The role of gas in the transition to net-zero power generation

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We find that in an electricity system increasingly transitioning to intermittent renewable generation, gas-powered generation (GPG) is the least cost way to add capacity to the predicted mix of generation and storage in 2025. This finding holds when we include a carbon price equal to either the average Australian or average European price of carbon credits in 2020/21.

Our finding is based on our estimates of the Whole of Electricity System Cost (WESC), which accounts for the characteristics of generation and storage capacity that the system needs to maintain reliability and stability. In contrast, estimates of the Levelized Cost of Electricity (LCOE), which are often used to compare the relative costs of generation and storage technologies, do not account for the extent to which each generation and storage technology contributes to reliability and stability. This means that LCOE does not account for the full cost to the system of investments.

Our estimates of WESC also indicate that the flexibility and dispatchability provided by GPG becomes more valuable to the system over time, as the system increasingly transitions to intermittent renewable generation.

The key messages of our report are the following:

- The operation of GPG has changed substantially in the NEM and WEM over the past two decades. On all the measures we consider, GPG is maintaining its role in generating to meet peak demand and as a bulk energy provider (although GPG output overall is trending downward). However, GPG is also operating increasingly flexibly around intermittent renewable generation. For instance, over recent years the trend in the NEM has been for GPG to start more often, but to operate for shorter periods of time once started.
- Requirements for flexible generation, which include gas, hydro and storage, will continue to increase as the penetration of intermittent generation increases.
- AEMO's recent forecasts of GPG have tended to significantly under-forecast GPG output. Our analysis suggests that the pattern of AEMO under-forecasting GPG output is likely to persist with the 2020 ISP forecasts. In other words, the actual need for GPG is likely to be greater than forecast in AEMO's 2020 ISP.
- Our analysis of the relative costs of different generation and storage technologies suggests that GPG will have an important ongoing role to play in the NEM. It is a mistake to think that investing in generation or storage technologies with the lowest LCOE will necessarily result in the lowest electricity system cost. The broader system benefits delivered by investing in generation or storage technologies that are flexible and dispatchable can deliver lower electricity system costs. We see this in our analysis of the NEM: we find investment in GPG delivers the lowest electricity system costs because the flexibility and dispatchability provided by GPG are characteristics that are valuable, and becoming more valuable, in the NEM.
- While gas prices are a key driver of the cost of operating GPG, the evidence suggests that changes in gas prices are unlikely to be a key driver of dispatch of GPG.
- In electricity markets with a much bigger share of intermittent renewable generation than the NEM – such as Germany, Texas and the UK – GPG continues to play an important role in the electricity market.

1 Introduction

The generation mix in Australia's electricity markets has changed significantly in the last decade, and is expected to continue to evolve over coming decades. Renewable generation has grown substantially, and is expected to come to dominate generation over coming decades. At the same time, the coal-fired generators that Australia's electricity markets have historically relied upon have become increasingly uneconomic. Over the last decade, large coal-fired power stations have retired, and more are scheduled to retire in coming years, in Victoria, New South Wales, South Australia and Western Australia, but no new coal-fired power stations have been built to replace them.

A decade ago, gas was widely expected to act as a 'transition fuel', with gas-powered generation (GPG) increasing, taking the place of coal-fired generation, and GPG supporting the growth of intermittent renewable generation. Since then, rapid reductions in the levelised cost of energy (LCOE) for solar and wind, rapid reductions in the cost of utility-scale storage, and increases in the price of gas, have led some to the view that there is no need for further investment in GPG, and that a mix of renewables and storage can meet Australia's electricity needs securely and reliably.

We have been engaged by the Australian Gas Industry Trust and Jemena to assess the potential role of GPG in Australia's electricity markets in coming decades. In doing so, we consider the role that GPG can play in providing electricity, firm capacity and system stability, and consider how GPG compares with other technologies in meeting the needs of Australia's electricity markets.

We have undertaken this project using a staged approach, with the findings from each stage informing subsequent stages:

- Section 2 provides an historical analysis of the role of GPG in Australia's electricity markets.
- Section 3 provides an assessment of the GPG forecasts from the Australian Energy Market Operator's Integrated System Plan.
- Section 4 provides an assessment of Whole of Electricity System Cost for different generation and storage technologies available in Australia's electricity markets.
- Section 5 considers the sensitivity of GPG output to gas prices.
- Section 6 surveys the role that GPG plays in other electricity markets

2 Historical analysis of the role of GPG

Box 1: Key takeaways

- Gas powered generation comes in a number of different configurations, which have different advantages (e.g. flexibility) and disadvantages (e.g. emissions factors).
- In the 2000s, there was significant investment in GPG in the NEM and in the WEM to keep up with increasing peak demand. In the 2010s, new investment was focused on intermittent renewable generation and several major coal-fired power stations retired. As of 2021, GPG accounts for 25% of the firm capacity in the NEM and around two-thirds of the firm capacity in the WEM.
- The operation of GPG has changed substantially in the NEM and WEM over the past two decades. On all the measures we consider, GPG is maintaining its role in generating to meet peak demand and as a bulk energy provider (although GPG output overall is trending downward), but it is also operating increasingly flexibly around intermittent renewable generation.
- Requirements for flexible generation, which include gas, hydro and storage, will continue to increase as the penetration of intermittent generation increases.
- We consider three case studies that illustrate ways in which the nature of GPG operation is changing.

We begin our assessment of the potential role of GPG in Australia's electricity markets in coming decades by undertaking an historical analysis of the role of GPG in Australia's two largest electricity markets:

- the National Electricity Market (NEM), which operates in Queensland, New South Wales, Victoria, Tasmania and South Australia
- the Wholesale Electricity Market (WEM) in Western Australia.

The intention of this first stage is to understand the role that GPG has played in the NEM and WEM to date, and how this has evolved as the markets themselves have evolved. This understanding will help us to draw lessons about the potential role of GPG in coming decades.

This section discusses the key characteristics of GPG and compares these with other forms of electricity generation and storage, provides a high-level analysis of general trends in the role of GPG in the NEM and WEM over time and illustrates the role that GPG plays in Australia's electricity markets through a number of case studies.

2.1 Characteristics of GPG

There are a number of different technologies for gas-powered generation, which have different generation properties and costs. These are outlined in Box 2.

Box 2: GPG comes in different forms

Steam turbines operate using pressure from steam to turn a shaft which is attached to a generator, and gas can be used as a fuel in a boiler to create steam. Most coal-fired power stations also use a steam turbine with coal as the fuel to create steam. Steam turbines are relatively simple machines, but are large, relatively inefficient, and relatively inflexible. For these reasons new steam-turbine based gas generation is unlikely to be built in the NEM or WEM. The only gas-based steam turbine generators in the NEM are the Torrens Island Power Station in South Australia and Newport Power Station in Victoria. In the WEM there are a number of gas-powered steam turbines that are associated with alumina refineries.

Gas turbines operate by combusting a mixture of compressed air and fuel gas. Hot combustion gas expands through the turbine, spinning blades which draw in more pressurised air and turning a shaft attached to a generator which produces electricity. Gas turbines come in two main forms – aero-derivative turbines (based on aeroplane turbines, hence the name) and industrial turbines. Aero-derivative turbines are smaller and lighter and so faster to start up, although they are less efficient than their industrial counterparts. This makes aero-derivative turbines suitable for peaking applications. Industrial turbines are generally larger and more fuel-efficient but less flexible and hence more suited to baseload or mid-merit applications.

Gas turbines can be paired with steam turbines that use recovered heat from the operation of the gas turbines to produce steam and turn a turbine. This type of configuration is called a **'combined cycle' gas turbine (CCGT)** and is more efficient than a gas turbine alone (called an **'open cycle' gas turbines (OCGT)**). This is because heat that was previously dissipated (i.e. lost energy) is used to produce additional electricity. CCGTs are relatively common in the NEM and WEM due to their high efficiencies, relatively low emissions, and relative flexibility compared with other baseload or mid-merit options.

Reciprocating engines use combustion of fuel gas with pistons to turn a shaft attached to a generator, in some ways similar to an internal combustion engine in a car. Reciprocating engines fuelled by gas are more fuel efficient than OCGTs, but significantly less so than CCGTs, and very flexible in their ability to start and stop quickly and to operate at low generation levels[1]. AGL has recently built a power station comprising reciprocating engine units in Barker Inlet in South Australia to replace an older gas steam turbine station retired around the same time.

Some gas powered generators may have 'dual fuel' capability, being able to operate by burning gas or liquid fuels, such as distillate. Liquid fuels are typically more expensive on an energy-equivalent basis, and produce more carbon-equivalent emissions. However, liquid fuel can be stored on site at lower cost than gas.

1 https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/Aurecon-2019-Cost-and-Technical-Parameters-Review-Draft-Report.PDF

Until recently, Australia's electricity markets have provided signals for the supply of energy and firm capacity (dispatchable on demand), with no value on the relative greenhouse gas emissions of different generation options. These signals for the supply of energy and firm capacity have been provided in different ways in the NEM and the WEM:

- In the NEM, the average electricity price has provided a signal for the requirement for energy, while the volatility in the electricity price (in particular, prices at or near the market price cap) has provided a signal for the requirement for firm capacity.
- In the WEM, there has been both a capacity market and an energy market. The average electricity price has provided a signal for the requirement for energy, while the capacity price and electricity price together have provided the signal for the requirement for firm capacity.

In both cases, while there was no value placed on lower greenhouse gas emissions, the stock of generation in Australia's electricity markets has historically reflected a mix of:

- "Baseload" coal: high capital cost, low fuel cost, high emissions.
- "Mid-merit" gas: moderate capital cost, moderate fuel cost, low emissions. Includes both steam turbines and, more commonly, CCGTs.
- Gas/liquid fuel "peakers": low capital cost, high fuel cost, high emissions. Includes both reciprocating engines and, more commonly, OCGTs.
- Hydro: high capital cost, low fuel cost, zero emissions.

The increased value policymakers have placed on lower greenhouse gas emissions, or renewable sources of generation, is changing the optimal generation mix and raising challenges for the design of Australia's electricity markets. The key issue is that the renewable generation technologies that have been built in Australia's electricity markets – principally wind and solar generation – are intermittent in nature. An increase in intermittent generation needs to be complemented by an increase in flexible sources of electricity supply, while an increase in intermittent generation makes it more difficult for baseload plant to operate efficiently.

Table 1 provides a broad summary of the typical characteristics of the principal sources of generation and storage available in the NEM and the WEM, but is intended only as a general guide. What **Table 1** seeks to illustrate is that an electricity market that seeks to efficiently deliver energy, firm capacity and low emissions is likely to need to rely on a mix of different generation and storage options. While renewables deliver zero emissions energy, other sources of generation and storage are necessary to provide firm capacity. As much as possible, electricity markets should be designed to reveal the value of the different services that are required and participants should be left to determine the optimal mix of supply in light of those values.

Table 1: Relative merits of different technologies

Technology	Energy	Firm capacity	Low emissions
Baseload coal	+++ (Tends to have lower fuel cost than gas, so operate at higher capacity factor than GPG.)	+++	---
Mid merit gas, including steam turbine and CCGT	++ (More efficient than peakers, so operate at higher capacity factor than peakers.)	+++	- (More efficient than peakers, so lower emissions than peakers.)
Peakers, including OCGT and reciprocating engines	+	+++	--
Hydro	++	+++	+++
Intermittent renewables (wind, solar PV)	++	---	+++
Pumped hydro	--- (Net consumer due to efficiency losses. Less efficient than batteries.)	+++ (can store/shift energy between seasons)	+/- (depends on source of pumping; typically it would be used to support renewables so likely positive)
Batteries	-- (Net consumer due to efficiency losses. More efficient than pumped hydro)	++ (generally shorter storage: often 1 hr, fast response for frequency control)	+/- (depends on source of charging; typically it would be used to support renewables so likely positive)

Coal plant will continue to retire at the end of their technical lives (or before, if the economics of remaining operating are unfavourable). In the absence of policy intervention, the required investment in new flexible sources is unlikely to occur without greater certainty over the mechanism for Australia to meet our emissions reduction commitments and greater certainty about future market design. This raises questions about how future demands for energy and dispatchable capacity will be met.

- Dispatch from coal energy is currently falling, as a result of being displaced largely with intermittent renewables (wind, solar PV) which can supply a lot of zero emissions energy but is not dispatchable.
- This will increase the price volatility in the market, which raises the value for additional dispatchable capacity to complement the intermittent renewables.
- This likely requires more peakers, pump hydro or batteries to provide sufficient dispatchable capacity. While batteries and pumped-storage hydro actually consume more energy than they produce, they provide value in dispatchable capacity. The extent to which batteries and pumped-storage hydro can provide dispatchable capacity depends on the ‘depth’ of storage. For example, batteries that provide 2 hours of storage are able to provide dispatchable capacity for less time than pumped-hydro that is able to provide 6 hours of storage. GPG, in contrast, can provide dispatchable capacity for as long as it has access to gas supply.
- An alternative (or complement) is increased energy from dispatchable renewables such as solar thermal with storage. Although this may currently be a higher cost option, the energy produced has more value than the energy produced from intermittent renewables.
- Of the electrical storage options available, hydro provides the largest and longest form of storage, enabling shifting of energy between seasons/years; solar thermal provides medium term storage across hours/days; batteries generally provide short-term storage across hours. Each has a different role to play.

In addition, the departure of legacy coal plant has revealed the importance of inertia and the potential value of ‘fast frequency response’, which can partially substitute for inertia. While wind, solar PV and batteries do not presently provide inertia, batteries can provide very fast frequency response.

2.2 Overview of GPG in the NEM

As discussed, GPG in the NEM consists of mid-merit plant and peakers. Currently, there are 13 mid-merit gas plant and 32 gas-powered peakers in the NEM.

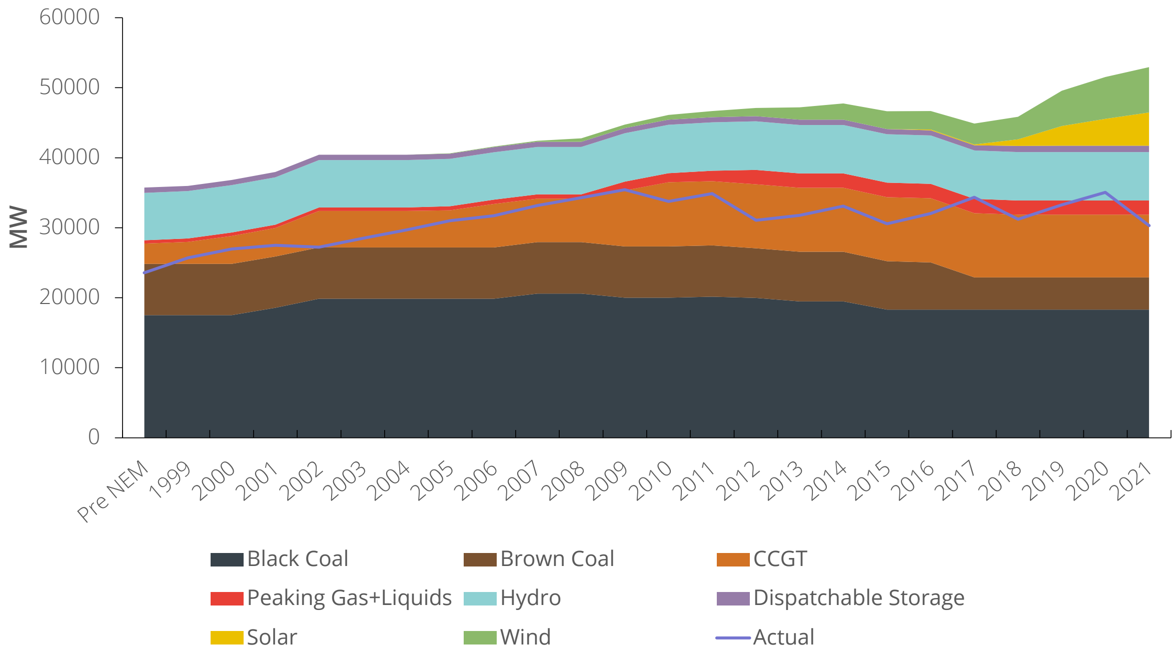
Figure 1 shows historical installed generation and storage capacity in the NEM, as well as maximum coincident demand in the NEM. **Figure 2** highlights how capacity has changed (via investment and retirements) over the same period. There are a number of key findings that can be drawn from these figures:

- Maximum coincident demand has stayed comfortably below levels of firm capacity (where firm capacity includes the capacity of black and brown coal, GPG, hydro and dispatchable storage). This implies that, historically, the NEM has had a significant reserve margin.
- GPG has made an increasingly important contribution to the reserve margin in the NEM. As can be seen in **Figure 2**, much of the new investment in the NEM during the period from market start until 2012 was GPG. Since then, almost all investment has been solar and wind. Combined with the retirement of coal fired generation over the last decade or so, this has

meant that GPG is increasingly important in meeting peak demand in the NEM. As of 2021, GPG accounts for 25% of the firm capacity in the NEM.

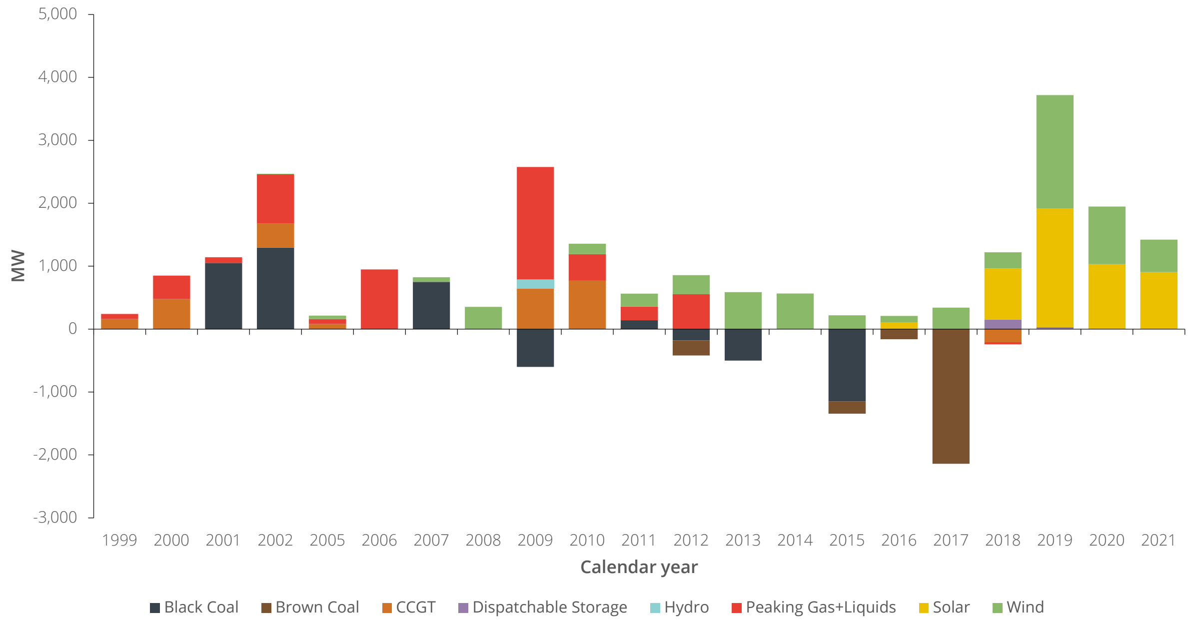
- Firm capacity has historically increased with increases in maximum demand. This was particularly evident during the period from market start until 2012, when the growth in maximum coincident demand (which was driven in part by the adoption of air conditioning leading to higher summer peak demand) was matched by the increase in firm capacity, largely from GPG.
- Since around 2017 firm capacity has fallen, even as maximum coincident demand has trended higher. This reduction in firm capacity is primarily due to the retirement of the Hazelwood Power Station in Victoria.

Figure 1: Generation mix in the NEM



Source: Frontier Economics

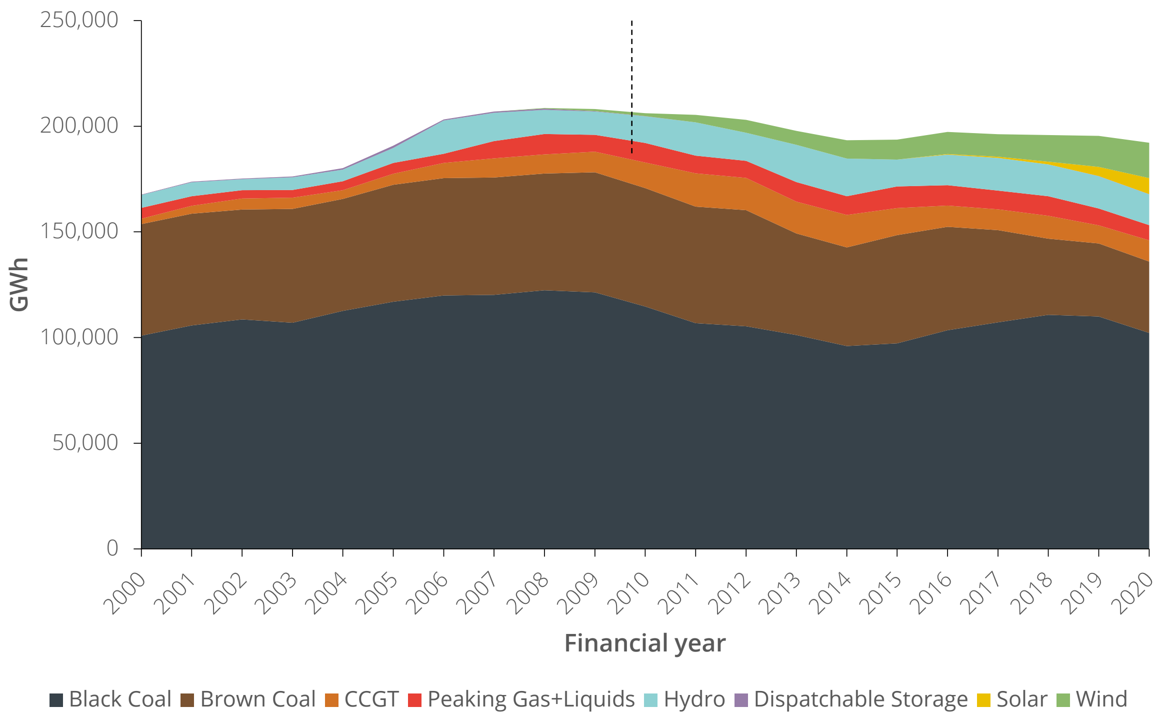
Figure 2: Investment and retirement in the NEM



Source: Frontier Economics

Figure 3 shows historical generation and storage output for the NEM. As expected, baseload coal generation accounts for a larger share of output than it does of capacity, and both mid-merit GPG and peakers run less frequently.

Figure 3: Historical output in the NEM, 2000-2020

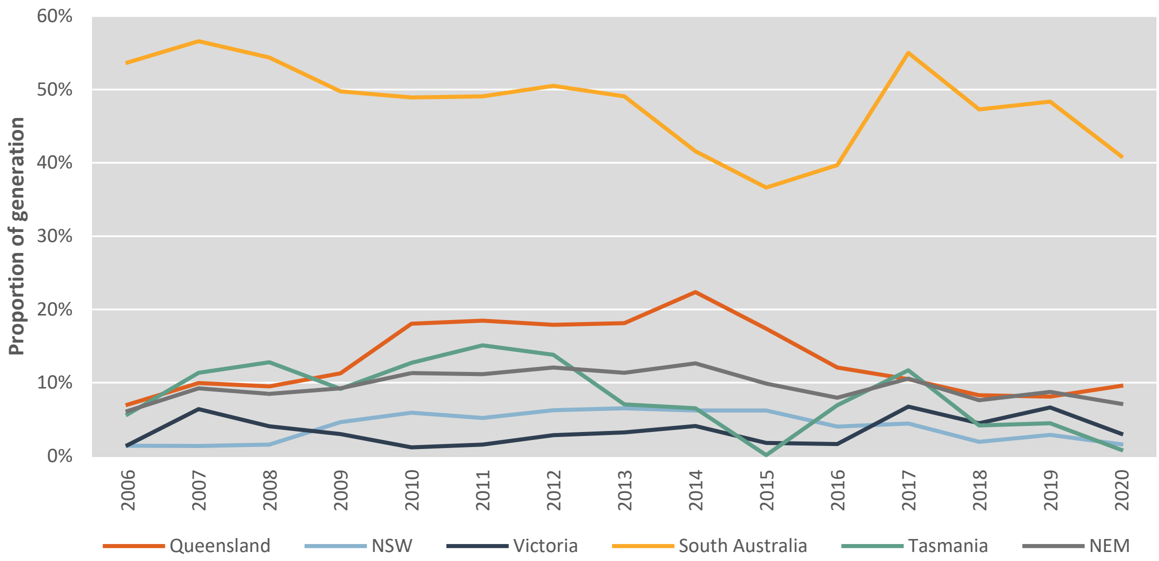


Source: Frontier Economics

The contribution of GPG to output in each region of the NEM varies considerably, as seen in **Figure 4**. It is clear from **Figure 4** that the operation of GPG can vary materially from year to year. Indeed, this flexibility is one of the chief benefits of GPG. Key drivers of these changes in GPG are the following:

- GPG decreased in South Australia to 2016, with increases in intermittent output in the form of rooftop solar PV, utility scale solar PV and wind generation. Following South Australia's system black event in 2016, GPG has been forced on via 'directions' and other security constraints (e.g. Heywood ROCOF constraint) from AEMO. This has meant that GPG has been running when it would otherwise not be, due to the amount of renewable generation online.
- GPG has declined in Queensland and NSW from around 2014 because of the impact of rooftop solar and utility scale renewables, which can have direct effect on GPG given it is higher cost that coal generation and so gets displaced before coal. The general decline in demand due to energy efficiency has also effected GPG.
- Victoria's GPG has increased from 2017 due to the closure of Hazelwood Power Station, which provided around 20% of Victoria's output. This is discussed further in Section 2.5.3.

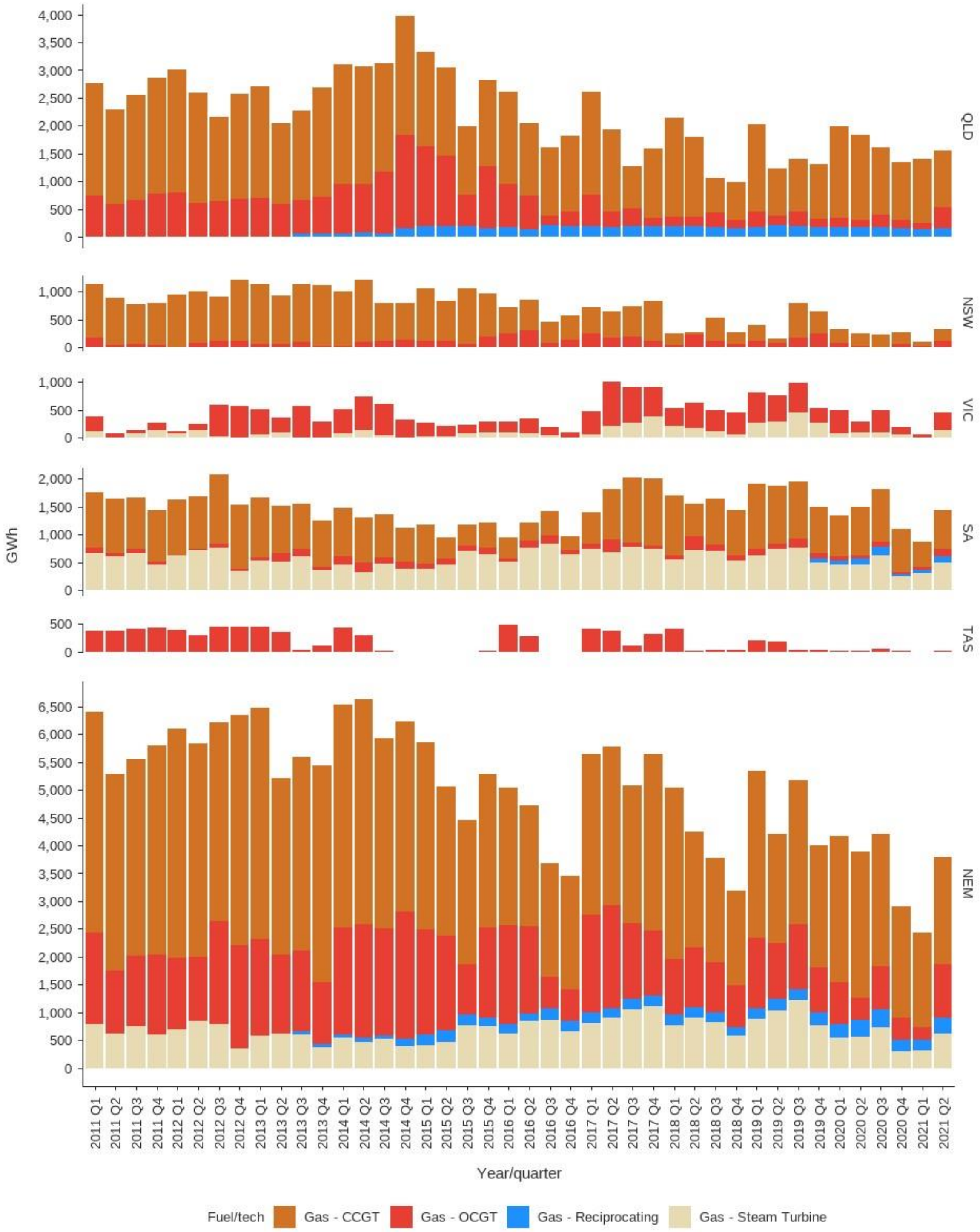
Figure 4: Proportion of generation that is gas-fired, 2006-2020



Source: AER State of the Energy Market 2021, p78, available https://www.aer.gov.au/system/files/State%20of%20the%20energy%20market%202021%20-%20Full%20report_1.pdf

Figure 5 provides a breakdown of GPG output in the NEM by region, quarter and GPG technology. Queensland and South Australia have historically produced the highest volumes of electricity with GPG. Victorian and South Australian output increased notably after the closure of Hazelwood Power Station in Victoria in 2017. At both the state and system level, GPG output can be volatile between quarters, depending on prevailing supply and demand conditions.

Figure 5: Quarterly GPG output, NEM, 2011 Q1 – 2021 Q2

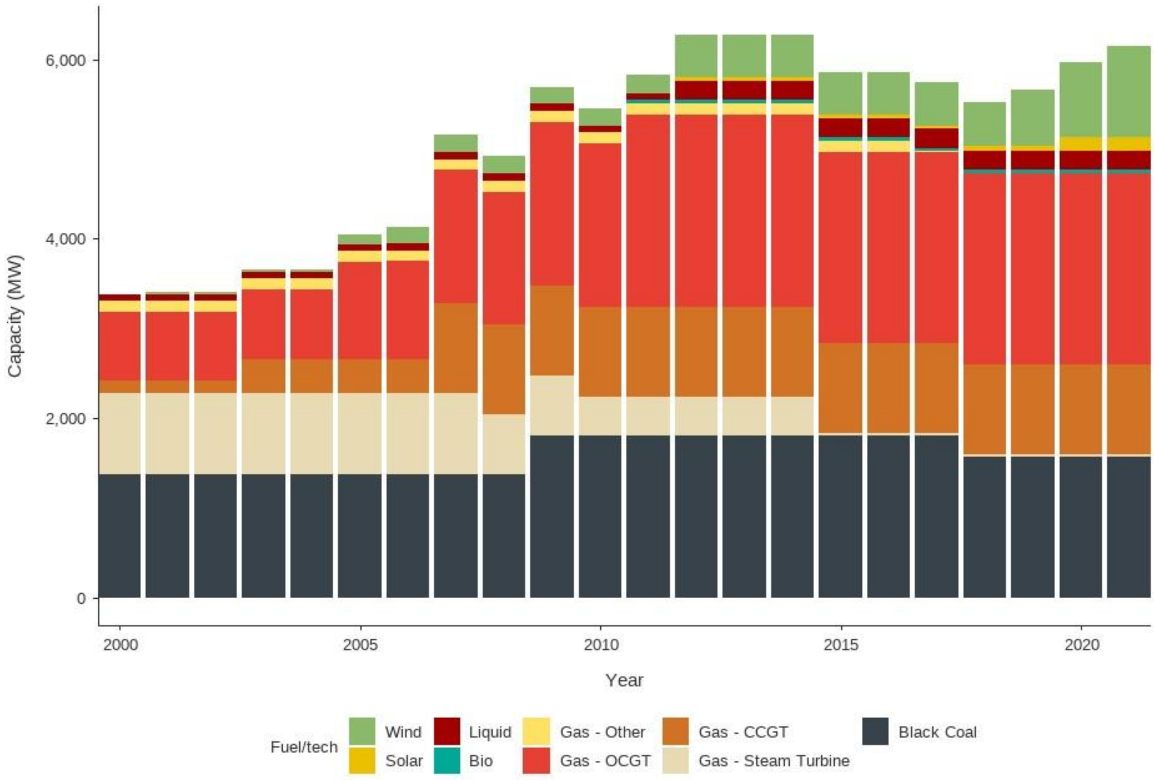


Source: Frontier Economics analysis of AEMO data

2.3 Overview of GPG in the WEM

GPG in the WEM is currently comprised of predominantly CCGT and OCGT generation. CCGT and OCGT currently make up around two-thirds of the WEM's dispatchable capacity, as outlined in **Figure 6**. Gas generation capacity has increased along with maximum demand as in the NEM.

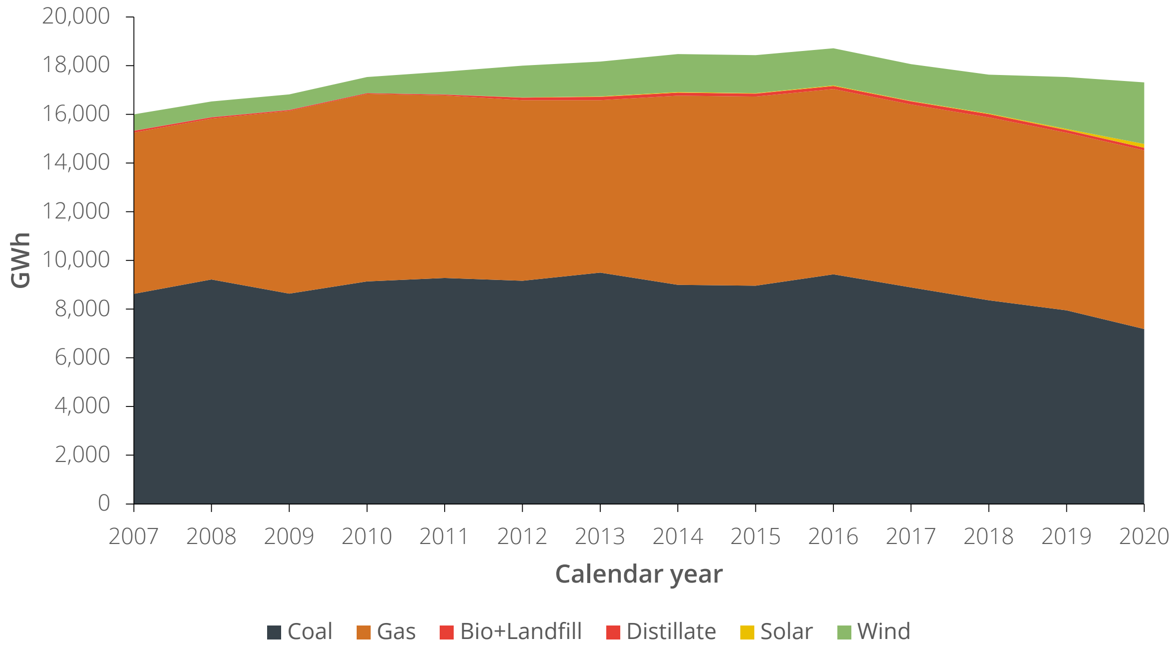
Figure 6: Generation mix in the SWIS



Source: Frontier Economics

Figure 7 illustrates output for SWIS on an annual basis. Despite having the majority of capacity, GPG in the WEM has accounted for around half of annual generation alongside black coal. Increases in intermittent generation – primarily wind – have mostly resulted in crowding out of coal output.

Figure 7: Historical output in the SWIS, 2007-2020



Source: Frontier Economics

2.4 How GPG tends to operate in Australia's electricity markets

The importance of GPG to Australia's electricity markets is not simply a matter of GPG's contribution to annual electricity output; the importance of GPG is only fully understood by investigating the circumstances in which GPG operates in Australia's electricity markets.

Daily operating patterns

One way of understanding this is looking at the time of day that GPG typically operates.

Figure 8 illustrates how typical daily operating patterns of GPG in the NEM have changed over time.

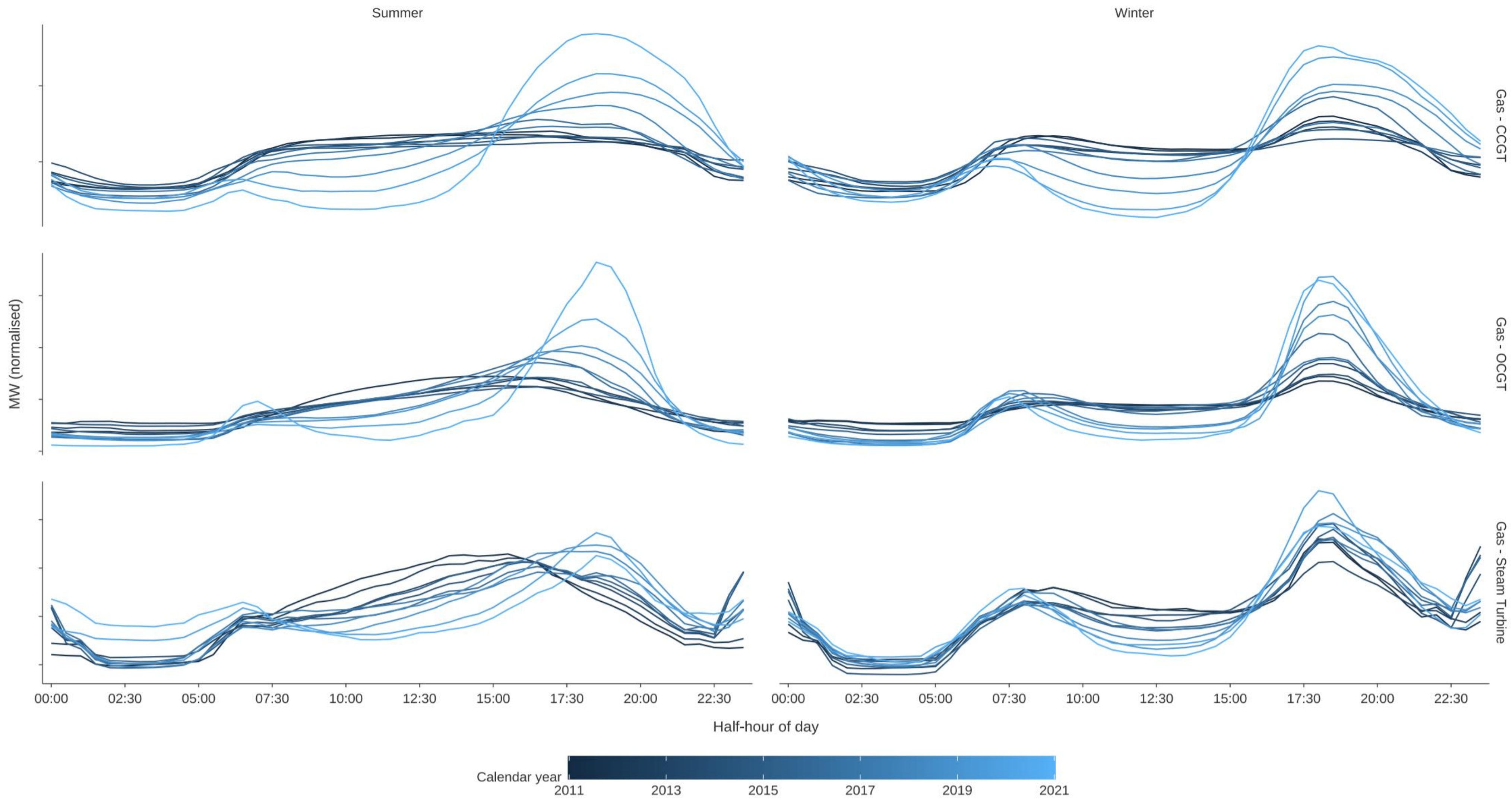
Figure 8 shows average daily operating output for each year from 2011 to 2020, for CCGTs, OCGTs and steam turbines in the NEM, in summer and winter. The average daily output in each year/season is then scaled to the same aggregate amount, so that **Figure 8** shows how the average daily pattern of operation changes from year to year, but not how the total amount of output changes from year to year.[2]

[2] So, for instance, the curve for summer 2020 for CCGT has been scaled to the same aggregate amount of MWh as the curve for summer in each of the other years for CCGT. This means that the variations in the curves simply show how the time of day that CCGT's are operating in summer has changed over the years, but show nothing about the aggregate amount of operation in summer over the years.

There are a number of key findings that can be drawn from **Figure 8**:

- Normalised patterns of operation had been relatively consistent for CCGT and OCGT up until around 2016. Over this period:
  - CCGT plant tended to operate, on average, fairly consistently through the day with some increase to meet higher peak demand during winter evenings.
  - OCGT plant tended to operate, on average, during the afternoon and evening peak demand periods in summer and the evening peaks in winter.
- Since around 2017, normalised patterns of operation have changed. In particular, it is clear that for all forms of GPG there has been a marked decrease in the extent to which GPG tends to operate during the day. This has been driven by the increase in solar generation, with GPG increasingly taking on the role of operating at times when renewable generation is not available. This effect occurred earlier for steam turbines, which are mostly found in South Australia. South Australia has a lot of rooftop solar and hence has seen daytime load reducing earlier than other regions.

Figure 8: Normalised output by GPG, by time of day, 2011-2020



Source: Frontier Economics

Relationship between GPG, demand and renewable dispatch

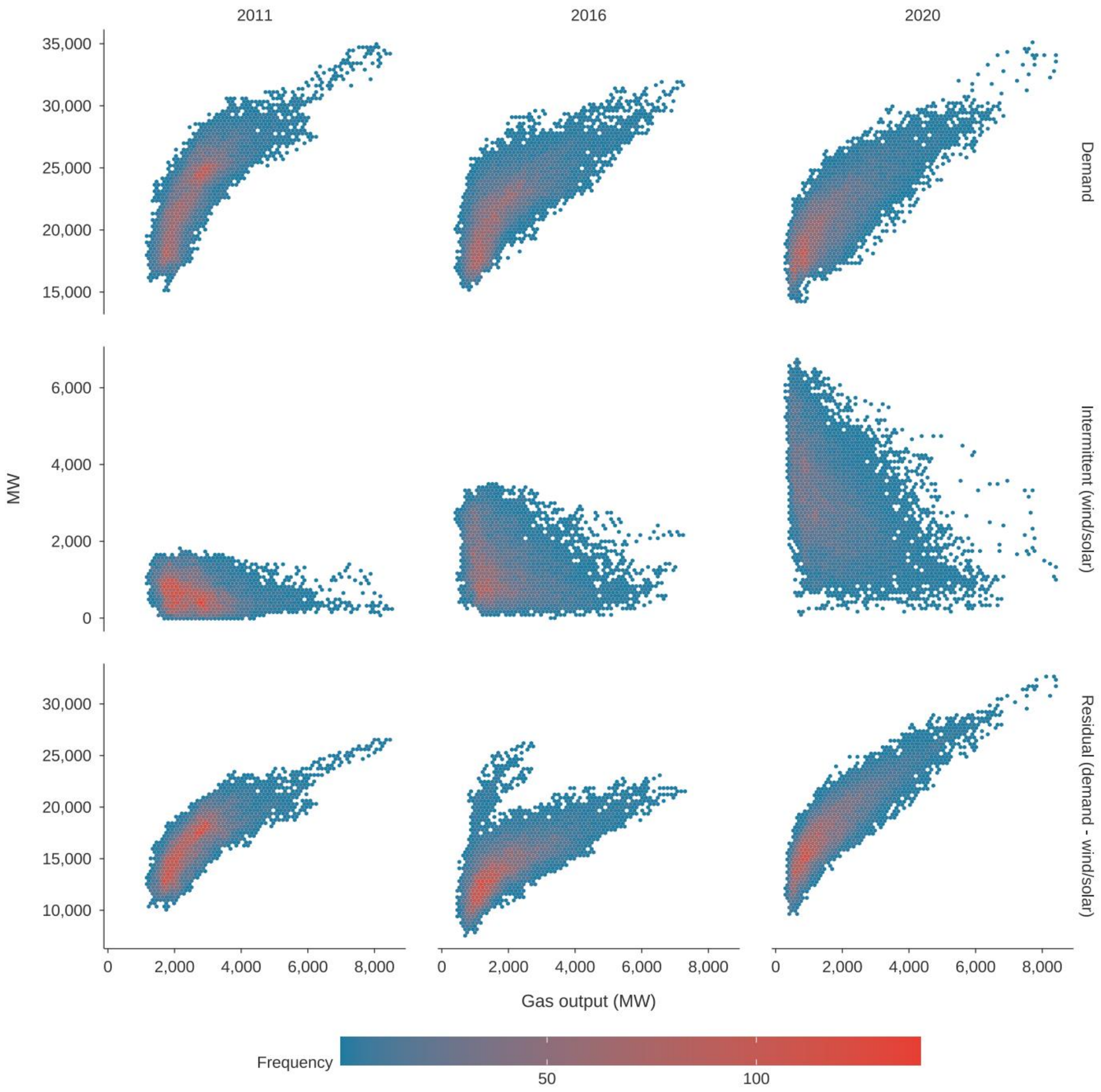
The typical daily operating patterns of GPG shown in **Figure 8** provide a useful indication of the way that GPG is increasingly taking on the role of operating at times when solar generation is not available, because solar generation follows a very consistent daily pattern. This isn't the case for wind generation, which operates according to much less regular or predictable patterns, including experiencing prolonged wind droughts for several days at a time. Another way of understanding the way the GPG operates in the NEM, and how this is related to demand conditions and the availability of renewable generation, is shown in **Figure 9**.

Figure 9 illustrates the historical relationship between GPG output (x axis) and each of demand, intermittent renewable generation, and the residual of demand and intermittent generation (the y-axes on the three 'rows') in the NEM.

- The first row of charts shows the level of GPG at levels of coincident demand (i.e. the sum of regional demands in the same time period) in the NEM. In all years shown, GPG shows a strong positive correlation with demand and GPG is running its hardest when demand is high. However, comparing 2020 to 2011, the range of gas output levels at different demand levels increases (the cluster of points gets wider). This indicates that the relationship between gas output and demand is becoming less consistent – in particular, it is clear that it is becoming more common for aggregate gas output to be relatively high even during periods of relatively lower demand. Comparing 2020 to 2011, it is also apparent that instances of very low gas output – including aggregate gas output levels close to zero across the NEM, are becoming more common.
- The second row shows the level of GPG at different levels of intermittent output, including utility scale solar and wind (rooftop PV is captured as reductions on the demand side). The amount of intermittent output has increased substantially from 2011 to 2020, as indicated by the height of the clusters of points. The increasingly prominent triangular shape indicates that GPG increasingly 'works around' intermittent generation, providing higher output when renewable generation is low, and less output when renewable generation is high.
- The third rows shows the level of GPG at different levels of residual demand, i.e. demand less intermittent generation. These charts are generally more tightly clustered than each of the demand and intermittent charts above because the combination of demand and intermittent generation (i.e. residual demand) is more strongly correlated with gas output than the individual factors. As with the demand charts, the lower level of gas output falls from 2011 to 2020 (shifting leftwards), but the correlation remains strong.

This illustrates that gas continues to serve demand at all levels, but is increasingly operating around intermittent generation.

Figure 9: Historical relationship between GPG and demand, intermittent renewable generation, and the residual (demand – intermittent generation)



Source: Frontier Economics analysis of AEMO data

Number of starts and hours of operation

Finally, an indication of the extent to which GPG is increasingly operating flexibly around the intermittency of renewable generation is provided by examining trends in the number of times each year that gas generators start, the average number of hours that gas generators operate each time they start, and how they are operating when started.

Figure 10 shows these metrics for GPG from 2010 to 2020. The metrics shown include, for each technology type and year:

- Starts: the average number of starts per unit
- Average run time (hours): the average number of hours operating after a start

- Capacity factor (running): shows the average level of output, as a percentage of total capacity, for a unit while operating
- Capacity factor (annual): shows the average level of output, as a percentage of total capacity, for a unit across the year

Broadly speaking, **Figure 10** indicates the following:

- There is a trend of number of starts increasing across technology types for GPG. 2020 has been an exception, due to subdued demand partly related to the COVID-19 pandemic, although these trends are reversing in 2021. An increasing number of starts is an indication of gas running more flexibly, but not necessarily increasing output.
- There is a trend for generally decreasing hours per start so generators are on average running fewer hours per start. The exception here is steam turbines, which includes the Torrens Island Power Station in South Australia, which run more due to the closure of Northern Power Station and Hazelwood and have been constrained on significantly since the South Australian blackout in 2016. While the number of starts has been increasing, the hours operating per start has decreased, suggesting that gas is running increasingly flexibly.
- Capacity factors while running indicate that the level at which gas is operating once started has not changed much across the period shown. That is, when gas is operating, it is not running at higher or lower output levels when operating.
- Capacity factors across the year, however, indicate that gas is running less overall through the period shown (again, with the exception of steam turbines in South Australia).

Figure 10: Number of starts by technology/region

Source: Frontier Economics

Our analysis indicates that GPG is operating in an increasingly flexible way in order to respond to the intermittency of renewable generation. Analysis by the AEMC helps explain the need for GPG to operate more flexibly. **Figure 11** shows ramping requirements in the NEM, or the amount of flexible generation or load required, to meet changes in the level of intermittent generation. Intermittent generation output can change rapidly, and flexible generation is required to fill the void when intermittent generation falls, or back off when intermittent generation increases. The ramping requirements (both up and down) have increased significantly in the period shown (Jan 2018-Jan 2021). This trend indicates the increasing opportunity, and requirement, for resources (generation, storage and demand response) that can respond quickly to these changes.

The AEMC also notes that fast-response alternatives are becoming critical to balance supply and demand in this volatile environment. Gas, hydro and batteries are able to respond to the variability of wind and solar because they can frequently alter output while continuing to remain economic. These technologies have been a focus of recent policies designed to stabilise the grid.

Figure 11: Changing ramping requirements due to wind/solar, 2018-2021

Note: Monthly top 1% of up and down 60 minute ramps in the National Electricity Market.
Source: AEMO, unpublished data.

Source: Australian Energy Regulator, State of the Energy Market 2021, p31, available [*https://www.aer.gov.au/system/files/State%20of%20the%20energy%20market%202021%20-%20Full%20report_1.pdf*](https://www.aer.gov.au/system/files/State%20of%20the%20energy%20market%202021%20-%20Full%20report_1.pdf)

2.5 Case studies of GPG operation

In order to provide some concrete examples of the flexibility that GPG offers Australia's electricity market, the following sections present some recent examples of outcomes in Australia's electricity markets, focusing on the way that GPG has operated.

2.5.1 Case study 1 – GPG providing flexibility in South Australia

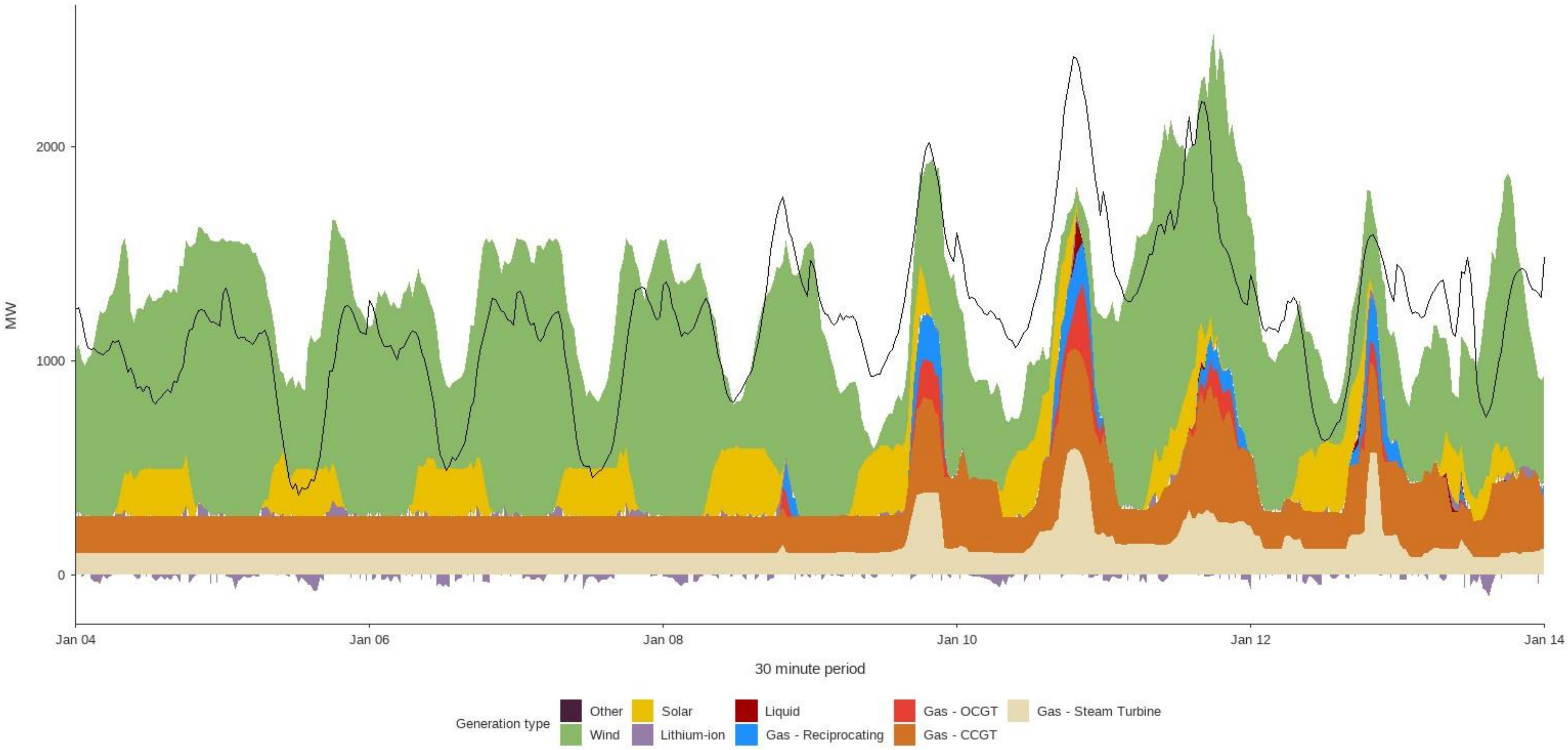
The first case study provides an example of the way that GPG provides flexibility to manage intermittent renewable generation.

Figure 12 provides half-hourly data for total generation and demand in South Australia for a 10-day period from the beginning of January 4 2021 to the end of January 13 2021. There are a number of key findings that can be drawn from **Figure 12**:

- During this period in summer, wind and solar generation account for the majority of generation in South Australia. Not only do wind and solar generation meet the majority of demand in South Australia, but there are extended periods when excess generation in exported to Victoria (indicated by periods when total generation in South Australia is higher than total demand in South Australia).
- Even when renewable generation in South Australia is significantly higher than total demand in South Australia, some gas generation continues to operate in order to provide system security. This is roughly 20 per cent of average demand, although a much higher proportion of demand during the solar trough in the middle of the day (which is driven by rooftop solar PV).
- When renewable generation falls substantially – as it does on January 9 and January 10 – gas is able to respond flexibly to meet demand (combined with imports from Victoria). Steam turbines and CCGT plant increase their output, and OCGT and reciprocating engines are both able to start and ramp up swiftly to meet demand.
- Output from GPG can be required for extended periods of time when intermittent generation is low. For instance:
  - On January 9, OCGT were operating for 6 hours and reciprocating engines were operating for 5.5 hours.
  - On January 10, both OCGT and reciprocating engines were operating for 9 hours.

  This is significantly longer than batteries can typically operate for at full output. For instance, the Hornsdale battery in South Australia can operate for around 1 hour and 20 minutes at full output. Hornsdale energy output (and charging) is visible on the chart under the "Lithium-ion" label.

Figure 12: Case study: South Australian gas flexibility



Source: Frontier Economics

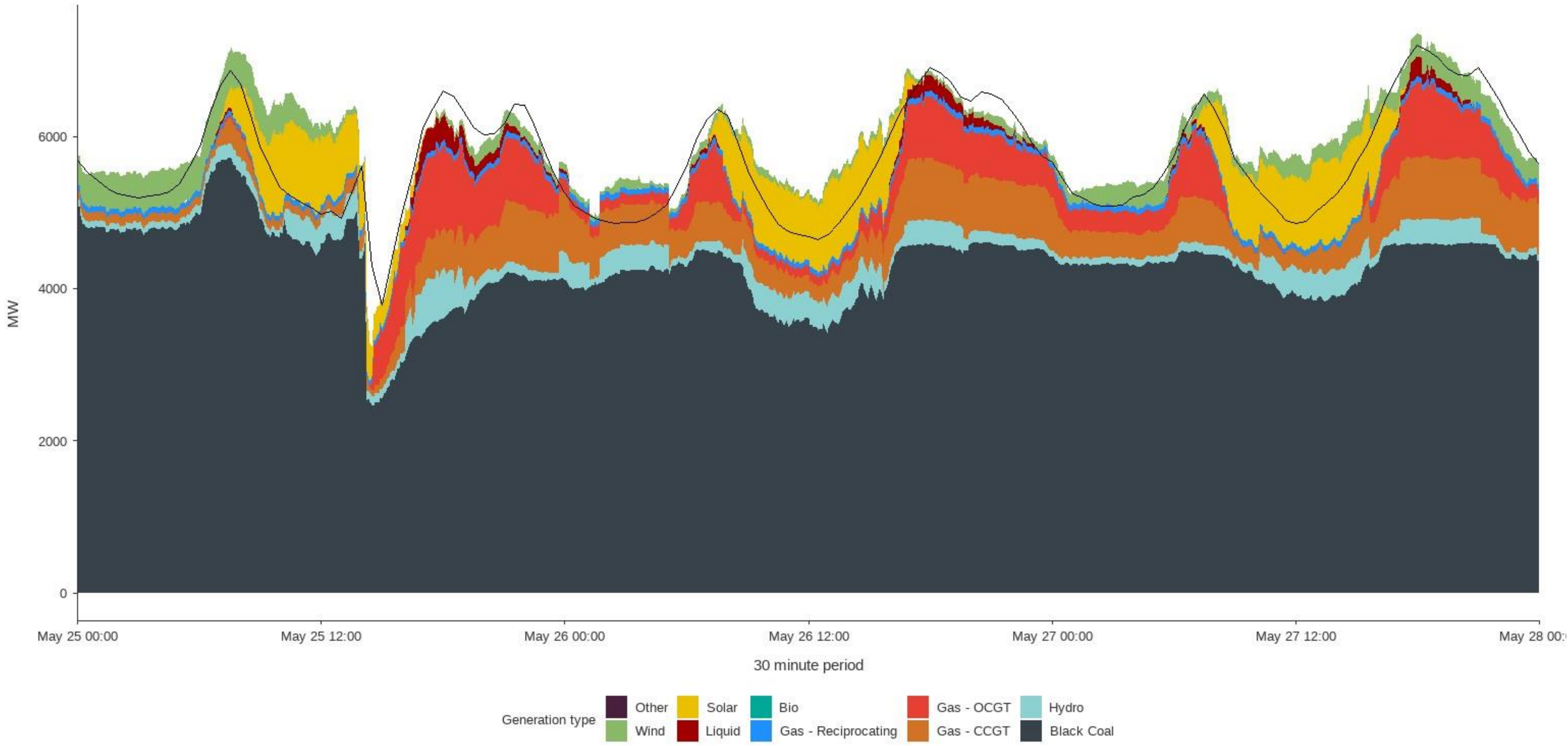
2.5.2 Case study 2 – GPG's firm capacity responding to Callide C outage

The second case study provides an example of the way that GPG provides flexibility to manage unexpected outages of other dispatchable capacity.

Figure 13 provides half-hourly data for total generation and demand in Queensland for a 3-day period from the beginning of May 25 2021 to the end of May 27 2021. There was an unexpected outage of Callide C power station in Queensland on May 25, following an explosion at the power station. There are a number of key findings that can be drawn from **Figure 13**:

- This explosion at Callide C power station led to the outage of the power station, shown by the rapid drop off of black coal generation in Queensland.
- As a result of the rapid reduction in black coal generation, a significant amount of load was shed (i.e. intentional blackouts were triggered) and Queensland stopped exporting excess electricity and began importing electricity.
- Following the rapid reduction in black coal generation, fast-starting OCGT gas generators were first to respond by increasing output. This was followed by increases in generation from CCGT, hydro and other coal-fired plant.
- As a result of the continued outage of Callide C power station, GPG continued to operate for the following days, weeks and months, particularly overnight when solar generation was unavailable.

Figure 13: Case study: Callide C outage



Source: Frontier Economics

2.5.3 Case Study 3 – Coal retirements

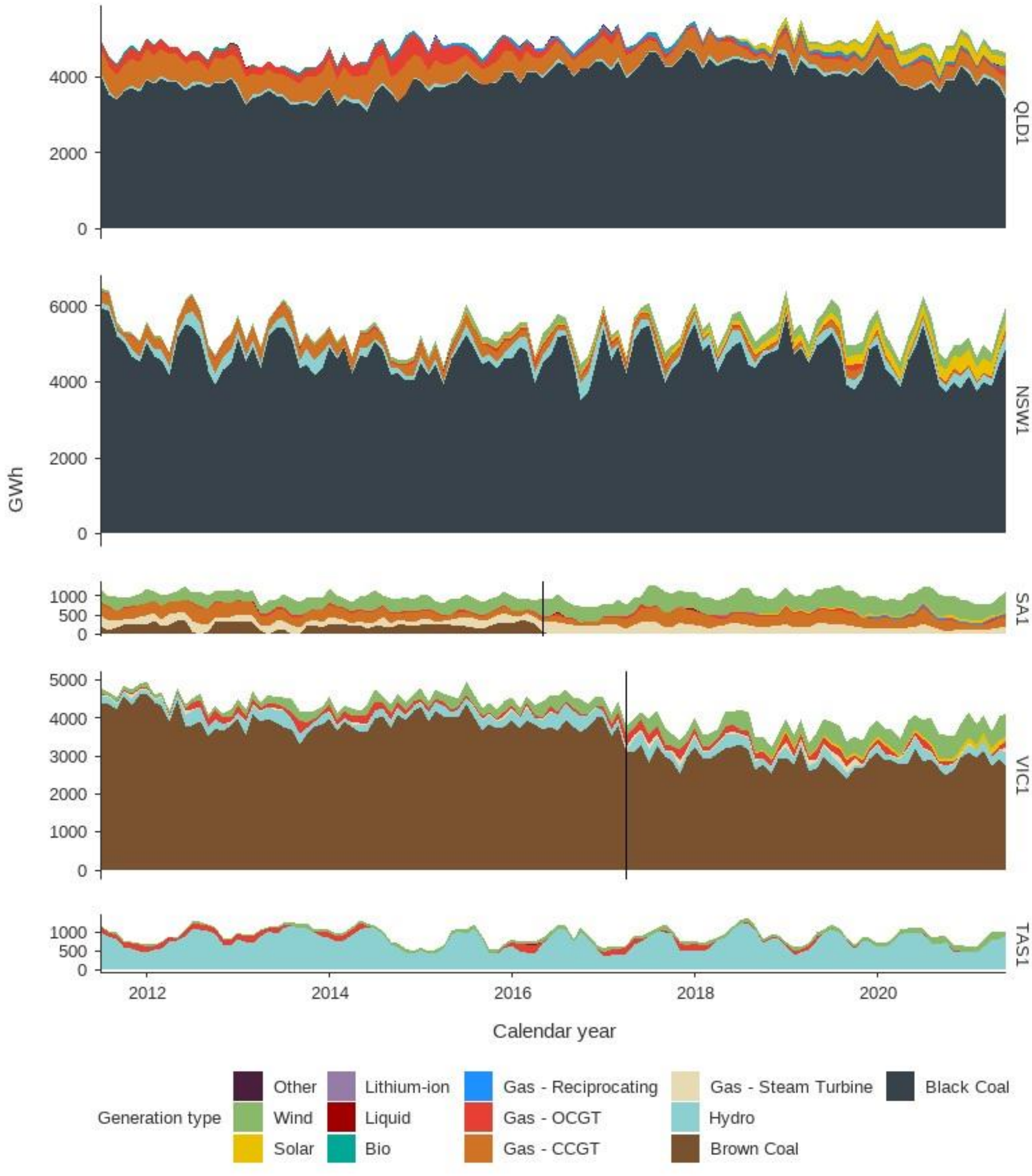
Figure 14 illustrates the effect on output in the NEM following the retirement of Northern Power Station in South Australia and Hazelwood Power Station in Victoria. The figure shows monthly output by fuel type and region in GWh. The vertical lines show the retirement dates of Northern Power Station (SA1 facet) and Hazelwood Power Station (VIC1 facet).

We show the effect of these closures on each region in the NEM because electricity is shared between regions via interconnectors. Changes in circumstances in one region typically also affect other regions, albeit to a lesser degree.

Northern Power Station was the last remaining coal fired power station in South Australia and closed in mid 2016. With a nameplate capacity of 520 MW, it provided around 22% of South Australia's capacity and 24% of South Australia's generation in 2015. As evident in the figure, Northern output was replaced with GPG in the form of steam turbines (Torrens Island) and CCGT, and over time, with increasing investment in renewable generation, mostly in the form of wind.

Hazelwood was one of four major brown coal fired power stations in Victoria at the time of its closure in early 2017. With a nameplate capacity of 1,600 MW, Hazelwood represented approximately 19% of Victoria's capacity and around 22% of Victoria's generation in 2016. Hazelwood's output was replaced by increased imports and reduced exports from Victoria in the following years. The impact on generation was an increase in gas output in South Australia, an increase in black-coal output from Queensland, increases in local gas generation, and more generally increasing investment in intermittent renewables over time.

Figure 14: Case study: Brown coal retirement in SA and VIC



Source: Frontier Economics

3 Assessment of GPG forecasts under AEMO's ISP

Box 3: Key takeaways

- Forecasting electricity consumption and output is challenging – AEMO's forecasts from a decade ago were not a good predictor of outcomes to 2021, and AEMO's current forecasts show a very different outlook.
- AEMO is forecasting a future in which we increasingly rely on intermittent generation to provide bulk energy and meet maximum demand.
- AEMO is forecasting a drop of gas output from around 9% of total output in 2020 to around 1% in 2030. But AEMO has significantly under forecast gas consumption for GPG in recent years.
- AEMO's explanation of forecast errors relates to 'unforeseen' events such as the closure of Hazelwood Power Station and a number of power station outage events. Unforeseen events that result in the need for greater GPG output are likely to remain a feature of the NEM. Indeed, it may be the case that the effect of unforeseen events increases:
  - This could be a result of increased reliance on intermittent renewable generation.
  - This could be due to increase outage rates. The forced outage rate, a measure of how often unforeseen outages occur, is trending up in coal-fired power stations, and at recent historical highs in Victoria and NSW.

  In our view, this suggests that the pattern of AEMO under-forecasting GPG output is likely to continue with the 2020 ISP forecasts. In other words, the actual need for GPG is likely to be greater than forecast in AEMO's 2020 ISP. Indeed, in its Gas Statement of Opportunities, AEMO forecasts that GPG output during the 2020s will be significantly higher (around 3 times higher) than it forecasts in the 2020 ISP, for reasons that are not made clear.

AEMO's ISP, and before that AEMO's NTNDP, have long forecasted GPG investment and dispatch in the NEM. AEMO has generally been forecasting declines in the requirement for dispatch from GPG.

The intention of this section is to test the extent to which AEMO's ISP forecasting properly captures the changing role of GPG in the NEM. This section begins by reviewing the accuracy of AEMO's historical forecasting of GPG before considering the implications of AEMO's most recent forecasts of GPG in the NEM.

3.1 AEMO's historical forecasting of GPG

The electricity market over the last decade has been characterised by rapid changes in technology and significant changes in key policies, both of which pose significant challenges in forecasting long-term outcomes. An indication of this is provided by comparing AEMO's forecasts for outcomes over the period 2011 to 2021 with actual outcomes over this period.

3.1.1 The challenges of long-term forecasting

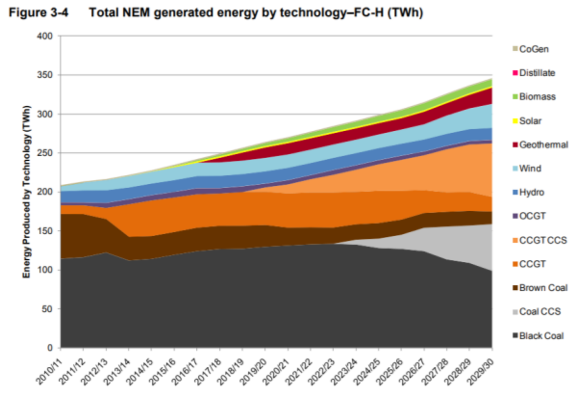
Figure 15 shows the forecasts that AEMO produced in 2010 of output in the NEM over the period from 2010/11 to 2029/30. The scenario on the left is the high carbon price scenario, and the scenario on the right is the base case carbon price scenario.

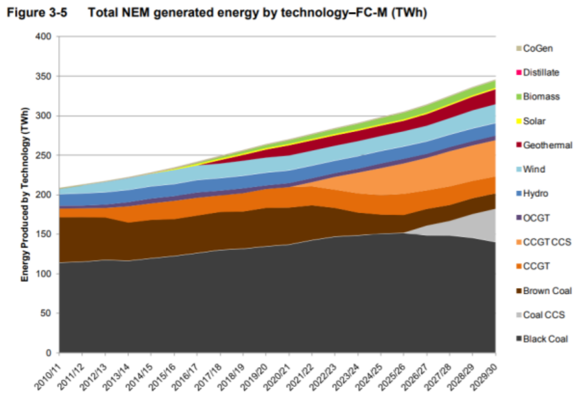
Figure 16, for comparison, shows the actual output in the NEM over the period 2010 to 2020, and the latest forecasts from AEMO for output in the NEM over the period from 2021 to 2029.

It is clear from this comparison between expected outcomes and actual outcomes (and the comparison between forecasts from 2010 with current forecasts) that there can be substantial forecasting error in electricity markets. Comparing AEMO's 2010 forecasts of outcomes in 2020/21 with actual outcomes in 2020/21, forecasting errors includes the following:

- Demand is substantially lower than forecast. In 2010 AEMO was forecasting demand in the NEM in 2020/21 would be around 260 TWh, while actual demand in 2020/21 was around 190 TWh.
- Coal-fired generation is substantially lower than forecast. In 2010 AEMO was forecasting output from coal-fired generation in the NEM in 2020/21 would be around 150 TWh, while actual output from coal-fired generation in 2020/21 was around 125 TWh.
- Gas-fired generation is substantially lower than forecast. In 2010 AEMO was forecasting that output from GPG, including GPG with carbon capture and storage, would increase substantially and play a central role in meeting forecast growth in demand. In 2010 AEMO was forecasting that output from GPG in the NEM in 2020/21 would be around 50 TWh, while actual output from GPG in 2020/21 was around 10 TWh.
- Some generation technologies that were forecast to play a role in the NEM have not eventuated. For instance, in 2010 AEMO was forecasting that GPG with carbon capture and storage, geothermal and biomass would all play important roles in meeting demand by 2020/21, with that role forecast to continue to grow after 2020/21. In fact, investment in geothermal and GPG with carbon capture and storage has not occurred and is no longer forecast in the near-term, and significant increased investment in biomass has not occurred.
- Other generation technologies that were not forecast to play a substantial role in the NEM have in fact emerged to a much greater extent than expected. Specifically, both solar and wind generation are contributing far more to output in the NEM in 2020/21 than was forecast, and doing do despite the fact that actual output is far lower than forecast.

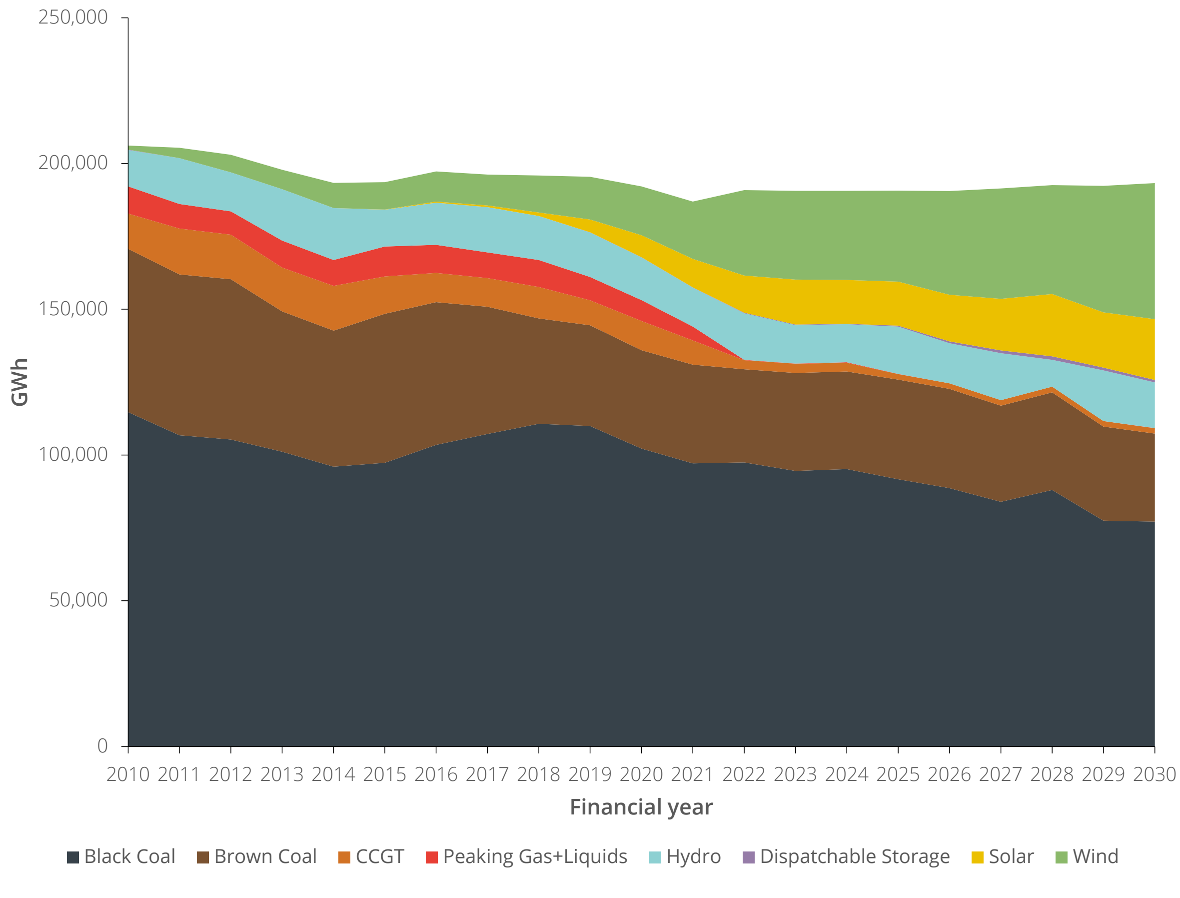
Figure 15: AEMO forecasts, NEFR 2010





Source: AEMO National Transmission Development Plan, 2010, p39

Figure 16: Historical and ISP forecast output for the same period



Source: Frontier Economics analysis of AEMO data

3.1.2 GPG forecasts from AEMO's latest ISP

Figure 17 and **Figure 18** illustrate historical and forecast levels of generation capacity and output in the NEM respectively. Values from 2022 onwards are taken from AEMO's most recent ISP (2020).

The key changes relating to capacity in **Figure 17** are an increase in investment in intermittent generation and dispatchable storage (pump hydro and batteries), and an ongoing decline in thermal generation, particularly coal-fired generation, with retirements of thermal generators that are not replaced with additional thermal generation.

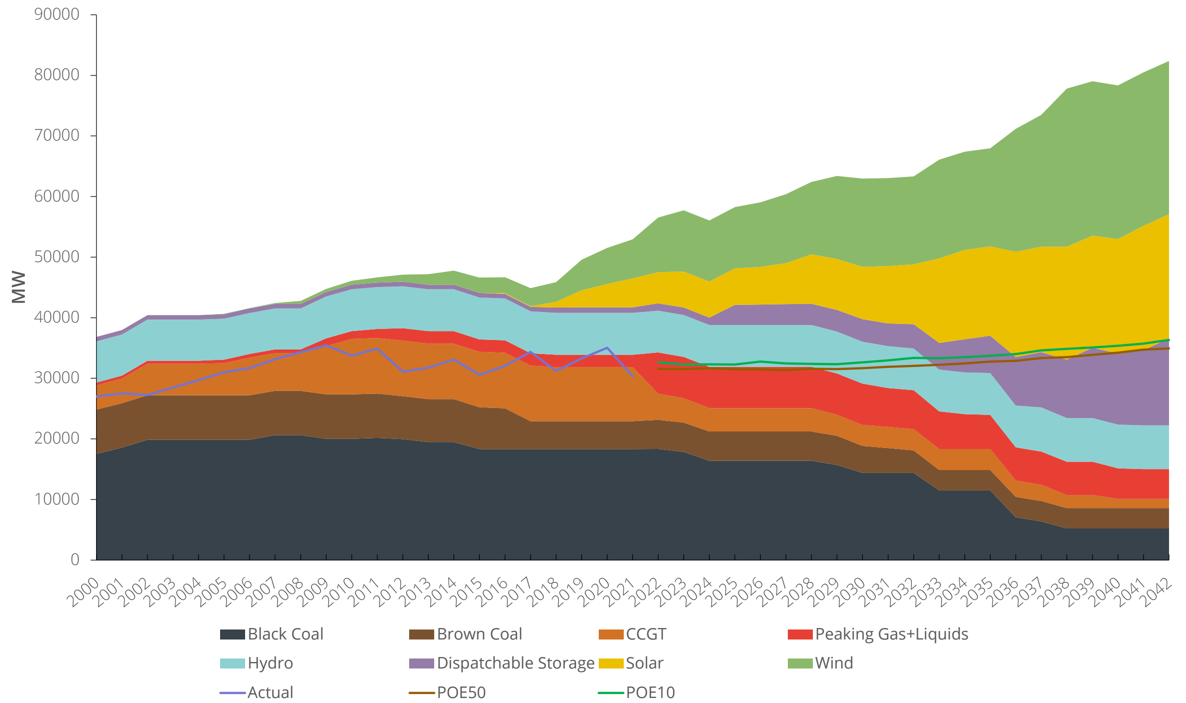
Figure 17 includes lines showing coincident maximum demand across regions in the NEM (i.e. maximum demand that happens at the same time in all NEM regions). Historical values of coincident maximum demand are denoted on the chart by the 'Actual' line. Also shown is AEMO's forecast of coincident maximum demand at two probability levels – a one in two year probability (POE50), and a one it ten year probability (POE10).

Up until the late 2020s, there is a significant 'buffer' of dispatchable capacity (coal, gas, hydro and dispatchable storage) above these actual and forecast coincident maximum demand lines. From the late 2020s onwards, AEMO is forecasting less of a buffer of dispatchable capacity as time goes on, meaning that we will be relying on output from intermittent renewable generation to meet maximum demand in some periods.

By the end of the modelling period (2042), AEMO is forecasting around half of the capacity in the NEM to be intermittent renewable capacity.

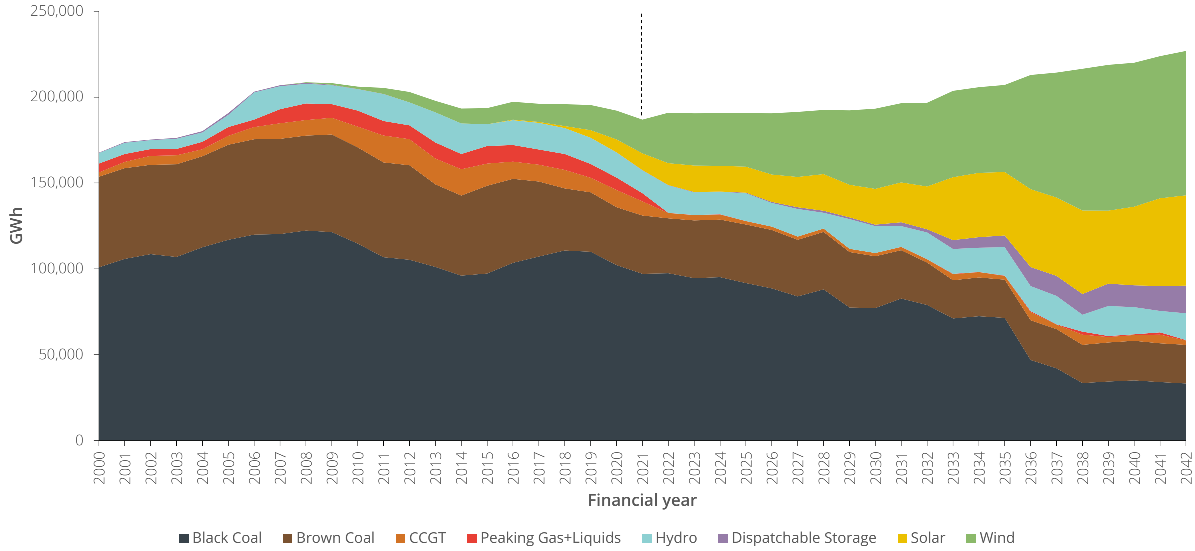
The key changes relating to output in **Figure 18** are an immediate forecast decline in GPG, steady declines in coal generation (and a rapid decline at the retirement of Bayswater 2036), and steady increases in intermittent output and dispatchable storage. By the end of the modelling period (2042), AEMO is forecasting that the majority of the energy output in the NEM will come from renewable sources. GPG is forecast to fall from supplying around 9% of generation in 2020 to around 1% of generation in 2030.

Figure 17: Historical and ISP forecast capacity



Source: Frontier Economics analysis of AEMO data

Figure 18: Historical and ISP forecast output



Source: Frontier Economics analysis of AEMO data

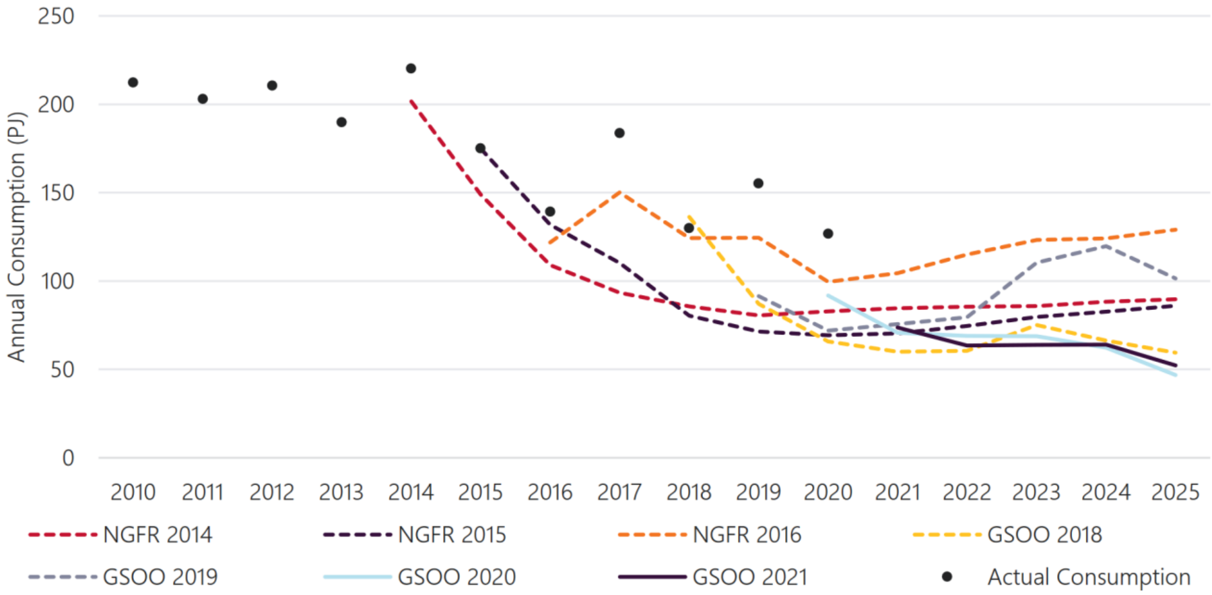
3.1.3 AEMO's track record forecasting gas consumption for GPG

Figure 19 illustrates AEMOs recent record of forecasting gas demand for GPG. AEMO has released gas forecasts for GPG in reports variously called the National Gas Forecasting Report (NGFR) and the Gas Statement of Opportunities (GSOO).

In **Figure 19**, the dots represent actual gas consumption for GPG, and each line represents a different forecast year from the NGFR or GSOO reports. From this figure, it is clear that AEMO has generally under-forecast gas consumption on a NEM-wide basis, as the forecast lines almost exclusively fall below the actual consumption lines.

A measure of AEMO's forecast accuracy is calculated in **Table 2**, as the percentage error of a forecast one year in the future. AEMO's forecasts have been significantly different from actual outcomes, particularly in more recent years (2019 and 2020).

Figure 19: AEMO forecasting record, NEM 2014-2021



Source: AEMO Gas Statement of Opportunities, 2021, p73, available https://aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2021/2021-gas-statement-of-opportunities.pdf?la=en

Table 2: AEMO forecasting record accuracy, one year in the future

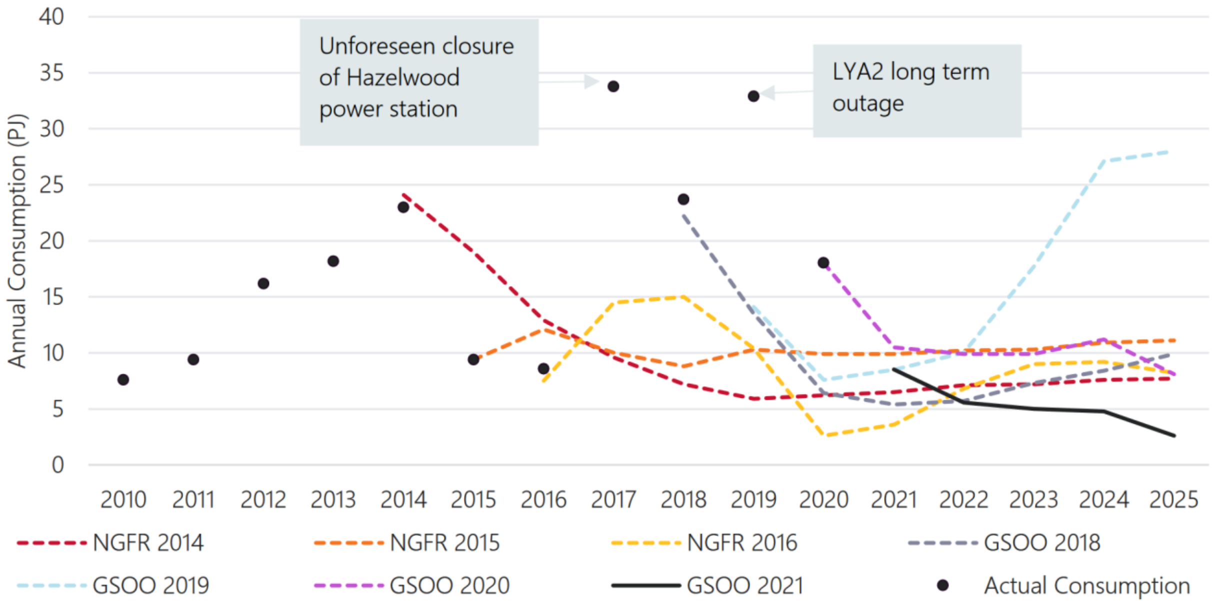
	2016	2017	2018	2019	2020
Year ahead forecast (PJ)	132	150	136	91	91.9
Actual consumption (PJ)	139	184	130	155	127
One year out forecast accuracy	-5%	-18%	5%	-41%	-27%

Source: AEMO forecasts, Frontier Economics analysis

AEMO investigates sources of GPG consumption forecasting error by region. **Figure 20** illustrates AEMO's reasons for forecasts deviating from actuals in Victoria.

- The 2017 Victorian deviation is attributed to the unforeseen closure of Hazelwood where actuals, resulting in actual gas consumption being about 3.5 times recent preceding year forecasts.
- The 2019 figure deviation relates to an outage of Unit 2 of Loy Yang A relating to an electrical short internal to the generator, which caused consequential damage to the stator and rotor components.

Figure 20: AEMO forecasting record, Victoria



Source: AEMO Gas Statement of Opportunities, 2021, p76, available https://aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2021/2021-gas-statement-of-opportunities.pdf?la=en

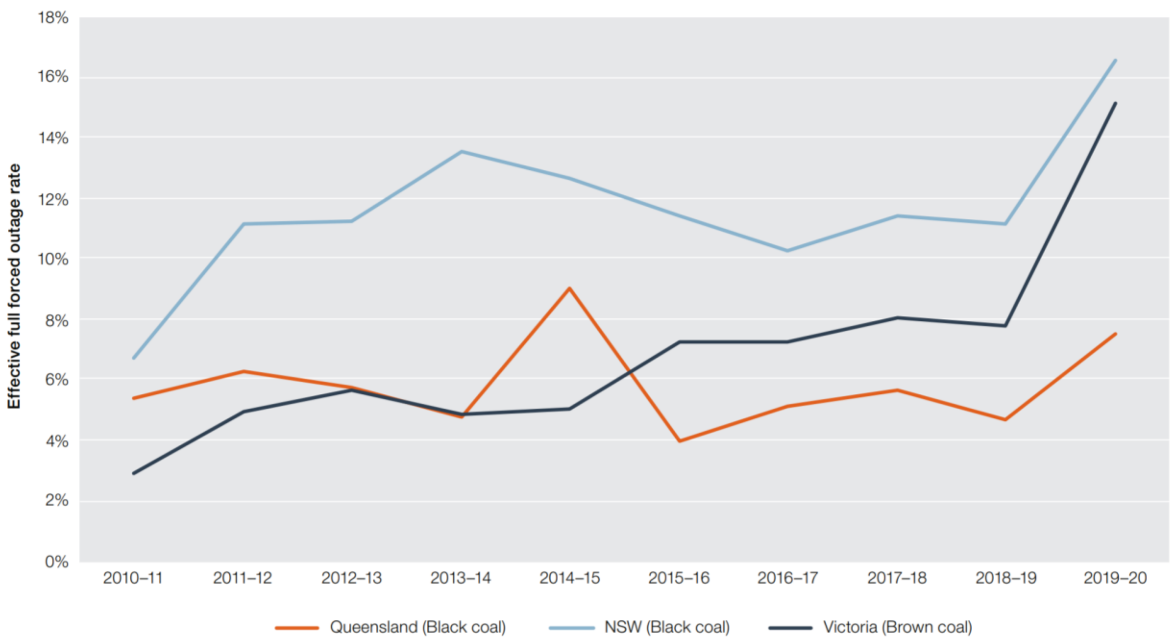
The extent to which AEMO accounts for potential future 'unforeseen' events with thermal generation when forecasting gas consumption by GPG is unclear. The forecasts of a sharp reduction in gas consumption by GPG presented in Section 3.1.2 suggests that AEMO does not do so. However, we consider that, with the aging thermal generation fleet and increasing penetration of intermittent generation, these factors are going to be an increasingly important driver of gas consumption by GPG and that it is going to be increasingly difficult for AEMO to account for these factors.

For instance, **Figure 21** illustrates forced outage rates for coal fleet in NEM. Forced outage rates refer to unforeseen outages that are unavoidable. We note that forced outage rates have generally increased over time in NSW and Victoria, and seen a marked increase in FY20 in all regions. There are three very recent examples of major outages:

- The long term outage of Unit 2 of Loy Yang A, as noted by AEMO
- The Callide C explosion in early 2021
- Flooding at Yallourn in 2021

As we saw in Section 2.5.2 in respect of the Callide C outage, these outages are a material driver of output by GPG.

Figure 21: Black and brown coal forced outage rates, NEM



Source: AER State of the Energy Market 2021, p26, available
https://www.aer.gov.au/system/files/State%20of%20the%20energy%20market%202021%20-%20Full%20report_1.pdf

3.2 In-depth analysis of ISP 2020 forecast

The ISP considers eight different "development paths" or future state of the transmission network in the NEM as well as a counterfactual state in which no further transmission investment is undertaken. The outputs of market modelling in each of these future states is used in a cost-benefit analysis to determine which state has the highest net benefits.

The development paths considered by AEMO are presented in **Figure 22**. Development paths 1-5 are the least cost future states that arise in specific scenarios (Central being what AEMO considers to be the most likely scenario). Development paths 6-8 test the option value of staging or accelerating VNI West and Marinus Link.

AEMO, in its cost-benefit analysis undertaken for the ISP 2020, find that DP6 is the least-costly of the development paths on two assessment approaches, including a scenario-weighted net benefit approach and a 'least regrets' approach. In the following analysis, we consider Development Path 1 (DP1) in detail, but our observations are applicable to all of the development paths. As illustrated in **Figure 22**, DP1 and DP6 reflect similar future network states.

Figure 22: Summary of AEMO development path transmission investment

Table 7 Candidate development paths, defined by timing of their common, major interconnection projects, based on least-cost development paths

<table>
<tr><th colspan="2">Development path</th><th>VNI Minor</th><th>Central-west Orana</th><th>Project Energy Connect</th><th>HumeLink</th><th>QNI medium and large</th><th>VNI West</th><th>Marinus Link Stage 1</th><th>Marinus Link Stage 2</th></tr>
<tr><td>1</td><td>Central least-cost</td><td rowspan="8">2022-23</td><td rowspan="8">2024-25</td><td rowspan="8">2024-25</td><td rowspan="8">2025-26</td><td>2032-33 and 2035-36</td><td>2035-36</td><td>2036-37</td><td>N/A</td></tr>
<tr><td>2</td><td>Slow low regret</td><td>N/A</td><td>N/A</td><td>N/A</td><td>N/A</td></tr>
<tr><td>3</td><td>Fast least-cost</td><td rowspan="6">2032-33 and 2035-36</td><td rowspan="2">2035-36</td><td>2031-32</td><td>N/A</td></tr>
<tr><td>4</td><td>Step least-cost</td><td>2028-29</td><td>2031-32</td></tr>
<tr><td>5</td><td>High DER least-cost</td><td>N/A</td><td>2031-32</td><td>2035-36</td></tr>
<tr><td>6</td><td>Central, early works ML</td><td>2035-36</td><td colspan="2">Variable†</td></tr>
<tr><td>7</td><td>Central, early works ML and VNI</td><td colspan="3">Variable†</td></tr>
<tr><td>8</td><td>Central, early works ML, accelerated VNI</td><td>2027-28</td><td colspan="2">Variable†</td></tr>
</table>

† Actual timing of these projects in each scenario under this candidate development path will be consistent with the least cost development timings listed in Table 6.

Source: ISP 2020, p66, available https://aemo.com.au/-/media/files/major-publications/isp/2020/final-2020-integrated-system-plan.pdf?la=en&hash=6BCC72F9535B8E5715216F8ECDB4451C

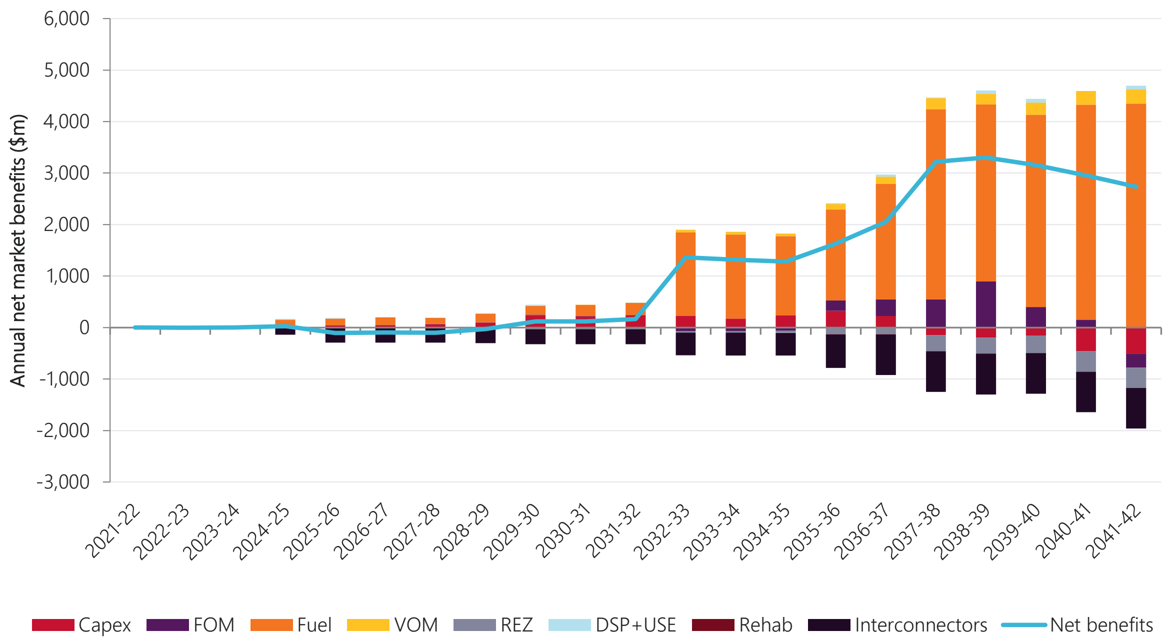
AEMO's cost-benefit analysis of these future states is based on the cost of network expansion, as well as market modelling that determines generation investment and generation output. The costs and benefits considered are the same as those considered in the Regulatory Investment Test for Transmission (RIT-T), and include, most importantly:

- Network capex and opex.
- Generation investment capex and opex.
- Generation fuel and variable operating and maintenance costs.

AEMO calculates a net-benefit value for each development path by comparing these costs in the relevant development path to the costs in the counterfactual case. If costs in the relevant development path are lower than in the counterfactual (on a net-present value basis), the development path is considered to be net-beneficial. A comparison of costs in DP1 and the counterfactual case is presented in **Figure 23**. In this figure, the positive bars refer to costs that are lower in DP1 than in the counterfactual case, and negative bars refer to costs that are higher in DP1.

Figure 23 illustrates that the cost-benefit analysis of DP1 (and similarly, the other development paths) is a relatively simple story: additional network investment is required (Interconnectors and REZ categories), but the cost of this investment is dwarfed by the fuel savings that arise from having these interconnectors in place. The Net benefits line, calculated as the sum of positive bars less the sum of negative bars, is highly positive from 2033 (around the time of significant coal retirement) to 2042.

Figure 23: Net market benefits, DP1 vs Counterfactual (positive values mean benefit to DP1)

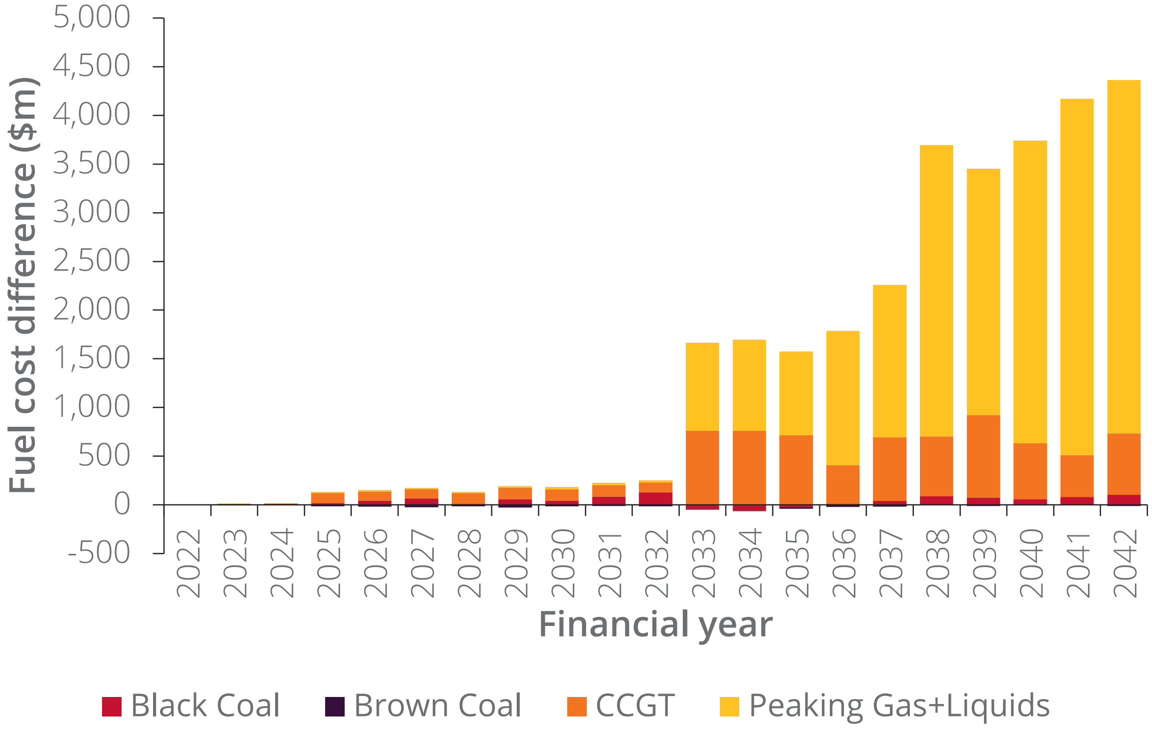


Source: ISP 2020 Generation Outlook, Central/DP1. To access, download this file and open the DP1 file in the Central folder: [*https://aemo.com.au/-/media/files/major-publications/isp/2020/final-2020-isp-generation-outlook.zip?la=en*](https://aemo.com.au/-/media/files/major-publications/isp/2020/final-2020-isp-generation-outlook.zip?la=en)

The fuel cost net benefits to DP1 illustrated in **Figure 23** are almost exclusively GPG-related, as illustrated in **Figure 24**, which shows a breakdown of the net fuel change bars by generator type. The majority of these changes relate to an increase in fuel cost relating to generators classed as Peaking Gas+Liquid generators, which are mostly gas powered (as opposed to liquid).

These costs are driven by a large amount of GPG output forecast in the Counterfactual case that does not appear in the DP1/Central case.

Figure 24: Breakdown of avoided fuel cost benefit into fuel sources



Source: Frontier Economics analysis of ISP 2020 Generation Outlook data

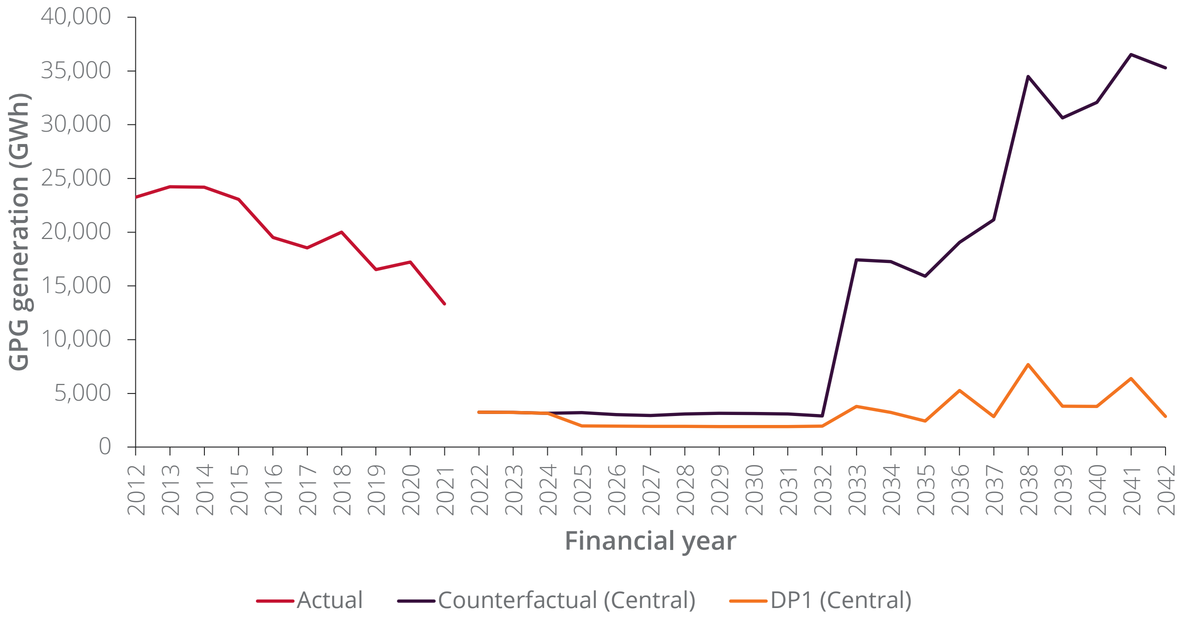
Figure 25 illustrates actual GPG output from 2012-2021 and ISP forecast output for the Counterfactual and DP1 cases from 2022-2042. This forecast has several salient features:

- Forecast gas output drops from an actual FY 2021 value of 13 TWh to around 3.3 TWh in both the Counterfactual and DP1 states of the world.
- In the DP1 scenario, forecast gas output decreases further from FY 2025 onwards. This reduction is mostly in South Australia, and is related to Energy Connect (a new interconnector between South Australia and New South Wales). AEMO assumes that with the new interconnector in place, gas will not be required to run in South Australia for system security reasons under normal operation conditions[3]. In the Counterfactual state of the world, gas is required to be operating at all times for system security reasons.

[3] For a detailed discussion, see ISP Appendix 7, A7.6, p47 available: https://aemo.com.au/-/media/files/major-publications/isp/2020/appendix--7.pdf?la=en

- From FY 2032 onwards, GPG output in the Counterfactual state of the world increases significantly and continues increasing. As illustrated in the cost breakdown in **Figure 24**, a significant portion of this generation is peaking gas generation rather than CCGT (mid-merit) gas. By 2040, peaking gas is producing more than double the output of CCGT (21.6GWh to 10.5GWh) and running at a capacity factor of 19%. Significant coal retirements begin occurring in FY 2023, which helps explain a requirement for additional gas, however a 19% capacity factor for peaking gas generation is unusual.
- Gas output in the DP1 state of the world continues in the range of 3-8 TWh to 2040, despite further coal retirements. Energy replacement from coal retirements largely comes from wind and solar PV generation, and is balanced by further investment in dispatchable storage.

Figure 25: Actual and forecast gas output, Counterfactual and DP1 (Central scenario)



Source: Frontier Economics analysis of ISP 2020 Generation Outlook

The 2020 ISP DP1 case relies on dispatchable storage and, in some cases, intermittent renewable generation, to meet demand, even if outages and other contingencies affecting dispatchable generation do not occur.

Figure 26 illustrates available capacity at times of NEM-wide peak demand for three forecast years: 2030, 2035, and 2040. The data behind this chart is derived from inputs used in ISP modelling as well as ISP outputs for the DP1/Central scenario[4].

The demand level shown is a 50% probability of exceedance (POE50) level, meaning a forecast 1-in-2 probability of this demand level occurring (i.e. this is the expected as opposed to extreme forecast). For each year, there are 9 'reference years' shown labelled 2011-2019. A reference year is a base year that AEMO uses to generate demand and renewable profile traces. AEMO's reasoning is that using one year may make the model 'overfit' based on specific outcomes in a particular year.

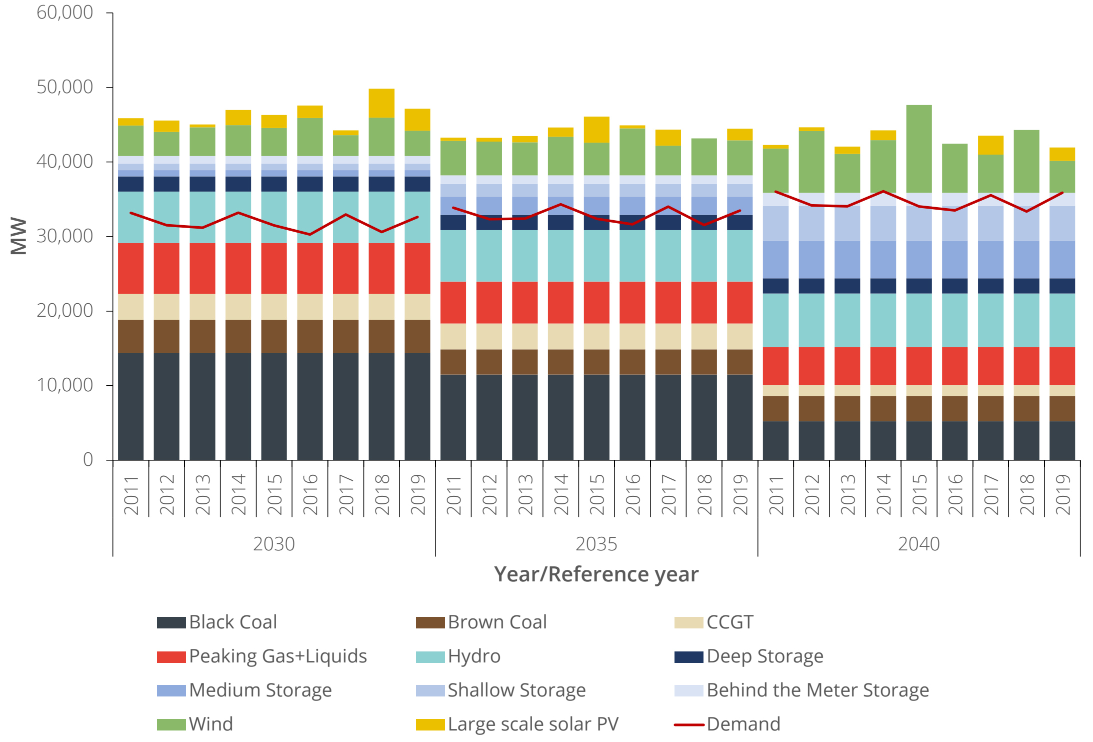
For each reference year within a forecast year, peak demand and renewable output differ based on the reference year used to generate the underlying traces. Non-renewable output is shown as nominal rated capacity, given that this generation is (by assumption) available to meet demand in high demand periods.

Figure 26 shows the peak demand level as a line against the available capacity in each reference year in each forecast year. In 2030, the POE50 peak demand line is comfortably below the amount of dispatchable capacity, all years falling within the hydro capacity band. In 2035, the POE50 peak demand level falls within the storage band, some years relying on deep storage (24 hours plus duration) and other years relying on medium storage (4 to 12 hours duration) to meet peak demand. By 2040, POE50 peak demand is being met by shallow (up to 2 hours duration) and behind-the-meter storage (i.e. batteries owned by households and businesses) and is on the verge of relying on intermittent generation (wind or solar).

Figure 27 is the same concept but considering POE10 demand, i.e. a 1-in-10 year demand forecast, which is AEMO's extreme demand forecast. Outcomes are similar to **Figure 26**, except that peak demand ends up relying on less reliable generation (short-term storage and intermittent renewables) earlier. By 2035, the modelled system is relying on shallow storage. By 2040, the modelled system is relying on intermittent renewable generation and behind-the-meter storage.

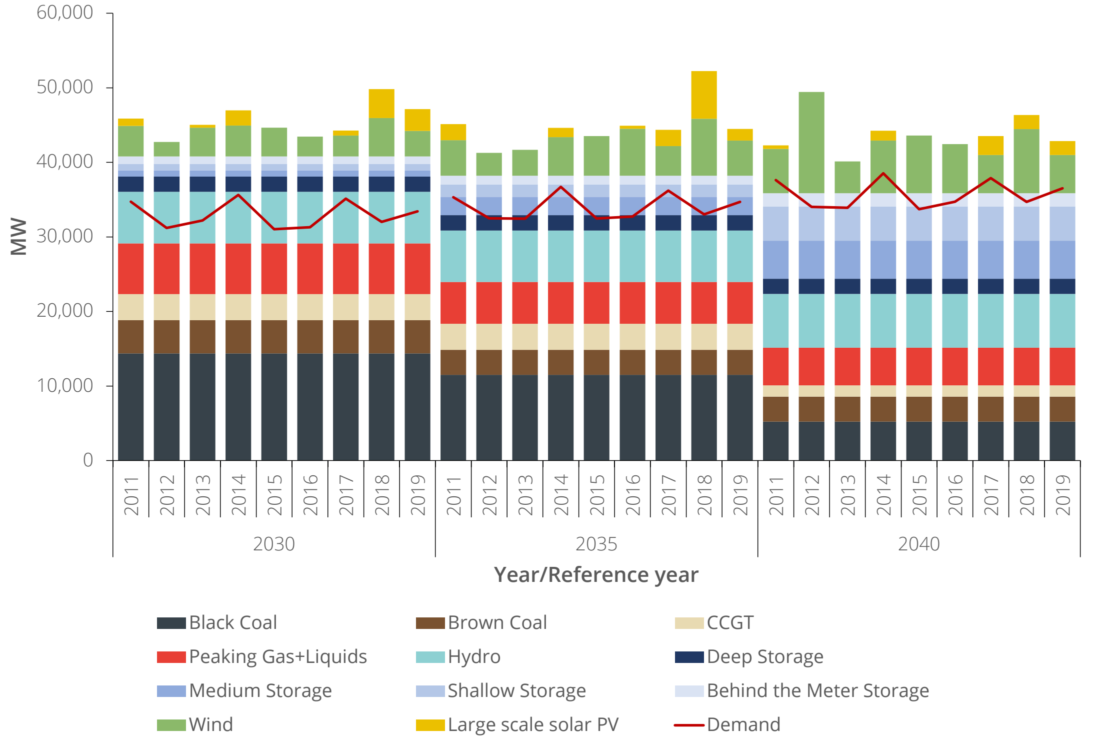
[4] Demand, solar and wind traces are available for download at the following link. Firm capacity values come from ISP 2020 Generation Outlook for DP1/Central. Data available here: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp/2019-isp-database

Figure 26: Coincident peak demand and available generation/storage capacity, POE50



Source: Frontier Economics analysis of ISP inputs and results

Figure 27: Coincident peak demand and available generation/storage capacity, POE10



Source: Frontier Economics analysis of ISP inputs and results

Our analysis of the ISP 2020 results has identified two important considerations.

First, the net benefits that justify the transmission system build-out are, in the majority, based on avoiding forecast output from GPG from 2033 onwards. This generation is mostly peaking generation that runs at higher-than-conventional capacity factors (producing, on average, 19% by 2040). With high forecast gas prices (relative to historical gas prices), this generation provides a large benefit in avoided cost in AEMO's development path states of the world.

Second, the ISP result represents a system which is near perfectly optimised to input assumptions in a persistent 'system normal' world. This is evident in two of the elements reviewed:

- GPG output immediately drops from 13 TWh to around 3 TWh in the first forecast year, with no major changes in supply or demand conditions from the last historical year to the first forecast year.
- The model invests in the bare minimum generation infrastructure to meet demand. This is a result of the model having foresight over what supply and demand conditions are coming in the future, including longer-term elements like generation retirement as well as shorter-term phenomena such as whether it will be windy tomorrow.

3.3 AEMO's GSOO and the ISP

There is overlap in the GSOO and the ISP with regard to the amount of fuel consumed for GPG. Both publications provide a forecast of gas consumed by GPG, although this is not the focus for the ISP.

While the GSOO and the ISP are typically published at different times of the year, AEMO tries to maintain consistency between modelling exercises. In the most recent GSOO, AEMO notes its adherence to the 2020 ISP: "*The 2021 GSOO assumed electricity interconnector development in line with the 2020 ISP, with similar projections for the development of generation capacity.*"[5]

However, despite using a similar development path for 'Central' cases, outcomes in the GSOO with regard to GPG imply significantly higher gas generation than the ISP. This is illustrated in **Figure 28**, which provides gas consumption for GPG in PJ from 2005 to 2040. As in the ISP, gas consumption falls from actual levels for the 2020s and starts increasing in the 2030s (although the increase in the GSOO starts earlier, around 2028 as opposed to 2033 in the ISP).

The amount of electricity generated in the ISP (see **Figure 25**) is reported in GWh, but we can compare to the GSOO outcomes by converting electrical output to fuel consumed, and vice versa, using an efficiency adjustment called a heat rate, typically reported in GJ/MWh. Using 2020 values for reported gas consumption for GPG and electricity output from GPG, we find an average NEM-wide GPG heat rate of around 8.6 GJ/MWh.

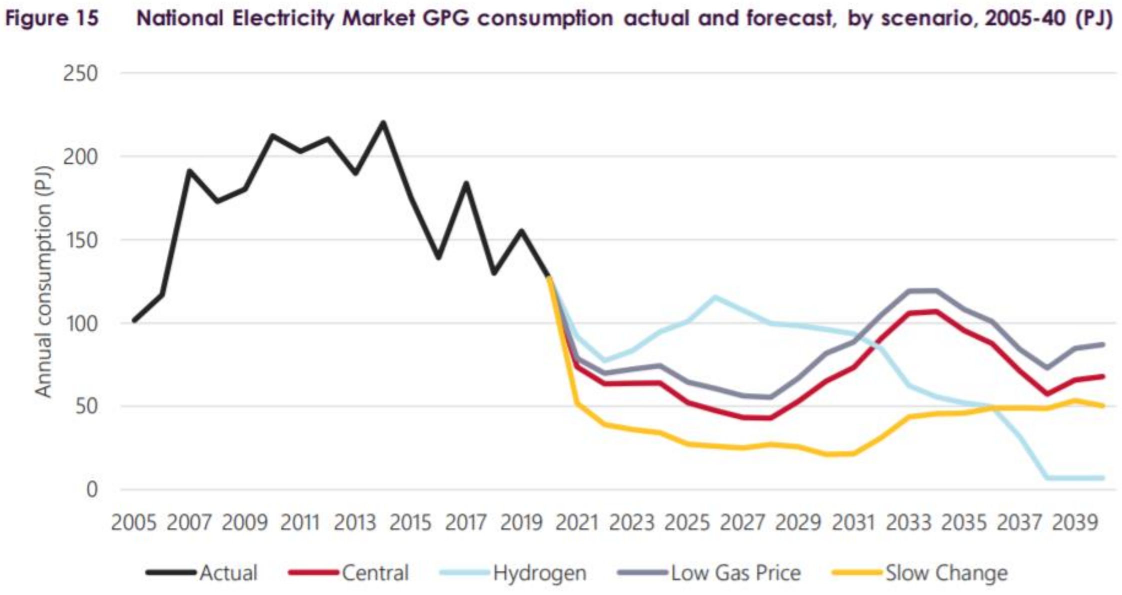
Applying this heat rate to the GPG gas consumption from the GSOO seen in **Figure 28** gives higher implied electrical output than the ISP is forecasting. For example, in 2027, the GSOO Central forecast is 43 PJ of gas consumption by GPG which is equivalent to around 5 TWh of

5 AEMO 2021 GSOO, p30. There is a footnote in the GSOO attached to this sentence, reading: "*Each scenario applies the actional ISP projects without decision rules, and the least-cost optimal pathway of the respective scenario longer term*". GSOO available: https://aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2021/2021-gas-statement-of-opportunities.pdf?la=en

electricity output by GPG. As in **Figure 25**, the ISP Central forecast for the same year is around 1.6 TWh of electricity output by GPG.

The source of the difference between these forecasts for GPG is unclear. The GSOO goes into detail about its GPG consumption forecast[6], including a discussion of generator bidding behaviour and different types of variability GPG generation faces. However, the reason for the differences between the ISP and the GSOO is not stated.

Figure 28: GSOO 2021 NEM GPG consumption and forecast



Source: AEMO 2021 GSOO, p32

6 AEMO GSOO, section 2.2.4 p30 , available https://aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2021/2021-gas-statement-of-opportunities.pdf?la=en

4 WESC

Box 4: Key takeaways

- Comparing costs of different generation and storage technologies using the levelized cost of electricity (LCOE) fails to account for the "when, where and how of power generation", as the IEA put it.
- In contrast, comparing the net costs of different generation and storage technologies using the Whole of Electricity System Cost (WESC) provides a much more complete picture of the costs and benefits to the electricity system.
- It is a mistake to think that investing in generation or storage technologies with the lowest LCOE will necessarily result in a lowest electricity system costs. The broader system benefits delivered by investing in generation or storage technologies with higher LCOE may deliver lower electricity system costs.
- This is precisely the result our modelling delivers for the NEM over the period 2025 to 2034 – even though CCGT has a higher LCOE than solar PV and wind, our modelling finds that the broader system benefits delivered by the flexibility and dispatchability of CCGT mean that whole of electricity system costs are lower with investment in CCGT than with investment solar PV, wind, batteries or pumped hydro. Where there is no carbon price, or a low carbon price, our modelling finds that CCGT has the most favourable WESC. Where there is a higher carbon price, our modelling finds that the WESC of CCGT and wind are very similar (with wind slightly more favourable) and are more favourable than the technologies.
- The key reason that the WESC for CCGT compares very favourably to other technologies is that CCGT is firm and dispatchable, both characteristics that are valuable, and becoming more valuable, in the NEM. For instance, the fact that investment in CCGT contributes to meeting peak demand means that other investment costs can be avoided, where this is much less true for renewable generation options.
- Similarly, the fact that CCGT can be dispatched when needed means that CCGT can benefit the system by avoiding the need to rely on expensive peaking plant or demand-side response. While this benefit is relatively small at the beginning of our modelling period, this benefit increases throughout the modelling period to 2035.
- As the value of firm dispatchable generation to the NEM increases beyond 2035, we would expect that the relative benefits offered by CCGT would increase further.

This section discusses the Whole of Electricity System Cost (WESC) as an approach for comparing the impact of different generation and storage technologies on an electricity system. We discuss how WESC compares with the Levelised Cost of Energy (LCOE), which has been the most common approach for comparing generation and storage costs, but suffers from significant shortcomings. We then describe our approach to estimating WESC, and present our estimates of WESC for a number of technologies including CCGT. These estimates are based on our modelling of outcomes in the electricity market over the 10 years from 2025.

4.1 Why calculate a WESC?

The costs of different generation and storage technologies have traditionally been compared using a measure known as the levelized cost of electricity (LCOE). However, it is clear that LCOE does not account for all of the costs and benefits to the electricity system of generation and storage technologies. This has led to increasing interest in alternative measures of the relative impact of investment in different generation and storage technologies.

The LCOE seeks to measure the direct costs of investment and operation of a specific generation or storage technology. It does this by:

- Starting with the amortised capital cost
- Adding fixed operational and maintenance costs (FOM)
- Adding variable operational and maintenance costs (VOM)
- Adding fuel costs
- Adding a carbon price, if relevant
- Dividing the total costs by the total electricity produced.

The resulting LCOE is expressed in $/MWh and is generally represented as a curve, indicating how the calculated LCOE varies with the assumed capacity factor. As the assumed capacity factor increases, the LCOE falls because fixed costs are recovered across a larger amount of electricity produced.

The LCOE is often used to determine the cost at which a generation or storage technology provides a given amount of electricity. However, the LCOE does not have any regard to the timing of the generation of electricity, or the technology it would displace if investment were to occur. The benefit or cost to the system may vary greatly from the LCOE, depending on the ability of that technology to lower the system cost. This is because the "LCOE is blind to the when, where and how of power generation".[7] The electricity produced by a technology which can only produce during off-peak periods is of lower value to the system than the electricity produced by a technology that can reliably generate during peak periods. The technology which can only produce during off-peak periods may actually increase costs elsewhere in the system, which the LCOE does not account for.

The Whole of Electricity System Cost (WESC) seeks to address these shortcomings of the LCOE by accounting for the impact that different generation and storage technologies have on the electricity system, and calculating the costs and benefits of these impacts. In doing so, it seeks to provide an alternative, more comprehensive, way of assessing the relative merits of investment in different generation and storage technologies.

4.2 Modelling approach

The calculation of a WESC is essentially an incremental cost-benefit analysis, where the costs of investing in an incremental amount of a technology are weighed up against the benefits it may provide to the electricity system.

[7] IEA (2014) The Power of Transformation. Wind, Sun and the Economics of Flexible Power Systems, Paris, France.

This makes the WESC more complicated to calculate than an LCOE; while the calculation of LCOE simply requires estimates of the direct costs of investment and operation of a specific generation or storage technology, and can be calculated without reference to outcomes in the electricity market, the calculation of WESC requires an assessment of the impact of investment in, and operation of, a specific generation or storage technology on investment and dispatch more broadly in the electricity market. For this reason, calculation of the WESC requires modelling of electricity market outcomes. This also means that estimates of WESC are dependent on assumptions about electricity market conditions over the modelling period, and that estimates of WESC will vary as electricity market conditions vary.

Furthermore, the calculation of WESC requires modelling of electricity market outcomes under both of Base Case and an Investment Case – the impact of investment in, and operation of, a specific technology can then be assessed by comparing investment and dispatch outcomes from the Investment Case with those in the Base Case.

4.2.1 Electricity market models

We assess electricity market impacts of investment and operation of specific generation and storage technologies using our electricity market models: *WHIRLYGIG* and *SYNC*.

To determine the capacity and investment in the system over the modelling period, we use our in-house long-term investment model for electricity markets, *WHIRLYGIG*. *WHIRLYGIG* relies on a detailed representation of the electricity system and, based on this, optimises total generation cost in the electricity market, calculating the least cost mix of existing generation plant and new generation plant options to meet demand. The model incorporates policy or regulatory obligations facing the generation sector, such as a renewable energy target, and calculates the cost of meeting these obligations. *WHIRLYGIG* provides a forecast of the least cost investment path as well as forecasts of generation retirements for economic reasons (scheduled retirements are an input into the model).

We use *WHIRLYGIG* to provide the investment path for the Base Case, under certain assumptions. We draw on information published by the Australian Energy Market Operator (AEMO) as part of the development of the 2020 Integrated System Plan (ISP) for these Base Case assumptions. This includes demand, generator costs and operating parameters, interconnector capacities and national and state renewable energy targets. However, for rooftop PV uptake we use the Clean Energy Regulator's forecasts rather than forecasts from the AEMO. These forecasts have been closer to the historical uptake of rooftop PV. These assumptions determine the capacity mix in the Base Case over the modelling period.

We then model dispatch outcomes in the NEM using our electricity market dispatch model, *SYNC*. *SYNC* is an electricity market dispatch model that focuses on detailed short-term (half-hourly) fluctuations in demand, supply and system constraints. *SYNC* relies on a detailed representation of the electricity system and, based on this, determines market-clearing dispatch and pricing outcomes. *SYNC* makes use of investment and retirement outcomes modelled in *WHIRLYGIG* and uses a long-term forecast of bidding patterns. The model focuses on factors that affect short term price fluctuations and volatility in the wholesale market. These include half-hourly fluctuations in demand and intermittent wind and solar generation, ramping constraints as well as start-up costs of different technologies. *SYNC* provides a dispatch and wholesale price forecast at a half-hourly level.

4.2.2 Calculation of WESC

We calculate WESC for an investment in the NEM for each of the following generation and storage technologies:

- CCGT
- Solar PV
- Wind
- Lithium-ion battery with 4 hours of storage
- Pumped-storage hydro with 6 hours of storage

We calculated the WESC by assuming that an additional 100 MW of each technology is invested in each of the mainland regions of the NEM (New South Wales, Queensland, Victoria and South Australia), totalling 400 MW of investment, on top of the capacity existing in the Base Case. Including investment in each mainland NEM region means that the estimated WESC is an average across the NEM, rather than being specific to an investment in any individual NEM region. We choose a relatively small investment in additional capacity because we are interested in the marginal changes to the electricity system as a result of additional capacity.

The modelling period begins in 2025, which provides for the lead time for new investment in each technology (CCGT and pumped-storage hydro in particular will require a number of years). The modelling period ends in 2034, providing 10 years of data. All fixed costs are amortised, so that the economic lives of each generation and storage technology are appropriately accounted for.

Given that we are calculating a WESC for 5 technologies, we end up modelling a Base Case and 5 Investment Cases, with the inputs in each Investment Case differing from the inputs in the Base Case only as a result of the assumed addition of the relevant incremental generation or storage capacity.

The calculation of the WESC is made up of the following components:

- Capital cost and fixed operating and maintenance costs of the new investment
- Avoidable OCGT capital and fixed operating and maintenance costs
- Variable operating and maintenance cost
- Fuel cost
- Transmission costs
- Carbon costs, where relevant.

We calculated the WESC by determining all of the costs outlined above for the NEM as a whole under the Base Case and under each of the Investment Cases. We then calculate the difference in each of these costs between the Investment Cases and the Base Case for each year. For each technology this gives a series of costs and benefits from 2025 to 2034, which are then discounted back to 2021 to derive a net cost or benefit to the electricity system of building an additional 400 MW of that technology. Below we outline each of those costs in more detail.

Capital cost and FOM cost of the new investment

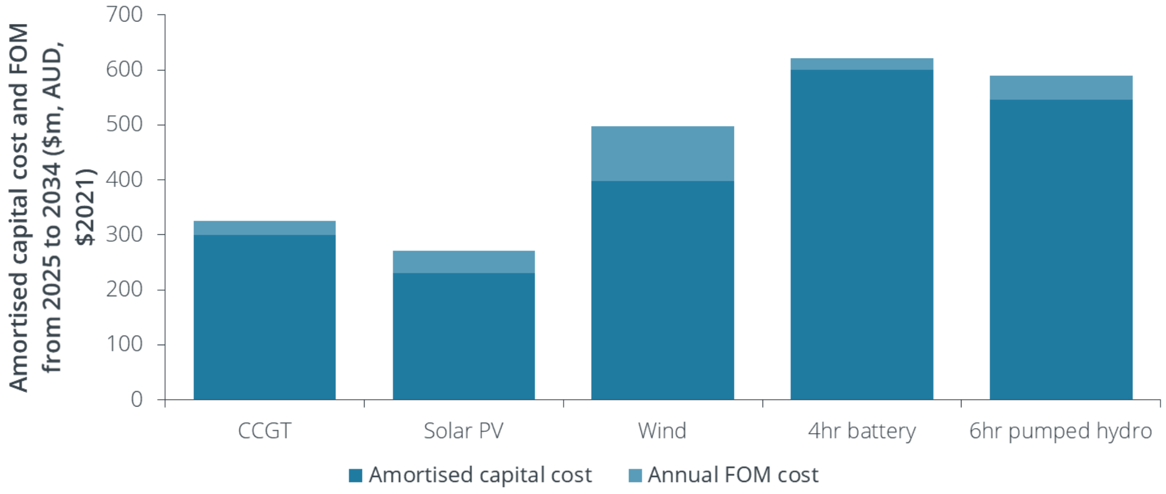
For each case, 100 MW of capacity of the specified technology was added to each of the mainland regions in the NEM, with this investment incurring capital costs. The capital costs, taken from

AEMO's ISP assumptions, of all the technologies were amortised over the relevant asset lives, and these are assumed to be incurred annually over the modelling period.

Additionally, each investment would require a fixed operating and maintenance cost to be incurred.

The assumed amortised capital cost over the period 2025 to 2034, for an investment made in 2025, along with the fixed operating and maintenance cost over this period, for each technology modelled, is shown in **Figure 29**.

Figure 29: Amortised capital and FOM cost for 400 MW of each technology, total from 2025 to 2034



Source: Frontier Economics' analysis of AEMO data

Avoided capital cost and FOM cost

With new investment in each of the technologies we consider, there is the potential for other investment to be avoided. Our investment modelling shows that over our modelling period there is investment in OCGT plant to ensure sufficient capacity in available in the NEM.

Based on this, it is assumed that investing in 400 MW of the technologies we consider will mean a certain capacity of open cycle gas turbine (OCGT) does not need to be built. Avoiding the capital cost and fixed operating and maintenance cost of the OCGT capacity is a benefit.

As OCGT generators are typically built to meet peak demand, the amount of avoided OCGT capacity will be equal to the amount of capacity the new investment can provide at times of peak demand. For 400 MW of CCGT, batteries and pumped-storage hydro, we have assumed that 400 MW of OCGT can be avoided being built, on the basis that each of these can operate at full capacity at times of peak demand. However, AEMO assumes that wind turbines typically contribute only 11 per cent of their capacity at peak demand times, and so for 400 MW of wind investment, only 44 MW of OCGT capacity would be avoided. Similarly, AEMO assumes that solar PV does not contribute any of its capacity at times of peak demand and so no OCGT capacity is avoided as a result of investment in solar PV.

Fuel costs and VOM

The variable costs for each technology type reflect differences in fuel costs and variable operating and maintenance costs.

For each of the Investment Cases, we run our half-hourly dispatch model, *SYNC*, from 2025 to 2034, to determine the dispatch costs under the Investment Case. These dispatch costs, which are made up of variable operating and maintenance costs and fuel costs, are subtracted from the Base Case to determine the fuel cost and VOM savings made under each scenario. These will be fuel cost and VOM savings since the added technology would only be dispatched by *SYNC* if it were to reduce the overall system costs.

To be clear, unlike the LCOE, the calculated differences in fuel costs and VOM are not simply the fuel costs and VOM of the additional 400 MW invested, but the change in the fuel costs and VOM across the entire market. So, in the CCGT Investment Case, when the new CCGT is operating there will be a fuel costs and VOM associated with that operation (which would also be accounted for under an LCOE) but there will be avoided fuel costs and VOM from other plant that are displaced by the new CCGT (which would not be accounted for under an LCOE).

Carbon cost

A cost of carbon can also form part of the variables costs for generation technologies. Currently there is no carbon pricing mechanism that applies to the NEM, so we have not included a carbon cost in our modelling of electricity dispatch. However, total carbon emissions in each of the Base Case and the Technology Cases are different, as a result of the slight difference in investment and dispatch. The cost of these differences in carbon emissions can be calculated by assigning a price to carbon emissions.

Reflecting this, our results are presented with three assumed carbon prices:

- With an assumed carbon price of zero throughout the modelling period.
- With an assumed carbon price throughout the modelling period that is equal to the average Australian Carbon Credit Unit (ACCU) price for FY2021
- With an assumed carbon price throughout the modelling period that is equal to the average European Union Emissions Trading System (EU ETS) price for FY2021 (converted to Australian dollars).

The cost of carbon or benefit of carbon abatement for each technology was determined by calculating the difference in carbon emissions between the Technology Case and the Base Case, and then multiplying the difference by the relevant carbon price. For technologies which would reduce emissions compared to the Base Case this would be a benefit, while any technologies which would increase carbon emissions this would be a cost.

Transmission costs

Depending on where the generation asset is located, transmission lines may need to be upgraded to allow transmission of the electricity the asset generates. As outlined in the ISP, transmission line capacity would only need to be increased if more generation is built in a Renewable Energy Zone than it can export. In the ISP, AEMO give limits on the capacity which can be built in a Renewable Energy Zone before augmentation of transmission lines is needed, and also the estimated cost of this augmentation to allow an additional MW of capacity to be built. This cost differs by region and renewable energy zone, reflecting the different costs to upgrading the transmission network across the NEM.

To calculate the cost of upgrading the transmission network, we took the average cost across all of the Renewable Energy Zones for each region and amortised that over 50 years, which is the AER's assumed asset life for transmission lines. This gave a cost which would be incurred if the additional generation was above the capacity limit for the zone in $/MW per annum for each region. We note that this is the average cost which would be incurred, and that if the additional generation capacity was not enough to require transmission augmentation then no cost would be incurred. In line with the ISP, we have assumed that only wind and solar PV will contribute to the limited capacity to be built in Renewable Energy Zones, so CCGT, batteries and pumped hydro will not incur any additional transmission costs.

Frequency control and ancillary services

AEMO uses ancillary services to manage the power system by maintaining key technical characteristics of the system, including standards for frequency, voltage, network loading and system restart processes.

AEMO operates eight separate markets for the delivery of Frequency Control Ancillary Services (FCAS) and recovers the costs of these services from customers and generators. The eight markets are split into two types, regulation and contingency. The cost of operating the contingency markets is recovered from all market participants in proportion to their consumed energy/generated energy. The cost of operating the regulation markets is recovered on a causer pays basis, so that generators or loads which are deemed to cause shifts in the frequency beyond what is allowed will incur the cost of rectifying the issue.

Historically, the regulation FCAS costs for the NEM have typically risen as more intermittent renewable generation has entered the system. AEMO publishes a portfolio's settlement factor monthly, which is multiplied by the total cost of regulation FCAS to get the amount a portfolio must pay. We analysed the settlement factors for renewable generation portfolios with a capacity close to 100 MW in each region to estimate the additional FCAS costs they impose on the system. We assumed that each firm technology (CCGT, batteries and pumped hydro) would not increase regulation FCAS costs, as they are typically able to provide system security. A typical settlement factor was estimated for wind and solar PV and was multiplied by the average annual cost of regulation FCAS for the last 5 years for each region. It was found that this cost was typically quite small, usually below 1 per cent of the capital cost of wind or solar PV. For this reason, we do not include it in the calculation of the WESC, however we note that it is unlikely to change results substantially as it would make up such a small portion of the cost stack for renewable generation.

Contingency FCAS costs were not evaluated in this analysis as they are not recovered on a causer pays basis, so there is no way to allocate costs to generators or portfolios. It is also less clear that adding more renewables or firm generation capacity would increase the costs of contingency FCAS.

Discount rate

A discount rate of 7 per cent was used in the modelling, as specified in the central estimate in the NSW Treasury guidelines[8]. All costs and benefits were discounted back to 2021, so even though the first modelling period is 2025 the costs and benefits incurred in this year are discounted back four years to 2021.

4.3 Results

We calculated the WESC for five different technologies, under three different carbon price assumptions. The five technologies examined were:

8 Accessible here: https://www.treasury.nsw.gov.au/sites/default/files/2017-03/TPP17-03%20NSW%20Government%20Guide%20to%20Cost-Benefit%20Analysis%20-%20pdf_0.pdf

- CCGT
- Solar PV
- Wind
- Lithium-ion battery with 4 hours of storage
- Pumped-storage hydro with 6 hours of storage

The results for each carbon price and technology are summarised below.

4.3.1 No carbon price

Figure 30 shows the net present value of the costs and benefits for the scenario without a carbon price, where benefits are above the x-axis and costs are below the x-axis.

The costs are made up of the capital cost and the fixed operating and maintenance costs of the technology being built, as well as any transmission costs.

The benefits include any avoided costs of OCGT investment, made up of the capital cost and fixed operating and maintenance costs. In addition, investment in the new technology may provide some fuel cost savings and/or variable operating and maintenance cost savings as a result of changes in dispatch. For the scenario without a carbon price, there is no benefit of carbon abatement. The dot on each bar in **Figure 30** is the total net cost or benefit for that technology – in other words, it is the WESC for each technology.

In the case with a carbon price of zero, an additional 400 MW of CCGT imposes the least cost on the NEM of the technologies modelled. That is, it has the most favourable WESC. The reasons are the following:

- CCGT has the second lowest capital cost and FOM of the technologies studied, with only solar PV having a lower capital cost and only batteries having a lower FOM. This was seen in **Figure 29**.
- The 400 MW of CCGT also enables investment in 400 MW of OCGT to be avoided, providing the highest avoided OCGT capital and FOM costs (equal to batteries and pumped-storage hydro).
- An additional 400 MW of CCGT typically displaces generation from OCGT and other peaking plant, as shown in **Figure 31**. This figure shows the NPV of the difference in dispatch between the technology scenario and the Base Case, using the same discount rate as used in the WESC analysis, being 7 per cent. A bar above the x-axis shows that technology being dispatched more than in the Base Case, whereas a bar below the x-axis shows that technology being dispatched less than in the Base Case.
- The fuel savings which occur under the CCGT case are due to the higher efficiency and lower fuel cost of CCGT plant compared to OCGT plant. These fuel costs savings are relatively modest, because CCGT does not operate a great deal and because there are fuel costs and VOM associated with operating CCGT (albeit lower costs than the displaced OCGT).

The avoided fuel cost benefits of investing in CCGT are less than the avoided fuel cost benefits from investing in other technologies. For instance:

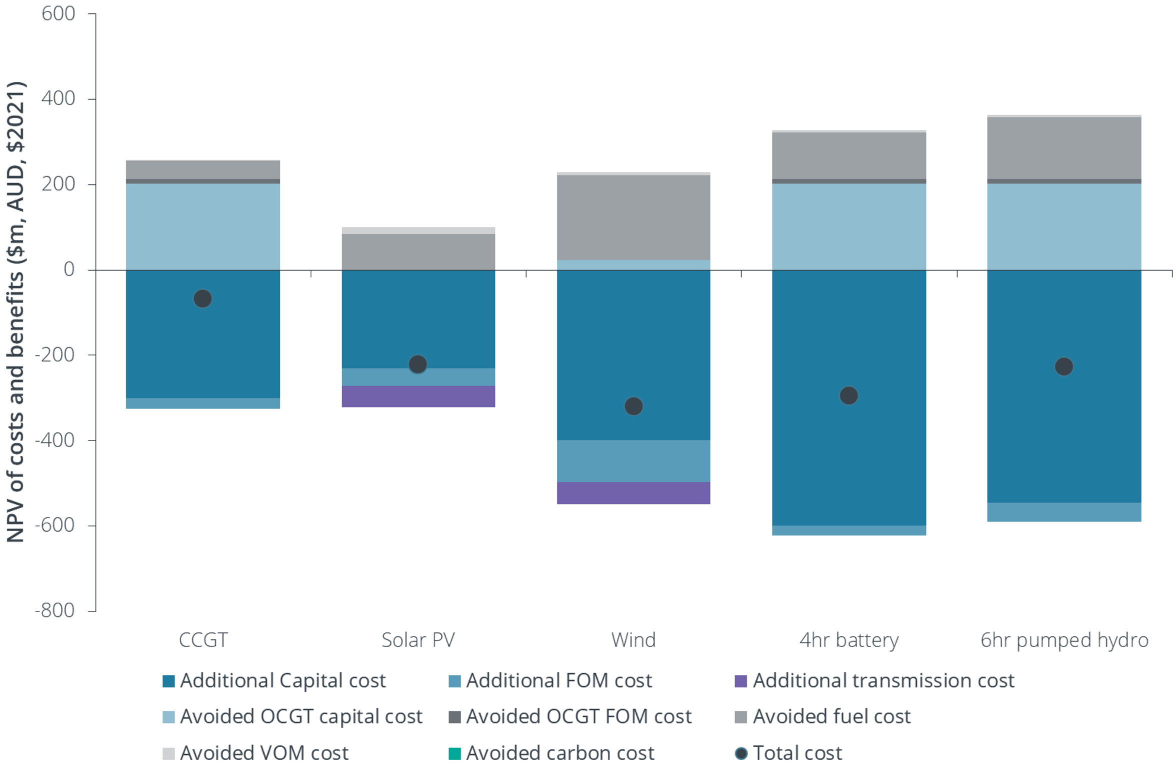
- Investment in 400 MW of solar PV results in a substantial reduction of coal output, as well as small amounts of hydro and a not insubstantial amount of wind.

- Investment in 400 MW of wind displaces a substantial amount of black and brown coal, with small amounts of hydro and CCGT. Wind is able to displace more plant which operates during high demand times than solar PV because wind is typically more correlated with demand than solar PV. Wind also has a higher capacity factor than solar PV, resulting in it being able to displace more generation overall.
- Investment in 400 MW of 4 hour batteries enables wind and solar PV to generate more and charge the batteries whereas would otherwise have been curtailed. This reduces the dispatch required from black coal most, followed by CCGT and then hydro and OCGT. In **Figure 31**, the lithium-ion bar below the x-axis means that batteries were charged more in total under the 4hr battery scenario than under the Base Case.
- It is a similar story for pumped hydro, where it enables renewables to generate more and displace black coal and gas. The 6 hour storage duration of pumped hydro allows more renewables to displace black coal and gas than the 4 hour batteries.

The low capital and FOM costs of CCGT, combined with the avoided OCGT capital and FOM costs and small fuel cost savings, mean 400 MW of CCGT imposes the least cost on the system compared to the other technologies. This is followed by solar PV, which is able to reduce VOM costs by displacing wind and coal, but is not able to avoid any of the OCGT capital and FOM costs, and may also incur additional transmission costs. Pumped-storage hydro with 6 hours of storage has substantial benefits, providing large avoided fuel cost benefits and avoided OCGT costs, but has a large capital cost, pushing it to a total higher cost than solar PV. Wind imposes the second most cost on the system of the technologies, as the substantial fuel cost savings and small avoided OCGT costs are not able to make up for the relatively high capital cost, FOM and possible additional transmission costs. Lastly, 4 hour batteries are the costliest of the technologies, having the highest capital cost while the benefits from the fuel cost savings and avoided OCGT capital and FOM costs do not outweigh the high capital costs.

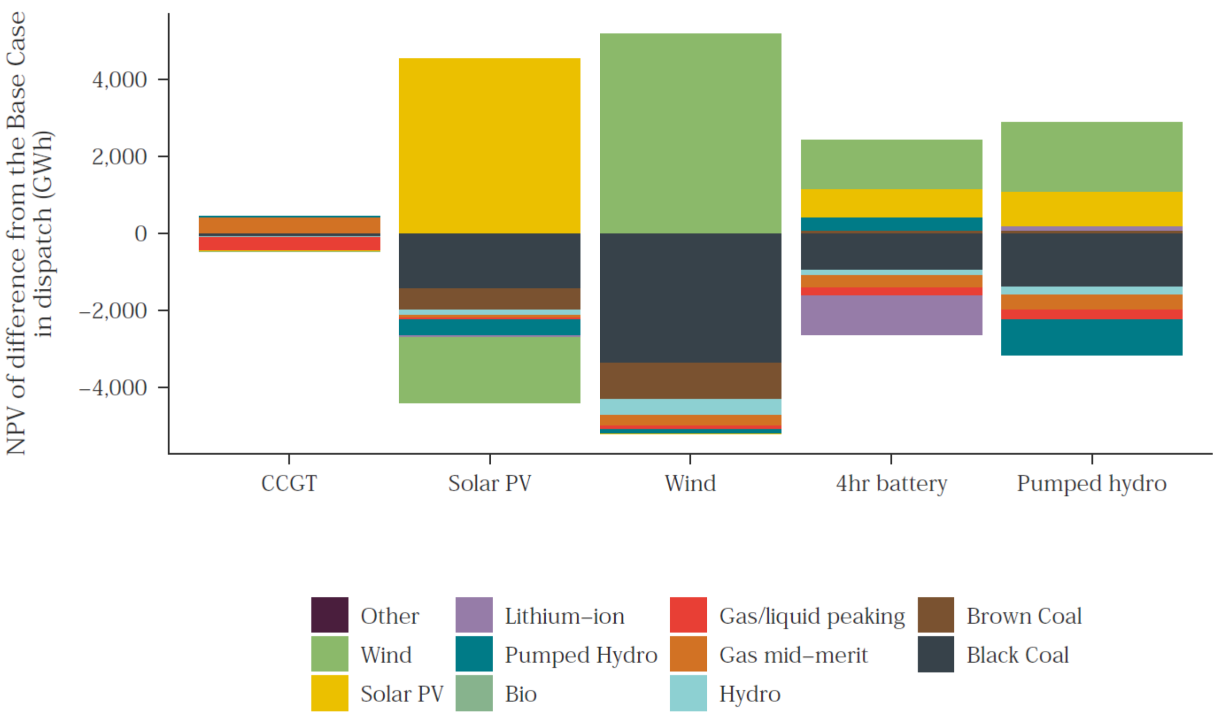
This result is unsurprising given the expected state of the NEM over the modelling period, where the QRET, VRET and the NSW Roadmap are all committing large amounts of renewable generation with little firm capacity. The additional 400 MW of wind and solar PV in the respective scenarios would compete with the capacity brought in through these schemes, suppressing their benefits. On the other hand, CCGT is able to provide what is likely to be needed in the future, which is firm capacity. Indeed, the relative benefit of the investment in CCGT increases over the modelling period to 2034. Although batteries and pumped hydro also provide firm capacity, their capital costs are high, but battery capital costs may fall rapidly in the future.

Figure 30: WESC results with no carbon price



Source: Frontier Economics' analysis

Figure 31: Dispatch results



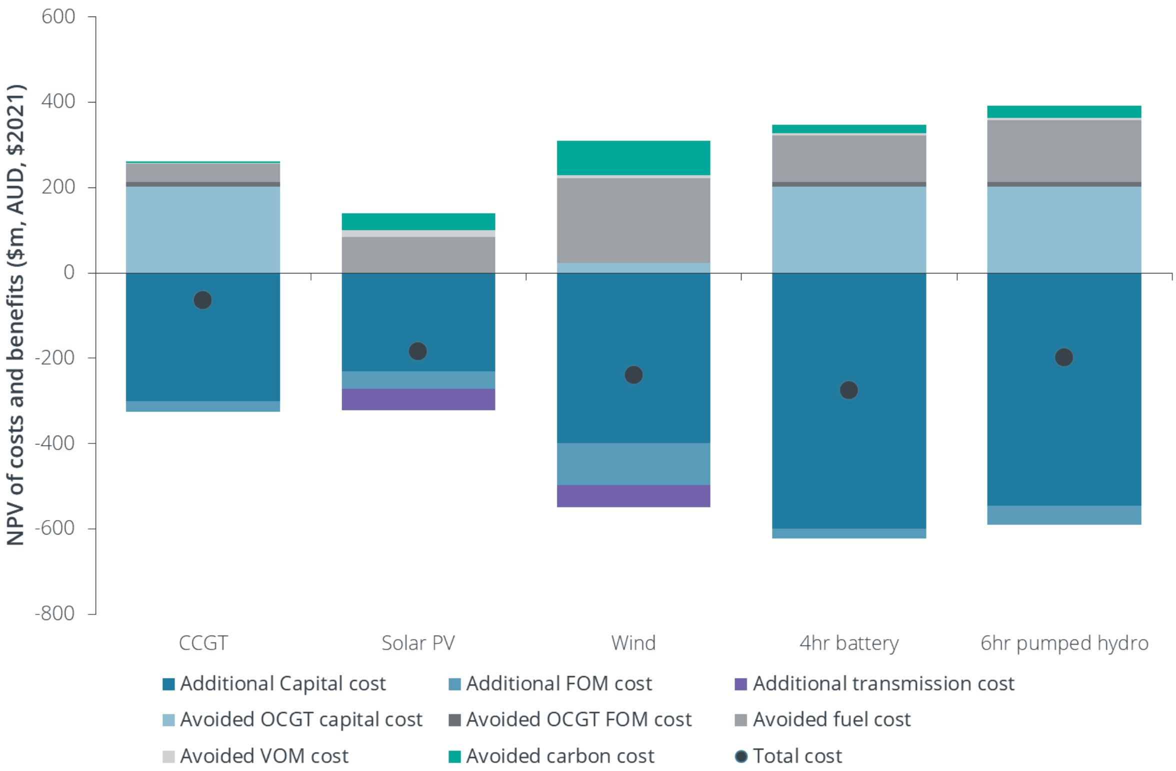
Source: Frontier Economics' analysis

4.3.2 ACCU carbon price

This scenario uses the average Australian Carbon Credit Unit FY2021 price of $17.17/tonne to value the benefit of carbon abatement. The only changes in the cost and benefit stack is the addition of the carbon abatement benefit, with all other items in the stack remaining the same from the no carbon price scenario. The carbon abatement benefit is calculated by taking the difference in carbon emissions between the Base Case and the Investment Case and multiplying it by the cost of carbon, which for this scenario is $17.17/tonne. This was done for each year from 2025 to 2034, and then discounted at 7 per cent. The results can be seen in **Figure 32**.

Wind receives the greatest benefit from carbon abatement as it displaces the most black and brown coal, resulting in the greatest emissions reduction. However, this benefit is not enough to make 400 MW of additional wind capacity net beneficial over the modelling period. Solar PV receives the second highest benefit from carbon abatement, about half as much as wind, as it displaces less black and brown coal. This benefit is not enough to move solar PV from being the second least costly technology with a $17.17/tonne carbon price. The 4 hour battery and 6 hour pumped hydro cases receive even less benefit from carbon abatement, with only a small amount of black coal, CCGT and OCGT displaced, and still have a large net cost. Finally, 400 MW of CCGT has the least benefit from carbon abatement, as the CCGT only displaces OCGT, resulting in only a very small benefit. However, with a $17.17/tonne carbon price, CCGT is still the least costly technology of those modelled.

Figure 32: WESC results with ACCU carbon price ($17.17/tonne, AUD)



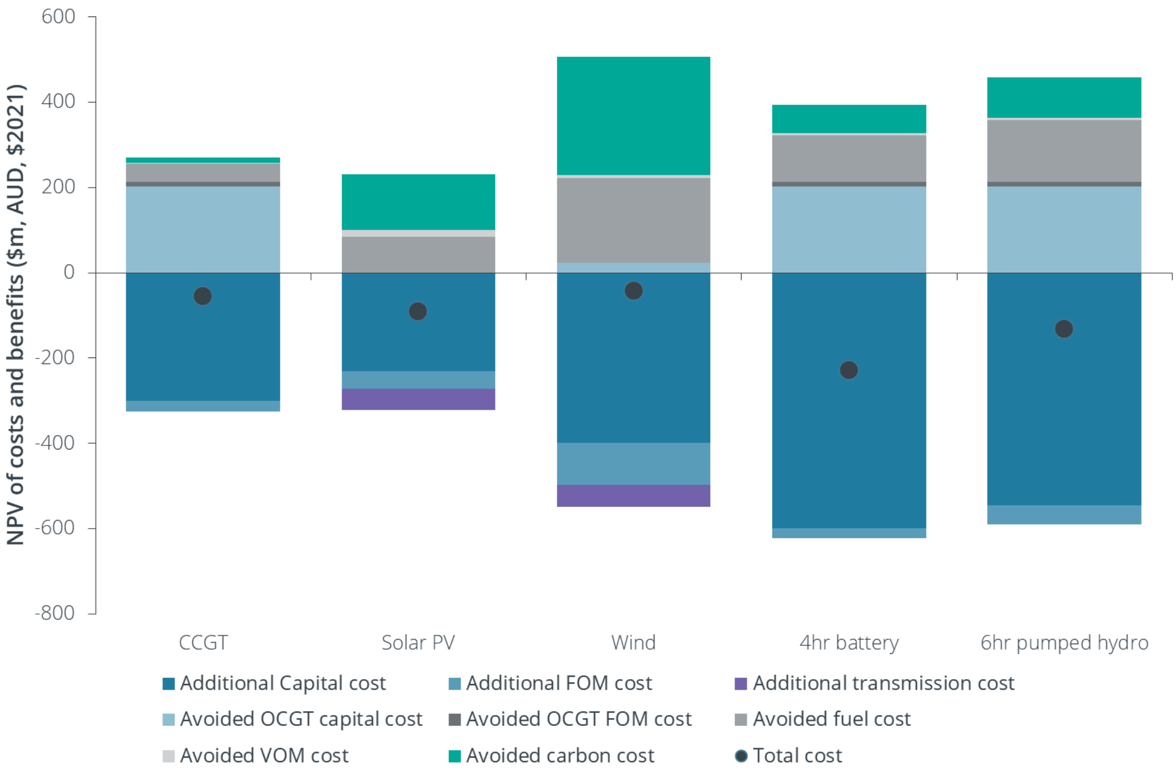
Source: Frontier Economics' analysis

4.3.3 EU ETS carbon price

This scenario uses the average European Union Emissions Trading System FY2021 price of EUR36.47/tonne to value the benefit of carbon abatement. This is converted to Australian dollars using the average EUR/AUD exchange rate over FY2021. This gives a carbon price of $58.22/tonne in Australian dollars. The only changes in the cost and benefit stack is the addition of the carbon abatement benefit, with all other items in the stack remaining the same from the no carbon price scenario. The carbon abatement benefit is calculated by taking the difference in carbon emissions between the Base Case and the technology case and multiplying it by the cost of carbon, which for this scenario is $58.22/tonne. This was done for each year from 2025 to 2034, and then discounted at 7 per cent. The results can be seen in **Figure 33**.

As in the ACCU carbon price scenario, wind receives the greatest benefit from carbon abatement as it displaces the most black and brown coal, resulting in the greatest emissions reduction. With the higher carbon price, this benefit is enough to make 400 MW of additional wind capacity the least costly technology over the modelling period. Although solar PV receives the second highest benefit from carbon abatement, this benefit is not enough to make it net beneficial over the modelling period. As before, the 4 hour battery and 6 hour pumped hydro cases receive even less benefit from carbon abatement, with only a small amount of black coal, CCGT and OCGT displaced, and still have a large net cost. Finally, 400 MW of CCGT has the least benefit from carbon abatement, as the CCGT only displaces OCGT, resulting in only a very small benefit. With a $58.22/tonne carbon price, CCGT and wind have very similar system costs (wind is very slightly cheaper) with solar and the other technologies more expensive.

Figure 33: WESC results with EU ETS carbon price ($58.22/tonne, AUD)



Source: Frontier Economics' analysis

4.4 Comparison of WESC to LCOE

As discussed, the intention of the WESC is to address shortcomings of the LCOE by accounting for the impact that different generation and storage technologies have on the electricity system, and calculating the costs and benefits of these impacts. In doing so, the WESC seeks to provide an alternative, more comprehensive, way of assessing the relative merits of investment in different generation and storage technologies.

To illustrate this difference between WESC and LCOE, we can compare our estimates of WESC with estimates of LCOE for the same technologies. The comparison is not straight-forward, since WESC and LCOE tend to be reported in different ways. Nevertheless, we can compare the relative outcomes for different technologies using WESC with the relative outcomes for different technologies using LCOE. This comparison is provided in **Figure 34**, **Figure 35** and **Figure 36**, for the three carbon price scenarios we use. Each of these figures presents the following information:

- **Estimates of LCOE**. The estimates of LCOE are shown on the left hand panel of each figure. Costs are shown as positive amounts, so a higher value for LCOE on these figures represents a technology that is more expensive. As previously discussed, LCOE is generally presented as a curve, illustrating how LCOE varies with capacity factor. We present only point estimates of LCOE. For wind generation and solar generation these point estimates use the average capacity factor for these technologies in the NEM. For CCGT we provide two point estimates, to give an indication of the range of LCOE outcomes for CCGT: one for a capacity factor of 30% and one for a capacity factor of 50%. LCOE is presented in $/MWh. The estimates of LCOE shown in these figures are calculated using the same input assumptions for capital costs, operating costs, fuel costs and efficiency that are used in our modelling of WESC.
- **Estimates of WESC**. The estimates of WESC are shown on the right hand panel of each figure. These estimates of WESC are the same as we have presented previously; the only difference is that in these figures, to aid comparison with LCOE, we present WESC in terms of total net cost rather than total net benefit. In other words, costs are shown as positive amounts, so a higher value for WESC on these figures represents a technology that results in higher net costs for the system as a whole. WESC is presented in terms of total net cost over the period 2025 to 2034, in $million.
- Estimates of LCOE are only presented for CCGT, wind and solar PV, not for storage technologies. The LCOE for storage technologies is very sensitive to assumptions about capacity factor and electricity costs when charging, meaning that presenting a point estimate LCOE for these technologies does not provide a complete picture.

It is clear from **Figure 34**, **Figure 35** and **Figure 36** that using LCOE as an indication of the lowest cost investment options presents a very different picture than using WESC as an indication of the lowest cost investment options.

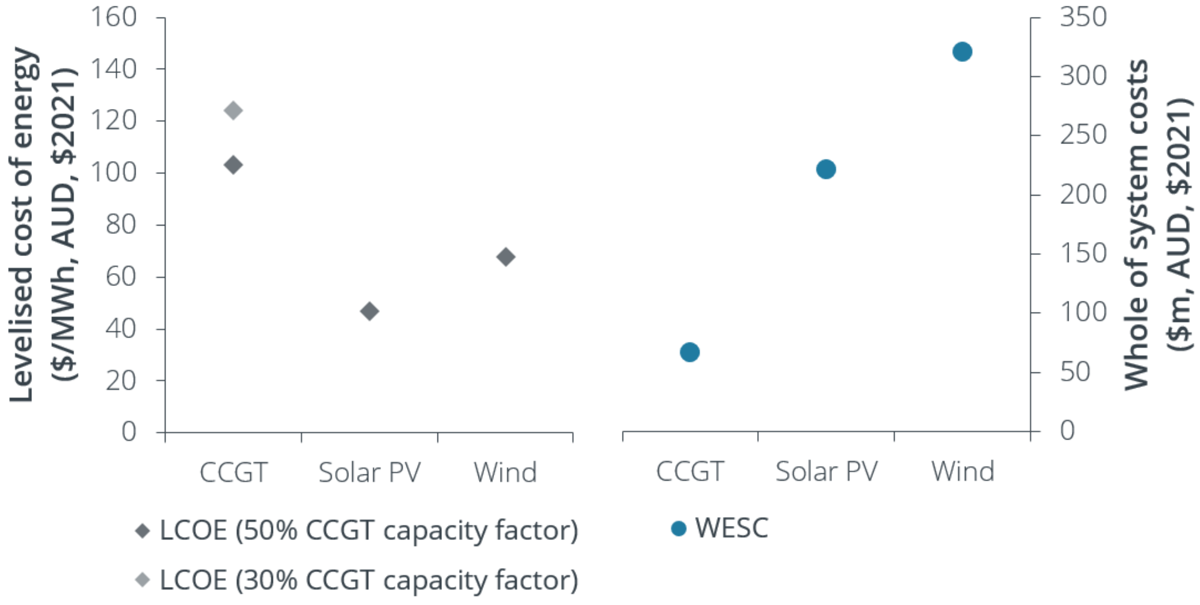
Considering the no carbon case presented in **Figure 34**, we can see that the LCOE of solar PV is lowest, followed by the LCOE of wind, with the LCOE of CCGT being the most expensive. This simply reflects the fact that solar PV has the lowest capital cost, low operating costs and no fuel costs. If we ignore the timing of electricity generation from solar PV, and its lack of dispatchability, as LCOE does, this indicates that electricity generated from solar PV is low cost. In contrast, CCGT has higher capital costs and has significant fuel costs. If we ignore the flexibility and dispatchability provided by CCGT, as LCOE does, this indicates that electricity generated from CCGT is high cost.

In contrast, and as seen above, the WESC for the no carbon case presented in **Figure 34** presents a very different picture of relative costs. As discussed, the flexibility and dispatchability of CCGT means that the WESC for CCGT compares very favourably to other technologies. The key reason is that CCGT is firm and dispatchable, both characteristics that are valuable, and becoming more valuable, in the NEM. For instance, the fact that investment in CCGT contributes to meeting peak demand means that other investment costs can be avoided, where this is much less true for renewable generation options. Similarly, the fact that CCGT can be dispatched when needed means that CCGT can benefit the system by avoiding the need to rely on expensive peaking plant or demand-side response. While this benefit is relatively small at the beginning of our modelling period, this benefit increases throughout the modelling period to 2035.

We can draw similar conclusions from the comparison of LCOE and WESC results for the carbon cases presented in **Figure 35** and **Figure 36**. In the carbon cases, the relative LCOE results are similar to the no carbon case – solar PV and wind are lowest (their LCOE is unchanged by a carbon price), while CCGT is highest (and increases as a result of a carbon price). As we have seen however, with a low carbon price CCGT has the most favourable WESC and with a high carbon price the WESC of CCGT and wind are very similar (with wind slightly more favourable).

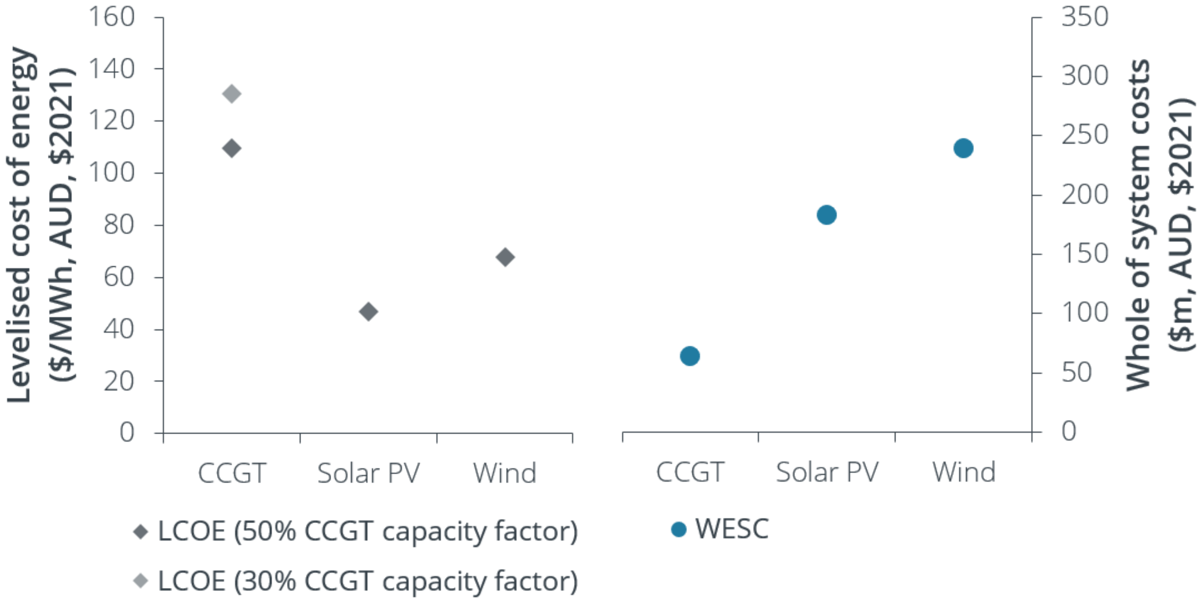
In short, it is a mistake to think that investing in generation or storage technologies with the lowest LCOE will necessarily result in a lowest electricity system cost. The broader system benefits delivered by investing in generation or storage technologies with higher LCOE may deliver lower electricity system costs. This is precisely the result our modelling delivers for the NEM over the period 2025 to 2034 – even though CCGT has a higher LCOE than solar PV and wind, the broader system benefits delivered by the flexibility and dispatchability of CCGT mean that whole of electricity system costs are lower with investment in CCGT than with investment in solar PV, wind, batteries or pumped hydro.

Figure 34: Comparison of WESC and LCOE in 2025 with no carbon price



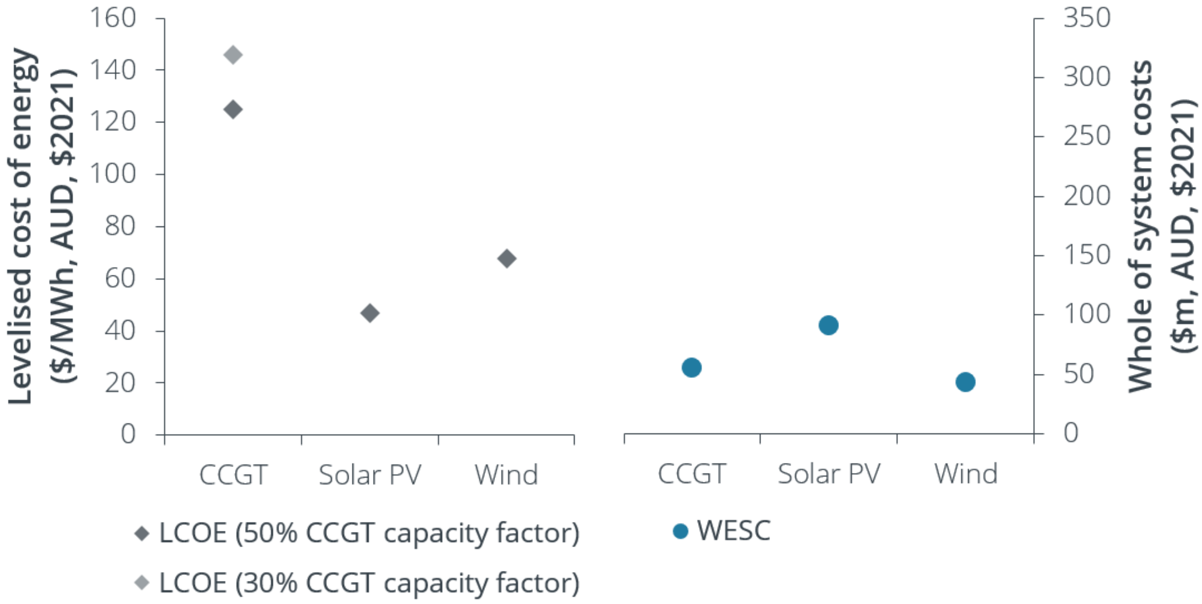
Source: Frontier Economics' analysis

Figure 35: Comparison of WESC and LCOE in 2025 with ACCU carbon price ($17.17/tonne, AUD)



Source: Frontier Economics' analysis

Figure 36: Comparison of WESC and LCOE in 2025 with EU ETS carbon price ($58.22/tonne, AUD)



Source: Frontier Economics' analysis

5 Sensitivity to gas prices

Box 5: Key takeaways

- While gas prices are a key driver of the cost of operating GPG, the evidence suggests that changes in gas prices are unlikely to be a key driver of dispatch of GPG.
- Evidence on the relative economics of GPG suggest that gas prices would have to change very materially in order for the economics of GPG to shift sufficiently for GPG to become cheaper than competing generation technologies it is currently more expensive than, or to become more expensive than competing generation technologies it is currently cheaper than.
- Analysis of historical GPG dispatch and gas prices suggests that gas prices tend not to be a key driver of dispatch of GPG.

This section considers the extent to which changes in gas prices are likely to result in changes in the operation of GPG in the NEM. We do this by considering the relative economics of GPG in the NEM and then examining the evidence for a link between gas prices and output from GPG.

5.1 The relative economics of GPG

The extent to which GPG operates in the NEM is primarily determined by the relative position of GPG in the supply curve for electricity in the NEM, which is commonly referred to as the merit order.

Figure 37 illustrates the current merit order for each region of the NEM, based on input assumptions from the 2020 ISP. The merit orders in **Figure 37** rank, for each region of the NEM, each form of generation according to its short-run marginal cost (SRMC). SRMC consists of fuel costs and variable operating and maintenance costs, and is taken to represent the opportunity cost of supplying electricity to the market. SRMC is not necessarily how generators will actually bid in the NEM, but should be similar at the margin in a competitive market. In **Figure 37** SRMC is represented on the Y-axis and cumulative generation capacity is represented on the X-axis.

Generally speaking, it would be expected that generation will be dispatched according to the merit orders seen in **Figure 37**: renewables first, given they have very low SRMC, followed by coal and then various forms of GPG.

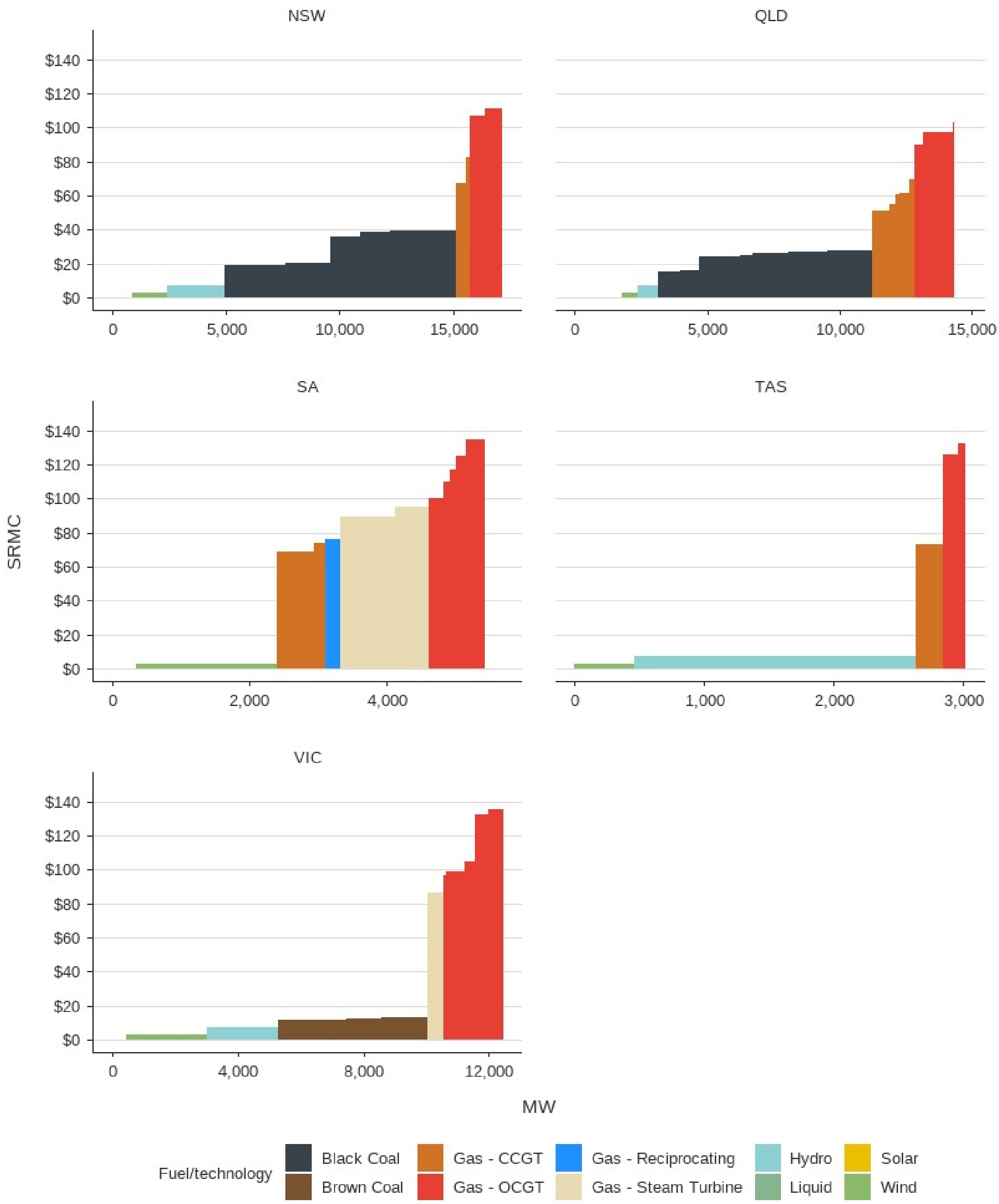
Of course a change in fuel prices can change this merit order. Since the gas price is the key determinant of the SRMC of GPG (along with the plant efficiency) a change in the gas price will directly result in a change in the SRMC. What is interesting about **Figure 37** is that it highlights the extent to which gas prices would need to change in order to change the relative position of GPG in the merit order (and therefore change the extent to which GPG would generally be expected to be dispatched). For instance, in order to GPG to be dispatched more frequently as a result of a change in gas prices, it would need to be the case that gas prices reduced enough to move the position of GPG in the merit order. It is unlikely that gas prices will change to that extent:

- In New South Wales and Queensland, gas prices would need to fall enough for GPG to become cheaper than black coal generation. Based on the 2020 ISP assumptions, this would imply a reduction in gas prices of roughly 50 per cent.
- In Victoria, gas prices would need to fall enough for GPG to become cheaper than brown coal generation. This would require even more significant reductions in gas prices.
- In South Australia and Tasmania, the only generation technologies that GPG could displace are renewables. There is no realistic gas price at which GPG would have a lower SRMC than renewables.

Likewise, since there are few generation options with an SRMC higher than GPG (just some liquid fuel peakers and some DSM) there is little prospect that higher gas prices will result in a material shift in the position of GPG in the merit order.

What this suggests is that realistic changes in gas prices are unlikely to be a key driver of changes in dispatch of GPG in the NEM.

Figure 37: SRMC merit order, ISP 2020 assumptions



Source: Frontier Economics analysis of ISP 2020 assumptions

Note: Scales truncated at $150 for clarity so liquid fuel entries not shown

5.2 Evidence on gas prices affecting output

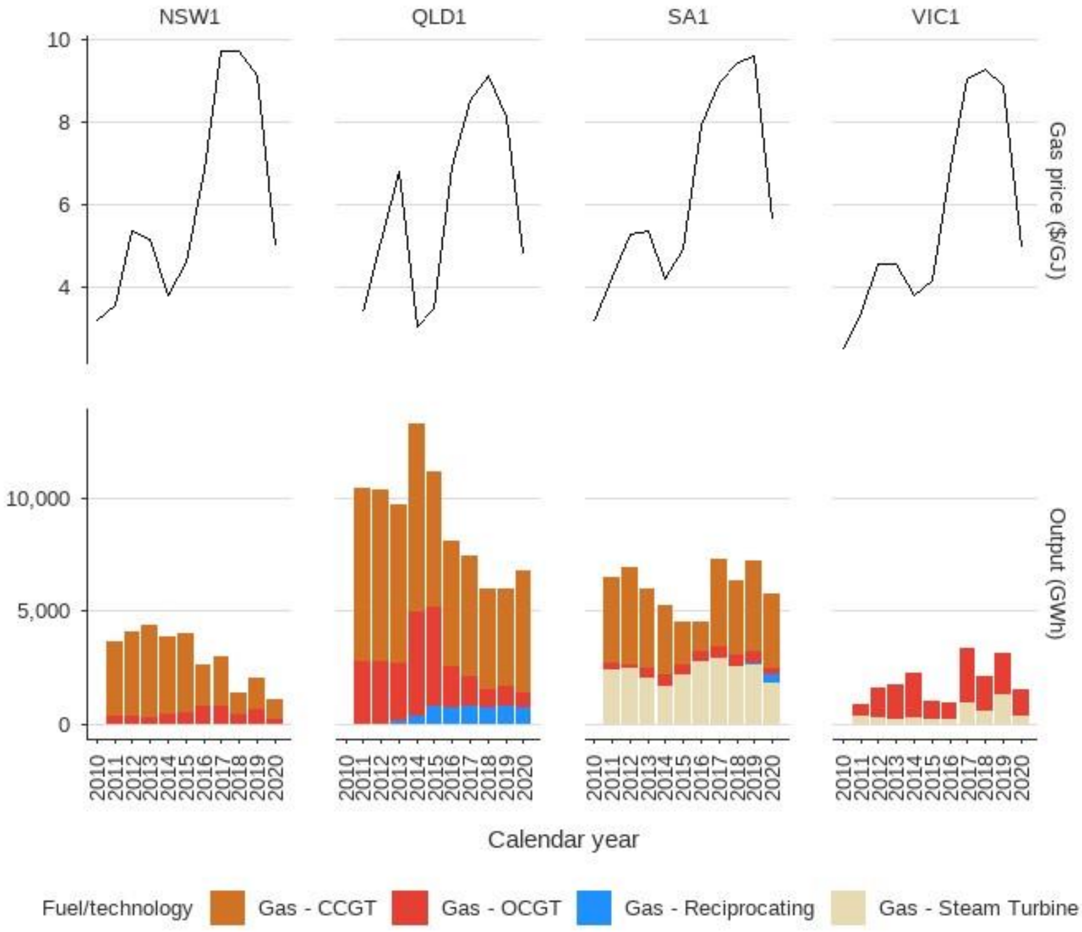
Another way of assessing the extent to which gas prices in the NEM are a driver of dispatch of GPG is to consider the historical relationship between gas prices and GPG dispatch.

Figure 38 illustrates gas prices and gas output in each region of the NEM over the period from 2010 to 2020. If gas prices were a key driver of dispatch of GPG in the NEM it would be expected that higher gas prices would be associated with lower GPG dispatch. However, there does not appear to be a strong correlation between gas prices and gas output:

- Queensland has the most evident correlation between gas prices and GPG dispatch, with gas dispatch rising at times of low prices in 2014 and 2015, and then subsequently falling as prices increased. The high rates of GPG dispatch in 2014 and 2015, and the low gas prices, are generally attributed to the abundance of gas in Queensland as the LNG export terminals neared commissioning.
- In New South Wales, GPG dispatch has generally decreased regardless of price movements, which is likely related to increasing penetration of renewables crowding out GPG.
- In South Australia and Victoria, GPG dispatch has increased with increasing prices. This is due in large part to the retirement of Hazelwood Power Station in Victoria.

Again, what this historical analysis suggests is that gas prices are not a key driver of changes in dispatch of GPG in the NEM, and that other factors tend to have a more material impact.

Figure 38: Gas prices and Gas output, 2010-2020



Source: Frontier Economics analysis of AEMO electricity and gas data

6 Assessment of the role of GPG in other markets

Box 6: Key takeaways

We have reviewed electricity markets in the United Kingdom, Germany, Texas, New Zealand and Brazil to investigate the role of GPG in these markets. Based on this review we make the following general observations:

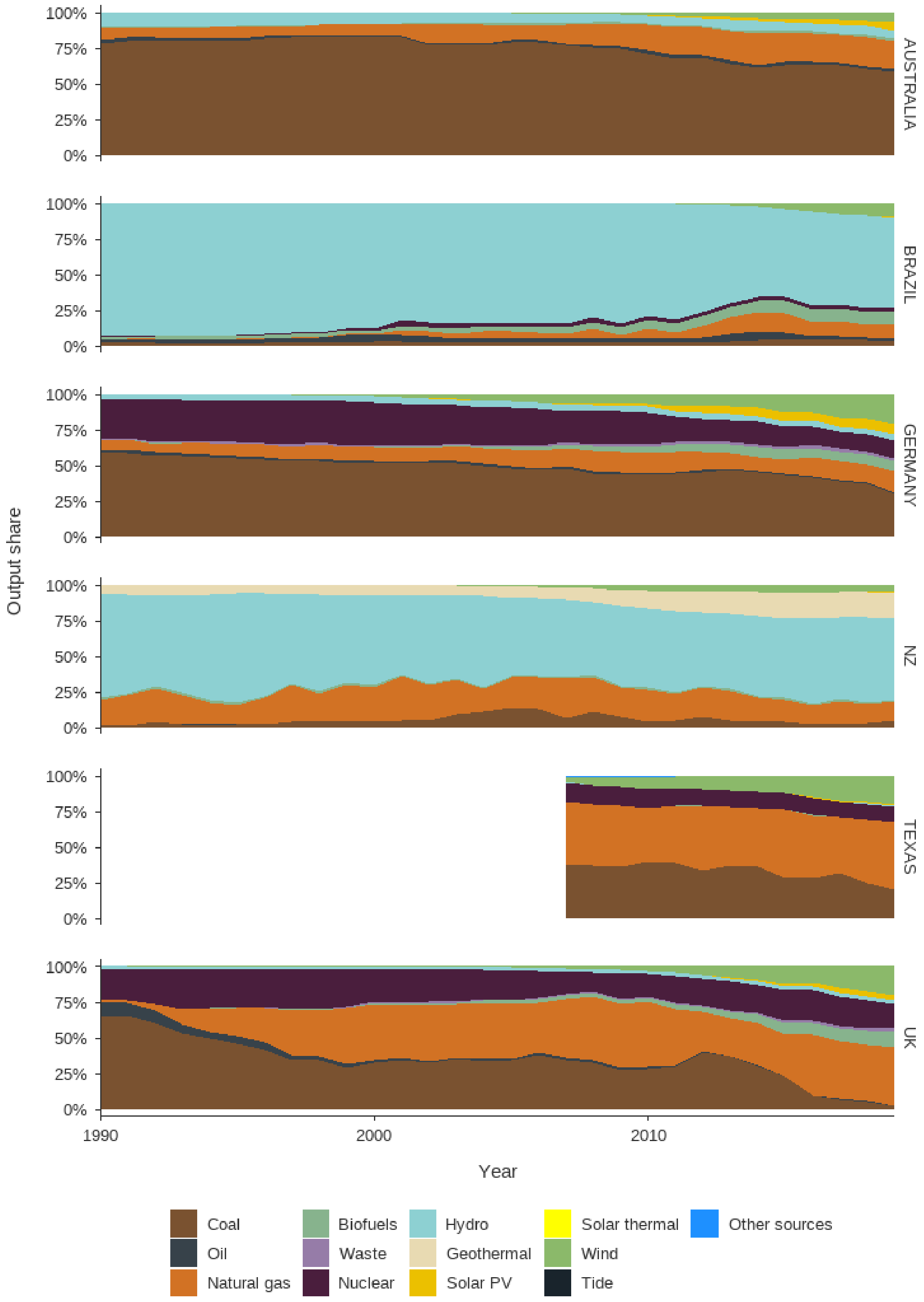
- All of the jurisdictions we reviewed have targets to achieve net zero by 2050 (although the strength of commitment differs). Some of the jurisdictions we reviewed have a higher penetration of intermittent renewable generation than Australia.
- In the jurisdictions that are retiring coal generation and nuclear generation – the UK, Germany, Texas – a combination of renewables and GPG are being used to replace the energy and capacity.
- In the jurisdictions with high or increasing proportions of intermittent renewable generation, this energy is typically displacing coal generation rather than GPG.
- In none of the jurisdictions have we seen material reductions in gas output, with the exception of New Zealand where geothermal generation is available and has increased its share of the generation mix.
- In regions dominated by hydro (New Zealand and Brazil), gas plays a less important role in terms of annual average output in most years, but is a very important part of the energy mix during dry years.
- In each of these jurisdictions, GPG remains important to a reliable and securely functioning electricity system.

This section provides a high-level analysis of the role of GPG in a number of international markets. Given that the major development in the NEM and WEM over the coming two decades is expected to be the retirement of coal-fired generation and the growth in renewables, our analysis focuses on jurisdictions in which one or both of these trends is relatively advanced. The jurisdictions we consider are:

- The United Kingdom (Section 6.1)
- Germany (Section 6.2)
- Texas (Section6.3)
- New Zealand (Section 6.4)
- Brazil (Section 6.5)

A summary overview of the energy mixes in Australia and these five jurisdictions is presented in **Figure 39**. It is clear that most of these jurisdictions are experiencing significant growth in intermittent renewable generation, like Australia.

Figure 39: Summary of output shares for relevant jurisdictions



Source: Frontier Economics analysis of IEA and ERCOT data. Note Texas only includes ERCOT accounting for around 90% of Texas load

6.1 United Kingdom

6.1.1 Stage in the energy transition

The UK has relied on coal, natural gas and nuclear power for its electricity consumption for the past three decades. The UK committed to a 2050 net zero target in 2019, and, like other developed nations, is phasing out its reliance on fossil fuels.

Figure 40 illustrates the past three decades of the UK's electricity mix, in terms of total output (top panel) and output shares (bottom panel). The move to a low-carbon electricity system is evident in a number of trends:

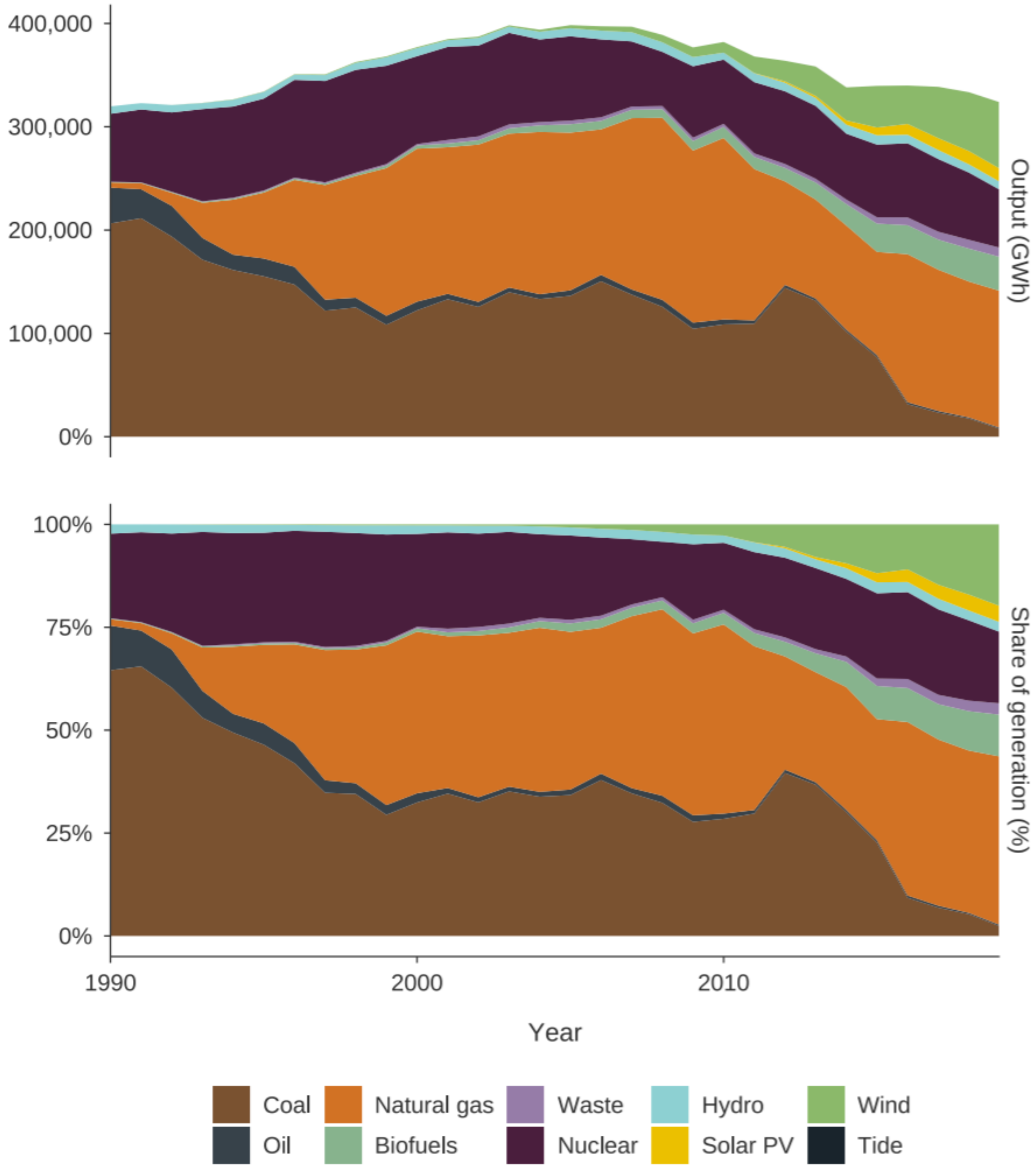
- Total electricity demand falling since the mid-2000s, reflecting energy efficiency measures, industry moving offshore, and consumer responses to increasing prices. Electricity imports and exports are not shown on this chart but are relatively small.
- Coal, the highest emitting generation type, is being phased out by October 2024[9]. Until the mid-2010s, coal fired generation played a significant role in the UK's electricity mix, producing around 39.6% of total generation in 2012. The majority of coal-fired power station retirements in the UK are in line with the stations' expected natural lives (around 50 years or so).
- Output from renewable electricity sources, including wind and solar, have increased steadily from the early 2000s. Wind and solar together now make up around 23.7% (2019) of total generation.
- Since the large-scale uptake of natural gas generation, and particularly CCGT, in the 1990s, GPG's generation share has been relatively constant at around 40% of overall generation. This is illustrated in **Figure 41**. The reduction of coal output reversed a trend in declining gas output in the early 2010s.

GPG in the UK accounted for 22% of total gas demand in 2020[10].

[9] https://www.scientificamerican.com/article/u-k-will-stop-using-coal-power-in-just-three-years/

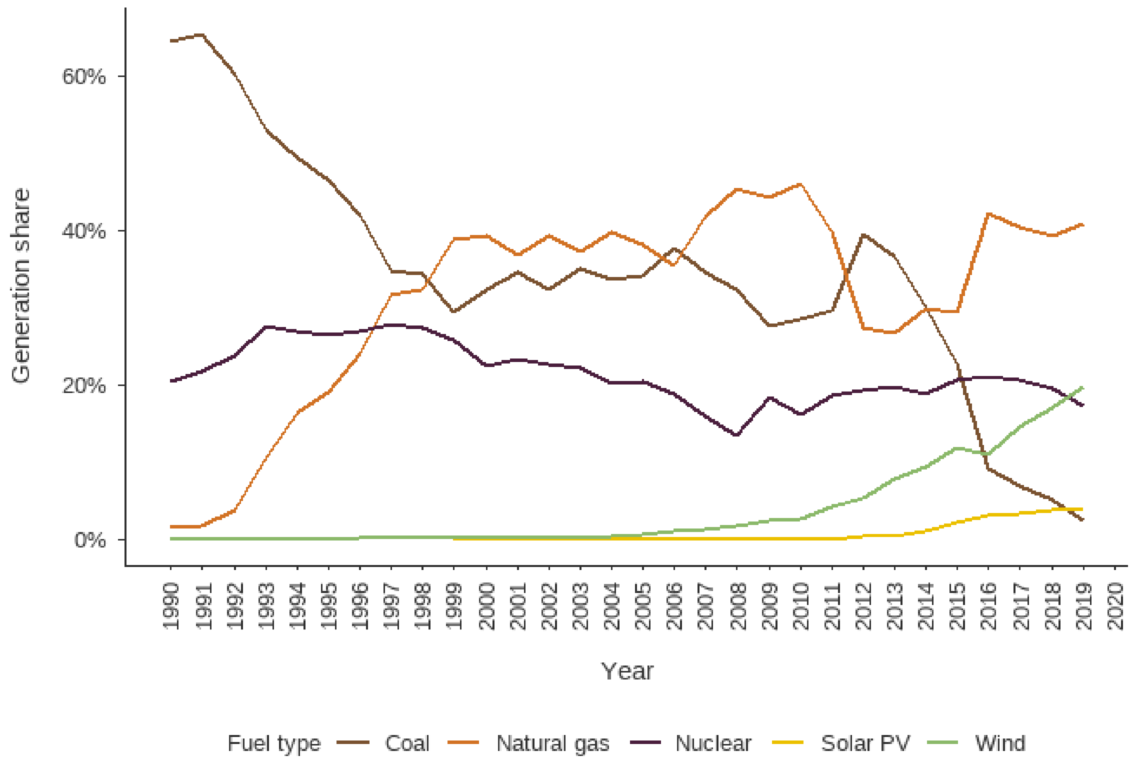
[10] https://www.nationalgrideso.com/document/199871/download

Figure 40: UK fuel mix, output, 1990-2019



Source: Frontier Economics analysis of IEA data: https://www.iea.org/fuels-and-technologies/electricity

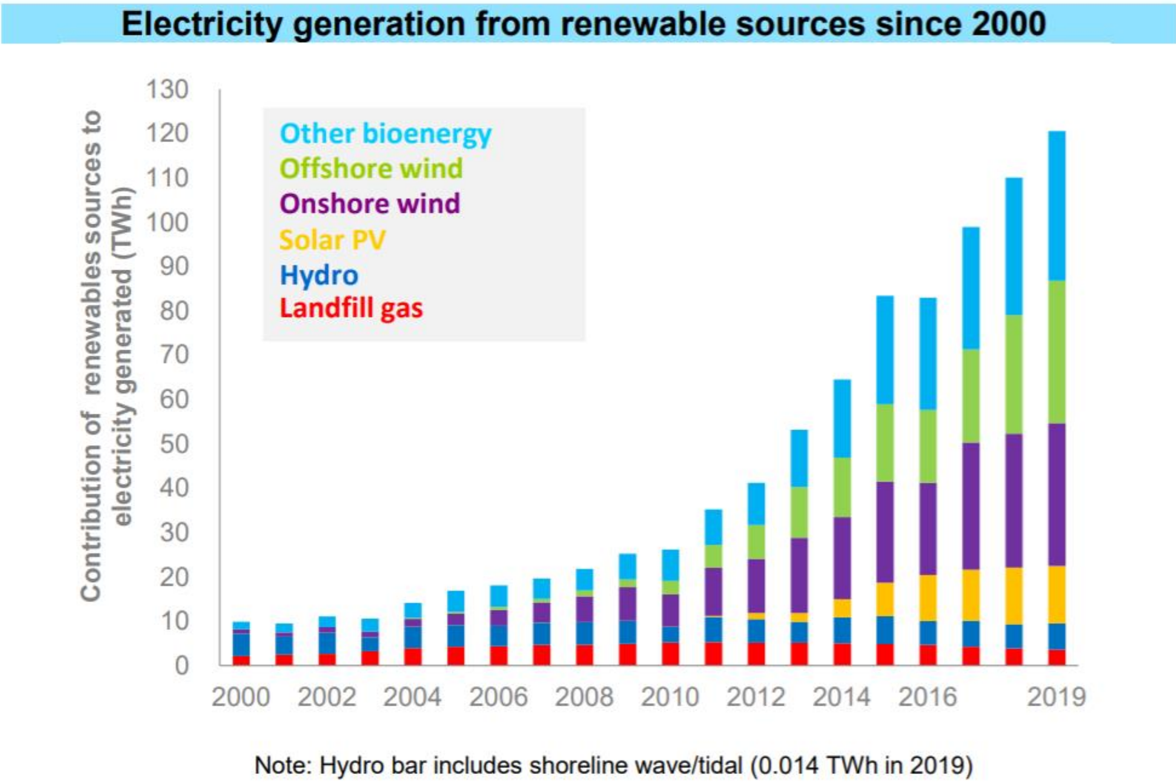
Figure 41: UK generation share, selected fuel types



Source: Frontier Economics analysis of IEA data

Renewable generation in the UK is predominantly in the form of wind and solar (64%), as illustrated in **Figure 42**. This means a significant, and growing, proportion of the UK's electricity generation mix is intermittent. Electricity storage in the UK is still nascent, with around 1.2GW of operational storage projects and 14GW in in the pipeline as at May 2021[11]. The average electricity consumption in the UK was around 33GW in 2020[12].

Figure 42: Electricity generation from renewable sources since 2000



					TWh
	1990	2000	2010	2018	2019
Onshore wind	-	0.9	7.2	30.2	32.2
Offshore wind	-	-	3.1	26.7	32.1
Solar PV	-	-	0.0	12.7	12.9
Hydro	5.2	5.1	3.6	5.4	5.9
Landfill Gas	0.1	2.2	5.2	3.9	3.6
Other Bioenergy	0.5	1.7	7.0	31.0	33.7
Total Renewables	**5.8**	**9.9**	**26.2**	**110.0**	**120.5**

Source:
https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/904503/UK_Energy_in_Brief_2020.pdf

11 https://www.energy-storage.news/piecing-together-the-jigsaw-of-value-in-uk-energy-storage/

12 https://www.statista.com/statistics/322874/electricity-consumption-from-all-electricity-suppliers-in-the-united-kingdom/

6.1.2 Similarities to Australia

There are a number of similarities between the transitions the UK and Australia are undergoing in their electricity sectors. **Figure 43** illustrates generation shares for both jurisdictions for selected generation types:

- Both the UK and Australia have experienced, and are planning for, a large-scale reduction of coal output. The UK is more advanced than Australia in this regard, having almost entirely phased out coal already. Australia remains reliant on coal for around 58% of all output.
- The share of intermittent renewable generation is increasing in both jurisdictions. The UK is more advanced in utility scale wind with around a 20% share, relative to around 6% in Australia.
- Both jurisdictions have significant capacities of GPG and rely on GPG to provide energy and security services.
- Like Australia, the UK has not adopted a 'gas by design' strategy in reducing carbon emissions[13]. However, the UK has relied heavily on GPG (particularly CCGT) in phasing out coal.
- The size of UK system is broadly similar to Australia (about 50% larger).

With increasing penetration of intermittent renewables, the UK is facing similar challenges to Australia in maintaining system security and reliability. The National Grid ESO has flagged storage, interconnection with other regions, and management of short circuit level and inertia as key issues[14].

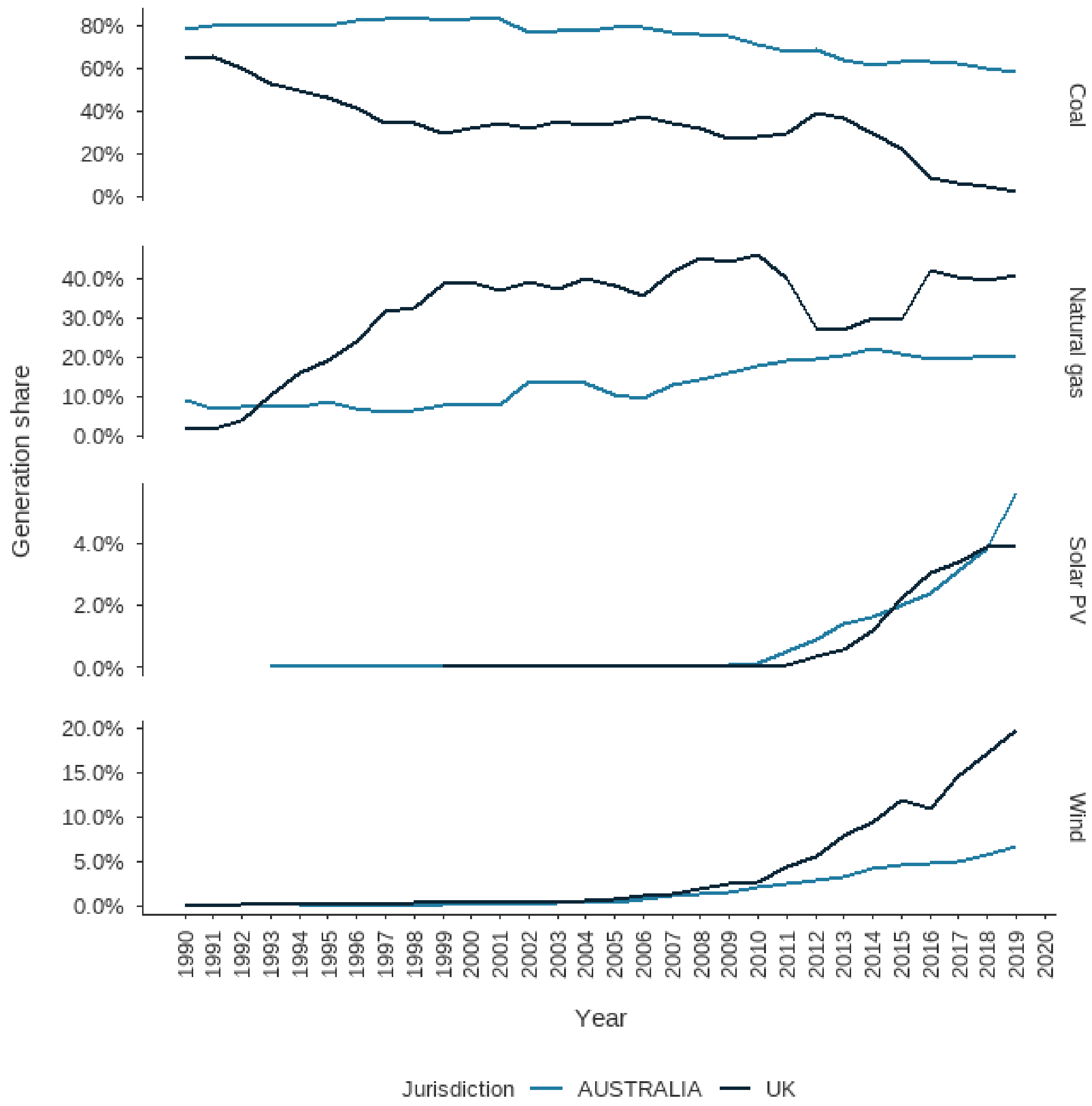
A specific example of inertia-related issues reminiscent of the Australian experience is described by the National Grid ESO. During a sunny period with low demand, the UK "saw low inertia on the system (which can impact stability) and low levels of flexibility (meaning supply couldn't adjust to meet demand). Despite having sufficient renewable electricity, National Grid ESO needed to use natural gas and biomass generation to make sure electricity continued to flow to consumers."[15]

13 https://warwick.ac.uk/fac/soc/impact/brexit/commentary/future_uk_gas_security_future_of_gas.pdf

14 https://www.nationalgrideso.com/document/190151/download

15 https://www.nationalgrideso.com/document/183556/download

Figure 43: Comparison of fuel mix shares, Australia and the UK



Source: Frontier Economics analysis of IEA data

6.1.3 Differences to Australia

The UK has a number of important differences to Australia's electricity systems:

- The UK has a significant proportion of nuclear generation in its energy mix, a dispatchable technology that provides a number of security services in addition to dispatchable energy. Despite being considered 'dispatchable', nuclear is typically less flexible than gas or coal generation.
- The UK's GPG fleet is mostly CCGT, which are relatively efficient and flexible. Australia has a more diverse mix of technologies which have varying levels of efficiency and flexibility.

- The UK has significantly less rooftop solar than Australia on a per-capita and absolute basis. The UK has around 4GW of small-scale systems (<50kW)[16]. Australia has over 13GW of distributed energy resources, around 9GW of which are residential (typically 10kW or less). The total capacity, along with higher solar PV capacity factors in Australia (better sun resources) mean that the impact of solar PV on load is much more pronounced in Australia and therefore more difficult to manage.
- The UK has a lot of relatively new CCGT gas generation.

6.1.4 Discussion

The experience in the UK shows that GPG can continue to play an important role in decarbonising electricity markets. As renewable generation has increased in the UK, the contribution of GPG to the UK's energy mix has remained steady, and even increased in recent years. GPG is used to provide electricity when intermittent wind and solar is generating at low levels, and also used to provide security to the electricity market. The recent experience in the UK suggests that GPG will continue to play an important role in the electricity market for some years to come.

6.2 Germany

6.2.1 Stage in energy transition

The German government adopted the Climate Action Plan 2050 in November 2016, making Germany one of the first countries to submit the long-term low greenhouse gas emission development strategy to the UN as required under the Paris Agreement.[17] Germany now has a target of being carbon neutral by 2045[18].

Figure 44 illustrates the past three decades of the Germany's electricity mix, in terms of total output (top panel) and output shares (bottom panel). The move to a low-carbon electricity system is evident in a number of trends:

- Output from renewable electricity sources, including wind and solar, have increased steadily from the late 1990s. Wind and solar together now make up around 28% (2019) of total generation. This does not include rooftop PV.
- Coal, the highest emitting generation type, has been gradually phased out from the 1990s. In recent years, coal output has decreased considerably on recent historical levels. The Fraunhofer Institute for Solar Energy Systems cite higher carbon prices, lower wholesale prices, lower gas prices (competitive pressure), higher renewable output, and fewer exports as reasons for reductions in coal output[19]. Germany's coal exit law plans for the following phase-out of coal[20]:

16 https://www.gov.uk/government/statistics/solar-photovoltaics-deployment

17 https://www.bmu.de/en/topics/climate-energy/climate/national-climate-policy/greenhouse-gas-neutral-germany-2050/

18 https://www.cleanenergywire.org/news/germany-pull-forward-target-date-climate-neutrality-2045

19 https://www.ise.fraunhofer.de/en/press-media/news/2020/public-net-electricity-generation-in-germany-2020-share-from-renewables-exceeds-50-percent.html

20 https://www.cleanenergywire.org/factsheets/spelling-out-coal-phase-out-germanys-exit-law-draft

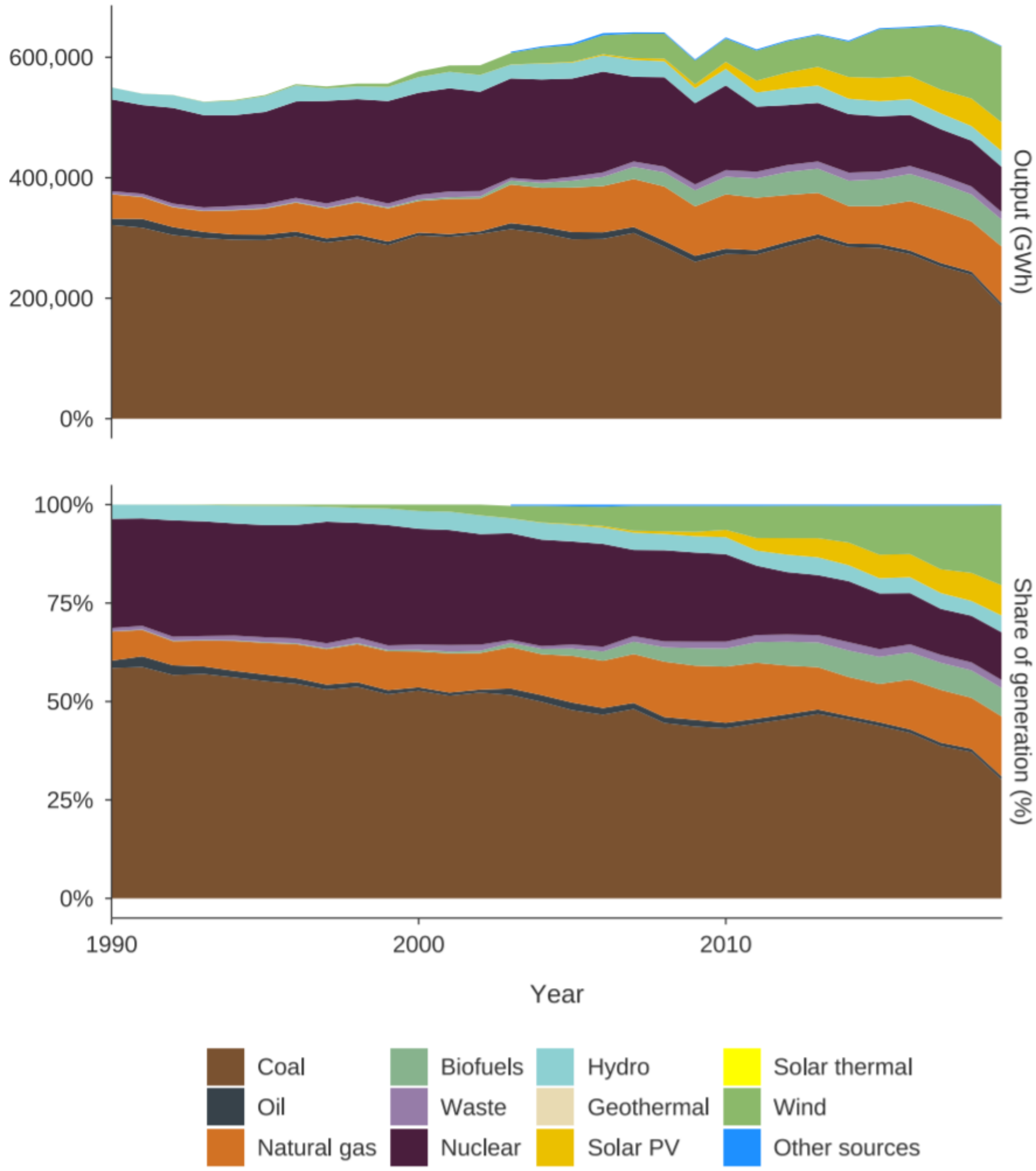
  - 30GW of coal to remain by the end of 2022 (down from around 44GW in 2019).
  - 17GW to remain by 2030.
  - By 2038 at the latest, no coal capacity will remain.
  - Reviews in 2026, 2029, and 2032 will decide whether the phase-out can be completed by 2035.

  Despite the reduction in output, coal remains an important part of Germany's energy mix with around 30% of output in 2019.

- Nuclear has seen a similar reduction in output from 1990s and 2000s levels. Following Japan's Fukushima disaster, Germany pledged to phase-out nuclear power. This phase out is expected to be complete in 2022[21]. Nuclear produced around 12% of Germany's electricity output in 2019.
- In the midst of increasing renewables and closures of coal and nuclear, Germany's GPG output share has increased, as illustrated in **Figure 45**. GPG represented around 15% of Germany's output in 2019.

[21] https://www.cleanenergywire.org/factsheets/history-behind-germanys-nuclear-phase-out

Figure 44: Germany fuel mix, output, 1990-2019



Source: Frontier Economics analysis of IEA data

6.2.2 Similarities to Australia

There are a number of similarities between the transitions Germany and Australia are undergoing in their electricity sectors. Germany's transition is more advanced than Australia's in terms of renewable output share. **Figure 45** illustrates generation shares for both jurisdictions for selected generation types:

- Both countries have broadly similar timelines for the phase-out of coal. As in **Figure 45**, Germany is starting from a lower base and has, to date, phased out coal quicker than in Australia.
- The share of intermittent renewable generation is increasing in both jurisdictions. Germany has significantly larger output shares of both PV and wind.
- Both jurisdictions have significant capacities of GPG and rely on GPG to provide energy and security services.
- Both jurisdictions have seen high rooftop PV uptake subsidised by governments.

Like Australia, the increasing penetration of intermittent generation has led to issues around dispatchable generation and the availability of security services and reliable generation in Germany. The chairwoman of electricity and water industry body BDEW recently said that moving away from coal and nuclear will require additional dispatchable generation (translated from German): "For a secure energy supply, we therefore also need new gas-fired power plants, as this is the only way we can obtain the required controllable power - this is proven by various studies - including the Agora report "Climate-neutral Germany". We have to build this new power plant capacity now."[22]

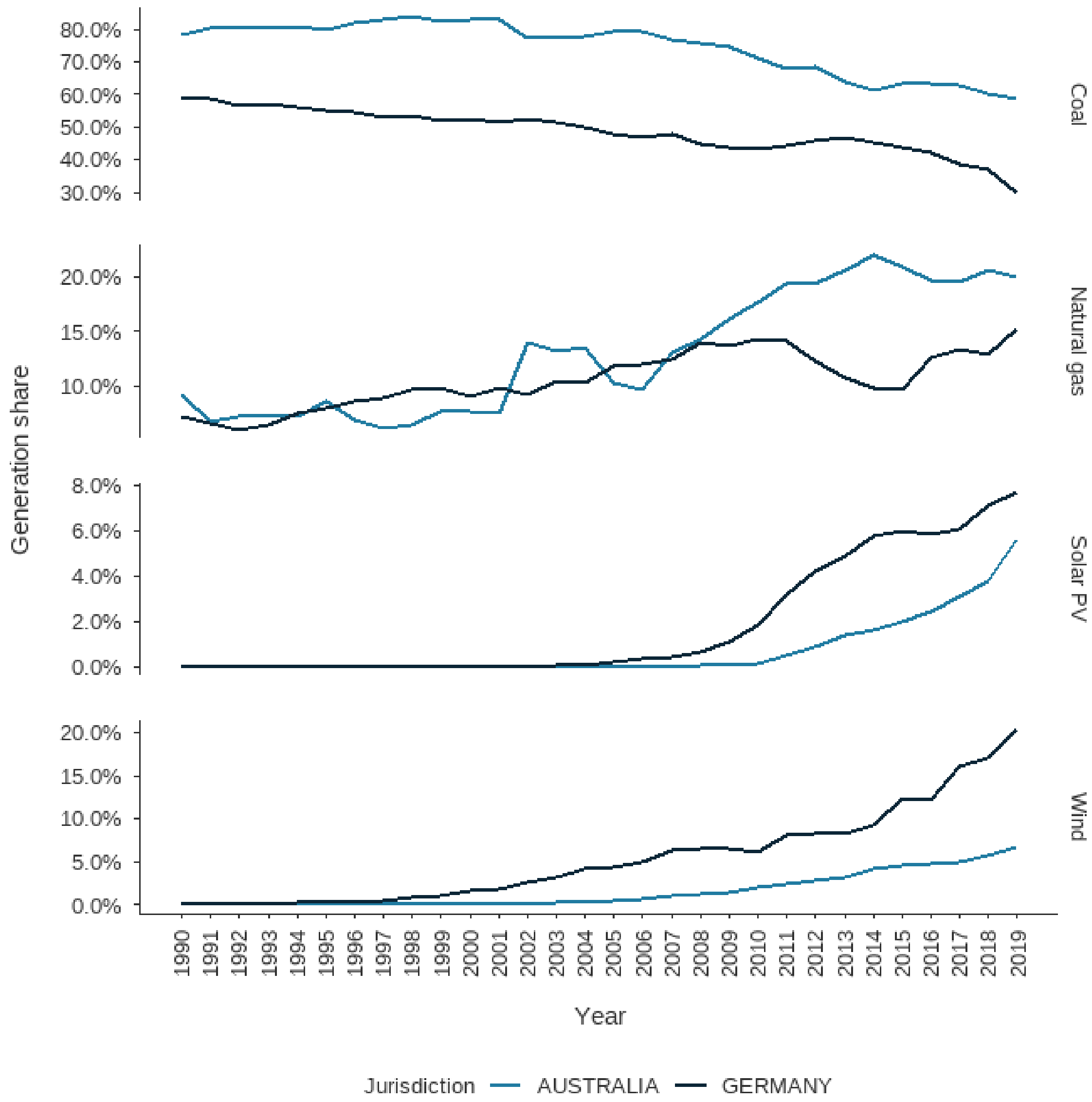
As in Australia, there are ongoing debates in Germany as to whether 100% renewable energy is feasible. The German Institute for Economic Research (DIW) argues that it is possible with coordinated expansion planning and interconnection with other regions[23]. Others variously argue that gas, storage or demand-side response is the answer to a cleaner system[24].

22 https://www.bdew.de/presse/presseinformationen/eu-taxonomie-darf-wichtige-energiewende-investitionen-nicht-gefaehrden/

23 https://www.diw.de/documents/publikationen/73/diw_01.c.822478.de/dwr-21-29-1.pdf

24 https://foreignpolicy.com/2021/02/10/is-germany-making-too-much-renewable-energy/

Figure 45: Comparison of fuel mix shares, Australia and Germany



Source: Frontier Economics analysis of IEA data

6.2.3 Differences to Australia

There are a number of important differences between Germany and Australia in this context:

- Germany is highly interconnected with neighbouring countries[25], allowing it to draw on diverse generation resources from its neighbours. Charts of Germany's fuel mix should be interpreted with this in mind, especially in comparison to Australia, which has no electricity interconnection to other countries.

25 See https://www.entsoe.eu/data/map/ (click "Show cross border only")

- Germany has relied on nuclear generation in the past, although this is to be phased out in the near future (end 2022).
- Germany electricity production faces a carbon price under the EU Emissions Trading System. EU carbon permits increased in price significantly in 2020, from around 25 EUR to 55 EUR per tonne[26]. Currently, prices are around 57 EUR or 92 AUD per tonne.
- The German electricity system is considerably larger than Australia, at around three times the size.

6.2.4 Discussion

Like in the UK, the experience in Germany shows that GPG can continue to play an important role in decarbonising electricity markets. As renewable generation has increased in Germany, and coal and nuclear are phased out, the contribution of GPG to Germany's energy mix has increased. At this stage, GPG remains essential to meeting Germany's energy and security of supply needs, and this is likely to continue during the phase out of nuclear generation (by 2022) and coal generation (by 2038, or possibly 2035). Indeed, the IEA is suggesting that Germany's reliance on GPG is likely to increase:

> *Although the German government is focused on a massive expansion of renewables, the phasing out of both nuclear and coal generation will increase Germany's demand for natural gas in power generation, including as a backup fuel source for renewables; hydrogen derived from renewable sources holds potential as a longer-term solution. The uptick in demand will increase Germany's already-high call on natural gas imports. Moreover, at the same time that Germany's own production of gas is small and declining, its gas imports from European sources are also set to fall in the coming years, especially from the Netherlands, where production from the Groningen field is declining and due to fully terminate by 2022 at the latest. As a result, security of natural gas supply is a top concern for the government, and diversification of gas supplies – including through the direct import of liquefied natural gas (LNG) – will become more important. Notably, the increased use of natural gas in electricity generation, especially to meet peak electricity demand, will also increasingly tie electricity security to gas security.*[27]

[26] https://tradingeconomics.com/commodity/carbon

[27] https://www.iea.org/reports/germany-2020

6.3 Texas

6.3.1 Stage in energy transition

Texas is the largest electricity producing state in the US. It has plentiful energy resources in oil, gas and coal as well as renewable resources in solar and wind.

The Public Utility Commission of Texas has a mandate from 2005 requiring 10GW of renewable capacity by 2025 (including 500MW of non-wind resource). Texas surpassed the overall 2025 goal in 2009 - in 2020, the state had more than 6GW of renewable capacity from sources other than wind.[28] Texas doesn't have a state-wide net zero 2050 target, but individual cities in Texas (such as Austin) have 2050 net zero targets.

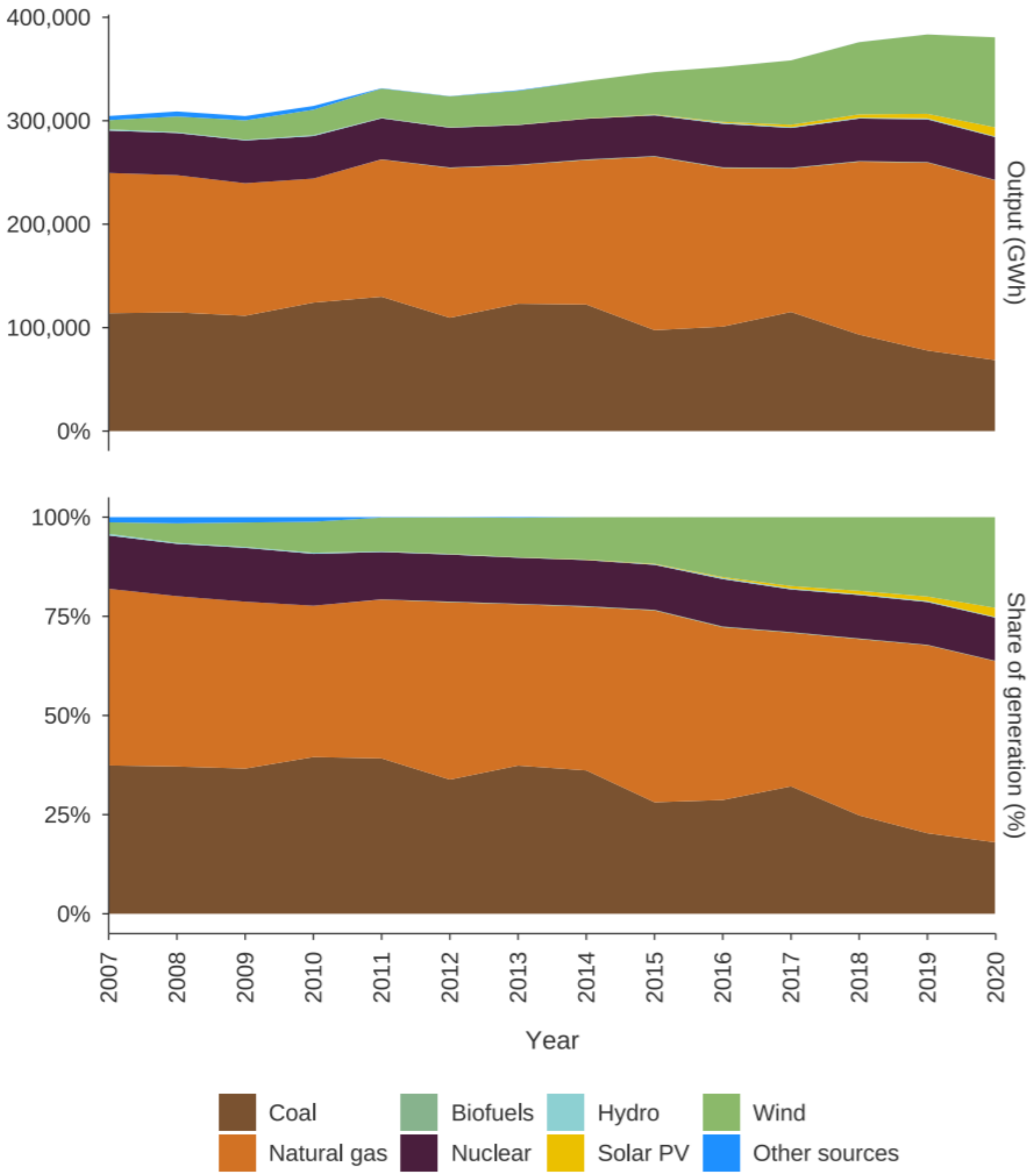
Figure 46 illustrates Texas' electricity generation from 2007 to 2020, in terms of total output (top panel) and output shares (bottom panel). The move to a low-carbon electricity system is evident in a number of trends:

- Output from renewable electricity sources, including solar and particularly wind, have increased steadily from the 2000s. Wind made up 22.8% of Texas' annual energy generation in 2021.
- Output from coal, the highest emitting generation type, has declined over the period shown. This is primarily due to the closure of three coal-fired power stations in 2018. Reasons cited for these closures include cheap gas, wind and low electricity market prices. [29] Despite the reduction in output, coal remains an important part of Texas' energy mix with around 18% of output in 2020.
- GPG has supplied between 38% and 48% of Texas' electricity needs in the period shown. Increases in intermittent renewables (mostly wind) have displaced coal, but not gas.

[28] https://www.eia.gov/state/analysis.php?sid=TX

[29] https://www.dallasnews.com/business/energy/2017/10/13/texas-largest-power-generator-speeds-up-coal-s-decline-with-closure-of-two-more-plants/

Figure 46: Texas fuel mix, output, 1990-2019



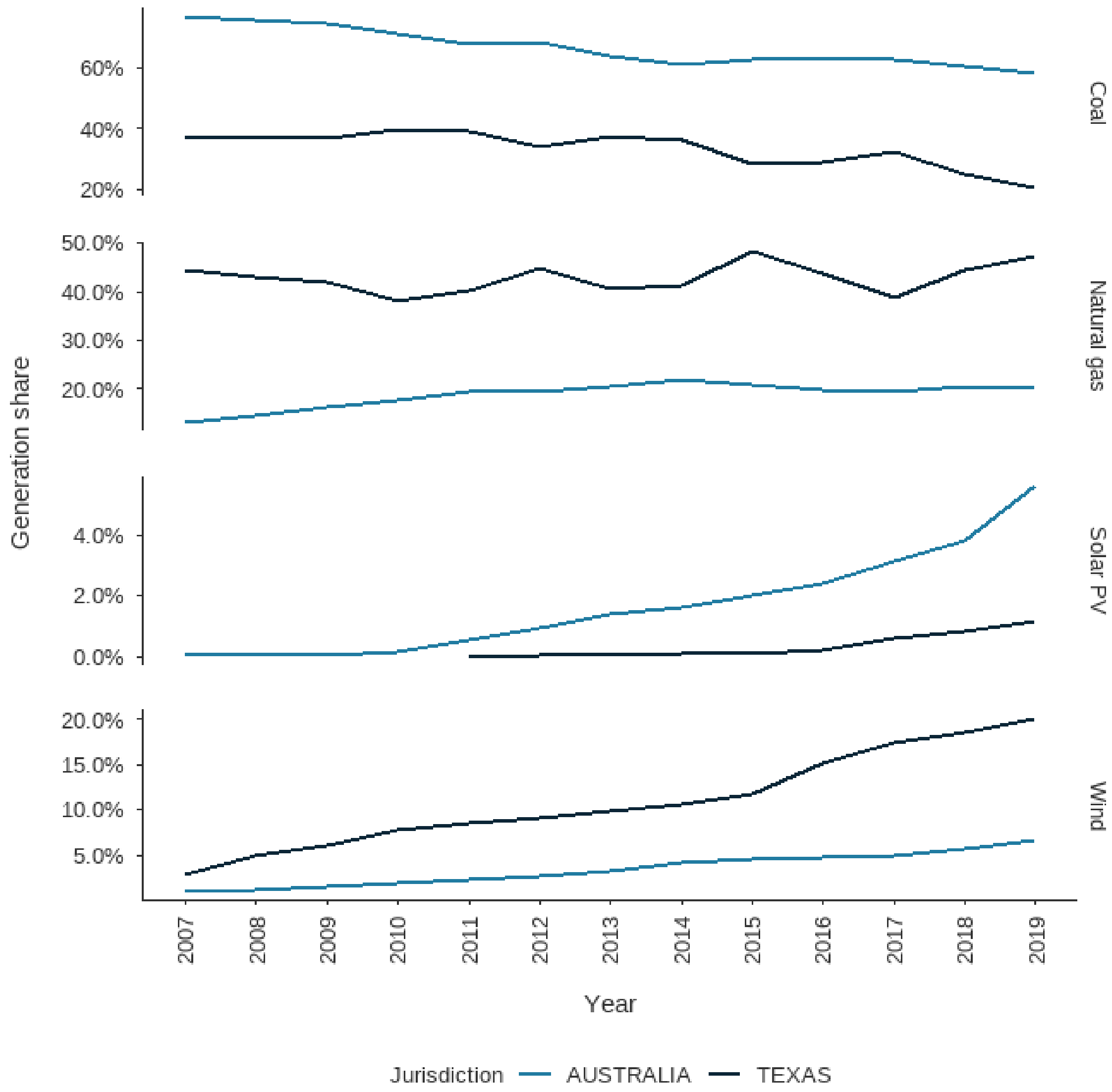
Source: Frontier Economics analysis of ERCOT data

6.3.2 Similarities to Australia

There are a number of similarities between the transitions Texas and Australia are undergoing in their electricity sectors. Texas' transition is more advanced than Australia's in terms of both growth in wind output and declines in coal output. **Figure 47** illustrates generation shares for both jurisdictions for selected generation types:

- Both Texas and Australia have experienced, and are planning for, a large-scale reduction of coal output. Texas is more advanced in reducing coal output, albeit from a lower base. Australia remains reliant on coal for around 58% of all output.
- The share of intermittent renewable generation is increasing in both jurisdictions. In particular, Texas has a large share of wind generation, similar to jurisdictions in Australia with the highest penetration of wind.
- Both jurisdictions have significant capacities of GPG and rely on GPG to provide energy and security services. GPG accounts for a larger share of total output in Texas.
- Both Australia and Texas have little or no other interconnection to other regions.

Figure 47: Comparison of fuel mix shares, Australia and Texas



Source: Frontier Economics analysis of IEA and ERCOT data

6.3.3 Differences to Australia

There are a number of important differences between Texas and Australia in this context:

- Texas continues to rely on nuclear generation for around 10% of its electricity.
- The Texan electricity system is considerably larger than Australia, at around twice the size.
- Gas is significantly cheaper in Texas than Australia.
- Texas has a much larger share of capacity in GPG, with 51% in 2021.

- GPG in Texas operates at a significantly higher capacity factor than in Australia, i.e. GPG in Texas plays more of a baseload role than in Australia.

6.3.4 Discussion

Texas had an exceptionally cold spell in February 2021 which pushed its power system to the extreme. The cold weather had three main effects on the power system:[30]

- Electricity demand was extremely high due to heating loads (60% of heating is electric) and temperatures 25 degrees C below February averages. Day ahead forecasts of electricity demand were well above even the most extreme forecasts (10GW above previous winter peak demand levels).
- Gas production was down by around 20%, due to frozen gas wells.
- Some gas, wind and nuclear generation was unavailable or limited in availability due to the cold. 31GW of gas generation was unavailable (due at least in part to limited gas production), around 3GW of wind generation was unavailable due to frozen turbines and wind output in general over the period was low, and four nuclear facilities in the state were offline due to frozen feed-water pumps.

The result of this confluence of events was significant customer load shedding.

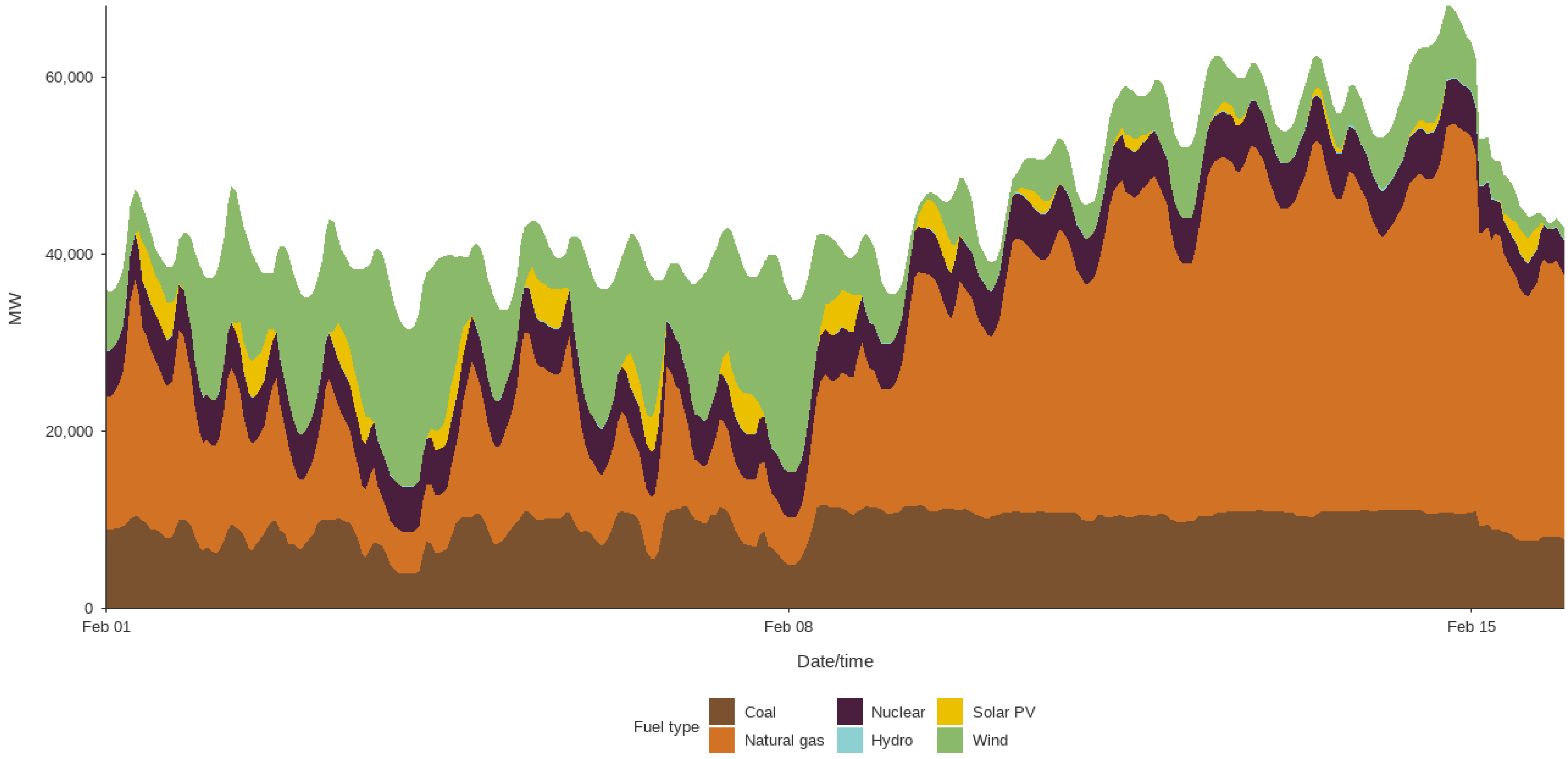
Figure 48 illustrates generation by fuel type in Texas during the period. The storms began around February 10. Intermittent solar and wind generation during this period was below the levels achieved in the prior week. In response to increased demand, all dispatchable forms of generation – namely coal, gas and nuclear – ramped up to meet (or attempt to meet) demand. In particular, it is clear the extent to which GPG ramped up to meet higher demand and to respond to the lower output from intermittent wind generation, much as it does in Australia. Despite this ramping up of generation, supply was still insufficient to meet demand and major rolling blackouts ensued.

The cause of the 2021 Texas crisis is widely accepted to be inadequate winterisation of gas infrastructure and electricity generation assets. Gas, wind and nuclear generation assets were unavailable or had limited available as a result of the cold weather, but gas capacity – being the largest source of generation in the state – saw the largest reductions.

In March 2021, legislation was introduced to prevent a future power outage in extreme temperatures.

30 https://www.iea.org/commentaries/severe-power-cuts-in-texas-highlight-energy-security-risks-related-to-extreme-weather-events

Figure 48: Generation in Texas, Feb 1-16 2021



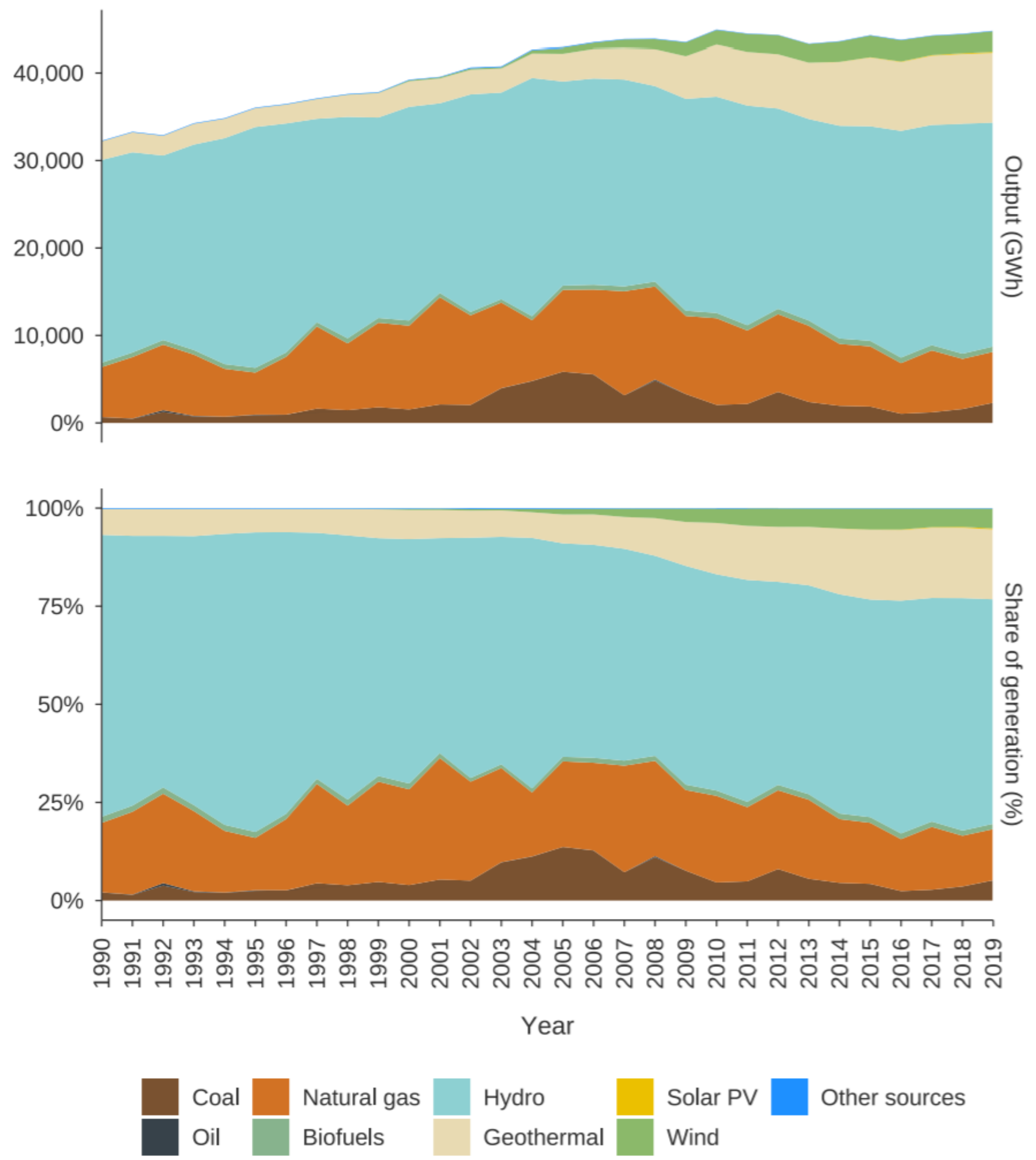
Source: Frontier Economics analysis of IEA data

6.4 New Zealand

6.4.1 Stage in energy transition

New Zealand is fortunate to have geography suitable for significant hydro and geothermal generation. This is reflected in New Zealand's fuel output mix, as illustrated in **Figure 49**.

Figure 49: New Zealand fuel mix, output, 1990-2019



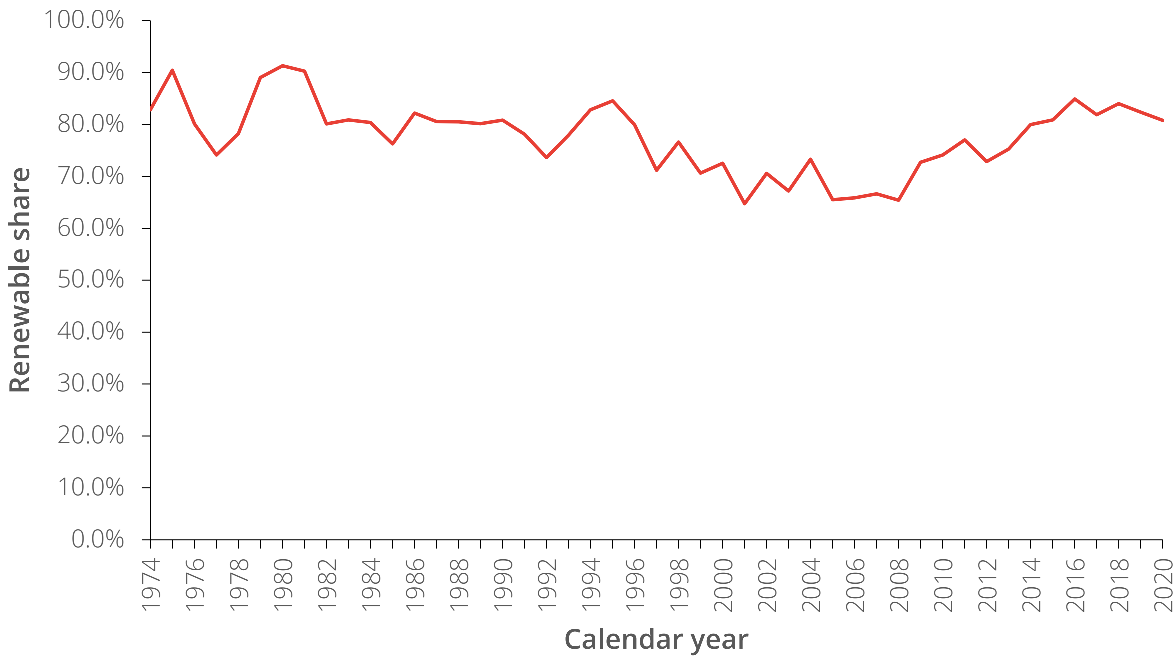
Source: Frontier Economics analysis of IEA data

New Zealand has a number of climate targets and schemes including:

- A legislated net-zero by 2050 target.
- An emissions trading scheme that began to take effect in 2021.[31]
- Labour have set a target for 100% renewable energy by 2030, recently brought forward from 2035, and with a review in 2025. We understand that this target is based on a "normal hydrological year", in that some years non-renewable energy may be required, and in others not.

New Zealand's renewable energy share for 2020 was 80.9%[32], so it has a comparatively easier task than many other developed nations to meet these targets. The renewable share has remained in this vicinity since at least the 1970s, as illustrated in **Figure 50**.

Figure 50: New Zealand renewable share, annual



Source: Frontier Economics analysis of MBIE data

Nevertheless, entirely phasing out coal and particularly gas will be a challenge for New Zealand. Coal can be shipped in, but all natural gas consumed in New Zealand is produced within the country. As consumption volumes decline, the economics of the gas industry will become increasingly challenging, and remaining gas customers will be charged increasing shares of remaining fixed costs.

31 https://www.beehive.govt.nz/release/emission-trading-reforms-another-step-meeting-climate-targets

32 https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/electricity-statistics/

6.4.2 Similarities to Australia

New Zealand's energy mix is most similar to Tasmania, which also has significant geological resources for hydro generation. However, unlike Tasmania, New Zealand is not interconnected with other regions.

6.4.3 Differences to Australia

New Zealand's dominance of renewable generation – and particularly dispatchable renewable generation in the form of hydro and geothermal – makes its energy mix distinctly different from more of Australia and from the other jurisdictions so far considered in this study.

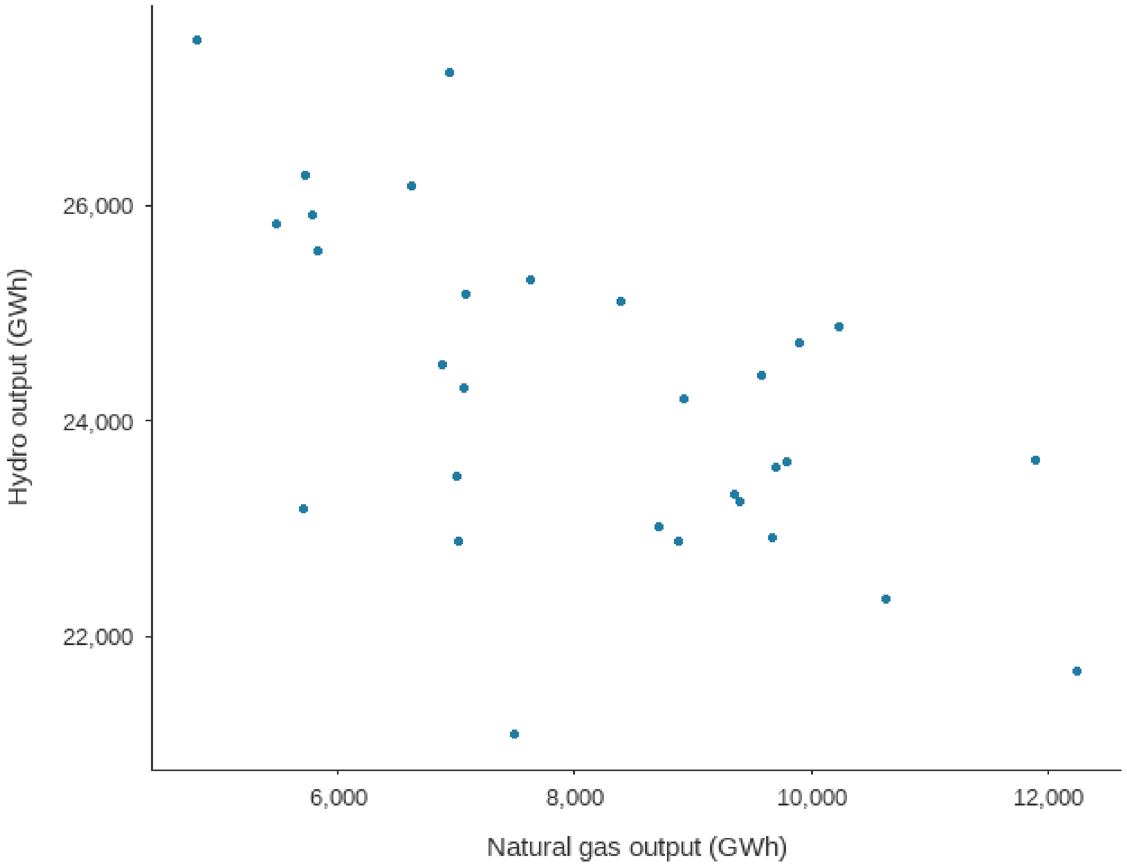
6.4.4 Discussion

New Zealand has several large industrial loads for both electricity and gas which, if removed or reduced, would alter demand dynamics considerably. Tiwai, New Zealand's only aluminium smelter, is a large consumer of electricity that is slated for closure by the end of 2024. Methanex, a methanol producer and large consumer of gas, recently mothballed its Waitara Valley facility in Taranaki due to being unable to secure gas supplies.

Similarly, New Zealand is experiencing difficulties with gas supply. Gas unavailability for Methanex is partially the result of poor performance of existing offshore wells (Pohokura and Maui) as well as a ban on future offshore gas and oil exploration.

Despite being a relatively small proportion of New Zealand's energy mix, coal and gas play an important role in the system, particularly in dry years. In dry years, when hydro generation is less available, coal and gas produce more to fill the gap and to ensure that electricity demand can be met even with lower hydro generation. This is illustrated in **Figure 51**, which shows a negative relationship between hydro and natural gas output (i.e. gas is higher when hydro is lower, and vice versa).

Figure 51: Relationship between annual hydro and natural gas output in New Zealand



Source: Frontier Economics analysis of IEA data

In 2021, New Zealand is on track to import record levels of coal to cover reduced gas production and reduced electricity production from hydro[33].

The New Zealand government is considering a number of solutions to its dry year problem under the NZ Battery Project[34]. The first phase of the NZ Battery Project is considering options for pumped hydro at Lake Onslow or other locations. The project has an early estimate timeframe of four to five years construction and two years commissioning, an estimated storage of five to seven TWh, and a cost of $4 billion.

33 https://www.nzherald.co.nz/nz/nz-importing-record-amount-of-coal-to-power-homes-and-businesses/3ZLXNQYGRXIOAEWAA5XWF344JM/

34 https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/low-emissions-economy/nz-battery/

6.5 Brazil

6.5.1 Stage in energy transition

Brazil is the only developing country considered in this study and its developing status is clear in the increase in demand seen in **Figure 52** – electricity output has almost tripled in the three decades shown. Brazil has the largest electricity sector in South America and, as at 2016, had 97% coverage of electricity services.

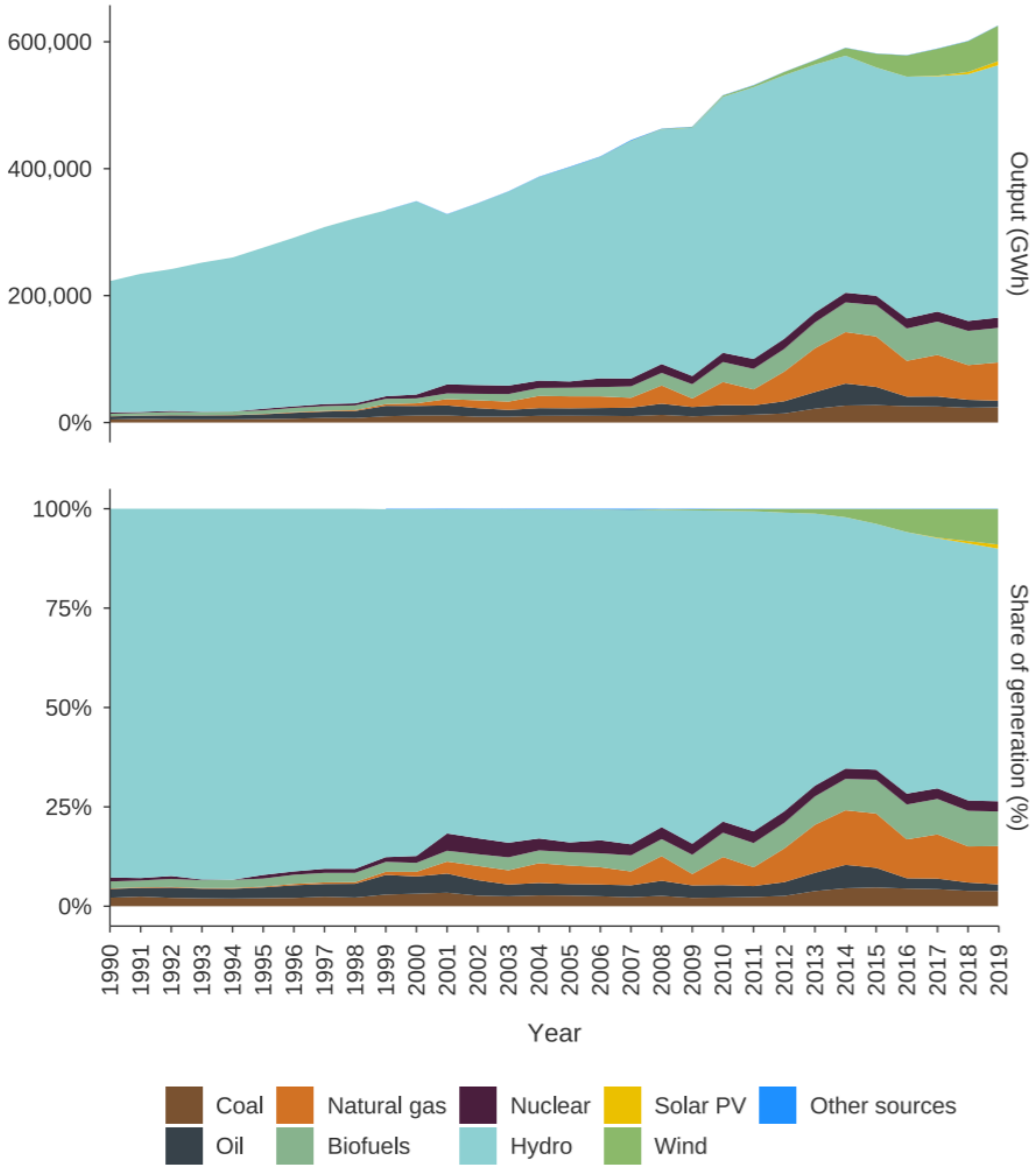
Like New Zealand, Brazil is fortunate to have geography and climate amenable to hydro, which currently represents around 65% of Brazil's electricity output. Wind generation development properly took off in 2012 and now accounts for around 9% of Brazil's electricity output.

Owing to demand growth and limited hydro resources, Brazil's emissions have increased over the period shown. This is the result of increasing output from coal, liquid fuel and gas generation.

The Brazilian government has recently announced a commitment to net zero by 2050, although the plan for the transition and external support required to meet this target is unclear[35].

[35] https://www.wri.org/news/statement-brazils-2050-climate-neutrality-goal-important-gesture-it-contradicts-climate

Figure 52: Brazil fuel mix, output, 1990-2019



Source: Frontier Economics analysis of IEA data

6.5.2 Similarities to Australia

Brazil's output mix is most similar to Tasmania, dominated by hydro and with low levels of wind and thermal generation.

Nationwide, Brazil has a similar share of natural gas output to Australia. Like in Australia, Brazil's gas-fired generation capacity plays an important security role. This is discussed further in Section 6.5.4.

6.5.3 Differences to Australia

There are several key differences between Australia and Brazil in terms of output mix:

- The Brazilian electricity system is considerably larger – around three times the annual output, and more than three times the capacity, of Australia's electricity system.
- Brazil depends on availability of hydro resources a lot more than Australia. While both countries are likely to see scarcity pricing or other energy supply issues in extreme dry years, Brazil's dependence on hydro is greater and therefore the impacts are considerably more dramatic.
- Gas contracts offered by the state-owned Petrobras are currently offered at Brent or Henry Hub benchmark prices, meaning wholesale natural gas is comparatively cheaper in Brazil than in Australia.

6.5.4 Discussion

Brazil is currently undergoing the worst drought in a century and taking a number of drastic measures to maintain electricity reliability. These measures include:

- Authorising thermoelectric plants to fire up without contracts for up to six months "on an exceptional and temporary basis"[36]. This would compensate gas and other thermal generators for producing electricity, paying fixed and variable costs, even if generators did not previously have a generation contract in place before the drought.
- Significantly increasing gas imports. In the first six months of 2021, Brazil has already imported more gas (both pipeline gas and LNG) than it did in the whole of 2020. While this is partly due to the effects of the drought, the Brazilian government has suggested that Brazil will remain a good market for LNG for years to come as a result of the increasing role of GPG in the energy transition.
- Implementing 'red flag' tariffs.
- Implementing voluntary power rationing programs for large customers[37].

Droughts in Brazil also occurred in 2014/15 and in the early 2000s. The drought during the early 2000s resulted in power rationing that affected millions of customers. The expansion in thermal generation (and renewables) since the early 2000s, and relatively lower reliance on hydro generation, has assisted security of supply in the current drought.

36 https://www.reuters.com/world/americas/brazil-grants-wide-authorization-thermal-plants-drought-2021-06-07/

37 https://www.bnamericas.com/en/news/brazil-ups-bet-on-voluntary-power-rationing-in-the-face-of-water-crisis

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