ESRG

ENERGY SYSTEMS RESEARCH GROUP
University of Cape Town

Assessment of new coal generation capacity targets in South Africa's 2019 Integrated Resource Plan for Electricity

Bruno Merven, Jesse Burton, Patrick Lehmann-Grube

01 November 2021

Executive summary

The Integrated Resource Plan (IRP) 2019 includes 1.5GW of new coal fired power plants in the final policy-adjusted scenario. This is despite substantial evidence that new coal power is not necessary for energy security, is more costly compared to alternatives, and will greatly increase greenhouse gas emissions in a sector where there are cost-competitive and commercially viable alternatives. This is in contradiction with the government's commitment to the goals of the Paris Agreement, its stated aim of achieving "net zero" carbon emissions by around 2050, and it being well-established in the literature that coal phase out before mid-century is needed to meet the Paris Agreement temperature goal of limiting warming to well below 2°C and pursuing efforts towards 1.5°C above pre-industrial levels.

Building on an earlier study to analyse the implications of the 2014 coal power procurement programme, this study assesses the impacts of the inclusion of 1.5 GW of new coal-fired power plants in the IRP 2019, using the South African TIMES model (SATIM).

Because proponents of new coal plants typically use three arguments in support of new coal, namely that it is cheap; that it is important for jobs; and that power systems require coal plants for "baseload", the study will briefly outline the literature that refutes these claims, using examples and evidence globally and in South Africa. In fact, an examination of the costs of coal compared to alternatives in South Africa and elsewhere in the world demonstrates that coal power is no longer competitive in many countries nor in South Africa. When we assess the employment creation opportunities in South Africa of different power system build plans we find that the highest employment creation across the economy comes from a high renewable system and that a high coal future actually leads to significant job losses in the country compared to a renewables-dominated build plan. We then briefly describe how the technical requirement for coal plants - long perceived as necessary because power systems had depended on coal and gas for so long - has changed fundamentally across the world, as many electricity systems with higher penetrations of renewable energy now demonstrate. We also briefly explain the challenge of achieving the Paris Agreement temperature goals to limit

average global temperature rise, and why, at a global level, new coal plants in the power sector are not compatible with these goals and will make achieving them more difficult.

After having reviewed the state of knowledge on costs of coal vs renewables, job creation potentials and the operation of power systems, we use our SATIM 2021 model to explore the consequences of adhering to the new coal capacity targets contained in the 2019 IRP. As the world has changed strongly since this IRP was concluded, we investigated two scenarios:

A Reference Scenario that takes into account recent trends in the decline of economic growth rates, the economic impact of Covid-19, lower electricity demand, and Eskom's fleet performance, etc. In other words, a scenario that most closely reflects current and projected reality in South Africa. We have updated this scenario, which diverges from the electricity system modelled by the IRP 2019, since following the IRP2019 build plan would provide significantly more generation capacity than needed in the 2020s, due to the slowing economic growth since 2018 and the large economic contraction during Covid, but also due to the deficiencies in forecasting in the IRP (which the IRP itself explicitly acknowledged but nevertheless used). The reference scenario thus develops an optimal build plan for the new situation we find ourselves in. We then force in 1.5 GW of new coal to document the impacts of this decision. This case also assesses two sensitivities - meaning we assess the effects of a different input assumption while holding other aspects of the scenario equal - on the drivers of the cost of new coal for the electricity system, namely an optimistic renewables cost sensitivity and a higher externality cost sensitivity.

In the second scenario the "climate policy scenario", we analyse the new coal decision in the context of South Africa's recently revised Nationally Determined Contribution (NDC) where a 2030 target has been specified to range from 350 Mt to 420 Mt CO_2-eq. Two cases are analysed here, with one meeting the 350 Mt level and the other meeting the 420 Mt level in 2030. The 420 case is found in the Addendum, as it was analysed after Cabinet approval of the updated NDC.

The lower range of 350 Mt is also aligned to the top end of South Africa's "fair share" range of emissions for limiting warming to 1.5°C, i.e. it falls into the very top of a 1.5°C aligned target for South Africa, when applying the fair share methodology developed by the Climate Equity Reference Project. Such a methodology considers historical responsibility for climate change, capability to act (measured though national income), and emissions related to meeting basic needs/living standards. This means that the methodology considers South Africa's status as a developing country (albeit a carbon-intensive one) and its need to address development priorities, as well as global considerations of equity.

Our key findings from this modelling are:

- If a new least cost plan were to be adopted, it would not contain any new coal power investments.
- Forcing new coal into a build plan that meets electricity demand consistently to 2030 and beyond would incur additional costs of at least R23bn in the reference case, or a 0.5% increase in the electricity price.
- The new coal capacity would increase cumulative greenhouse gas emissions to 2050 by 289 Mt CO_2-eq compared to the optimal build plan that excludes new coal plants.
- The sensitivities on lower renewables costs and higher externality costs show that the costs could be even greater, at R28.7 bn and R23.8 bn, respectively.

Table 1 Summary of additional costs with forced coal, Reference Scenario and sensitivities

Summary Costs		Reference Scenario	Optimistic RE Case	High Externality Case
Increase in Total Discounted Electricity System Costs	Billion Rand	23.0	28.7	23.8
Increase in average unit cost	c/kWh	0.81	1.12	0.94
Increase in average unit cost	%	0.48%	0.61%	0.48%
Increase in cumulative investment	Billion Rand	7.2	18.4	8.3

- The additional coal also reduces economic growth by 0.11% in 2030 and 0.08% in 2040 compared to the reference scenario without forced coal, and results in job losses of around 25 000 in 2030 across the economy.
- For the climate policy scenario, greenhouse gas emissions are capped to achieve the updated Nationally Determined Contribution range of 350 and 420Mt in 2030.
- To meet the 420 Mt target in 2030 would increase the power system costs by R74.4bn.
- To meet the 350 Mt target in 2030 while also building new coal would force Eskom's existing and cheaper coal fleet to retire earlier and run less to make space for the greenhouse gas emissions from the new coal plants. The new coal capacity also leads to faster uptake of renewable energy and faster electrification of demand sectors to offset the cumulative emissions impacts of the committed coal. This incurs additional costs of R109 bn in the power sector compared to achieving the climate policy goal without new coal capacity forced in.

Table 2 Comparison of additional costs of forced coal in reference and climate policy scenarios

		Reference	**Climate Policy**	
			420	350
Increase in Total Discounted Electricity System Costs	Billion Rand	23.0	74.4	109
Increase in unit cost	c/kWh	0.8	2.5	3.0[1]
Increase in unit cost	%	0.5%	1.3%	1.5%
Increase in cumulative investment	Billion Rand	7.2	61.8	139

Our modelling thus shows that under the two scenarios tested, new investments into coal-based power generation are costly and unnecessary for South Africa. Building the planned 1.5 GW would both increase greenhouse gas emissions and power system costs, driving up average electricity costs by 0.4-3.0[2] c/kWh or 0.5-1.5% in a reference and climate policy future respectively. Not only does forcing in new coal raise costs when climate goals are not

[1] The unit costs were updated since the report published 27 August 2021. In the earlier version the unit cost included CO_2 marginals resulting from the CO_2 constraint. In this version with addendum, we now report the unit cost using the planned CO_2 tax rather than the marginal to be more consistent with how system costs were reported (also using planned CO_2 tax and not the marginal).

considered, but it also makes the achievement of South Africa fair share contribution to climate change vastly more expensive to achieve.

In effect, South African users of electricity are being asked to pay more for electricity that increases emissions of air pollutants and greenhouse gases compared to a scenario where the South African government commits to no new coal plants. In a world where climate action is pursued, building new coal leads to a more rapid closure of Eskom's coal fleet and replacement with new, more expensive coal plants, and requires that more costly mitigation actions are pursued to allow space for the new coal. Based on our analysis, the new coal capacity in the IRP 2019 is not necessary for energy security, will raise greenhouse gas emissions unnecessarily, and is more costly than alternatives.

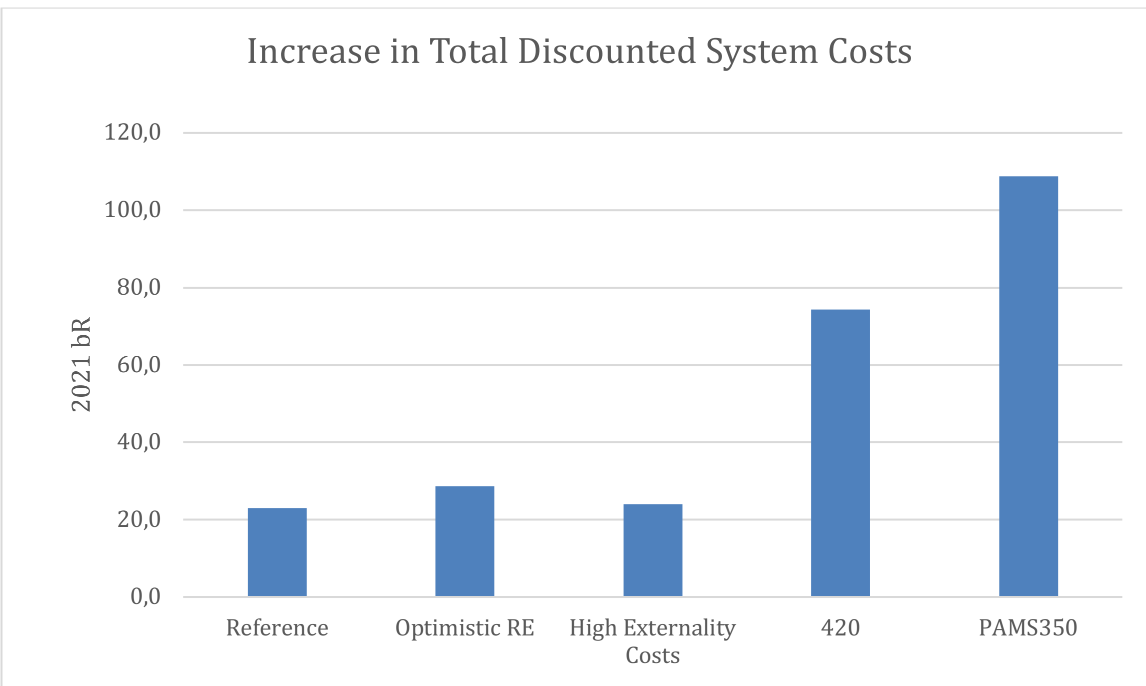


Figure 1 Increase in total discounted power system costs with forced coal, all scenarios

List of Figures

List of tables

Introduction

The Integrated Resource Plan 2019 included 1.5GW of new coal fired power plants in the final plan, despite substantial evidence that new coal power is not necessary for energy security and is more costly compared to alternatives, both in South Africa and globally. Furthermore, new coal power would greatly increase greenhouse gas emissions in a sector where there are cost-competitive and commercially viable alternatives to coal power and hence some of the cheapest options for mitigating greenhouse gases. This is despite the government's commitment to the goals of the Paris Agreement, its stated aim of achieving "net zero" carbon emissions by around 2050, and it being well-established in the literature that coal phase out before mid-century is needed to meet the Paris Agreement temperature goal of limiting warming to 1.5^{o}C above pre-industrial levels.

Building on earlier analysis undertaken to assess the implications of the 2014 coal power procurement programme, this study will assess the impacts of the inclusion of 1.5GW of new coal-fired power plants in the IRP 2019. Using the South African TIMES model (SATIM), the study follows that methodology in Ireland and Burton (2018), albeit using an updated model and scenarios that account for changes in key input assumptions (for example demand for electricity in the post-covid recession, updated cost of technologies). In each scenario, we assess the differences in total power system costs, the cost per unit of electricity generated, the greenhouse gas emissions, air pollutants, and water use when the build plan is lowest cost (i.e. excludes the coal capacity) and when the build plan includes the 1.5GW of new coal capacity contained in the IRP 2019. For the reference scenario, we also assess the impact on GDP and on net jobs of committed coal capacity versus a build plan that excludes the new coal.

The study first discusses the economics of coal versus renewables globally and in South Africa, and then outlines the socio-economic outcomes of different electricity sector policy choices. Section three explains how power systems are evolving to operate with lower levels of coal plants and why new coal plants are not needed for supply security. Section four summarises the global literature on new coal and climate policy, to show that coal is not compatible with global goals contained in the Paris Agreement. Finally, the modeling analysis shows that coal plants will raise costs in the power sector and for consumers. This finding is robust to different futures and input assumptions, which we show using three scenarios or 'futures', and several sensitivities.

Coal is more expensive than alternatives and does not feature in lowest cost electricity futures

In the last decade there has been a revolution in the energy industry that has resulted in a rapid and growing uptake of renewable energy. In the last 10 years, new capacity additions have shifted globally from fossil fuels to renewables, with 80% of new additions in 2020 coming from renewables (IRENA, 2021). This shift has particularly displaced new additions from coal. In 2019, renewables and nuclear combined generated more electricity than coal (IEA, 2020). While climate considerations have played a role in the proliferation of renewable energy, the underlying reason for increased renewable energy deployment has been the steady decrease in technology costs. Coupled with growing concerns about air pollution and climate policy supporting renewables uptake, new additions of renewables have surpassed fossil fuels in the power sector since 2016 (IEA, 2017).

Many independent studies across multiple power systems and globally now show the declining economic and financial viability of coal-fired power plants as well as the ascendency of renewable energy as the most cost-efficient alternative. In many countries and markets, renewables are now cheapest in direct capital costs, in levelised cost of electricity (LCOE) terms[2], and when integrated power system analyses are undertaken (as in this modelling study, the DMRE's IRP, and in work by the CSIR, where the power system as a whole is analysed, not project or technology level capital costs or LCOEs).

[2] The levelized cost of energy (LCOE) refers to the total cost of energy generation over a plant's lifetime in relation to the total energy produced in that lifetime.

South Africa is no exception as illustrated by falling auction prices over the past ten years in the Renewable Energy Independent Power Producers Procurement Programme (REIPPPP), the growing uptake of renewable energy for own use in e.g. the commercial sector, and in a variety of studies that assess what a least cost future power system for the country looks like (i.e. a power system that meets demand at lowest cost, and without artificially forcing in new generation capacity or specifying policy options to be pursued).

Comparing renewable and coal electricity costs internationally

Since 2009, wind and solar PV costs have decreased by 71% and 90% respectively (see Figure 2) (Lazard, 2020). Analysis by the International Energy Agency shows that in markets with good resources and cheap financing that solar power is the cheapest form of energy in history, and that at a global level "solar PV is consistently cheaper than new coal" (IEA, 2020: 18). Thus, at a global level the LCOE of solar PV and wind energy are generally cheaper than or cost-competitive with coal and other fossil fuels across various scenarios, including where subsidies for renewables are excluded.

The decrease in renewable energy costs has resulted in increased deployment of and investment in renewable energy capacity. While most investments initially took place in developed countries, in recent years developing countries have matched investment in new renewables, to the point that developing countries accounted for 54% of renewable energy capacity investment in 2019 (Frankfurt School, 2020, 26).

The decreasing costs of renewables means that new wind and solar outcompete coal in almost 100 countries covering two-thirds of the world population (Bloomberg, 2020) (Figure 3). The downward trend in LCOE of renewable energy is expected to continue based on enhanced uptake and on current auction results (IRENA, 2020).

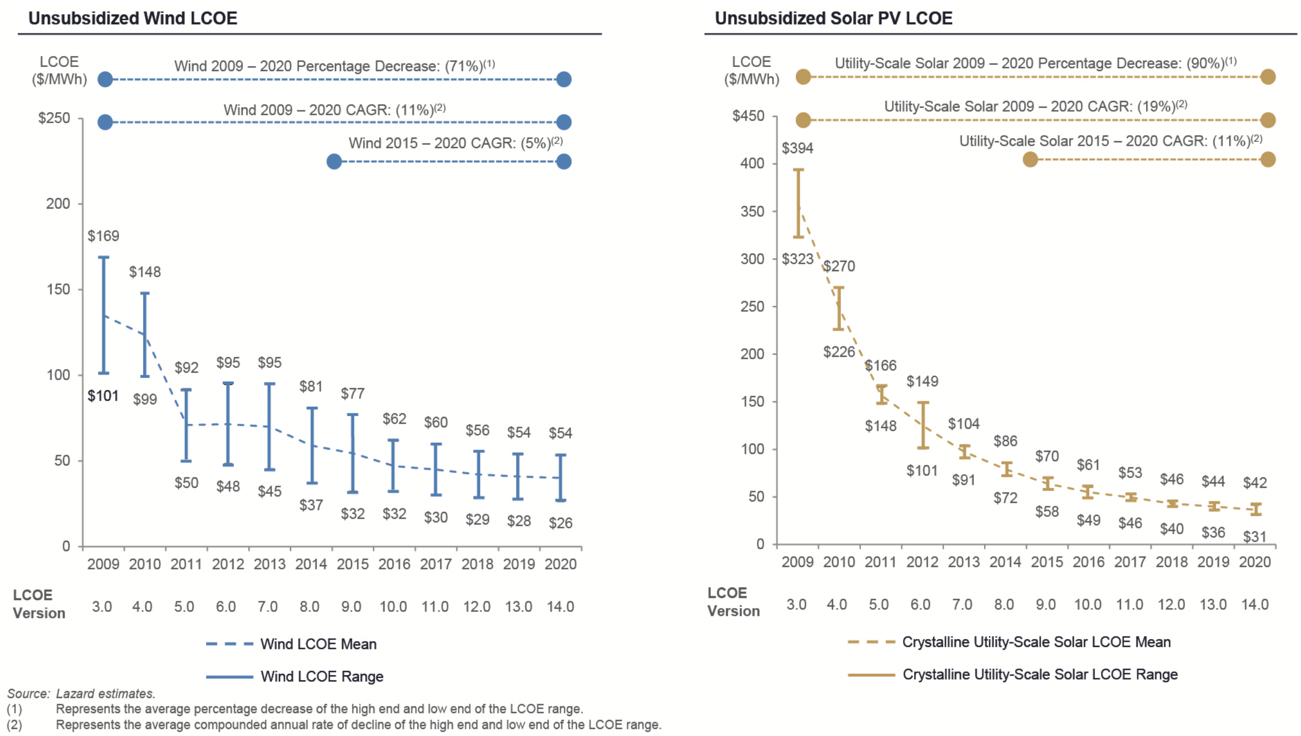


Figure 2 Levelised cost of wind and solar, 2009-2020 (Lazard, 2020)

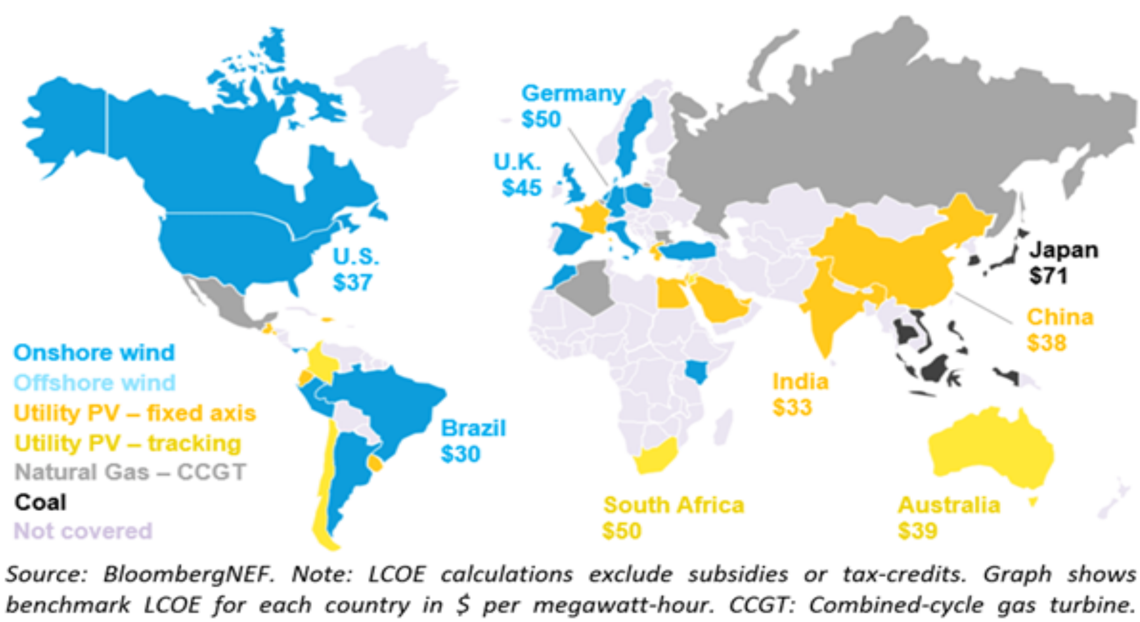


Figure 3 The cheapest source of new bulk electricity generation by country, 2020 H1 (Bloomberg, 2020)

In several countries, the costs of renewables have fallen to the point that not only is new coal uncompetitive against new renewables, but new renewables are often cheaper than the operating costs of existing coal plants, i.e. the capital and operating costs of new renewables plants outcompete the operating costs of coal (Figure 3) (Lazard, 2020; Carbon Tracker, 2020).

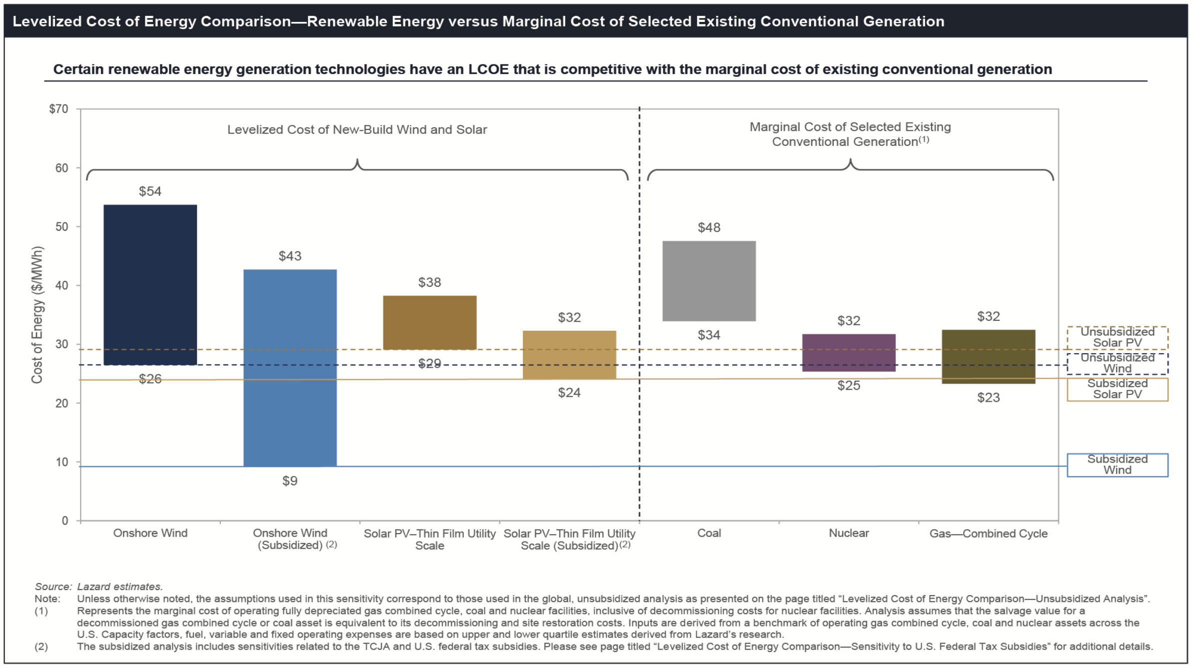


Figure 4 Levelised cost of renewable energy versus marginal costs of coventional generation technologies (Lazard, 2020)

In many countries, the discussion is thus no longer about whether new coal is competitive with new renewables, but rather about how costly the existing coal fleet is for consumers. Carbon Tracker has shown that around 42% of the world's coal fleet runs at a loss and that in many countries the immediate closure of coal plants would save consumers money. For example, 79% of the United States coal fleet is uncompetitive, compared with 81% in the European Union (Bodnar et al., 2020). In the EU, phasing out and replacing these uncompetitive coal plants with renewables and storage would generate $16 billion in savings in 2022 (Bodnar et al., 2020). For the United States, Clack et al. (2019) found that local wind or solar could provide the same amount of electricity more cheaply than 74% of the national fleet in 2018. By 2025, the "at-risk coal" would increase to 246 GW – nearly the entire U.S. fleet. Furthermore, a detailed assessment of Colorado coal phase out by Clack (2018) found that the state would save $2.5 bn by 2040 by replacing its coal fleet by 2025 with a mix of wind, solar, storage and natural gas, minus the cost of repaying all remaining coal plant capital.

In countries where the cross-over between coal and renewables has not yet occurred (for example due to lack of experience in renewable roll out or lack of policy frameworks), Carbon Tracker still estimates that new RE will outcompete almost all existing coal on a long-run marginal cost basis in almost all countries by 2030 (Carbon Tracker, 2020). It will thus become cheaper in this decade to build a new renewable plant than to operate an existing coal plant across almost all countries globally.

Looking beyond plant level economics, power system analysis also consistently shows that renewables offer the cheapest option for new capacity. Power system analyses are useful because coal proponents regularly argue that even if cheap, renewables still need "back up" for 'when the wind is not blowing and the sun is not shining'. Power system analysis accounts for the features of available energy technologies/resources, including wind and solar, and assesses the need for the costs of complementary system requirements to maintain security of supply in an integrated framework. In other words, such analysis caters for meeting electricity demand, including situations where "the wind is not blowing and the sun is not shining". Such analyses also consistently show the important role played by new renewables in secure and reliable systems that deliver power at lowest system cost, even when accounting for those complementary costs. These complementary costs are a feature of all power systems, where a portfolio of resources with different characteristics is typically required to meet demand[3].

There are multiple analyses that demonstrate that (i) new coal plants are not cost optimal in large coal-using countries, (ii) coal closures would benefit consumers, and (iii) high coal and high renewable power plans are comparable in cost. Such examples include:

- Australia (AEMO, 2020);
- Germany, Poland, and Czech Republic, where earlier phase out of coal and replacement with renewable resources will decrease wholesale power prices (Agora, 2020).

[3] The overall costs of financing, constructing, operating and decommissioning such a portfolio of resources, as represented in in energy models, translated into today's money, is called the total discounted system cost.

- In Poland, notably, approximately 45% of all coal-fired plants are projected to be unprofitable by the end of 2020 (Czyżak and Wrona, 2021).
- Vietnam (EREA and DEA, 2019); and
- India (Pachouri et al. 2021).

There is also evidence that new coal is not optimal for other reasons in developing countries, including import costs (Pakistan); net zero or climate commitments (e.g. China); local environmental impacts (Mexico); excess supply (Indonesia); and growing research into coal closures and just transition in emerging and developing countries, including Indonesia, South Africa, Mexico, Colombia, Argentina, and India.

Comparing renewable and coal electricity costs in South Africa

The falling costs of renewables at the international level has been echoed in South Africa, although delays in procurement mean the latest figures for new renewable projects are somewhat outdated. Nonetheless, when the last auction under the REIPPPP was held in 2015, renewables were approximately 60% cheaper than new coal plants on an LCOE basis. Figure 5 shows the realised prices for wind and solar, and the auction prices bid by the coal IPPs in the baseload IPP programme (in 2016 Rands). As can be seen from Figure 4, the actual price in 2016 (i.e. what project developers would be paid) per kilowatt hour for solar and wind was R0.62, whereas the tariff for the coal IPPs was R1.03.

Given the international drop in prices since then, renewables are almost certainly even cheaper now when compared to new coal plants. That difference will only grow larger, since renewables are expected to continue to fall in price, including in South Africa (Roff et al., 2020).

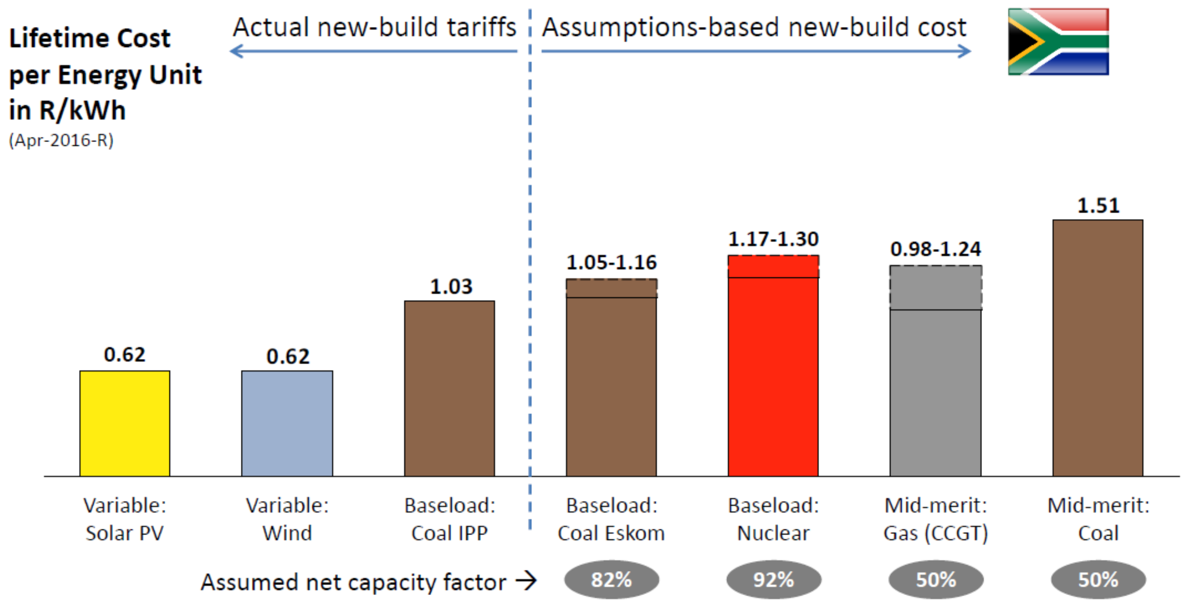


Figure 5 Levelised cost of electricity from different generation sources (Bischof-Niemz and Fourie, 2016)

Finally, there are many local power system studies showing that new coal is not part of a least-cost power plan for South Africa, including several studies from the University of Cape Town, the Centre for Scientific and Industrial Research (CSIR), and CSIR working with Meridian Economics.

Using the South African TIMES model, the University of Cape Town's (UCT) Energy Systems Research Group (ESRG) has shown in more than five different studies that a least-cost build plan would not include any new coal-fired plants. For new coal plants to form part of a modelled capacity expansion plan requires that they be artificially forced into the model.

Ireland and Burton (2018) looked at the impact of including the Thabametsi and Khanyisa coal IPPs in the South African power system and found that the two plants result in a significant and costly deviation from a least-cost scenario. If built, the coal IPPs (863MW) would have led to additional electricity costs of R3 billion per year between 2022 and 2025, and an additional R1.5 and R2bn per year from 2025 to 2050 (Ireland and Burton, 2018: 28). Overall, the coal IPPs would have led to R19.8bn rand in additional system costs compared to a least-cost build plan, adding over 200 Mt of greenhouse gases in their lifetimes. In a scenario where South Africa also achieved its National Climate Change Response White Paper target of the low-PPD, the additional costs of the plants would have reached R28bn in total discounted system costs[4].

Further studies by the ESRG have also found that coal does not feature in a least-cost new build mix, for example Burton et al. (2018); McCall et al. (2019); Merven et al. (2019); Merven et al. (2020). Instead, high levels of new wind and solar dominate the power system, along with flexible, complementary generators. And when accounting for climate policy objectives as outlined in the National Climate Change Response White Paper and the current Nationally Determined Contribution (NDC) under the Paris Agreement, renewable energy remains the most cost-effective option for achieving ambitious climate mitigation goals (Merven et al. 2021), even outcompeting new nuclear. Furthermore, the Burton et al. (2016) and McCall et al. (2019) analyses show that the earlier retirement of coal plants is a key mitigation action for South Africa.

The cost implications of adding new coal capacity are further evidenced in the 2020 Systems Analysis report of the Centre for Scientific and Industrial Research (CSIR) and Meridian Economics, which found that a least-cost new build mix till 2050 would not consist of any new coal capacity (Wright and Calitz, 2020). A least-cost new build power system consists of solar PV, wind, storage, and gas. The absence of coal in a future least-cost new build mix is also confirmed in previous studies by the CSIR (Wright et al., 2017a; Wright et al., 2017b; Wright et al., 2018), as well as additional studies by Meridian Economics, including analysis showing that early retirement of coal plants would result in considerable savings (Steyn et al., 2017) and that a 2040 coal phase out in South Africa would come with only a very small system cost increase (Roff et al., 2020).

The findings of local studies are further reinforced by international studies focused on South Africa. Using its own model, the National Renewable Energy Laboratory (NREL) in the United States determined that the most effective least-cost mix to 2050 would include no new

[4] The discounted system cost is the annual cost of the modelled system over the model period, converted into present value terms (i.e. today's money); this allows the costs of different systems to be assessed on comparable terms.

additional coal (Chartan et al., 2017). Oyewo et al. (2019) also found that in a cost-optimal pathway no coal or nuclear power is installed.

Coal creates fewer jobs than alternatives

Various studies have assessed the employment effects of energy policy choices in South Africa. They find that overall, RE creates more jobs than coal. However, different studies assess this question differently depending on the methodology used and type of analysis being undertaken (for a review of how jobs are counted, what are direct, indirect and induced jobs, see Tyler and Steyn (2018).

Beyond direct operations and maintenance (O&M) jobs in power plants (summarised in the table below), the analyses described in this section using SATIMGE (an integrated energy system and economy-wide model) accounts for economic interlinkages across sectors. The indirect employment (i.e. from coal mining and transport) is captured in the economic model by the links between the coal sector, trade and transport margins and the electricity sector. The construction jobs are captured by the sectors that are "brought into action" each time capacity in the power sector is increased. This would include the construction sector but also machinery, services etc. In addition to the indirect effects (not included in the table here but included in the modelling framework), are the induced effects, i.e. that the employees from the power sector now earn salaries and will spend this on things in the economy that will also have an impact.

The main advantage of the framework used in SATIMGE is that all these effects are taken into account and we can report the overall net effect on employment. The data in Tables 1 and 2 is important as it is used to specify the employment intensity of the power sector in the CGE depending on the capacity/production mix as observed in the energy model. The model can therefore assess the employment effects along the value chain of different energy choices.

This does not mean that the transition is frictionless or that supportive policies are not needed to ensure that coal workers and communities are supported during the transition away from coal – just transition planning, including worker transitions, economic diversification, social protection, and social dialogue are necessary and important. However, the evidence suggests that expanding coal for just transition reasons has worse employment outcomes overall. Hence targeted policies for workers and communities should be put in place at far lower cost than subsidising new coal (see for example, Tyler & Renaud for a summary of approaches to costing Just Transition and required just transition investment needs in South Africa).

Comparing renewable power jobs to coal power jobs

A comparison of the reported jobs numbers in the REIPPPP, the DMRE's Integrated Energy Plan figures, and Eskom generation figures shows that considerably more jobs are created per unit of electricity produced by wind and solar than by coal in terms of direct jobs in operation and maintenance of plants.

Table 3 Estimates of direct O&M labour Intensities for energy technologies (Merven et al., 2019)

	Jobs/TWh				Jobs/GW			
	PV	Wind	Coal	Nuclear	PV	Wind	Coal	Nuclear
REIPPP round 1,2	153	62			376	196		
REIPPP round 3	282	170			691	540		
McKinsey/IEP	107	127	28	60	262	405	184	420
EIA_2017	44	22			107	69		
Eskom			35.7	92.1			206	645
This Study	**153**	**98**	**50.8**	**92.1**	**376**	**311**	**333**	**645**

Table 4 Base year (2012) derived employment intensities by sub-activity

	Generation	Transmission	Tx+Other Corporate	Other corporate	Distribution
Eskom 2012	12.42	1.67		7.83	22.08
Munics 2012	1.08			3.7	23.48
Combined 2012	13.50	1.67		11.55	45.56
This Study	15.22		9.77		47.28

Given differences in capacity factors, it is typical to normalize the comparison to energy produced (i.e. jobs/TWh[5]) for purposes of comparison across technologies. Although there may be more jobs/GW[6] installed in coal than in wind, the lower capacity factor of wind increases the total jobs needed to meet a given level of demand. This is because different power plants/technologies have different capacity utilization – for example a coal plant will have 75% capacity utilization and a solar plant will have 25% capacity utilization. Higher installed capacity (GW) of renewables is therefore needed to provide the same electricity (TWh) as a coal plant. Jobs numbers are often reported as linked to production (TWh) so as to compare apples with apples, although employment is much more strongly linked to installed capacity (GW). For example, a peaking gas plant may run at 15% in a bad load shedding (or wind/solar) year and only at 1-2% in a better load shedding /wind solar year. However, it will employ the same number of workers that year regardless.[7]

Several studies have shown that the total jobs lost in coal mining and coal power are offset through increased employment in the renewable power sector and elsewhere in the economy. In comparing the net job creation of different government electricity planning scenarios (IRP 2016, IRP 2018, DEA and CSIR), Hartley et al (2018) found that the CSIR's least-cost scenario created the highest numbers of jobs in the power sector and across the economy compared to the government's IRP scenarios. The CSIR and UCT study states that "*a least cost electricity pathway with high penetration of renewable energy not only creates more jobs in the electricity sector (enough to offset decreases in the coal mining sector) but also creates the highest number of jobs in the whole economy*."

This is supported by an analysis of 69 scenarios developed by ESRG to assess different climate policy targets for 2030, undertaken for the Presidential Climate Commission. Figure 6 shows that for quite high differences in greenhouse gas emissions in 2030, the employment losses in

---

[5] TWh is a unit of measurement of electricity generated (Terawatt-hour = 1,000,000 MWh)
[6] GW is a unit of measurement of the capacity of a plant ie how much power it can generate (Gigawatt = 1,000 MW)
[7] Hence more GWs of installed capacity is needed in high renewables futures; nonetheless, they are still the most cost effective option for most power systems, as described in the preceding sectors.

the coal mining sector (yellow dots) are offset by gains in the electricity sector (red dots) as a whole. The green dots show the combined jobs in coal and power. Of course, this is not a frictionless process and consideration must be paid by the government to ensuring coal workers are supported in the transition.

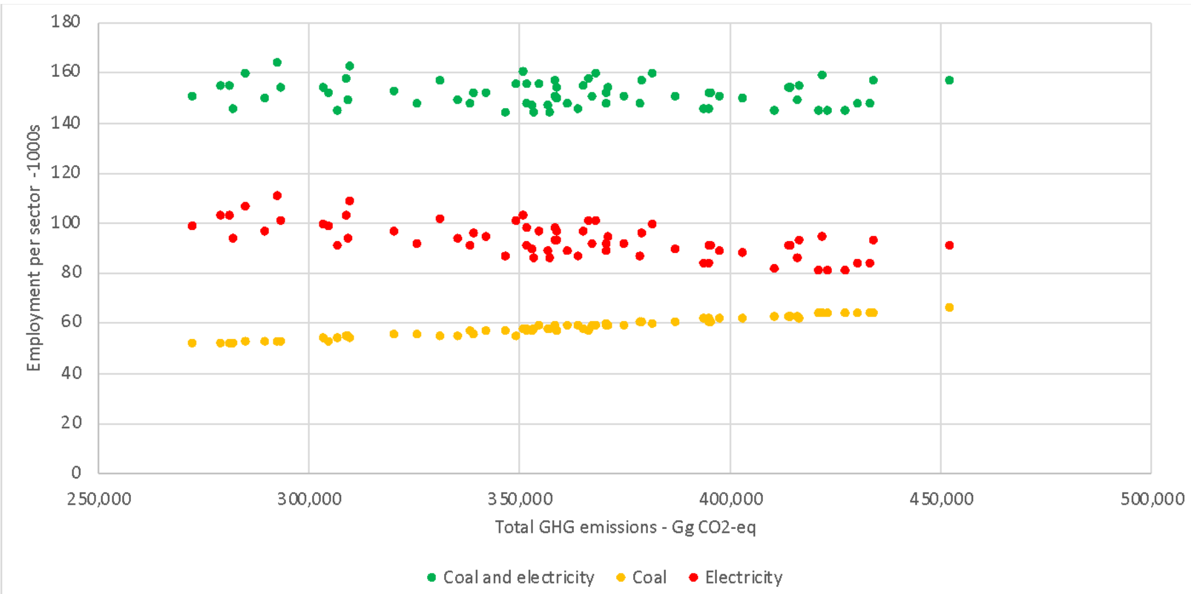


Figure 6 Total employment in the electricity sector (red) and coal sector (yellow) in 2030,for 69 cases, plotted against total GHG emissions in 2030. The combined figure for both sectors is in green (ESRG, 2021)

At an economy-wide level, higher renewable penetration can have increased benefits on employment (Merven et al., 2020), primarily because cheaper electricity has broader positive economic effects, which allows firms to grow and households to spend. Thus, while wind and solar provide more jobs/TWh than alternatives in the power sector, there are also wider benefits in the indirect and induced job creation potential.

The corollary also holds. For example, the renewable limits in the IRP 2019 – if kept in place indefinitely - would not save jobs in the long run and would result in higher electricity prices post-2030, compared to a build plan focused on renewables and flexible capacity. Constraining the roll out of new wind and solar (as in the IRP 2019, which caps annual renewable energy capacity) in the long-term has negative effects on the electricity price and the economy, with new nuclear and coal plants being built instead. The study highlights that a shift to increased renewable energy generation will have a positive impact on real GDP, employment, and real household income in South Africa. These real GDP employment and real household income gains are in the range of 5-6% by 2050 (versus limiting wind and solar roll out to 2050), and are substantial. The net positive gains from not constraining investment in renewable energy capacity post-2030 are experienced broadly across sectors in the economy, with the electricity and services sectors experiencing the largest gains (Merven et al., 2020).

A similar analysis, focused on an expanded, high-coal future for South Africa (Merven et al., 2019) found that a coal-dominated power sector to 2050 (including 25 GW of new coal power) would result in lower overall employment in the economy compared to a least-cost reference case of mostly wind and solar. By 2050, the level of real GDP in the high-coal scenario is 2.8% lower with ~1 million fewer jobs created (see Figure 6). The negative impact on GDP manifests across sectors, especially services. GDP in the mining sector is lower than in the reference case despite higher GDP in the coal mining sub-sector. Three drivers contribute to the lower employment: higher employment in RE versus coal power, higher electricity prices due to more expensive power, and higher investment in power sector slowing growth elsewhere.

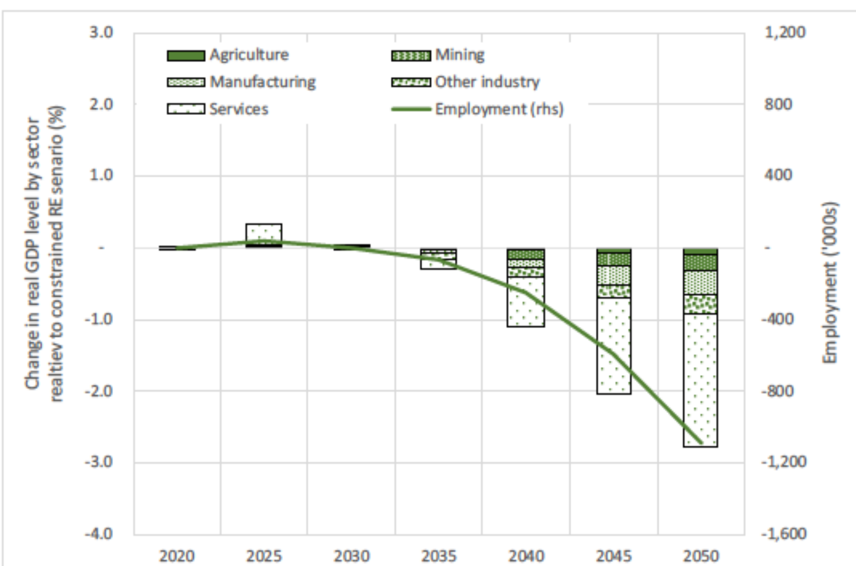


Figure 7 Change in real GDP and employment levels in a high coal scenario relative to the reference case (Merven et al, 2019)

The authors note that in the high-coal scenario, GDP in the coal mining sector is 30% higher with ~14 000 more jobs created (Fig 7). This increase, however, is small and only contributes 0.16 percentage points to total GDP and is unable to offset the decline in activity and employment in other sectors of the economy. The analysis states that "*a large proportion of employment in the coal-mining sector is made of secondary and tertiary skills (Grades 12 and higher) as opposed to unskilled labour, as is often assumed. Limiting the inclusion of renewable energy does not, therefore, protect a large share of unskilled jobs. Instead, the cap on renewable energy power capacity limits the potential to create employment for lower-skilled workers in other sectors of the economy*".

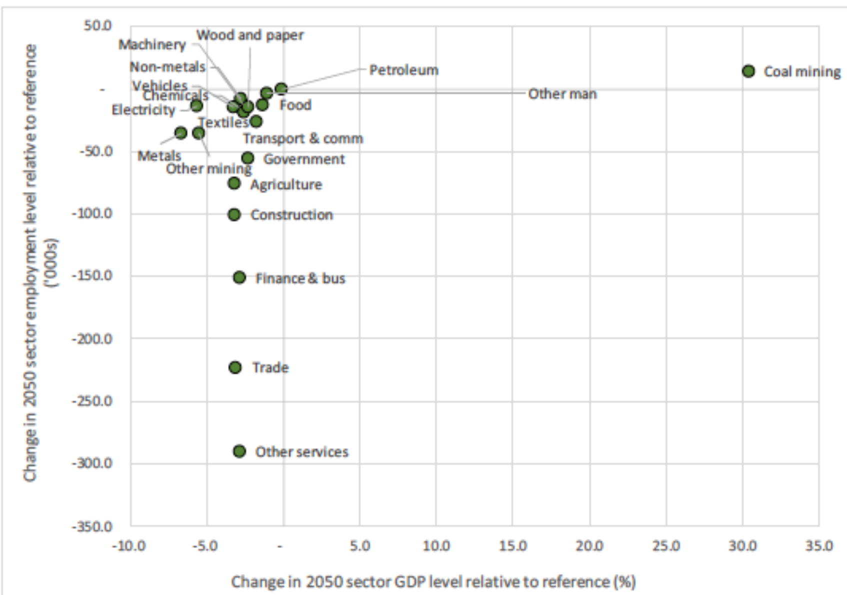


Figure 8 Change in sectoral growth and employment in a high coal scenario 2050 relative to the reference case in 2050 (Merven et al, 2019)

There is a thus a contradiction between protecting the coal-mining sector (and hence coal employment) through sub-economically increasing new coal in the power sector, and the creation and maintenance of jobs across various sectors in the economy. This is relevant given that the IRP pursues new coal on the basis that it is in support of a just transition, yet analysis shows (including the modelling in this study, see Results) that new coal capacity has negative GDP and employment outcomes for South Africa.

Understanding why “baseload” is not needed in power systems

Proponents of coal often argue that power systems need “baseload” plants because of when the “wind doesn’t blow and the sun doesn’t shine”. This, however, is an outdated approach to managing power systems that ignores that technology has advanced and that the costs of alternatives such as renewables have vastly improved, to the point that variable renewable energy (such as wind and solar) can be technically and economically supplemented by flexible dispatchable generators.

Essentially the argument that we “need baseload” assumes that only large continuously running power plants can consistently meet demand and maintain reliable supply. The term is a reference to the alignment of minimum (“base”) electricity demand (“load”), and the profile and economics of generators such as large coal and nuclear plants. Historically, it was the cheapest option to build and most cost-efficient to run these plants at close to maximum capacity with only slight variations in output due to their high capital costs and low variable costs (IRENA, 2015). Given the lack of viable technology alternatives in general in the past (depending on the system and available resources), “baseload” plants became the standard in electricity systems with high levels of coal, nuclear, and hydro built in the 20th century. However, the fluctuating nature of electricity demand and the economics of such generators meant that these plants were typically supplemented by mid-merit and peaking capacity plants. These resources were used as back-up to meet fluctuations in demand at lower costs, for example short increases in the day (mid-merit) or during peak hours (such as in the evenings in South Africa).

However, with the emergence of cost-effective renewable energy and gas generated electricity, baseload plants are no longer the least-cost option for most markets, and indeed are raising costs for consumers in some markets. The changing nature and operations of power systems is clear, with major grid and system operators moving away from the outdated concept of managing systems based on baseload, mid-merit, and peaking plants towards understanding how to integrate high levels of variable renewable energy and flexible capacity. This includes various energy system operators, such as the UK's National Grid, California Independent System Operator (California ISO, 2016), the Irish Transmission System Operator (EirGRid, 2021) and the Australian Electricity Market Operator (AEMO, 2019), entities which manage systems that are highly reliant on renewables. And the changing nature and operations of power systems also been recognized by industry leading bodies such as the International Energy Agency (IEA) (IEA, 2019) and IRENA (2019).

A stable or reliable electricity system requires the system operator to ensure that supply meets demand at every moment, regardless of how much demand fluctuates. It is these changes in demand and increasingly, in supply (because renewables are dispatched by the weather), that underpin the need for flexibility in the system, based on more responsive demand side measures and supply options that complement variable renewable energy.

What differentiates more modern approaches to power systems from the baseload approach is that instead of relying on continuously running nuclear or coal plants, electricity is generated by a complementary mix of resources. With the decline in renewable energy costs, renewables are now often the most cost-competitive capacity, complemented by flexible generators (Merven et al. 2021). There are a growing number of real-world examples of large, industrialised countries maintaining a stable electricity supply with renewables constituting a substantial and growing share of the electricity mix.

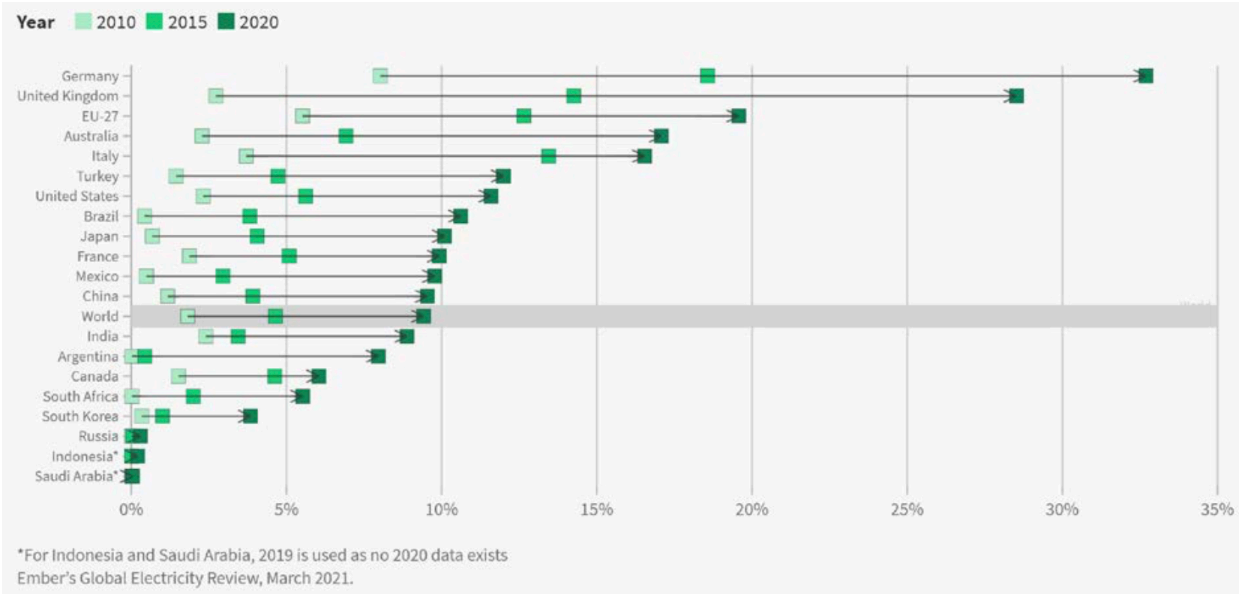


Figure 9 Percentage share of electricity from wind and solar in G20 countries, 2010-2020 (Jones, 2021)

Wind and solar energy constituted more than 10% of the average electricity mix in eight G20 countries in 2020, with Germany and the United Kingdom leading the way with 33% and 28%, respectively (Jones, 2021). Other European countries outside the G20 have energy systems that are highly dependent on renewables. For example, Denmark and Ireland generated 62% and 35% of their electricity from renewables in 2020, respectively (Agora Energiewende and Ember, 2021). This global transition to renewables has come at the expense of especially coal and nuclear. In all but three G20 countries, coal's share of the energy mix has fallen between 2015 and 2020. In this time period there was a 93% decline in UK coal generation, a 60% decline in Mexico, a 43% decline in the United States, and an 11% decline in Australia (Jones, 2021: 13). In terms of nuclear energy, European nuclear power generation fell by 10% in 2020 alone. This downward trend is set to continue in Europe as multiple countries phase out nuclear energy (Agora Energiewende and Ember, 2021). These changes to the energy systems of some the world's largest and most energy-intensive economies demonstrate the viability of power systems with variable renewable energy complemented by flexible generation.

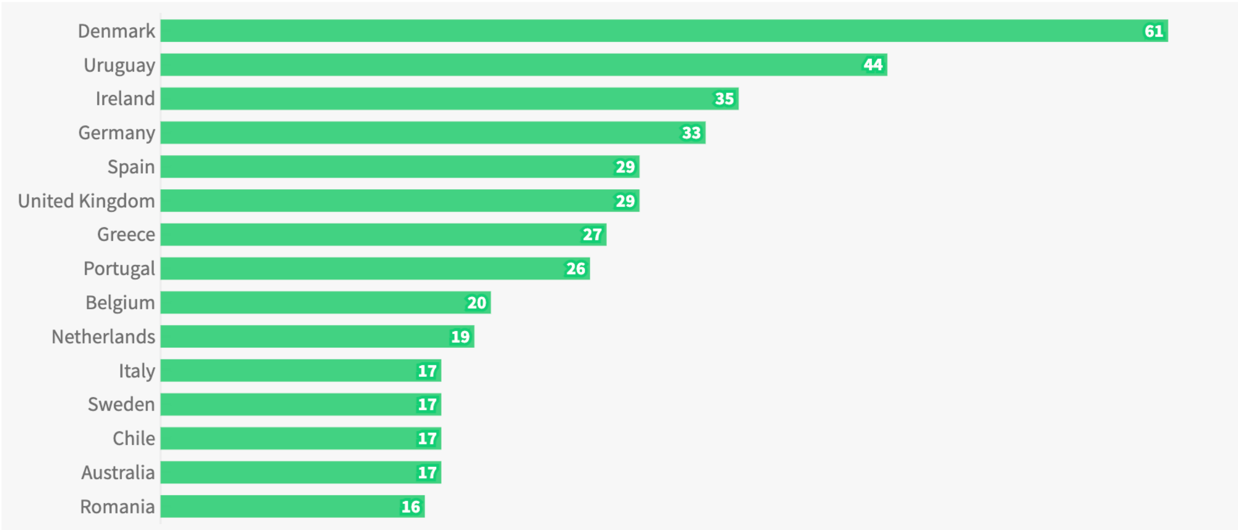


Figure 10 Top 15 countries for % of electricity production from wind and solar in 2020 (Ember, 2021)

Several large developing countries in the G20 – South Africa's peers - also manage renewables penetration higher than South Africa, notably India (8.9%), China (9.5%), Brazil (10.6%) and Turkey (12.0%); as do some major developed countries such as the US (11.6%) and Japan (10.1%).

Nevertheless, with increased renewables penetration there are necessary changes an electricity system must undergo in order to operate optimally. These changes include the ability to ensure continuous output of electricity despite the fluctuating nature of renewable energy supply. This can be achieved with electricity systems consisting of complementary dispatchable energy resources that can be turned on and off quickly by plant or system operators (Merven et al. 2021). Concerning other flexible sources, one must keep in mind that one cannot speak of a need for 'renewables back-up', as all systems require reserves to 'back up' the running generators, whether they are based on renewables or not. What variable renewable energy technologies do need is to be accompanied by complementary resources with particular characteristics. These complementary resources must be able to be turned on and off quickly, or to supplement particular weather patterns, providing storage of different durations. For example, as levels of solar start to drop in the late afternoon, a system may need high levels of flexible technologies which can ramp up to full power quickly, or incentives to shift load to match variable generation. Suitable dispatchable resources for complementing VRE can include concentrating solar power, pumped storage or hydro, batteries, geothermal, or demand side management, depending on the system in question and the type of electricity market (De Vivero et al., 2019; Merven et al. 2021). By integrating other flexible sources, energy systems reliant on renewables are able to operate with comparable levels of reliability. De Vivero et al. (2019) and AEMO (2019) have also outlined solutions to technical challenges associated with energy systems with high levels of renewable penetration, such as how to manage and operate distributed energy resources.

It is apparent that power systems do not require "baseload", that such plants are no longer economically viable nor technically necessary. Electricity systems in which renewables constitute a large share of the energy sources can meet demand reliably while remaining cost-competitive - or even, as described above, lowering costs.

New coal plants are not compatible with global climate goals

Strong action to cut emissions from coal is essential for limiting global warming to below 1.5°C above pre-industrial levels. Coal is the most emissions-intensive fossil fuel, and is the single largest source of global temperature increase, responsible for more than one-third of already experienced warming (IEA, 2019). Coal currently accounts for 39% of global fossil fuel and industrial emissions, and 75% in South Africa (Global Carbon Project, 2020). Two-thirds of coal-related emissions are in the power sector, where technically feasible and cheaper alternatives are already widely available. South Africa's dependence on coal in the energy system is amongst the highest in the world, with ~86% of electricity generated from coal.

Although the economic and technological trends highlighted in the previous sections are leading to a slowing demand for coal and a structural decline in some markets, these trends are currently insufficient for achieving Paris Agreement targets – namely 1.5°C or "well below 2°C" pathways - in two key ways: (i) while the global pipeline of new coal plants is shrinking, there are still net additions of new coal capacity globally; and (ii) the retirement of the existing fleet is happening far too slowly to achieve the emissions reductions consistent with the Paris Agreement.

In the years since the Paris Agreement was signed and ratified there has been an overall decline in the projected expansion of coal power globally, i.e. new coal capacity additions have slowed down considerably. Until 2020, global net additions of coal power are positive - despite high retirements in OECD countries - primarily due to even greater additions in China. Excluding Chinese coal expansion however, net retirements of coal globally for all other countries was reached in 2018. Nevertheless, this downward trend in new capacity additions comes nowhere close to achieving 1.5^{o}C or 2^{o}C pathways, unless significant installed coal capacity is "stranded," i.e. closed before the end of its technical, economic, or financial lifetime.

Since 2015, significant analysis has highlighted the rapid pace and scale of coal phase out needed to hold warming to well below 2^{o}C and 1.5^{o}C . Although slight differences exist across models and analyses, scenarios are broadly consistent about the need for rapid closure of coal power plants and phase out of coal for primary energy.[8] Prior to the inclusion of the 1.5^{o}C goal in the Paris Agreement, substantial analysis showed the scale of the challenge for achieving even 2^{o}C in a context of rapidly growing coal use over the last decades. The remaining carbon budget for 1.5^{o}C is so small that, unlike other fossil fuels, there is limited room for coal emissions in almost all scenarios, hence the high commonalities despite differences in assumptions.

In scenarios consistent with limiting warming to below 2°C, unabated coal power both declines rapidly and is almost completely phased out by 2050 (Audoly, Vogt-Schilb, and Guivarch 2014; Kriegler *et al.* 2014; Luderer *et al.* 2017; Rogelj *et al.* 2015; Williams *et al.* 2012). Holding warming below 2^{o}C requires early retirement of coal power plants globally (Guivarch and Hood

[8] Differing assumptions on temperature goals, peak warming targets/overshoot of the temperature goal, the remaining carbon budget, and the extent of use of carbon capture technologies typically account for small differences in the pace or scale of phase out targets.

2011; Pfeiffer *et al.* 2016; Rogelj *et al.* 2013). Higher levels of early retirement or stranding of assets will be needed if there are delays in ambitious climate policy and in stopping new coal power (Johnson et al. 2015; Luderer *et al.* 2017; Iyer *et al.* 2015; see UNEP, 2017 for full review). This is what has happened globally over the past 10 years, where retirements have not offset new coal capacity additions.

Pfeiffer et al (2016) showed that when plants are run to the end of their lives, to limit warming below 2^{o}C[9] would have required the world to halt the construction of all new fossil fuel power generation in 2017. The temperature goal can now only be achieved through the early retirement of existing coal plants, i.e. stranding plants before the end of their economic lives or retrofitting/repurposing them. Achieving "well below" 2^{o}C or 1.5^{o}C requires even faster coal phase out (Rogelj *et al.* 2015). Based on the IPCC SR1.5, the current emissions of ~14Gt/year from coal would need to fall to a range of 4.4 Gt to 8.5 Gt by 2030 to reach the goal of "well below 2^{o}C," and to a range of 3.3Gt to 4.8Gt to ensure that the goal of 1.5^{o}C is not breached.

To realise the Paris temperature goals thus requires the early retirement of existing power plants, as well as halting currently planned or under construction coal plants (Pfieffer et al., 2016; Rogelj et al., 2013). Staffan et al., (2020) estimate that in a scenario where there is a 66% chance of remaining below 2^{o}C, at current emissions levels the remaining emissions budget for the power sector will only last 10 years; and a scenario where there is a 66% chance of remaining below 1.5^{o}C the emissions budget would only last for 3 years (Staffan et al., 2020). Indeed, for a 66% chance of limiting warming to 1.5^{o}C without early retirement, the world needed to stop building new fossil fuel generating infrastructure in 2006 (Pfeiffer et al, 2016). This is calculated by examining the "committed emissions" – i.e. the associated emissions arising from fossil fuel infrastructure once built. The IEA projects that existing infrastructure globally already commits the world to 1.65^{o}C of warming, even if no more emitting infrastructure were built from today, i.e. that almost the entire emissions budget for the Paris Agreement is 'used up' by existing infrastructure.

[9] With a 50% probability.

The currently available emissions budget to realise both 2ºC and 1.5ºC temperature targets is rapidly shrinking. Evidently, rapid retirement of coal assets is now required in light of new capacity additions made globally over the past 10 years and delays in global mitigation action. This required reduction in coal-generated power is confirmed in a Climate Analytics (2019) analysis of the IPCC Special Report on 1.5C, which found that a 62-90% reduction in coal is needed below 2010 levels by 2030, and 91-99% reduction by 2040. Overall, the difference between 1.5ºC and 2ºC scenarios in terms of coal closure is only around 5 years (Climate Analytics, 2019). Slower declines in coal use in 2ºC modelling runs are partly a result of modelling inputs that assume new coal development was lower between 2010 and 2020 than it was in reality (Climate Analytics, 2019).

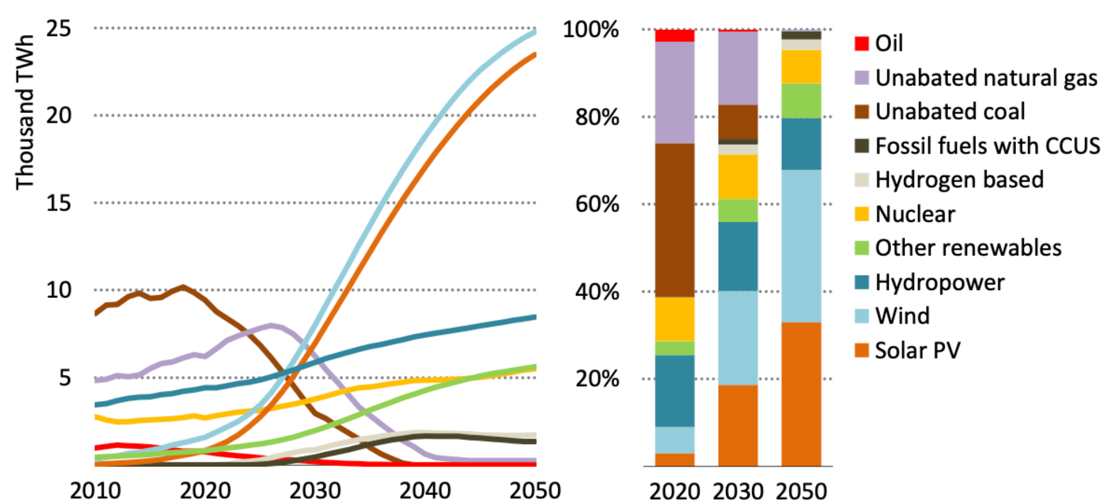


Figure 11 Global electricity generation by source in a 2050 net-zero emissions scenario (IEA, 2021)

These findings are further reflected in the IEA's recent Net Zero by 2050 analysis (IEA, 2021). In line with the IPCC analyses, the IEA shows that to achieve net-zero 2050 requires a 70% cut in unabated coal generation by 2030 in the power sector, and a complete global phase-out by 2040 (see Figure 8).

Given the extent to which coal needs to be phased out to meet Paris Agreement temperature targets, the addition of new coal capacity would either result in stranded assets or even earlier retirement for already operational coal plants (Cui et al., 2019; Staffan et al., 2020). Cui et al.

(Figure 12) show the difference between lifetime emissions of operating and planned coal plants globally and the remaining emissions budgets for 2°C and 1.5°C. As can be seen, the emissions from the existing and under construction coal fleet far exceed the available emissions space, unless plant lifetimes are reduced.

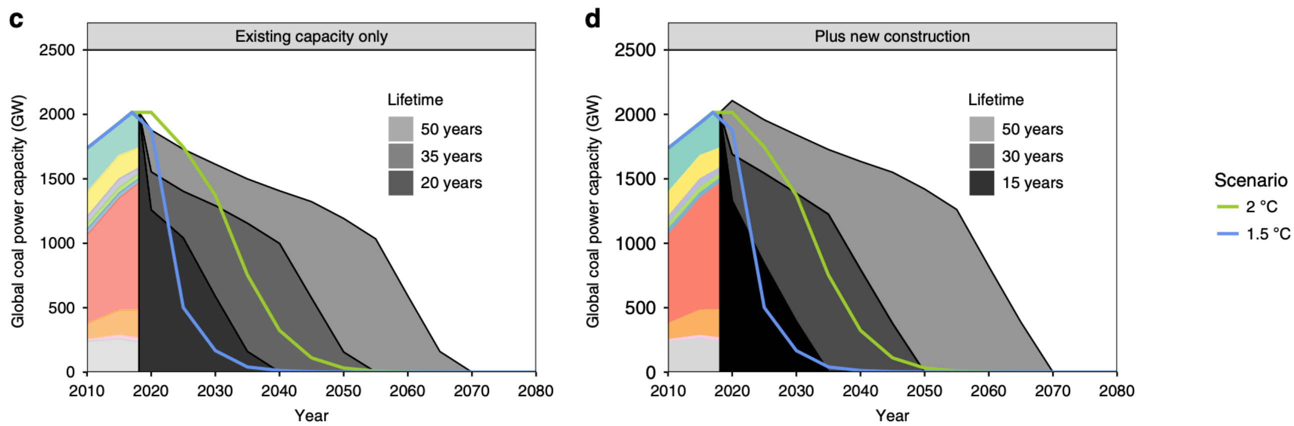


Figure 12 Existing coal capacity and lifetime of global fleet compared to Paris scenarios (Cui et al, 2019)

There are also local studies that examine the energy system implications of climate policy action in South Africa, for example, through modelled scenarios where GHG emissions are capped to comply with South Africa's Paris Agreement commitments. In these studies, early closure of coal plants – through running them less or early retirement – is one of the most cost effective actions that can be undertaken. McCall et al. (2019) found that phasing out coal in the power sector by 2040 is cost optimal for South Africa to fulfil its commitment to the Paris Agreement goal of limiting warming to well below 2°C. In this scenario, no additional coal capacity is added. The total phase-out of coal by 2040 is also reaffirmed in a 2°C compatible scenario by Burton et al. (2018). As in McCall et al. (2019), no new coal capacity is added in this scenario.[10]

[10] Although this type of modelling is based on cost optimization, scenario design and the inclusion of policy choices can lead to scenarios that go beyond a least cost technology pathway to incorporate other goals. Thus for example, the scenarios described here are cost optimal but also carbon constrained to achieve higher climate ambition, to a level where the technology roll out is accelerated and hence more costly than in a scenario where no ambitious policy action is considered. In each case the scenario is cost optimal subject to the constraints imposed on the model, but those constraints can differ in their broader objectives and overall costs.

Similarly, Wright and Calitz (2020) found that in multiple scenarios that align with the goals of the Paris Agreement and cover the period 2020-2050, no new nuclear or coal capacity is added. Roff et al. (2020) (based on the CSIR modelling) have come to similar conclusions in three different climate change mitigation scenarios for the period 2020-2050. The three scenarios look at new capacity built for 2Gt, 3Gt and 3.5Gt carbon budgets, and in all three scenarios no new coal or nuclear capacity is built (and indeed, existing coal capacity is closed earlier). Further studies include a net zero energy emissions analysis by Hanto et al. (2021) that includes an earlier phase out of all coal plants by 2035 in a climate policy scenario, and the National Business Initiative's Just Transition Pathways process has explored multiple scenarios for ambitious climate action in South Africa, including net zero emissions power system analyses where coal power is phased out before 2050. The NBI process and findings are clear that a policy position that commits to "no new coal capacity" is a "no regret" decision for the country.

The following section now uses our SATIM 2021 model to explore the implications of adhering to the new coal capacity targets contained in the 2019 IRP.

Scenarios

This section explores two scenarios, assessing the consequences of the new coal capacity targets contained in the 2019 IRP. As the world has changed strongly since this IRP was concluded, we investigated two scenarios: a Reference Scenario and a Climate Policy Scenario.

The Reference Scenario takes into account recent trends in the decline of economic growth rates, the economic impact of Covid-19, lower electricity demand, recent renewable energy costs, and up to date assessment of Eskom's fleet performance, etc. The IRP 2019 included various assumptions that have changed dramatically since the publication of the policy-adjusted scenario. For example, neither the GDP growth assumptions nor the electricity demand projections in the IRP 2019 have materialised (see Appendix for comparisons of demand). We have updated our model to reflect these changes, since following the IRP 2019 build plan would provide significantly more generation capacity than needed in the 2020s, due to the slowing economic growth since 2018 and the large economic contraction during Covid.

The reference scenario thus develops an optimal build plan for the new situation we find ourselves in. We then force in 1.5 GW of new coal to document the impacts of this decision. The scenario includes an economic analysis that analyses the employment and GDP impacts of the coal capacity.

The scenario also includes two sensitivities to future drivers of the cost of new coal. Since projections into the future are inherently uncertain, we have included these so as to assess the range of plausible outcomes driven by two key metrics: the future costs of renewable energy and the externality costs associated with coal power. The reference case takes a more conservative view on both renewable costs projections (assuming they will be higher) and externality costs (assuming they will be lower), relative to the sensitivities, which together provide a range that spans the uncertainty. The reference case uses a lower estimate also used by the DMRE in the IRP, whereas there are estimates made by others in literature (Naidoo et al, 2019), which we use again to span the uncertainty (full comparison of assumptions are in the Appendix).

In the second scenario, we explore a situation where South Africa revises its Nationally Determined Contribution (NDC) to be compatible with the global goals contained within the Paris Agreement to limit warming to well below 2^{o}C and pursue efforts towards 1.5^{o}C. In this scenario we constrain greenhouse gas emissions over the period to 2050, including meeting a 2030 target of around 350 Mt CO_2-eq. This is modelled using a cumulative CO_2eq constraint on Energy and Industrial Process emissions between 2020-2050 of 7 Gt.

The 2030 emissions outcome is in line with the bottom of the emissions range recommended by the Presidential Climate Commission in the recent update to South Africa's NDC. This level is also aligned to the top end of South Africa's "fair share" range of emissions for limiting warming to 1.5^{o}C, i.e. it falls into the very top of a 1.5^{o}C aligned target for South Africa, when applying the fair share methodology developed by the Climate Equity Reference Project. Such a methodology considers historical responsibility for climate change, capability to act (measured though national income), and emissions related to meeting basic needs/living standards. This means that the methodology considers South Africa's status as a developing country (albeit a carbon-intensive one) and its need to address development priorities, as well as global considerations of equity.

This scenario thus accords with the low range of the PCC proposal on the NDC update and the upper range of CERC's 1.5°C fair share range. This scenario also includes mitigation policies and measures (which would be necessary to reach this level of mitigation ambition), including the implementation of the National Energy Efficiency Strategy and the Green Transport Strategy on the demand side.

In each scenario, the model is run with and without the new coal capacity forced in, allowing us to report on the differences in the following indicators when new coal plants are included in the system, relative to runs where coal plants are not included. The indicators include:

- Total discounted system costs, cumulative investment in the power sector, and annual power system costs
- Electricity price
- Annual and cumulative greenhouse gas emissions nationally and in the power sector
- Air pollutant emissions (SOx, NOx)
- For the reference case we also report the GDP impacts and net job impacts.

In each scenario, one model run does not include new coal power in the build plan because new coal power does not feature as part of an optimal build plan. Instead, new build capacity is comprised of variable renewable energy (VRE) – wind and solar – complemented by flexible generation (batteries, gas, pumped storage etc), as well as the existing resources available to the system (existing coal, pumped storage etc). In all scenarios, the build plan must achieve the same levels of supply security and reliability, with the same requirements imposed on the model.

Results: Reference Scenario

In the reference case, new generation capacity is predominately variable renewable energy sources, namely wind and solar PV, supplemented by flexible generators. The capacity expansion and corresponding production mix with and without the forced coal are shown in Figure 13. In the case where the forced coal is included, the 1.5 GW of new coal capacity displaces between 3.2-3.4 GW of VRE (solar PV and wind) and 1.7-1.8 GW of flexible generators (flexible gas plants and batteries) over the horizon (2027-2050), compared to the case without forced coal.

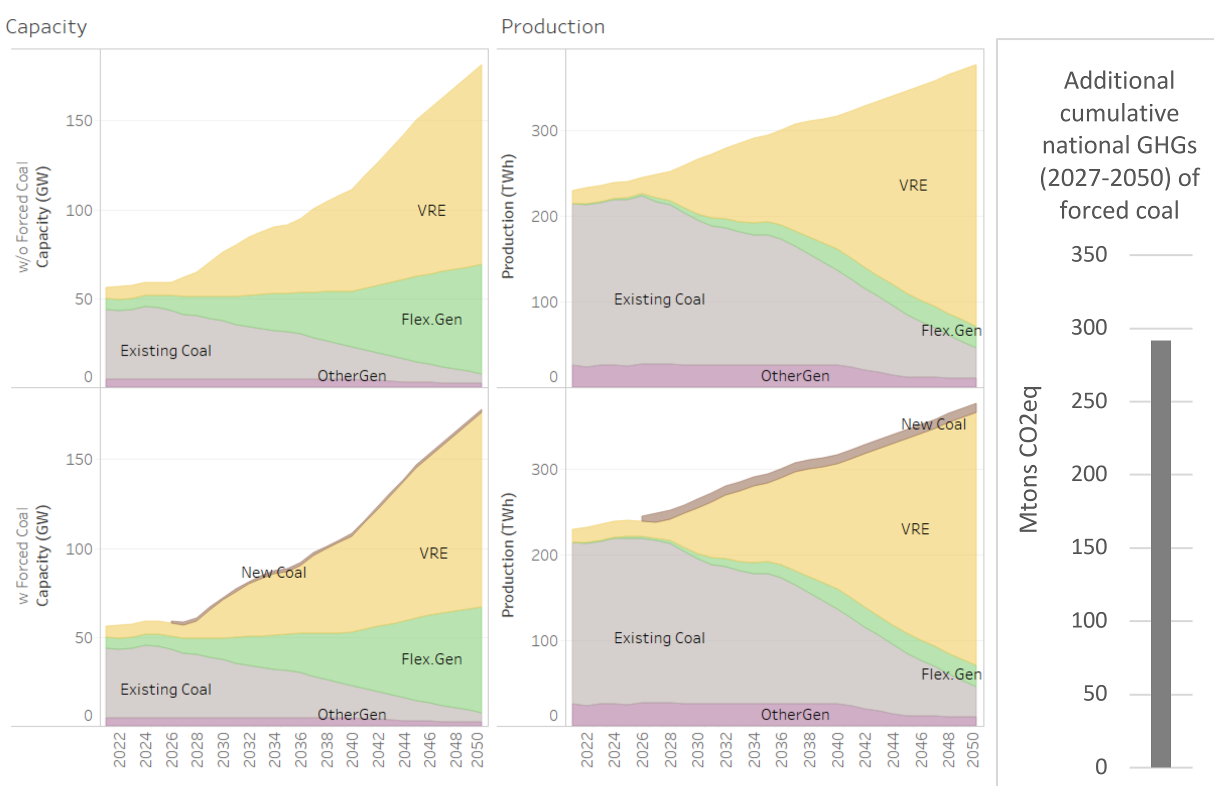


Figure 13 Capacity Expansion and Production Mix for the Reference Scenario w/o and w coal forced in, and additional cumulative emissions of forced coal

Since the coal plants are more expensive to build and run than the least-cost alternative, this pushes up the total discounted power system costs by R23 billion and the average unit cost of electricity by 0.8 c/kWh or 0.5%.

We note here that earlier analysis (Ireland & Burton, 2018) found a similar figure (~R20bn) for smaller planned capacity (863 MW). That analysis applied actual bid tariffs from the auction (i.e. the market prices of the plants), whereas this study uses the cost assumptions from the IRP 2019, which are likely also conservative.

Table 5 Summary Cost indicators for Reference Case and Sensitivities compared to Forced Coal

Summary Costs		**Reference case**	**Optimistic RE case**	**Higher externality case**
Increase in Total Discounted Electricity System Costs with forced coal	Billion Rand	23.0	28.7	23.8
Increase in average unit cost	c/kWh	0.81	1.12	0.94
Increase in average unit cost	%	0.48%	0.61%	0.48%
Increase in cumulative investment	Billion Rand	21.3	25.3	21.4

The additional system costs are even greater if more optimistic renewable energy costs are assumed to materialise (i.e. renewable costs in the future are lower), with the forced coal costing R28.7 billion. When we include a sensitivity on the externality costs of coal, applying the costs in Naidoo et al. (2019), the costs of the forced coal rise to R23.8 billion (Table 5).

Table 12 (in Appendix) shows a detailed breakdown of the costs differences with and without the forced coal for the Reference Scenario and sensitivities. This shows that most of the cost difference is explained by the higher investment and maintenance cost of the new coal, with the balance coming from higher Externality Costs[11], Environmental Levy[12] Costs and Carbon Tax costs when new coal is forced in. The fuel costs are lower with new coal capacity forced in, as

[11] Externality Costs are costs not "seen" by supplier of electricity and not included in the electricity tariff but are incurred by society. This is mainly costs associated with health impacts due to poorer air quality associated with SOx and NOx emissions.
[12] Eskom is charged an environmental levy by government for the electricity generated by fossil fuels, which is included in the tariff calculation.

the new coal is assumed to be fluidised bed technology, using very cheap low-grade coal; this compares to the reference without coal where the system uses slightly more expensive gas to balance the variable renewable energy production.

The additional investment required in the electricity sector and the higher unit cost for electricity results in an overall negative impact on GDP and employment as shown in Table 6. The 1.5GW of new coal capacity results in a small GDP impact, reducing growth by 0.11% in 2030 and 0.08% in 2040, relative to a reference case without coal; with around 25 000 fewer jobs in 2030 and 20 000 in 2040 when the new coal capacity is built.

Table 6 GDP and Employment impact of forced coal in 2030 and 2040 versus least cost

	2030	**2040**
GDP Loss relative to Least Cost	0.11%	0.08%
Employment Lost relative to Least Cost ('000)	25.8	19.7

Forcing in new coal capacity is worse for climate outcomes and more polluting, with higher cumulative greenhouse gas, SOx and NOx emissions, as shown in Table 7. The difference in SOx emissions is not very high as it is assumed that new coal capacity will be installed with Flue Gas Desulphurisation (FGD), in line with air pollution requirements.

The new coal capacity results in higher cumulative national greenhouse gas emissions than the reference without coal over the period 2027-2050. Total cumulative additional greenhouse gas emissions total 289 Mt to 2050. These lifetime emissions would be even higher if the new capacity lifetimes extends beyond 2050, the end of the modelling horizon in this analysis. In 2030, national emissions are 12Mt higher (all due to higher emissions in the power sector) than in a scenario without the forced new coal capacity.

Table 7 Emissions in 2030 and Cumulative emissions over period 2027-2050, Reference Scenario

		Without Forced Coal	**With Forced Coal**	**Difference**
National greenhouse gas emissions in 2030	Million tons (Mt) CO_2eq	442.8	454.6	12
Cumulative national greenhouse gas emissions (2027-2050)	Mt CO_2eq	8,962	9,251	289
Power sector greenhouse gas emissions in 2030	Mt CO_2eq	183	195	12
Cumulative power sector greenhouse gas (2027-2050)	Mt CO_2eq	3,164	3,456	292
Power Sector NOx in 2030	kton	655	673	18.5
Power Sector SOx in 2030	kton	1389	1396	6.8
Cumulative Power Sector NOx (2027-2050)	kton	10,440	10,883	443
Cumulative Power Sector SOx (2027-2050)	kton	21,137	21,297	160

Results: Climate Policy Scenario

In the Climate Policy scenario, forcing in additional coal capacity in the context of greenhouse gas emission reductions results in significantly higher system costs. To achieve a Paris Agreement-compatible fair share range requires that emissions are at least around 350 Mt CO_2-eq in 2030 with an overall budget of 7Gt over the period. This correlates with the upper end of the fair share range calculated by Climate Equity Reference Project for 1.5°C (including land use, land use change and forestry) for South Africa in 2030. Such a scenario requires that existing coal plants are closed earlier than contemplated in the IRP 2019 and are also run at lower load factors, lowering emissions.

We assume that new coal capacity will not be retired early, with an estimated lifespan of at least 30 years, based on the structure of the earlier bid rounds and requirements for finance [13]. New coal capacity – which as we have seen in the previous scenarios is accompanied by large increases in greenhouse gas emissions – this squeezes out other emissions when a cap on

[13] In the previous coal procurement programme, the PPAs were 30 years and the plants were guaranteed offtake of the electricity they generated at a high level, i.e. a take-or-pay contract would have been in place with Eskom.

carbon emissions is implemented. This means that the new coal capacity pushes out the relatively cheaper existing coal in Eskom's fleet more quickly, raising the costs of transition. The limited emission space also results in increased mitigation on the demand side (i.e. in demand sectors such as transport and industry), accelerating electrification to offset the emissions from the new coal capacity, pushing costs up further (eg faster switching to electric vehicles). In other words, the system with the forced coal IPPs has more emissions from the power sector than the system without the forced coal. Since both systems have to meet the same CO_2 limits, less space is available for other sectors (other than the power sector) such as transport and industry, which have to now include more mitigation action – this involves an increase in electricity use by those sectors. This can be seen in Table 18 and in Figure 27 in the appendix.

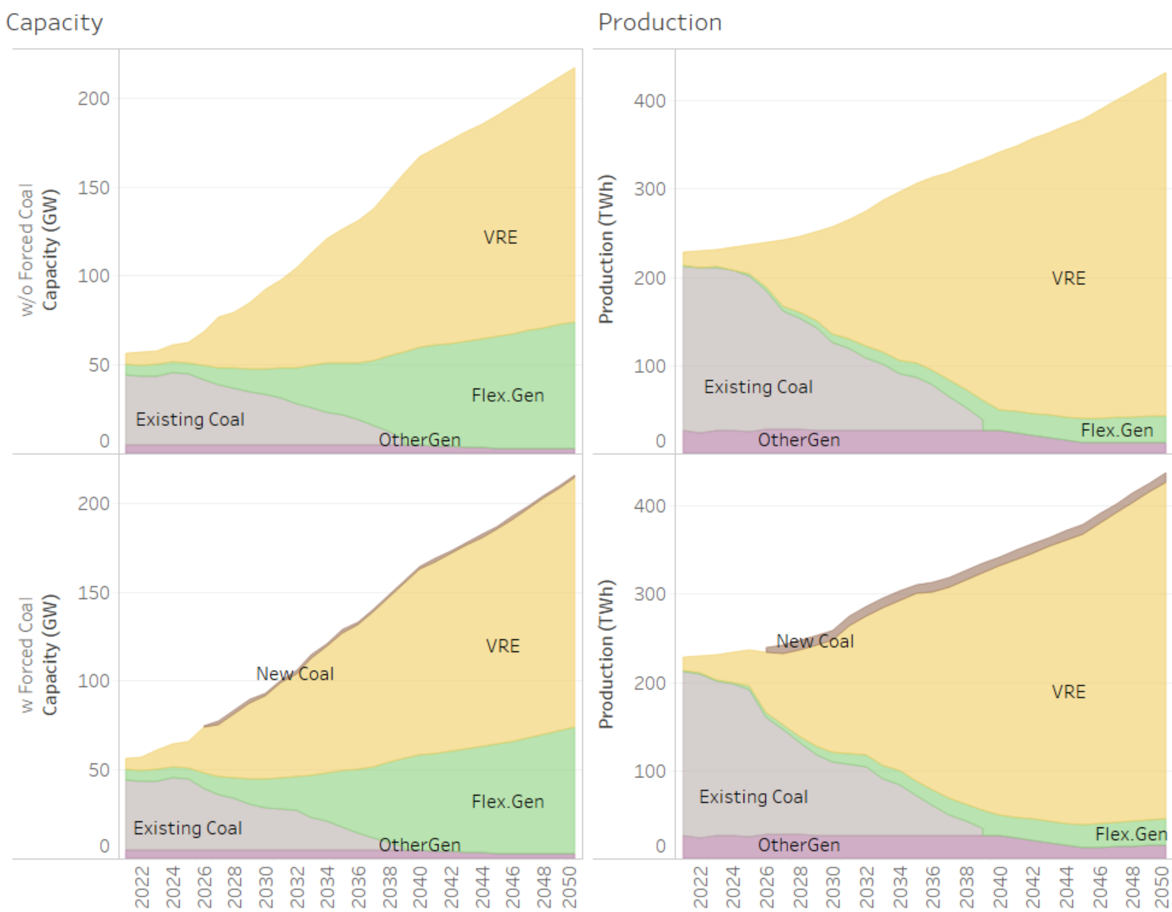


Figure 14 Capacity Expansion and Production Mix for the Climate Policy Scenario w/o and w Coal Forced In

Overall, pursuing a Paris Agreement-aligned emissions trajectory while also pursuing new coal-fired power plants raises costs significantly. New coal capacity in a climate-compatible future will result in an increase in total discounted system costs of R109 billion in the power sector.

Summary results

The following figures and tables contain summary results of the two scenarios and sensitivities that have been analysed. The figures show the difference in discounted system costs when new coal plants are forced into the system for the Reference and Climate Policy Scenarios. (Table 8).

Table 8 Summary

		Reference	Climate Policy
Increase in Total Discounted Electricity System Costs	Billion Rand	23	109
Increase in unit cost	c/kWh	0.8	8.0
Increase in unit cost	%	0.50%	3.5%
Increase in cumulative investment	Billion Rand	7.2	139

Figure 15 shows the national greenhouse gas emissions over the modelling period for the Reference and Climate Policy Scenario (CO_2-eq). As can be seen, in the Reference case the forced coal raises emissions consistently over the modelling period. In the Climate Policy scenario, the analysis shows that earlier emissions reductions are pursued to offset greenhouse gas emissions from the 1.5GW in the 2040s.

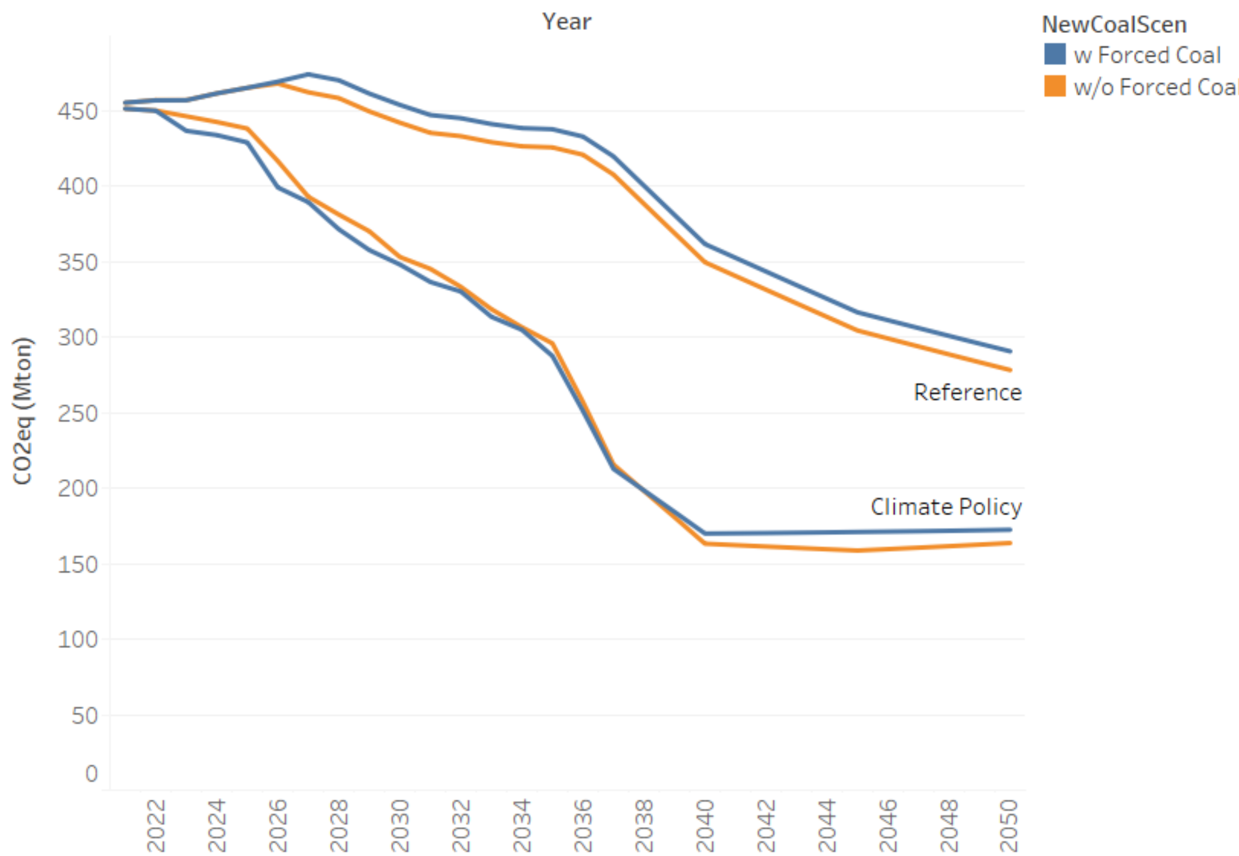


Figure 15 Projected national Greenhouse gas emissions

Figure 16 demonstrates the higher electricity costs (R/kWh) in both scenarios when the coal is forced into the build plan.

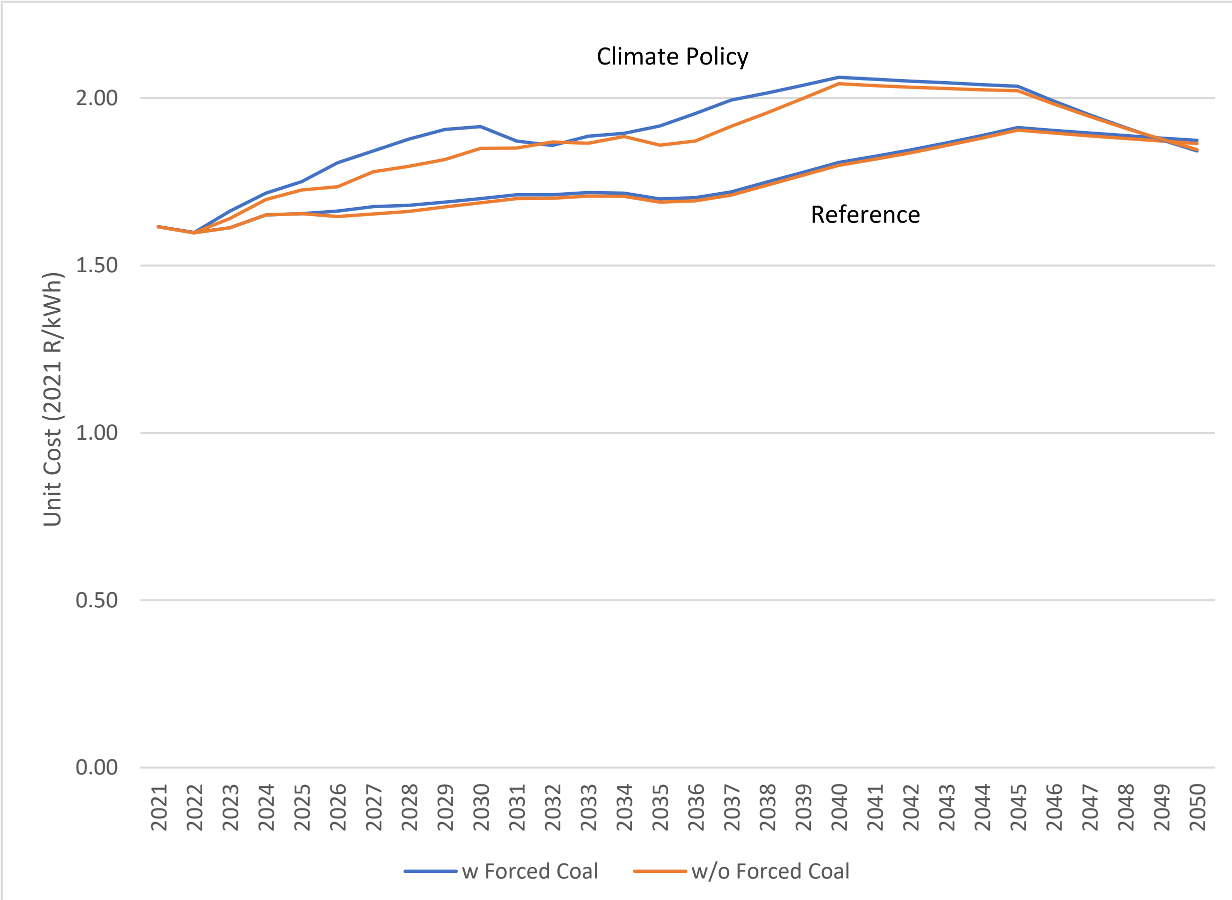


Figure 16 Projected Unit Cost for Electricity

Figure 14 summarises the additional discounted system costs from forced coal for each scenario, in 2021 ZAR.

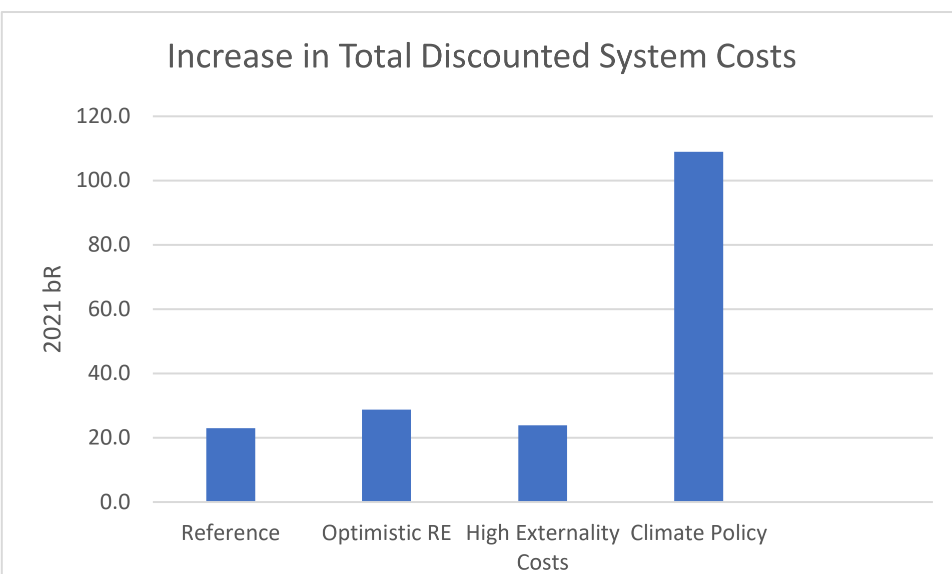


Figure 17 Increase in total discounted power system costs with forced coal, all scenarios

Conclusion

Our modelling shows that under the two scenarios tested, new investments into coal-based power generation are costly and unnecessary for South Africa. Building the 1.5 GW contained in the IRP 2019 would increase greenhouse gas emissions and power system costs, driving up average electricity costs by 0.8-8.0 c/kWh or 0.5-3.5% in a reference scenario and climate policy future scenario respectively. Not only does forcing in new coal raise costs when climate goals are not considered, leading to additional discounted system costs of R23bn, but it also makes the achievement of South Africa's fair share contribution to climate change vastly more expensive. In a climate policy scenario, pursuing emissions reductions and new coal would increase the system cost by R109bn.

In effect, South African users of electricity are being asked to pay more for electricity that increases emissions of air pollutants and greenhouse gases compared to a scenario where the South African government commits to no new coal plants. In a world where climate action is pursued, building new coal leads to a more rapid closure of Eskom's coal fleet and replacement with new, more expensive coal plants, and requires that more costly mitigation actions are pursued to allow space for the new coal. Based on our analysis, the new coal capacity in the IRP 2019 is not necessary for energy security, will raise greenhouse gas emissions unnecessarily, and is more costly than alternatives.

The Department of Mineral Resources and Energy's policy choice to include new coal plants does not make sense given their appeals to the need for a just transition. A just transition aims to protect workers and communities in the energy transition. The new coal plants would cost consumers more than a targeted support programme for coal workers; would increase carbon emissions and air pollutants; and make electricity expensive for all users, undermining GDP growth and employment elsewhere in the economy.

Addendum

On 14 September 2021, Cabinet approved South Africa's revised Nationally Determined Contribution (NDC) climate change mitigation target range for 2030 for submission to the UNFCCC. South Africa has revised its target range for 2025 to 398 to 510 and for 2030 to 350 – 420 Million tons of Carbon Dioxide equivalent (Mt Co2-eq).[14] At the time of publication of the report "Assessment of new coal generation capacity targets in South Africa's 2019 Integrated Resource Plan for Electricity" the final target range of the NDC was not known, and hence could not be included in the analysis (although that study did assess the lower range recommendation made by the PCC) . This addendum now analyses the impact of the new coal capacity in the IRP in light of the updated NDC target range for 2030.

The 350 Mt scenario has already been analysed in the main report. In this section we include the analysis of meeting the upper range of South Africa's NDC of 420 Mt CO2-eq by 2030, as well as the results of the lower range of the NDC, 350 Mt case, for comparison purposes.

Scenario: Assessing the 2030 Climate Policy Range

In the NDC update for South Africa (September 2021) as approved by Cabinet, South Africa commits to GHG levels ranging from 350 Mt to 420 Mt CO_2-eq in 2030. The upper range of the NDC commitment is to accommodate uncertainty in GDP growth over the period and in the effective implementation of mitigation policies, notably demand side efficiency improvements identified in the mitigation policies and measures (PAMS)[15]. In the analysis presented here we hold the GDP growth assumption the same as in the Climate Policy scenario analysed in the main report but we model the 420 case without PAMS, as done in the reference scenario. This case is referred to from this point on as the "420" case. The 350 case was modelled with PAMS and is referred to as the "350" case.

[14] https://www.gov.za/speeches/statement-virtual-cabinet-meeting-14-september-2021-20-sep-2021-0000
[15] PAMS: Policies and measures, which mainly consist of efficiency improvements in the energy consuming sectors.

Full implementation of existing PAMS is necessary but not sufficient to reach 350 Mt in 2030. Similarly, implementation of the PAMS would lower emissions below 420 Mt and hence it does not make sense to include them in that case (see Figure 18 which illustrates this conceptually).

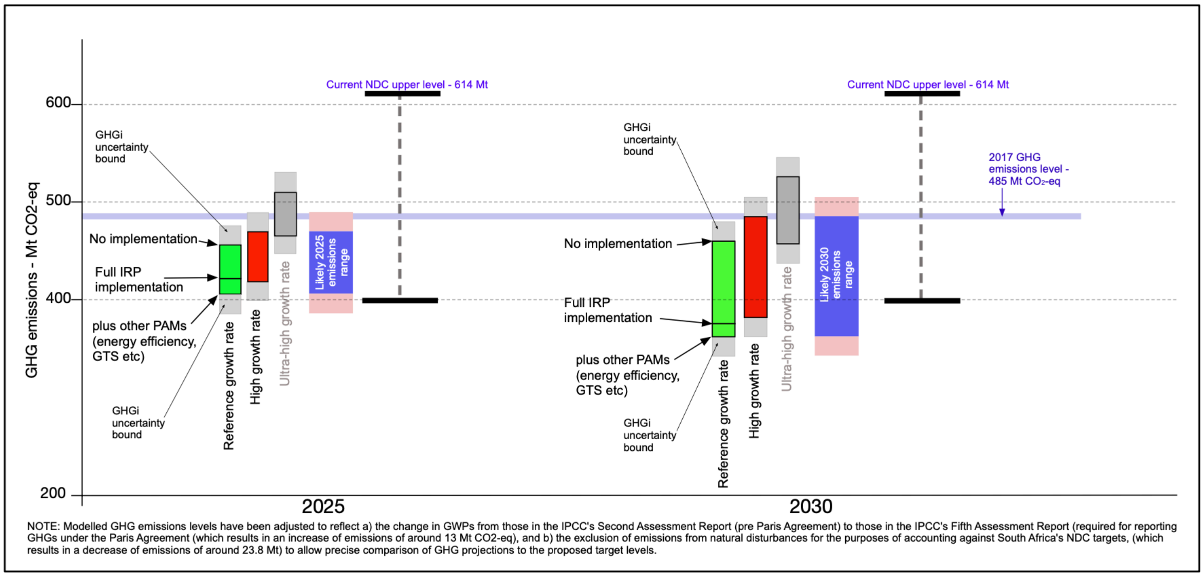


Figure 18 Range of likely GHG emissions outcomes for the South African economy in 2025 and 2030, given uncertainties in policy implementation, economic growth rates and GHG estimation (Marquard et al, 2021)

In order to reach an emissions level of 350 Mt in 2030, a cumulative emissions cap of 7 Gt between 2020 and 2050 was imposed. In order to reach 420 Mt in 2030, a cumulative cap of 8.5 Gt over the same period was imposed. As per the main report, we assume that new coal capacity will not be retired early, with an estimated lifespan of at least 30 years, based on the structure of the earlier bid rounds and requirements for finance [16].

Addendum results: Climate Policy Scenario

In both the 420 and the 350 cases, building and running new coal capacity is accompanied by increases in greenhouse gas emissions that squeeze out other emissions/emitting infrastructure when a total cap on greenhouse gas emissions is implemented. This means that the new coal

[16] In the previous coal procurement programme, the PPAs were 30 years and the plants were guaranteed offtake of the electricity they generated at a high level, i.e. a take-or-pay contract would have been in place with Eskom.

capacity pushes out the relatively cheaper existing coal in Eskom's fleet more quickly, raising the costs of transition. Thus for both cases in the Climate Policy scenario, forcing in additional coal capacity in the context of greenhouse gas emission reductions results in significantly higher system costs.

The limited emission space also results in increased mitigation on the demand side (i.e. in demand sectors such as transport and industry), accelerating electrification to offset the emissions from the new coal capacity, pushing costs up further (e.g. faster switching to electric vehicles). In other words, the system with the forced coal capacity has more emissions from the power sector than the system without the forced coal. Since both systems have to meet the same CO_2 limits, less space is available for other sectors (other than the power sector) such as transport and industry, which have to now include more mitigation action. This involves an increase in electricity use by those sectors.

The projected capacity expansion and production mix for the 420 and 350 cases are shown in Figure 20 and Figure 14/19 respectively.

These effects are more strongly observed in the 350 case, which has the more stringent GHG emissions constraint. This can be seen in the updated demand projection (Figure 27) and in the detailed cost breakdown in Table 18 in the appendix.

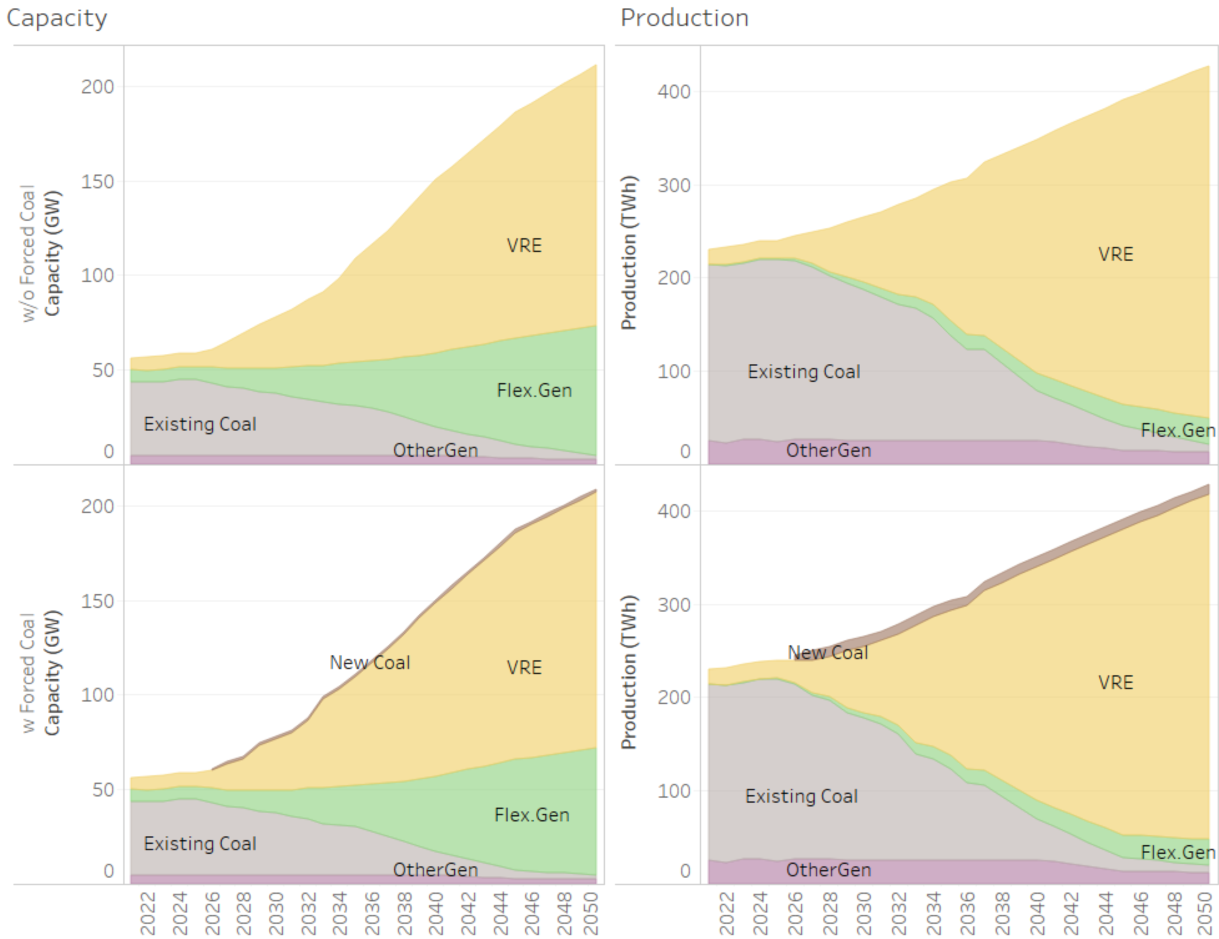


Figure 19 Capacity Expansion and Production Mix for the 420 Climate Policy Scenario w/o and w Coal Forced In

In the 420 case, the retirement of Eskom's fleet remains the same as in the reference case in the main report, and does not change with new coal forced in. However, the more stringent emissions cap in the 350 case means that an additional 4.6 GW is retired endogenously (i.e due to the optimisation in the model and not set outside the model) by 2030 versus the reference case and the 420 case. This is needed to achieve the more ambitious emissions target. The results also imply that a far higher roll out of renewable energy is needed than currently contemplated in the IRP 2019.

The result of forcing in the new coal capacity and limiting emissions to 350 Mt is that an additional 8.9 GW of Eskom's coal plants are retired by 2030.

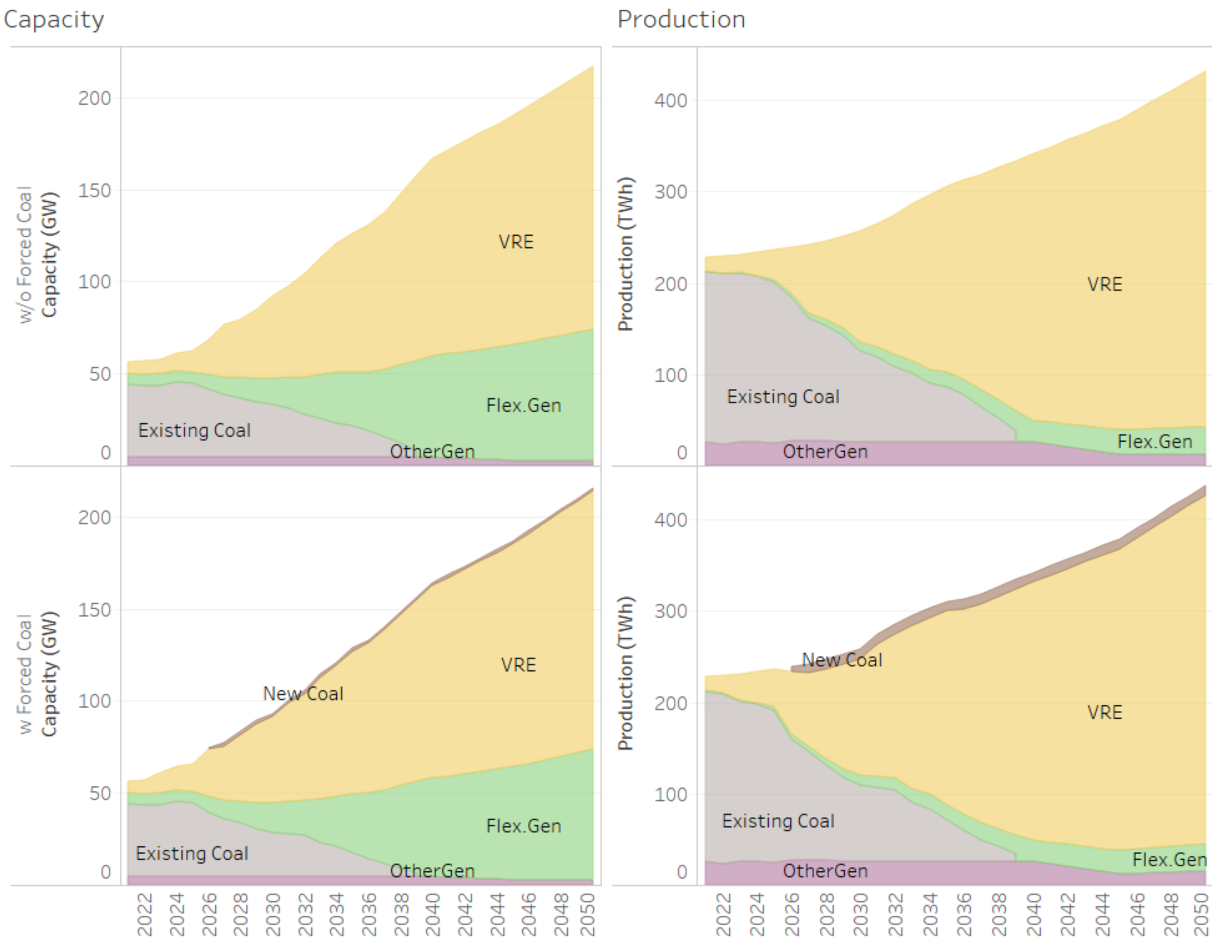


Figure 20 Capacity Expansion and Production Mix for the 350 Climate Policy Scenario w/o and w Coal Forced In

Summary results

The following figures and tables contain summary results of the Reference and Climate Policy scenarios, including the new sensitivity where South Africa achieved the upper level of its new NDC range - 420 Mt by 2030. The figures show the difference in discounted system costs when new coal plants are forced into the system for the Reference and Climate Policy Scenarios (Table 9).

Table 9 Summary of increase in total discounted system costs when coal capacity is committed

		Reference	Climate Policy	
			420	S350
Increase in Total Discounted Electricity System Costs	Billion Rand	23.0	74.4	109
Increase in unit cost	c/kWh	0.8	2.5	3.0[17]
Increase in unit cost	%	0.5%	1.3%	1.5%
Increase in cumulative investment	Billion Rand	7.2	61.8	139

Figure 21shows the national greenhouse gas emissions over the modelling period for the Reference and the Climate Policy Scenario, both cases (CO_2-eq). As can be seen, in the Reference case the forced coal raises emissions consistently over the modelling period. In the Climate Policy scenarios, the analysis shows that earlier emissions reductions are pursued to offset greenhouse gas emissions from the 1.5GW in the 2040s.

[17] This has been updated since the main report. In the main report the unit cost included CO2 marginals resulting from the CO2 constraint. In the addendum, we now report the unit cost using the planned CO2 tax rather than the marginal to be more consistent with how system costs were reported (also using planned CO2 tax and not the marginal).

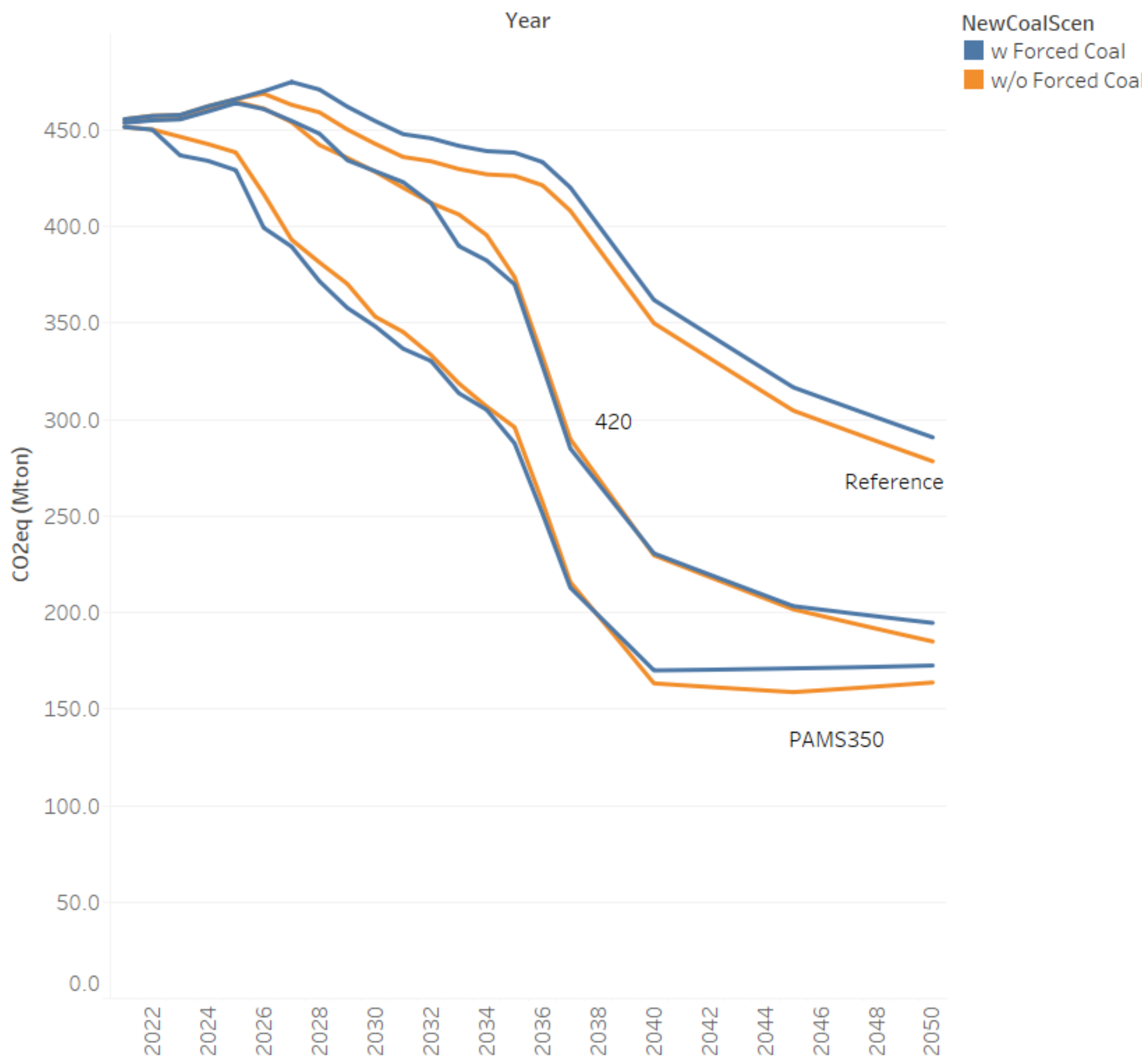


Figure 21 Projected national Greenhouse gas emissions

Figure 22 demonstrates the higher electricity unit costs (R/kWh) in both scenarios when the coal is forced into the build plan.

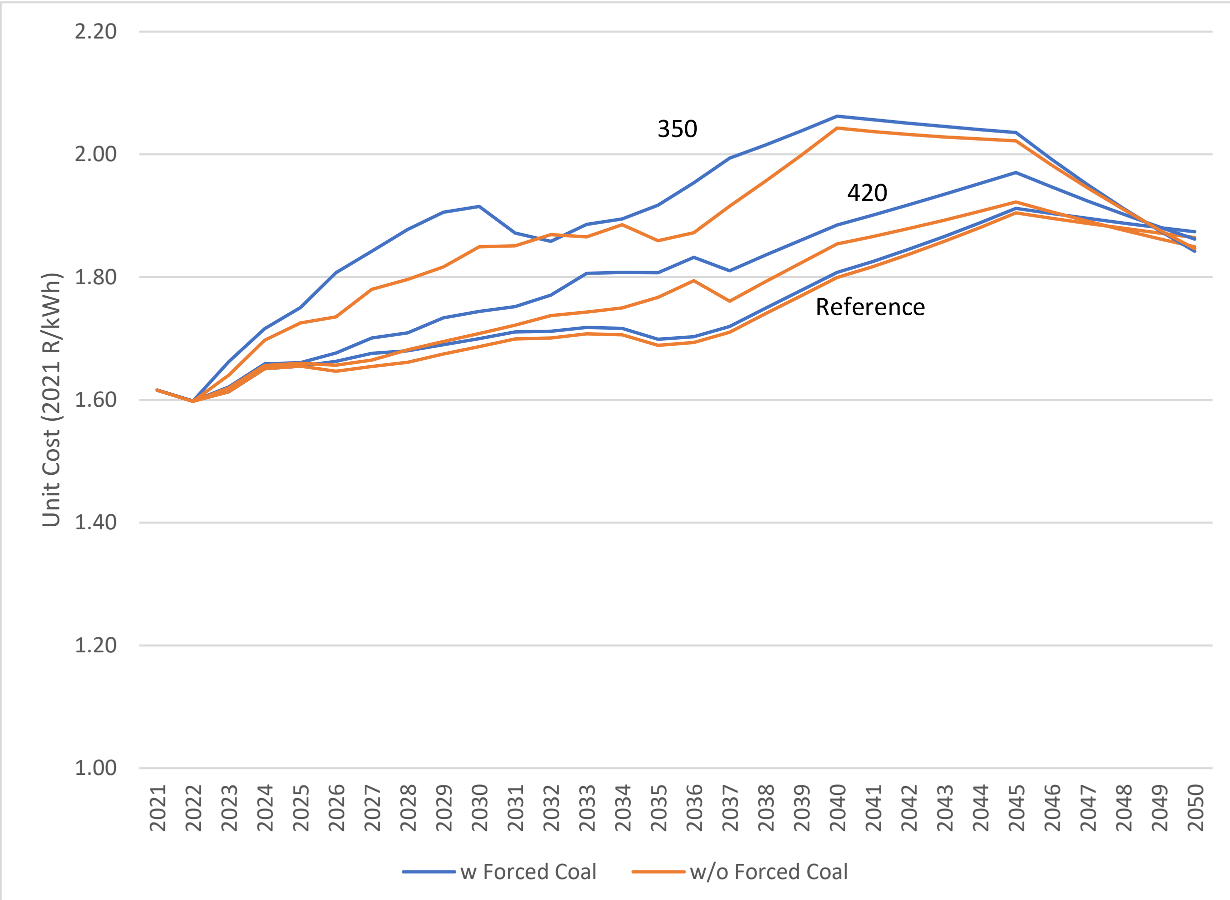


Figure 22 Projected Unit Cost for Electricity

Figure 23 summarises the additional discounted system costs from forced coal for each scenario, in 2021 ZAR.

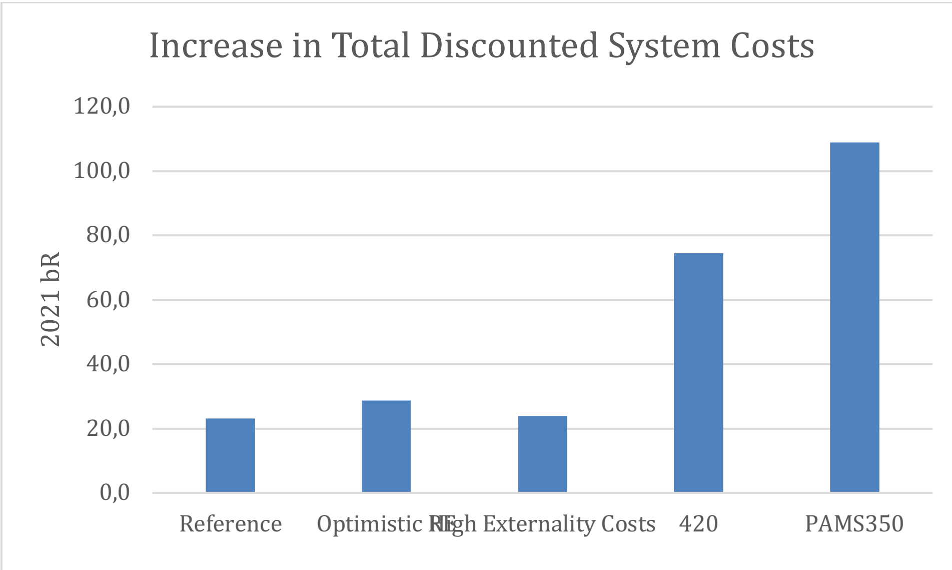


Figure 23 Increase in total discounted power system costs with forced coal, all scenarios

Conclusion

Our modelling shows that forcing in new coal raises costs even when climate goals are not considered, and leads to an additional discounted system cost of R23bn. New coal plants also make the achievement of South Africa's updated Nationally Determine Contribution targets, as well as South Africa's fair share contribution to climate change, vastly more expensive.

In a scenario where South Africa meets its own mitigation targets, as developed in its own NDC update of 2021, and builds new coal as contemplated in the IRP 2019, then this will increase power system costs by between R 74bn (420 Mt) and R109bn (350 Mt). Based on our analysis, the new coal capacity in the IRP 2019 is not necessary for energy security, will raise greenhouse gas emissions unnecessarily, and is more costly than alternatives.

References

1. AEMO. 2019. Maintaining Power System Security with High Penetrations of Wind and Solar Generation: International Insights for Australia. Australian Energy Market Operator. https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Future-Energy-Systems/2019/AEMO-RIS-International-Review-Oct-19.pdf
2. AEMO. 2020. 2020 Integrated System Plan: For the National Electricity Market. Australian Energy Market Operator. https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp
3. Agora Energiewende and Ember. 2021. The European Power Sector in 2020: Up-to-Date Analysis on the Electricity Transition. https://www.agora-energiewende.de/en/publications/the-european-power-sector-in-2020/
4. Agora. 2020. Modernising the European lignite triangle: Towards a safe, cost-effective and sustainable energy transition. Agora Energiewende and Forum Energii. https://www.agora-energiewende.de/fileadmin/Partnerpublikationen/2020/Lignite_Triangle/EN-Modernising_the_European_lignite_triangle.pdf
5. Bischof-Niemz and Fourie. 2016. Cost of new power generators in South Africa: Comparative analysis based on recent IPP announcements. CSIR. https://www.ee.co.za/wp-content/uploads/2016/10/New_Power_Generators_RSA-CSIR-14Oct2016.pdf
6. Bischof-Niemz. 2019. Opinion: Are there really more jobs in coal than in renewables? *Mining Weekly*. https://www.miningweekly.com/article/opinion-are-there-really-more-jobs-in-coal-than-in-renewables-2019-02-12/rep_id:3650
7. Bodnar, Gray, Grbusic, Herz, Lonsdale, Mardell, Ott, Sundaresan, and Varadarajan. 2020. How to Retire Early: Making Accelerated Coal Phaseout Feasible and Just. Rocky Mountain Institute. https://rmi.org/insight/how-to-retire-early

8. Burton, Caetano, and MCall. 2018. Coal Transitions in South Africa: Understanding the implications of a 2oC-compatible coal phase-out plan for South Africa. Energy Research Centre, University of Cape Town, Cape Town. https://www.iddri.org/sites/default/files/PDF/Publications/Catalogue%20Iddri/Rapport/20180609_ReportCoal_SouthAfrica.pdf
9. Burton, Marquard, and McCall. 2019. Socio-economic Considerations for a Paris Agreement-Compatible Coal Transition in South Africa. Climate Transparency. https://www.climate-transparency.org/wp-content/uploads/2019/07/CT-Just-Transition-in-South-Africa.pdf
10. California ISO. 2016. What the duck curve tells us about managing a green grid. California Independent System Operator. https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf
11. Carbon Tracker. 2020. How to waste over half a trillion dollars: The economic implications of deflationary renewable energy for coal power investments. Carbon Tracker Initiative. https://carbontracker.org/reports/how-to-waste-over-half-a-trillion-dollars/
12. Chartan, Reber, and Brinkman. 2017. Preliminary Findings of the South Africa Power System Capacity Expansion and Operational Model Study. National Renewable Energy Laboratory. https://www.nrel.gov/docs/fy18osti/70319.pdf
13. Clack. 2018. Retirement of Colorado Coal-fired Power Plants Using the WIS:dom Optimization Model. Vibrant Clean Energy. https://figshare.com/articles/presentation/Colorado_Coal_Retirement_Study_CRS_/13087679
14. Clack, Gimon, McKee, and O'Boyle. 2019. The Coal Cost Crossover: Economic Viability of Existing Coal Compared to New Local Wind and Solar Resources. Energy Innovation and Vibrant Clean Energy. https://vibrantcleanenergy.com/wp-content/uploads/2019/03/LCOE-Mapping/Coal-Cost-Crossover_Energy-Innovation_VCE_FINAL2.pdf

15. Climate Analytics. 2019. Global and regional coal phase-out requirements of the Paris Agreement: Insights from the IPCC Special Report on 1.5°C. Climate Analytics. https://climateanalytics.org/publications/2019/coal-phase-out-insights-from-the-ipcc-special-report-on-15c-and-global-trends-since-2015/
16. Cui, Hultman, Edwards, He, Sen, Surana, McJeon, Iyer, Patel, Yu, Nace, and Shearer. 2019. Quantifying operational lifetimes for coal power plants under the Paris goals. Nature Communications, 10. https://www.nature.com/articles/s41467-019-12618-3.pdf
17. Czyżak and Wrona. 2021. Achieving the goal: Coal phase-out in the Polish power sector. Instrat. http://instrat.pl/wp-content/uploads/2021/03/Instrat-Achieving-the-goal-v1.3.pdf
18. De Vivero, Burges, Kurdziel, and Hagemann. 2019. Transition towards a decarbonised electricity sector – A framework of analysis for power system transformation. NewClimate Institute, Re-expertise. https://newclimate.org/2019/10/02/transition-towards-a-decarbonised-electricity-sector/
19. EREA and DEA. 2019. Vietnam Energy Outlook Report 2019. https://www.ea-energianalyse.dk/wp-content/uploads/2020/02/1931_Vietnam-EOR_2019.pdf
20. IEA. 2017. Market Series Report: Renewables 2017 Analysis and Forecasts to 2022. International Energy Agency, Paris. https://www.iea.org/reports/renewables-2017
21. IEA. 2019. Status of Power System Transformation 2019: Power System Flexibility. International Energy Agency, Paris. https://www.iea.org/reports/status-of-power-system-transformation-2019
22. IEA. 2020. World Energy Outlook 2020. International Energy Agency, Paris. https://www.iea.org/reports/world-energy-outlook-2020
23. IEA. 2021. Net Zero by 2050: A Roadmap for the Global Energy Sector. International Energy Agency. https://www.iea.org/reports/net-zero-by-2050
24. IEA. 2019. Global Energy and CO^2 Status Report: The latest trends in energy and emissions in 2018. International Energy Agency, Paris. https://www.iea.org/reports/global-energy-co2-status-report-2019/emissions

25. Ireland and Burton/ 2018. An assessment of new coal plants in South Africa's electricity future: The cost, emissions, and supply security implications of the coal IPP programme. Energy Research Centre, University of Cape Town, Cape Town. https://cer.org.za/programmes/pollution-climate-change/publications/an-assessment-of-new-coal-plants-in-south-africas-electricity-future
26. IRENA. 2021. Renewable Capacity Statistics 2021. International Renewable Energy Agency, Abu Dhabi. https://www.irena.org/publications/2021/March/Renewable-Capacity-Statistics-2021
27. IRENA. 2015. From Baseload to Peak: Renewables Provide a Reliable Solution. International Renewable Energy Agency, Abu Dhabi. https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2015/IRENA_Baseload_to_Peak_2015.pdf
28. IRENA. 2020. Renewable Power Generation Costs in 2019. International Renewable Energy Agency, Abu Dhabi. https://www.irena.org/publications/2020/Jun/Renewable-Power-Costs-in-2019
29. Jones. 2021. Global Electricity Review 2021: Global Trends. Ember. www.ember-climate.org/global-electricity-review-2021
30. Lazard. 2020. Lazard's Levelized Cost of Energy Analysis: Version 14.0. https://www.lazard.com/media/451419/lazards-levelized-cost-of-energy-version-140.pdf
31. McCall, Burton, Marquard, Hartley, Ahjum, Ireland and Merven. 2019. Least-cost integrated resource planning and cost-optimal climate change mitigation policy: Alternatives for the South African electricity system. Energy Research Centre, University of Cape Town, Cape Town. https://lifeaftercoal.org.za/wp-content/uploads/2019/02/Alt-IRP-final-07022019.pdf
32. Merven, Hartley, McCall, Burton, and Schers. 2019. Improved representation of coal supply for the power sector for South Africa. Southern-Africa – Towards Inclusive Economic Development. https://sa-tied.wider.unu.edu/sites/default/files/pdf/SATIED_WP84_Merven_Hartley_McCall_Burton_Schers_October_2019.pdf

33. Merven, Hartley, Robinson, and Arndt. 2020. Modelling the costs of constraining the transition to renewable energy in South Africa. Southern-Africa – Towards Inclusive Economic Development. https://sa-tied.wider.unu.edu/sites/default/files/images/SA-TIED_WP102.pdf
34. Merven, Schers, Burton, McCall, Marquard, and Bergh. 2021. Comments for the National Energy Regulator of South Africa on the Ministerial Determination on the procurement of 2500 MW new generation capacity from nuclear. Energy Research Centre, University of Cape Town, Cape Town. http://www.epse.uct.ac.za/sites/default/files/image_tool/images/363/ESRG/Publications/2021_ESRG_Comments%20for%20NERSA%20on%20the%20procurement%20of%202500%20MW%20new%20generation%20capacity%20from%20nuclear_AcknFixed.pdf
35. Oyewo, Aghahosseini, Ram, Lohrmann, and Breyer. 2019. Pathway towards achieving 100% renewable electricity by 2050 for South Africa. Solar Energy, 191. https://www.sciencedirect.com/science/article/abs/pii/S0038092X19309144?via%3Dihub
36. Pachouri, Spencer, and Renjith. 2021. Exploring Electricity Supply-Mix Scenarios to 2030. The Energy and Resources Institute and Energy Transitions Commission. https://www.teriin.org/sites/default/files/2019-02/Exploring%20Electricity%20Supply-Mix%20Scenarios%20to%202030.pdf
37. Pfeiffer, Millar, Hepburn, and Beinhocker. 2016. The 2^0C capital stock for electricity generation: committed cumulative carbon emissions from the electricity generation sector and the transition to a green economy. Applied Energy, 179. https://www.inet.ox.ac.uk/publications/the-2-c-capital-stock-for-electricity-generation-committed-cumulative-carbon-emissions-from-the-electricity-generation-sector-and-the-transition-to-a-green-economy/
38. Qvist, Gładysz, Bartela, Sowizdzał. 2020. Retrofit Decarbonization of Coal Power Plants—A Case Study for Poland. *Energies*, 14, 120. https://www.mdpi.com/1996-1073/14/1/120

39. Roff, Steyn, Tyler, Renaud, Brand and Burton. 2020. A Vital Ambition: Determining the Cost of Additional CO^2 Emission Mitigation in the South African Electricity System. Meridian Economics. https://meridianeconomics.co.za/wp-content/uploads/2020/07/Ambition.pdf
40. Rogelj, McCollum, Reisinger, Meinshausen, and Riahi. 2013. Probabilistic cost estimates for climate change mitigation. Nature, 493. https://www.nature.com/articles/nature11787
41. Schers, Bagilet, and Burton. 2019. Managing the coal transition for workers in South Africa: Scenario analysis of age cohorts and skills profiles of coal workers. Southern-Africa – Towards Inclusive Economic Development. https://www.dropbox.com/sh/y9lfhu2lhpsugkd/AADEoaktB-0yz_opwcMcr0X1a/Session%203?dl=0andpreview=Managing+the+coal+transition+for+workers+in+South+Africa.pdfandsubfolder_nav_tracking=1
42. Steyn, Burton, and Steenkamp. 2017. Eskom's Financial Crisis and the Viability of Coal-Fired Power in South Africa: Implications for Kusile and the Older Coal-Fired Power Stations. Meridian Economics. https://meridianeconomics.co.za/wp-content/uploads/2017/11/CoalGen-Report_FinalDoc_ForUpload-1.pdf
43. Tyler and Steyn. 2018. An Overview of the Employment Implications of the South African Power Sector Transition. South African Wind Energy Association. https://sawea.org.za/wp-content/uploads/2018/08/SAWEA-Employment-in-SA-Power-Sector-July-2018-EMAIL-VERSION.pdf
44. Wright and Calitz. 2020. Systems analysis to support increasingly ambitious CO2 emissions scenarios in the South African electricity system. Council for Scientific and Industrial Research. https://researchspace.csir.co.za/dspace/bitstream/handle/10204/11483/Wright_2020_edited.pdf?sequence=7andisAllowed=y
45. Wright, Calitz, Bischof-Niemz, and Mushwana, 2017a. The long-term viability of coal for power generation in South Africa. Council for Scientific and Industrial Research. https://www.researchgate.net/publication/324409134_The_long-

term_viability_of_coal_for_power_generation_in_South_Africa/link/5accbab0aca272abdc656d6a/download

46. Wright, Bischof-Niemz, Calitz, Mushwana, van Heerden, and Senatla. 2017b. Formal comments on the Integrated Resource Plan (IRP) Update Assumptions, Base Case and Observations 2016. Council for Scientific and Industrial Research.https://www.researchgate.net/publication/315770295_Formal_comments_on_the_Integrated_Resource_Plan_IRP_Update_Assumptions_Base_Case_and_Observations_2016
47. Wright, Calitz, Ntuli, Fourie, Rampokanyo, and Kamera. 2018. Formal comments on the Draft Integrated Resource Plan (IRP) 2018. Council for Scientific and Industrial Research. file:///C:/Users/Patrick/Downloads/Wright_Formal%20comments_report.pdf

Appendix

Assumptions

Table 10 Assumptions applicable to all scenarios investigated

Assumption	Unit	Value	Source
Discount Rate (Real)		8.2%	IRP 2019
Average GDP growth (2021-2050)		2.6%	SATIMGE Reference
Sent out Demand in 2030 and 2050	2030 TWh 2050 TWh	270 386	SATIMGE Reference (see Figure 27)
New Coal Overnight Investment Cost (FBC w FGS assumed)	2017 R/kW (excl.ODC) 2021 R/kW (incl. ODC)	48,319 62,292	Cost of FBC with FGD, single unit as received by CER from DMRE on IRP 2019 assumptions with 10% Owners Development Costs (ODC)[18] added.
Net Efficiency		36%	Ireland and Burton 2018
Emission Factor Assumed for new coal (FBC)	tonN2O/MWh tonCO2/MWh ton CO_2-eq /MWh	0.863 0.963 1.230	Ireland and Burton 2018
Eskom Fleet Retirement			As per Eskom Comm April 2020 (see Table 12) with Endogenous Retirement if economic to do so from 2025 onward.
Eskom coal plants Minimum Annual Utilization		40%	SATIMGE Reference
Eskom Fleet Energy Availability Factor (EAF)		65%	As per Wright and Calitz 2020 (see Table 13 below for coal fleet EAF)
Employment Intensity of Power Plants			As Per Merven et al 2019 (see Table 3).

[18] The cost boundary in SATIM, unlike in IRP 2019, includes the Owners Development Costs (ODC), and this is applied across all power generating technologies.

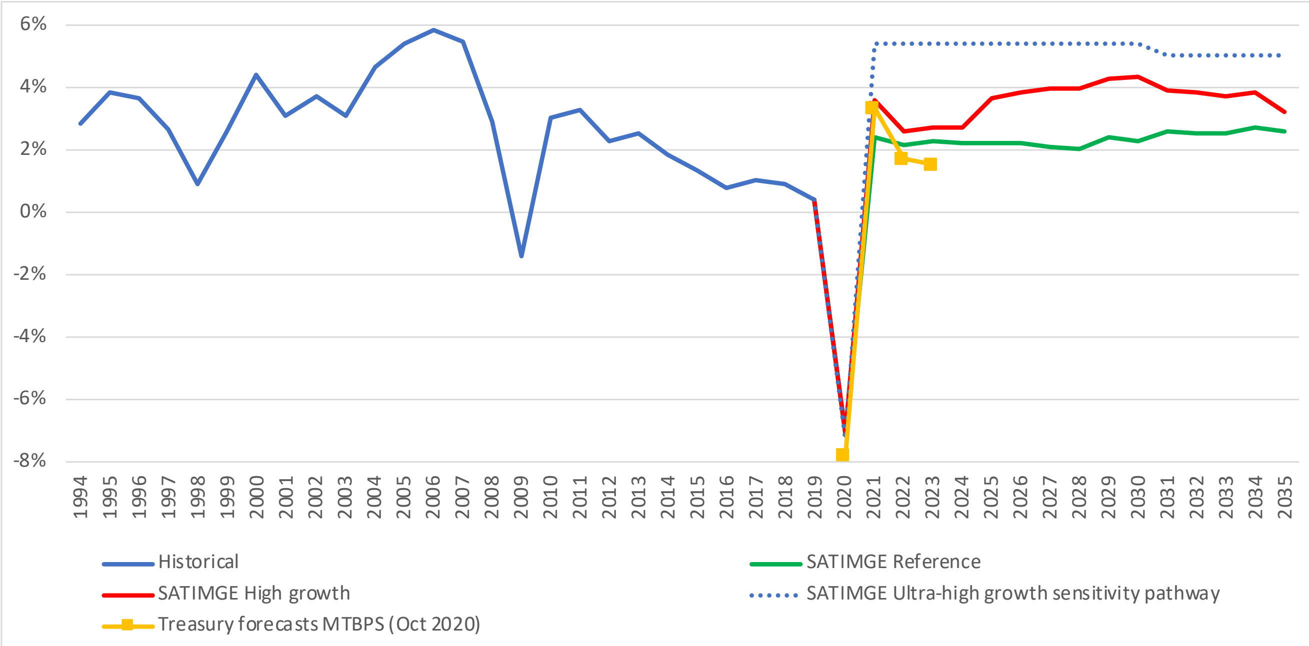
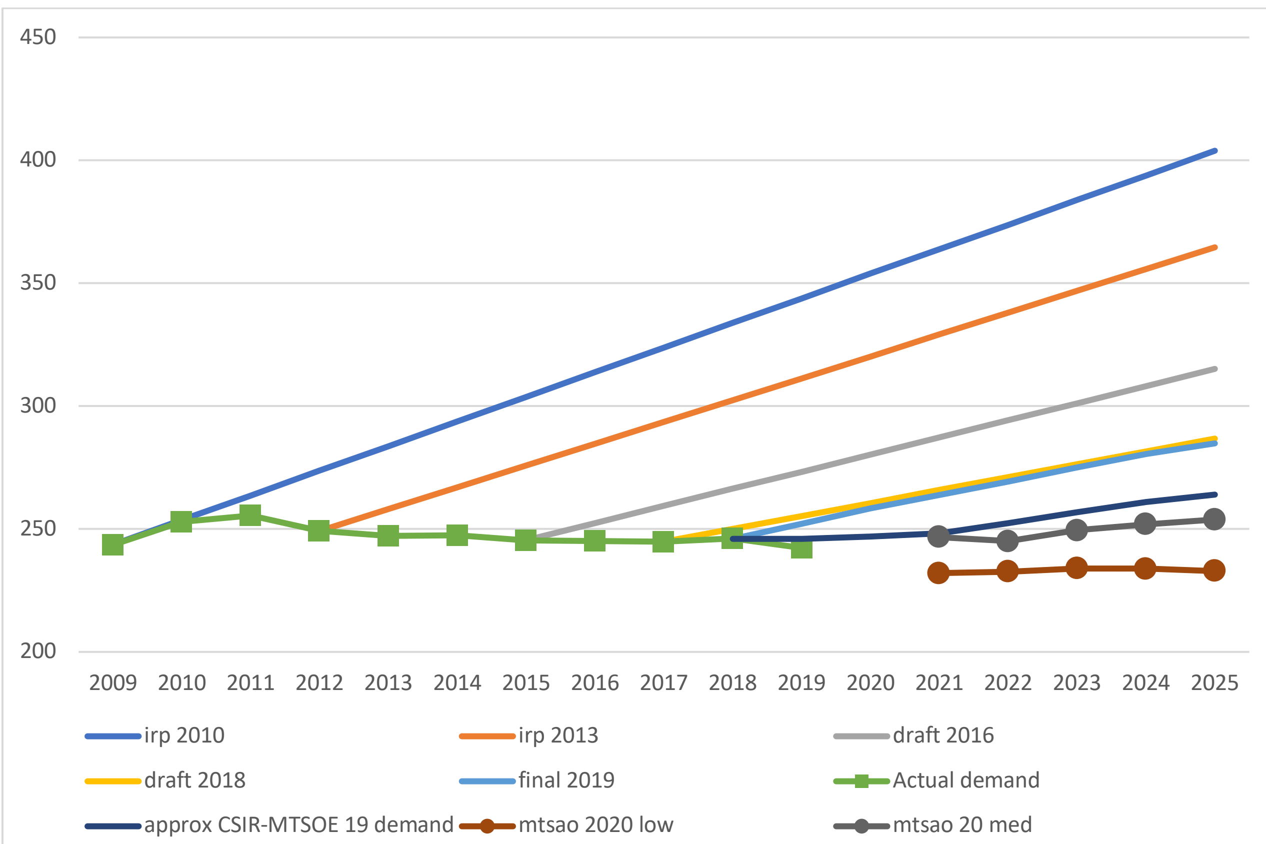


Figure 24 - Historical and projected GVA growth rates, along with Treasury's short-term forecast.



IRP 2019 used three demand forecasts:

- Upper: average 3.18% annual GDP growth, but assumed the current economic sectoral structure remained. This forecast resulted in an average annual electricity demand growth of 2.0% by 2030 and 1.66% by 2050.
- Median: based on an average 4.26% annual GDP growth by 2030, but with significant change in the structure of the economy. This forecast resulted in an average annual electricity demand growth of 1.8% by 2030 and 1.4% by 2050.
- Lower: based on 1.33% GDP growth to 2030, which resulted in a 1.21% average annual electricity demand growth by 2030 and 1.24% by 2050.

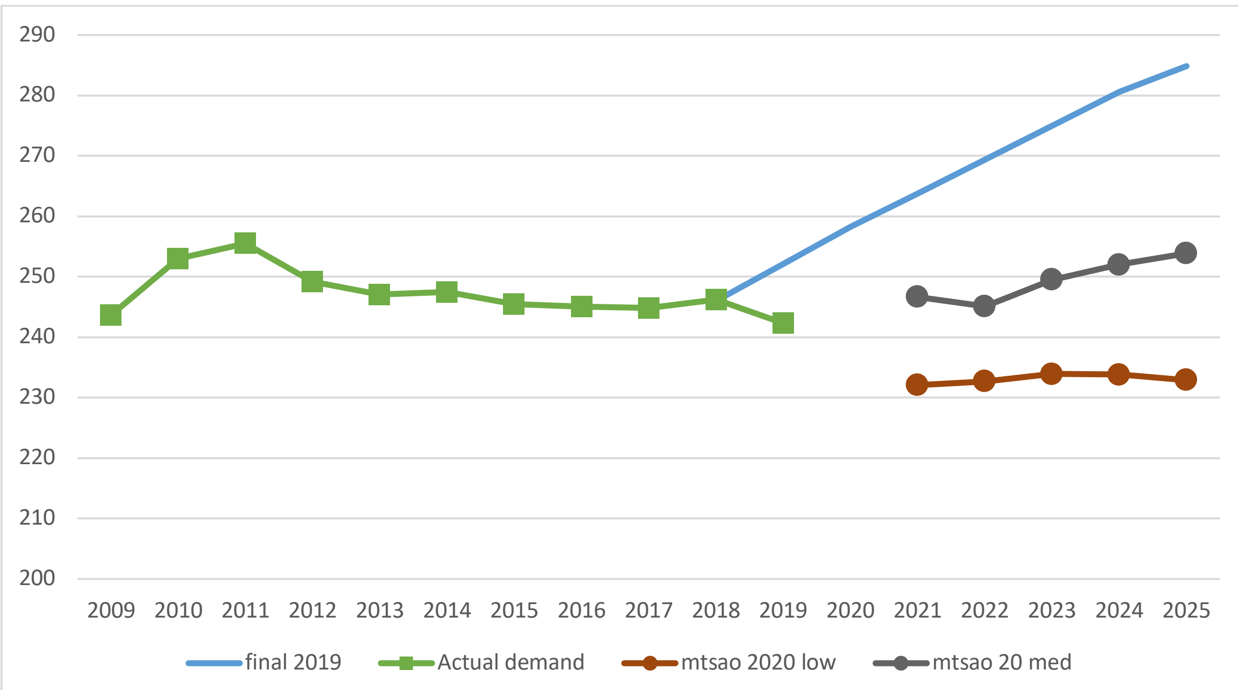


Table 11 Assumptions that vary across scenarios and sensitivity cases

	Reference	**Optimistic RE**	**High Externality**	**Climate Fair Share**
Renewable energy costs (see Figure 25 and Figure 26)	SATIMGE Reference costs	SATIMGE Optimistic costs	SATIMGE Reference costs	SATIMGE Reference costs
Externality costs	Based on IRP 2019 values	Based on IRP 2019 values	Externality impacts scaled to align with Naidoo et al (2019)	Based on IRP 2019

Mitigations Policies and Measures	none	none	none	NEES and GTS as per SATIMGE 2020

Table 12 Assumed Decommissioning Schedule for Eskom Coal fleet

Unit #		1	2	3	4	5	6	7	8	9
CAMDEN		2025	2026	2027	2028	2025	2026	2027	2028	
GROOTVLEI		2021	2021	2022						
KOMATI		2020	2020	2021	2022					
ARNOT		2021	2026	2026	2027	2029	2029			
DUVHA		2031	2031	2032	2033	2033	2034			
HENDRINA			2023		2021	2022	2025	2023	2022	2026
KENDAL		2039	2041	2042	2042	2043	2044			
KRIEL		2026	2027	2028	2029	2029	2030			
LETHABO		2036	2037	2037	2038	2040	2041			
MAJUBA DRY		2046	2047	2048						
MAJUBA WET					2049	2050	2051			
MATIMBA		2038	2038	2039	2040	2041	2042			
MATLA		2030	2031	2031	2032	2033	2034			
TUTUKA		2035	2036	2037	2037	2039	2041			
MEDUPI		2069	2068	2067	2067	2065				
KUSILE		2069								

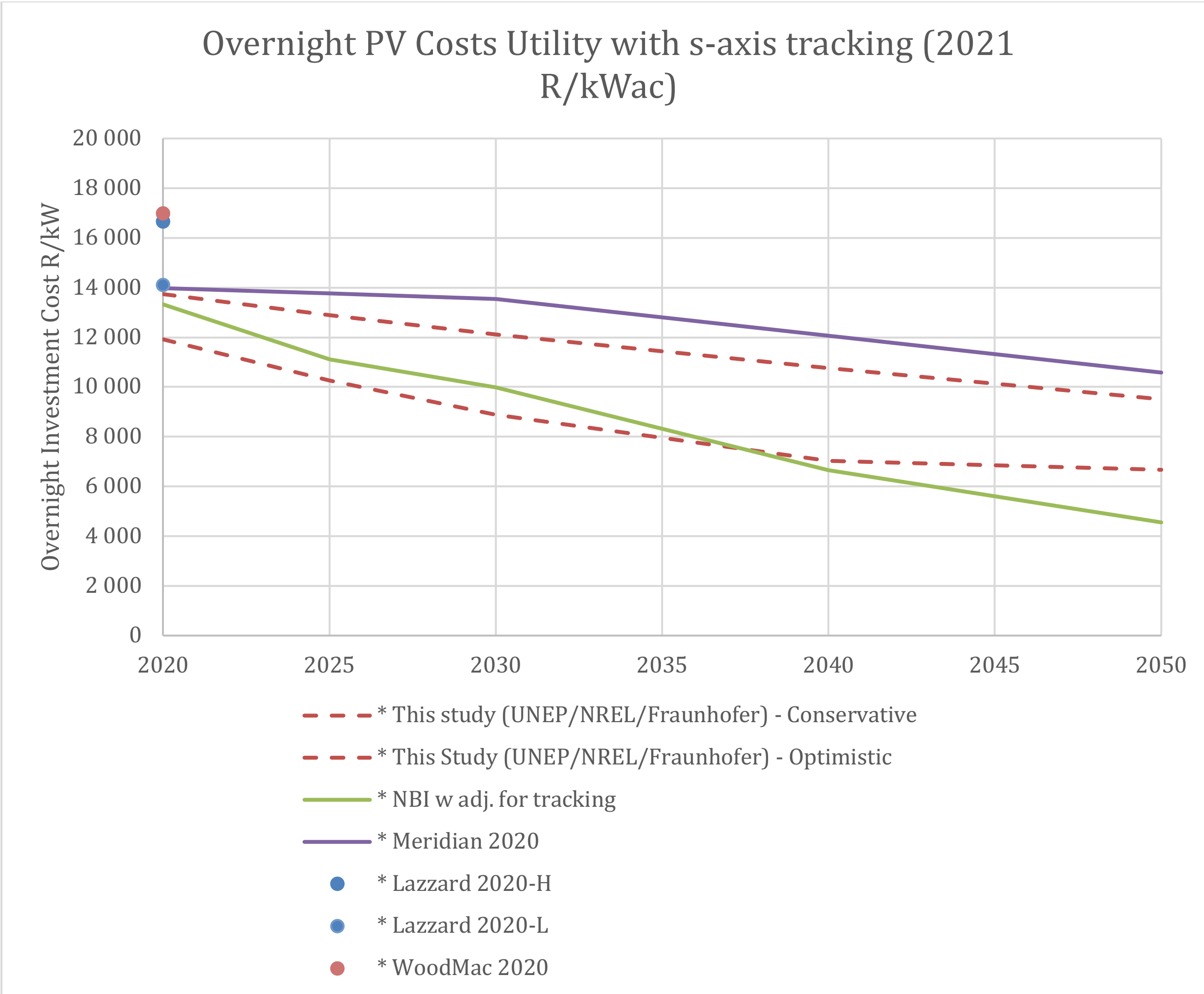


Figure 25 Projected Overnight Costs for PV with Single Axis Tracking (including ODC)

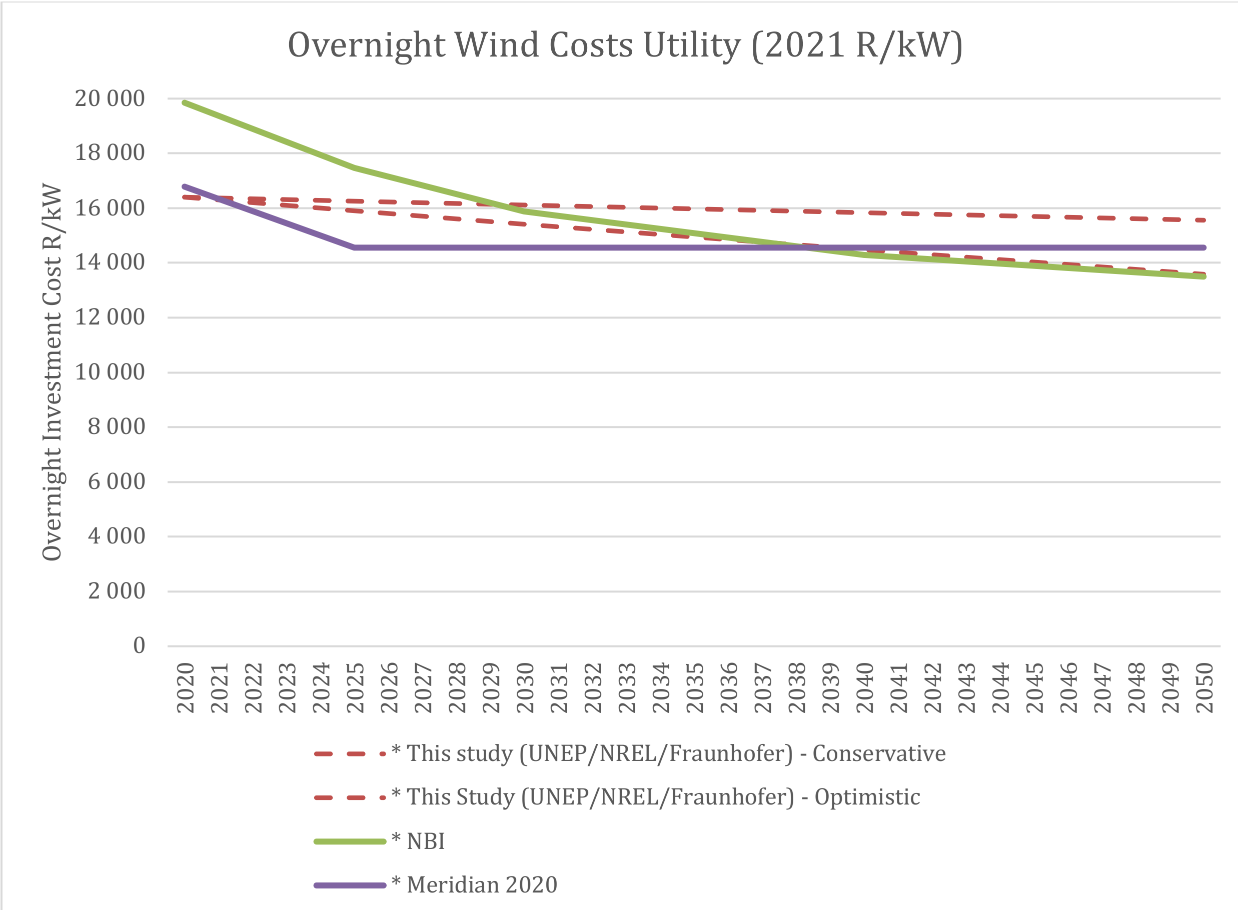


Figure 26 Projected Overnight Cost for Wind Including ODC

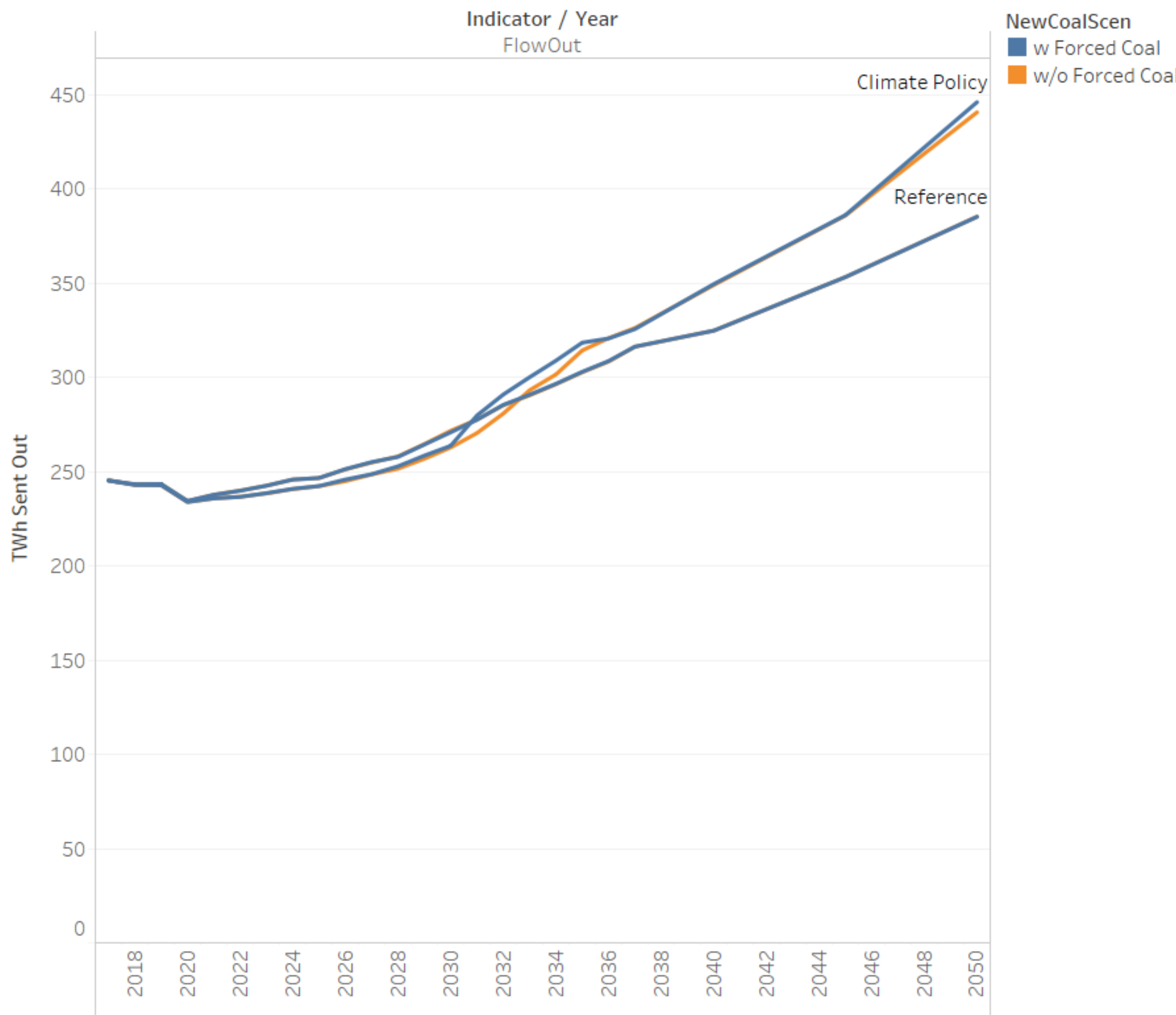


Figure 27 Projected Electricity Demand (net Sent out)

The higher demand comes from increased electrification of transport and production of renewable (ie green) Hydrogen for use in the transport and steel sectors.

Lower Energy Availability Factor. The EAFs for Eskom's coal plants contained in IRP 2019 have proved to be overoptimistic compared to actual EAFs for Eskom coal plants in 2019 and 2020, which has also contributed to current load-shedding. We apply lower EAFs based on (Wright and Calitz 2020). The IRP and Updated EAFs for Eskom's coal fleet are contained in Table 13 below.

Table 13 - Average EAFs for Eskom's coal plants (weighted by capacity)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Default EAF	68%	69%	71%	71%	72%	73%	72%	72%	72%	73%	72%
Lower EAF	61%	61%	62%	61%	60%	61%	60%	60%	60%	60%	59%

Addendum Appendix

Model Comparison to the modelling conducted for the Presidential Climate Commission

The model used in this analysis is similar to the version that was used in the modelling undertaken for the Presidential Climate Commission (PCC) which provided some of the technical basis for the PCC's deliberations on the proposed NDC update targets (PCC, 2021).[19]

In the PCC modelling all scenarios were run using the fully linked SATIMGE model which runs a full sector energy model (SATIM) and a general equilibrium model (eSAGE) iteratively. Changes in SATIM impacts variables in eSAGE (GDP), which then changes the energy demand, and causes changes in SATIM (system size, technology mix, costs and emissions). The main report includes runs that were done with the full linked model to obtain GDP and employment impacts.

However, the other runs, where total system cost and unit cost comparisons were sought, only the energy model (SATIM) was run. GDP is fixed and the same in the two runs with and without the new coal, and system costs can be more easily compared. A system cost which results from a run with lower GDP cannot be directly compared to one with a higher GDP because the cost difference is caused by both the change in system size (driven by GDP) and the decision that is being analysed (with and without the new coal power plant). Two sets of GDP trajectories were explored in the PCC modelling.

In this study, the GDP trajectory was fixed to being roughly halfway between the two at the 2030 horizon and ending up with a similar GDP as the low growth case by 2050. Other than growth uncertainties, the PCC modelling covered a range of other uncertainties and sensitivities, which include:

- With and without PAMS
- With and without Full IRP 2019 implemented
- With and without RE part of IRP 2019 implemented
- With and without endogenous coal retirement

In this study, we do not impose the IRP build plan. Rather, SATIM computes the capacity expansion plan that meets demand (which is assumed to be lower than what was assumed in the IRP 2019) at the least cost (i.e. without IRP implemented). This is because demand has been considerably lower than forecast in the IRP 2019 at the time of its release.

We assume no PAMS implementation except in the 350 case, and we assume that endogenous retirement for existing coal plants is possible in all runs, i.e. that plants are closed when it is

[19] PCC, 2021. Recommendations on South Africa's Draft Updated Nationally Determined Contribution, June 2021.

economic for them to do so. This is in contrast to the IRP analysis where plants are committed to run for a given lifetime regardless of costs, performance and emissions.

New Coal Technology

Different coal technologies are available in different configurations and sizes were considered for South Africa for the IRP and this study (EPRI 2017) and are summarized in the table below:

Technology	Config 1 LCOE [R/MWh]	Config 2 LCOE [R/MWh]	Config 3 LCOE [R/MWh][20]	Unit Size (MW) for 2x750 MW projects
Pulverized Coal (PF)	Without FGD LCOE: 1,201	With FGD LCOE: 1,466	With CCS LCOE:2,564	2x1x750
Integrated Gasification combined cycle (IGCC)	Without CCS LCOE: 1,717	With CCS LCOE: 2,293		
Fluidized Bed Combustion (FBC)	Without FGD LCOE: 1,449	With FGD LCOE: 1,513	With CCS LCOE: 2,462	3x 2x250

In this study we assumed that new coal would be FBC with FGD, for the following reasons:

- "Without FGD" does not meet air quality legislative requirements
- "With CCS" is too expensive relative to other options and will not be selected by the model, especially when transport and storage costs are included (they are not included in the table above).
- IGCC excluded because of higher costs.
- FBC chosen over PC because of smaller unit sizes, which would be preferred by IPP developers.

Assessing the viability of carbon capture and storage in South Africa

Carbon capture and storage (CCS) loosely refers to a family of technologies aimed at reducing emissions from the burning or use of fossil fuels. Essentially, the goal is to separate CO2 from the gases produced in the power plant (or other industrial facilities), store it underground, or utilize it in some way. There are three main steps: the separation of CO2 from the gas stream, its compression and transportation (via pipeline or shipping) and its storage in a suitable geological site (e.g. saline aquifers, depleted oil and gas reservoirs).

There are three broad categories based on capture processes: firstly, post-combustion CCS relies on 'scrubbing' CO_2 from flues following burning of coal; secondly, "oxy-combustion" or

[20] This is an underestimate as it excludes CO2 transport and storage costs which would raise costs even further

burning coal in pure oxygen (rather than air) leaves pure CO2 as a waste product, which can then be condensed and stored; and thirdly, pre-combustion technology which can only be used in coal gasification plants (and must be factored into construction rather than retrofitted)[21]. These are at varying levels of commercial development (post-combustion is widely use, while oxy-combustion is not yet commercial); there are also many separation technology options, also at varying stages of commercial development.

Despite the potentially important role it could play in mitigating greenhouse gas emissions, there are very few real-world examples of CCS currently operating at scale. Almost all climate change models with scenarios to limit warming use CCS in one form or another to meet temperature goals. Despite this reliance on the technology in models, the real world outlook on CCS has not kept pace with the technology roll out that would be required.

Of the total 51 facilities in 2019, only 19 are operating[22], and there are only two examples of CCS-enabled coal power generation (Canada's Boundary Dam Carbon Capture and Storage Project and the Petra Nova Carbon Capture Project in the USA), both coal-fired power plants. The remaining 17 are in either industrial processes or natural gas production[23]. Together, these 19 have the capacity to capture and store around 40 million tonnes of CO_2 annually[24], while the aforementioned coal plant examples resulted in 51% and 30% capture respectively. In May 2020, the Petra Nova capture plant was mothballed due to poor economics.[25]

While the cost of CCS is expected to decline (Figure 28), the additional technology does and will continue to significantly increase the cost of coal-fired power generation. The costs of capture at Boundary Dam (>$100/ton) and Petra Nova (>$60/ton) are prohibitively expensive, and would more than double the cost of a unit of electricity in major coal using countries such as India and South Africa, where new and existing coal plants are already challenged by new wind and solar.While HELE plants are more efficient, and the WCA and others typically promote higher efficiency plant combined with CCS, this increase in efficiency is partly offset by the efficiency penalties of the CCS plants which range from 8-15% (ie reduction in efficiency percentage points). Total energy penalties range from 15-28%.[26]

A 2017 paper on the Chinese coal power sector concluded that while the cost varies depending on capacity factor, coal price and other variables, the addition of 90% CO2 capture technology

---

[21] https://pubs.rsc.org/en/content/articlehtml/2018/ee/c7ee02342a and https://www.sciencedirect.com/science/article/pii/S2211467X18300634

[22] https://www.globalccsinstitute.com/wp- content/uploads/2019/12/GCC_GLOBAL_STATUS_REPORT_2019.pdf

[23] https://www.sciencedirect.com/science/article/pii/S2211467X18300634

[24] https://www.globalccsinstitute.com/wp-content/uploads/2019/12/GCC_GLOBAL_STATUS_REPORT_2019.pdf

[25] The plant depended on enhanced oil recovery (ie injecting the captured CO2 into oil wells), and low oil prices likely could not cover the considerable costs of the capture, even with US government subsidies. https://www.iea-coal.org/blogs/mothballed-petra-nova-has-already-proved-its-worth/

[26] (https://www.sciencedirect.com/science/article/pii/S2211467X18300634)

"would increase the plant cost of electricity generation significantly by 58%–108% in comparison with the plant without CCS"[27]. The study further concluded that to make this economically viable would require a minimum carbon price of $41/tonne imposed on coal-fired power plants, with the additional cost per kWh making coal even more uncompetitive with renewables and gas in many geographies.

Figure 28 Levelised cost of CO_2 capture for coal-fired power plants, historical & projected

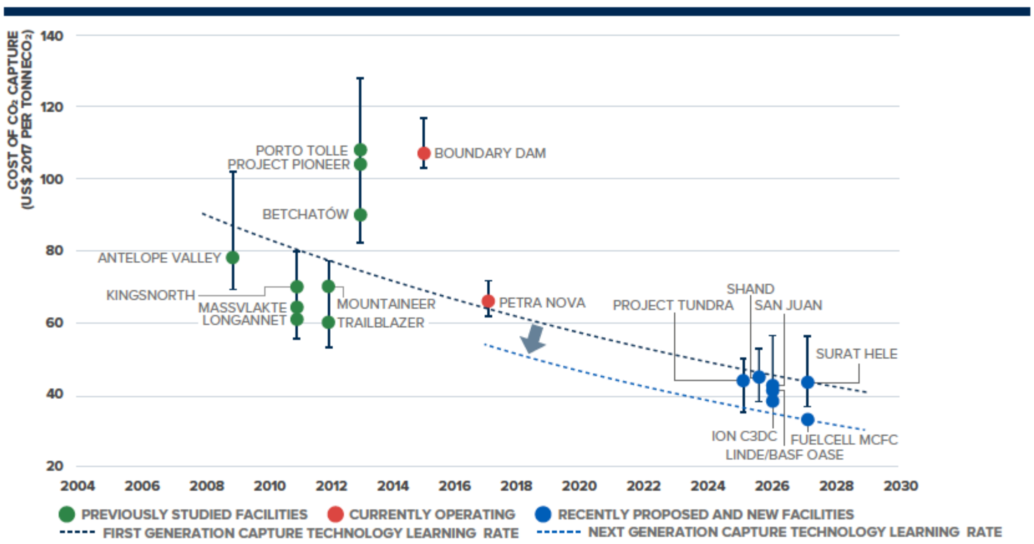


FIGURE 8 LEVELISED COST OF CO_2 CAPTURE FOR LARGE SCALE POST-COMBUSTION FACILITES AT COAL FIRED POWER PLANTS, INCLUDING PREVIOUSLY STUDIED FACILITIES[viii]

Further, although the costs by plant, capture technology, transport option, and storage differ widely, the table below highlights the considerable costs per ton of CO2 avoided when the costs along the entire value chain are assessed.

Cost of avoided CO_2 for different process plants, capture technologies and storage solutions.

	Cost ($2015/t$CO_2$)		References
	Min	Max	
Process plant			
Coal-fired power	24	110	[103–106,109–112]
Gas-fired power	67	115	[103,107,110–112]
Iron and steel	52	120	[103,106,113]
Refineries	6	160	[103,106,113]
Pulp and paper	47	93	[113]
Cement production	27	146	[103,106,113]
NGCC	10	146	[104–106,109]
Oxyfuel combustion	48	99	[106,109]
IGCC	3	140	[106,109]
Chemicals + bio or synfuel	20	111	[103,113]
Capture technology			
Post-combustion (amine)	63	87	[110]
Pre-combustion	47	60	[110]
Storage			
CCS	20	113	[106]
EOR/EGR	71	84	[107]

[27] https://www.cmu.edu/ceic/assets/docs/publications/published-papers/2017-and-2018/hu-and-zhai-2017.pdf

Source: Budinis et al

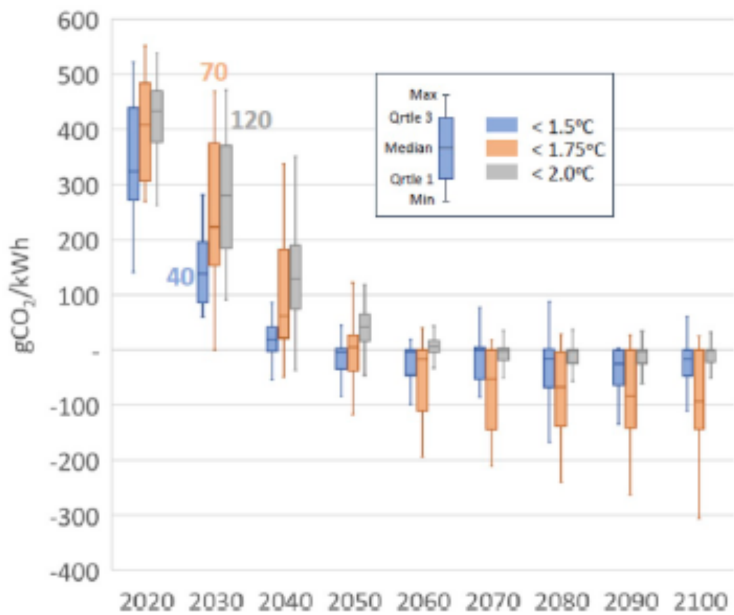
CCS is an example of a family of technologies that could reduce the GHG emissions of coal-fired power generation in comparison against the emission-intensive normal operations of coal power generation. However, in most cases these technology options remain considerably more emission-intensive than non-coal alternatives.

An overview of scenarios that meets the Paris Agreement temperature goals shows that CCS has a relatively small role to play in the future decarbonised power sector, primarily because even with CCS, emissions from coal power would still be too high under optimised scenarios to meet the stringent emissions reductions required to limit warming to below 2 or 1.5C. Furthermore, emissions can be more cheaply abated in the power sector than in other sectors without CCS (unlike in niche industrial applications, for example).

Figure 29 shows the emission-intensity of the power sector for various temperature goals, across families of Integrated Assessment Models. As can be seen, there is broad agreement across multiple scenarios that the electricity sector emissions essentially fall to zero or close to zero by 2050. Indeed, even by 2030 the below 1.5 °C scenarios have a median carbon intensity of electricity of 140gCO_2/kWh compared to 230gCO_2/kWh for the below 1.75 °C scenarios and 280 CO_2/kWh for the below 2 °C scenarios (vs 570g/kWh today). While there may be space at a national level (where countries can allocate emissions sub-optimally) for small quantities of coal power with CCS, in general, the emission reductions are simply not sufficient, and would require higher levels of emissions reduction elsewhere in national energy systems. Since emissions are harder to abate in other sectors, this is both technologically and economically challenging.

Figure 29 CO_2 intensity of electricity (Gambhir et al, 2019)[28]

[28] Energy system changes in 1.5°C, well below 2°C and 2°C scenarios in *Energy Strategy Reviews 23 (2019) 69–80* Ajay Gambhir, Joeri Rogelj, Gunnar Luderer, Sheridan Few, Tamaryn Napp



CCS readiness also relies on strategic infrastructure for transport and storage having been identified and secured, which is not the case in South Africa. In general, any focus on CCS should therefore be focused upon utilisation within niche industrial sectors where there are few other clear abatement options, and not on coal power, where CCS will make an already uncompetitive supply option more expensive.

Detailed assumptions on costs and emissions for the selected technology are given in the next section.

Detailed Assumptions

Table 14 Assumptions applicable to all scenarios investigated

Assumption	Unit	Value	Source
Discount Rate (Real)		8.2%	IRP 2019
Average GDP growth (2021-2050)		2.6%	SATIMGE Reference
Sent out Demand in 2030 and 2050	2030 TWh 2050 TWh	270 386	SATIMGE Reference (see Figure 27)
New Coal Overnight Investment Cost (FBC w FGS assumed)	2017 R/kW (excl.ODC) 2021 R/kW (incl. ODC)	48,319 62,292	Cost of FBC with FGD, single unit as received by CER from DMRE on IRP 2019 assumptions with 10% Owners Development Costs (ODC)[29] added.
Net Efficiency		36%	Ireland and Burton 2018
Emission Factor Assumed for new coal (FBC)	kgN2O/MWh[30] tonCO2/MWh ton CO_2-eq /MWh	0.863 0.963 1.230[31]	Ireland and Burton 2018
Eskom Fleet Retirement			As per Eskom Comm April 2020 (see Table 12) with Endogenous Retirement if economic to do so from 2025 onward.
Eskom coal plants Minimum Annual Utilization		40%	SATIMGE Reference
Eskom Fleet Energy Availability Factor (EAF)		65%	As per Wright and Calitz 2020 (see Table 13 below for coal fleet EAF)
Employment Intensity of Power Plants			As Per Merven et al 2019 (see Table 3).

[29] The cost boundary in SATIM, unlike in IRP 2019, includes the Owners Development Costs (ODC), and this is applied across all power generating technologies.
[30] This was erroneously specified as tonN2O/MWh in the main report (the model specification was correct). The ton CO_2-eq number is still the same.
[31] Using 310 as the GWP (global warming potential from the second assessment report see https://www.ghgprotocol.org/sites/default/files/ghgp/Global-Warming-Potential-Values%20%28Feb%2016%202016%29_1.pdf)

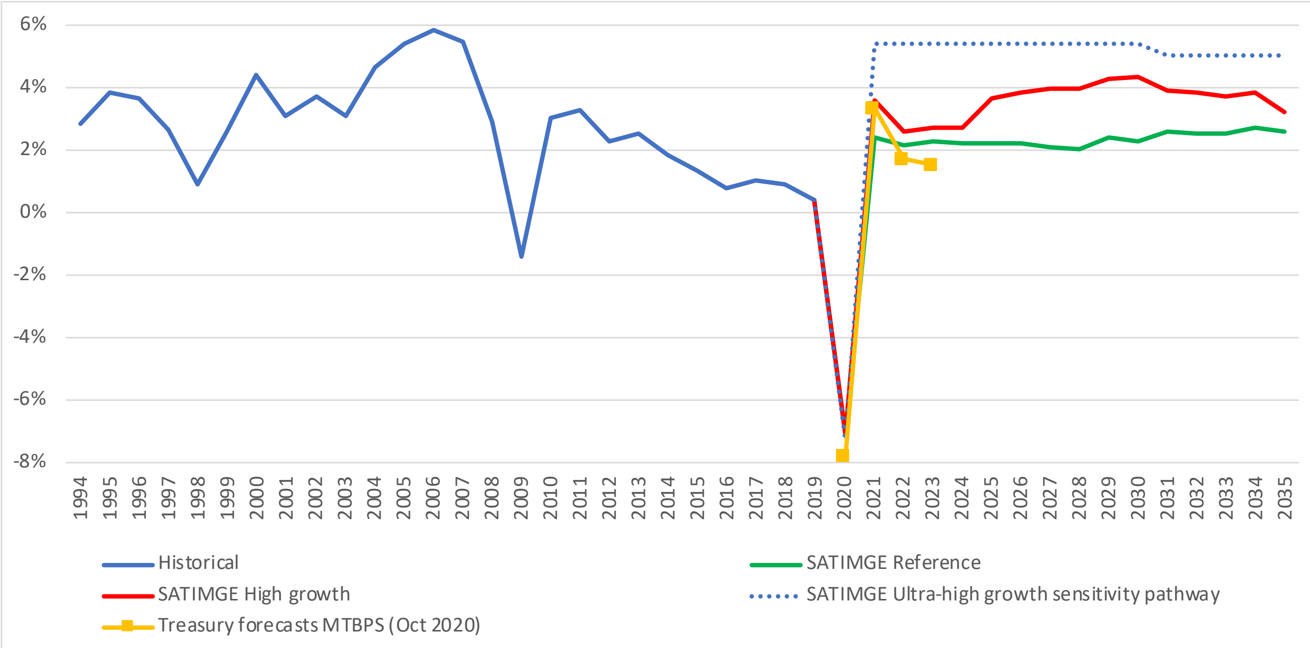
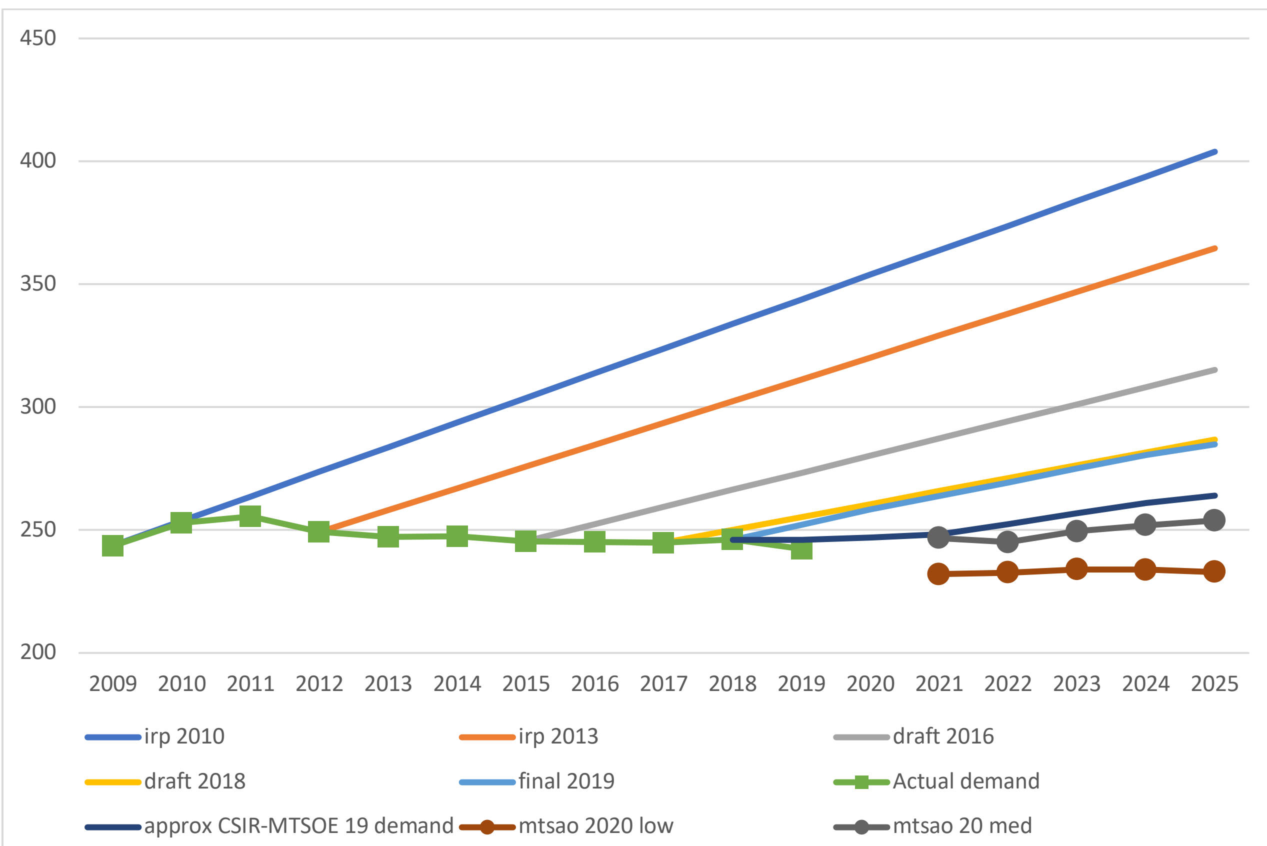


Figure 30 - Historical and projected GVA growth rates, along with Treasury's short-term forecast.



IRP 2019 used three demand forecasts:

- Upper: average 3.18% annual GDP growth, but assumed the current economic sectoral structure remained. This forecast resulted in an average annual electricity demand growth of 2.0% by 2030 and 1.66% by 2050.
- Median: based on an average 4.26% annual GDP growth by 2030, but with significant change in the structure of the economy. This forecast resulted in an average annual electricity demand growth of 1.8% by 2030 and 1.4% by 2050.
- Lower: based on 1.33% GDP growth to 2030, which resulted in a 1.21% average annual electricity demand growth by 2030 and 1.24% by 2050.

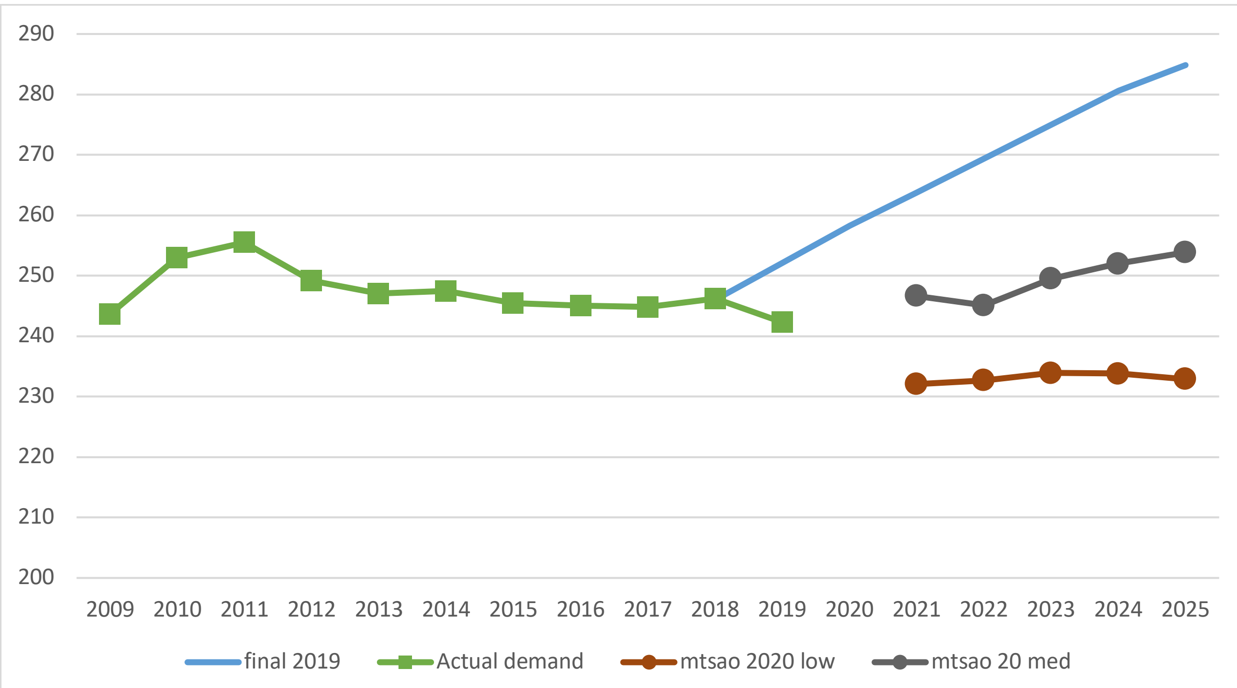


Table 15 Assumptions that vary across scenarios and sensitivity cases

	Reference	**Optimistic RE**	**High Externality**	**Climate Fair Share**
Renewable energy costs (see Figure 25 and Figure 26)	SATIMGE Reference costs	SATIMGE Optimistic costs	SATIMGE Reference costs	SATIMGE Reference costs
Externality costs	Based on IRP 2019 values	Based on IRP 2019 values	Externality impacts scaled to align with Naidoo et al (2019)	Based on IRP 2019

Mitigations Policies and Measures	none	none	none	NEES and GTS as per SATIMGE 2020

Table 16 Assumed Decommissioning Schedule for Eskom Coal fleet

Unit #		1	2	3	4	5	6	7	8	9
CAMDEN		2025	2026	2027	2028	2025	2026	2027	2028	
GROOTVLEI		2021	2021	2022						
KOMATI		2020	2020	2021	2022					
ARNOT		2021	2026	2026	2027	2029	2029			
DUVHA		2031	2031	2032	2033	2033	2034			
HENDRINA			2023		2021	2022	2025	2023	2022	2026
KENDAL		2039	2041	2042	2042	2043	2044			
KRIEL		2026	2027	2028	2029	2029	2030			
LETHABO		2036	2037	2037	2038	2040	2041			
MAJUBA DRY		2046	2047	2048						
MAJUBA WET					2049	2050	2051			
MATIMBA		2038	2038	2039	2040	2041	2042			
MATLA		2030	2031	2031	2032	2033	2034			
TUTUKA		2035	2036	2037	2037	2039	2041			
MEDUPI		2069	2068	2067	2067	2065				
KUSILE		2069								

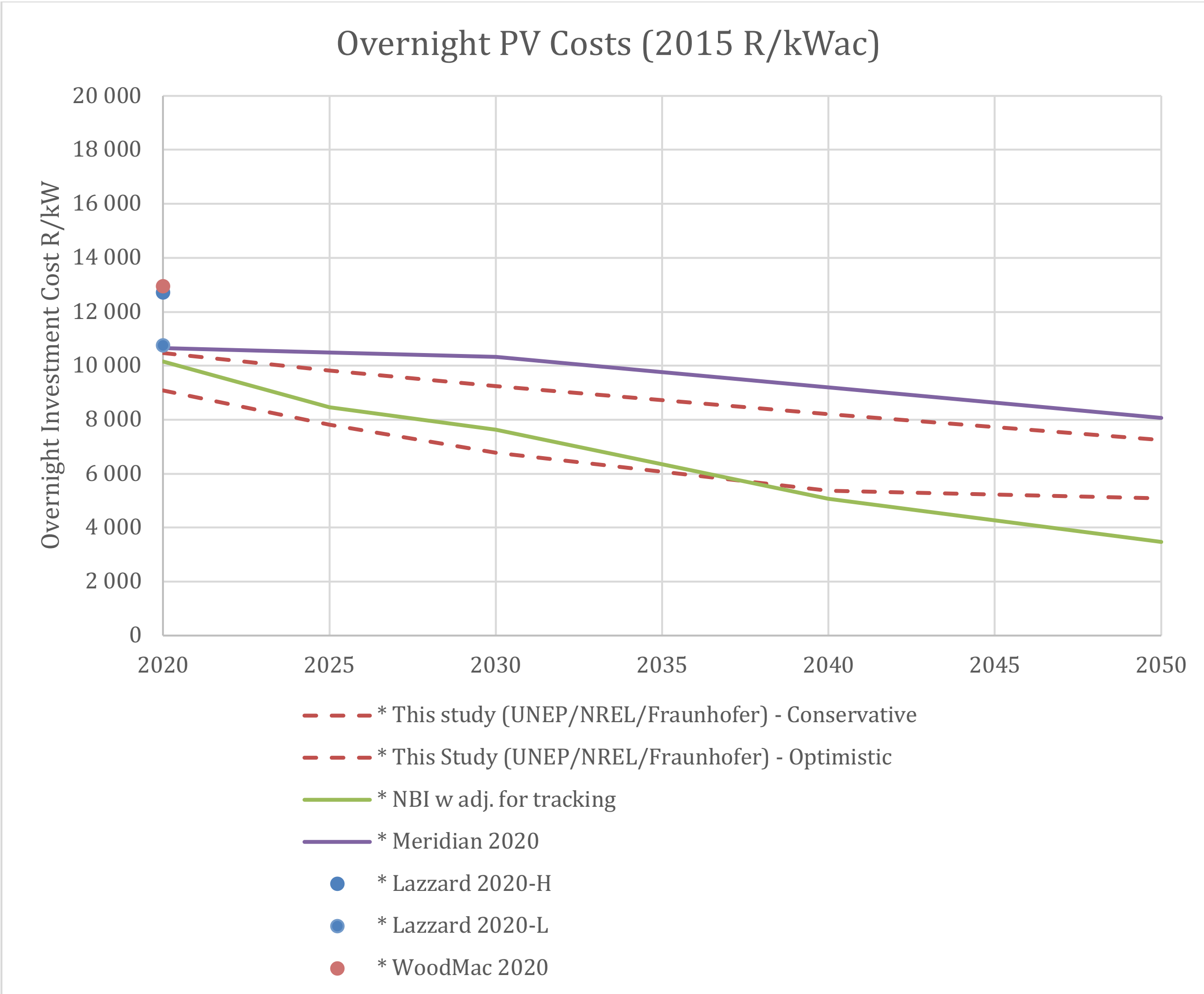


Figure 31 Projected Overnight Costs for PV with Single Axis Tracking (including ODC)

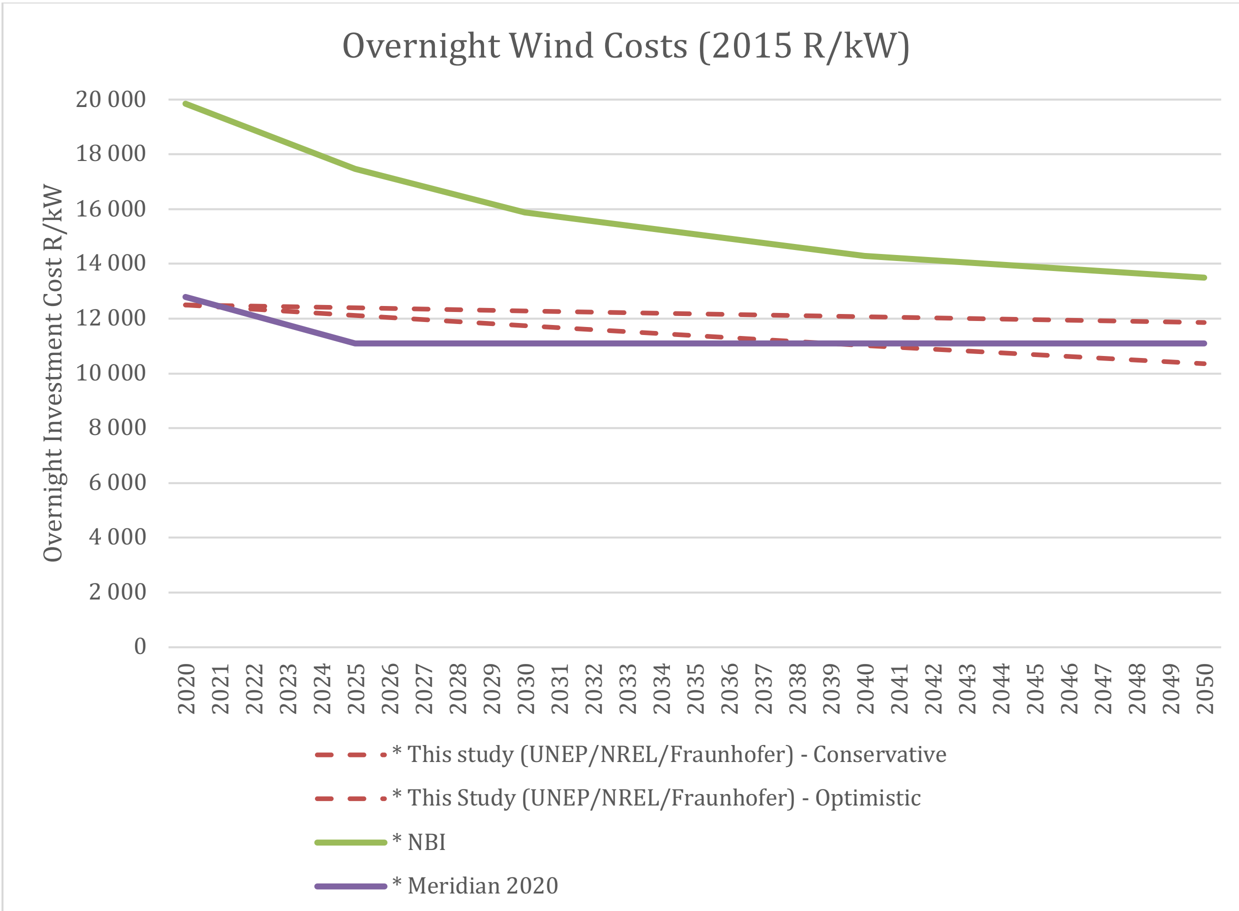


Figure 32 Projected Overnight Cost for Wind Including ODC

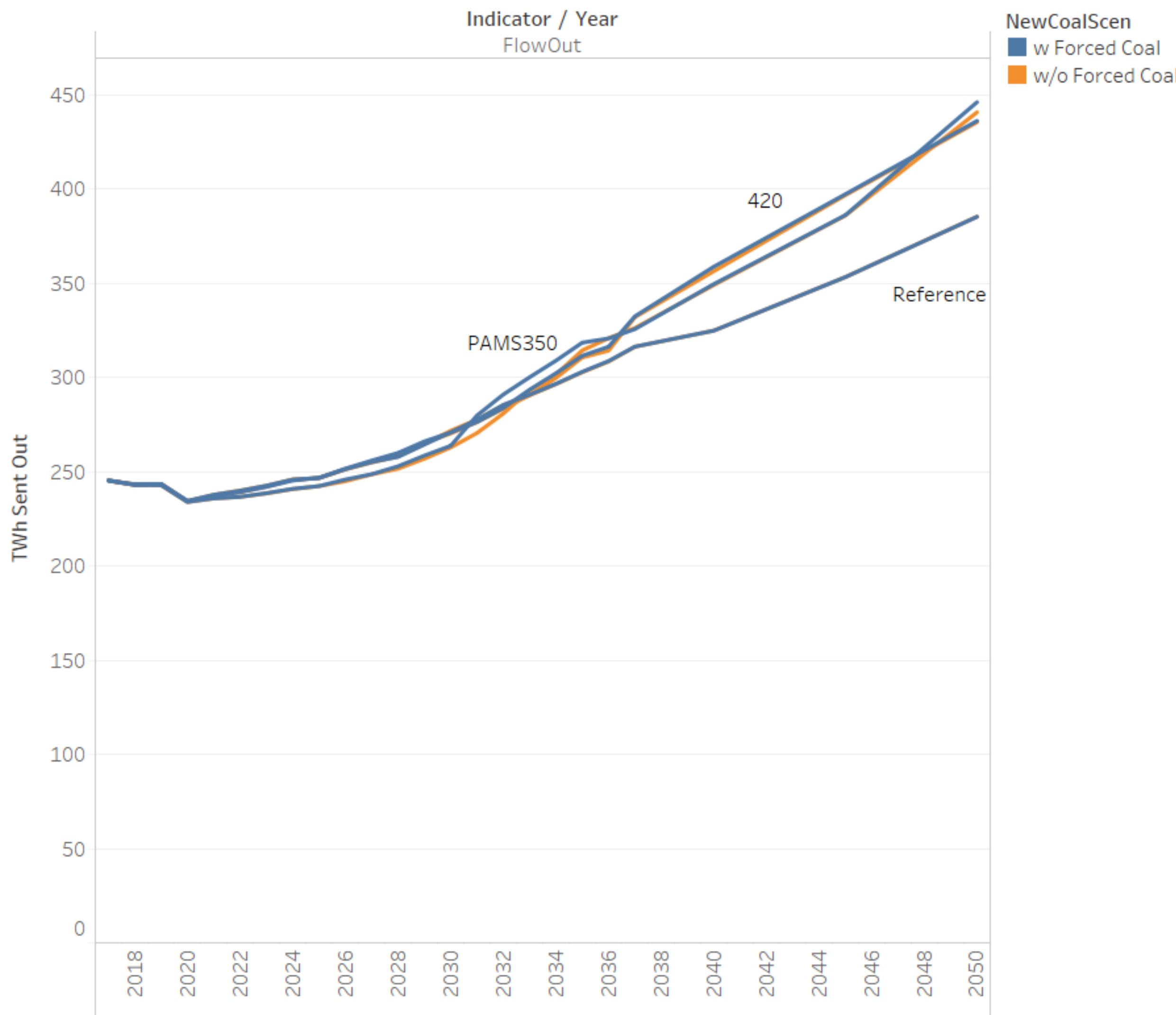


Figure 33 Projected Electricity Demand (net Sent out)

The higher demand comes from increased electrification of transport and production of renewable (ie green) Hydrogen for use in the transport and steel sectors.

Lower Energy Availability Factor. The EAFs for Eskom's coal plants contained in IRP 2019 have proved to be overoptimistic compared to actual EAFs for Eskom coal plants in 2019 and 2020, which has also contributed to current load-shedding. We apply lower EAFs based on (Wright and Calitz 2020). The IRP and Updated EAFs for Eskom's coal fleet are contained in Table 13 above.

Table 17 - Average EAFs for Eskom's coal plants (weighted by capacity)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Default EAF	68%	69%	71%	71%	72%	73%	72%	72%	72%	73%	72%
Lower EAF	61%	61%	62%	61%	60%	61%	60%	60%	60%	60%	59%

Table 18 Breakdown of total discounted Power System Costs with and without Forced Coal IPP in bR (2021)

		Reference	**Reference**	**OptRE**	**OptRE**	**Externality**	**Externality**	**Climate 420**	**Climate 420**
Indicator (group)	Subsubsector (Power)	w/o Forced Coal	w Forced Coal	w/o Forced Coal	w Forced Coal	w/o Forced Coal	w Forced Coal	w/o Forced Coal	w Forced Coal
Grand Total	**Total**	**4,771**	**4,794**	**4,696**	**4,725**	**4,946**	**4,969**	**5,096**	**5,204**
Annual Invest.Cost	**Total**	**2,528**	**2,546**	**2,465**	**2,487**	**2,528**	**2,546**	**2,950**	**3,060**
	New Coal		69.9		69.9		69.9		69.9
	VRE	495.2	460.1	419.7	389.3	495.3	460.2	827.1	857.7
	Flex.Gen	225.6	213.3	238.2	224.8	225.6	213.3	292.6	296.9
	Network	980.7	976.4	980.5	976.3	980.7	976.3	1,003.00	1,007.40
	Existing Coal	730.9	730.9	730.9	730.9	730.9	730.9	730.9	730.9
	OtherGen	95.7	95.7	95.7	95.7	95.7	95.7	96.2	97.4
Maintenance	**Total**	**1,087**	**1,096**	**1,088**	**1,098**	**1,087**	**1,096**	**1,214**	**1,242**
	New Coal		26.7		26.7		26.7		26.4
	VRE	179.6	165.5	174.1	160.9	179.6	165.5	318.9	328.8
	Flex.Gen	52	49.5	58.6	55.1	52	49.5	90.3	92.1
	Network	572.7	572.7	573	573.1	572.6	572.7	567.1	567.9
	Existing Coal	220.2	220	220.1	220	220.1	220	175.7	164.4
	OtherGen	62.1	62.1	62.1	62.1	62.1	62.1	62.1	62
Fuel Costs	**Total**	**833.3**	**823.8**	**821.5**	**813.8**	**835.6**	**826.1**	**698**	**681.8**
	New Coal		9.3		9.3		9.3		9.3
	VRE	0	0	0	0	0	0	0	0
	Flex.Gen	208.3	190.7	197.4	181.6	208.6	191.1	237.9	242.7
	Existing Coal	559.5	558.3	558.8	557.7	561.3	560	382.6	350.5
	OtherGen	65.5	65.5	65.3	65.3	65.6	65.7	77.5	79.4
Externality Costs	**Total**	**189.4**	**190.2**	**189.1**	**189.9**	**362.1**	**363.6**	**134.2**	**124**
	New Coal		1.2		1.2		2.4		1.2
	Flex.Gen	0.9	0.8	0.8	0.7	1.6	1.5	0.9	1
	Existing Coal	188.5	188.2	188.3	187.9	360.5	359.7	133.2	121.8
Levies	**Total**	**60.8**	**62.2**	**60.6**	**62.1**	**60.8**	**62.1**	**47.9**	**46.6**
	New Coal		1.7		1.7		1.7		1.7
	Flex.Gen	1.9	1.7	1.8	1.6	1.9	1.7	2.2	2.3
	Existing Coal	53.7	53.6	53.6	53.5	53.6	53.5	40.4	37.4
	OtherGen	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
CO2Tax	**Total**	**72.5**	**74.8**	**72.3**	**74.6**	**72.5**	**74.7**	**51.5**	**50.1**
	New Coal		2.5		2.5		2.5		2.5
	Existing Coal	2.4	2.1	2.2	2.0	2.4	2.1	2.6	2.6
	Flex.Gen	69	68.9	68.9	68.8	68.9	68.8	47.8	43.8

Table 19 Breakdown of total discounted Power System Costs with and without Forced Coal IPP in bR (2021)

		Reference		**OptRE**		**Climate: 420**		**Climate: 350**	
Indicator (group)	Subsubsector (Power)	w/o Forced Coal	w Forced Coal	w/o Forced Coal	w Forced Coal	w/o Forced Coal	w Forced Coal	w/o Forced Coal	w Forced Coal
Grand Total	**Total**	**4,771**	**4,794**	**4,696**	**4,725**	**4,971**	**5,046**	**5,096**	**5,204**
Annual Invest.Cost	**Total**	**2,528**	**2,546**	**2,465**	**2,487**	**2,732**	**2,811**	**2,950**	**3,060**
	New Coal		69.9		69.9		69.9		69.9
	VRE	495.2	460.1	419.7	389.3	**644.5**	**656.5**	827.1	857.7
	Flex.Gen	225.6	213.3	238.2	224.8	249.9	246.4	292.6	296.9
	Network	980.7	976.4	980.5	976.3	1,006.50	1,008.40	1,003.00	1,007.40
	Existing Coal	730.9	730.9	730.9	730.9	730.9	730.9	730.9	730.9
	OtherGen	95.7	95.7	95.7	95.7	100.1	98.6	96.2	97.4
Maintenance	**Total**	**1,087**	**1,096**	**1,088**	**1,098**	**1,165**	**1,191**	**1,214**	**1,242**
	New Coal		26.7		26.7		26.5		26.4
	VRE	179.6	165.5	174.1	160.9	245.1	250.4	318.9	328.8
	Flex.Gen	52	49.5	58.6	55.1	69.5	69.8	90.3	92.1
	Network	572.7	572.7	573	573.1	577.1	577.5	567.1	567.9
	Existing Coal	220.2	220	220.1	220	210.8	204.7	175.7	164.4
	OtherGen	62.1	62.1	62.1	62.1	62.9	62.6	62.1	62
Fuel Costs	**Total**	**833.3**	**823.8**	**821.5**	**813.8**	**779.4**	**757.4**	**698**	**681.8**
	New Coal		9.3		9.3		**9.3**		9.3
	VRE	0	0	0	0	0	0	0	0
	Flex.Gen	208.3	190.7	197.4	181.6	203.6	196.2	237.9	242.7
	Existing Coal	559.5	558.3	558.8	557.7	503	478.1	382.6	350.5
	OtherGen	65.5	65.5	65.3	65.3	72.8	73.8	77.5	79.4
Externality Costs	**Total**	**189.4**	**190.2**	**189.1**	**189.9**	**171.9**	**164.5**	**134.2**	**124**
	New Coal		1.2		1.2		1.2		1.2
	Flex.Gen	0.9	0.8	0.8	0.7	0.8	0.8	0.9	1
	Existing Coal	188.5	188.2	188.3	187.9	171.1	162.5	133.2	121.8
Levies	**Total**	**60.8**	**62.2**	**60.6**	**62.1**	**57**	**56.6**	**47.9**	**46.6**
	New Coal		1.7		1.7		1.7		1.7
	Flex.Gen	1.9	1.7	1.8	1.6	1.8	1.7	2.2	2.3
	Existing Coal	53.7	53.6	53.6	53.5	49.9	48	40.4	37.4
	OtherGen	5.2	5.2	5.2	5.2	5.3	5.3	5.2	5.2
CO2Tax	**Total**	**72.5**	**74.8**	**72.3**	**74.6**	**65.5**	**64.9**	**51.5**	**50.1**
	New Coal		2.5		2.5		2.5		2.5
	Existing Coal	2.4	2.1	2.2	2.0	2.2	2.1	2.6	2.6
	Flex.Gen	69	68.9	68.9	68.8	62.1	59.0	47.8	43.8