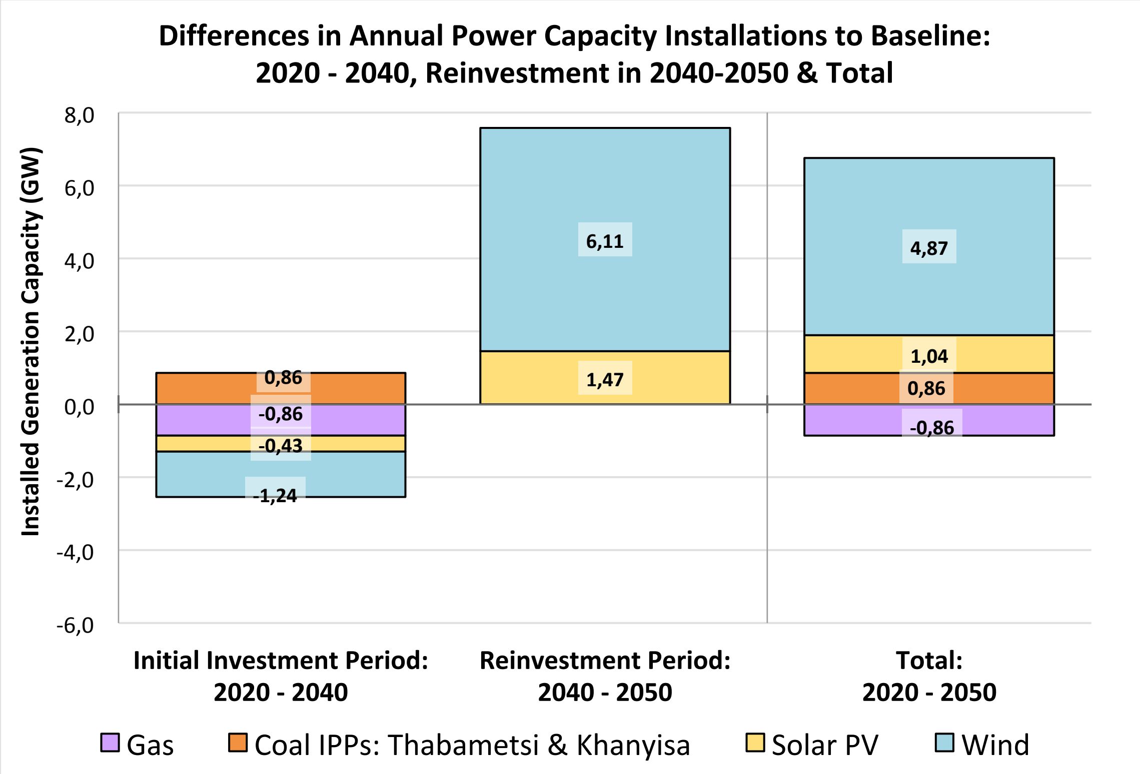

Figure 22: Total differences of alternative electricity generation mix per period (with reinvestment from 2040) and total difference in constructed generation capacity.

4.2.2.2 Electricity system costs

Figure 23 shows the increases in costs for each station individually and combined. Committing to both of the COAL IPPs results in annual increases in the electricity system costs of R2-R3.5bn per year from 2022 to 2040. The expansion of investment in new renewable energy in the 2040s to replace the existing fleet that cannot be run due to the commitment to the COAL IPPs and a commitment to meeting the carbon constraint results in very large increase in annual costs in the 2040s. Between 2040 and 2050, the annual difference in system costs when the COAL IPPs are committed compared to the CCP scenario without the COAL IPPs ranges from R2bn to R6bn.

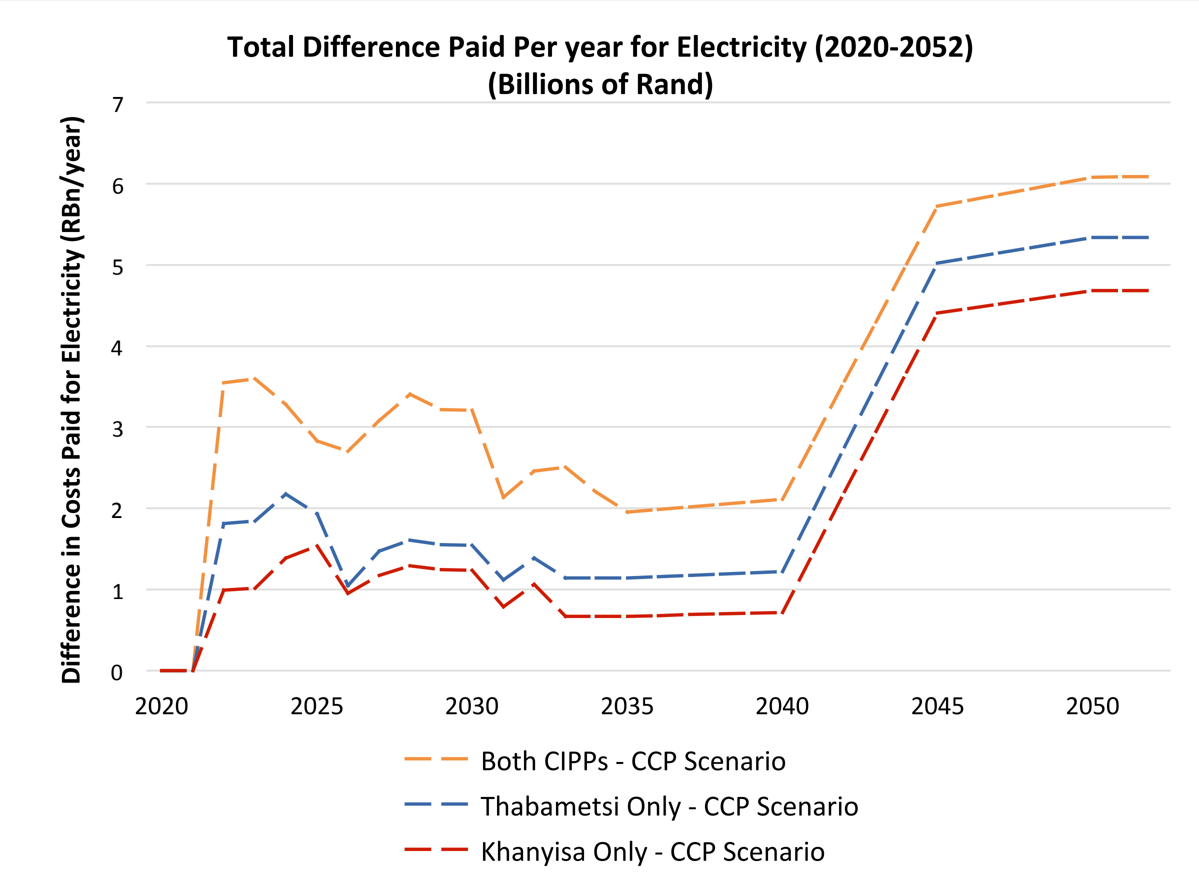

Figure 23: Total additional costs paid for electricity in climate change policy scenario for the individual and combined COAL IPPs

The total discounted system cost difference between the CCP scenario and the CCP plus coal scenario is R27.9 billion rand in present value terms. Figure 24 shows the difference in total discounted system costs for each coal IPPs individually, and combined.

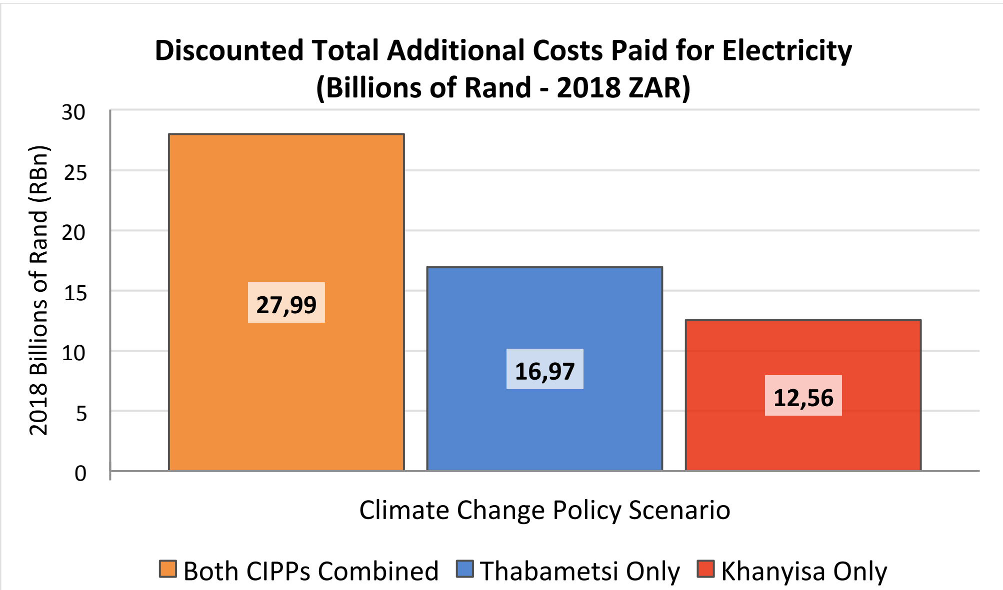

Figure 24: Discounted total additional costs paid for electricity for the individual and combined COAL IPPs

4.2.2.3 Greenhouse Gas Emissions

Since in the CCP scenario, we impose a GHG cap on the model, there are no differences in total emissions. However, the effect on the energy sector of meeting the constraint is important. With the coal IPPs committed, there is a need to reduce emissions in the power sector (through running other coal plants at lower load factors). In other sectors, emissions reductions come from the refineries sector reducing production (95%) and with marginal reductions from the transport (higher electrification).

4.3 Best and Worst Cases for Coal IPPs: Combined Sensitivities

This section analyses the impacts of the coal IPPs using combined sensitivity analyses on GHG-intensity and renewable energy and gas costs.

4.3.1 Electricity system cost deviations

Figure 25 shows the additional system costs incurred in the best-case and worst-case sensitivity analyses. Even in the best-case the inclusion of the coal IPPs increases the annual costs in the electricity system by up to R3.5bn initially, reducing to between R1-1.5bn per year over the period 2025-2040, and then to between R0.5 and R1bn to 2050. The best-case scenario includes very high costs for renewables and gas, increasing the system cost overall (and thus reducing the differential to the coal IPPs). Even in the best-case world, however, the coal IPPs increase the additional system cost by R16.14bn compared to the best case scenario with the coal IPPs excluded.

On the other hand, in the worst case, the coal IPPs would add costs of up to R3.5bn in the early years, and would maintain an increase of over R2bn per year to 2050. In total, the additional discounted system costs could increase by R23.11bn compared to a worst case without the coal IPPs.

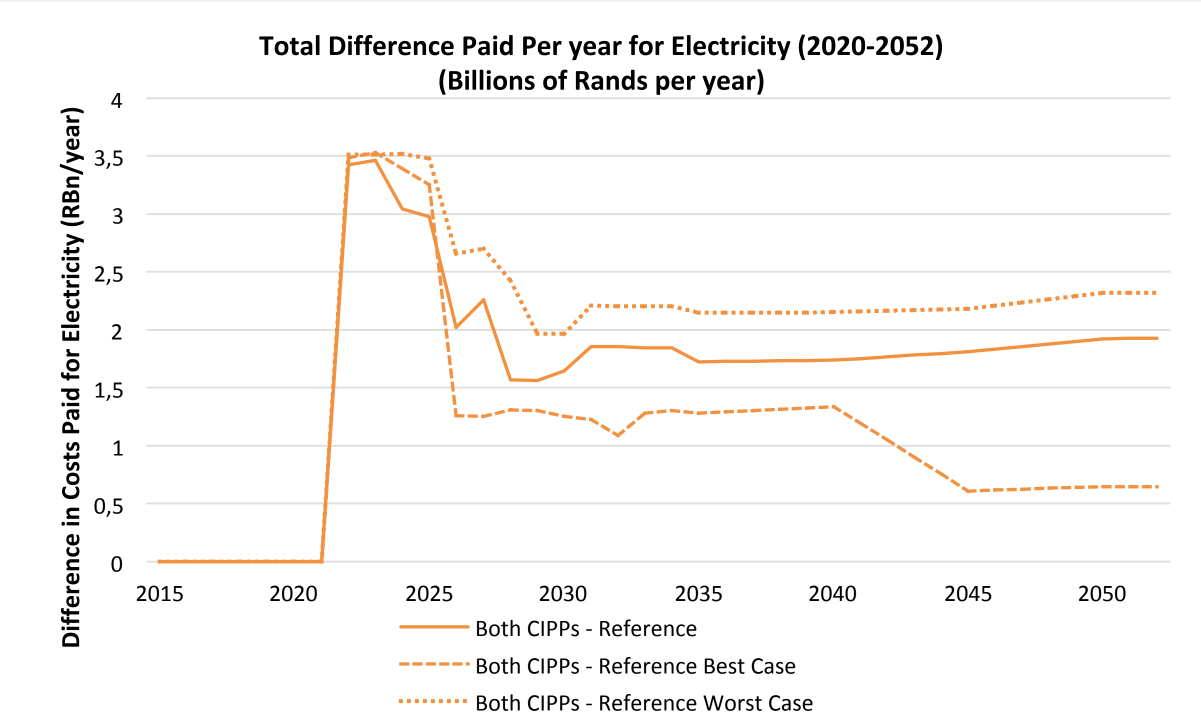

Figure 25: Reference, best-case, and worst-case additional annual electricity costs for the coal IPPs.

4.3.2 Greenhouse gas emissions

In the best case scenario, GHG emissions are significantly reduced due to the assumption of much higher efficiency plant (ultra super critical) and the mitigation of N_2O emissions. Even so, the difference in total GHG emissions between the best-case scenario with and without the coal IPPs is 97 Mt Co_2-eq. While there are emissions savings in the early 2020s, due to the lower GHG intensity of the coal IPPs compared to the least efficient of Eskom's existing plants, net additional emissions are positive before 2030. For comparison, the carbon tax is expected to reduce CO_2 emissions by around 115 Mt over the period 2020-2050 (ERC, 2018).

In the worst case, even though the GHG-intensity is the same as the reference scenario, cumulative emissions are higher due to higher cost renewable energy and gas being pushed out by 1-2 years. The result is worst case cumulative emissions of 217,9 Mt CO_2-eq by 2050.

The figure below shows the cumulative difference in GHG emissions by scenario, for both the individual and combined IPPs. Due to its relatively smaller size, the magnitude of the cost and emission impacts from Khanyisa are typically smaller than those from Thabametsi.

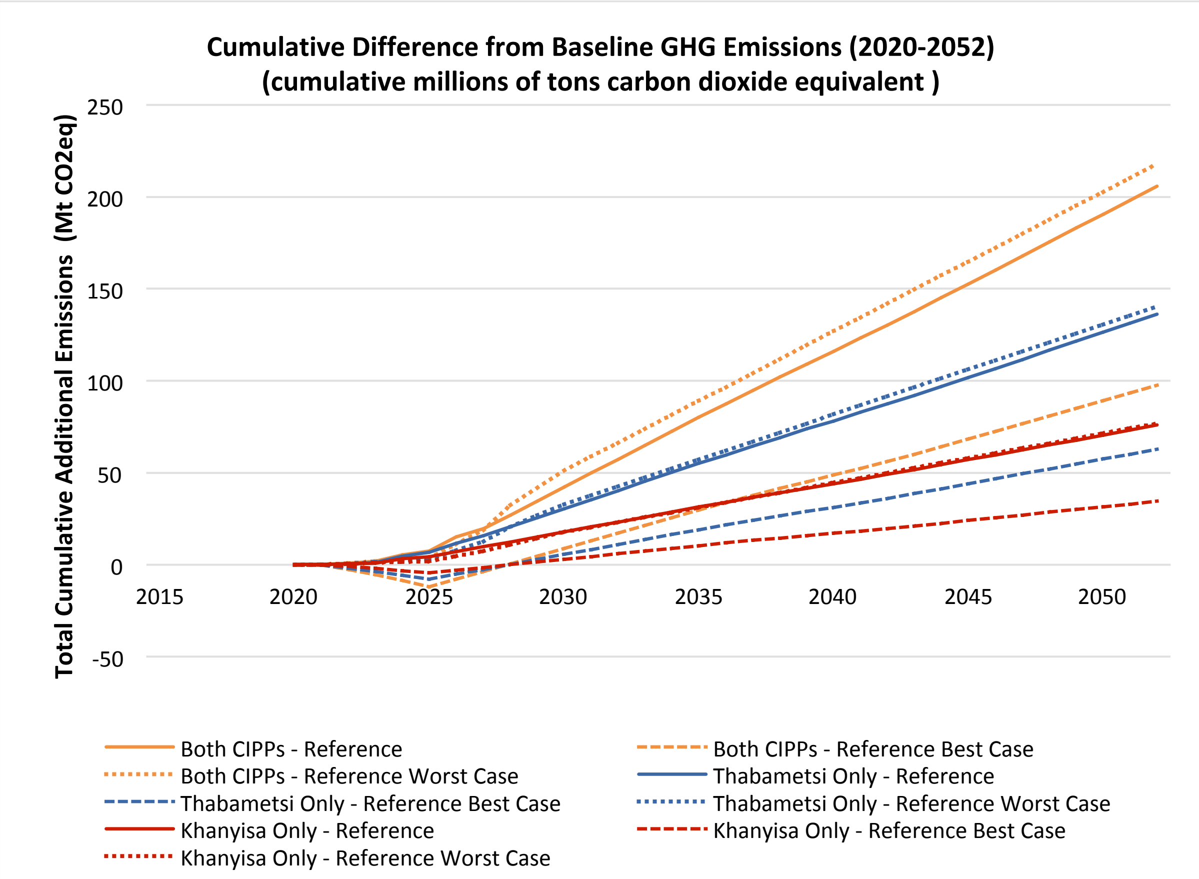

Figure 26: Cumulative added GHG emissions for the reference baseline, best-case and worst-case scenarios, for the individual and combined COAL IPPs

5. Conclusions

The result of the assessment of new coal IPPs has shown that these plants are not necessary to meet demand, and, further, that their inclusion in South Africa's electricity system will substantially raise costs in the electricity sector, and substantially increase GHG emissions over their lifetimes.

In the reference scenario, the additional present value cost of building the coal IPPs is R19.68 billion. The stations also increase emissions by 205,7Mt CO_2eq over the period. This amounts to a negative carbon price of R96/t CO_2-eq; that is, this is the price per ton that South Africans will pay for the extra emissions if the coal IPPs are built.

The analysis also includes sensitivities on costs and emissions to test whether more pessimistic renewable energy and gas costs could impact the overall findings. We find that even with pessimistic renewable energy cost projections and high gas costs, the coal IPPs still increase the system costs in the electricity sector compared to an optimised electricity build plan. Even in the best case for the coal IPPs, when competing alternatives are expensive and the IPPs are able to mitigate their emissions significantly, the overall increase in system costs is R16bn, and the increase in emissions is 97Mt. In the worst case for the coal IPPs, the increase in system costs is R23bn and emissions increase by 218Mt.

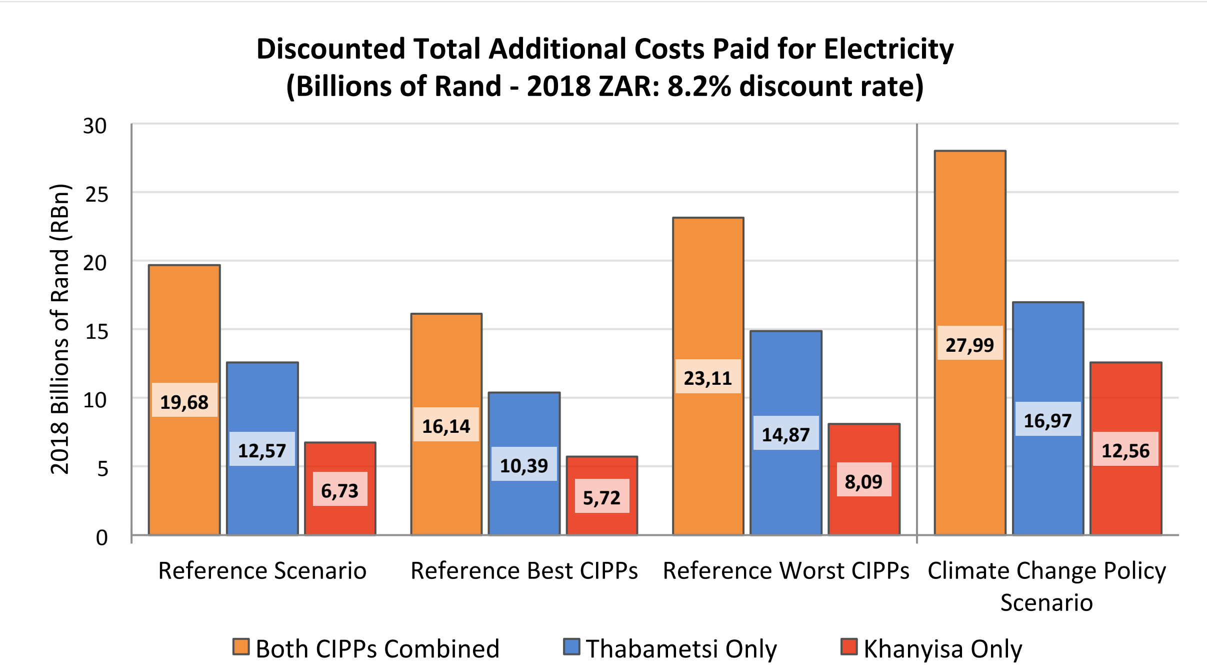

Figure 27: Summary of total discounted additional costs for electricity for all scenarios for the individual and combined IPPs[10]

In comparison, recent modelling on the emissions savings of mitigation policies showed that the emissions savings of the post-2015 National Energy Efficiency Strategy to 2050 will be 214 Mt CO_2-eq (ERC, 2018). Thus, the GHG emissions of the coal IPPs in the reference and worst case will almost offset the National Energy Efficiency Strategy. The coal IPP programme essentially negates key mitigation actions at the disposal of the government.

[10] In each case, the total additional costs are the difference between the scenario with and without the coal IPPs committed (ie reference compared to reference plus coal, CCP compared to CCP plus coal, best and worse with and without the coal.

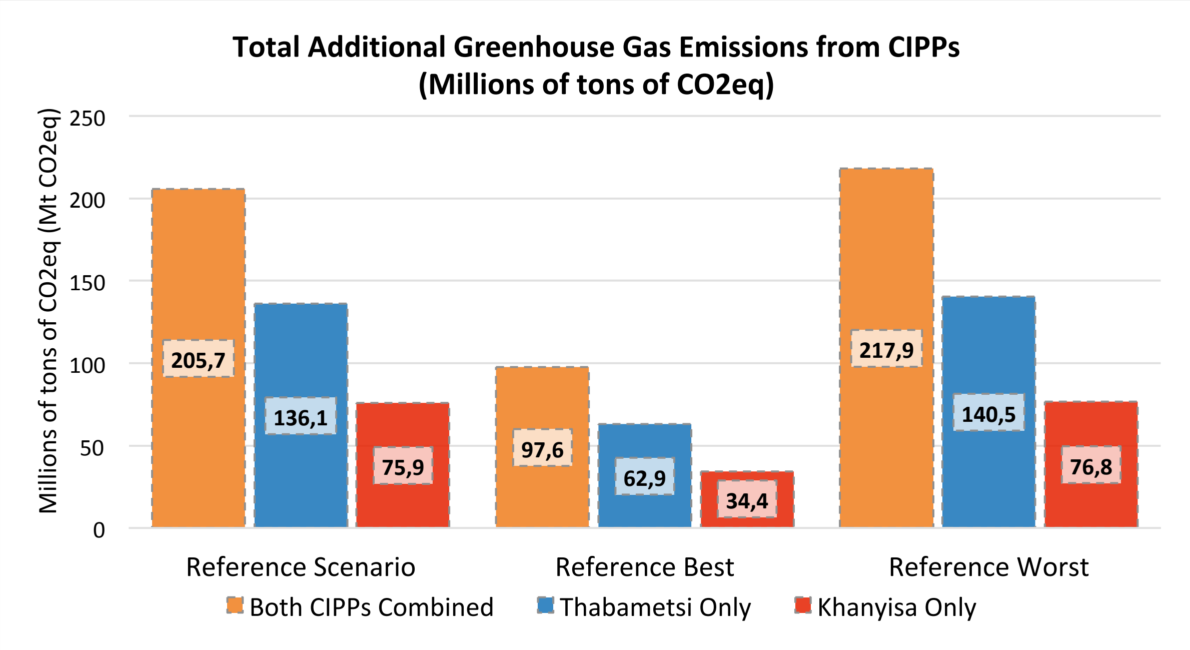

Figure 28: Total additional power sector GHG emissions in the reference baseline, best case, and worst case scenarios for the individual and combined COAL IPPs

Finally, we tested the effects of building the coal IPPs in the context of climate change mitigation policy. Should South Africa take its own climate change commitments seriously, building the coal IPPs will dramatically raise the costs of meeting the low-PPD carbon budget as outlined in the National Climate Change Response White Paper and committed to under the Paris Agreement. Further mitigation will be required in the power sector, with the existing fleet run at lower load factors to make room for the coal IPPs, and substantial higher investment required for new generation capacity. Notably, other sectors will also face higher mitigation burdens. In total, the additional discounted system costs to meet the low-PPD trajectory with the coal IPPs is R27.9bn.

The implications of these findings are clear. South Africa is currently facing a large surplus in generation capacity, in particular inflexible base supply capacity. Eskom is facing a financial crisis and rising electricity prices will drive consumers away from the utility. Investments that unnecessarily increase costs in the electricity sector should be avoided.

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Appendix A:

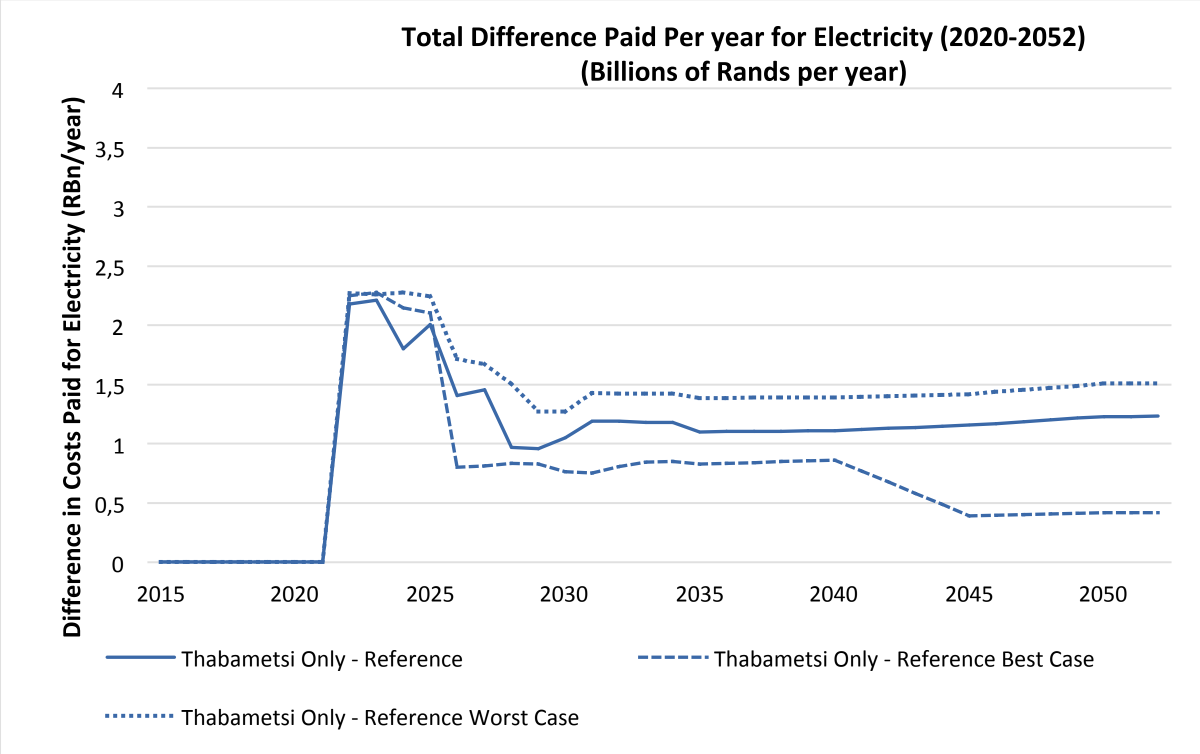

Figure 29: Reference, best base, and worst case additional annual electricity costs for Thabametsi only.

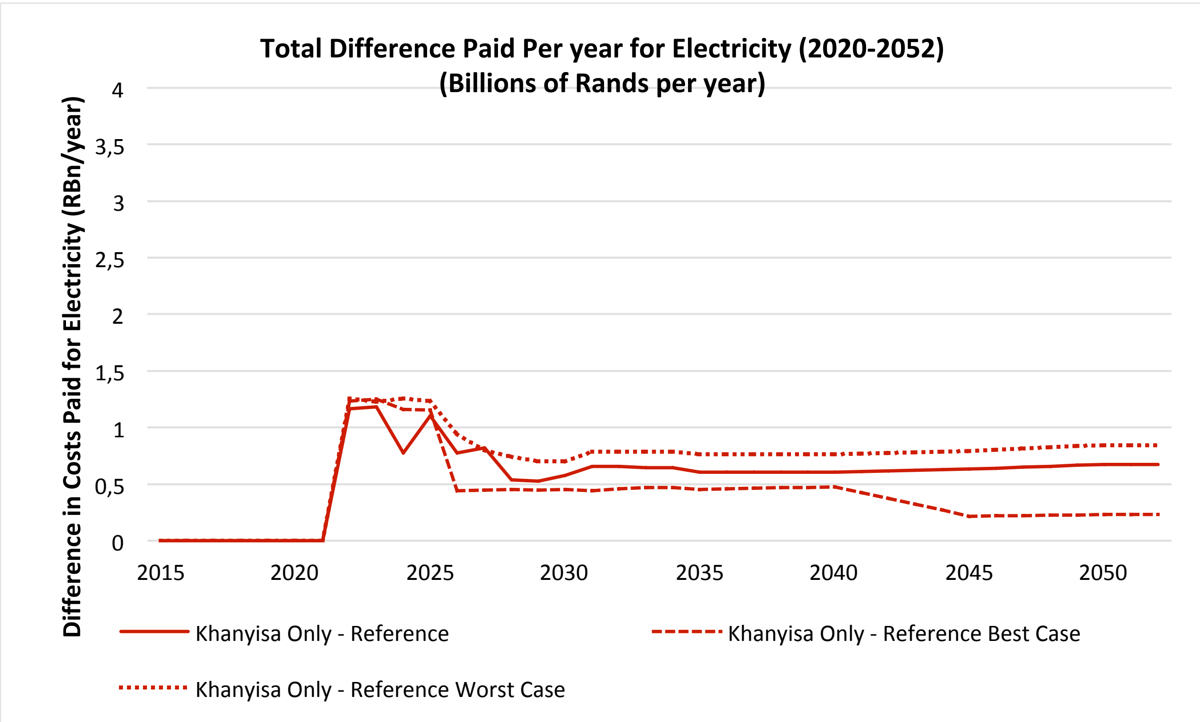

Figure 30: Reference, best base, and worst case additional annual electricity costs for Khanyisa only

Appendix B: Description of the ERC's TIMES model

The South African Times Model (SATIM)

Originally created for the Long Term Mitigation Scenarios, the South African Times Model (SATIM) is a full economic sector energy-systems model that undergoes continual development. SATIM is based on TIMES (a successor to MARKAL) which is a partial equilibrium linear optimisation model developed by the International Energy Agency.

The model includes economic costs, emissions, and a range of sector-specific constraints that can be applied at a point in time or cumulatively. A user interface provides a framework for both structuring the model and scenarios, and for interpreting results.

The SATIM model is fundamentally "sectoral", in that it organises the demand for energy by economic sector and characterises the demand for energy in a sector by the energy services required by that sector. SATIM is therefore a full-sector TIMES model that includes both the supply and demand side of the South African energy system. SATIM can be run using linear or mixed integer programming to solve the least-cost planning problem of meeting projected future energy demand, given assumptions such as the retirement schedule of existing infrastructure, future fuel costs, future technology costs, learning rates, and efficiency improvements, as well as any constraints such as the availability of resources. The model has five demand sectors and two supply sectors, which can be analysed individually or together. The demand sectors are industry, agriculture, residential, commercial, and transport, and the supply sectors are electricity and liquid fuels. SATIM allows for trade-offs between the supply and demand sectors, and it explicitly captures the impact of structural changes in the economy (i.e. different sectors growing at different rates), process changes, fuel and mode switching, and technical improvements related to efficiency gains (Altieri et al. 2015).

SATIM, however, does not endogenously account for the feedback from the economy as sectors and consumers respond to changes in energy prices, and as the economy responds to energy investment requirements. By not accounting for this feedback, it is likely that SATIM will over- or under-estimate energy demand when used independent of an economic model.

The level of detail for a sector depends on the relative contribution of the sector to total consumption and on how much funding has been historically received for developing that sector in the model. Thus, the model for the Transport sector is quite detailed but that of the Agricultural sector is quite simplistically represented in SATIM, because in South Africa the Agriculture sector accounts for relatively small energy consumption and low emissions.

In SATIM, services supplied to each of the five sectors are driven by technologies that require energy, with the quantity of that energy supply depending on the efficiency of the technology.

Useful energy is an exogenous model input disaggregated by energy carrier, for each demand sector. Final energy demand is determined endogenously using the assumed efficiencies of the least cost demand-side technologies selected by the model. The two supply sectors and primary energy sources must meet the sum of these demands, with the model optimizing the mix of supply-side technologies to meet the demand for final energy at least cost.

The SATIM model includes a number of parameters and general assumptions broadly covering, for each sector: (a) the structure of the sector and its energy services as it impacts on the demand for energy; (b) the establishment of base year demand for energy in the sector; (c) technical and cost parameters of the technologies available to satisfy the demand for energy services currently and in the future; (d) the projection of future demand for energy services.

SATIM can be broadly summarised as follows:

- Bottom-up (end-use) energy systems optimisation, similar to the national Integrated Energy Plan (IEP)
- Full economic sector representation allowing resource and emissions trade-offs between demand and supply
- Captures full economy energy emissions (excluding land use, land-use change and forestry) allowing the modelling of carbon taxes and carbon budgets.

Figure B.1 depicts the primary SATIM model components while Table summarises the economic demand sector representation. Of note is the importance of the base year energy balance which provides the calibration reference for the model's supply and demand assumptions.

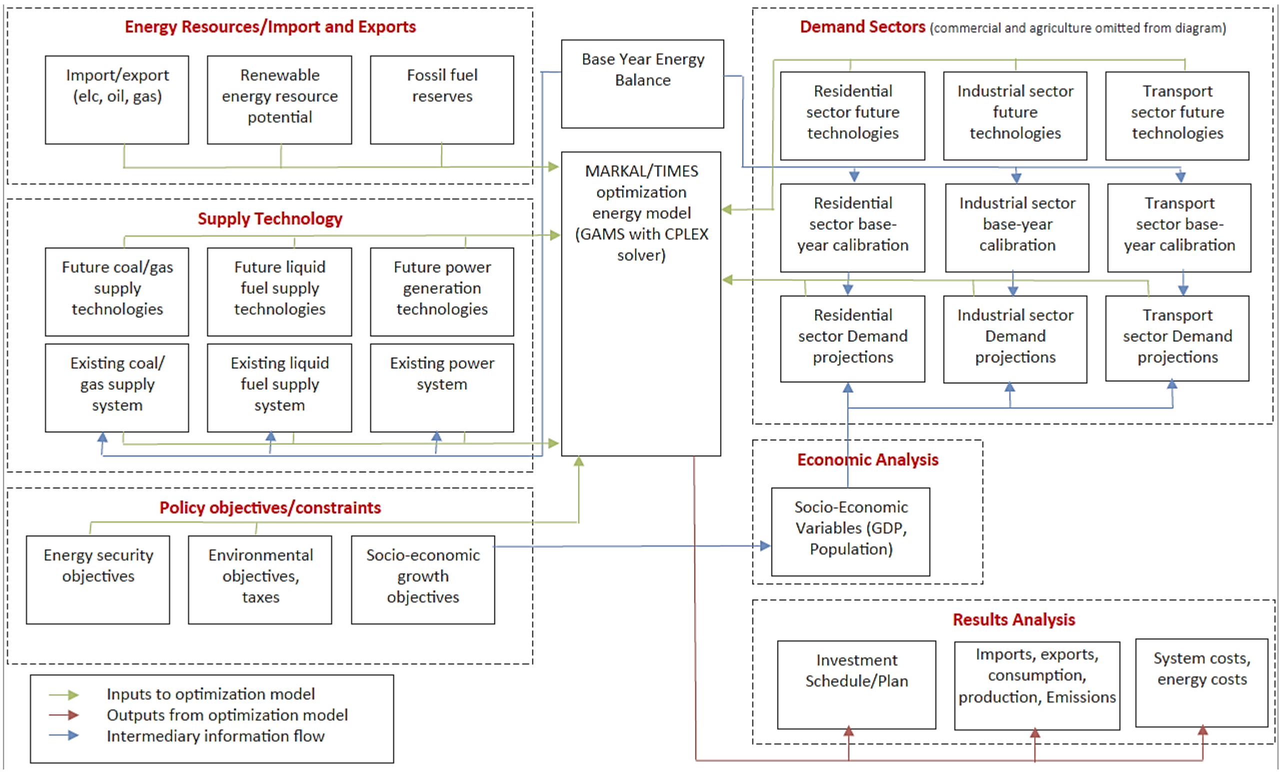

Figure B.1: A Schematic Summary of the South African Times Model (SATIM)

Table B.1: Summary of Economic Sector Representation in SATIM and their Main Drivers

Sector	Disaggregation	Driver
Agriculture	By end use: e.g. irrigation and traction.	Agriculture GDP
Residential	High, medium and low-income households: electrified and non-electrified	Population, Household-income, electrification

	By end use: e.g. cooking, lighting.	rate
Commercial	By end use: e.g. lighting, HVAC.	Total GDP, building stock
Industrial	By sector: Iron and Steel, Pulp and paper	Sectoral Value Added
	By end use: thermal fuel or electricity (e.g. compressed air, cooling, pumping)	
Transport	By Sector: Air, Freight and Pipeline	Transport GDP, Population and household category and income
	By end use: e.g. freight rail and road (light, medium, heavy)	
	By end use: e.g. Passenger: Cars, SUV, Bus.	