South Africa’s power generation future in the context of the Paris Agreement

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Abstract

South Africa’s National Climate Change Response White Paper defines a range within which greenhouse gas emissions stabilise for the period 2025 to 2035, after which they decline. This emission trajectory is to be realised in combination with continued economic growth, and also forms the basis for the country’s NDC targets in 2025 and 2030. Of South Africa’s greenhouse gas emissions, the majority comes from power generation. The power sector therefore will play a very important role in combining decarbonisation and economic growth. South Africa’s future power generation mix is determined by the governments’ Integrated Resource Plan (IRP). However, the GHG emissions which will result from implementing the most recent proposal for a new IRP might not be the most economical allocation of South Africa’s future emissions budget.

A possible cause is that national modelling on which basis the new IRP is generated does not include economic feedbacks and interactions with other sectors. This paper uses a linked energy and economy model that addresses these shortcomings and presents an alternative plan for South Africa’s electricity sector that is compatible with South Africa’s NDC and uses an economically rational allocation of its GHG emission budget. This paper furthermore includes several improvements on assumptions and inputs that the IRP does not consider adequately, notably most recent insights in cost developments of renewable energy and South Africa’s capacity to roll out these technologies.

We then continue our analysis and try to address the fact that South Africa’s NDC is considered insufficient to contribute to the overarching goal of the Paris Agreement, a high chance of stabilisation of global warming at 2°C, and preferably 1.5°C. With our linked energy-economy model, we show that a more ambitious NDC is feasible for South Africa at negligible economic costs, and we show what this means for South Africa’s IRP.

The more ambitious NDC will require substantial renewable capacity, and new energy storage capability to address variability, add flexibility, and increase system reliability. Storage, up to now, has not played a significant role in the national electricity planning process, however, energy storage has recently seen significant cost reductions and performance improvements, which are projected to increasingly improve. These results show that new storage options, particularly in the form of batteries, other new energy storage systems, and ‘power-to-X’ technologies need to be seriously considered in the national planning process.

1. Introduction

The Integrated Resource Plan (IRP) by the South African government informs decisions of what new power generating technologies are to be procured, and by when. The plan is informed by partial equilibrium energy systems modelling of only the electricity system of South Africa. The IRP is intended to be updated every few years based on new information, and latest developments in outlooks for economic growth and energy demand, as well as technology costs. Nevertheless, the IRP2010 (published in 2011) (DoE, 2011) is still the official document on which government bases their decisions on new power generation capacity. This paper intends to assess the latest version – the IRP2018 (DoE, 2018) – with the intent to inform public debate on the future of electricity generation in South Africa by proposing an alternative plan.

The draft IRP 2018 provides a necessary update to the IRP 2010, in particular by acknowledging that a least-cost electricity future for South Africa now primarily comprises renewable energy and does not feature new investment in nuclear- or coal-fired power. Nonetheless, the draft IRP 2018 reflects the fact that the Department of Energy is persisting in procuring new coal-fired power from the proposed Thabametsi and Khanyisa power plants, which have been 'forced into'[1] the 2018 IRP (DoE 2018, page 39 bullet 3). Similarly, Eskom is continuing the construction of Medupi and Kusile power plants (Mail and Guardian, April 2019), which are also included in the draft IRP.[2] Neither Eskom nor the draft IRP explicitly plan to decommission the oldest coal power stations[3]; and the draft IRP 2018 continues to assume that existing coal-fired power plants stay competitive until these reach 50 years of age. As a consequence, the draft IRP foresees these power plants to keep running their entire lifetimes, even though our analysis shows that earlier retirement could be a more economical option, and these stations should operate at lower rates due to the cost of fuel, and cost in Minimum Emission Standards retrofitting. Artificial and arbitrary constraints on renewable energy investment in the draft IRP also raise costs and limit the sector's contribution to meeting South Africa's future energy requirements and its climate change mitigation goals (DoE, 2018).

Further to this, is that the draft IRP comes at a time in which Eskom is in crisis. Its runaway capital and operating costs (Business Day, 2019) point to a potential utility death spiral as many of its customers start to invest in energy efficiency and on-site, distributed energy generation, leading to stagnating demand for electricity from the central grid. This is compounded by a slower economic growth in the country over the last few years. The IRP 2018 does not consider this context in its assessment of future technology roll out, nor does it consider the developments taking place in global energy technology that

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[1] The kind of model used for the IRP analysis would typically select a set of investments which could meet the demand required of a future electricity system at least cost. If a specific investment has been 'forced into' the model, it implies that the modellers have required the model to choose that investment regardless of its cost compared to other possible options, and that the investment in question has not been evaluated against other options.

[2] A recent study concludes that cancelling the last two units of Kusile would be cheaper than incurring any contract cancellation penalties (Steyn et al., 2017).

[3] The draft IRP places old coal-fired power plants in 'cold storage', the latter being described as a state in which units taken out of service could be brought back into service within a year if required.

will fundamentally alter the viability of the current fleet, either because of economics[4] or because of global climate change policy.

In this context, this study provides an alternative technical assessment of South Africa's electricity future, with a focus on a) a least-cost reference scenario and b) a least cost, *policy-adjusted* climate change mitigation scenario. The least-cost reference scenario can be compared to the modelling undertaken by the DoE for the IRP 2018, and highlights the most important parameters for assessing and providing a critical perspective on that modelling. A key difference between the approach used here and that of draft IRP is that we embed the electricity sector in an economy-wide model including all energy supply options and demand sectors beyond just electricity, while still including a level of detail on the electricity sector comparable to that of the approach used for IRP 2018.

The reference scenario in this work presents the basis for comparison to the draft IRP 2018 results and work, and also serves as the baseline for the mitigation scenario in the power sector in a new, more ambitious, NDC for South Africa.

The policy-adjusted climate change mitigation scenario therefore highlights the critical role played by the electricity sector in meeting South Africa's mitigation goals, compared to the roles of other sectors. The scenario shows the potential that exists, given the dramatic fall in costs of low-carbon technologies, for an accelerated decarbonisation of the electricity sector. This paper's analysis also anticipates South Africa's next nationally determined contribution (NDC), due to be communicated to the UNFCCC by 2025. This will almost certainly require a more ambitious mitigation goal in the light of current and future assessments of the adequacy of global mitigation efforts, which will be further highlighted in the Paris Agreement's Global Stocktake in 2023 (UNFCCC, nd).

This paper continues with a presentation of the methodology of our approach with a focus on key assumptions on power generation technologies (Section 2). This is followed by the results of our reference scenario (section 3.1). We then discuss the methodology through which we establish an economically feasible policy adjusted climate change mitigation scenario (section 3.2). The discussion of the results of this policy adjusted mitigation scenario has a focus on the least cost allocation of CO2 emissions to different sectors and the implications for power generation (also section 3.2). Finally we conclude with the implications of our scenarios for South Africa's draft IRP 2018, with special attention for some concerns about their feasibility (section 4).

2. Methodology

In this section we present some of the critical assumptions contained within the model, some of which differ rather significantly from the draft IRP2018. Our analysis uses the South African TIMES model (SATIM), a full sector energy systems model (ERC, nd) linked with a CGE economy model of South Africa – SATIMGE (see also: Altieri et al. (2015) and Merven et al. (forthcoming)). Both models have

[4] For example, a group of about 30 central banks overseeing the monetary system in half of global GDP recently called for including climate change in stress tests and financial risk evaluations (Insurance Journal, 2019; Financial Times, 2019).

been developed by the Energy Systems, Economy, and Policy (ESEP) team of the Energy Research Centre at the University of Cape Town.

The full descriptions of these models can be found in respectively Alton et al. (2014) & Merven et al. (forthcoming) and ERC (nd) & Hughes et al. (forthcoming). Here we discuss the assumptions that are most important for the results we obtain. These critical assumptions concern economic growth and future electricity demand (section 2.1), costs of coal-fired power generation (section 2.2), costs of the main alternative – renewable power generation – (section 2.3) and their built rates (section 2.4). Finally, this section discusses the for power generation important assumptions about air quality compliance (section 2.5).

2.1 Economic Growth and electricity demand

The first assumptions we discuss concern the outlook for economic growth. These assumptions are important because they inform for a large part the future electricity demand. In the CGE model part of our linked model economic growth is modelled mainly through assumptions about productivity gains, and investment (for more information see Altieri et al. (2015) and Merven et al. (*forthcoming*)). GDP growth meets actual growth observed for 2012 – 2017, while from 2018 onwards it corresponds to projections by National Treasury (2018) and IMF (2018). De facto, the GDP growth rate obtained is on average 2.6% *per annum* from 2015 to 2030, and higher to the end of the horizon of 3.6% *per annum* between 2030 and 2050. No dramatic shifts are foreseen in the structure of the economy. Together this seems to correspond to the GDP growth rate and economic structure foreseen in the upper demand forecast of the draft IRP 2018 (DoE, 2018).

Our general equilibrium and full sector models determine electricity demand endogenously, based not only on economic growth and income, but also on the costs of electricity and of the introduction of more energy efficient technologies for the use of electricity, as well as on the competitiveness of alternate fuels in meeting the demand for energy services. Nevertheless, our reference projection sees electricity demand increase to about 320 TWh by 2030, which is similar to the IRP, but then sees it increase to 550 TWh by 2050, which is higher than that of the IRP's upper demand forecasts for the same year (430 TWh). Half of the difference can be attributed to the introduction of electric vehicles in our reference scenario. This, again, highlights the importance of using a full sector energy model over an electricity only model. Conversion losses incurred in the included battery systems also increase the overall electricity generation requirement, especially towards the end of the projection period (2050). The remaining difference in electricity demand can be related to a difference with the IRP in demand forecasting methodology. A more detailed comparison, e.g. of electricity demand by sector, could provide useful insights for both demand forecasts.

2.2 Coal supply Costs in SATIM

We use the Energy Research Centre's coal supply model, which has station-specific coal supply options and costs, based on Dentons (2015), Steyn et al (2017), and Burton et al. (2019). The costs of coal per power station can be seen as box plots in Figure 1, in 2015 ZAR/GJ over the lifetime of the existing contracts.[5] The costs shown are delivered price to the stations and include transportation costs which often make up almost half of the costs in some instances - owing to structural contracting changes - more on this is given in Burton et al. (2019). A single horizontal line means that the station in question is supplied from a single tied mine/contract (Lethabo, Matimba, Matla, Medupi) or with lower volumes of coal being brought in to the station (e.g. Duvha). More information on this coal model is given in Burton et al. (2019).

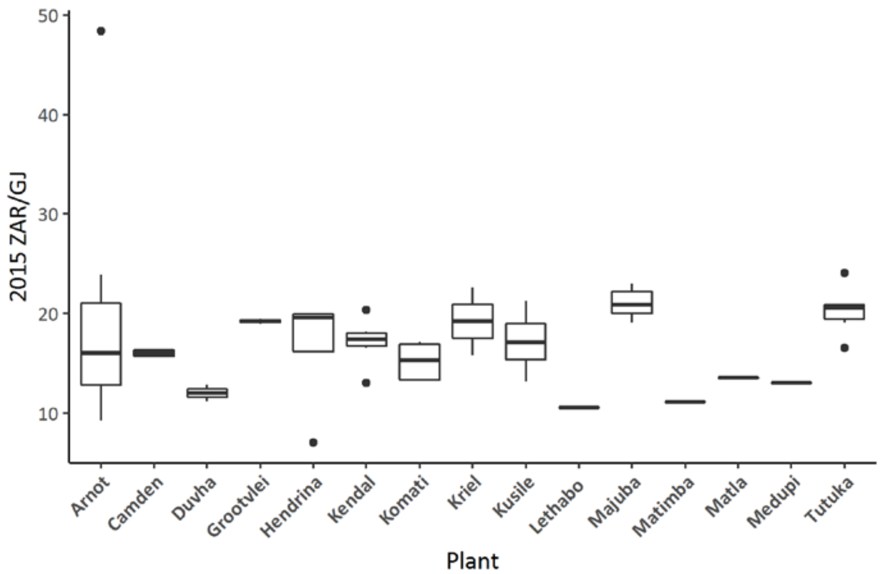

*Figure 1: Existing coal costs to coal power stations in SATIM **

** Explanation: Boxplots group the numerous values into quartiles (the upper quartile is represented by a single line on top of the box, the lower quartile is the line below the box, and the middle two quartiles by the box itself); the line in the box gives the median; dots are outliers (outside of the box)*

The cost of new coal supply to plants after the dedicated mines reach their end of life, or existing short and medium term contracts expire, is given in Table 1. The costs shown take into consideration extraction costs, washing/processing and transport up to the power plant. The contracted coal costs used here are lower in most instances than in the IRP, which uses a cost of 31 R/GJ for coal pulverised fuel (DoE, 2018 - table 2). The costs of coal for new supply, as given in Table 1 are higher, however.

Table 1: New coal supply costs 2015 R/GJ (Durbach et al, 2017)

	2020	***2030***	***2040***	***2050***
Central Basin	33	37	39	39
Waterberg	22	24	25	25

2.3 Renewable energy costs

Renewable energy costs in this analysis are based on the learning curves presented in Ireland & Burton (2018) and are focused on solar PV and onshore wind. Figure 2 shows the projected levelised cost of

[5] The costs are weighted by volume in the model.

solar PV and wind based on the improvements for the respective technology parameters. No total future national limits of installed PV and wind are imposed, and new capacity can be constructed from 2021 onwards. Annual added capacity installation limits are included until 2030 and thereafter removed – these limits are described further below and based on the experience of the SA REIPPPP. Wind and PV energy temporal production profiles, and the removal of total resource constraints are based on Fraunhofer (2015) and CSIR (2017). Figure 2 below uses levelised cost projections for comparison, however individual cost components and performance parameters are used in the model and not levelised costs[6].

The modelling in this study includes the assumption that wind and solar generators are never able to contribute reliably to the peak demand reserve margin requirement and must be fully backed up by dispatchable generation or available storage regardless of if their profiles do contribute during peak times (i.e. 0% firm capacity credit).

Solar PV learning assumptions

- 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). See Ireland & Burton (2018) for more details;
- In 2015 investment costs start at 12,500 R/kW and fixed O&M costs at 200 R/kW/year. In 2050 investment costs are 3,960 R/kW and fixed O&M costs are 200 R/kW/year.
- 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). Capacity factors remain fixed to 2050. Plant life is 25 years, and construction time is 1 year.
- Technology learning starts from 2015 and only capital cost reductions are applied. Capacity factors and O&M remain unchanged.

Onshore wind learning assumptions

- 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, 2017), IEA-Wind & Wiser et al., (2016), and Agora Energiewende (2017).
- In 2015 investment costs start at 12,500 R/kW and fixed O&M costs at 500 R/kW/year. In 2050 investment costs are 10,355 R/kW and fixed O&M costs are 450 R/kW/year.
- Annual capacity factors for new onshore wind farms are assumed to start at 36.4% for plants of size 100MW+ (DoE REDIS, 2018). Plant life is 20 years, and construction time 2 years.

[6] LCOE figure costs are quoted in April 2016 Rand, while SATIM base year costs are in January 2015 Rands using a 0.9416 ratio (SatsSA CPI) for comparison to the widely cited REIPPPP tariff announcements.[7] To compare our scenario with draft IRP 2018 emission trajectories we approximate IRP scenario's cumulative CO2 emissions through linear interpolation.

- Technology learning starts from 2015; capital and O&M cost reductions are applied, and annual capacity factors of new plants improve to 48% (existing plants do not improve).

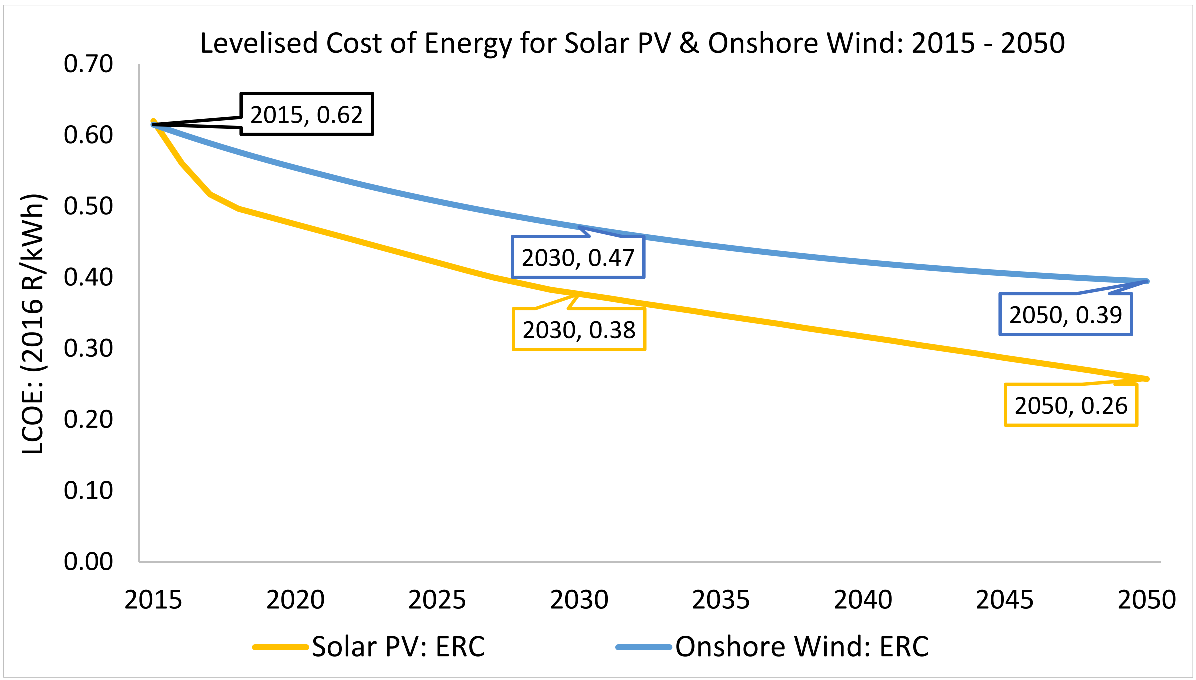

Figure 2: Solar PV and wind cost and learning assumptions 2015–2050 (April 2016 ZAR)

2.4 Renewable energy annual build rates

The IRP 2018 has imposed annual upper build limits on new renewable energy of 1600 MW for wind and 1000 MW for solar PV throughout the modelled period (to 2050) in most of the scenarios analysed. No explanation is offered for these build limits. It is clear that there could be limits to the extent to which annual rollout of renewable energy could be accelerated. One could think of technical (grid or Engineering, Procurement and Construction (EPC) capacity), logistical (e.g. port capacity), institutional (start dates and length of procurement processes), legal and financial (prudential) limits. However, while we concur that some limit needs to be imposed on the model to approximate the real-world constraints facing the sector, we argue that the specific annual limits used by the DoE are too low.

Developing realistic constraints is challenging and requires further work and assessment as the RE industry grows in South Africa and globally. In the meantime we have developed an interim approach to setting these limits, based on a number of considerations in existing studies and in conversations with the RE industry. We base our approach on: the work done by Ireland *et al.* (2017), who found that the limits imposed by the IRP were too low by global standards; research by Poeller, Obert & Moodley (2015) on solar PV investment and grid capacity availability which essentially finds that there are fewer logistical constraints for setting up utility PV than for wind, with practically no logistical constraints for distributed rooftop PV Senatla (2019); and lastly on the Transmission Development Plan 2018-2027 (Eskom, 2017), which accounts for solar PV expansion of 3500 MW and wind 4400 MW, for which transmission development is already planned over the period to 2027.

In addition to the literature, we interviewed several wind and solar PV project developers, EPC contractors, and industry representatives to test assumptions against their views on plausible timelines and rates of growth. All those we spoke with emphasized that initial constraints facing the sector can be overcome provided there is certainty in future roll-out.

In this work, the annual installation limits for PV and wind are set to start in 2021 at the total capacity awarded in round 4 of REIPPP for each technology. This is similar to the method and numbers used in Ireland and Burton (2018). Each year after 2021, the annual installation limit increases by the portion of capacity awarded in the final expedited round of REIPPP - 590 MW for PV and 618 MW for wind until 2030, when the limits are no longer imposed (Ireland and Burton, 2018). For the period after 2030, we assume that the capability for long-term capacity expansion will be developed in response to whatever is required by the IRP. Annual new build limits are therefore applied as in Table 1.

Table 2: Annual new build upper limits on renewable energy 2020–2030 (GW)

Technology	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2026*	*2027*	*2028*	*2029*	*2030*
Wind	1.36	2.04	2.73	3.41	4.09	4.77	5.45	6.13	6.81	7.49	8.17
Solar PV	1.40	2.00	2.59	3.18	3.77	4.36	4.95	5.54	6.13	6.72	7.31

2.5 Air quality compliance

The minimum emissions standards (MES) are the legislated maximum emission limit values for all existing and new power stations, in terms of the List of Activities published under the National Environmental Management: Air Quality Act, no 39 of 2004 (NEM, 2004). They are supplemented by an air emission licence (AEL) issued by the relevant licensing authority, usually a district or metropolitan municipality, to various facilities, which cannot operate without an AEL. Emissions from such facilities must at least meet the MES, unless, as described below, a postponement of compliance has been successfully obtained (which is reflected in the AEL). Stricter emission standards may also be included in AELs. The purpose of the AEL is to provide permission to emit particular pollutants within limits to a license-holder. In the case of Eskom, the licences set out these limits in terms of three pollutants: particulate matter (PM), sulphur dioxide (SO_2) and oxides of nitrogen oxide (NO_x), measured in mg/Nm^3.

The MES has both 'existing plant' and 'new plant' standards. The former had to be met by 1 April 2015, and the latter by 1 April 2020. Although termed 'new plant' limits, all plants must meet the 2020 limits, unless a postponement has been granted.

To meet the MES, Eskom can implement various technologies to limit pollutant emissions. For PM, this includes existing electrostatic precipitators (ESPs), or else fabric filter plants (FFPs), or a high frequency power supply (HFPS) and flue gas conditioning (FGC) (either with sulphur, ammonia or brine injection (Eskom BID, 2018). For NO_x, the implementation of low-NO_x burners is required. Finally, for SO_2, flue gas desulphurisation (FGD) technology is required (either wet or dry FGD). Eskom has since applied for, and been granted, postponements for compliance with both the 2015 and 2020 MES. The AQA allows for a maximum of five years of postponement, and Eskom can apply for more than one postponement. However, exemptions from the MES are not legally permissible, and thus ongoing postponements to compliance would not be allowed (Steyn, Burton & Steenkamp, 2017).

In this context, modelling Eskom's compliance with the MES is necessary to understand what the costs of compliance are likely to be, and what the implications will be of these costs for the decommissioning schedule of the fleet.

In this methodology, the stations (or units thereof) must either retrofit to meet the new plant MES by 2025 or retire. We excluded the stations that retire by 2025 (Hendrina, Komati, Grootvlei, Camden) or 2030 (Arnot and Kriel). The total capital costs for compliance per station across all pollutants are as shown in Table 3, where the costs per abatement technology are based on De Wit (2013).

Table 3: Total capex costs per station for compliance across all pollutants (2017 ZAR)

Station	*Total overnight capex (billion 2017 ZAR)*
Duvha	29.5
Kendal	40.5
Lethabo	36.5
Majuba (dry)	16.1
Majuba (wet)	16.1
Matimba	39.3
Matla	38.7
Tutuka	39.4
Medupi	33.0
Total	**289.2**

3. From least-cost to Paris-adjusted: Power generation in the context of the next NDC

This section presents the results for reference scenario first, and the results for the policy adjusted climate change mitigation scenario second. The additional methodology used for the policy adjusted scenario is presented here, in the second section, as it entails important new results from exploring different levels of carbon budget and their impact on the economy of South Africa.

The results presented here focus on the electricity sector as this is the domain of the IRP, but other energy sectors (and economy) will be touched upon as well.

3.1 Reference scenario

Peak electricity demand in 2050 for South Africa totals 65 GW, and total installed capacity is 229 GW including storage. As Figure 3 shows, in 2050 the installed capacity is made up primarily of wind and solar PV (161 GW), and a small contribution from existing coal (9 GW) and pumped storage (3GW). Investment in new battery storage technology begins in 2026, growing to 53 GW by 2050 to complement variable renewable energy technologies.

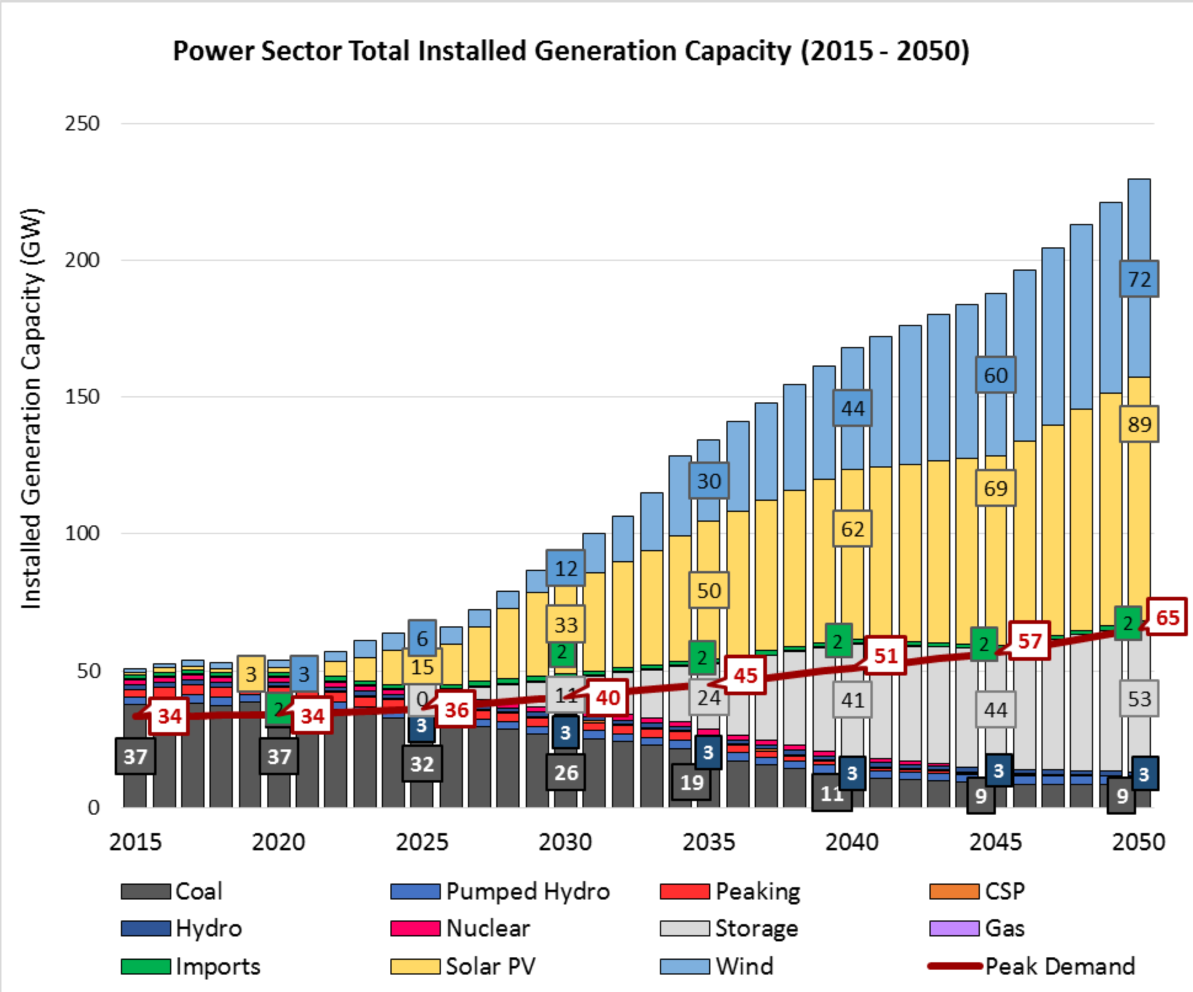

Figure 3: Generation capacity by technology for South Africa in the reference scenario

By 2030, renewables (wind, solar, micro-hydro, and biomass) produce 42% of electricity, and this increases to 90% by 2050 (of this, wind and solar together contribute 38% and 88% respectively). The higher demand forecast illustrates the important role of full sector analysis: in the reference case, large scale electrification of transport takes place. By 2050, 66% of private passenger vehicle activity is from electric vehicles, and 63% of road freight (primarily through the use of electrified light commercial vehicles). Transport demand for electricity accounts for 10.8 TWh and 40 TWh in 2030 and 2050 respectively.

The reference scenario includes large scale retrofitting of Eskom coal power stations to meet the 2020 MES ("new plant standards") by 2025. This study allows all stations that are scheduled to retire before 2030 to avoid meeting the 2020 plant standards. For the remainder of the fleet, plants must either implement the technology options to meet the 2020 new plant MES or else retire over the period to 2025. The results show that the least cost option is to retrofit most of the fleet to comply with the 2020 plant standards.

The scenario results show a total of 18 GW of plant retrofits across the fleet over the period to 2025. A total of 31 units are retrofitted out of a possible 42 across the fleet. All stations available for retrofitting are partially or fully retrofitted except Majuba power station, which is not retrofitted and is decommissioned as a result by 2025. These results show no new coal, nuclear, or gas power generation technologies as part of the optimal power mix.

3.2 Introducing carbon budgets for the energy sector

South Africa's NDC (for 2025 and 2030) originates from the National Climate Change Response White Paper in the form of the 'Peak Plateau, and Decline' (PPD) emissions trajectory range to 2050. This policy foresees national emissions reaching a plateau by 2025, remaining constant until 2035 and declining thereafter. For the electricity sector the Draft IRP 2018 foresees two possible emission trajectories (DoE, 2018, see Fig 9, p.29):

- A higher trajectory, the moderate decline approach, limits power generation emissions to 275 Mt of CO2 annually from 2025 to 2037 and projects a decline to about 200 Mt CO2eq by 2049/2050;
- The advanced decline approach sees emission reduction starting already in 2030/2031 going from 275 Mt CO2 to 140 Mt by 2050.

However, the scenarios explored in the Draft IRP 2018 project electricity sector emissions already to be lower than the "allowable" 275 Mt CO2 in 2020, as they turn out to be only 236 Mt CO2. For subsequent years, annual emissions are only reported for 2030, 2040 and 2050 (see Figures 11 to 13 in the draft IRP (DoE, 2018)). Also for 2030, foreseen CO2 emissions of the electricity sector are lower than the PPD trajectory, even when compared to the advanced decline approach. Clearly, the draft IRP 2018 finds it more economical for the electricity sector to have less fossil fuel use than their PPD approach allows for. This is coherent with the IRP's remark that renewables now are the least-cost power generation technology (DoE, 2018, p.37). Nevertheless, despite the draft IRP 2018's plans outperforming its own emission trajectories, one could criticize it potentially on the aspect that even the advanced decline approach reserves too much CO2 emissions for the electricity sector.

An estimation of the cumulative CO2 emission budgets (carbon budgets) of the IRP finds the draft IRP's central scenario (IRP 3) to have a carbon budget for power generation for the period 2020 – 2050 of about 5.7 Gt CO2, while the IRP's unconstrained renewables scenario (IRP 1) and the IRP's own carbon budget scenario (IRP 3) should result in 5.0 - 5.4 Gt of CO2 between 2020 and 2050 (see Table 4 below).[7,8] However, our own least-cost Reference scenario allocates only about 3.8 Gt CO2 cumulative for the same period (Table 4). The main reasons for the lower cumulative CO2 emissions for the electricity sector are the fact that air quality requirements force early retirement of the Majuba coal-fired power plant, and that no Coal IPPs are obligatory in our assumptions. And Kusile power station operates at 41% load factor in the long term. Furthermore, as mentioned, our constraint on renewables built rates is significantly higher.

[7] To compare our scenario with draft IRP 2018 emission trajectories we approximate IRP scenario's cumulative CO2 emissions through linear interpolation.

[8] DoE (2018) contains one carbon budget scenario, but this is not comparable to ours as it is only tested in combination with their constraint on new renewable built rates (DoE, 2018).

Analysis with our linked model however also implies that other sectors consume much more carbon budget than the electricity sector in a least-cost energy system. In our Reference scenario total energy use and industry emissions are projected to fall from 422 Mt CO_2 *par annum* in 2015 (historic) to 238Mt by 2050 (Figure 9). The main contributor to this decline in emissions would be the electricity sector, whose emission intensity declines rapidly from about 900 gram CO_2 per kWh in 2020 to around 100 gram CO_2 per kWh between 2040 and 2050, when it stabilizes. The already mentioned high penetration of renewable energy leads to the reduction of emissions in the electricity sector. However thermal coal power plants still provide base load capacity, which explains the latter sector's remaining emissions, with Medupi and Kusile remaining active, albeit at relatively low capacity. In a later stage also refineries contribute to the decline in CO_2 emissions, most emissions disappear due to Sasol's Secunda CTL plant retiring between 2040 and 2045. Transport electrifies substantially, but the sector's CO_2 emissions decrease only slowly due to also continued fossil fuel use. In industry emissions grow along with increased economic activity and there is little change in the mix of energy carriers – namely electricity and coal for process heat.

*Table 4: Cumulative, and upper and lower CO2 emissions in selected scenarios of the Draft IRP 2018 **

Scenario	*IRP 3 – PPD, & renewables built limit*	*IRP 1 – PPD, no renewables built limit*	*IRP 6 – Carbon budget, & ren. built limit***	*Reference this study (section 3.1)*
Annual CO2 emissions by year (Mt CO2/year)				
2020	236	236	236	230
2030	215	217	215	173
2040	153	123	116	57
2050	160	82	92	45
Cumulative periodic emissions (Gt CO2)**,***				
2020 – 2030	2.3	2.3	2.75 (2.3)	2.1
2030 – 2040	1.8	1.7	1.8 (1.7)	1.1
2040 – 2050	1.6	1.0	0.9 (1.0)	0.6
Total cumulative CO2 emissions (2020 - 2050)	**5.7**	**5.0**	**5.4 (5.0)**	**3.8**

Comments: * Source: Figures 11 to 13 in the Draft IRP 2018 (DoE, 2018), IRP 3 seems closest to the DoE's proposed IRP; ** Source Authors own calculation based on (DoE, 2018). Cumulative emissions per 10-year period are estimated by assuming a linear change in annual CO2 emissions for the given years; * For the IRP 6 scenario, stated emission budgets by DoE are given together with the linear interpolation of annual emissions in-between brackets, showing that the linear interpolation method might be biased to underestimate cumulative emissions of DoE's scenarios.**

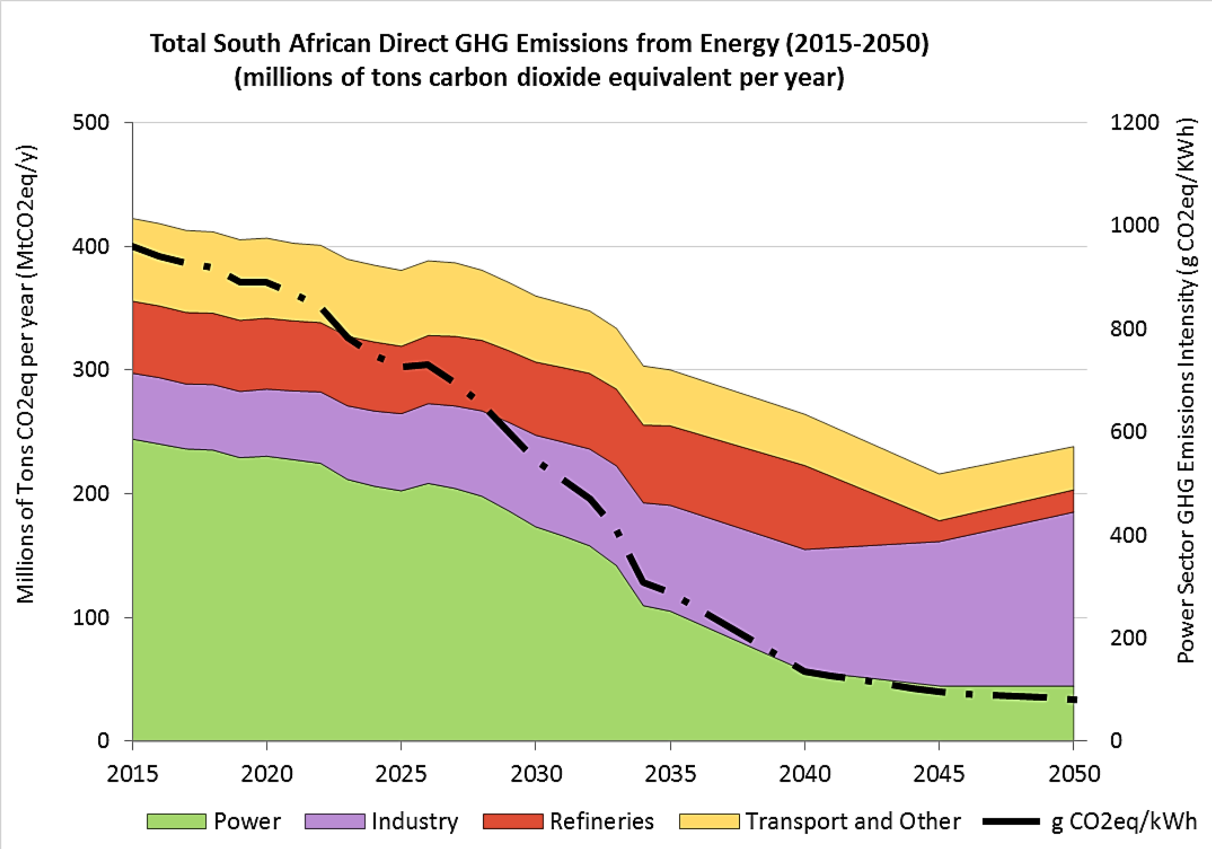

Figure 4: Sectoral emissions in the reference scenario

The cumulative CO2 emission budget for 2020 to 2050 is about 9.5Gt. This means that in our least-cost energy system a carbon budget of 5.7Gt is reserved for other sectors than electricity. Were the IRP to have a similar outlook for non-electricity energy sectors, the total carbon budget consumed for South Africa between 2020 and 2050 would end up between 10.7 and 11.4 Gt CO2. Cumulative emissions for all greenhouse gasses and sources would be between 3 to 4 gigatonnes CO2-eq higher due to emissions from industrial processes, agriculture and waste adding almost a third to South Africa's energy use CO2 emissions (DEA, 2013; see also CarbonBrief, 2018).

However, cumulative emissions in the range of 14 to 15 Gt for 2020 to 2050 are only acceptable if South Africa would be accredited a very high range for what is considered a "fair" carbon budget: Upper range estimates for a fair carbon budget for South Africa for the period 2009-2050 range from 11 to 16 Gt CO2 (WWF, 2014), of which at least 1/4th is to disappear between 2009 and 2020.[9] This leaves maximally 12 Gt of CO2-eq greenhouse gas emissions between 2020 and 2050. In other words, allocating 5 to 5.7 Gt of cumulative CO2 emissions for this period to the electricity sector would require other sectors to emit a few Gigatonnes cumulative less of greenhouse gas emissions than what we think is economically rational.

Even if the projected 5 to 5.7 Gt CO2 emissions would be an acceptable part of South Africa's carbon budget under an advanced decline approach, then still South Africa's lower range of the PPD in 2025

[9] Low ranges for estimates of fair cumulative carbon budgets for South Africa between 2009 and 2050 vary between 7 and 10 Gt CO2 eq emissions (WWF, 2014).

and 2030 is deemed only “2 degrees compatible”, but insufficient for meeting the Paris Agreement’s goal of keeping temperature change well below 2°C, leave alone 1.5°C (CAT, 2018). Also in the long term (in 2050), the PPD range is deemed “insufficient” (meaning a 3 degree world) at the upper end, and only “2 degrees compatible” at the very low end.

3.3 Additional methodology

Thus, in the light of the previous, that even the advanced decline PPD trajectory is insufficient to respect the Paris Agreement in the long term, this section presents a new methodology for evaluating the carbon budget for a more ambitious NDC for South Africa. It not only explores the potential for the electricity sector to achieve lower CO2 emissions over time but also for South Africa’s energy system as a whole. The main objective is to find an economically rational Paris Agreement-compatible CO_2 emission trajectory for the electricity sector.

One possible approach for doing this is to use a model, such as SATIM, where all large emitting sectors and their main mitigation options are characterized, and in which an overall country-wide CO2 emission trajectory can be imposed in such a way that the different sectors “compete” for carbon space. A possible further sophistication is to not specify a trajectory but rather to specify a cumulative emission constraint for a given period of time, such that carbon space allocation over time is also done in a more rational manner. However, such an analysis would still miss out on the consequences for the South African economy and feedback loops from the economy to the energy system in terms of prices and demand.

Constraining the energy system of greenhouse gas (GHG) emissions will, beyond a certain level, certainly require structural changes, which is typically expected to impose an additional cost on an economy that has largely been based on fossil fuel-based infrastructure and energy sources. While a number of studies evaluate economic impacts of various mitigation policies (Altieri et al., 2015; Alton et al., 2014; Devarajan et al., 2011; Merven et al., 2014; Pauw, 2014; Schers et al., 2015; Van Heerden et al. 2006), the point at which more ambitious mitigation may start to have deleterious effects on the South African economy has never been explored. This is all the more important as recent changes in key drivers (specifically the cost of renewable energy technologies, and changes in the coal price) have significantly changed the economics of mitigation in South Africa.

The linked energy and economy (SATIM-GE) model provides the platform to perform such a ‘stress test’ for the economy in handling increasing climate change mitigation in the energy system. We “stress test” the model by first analysing general trends and shocks in the electricity price, a precursor to economic impact, of the energy only model – SATIM to estimate a starting point for further investigation with the more computation and resource intensive SATIM-GE. Electricity price is a good proxy for economic impact as increases generally lead to higher costs of production and higher costs of living.

This methodology entails using a cumulative CO2-equivalent (CO2eq) carbon budget for the period of 2020 to 2050 for the energy model, and gradually lowering the budget by 0.5Gt in subsequent scenarios and analyse the results of these. We begin this sensitivity analysis starting at a carbon budget of 9Gt

CO2eq for the 2020 to 2050 period for all energy and industrial process sectors. We use 9Gt as the starting point, as from our work and experience with the SATIM model finds 9.5Gt as to be approximately the emissions budget in an unconstrained reference scenario.

3.4 Identifying an economical frontier for climate change mitigation

Figure 4 shows the electricity price for the series of scenarios in lowering the emissions budget by 0.5Gt sequentially starting with 9Gt. The graph shows that imposing a more stringent GHG budget on the entire energy system has a relatively limited impact on electricity prices between the reference (approximately 9.5Gt) and 8Gt budget scenarios, in particular to 2040, although the difference grows post-2040 where coal power stations running in the reference scenario are replaced with additional RE capacity. At 7.5Gt and below, the electricity's producer price follows a significantly higher trajectory in general over the entire modelling period. This indicates a possible tipping point for the electricity sector in terms of its ability to absorb further mitigation effort. Prior to 2035, the electricity price is lower in the increasing mitigation scenarios and this owes to less retrofitting of some units at the coal power stations for MES requirement.

Observing the relative contributions to mitigation from different sectors in Figure 5, it is striking that almost all mitigation occurs in the power sector, followed by a much smaller contribution from the refineries sector. In the refineries sector most of the mitigation results from lowered output from synthetic fuels plants, and a higher proportion of liquid fuels are imported. Electrification of transport occurs in the reference case, and thus there is minimal additional mitigation from the transport sector under any of the emissions constraints. This result highlights how important the electricity sector is in mitigation efforts for any NDC that South Africa adheres to. This is also largely a result of the changes that have taken place globally in reducing the cost of RE generation.

As a next step in estimating the new carbon budget, we assessed a series of more narrow increments of 100Mt and explored the effects of different GHG budgets on the energy sector and economy model – SATIMGE at the region of budget where a possible tipping point was observed - around 7.5 Gt and 8Gt carbon budgets.

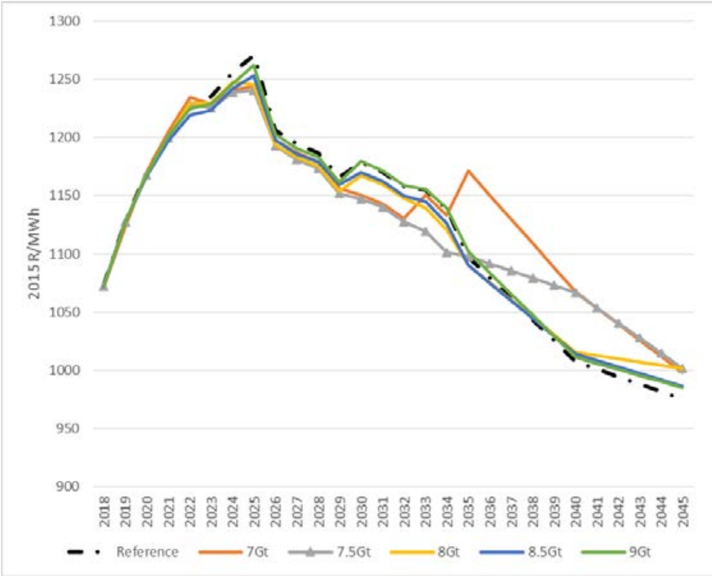

Figure 5 Effect on the electricity price of various GHG emissions budgets in SATIM compared to the reference scenario

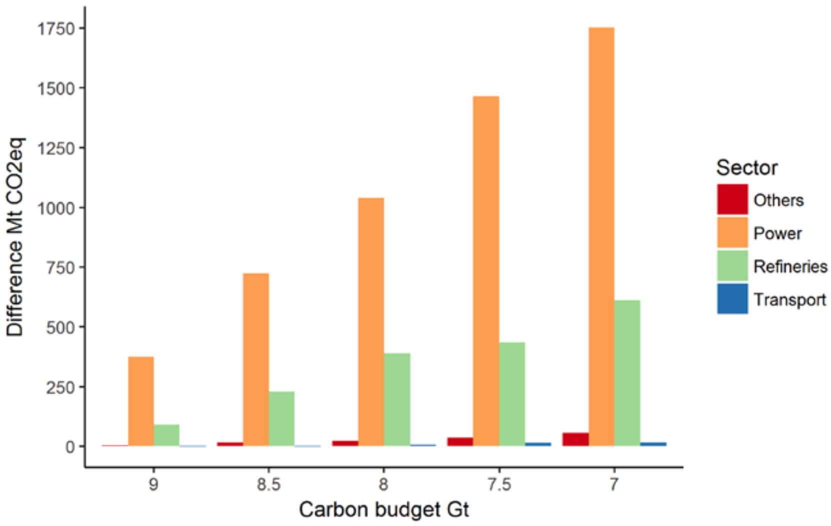

Figure 6: Sectoral contribution to mitigation with decreasing carbon budget – total Mt GHG mitigated relative to reference

The results of the sensitivity analysis to GHG emissions budgets on the economy are presented in Figure 6. At 7.5Gt, the impact on the economy by 2045 is a 16% reduction in GDP compared to the reference scenario. The sudden shift likely points at rigidities in the economic model that require further analysis to assess the extent to which the current CGE modelling framework may over/under estimate costs to the economy under a high ambition scenario: It might not capture all aspects of a large scale economic transformation away from fossil fuels towards new sectors very well. The future economy probably looks different in such a deep transition, with new activities and sectors appearing. The flexibilities in behavioural shifts, consumer preferences, or the future relationship between the utilisation of capital and labour might therefore not be captured very well by the current model. Developing scenarios and technological assumptions for a full sectoral transition to a low carbon society, as in Altieri et al. (2015), was out of scope for the present study. GHG future as was done in the DDPP paper. For the time being we consider this to be beyond a reasonable growth impact scenario for South Africa to handle as a developing country, and we restrict our analysis to exploring the region above 7.5Gt mitigation effort.

From this sensitivity analysis we proceed to use a GHG budget of 7.75Gt as a high ambition scenario for South Africa's contribution to limiting warming to "well below 2ºC" as per its commitment to the Paris Agreement. This GHG budget of 7.75Gt can be achieved with only a small negative effect on the economy in SATIMGE, as a reduction in GDP amounts to only 4% by 2050, compared to the reference scenario. Implications for this scenario are presented in more detail below.

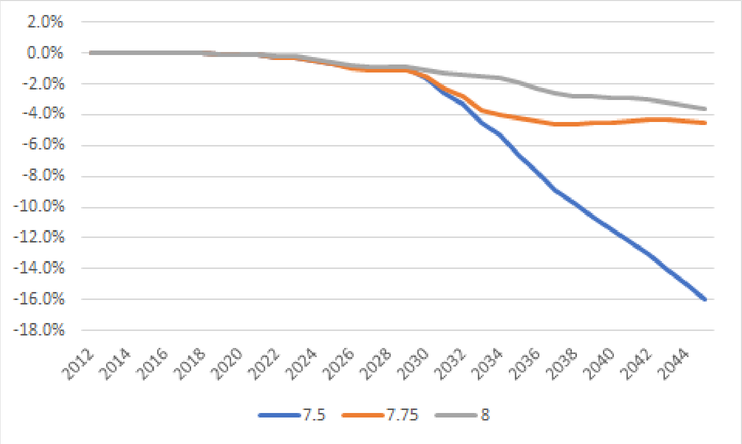

Figure 7: Impact on economy of increasing climate mitigation ambitions of South Africa relative to reference scenario

3.5 Result: A more ambitious next NDC and a "Paris-adjusted" outlook for South Africa's power generation

Economic impacts of a more ambitious NDC

Under the cumulative 7.75 Gt CO_2-eq emissions constraint (for 2020 –2050) real GDP ends up only 4.2% lower by 2050 than in our reference case with approximately 9.5 Gt CO2eq carbon budget (Figure 7). This translates into a 0.14 percentage point decline in annual average growth rate and implies that the level of real GDP experienced under the unconstrained least cost scenario in 2050 would be delayed by only 1 to 2 years.

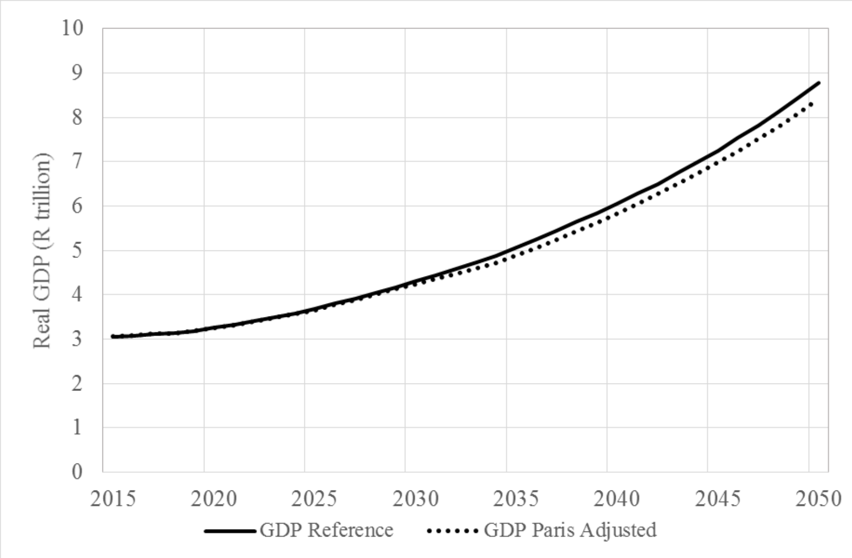

Figure 8: GDP level for the reference scenario and the Paris-adjusted scenario

Lower growth is caused by a slight increase of the total costs of South Africa's energy system. This is true for all sectors to some extent, but mainly for power generation. The cost increase in power generation is due to an increase in the investment requirement for power generation, which is 11.6% higher than in our reference. This has an impact on economic growth through lower availability of investment funds for other sectors. Also, the average electricity price ends up being higher in the second half of the projection horizon (from 2035 to 2050, see Figure 8): By 2050 the electricity price of our Paris-adjusted scenario is 3.4% higher.

How these costs for electricity production compare to those of the draft IRP 2018 is unclear. What is significant though, is that the draft IRP sees unit electricity costs continuing to rise, whereas in our scenarios, electricity production costs decrease once the bulk of investments (replacing old capacity, and retro-fitting for MES) is past (by 2030). It would be logical to expect increasing electricity prices of the IRP to slow down economic development.

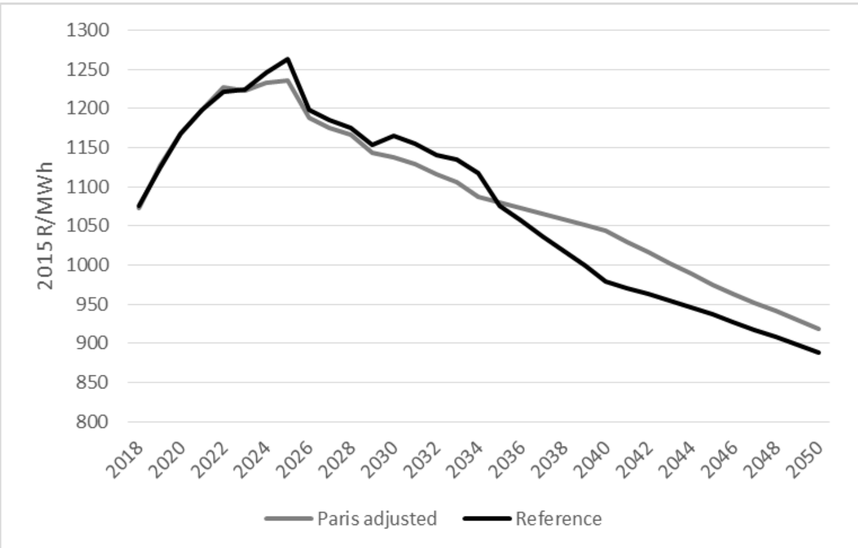

Figure 9: Electricity price comparison for reference and Paris-adjusted scenarios

Table 5: Unit electricity costs (ct/kWh) in the IRP 3 scenario of the draft IRP 2018 (DoE, 2018)

Scenario	*Draft IRP 2018 scenario 3*
2020	Not published
2030	115
2040	132
2050	143

For the 7.75Gt cumulative CO2 emissions for the whole system the carbon budget of our Paris-adjusted scenario Figure 10 shows the trend in the decline in emissions accelerates by 2020.This is the beginning of the emission reduction relative to our reference. The power sector contributes most to this additional mitigation effort with fewer coal units operating overall (and some plants are not retrofitted for MES compliance). Those that do run are operating with lower load factors and result in an electricity carbon intensity of just 8g CO2eq/kWh by 2040 and zero by 2050. In this scenario, as was the case in the reference, wind and solar make up all new generating technologies, and again, requires a large role out of battery storage technologies.

In the refineries sector the largest decrease in emissions starts earlier than in our reference, as CTL facilities go offline between 2035 and 2040 compared to 2045 in the reference scenario. CTL production levels also reduce over the entire period due to lower demand for liquid fossil fuels for transport – driven somewhat by lower GDP, but mostly by higher electrification of transport. As in the reference scenario, transport is largely electrified and thus most of the emissions savings would come from upstream power sector emissions savings.

Although the rate of growth is somewhat lower for the industrial sector relative to the reference scenario, and despite higher uptake of fuel switching to electricity, coal remains the lowest-cost supply option for heat in the industrial sector for a long time. In the long term the industrial sector therefore becomes the largest source of emissions from energy in South Africa – the majority of these from process heat requirements, particularly from boilers.

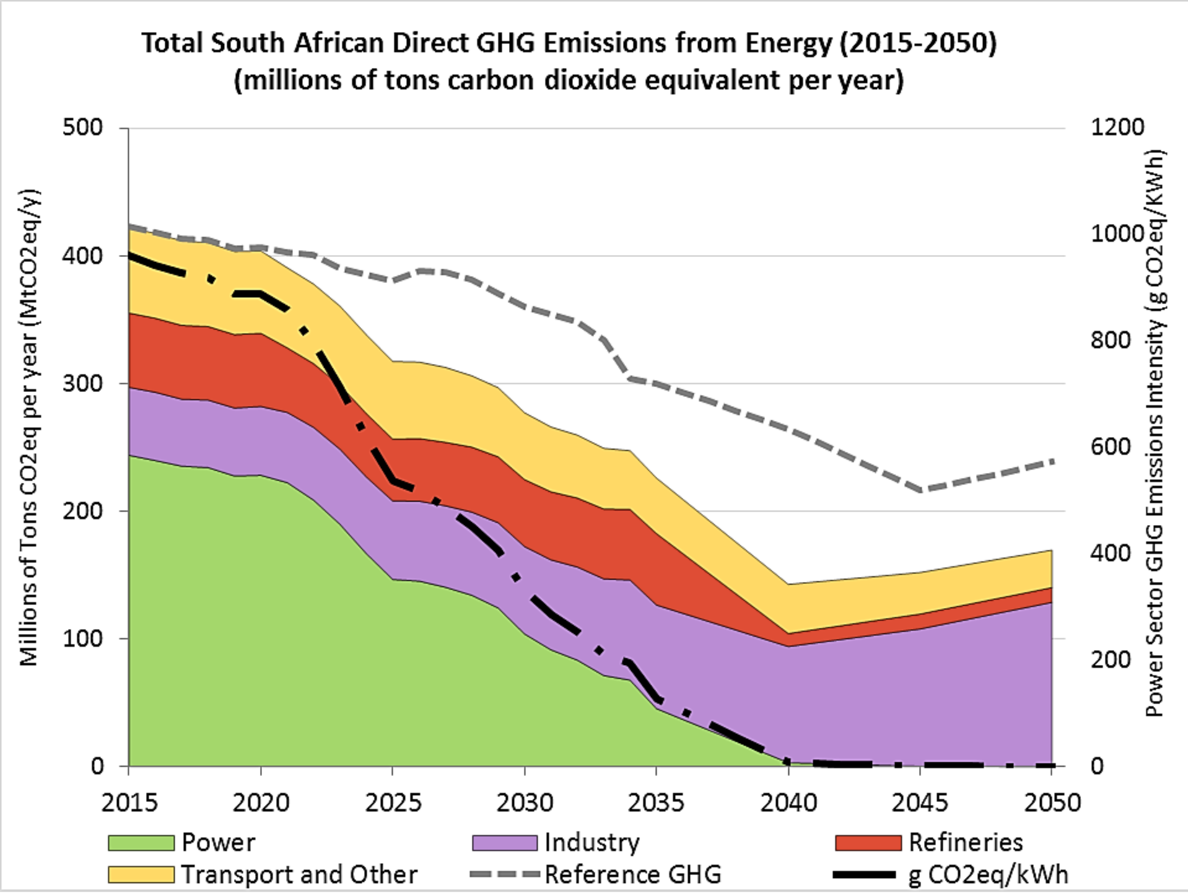

Figure 10: Sectoral emissions in the Paris-adjusted scenario

An outlook for South Africa's electricity sector compatible with the Paris Agreement

For the 7.75Gt cumulative of our Paris-adjusted scenario for the whole system the carbon budget for electricity sector amounts to 2.27 Gt CO2 emissions. The impact on economic growth affected electricity demand - the result is a total demand for electricity of 312 TWh in 2030 and 542 TWh in 2050, and is a slightly lower than the reference scenario.

For the composition of the technology mix for power generation the carbon budget of 7.75Gt cumulative for the whole system yields very similar results to the reference scenario. The only differences are some scale-up of renewables in the mix; but with a slight change in the mix ratio of wind and solar technologies – with more wind in these results than in the reference scenario, but only slightly more solar capacity. This slight change in ratio of the two technologies owes to the higher capacity factor that wind technology offers – helping to meet peak demand in the evenings (we would like to state again here, that there is no capacity credit given to wind or solar technologies to meet the peak).

As with the reference scenario, all new electricity generation capacity is a combination of wind, solar PV, and battery storage. Total installed capacity is 113 GW by 2030 and 240 GW by 2050. The installed capacity is 11 GW higher than the reference case by 2050 despite the lower electricity demand, and renewable energy technologies (wind, solar, micro-hydro, and biomass) provide 62% of electricity generated by 2030 and 99% by 2050 (of this, wind and solar together make up 57.3% and 96.3% by 2030 and 2050 respectively).

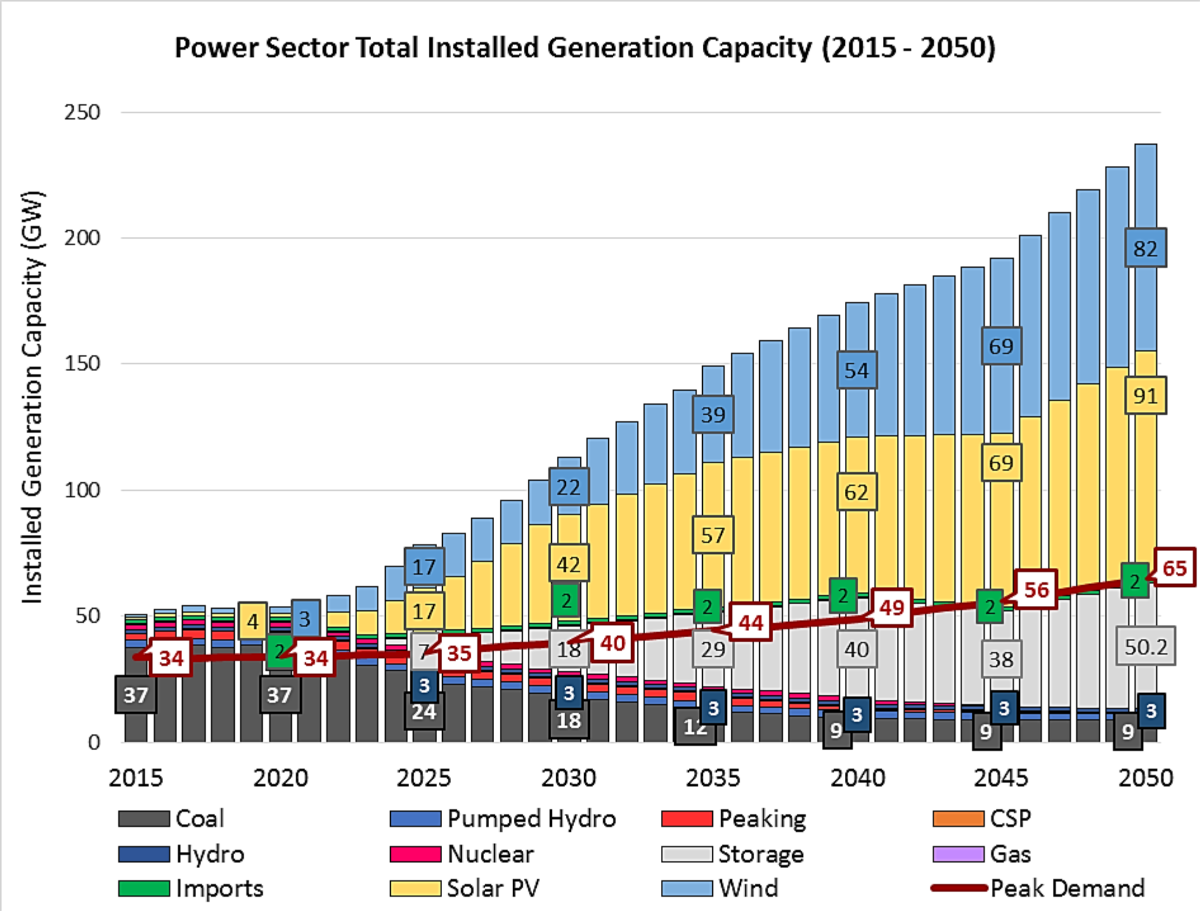

Figure 11*:Total installed capacity in the Paris-adjusted scenario*

4. Discussion and recommendations

4.1 Higher future renewable energy procurement and no new coal

This study has provided a techno-economic assessment to provide an alternative to the Draft IRP 2018 published by the South African Department of Energy (DoE, 2018). It took the newest insights on costs of power generation technologies into account and examined what they mean for a least-cost scenario for South Africa’s electricity sector up to 2050. The findings lead to a significantly different plan for South Africa’s future electricity supply than those of the Draft IRP 2018, which is currently being updated by the Department of Energy. Firstly, the study reiterates findings of other recent studies that a future least-cost electricity supply will come primarily from wind and solar PV. Renewable energy plus flexibility provides the least cost pathway for the electricity sector. In contrast to what the draft IRP suggests, South Africa’s electricity future does not require new coal or nuclear thermal power plants. In fact, adding such power plants would unnecessarily increase South Africa’s electricity costs as found in a previous study (Ireland and Burton, 2018).

This is also recognized in the draft IRP 2018, which states that renewables are now the least-cost power generation technology (DoE, 2018, p.37). The main difference between our least-cost plan and the investment plan of the Draft IRP 2018 is that we see sufficient evidence for a far greater capacity for South Africa to deploy renewable power generation than the Draft IRP (section 2.4), and therefore do not impose a low constraint on its future capacity like the Draft IRP does. We consider the lack of exploration of the constraints for renewable build-out to be a key oversight of the draft IRP, and we strongly recommend the Department of Energy to conduct detailed analysis on this question.

4.2 The introduction of utility-scale battery storage

This study has shown that battery storage can provide a central role in addressing the variability of renewable power generation. A cost-optimal introduction of battery technology starts by 2024 and then gradually grows to a capacity of 50 GW by 2050, supporting a total installed power generation capacity of 185 GW, mostly wind and solar PV. Investigating a large scale procurement programme for batteries and other technologies to provide grid-scale storage and flexibility capabilities for variable renewable energy should therefore be seriously pursued in the near future in South Africa.

The introduction of significant battery storage capacity is a big difference compared to the draft IRP. Even in the DoE's scenario in which there is no build-constraint on renewables, no battery storage technologies are introduced into the plan. Instead, the IRP foresees typical technologies such as gas and hydro to complement the variability of renewables.[10] This is at odds with several recent long term projections for electricity supply globally. For example, the IEA World Energy Outlook (2018) projects 220GW of battery storage in their reference "New Policies" scenario, and doubling to 540GW in a "cheap storage" scenario if storage becomes 70% cheaper than today. Furthermore, neither of these two IEA scenarios reported include Paris compatible emissions reductions (which their "Sustainable Development Scenario" does). The latter would significantly increase global projections for battery storage.

The new insights on reduced costs and cost expectations for battery storage lead batteries to replace gas turbines in our projections as the technology to absorb variability of renewables, provide peaking capability, and improve system flexibility and reliability. Uncertainty analysis on future costs and performance of batteries and other storage technologies was not included in the scope for the present study – this will, however, form an important area of future work. We are nevertheless confident about our assumptions about future costs for battery storage technology, as they have been based on a review of several studies (Ireland et al., 2017). Furthermore, findings for the future power generation mix are quite robust for our assumption about battery costs. In previous studies that used higher future costs for battery storage the outlook for the power generation mix was similar to that of the present study, but with the difference that gas turbines were deployed in combination with renewables, instead of battery storage (Ireland & Burton, 2018). Both studies have in common is that they find a similar decrease in coal-based power generation and a similar increase of renewables.[11]

Depending on the requirements for longer term storage, such as meeting consecutive days of low RE resource availability, it is possible that a combination of battery storage and gas (or other low carbon

[10] The Draft IRP 2018 in its unconstrained renewables scenario foresees by 2050 about 62% of electricity to be suppied by renewables, and 7% of electricity to be supplied by hydro or imported hydro-energy, and 11% by gas-turbine technology (DoE, 2018, p.36, fig 13).

[11] Another difference between the present study and Ireland & Burton (2018) is that in this study we have included MES requirement on the coal plants, updated coal prices for stations, and included batteries - and thus obtain a faster introduction of renewables into the South African power generation system.

generating technologies such as CSP) could be used effectively. Despite having our results showing only battery storage, we would like to emphasise that storage capacity and flexibility will likely be made up of a variety of technology options that complement the variability of renewable energy (RE). Inter-sectoral linkages and ‘power-to-X’ technologies are another promising route, e.g. flexible charging of electric vehicles, thermal storage for industry, or flexible production of hydrogen through electrolysis for use in power-to-gas, and/or the iron and steel industries, power-to-power, or power-to-liquids applications. These power-to-X technologies are options that are already being explored in many countries to address RE variability (Lund et al, 2015; JRC, 2015). Flexible demand response and time-shifting enabled through so-called “smart-grid” technologies are also foreseen to provide similar flexibility to the South African energy system (Ireland et. al., forthcoming). Their inclusion is an important area for future work in energy modelling, and we therefore agree with the draft IRP 2018 that further study into technology options to absorb the variability of renewables is important.

4.3 Affordability of more ambitious climate policy

Finally, this study examined the effects on the energy system and economy of more ambitious climate change mitigation policy than currently pursued by the South African government. We acknowledge that further analysis is needed to assess the extent to which the modelling framework may over/under count costs to the economy under a high ambition scenario. Such analysis would enter new territory as it requires a rich set of scenarios and assumptions about future technology and behaviour in all sectors, not only energy.

With current knowledge on economic and technological change we find a pathway in which South Africa respects its commitment to the Paris Agreement goal of limiting warming to well below 2ºC and that is economically feasible. More ambitious mitigation policy is possible through rapid decarbonisation of the electricity sector and fuel switching. This pathway reduces emissions to below the level of the low-PPD by 2050 and translates into an only 4% lower GDP by 2050, relative to reference economic development without an emission constraint – thus translating to only a delay of between 1 and 2 years in obtaining the same GDP.

In this Paris adjusted scenario, well below 2°C compatible pathway, it is most economical for the South African economy to only allocate 2.3 Gt of cumulative CO2 emissions for the period 2020 to 2050 to the electricity sector. This leaves ample cumulative greenhouse gas emission space to be used by for South Africa’s industry and transport sectors to support South Africa’s economic development. The IRP 2018, which currently allocates more than 5Gt of greenhouse gases to the electricity sector, should therefore significantly reduce this allocation in line with a least cost full sector allocation of South Africa’s greenhouse gas emissions space to different sectors. Phasing out coal in the power sector by 2040 is a key element in this cost optimal way to achieve the well below 2°C compatible emissions pathway.

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