ACHIEVING NET-ZERO IN SOUTH AFRICA'S POWER SECTOR

Meridian Economics in collaboration with the Council for Scientific and Industrial Research (CSIR)

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All errors remain those of the project team.

KEY FINDINGS:

1. **A Net Zero pathway comes at little additional cost until the late 2030's or even early 2050's.**
2. **Build renewables now to create optionality for net zero in later years.**
3. **A net zero power system is largely achievable with established technologies.**

1 EXECUTIVE SUMMARY

This techno-economic study provides insights for decision making in order to achieve net zero emissions in the South African power sector by mid-century.

The work is an extension of the joint Meridian-CSIR modelling project undertaken in 2020 – The Vital Ambitions ("*Ambitions*") study [1] – which modelled long-term power sector decarbonisation scenarios. This net zero extension makes use of the Ambitions modelling framework, but includes further constraints compliant with a net zero emissions state. The project's findings confirm those of all recent modelling studies considering the decarbonisation of the South African power system: that in the short to medium term the priority is an ambitious build out of renewable energy.

1.1 STUDY CONTEXT

In 2020, the joint Meridian-CSIR 'Ambitions' study [1] analysed the system cost implications of increasingly ambitious decarbonisation scenarios for the South African power sector. The study found that power system transition pathways that involved an ambitious, accelerated rollout of renewable energy were both feasible and had cost implications that were far lower than previously thought, due to the reduction in renewable energy costs over the past decade. The Ambitions study provided evidence that emissions mitigation in the South African power system need not come at an additional cost. This finding held for power system pathways that fell within a carbon budget range associated with South Africa's fair contribution to achieving the temperature goals of the Paris Agreement of the United Nations Framework Convention on Climate Change (UNFCCC).

The concept of 'net zero by 2050' was introduced to the global decarbonisation discourse by the Intergovernmental Panel on Climate Change (IPCC)'s 2018 Special Report on 1.5˚C, gaining traction as countries, sectors and companies included a net zero goal as part of their decarbonisation targets. In South Africa, the target of 'net zero by 2050' is included as an aspirational goal in the Low Emissions Development Strategy and is included in the national power utility Eskom's Just Energy Transition vision.

Given the target's growing prominence and role in the fight to tackle climate change, Meridian sought to better understand the implications of achieving power sector net zero in South Africa by building on the analysis in the Ambitions study, to inform the evolving energy policy and planning discussion. Before doing this, we undertook a deep dive into the climate science and policy origins of the net zero concept in 'Defining 'Net Zero' for analysis of the South African power sector' (hereafter the "**NZ Briefing Note**" [2]), developing a six part framework to guide our modelling work.

This report presents the outcomes of this Ambition's extension modelling work, based closely upon the framework and conceptual arguments developed in the NZ Briefing Note.

1.2 WHAT DOES 'NET ZERO' FOR THE SOUTH AFRICAN POWER SYSTEM MEAN?

The origins of the 'net zero' concept lie in scientific analysis of what is required to limit global warming to a specific temperature target. Achieving global net zero carbon dioxide emissions 'by 2050' implies ambition to limit global temperature rise to a target of 1.5˚C. The Paris Agreement stipulates a target of limiting warming to 'well below 2˚C and pursuing efforts to limit warming to 1.5 ˚C'.

The NZ Briefing Note identified the importance of employing a carbon budget, along with net zero carbon emissions at a certain point, to determine alignment with the Paris Agreement. This is because the emissions trajectory before a net zero point is reached (and resultant cumulative carbon budget) – is what drives the level of temperature increase. Because the IPCC's 2050 net zero date is derived at the global level, a range of net zero dates are possible sub-globally. These dates could differ for countries and for sectors, depending on their starting points and decarbonisation capabilities available to them.

Within this context, this study takes the following as a working definition of net zero for the South African power system: A **credible, net zero power system must have cumulative emissions that remain within a Paris-aligned appropriate sector-level carbon budget and must be observed as having sustainable net zero emissions after a certain date.** The definition is intentionally broad, acknowledging the political and policy role in defining Paris-aligned net zero more closely at a sub-global, sub-national scale. The breadth allows for a full exploration of the techno-economic implications of net zero for the South African power sector.

1.3 WHAT WE SET OUT TO DO

Using the Ambition's project power system modelling framework, we set out to answer the following in relation to achieving a net zero power system for South Africa:

- What decisions are required now?
- What are the cost implications?
- What technologies are required for (transition to) net zero?
- What policy levers are required?
- What are the implications of different net zero dates?

The study imposes three policy-type levers for achieving net zero for the SA power system – use of a carbon budget, a net zero date, and a coal phase-out date. We test the impact of these three levers in various combinations on a reference scenario selected from the Ambitions study – the 'Ambitious RE build programme' scenario.

Box 1 Policy levers considered for achieving net zero

1. *Imposing a Paris-aligned carbon budget on power sector emissions*. Two carbon budgets are considered by this study, 2.3 Gt and 2.8 Gt, both lying within the Paris-aligned range of 2 – 3.1Gt identified in the NZ Briefing paper deep dive and applied to the period 2021 - 2060. We acknowledge significant uncertainties still surrounding carbon budget determination, including that these uncertainties increase as one allocates budgets from the global to national and then to sectoral scale.
2. *Imposing a net zero date*. We investigate two net zero dates, 2050 and 2055, for the power system. The International Energy Agency (IEA) has more recently suggested that global Net Zero by 2050 (a 1.5˚C temperature goal) implies the developing world power sector must achieve net zero by 2040 on average. Whilst we don't model a net zero date by 2040 explicitly, our results enable us to comment on the implications of this date in the context of a power system with high coal dependency.
3. *Phasing out all coal by 2040*. We apply a coal phase out by 2040 constraint to test its implications for the SA power system.

The choice of carbon budgets and net zero dates was guided by the working definition of net zero developed for the project. The three levers are imposed in various combinations, to investigate their impact, together with the corresponding behaviour of the system.

The reference scenario selected for the project assumes an ambitious RE build programme which, in the Ambitions study, comprised a build out of renewables that achieved cumulative emissions within a Paris-aligned power sector carbon budget range. This scenario is named the *Ambitious RE Only* scenario in the context of this Net Zero study, given that it includes no other policy levers to achieve decarbonisation.

This reference scenario, whilst ambitious in terms of the pace of RE build-out, still contains carbon risk for the country in a world increasingly aware of the importance of achieving the Paris temperature goals. The power sector contains many of the lowest cost mitigation reduction opportunities across the economy. It is also the driver of both near term and economy-wide decarbonisation potential. A carbon intensive power supply represents significant risk to exporters as key import markets implement Carbon Border Adjustment Mechanisms (CBAMs). In addition, financiers are increasingly sensitive to the carbon intensity of their portfolios, putting South Africa at risk as an investment destination.

A total of six scenarios using various combinations of the three policy levers in Box 1 are considered. We acknowledge that this is likely not enough to fully consider the entire 'problem space' but is sufficient to reveal some important findings of how the SA power system may respond to the various levers. All scenarios are constrained to at least follow the minimum RE build programme that defines the *Ambitious RE Only* (reference) scenario, and then subjected to additional constraints in the form of the policy levers. The modelling platform optimises for least cost in each scenario, subject to any constraints imposed. A summary of the scenarios and observations of the impact of different policy levers is provided in Table 1 below.

Table 1: Summary of Results - Policy Levers and Observations[1]

	Scenario	Policy Lever Imposed			Observations			
		Coal off by 2040	Carbon Budget	Net Zero date	Cumulative Emissions to 2050 (Gt)	Emissions 2050-2060	Levelised system cost[2] increase / (decrease) to 2050	Paris-aligned Net Zero
Reference Scenario								
	Ambitious RE Only	×	×	×	2.80	0.43	0.0%	No
Study Scenarios								
	Coal off by 2040, 2.3Gt CO_2 budget	✓	✓	×	2.27	0.07	+1.4%	No
	Coal off by 2040, 2.3Gt CO_2 budget, NZ2050	✓	✓	✓ 2050	2.34	0	+1.4%	Yes
	Coal off by 2040	✓	×	×	2.35	0.09	+1.3%	No
	NZ2050	×	×	✓ 2050	2.70	0	+0.4%	Yes
	2.8Gt CO_2 budget	×	✓	×	2.53	0.23	+0.2%	No
	2.8Gt CO_2 budget, NZ2055	×	✓	✓ 2055	2.69	0.08	+0.05%	Yes

Only three of the scenarios considered comply with the working definition of net zero, and all of these involve the application of a net zero date. The cumulative emissions to 2050 associated with each scenario including the reference case are low compared to those associated with the power sector in the National Business Initiative's (NBI's) Net Zero Pathways for the Power Sector [3], but fall well within the range found by the Energy System Research Group's (ESRG's) Net Zero project [4][3]. Hence, all scenarios can be said to fall within a Paris-aligned budget range.

1.4 MODELLING PLATFORM AND ASSUMPTIONS

The study utilised the same long-term generation capacity expansion planning framework and modelling platform (PLEXOS) as did the Ambitions study. PLEXOS is well-established in the South African electricity modelling community, including for use in the development of the power sector's Integrated Resource Plan (IRP).

Most of the basic power system assumptions were drawn from the Ambitions work, outlined

[1] Note that the carbon budgets in the scenario names are rounded, whilst the cumulative emissions to 2050 figures are not.

[2] The system costs considered for the model include capital cost for new capacity, fixed cost, variable operation and maintenance costs (FOM and VOM) of both existing and new capacity, fuel cost as well as start-up and shutdown costs. Other costs considered are the cost of retaining reserve capacity required to maintain system adequacy, along with the cost of unserved energy. Costs that are excluded from the system modelling are costs associated with transmission and distribution, others that do not fall into the scope of the modelling as well as unavoidable costs (e.g., sunk capital costs and actual cost of decommissioning plants).

[3] Whilst the ESRG Net Zero Pathways Report does not provide power sector budgets, these were received by the authors from the ESRG in May 2022 upon request.

in Meridian's 'A Vital Ambition' Report and the CSIR's Technical Report. A number of additional technologies and fuel options were made available to the model, specifically to enable the consideration of net zero emissions power systems, including Direct Air Carbon Capture (DACC) technology and green hydrogen-fuelled turbine generators. Whilst the Ambitions model ran to 2060, results were only reported to 2050. This project maintains this approach although, where material to the research questions, results from the 2050-60 period are additionally highlighted.

1.5 KEY FINDINGS:

1.5.1 A NET ZERO PATHWAY COMES AT LITTLE ADDITIONAL COST UNTIL THE LATE 2030'S OR EVEN EARLY 2050'S

A key finding in the Ambitions study was that the cost of implementing an *Ambitious RE Only* scenario (this study's reference case) relative to SA's existing policy trajectory is not material. This study extends this result by finding that pathways that additionally achieve net zero by 2055 are no more expensive until at least the late 2030s, and in one case the early 2050s.

Panel (a) of Figure 1 depicts the annual system cost differentials for each of the scenarios run in the project (which can be broadly categorised into those with and without a net zero date constraint) relative to the reference *Ambitious RE Only* scenario[4]. Until the late 2030s, there are no significant cost differences between the scenarios.

Thereafter, two key policy levers drive an increase in annual system costs relative to the *Ambitious RE Only* scenario:

1. A decision to take all coal-fired power off the system in 2040 increases the relative system cost by just under 5%. This is driven by the need for additional renewables, storage and peaking capacity earlier than would otherwise be economically optimal.
2. Imposing a net zero date results in the relative system cost differential increasing from 5% to just less than 15%. This 'last mile' decarbonisation cost is driven predominantly by a fuel switch to green hydrogen[5] (which results in the doubling of the cost of peaking fuel, further elaborated in section 1.5.7) and the deployment of additional battery storage and renewable capacity.

However, if a modest carbon price is applied on the power system from 2030, the cost differentials resulting from imposing the coal off and net zero policy levers are dramatically reduced. This is demonstrated in panels (b) and (c) of Figure 1.

At a fixed carbon price of $30/ton from 2030, (in line with the carbon tax proposed by National Treasury[6]), taking coal off in 2040 becomes economically rational. The "last mile" premium that comes with enforcing a net zero date is eliminated if carbon emissions attract a cost of ~$65/ton or more from 2030.

For context, the world is fast adopting carbon pricing, with 23% of global greenhouse gas emissions already under carbon price instruments in 2022 [5]. The International Energy Agency (IEA) considers carbon prices

[4] This is expressed as an average cost differential for each 5year period from the mid-2020s to 2060 (the end of our modelling period).

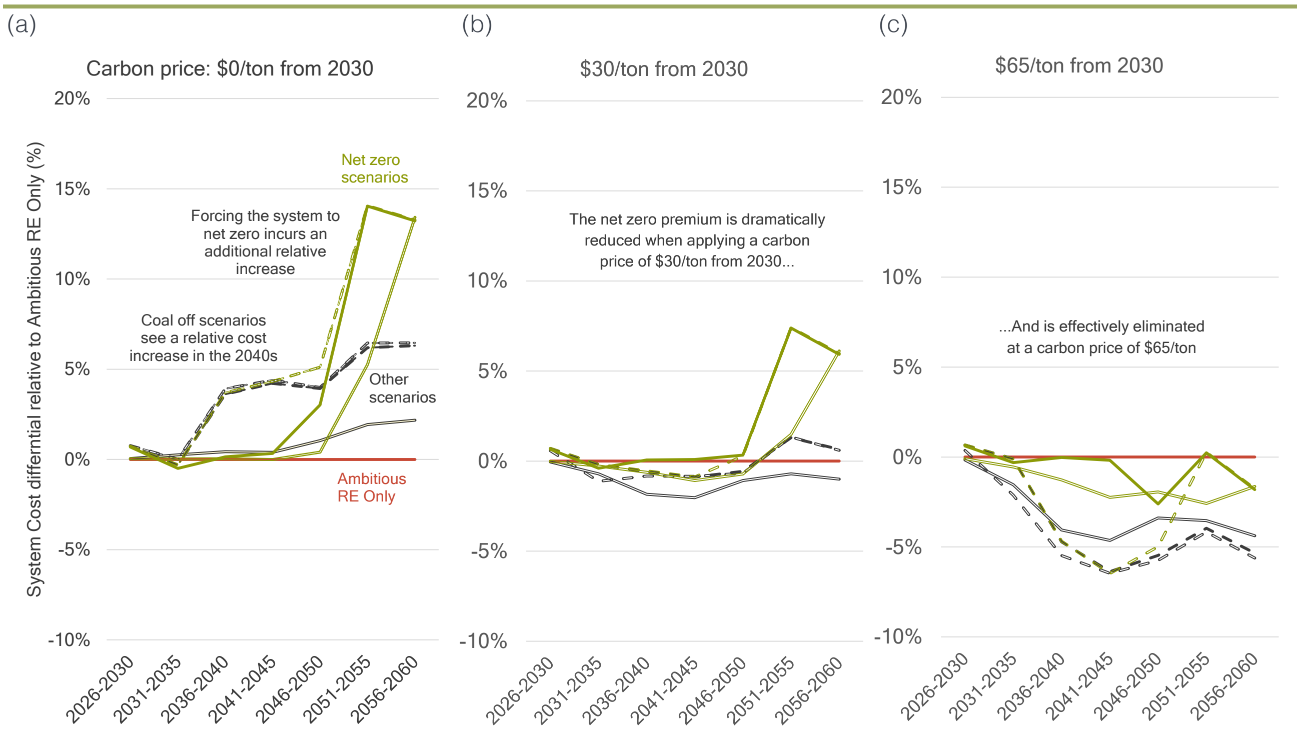
[5] Includes the switch to green hydrogen of all peaking plant, and *Sasol's CCGT and ICE power plants currently run by gas.*

[6] The South African Carbon Tax Act of June 2019 and Amendment Bill of July 2022 stipulates a $30/ton carbon tax rate by 2030. Exchange rate assumed for this project was 15 ZAR/USD, which results in a carbon price of R450/ton for 2030 onwards.

for developing countries including South Africa of \$90 in 2030 rising to \$200 in 2050 for a global net zero scenario [6].

We find in our analysis that the coal off policy lever is the main driver of emissions reductions, with our most ambitious Net Zero scenario – *Coal off by 2040, 2,3Gt NZ2050* – delivering almost 1 Gt of additional emissions reductions over the *Ambitious RE Only* case by 2060. The other two Net Zero scenarios – which see later coal closure – deliver lower but still significant emissions reductions of 0.5 Gt of emissions savings each.

Figure 1: Annual System Cost relative to *Ambitious RE Only* with different levels of carbon pricing from 2030



1.5.2 BUILD RENEWABLES NOW TO CREATE OPTIONALITY FOR NET ZERO IN LATER YEARS

Whichever of the three policy levers is deployed – a Paris-aligned carbon budget, coal phase out by 2040, or a net zero date – all scenarios require the same short-term action: rapidly increasing annual deployment to approximately 6 GW of new renewable capacity (wind and solar), 0.5 – 1 GW of peaking capacity (open cycle turbines / internal combustion engines) and 0.5 – 1 GW of battery storage every year from now until 2030, and beyond. This approach is roughly the same immediate action required to cost-effectively alleviate the loadshedding crisis, as demonstrated by other power system modelling studies [7]. This scale of renewables and flexible capacity rollout has increasingly been endorsed by government [8] and business in energy planning fora. In practical terms, this build programme will need to be implemented through a combination of government procurement programmes and private sector initiatives and will require:

- Strong emphasis on removing grid constraints, streamlining permits, and other necessary measures to accelerate the rollout of renewable energy.
- Initiating additional peaking capacity procurement (for OCGTs, ICE technologies, designed to provide

quick response balancing power), and storage procurement programmes with haste.

Notable differences between the scenario capacity expansion plans only appear around 2035, driven by whether a decision is made to phase out coal by 2040 or later. Opting for a coal-off-by-2040 policy means that some of the capacity investments in pumped storage would need to be advanced by approximately 5 years compared to the *Ambitious RE Only* scenario, which might require investment decisions to be made within this decade[7]. Other long-duration storage options could also fulfil this role in the future, although they were not analysed in the modelling.

In sum, corralling focus on a significant renewables programme that ramps rapidly to 6 GW per year (private and public procurement) in the short-term will serve two crucial objectives: first it will aid to alleviate load shedding cost-effectively, and second create the optionality for SA to fulfil its climate commitments and achieve the ambitious net zero target in later years.

1.5.3 A NET ZERO POWER SYSTEM IS LARGELY ACHIEVABLE WITH ESTABLISHED TECHNOLOGIES

With the exception of zero-emission thermal peaking plant, all of the technologies required to support a credible transition to net zero exist at commercial scale today. These technologies include wind and solar PV, hydro plants, batteries and pumped storage.

Thermal peaking is foreseen to play a critical role in providing system balancing services over extended time periods (multi-hour and multi-week), and as generator of last resort in maintaining security of supply in the face of low probability, high impact events that affect the power system.

Currently, thermal peakers are run on fossil fuels. In a net zero system, peakers will likely be 100% fuelled by green fuels such as green hydrogen or ammonia. This technology is proven but still in fairly early stages of commercial rollout, although it is anticipated that 100% green- fuelled peaking plant will be readily available at the required commercial scale well before the net zero dates by when they will need to be deployed in a developing country context (i.e. 2040 onwards).

Figure 2 and Figure 3 illustrate the installed capacity and energy generation mix in 2030 and 2050 for our most ambitious Net Zero scenario.

[7] Deployment of new pumped storage capacity is optimal between 2036 and 2042 in all scenarios, with the **Coal Off by 2040** scenarios requiring this capacity to be built at the early end of this range, whilst other scenarios see the same amount of capacity built, but more incrementally during this period.

Figure 2: Installed Capacity for *Coal off by 2040, 2.3Gt CO2 budget, NZ2050* scenario

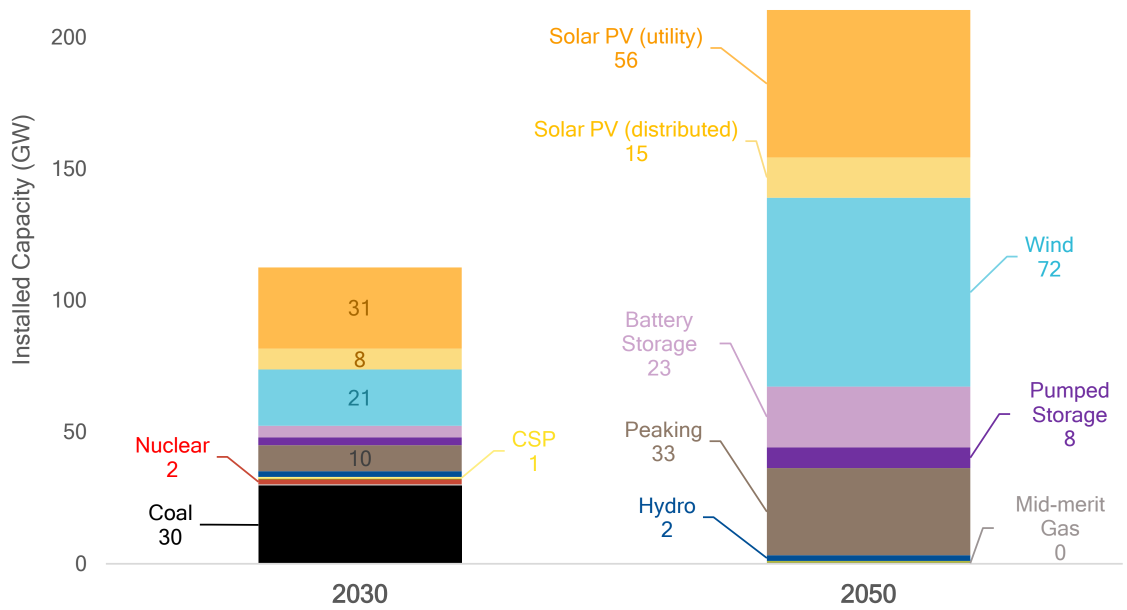
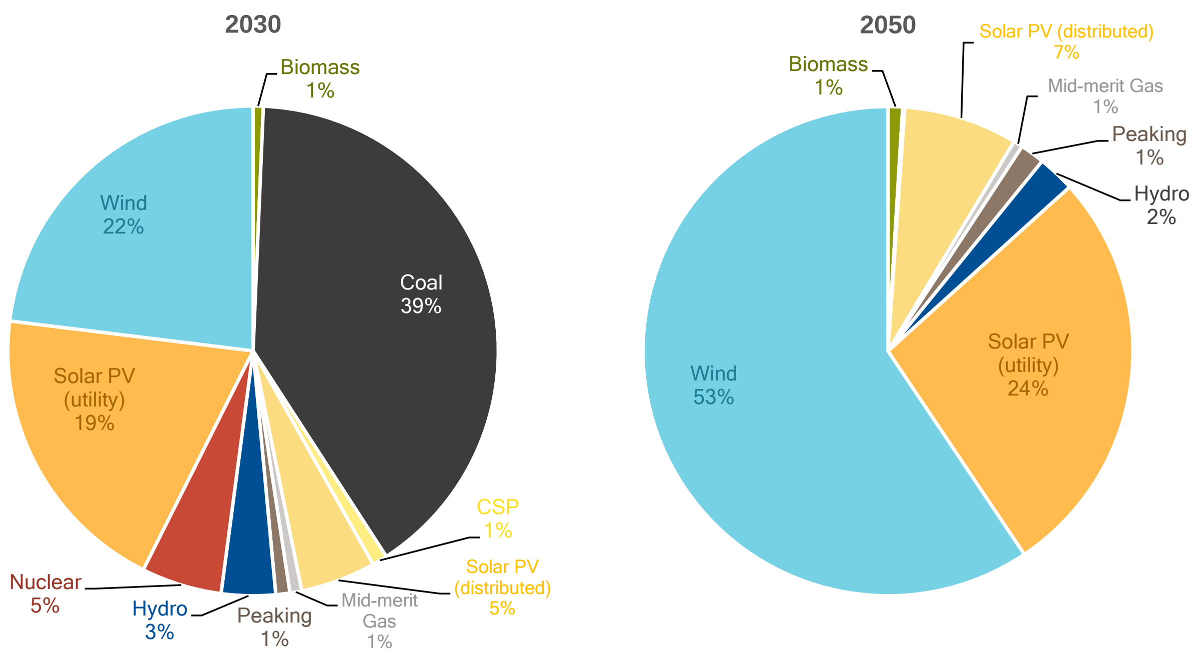


Figure 3: Energy generation mix for *Coal off by 2040, 2.3Gt CO2 budget, NZ2050* scenario



1.5.4 COAL HAS A ROLE IN SOUTH AFRICA'S NET ZERO POWER SYSTEM TRANSITION

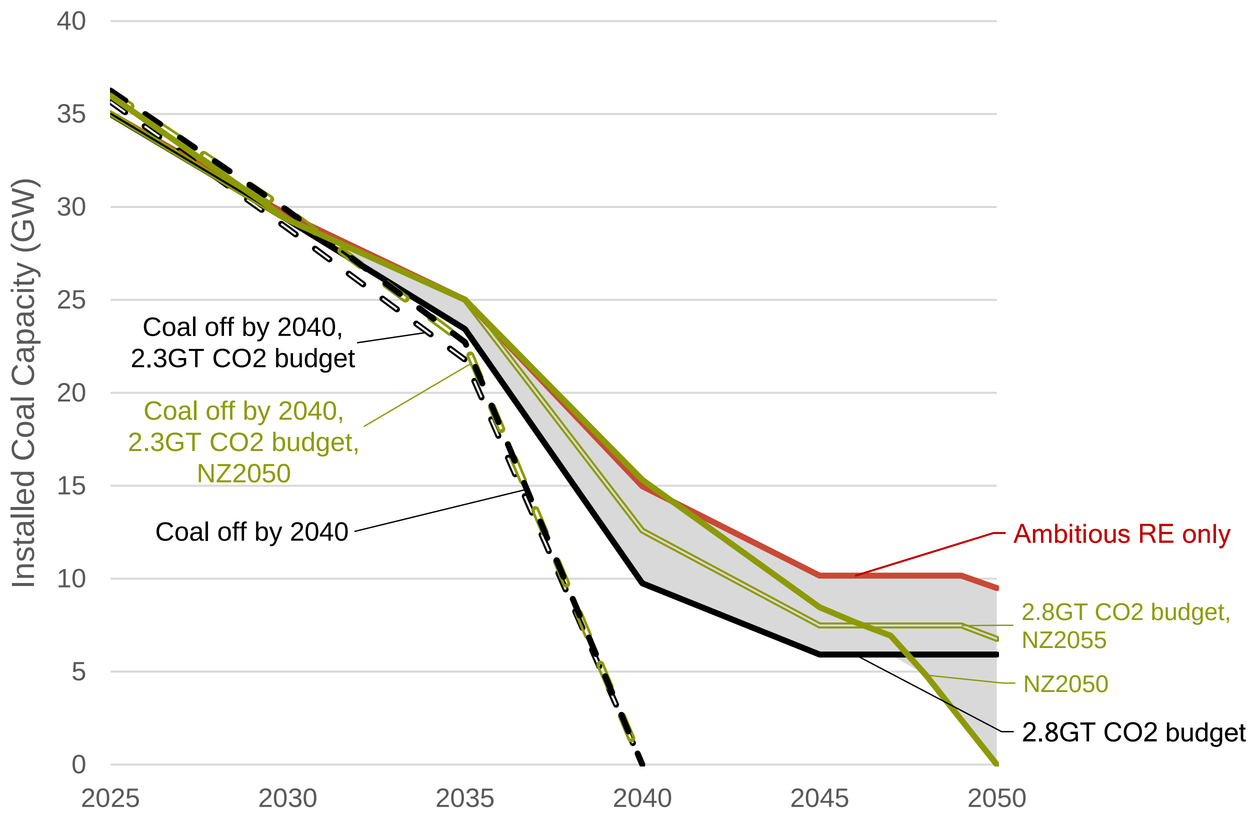
The modelling analysis shows that until 2030 there are no major differences in the rate of coal retirement across scenarios. 10-11 GW is retired by 2030, which is aligned to the decommissioning schedule in the 2019 Integrated Resource Plan (IRP) [9]. By 2050 the majority of SA's coal fleet is economically retired due to it being more expensive to run than alternative generation options. In the *Ambitious RE Only* scenario, over 60% of the fleet is retired by 2040, increasing to 75% by 2045.

Imposing a carbon budget or coal off policy lever accelerates the coal retirement rate. But unless it is forced off by either imposing a net zero date or a coal-off policy, we find that a small amount of coal-fired capacity remains on the system providing system services throughout the modelling period to 2060 regardless of the size of the carbon budget. In practice, this might entail coal plant capacity intentionally standing idle and producing very little overall energy, but providing flexibility during multi-day low renewables resource events, and back-up in the event of the unforeseen. Further work however is required to assess the technical feasibility of operating the SA coal plants in this manner.

Scenarios which include a coal-off policy-type measure are effective at achieving the lowest cumulative emissions across the suite, up to ~0.5 Gt of additional emissions reductions by 2050, and almost 1 Gt by 2060. In addition, these scenarios see a reduced power system cost if a carbon price of just $30/ton is imposed from 2030, as discussed in 1.5.1 above.

However, it is worth noting that forcing all the coal off may be a particularly challenging policy lever to implement in a country systemically dependent on coal, together with the challenges of achieving the necessary RE build rate.

Figure 4: Coal installed capacity across all scenarios



1.5.5 THERE DOES NOT APPEAR TO BE AN ECONOMIC CASE FOR 'BIG GAS' IN A NET ZERO SYSTEM

Whilst coal plant can remain on the system up to the net zero date, the modelling results demonstrate that Combined Cycle Gas Turbine (CCGT) plants at mid-merit capacity factors (i.e. producing significant amounts of energy) are not economic in scenarios which include a carbon budget within a Paris-aligned range.

The results show that the more economic option is a combination of renewables and flexible Open Cycle Gas Turbine (OCGT) / Internal Combustion Engine (ICE) capacity, 'spending' the carbon budget on emissions from these plants fuelled by gas or diesel until a fuel switch to green hydrogen or ammonia occurs.

1.5.6 CARBON CAPTURE AND REMOVAL TECHNOLOGIES ARE NEITHER ESSENTIAL NOR ECONOMIC OPTIONS IN A NET ZERO SYSTEM

The modelling finds that it is more economic to deploy greater capacity of Solar PV and Wind, along with storage and a final switch to green hydrogen for peaking plant, than to capture and sequester carbon in the SA context. Carbon Capture, Utilisation and Storage (CCUS) was included as an option available to the model to reduce emissions from new build thermal plant fired with fossil fuels, as was Direct Air Carbon Capture and Storage (DACCS). However, neither are chosen in the optimisation due to their high costs. In addition, retrofitting CCUS on the existing coal fleet is in general not considered feasible, even in the few instances where it might be technically possible[8].

1.5.7 UNCERTAINTIES AROUND FUTURE FUEL PRICING PRESENT A POTENTIAL CASE FOR GREEN HYDROGEN PEAKING SOONER

The competitiveness of hydrogen-fired peaking plants with natural gas-fired generation depends on future gas and carbon prices and the learning rate of electrolyser costs. Conservative green hydrogen learning curves and static fossil fuel costs are assumed in the modelling, resulting in green hydrogen for peaking not becoming economically competitive with natural gas within the modelling timeframe[9]. The fuel switch from gas/diesel to green hydrogen for OCGT/ICE peakers only occurs when a net zero date is enforced, contributing an increase in system cost of approximately 5%[10] at that point.

However, there are compelling reasons to believe that this may be overly conservative, and worth probing further. There are significant uncertainties related to the future economics of gas, diesel, and green hydrogen. We therefore ran a sensitivity analysis, which suggests that it is possible that the switch to green hydrogen may happen sooner than anticipated, and may not even result in a system cost increase. There are a number of reasons for this. First, volatility in the Liquid Natural Gas and diesel markets (as witnessed in recent months), combined with ongoing reductions in green hydrogen production costs could lead to cost parity between these fuels earlier than expected on a risk-adjusted basis. Second, the use of curtailed renewable energy (evident in some of the scenarios by the year 2035) for green hydrogen production and the impact of impending carbon taxes, are factors not included in the system modelling that could further accelerate the convergence between gas and green hydrogen costs. Finally, the development of the green hydrogen sector in SA and globally will be primarily driven by other energy-intensive sectors (shipping, aviation, steel manufacturing, etc)

[8] Personal communications: CSIR Energy Engineer, Independent Energy Engineer, and others.

[9] Green ammonia co-firing for peaking is also considered as a fuel option, but is not chosen by the model due to its higher cost than green hydrogen as fuel.

[10] Peaking fuel accounts for approximately 5% of total system cost in 2050, so a doubling of the fuel cost (as would be occasioned by a switch from gas to hydrogen in our modelling) increases total system cost by a similar amount. This impact is experienced only from the year that the fuel switch is made, and is included in the overall levelized system cost for the full modelling period.

decarbonising. This means that the additional costs for producing green hydrogen for the power sector will be marginal. A fully sector-coupled model would be required to study these synergies and we recommend this as an area for further investigation.

1.5.8 POLICY-LEVERS FOR NET ZERO

Our study finds that a net zero date must be imposed in order to achieve certainty of net zero emissions from the power system.

All seven scenarios considered (including the *Ambitious RE Only* scenario) achieve cumulative emissions within a Paris-aligned carbon budget range over the modelling period (2021-2060). However, only three of the seven achieve 'net zero' emissions at any point in the modelling period – those where a net zero date is imposed. These were highlighted in green in Table 1. The policy-lever of enforcing a net zero date is therefore necessary to achieve net zero at least before 2060. Without this, carbon emissions remain on the system post-2060, produced either by coal-fired power plant or fossil-fired peaking plant, or both.

Findings associated with the use of the individual levers however are informative:

Ultimately, all sectors need to achieve net zero. In that the power sector is systemically important for SA's decarbonisation, and represents least-cost mitigation opportunities, it would seem to be useful to ensure that the power sector achieves net zero as soon as feasibly possible, which the findings from this study suggest is possibly sooner than anticipated.

Stipulating a date by which coal must be phased out – a prominent discourse in the international climate negotiations including in association with climate finance – does achieve significant emission reductions over the full modelling period (i.e. to 2060): ~1 Gt more emission reductions than that of the *Ambitious RE Only* scenario (no policy-levers), and ~0.5 Gt more than when only the levers of carbon budgets plus net zero dates are employed. There are questions though as to whether this is practically possible or optimal from a system flexibility perspective.

Finally, in analysing the results of the modelling exercise we have identified that imposing a modest carbon price swings the economics away from fossil-based energy and towards green energy. We identified that a carbon price from 2030 of $30-$65/ton would bring a net zero power system to cost-parity with our *Ambitious RE Only* scenario.

Whilst electricity consumers in South Africa do not currently feel the effect of the country's carbon tax[11] (a position that National Treasury has indicated may be revised in 2026), carbon pricing is in the process of being imposed on South Africa's electricity supply by the EU's CBAM[12]. The current CBAM design does however indicate the potential for exporting countries to retain some carbon pricing revenue within the country should electricity emissions be priced domestically. This study suggests that imposing the carbon tax on electricity, at least at a modest level, could be a useful policy lever for supporting sectoral decarbonisation. However, a carbon tax on electricity would need careful design in order to enable economic actors the agency to reduce their tax liability through low-carbon choices. As the market currently stands, the carbon tax on electricity would simply be passed through to a disempowered

[11] The carbon tax on electricity is currently offset by a combination of the Environmental Levy and a renewables premium.

[12] Under the CBAM design approved by the EU in May 2023, electricity emissions embedded in SA exports such as aluminium, iron and steel and cement will attract the EU emissions trading scheme carbon price. In July 2023, this price was in the region of Euro 90/ton https://tradingeconomics.com/commodity/carbon accessed 11 August 2023,

consumer via the Eskom tariff, although consumers will face increasing choice with the new competitive multi-market envisaged in draft SA electricity regulation. Consideration might be given for recycling carbon tax revenues to support the grid infrastructure necessary for the sector's decarbonisation.

1.5.9 CONCLUSION

The exploration of net zero power systems for South Africa underlines the importance of accelerating the build out of RE up to at least 6 GW per year as the action that will most quickly alleviate loadshedding and simultaneously ensure that the power sector is rapidly decarbonised in the face of potentially crippling carbon border taxes. As long as an ambitious renewables build programme with commensurate flexible OCGT and storage capacity is implemented, there is ample time to consider the additional policy options of stipulating an all coal off date, or net zero date. Whilst these options do come with additional costs from the late 2030s, these costs disappear with the imposition of modest carbon prices.

Were coal to be phased out by 2040, up to 1 Gt of additional carbon emissions reduction could be achieved in the power sector, supporting decarbonisation of the entire South African economy and insulating it from the effects of CBAMs.

All of these policy options will need to be considered at the time in the context of the country's commitment to a Just Energy Transition.

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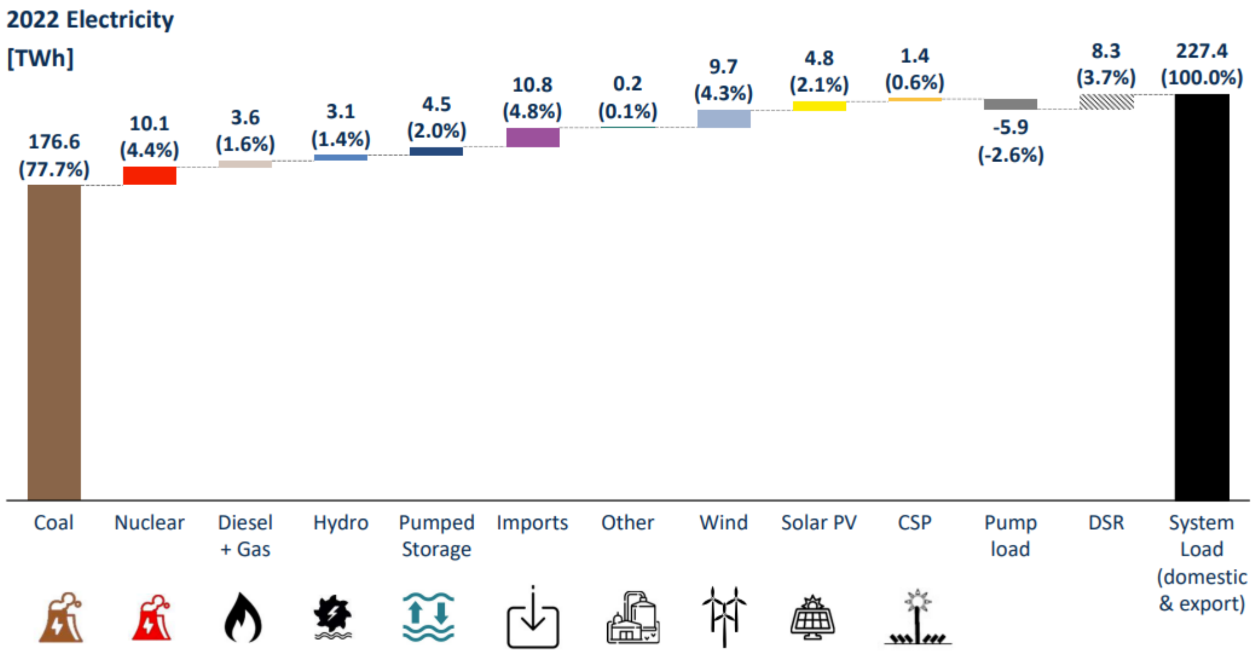
BECCS	Bioenergy with Carbon Capture and Storage
CBAMs	Carbon Border Tax Adjustment Mechanisms
CCGT	Closed Cycle Gas Turbine
CCU	Carbon Capture and Utilisation
CCUS	Carbon Capture, Utilisation and Storage
CCS	Carbon Capture and Storage
CDR	Carbon Dioxide Removal
COP	Conference of the Parties
CO_2	Carbon Dioxide
CSIR	Council for Scientific and Industrial Research
DAC	Direct Air Capture
DACCS	Direct Air Carbon Capture and Storage
DFFE	Department of Forestry, Fisheries and the Environment
DG	Distributed generation
DSR	Demand side response
EG	Embedded generation
ESRG	Energy System Research Group
EU	European Union
EWH	Electric water heater
FSRU	Floating Storage and Regasification Unit
GHG	Greenhouse Gases
Gt	Gigaton
GW	Gigawatts
H_2	Hydrogen
IAM	Integrated Assessment Model
IEA	International Energy Agency
ICE	Internal combustion engine
IPCC	Intergovernmental Panel on Climate Change
IPP	Independent Power Producer
IRP	Integrated Resource Plan
LCOE	Levelised Cost of Energy
LCOH	Levelised Cost of Hydrogen
LNG	Liquid Natural Gas
Mt	Megaton
NBI	National Business Initiative
NDC	Nationally Determined Contributions
NET	Negative Emissions Technologies
NGFS	Network for Greening the Financial System
NZ	Net Zero
OCGT	Open Cycle Gas Turbine
PEM	Polymer Electrolyte Membrane
RE	Renewable Energy
REIPPPP	Renewable Energy Independent Power Producer Procurement Programme
SA	South Africa
UNFCCC	United Nations Framework Convention on Climate Change

2 INTRODUCTION AND CONTEXT

2.1 SOUTH AFRICA'S POWER SECTOR

South Africa's electricity demand is predominantly met by coal-fired power, with the country's heavy reliance on coal having been driven by abundant reserves and historically low coal prices. Coal-fired power stations produced 78% of total electricity generation in 2022, with plants mainly owned and operated by Eskom power utility. Eskom's combined fleet (including coal, nuclear and thermal peaking plants) currently supplies around 90% of the country's total electricity demand, with the remaining demand being met by Independent Power Producers (IPPs), municipalities, self-generation and imports. South Africa has 44 813 MW of installed coal capacity, approximately 11 GW of which is due for decommissioning over the next 10 years [9], [10].

Figure 5: Share of annual demand met by each power generation technology in SA power system in 2022 [11]

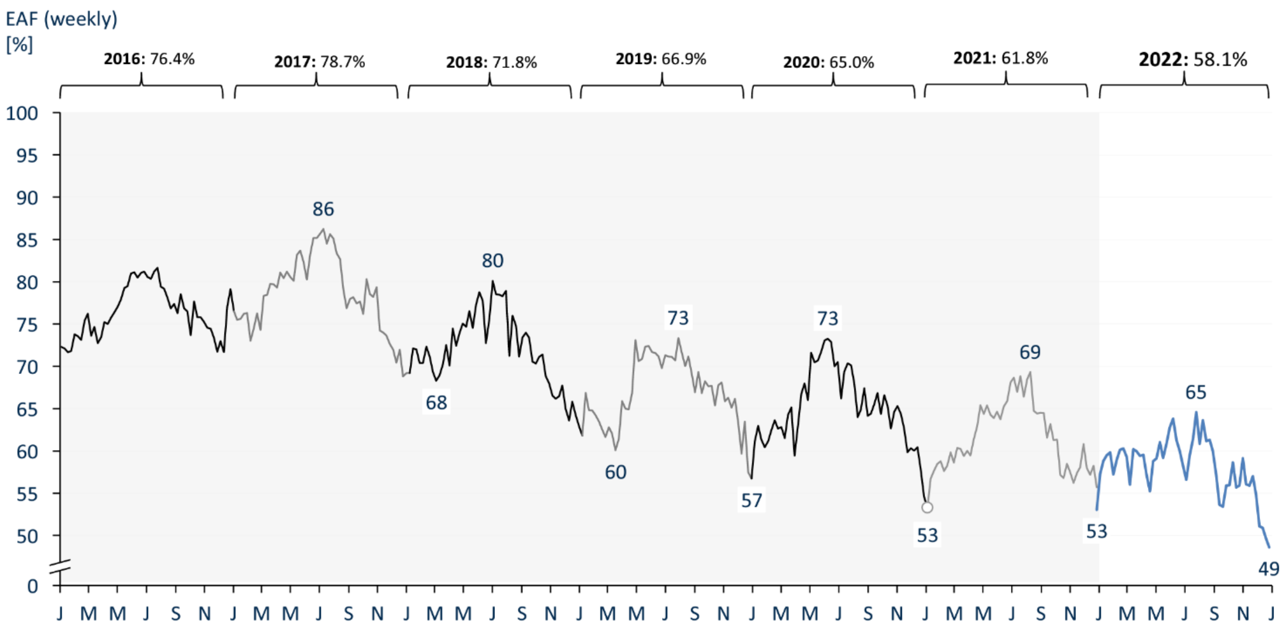


Whilst South Africa has committed to reducing its reliance on coal and transitioning to a low carbon future, the country currently faces an acute power crisis as demonstrated by rolling power outages (termed 'load shedding'). This crisis has been driven predominantly by a) the deteriorating performance of Eskom's coal fleet due to years of insufficient maintenance (see Figure 6), corruption and mismanagement, and b) lack of coordinated national efforts to procure new generation capacity. Frequent breakdowns and unplanned outages caused the share of coal generation in the energy mix to in 2022 drop below 80% for the first time [11].

The country now confronts a significant supply gap exceeding 6 GW, but procurement processes have not been swift or consistent enough to close this growing deficit [12]. Furthermore, current grid capacity constraints inhibit the ability to connect new generation capacity to the grid. In 2022 the Energy Action Plan was published and the National Electricity Crisis Committee (NECOM) established to guide, coordinate and implement actions to address the crisis.

There is growing recognition amongst stakeholders that a large rollout of renewable energy and commensurate flexible capacity is required. For example, the Presidential Climate Commissions (PCC) recent recommendations for SA's electricity system – which are based on a selection of recent power system modelling studies – assert that an additional 50-60GW of renewable energy with co-located storage and 3-5GW peaking capacity is required by 2030 to resolve load shedding [8].

Figure 6: Declining Eskom Fleet EAF, to an average of 58.1% in 2022 [11]



2.2 SOUTH AFRICA'S CLIMATE AMBITION

In 2021, South Africa updated its Nationally Determined Contribution (NDC) to the Paris Agreement with revised emissions targets, which signals a significant ramp up in climate ambition. Climate Action Tracker has issued an analysis concurring that the upper bound of the NDC's 2030 target of 420MtCO_2e is consistent with SA's fair share contribution to a 'well below 2˚C pathway', with the lower bound consistent with a 1.5˚C pathway [13][13]. The country is due to submit an updated NDC in 2025. South Africa has a draft climate change Bill which is yet to be published, which will include targets at the sectoral level (Sectoral Emissions Targets), as well as mandatory company level carbon budgets.

The Intergovernmental Panel on Climate Change's 2018 Special Report on 1.5˚C introduced the concept of 'Net Zero by 2050' to the global decarbonisation discourse with great effect spurring target setting and commitments at country, city, sector and company level. South Africa has expressed an aspiration to commit to net-zero CO_2 emissions by 2050 in its Low Emissions Development Strategy (SA LEDS, 2020). The State-owned power utility, Eskom, has included a Net Zero ambition in its Just Energy Transition medium- to long-term strategy [15].

[13] Subsequent analysis by Climate Action Tracker suggests a revised assessment, of the upper *bound as 'insufficient' and the lower bound as 'almost sufficient'* for a Paris aligned 1.5C temperature goal. [14]

Decarbonising South Africa's electricity supply is a priority for whole-economy decarbonisation. Most of the decarbonisation targeted in the NDC has to come from the power sector [8], with the global power sector anticipated to grow between two and three-fold by 2050 in order to provide for affordable economy-wide decarbonisation. Further, the advent of CBAMs such as that of the European Union presents a significant risk for electricity-intensive exporting industries given the high carbon intensity of the South African power supply. Finally, the international financial community is increasingly sensitised to the carbon intensity of investments, with carbon intensive countries and activities at risk of increased financing costs, and challenges accessing capital.

2.3 OBJECTIVES OF THIS STUDY

Within this context, the aim of this study was to shed light on the implications of net zero power system pathways for South Africa in the medium to long-term.

Meridian-CSIR's recent Vital Ambition ("*Ambitions*") project [1] found that future power system pathways with ambitious renewable energy builds were both feasible and come at no significant additional cost to SA's existing energy policy direction. In the context of the current supply gap – there is evidence that a large, sustained ramp up in renewable energy with commensurate peaking and storage is imperative to address load shedding and set SA up to meet its climate targets in future. Given the 'net zero' target's growing prominence internationally, and the importance of a decarbonised electricity supply to the South African economy, Meridian sought to understand the feasibility and cost implications of 'net zero' for the power sector (building on the Ambitions analysis) to inform South Africa's evolving medium- to long-term energy policy and planning discussion.

We first did a deep dive into what net zero might imply *conceptually* for sectoral decarbonisation analysis at a sub-global level in a Net Zero (NZ) Briefing Note [2], clarifying terminology, the role of non-CO_2 global warming gases (GHGs), dimensions of carbon capture, utilisation, and storage, how natural sinks fit in, and how to think around sectoral interlinkages and uncertainty. Whilst we argue the primacy of the carbon budget in the NZ Briefing Note, the net zero concept nevertheless highlights issues related to both climate science and policy which have implications for analytical work to understand the impact of Paris-aligned decarbonisation goals.

The NZ Briefing Note interrogation of the net zero concept revealed the importance of emissions achieving and sustaining net zero around mid-century. For modelling purposes, this means that CO_2 emissions cannot continue once an imposed carbon budget has been used up. Prior to the net zero concept gaining traction, many modelling exercises utilising carbon budgets to constrain emissions did not impose this requirement. In addition, the net zero concept highlights the role of storage and removal technologies. These need to be appropriately specified for modelling purposes, and many are context determined. Assumptions need to be made about the availability of natural carbon sinks.

In the NZ Briefing Note's deep dive into the climate science and policy origins of the net zero concept [2], we developed a six part framework to guide South African power system modelling work. This report presents the outcomes of the modelling work, based closely upon the framework and conceptual arguments developed in the deep dive.

At a high level, the project sought to understand the implications of 'net zero' for the South African power sector. As described in the NZ Briefing Note, the concept is primarily a political / discourse device at the national and even sub-national level, but nevertheless has implications for analysis of long-term power sector decarbonisation, and for the types of policy levers to assist in the achievement of Paris-aligned decarbonisation.

Using a power system modelling framework, we set out to answer the following about achieving a Paris-aligned Net Zero power system for South Africa:

- What decisions are required now?
- What are the cost implications?
- What technologies will make up a (transition to) net zero?
- What policy levers are required?
- What are the implications of different net zero dates?

The body of the report covers the analytical approach, findings and reflections. It is accompanied by a technical appendix which provides details of the modelling platform and assumptions utilised.

3 ANALYTICAL APPROACH

3.1 SIX-POINT FRAMEWORK FOR ANALYSING NET ZERO IN THE SOUTH AFRICAN POWER SECTOR

In the NZ Briefing Note we developed a framework for a net zero analysis of the South African power sector. An updated version of this 6-part framework is represented in the box below, our specific application to the modelling summarised in the following text with specific aspects elaborated in the body of this report.

Box 2. Six-point framework for analysing Net-Zero[14]

1. *Budget Range*: Net zero power sector modelling for South Africa should be constrained with an appropriate CO_2 emissions budget range that reflects equity, context and uncertainty considerations, and is associated with particular temperature goals. In the case of Paris aligned net zero, the Ambitions project found this to imply an associated power sector budget range of 2-3.1 Gt (See NZ Briefing Note). For net zero analysis, this range was imposed from 2021 for the modelled period (i.e. to 2060). Updated ESRG net zero modelling suggests this range as being broader in both directions (e.g. 1.4Gt to 3.9 Gt).
2. *Budget timeframes*: Given that 'net zero' is a global average, it is politically and analytically appropriate to consider applying emissions budgets to timeframes beyond 2050 for the South African power sector given that the country is classified as 'developing' under the UNFCCC. The actual modelling timeframe chosen will balance the objectives of the study with the utility of modelling far into the future.
3. *Enforcing the budget*: No further CO_2 emissions should be allowed beyond the analytical timeframe. This can be achieved by forcing in a net zero date, or by checking modelling results to ensure that any CO_2 emissions left on the system at the modelling end date will reduce to zero within the following year.
4. *Natural sinks:* Given the uncertainty surrounding the size of South Africa's land sink, and that the power sector is characterised by relatively low-cost abatement options compared to the rest of the economy, we assume that no land sink is available to the power sector. This assumption could be relaxed just by widening the power sector's budget range.
5. *Identifying and pricing removal and storage technologies*: CC(U)S at source in the South African power sector is only potentially feasible for new coal and gas plant, not retrofits, therefore only these options need be made available to a model. CC(U)S at source relies on local storage availability, and should therefore be priced accordingly together with a consideration of the finite storage space available domestically. Carbon capture and storage removal technologies (DACCS and BECCS being the most promising currently) are not geographically dependent. Therefore, these emissions removal efforts can be

[14] The ESRG net zero budget range was determined from a data spreadsheet provided by ESRG on request in May 2022. The authors understand this range to be associated with the ESRG Net Zero Pathways project [4], although power sector budgets are not reported in the publication.

implemented outside the country and should be considered as a global market determined price per unit of emissions removed.

6. *Power demand:* Power demand must be uncoupled from historical trends and economic structures, to account for the increased need for electrification of sections of transport, industry and beyond. As economies transition towards net zero, there will be a changing role for power, which needs to be acknowledged beyond a simple demand increase in sectoral models. Different modelling and analytical approaches will likely be required in order to fully explore these changes.

We used this framework as our starting point for approaching the modelling task:

1. **Carbon** budgets of 2.3 and 2.8 Gt are used as representative points well within the Ambition's project determined Paris-aligned range for the power sector (and sustained by the updated ESRG Net Zero Pathways report range)[15].
2. The Ambitions modelling timeframe (2050) was **extended to 2060,** to consider net zero dates beyond 2050. The carbon budgets are applied over the full modelling period to 2060. In the study we consider net zero dates of 2050 and 2055.
3. The extended modelling timeframe also enabled a consideration of whether **emissions remained on the system** post 2050. This timeframe is still considered tractable from a modelling horizon perspective.
4. No provision was made for additional carbon space for the power sector from South Africa's **natural sinks.**
5. **New coal fired power with CCS** was made available to the model for the Ambitions study, and was maintained here. Retrofitting CCS to the existing coal plants is neither considered economic nor feasible given the age of fleet. **A DACC price per tonne** was additionally made available to the model to provide the option for the removal of gas plant emissions. Unlike for coal, CCS is ill-suited to gas plants due to the ramp-up/ramp-down operating regime and the low emissions intensity of the turbines [3].
6. This study used the Ambitions power demand assumptions. This was not updated to reflect the implications of sector coupling. However, we did consider the implications of power requirements to produce green hydrogen used in turbines, and this is discussed in the findings section on green hydrogen.

3.2 MODELLING PLATFORM

The study utilises the same long-term generation capacity expansion planning framework and modelling platform (PLEXOS) of the Ambitions work. This is well-established in the South African electricity modelling community, including for use in the development of the power sector's Integrated Resource Plan (IRP). Further information on long term generation capacity expansion planning is provided in Appendix 6.26.2.

The intention of this project was to capitalise on the extensive model development

[15] The budgets were derived from the realised emissions *between 2021 and 2050 of two 'Paris-aligned' power system* pathways in the Ambitions project. These cumulative emissions were applied as carbon budgets over the 2021 – 2060 modelled period.

investment of the Ambitions study to shed light on recent developments in the policy landscape. The Ambitions model required slight re-calibration, primarily to enable it to run in the latest version of PLEXOS (8.2).

3.3 ASSUMPTIONS

The **basis of the assumptions used in this study were drawn from the Ambitions work**, outlined in Meridian's 'A Vital Ambition' Report and the CSIR's Technical Report published in 2020. These assumptions included the Capex and Opex costs of competing generation technologies, learning rates, emissions factors, plant capacity factors, fuel costs and the nature and quantum of demand in each year.

There have been a number of developments that impact the accuracy of these assumptions in the intervening years. However, we decided to maintain the original assumption base for both pragmatic and principle reasons which are outlined below.

Learning rates and the assumed demand trajectory create a set of forecast data for each year of the analysis, including for years that have now elapsed i.e. 2020-2022. It is in the nature of time-consuming, long-term prospective studies such as this one that the march of history overtakes the early years of the forecast period. This does not undermine the results of the study provided the long-term assumptions remain intact and sufficient circumspection is applied to implications of the near-term results.

At least three major developments in the modelled environment occurred during the now-elapsed period – the effect of Covid-19 saw a dramatic drop in power demand in 2020, renewables prices bid into (particularly BW5 in 2021) the Renewable Energy Independent Power Producer Procurement Programme (REIPPPP) were much lower than anticipated, and the collapse in performance of the coal fleet has led to unprecedented levels of load shedding from 2021 to the present [11].

Whilst South Africa's power consumption has yet to recover to pre-Covid levels based on StatsSA data of electricity available for distribution, much if not all of this difference can be accounted for by unserved energy resulting from the performance collapse of the coal fleet. If we add back the unserved energy in 2022 (~12TWh [11]) to that actually distributed (227+12 = 239TWh) as a conservative indicator of what demand would have been without load shedding, it would indicate recovery to within 1% of the 2019 figure of 242TWh by 2022. This is 10TWh lower than our forecast demand assumption of 252TWh for the same year. However, merely accounting for unserved energy takes no account of the additional demand that would have developed in a growth environment where power security was assured.

This issue raises an important principle question around demand forecasting and the difference between attempting to predict the future trajectory of power generated, versus forecasting a level of demand necessary to build a system that will facilitate the economic growth the country requires. Our demand forecast and the study focus is based on the latter.

A further consideration is the interaction between other assumptions and the demand. For instance, whilst the modelled demand assumption for the elapsed history is materially higher than the power served, the forecast performance of the coal fleet was also far higher than what has actually obtained. The supply gap requiring new generation capacity has if anything widened in reality compared to the forecast.

Whilst renewable technology costs appeared to have fallen precipitously lower than our forecasts in the announcement of REIPPPP BW5 prices in 2021, subsequent changes in both the global (supply chains, borrowing costs) and domestic (grid scarcity) environments suggest sustainable prices going forward are likely much closer to our forecasts. Certainly, in the medium term, grid scarcity will place upward pressure on the cost of renewables as projects are forced into areas of lower resource in order to be able to connect to the transmission network.

To summarise then, despite the impact of developments since 2020 we decided to maintain the original assumption base for the following reasons – due to the long-term prospective nature of the study, the shorter-term impact of the recent developments, comparability with our previous results, and the benefits of capitalising on our existing models and datasets.

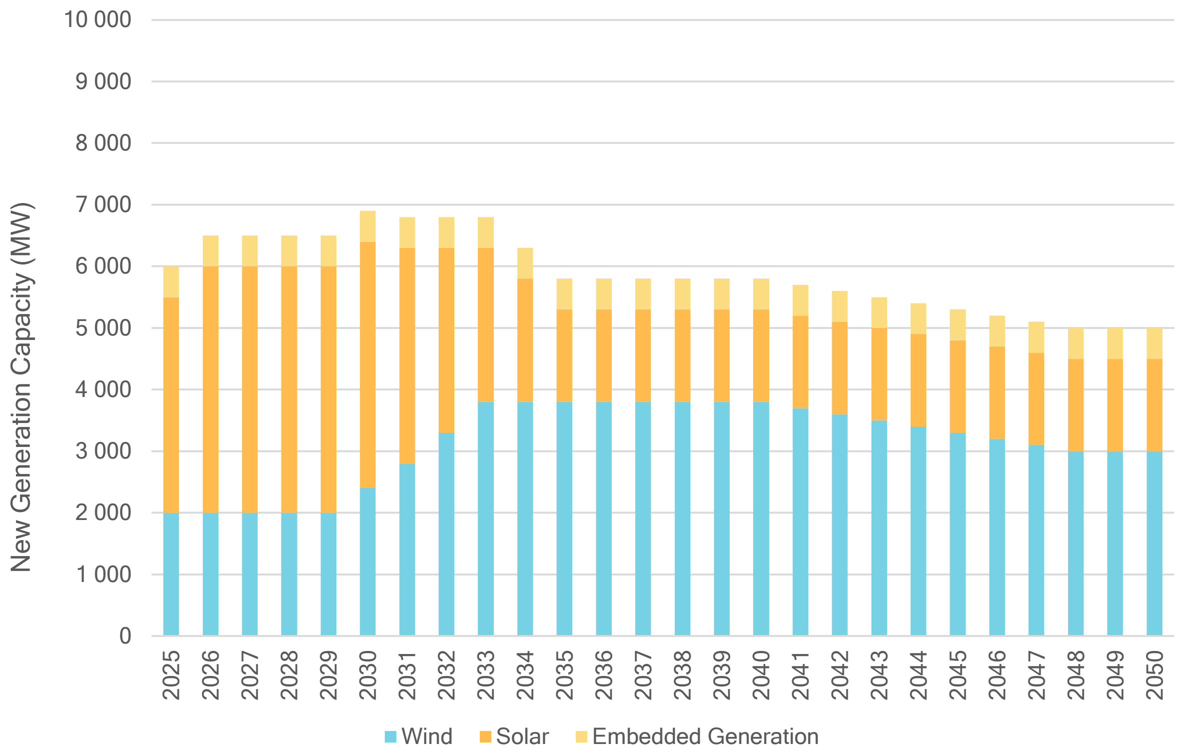
In order to deal with disparities between the short-term power system characteristics and the longer-term modelling assumptions we have ignored any findings from the power system modelling prior to the second half of the current decade.

To our original assumption set we then made a number of additional **technology additions specifically to enable the consideration of Net Zero** scenarios. These are summarised here, with further technical detail being provided in Appendix 6.36.3.

- A DACC price per tonne which would allow for removal of gas plant emissions;
- A new fuel for OCGTs, CCGTs and ICEs is included, in the form of green hydrogen blended with natural gas at a ratio of up to 50% (by energy) from 2030 and up to 100% (by energy) from 2040 onwards. Green ammonia co-firing is also considered as a fuel option, but is not chosen by the model due to its higher cost than green hydrogen as fuel;
- The minimum capacity factor of OCGTs was revised upwards to 2% to better reflect the realistic minimum dispatch frequency of this capacity.

Furthermore, for all scenarios, an annual minimum build requirement is imposed on the model for new Solar PV and Wind capacity (Figure 7). This minimum requirement is specified to reflect a realistic, smooth build of RE over the planning horizon (as opposed to an erratic annual RE build profile which is an output of the model in absence of this specification). This minimum build programme is designed to consider an initial RE industry ramp up, potential grid constraints (resulting in a 'solar-heavy' build until at least 2030), realistic industry capabilities and total renewable energy generation over the period to situate the power sector within a Paris-aligned carbon budget range (See p.46-49 of the Ambitions study for further detail [1]).

Figure 7: Annual Minimum Build Requirement for New Renewable Capacity



Finally, we applied the carbon budgets as budgets to 2060. Whilst we modelled to 2060 both to consider various net zero dates, we report predominantly on the period to 2050, given the traction this timeframe typically has in the climate and energy policymaking community.

3.4 DEFINING SCENARIOS

The NZ Briefing Note identified the importance of a carbon budget for determining Paris-alignment, in conjunction with achieving net zero by a particular date: A credible, Paris-aligned 'net zero' power system must have cumulative emissions that remain within an appropriate sector level carbon budget, and must be observed as achieving sustainable net zero emissions. The particular timing of achieving net zero emission is discussed in depth in the NZ Briefing Note. Whilst global net zero must be achieved around mid-century, this date may vary at a national or sectoral level.

The reference scenario chosen for the project was that of the Vital Ambitions project's 'Ambitious RE build programme' (see Appendix 6.1 for more information on the Ambitions scenarios) and is termed *'Ambitious RE Only'* for this study as it does not include any of the other policy levers. This reference scenario, whilst ambitious in terms the pace of RE build-out, still contains significant carbon risk for the country in a world increasingly aware of the importance of achieving the Paris temperature goals. The power sector is the driver of both near-term and system-wide decarbonisation potential across the economy. A carbon intensive power supply therefore represents significant risk to exporters as key import markets implement CBAMs. In addition, financiers are increasingly sensitive to the carbon intensity of their portfolios, putting South Africa at risk as an investment destination.

Run in the updated PLEXOS modelling environment to 2060, the *Ambitious RE Only* scenario was found not to achieve sustained net zero emissions on its own. Therefore, to achieve Paris-aligned net zero power system scenarios in a modelling environment we experimented with the use of three possible policy-type levers for achieving net zero for the SA power system: use of a carbon budget, a net zero date, and a coal phase-out date (these are elaborated in Box 3).

Box 3 Policy levers considered for achieving net zero

1. *Imposing a Paris-aligned carbon budget on power sector emissions*. Two carbon budget sizes are considered by this study, 2.3 Gt and 2.8 Gt, both lying within a Paris-aligned range of 2 – 3.1 Gt identified by the Ambitions project and reporting in the NZ Briefing paper deep dive. Subsequent analysis by the ESRG suggests a broader range of 1.4 – 3.9 Gt, implying that our chosen carbon budgets do not fully explore the envelope of the Paris-aligned range. We further acknowledge significant uncertainties still surrounding carbon budget determination, including that these uncertainties increase as one allocates budgets from the global to national and then to sectoral scale.
2. *Imposing a net zero date*. We investigate two net zero dates, 2050 and 2055, for the power system. The International Energy Agency (IEA) has more recently suggested that global Net Zero by 2050 (a 1.5˚C temperature goal) implies the developing world power sector must achieve net zero by 2040 on average. Whilst we don't model a Net Zero date by 2040 explicitly, our results enable us to comment on the implications of this date in the context of a power system with high coal dependency.
3. *Phasing out all coal by 2040*. We apply a coal phase out by 2040 constraint to test its implications for the SA power system.

The choice of carbon budgets and net zero dates was guided by the working definition of net zero developed for the project.

We note that a carbon budget approach is best aligned with a fundamental principle of system modelling – introducing as few constraints on the model as possible in order to best understand system behaviour. Imposing a carbon budget over the modelling timeframe provides the greatest flexibility for the South African power system to respond appropriately, accounting for changing circumstances[16].

A coal-phase down policy lever was included both because the IEA's Net Zero by 2050 global roadmap finds that all un- abated coal power plants are phased out by 2040 [16], and an Ambitions project scenario exists for coal phase down by 2040.

Using various combinations of the three lever options, we constructed a total of six potential Net Zero scenarios. We acknowledge that this is likely not enough to fully consider the entire 'problem space' but is sufficient to reveal some important findings of how the SA power system may respond to the various levers. Scenarios are defined by the constraint set applied to an otherwise least cost capacity expansion plan. All scenarios are constrained

[16] The return to use of mothballed coal fired power plant in Europe *as a response to Russia's 2022 invasion of the* Ukraine is an example of such a change – this would have been impossible had the plant been decommissioned.

to at least follow the minimum RE build programme that comprises the reference *Ambitious RE Only* scenario.

Running scenarios in PLEXOS is a highly time and computing capacity intensive exercise. We therefore had to carefully construct the scenarios we wished to explore and limited this to a total of six plus the *Ambitious RE Only* scenario as reference.

We anticipated that scenarios with a carbon budget imposed for the full modelling lifetime (to 2060) would naturally show emissions declining to (net) zero sometime in the 2050s. We expected to see some scenarios 'naturally' achieving net zero by virtue of imposing a budget or coal phase down by 2040 only, and that others would be forced to net zero by imposing net zero dates. We therefore opted to construct scenarios with a range of different combinations of constraints (or types of policy levers).

The full set of scenarios run are presented in Table 2, and briefly described in the text following.

Table 2: Summary description of study scenarios

Graph Key	Scenario	Description	Policy Lever Imposed		
			Coal off by 2040	Carbon Budget Constraint	Net Zero date
Reference Scenario					
	Ambitious RE Only	RE Build programme from Ambitions Study, (min 5-6GW RE installed per annum)	×	×	×
Study Scenarios					
	Coal off by 2040, 2.3GT CO_2 budget	RE build programme 2.3Gt carbon budget constraint, all coal forced off by 2040	✓	✓	×
	Coal off by 2040, 2.3Gt CO_2 budget, NZ2050	RE build programme, 2.3Gt carbon budget constraint, NZ enforced in 2050	✓	✓	✓ 2050
	Coal off by 2040	RE build programme, with all coal decommissioned by 2040	✓	×	×
	NZ2050	RE build programme, NZ enforced in 2050	×	×	✓ 2050
	2.8GT CO_2 budget	RE build programme, with 2.8Gt carbon budget constraint imposed	×	✓	×
	2.8GT CO_2 budget, NZ2055	RE build programme, 2.8Gt carbon budget constraint imposed, NZ enforced in 2055	×	✓	✓ 2055

The first scenario, entitled *Ambitious RE Only,* falls within a Paris aligned carbon budget range. However, it is not observed as achieving sustained net zero emissions.

The next three scenarios explore the implication of using single policy levers for decarbonisation – applied to the *Ambitious RE Only* case: all coal powered generation being retired by 2040; the application of a carbon budget of 2.8 Gt; the application of a net zero date.

Two scenarios consider mixes of two policy targets – carbon budget and a net zero date, as well as a coal off by 2040 constraint with a carbon budget. The final scenario considers all three policy levers together.

The carbon budgets utilised in this study were determined by the Ambitions project, taking the cumulative *realised* CO_2 emissions of 1) the 'Ambitious RE pathway' (2.77 Gt) and 2) the 'Ambitious RE pathway with all coal off by 2040' (2.34 Gt) scenarios for the period 2021-2050. These cumulative emissions budgets fell within our identified Paris-aligned range. For this study, we applied these as upfront carbon budgets of 2.77 Gt (~2.8 Gt) and 2.34 Gt (~2.3 Gt) for 2021-2060. .

The significant uncertainties still surrounding carbon budget determination are acknowledged, including that these uncertainties increase as one allocates budgets from the global to the national to the sectoral scale.

A priori, none of the single-constraint scenarios can be claimed as Paris-aligned net zero. Only those including both a budget *and* a net zero date are sure to be Paris-aligned before actually running the model.

With the exception of necessary constraints to implement the three different policy levers in respective scenarios, all modelling assumptions are common to all scenarios in order to allow a like-for-like comparison between outcomes.

4 FINDINGS

Table 3 presents a summary of the modelling results for each scenario. The summary includes cumulative carbon budget, levelized system cost and Paris-aligned net zero compliance according to our working definition. The following are notable comparisons between the scenarios at a high level:

- All scenarios, including the *Ambitious RE Only* scenario achieve a Paris-compliant carbon budget by 2050, but some have residual emissions post this date.
- Only three out of seven scenarios end up being Paris-aligned net zero by the end of the modelling period (2060) whilst the rest have residual emissions ranging from ~7-26 Mtpa. *All three of these include the net zero policy-type lever.* We therefore conclude that a net zero date needs to be enforced in order to remove emissions and ensure finite carbon budgets.
- Importantly, the levelized system cost[17] does not vary significantly across scenarios, suggesting that a Paris-aligned net zero system can be achieved at little additional cost.
- In terms of capacity expansion – no significant differences between scenarios are indicated in the near term. All scenarios require the same action: a rapid ramp up of renewables, storage and peaking capacity. This creates the option for taking coal off and achieving net zero down the line – decisions that do not need to be made now. As with the Ambitions study, no new nuclear or new coal is built in any scenario due to cost.
- Net zero is achieved in each instance by swapping fossil fuels in peakers to green hydrogen. This incurs a cost penalty that is reduced[18] the later in the modelling period that this swap occurs. The impact on system costs remains minimal, however, given that the peaking fuel in use is a very small percentage of the overall system cost at that point.

The remainder of this section expands on further findings of the modelling exercise.

[17] The system costs considered for the model include capital cost for new capacity, fixed cost, variable operation and maintenance costs (FOM and VOM) of both existing and new capacity, fuel cost as well as start-up and shutdown costs. Other costs considered are the cost of retaining reserve capacity required to maintain system adequacy, along with the cost of unserved energy. Costs that are excluded from the system modelling are costs associated with transmission and distribution, others that do not fall into the scope of the modelling as well as unavoidable costs (e.g., sunk capital costs and actual cost of decommissioning plants).

[18] Later costs have lower impact in present value terms, and cost learning has time to manifest in narrowing the gap between green hydrogen and fossil fuels.

Table 3: Summary of Results

Scenario	Observations			
	Cumulative Emissions to 2050 (Gt)	Emissions post-2050	Levelised System Cost Relative to Ref Scenario (2021 – 2050)	Paris-aligned Net Zero
Reference Scenario				
Ambitious RE only	2.80	0.43	0.00%	No. Does not achieve net zero emissions during the modelled period (2060)
Study Scenarios				
Coal off by 2040, 2.3Gt CO_2 budget	2.27	0.07	+1.45%	No. Does not achieve net zero during the modelled period, gas emissions remain on the system (~7 Mtpa)
Coal off by 2040, 2.3Gt CO_2 budget, NZ2050	2.34	0	+1.41%	Yes by 2050.
Coal off by 2040	2.36	0.09	+1.32%	No. Does not achieve net zero during the modelled period, gas emissions remain on the system (~7 Mtpa)
NZ2050	2.70	0	+0.37%	Yes by 2050.
2.8Gt CO_2 budget	2.53	0.23	+0.22%	No. Does not achieve net zero during the modelled period, coal emissions remain on the system (~26 Mtpa)
2.8Gt CO_2 budget, NZ2055	2.69	0.08	+0.05%	Yes by 2055.

4.1 NET ZERO EMISSIONS AT LITTLE ADDITIONAL COST?

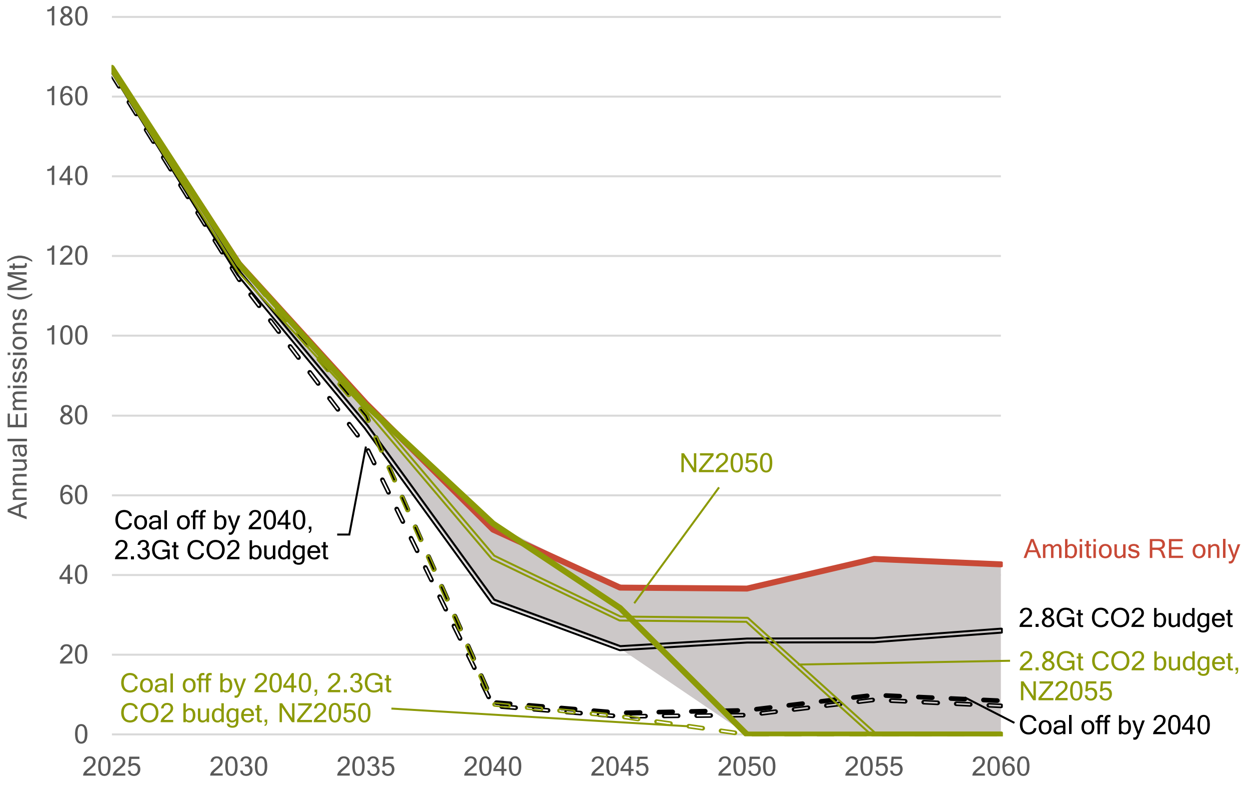
We were anticipating a significant cost premium for achieving net zero emissions over and above our *Ambitious RE Only* scenario (which still has coal on the system and fossil-fired peaking plant in 2060). However, this study finds that there is little additional cost for a Net Zero pathway until at least the late 2030s and even into the 2040s, depending on the suite of other policy levers imposed.

4.1.1 EMISSIONS TRAJECTORIES

The graph below indicates annual emissions trajectories associated with each scenario. The coal off by 2040 scenarios (indicated by dashed lines) depict a significant decline in emissions until 2040, with residual emissions originating from fossil-fired peaking plants (which are switched to be fuelled by green hydrogen by 2050 in the *Coal off by 2040, 2.3Gt CO_2 budget, NZ2050* scenario). These scenarios achieve significantly greater cumulative emission reductions as a result.

The *NZ2050* scenario (where only a net zero date is imposed) exhibits substantial reductions in emissions relative to the *Ambitious RE Only* scenario from 2045. In this scenario, the last coal units (totalling 2 GW) are retired by 2049, followed by a fuel switch for installed OCGT peaking plant to green hydrogen. A similar trend is observed before 2055 for the *2.8Gt CO_2 budget, NZ2055* scenario.

Figure 8: Annual Emissions Trajectories for each Scenario



4.1.2 COST IMPACT OF ACHIEVING NET ZERO

A key finding in the Ambitions study was that the cost of implementing an *Ambitious RE Only* scenario (this study's reference case) relative to SA's existing policy trajectory is not material. The *Ambitious RE Only* scenario achieves a carbon budget that is Paris-aligned according to our updated carbon budget range of 1.4 – 3.9 Gt, but does not achieve net zero over the modelling period. What then does it cost to additionally achieve net zero in the South African power system?

Somewhat contrary to what we had expected, this study finds that Net Zero pathways are no more expensive than the *Ambitious RE Only* scenario until the late 2030s in our most ambitious Net Zero case[19] , and until the early 2050s in our least ambitious Net Zero case[20].

Figure 9 shows the annual system cost differentials for each of the scenarios run (which can be categorised into those with and without a Net Zero date constraint) relative to the reference *Ambitious RE Only* scenario[21]. Until the late 2030s, there are no significant cost differences between the scenarios. Thereafter, two key policy levers drive a relative increase in the annual system cost:

1. A decision to take all coal-fired power off the system in 2040 increases the relative system cost by just under 5% at or around that period. This is driven by the need for additional renewables, storage and peaking capacity earlier than would otherwise be economically optimal.

[19] Coal off by 2040, 2.3Gt CO_2 budget, NZ2050

[20] 2.8Gt CO_2 budget, NZ2055

[21] This is expressed as an average cost differential for each 5year period from the mid-2020s to 2060 (the end of our modelling period).

2. Imposing a net zero date results in the relative system cost differential increasing from 5% to just less than 15%. This 'last mile' decarbonisation cost is driven predominantly by a fuel switch to green hydrogen[22] (which results in the doubling of the cost of peaking fuel, further elaborated in section 1.5.7) and the deployment of additional battery storage and renewable capacity.

However, when accounting for a modest carbon price applied from 2030, the cost differentials resulting from imposing coal off and net zero policy levers are dramatically reduced.

At a fixed carbon price of $30/ton from 2030, (in line with the carbon tax as proposed by National Treasury[23]), taking coal off in 2040 becomes economically rational. The "last mile" premium that comes with enforcing a Net Zero date is eliminated if carbon emissions attract a cost of ~$65/ton or more from 2030.

For context, the world is fast adopting carbon pricing, with 23% of global greenhouse gas emissions already under carbon price instruments in 2022 [5]. The International Energy Agency (IEA) identifies carbon prices for developing countries including South Africa of $90 in 2030 rising to $200 in 2050 for a global Net Zero scenario [6].

We find in this analysis that the Coal Off policy lever is the main driver of emissions reductions, with our most ambitious Net Zero scenario (which includes a coal-off constraint by 2040) delivering almost 1 Gt of additional emissions reductions over the *Ambitious RE Only* case by 2060. The other two Net Zero scenarios – which see later coal closure – deliver lower but still significant emissions reductions, with the *NZ2050* and *2.8Gt CO_2 budget, NZ2055* delivering 0.5 Gt of emissions savings each.

[22] Includes the switch to green hydrogen of all peaking plant, *and Sasol's CCGT and ICE power plants cur*rently run by gas.

[23] The South African Carbon Tax Act of June 2019 and Amendment Bill of July 2022 stipulates a $30/ton carbon tax rate by 2030. Exchange rate assumed for this project was 15 ZAR/USD, which results in a carbon price of R450/ton for 2030 onwards.

Figure 9: Annual System Cost relative to *Ambitious RE Only* with different levels of carbon pricing from 2030

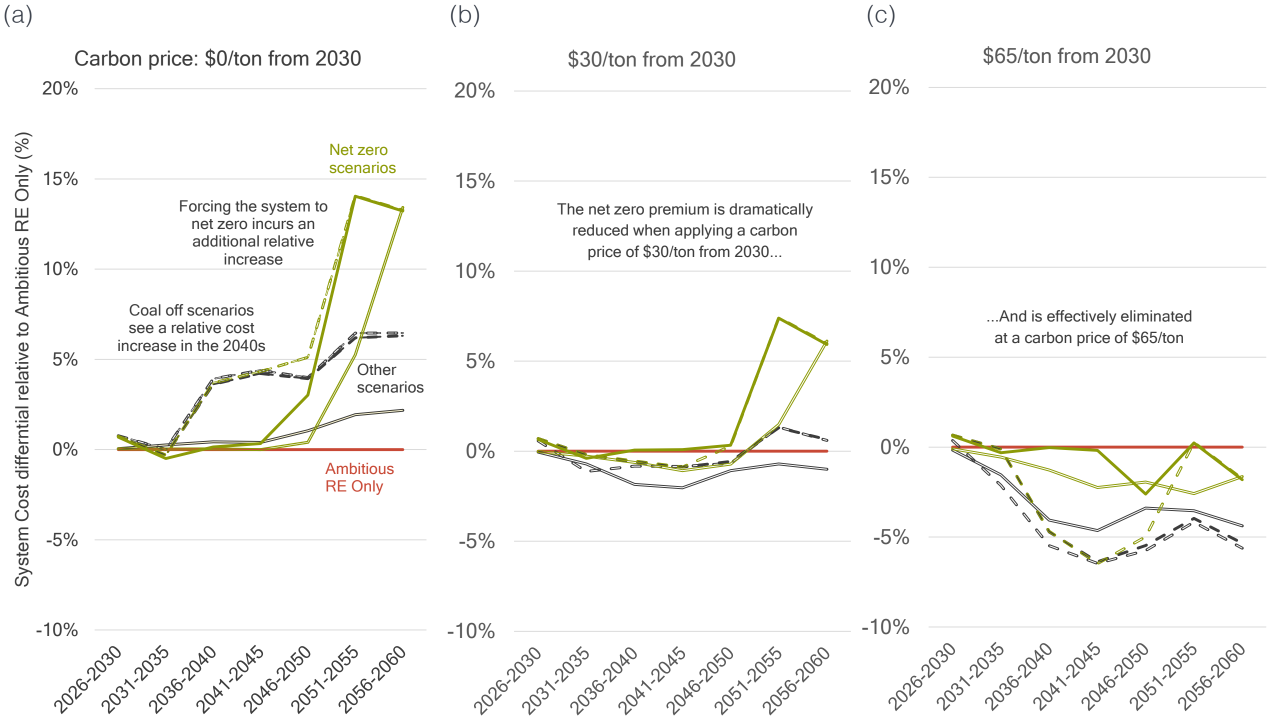


Figure 10 depicts the levelised system cost (i.e. the total incremental cost of running the power system, levelised over the period) and emissions for all the modelled scenarios compared to the *Ambitious RE Only* scenario for the period 2021-2050. What it shows is that the levelised system cost up until the point at which the power system finally achieves net zero does not vary significantly across the scenarios modelled.

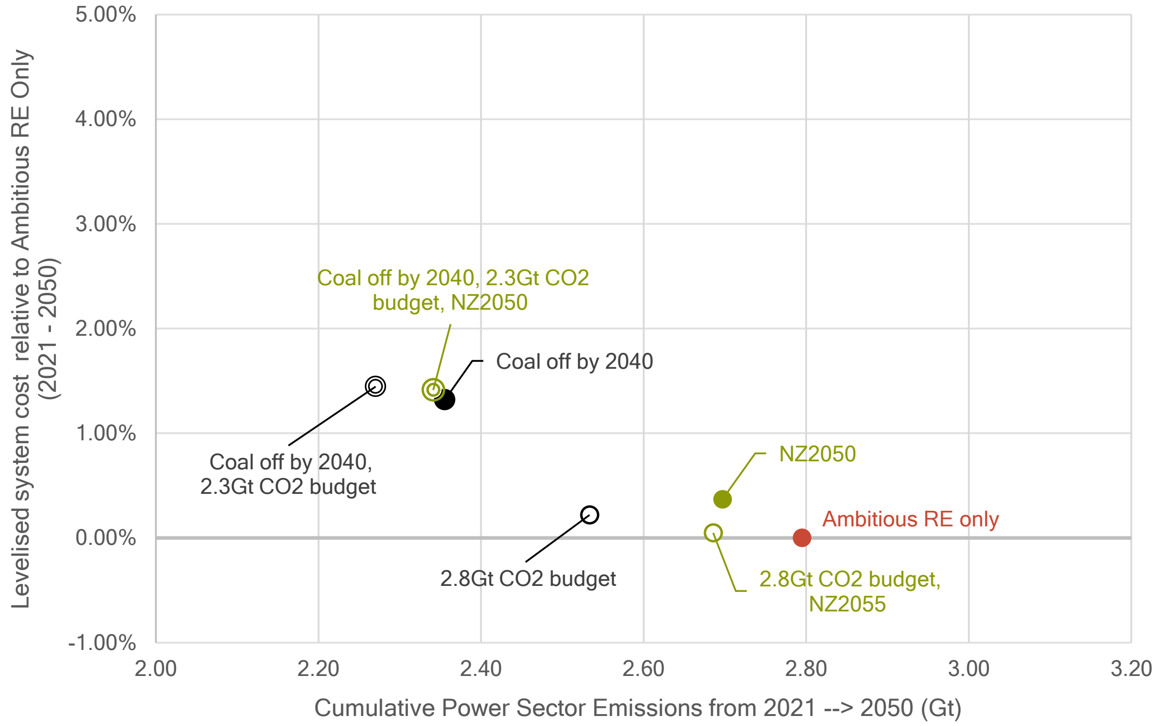
Pathways to net zero emissions by 2050 can be achieved at a modest premium of 0.4%-1.4%[24] on the cost of the reference case over the modelled ~30yr period, depending on the policy levers imposed. Importantly, from the perspective of carbon risk to the economy, our most ambitious Net Zero scenario (which includes a coal-off constraint and a tight carbon budget) results in the greatest relative levelised cost increase (+1.4%), but substantially decreased emissions of more than 0.5 Gt by 2050. As shown in Figure 10, when applying a carbon price of $30/ton[25] from 2030 - as per National Treasury's announced carbon tax rates [17] – this fairly conservative estimate effectively cancels out the cost differential.

Given the modest cost premiums of the Net Zero scenarios over an *Ambitious RE Only* scenario, which vanish when a carbon price is taken into account, we can conclude that net zero is indeed achievable from a cost perspective.

[24] These include the **NZ2050** and **Coal off by 2040, 2.3 Gt CO_2 budget, NZ2050** scenario. The **2.8 Gt CO_2 budget, NZ2055** only achieves NZ by 2055.

[25] See South African Carbon Tax Act of June 2019 and Amendment Bill of July 2022 stipulating a $30/ton carbon tax rate by 2030. Assumed exchange rate for this project was 15 ZAR/USD, which results in a carbon price of R450/ton for 2030 onwards.

Figure 10: Emissions and Levelised Cost of Scenarios relative to the *Ambitious RE Only* Scenario (with carbon price of $0/ton) for 2021-2050 period*



* Figure 10 shows costs and emissions to 2050 at which date the **2.8Gt CO_2 budget, NZ2055** scenario has not yet reached net zero. By 2055 at its Net Zero date, this scenario delivers 0.4Gt emissions savings over the **Ambitious RE Only** scenario at a premium of 0.25% in levelised cost.

Figure 11: Emissions and Levelised Cost of Scenarios relative to the *Ambitious RE Only* Scenario (with carbon price of $30/ton) for 2021-2050 period*

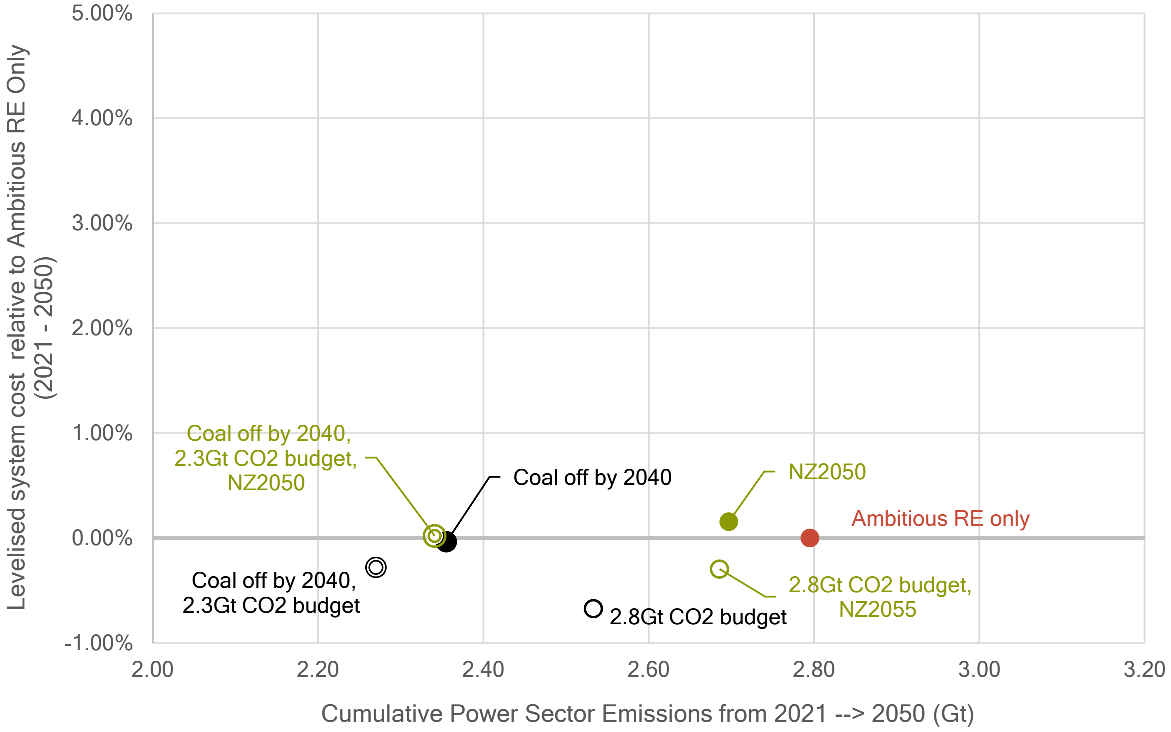


*Figure 11 shows costs and emissions to 2050 at which date the **2.8Gt CO_2 budget, NZ2055** scenario has not yet reached net zero. By 2055 at its Net Zero date, this scenario delivers 0.4Gt emissions savings over the **Ambitious RE Only** scenario at a discount of 0.23% in levelised cost

4.2 IMPLICATIONS FOR NEAR-TERM ACTION: RAMP UP TO 6 GW+ RENEWABLES, 0.5 - 1 GW PEAKING AND STORAGE (EACH) P.A.

The required deployment of generation capacity across different technologies for various scenarios reveals that in the short- and medium-term, a rapid and consistent expansion of renewables, storage, and peaking capacity is necessary. There are no significant differences between scenarios (with net zero, coal off, carbon budget, or without policy levers) until at earliest 2035. In sum, focusing on implementing an ambitious renewable energy build programme in the near term will set the SA power system up to play its part in decarbonising the economy; staying within a Paris-aligned carbon budget range, while retaining the flexibility to accelerate coal phase-out and achieve net zero in the future.

4.2.1 INSTALLED CAPACITY REQUIREMENTS

Figure 12 to Figure 16 below indicate the required installed capacity for each technology type at 5-year intervals from 2025 up to and including 2050. There is negligible difference in the installed capacity of wind and solar PV across all scenarios. Approximately 30 GW of solar and 20 GW of wind is required across all scenarios by 2030, with 5 GW battery storage and 10 GW peaking capacity.

In scenarios with a coal off policy by 2040, certain capacity investments in additional OCGT, battery storage, and pumped storage (to replace system services provided by coal) are brought forward by a few years (coal off scenarios are indicated by dashed lines in the figures below).

The deployment of new pumped storage capacity is indicated as optimal between 2035 and early-2040 in all scenarios, with coal off scenarios necessitating the earlier construction of a significant amount of long-term storage capacity within this period. Other scenarios show the same capacity requirement but with a more incremental approach (Figure 14). Considering the long lead times (8+ years) for pumped storage investments, this suggests that decisions regarding pumped storage may need to be considered before the end of this decade. On the other hand, investment decisions for OCGTs and battery storage, technologies with shorter lead times, can be made in the mid-to-late 2030s.

Figure 12: Installed Solar PV and Wind Generation Capacity for each scenario

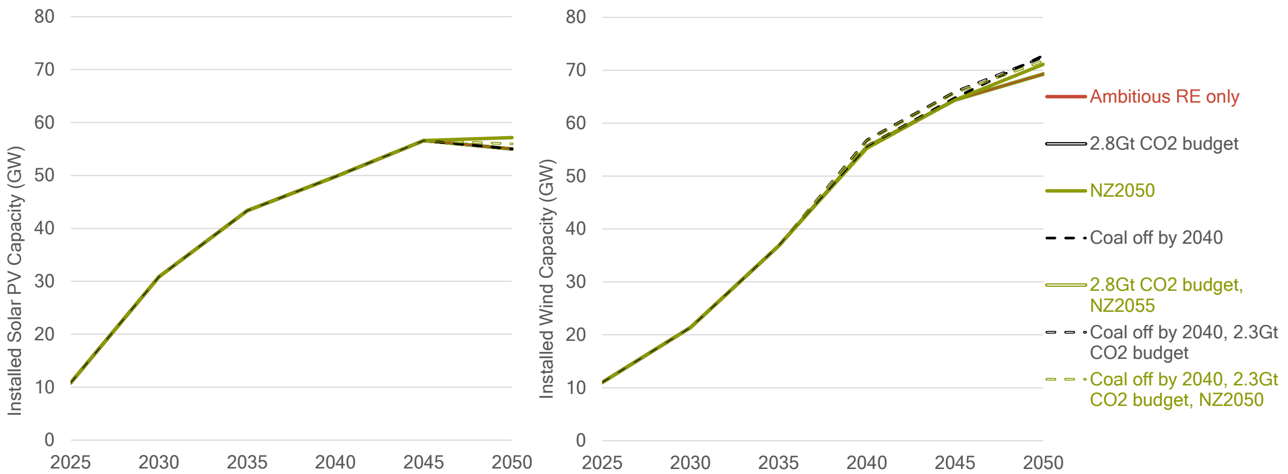


Figure 13: Installed OCGT Peaking Capacity and Battery Storage Capacity for each scenario

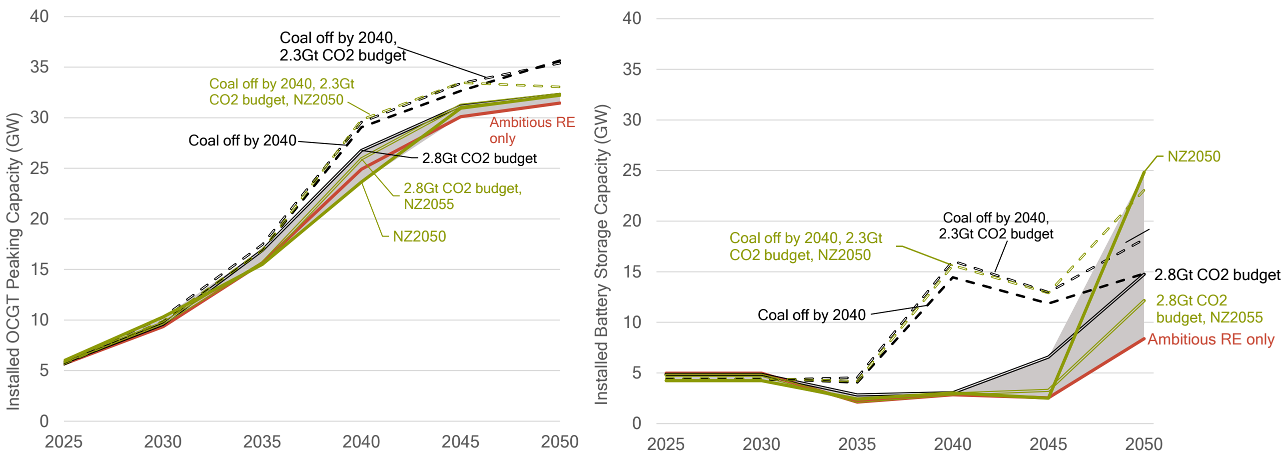
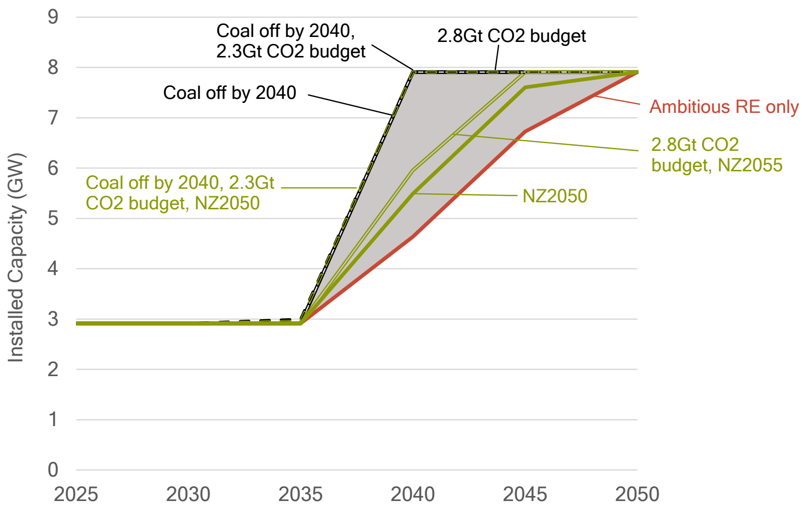


Figure 14: Installed Pumped Storage Capacity for each scenario



The implications of the modelling results for practical, short-term action are as follows: SA needs to deploy approximately 6 GW of new renewable capacity (wind and solar), 0.5 – 1 GW peaking capacity (open cycle turbines / internal combustion engines), and 0.5 – 1 GW battery storage every year from now until 2030 (and beyond) – through government procurement programmes and private sector initiatives. This requires:

- Strong emphasis on removing grid constraints, streamlining permits, and other necessary measures to accelerate the rollout of renewable energy.
- Initiating a peaking capacity procurement programme with haste for OCGTs and/or ICE technologies designed to provide quick response balancing power.

Additionally, given the pumped storage requirement in the 2030s, action is required to start investigating possible sites and establish processes to accommodate the longer lead times associated with constructing pumped storage assets. Other long-duration storage options could also fulfil this role in the future, although they were not analysed in the modelling.

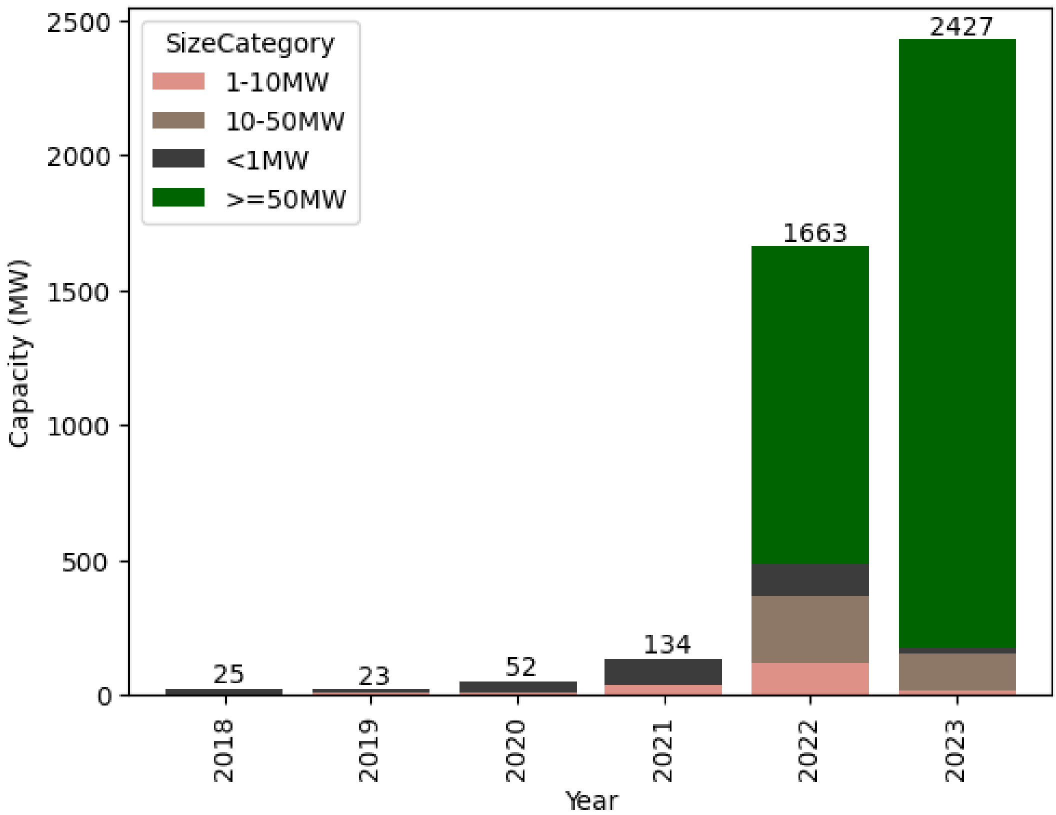
4.2.2 STOCKTAKE - WHERE ARE WE NOW?

The restarting of the REIPPPP, after a seven-year disruption due to political and institutional factors, has seen 9 out of 25 initially awarded projects under Bid Window (BW) 5 reach financial close (amounting to less than 1 300 MW), and six preferred bidders appointed from BW6 amounting to 1 000 MW, all from Solar PV. The new generation capacity BW5 is set to come online from early 2025, whilst 4 projects are awaiting financial close and the remaining 12 failed to reach financial close. No wind projects were awarded under BW6 due to grid capacity constraints in the Eastern and Western Cape supply areas, which would have increased the allocation up to 3 200 MW under this window. BW7 and BW8 are expected to be launch in Q3 and Q4 of 2023, with a target allocation of 5 GW in each round for both solar and wind projects that can be developed in provinces where grid capacity is available.

Procurement under the Risk Mitigation IPP Procurement Programme has only seen three projects amounting to 150 MW reach financial close out of the target 2 000 MW. The remaining eight projects are currently contested. 1.3 GW of battery storage is expected to be procured under the Government's Energy Storage IPPPP and by Eskom. New gas generation of 3 GW is currently being considered, but it is not clear whether this gas will play a peaking or base supply role in the power system. Furthermore, clarity is yet to be gained on the long-term supply of gas to support the economic viability of such projects.

Over the past two years, there has been a significant drive from the private sector to increase efforts in addressing their power needs. This has seen the registration of 1.7 GW private generation projects with NERSA in 2022 and 2.5 GW distributed generation registered in 2023 to date, majority of this comprised of projects 50MW and greater (Figure 15). This has been enabled by changes to Schedule 2 of the Energy Regulation Act in October 2021, which allowed private players to develop and procure their own power with no limits on plant capacity.

Figure 15: NERSA registrations in the distribution generation market [18]



This stocktake suggests that, though progress has been made in terms of renewable energy procurement at both government and increasingly at private sector level, we are still well shy of the required installation rate of approximately 6 GW of renewable energy capacity per year.

Furthermore, additional battery storage procurement rounds should be initiated as soon as possible to ensure that the requisite pipeline of capacity can come online as required to meet power system requirements, to alleviate and moderate grid capacity constraints, and to provide certainty to the storage market.

Finally, it is clear that new peaking capacity must be delivered in the short-term. Clarifying that the new 3GW of 'gas & diesel' capacity requirement as stipulated in the IRP [9] should be procured as peaking capacity and expediting this procurement process would be a logical next step.

4.2.3 COAL DECOMMISSIONING

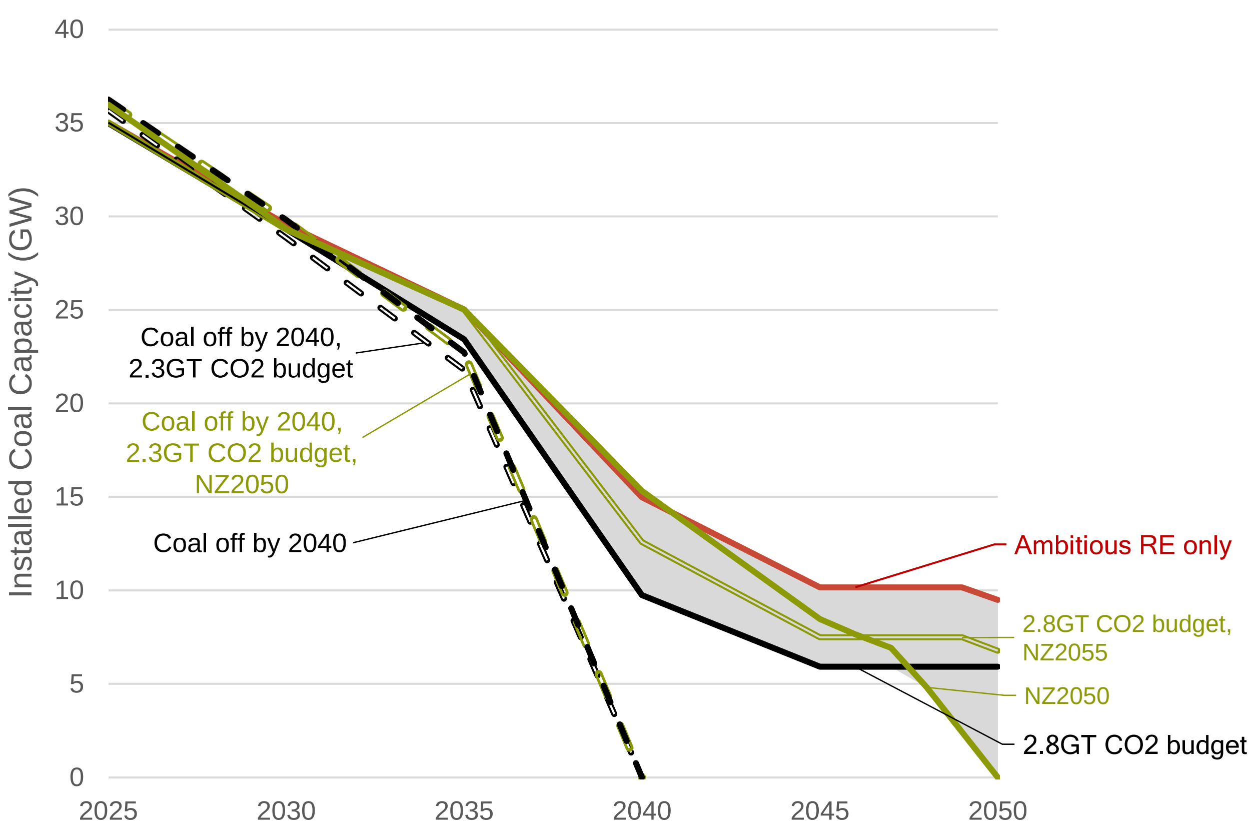
Our modelled scenarios illustrate that a net zero power system ultimately does not include any operational coal-fired power. Based on analysis of current cost estimates and expert opinions, the feasibility of retrofitting existing coal plants with CCS is deemed economically unviable and thus excluded from our modelling analysis. As a result, the logical course of action in the modelling simulation is the closure of coal stations.

The scenarios where a coal off by 2040 policy lever is imposed (dashed lines in the graph below) achieve significantly greater cumulative emission reductions (see section 4.1), although at a slightly higher overall system cost. It is worth noting that there are both practical and political feasibility questions with regard to enforcing a 2040 coal shut down date in South Africa.

In the other scenarios, coal is retired at the most economic pace but within the bounds of a carbon budget. In the scenarios with enforced net zero dates, the last units of coal come off at the particular net zero date (indicated by the green lines in Figure 16, barring the *2.8Gt CO_2 budget, NZ2055* scenario where the coal off date is not depicted on the graph). These scenarios have slightly lower system costs over the modelled period than those where coal is forced off by 2040, and notably allow more optionality for SA's coal fleet and power system development whilst remaining net zero compliant. This optionality is traded off against the slower decline of power system (and thus economy-wide) carbon intensity.

There may be practical reasons why keeping coal-plant capacity available to the system (i.e. mothballing, not fully decommissioning) might be a useful system reliability option for South Africa in the late 2030s and 2040s. It is worth investigating options for how the coal might be utilised in such a way that capacity is available to be fired up when needed as back up during periods where extended low renewable resources are anticipated (e.g. once or twice a year for a couple of weeks at a time) – but provides very little overall energy (and therefore emissions) to the system. There remain questions around the operational feasibility of such an option and further research on the possibilities for 'flexibilising' the coal fleet is required.

Figure 16: Installed Coal Generation Capacity for each scenario



4.3 A NET ZERO POWER SYSTEM IS LARGELY ACHIEVABLE BASED ON ESTABLISHED TECHNOLOGIES

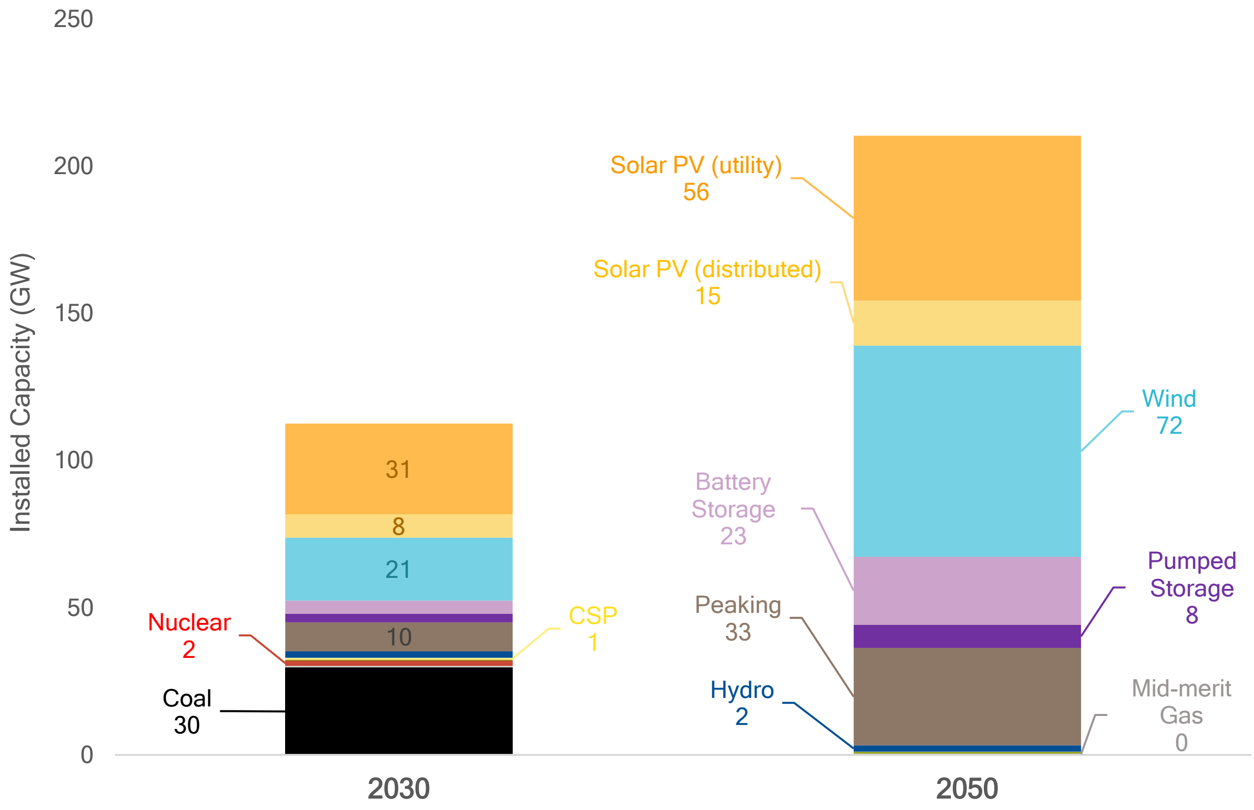
The three scenarios investigated in this study that are net zero aligned illustrate that full decarbonisation of SA's power system is achieved by:

- **Replacing all coal-fired power generation** with a combination of renewables, flexible peaking plant and storage capacity. Coal power is decommissioned over a period of ~20 or more years, with the last coal units coming off between 2040 and 2055 (i.e. at the respective coal-off or net zero dates in each scenario);
- **Switching all fuel for flexible peaking plant capacity**, which provides flexibility and balancing services to the power system, from fossil fuels (diesel / gas) to 100% green hydrogen.

The charts below illustrate what the installed capacity (Figure 17) and generation mix (Figure 18) looks like in the years 2030 and 2050 for one of the scenarios that achieves net zero emissions by 2050[26]. By 2030 the SA power system has ~110 GW installed generation capacity of which 21 GW is wind, 39 GW is solar (inclusive of distributed generation), 10 GW is flexible peaking capacity and roughly 5 GW is battery storage. 30 GW coal remains on the system, generating almost 40% of annual electricity.

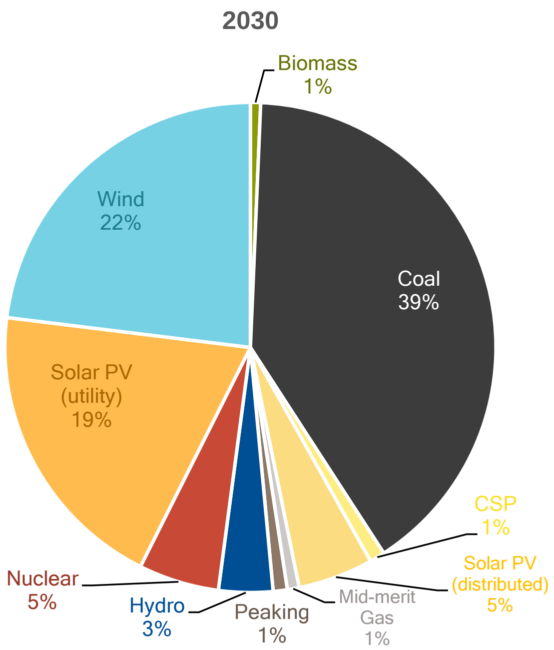
[26] Based on Net Zero scenario with coal off by 2040 and 2.3 Gt carbon budget (**Coal off by 2040, 2.3Gt CO_2 budget)**

Figure 17: Installed Capacity (GW) for a Net Zero scenario (*Coal off by 2040, 2.3Gt CO_2 budget*)



By 2050 (or 2055 in the case of the *2.8Gt CO_2 budget, NZ2055* scenario), no more coal generation capacity remains on the system. Around 95% of annual energy is produced by wind and solar and 2% by peaking plant – which at this stage is fuelled by green hydrogen. Importantly, this is actually a zero-emissions power system. Direct Air Capture technologies – although made available as an option to the model – are not chosen due to being uneconomic relative to the alternative: green hydrogen fuelled gas turbines. In our modelling exercise, we do not assume that any of SA's available carbon sink capacity is allocated to the power sector (which would theoretically allow for some remaining annual emissions).

Figure 18: Generation for Net Zero scenario for 2030 (left) and 2050 (right)



All of the technologies required to support the transition to net zero exist today – namely wind, solar PV, hydro, batteries, pumped storage and gas turbines. There are already a number of existing turbine models which can be fuelled by a blend of natural gas and hydrogen, or by hydrogen alone. However, additional development will be required in order for 100% hydrogen fuelled turbines to reach commercial deployment at the level required to support national decarbonisation plans (more on this in section 4.3.2 4.3.2below).

See section 6.5 for full suite of figures on the installed capacity and energy mix evolution for all scenarios.

The following section explains why we need technologies that can fulfil storage and peaking functions in a net zero power system.

4.3.1 WHY WE NEED BOTH STORAGE AND PEAKING IN A NET ZERO SYSTEM

As the penetration of renewable energy resources increases, so does the requirement for flexible dispatchable power to balance out mismatches between variable power supply and demand. Renewable energy is variable on a daily basis, but also on a seasonal basis, i.e. some months of the year have lower wind and/or solar resources. The power system needs technologies which can provide short-term, multi-hour balancing services on a daily basis, but also over seasonal timescales.

Battery storage and pumped storage technologies can, and already do, provide balancing functions on a daily basis – i.e. helping to meet the 'evening peak'. However, these technologies cannot yet provide such services over multi-day, or seasonal timescales due to their quick discharge duration – they usually need to be recharged daily [19]. Also, due to forecasting error (although small), sporadic unplanned outages or extreme weather events the battery charge levels may not be adequate and additional system security/dispatchable technologies may be required[27]. That said, battery technologies are advancing rapidly, and there is substantial investment globally into the provision of longer-duration battery (and other) storage options. The technology outlook by 2030 may look quite different from that of today.

Currently though, OCGTs/ICEs, fired by fuels which can be stored, are the main commercially available technologies capable of providing balancing services over multi-hour or multi-day periods in which renewables resources may be low and existing storage capacity is not able to be discharged. Green hydrogen can be burnt in these machines [20], thereby providing a low-carbon peaking / balancing and long-duration storage option [21].

4.3.2 THE FEASIBILITY OF HYDROGEN AS A PEAKING FUEL

There are several technical aspects to consider when discussing the potential of green hydrogen-fired peaking plant to support South Africa's power sector decarbonisation. One aspect relates to storage and handling of hydrogen. It is worth noting that hydrogen can cause embrittlement of metal components such as pipes and tanks, leading to earlier deterioration. Additionally, due to its smaller molecular size compared to natural gas, there is a higher risk of leakage. Furthermore, hydrogen is less energy dense, requiring larger quantities to generate the same amount of power, and it burns at a higher temperature. Consequently, modifications are necessary to adapt existing peaking gas turbines for hydrogen combustion, including adjustments to the combustion chamber, installation of new piping and fuel skids, implementation of leakage detectors and other safety enhancements. Moreover, modifications are also required to address the increase in NOx emissions resulting from

higher concentrations of hydrogen being combusted (due to the higher heat of air in the reaction) [22]. We have not considered these costs in terms of the OCGT capex – with OCGT capex remaining the same regardless of what fuel is being burned (gas, diesel, green hydrogen). However, we have included a cost in for the price of green hydrogen fuel to account for integration and storage.

[27] A stochastic, reliability assessment was beyond the scope of the study.

Box 4: Use cases for hydrogen in industry

Major global gas turbine vendors such as Mitsubishi Power, GE Power, and Siemens have already introduced turbines capable of utilizing hydrogen in various capacities to cater to decarbonization goals. For instance:

- Mitsubishi is currently converting one unit at the Nuon Magnum combined cycle gas power plant (1.32 GW) to run on 100% hydrogen by 2023, with a unit capacity of 440 MW [21]
- Siemens offers a range of gas turbines that can operate on different levels of hydrogen fuel blended with natural gas, including their larger 'heavy-duty' (100 – 600 MW) gas turbines are capable of burning 30-50% hydrogen [22], and the SGT-A35 turbine can operate on 100% hydrogen. Siemens is collaborating on the HYFLEXPOWER project which aims to demonstrate the use of 100% hydrogen as fuel in 2023 [23]
- Similarly, GE has been actively engaged in research and development in the hydrogen-fuelled turbine space, with some of their turbine classes already equipped for 100% hydrogen combustion (B, E, F class) [24].

Considering ongoing advancements by leading turbine manufacturers, the dedicated research and development support for hydrogen-fired turbines, and the possibility of retrofitting existing gas turbines for hydrogen firing, it is highly likely that these options will be commercially available at the scale necessary to support the 'last-mile' decarbonisation of SA's power system by 2040, if not earlier.

Importantly, there is no immediate need to make investment decisions regarding green hydrogen peaking now. As outlined in section 4.2.1 the installed peaking capacity requirements are very similar across scenarios – regardless of whether they achieve net zero emissions or not. A decision about a fossil-to-green-fuel switch only needs to be made in the late 2040s, allowing time for a "wait-and-see" approach. Furthermore, it is possible that more efficient emissions-free technologies may emerge in the coming decades to fulfil the same peaking function required by the SA power system, providing additional options for consideration.

This flexibility creates a favourable environment for exploring and evaluating various pathways towards a net zero power sector.

4.4 GREEN HYDROGEN: THE LAST MILE OR THE NEXT MILE?

Once all coal capacity is closed, the modelling results show that residual emissions in the power system stem from peaking plant (OCGTs/ICEs) fuelled by gas or diesel. 'Last mile' decarbonisation (i.e. removing these remaining emissions from the system) involves replacing fossil-based fuel for peaking plant with green hydrogen[28]. In this section, we investigate the volume of fuel required to support power system flexibility and the cost impact of switching this fuel to green hydrogen. We also investigate some factors/alternative futures that might lead to

[28] Green ammonia co-firing is also considered as a fuel option but is not chosen by the model due to its higher cost than green hydrogen as fuel.

green hydrogen adoption sooner than anticipated in the modelling.

This is not an exhaustive scoping of all future possibilities, but rather a thought experiment to both highlight the limitations of continuous and near-linear modelling frameworks for understanding the evolution of highly complex and uncertain systems, together with an identification of policy relevant aspects of South Africa's power system decarbonisation.

4.4.1 VOLUMES OF PEAKING FUEL REQUIRED

We observe a total fuel requirement of 120 - 160 PJ by 2050 across the scenarios, which is predominantly for peaking plant[29]. Until 2030, peaking plant is fuelled by diesel or Liquid Natural Gas (LNG), after which it is fuelled almost entirely by LNG due to its favourable economics (see our cost assumptions in Figure 21 below). Given the high cost of green hydrogen relative to relative to LNG and diesel, we only see green hydrogen feature in the Net Zero scenarios, and only at the point where the model is forced to net zero emissions. None of the other scenarios see a switch to green hydrogen.

Fuel offtake is fairly volatile year-on-year due to the intermittent manner in which peaking plants operate. We therefore display fuel offtake as an annual average over each 5-year period in Figure 19. The scenarios with a coal off by 2040 policy lever see a substantial rise in fuel required in the 2040s due to an increased requirement for flexible capacity to complement renewables when replacing coal. This rise in fuel offtake is less marked in scenarios where coal is not forced off.

Figure 19 shows the *total fuel* offtake, which includes fuel offtake by OCGT and CCGT plant[30]. As described in section 4.6 below, CCGT plant does not feature in scenarios which are constrained to a Paris-aligned carbon budget. The only scenario which sees CCGT built is that which imposes a Coal off by 2040 constraint and no carbon budget. In this scenario, 1.4 GW of CCGT is built to replace coal capacity and as a result, this scenario sees the highest fuel offtake from 2040 onwards. In all the other scenarios, including those with coal-off policy levers, no CCGT is built due to its emissions intensity. Instead, the model builds a combination of renewables, storage and peaking capacity – and therefore the fuel requirement is driven only by peaking plant and Sasol's plants.

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[29] *For context, the NBI's gas study sees 140-*240 PJ/a *depending on whether it is a 'high' or 'low' gas scenario whilst the ESRG's net zero study s*ees 300-350 PJ/a required in 2050.

[30] All the scenarios include the simplistic assumption, in absence of better information, that the Sasol CCGT and ICE capacity of 250 MW + 175 MW will continue to run through the entire modelling period at minimum 60% capacity factor using sub-economic gas priced at R75/GJ. This results in a constant annual requirement of 25PJ and is included in Figure 19Figure 19Figure 19.

Figure 19: Total fuel offtake (annual average for each 5yr period)

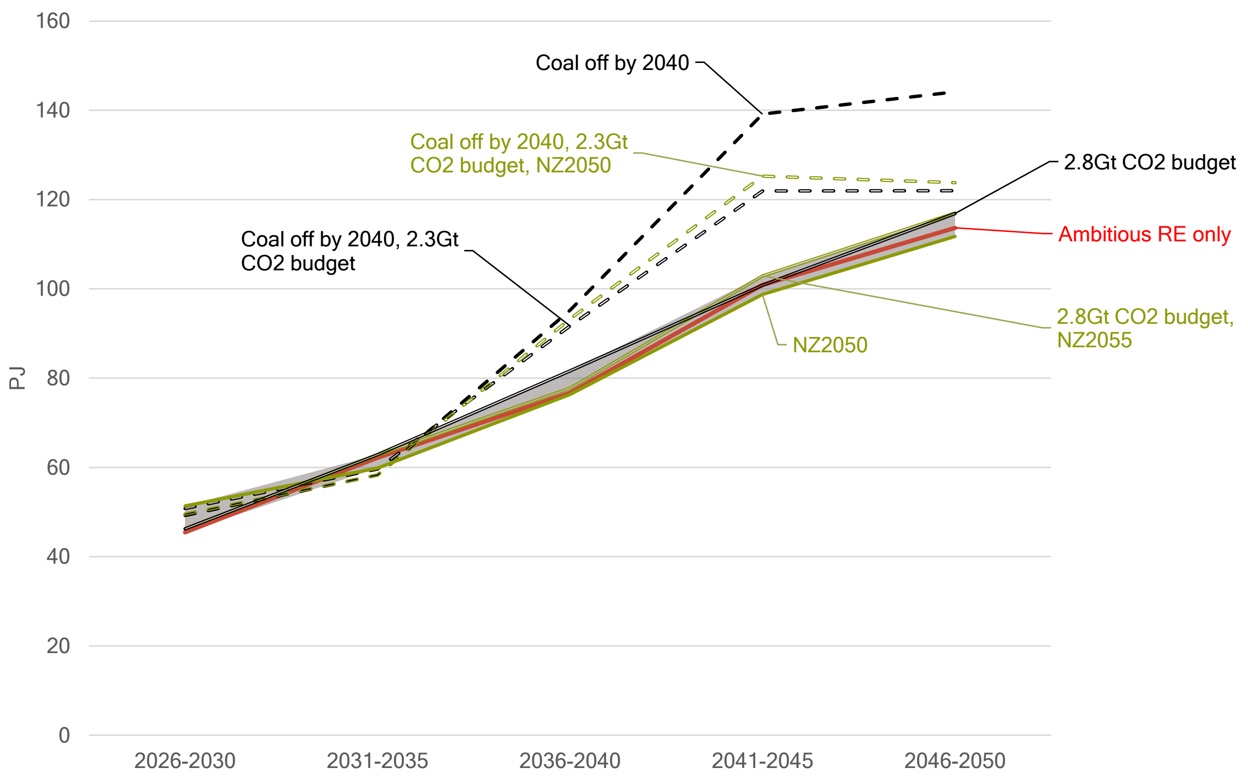
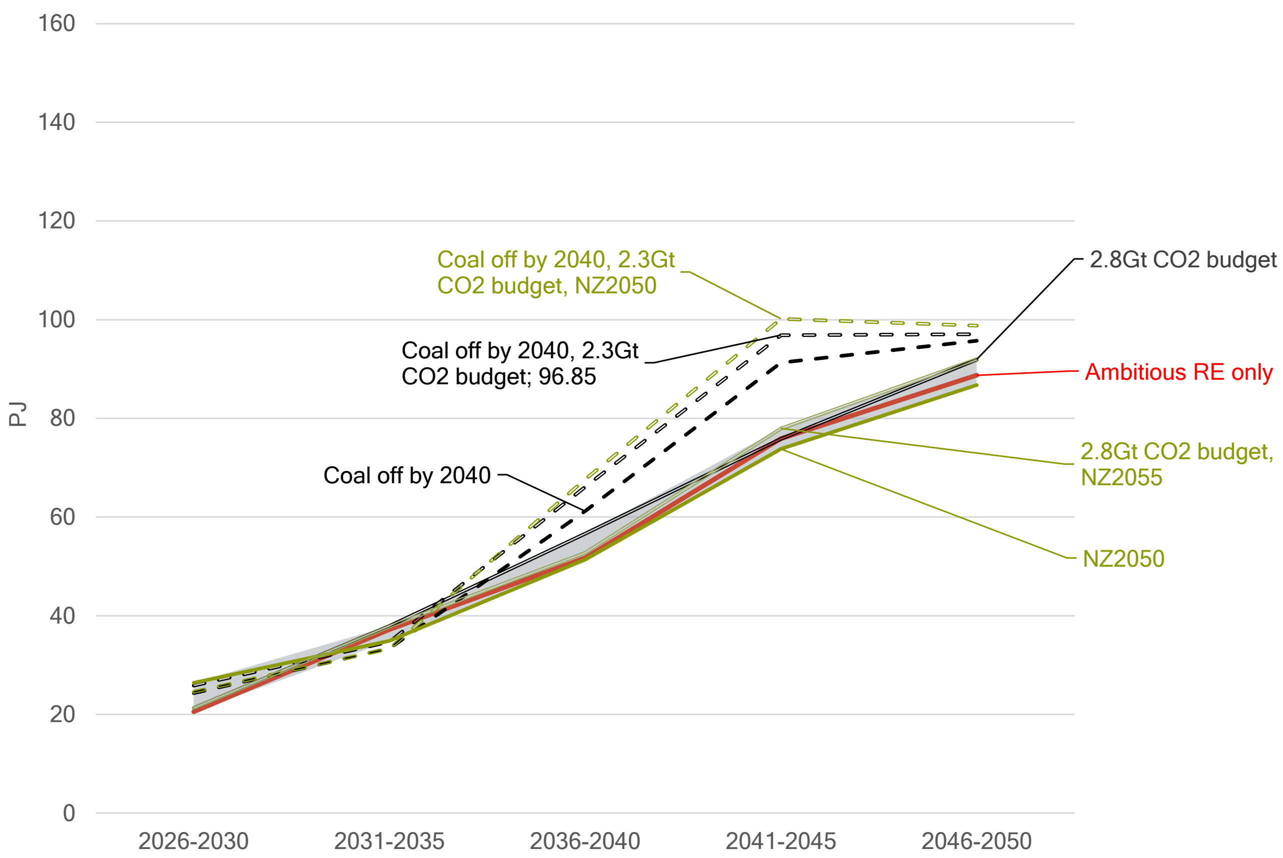


Figure 20 shows the total fuel requirement for *peaking plant only*, i.e. it excludes the Sasol CCGT + ICE plant, and the CCGT plant that is built in the *Coal off by 2040* scenario. In reality, the cheap gas resource and economic lives of the Sasol plants will have ended before 2050. Our focus on fuel volumes under a net zero scenario (which builds no CCGT plant) leads us to exclude these plants and only use the volumes from Figure 20 for the rest of the 'last mile' analysis.

Figure 20: Total peaking fuel offtake (annual average for each 5yr period)



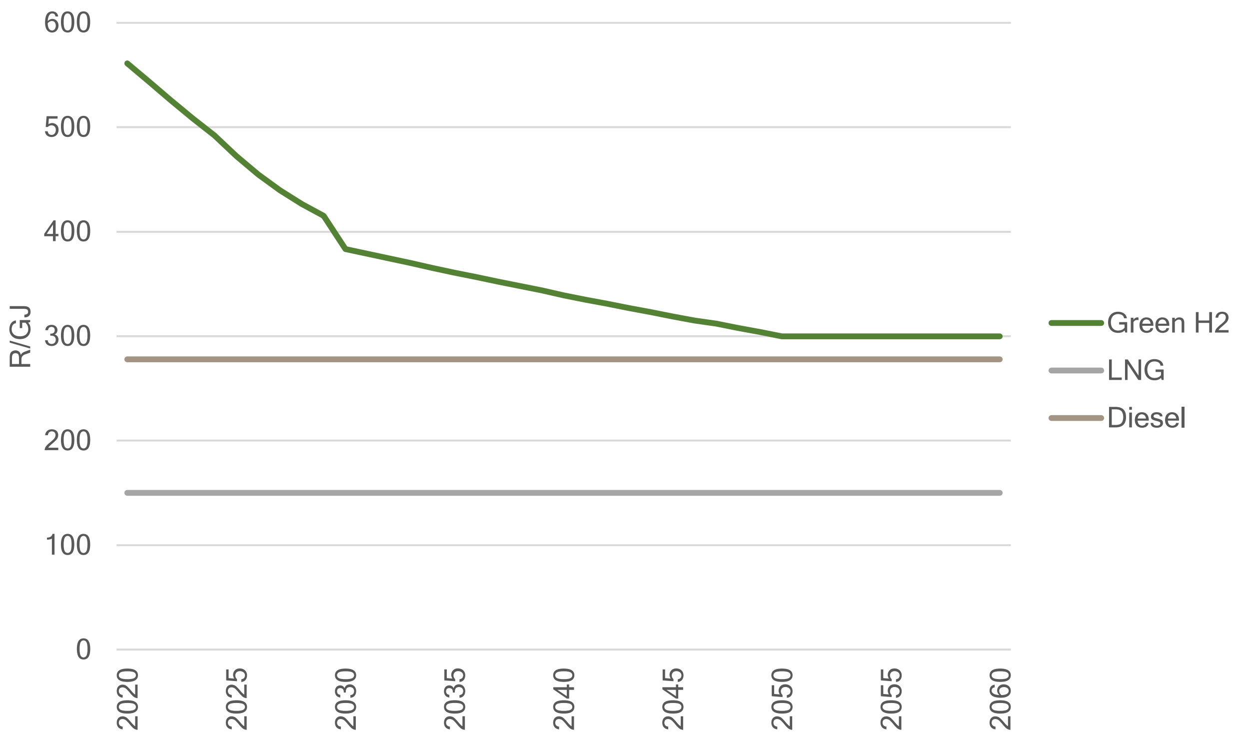
4.4.2 SYSTEM COST IMPACT OF GREEN PEAKING FUEL SWITCH

In our investigation of the peaking fuel requirements for achieving a net zero power system in South Africa, an important question arises: what will be the cost of switching from LNG to green hydrogen when the time comes? Currently, green hydrogen is considerably more expensive compared to alternative fuel options, with costs roughly two times higher than diesel and three times higher than LNG.

Based on the current costs of various fuel options and projected learning curves for green hydrogen, our modelling demonstrates that it is economically favourable to delay final decarbonisation (i.e. transitioning all peaking fuel from LNG to green hydrogen) as long as possible. This is evidenced in the modelling results which only see a switch to green hydrogen in scenarios with a defined net zero date, and the switch only occurring at that date, despite allowing the option of a gradual transition to green hydrogen from 2030.

By 2050, our modelling assumes that green hydrogen will be available at R300/GJ (equivalent to approximately $2.4/kg) for the OCGT peaking plants. In comparison, we maintain static assumptions for LNG and diesel at R150/GJ and R278/GJ, respectively. Consequently, by 2050, when the majority of the peaking fuel is supplied by LNG, switching to green hydrogen at R300/GJ involves a doubling of the price of peaking fuel.

Figure 21: Peaking fuel cost assumptions



4.4.2.1 Quantifying the cost implications of a switch to green fuel

With the price of peaking fuel doubling, we expected to see a significant increase[31] in the system cost in the year when the switch to green hydrogen occurs. Surprisingly, we found the impact of this fuel switch on the overall system cost to be a modest increase of roughly 4%-6%. The reason is as follows: although the installed capacity of peaking plant is significant by 2050 (33 GW average across scenarios, as shown in section 4.2.1, this capacity is run at very low capacity factors – less than 4% annually as seen in Figure 22. Because this capacity is run so infrequently, the cost of the peaking fuel is in the region of 4-6% of the total annual system cost. Therefore, a doubling of the peaking fuel price increases the total system cost by a similar amount.

[31] According to the power sector modelling study conducted by the NBI, removing residual power sector emissions and achieving net zero results in a 30% increase in costs relative to a renewables-dominant system [3].

Figure 22: Average annual OCGT Capacity Factor for all scenarios for each 5yr period

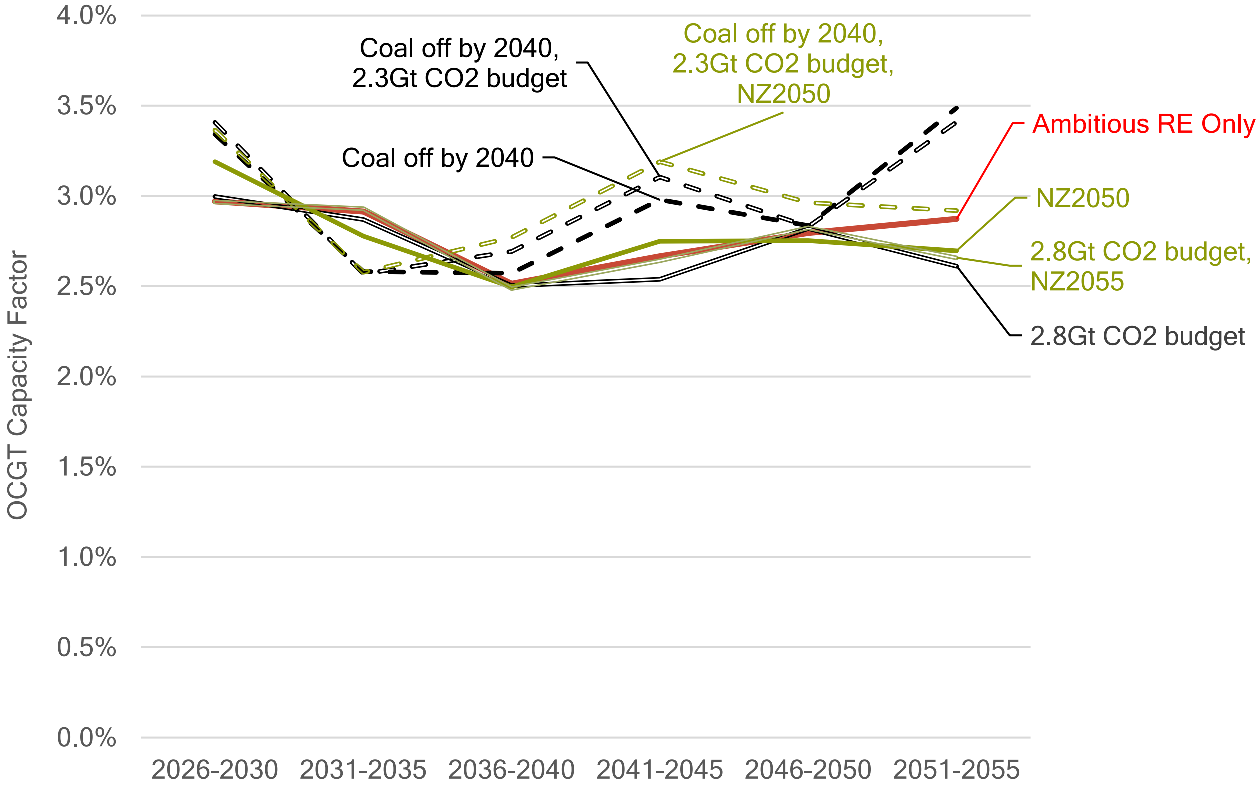
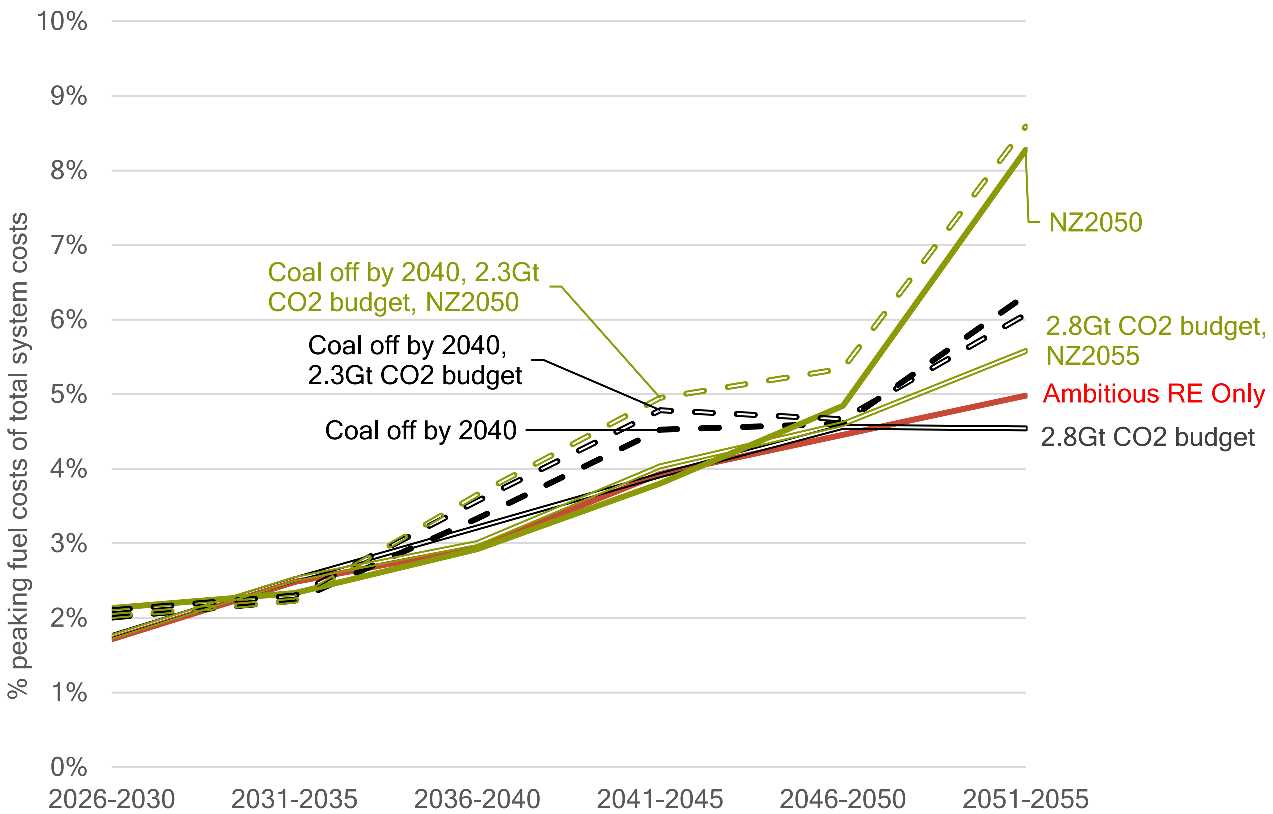


Figure 23 illustrates the cost trajectory for peaking fuel used in the OCGTs expressed as a percentage of the total cost of the power system. Note that the cost of peaking fuel starts below 1% and increases steadily as the penetration of renewable energy increases.

As we would expect, scenarios in which coal is taken off by 2040 require increased peaking support over this period compared to other scenarios (Figure 22 shows that the capacity factors of the plant are slightly higher in the 2040s, and Figure 23 shows the increase in peaking fuel cost relative to total system cost).

In the final few years before 2050, peaking fuel makes up, on average, approximately 5% of total system cost in all scenarios, with the marked increase occasioned by the switch to hydrogen visible after 2050 in the scenarios with a 2050 net zero date imposed (Figure 23). This contributes to the overall relative system cost increase highlighted in section 4.1.2.

Figure 23: Peaking fuel cost as percentage of total power system cost (annual average over 5-year periods)



4.4.2.2 Sensitivity of the cost impact of the green hydrogen fuel switch

Of course, estimating the costs associated with a switch to green hydrogen so far in the future carries significant forecast risk and it is prudent to analyse the sensitivity of the cost impact of the fuel switch to both fuel price assumptions and the years over which the transition to hydrogen would occur.

The below tables illustrate the system cost[32] increase (red) or decrease (green) of switching all peaking fuel from LNG to green hydrogen. The tables show the percentage increase in system cost occasioned by the fuel switch (average of the two scenarios that achieve Net Zero by 2050) – across a range of prices for each fuel. This cost increase will also be influenced by the total volume of fuel that needs to be switched in a given year. As discussed in section 4.4.14.4.1, the annual fuel requirement for peaking is highly variable year-on-year. We have therefore presented two sensitivity tables –Table 4 indicating the cost increase in a selected year between 2045 and 2050 where there is a higher fuel requirement for peaking (~130 PJ) and indicating the cost increase in a selected year with a lower fuel requirement (~70PJ). Under the current assumptions (R300/GJ for Green Hydrogen and R150/GJ for LNG) the resultant cost increase is 3.2%-6.6%.

[32]This is different from the total levelized system cost shown in section 4.1 above which is based on costs and energy served over the 2021-2050 period. The system cost increase occasioned by the switch to green hydrogen is the system cost shock experienced in the year of the switch.

Table 4: System cost impact of fuel switch to green hydrogen to achieve Net Zero in a high fuel offtake year between 2045 and 2050 (~130 PJ)

Carbon Tax (R/ton) 0

Hydrogen Price

Gas Price ($/GJ)	Gas Price (R/GJ)	1.20	1.60	2.00	2.40	2.80	3.20	3.60	4.00	4.40	4.80 $/kg
		150	200	250	300	350	400	450	500	550	600 R/GJ
20.00	300	-3.3%	-2.2%	-1.1%	0.0%	1.1%	2.2%	3.3%	4.4%	5.5%	6.6%
18.33	275	-3.0%	-1.8%	-0.6%	0.6%	1.8%	3.0%	4.2%	5.4%	6.6%	7.8%
16.67	250	-2.6%	-1.3%	0.0%	1.3%	2.6%	4.0%	5.3%	6.6%	7.9%	9.2%
15.00	225	-2.2%	-0.7%	0.7%	2.2%	3.7%	5.1%	6.6%	8.0%	9.5%	11.0%
13.33	200	-1.6%	0.0%	1.6%	3.3%	4.9%	6.6%	8.2%	9.9%	11.5%	13.2%
11.67	175	-0.9%	0.9%	2.8%	4.7%	6.6%	8.5%	10.3%	12.2%	14.1%	16.0%
10.00	150	0.0%	2.2%	4.4%	6.6%	8.8%	11.0%	13.2%	15.4%	17.6%	19.8%
8.33	125	1.3%	4.0%	6.6%	9.2%	11.9%	14.5%	17.1%	19.8%	22.4%	25.0%
6.67	100	3.3%	6.6%	9.9%	13.2%	16.5%	19.8%	23.1%	26.3%	29.6%	32.9%
5.00	75	6.6%	11.0%	15.4%	19.8%	24.1%	28.5%	32.9%	37.3%	41.7%	46.1%

Table 5: System cost impact of fuel switch to green hydrogen to achieve Net Zero in a low fuel offtake year between 2045 and 2050 (~70 PJ)

Carbon Tax (R/ton) 0

Hydrogen Price

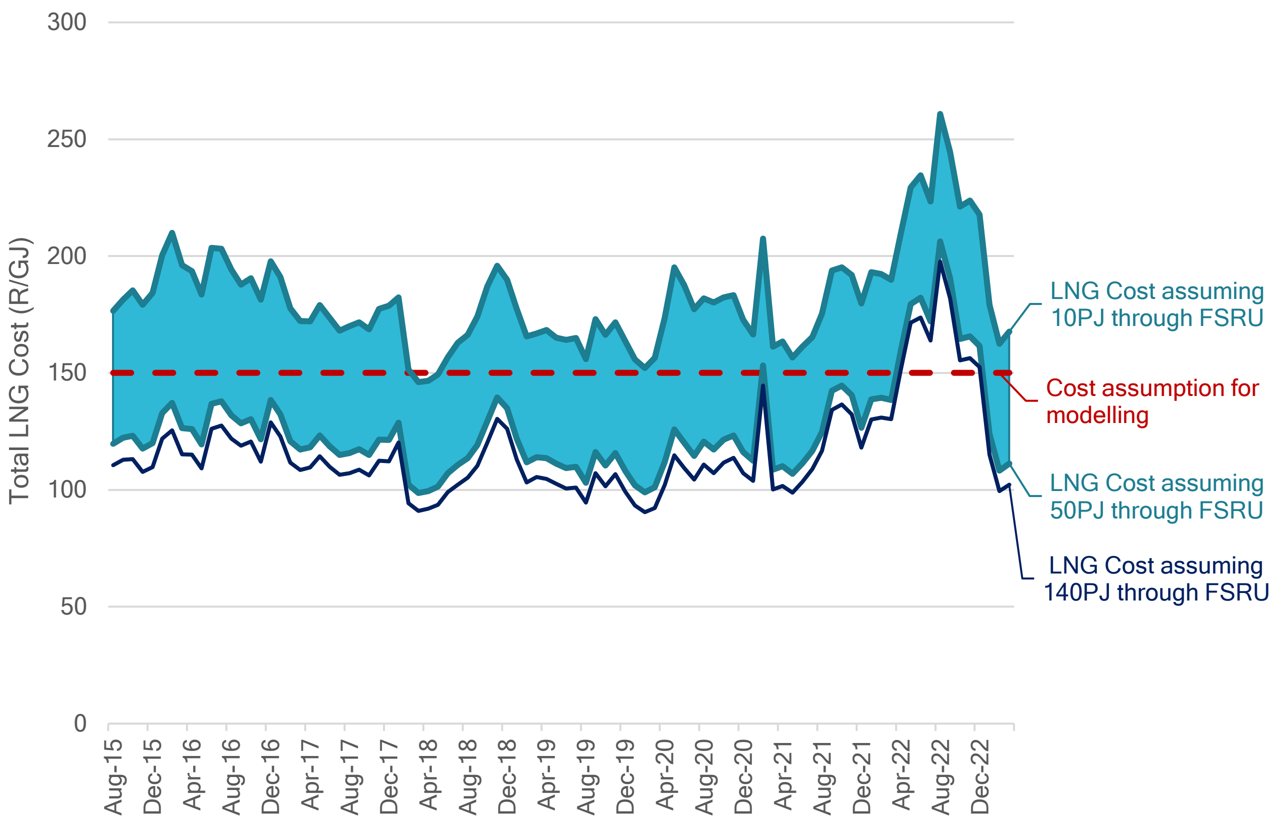
Gas Price ($/GJ)	Gas Price (R/GJ)	1.20	1.60	2.00	2.40	2.80	3.20	3.60	4.00	4.40	4.80 $/kg
		150	200	250	300	350	400	450	500	550	600 R/GJ
20.00	300	-1.6%	-1.1%	-0.5%	0.0%	0.5%	1.1%	1.6%	2.2%	2.7%	3.2%
18.33	275	-1.5%	-0.9%	-0.3%	0.3%	0.9%	1.5%	2.1%	2.6%	3.2%	3.8%
16.67	250	-1.3%	-0.6%	0.0%	0.6%	1.3%	1.9%	2.6%	3.2%	3.9%	4.5%
15.00	225	-1.1%	-0.4%	0.4%	1.1%	1.8%	2.5%	3.2%	3.9%	4.7%	5.4%
13.33	200	-0.8%	0.0%	0.8%	1.6%	2.4%	3.2%	4.0%	4.8%	5.6%	6.5%
11.67	175	-0.5%	0.5%	1.4%	2.3%	3.2%	4.2%	5.1%	6.0%	6.9%	7.8%
10.00	150	0.0%	1.1%	2.2%	3.2%	4.3%	5.4%	6.5%	7.5%	8.6%	9.7%
8.33	125	0.6%	1.9%	3.2%	4.5%	5.8%	7.1%	8.4%	9.7%	11.0%	12.3%
6.67	100	1.6%	3.2%	4.8%	6.5%	8.1%	9.7%	11.3%	12.9%	14.5%	16.1%
5.00	75	3.2%	5.4%	7.5%	9.7%	11.8%	14.0%	16.1%	18.3%	20.4%	22.6%

The cost of green hydrogen in South Africa today is around $4-6/kg [23], but experts expect the cost to fall dramatically into the future as the costs of renewables and electrolysers decrease and economies of scale are realised in line with global trends [24]. Current forecasts suggest that a green hydrogen cost of between $1/kg and $2/kg could be realised by 2050 [25].

Although cheaper than green hydrogen today, the LNG price is dictated by global hydrocarbon markets. Figure 24 illustrates the cost of LNG in 2019 R/GJ as if it were theoretically delivered to an SA-based OCGT on the coast – the price includes the cost of the molecule, cost of liquefaction, an LNG carrier, and a Floating Storage and Regasification Unit (FSRU) for different offtake volumes. The cost of the FSRU and therefore the LNG price as delivered reduces as greater volumes are achieved (see the lower bound on the chart)[33]. It is important to note the volatility associated with LNG pricing which introduces uncertainties not captured in our modelling.

Political and economic factors, global trade dynamics and carbon pricing can significantly impact the price of LNG, factors beyond South Africa's control. In contrast, green hydrogen production, once renewable plants and electrolysers have been constructed domestically, is insulated from geopolitical disturbances, exchange rate risks, carbon pricing, and fluctuations in global hydrocarbon markets. This immunity to external factors provides an advantage and reduces pricing uncertainties in the long run.

Figure 24: Theoretical Cost of LNG for OCGT on the Coast



The cost impact of a switch from gas to green hydrogen presented in Table 4and assumes there is no direct cost associated with emissions from fossil fuels. However, a recent IEA publication suggests an appropriate carbon price for emerging economies

[33]Cost of the molecule is derived from Henry Hub +15% https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm ; liquefaction fee: $2.37/GJ; LNG Carrier Cost: $1.42/GJ; FSRU cost @10PJ: $5.29/GJ; FSRU cost @ 30PJ: $2.04/GJ; FSRU cost @ 50PJ: $1.39/GJ; FSRU cost @140PJ: $0.76/GJ.

between 2040 and 2050 ranges from $160 - $200/ton [6].

Table 6 illustrates the cost impact of the switch from gas to green hydrogen to achieve a Net Zero system if a carbon tax of $160/ton were to be applied (ZAR 2 400/ton). Under our base case assumption of R150/GJ for gas, imposition of the carbon tax would see cost parity in 2050 with green hydrogen at a price of $2.16/kg – which is 10% lower than our base case assumption of $2.44/kg.

To achieve a price of $2.16/kg, all else being equal, a discount of 20% would be required on the LCOE[34] of renewable energy. It is quite possible this reduction could be realised through absorption of (otherwise) curtailed renewable energy from the power system.

Curtailed energy is that which is produced and needs to be 'dumped' or wasted because it cannot be stored or used at time of production due to full storage assets and/or low demand.

Electrolysers which produce hydrogen can ramp up and down quickly to absorb excess energy on the system which would otherwise be curtailed. This energy is likely to come at *significantly* lower cost than the levelized tariff from a dedicated plant (used in the base case assumption)[35]. As shown in section 4.4.30 it is not unreasonable to assume that up to 50% of the energy required for hydrogen production could be obtained via curtailed renewable energy.

Given the above, depending on the assumptions around LNG pricing and accounting for some use of curtailed energy we could even see a cost *saving* through the fuel switch to green hydrogen.

Table 6: System cost impact of fuel switch to green hydrogen to achieve Net Zero in a high offtake year, including consideration of a $160/ton carbon tax

Carbon Tax (R/ton) 2400 — Hydrogen Price

Gas Price		1.20	1.60	2.00	2.40	2.80	3.20	3.60	4.00	4.40	4.80	$/kg
		150	200	250	300	350	400	450	500	550	600	R/GJ
20.00	300	-4.2%	-3.4%	-2.7%	-1.9%	-1.1%	-0.3%	0.5%	1.3%	2.0%	2.8%	
18.33	275	-4.1%	-3.3%	-2.4%	-1.6%	-0.8%	0.1%	0.9%	1.8%	2.6%	3.4%	
16.67	250	-3.9%	-3.0%	-2.1%	-1.2%	-0.4%	0.5%	1.4%	2.3%	3.2%	4.1%	
15.00	225	-3.7%	-2.8%	-1.8%	-0.9%	0.1%	1.0%	2.0%	3.0%	3.9%	4.9%	
13.33	200	-3.5%	-2.5%	-1.4%	-0.4%	0.6%	1.6%	2.7%	3.7%	4.7%	5.8%	
11.67	175	-3.2%	-2.1%	-1.0%	0.1%	1.2%	2.3%	3.5%	4.6%	5.7%	6.8%	
10.00	150	-2.9%	-1.7%	-0.5%	0.7%	2.0%	3.2%	4.4%	5.6%	6.8%	8.0%	
8.33	125	-2.6%	-1.2%	0.1%	1.5%	2.8%	4.2%	5.5%	6.9%	8.2%	9.5%	
6.67	100	-2.1%	-0.6%	0.9%	2.4%	3.9%	5.4%	6.9%	8.4%	9.9%	11.4%	
5.00	75	-1.5%	0.2%	1.9%	3.5%	5.2%	6.9%	8.6%	10.3%	12.0%	13.7%	
$/GJ	R/GJ											

[34] Levelised Cost of Energy

[35] A hydrogen price of $2.44/kg in 2050 will require an average renewable energy LCOE of ZAR 45c/kwh. $2.16/kg would require an average LCOE of 36c/kWh.

4.4.3 USING CURTAILED ENERGY FOR HYDROGEN PRODUCTION

As variable renewable energy sources are added to the grid, the requirement for flexible dispatchable power to ensure that system balance is maintained increases and so does the amount of curtailed energy. The production of green hydrogen is increasingly being recognised as an important tool for providing flexibility to electricity systems with electrolysers being able to absorb renewable energy on the system in times of excess. However, the high cost of green hydrogen production is still a limiting factor for these solutions [26].

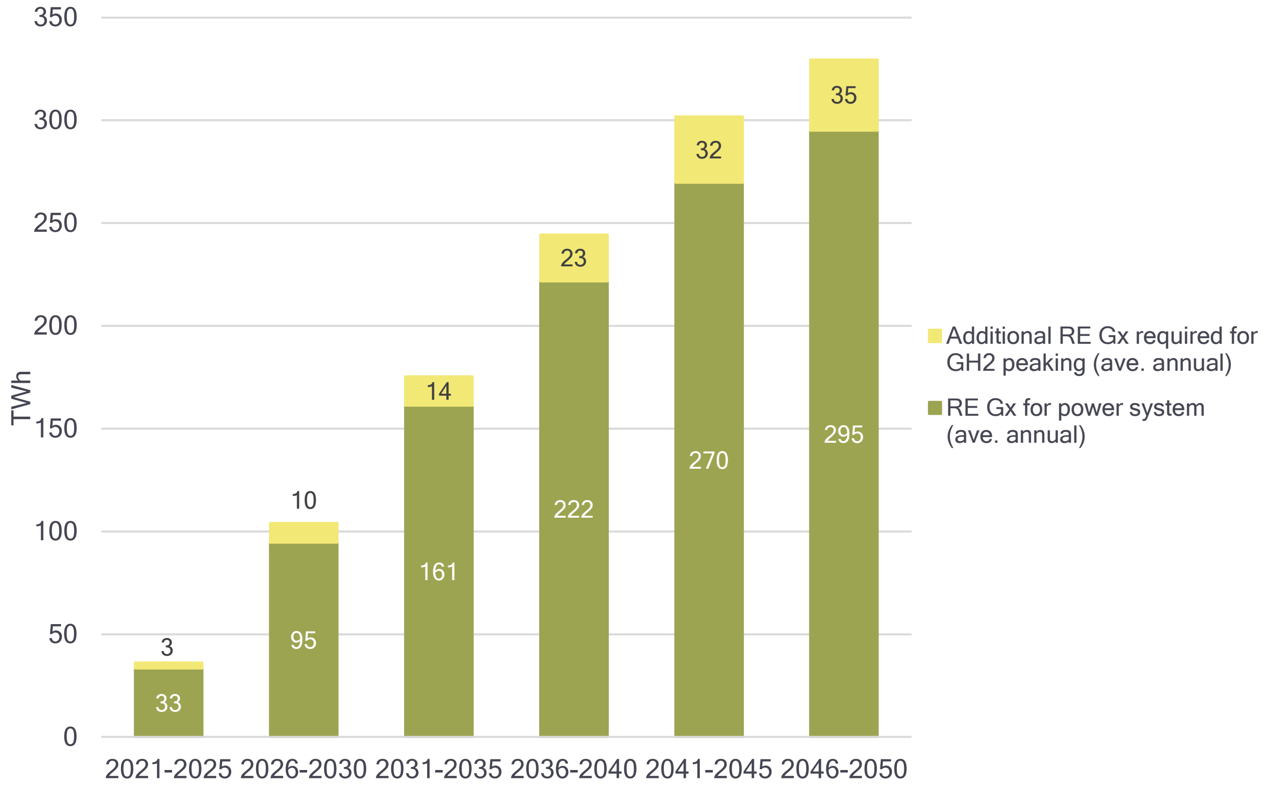
In order to produce green hydrogen as fuel to fire the peaking capacity in our modelled scenarios there is a need for additional renewable energy over and above that required to meet the forecast power system demand. This renewable energy requirement is treated as exogenous to the modelling exercise (i.e. our build programmes do not account for this energy requirement). In the following section we investigate how much renewable energy is required to produce green hydrogen for peaking, and consider the potential for using curtailed power to provide this requirement.

4.4.3.1 Quantum of renewable energy required for green hydrogen peaking

As a thought experiment – we assume that the entire peaking fleet would be fuelled by green hydrogen, for the duration of the modelling study. Our modelled scenarios illustrate that we need an additional ~7-15% (on average ~12%) *more* renewable energy capacity (and generation) in each year, relative to that required for the power system, to produce enough green hydrogen to fuel peaking requirements.

Figure 25 below depicts the average annual energy generation required from renewables for: 1) the power system (dark green shading), and 2) the production of green hydrogen to fuel the peaking fleet (light green shading), based on the theoretical assumption that all peaking plant was fuelled by green hydrogen. All values are expressed as the *annual average* requirement across each of the 5-year periods, and across all scenarios modelled.

Figure 25: Renewable Energy required for the SA power system plus (theoretical) additional volume required to produce GH_2 to fuel all peaking plant (average required for 5yr periods)



4.4.3.2 The effect of using curtailed renewable energy to produce green hydrogen

Electrolysers (linked to hydrogen storage) provide a valuable flexible load that can be ramped up and down quickly to absorb power which would otherwise be curtailed. Electrolyser flexibility provides the opportunity to "mop up" excess power at times of the day when energy is cheap (supply is high and demand is low) – this phenomenon has already manifested in wholesale electricity markets with growing renewable penetration.

Theoretically therefore, hydrogen could be produced with power that has a significant discount on the conventional cost of renewable energy.

Figure 26 illustrates the impact of utilising curtailed energy for hydrogen production to meet the demand for peaking fuel. We make the simplistic assumption that all curtailed energy in the system can be utilised by electrolysers to produce green hydrogen. The average annual additional renewable energy generation requirement for each 5-year period is dramatically reduced, with the exception of the initial years (2025-2030) where renewable energy penetration is low and therefore curtailed energy is also low.

However, post 2035, curtailed energy represents half the energy requirement (or more).

Figure 26: Renewable Energy required for the SA power system plus (theoretical) additional volume required to produce GH_2 to fuel all peaking plant - *when using curtailed energy*

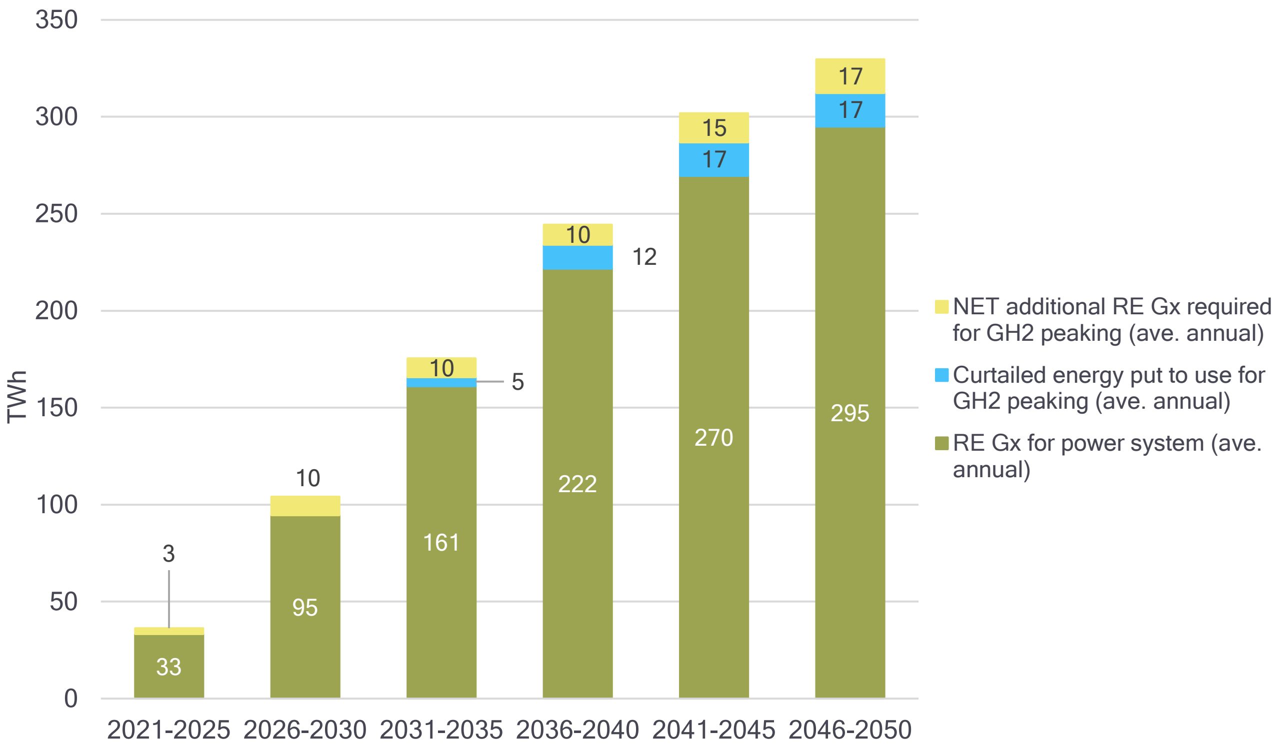
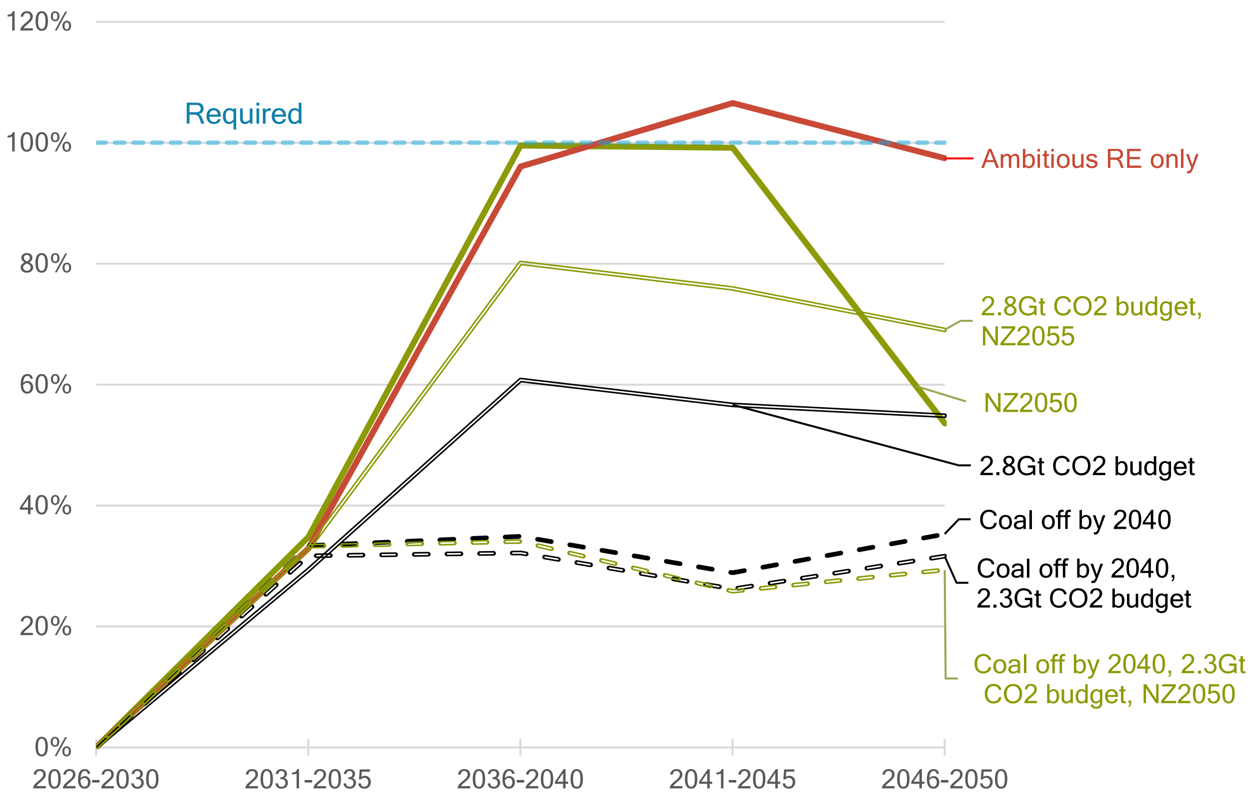


Figure 27 illustrates the quantum of curtailed energy for each of the scenarios considered in this study. As can be seen, depending on the scenario assumptions, in the years between 2035 and 2050 the curtailed energy ranges between 30% and 100% of the energy required for green hydrogen production to fuel the peaking plant. Renewable energy makes up around 50% of the cost of producing green hydrogen, and reducing this cost improves the economics of hydrogen over other fuels (e.g. LNG). As demonstrated in section 4.4.2.24.4.2.2, depending on the assumptions around LNG pricing and carbon tax, there are credible scenarios where a cost *saving* will be realised through the fuel switch to green hydrogen.

Currently the capital cost of electrolysers, nascent turbine technology and the externalisation of emissions costs relegate an economic switch to green hydrogen well into the 2040s. However, the confluence of these factors and the likely over-production of renewable energy in an increasing number of daylight hours that will accompany a sustained renewable rollout could lead to an economic case for a switch to green hydrogen far earlier than 2050.

Figure 27: Curtailed renewable energy as % of what is required to produce green hydrogen for peaking requirements (annual average for each 5-year period)



4.5 CARBON CAPTURE AND STORAGE (CCS) AND CARBON REMOVALS

As discussed in the NZ Briefing Note, Carbon Capture and Storage (CCS) is a mitigation mechanism that can reduce emissions from the power sector, but does not contribute to a net zero state. For this, carbon removals are required. We consider both CCS as mitigation, and carbon removals in this section.

4.5.1 CCS AS A MITIGATION MEASURE

Retrofitting CCS to the existing coal plants is neither considered economic nor feasible given the age of the fleet. New coal fired power with CCS was made available to the model, but even this is never chosen given its costs. Gas with CCS is not considered, rather, a DACC price per tonne is made available to the model to enable the removal of gas-related emissions. Whilst technically feasible, capturing emissions directly from gas plants has yet to be demonstrated as economically suitable due to the ramp-up/ramp-down operating regime and the low emissions intensity of the turbines [3]. Further details on CCS costing and feasibility are contained in the technical appendix.

4.5.2 CARBON REMOVALS - NET ZERO IS ACTUALLY ABSOLUTE ZERO

Whilst the six-point framework proposes that a price of an international Carbon Removal Credit will ultimately be appropriate to use for power sector net zero analysis, in our study we used the price of DACCs as a proxy, with details of this in the technical appendix.

DACC was made available as a particular technology, but again never chosen by the model given its high cost relative to substituting green hydrogen for natural gas in OCGTs. Natural gas remains the last source of emissions in the SA power system towards mid-century, therefore the option is either to omit these emissions (a net zero system) or to counter them with removals (a net zero system. Therefore the Net Zero scenarios demonstrated in this study are also ‘absolute zero scenarios’.

4.6 THERE DOES NOT APPEAR TO BE AN ECONOMIC CASE FOR ‘BIG GAS’ IN A NET ZERO POWER SYSTEM

Whilst coal plant remains on the system up to and in some cases beyond 2040, the modelling results demonstrate that CCGT plants running at mid-merit capacity factors (i.e. producing significant amounts of energy) are not economic in scenarios which include a Paris-aligned carbon budget. The results show that the more economic option is a combination of renewables and flexible OCGT/ICE capacity, ‘spending’ the carbon budget on emissions from these plants fuelled by gas or diesel until a fuel switch to green hydrogen or ammonia occurs.

Box 5: Classification of dispatchable gas generation options [27]

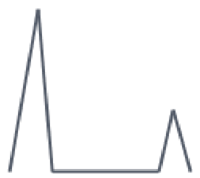
Open Cycle Gas Turbines (OCGTs) are fast-acting combustion turbines that compress and heat air using gaseous fuel to produce electricity. They provide quick power to the grid (within 5-12 minutes) and are often used for flexible peaking power. OCGTs can run on various fuels, including gas, diesel, and green hydrogen.

Internal Combustion Engines (ICEs) are fast-acting engines that burn fuel in a combustion chamber to generate power. They supply power to the grid even more rapidly than OCGTs (start-up time of 3-10 minutes) and are commonly used for backup or emergency power. ICEs are smaller and more easily added incrementally compared to OCGTs.

Both OCGTs and ICEs are flexible dispatchable generators, increasingly used for larger utility-scale power generation, especially in areas with high levels of intermittent renewable energy sources.

Combined Cycle Gas Turbines (CCGTs) are similar to OCGTs but have an additional steam cycle. They are more complex and expensive to build but offer higher efficiency, generating more electricity with the same amount of fuel. CCGTs have a longer start-up time (90-240 minutes) and are generally used to provide mid-merit capacity in power systems

Table 7: Classification of dispatchable generators into functional categories

Classification		Utilisation	Generator examples
	**Peaking plants** are fast-acting plants that are used to cater for quick changes in power demand. They tend to be the most expensive category of plant to run and are therefore run infrequently, standing idle the rest of the time.	• Low • < 1 000 hours per year (< 11% Annual Capacity Factor)	• Open Cycle Gas Turbines (OCGT) • Internal Combustion Engines (ICE)
	**Mid-merit plants** are 'load-following' plants and are able to adjust power output in response to fluctuating demand.	• Medium • 1 000-6 000 hours per year (11%-69% Annual Capacity Factor)	• Combined Cycle Gas Turbines (CCGT)
	Base supply plants are generators that are optimised for operation at full output with minimal interruption, to meet a minimum level of demand over a particular period.	• High • > 6 000 hours per year (> 69% Annual Capacity Factor)	• Nuclear plants • Coal plants

Only one scenario in this study sees new CCGT capacity built at all – the *Coal off by 2040* scenario – where a coal off constraint is imposed in 2040 and where neither a carbon budget nor net zero date is imposed. 1.4 GW of CCGT is built in 2040 in this scenario.

In the case of all the other scenarios, we observe that as soon as either a carbon budget or a net zero emissions date is imposed on the model, no CCGT is built.

In the Vital Ambitions study we also found CCGT capacity to be built in the equivalent of this study's *Coal off by 2040* scenario – i.e. a scenario with the same RE build programme, coal off by 2040 constraint, and no carbon budget imposed. The CCGT is built to replace power provided by coal, but subsequently runs on average at the lower end of the mid-merit capacity factor range (~25%). This means that it is run fairly flexibly, closer to a flexible / peaking role rather than a 'base' supply role.

In the Net Zero study, we modified our assumption around OCGT capacity factors from the Ambitions study – specifying that OCGTs would run at a minimum of 2% per annum (the Ambitions study had no minimum capacity factor constraint) – being more representative of their reasonable operating conditions. With this more realistic modelling constraint, the economic case for CCGT capacity is reduced – it is more economic to run the OCGT capacity slightly harder, than to build CCGT capacity and run it at lower capacity factors.

As shown in Figure 28, the cumulative installed capacity of CCGT in the *Ambitions Coal off by 2040* scenario is more than 5 GW in the Ambitions Study, whilst it is only 1.4 GW in this *Net Zero Coal off by 2040* scenario. Whilst a similar quantum of new OCGT capacity is built across each of the different study scenarios, Figure 29 shows that the annual capacity factor of the OCGTs is higher in the *Net Zero Coal off by 2040* scenario (1.5%-3.5%) than that of the Ambitions version of this scenario (1-2%).

Whilst we previously observed in the Ambitions study an economic case for new CCGT capacity when coal is forced off by 2040, this case vanishes under scenarios that will achieve net zero. The combination of new OCGT and renewable capacity, combined with generation from the declining coal fleet provides a more economic pathway than the build of new CCGT capacity

Figure 28: Cumulative New Build CCGT capacity in Budget-unconstrained Coal off by 2040 scenarios for previous 'Ambitions Study' and Net Zero Study

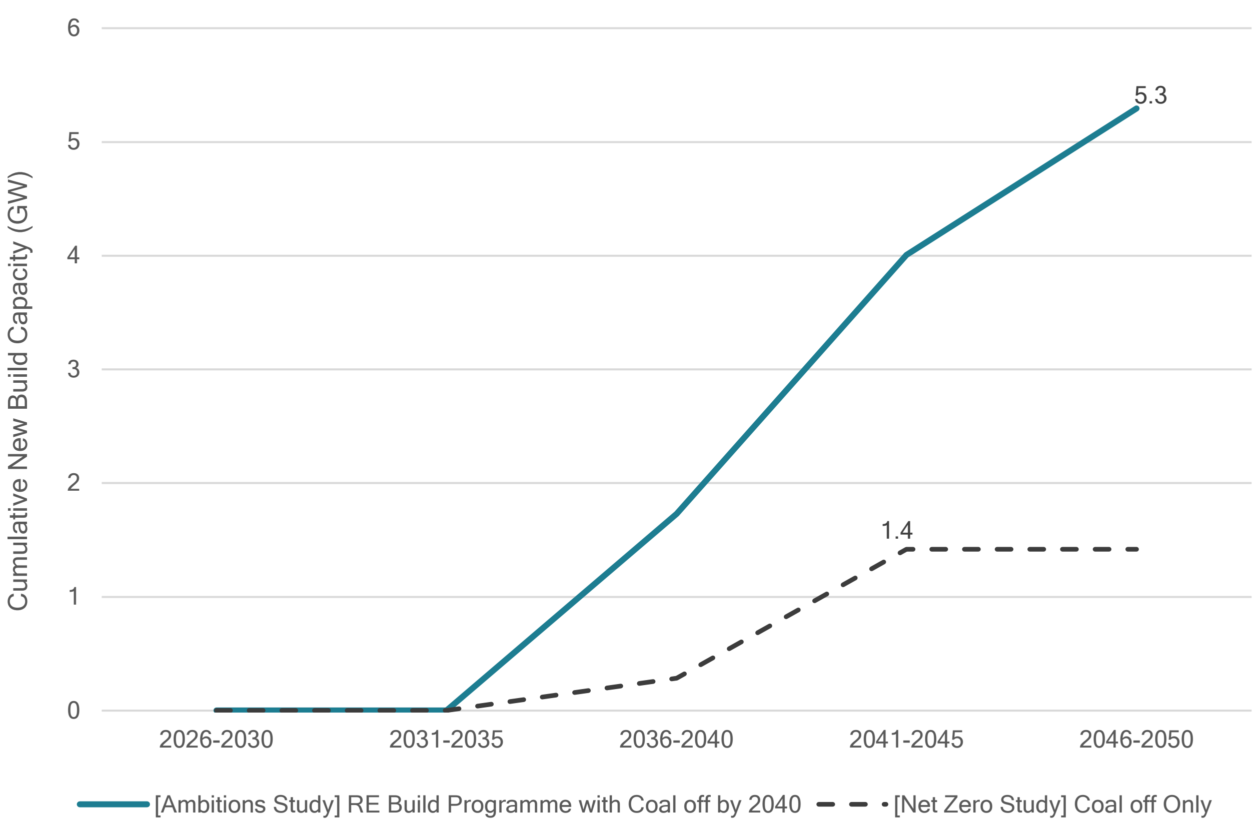
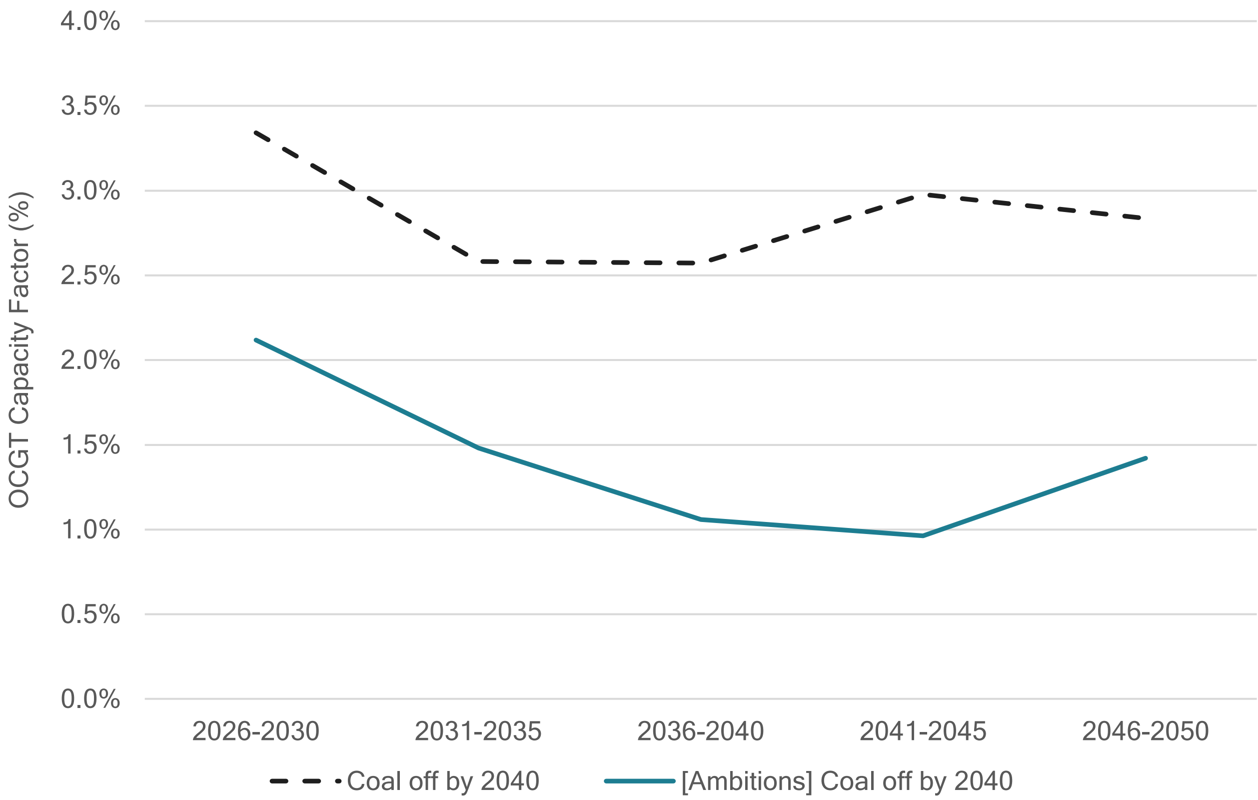


Figure 29: Average annual OCGT capacity factor for NZ and ambitions studies across each 5yr period



5 CONCLUSION

This report has presented an investigation of the policy levers and implications associated with aligning South Africa's power sector with a 'Net Zero' goal in the long term. Stemming from the joint Meridian-CSIR modelling project of 2020, this extension builds upon the findings of the "Vital Ambitions" study, incorporating constraints compliant with a net zero emissions state.

The study responds to the concept of 'Net Zero by 2050' gaining traction in various sectors and countries. In South Africa, this target is recognized both in the Low Emissions Development Strategy and Eskom's Just Energy Transition vision. The report's objective was to understand the implications of achieving power sector net zero in South Africa, using a six-part framework to guide the modelling work.

The study finds that Net Zero pathways are no more expensive than the *Ambitious RE Only* scenario until the late 2030s in our most ambitious Net Zero case[36] , and until the early 2050s in our least ambitious Net Zero case[37]. Two key policy levers drive an increase in system costs relative to the *Ambitious RE Only* scenario thereafter: a decision to take all coal-fired power off the system in 2040 results in a relative system cost increase of just under 5%, driven by the need for additional renewables, storage and peaking capacity earlier than would otherwise be economically optimal. Imposing a net zero date increases the cost differential from 5% to 15%, driven predominantly by a fuel switch to green hydrogen[38] (which results in the doubling of the cost of peaking fuel) and the deployment of additional battery storage and renewable capacity.

These cost differentials are drastically reduced when taking into account National Treasury's impending $30/ton carbon tax from 2030 (without escalation), and effectively eliminated at a carbon price of $65/ton.

Regardless of the policy lever chosen, all scenarios – not only the Net Zero ones – necessitate rapid deployment of approximately 6 GW of new renewable capacity annually plus 0.5-1 GW of peaking capacity (open cycle turbines / internal combustion engines) and 0.5-1 GW of battery storage every year from now until 2030, and beyond. Such a rollout aligns with efforts to alleviate the current load shedding crisis and sets the foundation for the South African power system to respond to the growing decarbonisation pressures arising from trade partners and capital providers.

The transition to a net zero power system can largely be achieved using existing technologies, encompassing wind and solar PV plants, hydro plants, batteries, and pumped storage. The only exception is the zero-emission thermal peaking plant, which is anticipated to be fuelled by green fuels such as green hydrogen or ammonia in the future. This technology whilst proven is not yet commercially available at the scale required.

The report presents a deep dive into the role of green hydrogen as fuel for peaking plant in the transition to a net-zero emissions power system and conducts sensitivities on the evolving economic viability of green hydrogen versus gas in light of the uncertainties related to future pricing of these fuel options. The analysis underscores the limitations of continuous and near-linear modelling frameworks for understanding the evolution of highly complex and uncertain systems, together with an identification of policy

36 Coal off by 2040, 2.3Gt CO2 budget, NZ2050

37 2.8Gt CO2 budget, NZ2055

38 Includes the switch to green hydrogen of all peaking plant, *and Sasol's CCGT and ICE power plants currently run by gas.*

relevant aspects of South Africa's power system decarbonisation.

Ultimately, though, the immediate implications of this modelling study are clear – and aligned to other credible South African energy and power modelling projects [28]. As long as an immediate effort is made to ensure an ambitious rollout of renewables along with commensurate peaking and storage capacity, there is ample time to consider the additional policy options of stipulating an all coal off date, or net zero date. These will need to be considered in the context of the country's commitment to a Just Energy Transition.

6 TECHNICAL APPENDIX

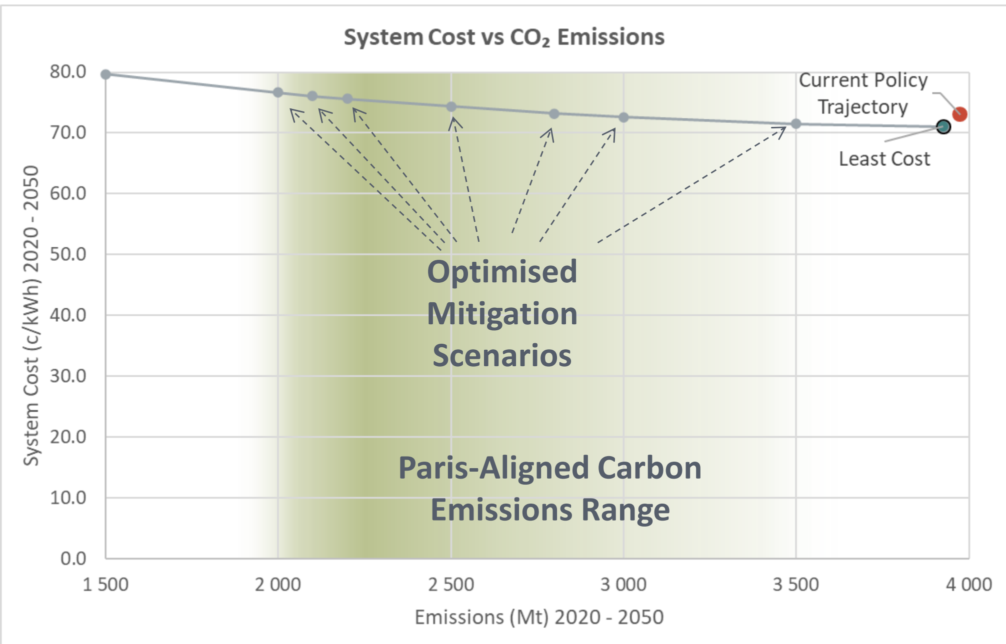
6.1 AMBITIONS PROJECT APPROACH

A number of optimised scenarios were considered in the Ambitions project (as shown in Figure 30 below). The analysis showed that there is a relatively flat cost curve for decarbonising the power sector. This would indicate that in decarbonising the economy, there is likely to be added pressure on the power sector to decarbonise quickly, relieve the burden of decarbonisation in other sectors, and further expand into those sectors with decarbonised power.

When adapting modelling outcomes to incorporate real-world contexts, the theoretically optimised scenarios need to be stress-test against practical grid infrastructure expansion and the constraints around the speed of RE industry build over time. In order to support the required RE build-out, existing transmission grid constraints would need to be resolved expeditiously. However, grid expansion has longer lead times in comparison to RE generation projects, resulting in a real-world bottle neck for RE build in the short to medium term. The RE industry will also need time to establish itself in order to ramp up to an achievable build out rate.

Three of the optimised scenarios were made more credible and realistic by ensuring a smoothed and realistic RE build based on international RE build experience and engagement with local industry participants. This result was two reality-adjusted build pathways ('Modest' and 'Ambitious' RE pathways) which imposed a specified minimum annual RE build, and a 'coal-off-by-2040' pathway which applied a constraint of shutting down coal generation by 2040 on the Ambitious RE pathway. This Net Zero study takes the Ambitious RE pathway as its reference scenario – here termed *Ambitious RE Only*. As there was no net-zero constraint imposed on this scenario, it formed the basis on which scenarios in this net-zero study were established.

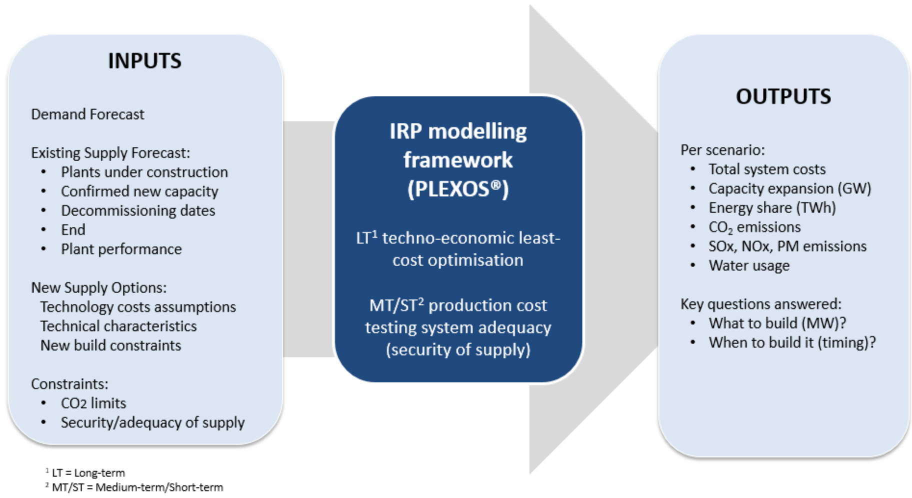
Figure 30: Power System Cost vs CO_2 Emissions for optimised scenarios in the Ambitions Project (Paris-aligned emissions range highlighted)



6.2 LONG TERM GENERATION CAPACITY EXPANSION MODELLING FRAMEWORK

As per the 'Ambitions' project, a long-term generation capacity expansion planning framework was applied in this study. This is a well-established framework in South African electricity modelling, which uses PLEXOS an energy market simulation platform that has been used in the government process to develop the IRP. As indicated in Figure 31 the framework uses a range of input assumptions, informed by a variety of data sources, to develop a set of scenarios that feed into the techno-economic cost optimisation simulation. The system planning model ensures that in all scenarios, electricity demand is met on an hourly, daily, and seasonal basis, which is assessed by a 'system adequacy' test.

Figure 31: Methodology that incorporates power sector capacity expansion energy planning *(Source: CSIR)*



The planning horizon considered for this study is 2020 – 2060 with an hourly temporal resolution of optimisation. With an overarching objective function of least cost (subject to predefined boundary conditions), the model also co-optimizes existing supply-side options and new-build investments over the planning horizon. The definition of input assumptions and boundary conditions determine the range of scenarios which can then be compared against each other. The outputs from the generation capacity expansion planning include the capacity, cost and timing of new power generators as well as the expected energy production across the available power generators. It also produces a cost-optimal retirement schedule for the existing generation assets.

Different electricity generation technologies have different capacity and energy generation profiles, which makes direct cost comparisons inaccurate. These technologies need to be understood in a system that can optimally deliver power using characteristics of the different generation sources to meet demand most economically. A least-cost optimisation model ensures that electricity demand is met reliably and cost efficiently.

In economics, an 'avoidable cost' is a cost that can be eliminated by not engaging in or no longer performing an activity. An avoidable cost is therefore any future cost over which we still have decision agency i.e. a cost that we choose to incur. In context of this study, these are all the yet-to-be-incurred costs of generating electricity from 2020 – 2060. We refer to the sum of these costs for each power system scenario as its ‘system cost’. The model ensures the specified system constraints are met for each scenario at the lowest possible system cost.

In attempting to minimise the system cost for a scenario the optimisation model performs the following functions:

- Selects most economic combination of new technologies and necessary capacity to install each year,
- Decides how hard to run existing resources to meet energy generation requirement for the year most economically, including the cost-optimised dispatch of coal fired power,
- Optimally closes existing generators to avoid fixed costs from keeping them available. This is a critical element of the modelling we performed - retirement of existing capacity is based on an economic decision, not on a pre-defined retirement schedule.

The system costs considered for the model include capital cost for new capacity, fixed cost, variable operation and maintenance costs (FOM and VOM) of both existing and new capacity, fuel cost as well as start-up and shutdown costs. Other costs considered are the cost of retaining reserve capacity required to maintain system adequacy, along with the cost of unserved energy. Costs that are excluded from the system modelling are costs associated with transmission and distribution, others that do not fall into the scope of the modelling as well as unavoidable costs (e.g., sunk capital costs and actual cost of decommissioning plants.

6.3 NET ZERO MODELLING ADDITIONS

6.3.1 CO_2 REMOVAL AND STORAGE TECHNOLOGIES

The NZ Briefing Note developed a framework for understanding removal and storage technologies. There, four broad options were highlighted, being Carbon Capture, Utilisation and Storage (CCUS) (with utilisation being in its nascency although potentially important in future global mitigation efforts); Direct Air Carbon Capture and Storage (DACCS); Bio-energy with Carbon Capture and Storage (BECCS); and Natural ecosystem options.

Of these technologies, CCS at source for new coal fired power plant together geographically independent carbon removals were found to be relevant to South African power system modelling.

CCS at source is only made available to the model for new coal fired power plant. Data used for modelling of CCS in new coal was based on technology costs and technical performance characteristics used in the development of the IRP 2019 [EPRI technology cost assumptions]. All results are expressed in 2019 Rands. These costs are associated with the increase in capital cost to build new plants with CCS technology integrated, together with the increased operational, maintenance and fuel costs for running these plants [29], [30].

Particularly given the age of South Africa’s coal fleet, the cost of retrofitting CCS on existing plant renders this option highly unlikely to be feasible. For retrofitting existing fossil-fuel power plants to be economically viable, the power plants in question would require capital for retrofitting an amine scrubber [29]. Additionally, studies indicate that a more economic approach to retrofitting existing fossil-fuel based plants with post-combustion CCS technology is to rebuild the turbine and boiler to increase the efficiency and output of the existing plant by converting it to a supercritical unit. The capital cost required for this endeavour renders the option of retrofitting existing power plants with CCS economically non-viable overall [29].

CCS for gas is similarly not made available to the model on commercial and technological feasibility grounds [31], [32].

For **carbon removal not associated with the physical power system:** Whilst the six-point framing proposes that a price of an international Carbon Removal Credit will ultimately be appropriate to use for power sector net zero analysis, in our study we used the price of DACCs as a proxy. Were DACCs plants to be operated in South Africa, an electricity penalty would be incurred given the significant amounts of power required to run this plant. This is not factored into the demand in our current analysis.

To represent costs, although DACCS is nascent at this stage and data on operating facilities at-scale is sparse, an equivalent starting point and proxy for DACCS learning rates has been utilised: an equivalent capital investment cost of 520 USD/tCO_2 (2020) with linear reduction in costs towards 260 USD/tCO_2 (2030) and 105 USD/tCO_2 (2050) [33]–[35]. Capital investment cost dominates potential DACCS facilities and hence the fixed operations and maintenance (FOM) costs as well as variable operations and maintenance (VOM) costs are not considered for the purposes of this study.

6.3.2 GAS AND DOMESTIC GREEN HYDROGEN

In addition to existing open-cycle gas turbines (OCGTs) operating on distillate fuels (diesel, jet fuel), an option for additional OCGT fuelled with distillate fuels was included explicitly in the model, alongside natural gas fired OCGTs. The inclusion of distillate-fired OCGTs as a potential technology option was done for the purpose of exploring whether they are appear in the modelled technology mix versus natural gas-fired turbines.

In addition, blending hydrogen with natural gas as a feedstock for OCGTs, CCGTs and ICEs is included as a potential option for selection in the model. The blending potential is constrained to 50% (by energy value) from 2030 but is able to increase to 100% (by energy) from 2040 onwards if viable, with a linear scaling of this constraint between 2030 and 2040.

The hydrogen feedstock is modelled as being produced locally from renewable electricity via electrolysis and is classified as green hydrogen[39]. Generation of the renewable electricity required for this green hydrogen production is, however, exogenous to the model – in other words there is no additional electricity demand included in the models to produce hydrogen for utilisation in power generation.

For this analysis, the future green hydrogen levelized cost in South Africa has been estimated between 2025 (likely the earliest start date for local production) and 2050, using the following input assumptions:

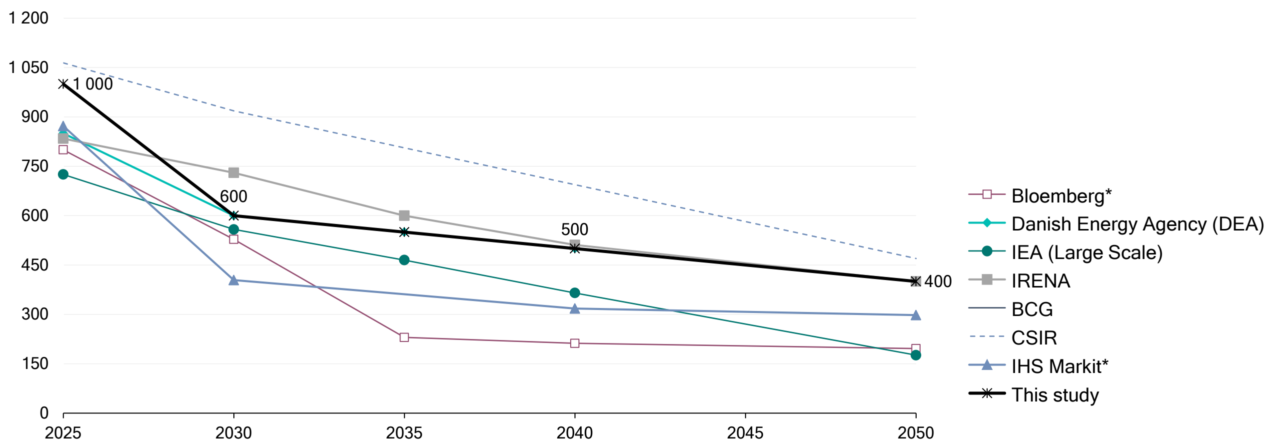
- Solar and wind resource profiles from [36] were used to represent good wind and solar resource conditions in South Africa, with a 40% wind load factor and 23% solar load factor.
- The Weighted Average Cost of Capital (WACC) was assumed to be 8%.
- Capital costs and learning rates for solar PV and wind were obtained from

[39] Green hydrogen is classified as hydrogen which is produced via electrolysis and energy sources such as wind and solar which don't release greenhouse gases when generating electricity.

the Ambitions study [1]Click or tap here to enter text.

- The learning rate for electrolyser capital cost (based on Polymer Electrolyte Membrane, PEM, technology) reductions was taken from the Danish Energy Agency [37]Click or tap here to enter text., as shown in Figure 32.
- Electrolyser efficiency was assumed to be 65% today, increasing to 75% by 2050.
- Electrolyser lifetime was assumed to be 80 000 hours
- Overnight cost of large-scale PEM electrolysers will decrease from ~1 100 USD/kW installed today to ~400 USD/kW installed by 2050 as shown in Figure 32.

Figure 32: PEM Electrolyser overnight capital cost trajectory to 2050[40] [25], [38]-[40]



The resulting levelized cost of green hydrogen, along with the main cost components is shown in Figure 33. For reference, these costs are compared to a number of published long term LCOH estimates for South Africa in Figure 34.

[40] Notes: Capital cost shown includes stack and balance of plant. *Published cost estimates based on stack only or balance of plant are not consistent/not always specified, figures adjusted to include balance of plant.

Figure 33: Reference forecasted levelised cost of green hydrogen in South Africa for this analysis[41]

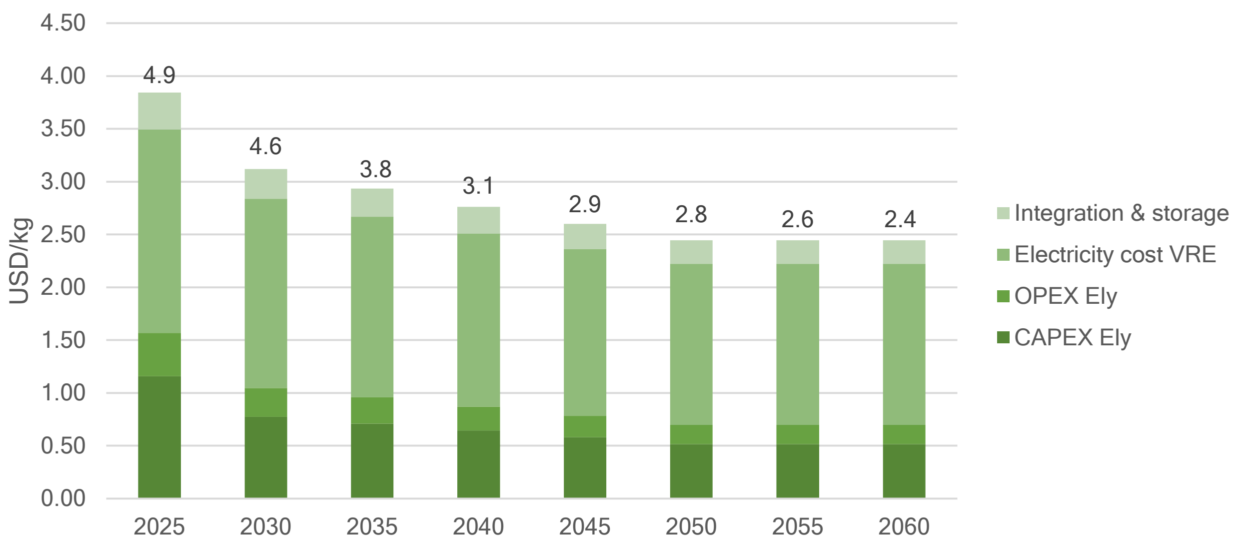
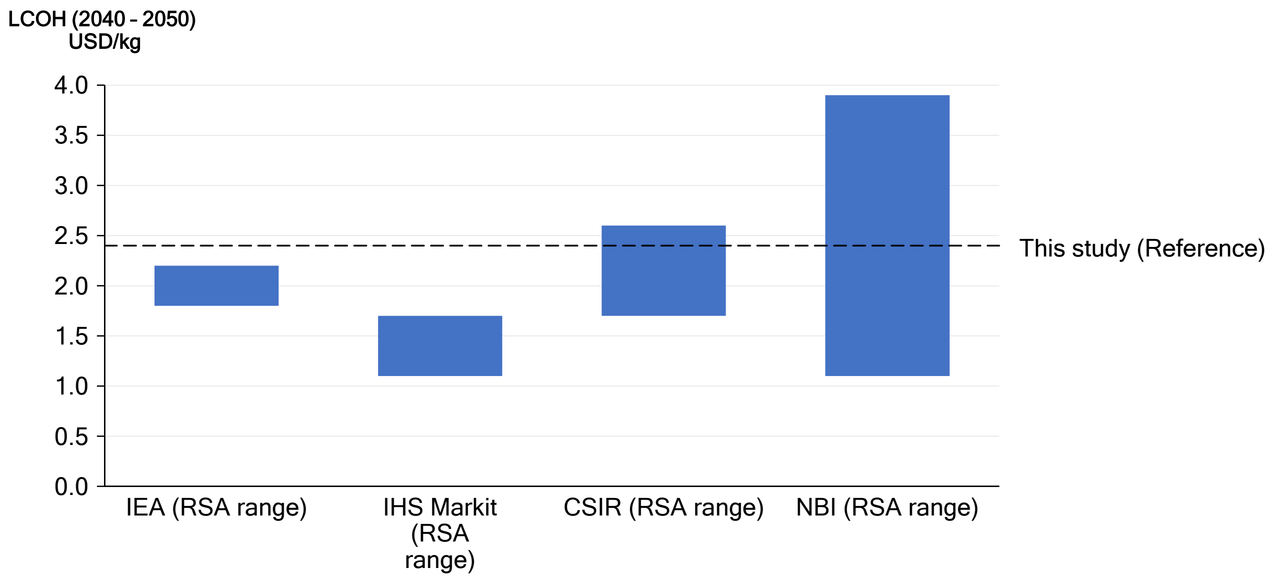


Figure 34: Benchmarking this study's assumptions against other long term LCOH forecast lower and upper limit ranges for South Africa [3], [25], [40]-[42]



6.3.3 SOUTH AFRICA'S GREEN HYDROGEN OPPORTUNITY

South Africa's extensive solar and wind resource, combined with abundant available land, makes power-to-hydrogen one of the promising available deep-decarbonisation opportunities that could contribute to achieving net zero emissions in the power

[41] Notes: Expected LCOH cost curve in SA based on greenfield projects. Renewable energy costs from Ambitions study assuming NREL ATB; Learning rate – *NREL 2019 ATB "mid";* electrolyser Capex aligned with Danish Energy Agency cost trajectory. Aggregated weather data used from CSIR wind and solar aggregation study; 40% wind load factor and 23% solar load factor. Weighted Average Cost of Capital (WACC) assumed to be 8%. Electrolyser efficiency assumed to be 65% in 2020, improving to 75% by 2050. Electrolyser lifetime assumed to be 20 years with stack replacement at year 10. Grid integration and storage assumed to make up ~10% of LCOH.

sector. Green hydrogen, produced by splitting water into hydrogen and oxygen using renewable electricity in a process unit known as an electrolyser, is classified as being a zero-carbon energy source.

As a fuel, hydrogen can be used in fuel cells and can also be combusted in engines and turbines. It can also be further converted into other energy carriers, such as ammonia, methanol, methane and liquid hydrocarbons. Ammonia can also be used as a fuel but there are several challenges in ammonia combustion, such as low flammability, NOx emissions, and low radiation intensity. However, because of renewed interest in the field, ammonia turbines are likely to be commercialised in the medium term and are currently being used at a pilot scale of 50 kW [43]. Outside of the electricity sector, green hydrogen can be used for production of green chemicals.

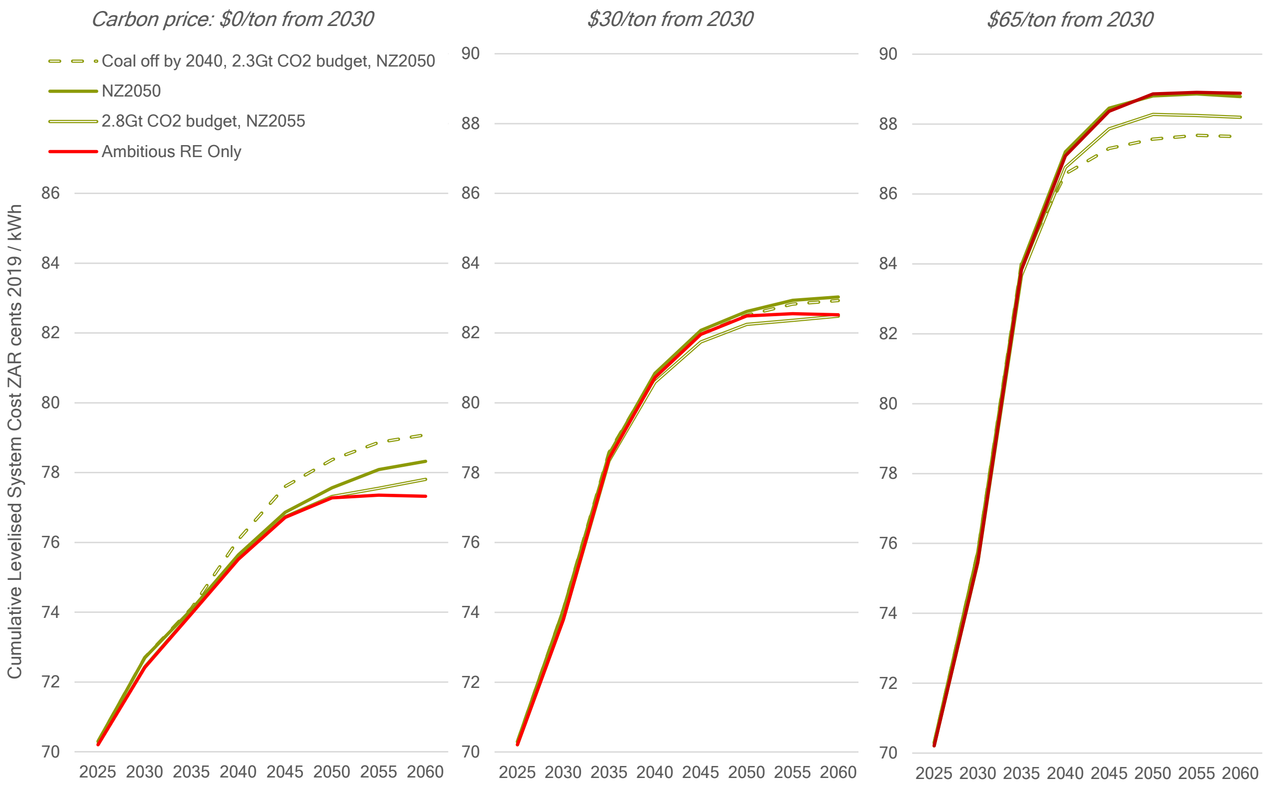
Four types of electrolyser technologies are identified; alkaline, polymer electrolyte membrane (PEM), solid oxide (SO), and anion exchange membrane (AEM). The majority of operational technologies are alkaline and PEM.

Electricity currently dominates the cost of green hydrogen production, followed by the capital cost of the electrolysers. Many publications identify promising potential for further electrolyser cost reductions, largely driven by economies of scale and technological innovation to further improve the performance of the technology (both efficiency and lifetime) [44]. Capital costs for AEC systems currently lie between 700 and 1 400 EUR/kW [25], [37], [41], [42], [44]. For PEM the range is 800 to 2 000 EUR/kW. SO electrolysers are less well established technologies, with costs of production estimated at 3 000 to 5 000 EUR/kW [45].

6.4 ADDITIONAL INFORMATION

Figure 35 below illustrates the cumulative levelised cost trajectories for the *Ambitious RE Only* scenario and Net Zero scenarios over the full modelled period. Until early 2040, the scenarios track the same cost pathway. Thereafter, a relative cost increase is observed for the scenario where a coal off policy is enforced in 2040. In the 2050s, 'last mile' decarbonisation in the form of a green fuel switch raises the cost of the *NZ2050 and NZ2055* scenarios relative to the *Ambitious RE Only* case.

Figure 35: Cumulative levelised system cost of Net Zero constrained and *Ambitious RE Only* scenarios with different levels of carbon pricing



6.5 ADDITIONAL INFORMATION ON INSTALLED CAPACITY AND ENERGY GENERATION MIX FOR EACH SCENARIO

Figure 36: Installed Capacity - Ambitious RE Only

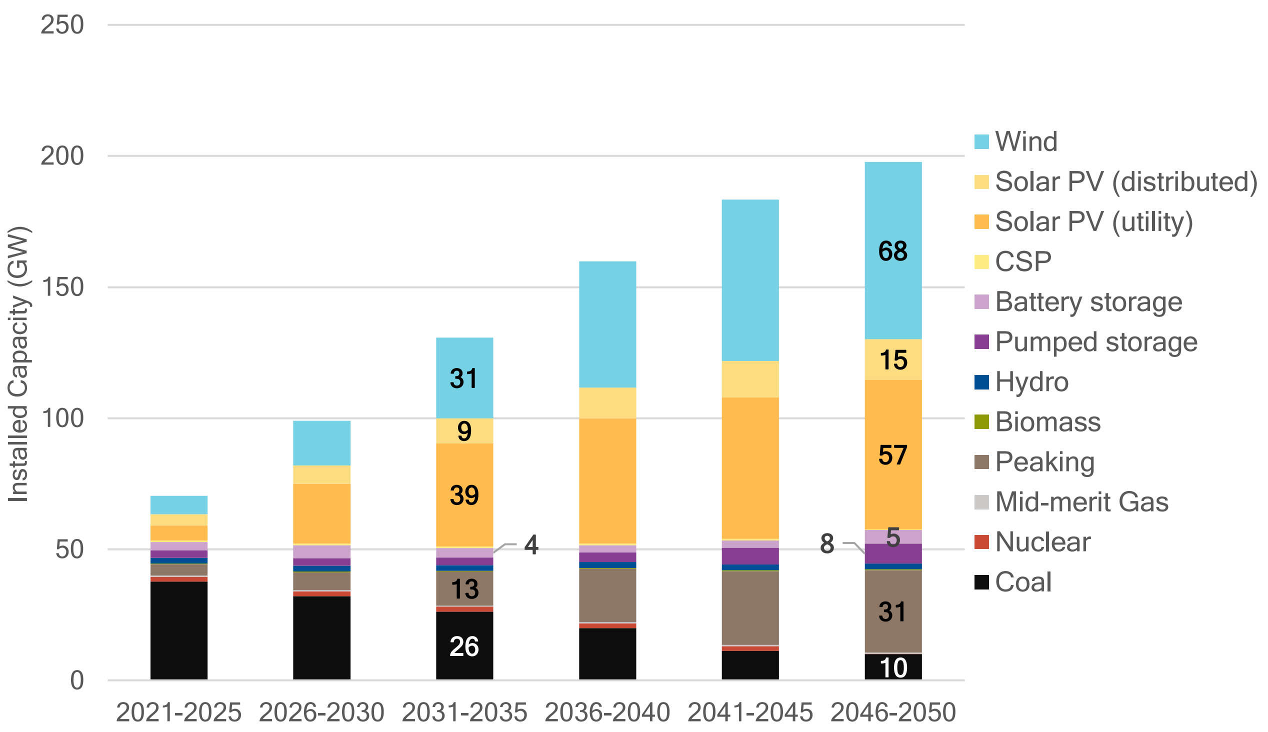


Figure 37: Installed Capacity - 2.8Gt CO_2 budget

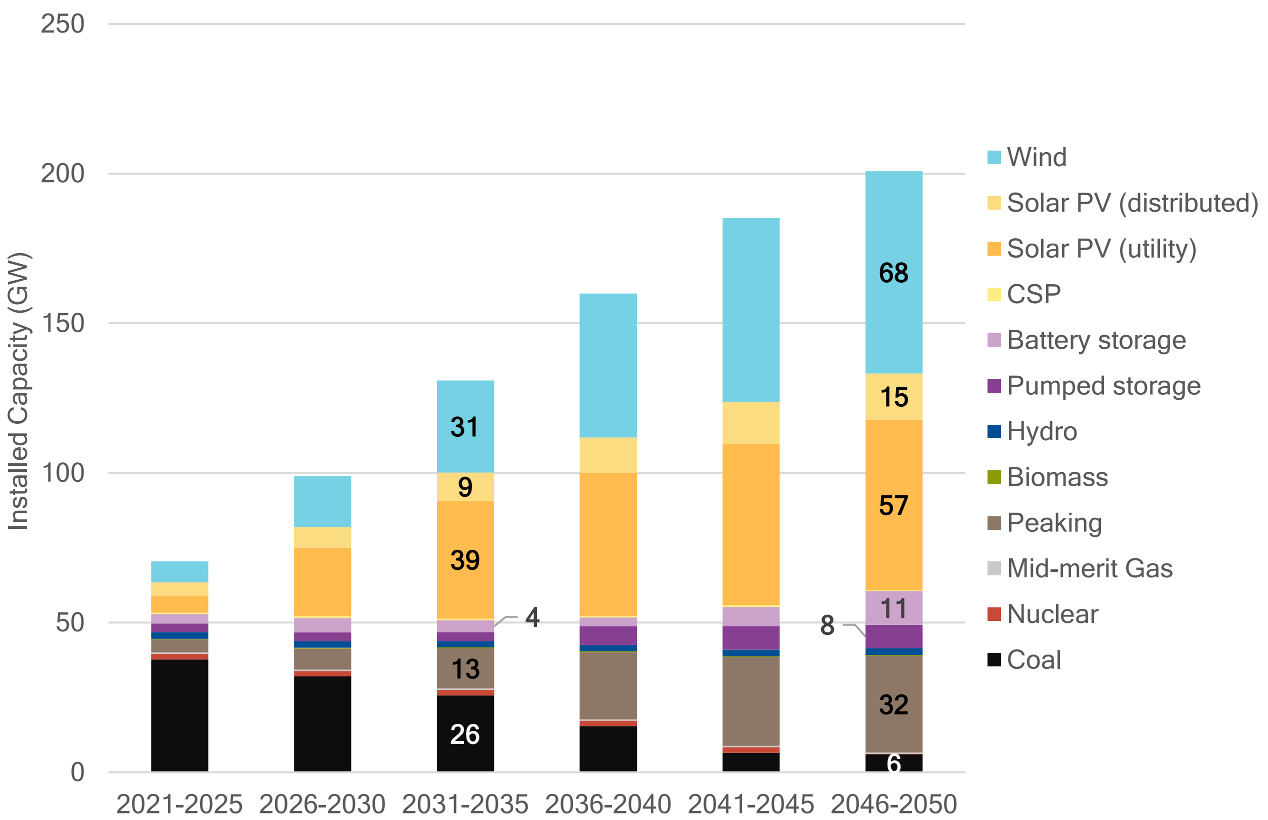


Figure 38: Installed Capacity - Coal off by 2040

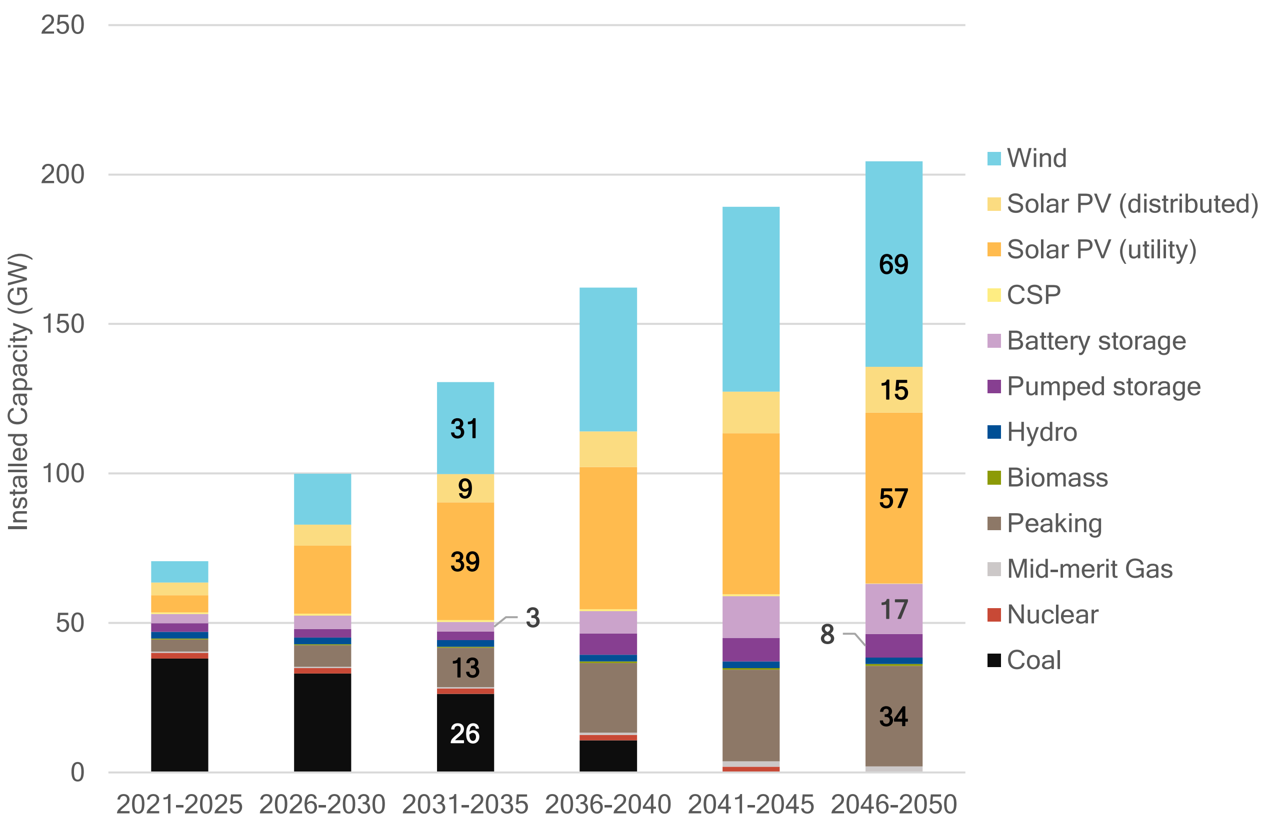


Figure 39: Installed Capacity - Coal off by 2040, 2.3Gt CO_2 budget

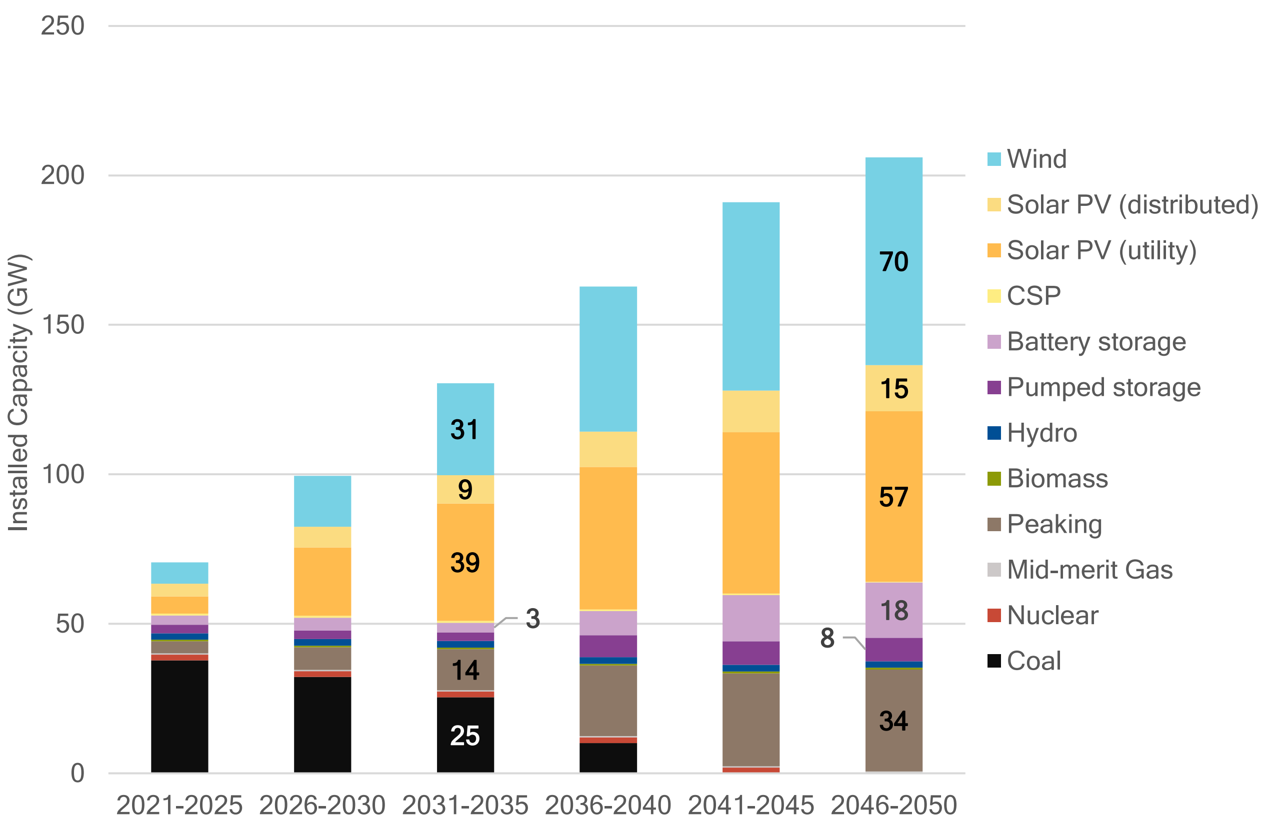


Figure 40: Installed Capacity - Coal off by 2040, 2.3Gt CO_2 budget, NZ2050

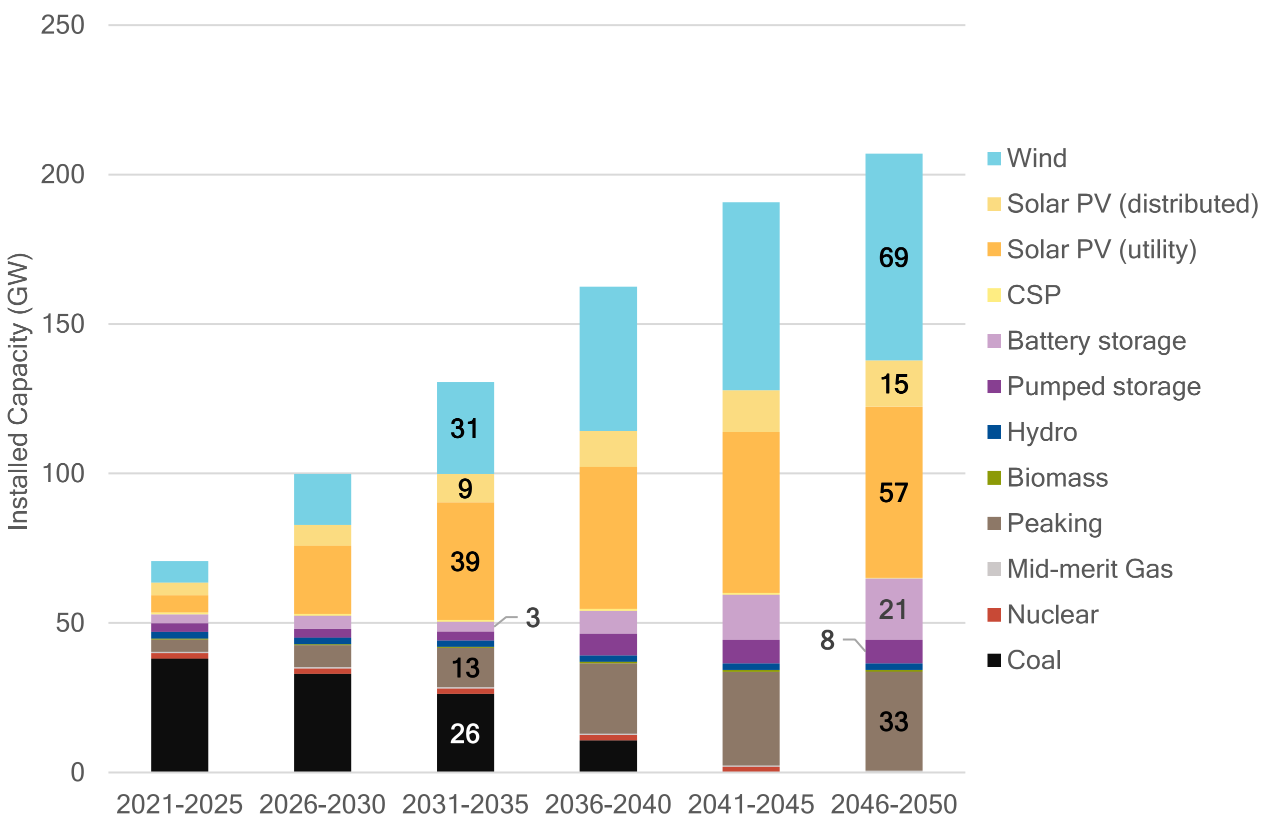


Figure 41: Installed Capacity - NZ2050

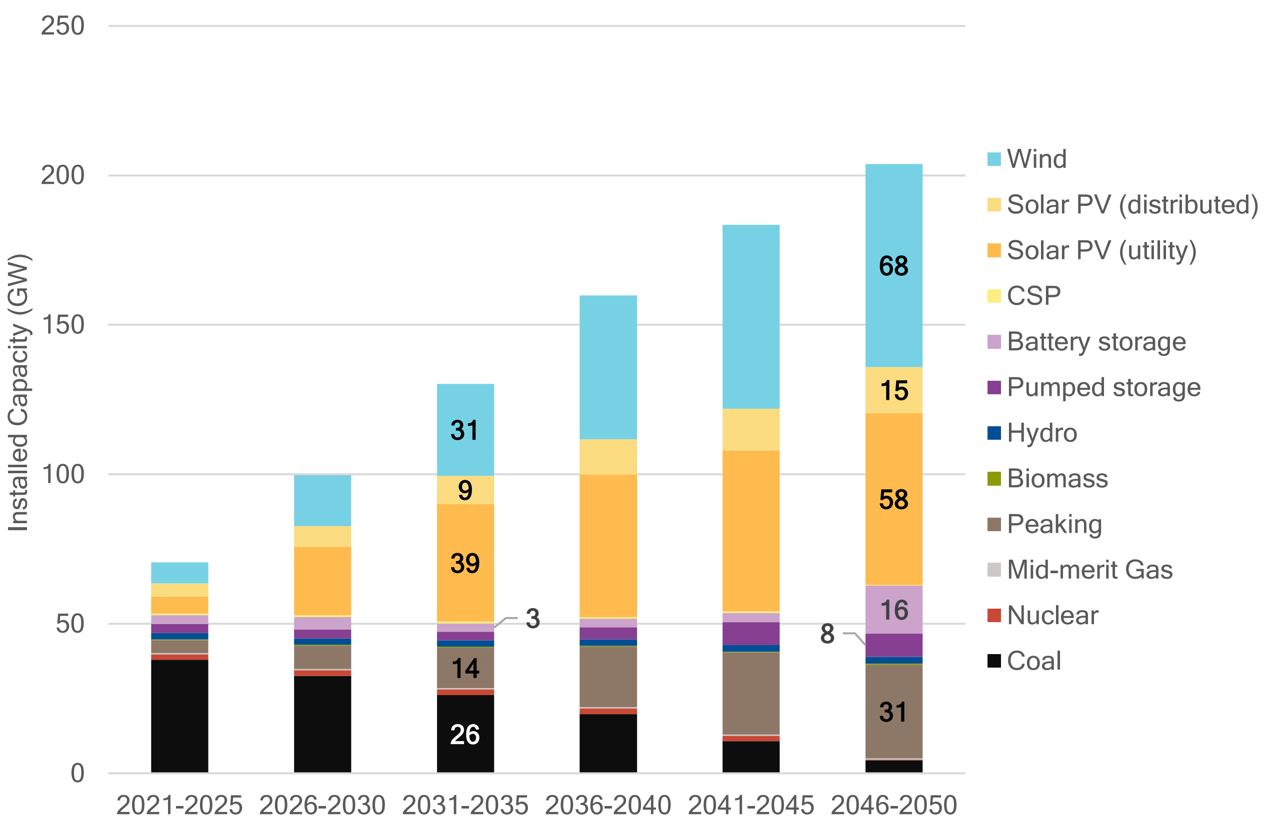


Figure 42: Installed Capacity - 2.8Gt CO_2 budget, NZ2055

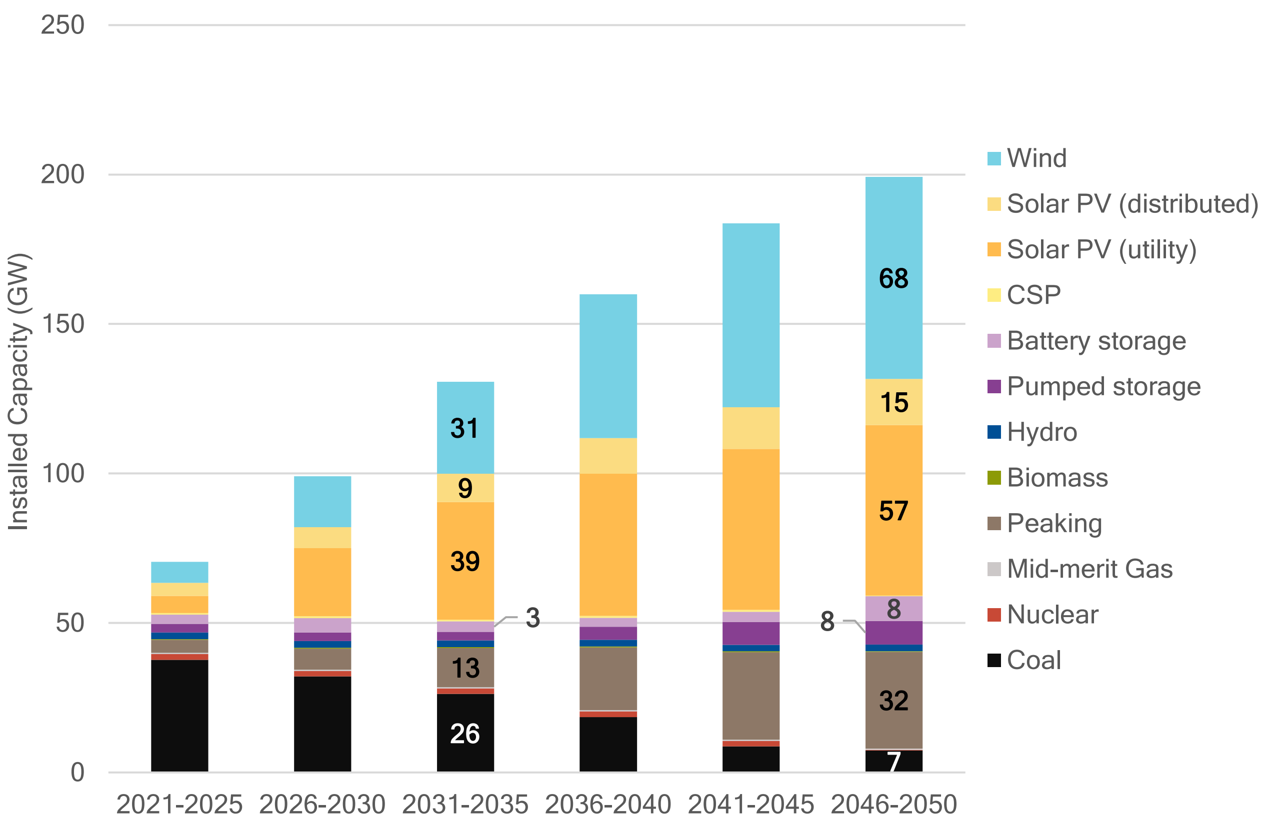


Figure 43: Energy Generation - Ambitious RE Only

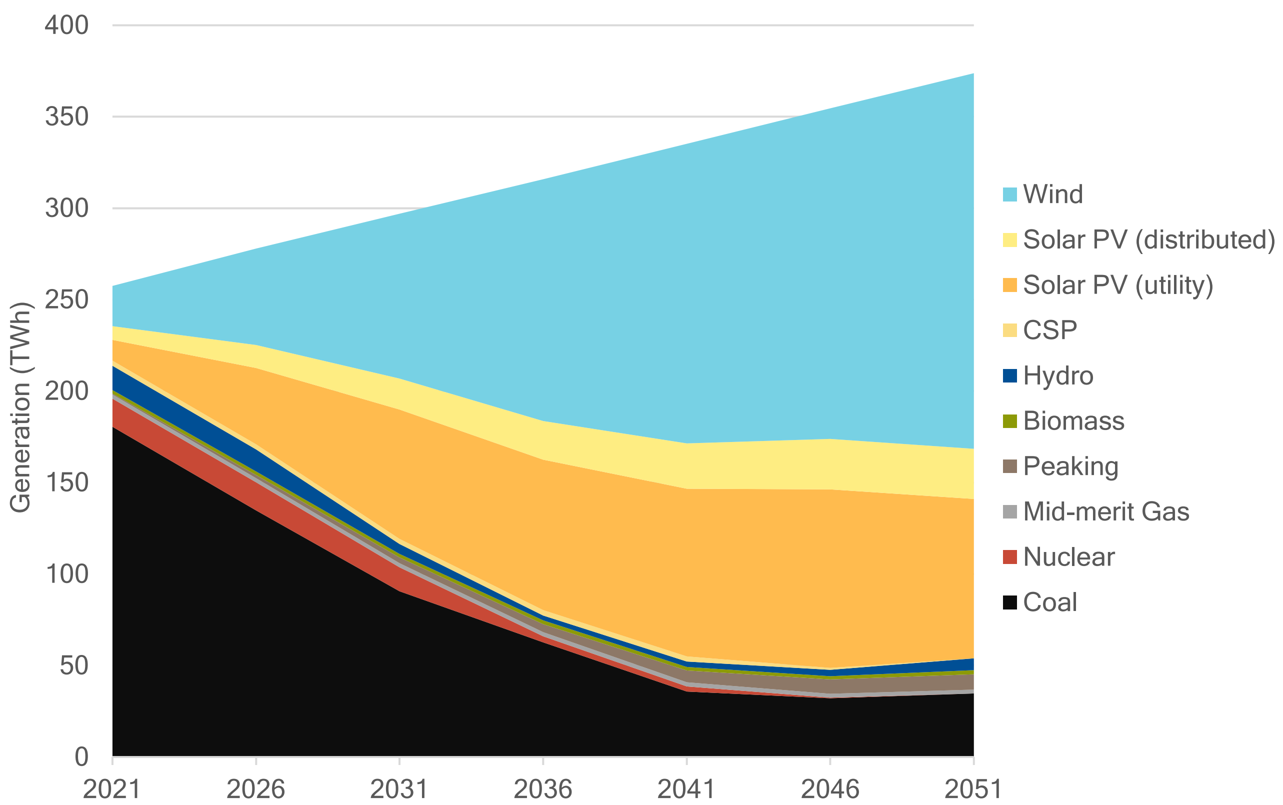


Figure 44: Energy Generation - 2.8Gt CO2 budget

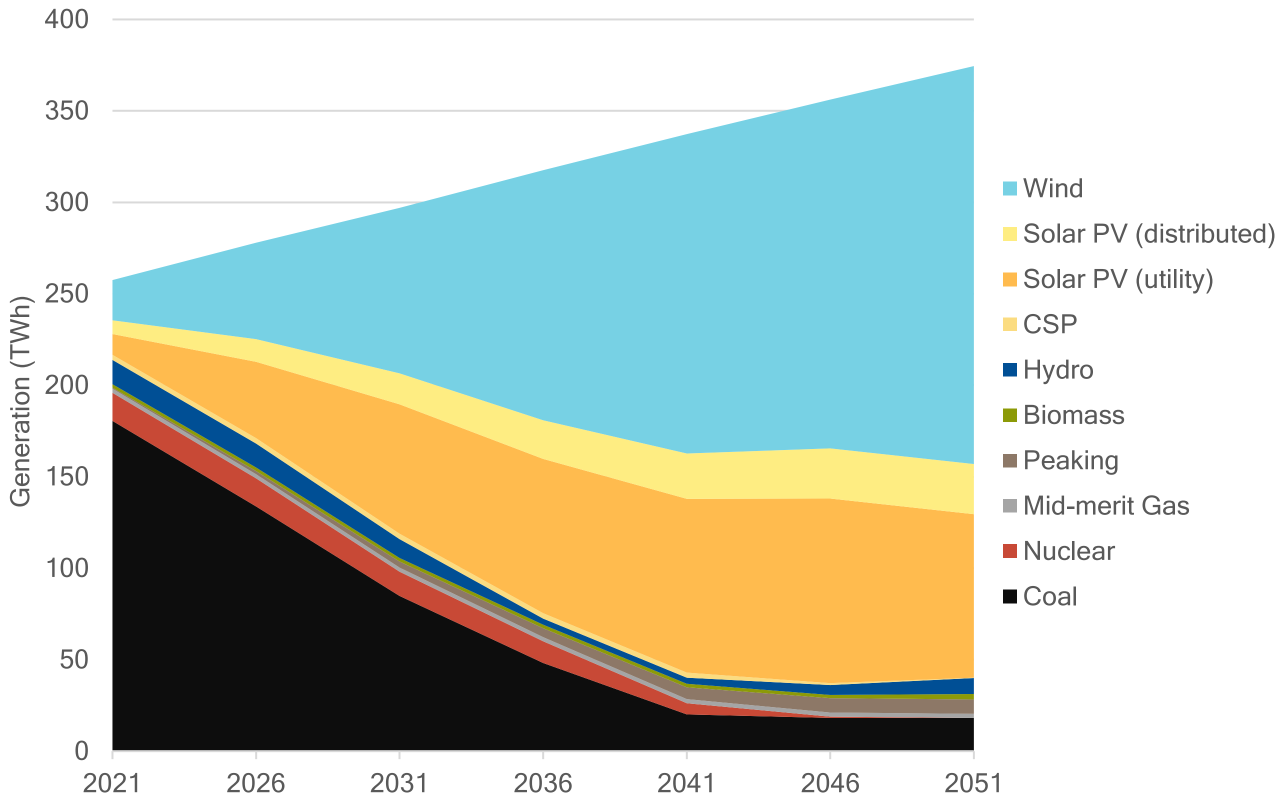


Figure 45: Energy Generation - Coal off by 2040

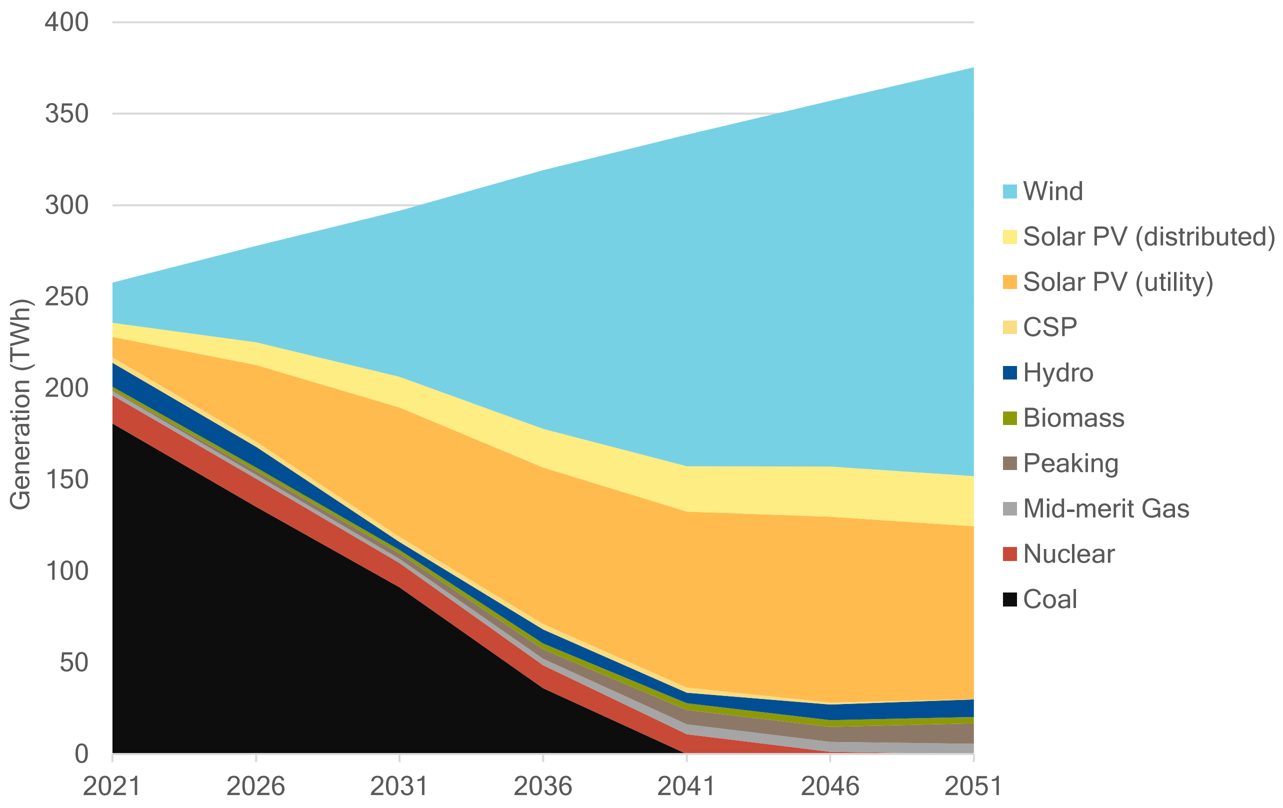


Figure 46: Energy Generation - Coal off by 2040, 2.3Gt CO_2 budget

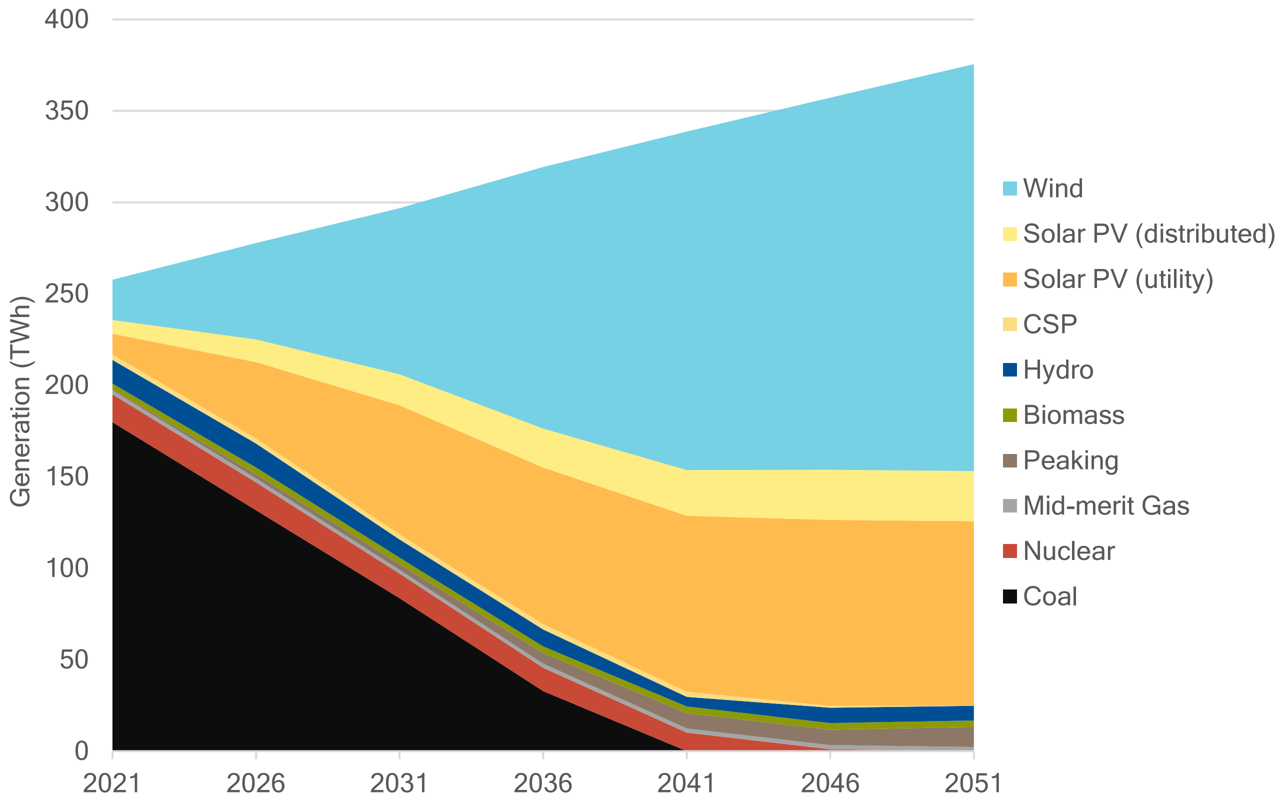


Figure 47: Coal off by 2040, 2.3Gt CO2 budget, NZ2050

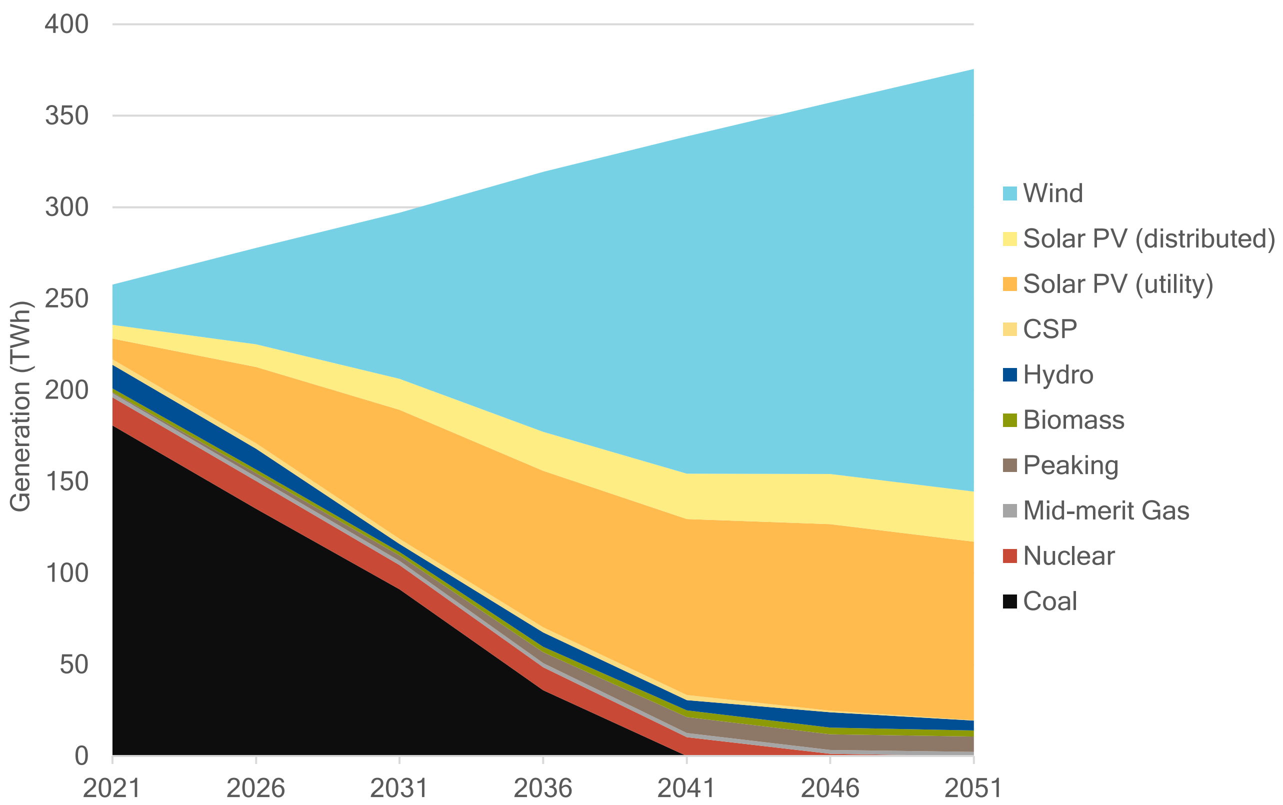


Figure 48: Energy Generation - NZ2050

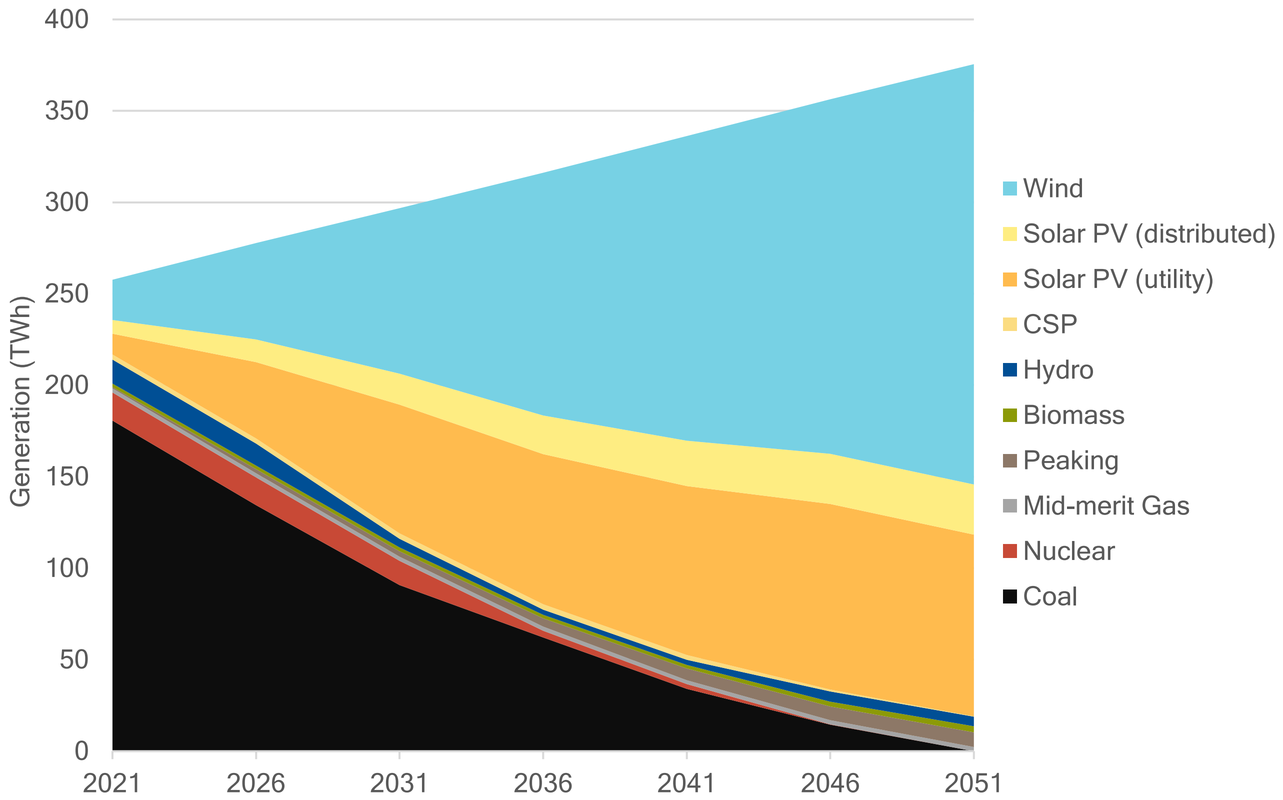
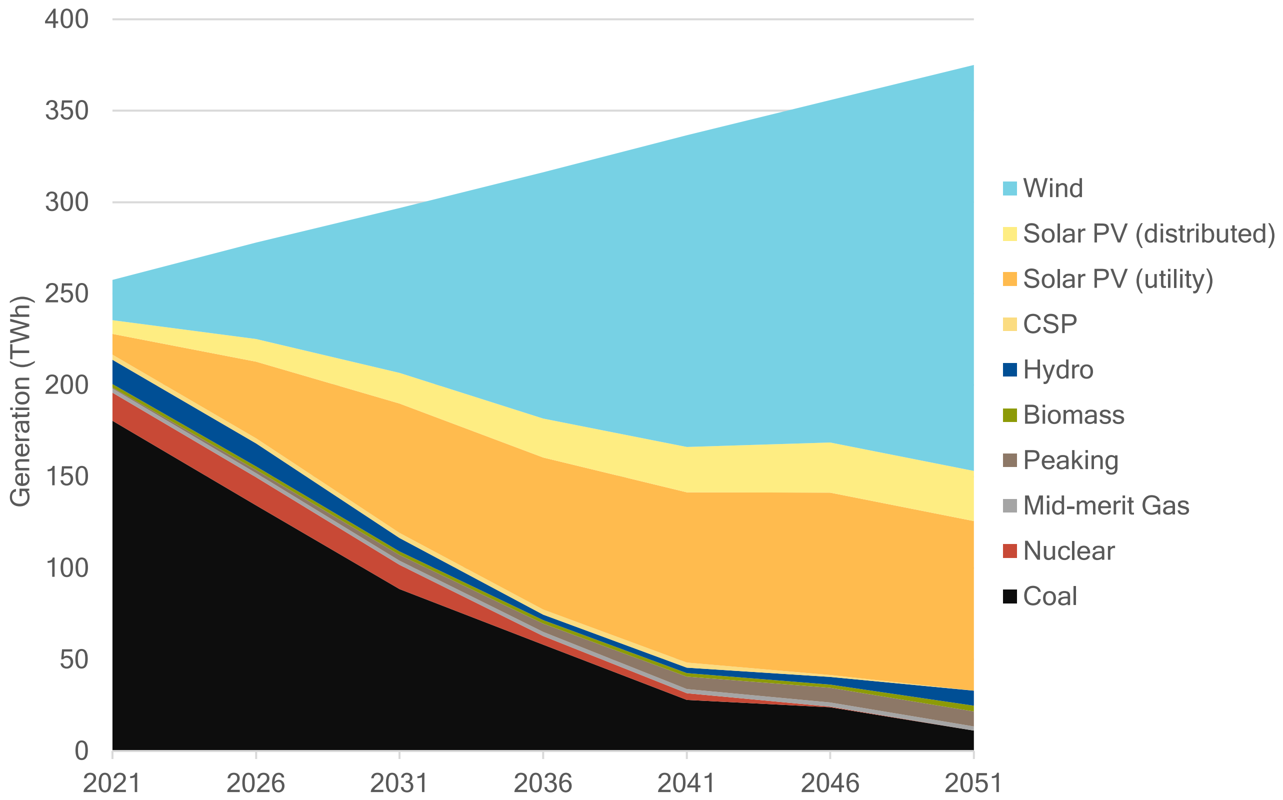


Figure 49: 2.8Gt CO2 budget, NZ2055



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