Wholesale electricity pricing modelling

A FINAL REPORT PREPARED FOR COAL INNOVATION NSW

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Not NSW Government Policy

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Executive summary

Coal Innovation NSW (**CINSW**) is currently undertaking the *Future of NSW Coal Electricity Generation Industry Study* (**Future of NSW Coal Study**). The Future of NSW Coal Study is intended to provide the NSW Government with wholesale electricity pricing and economic impact modelling of the future electricity generation market in the National Electricity Market (**NEM**) and in NSW.

Frontier Economics and the Centre of Policy Studies (**CoPS**) have been engaged by CINSW to undertake modelling for the Future of NSW Coal Study. Frontier Economics has been largely responsible for electricity market modelling and CoPS has been largely responsible for Computable General Equilibrium (**CGE**) modelling. Frontier Economics and CoPS have worked together to ensure that the electricity market modelling and CGE modelling are internally consistent.

This report sets out the results of our modelling on the future of the wholesale electricity market in NSW and in the rest of the NEM.

Overview of our electricity market modelling

There are two related aspects to the electricity market modelling that we are required to undertake for this project:

- Modelling expected long-term investment outcomes in NSW and the rest of the NEM for the 33 years from 2017/18 to 2049/50.
- Modelling expected half-hourly dispatch and prices in NSW and the rest of the NEM for the 33 years from 2017/18 to 2049/50.

These two aspects of the electricity market modelling for this project are undertaken as part of a coherent framework.

We model long-term investment outcomes in NSW and the rest of the NEM using our long-term optimisation model, *WHIRLYGIG*. In order to model long-term investment and retirement decisions over the 33-year modelling period, *WHIRLYGIG* models 54 representative demand points for each year, rather than the full 17,560 half hours of the year. However, it is clear that modelling sequential half-hourly outcomes is important for a robust assessment of dispatch and prices in the context of a generation mix that increasingly consists of variable wind and solar generation. For this reason, we model dispatch and pricing making use of our half-hourly dispatch model – *SYNC*.

Overview of CGE modelling

The CGE modelling that we have undertaken relies on applications of the Victoria University Regional Model (**VURM**), which is the rebranded version of the Monash Multi-Regional Forecasting model (**MMRF**). The change of name reflects CoPS' move from Monash University to Victoria University in early 2014.

VURM is a dynamic economic model of Australia's six states and two territories. It models each region as an economy in its own right, e.g., the model contains region-specific prices, consumers, industries, etc. Technical documentation of the model equations and database can be downloaded from http://www.copsmodels.com/elecpapr/g-254.htm.

Modelling input assumptions

Our Base Case consists of a series of "most likely" or central predictions for all inputs and assumptions.

For the electricity market modelling, for the most part we draw on information published by the Australian Energy Market Operator (**AEMO**) for these Base Case assumptions. Our Base Case demand inputs are based on the central scenario of AEMO's March 2018 update to its Electricity Forecasting Insights report. Our Base Case inputs for generation capability and costs are based on the inputs developed as part of AEMO's Integrated System Plan (**ISP**).

For the CGE modelling, the Base Case is based on business-as-usual trends in demography, technology and Australia's trading conditions with the rest of the world. The Base Case incorporates a large amount of information from specialist forecasting agencies and information on electricity supply from Frontier Economics' modelling.

Modelling scenarios

In addition to the Base Case, we undertake electricity market modelling the following scenarios:

- **HELE Scenario**: In the HELE Scenario we provide for all black coal generators in the NEM to be repowered. The assumptions we use to define the repowering of these black coal were provided to CINSW by The Electric Power Research Institute (EPRI).
- **Grid Storage Scenario**: The Grid Storage Scenario is designed to investigate the effect of additional uptake of utility-scale storage. Specifically, in the Grid Storage Scenario we assume that there is increased uptake of pumped hydro generation plant across the NEM.
- **Rooftop PV Scenario**: In the Rooftop PV Scenario we assume that there is increased uptake of rooftop PV and distributed batteries. Rather than using AEMO's neutral forecasts for rooftop PV and distributed battery adoption, we use AEMO's strong forecasts for adoption.
- **MEGS Scenario**: In the MEGS Scenario we model prices for the investment results in selected years that are generated by MEGS.

- **High Demand Scenario**: In the High Demand Scenario we model outcomes making use of the strong scenario of AEMO's March 2018 update to its Electricity Forecasting Insights report.
- **High Solar Thermal Cost Scenario**: In the High Solar Thermal Cost Scenario we model outcomes making use of a higher estimate of the capital cost of solar thermal plant.
- **Interconnector Expansions Scenario**: In the Interconnector Expansions Scenario we configure interconnector capacities to match AEMO's recent report on Regions and Marginal Loss Factors.
- **Updated Entrant Fuel Cost Scenario**: In the Updated Entrant Fuel Cost Scenario we make use of the updated coal price forecasts for new entrant generators in the NEM that AEMO has released as part of its ISP. This updated coal price forecasts represents a substantial increase over the original coal price forecasts that AEMO has released as part of its earlier ISP releases.
- **Updated Entrant Fuel Cost HELE Scenario**: In the Updated Entrant Fuel Cost HELE Scenario we make use of the same updated coal price forecasts for new entrant generators discussed above, but we use that updated coal price forecast in the HELE Scenario.
- **High Renewable Drought Scenario**: In the High Renewable Drought Scenario we model a longer renewable drought that we have in our Base Case and other scenarios.
- **High Emissions Reduction Scenario**: In the High Emissions Reduction Scenario the carbon emissions target for the NEM is changed to be a 90% reduction by 2040. Along with this change, the QRET and VRET were assumed to be rolled into a national scheme.
- **Alternate Coal Price Scenario**: In the Alternate Coal Price Scenario, coal prices were taken from the IHS report provided by DPE. Compared to the Base Case coal prices, this results in higher coal prices in early years, but lower coal prices over the rest of the modelling period.
- **High Gas Price Scenario**: In the High Gas Price Scenario the assumed gas price is increased by $5/GJ (relative to the Base Case) over the period from 2019 till 2024, and thereafter remains $5/GJ higher for the rest of the modelling period.

For the CGE modelling, we undertaken modelling of the Base Case and three of these scenarios, being the following:

- High Demand Scenario.
- High Solar Thermal Cost Scenario.
- Alternate Coal Price Scenario.

Implications of our modelling

The key implications of our electricity market modelling are summarised in Table 1.

Table 1: Implications of our modelling

Implication	Explanation
There is a reasonable path to replacing NSW's retiring coal-fired generation	Over the next 20 years, four out of five of NSW's baseload coal-fired generators will retire. Our electricity market modelling indicates that a mix of generation and storage technologies can replace these coal-fired generators so that demand for electricity in NSW continues to be met. For instance, in the Base Case, we see significant new investment in solar PV and solar thermal generation with storage, above what's already committed, with lesser amounts of new investment in coal-fired plant, gas-fired plant and wind generation. While there is a reasonable path to replacing NSW's retiring coal-fired generation, we note that our modelling suggests there will be material wholesale price increases following the retirement of Liddell power station in 2021/22 and Vales Point power station in 2027/28 if, as our modelling suggests, there is no new investment in utility-scale generation in NSW following the closure of these plant.
New coal-fired generation may have a place in NSW	Our Base Case modelling sees investment in 3,400 MW of new supercritical coal plant (without carbon capture and storage (CCS)) in NSW in 2032/33 and 2033/34. This coincides with the retirement of Eraring power station in 2032/33 and Bayswater power station in 2034/35. This new coal plant continues to operate until the end of the modelling period. This result is quite consistent across the scenarios for which we have modelled long-term investment: there are slight differences in the capacity of new coal plant, and slight differences in the timing of new coal plant, but almost all scenarios see quite similar results in this regard. The exception is where we have a more aggressive emissions reduction target, in which case we see no new investment in coal plant. Importantly, this modelling result is based on us using the same cost of capital for all generation technologies. If the perception of greater risk for investment in coal plant results in a requirement for a higher return for coal plant, it may be the case that other investment proceeds in place of investment in new coal plant. We also see new investment in combined cycle gas turbines (CCGT), including CCGT with carbon capture and storage (CCS), but smaller amounts and later in the modelling period. The decision primarily to invest in new coal plant rather than new gas plant reflects the relative cost of the two technologies in supplying the required baseload electricity. While the assumed capital cost of coal plant is significantly higher than CCGT plant, the assumed fuel cost for coal plant is much lower than for gas plant (below $2.50/GJ in NSW in the long term compared with around $9.00/GJ in NSW in the long term). Different relative costs – including capital costs, fuel costs and the costs of complying with emissions reductions targets – could well see investment in new gas plant instead of new coal plant. While comparing levelised costs can provide an indication of relative economics of coal and gas plant, it is important to bear in mind that levelised costs depend on required capacity factors, and the economics of coal and gas plant are also affected by the flexibility of their operation.

Lower coal prices or higher gas prices do no significantly increase coal investment	In scenarios in which we have modelled lower coal prices or higher gas prices we do not see significantly greater investment in coal plant. The reason is that investment in significantly more new coal plant than we see in the Base Case (around 3,400 MW) makes it more difficult to meet the emissions target in our modelling. Additional emissions from additional coal plant would need to be offset somehow; the only real option is investing in carbon capture and storage (at higher capital cost). The sensitivity of coal investment to the assumed emissions target is shown in the scenario we model with a more aggressive emissions reduction target. With more aggressive emissions reduction target we see no new investment in coal plant.
Higher demand does not improve the case for new coal-fired generation in NSW	Assuming that the emissions target is unchanged, higher demand for electricity does not increase the amount of coal-fired generation built in NSW in the future. The reason is that meeting the same emissions target in a world of higher demand makes the emissions reduction task more difficult, and makes it more difficult to justify additional investment in coal-fired plant.
The case for re-powering existing coal-fired power stations in NSW is not clear	Our HELE Scenario includes options for investing in repowering NSW's existing coal-fired power stations as USC or A-USC plant. However, our modelling of the HELE Scenario finds that investment in greenfields supercritical coal plant is preferred to these repowering options. The principal reason for this is that the assumed coal price for greenfields coal plant is much lower than the assumed coal price for existing generation plant (which we assume also apply to repowering options). If this difference in relative coal prices did not occur it would be more likely that the lower capital cost associated with repowering options would mean that this would be more likely. In the Updated Entrant Fuel Cost HELE Scenario we see re-powering of Bayswater power station, in preference to investment in greenfields coal plant. This confirms that the assumed low coal price for existing generation plant was the reason that greenfields coal plant was built in preference to re-powering in the HELE Scenario. Given that the fuel costs in the Updated Entrant Fuel Cost HELE Scenario are AEMO's current view, this suggests to us that there is a case for re-powering an existing coal-fired power station.
Additional pumped-storage hydro need not directly compete with coal-fired power stations	In the scenario in which we assumed investment in additional pumped-storage hydro generation across the NEM, we do not see the displacement of new coal-fired generation in NSW or the earlier retirement of coal-fired generation in NSW. The reason is that pumped-storage hydro generation is not a net producer of electricity; indeed, it is a net consumer of electricity since it takes more electricity to pump water uphill than is generated by releasing the water back downhill. Pumped-storage hydro is used to time-shift electricity consumption and, as such, can improve the economics for baseload generation like coal-fired generation. Instead, we see that the additional pumped-storage hydro generation displaced solar thermal generation (because part of the benefit of solar thermal generation is the storage that it provides, and this additional storage becomes less valuable with additional pumped-storage hydro generation), and facilitates additional investment in solar PV and wind generation (which occurs in place of solar thermal generation).

Coal-fired generation retirements mean that NSW is likely to be on track to achieve net zero emissions	The investment in some new coal-fired generation in NSW is consistent with NSW's policy objective of net zero emissions by 2050 (subject to our assumption that emissions reductions of up to 10 per cent of current emissions can be offset). Much of NSW's generation is currently relatively carbon-intensive black coal generation. Our modelling indicates that a mix of generation and storage technologies can replace NSW's coal-fired generation as major power stations retire. Other than the 3,400 MW of new coal-fired generation, this mix of technologies are all renewable or CCS. This means that NSW's emissions fall significantly over time, and even with 3,400 MW of new coal generation NSW's total emissions remain consistent with our modelled NSW emissions constraint. To facilitate this, new coal reduces its capacity factor to 30% at the end of the 2040s and retires a small portion. A similar pattern is observed across the NEM, which means that total emissions for the electricity sector in the NEM also remain consistent with our modelled NEM-wide emissions constraint.
Coal-fired generation retirements can result in higher wholesale prices in NSW	While policy-driven renewable investment in Victoria and Queensland will result in lower wholesale prices for NSW in the near term, major generation retirements in NSW can result in wholesale price increases. For instance, in the Base Case, and each of our other scenarios, our modelling forecasts material wholesale price increases in NSW following the retirement of Liddell power station and then Vales Point power station. Prices increase largely because we see no new investment in utility-scale generation in NSW following these retirements (other than largely renewable investments that have already been committed and also including forecast new investment in behind-the-meter solar PV and batteries in NSW and across the NEM). New investment is not seen after the retirements in of Liddell power station and Vales Point power stations in NSW due to the large amount of investment in Queensland and Victoria brought on by the QRET and VRET schemes. However, the later retirements of Eraring power station and Bayswater power station do not see the same wholesale price increases, because we see substantial new investment in NSW following these retirements.
Coal-fired generation retirements will significantly increase the diversity of NSW's electricity supply	NSW's generation mix is currently dominated by coal-fired generation. As discussed, our modelling indicates that a mix of generation and storage technologies can replace this coal-fired generation as major power stations retire. This *mix* of technologies – including new coal plant, new CCGT with CCS, solar thermal, solar PV, wind generation and batteries – means that NSW's generation supply will become significantly more diverse. It is clear from our modelling results that, where intermittent renewable plant forms an important part of the generation mix, there is a benefit to having a diverse mix of new generation plant. This is because this diversity reduces the risk that a large share of the generation mix will face drought (solar, wind or hydro) at the same time. Investors will also see some benefit in diversity because too much intermittent generation of a particular type in a given region will drive down prices in that region when that generation technology is operating (for instance, too much wind in South Australia will result in very low, or negative, prices during windy periods).

There are a number of risks to a smooth path to replacing NSW's retiring coal-fired generation	There are a number of risks to a smooth transition for NSW's energy supply as coal-fired generation retires. The risks include the following: Unexpected demand shocks – It can take time for market participants and investors to identify and respond to unexpectedly higher demand growth. If demand growth is unexpectedly higher than forecast, NSW customers are likely to be exposed to materially higher prices until new investment occurs This is particularly the case as dispatchable coal plant retires, since intermittent renewable has little ability to increase output in response to higher demand. Delayed investment in batteries – Our modelling incorporates significant investment in behind-the-meter solar PV and batteries, based on AEMO's forecasts. Our modelling indicates that these behind-the-meter batteries are increasingly important in meeting demand. Indeed, without this forecast adoption of behind-the-meter batteries (or without them operating at times of peak demand), significant additional new investment in utility-scale generation or storage would be necessary to ensure that NSW can continue to meet demand. Delayed investment in major generation plant – A delayed investment in planned new generation plant can have an even more significant effect than unexpected demand shocks. The reason is that investments, particularly in coal and gas plants, tend to be lumpy, and the capacity of a single power station can be much larger than any likely demand shock.
While modelling outcomes are dependent on assumptions, most trends persist in all scenarios	Our modelling shows substantial similarity in key results across most, or all, scenarios. This includes: • Little need for new investment in NSW until the early 2030s (except in the High Demand Scenario). • New coal-fired generation around the closure of Bayswater and Eraring power stations (except in the High Emissions Reduction Scenario). • Substantial investment in new renewable generation and storage (either solar thermal with storage or stand-alone batteries). • Lower wholesale electricity prices during the 2020s following by long-term wholesale electricity prices around \$80/MWh to \$100/MWh. Nevertheless, it is clear that specific outcomes do depend on input assumptions. For instance, where we model a higher solar thermal capital cost we see that there is no investment in solar thermal plant in NSW, and greater investment in solar PV, batteries and gas plant. Similarly, when we model higher fuel prices for greenfields coal plant in NSW, we that there is much less investment in greenfields coal plant, or investment in re-powered coal plant instead (where it is an option).

Macroeconomic effects of modelled scenarios are generally small	The deviations from the Base Case of the three scenarios that we have undertaken CGE modelling for are small: • The High Demand Scenario sees increased real GSP (by 0.15 per cent in 2050 compared to the Base Case) and increased employment (by 0.07 per cent in 2050 compared to the Base Case). This is due to switching towards electricity, which has a relatively high local content, away from non-electricity inputs, which have, on average, a lower local content. • The Alternate Coal Price Scenario sees small increases in GSP and employment when prices are lower than the Base Case and small decreases in GSP and employment when prices are higher than the Base Case. • The High Solar Thermal Cost Scenario sees small reductions in GSP and employment as a result of what is effectively a significant technological deterioration. Given that we have undertaken macroeconomic modelling of scenarios that saw some of the largest differences in the energy sector, this suggests that the macroeconomic consequences of the energy scenarios that we have investigated will be small. So, for instance, the macroeconomic consequences of a difference between building new coal plant in NSW in the 2030s, or building a mix of other plant instead of coal, would be small.

1 Introduction

This report from Frontier Economics and the Centre of Policy Studies (**CoPS**) to Coal Innovation NSW (**CINSW**) sets out the results of our modelling on the future of the wholesale electricity market in NSW and in the rest of the National Electricity Market (**NEM**).

1.1 Background

CINSW is currently undertaking the *Future of NSW Coal Electricity Generation Industry Study* (**Future of NSW Coal Study**). The Future of NSW Coal Study is intended to provide the NSW Government with wholesale electricity pricing and economic impact modelling of the future electricity generation market in the NEM and in NSW.

The Future of NSW Coal Study has been structured into four stages.

- **Stage 1** is to develop a comprehensive baseline of data and examine two reference scenarios. The two reference scenarios are 'business as usual' and 'basic emissions abatement policy'.
- **Stage 2** is to test outcomes under several options and scenarios that NSW could put in place under a carbon constrained future.
- **Stage 3** is to undertake:
  - a comparable assessment of the Stage 1 and Stage 2 modelling with a range of recently published reports.
  - modelling of NSW wholesale electricity pricing under a number of scenarios.
- **Stage 4** is to develop a Computable General Equilibrium (**CGE**) model to assess the potential economic impacts of the scenarios modelling in Stage 3.

Stage 1 and Stage 2 of the Future of NSW Coal Study have already been undertaken. Ernst & Young (**EY**) completed these first two stages on behalf of CINSW.

1.2 Frontier Economics' and CoPS' engagement

Frontier Economics and CoPS have been engaged by CINSW to undertake Stage 3 and Stage 4 of the Future of NSW Coal Study. Frontier Economics has been largely responsible for the electricity market modelling required under Stage 3 and CoPS has been largely responsible for the CGE modelling required under Stage 4. Frontier Economics and CoPS have worked together to ensure that the modelling for Stage 3 and Stage 4 is internally consistent.

Frontier Economics has previously provided CINSW with a final report for the comparable assessment of the Stage 1 and Stage 2 modelling with a range of recently published reports.[1]

Frontier Economics has also previously provided CINSW with an earlier version of this modelling report.[2] This updated version of our modelling report includes results for four additional scenarios that we have modelled.

1.3 This report

This report sets out the results of our modelling on the future of the wholesale electricity market in NSW and in the rest of the NEM.

This report is structured as follows:

- Section 2 outlines the modelling methodology that we have used to undertake modelling on the future of the wholesale electricity market in NSW and in the rest of the NEM.
- Section 3 sets out the key input assumptions that we have used, and outlines the various scenarios that we have modelled.
- Section 4 sets out the results of our electricity market modelling, focusing on NSW.
- Section 5 sets out our CGE modelling.

Appendix A provides summary modelling results for other regions of the NEM.

1 Frontier Economics, *Comparable assessment*, A Report Prepared for Coal Innovation NSW, May 2018.

2 Frontier Economics, *Wholesale electricity pricing modelling*, A Final Report Prepared for Coal Innovation NSW, July 2018

2 Electricity market modelling methodology

This section describes the methodology that we have used to undertake modelling on the future of the wholesale electricity market in NSW and in the rest of the NEM.

2.1 Overview of our electricity market modelling approach

There are two related aspects to the modelling that we are required to undertake for Stage 3 of this project:

- Modelling expected long-term investment outcomes in NSW and the rest of the NEM for the 33 years from 2017/18 to 2049/50.
- Modelling expected half-hourly dispatch and prices in NSW and the rest of the NEM for the 33 years from 2017/18 to 2049/50.

These two aspects of the modelling for this project are undertaken as part of a coherent framework. We describe our approach to each of these aspects in the sections that follow.

2.2 Modelling long-term investment outcomes

We model long-term investment outcomes in NSW and the rest of the NEM using our long-term optimisation model, *WHIRLYGIG*.

WHIRLYGIG is a long-term investment model for electricity markets. *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 least cost dispatch. *WHIRLYGIG* provides an estimate of the long run marginal cost (LRMC) of electricity and the marginal cost of meeting any policy obligations. An overview of *WHIRLYGIG* is provided in Figure 1.

WHIRLYGIG models outcomes in the electricity market, but does not jointly model outcomes in markets for ancillary services.

WHIRLYGIG includes a representation of demand and supply conditions in each of the regions of the NEM, including the capacity of interconnectors between the regions. *WHIRLYGIG* does not include existing intra-regional network constraints, largely because there is no robust way to forecast these network constraints in the long-term without detailed network modelling undertaken by the transmission network service providers.

Figure 1: *WHIRLYGIG* schematic

In order to model long-term investment and retirement decisions over the 33-year modelling period, *WHIRLYGIG* models 54 representative demand points for each year, rather than the full 17,560 half hours of the year. *WHIRLYGIG* also models additional demand points that represent peak demand outcomes for a 1-in-10 year (POE10). These representative demand points are defined to capture a diverse range of outcomes for demand (ensuring we account for periods of high demand), solar PV generation and wind generation (ensuring we account for periods of low generation) across seasons. *WHIRLYGIG* includes dispatch of the power system for each one of these 54 representative demand points for each year, to ensure demand can be met at each point, having regard to the level of intermittent generation for that point.

Nevertheless, it is clear that modelling sequential half-hourly outcomes is important for a robust assessment of dispatch and prices in the context of a generation mix that increasingly consists of variable wind and solar generation. For this reason, we model dispatch and pricing making use of our half-hourly dispatch model – *SYNC*.

2.3 Modelling expected half-hourly dispatch and wholesale prices

We model dispatch and wholesale price outcomes in NSW and the rest of the NEM using our electricity market dispatch model, *SYNC*.

SYNC is an electricity market dispatch model that focuses on detailed short-term (half-hourly or less) 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 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. An overview of *SYNC* is provided in Figure 2.

SYNC models outcomes in the electricity market, but does not jointly model outcomes in markets for ancillary services.

SYNC includes a representation of demand and supply conditions in each of the regions of the NEM, including interconnectors between the regions. *SYNC* does not include existing intra-regional network constraints, largely because there is no robust way to forecast these network constraints in the long-term without detailed network modelling undertaken by the transmission network service providers.

Figure 2: *SYNC* schematic

Once we have modelled *SYNC*, we test whether the results are consistent with the investment outcomes in *WHIRLYGIG* and, if not, adjust our *WHIRLYGIG* modelling accordingly and repeat our modelling process.

We note that this sequential modelling approach – with investment decisions modelled in a long-term model with a simplified demand duration curve and dispatch and wholesale prices modelled in a half-hourly dispatch model – is consistent with the modelling framework adopted by AEMO for its Integrated System Plan.

It is worth noting that while *WHIRLYGIG* seeks to minimise total system costs, *SYNC* is determining dispatch and prices. While system costs and price outcomes are related they can move in different ways: for instance, system costs can increase without prices increasing. The reason is the treatment of capital costs. Capital costs are an important determinant of what generation technology gets built (although not the only determinant – *WHIRLYGIG* also considers operating costs, including fuel costs, and operating characteristics, in deciding what generation technology gets built). And obviously the sort of generation technologies that get built are an important determinant of prices – this is why we need to know what the generation mix looks like when we forecast prices. Importantly, though, for a given mix of generation technology, the prices that we will see in the market will not be affected by capital costs. This is because these capital costs are sunk, and generators do not seek (and should not seek) to include these sunk fixed costs in their bids in to the market. Rather, their bids should be based on short run marginal cost.

In those scenarios in which we are forcing in a particular kind of generation plant we do not need to know its capital cost to get the investment mix (since we are forcing it in). We do still need the capital costs of all the other plant so that they can be optimised around this plant. And in the cases in which we are forcing in a particular kind of generation plant we also do not need to know its capital cost to forecast prices, since sunk capital costs do not affect prices. The only reason we need to know the capital costs of those plant that we are forcing in is to report total system cost.

3 Electricity market modelling assumptions

This section sets out the key input assumptions that we have used in our electricity market modelling, and outlines the various scenarios that we have modelled.

3.1 Base Case modelling assumptions

Our Base Case consists of a series of "most likely" or central predictions for all inputs and assumptions. For the most part we draw on information published by the Australian Energy Market Operator (AEMO) for these Base Case assumptions.

3.1.1 Demand forecast

Our Base Case demand inputs are based on the central scenario of AEMO's March 2018 update to its Electricity Forecasting Insights report,[3] as shown in Figure 3 (for annual consumption) and Figure 4 (for annual maximum demand, for 50% probability of exceedance (POE) and 10% POE).[4]

AEMO's demand forecast takes into account the contribution by rooftop PV and non-utility battery to annual consumption and peak demand. In other words, its operational energy forecast excludes consumption met by rooftop PV, and accounts for rooftop PV and non-utility battery's contribution to peak demand. In addition, AEMO also forecasts energy consumption that is "saved" due to improvements in energy efficiency measures. Our Base Case demand forecast reflects the neutral forecast for these components as part of operational demand forecasts.

In general, as seen in Figure 3, NSW operational energy consumption is forecast to be quite stable over the period to the 2030s. It undergoes a mild reduction in the early years before flattening out in the 2020s. It then experiences a slight recovery in the 2030s which we extrapolate to continue to 2050. We see a similar trend for peak demand, as seen in Figure 4.

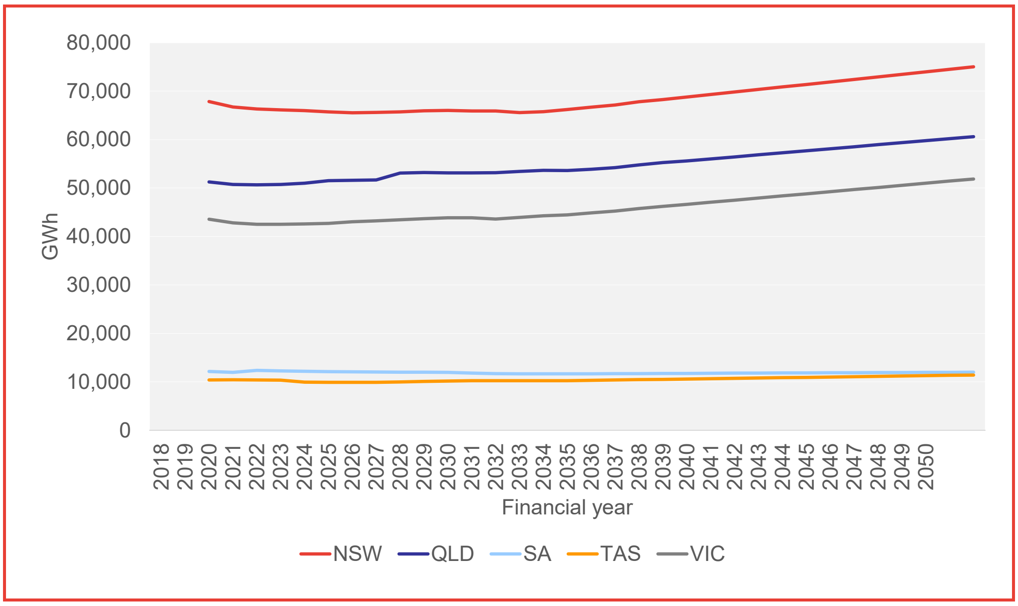
Demand forecasts in the two major NEM regions adjacent to NSW, Victoria and Queensland, will also have a material impact on the modelling results due to the interconnectedness of the NEM. The general patterns in Victoria and Queensland are quite similar to NSW, although forecast demand in Victoria and Queensland does not decrease to the same extent as it does in NSW.

The same set of AEMO neutral energy forecasts are used in all our scenarios.

3 AEMO, *2018 Electricity Forecasting Insights – March 2018 Update*, 29 March 2018.

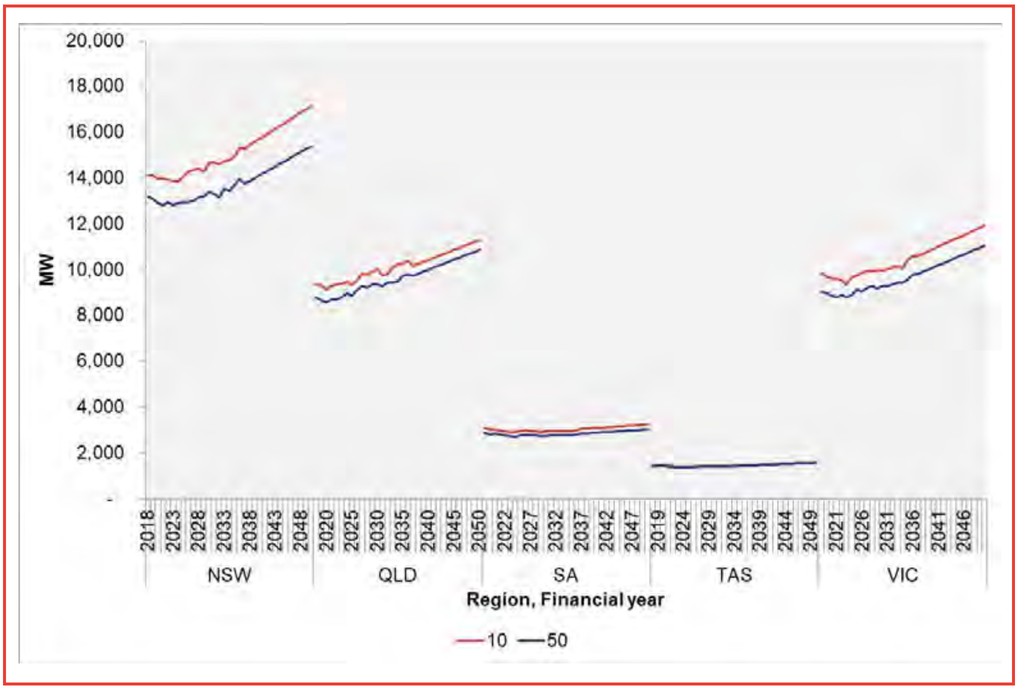
4 AEMO forecasts up to financial year 2036/37. We have applied a linear trend and extrapolated out to financial year 2041/42.

Figure 3: Energy consumption forecast (Operational, sent-out, GWh)



Source: AEMO 2018 EFI – March 2018 Update with Frontier Economics extrapolation post 2036/37.

Figure 4: Maximum demand forecast (Operational, sent-out, MW)



Source: AEMO 2018 EFI – March 2018 Update with Frontier Economics extrapolation post 2036/37.

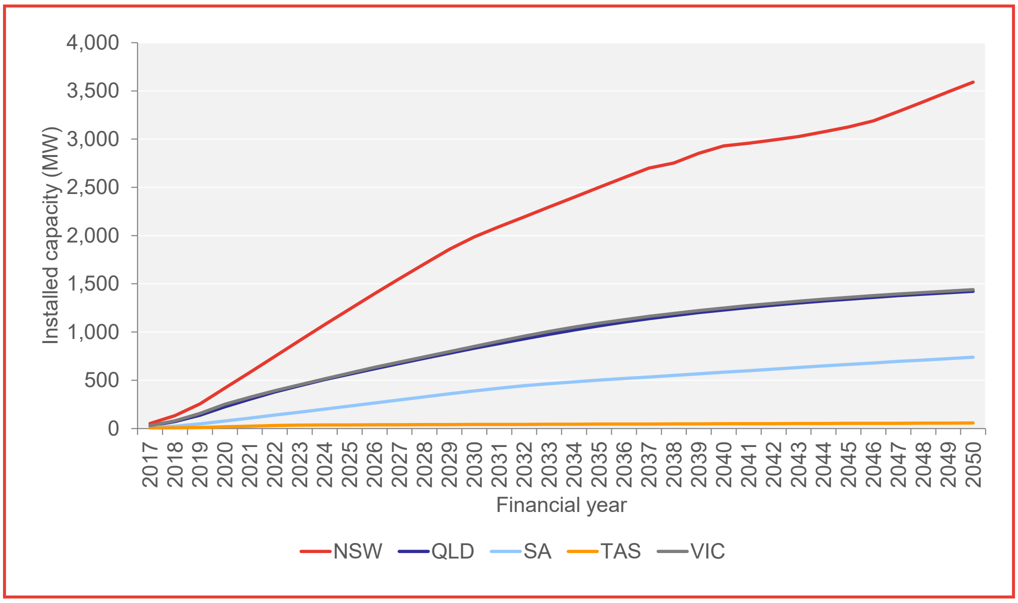
Electricity market modelling assumptions

3.1.2 Distributed battery capacity

AEMO's demand forecasts contain projections for distributed battery installation. We have incorporated AEMO's neutral projection of distributed battery installation in our Base Case, and have assumed in our modelling that these batteries respond to wholesale prices and peak demand. Figure 5 and Figure 6 show the capacity and energy storage of distributed batteries in the Base Case.

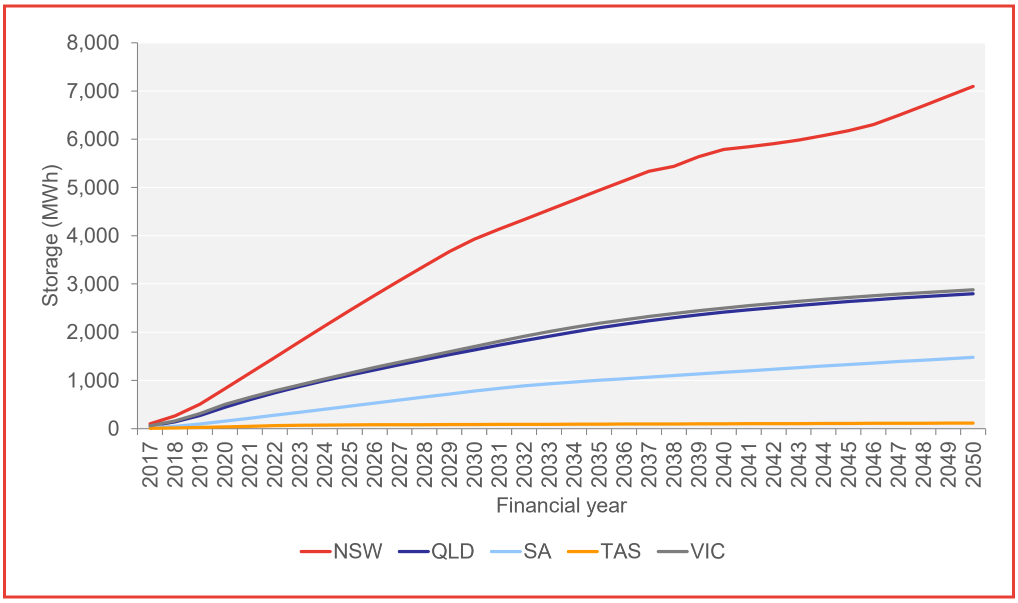
The same set of AEMO distributed battery forecasts are used in all scenarios, with the exception of the Rooftop PV Scenario.

Figure 5: Distributed battery capacity



Source: AEMO 2018 EFI – March 2018 Update with Frontier Economics extrapolation post 2036/37.

Figure 6: Distributed battery storage



Source: AEMO 2018 EFI – March 2018 Update with Frontier Economics extrapolation post 2036/37.

3.1.3 Generation options

The options we include for new generation plant are those that are included in the CSIRO's Electricity Generation Technology Cost Projections report,[5] which is the source of capital costs proposed in AEMO's ISP consultation report.

These new generation plant options are:

- Supercritical PC - Black coal
- UltraSupercritical PC - Black coal
- UltraSupercritical PC - Black coal with carbon capture and storage (CCS)
- Supercritical PC - Brown coal
- UltraSupercritical PC - Brown coal
- UltraSupercritical PC - Brown coal with CCS
- Nuclear
- CCGT
- CCGT with CCS

5 Jenny Hayward and Paul Graham, *Electricity generation technology cost projections 2017-2050*, CSIRO, December 2017.

- OCGT
- Biomass - steam turbine
- Utility PV
- Wind - onshore
- Solar thermal with storage (6hrs storage)
- Large Scale Battery Storage (2hrs storage)
- Pumped Hydro (6hrs storage).

Consistent with CSIRO's report we are assuming that all of these technologies will be ready for commercial deployment during the modelling period. We don't consider this to be an unrealistic assumptions: each of these technologies have already been deployed on a commercial scale somewhere in the world.

We have retained nuclear as an option but recognise that constructing a nuclear power plant it is not consistent with current policy.

Note that we also include additional generation technologies in our HELE Scenario, as discussed below.

3.1.4 Fuel prices

Our fuel price forecasts are sourced from AEMO's Integrated System Plan (ISP) modelling assumptions.[6]

The average combined cycle gas turbine (CCGT) gas prices used in our modelling for reach region are shown in Figure 7. The corresponding open cycle gas turbine (OCGT) gas prices are 50 per cent higher.

The coal prices for NSW, Queensland and Victoria power stations are shown in Figure 8 to Figure 10.

The fuel costs are the same in all our modelling scenarios.

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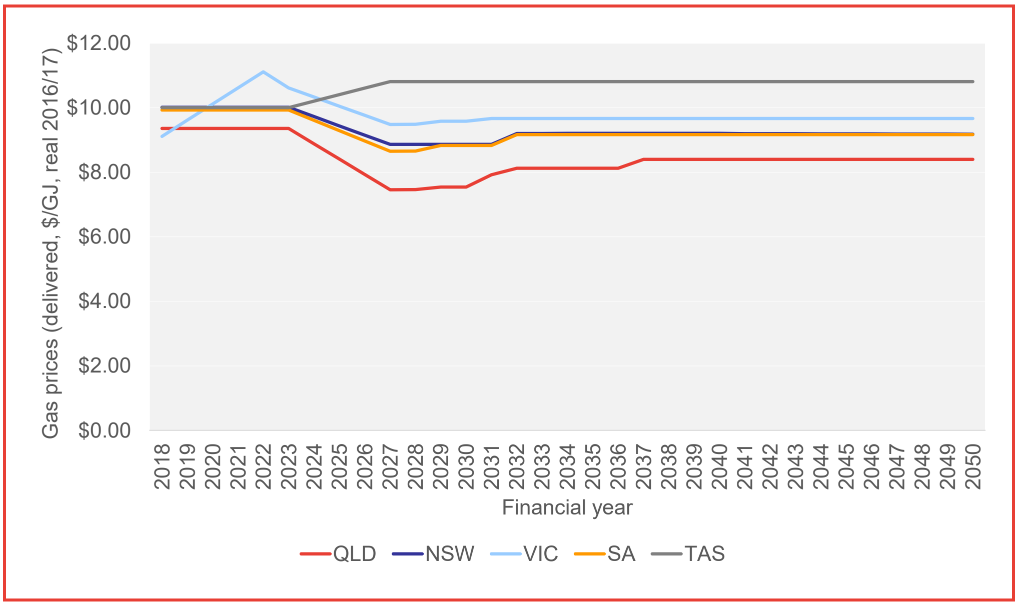
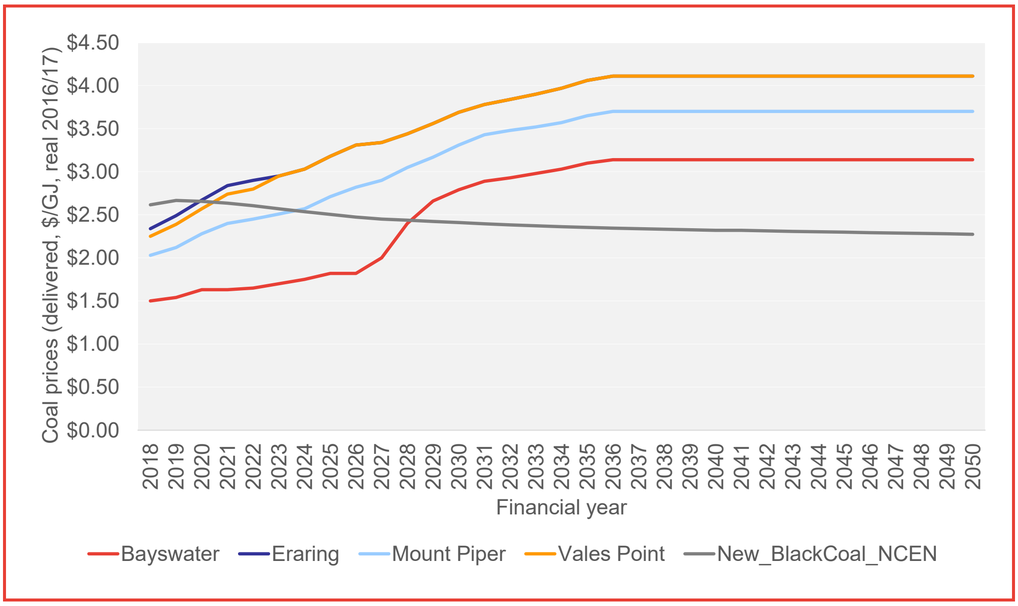
6 AEMO, *Integrated System Plan modelling assumptions*. Available here: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2018/2018-Integrated-System-Plan--Modelling-Assumptions--v21.xlsx

Figure 7: Average gas prices for CCGT plant



Source: AEMO ISP modelling assumptions.

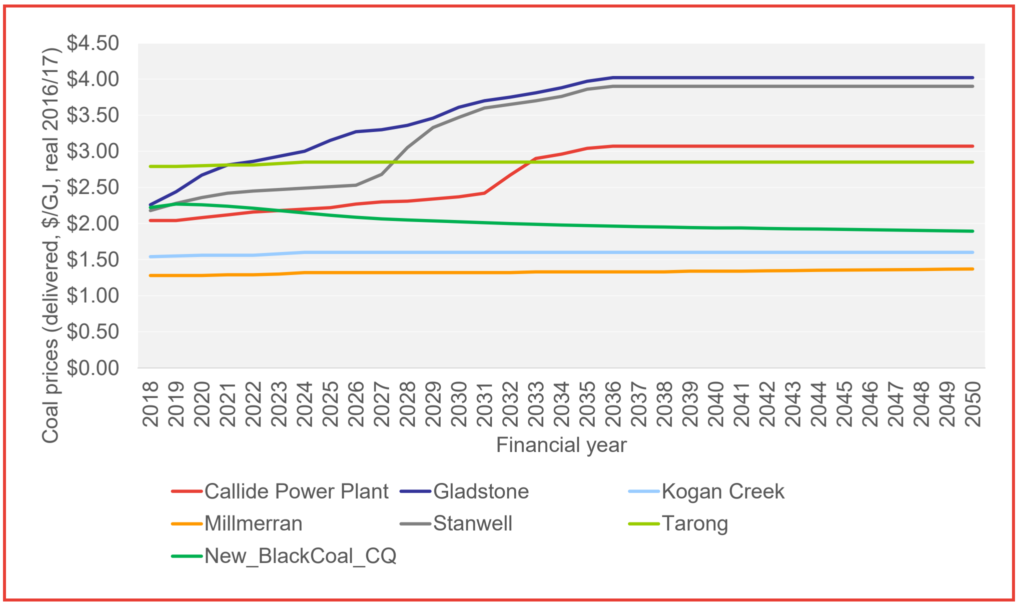
Figure 8: Coal prices for NSW power stations



Source: AEMO ISP modelling assumptions.

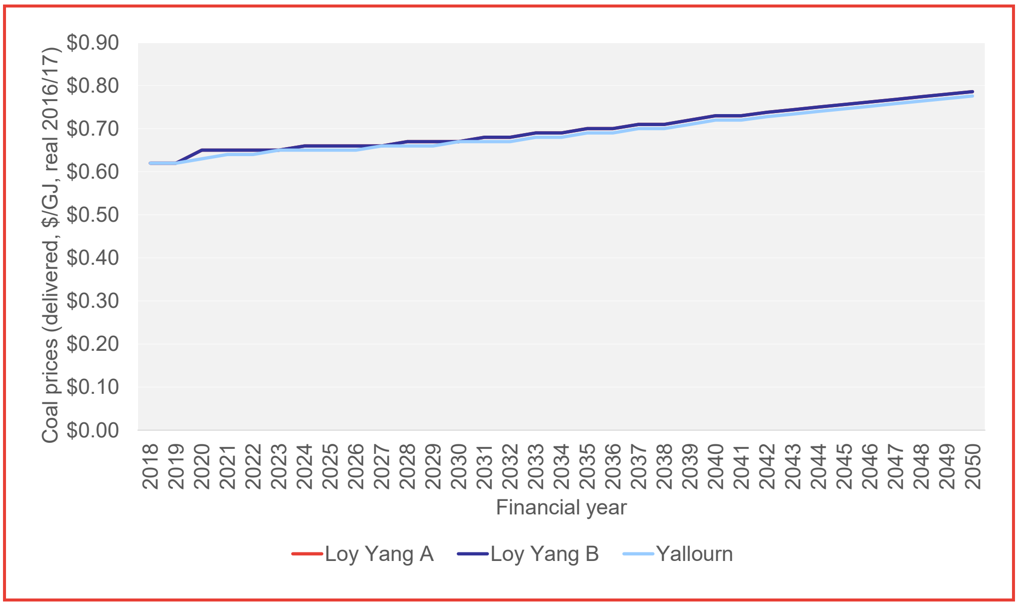
Electricity market modelling assumptions

Figure 9: Coal prices for QLD power stations



Source: AEMO ISP modelling assumptions.

Figure 10: Coal prices for VIC power stations



Source: AEMO ISP modelling assumptions.

3.1.5 Capital Costs

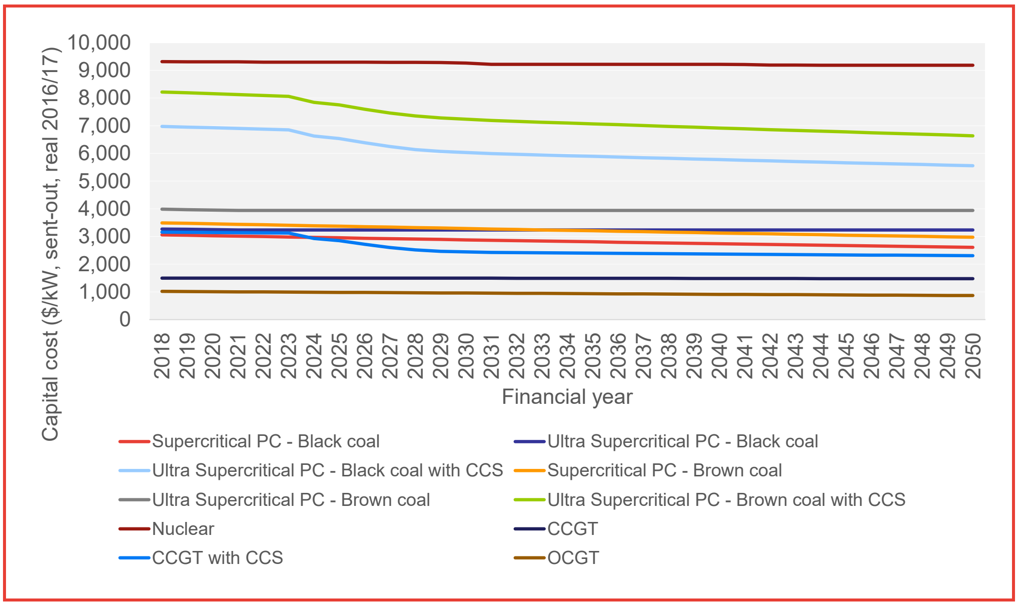
The capital costs for new entrant power station are based on CSIRO's two-degree scenario in its Electricity Generation Technology Cost Projections report,[7] which is the source of capital costs proposed in AEMO's ISP consultation report.

Figure 11 and Figure 12 show the capital cost used in our Base Case for thermal and renewable technologies. For comparison purpose, we have shown CCGT capital costs for both charts.

While the cost of traditional and mature gas and coal technologies are predicted to remain stable, there are significant cost reductions in new thermal CCS technologies as well as new renewable technologies such as solar and battery.

These capital costs are used in all our modelling scenarios.

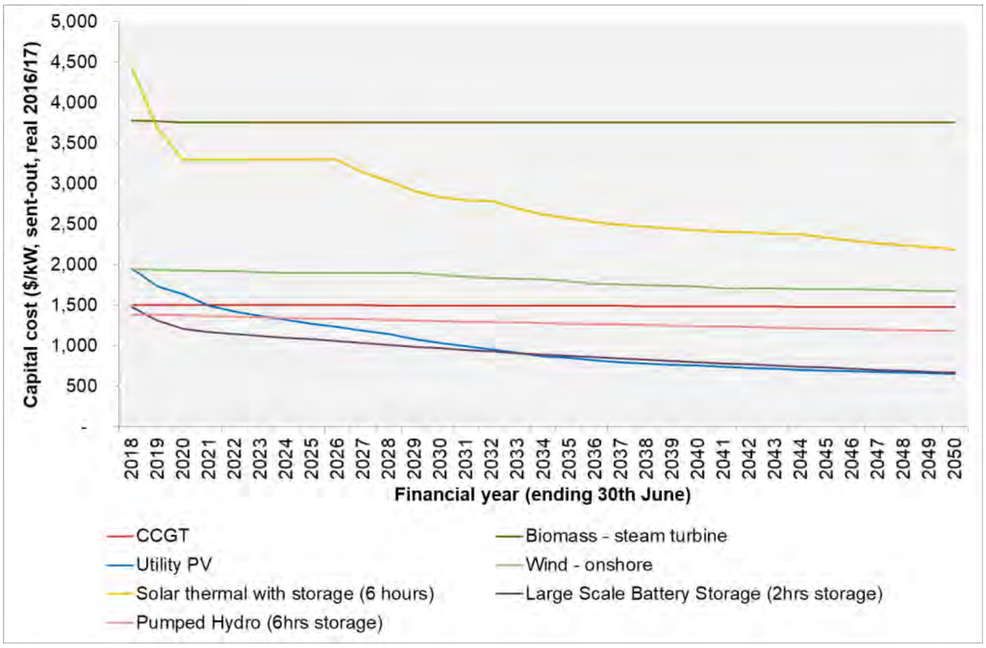
Figure 11: Capital costs – thermal technologies



Source: AEMO ISP modelling assumptions.

7 Jenny Hayward and Paul Graham, *Electricity generation technology cost projections 2017-2050*, CSIRO, December 2017.

Figure 12: Capital costs – renewable technologies



Source: AEMO ISP modelling assumptions.

Note: CCGT capital cost included as a reference point.

3.1.6 WACC

We amortise capital costs using an assumed real pre-tax weighted average cost of capital (WACC) of 8.3 per cent. This is also used as the discount rate in our long-term investment modelling.

We use the same WACC of 8.3 per cent to amortise the capital costs of all generation technologies. Other modelling reports, including reports that we reviewed as part of our Comparable Assessment Report,[8] use a different WACC for different technologies. For instance, Jacobs modelling for the Finkel Report[9]"used a WACC of 14.9 per cent for coal generation, 8.1 per cent for gas generation and 7.1 per cent for renewable generation. This was to reflect uncertainty that investors and plant owners face regarding emissions reduction policy.

We use the same WACC for all generation technologies for the modelling for this report because we are interested in understanding the relative economics of

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8 Frontier Economics, *Comparable assessment*, A Report Prepared for Coal Innovation NSW, May 2018.

9 Jacobs, *Report to the Independent Review into the Future Security of the National Electricity Market*; Emissions mitigation policies and security of electricity supply, 21 June 2017.

different generation technologies. There is no doubt that coal generation is more exposed to carbon risk than gas generation or renewable generation, and we account for this in the way that we model emissions constraints and renewable targets (as discussed below). We can also account for this by modelling different scenarios with different emissions constraints and/or renewable targets. To also assume that coal generation is exposed to a significantly higher cost of capital would not provide a clear picture of the relative economics of coal generation plant.

We would also note that given renewable investments are largely policy-driven investments – at least for the next 10 to 15 years – these investments are also exposed to policy risk and risk of changes to market design. What this suggests is that even if we thought it would be useful for this project to adjust the WACC to account for policy and market risk, this task would not be simple and should not be undertaken only for coal plant.

3.1.7 New entrant operating parameters

Our new entrant operating parameters are based on AEMO's 2018 ISP and AEMO's NTNDP 2016 modelling assumption where possible. In the instances where data is missing from AEMO's sources, we have sourced data from Frontier Economics' internal database.

Table 2 and Table 3 summarise the auxiliary power, efficiency, outage rates and carbon rate of the new entrant technologies. We have assumed that CCS technology captures 90% of the combustive emission in our modelling.

Capacity factors for utility solar PV and wind plant are shown in Table 4. When modelling utility solar PV and wind plant, their time of operation is determined by half-hourly generation traces for each technology type and region. These half-hourly generation traces are from the same historical year as the half-hourly demand traces that we use; we do this to ensure we properly preserve the correlation between weather conditions, demand and intermittent generation.

We assume that utility solar PV does not contribute to meeting peak demand (on the basis that peak demand is expected to occur in the evening) and that wind only contributes a proportion of its capacity (its "firm contribution") as maintained in AEMO's generation information releases.

Table 2: Auxiliary and thermal efficiency

Technology	Aux	Heat Rate (GT)	Equivalent planned outage rate	Equivalent forced outage rate
Supercritical PC - Black coal	7%	7.79	8.2%	6.7%
Ultra-Supercritical PC - Black coal	7%	7.51	8.2%	6.7%
Ultra-Supercritical PC - Black coal with CCS	19%	8.73	8.2%	9.1%
Supercritical PC - Brown coal	10%	10.90	8.2%	10.8%
Ultra-Supercritical PC - Brown coal	10%	10.51	8.2%	10.8%
Ultra-Supercritical PC - Brown coal with CCS	24%	11.83	8.2%	11.4%
Nuclear	5%	10.03	8.2%	9.1%
CCGT	3%	6.68	5.5%	2.0%
CCGT with CCS	10%	7.10	5.5%	3.0%
OCGT	1%	9.98	0.8%	1.8%
Solar thermal with storage	10%	NA	3.3%	10.8%

Source: AEMO ISP modelling assumptions, AEMO 2016 NTNDP modelling assumption and Frontier Internal estimates.

Table 3: Emission rate (combustive, t/MWh, sent-out)

Technology	NSW	QLD	SA	TAS	VIC
Supercritical PC - Black coal	0.71	0.72	NA	NA	NA
Ultra-Supercritical PC - Black coal	0.68	0.70	NA	NA	NA
Ultra-Supercritical PC - Black coal with CCS	0.07	0.07	NA	NA	NA
Supercritical PC - Brown coal	NA	NA	NA	NA	1.06
Ultra-Supercritical PC - Brown coal	NA	NA	NA	NA	1.02
Ultra-Supercritical PC - Brown coal with CCS	NA	NA	NA	NA	0.10
CCGT	0.45	0.41	0.43	0.38	0.38
CCGT with CCS	0.03	0.04	0.04	0.04	0.04
OCGT	0.65	0.60	0.63	0.56	0.56
Biomass - steam turbine	0.06	0.06	0.06	0.06	0.06
Nuclear	0.00	0.00	0.00	0.00	0.00

Source: AEMO 2016 NTNDP modelling assumption and Frontier Internal estimates.

Table 4: Utility Wind and solar capacity factors

Region	Fixed Plate	Single-axis Tracking	Wind - onshore
NSW	21.54%	25.10%	37.39%
QLD	23.09%	27.95%	37.37%
SA	21.06%	24.54%	41.26%
VIC	21.10%	24.58%	39.49%
TAS	20.48%	23.87%	43.00%

Source: Frontier Economics analysis of ARENA auction results and NTNDP data.

Electricity market modelling assumptions

3.1.8 Interconnectors

Our modelling accounts for the existing interregional interconnectors in the NEM. We do not model any expansions of the capacity of these interconnectors (other than an assumed increase to the capacity of Basslink in the Grid Storage Scenario or the various augmentations under the Interconnector Expansion scenario).

3.1.9 Renewable and climate change policies

Emission target

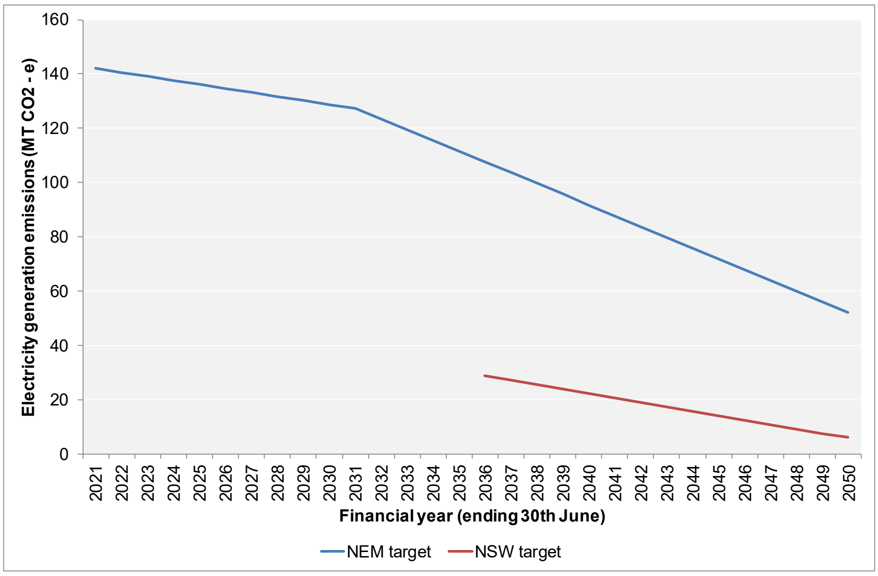
In our modelling we assume the same emission target as in AEMO's ISP consultation report, which to 2030 is consistent with the Australian Government's broader commitment to the COP21 Paris Agreement (which aimed to strengthen the global response to the threat of climate change by keeping a global temperature rise this century well below 2 degrees Celsius above pre-industrial levels).

This emission target is shown in Figure 13. Under this trajectory, the NEM will achieve a proportional share of 28% reduction by 2030, and ongoing emissions reductions to the end of our modelling period in 2050.

This is used in conjunction with a 90% emissions reduction by 2050 for each state individually.

In our modelling, we assume that the modelled emissions target is implemented through an emission intensity scheme so that its impact on wholesale prices will be relatively neutral compared to assuming that the emissions target will be implemented through a cap and trade scheme. We model the emissions target by including a constraint in our investment modelling that total emissions cannot exceed the emissions target.

Figure 13: Emission target modelled



Source: AEMO ISP modelling assumptions.

LRET

We model the legislated Large-scale Renewable Energy Target (LRET), which will reach 33 TWh in 2020 in all scenarios. We model this as a national target, with a pro-rated share of that target being met by the NEM.

Renewable energy targets in Victoria and Queensland

We model the Victorian Renewable Energy Target (VRET), which seeks to source 40 per cent of the state's energy generation from renewable plant[10] by 2025 and the Queensland energy pathway to achieving 50 per cent renewable energy generation (QRET) by 2030.

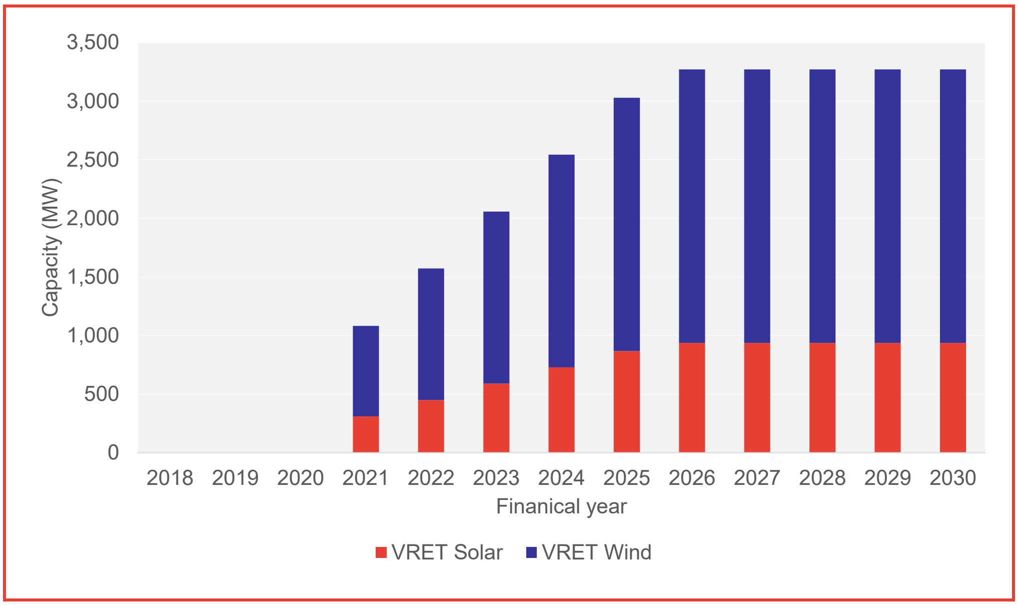
Figure 14 and Figure 15 show the additional capacity provided by utility level wind and solar PV plant under VRET[11] and QRET[12] that we include in our modelling. These are additional to the contribution to the target made by forecast rooftop PV, existing renewable plant and plant already in the pipeline.

10 Including rooftop PV and existing hydro.

11 State of Victoria Department of Environment, Land, Water and Planning, *Victorian Renewable Energy Auction Scheme*, 2015.

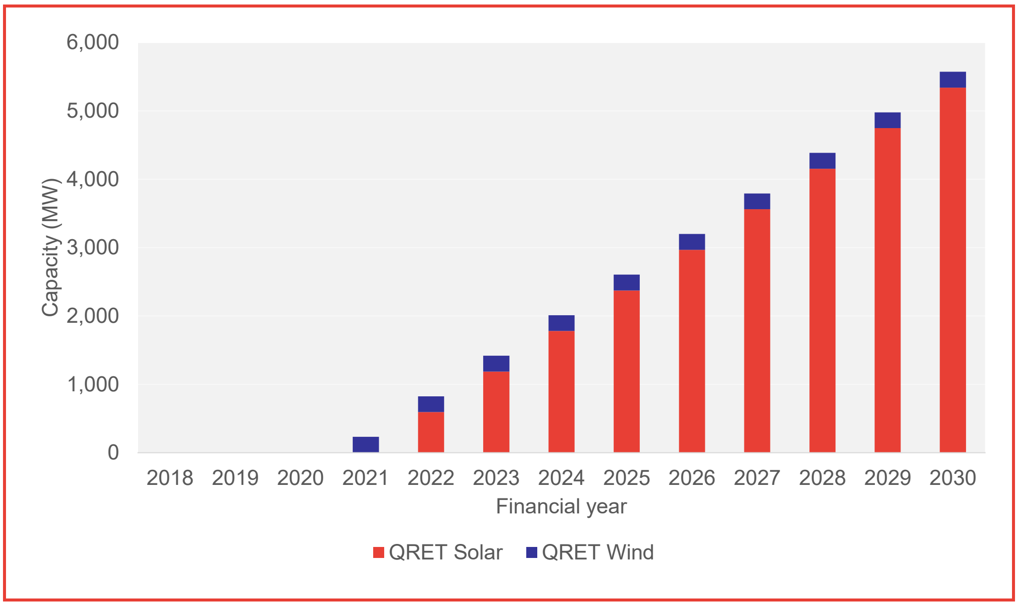
12 Queensland Renewable Energy Expert Panel, *Credible pathways to a 50% renewable energy target for Queensland*, Final Report, 30 November 2016.

Figure 14: Additional utility VRET capacity



Source: Frontier Economics analysis.

Figure 15: Additional utility QRET capacity



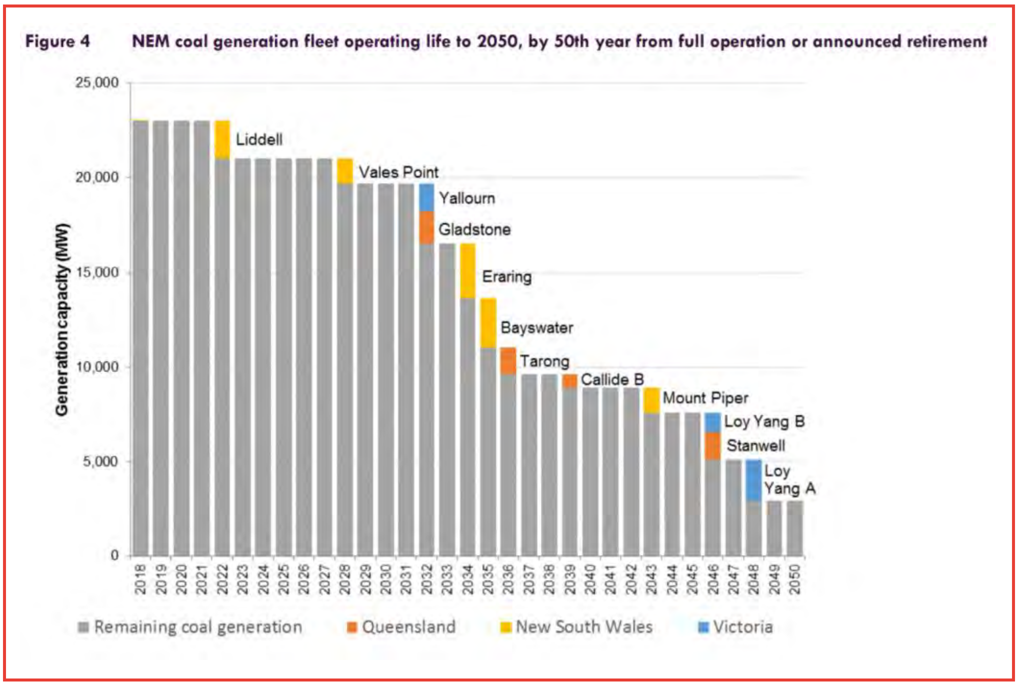
Source: Frontier Economics analysis.

3.1.10 Plant retirement

In all scenarios we model the retirement of existing black and brown coal baseload plant. We assume that these stations will not operate beyond the assumed technical end life as in AEMO's ISP consultation report, shown in Figure 16. Most of these stations will reach their 50-year technical life limit by these assumed end years.

In addition, we model economic retirement where it is not economic for a plant to remain operating up to these retirement dates.

Figure 16: Announced or technical last year (inclusive) of operation of baseload coal plant



Source: AEMO Integrated System Plan Consultation.

3.1.11 Inertia constraint

We have included an inertia constraint in all our modelling.

The inertia constraint is to ensure a minimum amount of inertia is available in each NEM region. The required amount of inertia is set out in Table 5. The amount of inertia provided by each generation type is set out in Table 6. The information in Table 5 and Table 6 was provided by Red Vector. While no inertia contribution for solar thermal was provided by Red Vector, we have assumed that it provides the same inertia as OCGT plant.

Table 5: Inertia requirement

Region	Inertia requirement (MW.s)
Queensland	7,500
New South Wales	7,500
Victoria	7,500
South Australia	5,000
Tasmania	2,500

Source: RED Vector.

Table 6: Inertia contribution

Generation type	Inertia ($MW.s/MW_{capacity}$)
Solar, Wind, Battery	0
ICEs	1.0
Hydro	3.7
Biomass, Coal	4.9
OCGT, CHP, Torrens B, QLD CCGT	5.0
Coal CCS, Torrens A, VIC gas steam	5.7
SA CCGT	6.5
SA Quarantine U5	6.9
Other CCGT	7.2

Source: RED Vector.

Note: We have also assumed that solar thermal with storage provides 5.0 $MW.s/MW_{capacity}$ of inertia.

3.2 Modelling scenarios

As required by our terms of reference, we have modelled a number of scenarios in order to assess outcomes under a spectrum of potential energy market supply-demand scenarios. These scenarios are discussed in the sections that follow.

HELE Scenario

In the HELE Scenario we provide for all black coal generators in the NEM to be repowered. The assumptions we use to define the repowering of these black coal were provided to CINSW by The Electric Power Research Institute (EPRI). EPRI provided four options for repowering each plant:

- USC – maintaining original fuel firing rate.
- USC – maintaining original net power output.
- A-USC – maintaining original fuel firing rate.
- A-USC – maintaining original net power output.

The costs and technical characteristics for these four repowering options are summarised in Figure 17 through Figure 20.

Figure 17: USC – maintaining original fuel firing rate

USC RETROFIT CASE	
Type	Retrofit USC
Steam Conditions:	290 bar/ 600°C/ 620°C
Gross Power	802 MW
Auxiliary Power	62 MW
Net Power	740 MW
Net Efficiency (HHV)	42.1 %
Heat Rate	8546 kJ/ kWh 8100 (BTU/kWh)
Capital Cost (Aus$ / kW)	1568
Fixed O&M Cost (Million Aus$ / year)	86.2
Carbon Rate (Sent out)	0.87 tonne CO2-e/MWh 870 g/kWh
Forced Outage Rate / Planned Outage Rate	0.43 – 0.50 (Based on 86%-90% USC availability)

Source: EPRI, Estimating the Cost and Performance of Repowering a Subcritical Australian PC Unit to Advanced Steam Conditions, *Coal Innovation NSW Study, May 2018.*

Figure 18: USC – maintaining original net power output

USC RETROFIT CASE	
Type	Retrofit USC
Steam Conditions:	290 bar/ 600°C/ 620°C
Gross Power	683 MW
Auxiliary Power	52 MW
Net Power	630 MW
Net Efficiency (HHV)	42.1 %
Heat Rate	8546 kJ/ kWh 8100 (BTU/kWh)
Capital Cost (Aus$ / kW)	1593
Fixed O&M Cost (Million Aus$ / year)	87.6
Carbon Rate (Sent out)	0.87 tonne CO2-e/MWh 870 g/kWh
Forced Outage Rate / Planned Outage Rate	0.43 – 0.50 (Based on 86%-90% USC availability)

Source: EPRI, Estimating the Cost and Performance of Repowering a Subcritical Australian PC Unit to Advanced Steam Conditions, *Coal Innovation NSW Study, May 2018.*

Figure 19: A-USC – maintaining original fuel firing rate

A-USC RETROFIT CASE	
Type	Retrofit A-USC Standard Boiler
Steam Conditions:	241 bar/ 732°C/ 760°C
Gross Power	806 MW
Auxiliary Power	46 MW
Net Power	760 MW
Net Efficiency (HHV)	43.7 %
Heat Rate	8229 kJ/ kWh 7800 (BTU/kWh)
Capital Cost (Aus$ / kW)	1725
Fixed O&M Cost (Million Aus$ / year)	94.9
Carbon Rate (Sent out)	0.83 tonne CO2-e/MWh 830 g/kWh
Forced Outage Rate / Planned Outage Rate	0.43 – 0.50 (Based on 86%-90% USC availability)

Source: EPRI, Estimating the Cost and Performance of Repowering a Subcritical Australian PC Unit to Advanced Steam Conditions, *Coal Innovation NSW Study, May 2018.*

Figure 20: A-USC – maintaining original net power output

A-USC RETROFIT CASE	
Type	Retrofit A-USC Standard Boiler
Steam Conditions:	241 bar/ 732°C/ 760°C
Gross Power	668 MW
Auxiliary Power	38 MW
Net Power	630 MW
Net Efficiency (HHV)	43.7 %
Heat Rate	8229 kJ/ kWh 7800 (BTU/kWh)
Capital Cost (Aus$ / kW)	1758
Fixed O&M Cost (Million Aus$ / year)	96.7
Carbon Rate (Sent out)	0.83 tonne CO2-e/MWh 830 g/kWh
Forced Outage Rate / Planned Outage Rate	0.43 – 0.50 (Based on 86%-90% USC availability)

Source: EPRI, Estimating the Cost and Performance of Repowering a Subcritical Australian PC Unit to Advanced Steam Conditions, *Coal Innovation NSW Study, May 2018.*

For each of these four options, we also model a repowering option with CCS, based on estimates of the cost of CCS from the *Australian Power Generation Technology Report.*[13]

Grid Storage Scenario

The Grid Storage Scenario is designed to investigate the effect of additional uptake of utility-scale storage. Specifically, in the Grid Storage Scenario we assume that there is increased uptake of pumped hydro generation plant across the NEM as set out in Table 7.

We are focused on increased grid storage in this scenario, so do not change our base case assumptions about the rate of uptake of distributed storage (which are small-scale batteries installed on residential and commercial properties).

13 http://www.co2crc.com.au/wp-content/uploads/2016/04/LCOE_Report_final_web.pdf

Table 7: Grid Storage Scenario – assumed investment

Storage	Region	Capacity (MW)	Start	Storage (MWh)	Comment
QLD entrant	QLD	200	2032/33	4,800	Cultana equivalent
Snowy 2.0[14]	NSW	2,000	2024/25	48,000	
Shoalhaven upgrade	NSW	240	2021/22	-	Assume no increase in storage.
Cultana[15]	SA	200	2022/23	4,800	
Battery of the Nation[16]	TAS	1,150	2029/30	27,600	Assumed partial investment. Accompanied by 700 MW augmentation to Basslink.
VIC entrant	VIC	200	2032/33	4,800	Cultana equivalent

Source: Frontier Economics.

We note that the additional storage that is identified in Table 7 are not included in the Base Case because they do not meet the standard criteria for inclusion as a committed investment. The standard criteria that we use for committed investment (and the criteria that is also used by many other modellers for similar purposes) is that a final investment decision has been reached for the project.

Rooftop PV Scenario

In the Rooftop PV Scenario we assume that there is increased uptake of rooftop PV and distributed batteries. Rather than using AEMO's neutral forecasts for rooftop PV and distributed battery adoption, we use AEMO's strong forecasts for adoption. The differences are shown in Figure 21 and Figure 22.

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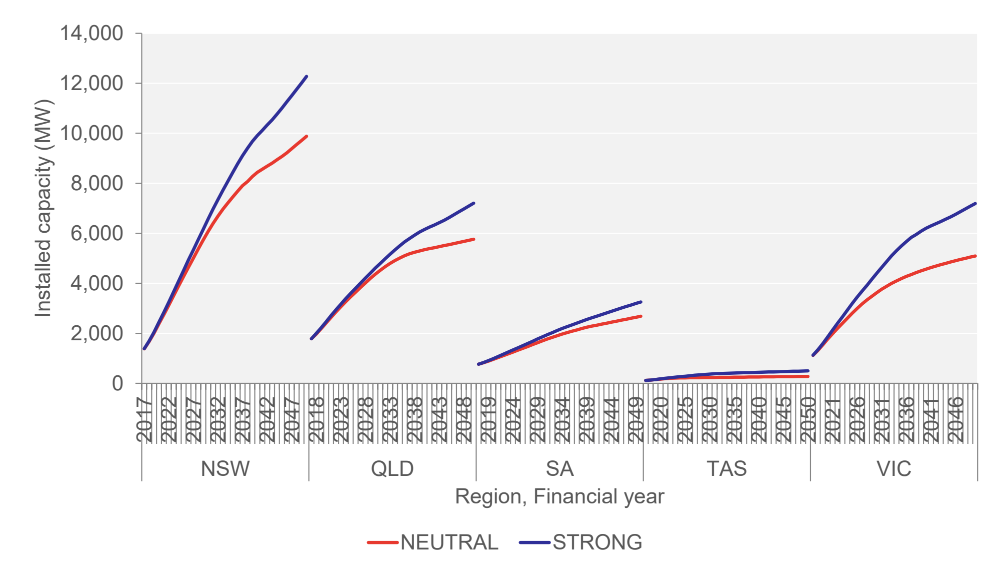
[14] https://www.snowyhydro.com.au/our-scheme/snowy20/

[15] https://www.energyaustralia.com.au/about-us/energy-generation/energy-projects/pumped-hydro

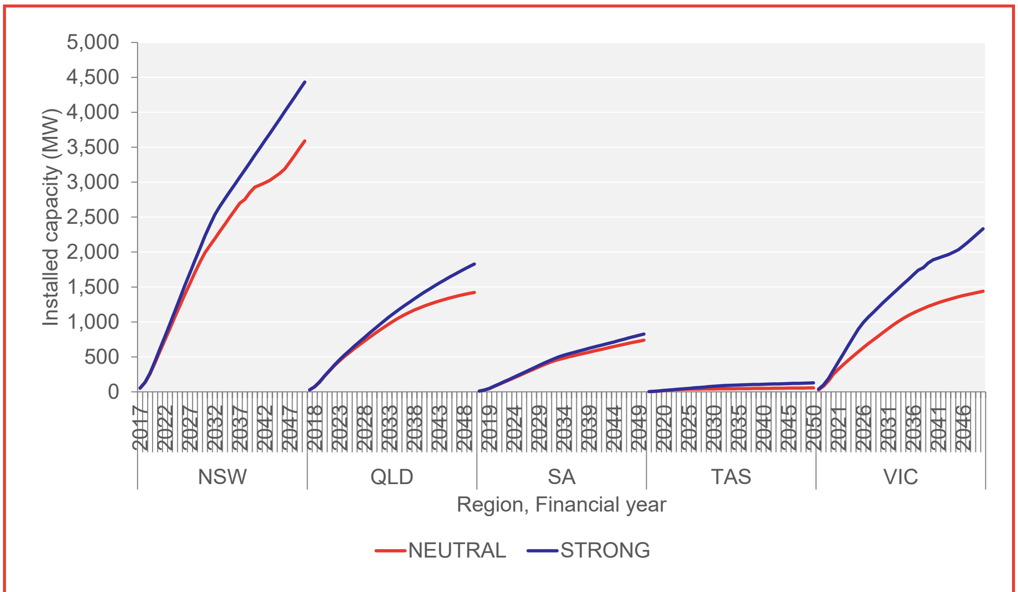
[16] https://www.hydro.com.au/clean-energy/battery-of-the-nation

Figure 21: Rooftop PV capacity



Source: AEMO 2018 EFI – March 2018 Update with Frontier Economics extrapolation post 2036/37.

Figure 22: Battery capacity



Source: AEMO 2018 EFI – March 2018 Update with Frontier Economics extrapolation post 2036/37.

MEGS Scenario

In the MEGS Scenario we model prices for the investment results in selected years that are generated by MEGS.

Electricity market modelling assumptions

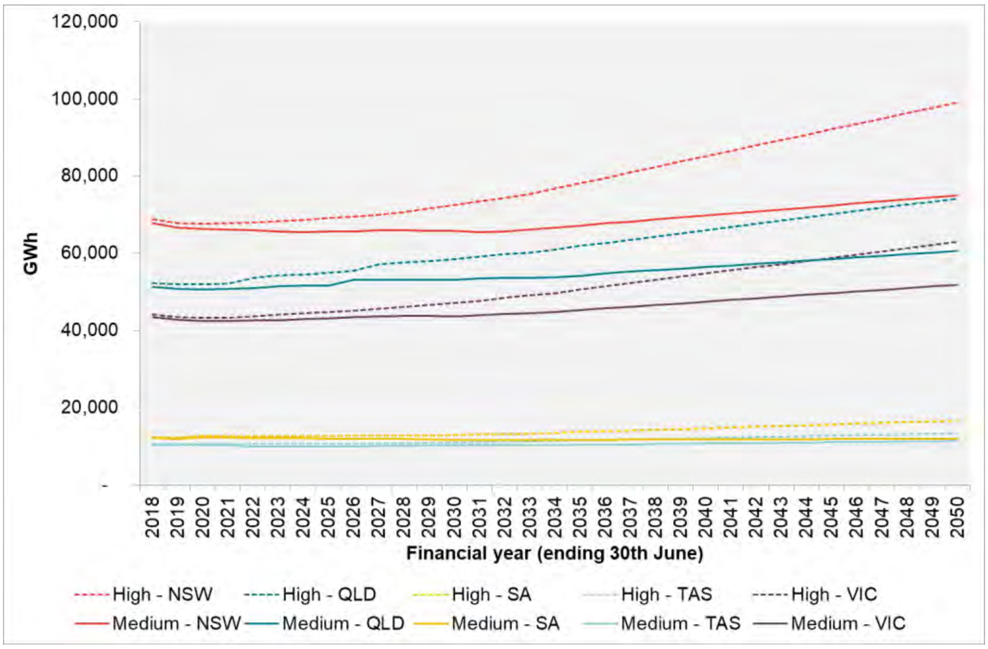
Red Vector provides investment results on 5-yearly intervals. We take the resulting mix of generation capacity, combined with our Base Case assumptions for generation costs, demand and greenhouse policy, and model the resulting dispatch and price outcomes in *SYNC*.

High Demand Scenario

In the High Demand Scenario we model outcomes making use of the strong scenario of AEMO's March 2018 update to its Electricity Forecasting Insights report. AEMO notes that the High Demand Scenario has stronger growth in maximum demand (and minimum demand) over time because, among other things, there is higher projected EV uptake and changes in charging assumptions.

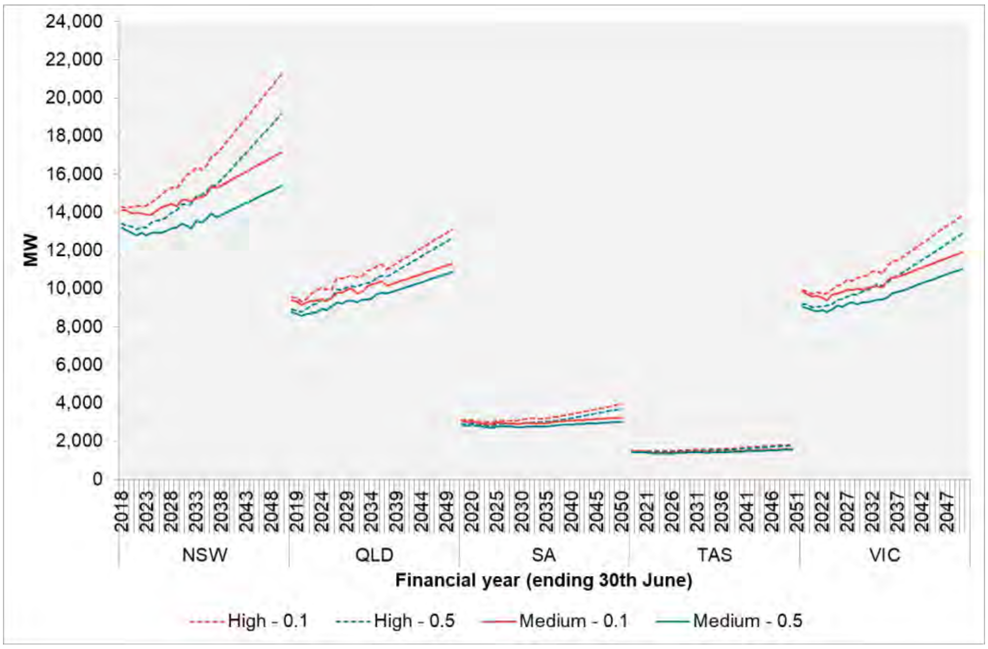
A comparison of the annual consumption and maximum demand forecasts used in the High Demand Scenario with those used in the Base Case is provided in Figure 23 and Figure 24.

Figure 23: Energy consumption forecast (Operational, sent-out, GWh) – comparing Base Case and High Demand Scenario



Source: AEMO 2018 EFI – March 2018 Update with Frontier Economics extrapolation post 2036/37.

Figure 24: Maximum demand forecast (Operational, sent-out, MW) – comparing Base Case and High Demand Scenario



Source: AEMO 2018 EFI – March 2018 Update with Frontier Economics extrapolation post 2036/37.

High Solar Thermal Cost Scenario

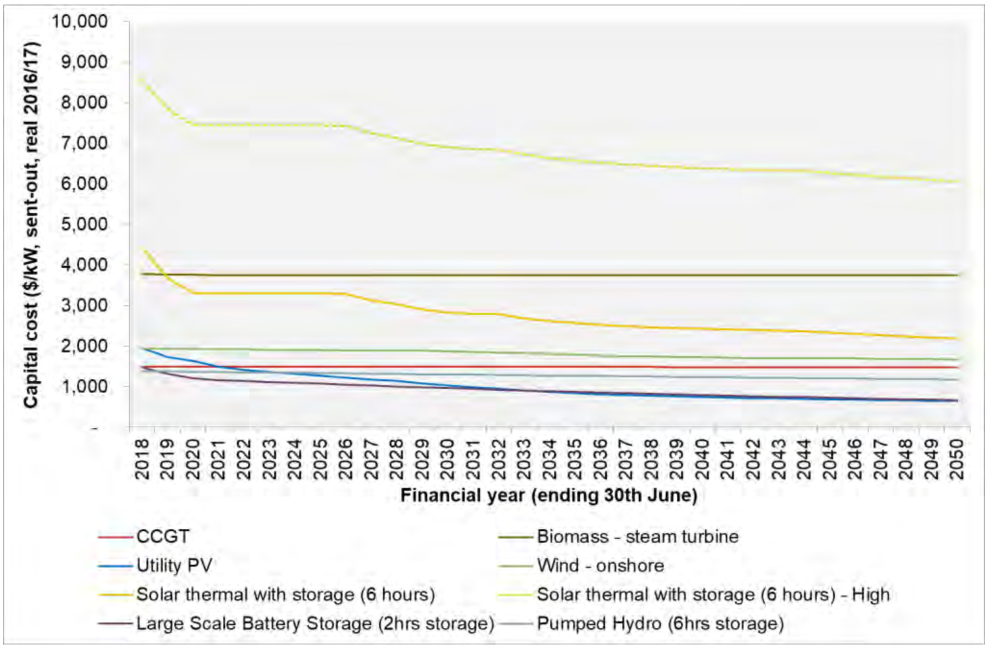
In the High Solar Thermal Cost Scenario we model outcomes making use of a higher estimate of the capital cost of solar thermal plant.

As discussed our capital costs assumptions for new entrant power station are based on CSIRO's two-degree scenario in its Electricity Generation Technology Cost Projections report,[17] which is the source of capital costs proposed in AEMO's ISP consultation report. This report included a substantial reduction in the estimated capital cost of solar thermal plant, relative to earlier reports. Given this substantial cost reduction, and the uncertainty associated with the cost of solar thermal plant (given that there is limited development activity globally) this scenario is designed to assess outcomes in the even that solar thermal costs are more consistent with earlier estimates.

17 Jenny Hayward and Paul Graham, *Electricity generation technology cost projections 2017-2050*, CSIRO, December 2017.

The capital cost estimate for solar thermal plant that we use for this scenario is from the Australian Power Generation Technology Report.[18] A comparison is this with the Base Case capital cost is provided in Figure 25.

Figure 25: Capital costs – solar thermal comparison



Source: AEMO ISP modelling assumptions and APGTR

Interconnector Expansions Scenario

In the Interconnector Expansions Scenario we configure interconnector capacities to match AEMO's recent report on Regions and Marginal Loss Factors.[19] This report incorporates augmentation to a number of interconnectors in the NEM, as follows:

- NSW to QLD: augmentation of 920/758 MW (export/import).
- VIC to NSW: augmentation of 120 MW (export).
- SA to NSW: new interconnector of 750/750 MW (export/import).

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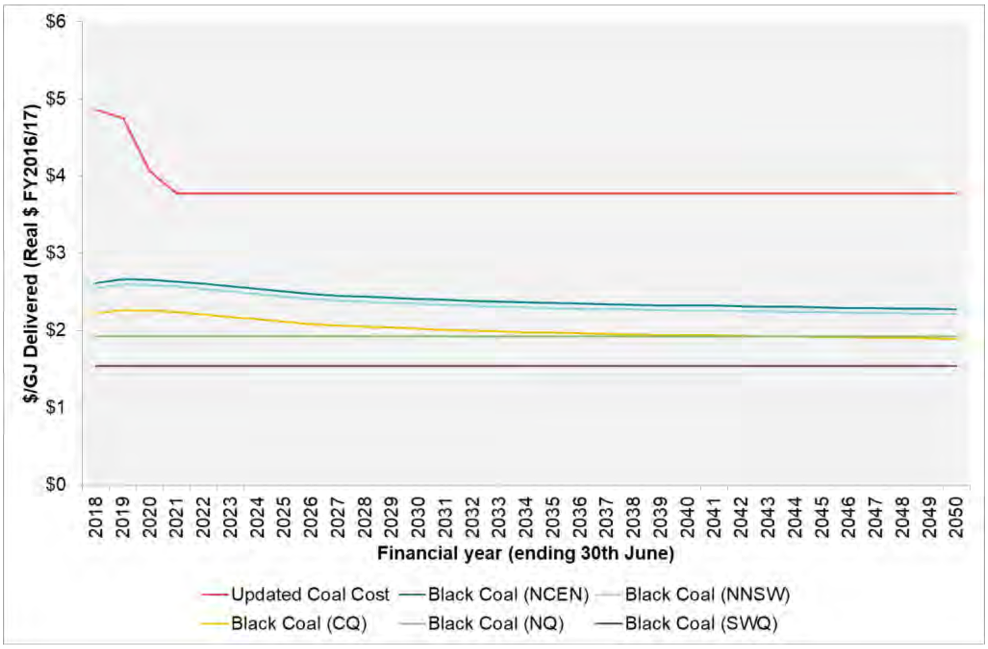
18 CO2CRC, *Australian Power Generation Technology Report*, 2015 (**APGTR**).

19 AEMO, *Regions and Marginal Loss Factors*, 2018

Updated Entrant Fuel Cost Scenario

In the Updated Entrant Fuel Cost Scenario we make use of the updated coal price forecasts for new entrant generators in the NEM that AEMO has released as part of its ISP. This updated coal price forecasts represents a substantial increase over the original coal price forecasts that AEMO has released as part of its earlier ISP releases, as shown in Figure 26.

Figure 26: New entrant coal price – comparing Base Case and Updated Entrant Fuel Cost Scenario



Source: AEMO ISP modelling assumptions

Updated Entrant Fuel Cost HELE Scenario

In the Updated Entrant Fuel Cost HELE Scenario we make use of the same updated coal price forecasts for new entrant generators discussed above, but we use that updated coal price forecast in the HELE Scenario.

High Renewable Drought Scenario

In the High Renewable Drought Scenario we model a longer renewable drought that we have in our Base Case and other scenarios.

The modelling for our Base Case and other scenarios is based on half-hourly patterns of demand and intermittent generation from 2017. As we have discussed, 2017 had a significant solar and wind drought affecting NSW and Victoria for three days in winter. As it happens, this solar and wind drought affecting NSW and Victoria was the most severe 3-day drought that we observe in the seven years for which we have a consistent set of data for intermittent generation.

However, there are solar and wind droughts that have lasted for more days and have been almost as severe (in terms of average quantity of solar and wind generation during the drought). To test the resilience of the system to a longer drought we have re-run the Base Case dispatch modelling incorporating a severe 5-day drought that we identified in 2009/10. This 5-day drought was almost as severe (in terms of average quantity of solar and wind generation during the drought) as the 3-day drought in 2017. We measure the levels of droughts by average MWh per day. To replicate the 5-day drought we adjust our 3-day droughts renewable profiles so that the average MWh per day is equal to the 5-day drought. We then calculate an average days renewable profile from those 3-days and use this average day to replace the profiles in days 4 and 5, ensuring that we have the same length and average MWh per day as the 5-day drought.

High Emissions Reduction Scenario

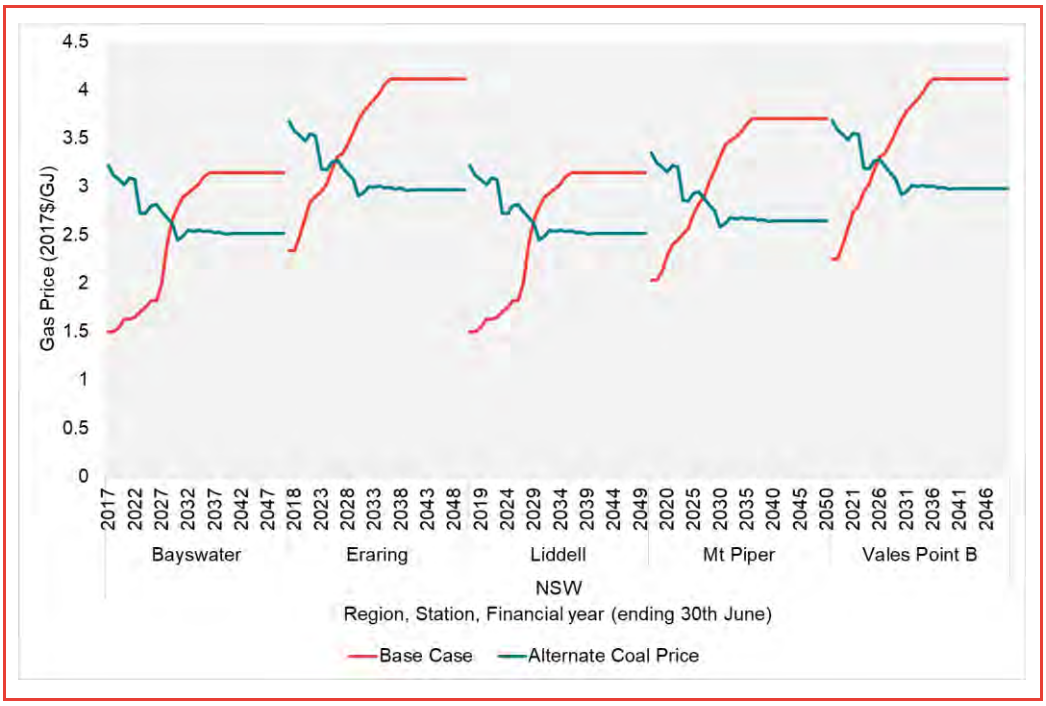
In the High Emissions Reduction Scenario the carbon emissions target for the NEM is changed to be a 90% reduction by 2040. Along with this change, the renewable targets reflected in the existing QRET and VRET were assumed to be rolled into a single national renewable scheme, meaning that the committed investment from these schemes can move to regions other than Queensland and Victoria in this scenario.

Alternate Coal Price Scenario

In the Alternate Coal Price Scenario, coal prices were taken from the IHS report provided by DPE. Compared to the Base Case coal prices, this results in higher coal prices in early years, but lower coal prices over the rest of the modelling period. This comparison can be seen for both existing coal plants and new entrants in Figure 27 and Figure 28.

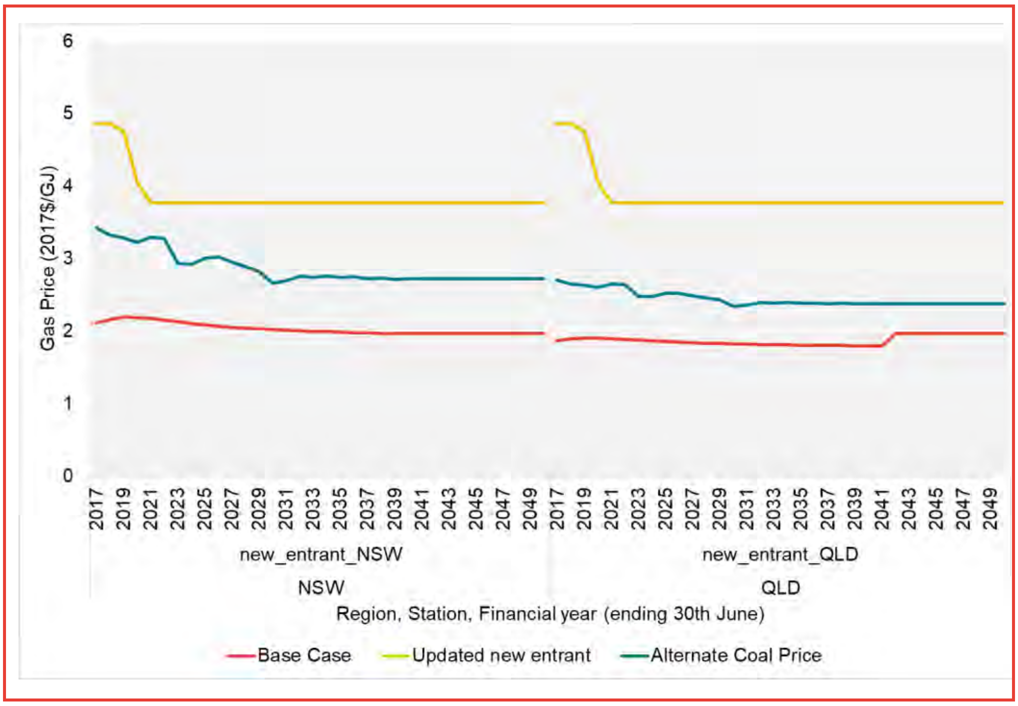
The comparison in Figure 28 shows coal prices in both the Base Case and the Updated Entrant Coal Price Scenario. The coal prices from this Alternate Coal Price Scenario fall between these too previous input assumptions.

Figure 27: Coal prices in the Alternate Coal Price Scenario compared to the Base Case



Source: Frontier Economics

Figure 28: New Entrant coal prices in NSW and Queensland for the Base Case and Alternate Coal Price Scenario



Source: Frontier Economics

Electricity market modelling assumptions

High Gas Price Scenario

In the High Gas Price Scenario the assumed gas price is increased by $5/GJ (relative to the Base Case) over the period from 2019 till 2024, and thereafter remains $5/GJ higher for the rest of the modelling period. This increase was based on an increased oil price coinciding with a higher exchange rate.

Forced Black Coal with CCS Scenario

In the Forced Black Coal with CCS Scenario 1500 MW of Black Coal with CCS is committed in 2034 and another 1500 MW is committed in 2035.

4 Electricity market modelling results

This section summaries the results of our electricity market modelling.

In the tables that follow, we present the same nine charts for each modelling scenarios:

- **NSW generation investment** – this chart shows forecasts of new investment in NSW, for each year of the modelling period and each technology type. This chart includes committed new investments (such as renewable generation investments already committed in NSW) as well as modelled new investments. This chart does not show new investments in behind-the-meter rooftop PV and storage.
- **NSW generation capacity** – this chart shows forecasts of the total generation capacity in NSW, for each year of the modelling period and each technology type. This chart accounts for new investments and retirements. This chart includes capacity of behind-the-meter rooftop PV and storage.
- **NSW capacity to meet peak demand** – this chart shows forecasts of the aggregate contribution of capacity to meeting peak demand in NSW, for each year of the modelling period and each technology type. This chart accounts for the forecast availability of each technology type to meet peak demand (for instance, both solar PV and wind are assumed to make little to no contribution to meeting peak demand in NSW). This chart also shows POE10 and POE50 peak demand in NSW, for the purposes of comparison.
- **NSW dispatch** – this chart shows forecasts of the total annual dispatch of generation plant in NSW, for each year of the modelling period and each technology type. This chart includes dispatch of behind-the-meter rooftop PV and storage. Pumping of pump-storage hydro plant and charging of batteries are shown as negative dispatch.
- **NSW half-hourly dispatch** – this chart shows forecasts of typical daily patterns of NSW dispatch at several points in the modelling period. Specifically, this chart shows average daily dispatch (by half-hour) for January and July in each of 2017/18, 2029/30, 2039/40 and 2047/48. It is important to note that these average daily shapes will not necessarily reflect outcomes on any single day in the relevant month, and will certainly not represent outcomes on the highest demand day of the relevant month; the daily shapes are averages of outcomes for every day in the relevant month.
- **NSW imports** – this chart shows forecasts of the total net annual imports from Victoria and Queensland, for each year of the modelling period. Net imports into NSW are shown as positive, net exports from NSW as negative.
- **NSW diversity of generation** – this chart shows forecasts of the share of electricity generation in NSW and imports into NSW, for each year of the

modelling period and each technology type. This chart includes generation of behind-the-meter rooftop PV. This chart does not include net energy use by pump-storage hydro plant and batteries.

- **NSW carbon emissions** – this chart shows forecasts of the total annual carbon emissions of generation plant in NSW, for each year of the modelling period.
- **NSW wholesale and retail prices** – these charts show forecasts of NSW wholesale regional reference prices and forecasts of NSW retail prices for residential customers, small and medium enterprise (SME) customers and commercial and industrial (C+I) customers, for each year of the modelling period.

For the MEGS Scenario we do not present the first chart – NSW generation investment – since we do not model investment ourselves. Similarly, our ability to explain the results for the MEGS Scenario is somewhat constrained by the fact that we have not been responsible for modelling investment in this scenario.

For the HELE Scenario we do not present any of these charts. As we discuss below, we do not see investment in any of the redevelopment options in the HELE Scenario which means that the modelling results are identical to the Base Case modelling results. We discuss the reason for this result below.

Investment, capacity and dispatch results are presented here by fuel type. For coal and gas generation, where CCS is part of the generation mix this is identified separately (for instance, black coal with CCS is identified separately to black coal).

The data behind these charts is provided in a spreadsheet provided with this report, which we would recommend for closer consideration of the results.

Additional results for other regions in the NEM are provided in Appendix A.

Scenario – Base Case

NSW investment, retirement and installed capacity

In the Base Case, our modelling indicates that there is no need for new investment in utility-scale generation or storage in NSW – beyond investment that is already committed – until 2032/33.

We do see some new investment occurring over the next five years. This is principally committed windfarms and solar farms, which include:

- Bondangora Wind Farm – 113 MW
- Crookwell 2 Wind Farm – 91 MW
- Sapphire Wind Farm Phase 1 and 2 – 270 MW
- Silverton Wind Farm – 199 MW
- Manildra Photovoltaic Solar Farm – 50 MW
- Beryl Solar Farm – 100 MW

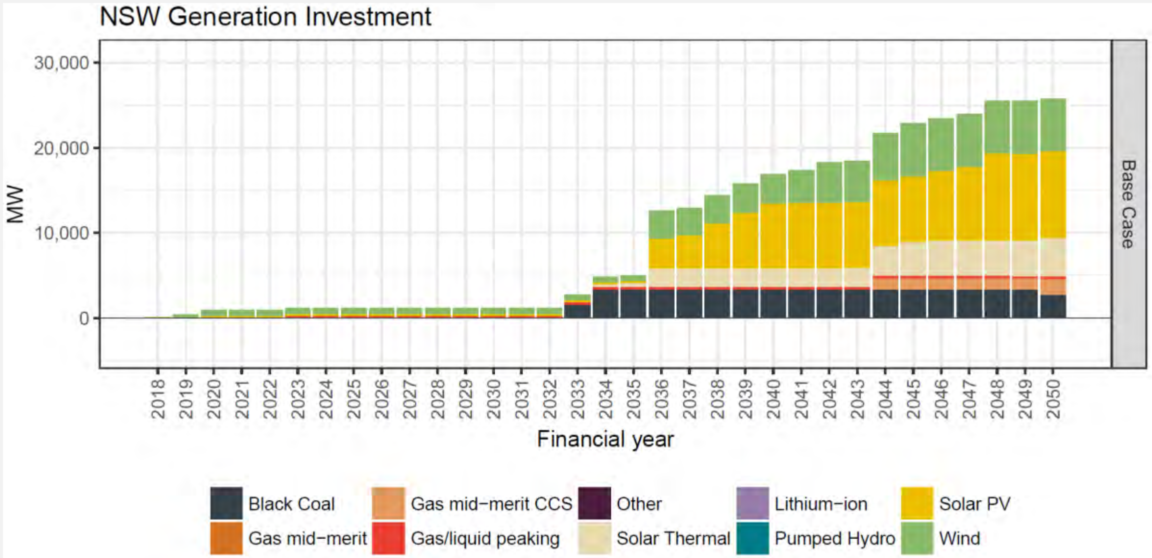
We also see AGL's committed investment in the first stage of its NSW Generation Plan, with investment in a 250 MW gas peaking plant and upgrade of Bayswater's capacity by 100 MW.

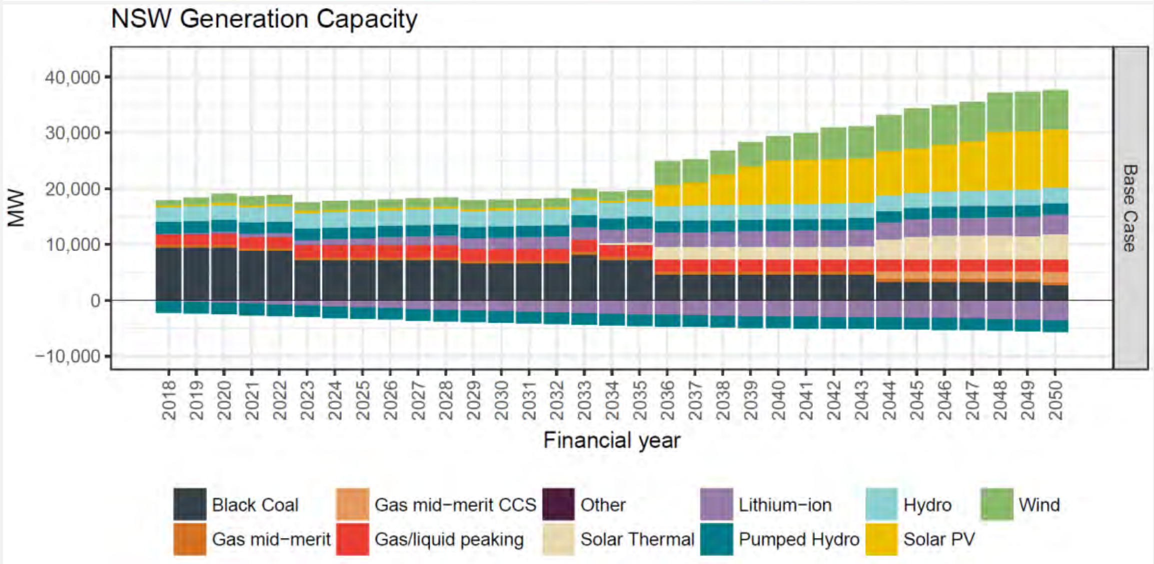
There is retirement of existing generation capacity prior to 2032/33 – notably Liddell power station in 2021/22 and Vales Point power station in 2027/28 (although our modelling has one unit of Vales Point retiring for economic reasons in 2019/20, which is seen by the drop in coal capacity). But the model does not see the need for new investment to replace this due to the committed investments discussed above, the forecast reduction in NSW demand, the forecast significant investment in distributed storage and an increasing reliance on imports (discussed below).

With the retirement of Eraring power station in 2032/33 and Bayswater power station in 2034/35, new investment is required. We see investment in new coal plant (3,400 MW of supercritical black coal), as well as significant investment in wind, solar PV and solar thermal. Renewable investment continues to grow until 2050, and with the closure of Mt Piper power station there is additional investment in gas plant, including CCGT with CCS.

Overall, this results in a substantial shift in the mix of generation capacity in NSW.

Investment and capacity results for other regions are set out in Appendix A.





Scenario – Base Case

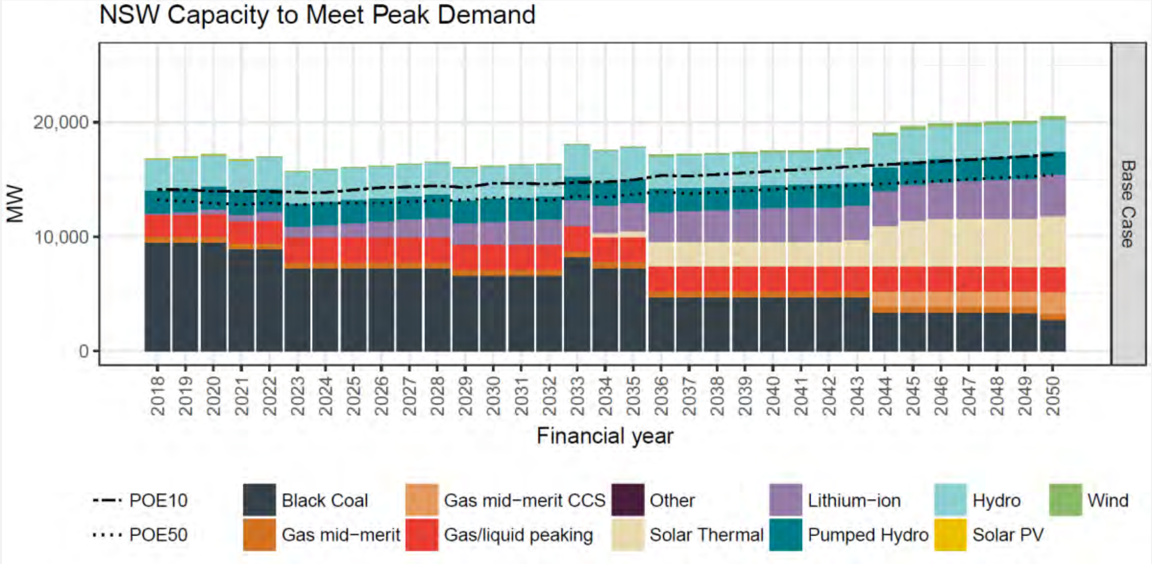
NSW diversity of capacity to meet peak demand

Accounting for the expected ability to generate at peak times, it is clear that NSW is forecast to have installed capacity in excess of peak demand (although as out dispatch results suggest, some of this capacity will not be much used for generation).

Our results also show that NSW is currently very reliant on coal-fired generation, hydro generation and, to a lesser extent, gas generation.

In the Base Case, over time the contribution of coal-fired generation to meeting peak demand diminishes, as plant retire. As a result, NSW becomes increasingly reliant on solar thermal generation, gas generation and batteries for meeting peak demand.

Our assumption is that solar PV does not contribute at times of peak demand, and that wind only contributes at a small fraction of its total capacity (although batteries that will effectively be charged by solar PV and wind are assumed to be available to meet peak demand).



Scenario – Base Case

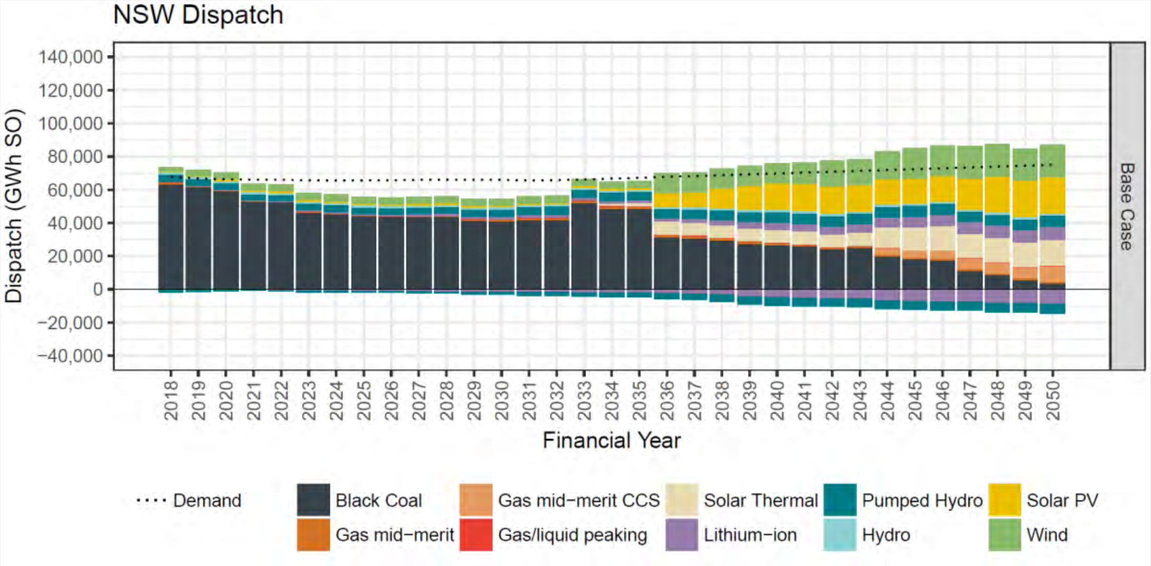
NSW dispatch

In the Base Case, our modelling indicates a substantial change over time in the mix of generation plant supplying NSW's electricity. Currently, and for the first 15 years of the forecast period, coal-fired generation dominates dispatch in NSW, with relatively small contributions from hydro generation, gas plant, solar PV and wind.

Following the retirement of Liddell power station in 2021/22, the amount of dispatch from coal-fired generation decreases materially, but dispatch from other generation in NSW does not increase. Indeed, our modelling suggests that, with the retirement of Liddell power station, dispatch of generation plant in NSW will fall well short of annual consumption in NSW. This implies a much greater net reliance on imports, as we will discuss below. This does raise the question of why it is economic for NSW to rely on imports, rather than for new investment to replace Liddell power station. The reason is that the VRET in Victoria and the QRET in Queensland drive significant renewable investment in these states (principally wind in Victoria and solar PV in Queensland). This additional investment is in excess of what is required in these states to meet their annual consumption, so the excess is exported into NSW. In short, policy-driven renewable investment in Victoria and Queensland crowds out new investment in NSW.

With new investment in coal generation in 2032/33 we see a brief increase in coal dispatch. However, with the retirement of Eraring power station in 2032/33 and Bayswater power station in 2034/35 we see substantial changes in the generation mix in NSW. Solar thermal generation increases substantially (due to its low capital costs, which we test in the High Solar Thermal Cost Scenario), as does solar PV generation and wind. Around this time we also see that dispatch in NSW returns to levels that are better matched to annual consumption in NSW. The reason is that retirements of coal-fired generation in Victoria and Queensland mean that generation in those states becomes better matched with annual consumption.

With the retirement of Mt Piper power station, and new investment in CCGT with CCS, there is growth dispatch by CCGT with CCS from 2043/44.



NSW half-hourly dispatch

Half-hourly dispatch for NSW shows the same overall pattern as suggested by the annual dispatch results presented above.

In 2017/18, coal generation accounts for the majority of dispatch in both July and January, with mid-merit gas and imports also operating fairly consistently. Hydro generation, pumped-storage hydro and gas peaking plant operate more intermittently in order to meet daily peaks in demand.

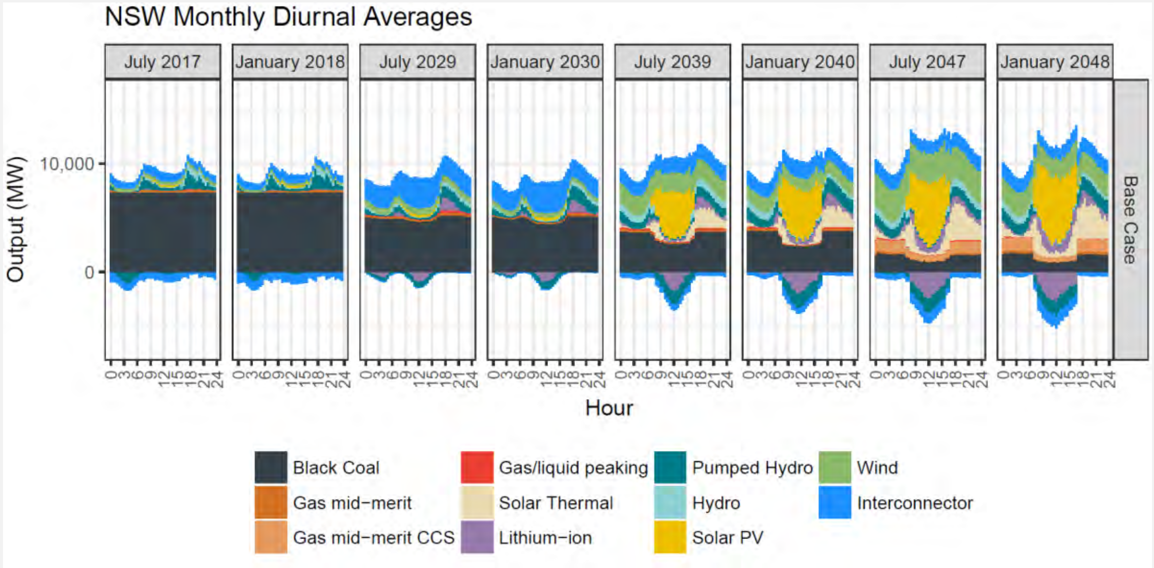
By 2029/30 there are a number of notable changes to these patterns of half-hourly demand. First, coal generation has decreased with plant retirement, and imports play a much more important role in meeting daily demand. Second, batteries play a much more important role in meeting daily peaks in demand, supporting pumped storage hydro (and increased operation from gas plant) in meeting daily fluctuations in demand.

By 2039/40, changes are very material. Coal generation has decreased very substantially, with Mt Piper power station and the new plant the only remaining coal power stations in NSW. There is also a very substantial increase in solar PV generation, with battery and pumped-storage hydro charging/pumping (during sunlight hours) and discharging/generating (during the evening peak) helping to smooth out the daily pattern of solar PV generation. It is also clear that solar thermal plant also plays a very important role in managing the intermittency of solar PV and wind generation, with solar thermal plant (with storage) operating a lot in the evening (and into the early morning).

By 2047/48, the trend continues with coal generation being replaced by CCGT with CCS and wind. Increased solar PV investment allows pumped hydro and batteries to charge more during the day, shifting generation to morning and evening peaks. On average, thermal generation continues to account for around one quarter of total generation when solar is not generating.

These half-hourly dispatch results indicate that gas plant – including peaking plant – frequently operate during the evening and overnight, and sometimes even during the day, to manage the intermittency of renewable generation. This means that these gas plant – which have high SRMC – will be setting the wholesale price quite frequently, even though their capacity factors are low over the entire year. The rest of the time we would expect coal plant to be setting the wholesale price.

Daily dispatch results for the single week of lowest renewable generation for these same 4 years are presented in Appendix A.

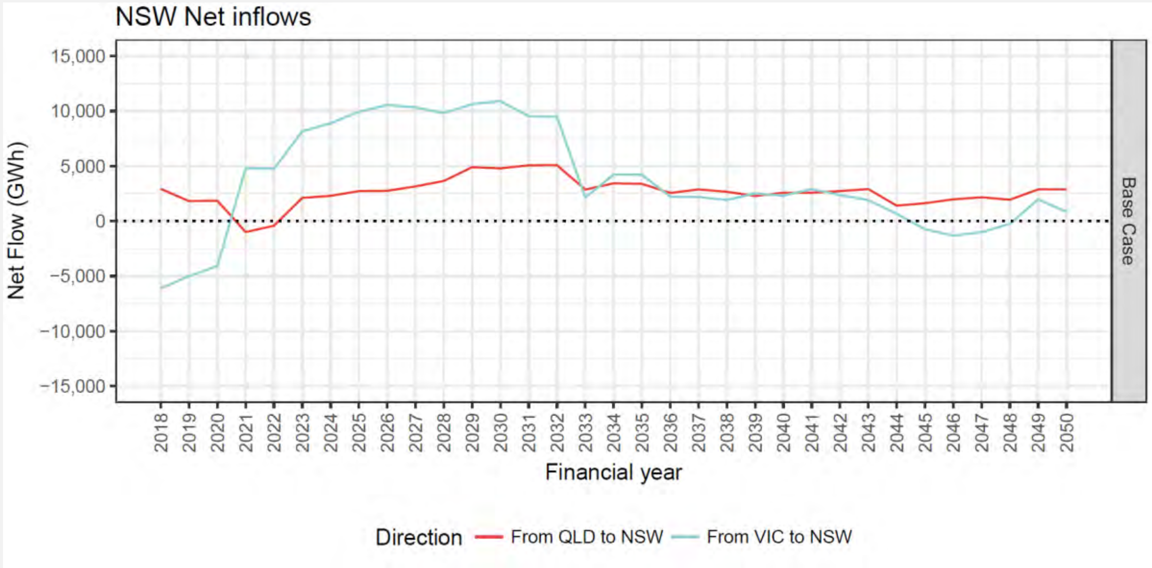


Scenario – Base Case

NSW imports

As discussed above, in the Base Case our modelling indicates a substantial change in patterns of regional flows over the modelling period. These are predominantly driven by the effect of the VRET and QRET, which result in substantial renewable investment in Victoria and Queensland. This leads to excess energy in these regions, both of which export into NSW.

Clearly, NSW becomes more reliant on interconnectors in this scenario, during the 2020s and the early 2030s. This reliance does not exceed the capability of the existing interconnectors and, indeed, the existing interconnectors would generally have capacity for even larger imports. However, reliance on imports to this extent does materially increase NSW's exposure to unexpected failure of these interconnectors.

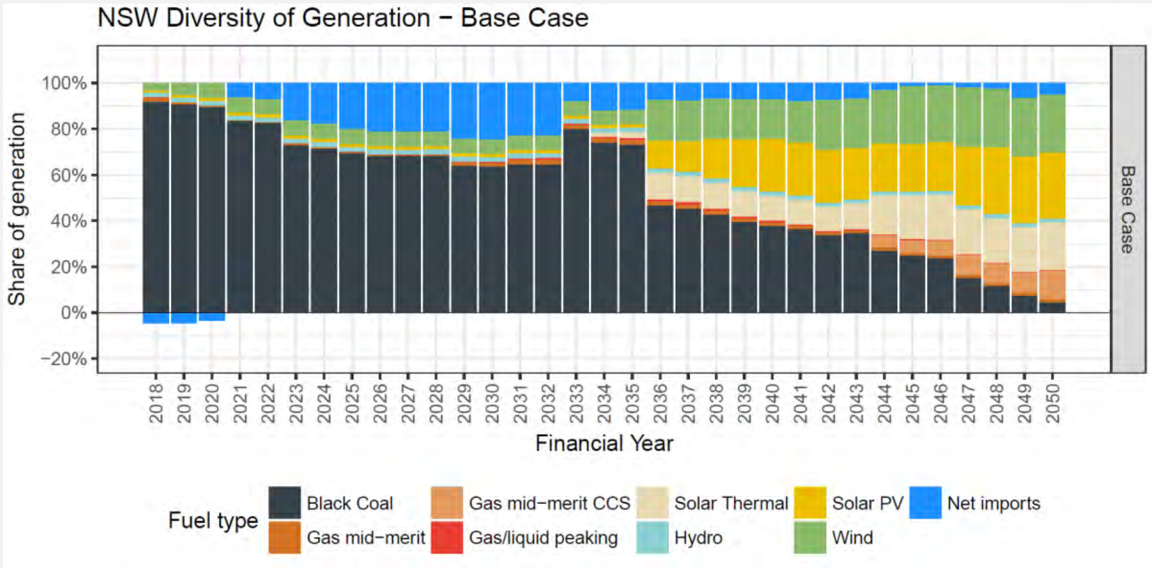


NSW diversity of energy supply

Consistent with the results for dispatch and imports that we have seen, the Base Case sees a substantial increase over time in the diversity of technologies that supply NSW's electricity.

Currently, and for the first 15 years of the modelling period, coal-fired generation dominates the generation mix.

With the successive retirement of NSW's coal-fired generators this reliance on coal is much reduced by the end of the modelling period. Initially, NSW relies increasingly on imports from Victoria and Queensland. Subsequently, following the retirement of Eraring power station and Bayswater power station, the generation mix shifts substantially towards solar thermal, solar PV and wind. Following the retirement of Mt Piper power station, we also see an increase for CCGT with CCS. The result is a much more balanced generation mix, and reduced reliance on a single technology type or fuel source.



Scenario – Base Case

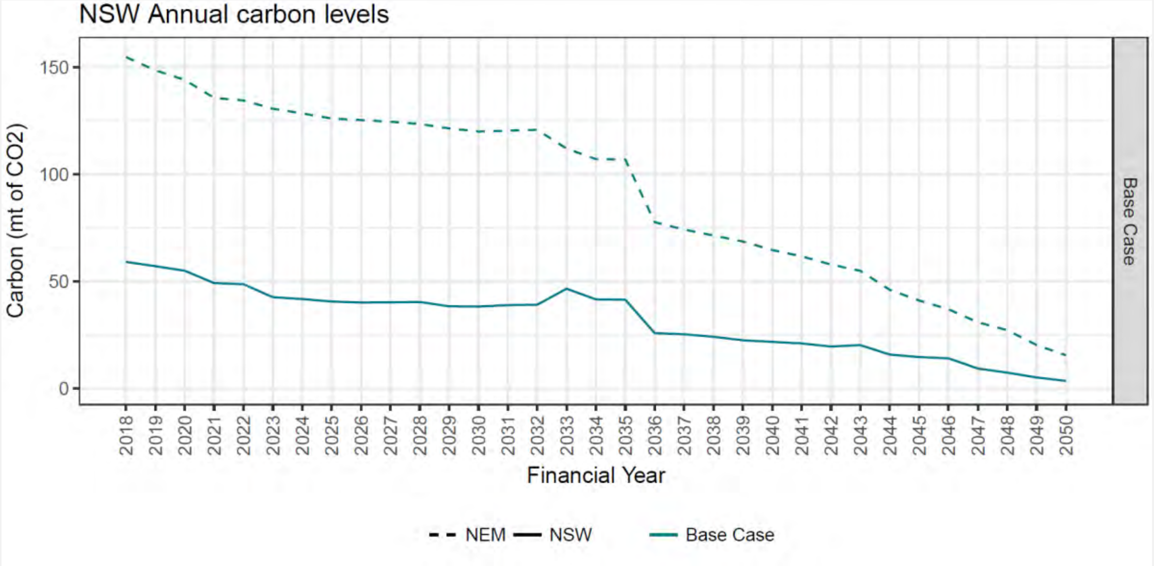
NSW carbon emissions

Consistent with the results for dispatch that we have seen, over time we see a significant reduction in total emissions from NSW power stations. These reductions are primarily the result of the retirement of NSW's coal-fired power stations. We see an initial reduction in 2020/21 after the early retirement of one unit of Vales Point power station, followed by further reduction in 2022/23 (after the retirement of Liddell power station), 2028/29 (after the retirement of the other unit of Vales Point power station), 2033/34 (after the retirement of Eraring power station), 2035/36 (after the retirement of Bayswater power station) and 2043/44 (after the retirement of Mt Piper power station).

Since retiring coal-fired power stations are primarily replaced by a combination of renewable generation or CCGT with CCS, total carbon emissions in NSW fall to around 10 per cent by the each of the modelling period.

This substantial reduction in carbon emissions is achieved despite significant investment in new coal plant in the early 2030s. Given that all other investment is in renewable plant or CCGT with CCS, emissions from this new coal plant is consistent with the required emissions reduction.

We see emissions in total for NSW reduce from 59 million tonnes of carbon dioxide in 2018, to 3.5 million tonnes in 2050. This is a total reduction of 55.5 million tonnes of carbon dioxide, driven by a large amount of investment in renewable technologies.



Scenario – Base Case

NSW wholesale prices

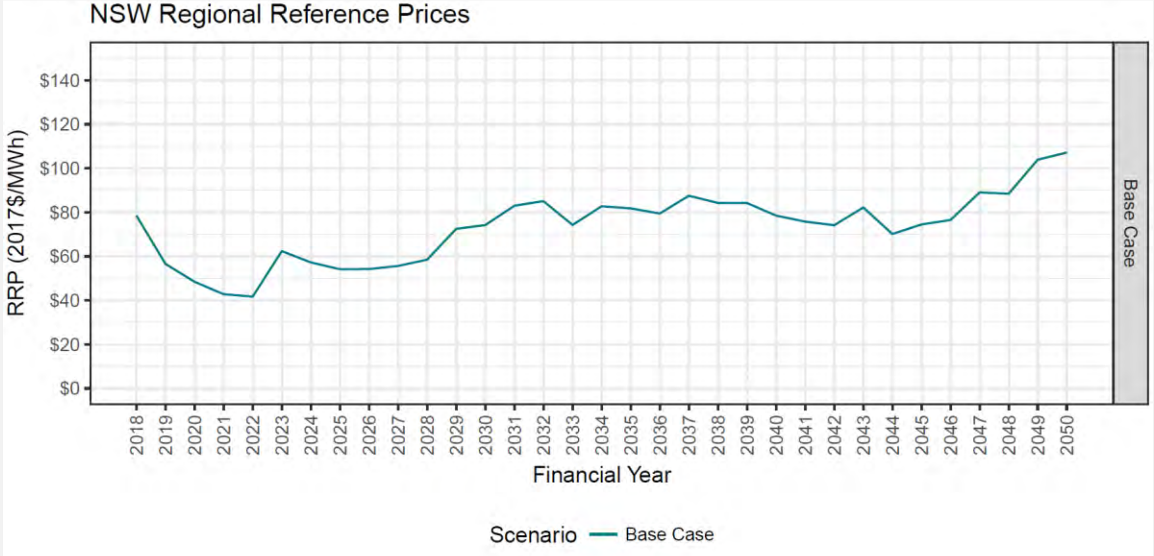
Our modelling indicates that wholesale prices in NSW will fall over the coming few years, from around $75/MWh in 2017/18 to close to $40/MWh in 2020/21. This is driven by substantial investment in renewable plant in both Queensland and Victoria, and the resulting export of renewable energy into NSW (as well as committed investments in NSW). This trend of low prices over time in response to increased renewables investment in Queensland and Victoria persists for much of the 2020s, albeit interrupted by material price increases following the retirement of Liddell power station in 2021/22 and Vales Point power station in 2027/28. We see price increases after these closures because our modelling suggests that there will not be new investment in utility-scale generation in NSW following the closure of these plant.

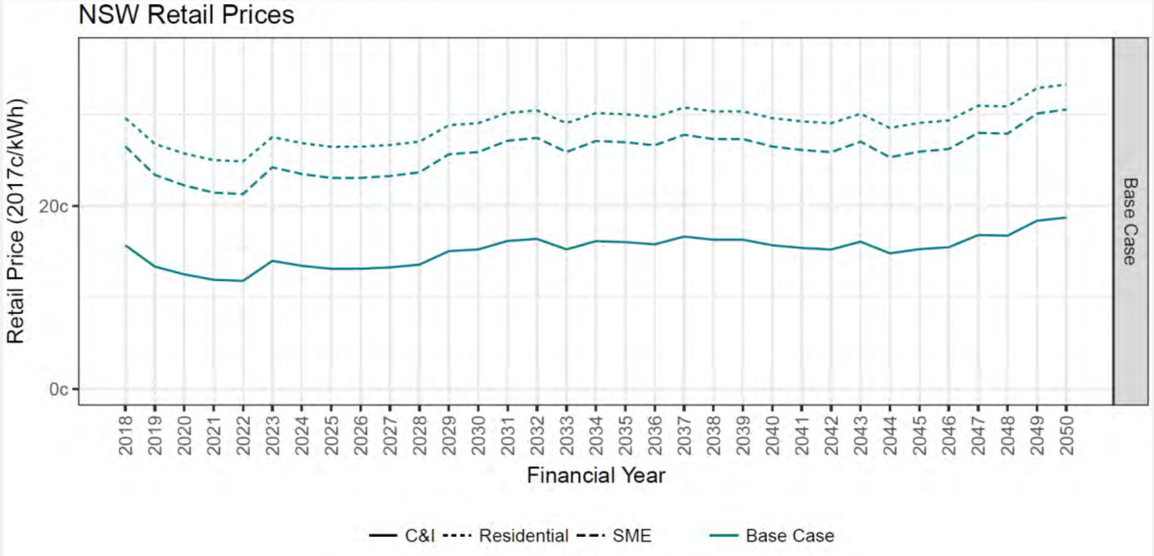
The retirement of Eraring power station in 2032/33 and Bayswater power station in 2034/35 does not see the same material increases in price because these retirements result in substantial new investment in NSW. This significant new investment more than replaces the *capacity* of Eraring power station and Bayswater power station, and this additional supply has the effect of lowering prices.

In the long-term, prices stabilise around $80/MWh in NSW. As discussed these long-term prices reflect the fact that gas plant and coal plant remain marginal for much of the year, even though renewable plant accounts for an increasing share of total generation. Indeed, there only needs be a requirement for one thermal plant to be operating to meet demand are the marginal cost of that thermal plant will set the price for the entire market. As we have seen in the figure showing NSW half-hourly dispatch, even in 2049/50 there, on average, some thermal plant operating throughout the day even in summer.

Retail prices follow the same trend as wholesale prices, but do not fluctuate as much as wholesale prices. The reason is that a large component of the retail price is network tariffs, which we assume remain constant in real terms. While there is likely to be significant transmission network investment over the period to 2050, this need not imply a significant increase in network tariffs, particularly since more of a retail customer's network tariffs are driven by distribution tariffs.

Wholesale and retail prices for other regions are set out in Appendix A.





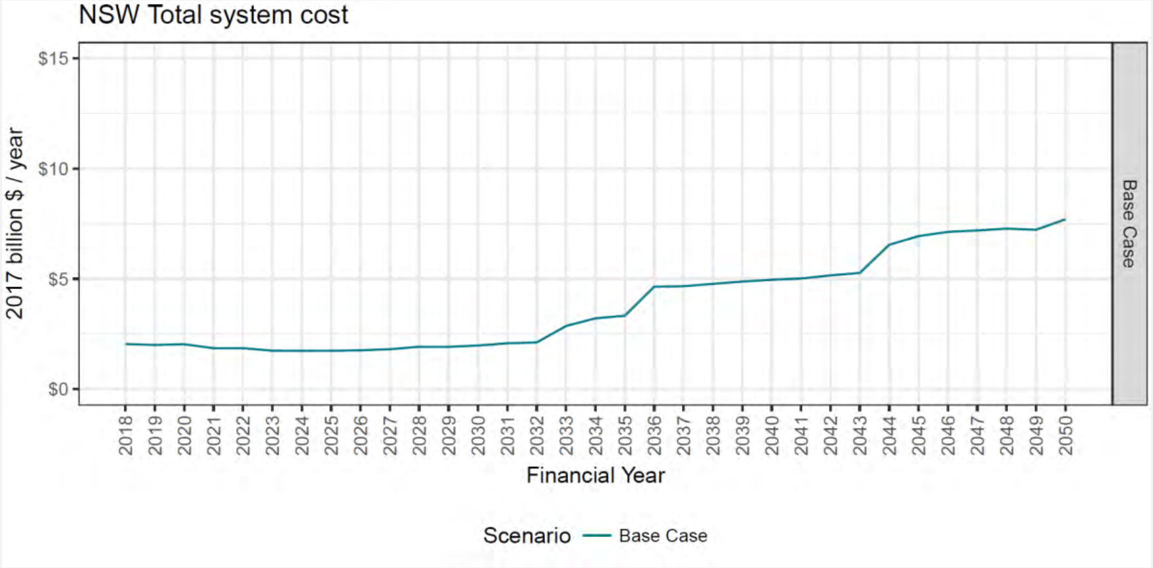
Scenario – Base Case

NSW total system cost

Total system costs fall in early years, for several reasons:

- as committed investments enter whose capital is already sunk
- existing plant retire that otherwise would incur fixed operating costs
- there is greater reliance on imports and therefore less operating and fuel costs incurred in NSW.

As new investments are needed, total system costs start to increase. Later on, when coal plants start to retire, a lot more new investment is needed, which incurs high capital costs, leading to the increase towards the end of the modelling horizon.



Grid Storage Scenario

NSW investment, retirement and installed capacity

In the Grid Storage Scenario, our modelling shows that investment outcomes in NSW will be substantially the same as the Base Case. We see the same committed investment over the next five years as in the Base Case – new wind farms and solar farms, as well as AGL's committed investment in Bayswater's upgrade and a gas peaking plant. We also see the committed investment in the new pumped storage hydro in NSW that we model in this case:

- Snowy 2.0.
- The expansion in Shoalhaven's capacity.

The committed pumped storage hydro appears as both positive and negative invested capacity to show it's need to consume electricity to store it.

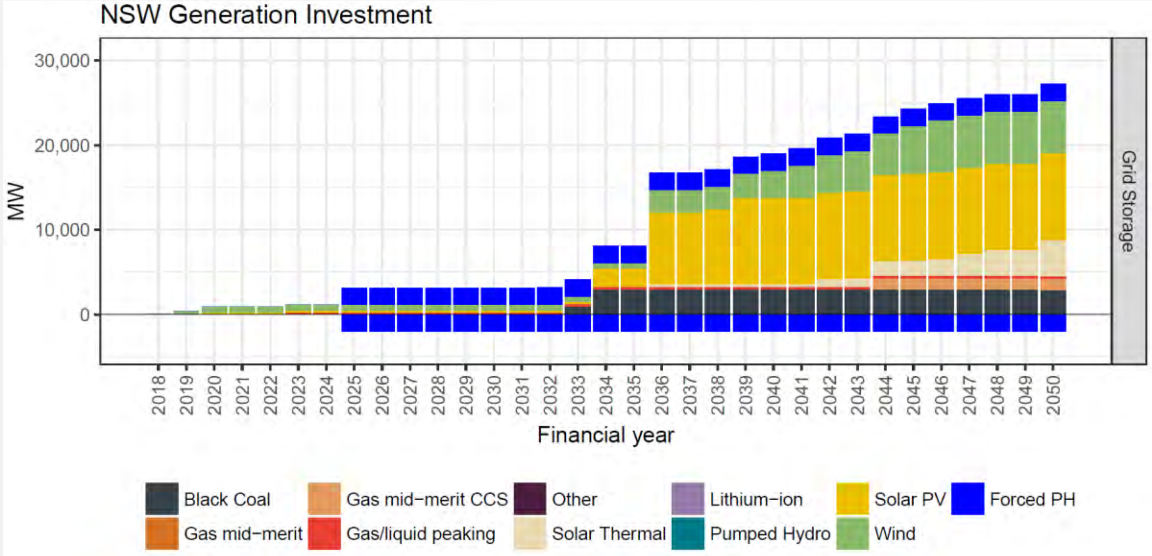
Beyond that, we do not see new investment until 2032/33.

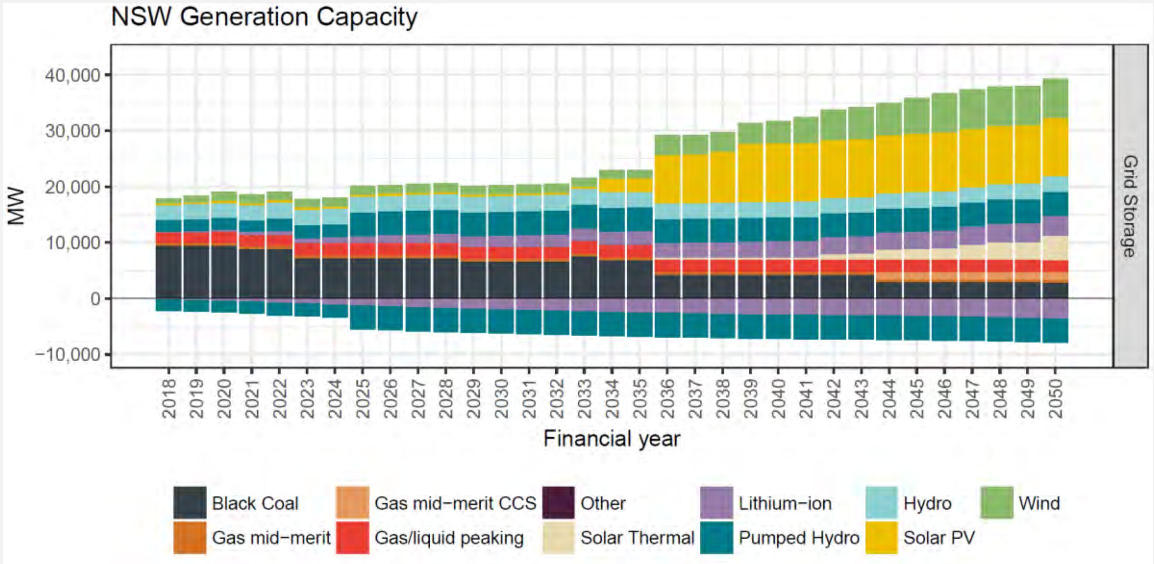
As in the Base Case, with the retirement of Eraring power station in 2032/33 and Bayswater power station in 2034/35, new investment is required. We see the same types of investment: new coal plant as well as significant amounts of solar thermal, solar PV and wind generation. Following the retirement of Mt Piper power station, we also see investment in CCGT with CCS, as we did in the Base Case.

Because of the additional storage provided by pumped storage, we see less investment in solar thermal (which also provides storage) and more investment in solar PV. We also see a slight delay in investment in some coal capacity, and slightly less investment in wind plant and CCGT with CCS.

The overall result – as in the Base Case –is a substantial shift in the overall mix of generation capacity in NSW.

Investment and capacity results for other regions are set out in Appendix A.





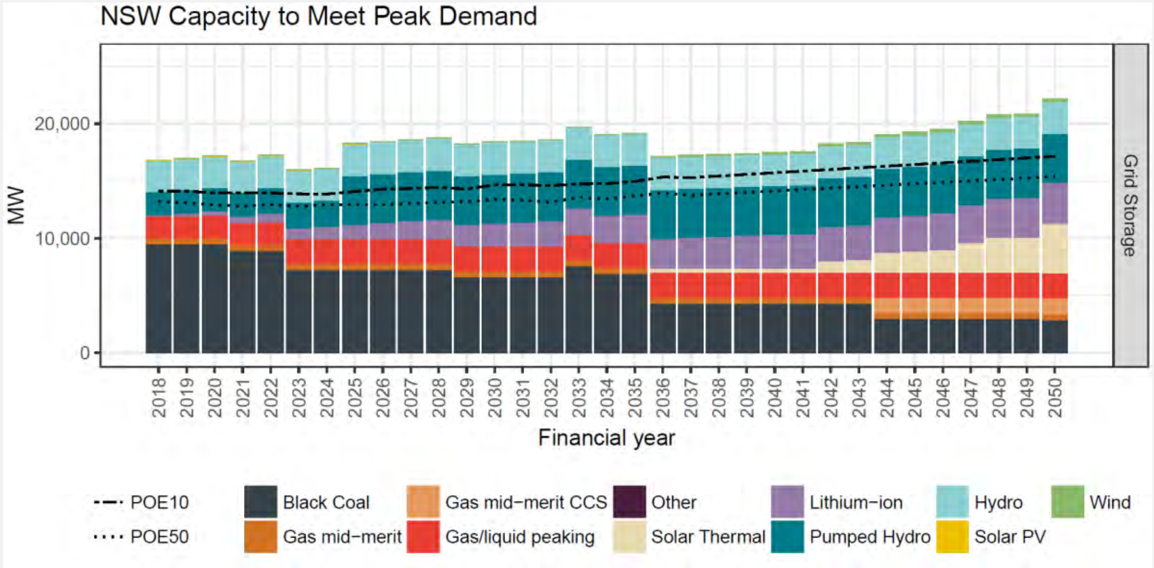
Grid Storage Scenario

NSW diversity of capacity to meet peak demand

Accounting for the expected ability to generate at peak times, it is clear that NSW is currently very reliant on coal-fired generation, hydro generation and, to a lesser extent, gas generation.

As in the Base Case, in the Grid Storage Scenario, over time the contribution of coal-fired generation to meeting peak demand diminishes, as plant retire. As a result, NSW becomes increasingly reliant on solar thermal generation, gas generation and batteries for meeting peak demand. In the Grid Storage Scenario different patterns of investment mean that NSW is less reliant on solar thermal plant as a result of the increased investment in pumped storage capacity (which contributes to peak demand). In the Grid Storage Scenario there is also greater total capacity to meet peak demand than there is in the Base Case, as a result of the increased investment in pumped storage capacity.

Our assumption is that solar PV does not contribute at times of peak demand, and that wind only contributes at a small fraction of its total capacity.

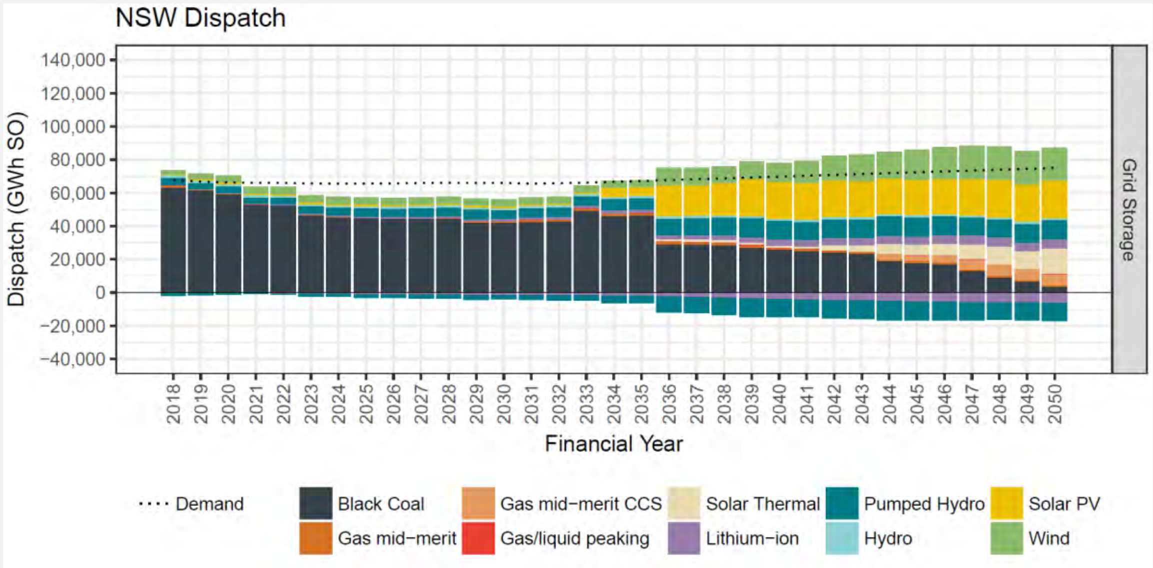


NSW dispatch

Like in the Base Case, in the Grid Storage Scenario our modelling indicates a substantial change over time in the mix of generation plant supplying NSW's electricity.

This change over time is very similar to the change over time that we see for the Base Case: an initial reliance on coal-fired generation gradually changes to a mix in which solar thermal and solar PV are crucial, and there is also an increasing contribution from wind, batteries, pumped-storage hydro and gas.

The differences that we see relative to the Base Case largely mirror the differences in investment that we discuss above: because of the additional storage provided by pumped storage, we see less dispatch from solar thermal (which also provides storage) and more dispatch from solar PV, supported by additional pumped-storage hydro.



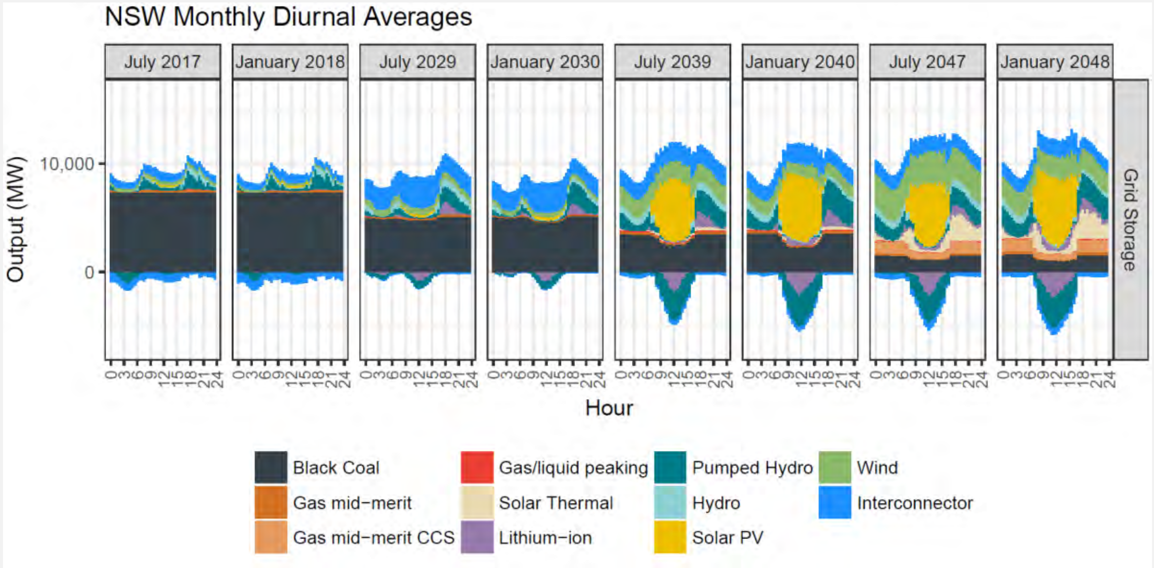
Grid Storage Scenario

NSW half-hourly dispatch

Patterns of half-hourly dispatch are quite similar to those for the Base Case. As in the Base Case, in 2017/18 coal accounts for the majority of dispatch. By 2029/30, imports and batteries play a more important role in meeting demand. By 2039/40, coal dispatch has decreased very materially, replaced by a combination of renewables and storage. By 2047/48, coal generation has decreased even more, being replaced by CCGT with CCS, wind and pumped hydro.

Relative to the Base Case, daily patterns of dispatch in the Grid Storage Scenario show a greater reliance on pumped storage dispatch to meet demand in the evening peaks. This greater use of pumped storage to meet evening peaks means that we see less dispatch from solar thermal generation.

Daily dispatch results for the single week of lowest renewable generation for these same 4 years are presented in Appendix A.



NSW imports

Like in the Base Case, in the Grid Storage Scenario we see a substantial change in patterns of regional flows over the modelling period. These are predominantly driven by the effect of the VRET and QRET, which result in substantial renewable investment in Victoria and Queensland. This leads to excess energy in these regions, both of which export into NSW.

Clearly, NSW becomes more reliant on interconnectors in this scenario, during the 2020s and the early 2030s.

Relative to the Base Case there is very little change in net imports.

Grid Storage Scenario

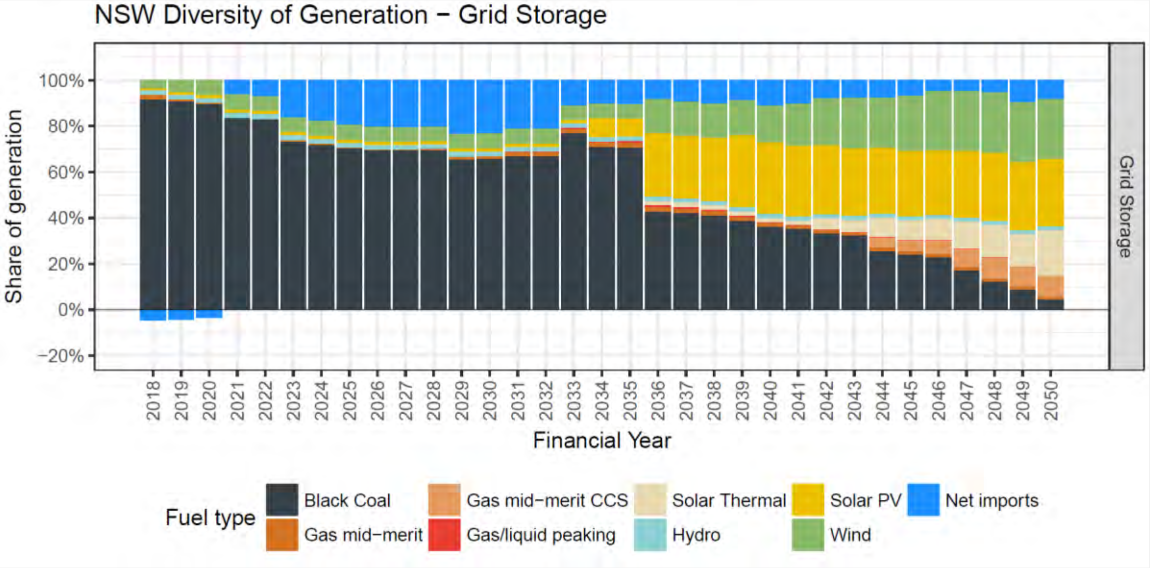
NSW diversity of energy supply

Like in the Base Case, in the Grid Storage Scenario we see a substantial increase over time in the diversity of technologies that supply NSW's electricity.

NSW's initial reliance on coal-fired generation is replaced by a mix of generation that includes substantial amounts of solar thermal, solar PV and wind, with smaller amounts of hydro, gas and imports.

The result is a much more balanced generation mix, and much reduced reliance on a single technology type or fuel source. However, the long-term generation mix if undoubtedly more exposed to intermittent sources than it is at present.

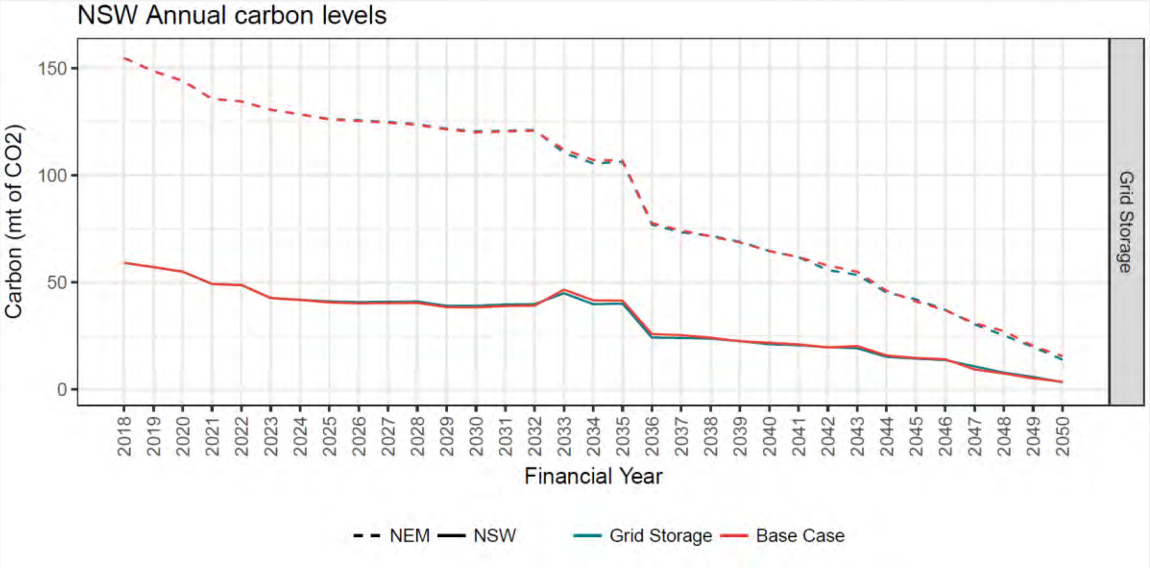
Relative to the Base Case, and consistent with the results we have seen above, in the Grid Storage Scenario the reduction in solar thermal generation in NSW (which is not entirely balanced by an increase in wind and solar PV generation) results in somewhat increased reliance on imports in the long term.



NSW carbon emissions

Consistent with the results for dispatch that we have seen, over time we see a significant reduction in total emissions from NSW power stations. As in the Base Case, these reductions are primarily the result of the retirement of NSW's coal-fired power stations.

Given that additional pumped-storage hydro results in a delay and slight reduction in investment in coal and gas plant, and given that NSW is slightly more dependent on imports, we see that total emissions in NSW are slightly less in total.



Grid Storage Scenario

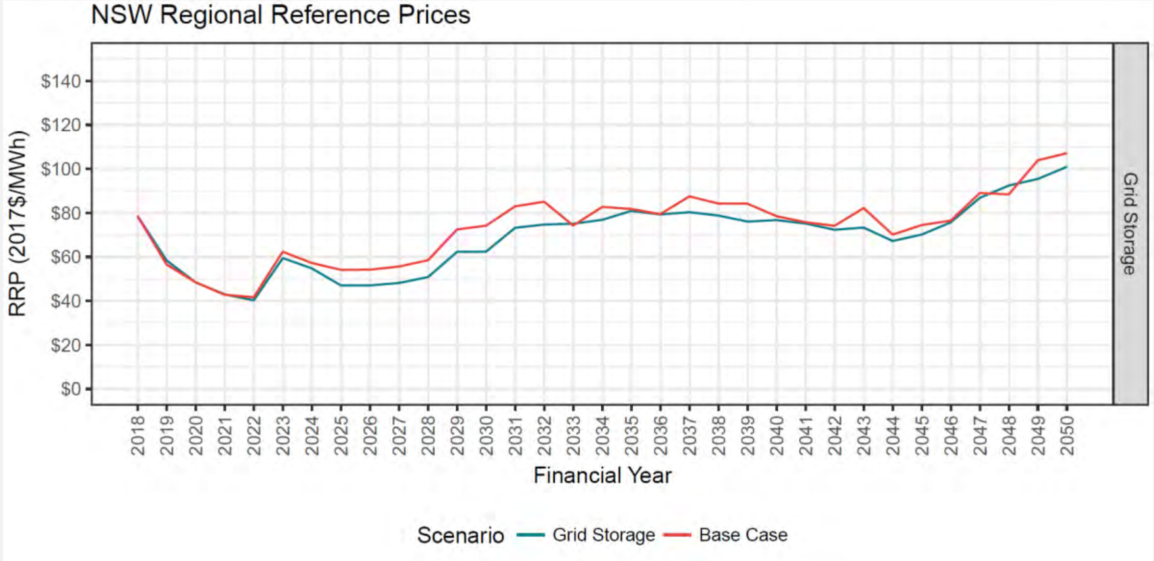
NSW wholesale prices

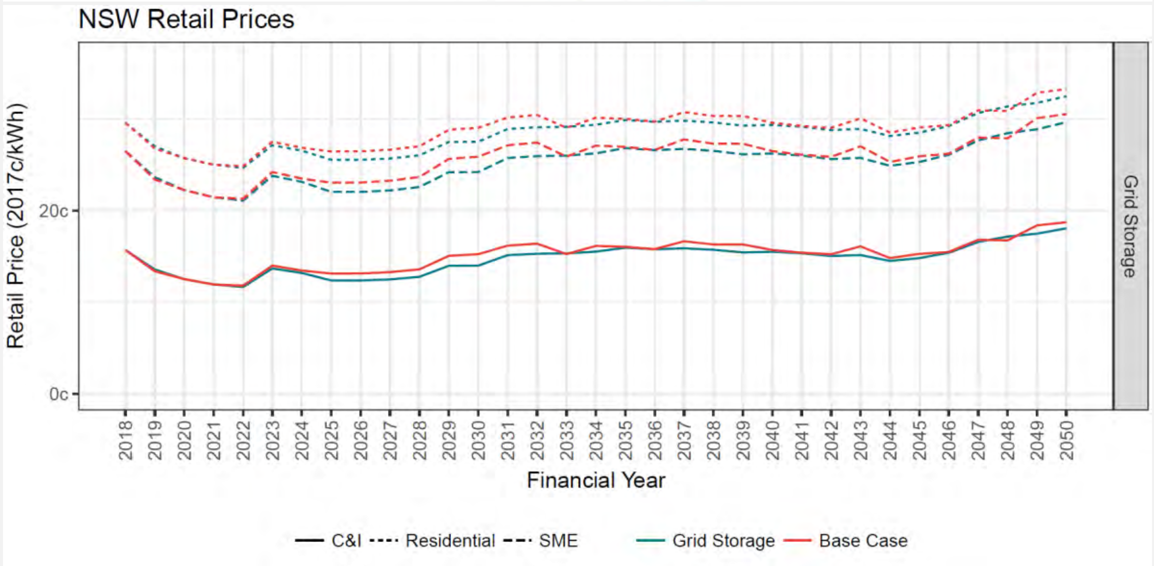
As in the Base Case, our modelling indicates that in the Grid Storage Scenario wholesale prices in NSW will fall over the coming few years, from around $75/MWh in 2017/18 to around $40/MWh in 2020/21. This is driven by substantial investment in renewable plant in both Queensland and Victoria, and the resulting export of renewable energy into NSW (as well as committed investments in NSW).

Over most of the modelling period the prices in the Grid Storage Scenario are somewhat lower than the prices in the Base Case. The reason is the additional capacity available in NSW (and across the NEM) as a result of the assumed investment in additional pumped-storage hydro plant.

Retail prices follow the same trend as wholesale prices, but do not fluctuate as much as wholesale prices. The reason is that a large component of the retail price is network tariffs, which we assume remain constant in real terms.

Wholesale and retail prices for other regions are set out in Appendix A.

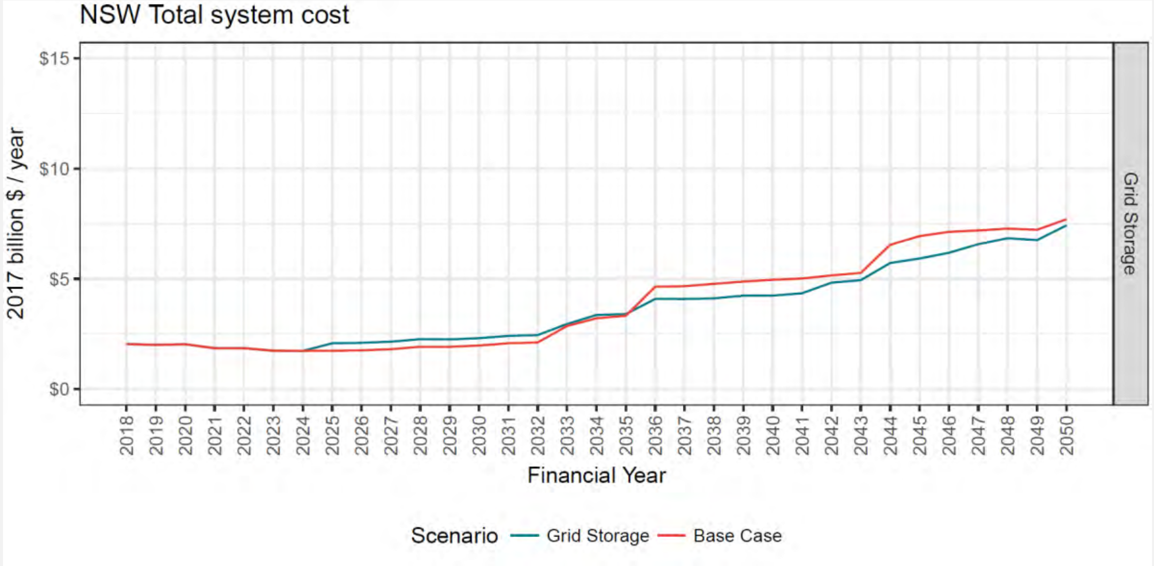




Grid Storage Scenario

NSW total system cost

The total system cost for the Grid Storage Scenario is the same as the Base Case up until the point of investment for Snowy 2.0, where the Grid Storage Scenario has a higher total system cost until 2035. After this point, as Snowy 2.0 displaces other investments that occur in the Base Case, and as pumped hydro is able to reduce dispatch by gas peaking plant, the total system costs are lower.



Rooftop PV Scenario

NSW investment, retirement and installed capacity

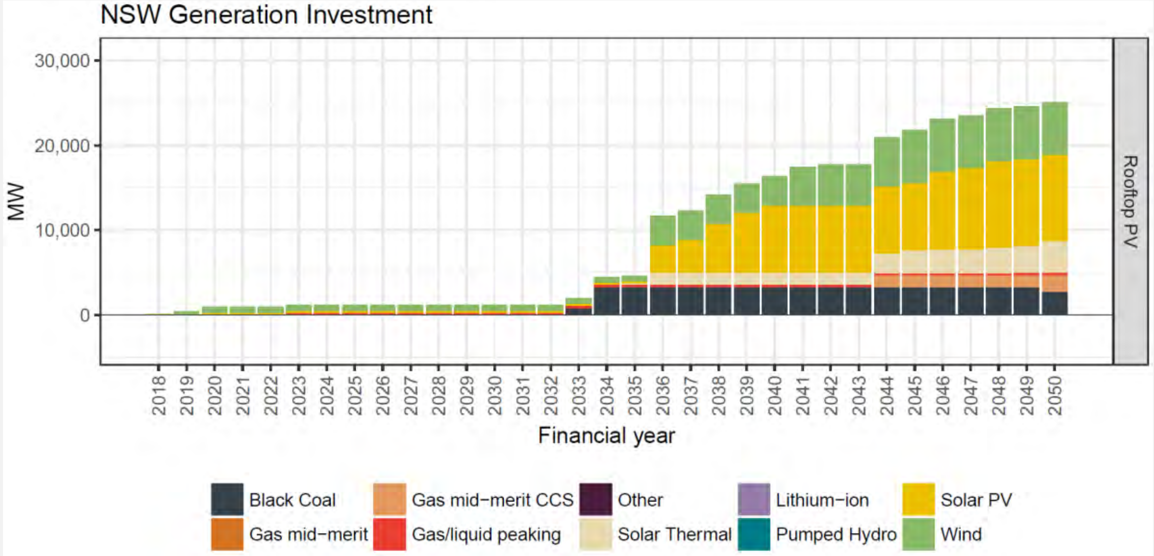
In the Rooftop PV Scenario, our modelling shows that investment outcomes in NSW will be substantially the same as the Base Case. We see the same committed investment over the next five years as in the Base Case – new wind farms and solar farms, as well as AGL's committed investment in Bayswater's upgrade and a gas peaker.

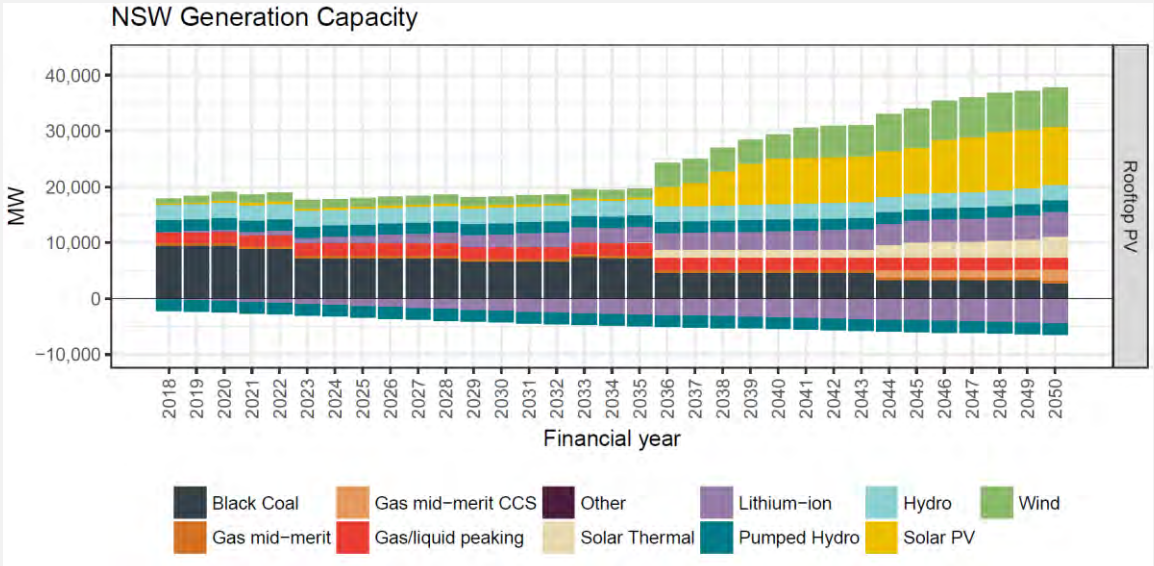
As in the Base Case, with the retirement of Eraring power station in 2032/33 and Bayswater power station in 2034/35, new investment is required. At this point, given that these retirements will be announced in advance, our modelling sees that it is least cost to invest in significant amounts of solar and wind (several thousand MWs of each) in a single year. In reality, commercial decisions may see these investment spread over a few years. Either way, the trends we see in our results will not be materially different.

Following the retirements of Eraring power station and Bayswater power station we see the same types of investment: new coal plant as well as significant amounts of solar thermal, solar PV and wind generation. Following the retirement of Mt Piper, we also see investment in CCGT with CCS. However, with increased rooftop PV capacity we see a corresponding decrease in utility-scale solar thermal and some increase in wind investment (because its economics improve relative to utility-scale solar).

The overall result – as in the Base Case – is a substantial shift in the overall mix of generation capacity in NSW.

Investment and capacity results for other regions are set out in Appendix A.





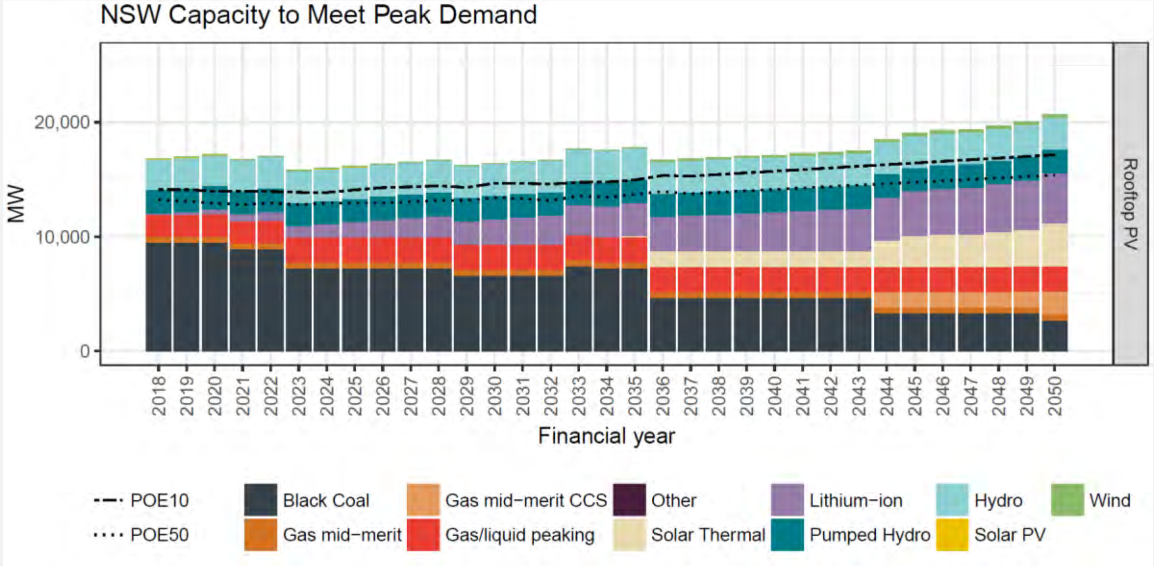
Rooftop PV Scenario

NSW diversity of capacity to meet peak demand

Accounting for the expected ability to generate at peak times, it is clear that NSW is currently very reliant on coal-fired generation, hydro generation and, to a lesser extent, gas generation.

As in the Base Case, in the Rooftop PV Scenario, over time the contribution of coal-fired generation to meeting peak demand diminishes, as plant retire. As a result, NSW becomes increasingly reliant on solar thermal generation, gas generation and batteries for meeting peak demand.

Our assumption is that solar PV does not contribute at times of peak demand, and that wind only contributes at a small fraction of its total capacity.

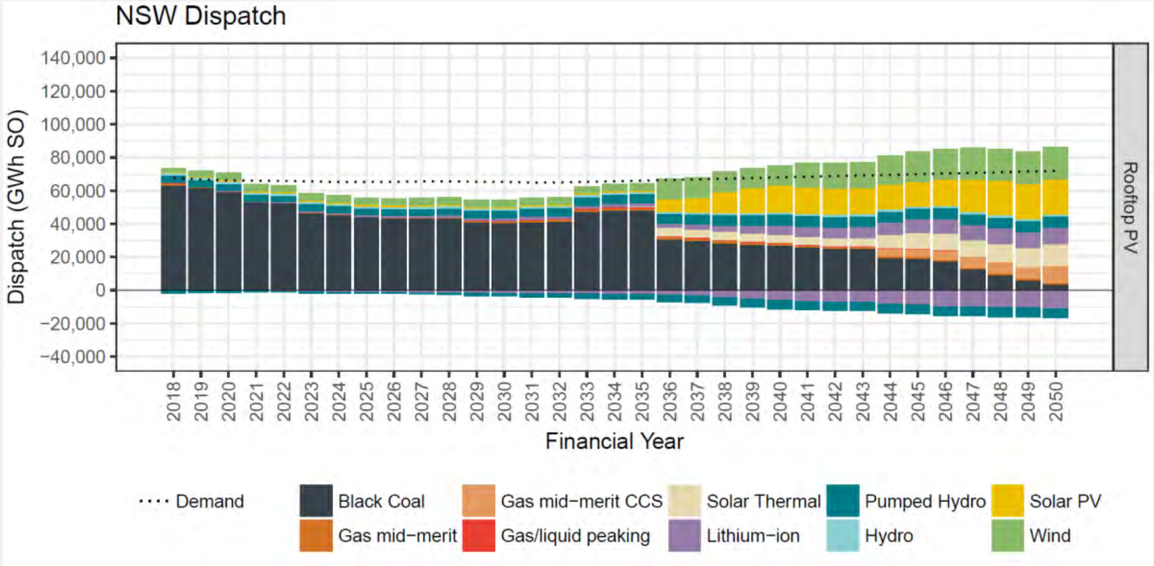


NSW dispatch

Like in the Base Case, in the Rooftop PV Scenario our modelling indicates a substantial change over time in the mix of generation plant supplying NSW's electricity.

This change over time is very similar to the change over time that we see for the Base Case: an initial reliance on coal-fired generation gradually changes to a mix in which solar thermal and solar PV are crucial, and there is also an increasing contribution from wind, batteries, pumped-storage hydro and gas.

The differences that we see relative to the Base Case largely mirror the differences in investment that we discuss above: less utility-scale solar thermal dispatch is required because increased rooftop PV reduces demand. And increased rooftop PV improves the relative economics of wind with respect to solar thermal and solar PV, so we see some increase in wind dispatch.



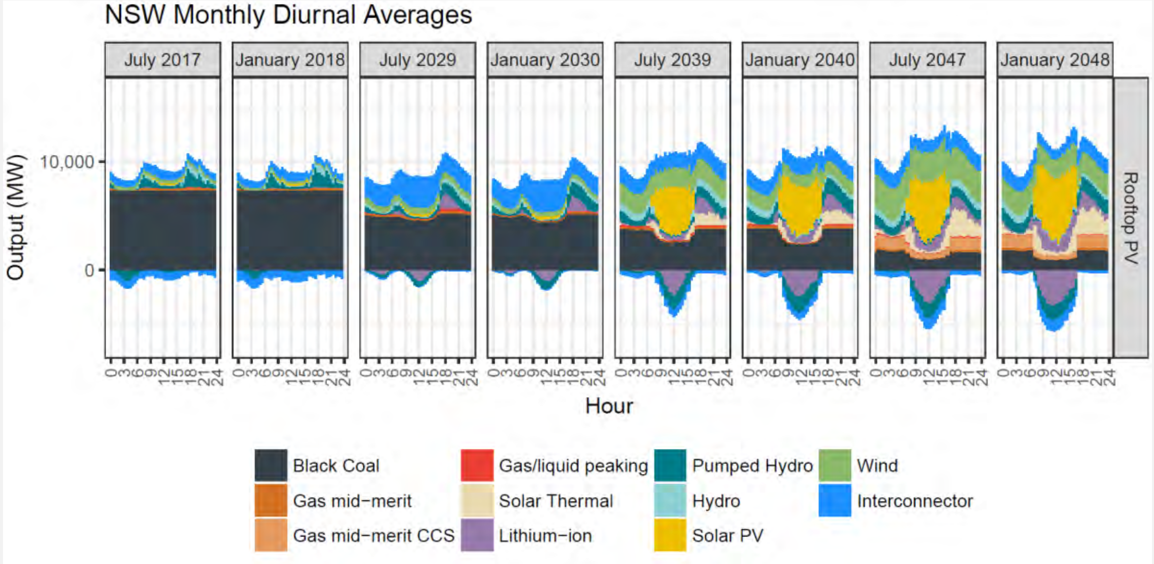
Rooftop PV Scenario

NSW half-hourly dispatch

Patterns of half-hourly dispatch are similar to those for the Base Case. As in the Base Case, in 2017/18 coal accounts for the majority of dispatch. By 2029/30, imports and batteries play a more important role in meeting demand. By 2039/40, coal dispatch has decreased very materially, replaced by a combination of renewables and storage. By 2047/48, coal generation has decreased even more, being replaced by CCGT with CCS and wind.

Relative to the Base Case, daily patterns of dispatch in the Rooftop PV Scenario show less utility-scale solar thermal dispatch, and a slight increase in wind dispatch.

Daily dispatch results for the single week of lowest renewable generation for these same 4 years are presented in Appendix A.

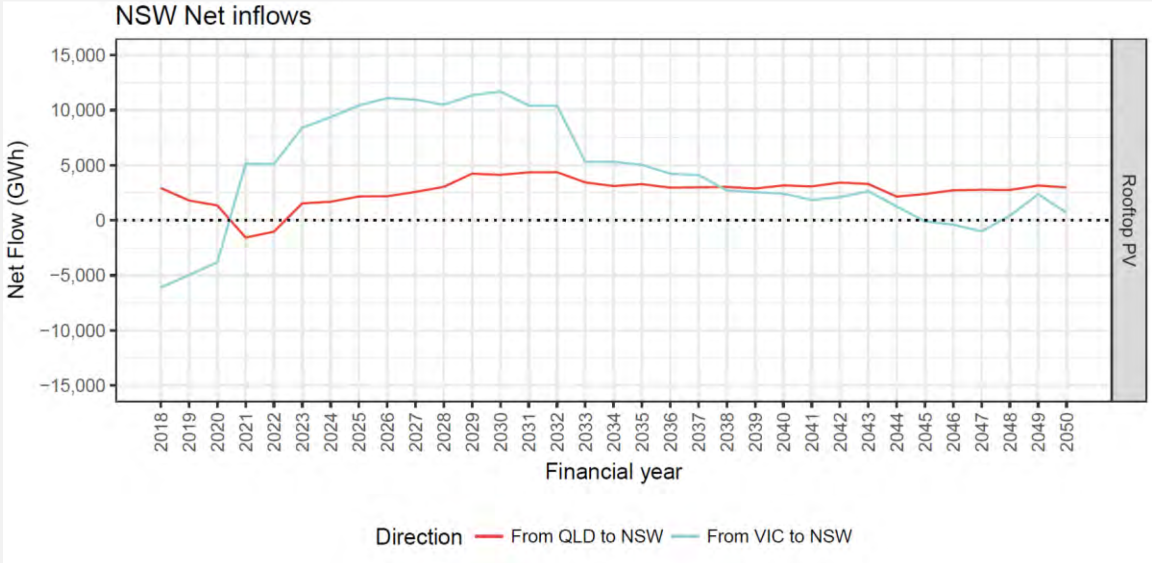


NSW imports

Like in the Base Case, in the Rooftop PV Scenario we see a substantial change in patterns of regional flows over the modelling period. These are predominantly driven by the effect of the VRET and QRET, which result in substantial renewable investment in Victoria and Queensland. These leads to excess energy in these regions, both of which export into NSW.

Clearly, NSW becomes more reliant on interconnectors in this scenario, during the 2020s and the early 2030s.

Relative to the Base Case there is very little change in net imports.



Rooftop PV Scenario

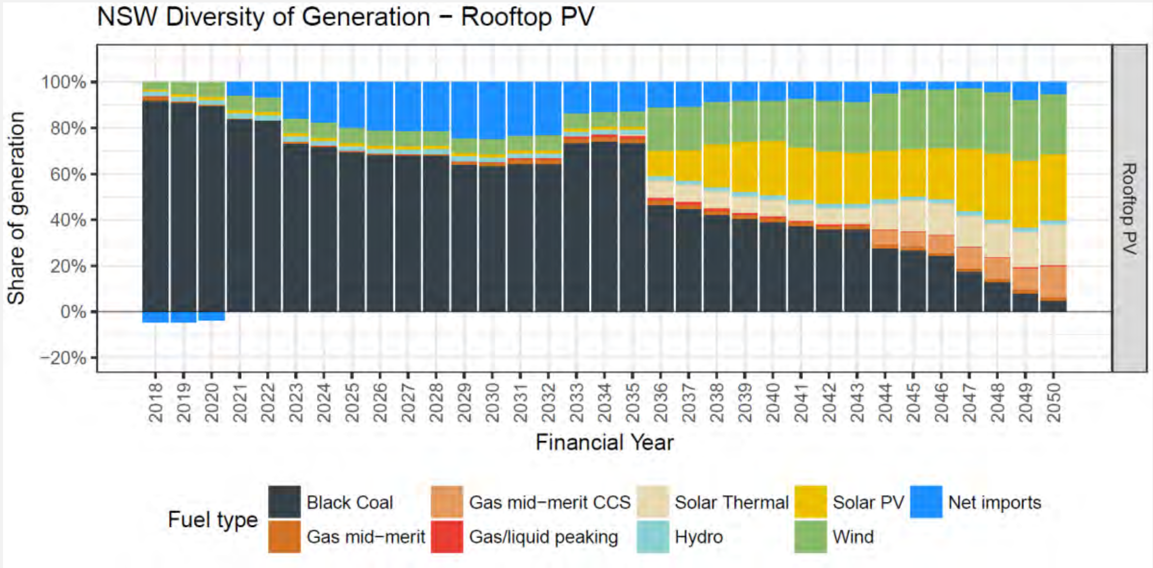
NSW diversity of energy supply

Like in the Base Case, in the Rooftop PV Scenario we see a substantial increase over time in the diversity of technologies that supply NSW's electricity.

NSW's initial reliance on coal-fired generation is replaced by a mix of generation that includes substantial amounts of solar thermal, solar PV and wind, with smaller amounts of hydro, gas and imports.

The result is a much more balanced generation mix, and much reduced reliance on a single technology type or fuel source.

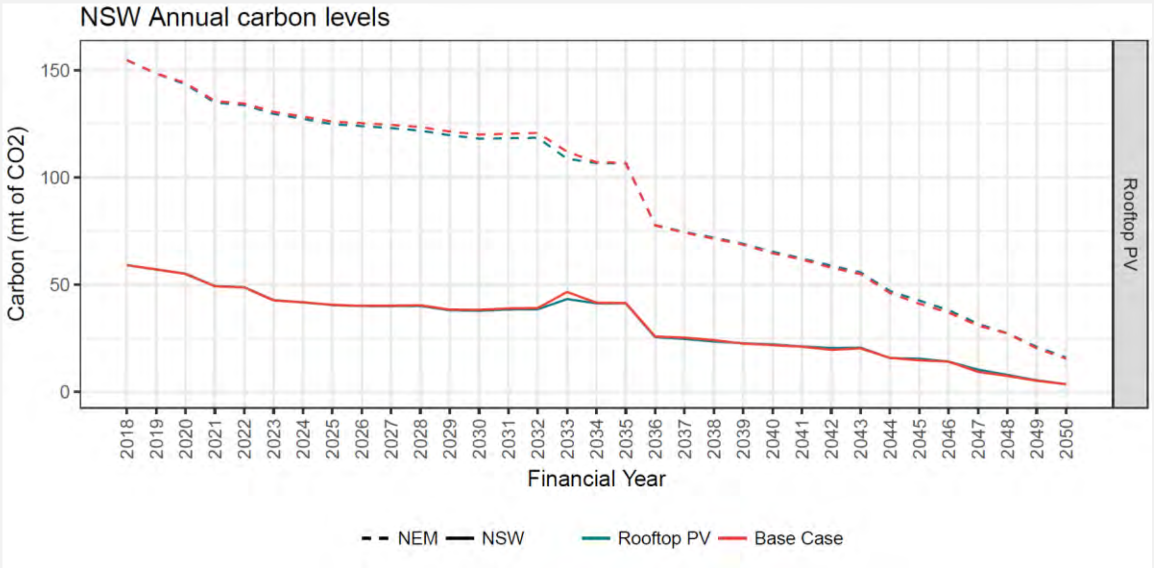
Relative to the Base Case, and consistent with the results we have seen above, in the Rooftop PV Scenario we slightly less utility-scale solar thermal dispatch and some increase in wind dispatch.



NSW carbon emissions

Consistent with the results for dispatch that we have seen, over time we see a significant reduction in total emissions from NSW power stations. As in the Base Case, these reductions are primarily the result of the retirement of NSW's coal-fired power stations.

Given there is an increase in rooftop PV generation, the Rooftop PV Scenario tends to have very slightly lower emissions than the Base Case (the difference tends not to be material because the increase in rooftop PV generation largely displaces other forms of utility-scale renewable generation).



Rooftop PV Scenario

NSW wholesale prices

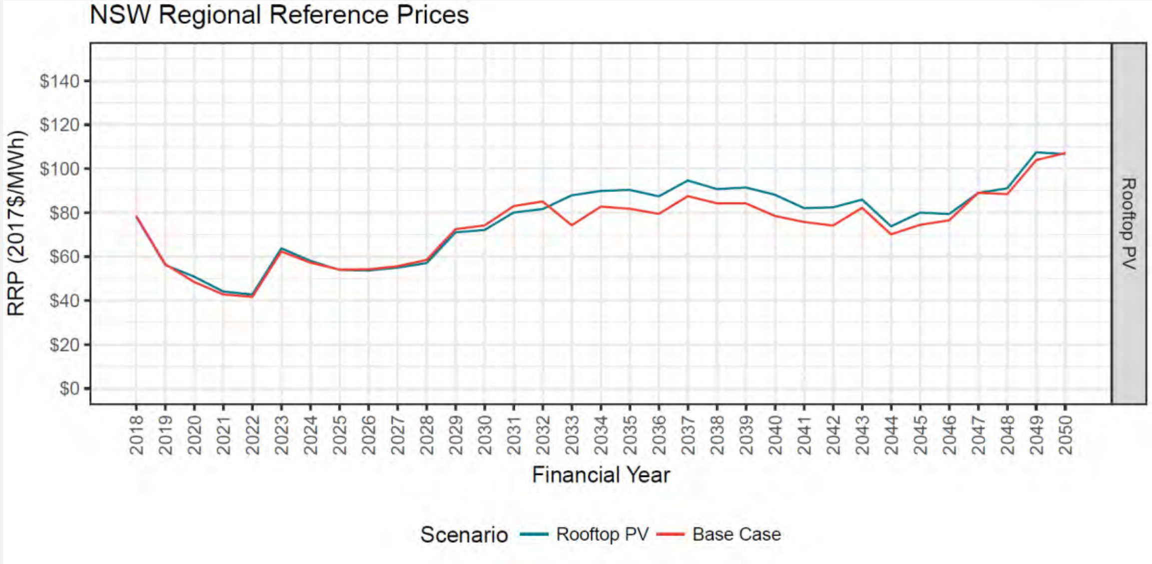
As in the Base Case, our modelling indicates that in the Rooftop PV Scenario wholesale prices in NSW will fall over the coming few years, from around $75/MWh in 2017/18 to around $40/MWh in 2020/21. This is driven by substantial investment in renewable plant in both Queensland and Victoria, and the resulting export of renewable energy into NSW.

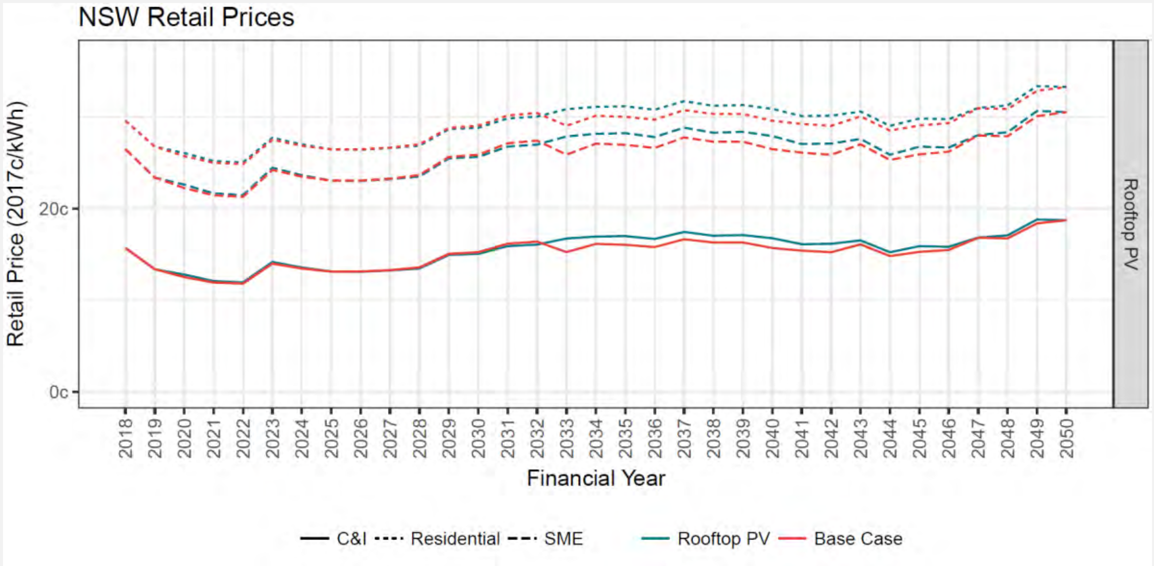
Over the period to the mid-2030s the prices in the Base Case and the prices in the Rooftop PV Scenario are quite similar. After the mid-2030s, however, prices in the Rooftop PV Scenario are consistently higher than in the Base Case. This is the result of the change in the generation mix: in the Base Case the modelling found that solar thermal tended to be the least cost investment (providing the benefits of renewable generation, with storage, while contributing to inertia).

In the Rooftop PV Scenario, however, additional rooftop PV displaces a material amount of solar thermal. Since rooftop PV is less flexible in responding to daily patterns of demand, we see higher prices in the Rooftop PV Scenario. As investment tends back towards the Base Case, prices also tend back towards the Base Case prices.

Retail prices follow the same trend as wholesale prices, but do not fluctuate as much as wholesale prices. The reason is that a large component of the retail price is network tariffs, which we assume remain constant in real terms.

Wholesale and retail prices for other regions are set out in Appendix A.

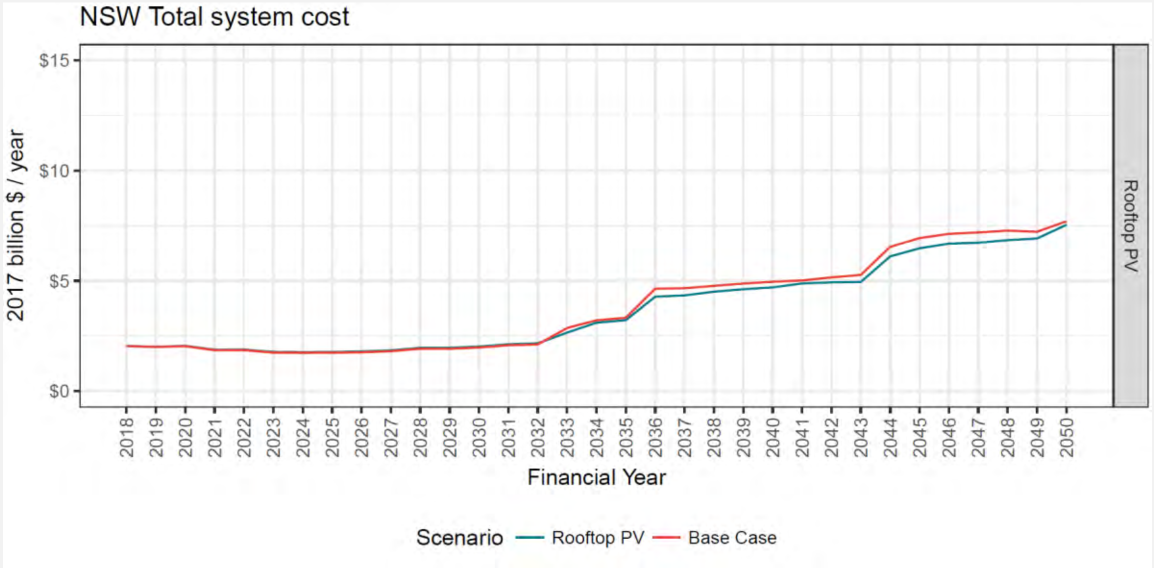




Rooftop PV Scenario

NSW total system cost

The total system cost for the Rooftop PV Scenario follows much the same trend as the Base Case. Total system costs are slightly lower than the Base Case in NSW, however other regions' costs are more, meaning that this scenario is more costly to the system as a whole than the Base Case. This reflects the fact that it is more expensive to have distributed solar PV rather than utility scale.



MEGS Scenario

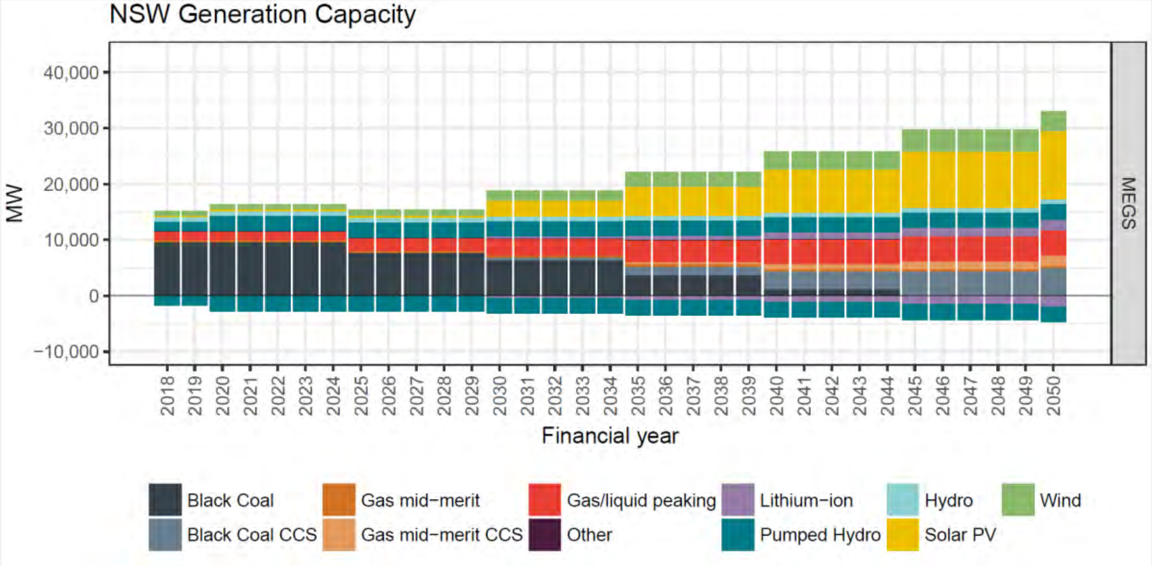
NSW investment, retirement and installed capacity

In the MEGS Scenario, the modelling results from Red Vector show a significant shift in the mix of generation.

The starting point is similar to our Base Case starting point, as would be expected: predominantly coal-fired generation, with hydro, gas generation and some wind and solar.

Over time the investment mix changes substantially. As existing coal-fired plant retires the modelling shows investment in coal with CCS and gas plant – largely peaking plant. There is also significant investment in solar PV and wind. Unlike the Base Case, however, there is no investment in solar thermal.

Investment and capacity results for other regions are set out in Appendix A.

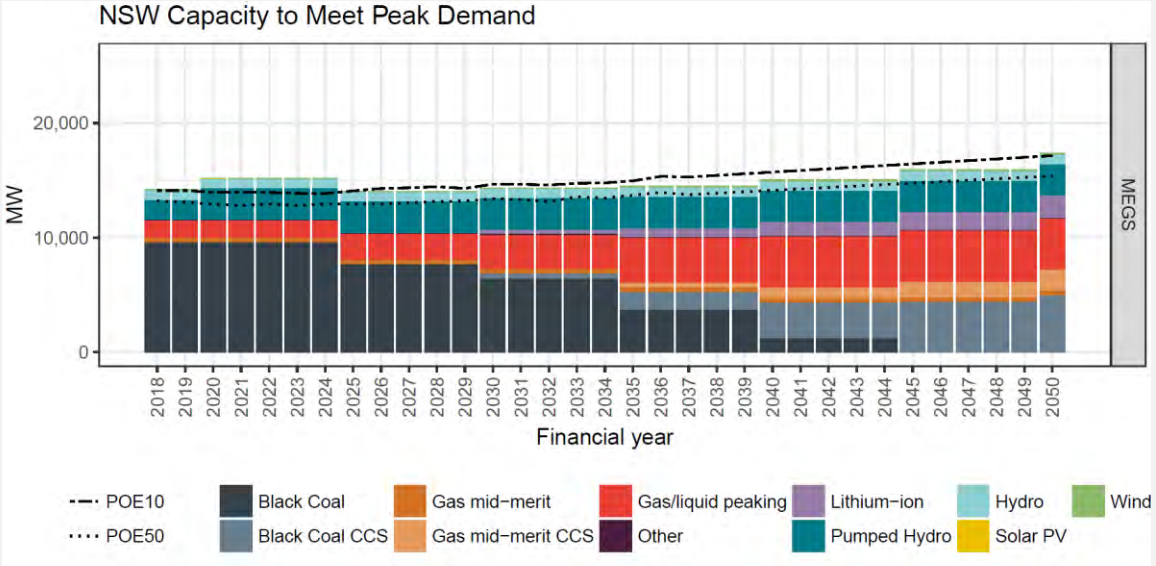


NSW diversity of capacity to meet peak demand

Accounting for the expected ability to generate at peak times, it is clear that NSW is currently very reliant on coal-fired generation, hydro generation and, to a lesser extent, gas generation.

As in the Base Case, in the MEGS Scenario, over time the contribution of coal-fired generation to meeting peak demand diminishes, as plant retire. As a result, NSW becomes increasingly reliant on new coal with CCS, CCGT with CCS, gas peaking plant and batteries for meeting peak demand.

Our assumption is that solar PV does not contribute at times of peak demand, and that wind only contributes at a small fraction of its total capacity.

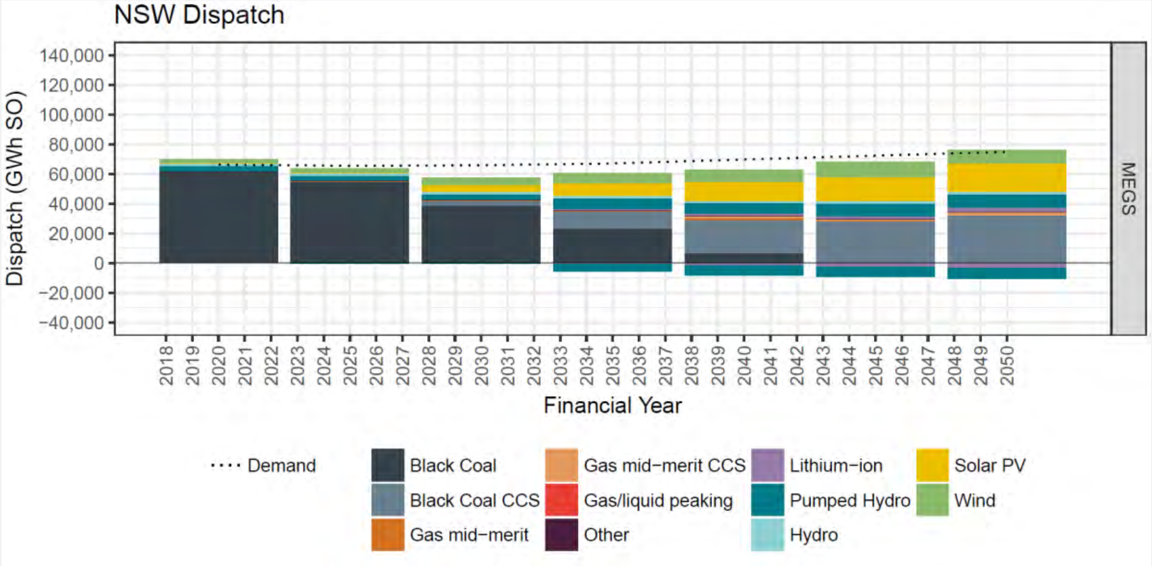


MEGS Scenario

NSW dispatch

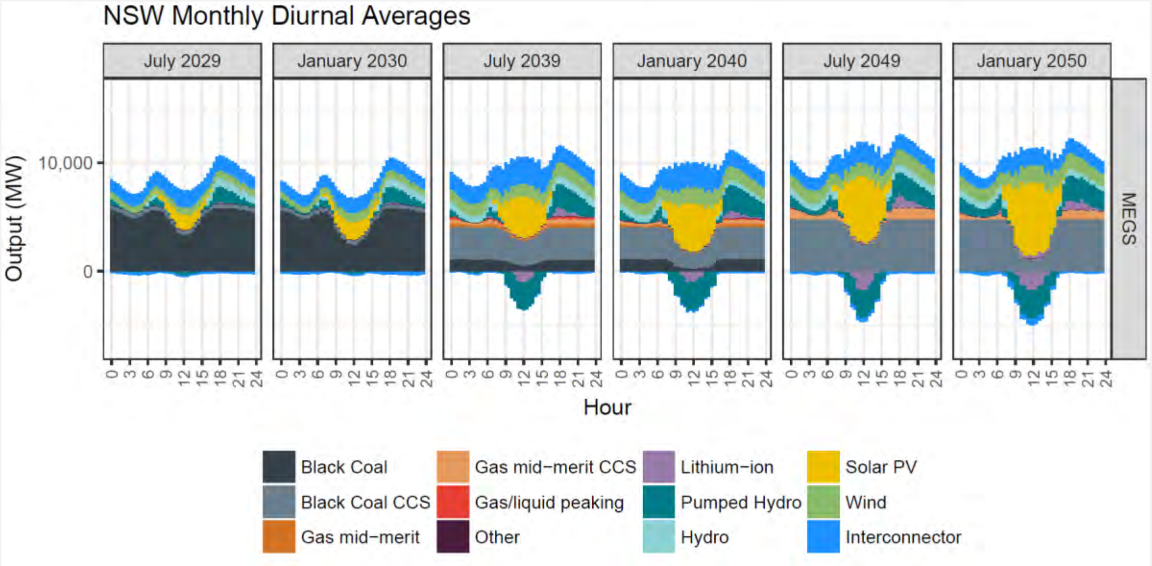
Patterns of dispatch in the MEGS Scenario are very much a function of the investment results provided by Red Vector. Dispatch from coal remains a dominant part of the mix (albeit coal with CCS replaces existing coal without CCS), with renewable generation accounting for a larger and larger proportion of dispatch.

In contrast, gas plant dispatch is not substantial. This is because gas plant is at the top of the merit order, and our modelling finds that with substantial renewable capacity and coal capacity in NSW, gas plant is not required to dispatch very often.



NSW half-hourly dispatch

The patterns of half-hourly dispatch for the MEGS Scenario very much reflect the investment mix that we observe. Coal with CCS accounts for the majority of dispatch, but has to ramp down considerably on a typical day at times of high solar PV generation. Batteries and pumped hydro charge/pump during the middle of the day and discharge/generate in the evening and early morning. Gas generation also tends to operate at times when there is not solar PV generation.



MEGS Scenario

NSW imports

NSW net imports in the MEGS Scenario follow a quite different pattern to NSW net imports in the Base Case.

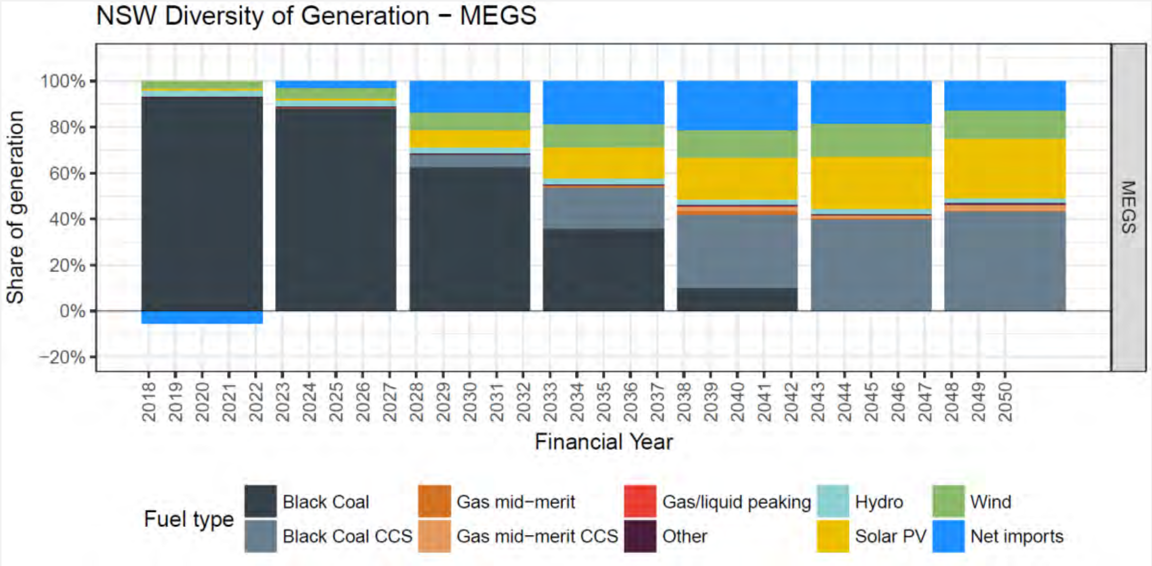
First, there is not the same substantial increases in net imports during the 2020s in the MEGS Scenario that we observe in the Base Case. Presumably this reflects different patterns of investment in the MEGS Scenario – specifically in the MEGS Scenario there is not the same substantial renewable investment in Queensland and Victoria during the 2020s (which is driven by the QRET and VRET in the Base Case).

Second, NSW net imports remain at higher levels during the 2030s and 2040s than in the Base Case. Again, this appears to be driven by investment outcomes in Queensland and Victoria during the 2030s and 2040s; in the MEGS Scenario there is significantly more renewable investment in these regions in the 2030s and 2040s than in the Base Case.

NSW diversity of energy supply

The diversity of energy supply in the MEGS Scenario is substantially different from the Base Case. Coal with CCS dominates dispatch, with significant contributions from renewable in the form of solar PV and wind. Imports also remain important.

However, unlike the Base Case, there is no contribution from solar thermal plant and very little from gas (including CCGT with CCS). The reduced contribution from gas appears to reflect the generally greater capacity in the MEGS Scenario, which results in reduced dispatch from gas plant which has a high short run marginal cost (relative to coal and renewables).

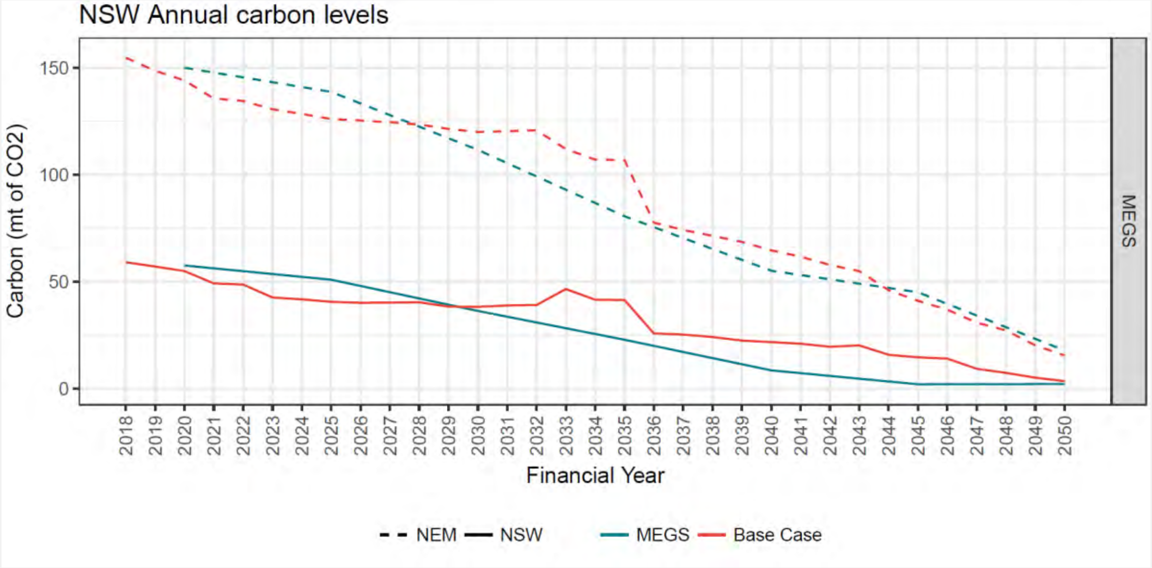


MEGS Scenario

NSW carbon emissions

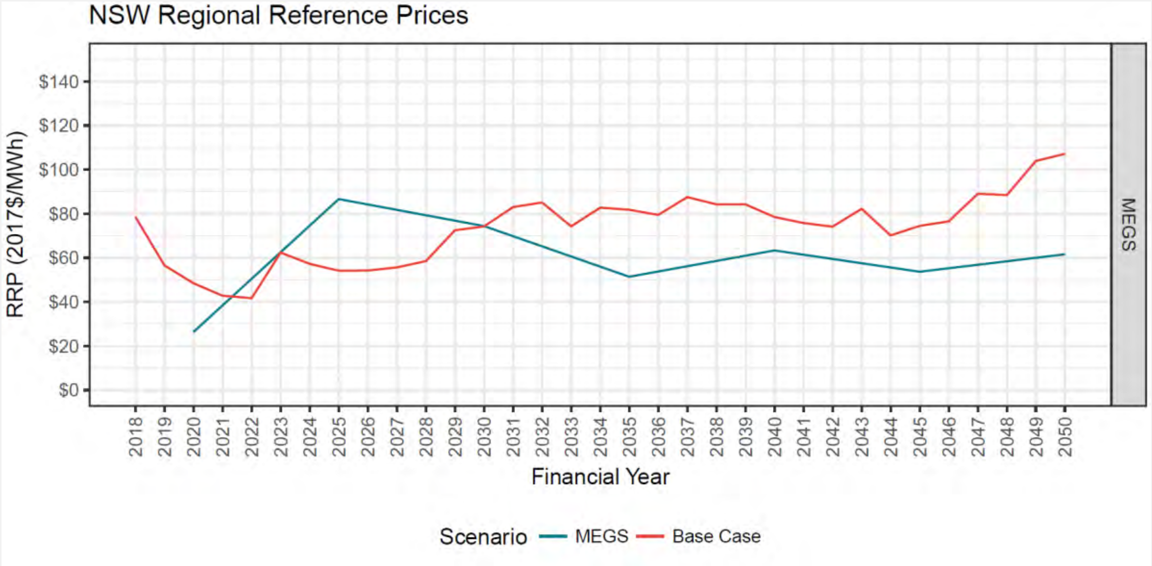
From around 2030, NSW carbon emissions are substantially lower in the MEGS Scenario than in the Base Case. This is a direct result of differences in investment outcomes. In the MEGS Scenario, other than some gas peaking plant which runs very infrequently, all new investment is either renewable or CCS. This means that emissions fall to almost zero by 2050.

In the Base Case, however, there is some investment in conventional coal plant which maintains higher emissions.



NSW wholesale prices

For most of the modelling period wholesale prices in NSW in the MEGS Scenario are substantially lower than wholesale prices in the Base Case. This is primarily the result of the greater generation capacity that is available in the MEGS Scenario, which means that more expensive gas plant is marginal less often.



Electricity market modelling results

High Demand Scenario

NSW investment, retirement and installed capacity

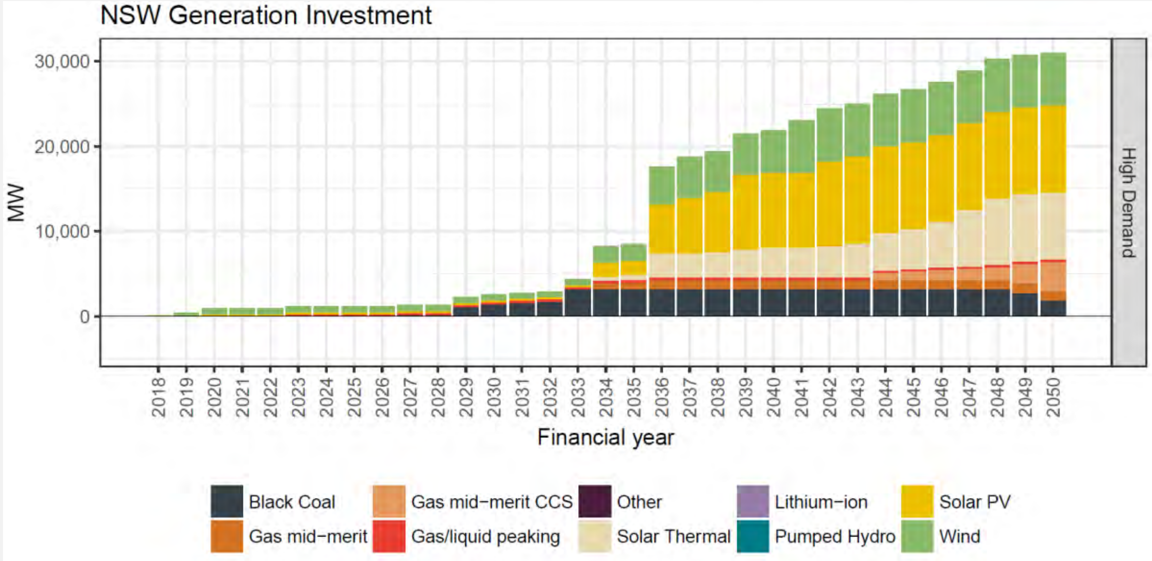
In the High Demand Scenario, our modelling shows that investment outcomes in NSW will have a similar patter to those in the Base Case, but with higher total investment. We see the same committed investment over the next five years as in the Base Case – new wind farms and solar farms, as well as AGL's committed investment in Bayswater's upgrade and a gas peaking plant.

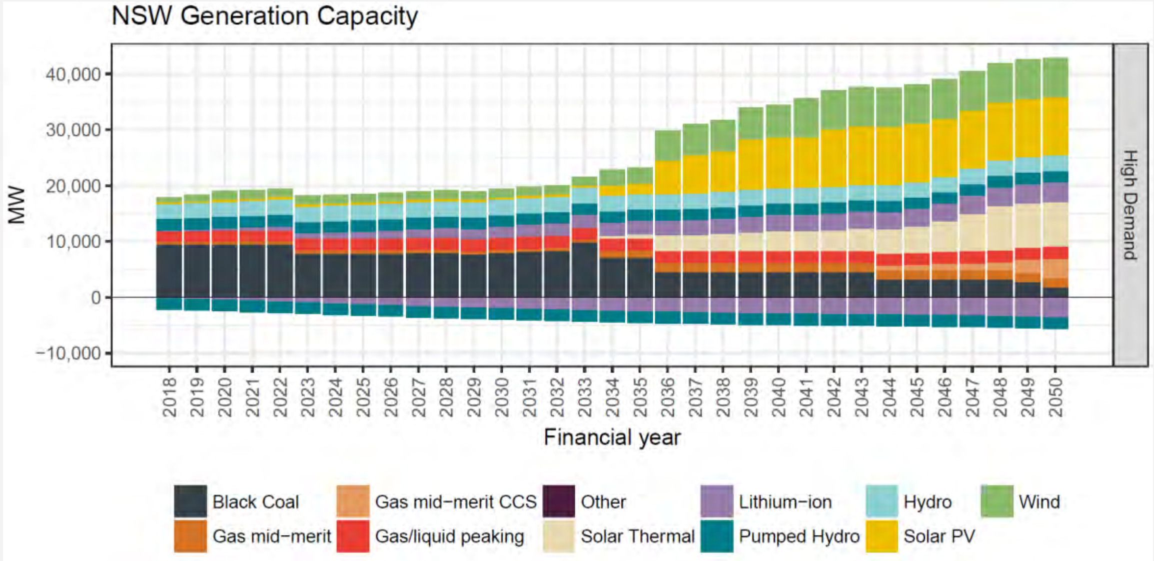
Beyond that, and unlike the other cases that we model, we see additional new investment commencing with the closure of Vales Point power station in the late 2020s (unlike in the Base Case, Vales Point power station does not close early in the High Demand Scenario). This is earlier investment in new coal plant and additional renewable plant than we see in other cases.

Beyond this we see the same types of investment: new coal plant and gas plant as well as significant amounts of solar thermal, solar PV and wind generation. While most of the additional generation plant is renewable, we also see significantly more gas plant (including CCGT with CCS) to generate when intermittent generation does not.

The overall result – as in the Base Case –is a substantial shift in the overall mix of generation capacity in NSW.

Investment and capacity results for other regions are set out in Appendix A.





High Demand Scenario

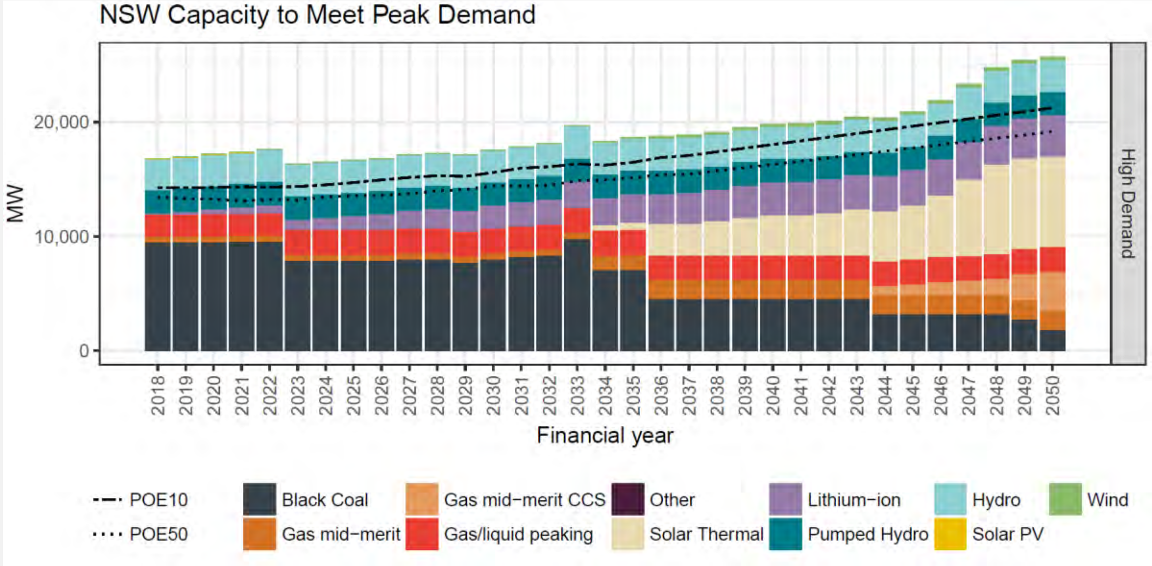
NSW diversity of capacity to meet peak demand

Accounting for the expected ability to generate at peak times, it is clear that NSW is currently very reliant on coal-fired generation, hydro generation and, to a lesser extent, gas generation.

As in the Base Case, in the High Demand Scenario, over time the contribution of coal-fired generation to meeting peak demand diminishes, as plant retire. As a result, NSW becomes increasingly reliant on solar thermal generation, gas generation and batteries for meeting peak demand.

In the High Demand Scenario that stronger growth in peak demand results in solar thermal plant and gas plant to ensure NSW is able to meet peak demand.

Our assumption is that solar PV does not contribute at times of peak demand, and that wind only contributes at a small fraction of its total capacity.

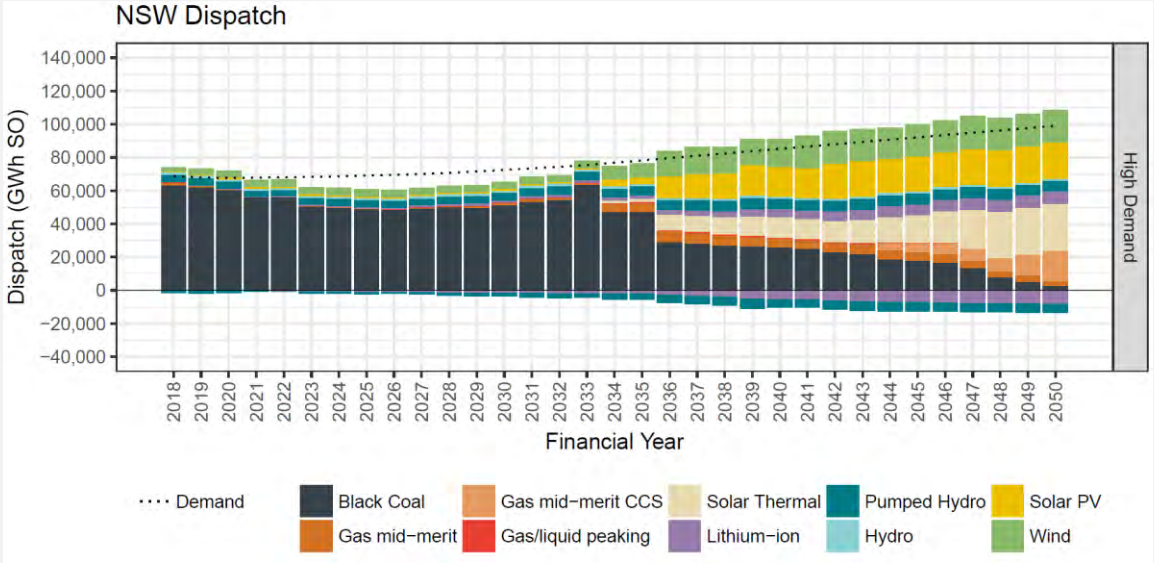


NSW dispatch

Like in the Base Case, in the High Demand Scenario our modelling indicates a substantial change over time in the mix of generation plant supplying NSW's electricity.

This change over time is very similar to the change over time that we see for the Base Case: an initial reliance on coal-fired generation gradually changes to a mix in which solar thermal and solar PV are crucial, and there is also an increasing contribution from wind, batteries, pumped-storage hydro and gas.

The differences that we see relative to the Base Case largely mirror the differences in investment that we discuss above: because of stronger demand growth we see the need for greater dispatch from solar thermal and gas plant in particular.



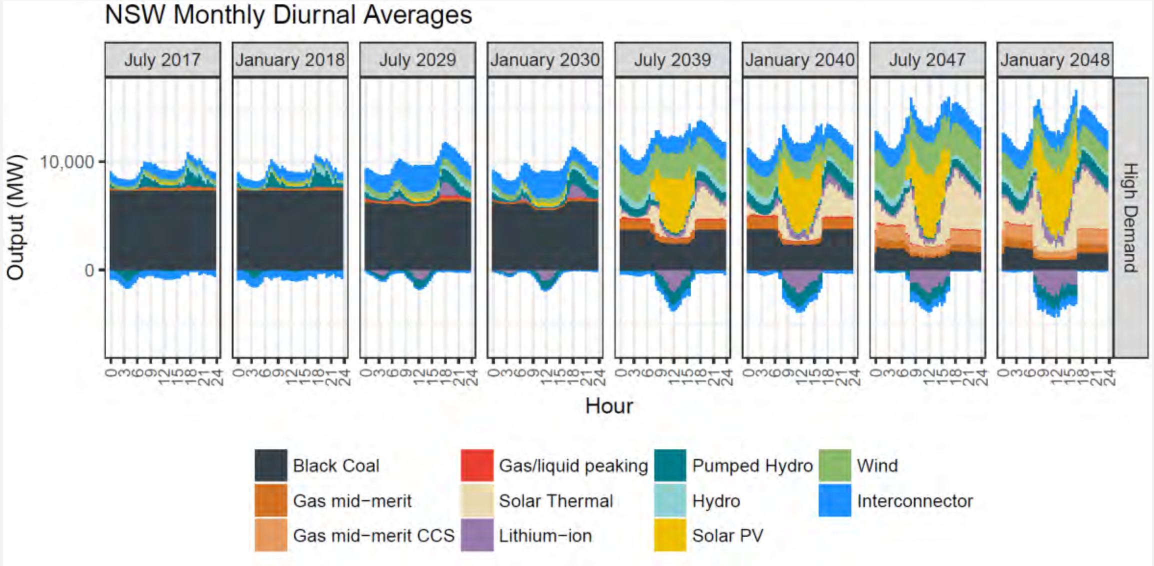
High Demand Scenario

NSW half-hourly dispatch

Patterns of half-hourly dispatch are quite similar to those for the Base Case. As in the Base Case, in 2017/18 coal accounts for the majority of dispatch. By 2029/30, imports and batteries play a more important role in meeting demand. By 2039/40, coal dispatch has decreased very materially, replaced by a combination of renewables, storage and gas. By 2047/48, coal generation has decreased even more, being replaced by CCGT with CCS, renewables and storage.

Relative to the Base Case, daily patterns of dispatch in the High Demand Scenario show a greater reliance on solar thermal generation and gas generation to meet demand. These are particularly important in meeting the increased demand in the evening and overnight.

Daily dispatch results for the single week of lowest renewable generation for these same 4 years are presented in Appendix A.

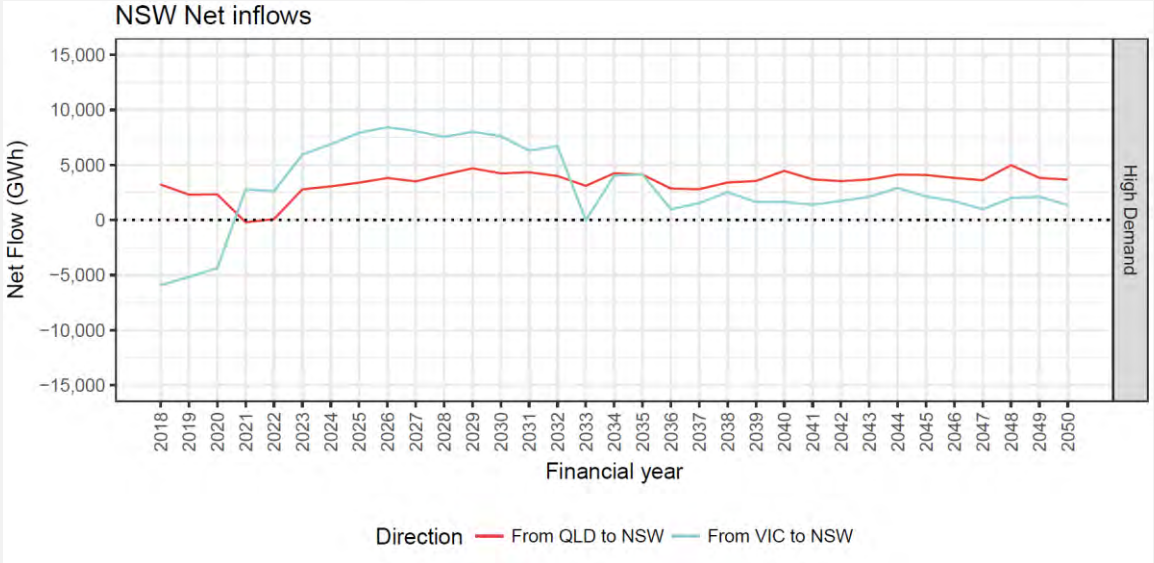


NSW imports

Like in the Base Case, in the High Demand Scenario we see a substantial change in patterns of regional flows over the modelling period. These are predominantly driven by the effect of the VRET and QRET, which result in substantial renewable investment in Victoria and Queensland. This leads to excess energy in these regions, both of which export into NSW.

Clearly, NSW becomes more reliant on interconnectors in this scenario, during the 2020s and the early 2030s.

Relative to the Base Case there is little change in net imports.



High Demand Scenario

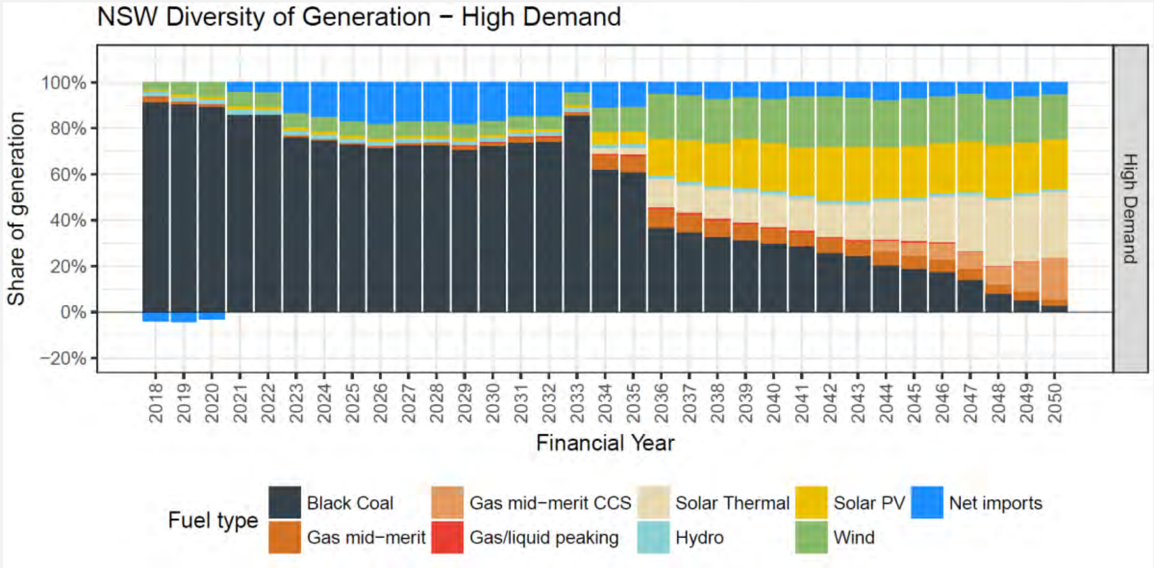
NSW diversity of energy supply

Like in the Base Case, in the High Demand Scenario we see a substantial increase over time in the diversity of technologies that supply NSW's electricity.

NSW's initial reliance on coal-fired generation is replaced by a mix of generation that includes substantial amounts of solar thermal, solar PV and wind, with smaller amounts of hydro, gas and imports.

The result is a much more balanced generation mix, and much reduced reliance on a single technology type or fuel source. However, there is a much greater reliance on intermittent generation plant.

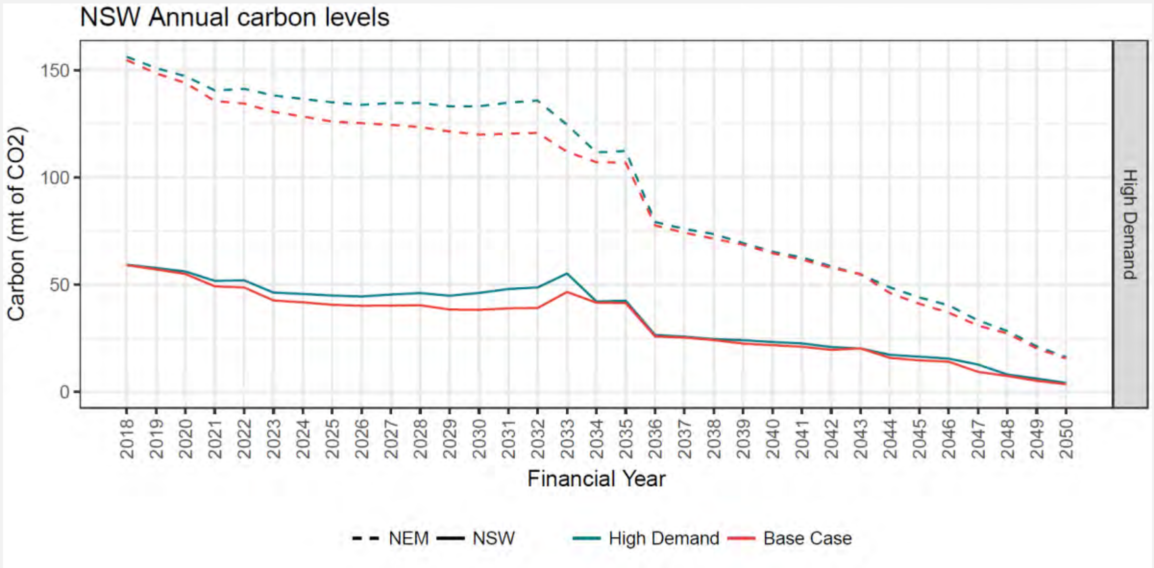
Relative to the Base Case, and consistent with the results we have seen above, in the High Demand Scenario the increased demand for electricity results in greater investment in solar thermal and gas plant to provide additional 'dispatchability'; the result is a greater share of generation accounted for by solar thermal and gas plant.



NSW carbon emissions

Consistent with the results for dispatch that we have seen, over time we see a significant reduction in total emissions from NSW power stations. As in the Base Case, these reductions are primarily the result of the retirement of NSW's coal-fired power stations.

Given the increase in demand, there are times in which we see increased emissions in NSW and the NEM under the High Demand Scenario; ultimately, however, the same emissions target is achieved in 2050.



High Demand Scenario

NSW wholesale prices

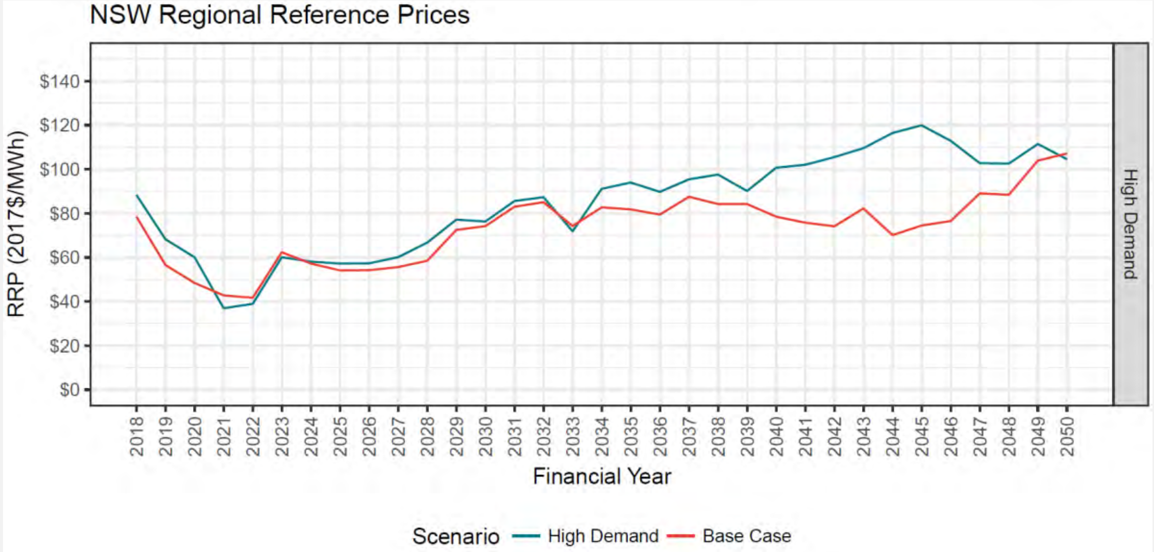
As in the Base Case, our modelling indicates that in the High Demand Scenario wholesale prices in NSW will fall over the coming few years, from around $85/MWh in 2017/18 to around $40/MWh in 2020/21. This is driven by substantial investment in renewable plant in both Queensland and Victoria, and the resulting export of renewable energy into NSW (as well as committed investments in NSW).

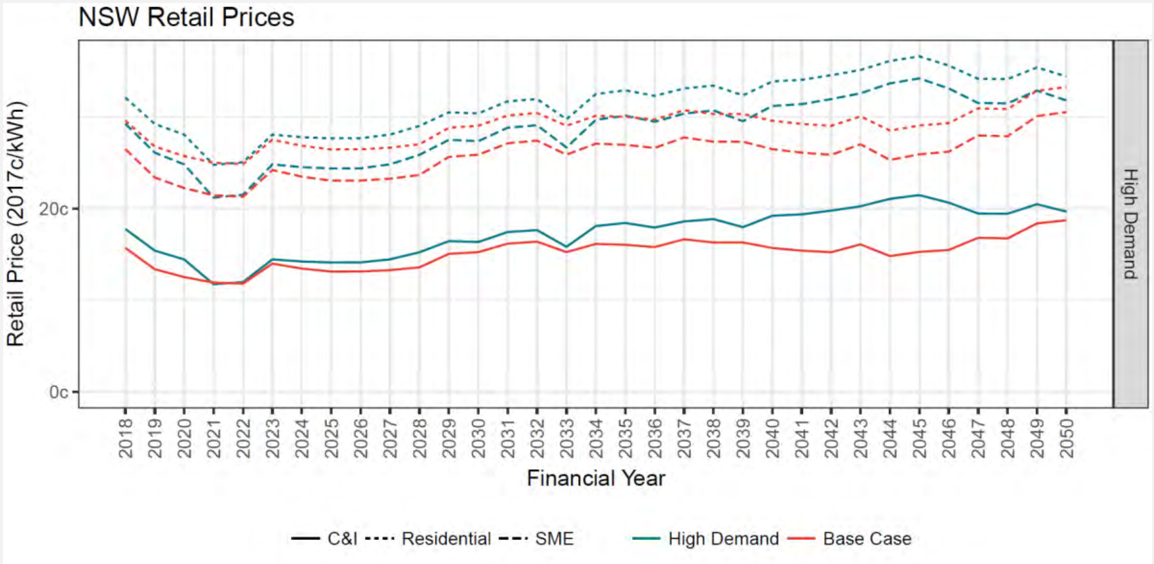
Over the modelling period until the mid-2030s prices are quite similar in the High Demand Scenario and the Base Case. However, as the different in demand starts to widen during the 2040's there is a period where prices in the High Demand scenario are higher (reflecting the need for additional generation and the higher cost of meeting the same emissions target in a world of higher demand).

However, by the end of the modelling period prices in the Base Case and the High Demand Scenario have reached the same long-term level, reflecting the long-term cost of building and operating new plant.

Retail prices follow the same trend as wholesale prices, but do not fluctuate as much as wholesale prices. The reason is that a large component of the retail price is network tariffs, which we assume remain constant in real terms.

Wholesale and retail prices for other regions are set out in Appendix A.

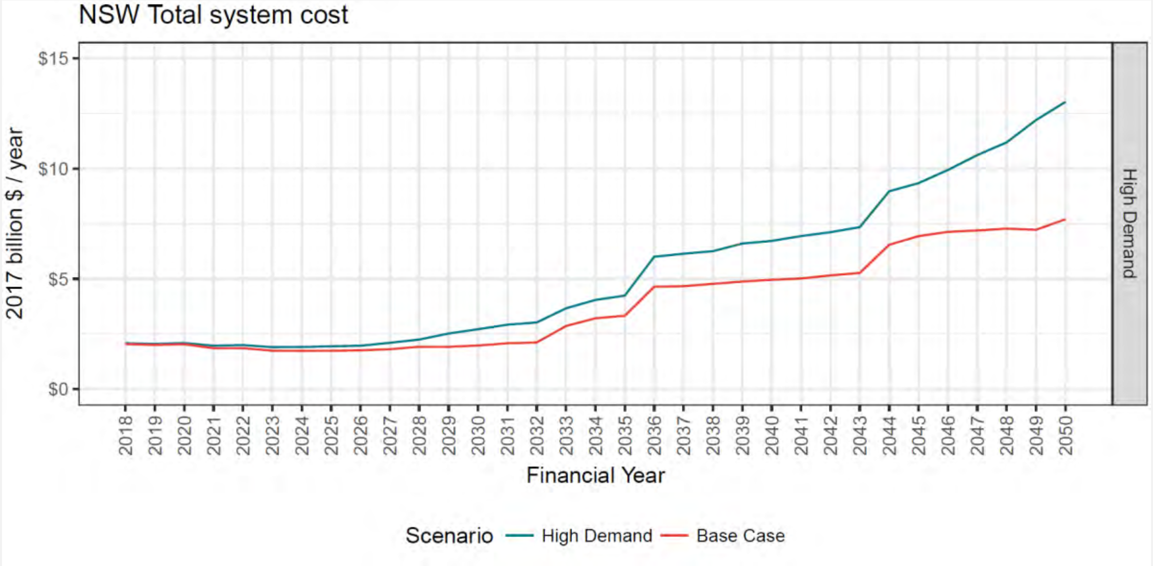




High Demand Scenario

NSW total system cost

As expected, due to the increased demand in the High Demand Scenario total system cost is substantially higher. Since more investment is required in later years when retirements occur, total system costs end up much higher than in the Base Case.



High Solar Thermal Cost Scenario

NSW investment, retirement and installed capacity

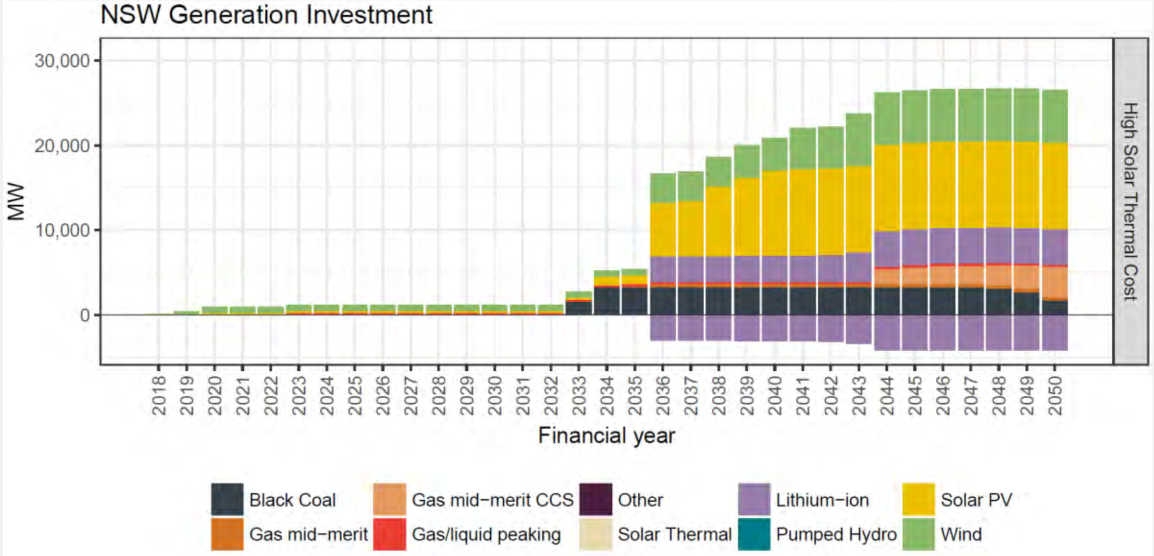
In the High Solar Thermal Cost Scenario, our modelling shows that investment outcomes in NSW will be materially different to the Base Case.

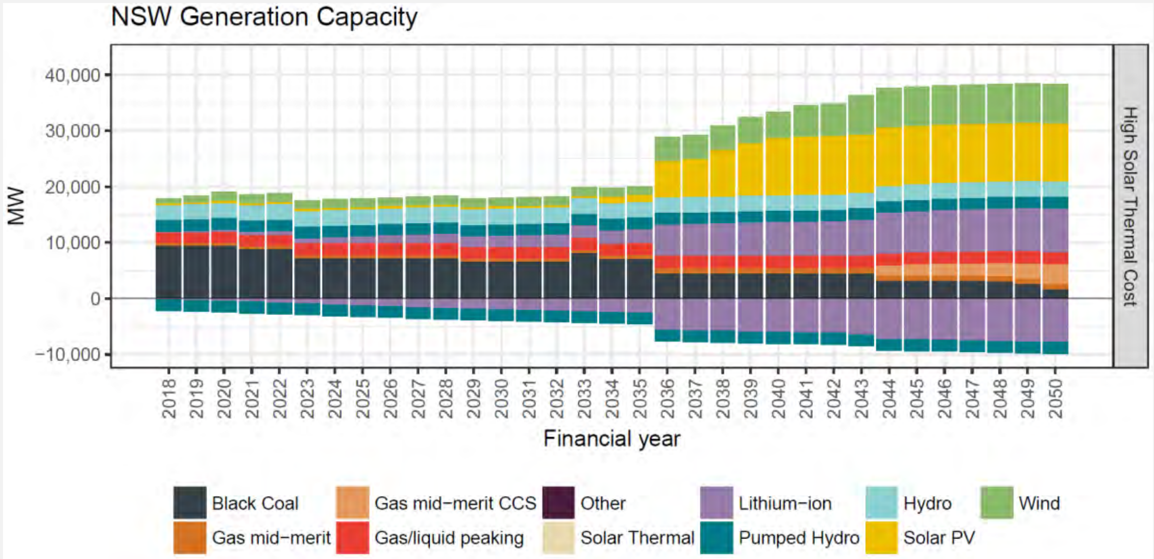
We do, of course, see the same committed investment over the next five years as in the Base Case – new wind farms and solar farms, as well as AGL's committed investment in Bayswater's upgrade and a gas peaker. And, like the Base Case, beyond that, we do not see new investment until 2032/33.

As in the Base Case, with the retirement of Eraring power station in 2032/33 and Bayswater power station in 2034/35, new investment is required. However, the new investment that we see is materially different. Specifically, in the High Solar Thermal Cost Scenario we see no investment in solar thermal plant (due to its assumed higher cost). This investment is replaced by a combination of some additional solar PV, a significant amount of battery storage, and additional gas plant (including CCGT with CCS).

The overall result – as in the Base Case –is a substantial shift in the overall mix of generation capacity in NSW.

Investment and capacity results for other regions are set out in Appendix A.





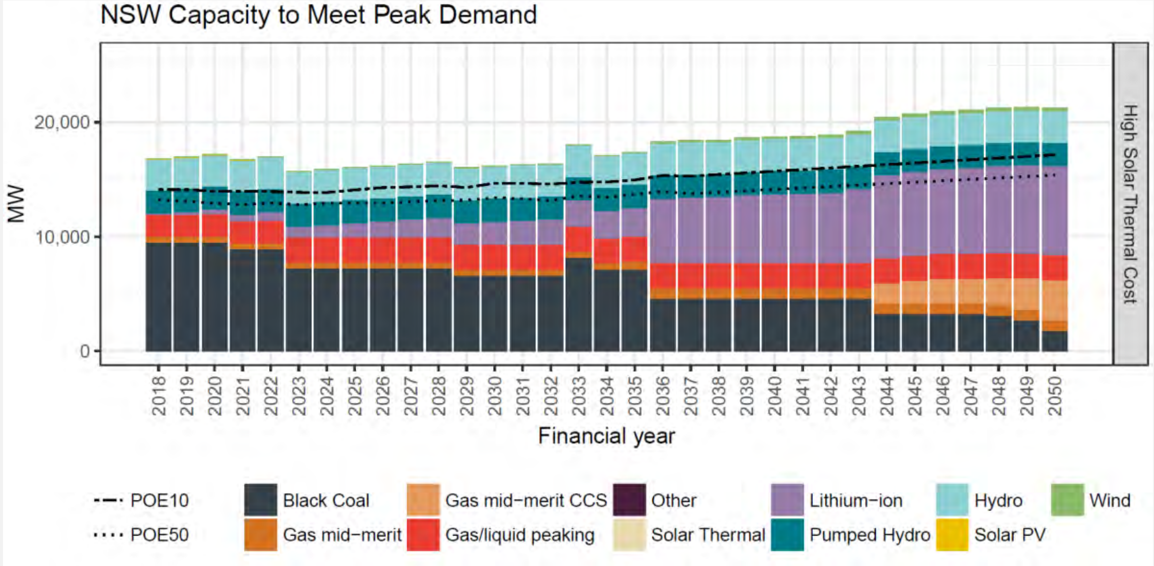
High Solar Thermal Cost Scenario

NSW diversity of capacity to meet peak demand

Accounting for the expected ability to generate at peak times, it is clear that NSW is currently very reliant on coal-fired generation, hydro generation and, to a lesser extent, gas generation.

As in the Base Case, in the High Solar Thermal Cost Scenario, over time the contribution of coal-fired generation to meeting peak demand diminishes, as plant retire. Without solar thermal generation, however, NSW becomes increasingly reliant on batteries and gas plant to meet peak demand. Indeed, the combination of distributed and utility-scale batteries means that battery storage accounts for almost half of the capacity relied on to meet peak demand.

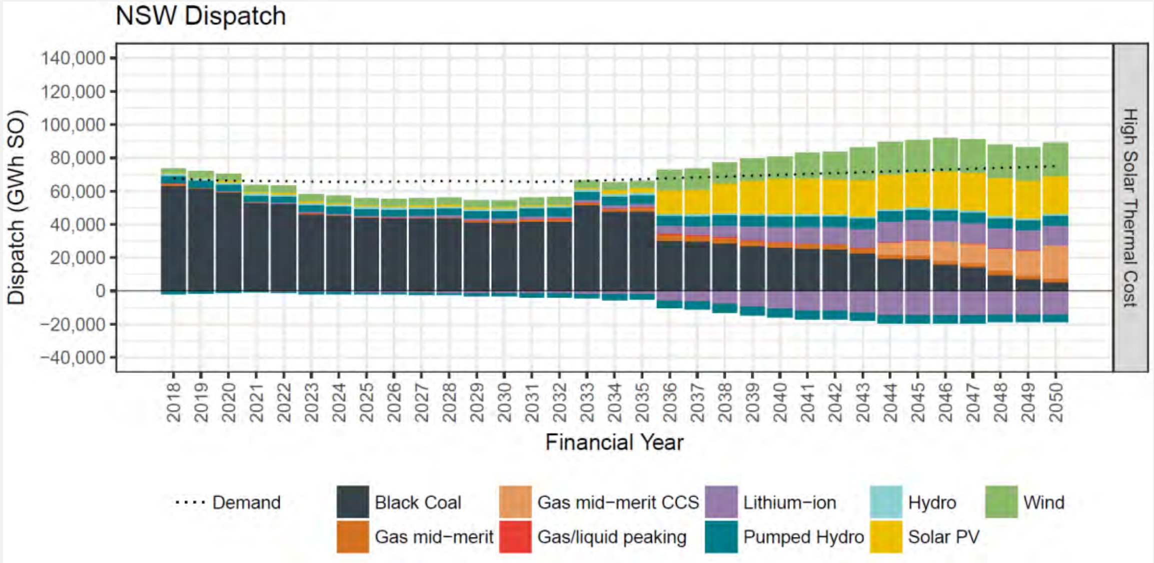
Our assumption is that solar PV does not contribute at times of peak demand, and that wind only contributes at a small fraction of its total capacity.



NSW dispatch

Like in the Base Case, in the High Solar Thermal Cost Scenario our modelling indicates a substantial change over time in the mix of generation plant supplying NSW's electricity.

The differences that we see relative to the Base Case largely mirror the differences in investment that we discuss above: because of the assumed higher cost of solar thermal, we see no dispatch from solar thermal and more dispatch from solar PV, gas plant and batteries (both charging and discharging).



High Solar Thermal Cost Scenario

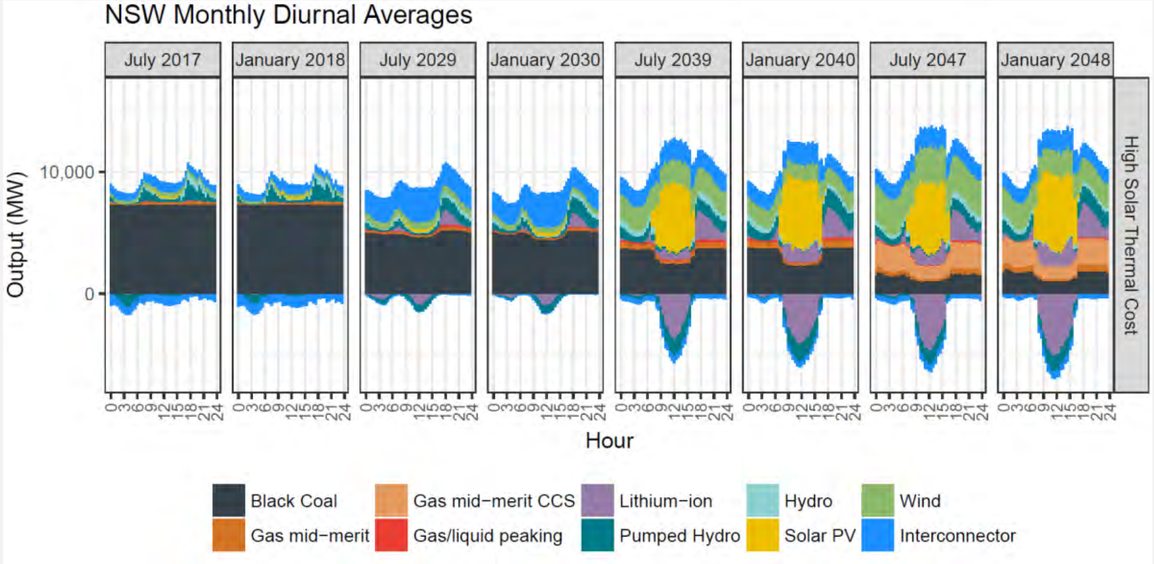
NSW half-hourly dispatch

Patterns of half-hourly dispatch are initially quite similar to those for the Base Case. As in the Base Case, in 2017/18 coal accounts for the majority of dispatch. By 2029/30, imports and batteries play a more important role in meeting demand.

By 2039/40 there are material changes in half-hourly dispatch and material differences between the Base Case and the High Solar Thermal Cost Scenario. With the absence of any solar thermal plant in the High Solar Thermal Cost Scenario gas plant and batteries play a much more important role is helping to time-shift excess solar PV generation and meet high demand in the evening and overnight.

By 2047/48, the trend continues with coal generation decreasing even more, being replaced by CCGT with CCS, and renewables with storage.

Daily dispatch results for the single week of lowest renewable generation for these same 4 years are presented in Appendix A.

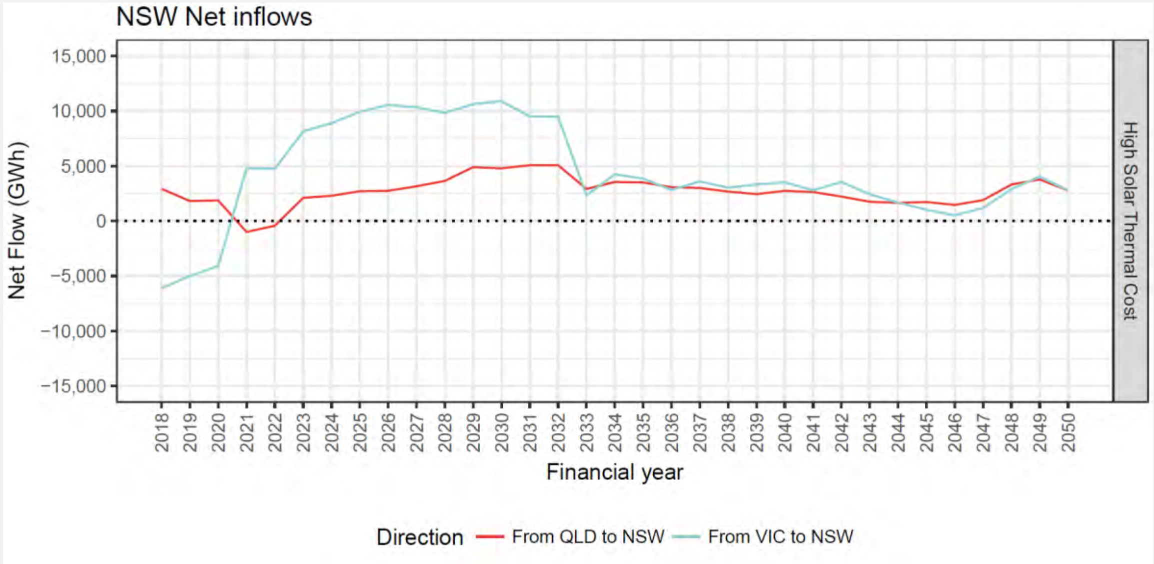


NSW imports

Like in the Base Case, in the High Solar Thermal Cost Scenario we see a substantial change in patterns of regional flows over the modelling period. These are predominantly driven by the effect of the VRET and QRET, which result in substantial renewable investment in Victoria and Queensland. This leads to excess energy in these regions, both of which export into NSW.

Clearly, NSW becomes more reliant on interconnectors in this scenario, during the 2020s and the early 2030s.

Relative to the Base Case there is very little change in net imports.



High Solar Thermal Cost Scenario

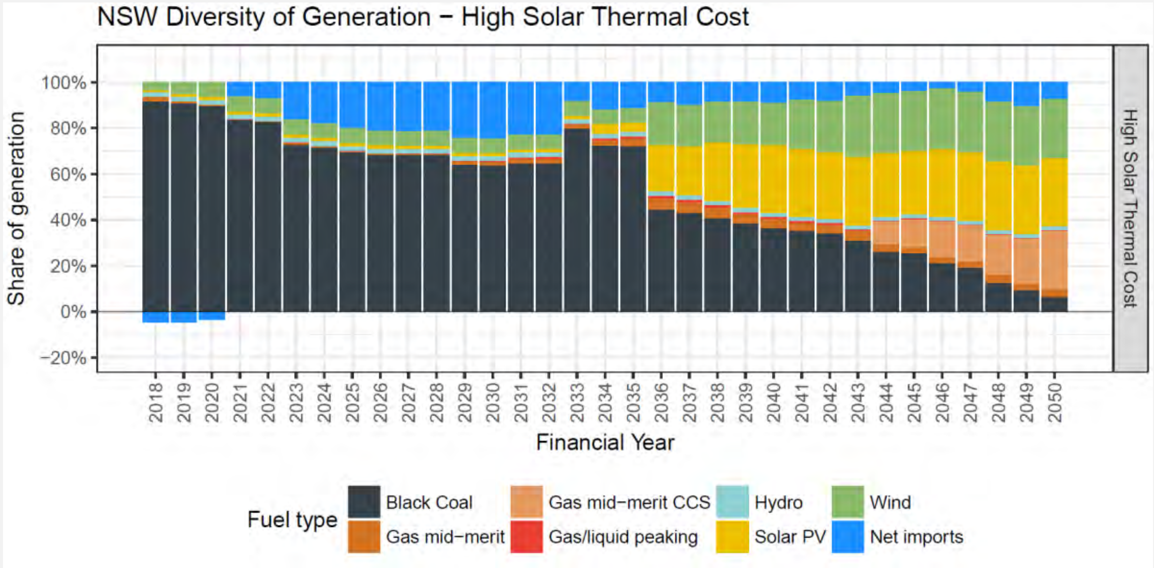
NSW diversity of energy supply

Like in the Base Case, in the High Solar Thermal Cost Scenario we see a substantial increase over time in the diversity of technologies that supply NSW's electricity.

NSW's initial reliance on coal-fired generation is replaced by a mix of generation that includes substantial amounts of solar PV, wind and gas plant, with smaller amounts of hydro and imports.

The result is a much more balanced generation mix, and much reduced reliance on a single technology type or fuel source.

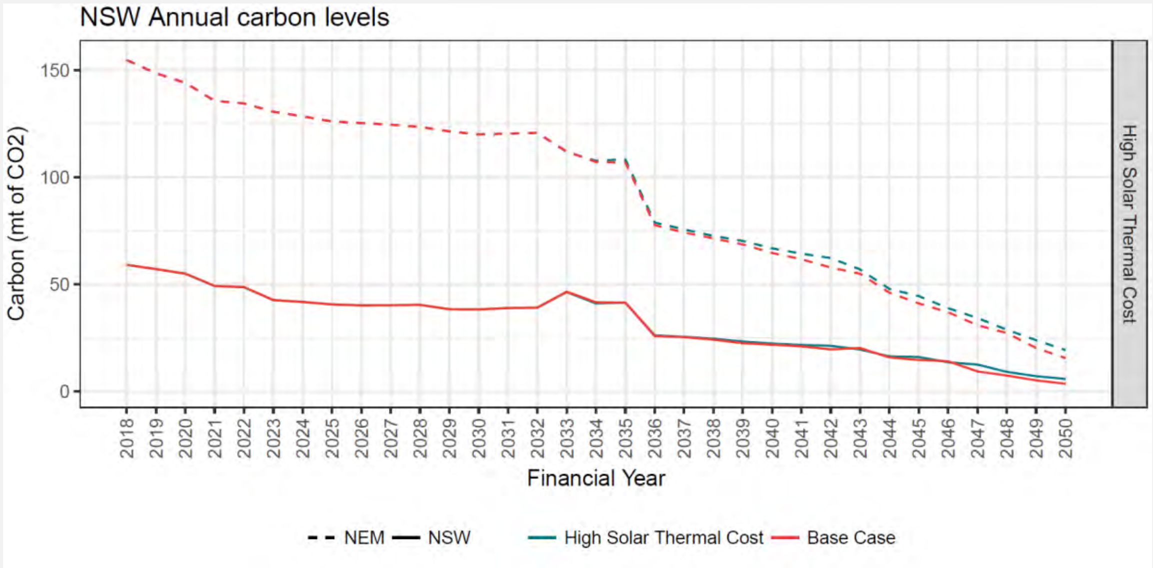
Relative to the Base Case, and consistent with the results we have seen above, in the High Solar Thermal Cost Scenario the absence of solar thermal generation in NSW results in somewhat increased reliance on gas plant in particular in the long term.



NSW carbon emissions

Consistent with the results for dispatch that we have seen, over time we see a significant reduction in total emissions from NSW power stations. As in the Base Case, these reductions are primarily the result of the retirement of NSW's coal-fired power stations.

There is little difference in emissions between the Base Case and the High Solar Thermal Cost Scenario.



High Solar Thermal Cost Scenario

NSW wholesale prices

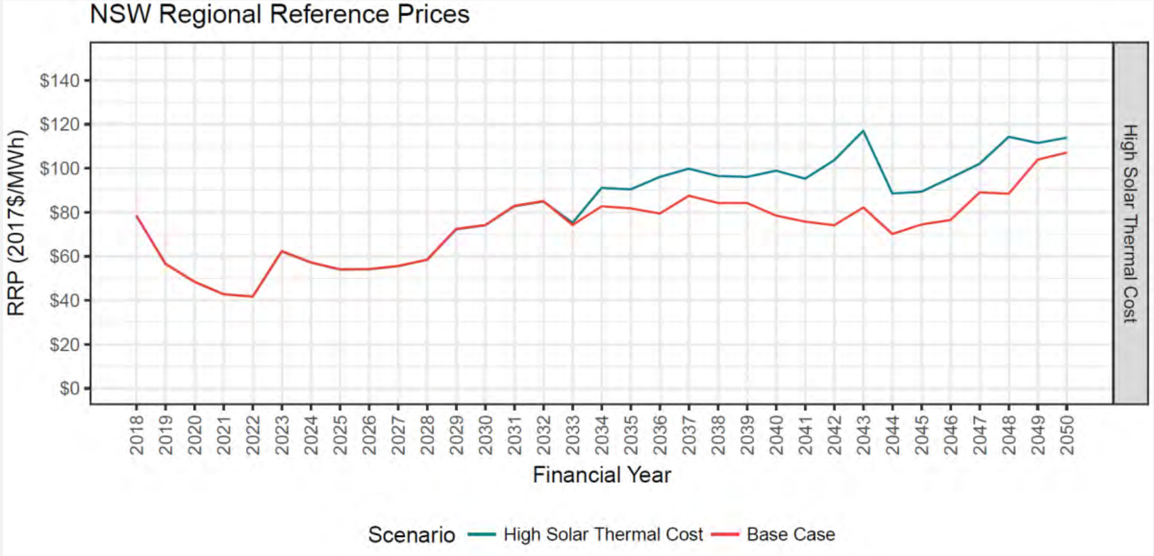
NSW wholesale prices are identical in the High Solar Thermal Cost Scenario and the Base Case until investment outcomes change in the early 2030s.

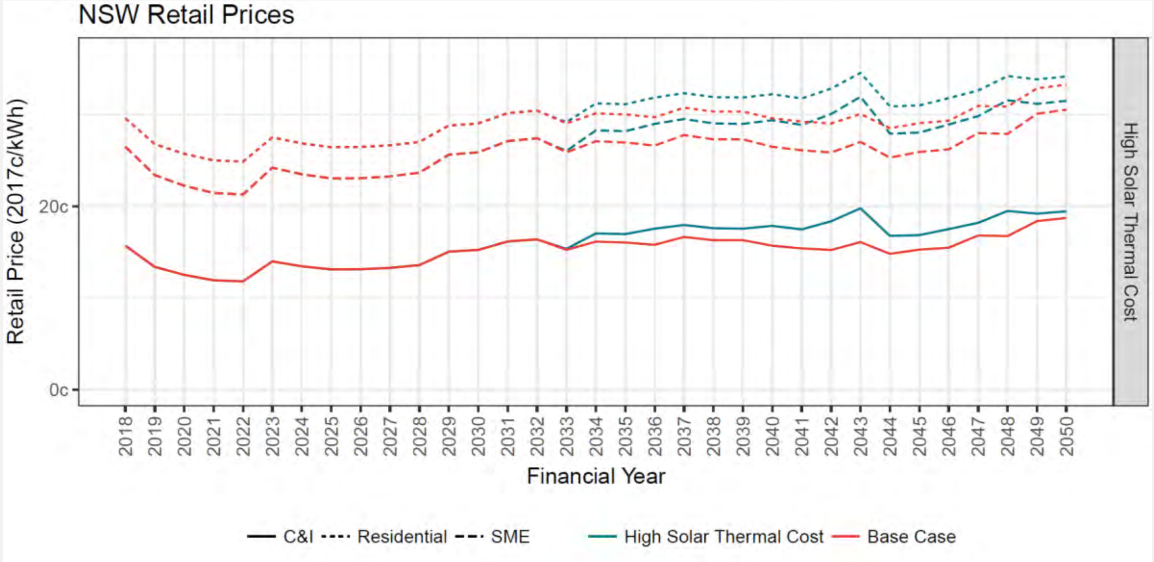
As in the Base Case, our modelling indicates that in the High Solar Thermal Cost Scenario wholesale prices in NSW will fall over the coming few years, from around $75/MWh in 2017/18 to around $40/MWh in 2020/21. This is driven by substantial investment in renewable plant in both Queensland and Victoria, and the resulting export of renewable energy into NSW (as well as committed investments in NSW).

Prices will then gradually increase until new investment is required in the early 2030s. At this point, the higher cost of solar thermal generation results in a mix of generation that leads to higher prices. In particular, the greater reliance on gas plant means that gas plant sets the marginal price more often than it does in the Base Case. This results in higher average NSW wholesale prices in the High Solar Thermal Cost Scenario.

Retail prices follow the same trend as wholesale prices, but do not fluctuate as much as wholesale prices. The reason is that a large component of the retail price is network tariffs, which we assume remain constant in real terms.

Wholesale and retail prices for other regions are set out in Appendix A.





High Solar Thermal Cost Scenario

NSW total system cost

As expected, due to the increased price of solar thermal in the High Solar Thermal Cost Scenario, total system cost ends materially higher. During the late 2030's total system cost is lower, because the investment in solar PV that replaces solar thermal comes at a lower capital cost. However this is reversed in the late 2040's as a lot more batteries are required in place of the storage that solar thermal provides, alongside more gas mid-merit CCS.

Interconnector Expansions Scenario

NSW investment, retirement and installed capacity

In the Interconnector Expansions Scenario, the changes to interconnectors are:

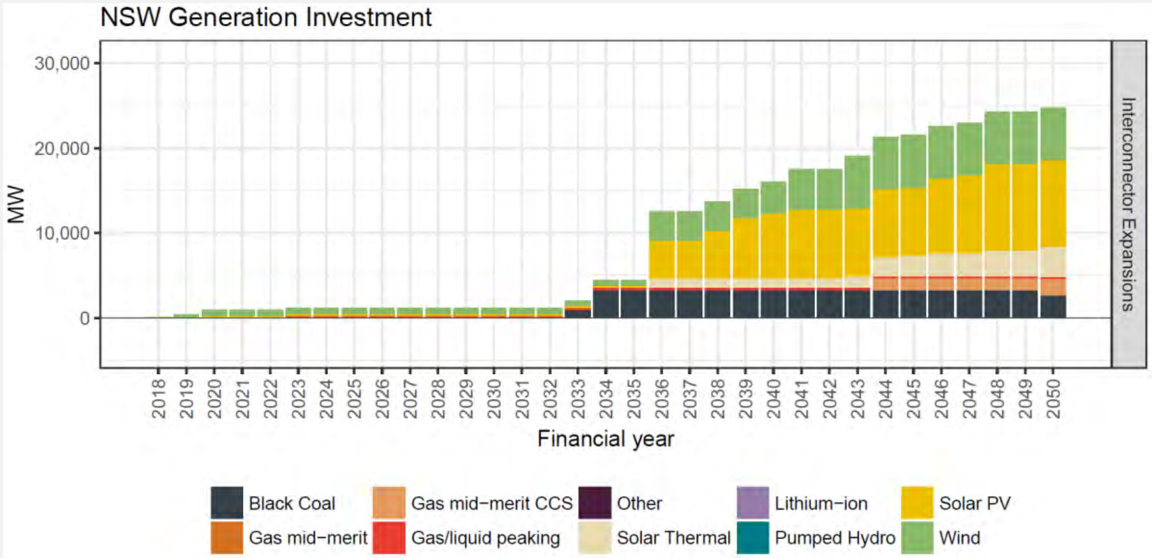
- NSW to QLD: augmentation of 920/758 MW (export/import).
- VIC to NSW: augmentation of 120 MW (export).
- SA to NSW: new interconnector of 750/750 MW (export/import).

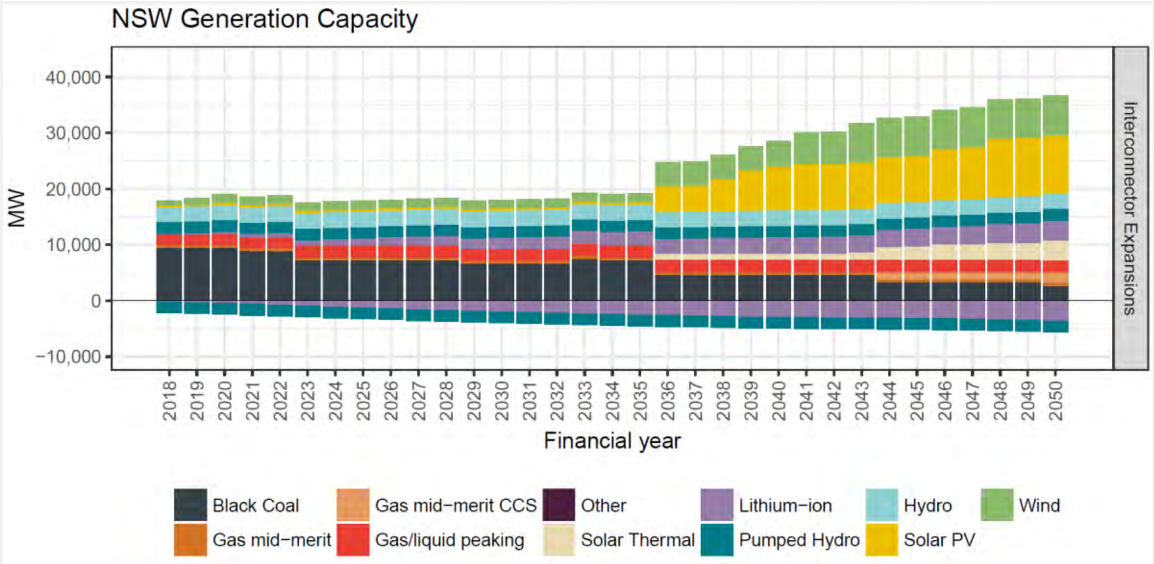
Our modelling shows that investment outcomes in NSW will be substantially the same as the Base Case. We see the same committed investment over the next five years as in the Base Case – new wind farms and solar farms, as well as AGL's committed investment in Bayswater's upgrade and a gas peaker.

Beyond that, we do not see new investment until 2032/33.

As in the Base Case, with the retirement of Eraring power station in 2032/33 and Bayswater power station in 2034/35, new investment is required. We see the same types of investment: new coal plant as well as significant amounts of solar thermal, solar PV and wind generation. Following the retirement of Mt Piper power station, we also see investment in CCGT with CCS, as we did in the Base Case.

The only notable difference from the Base Case is some reduction in solar thermal investment in the Interconnector Expansions Scenario, as a result of an increased ability to import electricity. Investment and capacity results for other regions are set out in Appendix A.





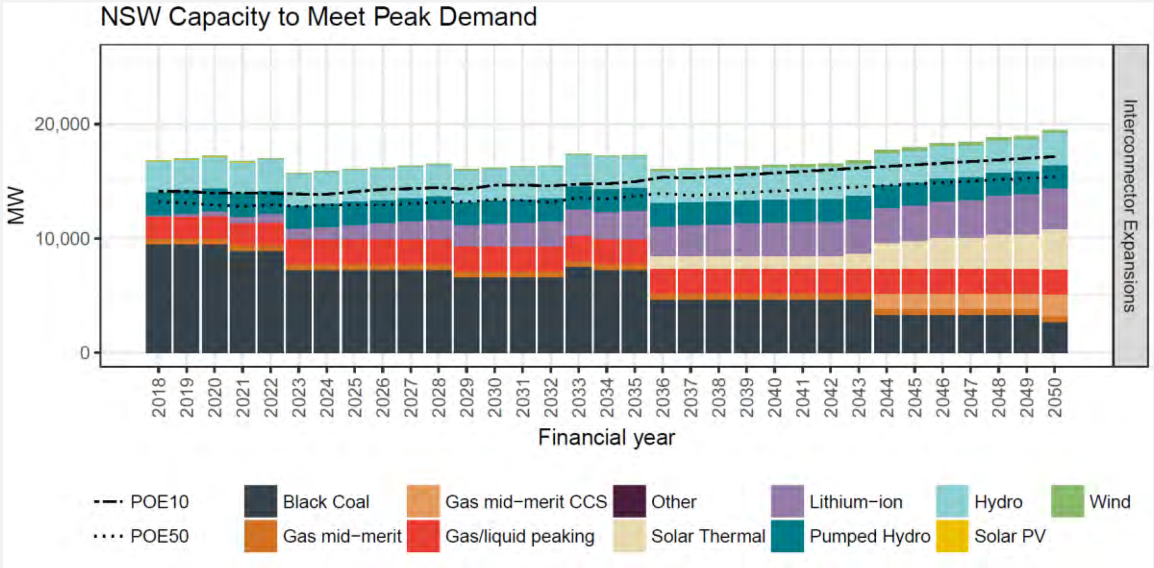
Interconnector Expansions Scenario

NSW diversity of capacity to meet peak demand

Accounting for the expected ability to generate at peak times, it is clear that NSW is currently very reliant on coal-fired generation, hydro generation and, to a lesser extent, gas generation.

As in the Base Case, in the Interconnector Expansions Scenario, over time the contribution of coal-fired generation to meeting peak demand diminishes, as plant retire. As a result, NSW becomes increasingly reliant on solar thermal generation, gas generation and batteries for meeting peak demand. In the Interconnector Expansions Scenario the reduction in investment in solar thermal results in NSW results in a reduction in excess capacity above forecast peak demand relative to the Base Case.

Our assumption is that solar PV does not contribute at times of peak demand, and that wind only contributes at a small fraction of its total capacity.

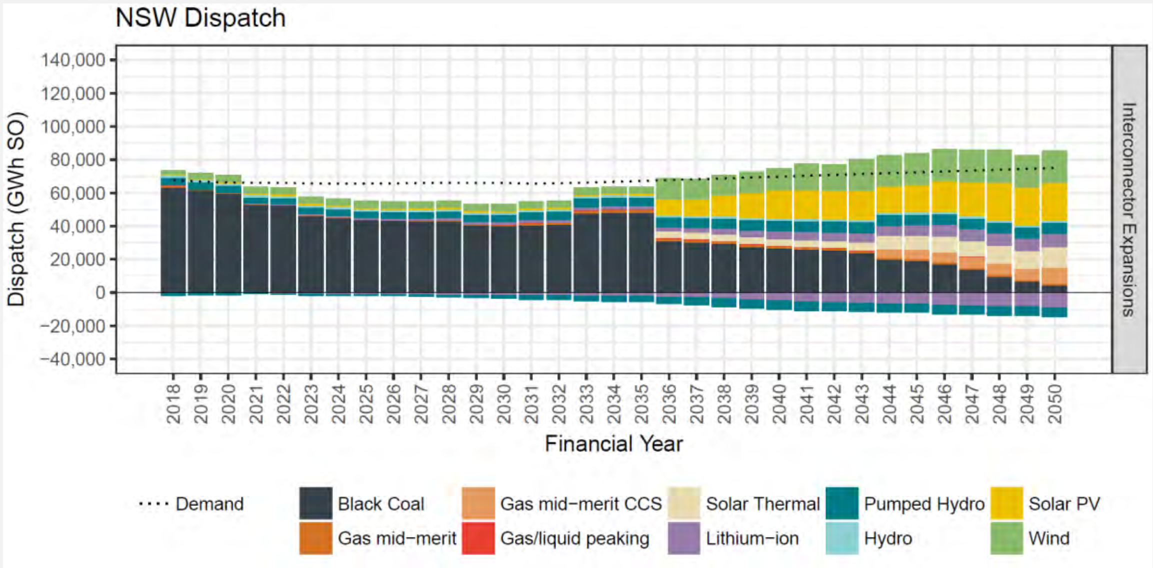


NSW dispatch

Like in the Base Case, in the Interconnector Expansions Scenario our modelling indicates a substantial change over time in the mix of generation plant supplying NSW's electricity.

This change over time is very similar to the change over time that we see for the Base Case: an initial reliance on coal-fired generation gradually changes to a mix in which solar thermal and solar PV are crucial, and there is also an increasing contribution from wind, batteries, pumped-storage hydro and gas.

The differences that we see relative to the Base Case largely mirror the differences in investment that we discuss above: we see less dispatch from solar thermal which, as we shall see, results in greater reliance on imports.



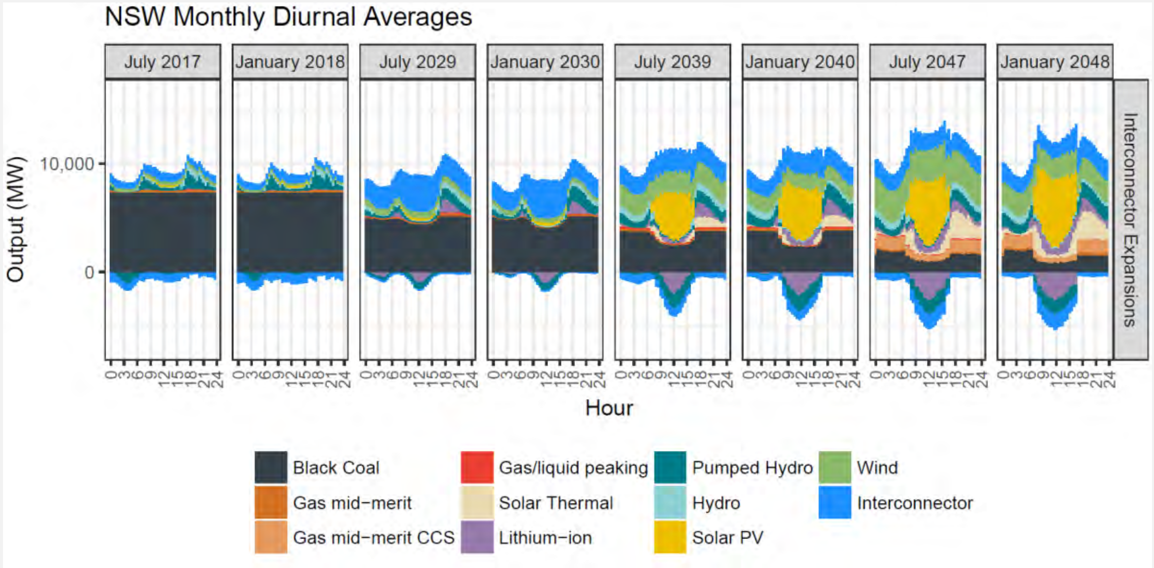
Interconnector Expansions Scenario

NSW half-hourly dispatch

Patterns of half-hourly dispatch are quite similar to those for the Base Case. As in the Base Case, in 2017/18 coal accounts for the majority of dispatch. By 2029/30, imports and batteries play a more important role in meeting demand. By 2039/40, coal dispatch has decreased very materially, replaced by a combination of renewables and storage. By 2047/48, coal generation has decreased even more, being replaced by CCGT with CCS and renewables with storage.

Relative to the Base Case, daily patterns of dispatch in the Interconnector Expansions Scenario show a greater reliance on imports to meet demand.

Daily dispatch results for the single week of lowest renewable generation for these same 4 years are presented in Appendix A.

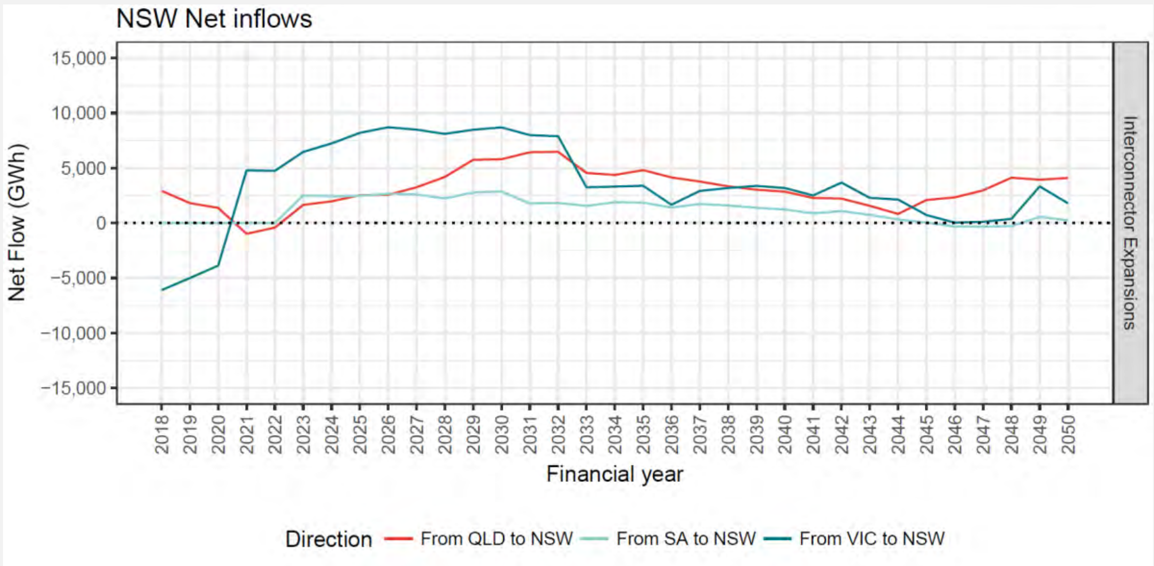


NSW imports

Like in the Base Case, in the Interconnector Expansions Scenario we see a substantial change in patterns of regional flows over the modelling period. These are predominantly driven by the effect of the VRET and QRET, which result in substantial renewable investment in Victoria and Queensland. This leads to excess energy in these regions, both of which export into NSW. Indeed exports into NSW are substantial as shown below.

In the Interconnector Expansions Scenario we also see imports from South Australia to NSW through the new interconnect, resulting in an increase in total imports into NSW.

After Mount Piper retires in 2043/44 NSW starts to import more electricity from Queensland, rather than dispatch gas mid-merit plants, which are relatively more expensive than importing coal-generated electricity from Queensland.



Interconnector Expansions Scenario

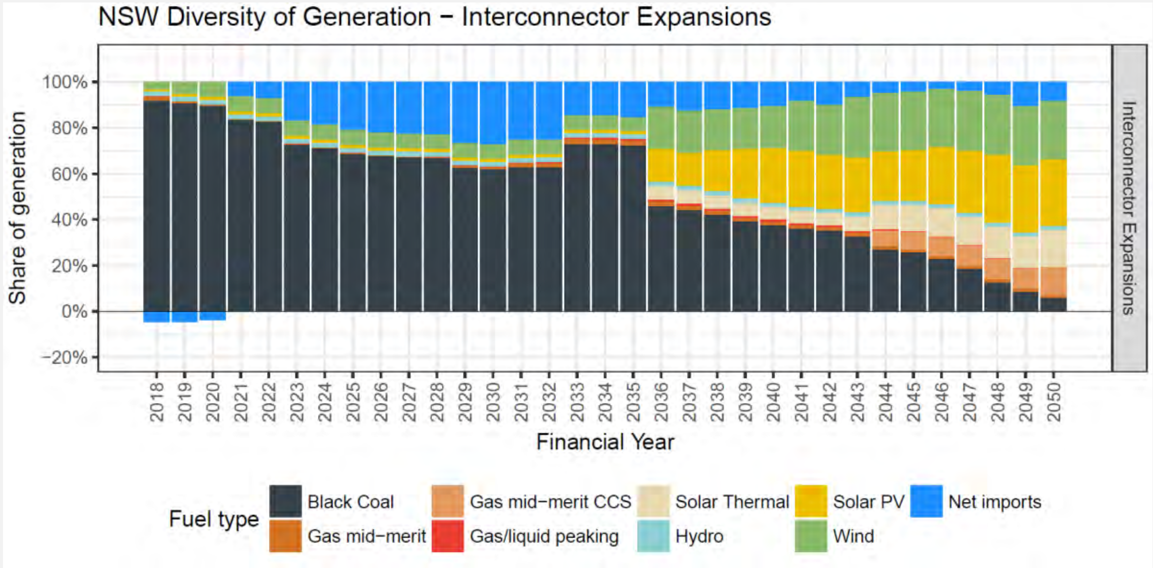
NSW diversity of energy supply

Like in the Base Case, in the Interconnector Expansions Scenario we see a substantial increase over time in the diversity of technologies that supply NSW's electricity.

NSW's initial reliance on coal-fired generation is replaced by a mix of generation that includes substantial amounts of solar thermal, solar PV and wind, with smaller amounts of hydro, gas and imports.

The result is a much more balanced generation mix, and much reduced reliance on a single technology type or fuel source.

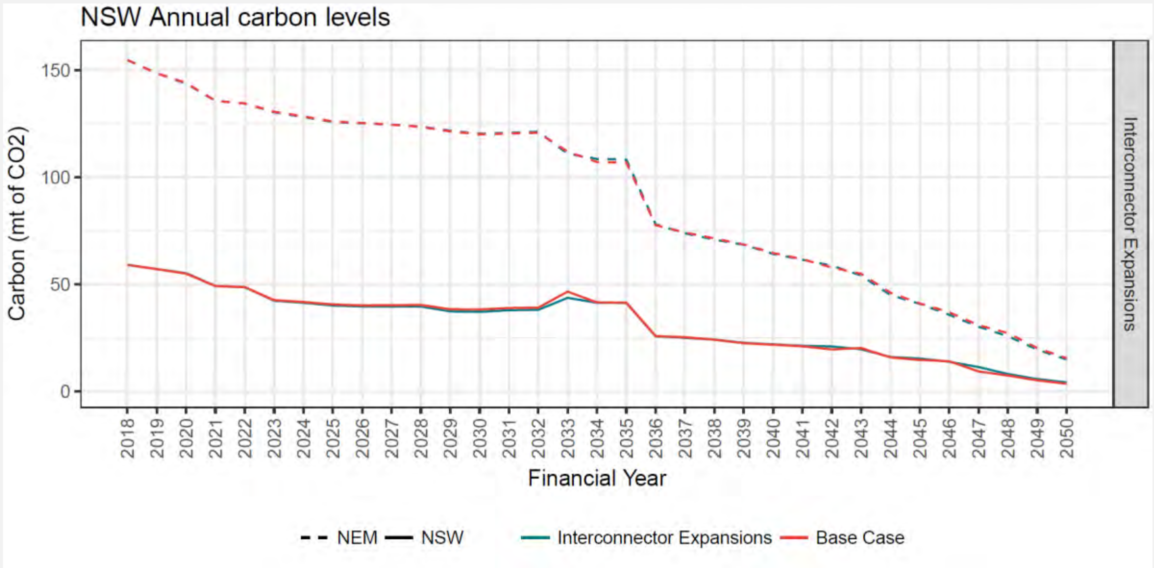
Relative to the Base Case, and consistent with the results we have seen above, in the Interconnector Expansions Scenario the reduction in solar thermal generation in NSW (which is not entirely balanced by an increase in wind and solar PV generation) results in somewhat increased reliance on imports in the long term.



NSW carbon emissions

Consistent with the results for dispatch that we have seen, over time we see a significant reduction in total emissions from NSW power stations. As in the Base Case, these reductions are primarily the result of the retirement of NSW's coal-fired power stations.

There is very little difference in total emissions between the Interconnector Expansions Scenario and the Base Case; this is largely because reduced solar thermal generation (which is zero emissions) is balanced by increased imports (which do not cause emissions in NSW).



Interconnector Expansions Scenario

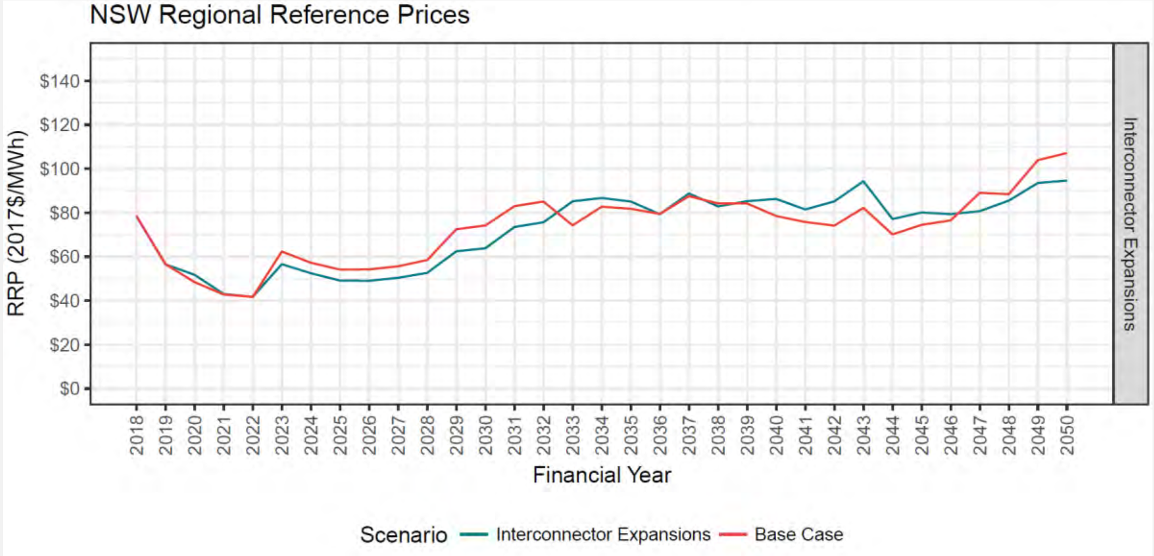
NSW wholesale prices

As in the Base Case, our modelling indicates that in the Interconnector Expansions Scenario wholesale prices in NSW will fall over the coming few years, from around $75/MWh in 2017/18 to around $40/MWh in 2020/21. This is driven by substantial investment in renewable plant in both Queensland and Victoria, and the resulting export of renewable energy into NSW (as well as committed investments in NSW).

Over the rest of the modelling period, prices in the Interconnector Expansions Scenario are quite close to prices in the Base Case: on occasion prices are lower in the Interconnector Expansions Scenario (this generally coincides with periods of high imports and reflects that the ability to import additional low-price electricity from other regions); on other occasions prices are higher in the Interconnector Expansions Scenario (reflecting exports from NSW at times, resulting in higher prices).

Retail prices follow the same trend as wholesale prices, but do not fluctuate as much as wholesale prices. The reason is that a large component of the retail price is network tariffs, which we assume remain constant in real terms. While the cost of interconnectors if likely to be reflected in tariffs, transmission tariffs make up a small proportion of total retail tariffs.

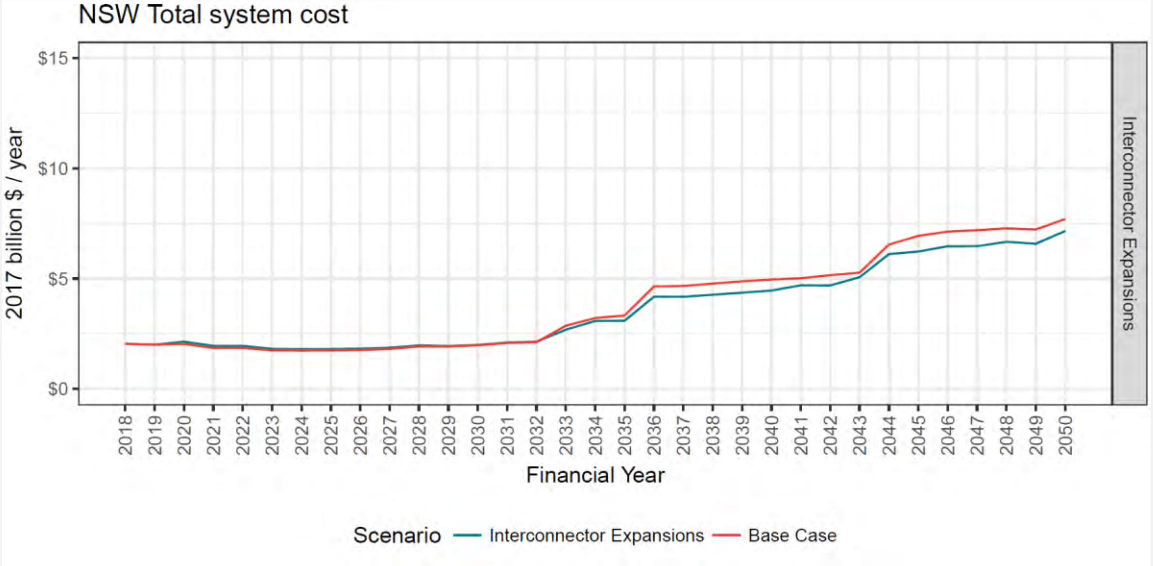
Wholesale and retail prices for other regions are set out in Appendix A.



Interconnector Expansions Scenario

NSW total system cost

During the early years of the modelling period, total system cost for the Interconnector Expansions Scenario is slightly higher than the Base Case. However this difference disappears as the expanded interconnectors allow regions to share generation more easily. In later years, the Interconnector Expansions Scenario has a materially lower total system cost in NSW.



Updated Entrant Fuel Cost Scenario

NSW investment, retirement and installed capacity

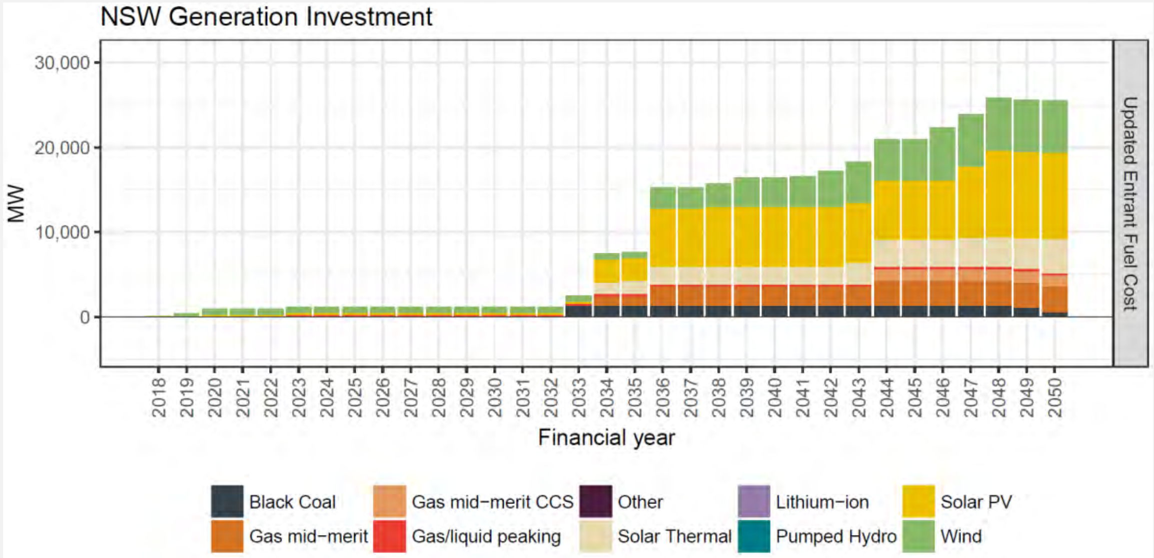
In the Updated Entrant Fuel Cost Scenario, our modelling shows that investment outcomes in NSW will differ from the Base Case from the point at which Eraring retires (2034).

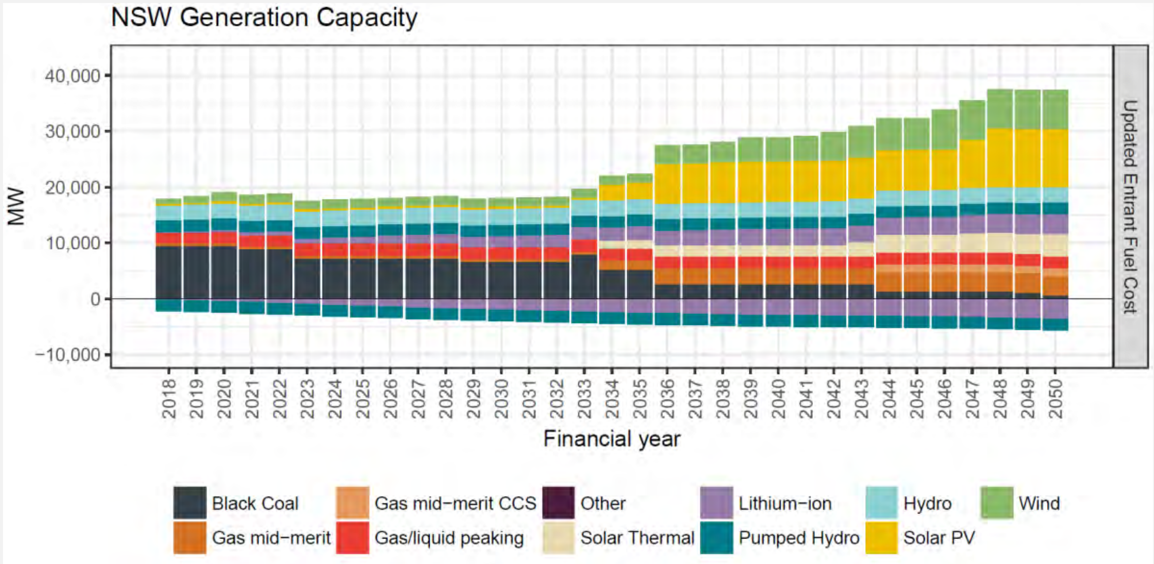
We see the same committed investment over the next five years as in the Base Case – new wind farms and solar farms, as well as AGL's committed investment in Bayswater's upgrade and a gas peaker.

As in the Base Case, with the retirement of Eraring power station in 2032/33 and Bayswater power station in 2034/35, new investment is required. However, instead of 3,400 MW of coal plant, we instead see only 1,000 MW with the difference made up of new CCGT plant. We also see some reductions in investment in solar thermal plant and delays in investment in solar PV and wind. Aside from this switching of technologies we see the same types of investment: significant amounts of solar thermal, solar PV and wind generation. Following the retirement of Mt Piper power station, we also see investment in CCGT with CCS, as we did in the Base Case. Note that there is an earlier increase in the amount of solar PV invested as compared to the base case, approximately 2,500 MW extra in 2034 that persists until 2039.

The overall result – as in the Base Case – is a substantial shift in the overall mix of generation capacity in NSW.

Investment and capacity results for other regions are set out in Appendix A.





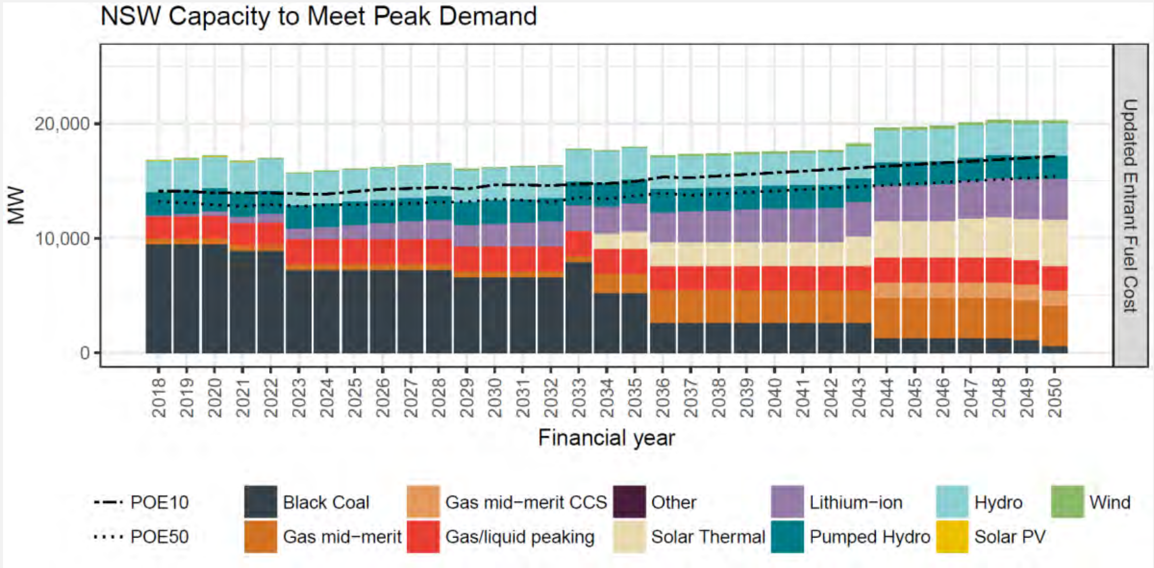
Updated Entrant Fuel Cost Scenario

NSW diversity of capacity to meet peak demand

Accounting for the expected ability to generate at peak times, it is clear that NSW is currently very reliant on coal-fired generation, hydro generation and, to a lesser extent, gas generation.

As in the Base Case, in the Updated Entrant Fuel Cost Scenario, over time the contribution of coal-fired generation to meeting peak demand diminishes, as plant retire. As a result, NSW becomes increasingly reliant on solar thermal generation, gas generation and batteries for meeting peak demand. In the Updated Entrant Fuel Cost Scenario different patterns of investment mean that NSW is less reliant on coal plant as a result of swapping out gas for coal.

Our assumption is that solar PV does not contribute at times of peak demand, and that wind only contributes at a small fraction of its total capacity.

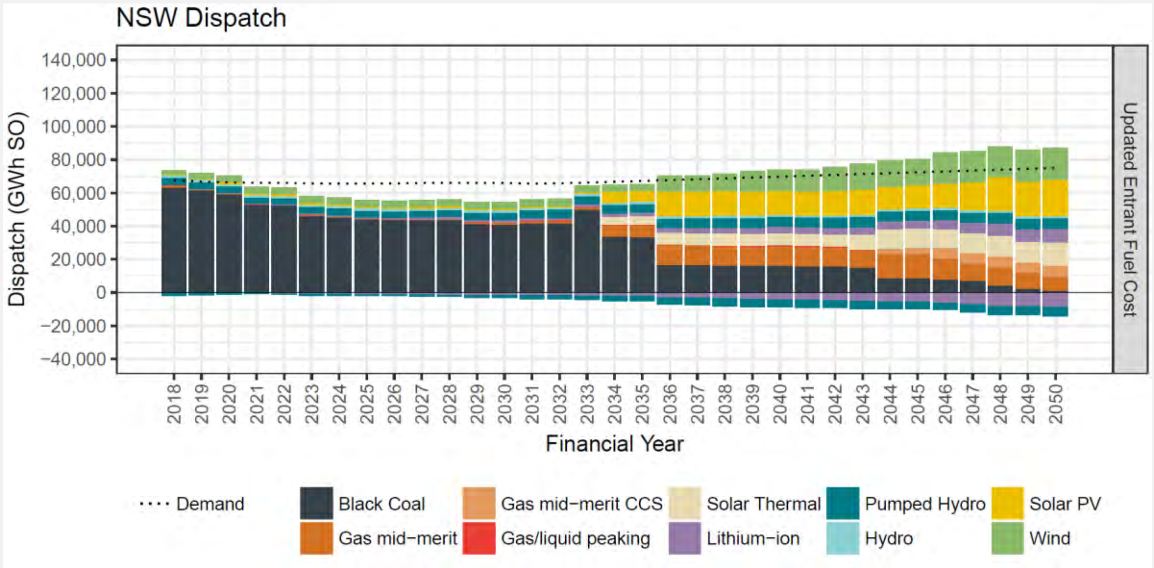


NSW dispatch

Like in the Base Case, in the Updated Entrant Fuel Cost Scenario our modelling indicates a substantial change over time in the mix of generation plant supplying NSW's electricity.

This change over time is very similar to the change over time that we see for the Base Case: an initial reliance on coal-fired generation gradually changes to a mix in which solar thermal, solar PV and now also gas are crucial. There is also an increasing contribution from wind, batteries and pumped-storage.

The differences that we see relative to the Base Case largely mirror the differences in investment that we discuss above: because of the swapping out of coal for gas, we see less dispatch coal and more dispatch from gas.



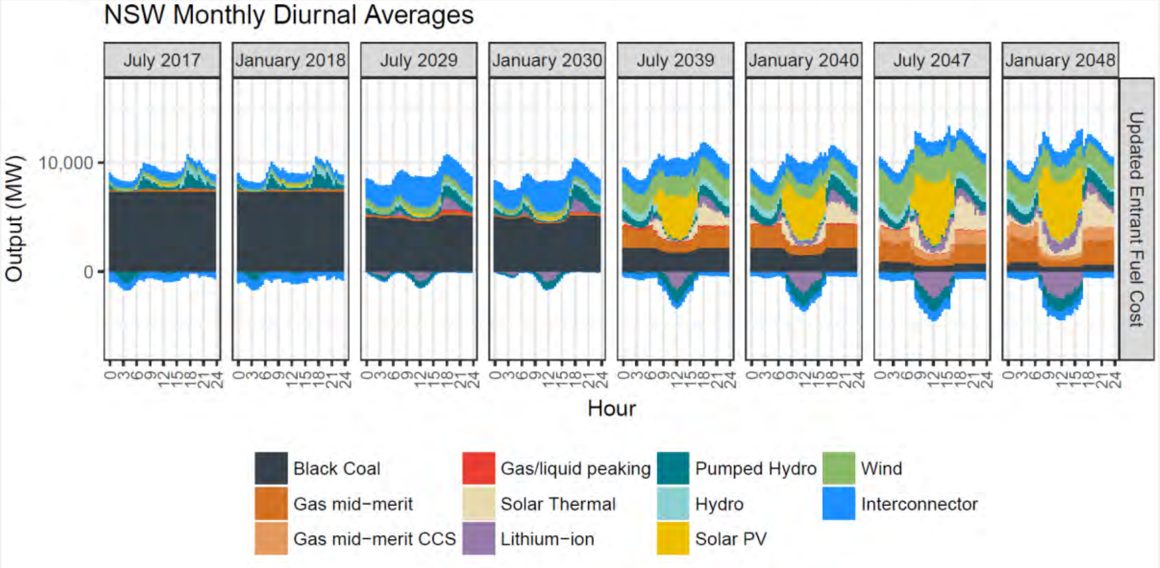
Updated Entrant Fuel Cost Scenario

NSW half-hourly dispatch

Patterns of half-hourly dispatch are quite similar to those for the Base Case. As in the Base Case, in 2017/18 coal accounts for the majority of dispatch. By 2029/30, imports and batteries play a more important role in meeting demand. By 2039/40, coal dispatch has decreased very materially, replaced by a combination of gas, renewables and storage. By 2047/48, coal generation has decreased even more, being replaced by CCGT with CCS and renewables with storage.

The consistent result of gas replacing coal holds for half hourly dispatch. Beyond this change there is little change as compare to the base case.

Daily dispatch results for the single week of lowest renewable generation for these same 4 years are presented in Appendix A.



NSW imports

Like in the Base Case, in the Updated Entrant Fuel Cost Scenario we see a substantial change in patterns of regional flows over the modelling period. These are predominantly driven by the effect of the VRET and QRET, which result in substantial renewable investment in Victoria and Queensland. This leads to excess energy in these regions, both of which export into NSW.

Clearly, NSW becomes more reliant on interconnectors in this scenario, during the 2020s and the early 2030s.

Relative to the Base Case there is a reduction in imports from 2034 to 2039, coinciding with the transitory increased investment in solar PV.

Updated Entrant Fuel Cost Scenario

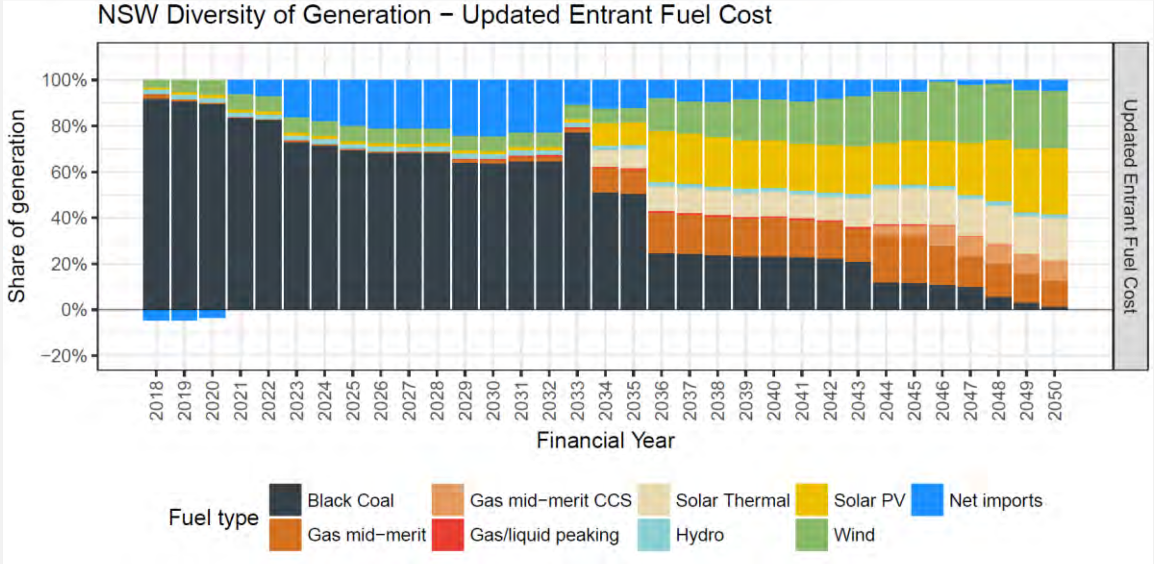
NSW diversity of energy supply

Like in the Base Case, in the Updated Entrant Fuel Cost Scenario we see a substantial increase over time in the diversity of technologies that supply NSW's electricity.

NSW's initial reliance on coal-fired generation is replaced by a mix of generation that includes substantial amounts of gas, solar thermal, solar PV and wind, with smaller amounts of hydro and imports.

The result is a much more balanced generation mix, and much reduced reliance on a single technology type or fuel source.

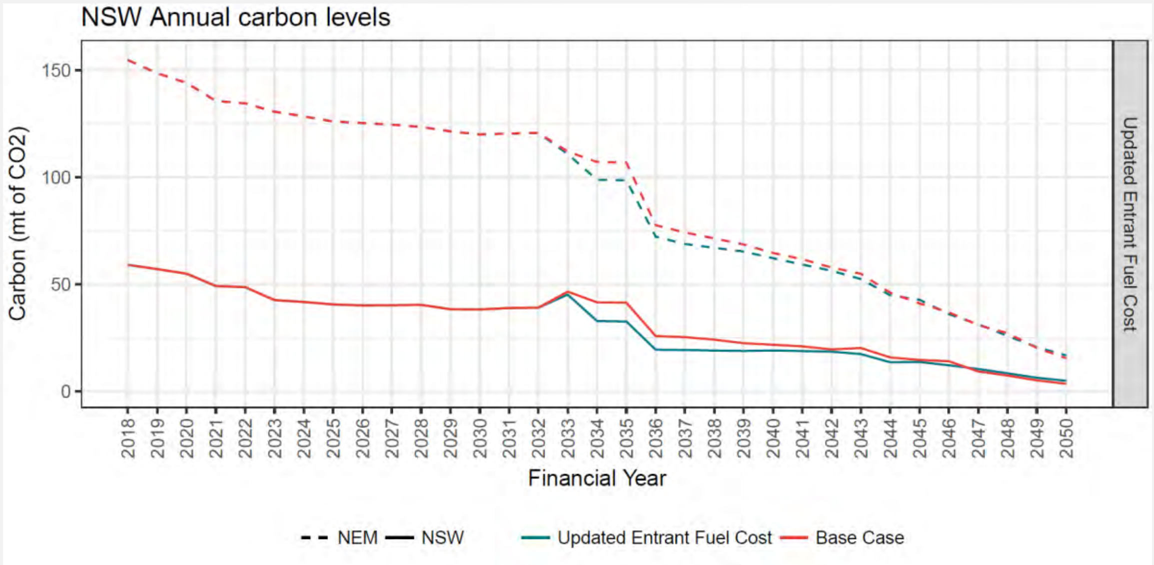
Relative to the Base Case, and consistent with the results we have seen above, in the Updated Entrant Fuel Cost Scenario the swapping out of coal for gas results in a decreased reliance on coal and an increased reliance on gas in the long term.



NSW carbon emissions

Consistent with the results for dispatch that we have seen, over time we see a significant reduction in total emissions from NSW power stations. As in the Base Case, these reductions are primarily the result of the retirement of NSW's coal-fired power stations.

Given that a significant portion of coal is now replaced by CCGT plant with a lower carbon rate we see a significant impact in carbon levels over the medium term before converging again in the late 2040s when carbon levels are driven by the imposed carbon policy constraints. This is, in part, a consequence of the reduced and delayed investment in renewables we see alongside the shift to investment in gas plant.



Updated Entrant Fuel Cost Scenario

NSW wholesale prices

As in the Base Case, our modelling indicates that in the Updated Entrant Fuel Cost Scenario wholesale prices in NSW will fall over the coming few years, from around $75/MWh in 2017/18 to around $40/MWh in 2020/21. This is driven by substantial investment in renewable plant in both Queensland and Victoria, and the resulting export of renewable energy into NSW (as well as committed investments in NSW).

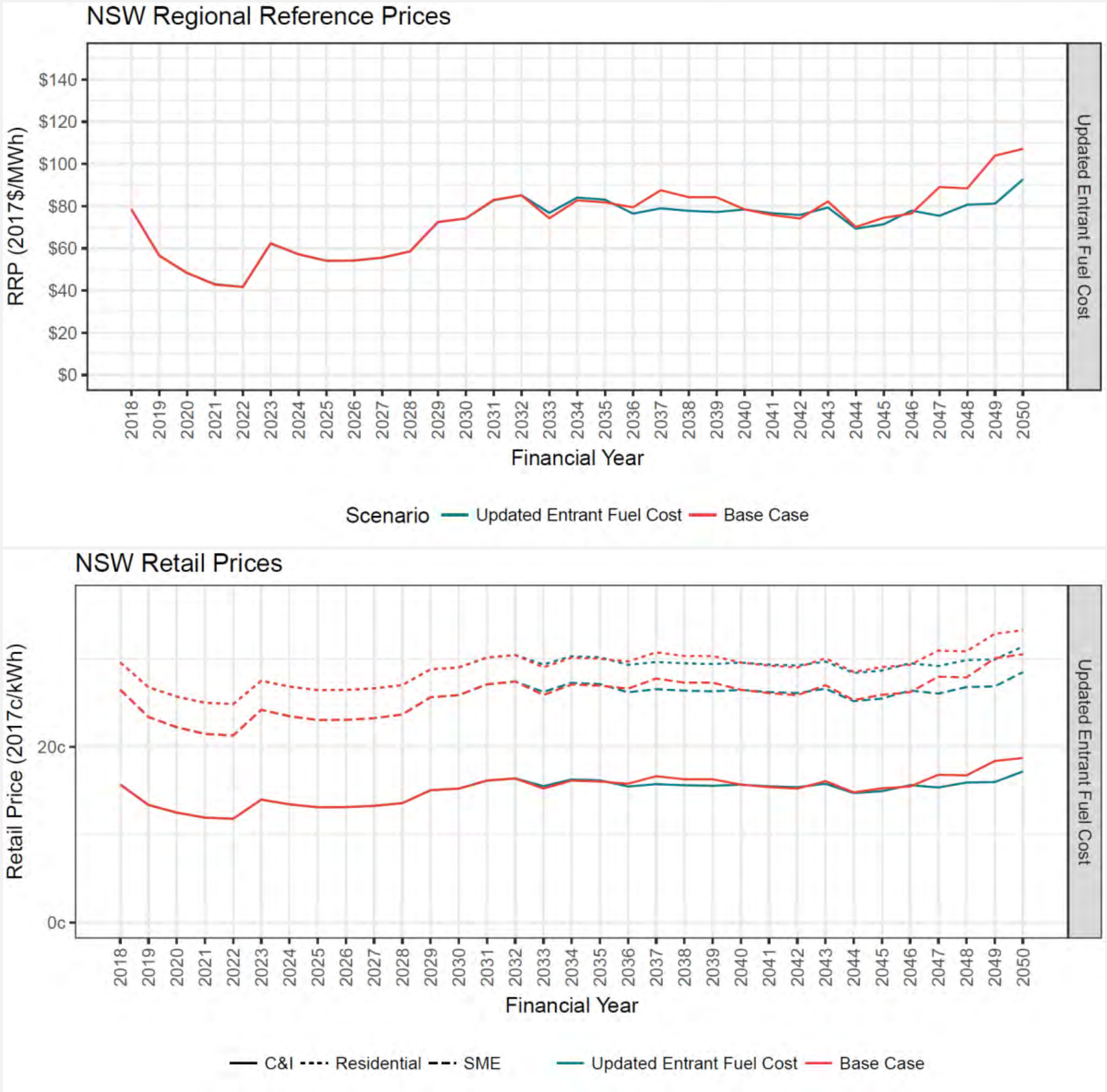
From 2033 to 2035 price increases slightly due to replacement of cheap SRMC coal with more expensive SRMC gas. From 2037 to 2039 prices are lower due to the transitory increased solar PV investment relative to the Base Case. They are also lower due to the generation mix incurring less cost for meeting the emissions constraints; coal plant effectively costs more to run in the Base Case than in the Updated Entrant Fuel Cost scenario.

After this, prices equalise until 2047, after which prices are materially lower. This is again because of the decreased emission constraint cost as compared to the Base Case.

This result appears counter intuitive: we have increased the coal price and wholesale prices have fallen. However, the system cost has increased significantly as compared to the Base Case (as seen in the comparison of NSW total system cost). In economic terms, the supply curve has flattened out, increasing the cost of supply under the curve but lowering the margin price (the point at which the supply curve meets the demand curve). This flattening of the supply curve is due to different patterns of investment and, importantly, a different cost of meeting the emissions constraint.

Retail prices follow the same trend as wholesale prices, but do not fluctuate as much as wholesale prices. The reason is that a large component of the retail price is network tariffs, which we assume remain constant in real terms.

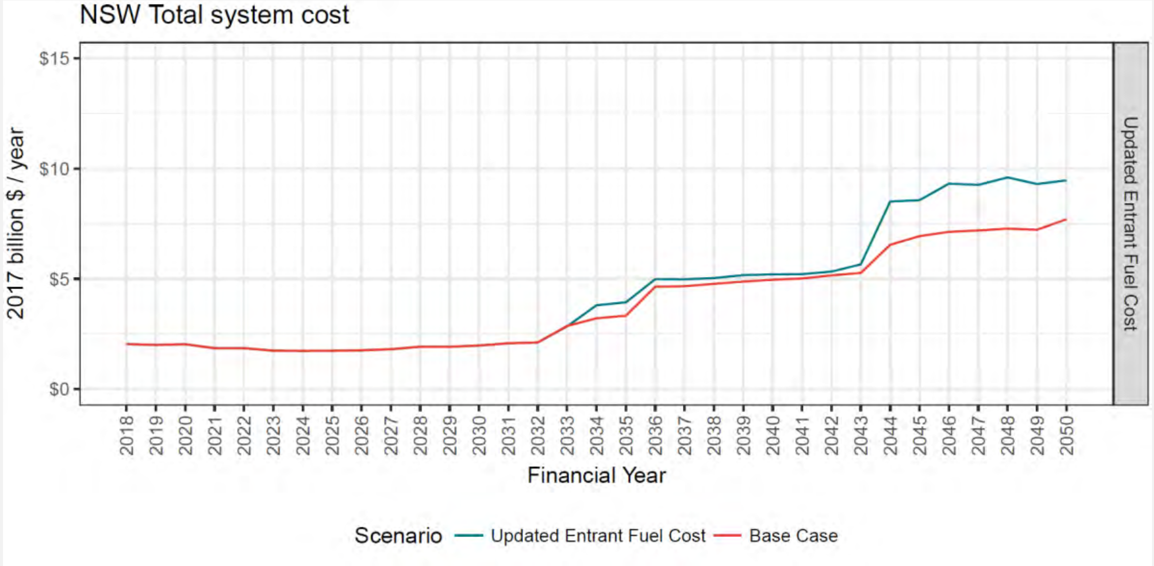
Wholesale and retail prices for other regions are set out in Appendix A.



Updated Entrant Fuel Cost Scenario

NSW total system cost

The total system cost is much higher in the Updated Entrant Fuel Cost Scenario, as compared to the Base Case. This is because of the higher fuel cost that new entrant coal plants must pay, which pushes up the cost.



Updated Entrant Fuel Cost HELE Scenario

NSW investment, retirement and installed capacity

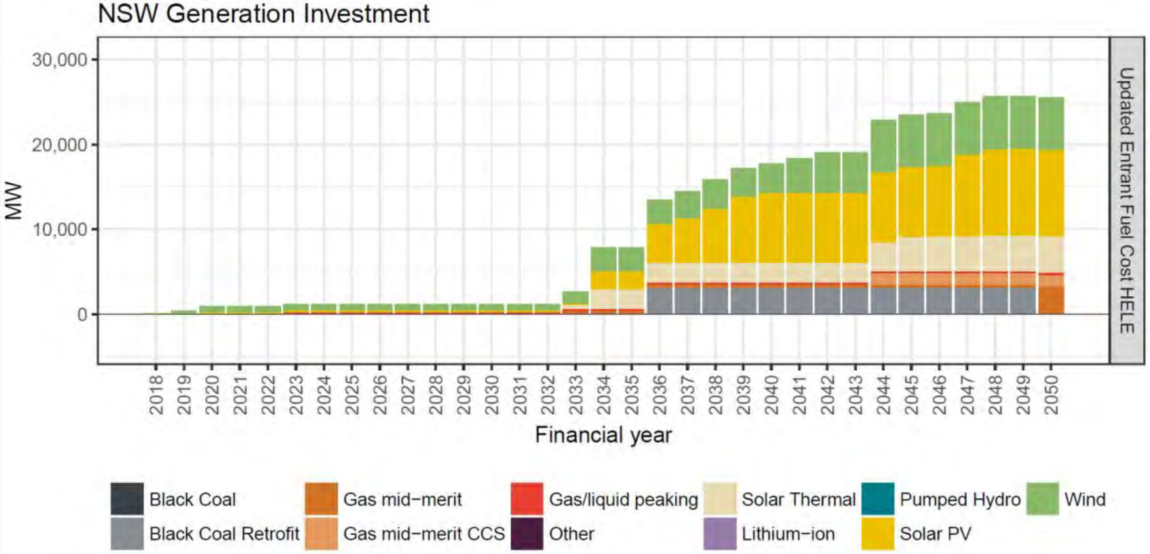
In the Updated Entrant Fuel Cost HELE Scenario, our modelling shows that investment outcomes in NSW will differ from the Updated Entrant Fuel Scenario from the point at which Gladstone and Yallourn retire (2033). In both the Base Case and the Updated Entrant Fuel Cost Scenario there is an initial investment in coal plant at this point. However, with the availability of coal plant retrofits, the model opts to instead invest in a non-equivalent quantity of wind and solar thermal before upgrading Bayswater at its end of life (2036) to an A-USC with original firing. Even with the increased fuel price, this investment replaces all coal and almost all gas investment seen in the Base Case and Updated Entrant Fuel Cost Scenario.

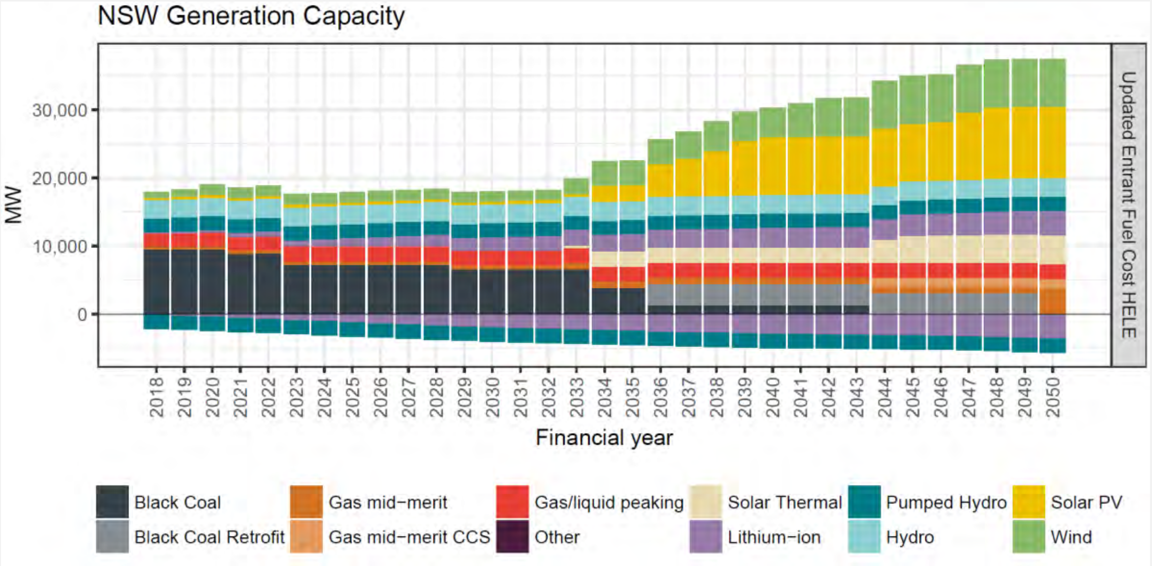
This retrofit appears to only be a medium-term solution though as the Bayswater retrofit is retired in 2050 due to the emissions constraints. CCGT gas takes its place in the long term. Essentially what we are seeing is that a coal plant retrofit can be a lower cost solution that the alternative investments, but only for so long as the retrofitted coal plant's emissions are consistent with the emissions target. By 2050 our modelling suggests that the emissions target makes the continued operation of coal plant without CCS problematic. And our modelling suggests that coal plant with CCS is not an economic option compared with the alternative options for achieving low emissions.

Aside from this switching of technologies we see the same types of investment: significant amounts of solar thermal, solar PV and wind generation. Following the retirement of Mt Piper power station, we also see investment in CCGT with CCS.

The overall result – as in the Base Case and Updated Entrant Fuel Cost Scenario–is a substantial shift in the overall mix of generation capacity in NSW.

Investment and capacity results for other regions are set out in Appendix A.





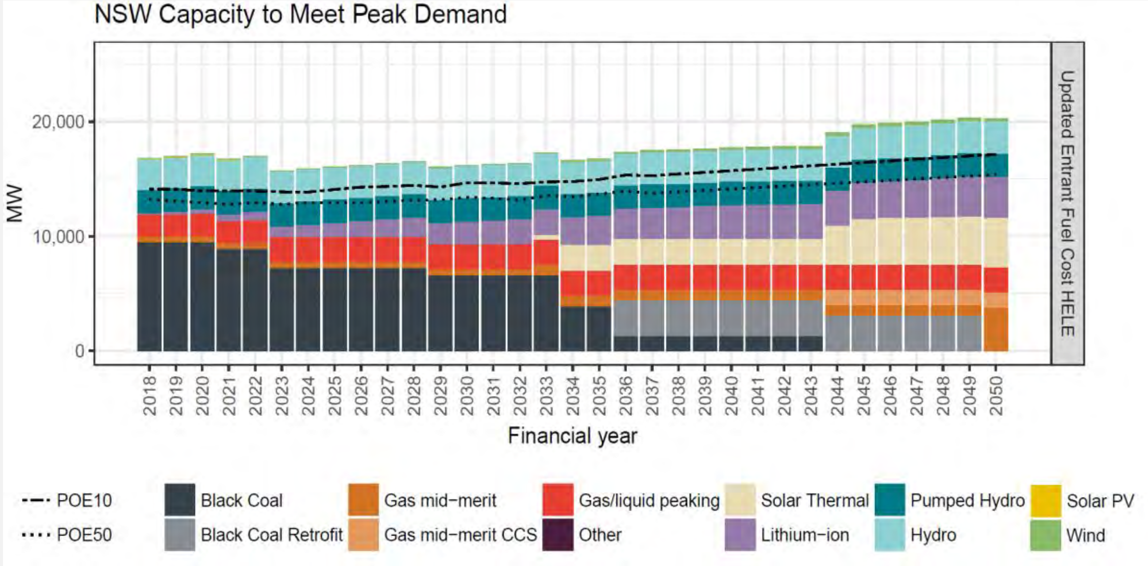
Updated Entrant Fuel Cost HELE Scenario

NSW diversity of capacity to meet peak demand

Accounting for the expected ability to generate at peak times, it is clear that NSW is currently very reliant on coal-fired generation, hydro generation and, to a lesser extent, gas generation.

As in the Base Case and Updated Entrant Fuel Cost Scenario, in the Updated Entrant Fuel Cost HELE Scenario, over time the contribution of coal-fired generation to meeting peak demand diminishes, as plant retire. As a result, NSW becomes increasingly reliant on solar thermal generation and batteries for meeting peak demand. The Updated Entrant Fuel Cost HELE Scenario is closer to the Base Case since there is no longer the swapping out of coal for gas.

Our assumption is that solar PV does not contribute at times of peak demand, and that wind only contributes at a small fraction of its total capacity.

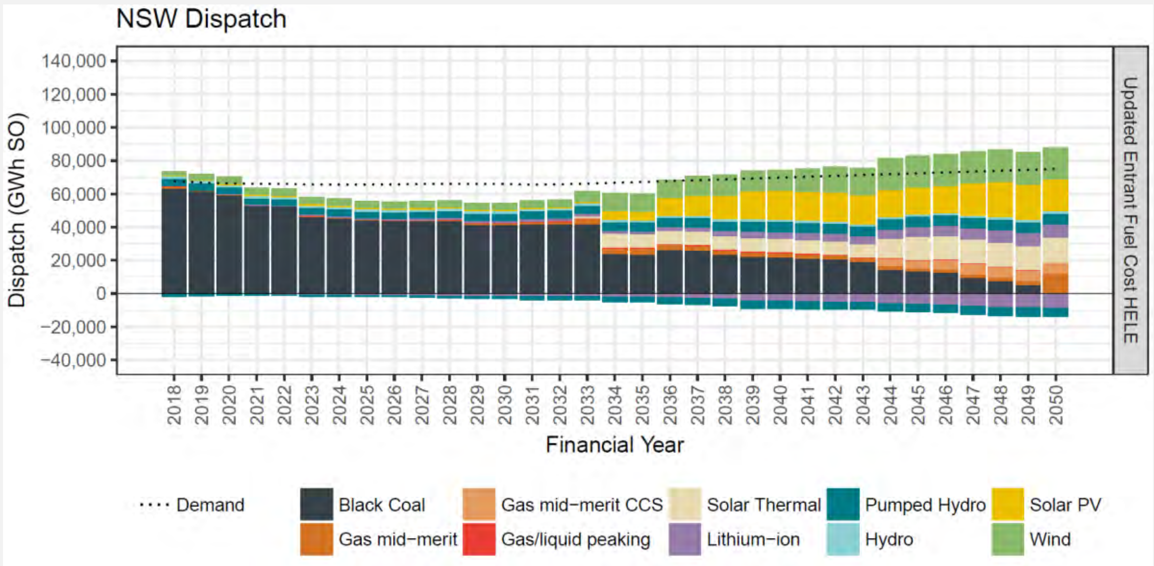


NSW dispatch

Like in the Base Case, in the Updated Entrant Fuel Cost HELE Scenario our modelling indicates a substantial change over time in the mix of generation plant supplying NSW's electricity.

This change over time is very similar to the change over time that we see for the Base Case: an initial reliance on coal-fired generation gradually changes to a mix in which solar thermal and solar PV are crucial. In the long term, gas also becomes crucial as it replaces the Bayswater retrofit. There is also an increasing contribution from wind, batteries and pumped-storage.

The differences that we see relative to the Base Case and the Updated Entrant Fuel Cost Scenario largely mirror the differences in investment that we discuss above: because the swapping out of coal for gas only occurs in the final year, we see coal dispatch that more closely mirrors the Base Case until that point.



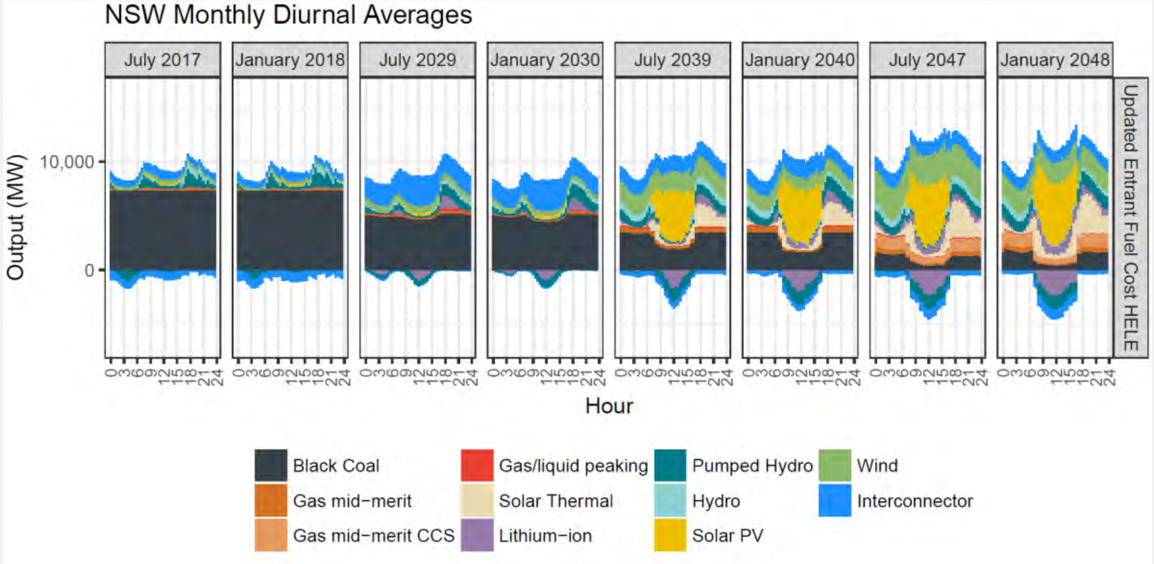
Updated Entrant Fuel Cost HELE Scenario

NSW half-hourly dispatch

Patterns of half-hourly dispatch are quite similar to those for the Base Case. As in the Base Case, in 2017/18 coal accounts for the majority of dispatch. By 2029/30, imports and batteries play a more important role in meeting demand. By 2039/40, coal dispatch has decreased very materially, replaced by a combination of gas, renewables and storage. By 2047/48, coal generation has decreased even more, being replaced by CCGT with CCS and renewables with storage.

There is little change as compare to the base case.

Daily dispatch results for the single week of lowest renewable generation for these same 4 years are presented in Appendix A.

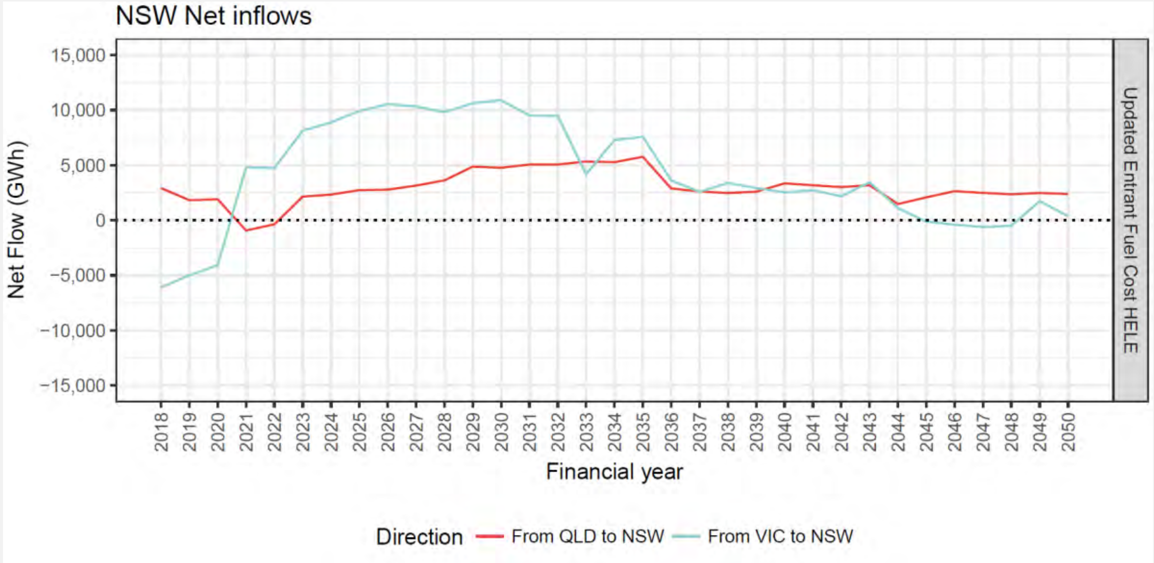


NSW imports

Like in the Base Case, in the Updated Entrant Fuel Cost HELE Scenario we see a substantial change in patterns of regional flows over the modelling period. These are predominantly driven by the effect of the VRET and QRET, which result in substantial renewable investment in Victoria and Queensland. This leads to excess energy in these regions, both of which export into NSW.

Clearly, NSW becomes more reliant on interconnectors in this scenario, during the 2020s and the early 2030s.

Relative to both the Base Case and the Updated Entrant Fuel Cost Scenario there is an increase in imports from 2033 to 2035, coinciding with delayed thermal investment in anticipation of upgrading Bayswater at its end of life (2036).



Updated Entrant Fuel Cost HELE Scenario

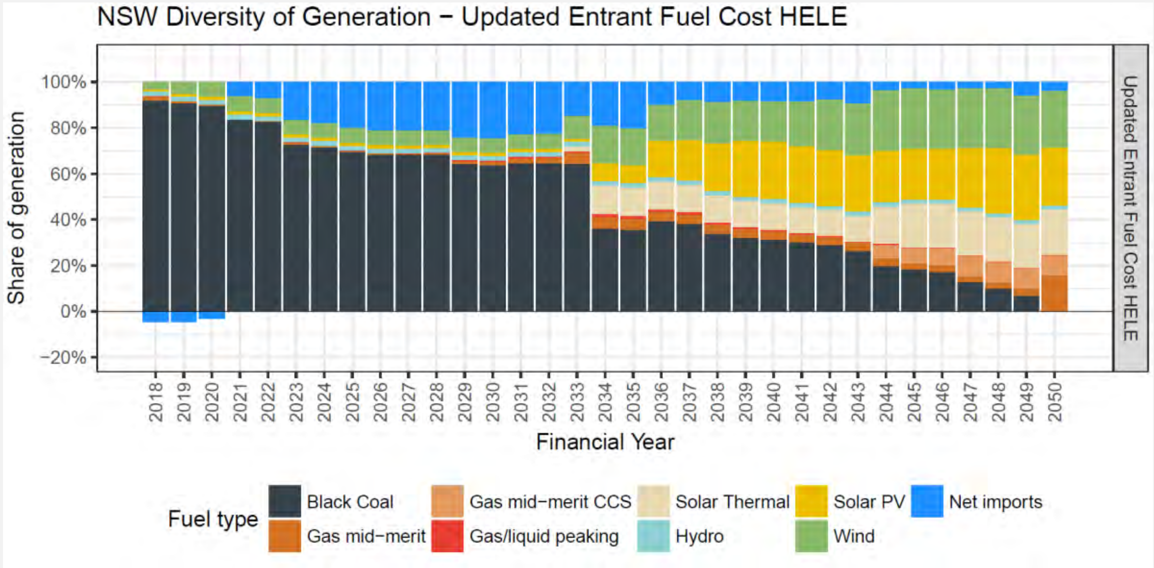
NSW diversity of energy supply

Like in the Base Case, in the Updated Entrant Fuel Cost HELE Scenario we see a substantial increase over time in the diversity of technologies that supply NSW's electricity.

NSW's initial reliance on coal-fired generation is replaced by a mix of generation that includes substantial amounts of solar thermal, solar PV and wind, with smaller amounts of gas, hydro and imports. In the long term however (2050) gas becomes substantial.

The result is a much more balanced generation mix, and much reduced reliance on a single technology type or fuel source.

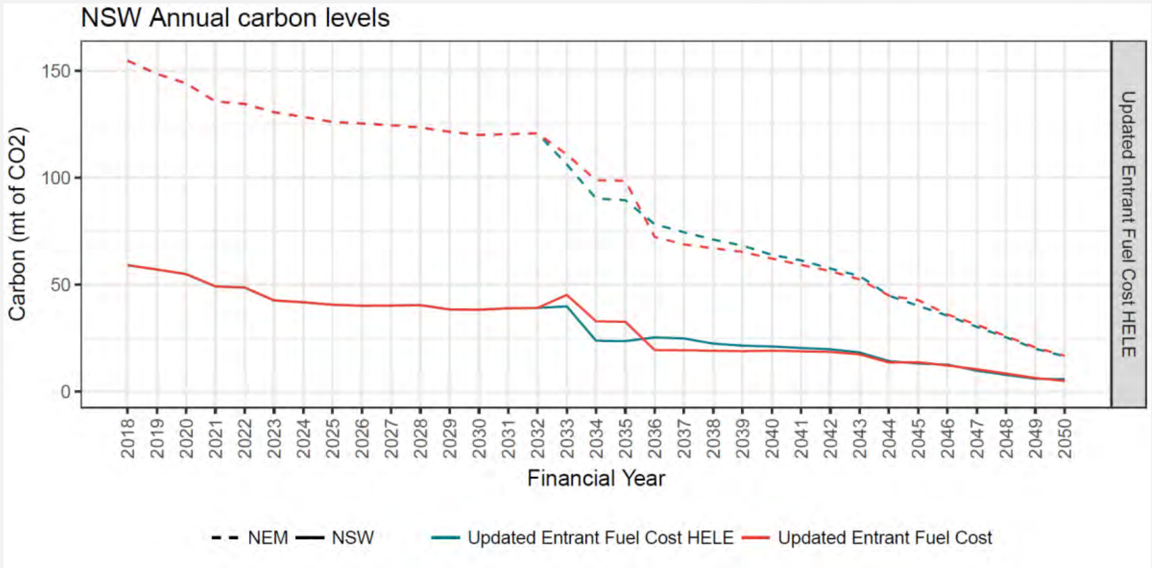
Relative to the Base Case, and consistent with the results we have seen above, in the Updated Entrant Fuel Cost Scenario the swapping out of coal for gas results in a decreased reliance on coal and an increased reliance on gas in the long term.



NSW carbon emissions

Consistent with the results for dispatch that we have seen, over time we see a significant reduction in total emissions from NSW power stations. As in the Base Case, these reductions are primarily the result of the retirement of NSW's coal-fired power stations.

The delayed thermal investment sees a lower carbon level initially however with the replacement of Bayswater we see a return to the carbon levels in the Base Case, reflecting higher emission coal plant investment rather than the lower emission gas plant investment of the Updated Entrant Fuel Cost Scenario.



Updated Entrant Fuel Cost HELE Scenario

NSW wholesale prices

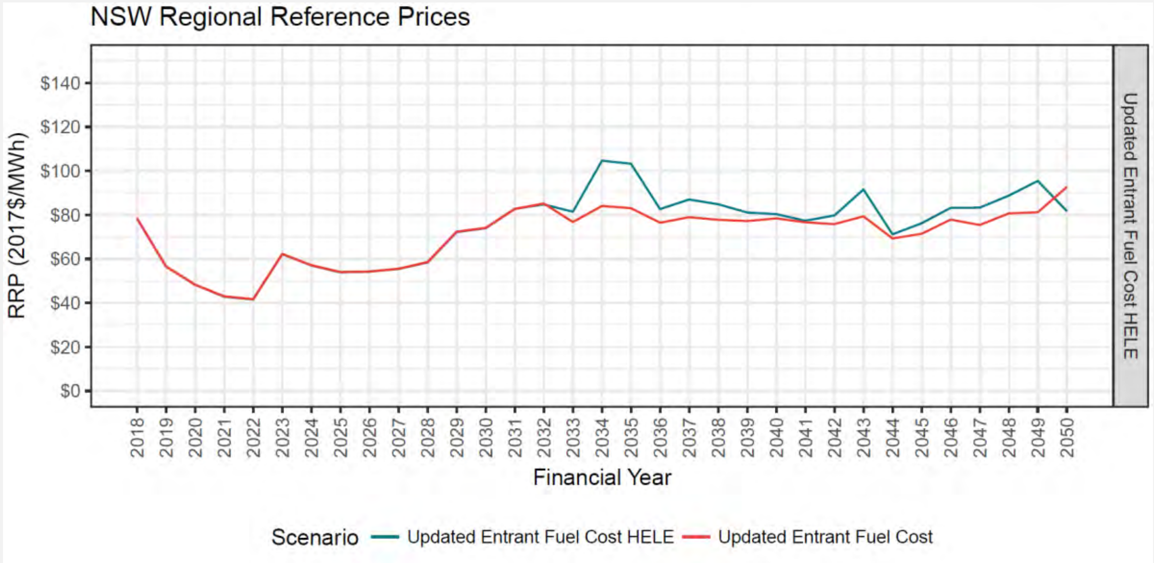
As in the Base Case, our modelling indicates that in the Updated Entrant Fuel Cost HELE Scenario wholesale prices in NSW will fall over the coming few years, from around $75/MWh in 2017/18 to around $40/MWh in 2020/21. This is driven by substantial investment in renewable plant in both Queensland and Victoria, and the resulting export of renewable energy into NSW (as well as committed investments in NSW).

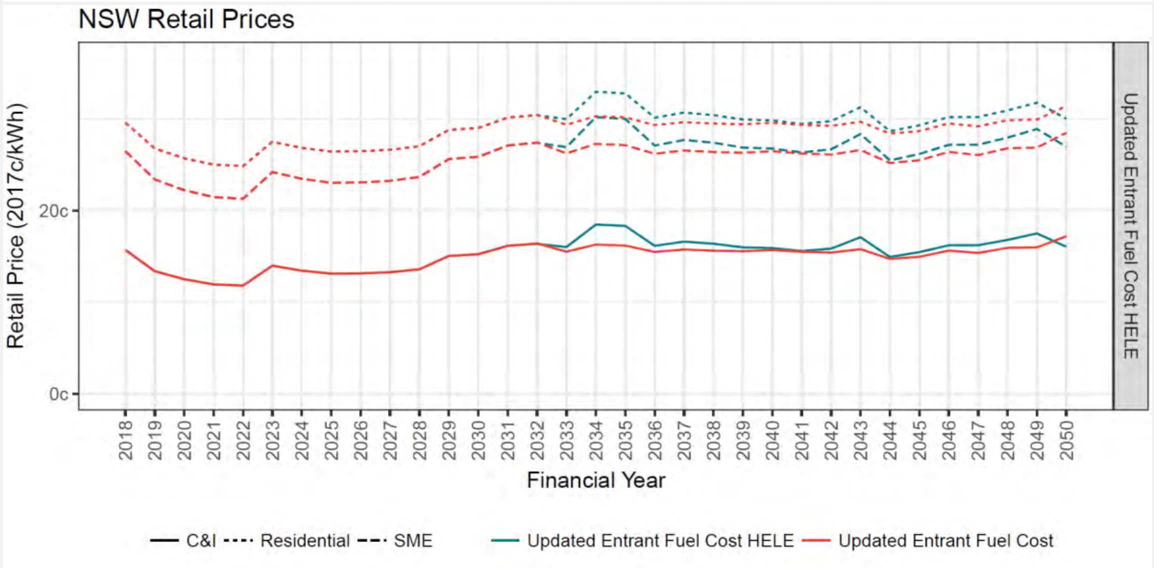
From 2033 to 2035 price increases materially due to the delayed investment in thermal plant. From 2037 to 2049 prices return to nearer their Base Case levels. Prices are reduced in the final year as the emissions constraint is eased by the replacement of all coal plant with lower emissions CCGT.

In a result similar to the Updated Entrant Fuel Cost Scenario, the model minimises the cost of the system by retrofitting in 2036 rather than 2033. It is less cost to sustain two years of higher prices than pay the capital cost that it could otherwise put off until 2036. This has reversed the flattening out of the supply curve seen in the Updated Entrant Fuel Cost Scenario, reducing the cost of supply under the curve but increasing the marginal cost at which it meets demand.

Retail prices follow the same trend as wholesale prices, but do not fluctuate as much as wholesale prices. The reason is that a large component of the retail price is network tariffs, which we assume remain constant in real terms.

Wholesale and retail prices for other regions are set out in Appendix A.

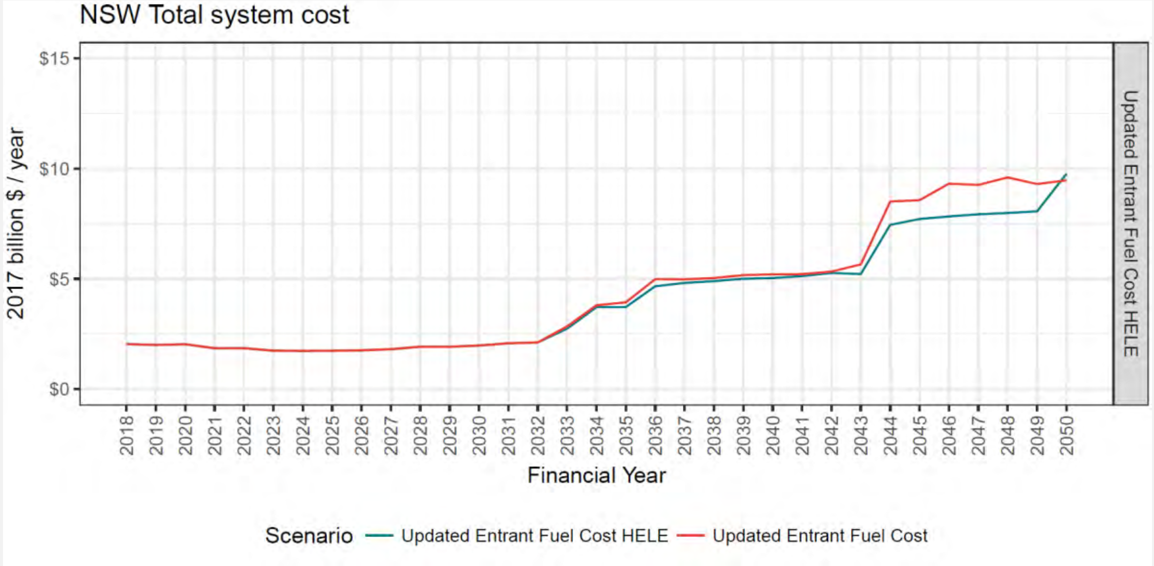




Updated Entrant Fuel Cost HELE Scenario

NSW total system cost

The total system cost for the Updated Entrant Fuel Cost HELE Scenario are lower when compared to the Updated Entrant Fuel Cost Scenario until 2050, due to the cheaper repowering of existing coal plants. However in 2050 significant investment is required in gas mid-merit, which means that this year incurs a high amount of capital cost. This pushes this total system cost of this scenario over the Updated Entrant Fuel Cost Scenario.



Scenario – High Emissions Reduction

NSW investment, retirement and installed capacity

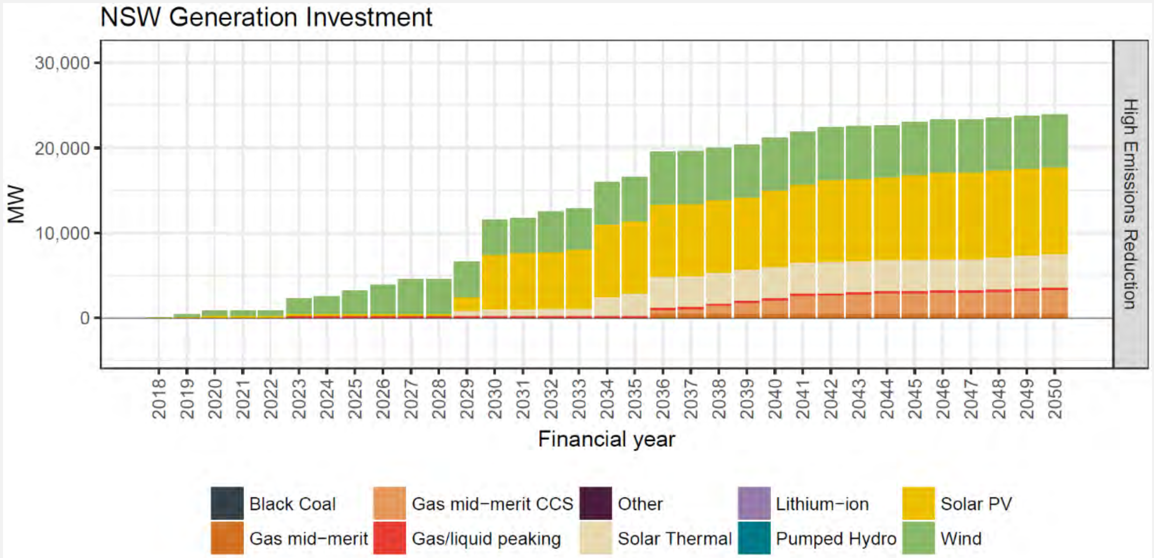
In the High Emissions Reduction Scenario, our modelling shows that investment outcomes in NSW will be materially different to the Base Case.

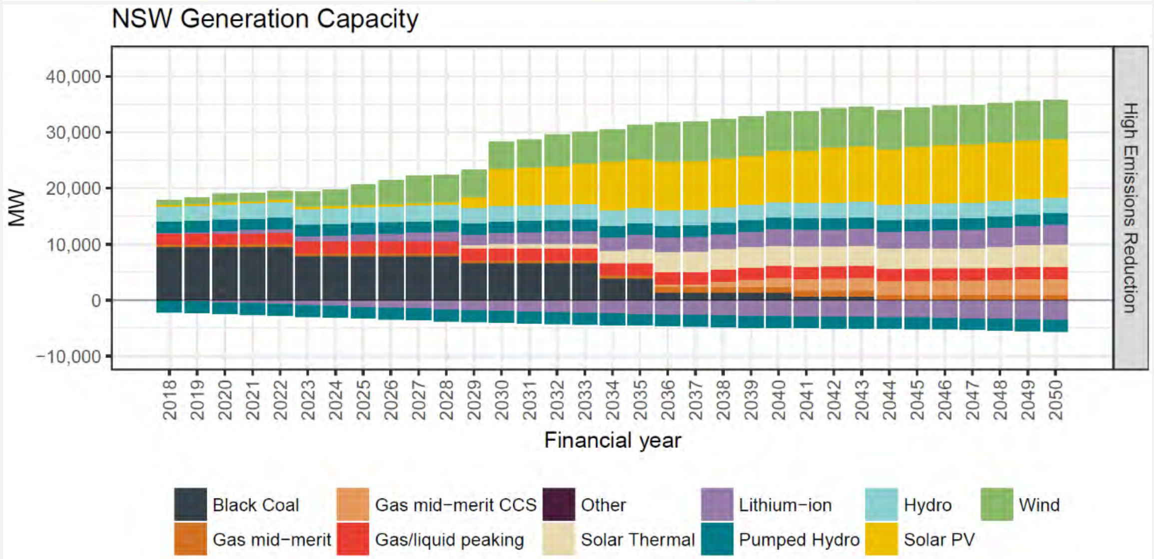
We do, of course, see the same committed investment over the next five years as in the Base Case – new wind farms and solar farms, as well as AGL's committed investment in Bayswater's upgrade and a gas peaker. However, unlike the Base Case, we see substantial new investment in solar and wind during the 2020s and first half of the 2030s.

As in the Base Case, with the retirement of Eraring power station in 2032/33 and Bayswater power station in 2034/35, further new investment is required. However, the new investment that we see is materially different. Specifically, in the High Emissions Reduction Scenario we see investment in solar PV and a solar thermal plant, helping to meet the emissions constraint while providing dispatchable power generation. This investment replaces a sizeable coal investment in the Base Case. This investment is later supplemented with gas mid-merit both with (and a little without) CCS.

The overall result – as in the Base Case – is a substantial shift in the overall mix of generation capacity in NSW, however this time it shifts largely towards renewables. While thermal plant with CCS is an alternative option, and we do so investment in gas plant with CCS, our modelling indicates that coal with CCS is higher cost than alternative options for achieving low emissions.

Investment and capacity results for other regions are set out in Appendix A.





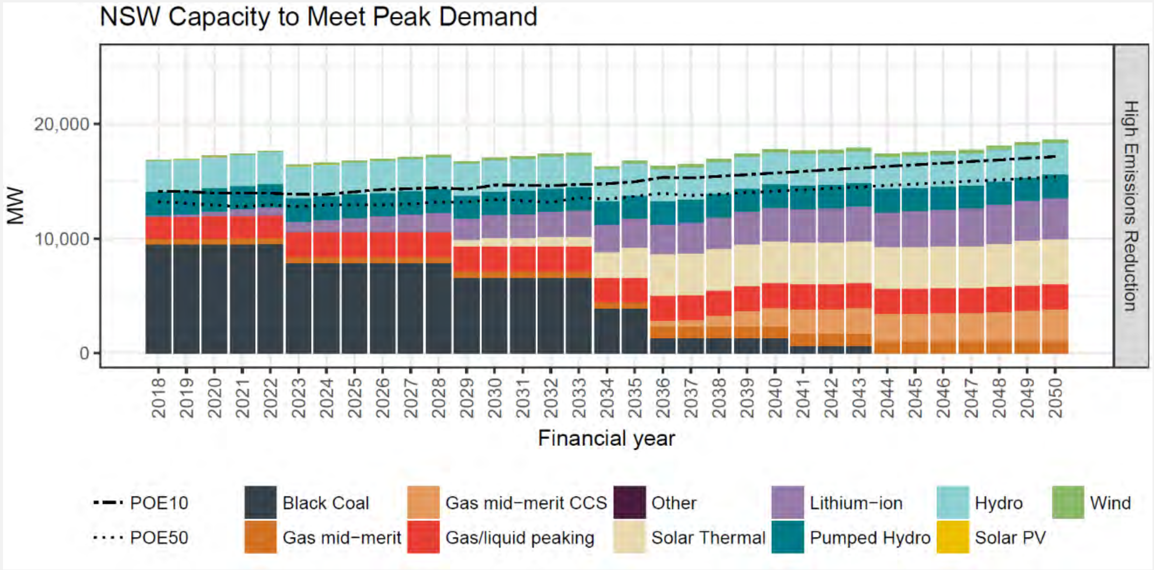
Scenario – High Emissions Reduction

NSW diversity of capacity to meet peak demand

Accounting for the expected ability to generate at peak times, it is clear that NSW is currently very reliant on coal-fired generation, hydro generation and, to a lesser extent, gas generation.

As in the Base Case, in the High Emissions Reduction Scenario, over time the contribution of coal-fired generation to meeting peak demand diminishes, as plant retire. Since the large investment in wind and solar do not contribute to the ability to meet peak demand, NSW becomes increasingly reliant on batteries, solar thermal plant and gas plant to meet peak demand.

Our assumption is that solar PV does not contribute at times of peak demand, and that wind only contributes at a small fraction of its total capacity.



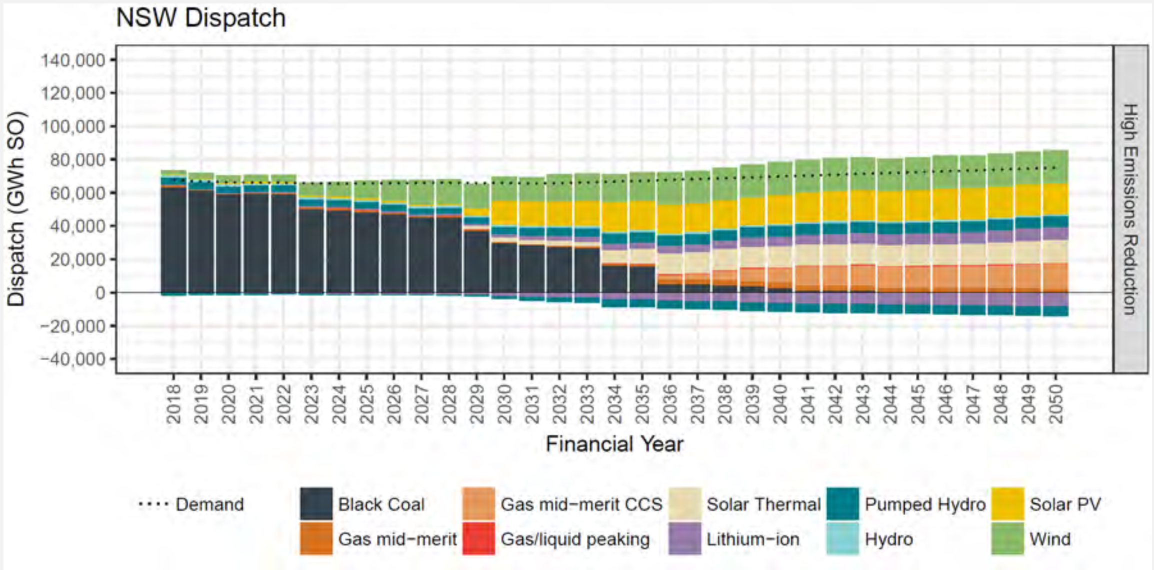
NSW dispatch

Like in the Base Case, in the High Emissions Reduction Scenario our modelling indicates a substantial change over time in the mix of generation plant supplying NSW's electricity.

This change over time is a similar but more pronounced change over time that we see for the Base Case: an initial reliance on coal-fired generation gradually changes to a mix in which solar thermal and solar PV are crucial, and there is also an increasing contribution from wind, batteries, pumped-storage hydro and gas.

The differences that we see relative to the Base Case largely mirror the differences in investment that we discuss above: more solar thermal plant investment increases the amount generated by them, while a reduction in coal output means that gas mid-merit with CCS generates instead. These dispatchable plant compliment the increase in renewable investment.

Relative to the Base Case we see far less reliance on imports during the 2020s. This is a result of our assumption that the VRET and QRET are rolled into a national scheme.



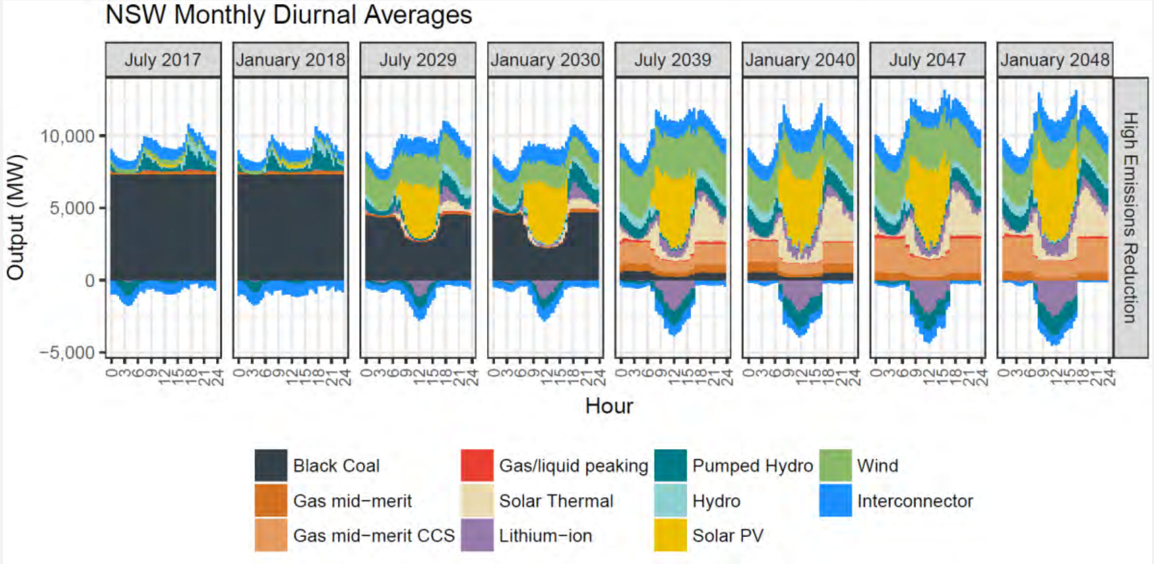
Scenario – High Emissions Reduction

NSW half-hourly dispatch

Patterns of half-hourly dispatch are similar to those for the Base Case. As in the Base Case, in 2017/18 coal accounts for the majority of dispatch. By 2029/30, imports and batteries play a more important role in meeting demand. By 2039/40, coal dispatch has decreased very materially, replaced by a combination of renewables and storage. By 2047/48, coal generation has disappeared completely, being replaced by CCGT with CCS and wind.

Relative to the Base Case, daily patterns of dispatch in the High Emissions Reduction Scenario show slightly less utility-scale solar thermal dispatch, replaced by gas and a slight increase in wind dispatch.

Daily dispatch results for the single week of lowest renewable generation for these same 4 years are presented in Appendix A.



NSW imports

Like in the Base Case, in the High Emissions Reduction Scenario we see a substantial change in patterns of regional flows over the modelling period. The reliance on importing from Victoria disappears both because we assume that the VRET is rolled into a national target and because their cheap coal plants retire. This, in turn, results in NSW importing slightly more from Queensland. Towards the later years NSW imports from Victoria are negligible, while the reliance on Queensland has almost doubled.

Relative to the Base Case, the assumption that the VRET and QRET are rolled into a national scheme result in large changes in net inflows.

Scenario – High Emissions Reduction

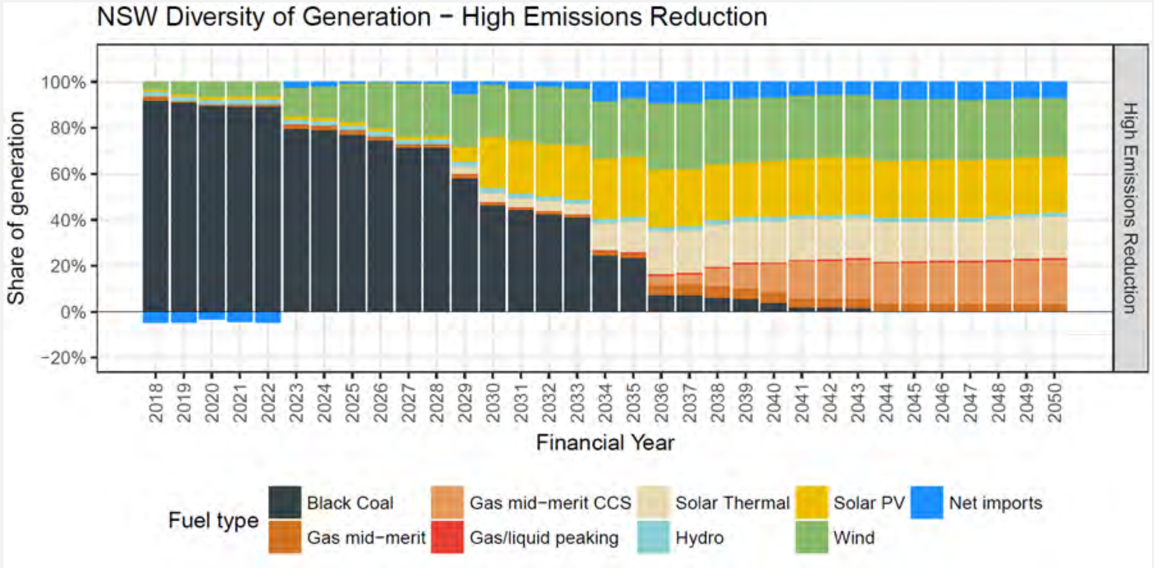
NSW diversity of energy supply

Like in the Base Case, in the High Emissions Reduction Scenario we see a substantial increase over time in the diversity of technologies that supply NSW's electricity.

NSW's initial reliance on coal-fired generation is replaced by a mix of generation that includes substantial amounts of solar thermal, solar PV and wind, with smaller amounts of hydro, gas and imports.

The result is a much more balanced generation mix, and much reduced reliance on a single technology type or fuel source.

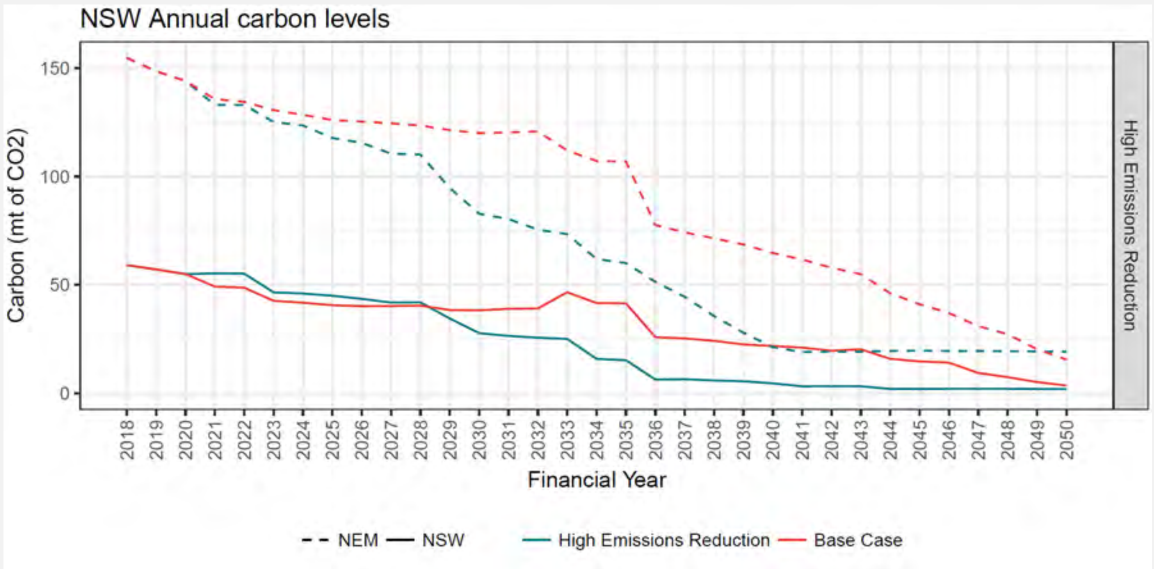
Relative to the Base Case, and consistent with the results we have seen above, in the High Emissions Reduction Scenario the reduction in coal generation in NSW (which is not entirely balanced by an increase in wind and solar PV generation) results in somewhat increased reliance on imports in the long term. However, NSW's reliance on imports during the 2020s is much reduced.



NSW carbon emissions

Consistent with the results for dispatch that we have seen, over time we see a significant reduction in total emissions from NSW power stations. As in the Base Case, these reductions are primarily the result of the retirement of NSW's coal-fired power stations. With no new investment in coal plant in NSW, emissions during the 2030s are significantly lower than in the Base Case.

The retirement of Victorian coal plants, and reduced imports from Victoria, does see higher emissions in NSW initially, however with the retirement of coal plants we see much lower carbon levels than in the Base Case.



Scenario – High Emissions Reduction

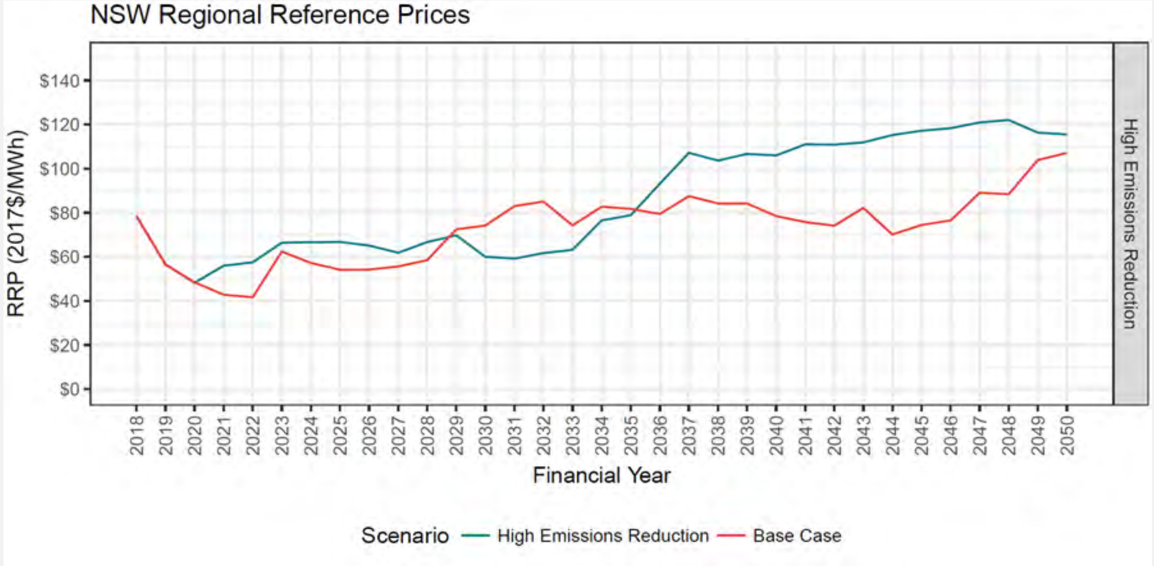
NSW wholesale prices

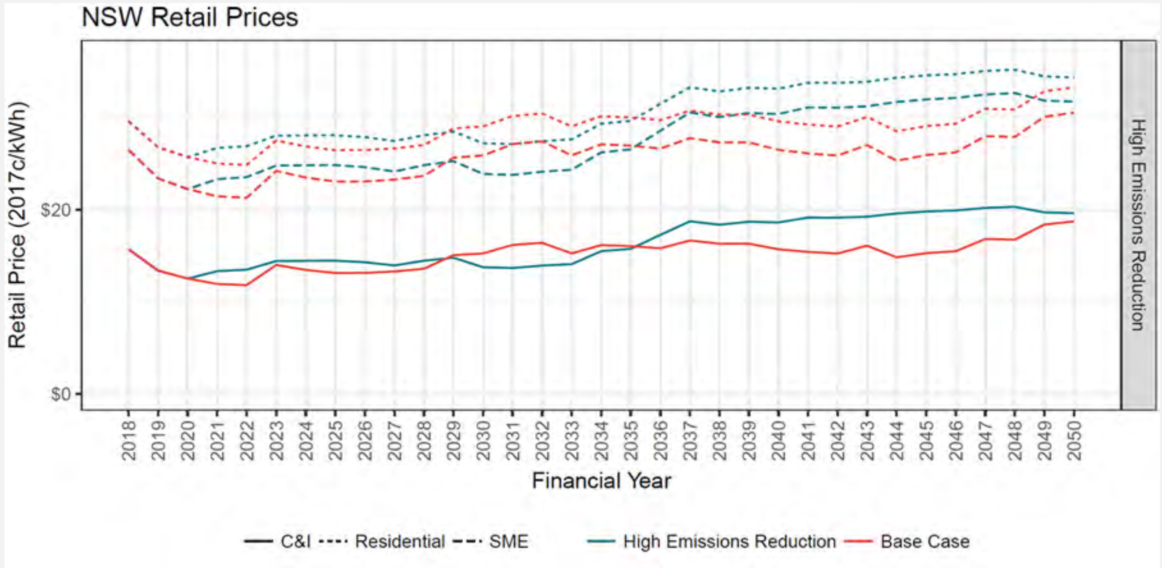
As in the Base Case, our modelling indicates that in the High Emissions Reduction Scenario wholesale prices in NSW will fall over the coming few years, from around $75/MWh in 2017/18 to around $55/MWh in 2020/21. This is driven by substantial investment committed investment in renewable plant over this period.

Prices increase earlier in the High Emissions Reduction Scenario as a result of earlier retirement of coal plant in Victoria. Prices then continue to gradually increase until new investment is required in the early 2030s. At this point, the increased renewables investment starts to reduce prices. Longer-term, however, the increased cost of meeting the emissions target means that prices tend to be significantly higher than in the Base Case; wholesale prices are in the order of $30/MWh to $40/MWh higher and retail prices for residential customers are in the order of 5c/kWh higher during the late 2030s and much of the 2040s.

Retail prices follow the same trend as wholesale prices, but do not fluctuate as much as wholesale prices. The reason is that a large component of the retail price is network tariffs, which we assume remain constant in real terms.

Wholesale and retail prices for other regions are set out in Appendix A.

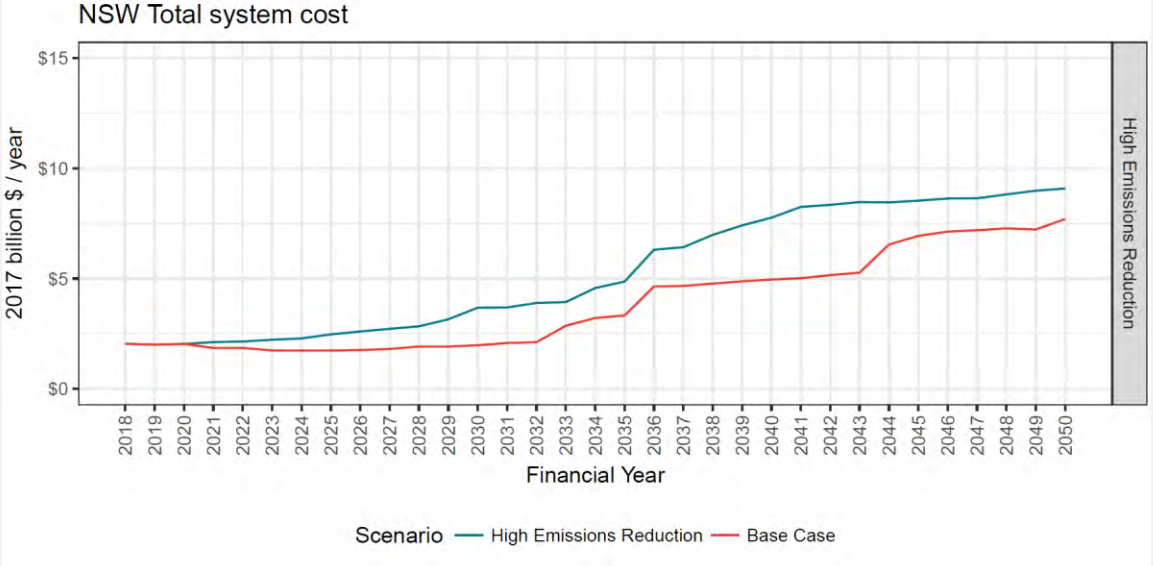




Scenario – High Emissions Reduction

NSW total system cost

The High Emissions Reduction Scenario has a higher total system cost, which represents the extra costs associated with achieving a lower emissions target. It follows much the same trajectory as the Base Case, except does not see a reduction in costs in the 2020's, because extra investment is required to meet the stricter emissions target.



Scenario – Alternate Coal Price

NSW investment, retirement and installed capacity

In the Alternate Coal Price Scenario, our modelling shows that investment outcomes in NSW will be substantially the same as the Base Case. We see the same committed investment over the next five years as in the Base Case – new wind farms and solar farms, as well as AGL's committed investment in Bayswater's upgrade and a gas peaker.

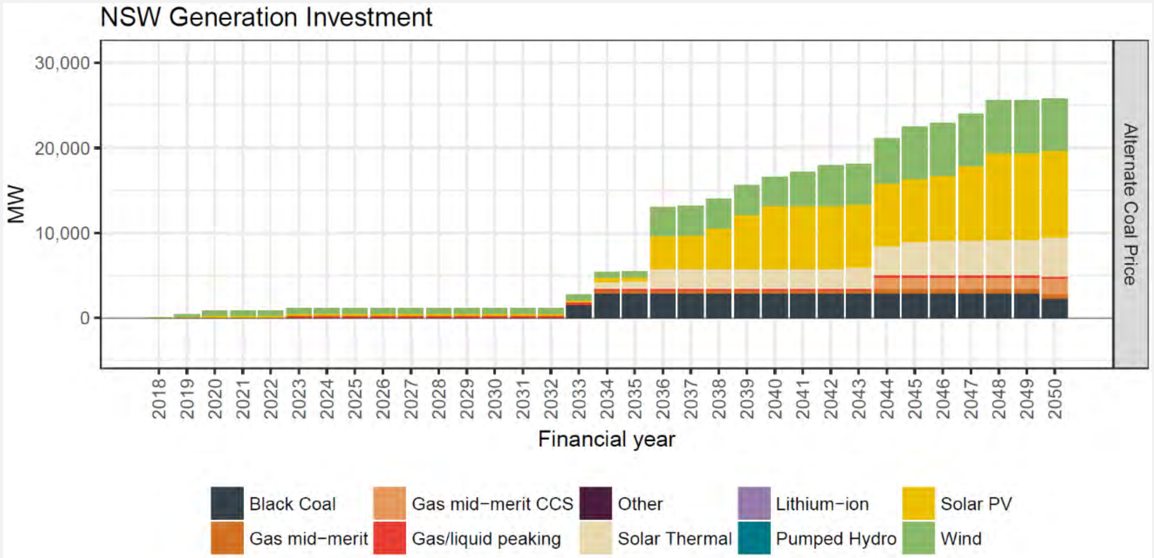
Beyond that, we do not see new investment until 2032/33.

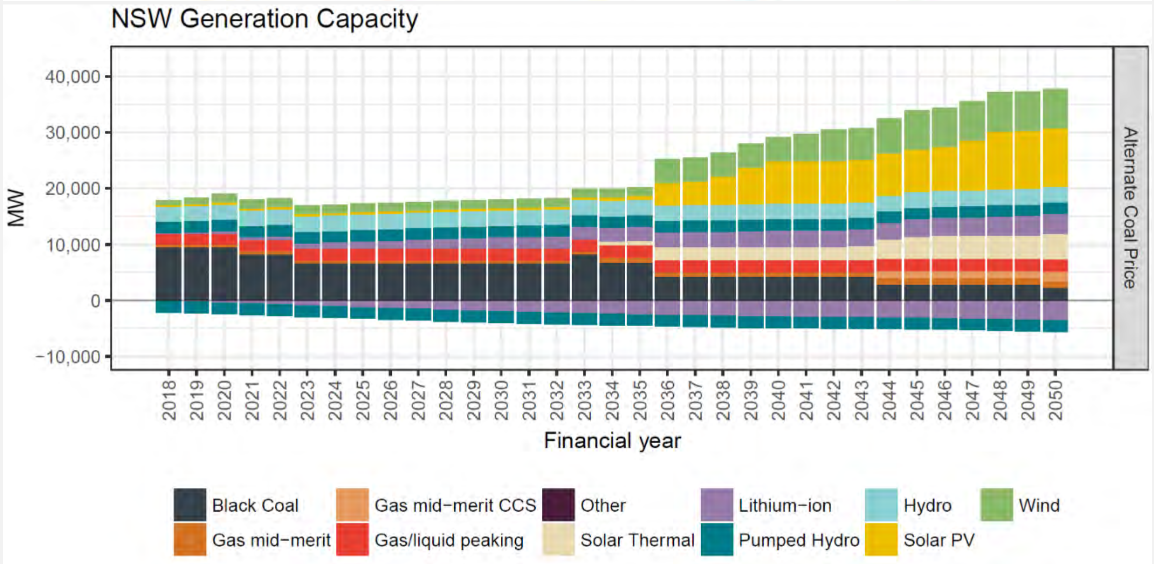
As in the Base Case, with the retirement of Eraring power station in 2032/33 and Bayswater power station in 2034/35, new investment is required. We see the same types of investment: new coal plant as well as significant amounts of solar thermal, solar PV and wind generation. Following the retirement of Mt Piper power station, we also see investment in CCGT with CCS, as we did in the Base Case.

The only notable difference from the Base Case is a slight increase in mid-merit gas investment. This occurs because the Alternate Coal Price has a higher coal for existing NSW coal generators during the early years of the modelling period, which is sufficient to cause Vales Point to retire early. This leads to some additional investment in gas plant.

Ordinarily, a lower coal price for new entrant coal plant would be expected to result in greater investment in new plant (in place of investment in gas plant or renewable plant). That this does not occur indicates that any investment in coal plant in excess of the investment that we see in the Base Case would make it more difficult to meet the emissions target. In order for significant investment in new coal plant in excess of the investment that we see in the Base Case to occur it is likely that the coal plant would need to be CCS plant; the substantial additional capital cost of CCS plant makes that uneconomic to the alternatives, even at a lower coal price.

Investment and capacity results for other regions are set out in Appendix A.





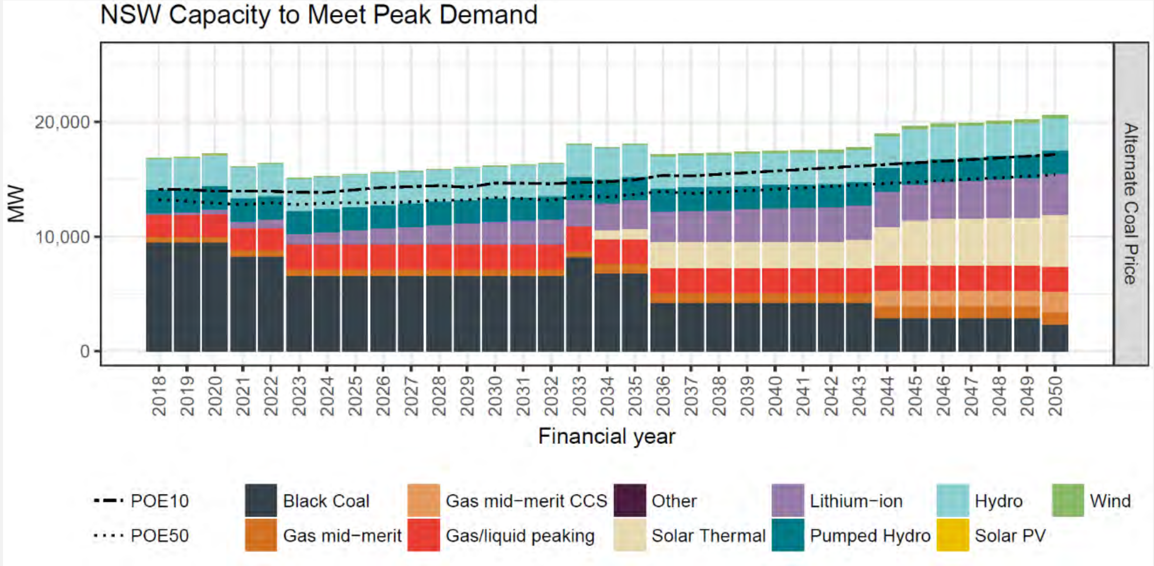
Scenario – Alternate Coal Price

NSW diversity of capacity to meet peak demand

Accounting for the expected ability to generate at peak times, it is clear that NSW is currently very reliant on coal-fired generation, hydro generation and, to a lesser extent, gas generation.

As in the Base Case, in the Alternate Coal Price Scenario, over time the contribution of coal-fired generation to meeting peak demand diminishes, as plant retire. Since the large investments in wind and solar do not contribute to the ability to meet peak demand, NSW becomes increasingly reliant on batteries, solar thermal plants and gas plants to meet peak demand.

Our assumption is that solar PV does not contribute at times of peak demand, and that wind only contributes at a small fraction of its total capacity.

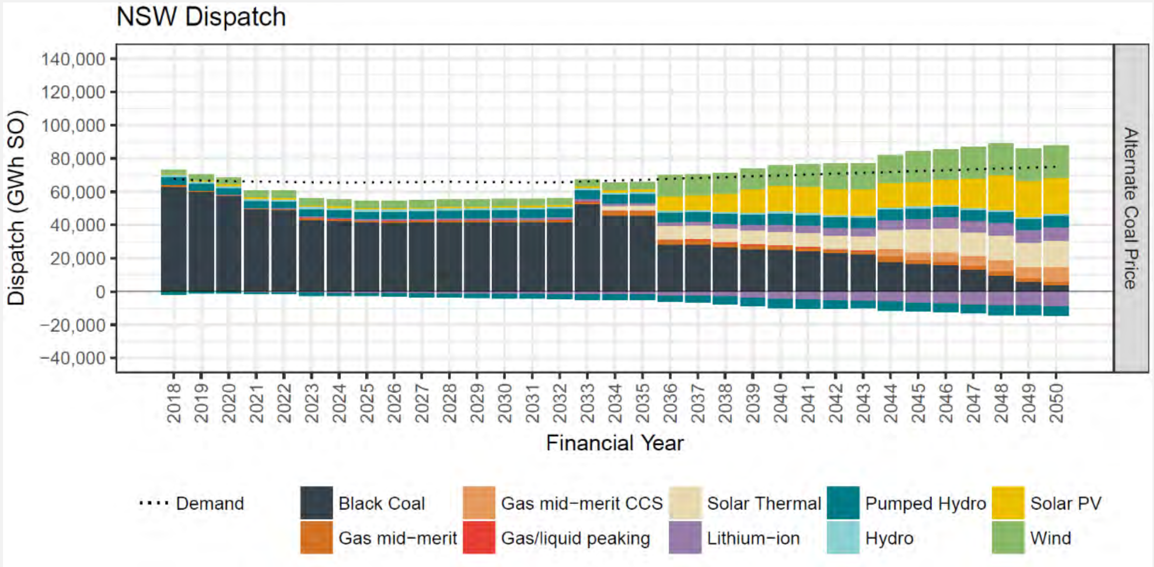


NSW dispatch

Like in the Base Case, in the Alternate Coal Price Scenario our modelling indicates a substantial change over time in the mix of generation plant supplying NSW's electricity.

This change over time is very similar to the change over time that we see for the Base Case: an initial reliance on coal-fired generation gradually changes to a mix in which solar thermal and solar PV are crucial, and there is also an increasing contribution from wind, batteries, pumped-storage hydro and gas.

The differences that we see relative to the Base Case are very minor. We see small decreases in coal output early on. This occurs because the Alternate Coal Price has a higher coal for existing NSW coal generators during the early years of the modelling period. We also see small increase in coal output later in the modelling period as lower coal prices result in increased dispatch.



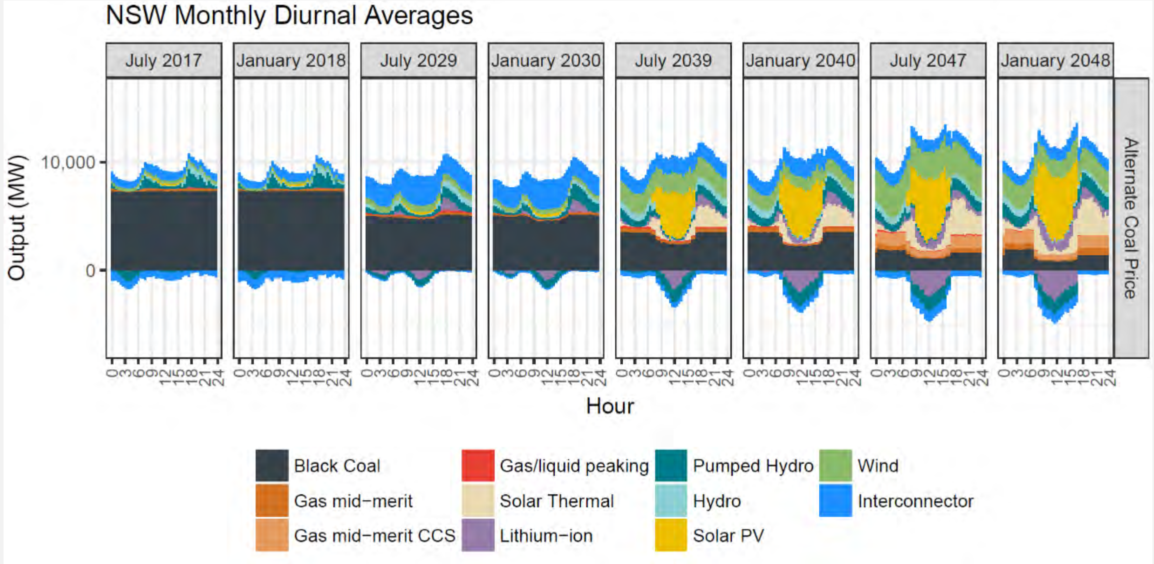
Scenario – Alternate Coal Price

NSW half-hourly dispatch

Patterns of half-hourly dispatch are quite similar to those for the Base Case. As in the Base Case, in 2017/18 coal accounts for the majority of dispatch. By 2029/30, imports and batteries play a more important role in meeting demand. By 2039/40, coal dispatch has decreased very materially, replaced by a combination of renewables and storage. By 2047/48, coal generation has decreased even more, being replaced by CCGT with CCS and renewables with storage.

Relative to the Base Case, daily patterns of dispatch in the Alternate Coal Price Scenario show a slightly greater reliance on coal to meet demand as a result of the lower coal price.

Daily dispatch results for the single week of lowest renewable generation for these same 4 years are presented in Appendix A.



NSW imports

Like in the Base Case, in the Alternate Coal Price Scenario we see a substantial change in patterns of regional flows over the modelling period. These are predominantly driven by the effect of the VRET and QRET, which result in substantial renewable investment in Victoria and Queensland. These leads to excess energy in these regions, both of which export into NSW.

The higher black coal price applies to all coal plants except some mine mouth mines found in Queensland, which retain their cheaper price. This means that they have a comparative advantage and so produce more electricity, allowing NSW to import this at a cheaper price than producing it themselves. This increases the imports from Queensland and decreases the imports from Victoria. This slowly returns to the same levels as the base case as coal prices decrease.

Scenario – Alternate Coal Price

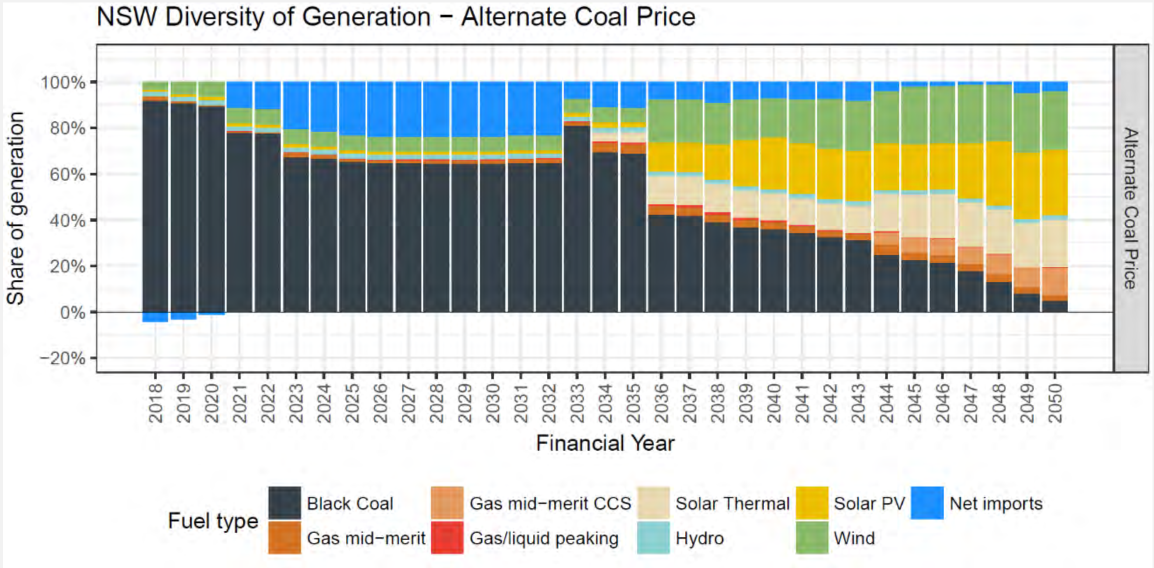
NSW diversity of energy supply

Like in the Base Case, in the Alternate Coal Price Scenario we see a substantial increase over time in the diversity of technologies that supply NSW's electricity.

NSW's initial reliance on coal-fired generation is replaced by a mix of generation that includes substantial amounts of solar thermal, solar PV and wind, with smaller amounts of hydro, gas and imports.

The result is a much more balanced generation mix, and much reduced reliance on a single technology type or fuel source.

Relative to the Base Case, and consistent with the results we have seen above, in the Alternate Coal Price Scenario the coal plants run slightly harder later on, resulting in a slight increase in their share of generation.



NSW carbon emissions

Consistent with the results for dispatch that we have seen, over time we see a significant reduction in total emissions from NSW power stations. As in the Base Case, these reductions are primarily the result of the retirement of NSW's coal-fired power stations.

There is very little difference in total emissions between the Alternate Coal Price Scenario and the Base Case; this is largely because less new coal is built, but instead existing coal generates more electricity later. The slight dip early on is due to the higher coal price disincentivising coal generation.

Scenario – Alternate Coal Price

NSW wholesale prices

As in the Base Case, our modelling indicates that in the Alternate Coal Price Scenario wholesale prices in NSW will fall over the coming few years, but not as much as in the Base Case, from around $75/MWh in 2017/18 to around $55/MWh in 2020/21. This is driven by a higher coal price for existing coal plant in NSW early on in the Alternate Coal Price Scenario, driving up prices over this period.

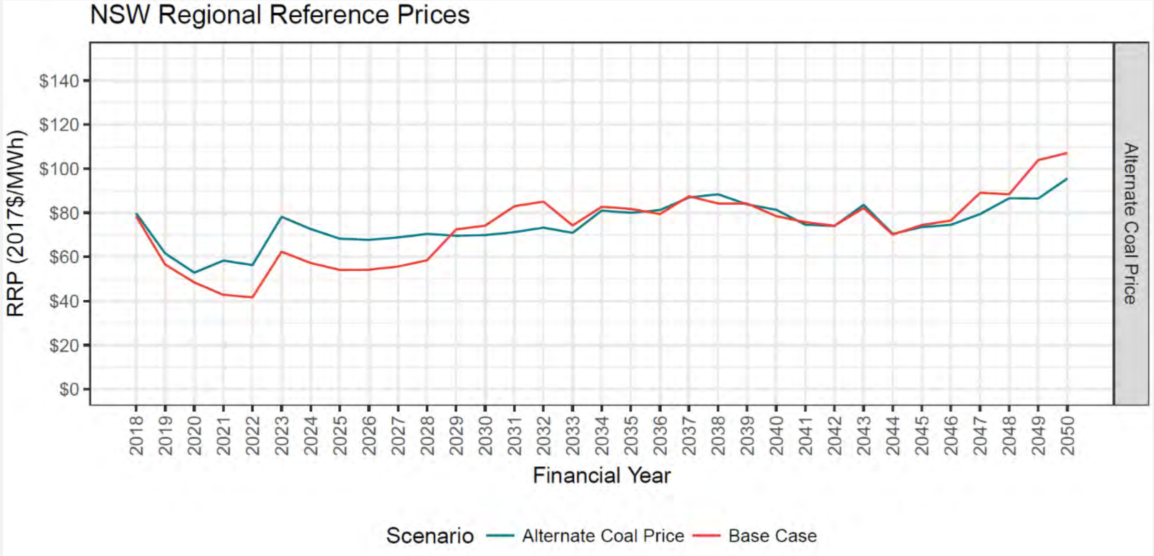
Until 2029, prices in the Alternate Coal Price Scenario are higher than prices in the Base Case, due to the higher coal price. From 2029 the coal price becomes lower than in the Base Case for most generators, resulting in lower wholesale electricity prices for a few years.

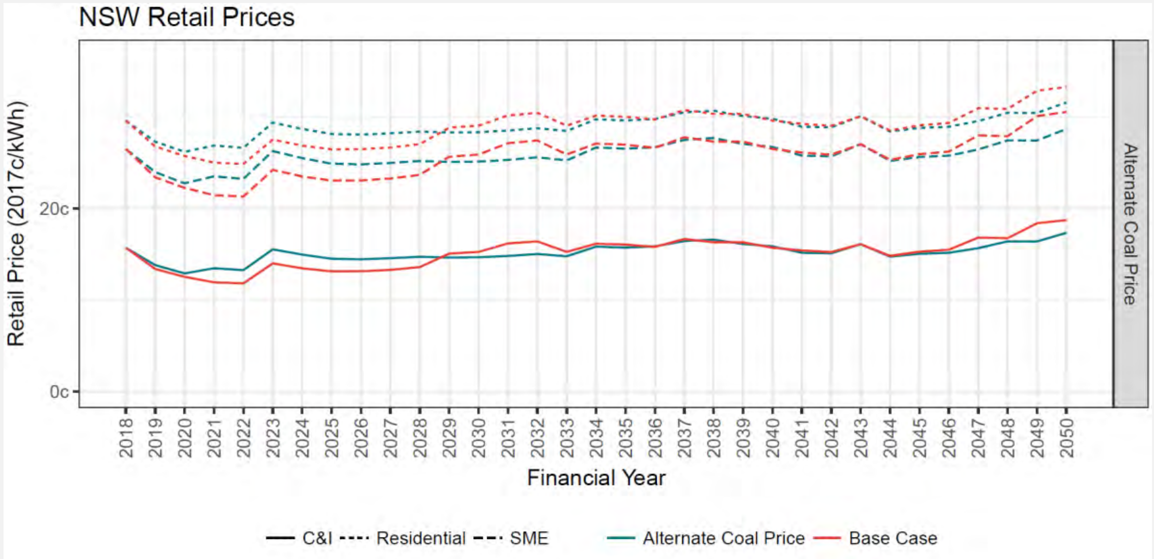
Following the retirement of Bayswater power station and Eraring power station the wholesale electricity prices in the Alternate Coal Price Scenario are much the same as in the Base Case. Even though coal prices in the two scenarios are quite different, wholesale electricity prices are much the same because the relatively small amount of coal plant remaining in NSW does not set the marginal electricity price very often.

For the last few years of the modelling period wholesale electricity prices in the Alternate Coal Price Scenario are a little lower than in the Base Case. The reason is that lower investment in new coal plant means that the cost of meeting the emissions target is lower in the Alternative Coal Price Scenario, leading to lower wholesale electricity prices.

Retail prices follow the same trend as wholesale prices, but do not fluctuate as much as wholesale prices. The reason is that a large component of the retail price is network tariffs, which we assume remain constant in real terms.

Wholesale and retail prices for other regions are set out in Appendix A.

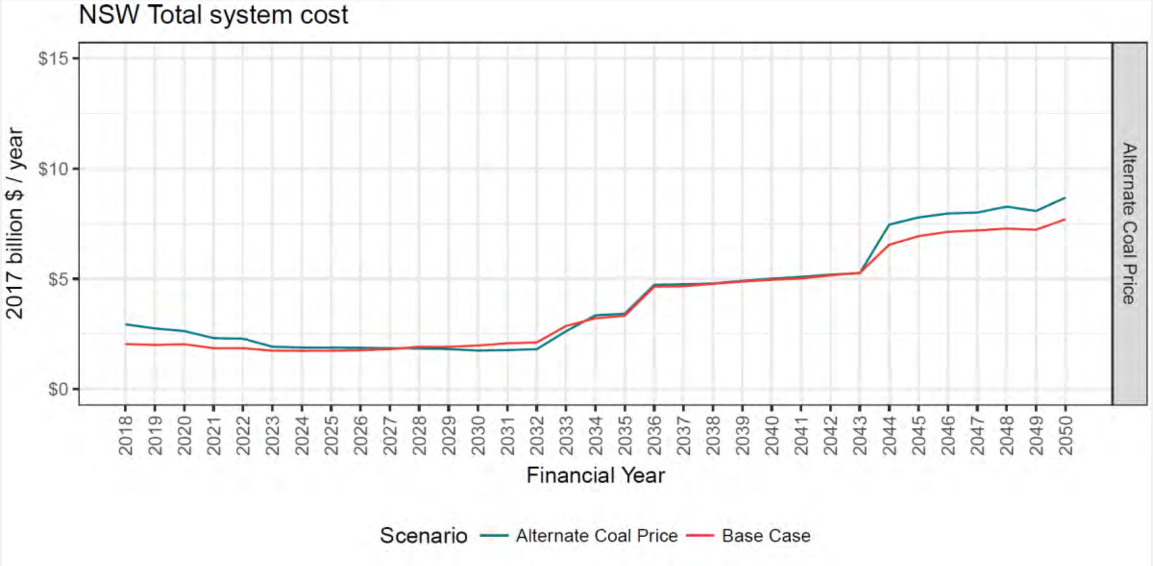




Scenario – Alternate Coal Price

NSW total system cost

The total system cost for the Alternate Coal Price follows mainly from the different coal price used. Since it starts out higher for current coal plants, the system cost is higher, but falls as the coal price does. From 2030 to 2034 the cost to the system is lower, since existing coal prices are lower and the plants haven't retired yet. As plants retire and new coal is built to replace them, they incur the new entrant coal price, which is much higher. This results in a much higher total system cost as compared to the Base Case.



Scenario – High Gas Price

NSW investment, retirement and installed capacity

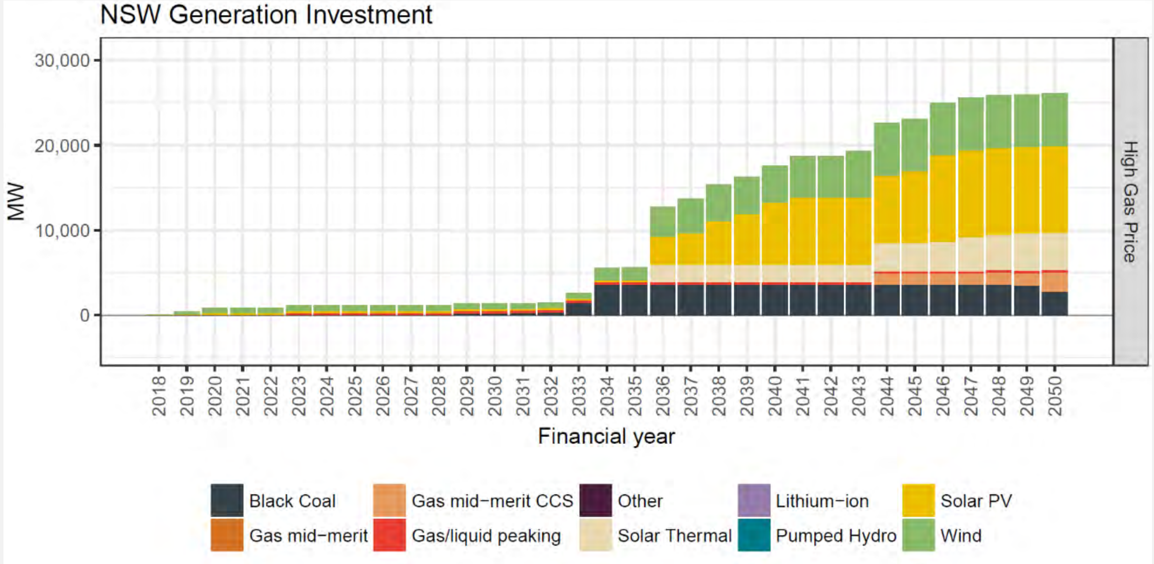
In the High Gas Price Scenario, our modelling shows that investment outcomes in NSW will be substantially the same as the Base Case. We see the same committed investment over the next five years as in the Base Case – new wind farms and solar farms, as well as AGL's committed investment in Bayswater's upgrade and a gas peaker.

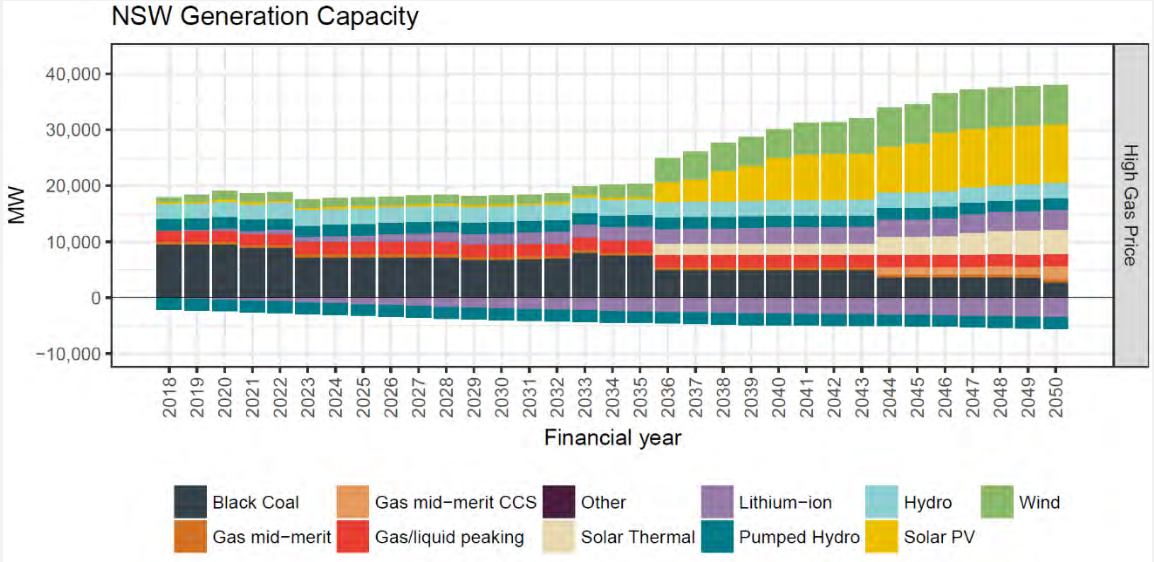
Beyond that, we do not see new investment until 2032/33.

As in the Base Case, with the retirement of Eraring power station in 2032/33 and Bayswater power station in 2034/35, new investment is required. We see the same types of investment: new coal plant as well as significant amounts of solar thermal, solar PV and wind generation. Following the retirement of Mt Piper power station, we also see investment in CCGT with CCS, as we did in the Base Case.

The only notable difference from the Base Case is the extra 300 MW of coal investment in the High Gas Price Scenario, as a result of the increased competitiveness of coal.

Investment and capacity results for other regions are set out in Appendix A.





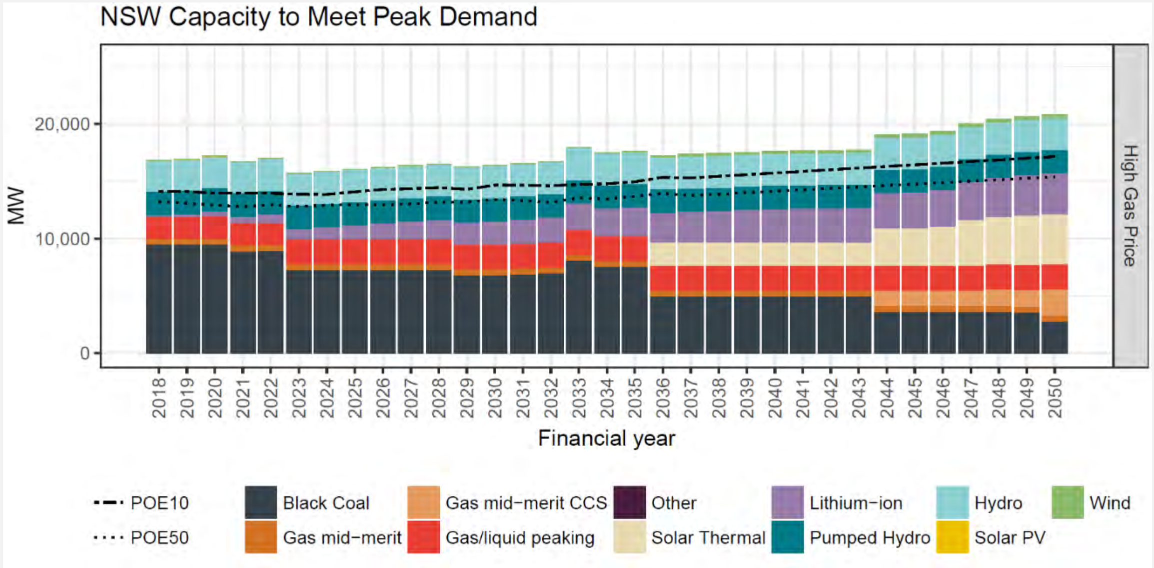
Scenario – High Gas Price

NSW diversity of capacity to meet peak demand

Accounting for the expected ability to generate at peak times, it is clear that NSW is currently very reliant on coal-fired generation, hydro generation and, to a lesser extent, gas generation.

As in the Base Case, in the High Gas Price Scenario, over time the contribution of coal-fired generation to meeting peak demand diminishes, as plant retire. Since the large investment in wind and solar do not contribute to the ability to meet peak demand, NSW becomes increasingly reliant on batteries, solar thermal plants and gas plants to meet peak demand.

Our assumption is that solar PV does not contribute at times of peak demand, and that wind only contributes at a small fraction of its total capacity.

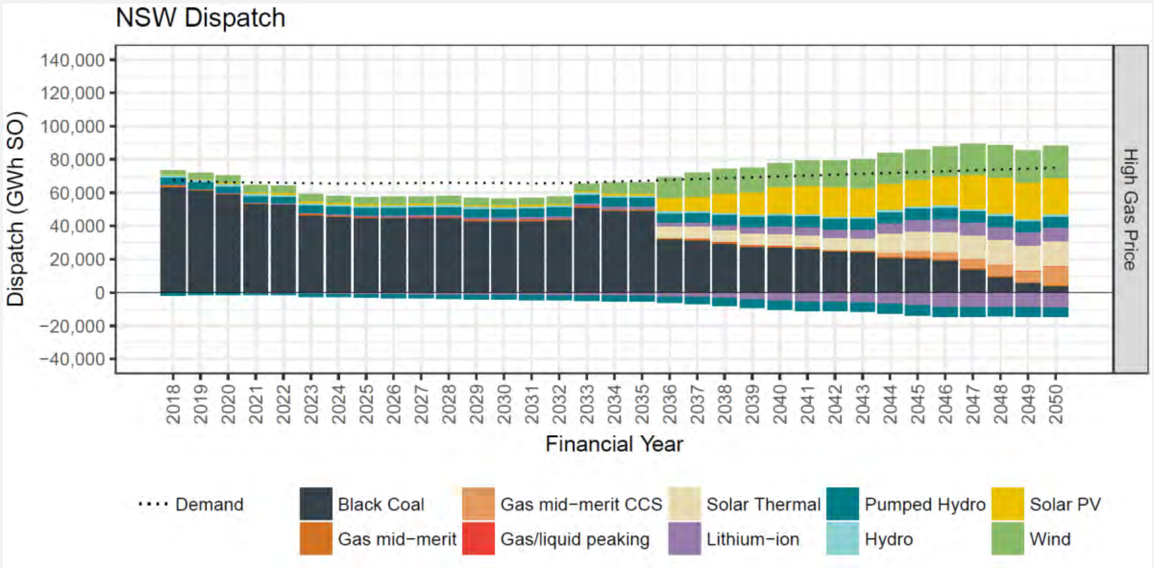


NSW dispatch

Like in the Base Case, in the High Gas Price Scenario our modelling indicates a substantial change over time in the mix of generation plant supplying NSW's electricity.

This change over time is very similar to the change over time that we see for the Base Case: an initial reliance on coal-fired generation gradually changes to a mix in which solar thermal and solar PV are crucial, and there is also an increasing contribution from wind, batteries, pumped-storage hydro and gas.

The differences that we see relative to the Base Case are very minor, with only small increases in coal output, as well as wind due to the increases in investment. A small decrease in solar thermal output is also seen.



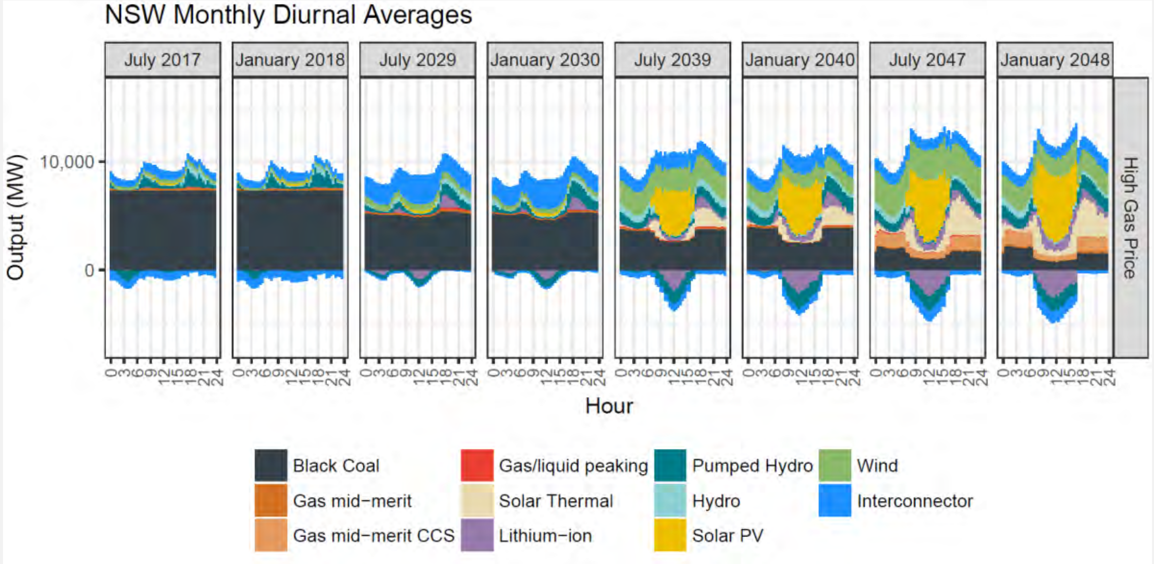
Scenario – High Gas Price

NSW half-hourly dispatch

Patterns of half-hourly dispatch are quite similar to those for the Base Case. As in the Base Case, in 2017/18 coal accounts for the majority of dispatch. By 2029/30, imports and batteries play a more important role in meeting demand. By 2039/40, coal dispatch has decreased very materially, replaced by a combination of renewables and storage. By 2047/48, coal generation has decreased even more, being replaced by CCGT with CCS and renewables with storage.

Relative to the Base Case, daily patterns of dispatch in the High Gas Price Scenario show a slightly greater reliance on coal to meet demand.

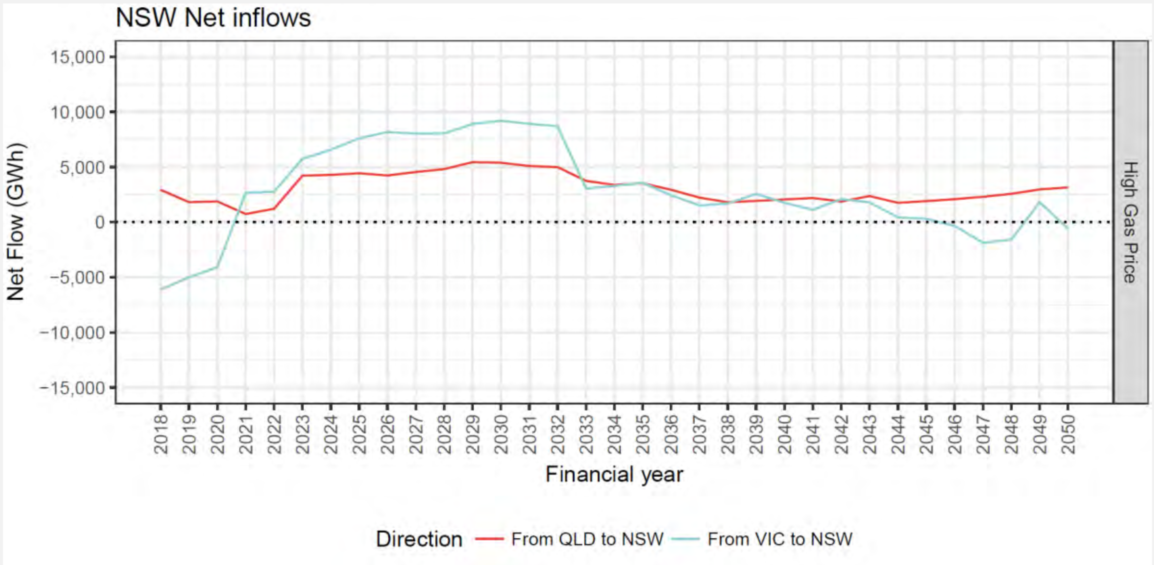
Daily dispatch results for the single week of lowest renewable generation for these same 4 years are presented in Appendix A.



NSW imports

Like in the Base Case, in the High Gas Price Scenario we see a substantial change in patterns of regional flows over the modelling period. These are predominantly driven by the effect of the VRET and QRET, which result in substantial renewable investment in Victoria and Queensland. These lead to excess energy in these regions, both of which export into NSW.

A higher gas price means that the Queensland coal powered generators run at a slightly higher capacity, allowing NSW to import electricity cheaper than running their own gas plants. This leads to NSW importing slightly more from Queensland through the 2020's than in the Base Case. This means that NSW also relies slightly less from imports from Victoria.



Scenario – High Gas Price

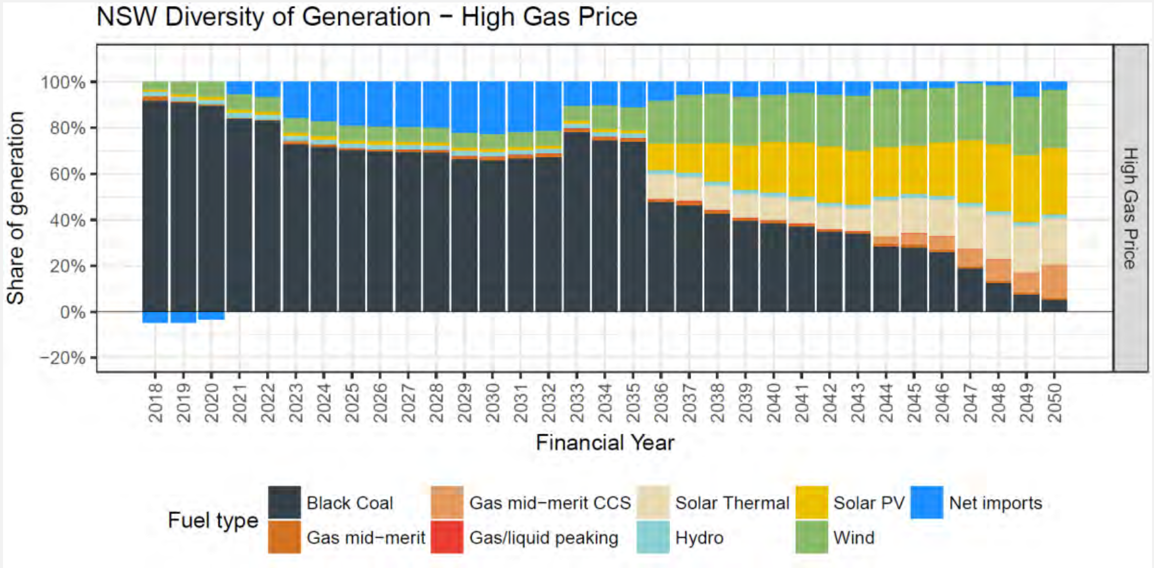
NSW diversity of energy supply

Like in the Base Case, in the High Gas Price Scenario we see a substantial increase over time in the diversity of technologies that supply NSW's electricity.

NSW's initial reliance on coal-fired generation is replaced by a mix of generation that includes substantial amounts of solar thermal, solar PV and wind, with smaller amounts of hydro, gas and imports.

The result is a much more balanced generation mix, and much reduced reliance on a single technology type or fuel source.

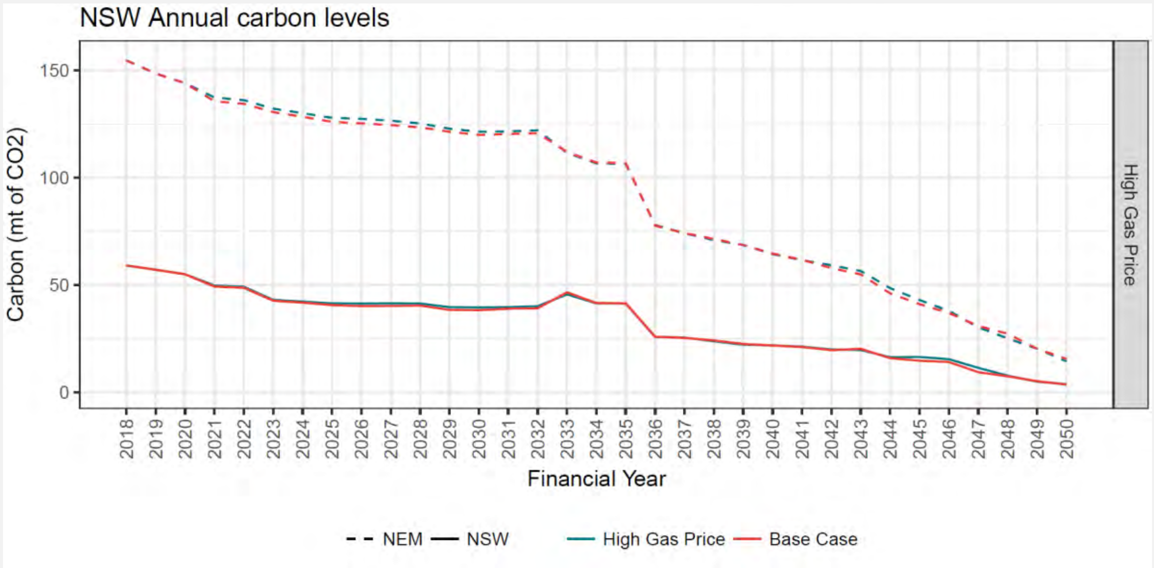
Relative to the Base Case, and consistent with the results we have seen above, in the High Gas Price Scenario the increased investment in coal plants mean that they increase their share of generation.



NSW carbon emissions

Consistent with the results for dispatch that we have seen, over time we see a significant reduction in total emissions from NSW power stations. As in the Base Case, these reductions are primarily the result of the retirement of NSW's coal-fired power stations.

There is very little difference in total emissions between the High Gas Price Scenario and the Base Case; largely because investment is extremely similar. At times the High Gas Price Scenario has carbon levels that are higher than the Base Case because coal plants are generating more due to the higher cost of gas generation.



Scenario – High Gas Price

NSW wholesale prices

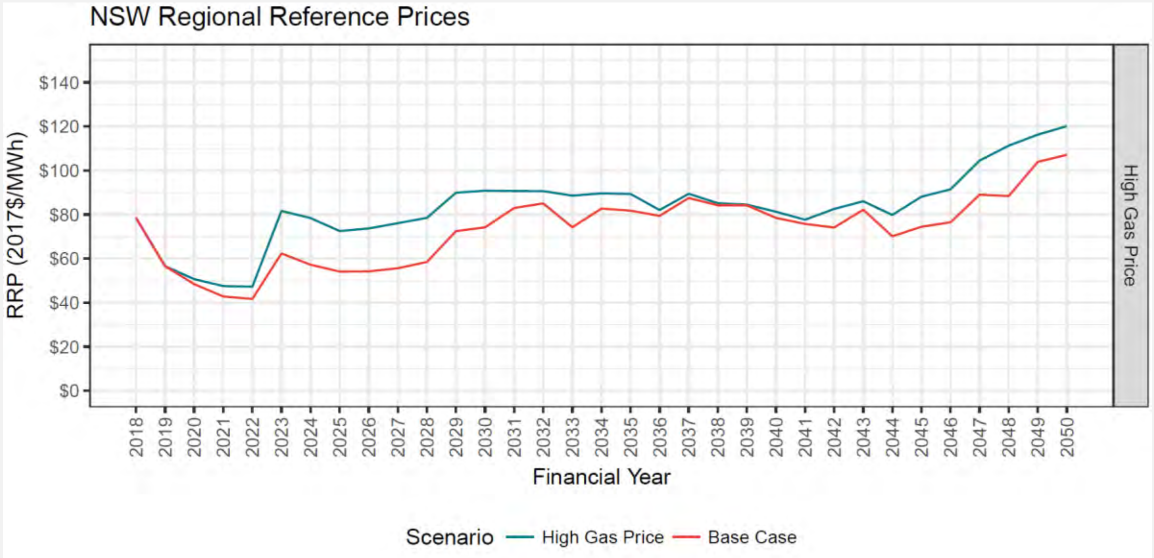
As in the Base Case, our modelling indicates that in the High Gas Price Scenario wholesale prices in NSW will fall over the coming few years, but not as much as in the Base Case, from around $75/MWh in 2017/18 to around $45/MWh in 2020/21. This is driven by a higher gas price early on, driving up prices.

Until 2037, wholesale electricity prices in the High Gas Price Scenario are higher than prices in the Base Case, due to the higher gas price. From 2037 to 2041 prices are similar to the Base Case, however prices then rise more than in the Base Case till 2050. The higher prices seen for most years is because when gas is the marginal generator, it has a higher SRMC due to the increased gas price.

Relative to the Alternate Coal Price Scenario, we can see that the High Gas Price Scenario affects the wholesale electricity price more consistently, because gas plant sets the marginal price more often than coal plant.

Retail prices follow the same trend as wholesale prices, but do not fluctuate as much as wholesale prices. The reason is that a large component of the retail price is network tariffs, which we assume remain constant in real terms.

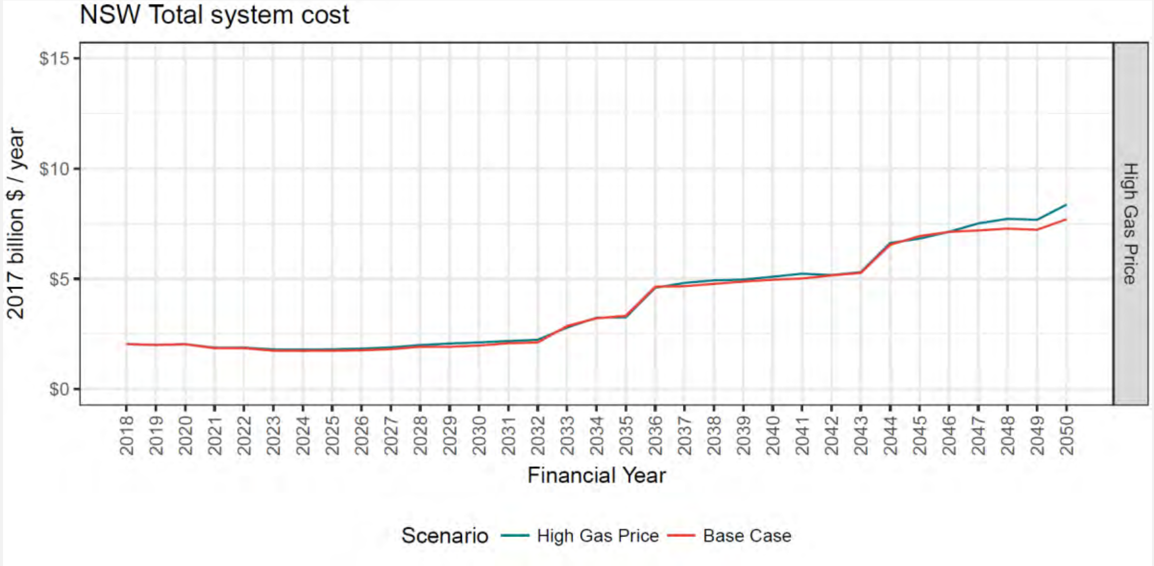
Wholesale and retail prices for other regions are set out in Appendix A.



Scenario – High Gas Price

NSW total system cost

The total system cost for the High Gas Price Scenario is higher than the Base Case, as expected. Since the gas price has increased, these plants must incur higher costs, which pushes up the total system costs. Since gas plant is not dispatched often, the different in total system cost is small.



Scenario – Forced Black Coal CCS

NSW investment, retirement and installed capacity

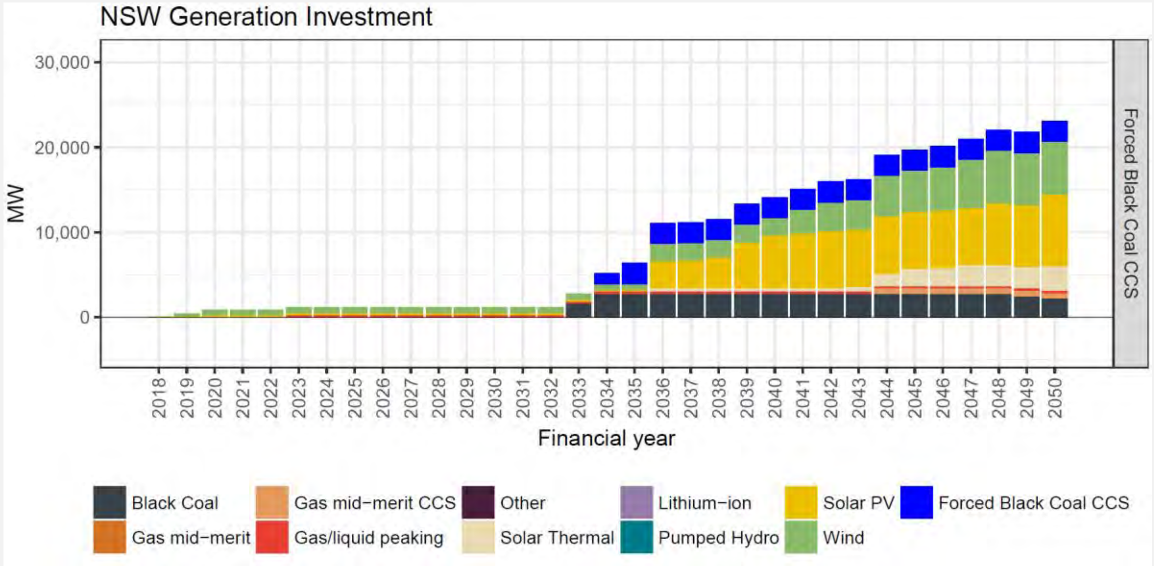
In the Forced Black Coal CCS Scenario, our modelling shows that investment outcomes in NSW will be substantially the same as the Base Case. We see the same committed investment over the next five years as in the Base Case – new wind farms and solar farms, as well as AGL's committed investment in Bayswater's upgrade and a gas peaker.

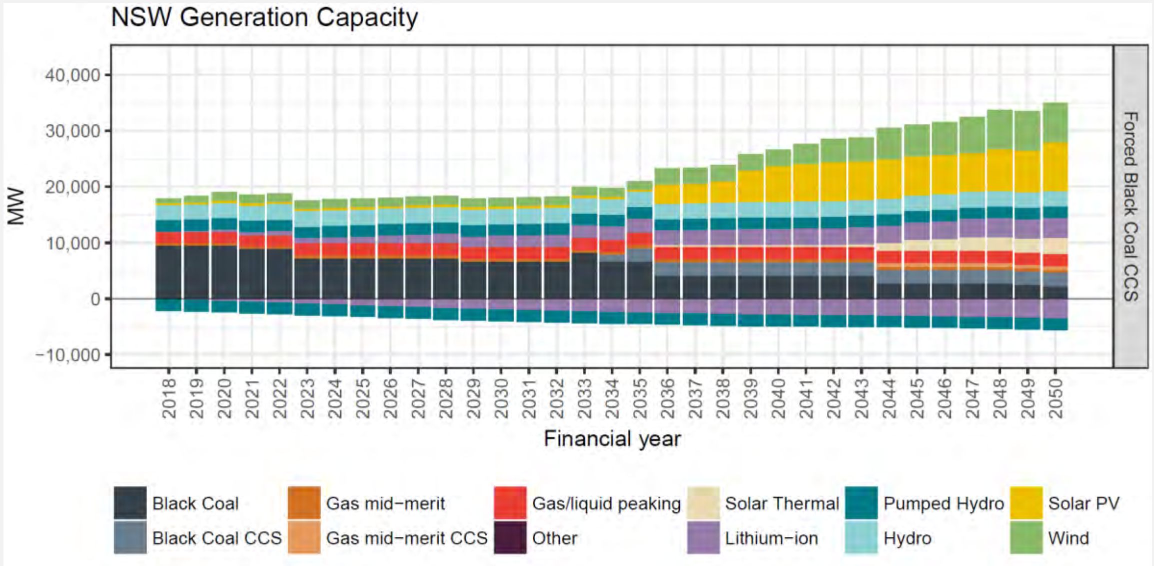
Beyond that, we do not see new investment until 2032/33.

As in the Base Case, with the retirement of Eraring power station in 2032/33 and Bayswater power station in 2034/35, new investment is required. We see the same types of investment: new coal plant as well as significant amounts of solar PV and wind generation, with smaller amounts of solar thermal. However in this scenario, some of that new investment is in the form of forced black coal with CCS. The forced investment in black coal with CCS sees less investment in renewable plant, particularly solar thermal plant.

We also see some changes relative to the Base Case in investment following the retirement of Mt Piper power station, with investment in solar thermal plant but no investment in CCGT with CCS.

Investment and capacity results for other regions are set out in Appendix A.





Scenario – Forced Black Coal CCS

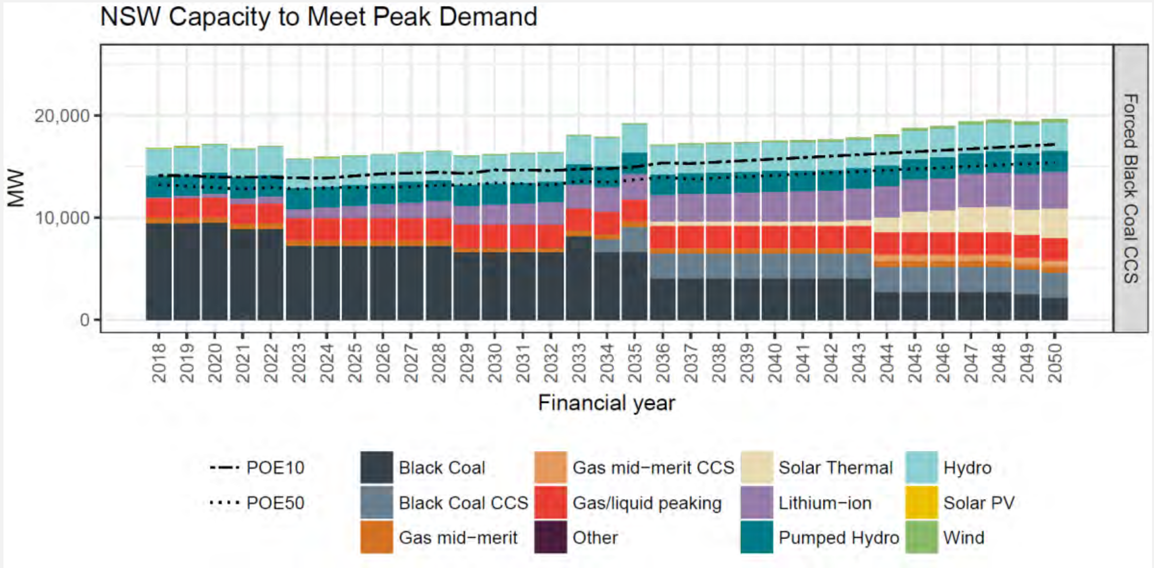
NSW diversity of capacity to meet peak demand

Accounting for the expected ability to generate at peak times, it is clear that NSW is currently very reliant on coal-fired generation, hydro generation and, to a lesser extent, gas generation.

As in the Base Case, in the Forced Black Coal CCS Scenario, over time the contribution of coal-fired generation to meeting peak demand diminishes, as plants retire. Since the large investment in wind and solar does not contribute to the ability to meet peak demand, NSW becomes increasingly reliant on batteries, solar thermal plants and gas plants to meet peak demand.

With the forced black coal CCS plant, NSW ends up relying more heavily on coal than in the Base Case, but this still does not make up the majority of capacity to meet peak demand.

Our assumption is that solar PV does not contribute at times of peak demand, and that wind only contributes at a small fraction of its total capacity.

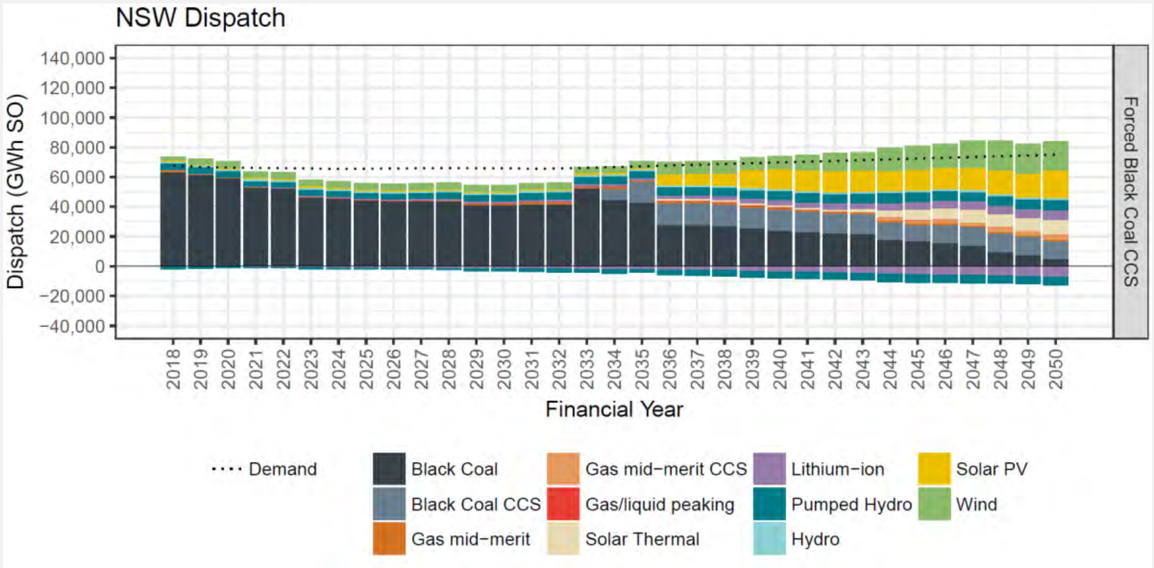


NSW dispatch

Like in the Base Case, in the Forced Black Coal CCS Scenario our modelling indicates a substantial change over time in the mix of generation plant supplying NSW's electricity.

This change over time is very similar to the change over time that we see for the Base Case: an initial reliance on coal-fired generation gradually changes to a mix in which solar thermal and solar PV are crucial, and there is also an increasing contribution from wind, batteries, pumped-storage hydro and gas.

The differences that we see relative to the Base Case are similar to the changes we see in investment, where black coal with CCS replaces output of some conventional black coal, solar thermal and renewables.



Scenario – Forced Black Coal CCS

NSW half-hourly dispatch

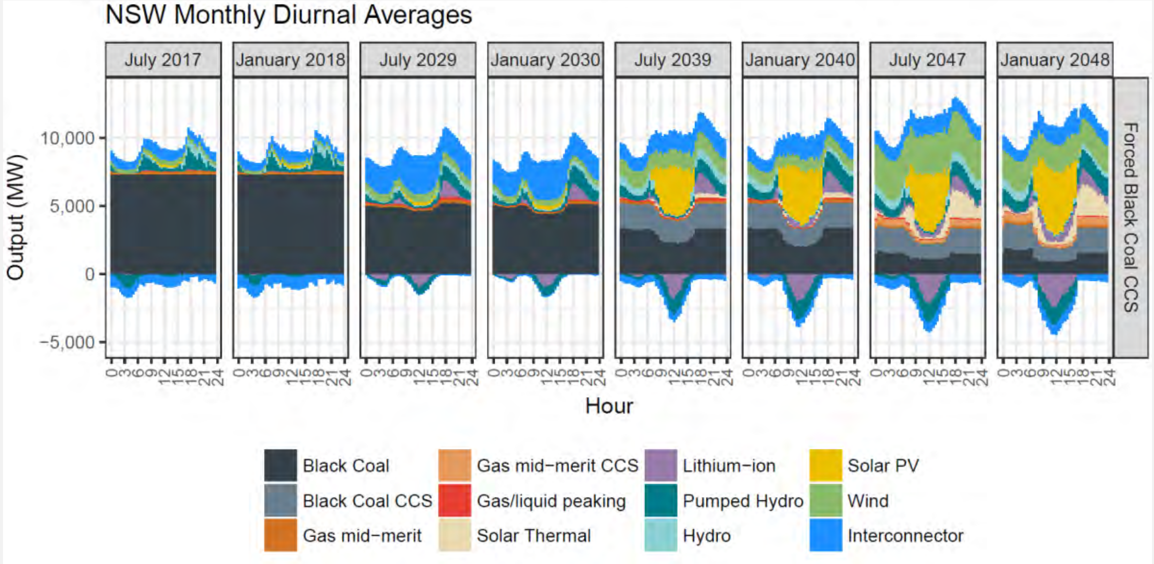
Patterns of half-hourly dispatch are quite similar to those for the Base Case, with some minor changes. As in the Base Case, in 2017/18 coal accounts for the majority of dispatch. By 2029/30, imports and batteries play a more important role in meeting demand.

By 2039/40, we see similar average levels of coal dispatch, albeit with lower levels of dispatch during the middle of the day. However, the composition of this dispatch has changed materially to include black coal with CCS.

By 2047/48, coal generation has decreased further with the retirement of Mt Piper power station. The difference is made up by renewables and storage.

Relative to the Base Case, daily patterns of dispatch in the Forced Black Coal CCS Scenario show a much greater reliance on coal, including coal with CCS, to meet demand.

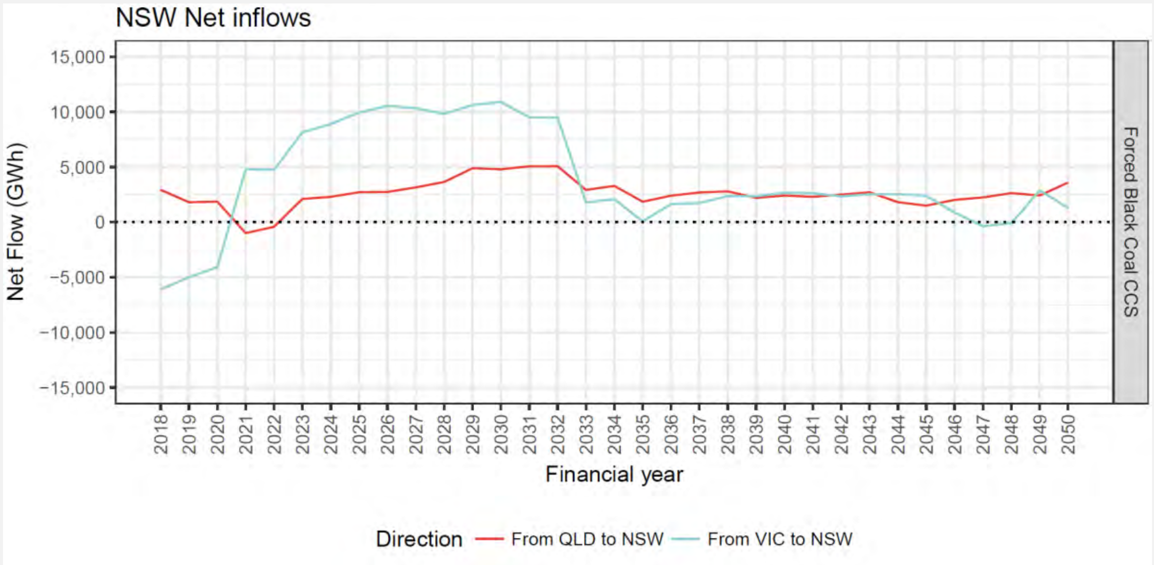
Daily dispatch results for the single week of lowest renewable generation for these same 4 years are presented in Appendix A.



NSW imports

Like in the Base Case, in the Forced Black Coal CCS Scenario we see a substantial change in patterns of regional flows over the modelling period. These are predominantly driven by the effect of the VRET and QRET, which result in substantial renewable investment in Victoria and Queensland. These lead to excess energy in these regions, both of which export into NSW.

Patterns of flow are very similar to the Base Case. The forced black coal CCS means that NSW relies slightly less on inflows in the mid 2030's. However, this starts to increase again as Victoria has increased investment in this scenario, causing NSW to import more than in the Base Case.



Scenario – Forced Black Coal CCS

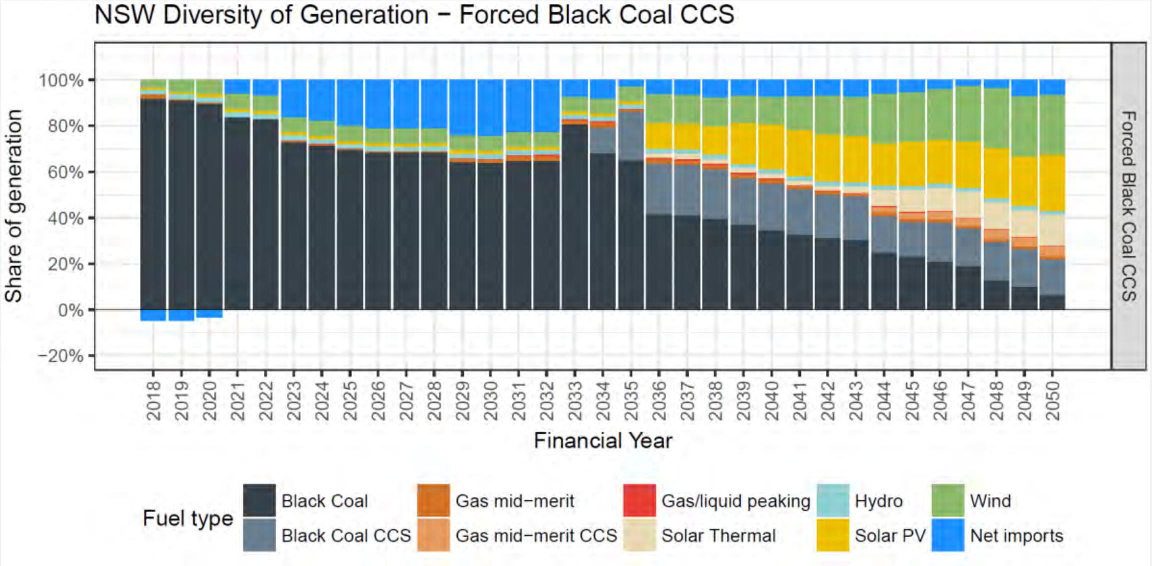
NSW diversity of energy supply

Like in the Base Case, in the Forced Black Coal CCS Scenario we see a substantial increase over time in the diversity of technologies that supply NSW's electricity.

NSW's initial reliance on coal-fired generation is replaced by a mix of generation that includes substantial amounts of solar thermal, solar PV and wind, with smaller amounts of hydro, coal with CCS and imports.

The result is a much more balanced generation mix, and much reduced reliance on a single technology type or fuel source.

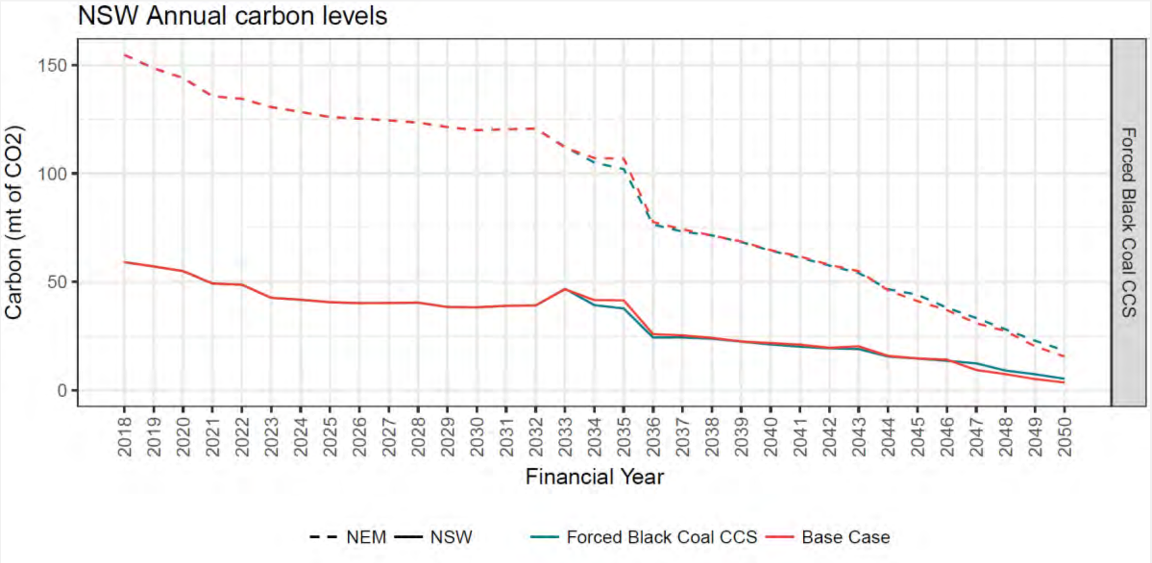
Relative to the Base Case, and consistent with the results we have seen above, in the Forced Black Coal CCS Scenario the forced investment in coal plants with CCS mean that they replace some renewables.



NSW carbon emissions

Consistent with the results for dispatch that we have seen, over time we see a significant reduction in total emissions from NSW power stations. As in the Base Case, these reductions are primarily the result of the retirement of NSW's coal-fired power stations.

There is very little difference in total emissions between the Forced Black Coal CCS Scenario and the Base Case; largely because investment is extremely similar, only swapping out a mix of renewables and CCGT with CCS for coal with CCS; none of these technologies have substantial emissions. In the last few years of the modelling period the Forced Black Coal CCS Scenario has carbon emissions that are slightly higher than the Base Case because the forced coal CCS plant is generating instead of CCGT with CCS, which emits slightly less carbon. This scenario still reaches the target of 10% emissions by 2050.



Scenario – Forced Black Coal CCS

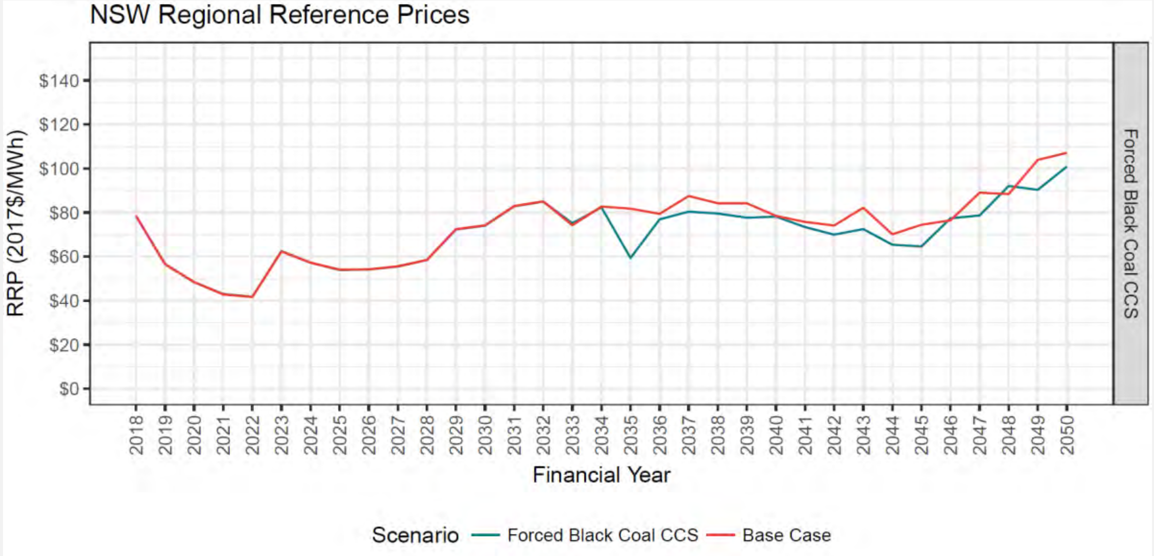
NSW wholesale prices

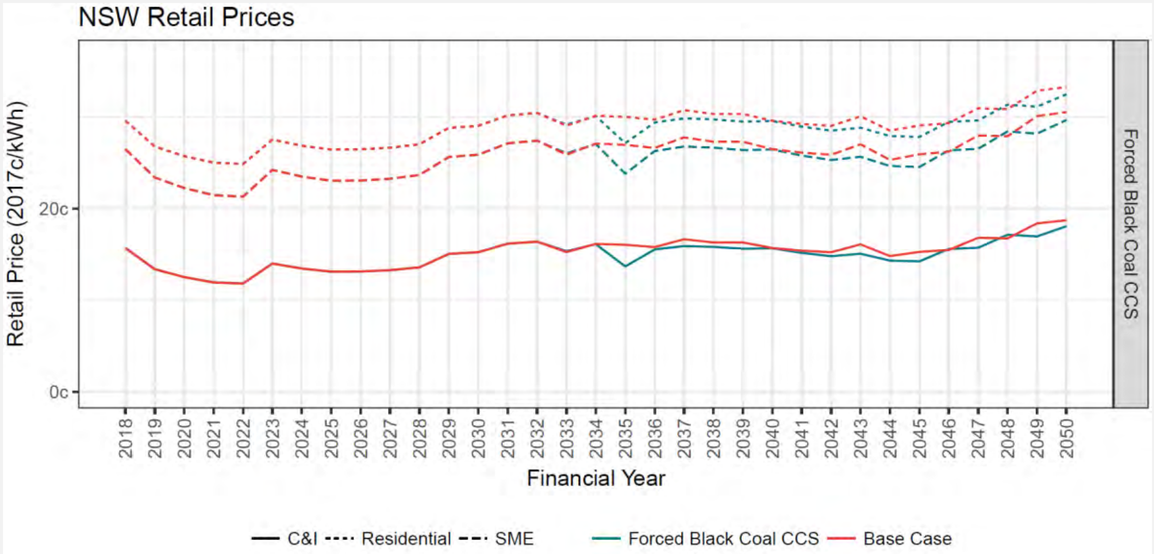
As in the Base Case, our modelling indicates that in the Forced Black Coal CCS Scenario wholesale prices in NSW will fall over the coming few years, in line with the Base Case, from around $75/MWh in 2017/18 to around $45/MWh in 2020/21.

Until 2033/2034, wholesale electricity prices in the Forced Black Coal CCS Scenario are the same as prices in the Base Case, due to the same investment path and dispatch. From 2033/2034 onwards prices start to deviate, largely due to the forced coal with CCS. Prices drop sharply in 2034/35 because the coal with CCS plant is operating and Bayswater has not yet retired. The price then increases again when Bayswater retires, but stay lower than in the Base Case for the rest of the modelling horizon.

Retail prices follow the same trend as wholesale prices, but do not fluctuate as much as wholesale prices. The reason is that a large component of the retail price is network tariffs, which we assume remain constant in real terms.

Wholesale and retail prices for other regions are set out in Appendix A.

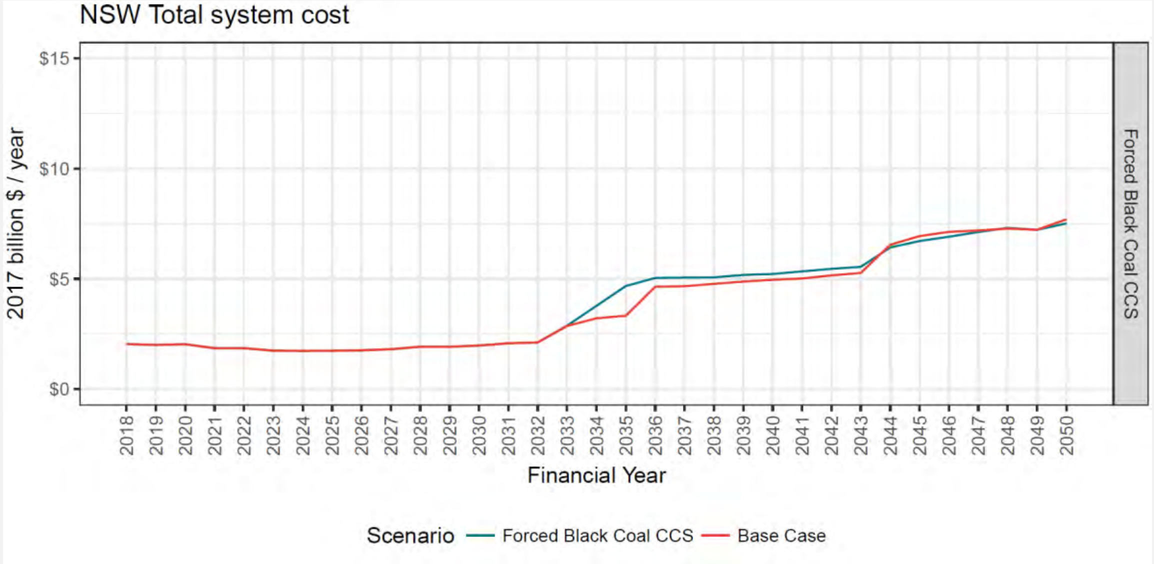




Scenario – Forced Black Coal CCS

NSW total system cost

Total system cost is the same up until 2034, when the Black Coal with CCS is invested in. In 2034 and 2035, the capital cost of the Black Coal with CCS increases the total system cost until about 2044. In 2044 less generation has to be invested in in this case, which reduces the total system cost slightly in later years. However overall the total system cost is higher than the Base Case.



HELE Scenario

As discussed above, in the HELE Scenario we provide for all black coal generators in the NEM to be repowered. The assumptions we use to define the repowering of these black coal were provided to CINSW by The Electric Power Research Institute (EPRI). EPRI provided four options for repowering each plant, including costs and technical characteristics for each option. We also include repowering options with CCS.

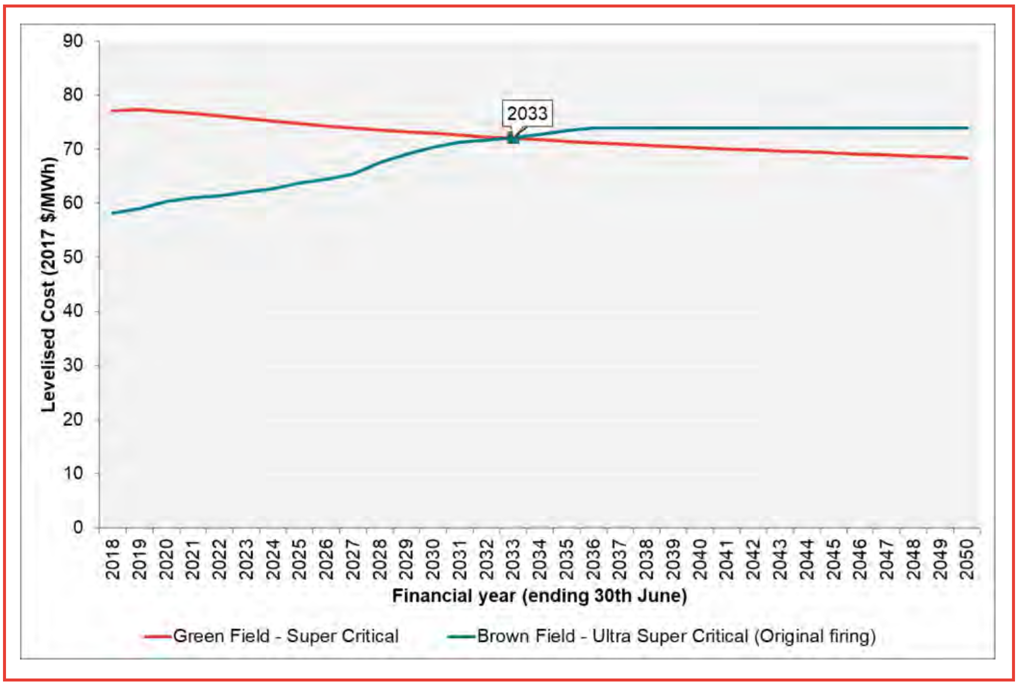
We have modelled a number of variants of the HELE Scenario, with increasingly greater freedom regarding the timing of repowering the existing black coal generators in NSW. However, in none of these cases have we found that one of the repowering options is adopted (in NSW or elsewhere). As a result, the modelling results for the HELE Scenario end up identical to the modelling results for the Base Case, including with the same investment in new greenfields coal plant that we see in the Base Case.

On the face of it this result seems counterintuitive: the capital costs for repowering existing plant that have been provided by EPRI are materially lower than the capital cost from AEMO's 2016 NTNDP for new greenfield plant. Initially the capital cost for repowering are about half of the capital cost for a greenfield plant from AEMO's ISP, although this difference diminishes over the modelling period due to the assumption of falling capital costs in AEMO's 2016 NTNDP.

However, the assumed fixed operating and maintenance (FOM) costs and the assumed fuel costs for the repowering option are higher than for the assumed greenfield options. With regard to the assumed difference in fuel costs, which ends up being the most material, the coal cost for new entrant coal plant is around \$2.30/GJ in the long-term, while the coal cost for existing plant are all above \$3.00/GJ, and some above \$4.00/GJ in the long-term. Indeed, the repowering option that would best meet the timing requirements for new investment in NSW (in 2032/33, to assist in managing the retirement of Eraring power station and then Bayswater power station) would be Vales Point power station, but AEMO's 2016 NTNDP assumes that Vales Point power station would face a coal cost above \$4.00/GJ in the long-term.

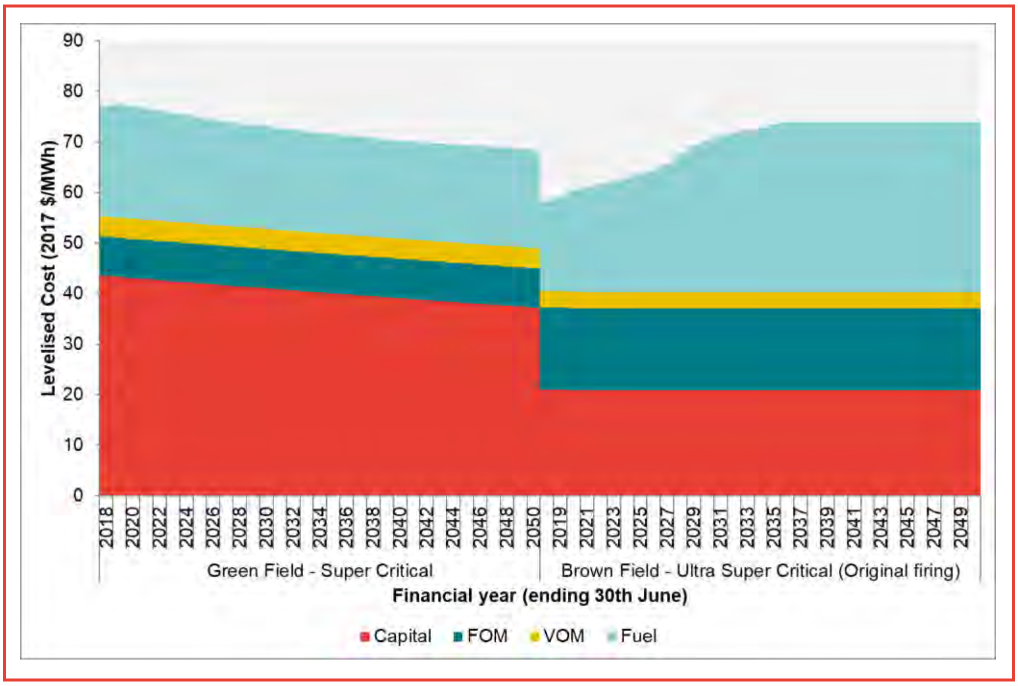
The resulting differences in the levelized cost of generation from greenfield coal plant and a repowered coal plant in NSW are shown in Figure 29 and Figure 30. Initially the repowered coal plant has a lower levelized cost, but by the early 2030s, when the need for new investment occurs, the levelized cost of greenfield plant is lower.

Figure 29: Levelised cost of greenfield coal plant and repowered coal plant in NSW (80% capacity factor)



Source: Frontier Economics Analysis

Figure 30: Levelised cost components of greenfield coal plant and repowered coal plant in NSW (80% capacity factor)



Source: Frontier Economics Analysis

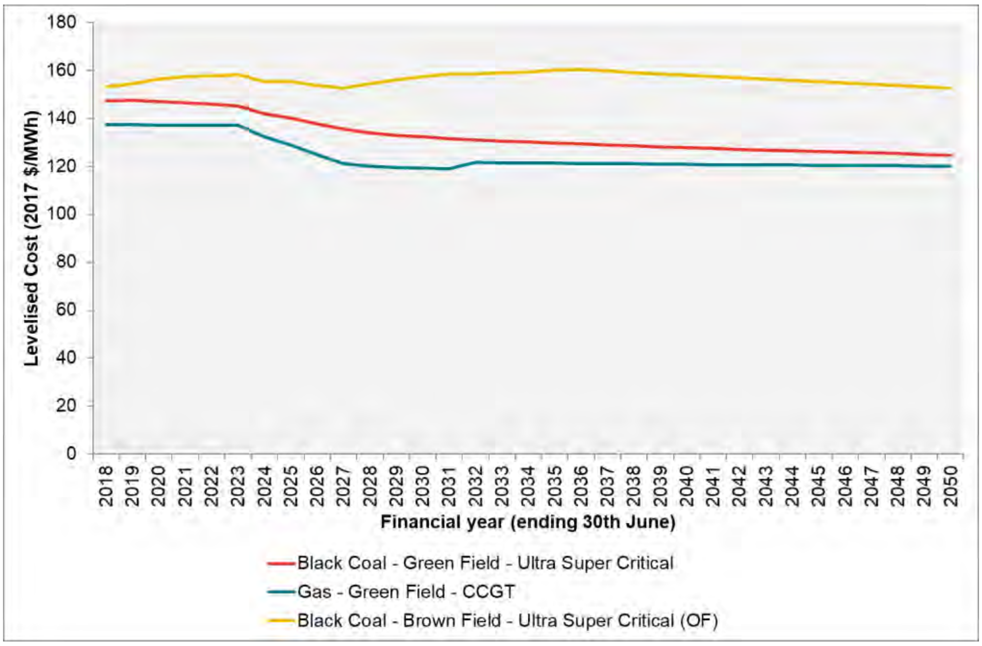
MEGS Scenario and CCS

In the MEGS Scenario we see significant investment in coal with CCS in NSW. However, we do not see investment in coal with CCS in NSW in any of the other scenarios. Rather, we see some investment in CCGT with CCS.

The reason that we do not see investment in coal with CCS in any of our investment modelling is that the input assumptions that we have used – primarily from AEMO's ISP – indicate that the levelized cost of CCGT with CCS is lower than the levelized cost of coal with CCS. This is shown in Figure 31 and Figure 32, which compare the levelized cost of CCGT with CCS with greenfield coal with CCS and with repowered coal with CCS for a capacity factor of 80 per cent, and in in Figure 33 and Figure 34, which provide the same comparison but for a capacity factor of 30 per cent.

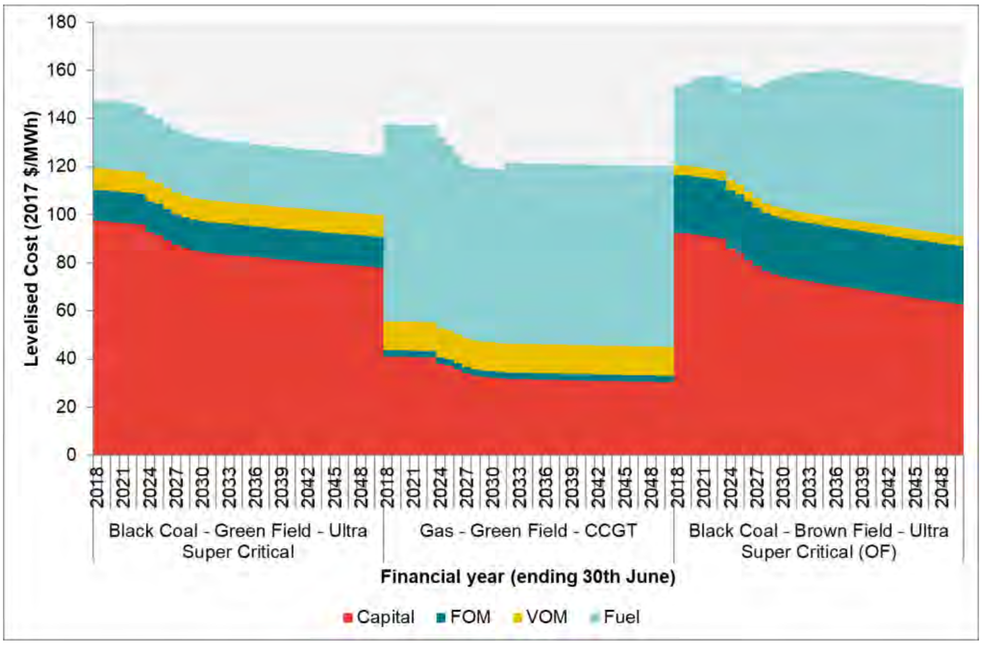
What this comparisons show is that for baseload duty CCGT with CCS is slightly cheaper than coal with CCS (as a result of its substantially lower capital costs and FOM) and for mid-merit duty CCGT with CCS is substantially cheaper than coal with CCS (again, as a result of its substantially lower capital costs and FOM).

Figure 31: Levelised cost of gas and coal CCS entrants (80% capacity factor)



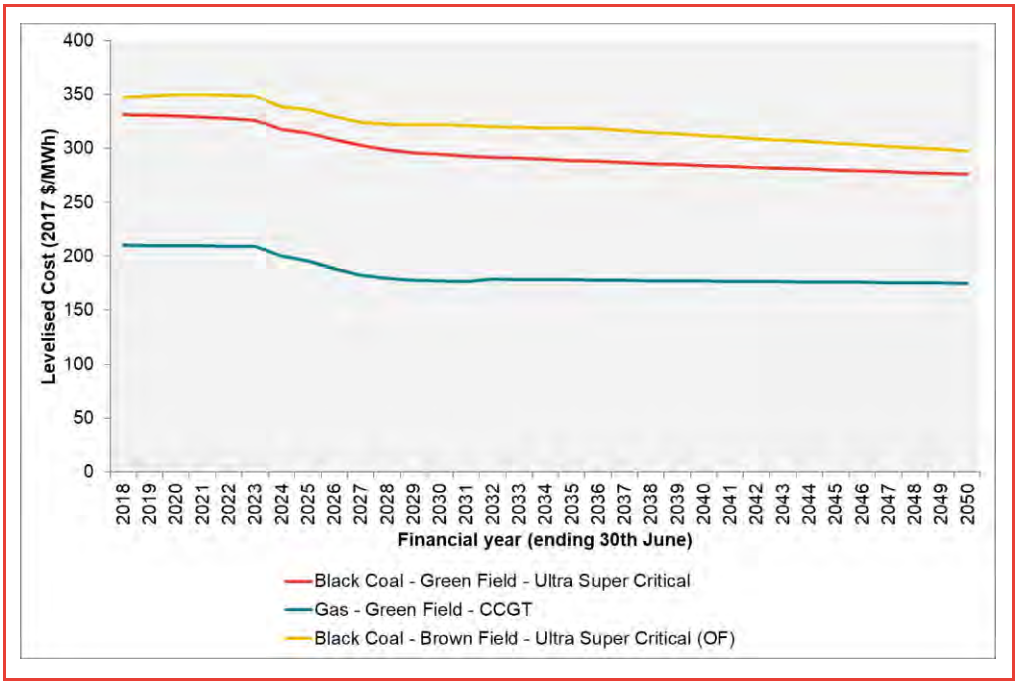
Source: Frontier Economics Analysis

Figure 32: Levelised cost components of gas and coal CCS entrants (80% capacity factor)



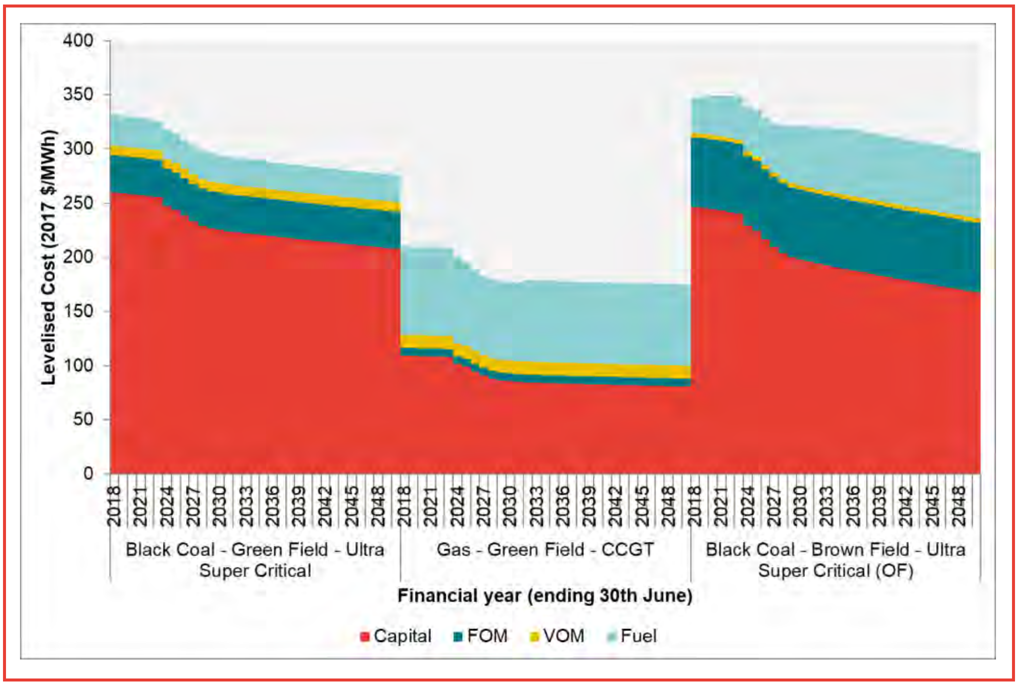
Source: Frontier Economics Analysis

Figure 33: Levelised cost of gas and coal CCS entrants (30% capacity factor)



Source: Frontier Economics Analysis

Figure 34: Levelised cost components of gas and coal CCS entrants (30% capacity factor)



Source: Frontier Economics Analysis

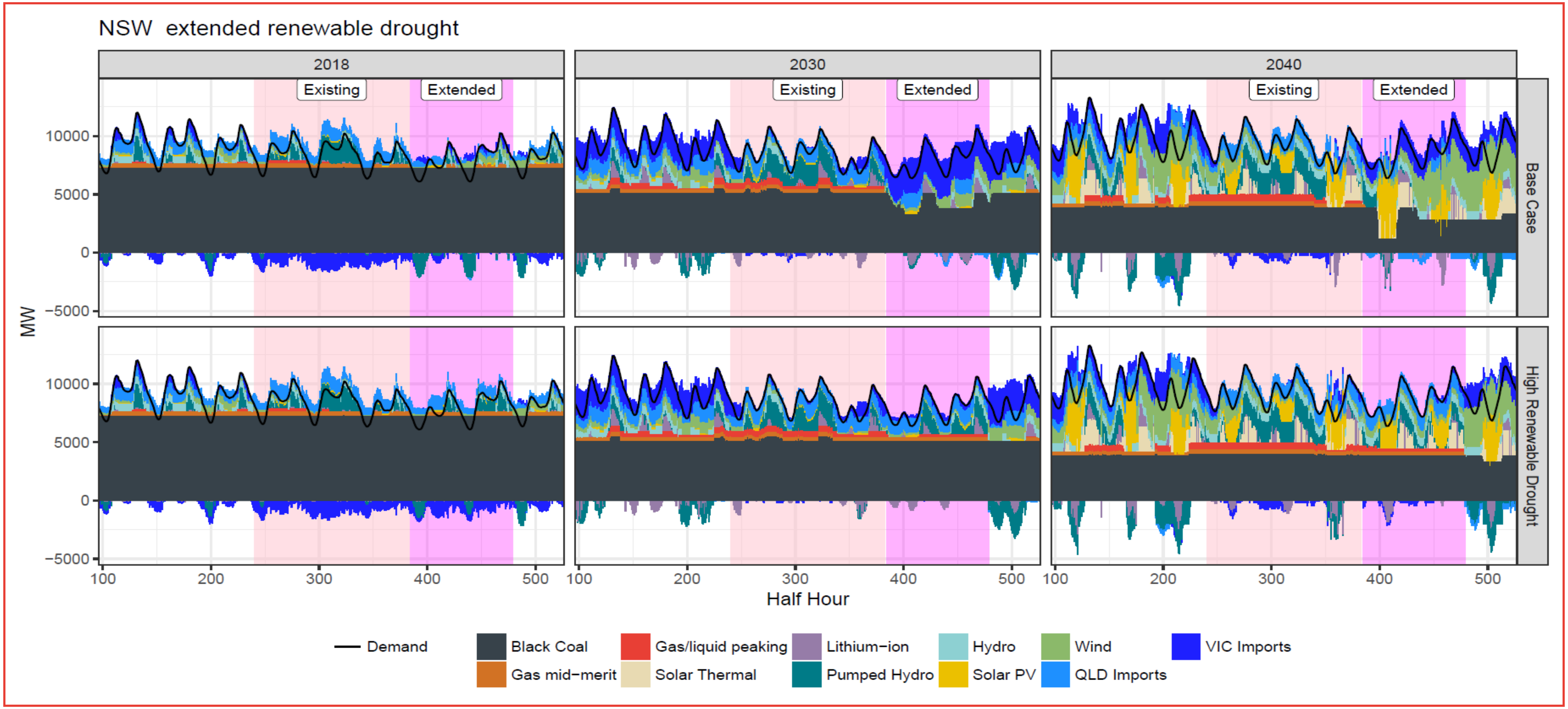
High Renewable Drought Scenario

Our examination of the Base Case in which we model a longer renewable drought – the High Renewable Drought Scenario – reveals that the mix of plant that is modelled in the Base Case is able to meet demand even in the event of the longer, 5-day wind and solar drought in NSW and Victoria that we have incorporated in this scenario. This is shown in the figures below, which compare outcomes over the drought period in the Base Case and the High Renewable Drought Scenario, for 2017/18, 2029/30 and 2039/40. What stands out from this figures is that even with the extended renewable drought the system is able to continue to meet demand with greater generation from coal and gas plant and use of storage and interconnection. The fact that renewable droughts tend not to be coincident across the entire east coast is an important factor in being able to rely on imports from neighbouring states during periods of renewable drought in NSW.

We do not present annual results for this High Renewable Drought Scenario, but since we are only changing intermittent generation in two days of the year, annual dispatch and prices will not be much different to the Base Case.

We present equivalent figures for other scenarios in Appendix A. We find in all cases that the system is able to continue to meet demand with greater generation from coal and gas plant and use of storage and interconnection.

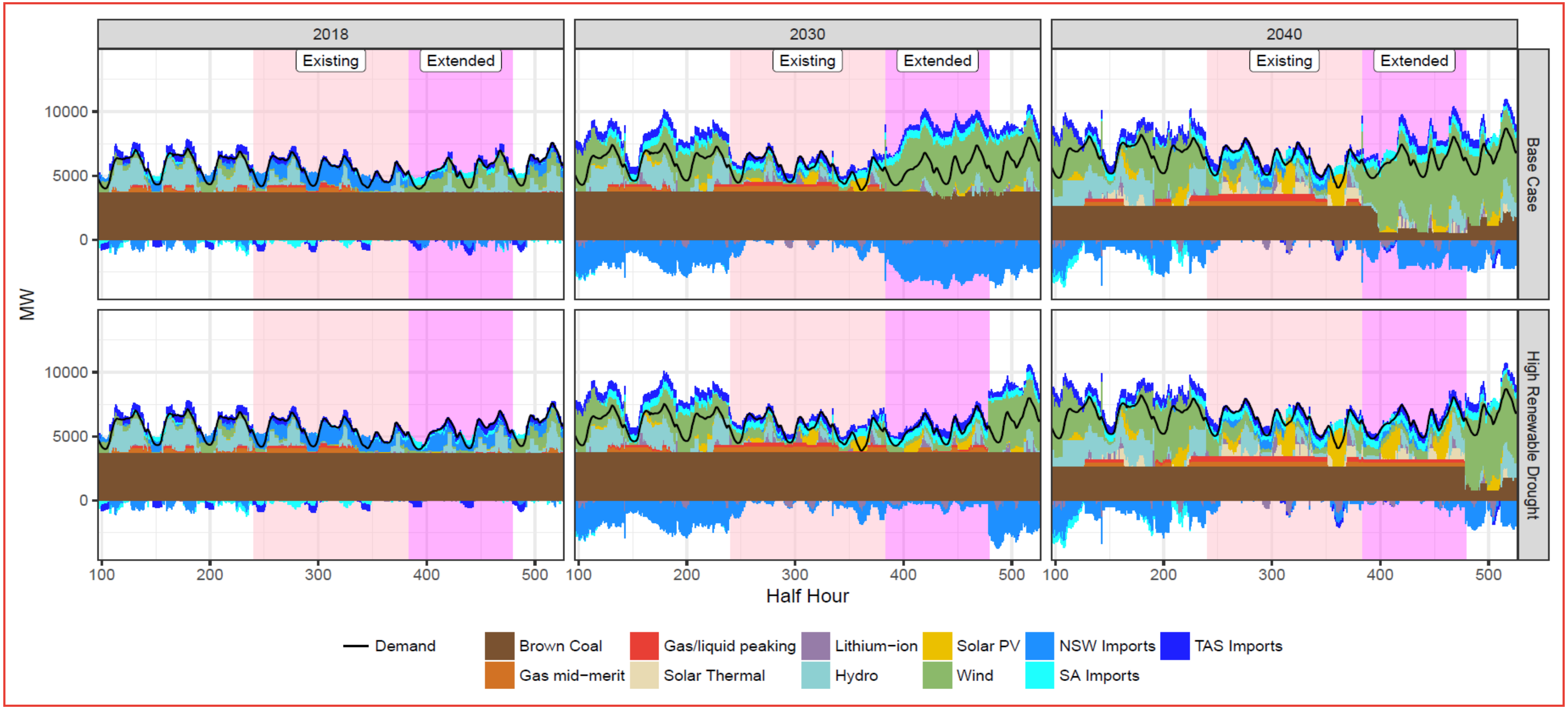
Figure 35: High Renewable Drought Scenario – NSW half-hourly dispatch for extended week of lowest renewable



Source: Frontier Economics

Note: the x-axis records the numbered sequence of half-hours that this week represents. This is a sequence from Sunday to Sunday very early in the financial year; that is, a week in early July.

Figure 36: High Renewable Drought Scenario – VIC half-hourly dispatch for extended week of lowest renewable



Source: Frontier Economics

Note: the x-axis records the numbered sequence of half-hours that this week represents. This is a sequence from Sunday to Sunday very early in the financial year; that is, a week in early July.

5 CGE modelling

CINSW seeks to understand the economic impacts on NSW of various energy futures. To do so, four of the energy market modelling scenarios have been modelled: a reference case (referred to as the Base Case) and three alternative (referred to as policy) cases.

The four scenarios are as follows.

- **Base Case.** The three policy simulations are compared against this control simulation. It is built using business-as-usual assumptions for the key drivers of economic growth (productivity and demographic changes), for federal and state-government policies, and for the electricity generation and supply sectors across the NEM.
- **High Demand Scenario.** For the High Demand Scenario, we use AEMO's strong demand scenario instead of their neutral demand scenario that we use in the Base Case.
- **Alternate Coal Price Scenario**. For the Alternative Coal Price Scenario, we use the latest new entrant coal price forecasts from AEMO's 2018 ISP. The Base Case used new entrant coal prices forecasts which were originally developed for AEMO's 2016 NTNDP, which were materially lower. We also give the model options of retrofitting existing coal plant at any point during their lifetime, upgrading them to High Efficiency Low Emissions (HELE) plant.
- **High Solar Thermal Cost Scenario**. For the High Solar Thermal Cost Scenario, we revert solar thermal capital costs from the ISP 2018 to those found in the 2016 Australian Power Generation Technology Report (APGTR). These capital costs are significantly higher for solar thermal plant than those found in ISP 2018 that were used in the Base Case.

The analysis relies on applications of the Victoria University Regional Model (**VURM**), which is the rebranded version of the Monash Multi-Regional Forecasting model (**MMRF**). The change of name reflects the Centre of Policy Studies' (**CoPS'**) move from Monash University to Victoria University in early 2014.

VURM is a dynamic economic model of Australia's six states and two territories. It models each region as an economy in its own right, e.g., the model contains region-specific prices, consumers, industries, etc. Technical documentation of the model equations and database can be downloaded from http://www.copsmodels.com/elecpapr/g-254.htm.

The rest of this section is organized as follows. A brief description of VURM is given in Section 5.1. For the simulations reported, we use information on the composition of electricity supply, electricity prices and costs from modelling undertaken by Frontier Economics. In Section 5.2, we describe the linking process, whereby Frontier's projections are incorporated into the VURM modelling. Section 5.3 deals with inputs and projections for the Base Case and Section 5.4 deals with the alternative scenarios.

5.1 Overview of the VURM Modelling framework

Based on the model's full database for 2015-16, in each region 79 industries produce 83 commodities.[20] Capital is industry- and region-specific. In each region, there is a single household and a regional government. There is also a Federal government. Finally, there are foreigners, whose behaviour is summarised by demand curves for international exports and supply curves for international imports.

The model includes a number of satellite modules providing more detail on government finance accounts, household income accounts, population, and energy and greenhouse gas emissions. Each of the 'satellite' modules are linked into other parts of the model, so that projections from the model core can feed through into relevant parts of a module and vice versa, changes in a module can feed back into the model core. The model also includes extensions to the core model theory dealing with links between demography and government consumption, the supply and interstate mobility of labour, and export supplies.

The model has a particular focus on greenhouse study and thus includes:

- a full set of energy and greenhouse-gas accounts that covers each emitting agent, fuel and region recognized in the model;
- quantity-specific carbon taxes or prices;
- equations for inter-fuel substitution in transport and stationary energy; and
- a representation of Australia's NEM.

Energy and emissions accounting

VURM includes accounting for all domestic emissions, except those arising from land clearing and land-use change. It does not include emissions from the combustion of Australian exports by the importing economy, but does include any fugitive or combustion emissions arising in Australia from the extraction or production of those exports.

VURM tracks emissions of greenhouse gases according to: emitting agent (79 industries and the household sector); emitting region (8 regions); and emitting activity (5 activities). Most of the emitting activities involve the burning of fuels

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[20] For the simulations reported in this paper, the full set of (79 industries, 83 commodities) has been aggregated to 70 industries uniquely producing 70 commodities.

(coal, natural gas and a single refined petroleum product). A residual category, named *Activity*, covers non-combustion emissions such as emissions from mines, as well as agricultural emissions not arising from burning of the fuel. *Activity* emissions are assumed proportional to the level of activity in the relevant industries (animal-related agriculture, coal, oil and gas mining, cement manufacture, etc.).

Carbon taxes and prices

VURM treats an emissions price/tax as a specific tax on emissions of greenhouse gases (**GHG**). On emissions from fuel combustion, the tax is imposed as a sales tax on the use of fuel. On *Activity* emissions, it is imposed as a tax on the production of the relevant industries.

Inter-fuel substitution

VURM allows for various forms of inter-fuel substitution in electricity and non-electricity sectors.

Electricity-generating industries are differentiated according to the type of fuel used. There is also an end-use supplier (*Electricity supply*) in each region and a single dummy industry (*NEM*) covering the six regions that form the NEM (New South Wales, Victoria, Queensland, South Australia, the Australian Capital Territory and Tasmania). Electricity flows to the local end-use supplier either directly in the case of Western Australia and the Northern Territory or *via* the *NEM* in the remaining regions. Further details of the operation of *NEM* are given below.

Purchasers of electricity from the generation industries (the NEM in the case of those regions in the NEM or the *Electricity supply* industry in each non-NEM region) can substitute between the different generation technologies in response to changes in generation prices, with the elasticity of substitution between the technologies typically set at around five.

For other energy-intensive commodities used by industries, VURM allows for a weak form of input substitution. If the price of cement (say) rises by 10 per cent relative to the average price of other inputs to construction, the construction industry will use 1 per cent less cement and a little more labour, capital and other materials. In most cases, as in the cement example, a substitution elasticity of 0.1 is imposed. For important energy goods (petroleum, electricity and gas), the substitution elasticity in industrial use is set at 0.25.

National Electricity Market

The NEM is a wholesale market covering nearly all of the supply of electricity to retailers and large end-users in NEM regions. VURM represents the NEM as follows.

Final demand for electricity in each NEM region is determined within the CGE-core of the model, in the same manner as demand for all other goods and services.

All end users of electricity in NEM regions purchase their supplies from their own-region *Electricity supply* industry. Each of the *Electricity supply* industries in the NEM regions sources its electricity from a dummy industry called *NEM*, which does not have a regional dimension. In effect, the *NEM* is a single industry that sells a single product (electricity) to the *Electricity supply* industry in each NEM region. *NEM* sources its electricity from generation industries in each NEM region. Its demand for electricity is price-sensitive. For example, if the price of hydro generation from Tasmania rises relative to the price of gas generation from New South Wales, then *NEM* demand will shift towards New South Wales gas generation and away from Tasmanian hydro generation.

The explicit modelling of the NEM enables substitution between generation types in different NEM regions. It also allows for interregional trade in electricity, without having to trace explicitly the bilateral flows. Note that Western Australia and the Northern Territory are not part of the NEM and electricity supply and generation in these regions is determined on a region-of-location basis.[21]

5.2 Incorporating Results from the Frontier model

VURM's modelling of electricity generation and supply, the NEM and electricity prices is quite sophisticated in a CGE context. Despite this, the model is inadequate as a tool for addressing the question at hand. Thus, VURM is linked to a more sophisticated bottom-up model of electricity supply, run and maintained by the Frontier Economics.[22]

There are a number of reasons to prefer linking to a detailed electricity model over the use of VURM's standard treatment of electricity.

- **Technological detail.** VURM recognizes six generation technologies. Frontier Economics' model recognizes many hundreds, some of which are not fully proved and/or are not in operation. For example, VURM recognizes one form of coal generation whereas the Frontier model recognizes many forms, e.g., cleaner gasification technologies and generation in combination with carbon capture and storage. Having all known technologies available for production now or in the future, allows for greater realism in simulating the technological changes available in electricity generation in response to

[21] Note that transmission costs are handled as margins associated with the delivery of electricity to *NEM* or to the *Electricity supply* industries of WA and the NT. Distribution costs in NEM-regions are handled as margins on the sale of electricity from *NEM* to the relevant *Electricity supply* industries.

[22] The idea that examining environmental issues could be tackled effectively by linking a CGE model with a detailed bottom-up energy model has a long history with Australian modelers. A short history and description of such efforts is given in Section 3 of: Philip D. Adams and Brian R. Parmenter, "Computable General Equilibrium Modelling of Environmental issues in Australia: Economic Impacts of an Emissions Trading Scheme" chapter 3 in P.B. Dixon and D. Jorgenson (eds*) Handbook of CGE Modelling*, Vol. 1A, 2013, Elsevier B.V.

emissions reduction policies. The Frontier Economics model also captures details of the interrelationships between generation types. A good example of this is the reliance by hydro-generation on base-load power in off-peak periods to pump water utilized during peak periods back to the reservoir.

- **Changes in investment and capacity.** VURM treats investment in generation like all other forms of investment. Capital supply is assumed to be a smooth increasing function of expected rates of return that are set equal to current rates of return. Changes in generation capacity, however, are generally lumpy, not smooth, and investment decisions are forward-looking, given long asset lives. Frontier Economics' model allows for lumpy investments and for realistic lead times between investment and capacity change. It also allows for forward-looking expectations, which aligns more with real-world experience than does VURM's standard (static) assumption.
- **Policy detail.** Currently, in Australia there are numerous policies at the state, territory and Commonwealth levels affecting electricity generation and supply. These include: market-based instruments to encourage increased use of renewable generation; regulations affecting the prices paid by final residential customers; and regional policies that offer subsidies to attract certain generator types. Some of these policies interact with each other. Interactions and policy details are handled well in the Frontier Economics model, but are generally outside the scope of stand-alone modelling in VURM.
- **Sector detail.** In VURM, electricity production is undertaken by symbolic industries – *Electricity-coal Victoria*, *Electricity-gas NSW* etc. In the Frontier Economics model, actual generation units are recognized, e.g., unit *x* in power station *y* located in region *z*. Thus, results from the detailed electricity model can be reported at a more granular level, and in a way that industry experts fully understand. This adds to credibility in result reporting.

Linking

In a more extensive study, the linking of the two models would proceed in an iterative way. However, for the current study, there is no iteration – results from Frontier Economics' system are fed directly into the VURM model as once-only shocks.

The electricity model is run (with appropriate constraints relating to greenhouse gas emissions if necessary) to provide annual projections by State for:

- sent-out generation (GWh) by generation type, aggregated to VURM's level of detail;
- fuel usage by generation type (Pj), aggregated appropriately;
- emissions by generation type (tonnes of GHG), aggregated appropriately;

- investment ($m) and capacity (GW) by generation type, aggregated appropriately;
- unit revenue by generation type ($ per GWh) aggregated appropriately;
- operating costs (fixed and variable) by generation type ($ per GWh) aggregated appropriately; and
- retail electricity prices by final customer category (Industrial, SME and Residential) ($ per GWh).

Items 1-7 are then input to VURM, enabled by changes to the exogenous/endogenous classification of variables[23] that in effect turn off VURM's treatment of electricity supply and investment in the NEM states and Western Australia. Details of the *closure* changes are available on request.

Changes in generation mix imposed on VURM are initially cost-neutral, and so have no effect on the average generation price. Frontier Economics' estimates of changes in unit revenue by generator type and region are introduced into VURM *via* changes in a miscellaneous *Other cost* category. *Other cost* is a non-produced factor of production with a return that accrues to the producer. If Frontier Economics' modelling indicates an increase in unit revenue that exceeds a weighted average of cost increases for material inputs, capital and labour, then in the VURM modelling the surplus accrues to *Other cost* (essentially, the surplus accrues as a "pure profit").

Frontier Economics' estimates of changes in retail prices for each customer type in each region are introduced into VURM *via* changes to *phantom taxes*. A phantom tax is a wedge between the price received by the producer and the price paid by the user. Unlike actual taxes imposed by governments, revenue from a phantom tax accrues to the producer of the product. There are three customer types – Industrial, SME and Residential.

5.3 Base Case

The Base Case is based on business-as-usual trends in demography, technology and Australia's trading conditions with the rest of the world. This is the reference-case simulation against which the other simulations are compared.

The Base Case includes the effects of current government policies. Inputs to the Base Case are explained below.

Inputs

The Base Case incorporates a large amount of information from specialist forecasting agencies and information on electricity supply from Frontier

23 An endogenous variable is a variable determined by the model. An exogenous variable is a variable determined by the user.

Economics' modelling. VURM traces out the implications of these inputs at a fine level of industrial and regional detail.

Information imposed in the Base case includes the following.

1. *Changes in population and labour force*. These numbers come from the 2017 issue of the Federal Treasury's Intergenerational Report (IGR).
2. *Changes in real GDP and underlying productivity*. For the years up to and including 2019, real GDP is an exogenous variable and set to growth rates consistent with 2017 Federal budget projections. To accommodate this information, we allow the rate of all-factor technological progress (also known as total factor productivity) to adjust endogenously.
3. From 2020 onwards, real GDP is endogenous and driven, in the main, by exogenous assumptions for growth in the labour force and growth in all-factor productivity. For all industries we assume all-factor technological progress at an annual rate of 1.5 per cent. Productivity growth at this rate is necessary to achieve real GDP growth within the historical trend range of 2.5 to 3.5 per cent.
4. *Changes in world trading conditions*. In VURM, the behaviour of the Rest of World (RoW) is modelled *via* changes in the positions of export demand and import supply schedules. The export demand schedules are downward sloping, while the import supply schedules are flat at world prices.
5. Foreign currency prices for imports other than oil are assumed unchanged through the projection period. We assume a foreign-price of imported oil based on data from the International Energy Agency (IEA)'s 2017 *World Energy Outlook*.
6. On the export side, foreign demand schedules for energy products (oil, coal and LNG) move to accommodate growth in world prices. These are consistent with the IEA's 2017 *World Energy Outlook* through to 2020. For the years after 2020, growth rates were moderated from 2020 levels to zero.
7. For non-energy commodities, export demand schedules shift to accommodate *initial* changes in the overall Terms of Trade (ToT) that are imposed exogenously. For the initial setting, it is assumed that the ToT returns to a historically normal level by 2020, and remains at that level thereafter.
8. *Regional GSP*. Up to and including 2019, growth rates are set to values based mainly on published state government forecasts. Growth rates for 2020 onwards are determined endogenously.
9. *National-level assumptions for changes in industry production technologies and household preferences*. Changes are imposed that mimic the effects of autonomous energy efficiency improvements. Specifically, we assume that all industries reduce their use of electricity and gas per unit of output at the rate of 0.5

per cent per annum, and that the share of energy products in the budget of the representative household falls by 0.5 per cent per annum.

10. *Forecasts for land-use change and for forestry sequestration.* Estimates taken from modelling undertaken by CoPS for a ClimateWorks study: *Pathways to Deep Decarbonisation in 2050: How Australia can prosper in a low carbon world.* http://climateworks.com.au/sites/default/files/documents/publications/climateworks_pdd2050_technicalreport_20140923.pdf .

11. *Capital constraints and expansions in certain mining and manufacturing industries.* A number of assumptions were made about future capacity changes in certain manufacturing industries based on information supplied by industry experts. Specifically, we assume no new net investment for industries producing aluminium, iron and steel, and refined petroleum products. Plant closures are modelled for the motor vehicles and parts industry in Victoria and South Australia continuing into 2017, and large capacity increases are assumed for LNG produced in Queensland in 2017.

12. *Initial changes in generation supply, prices, etc., from Frontier's model.* As explained in Section XX, the VURM modelling incorporates information from Frontier Economics' model from 2018 onwards.

13. *Greenhouse Gas emission targets.* We impose state-based targets for New South Wales, Victoria and Queensland, and a nation target for the Australia as a whole. For New South Wales we assume zero net emissions by 2050 in line with the *aspirational objective* announced at the end of 2016. Australia has committed under the Paris Accord to reduce emissions to 26-28 per cent on 2005 levels by 2030. In our modelling, we assume that this commitment is met and that by 2050 net emissions Australia-wide have been reduced to zero.

Key Base Case projections

Figure 3 to Figure 39 show three key projections from the Base Case. Growth in Australia's real GDP compared to growth in NSW's real GSP is given in Figure 3. Figure 38 shows similar information for employment. Trajectories for greenhouse gas emissions from electricity and other sources in NSW are given in Figure 39.

While generation investments in NSW are significant – particularly in the 2030s and 2040s – these investments are relatively minor in the context of NSW GSP. Total generation investments over the 2030s and 2040s amount to the low tens of billions in total, while *annual* GSP is in the hundreds of billions. Similarly, total employment from increased generation plant in NSW during the 2030s and 2040s is a small component of the total NSW economy.

Figure 37: Base Case Growth rates for Australia real GDP and NSW real GSP

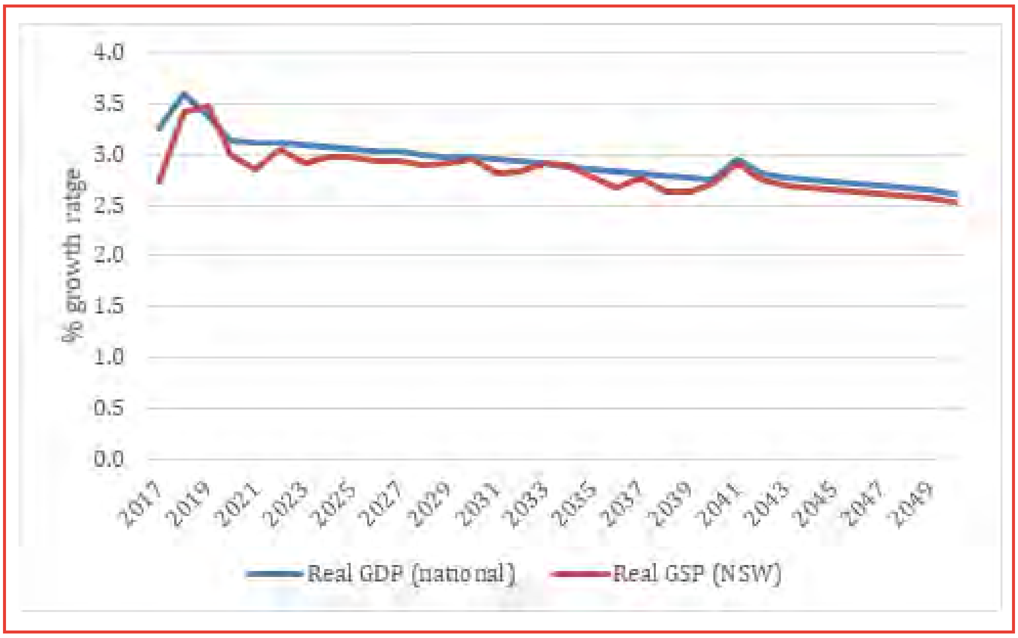
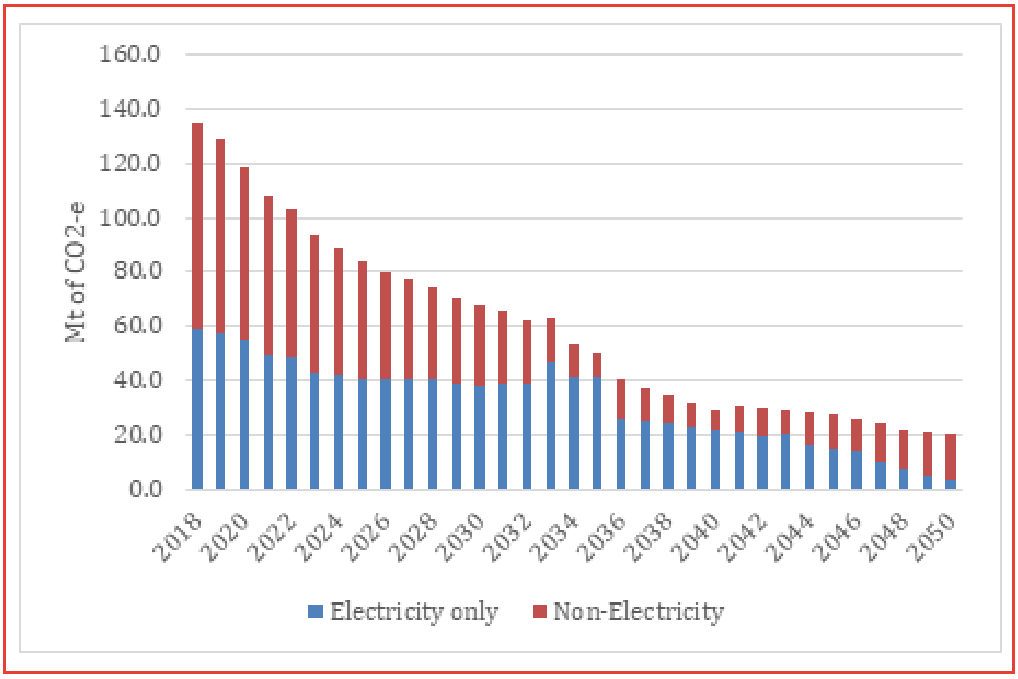


Figure 38: Base Case Growth rates for Australia and NSW employment

Figure 39: Base Case Greenhouse Gas Emissions in NSW



As shown in Figure 3, in the Base Case we assume economic growth in NSW at a rate similar to that for Australia as a whole. Growth in NSW's employment, however, is forecast to be a little below the national average (see Figure 38), reflecting current long-term demographic trends. Finally, as shown in Figure 39, electricity emissions in NSW fall to nearly zero by 2050, but there remains a non-negligible amount of emissions from non-electricity sources (around 18 Mt of CO2-e). In our current modelling, we do not account for major biodiverse reforestation projects that will be necessary if Australia and its regions are to achieve zero *net* emissions by 2050.

5.4 Policy simulations

The policy scenarios deviate from the Base Case due to the different assumptions for energy demand and for costs of coal and solar. Results are reported as deviations between the values of variables in the policy simulations and their values in the Base Case.

In Section XX, we explain the main macroeconomic mechanisms that operate in deviating from the Base Case. Results are given in Section XX (High Demand Scenario), Section XX (Alternate Coal Price Scenario) and Section XX (High Solar Thermal Cost Scenario).

5.4.1 Simulation design

Inputs from Frontier Economics' modelling are discussed first, followed by a description of key assumptions affecting the macroeconomic response to the Frontier Economics inputs.

Deviations in key electricity supply variables

As indicated in Section 3, Frontier Economics' modelling provides inputs that cover a broad range of variables for the supply side of the NEM. Key variables are generation (or dispatch) by technology type, and retail and wholesale electricity prices. Deviations from Base Case for generation by technology type in NSW are shown in Figure 40 (High Demand Scenario), Figure 41 (Alternate Coal Price Scenario) and Figure 42 (High Solar Thermal Cost Scenario).

In the High Demand Scenario (Figure 40), increased electricity demand in NSW is initially met through increased coal generation. After 2034, the increased demand is satisfied by a mix of low-emission gas and non-hydro renewable generation, with coal generation returning to its Base Case level.

For the Alternate Coal Price Scenario (Figure 41), negligible changes occur in NSW generation through to 2032. Then, between 2033 and 2035, there are reductions (relative to Base Case levels) in coal generation and corresponding increases in generation primarily from other renewable sources. Thereafter, coal generation remains below its Base Case level and other renewable generation remains above, but the size of the deviations is much less than between 2033 and 2035.

Finally, for High Solar Thermal Cost Scenario (Figure 42), again we see little impact out to 2034. Then, in 2034 and through to 2044 we see an increase in NSW generation, particularly from other renewable sources, with some of the additional generation dispatched interstate. From 2045 onwards, there is a progressive *fanning out* of changes with gas generation replacing the now more expensive sources of other renewable generation.

Figure 40: Generation by Technology type in NSW (changes in GWh from Base Case for High Demand Scenario)

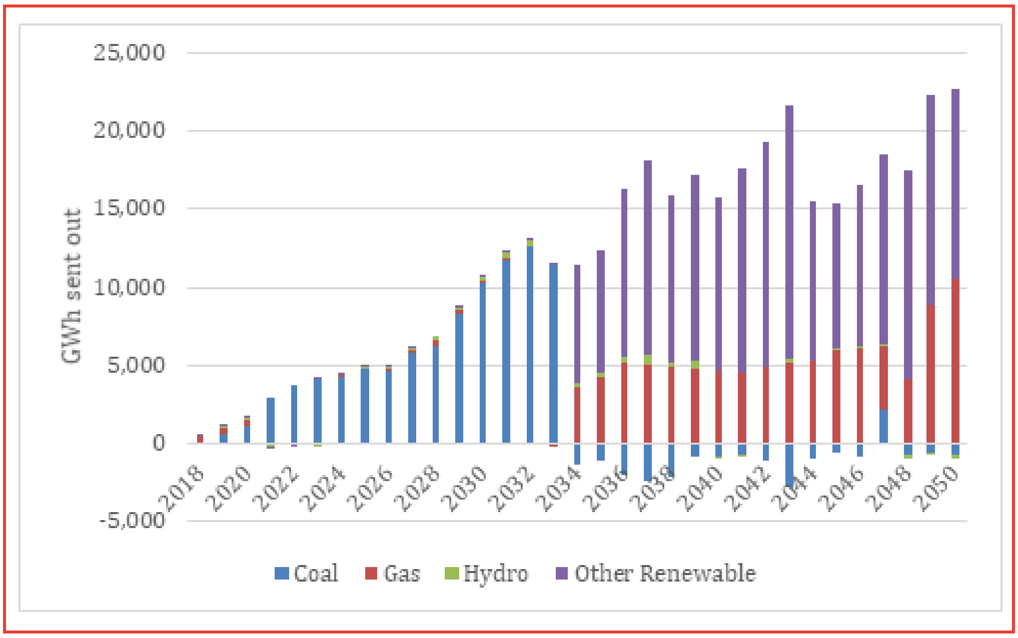


Figure 41: Generation by Technology type in NSW (changes in GWh from Base Case for Alternate Coal Price Scenario)

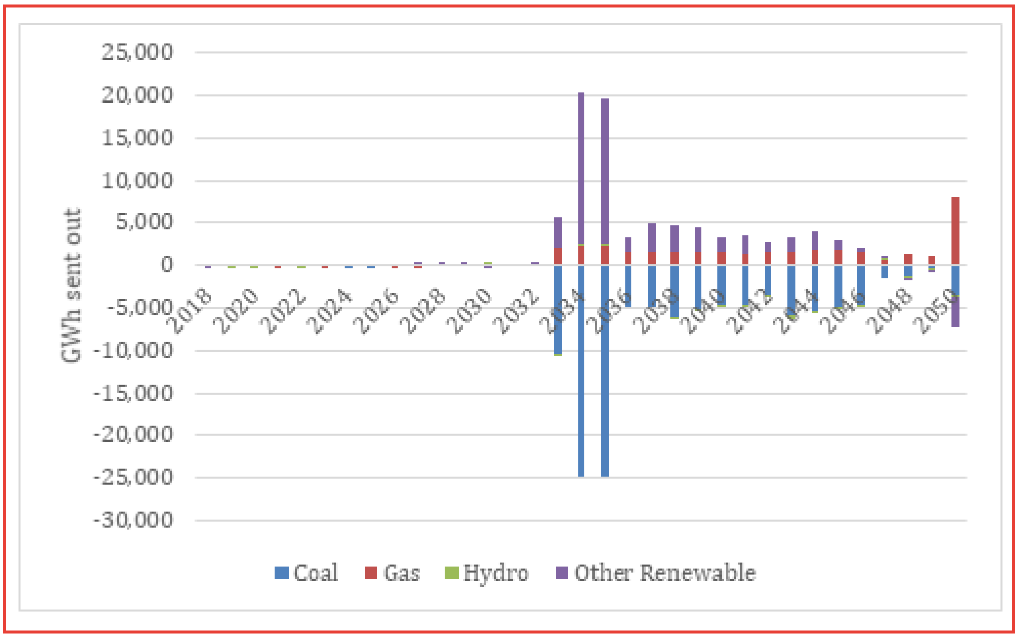


Figure 42: Generation by Technology type in NSW (changes in GWh from Base Case for High Solar Thermal Cost Scenario)

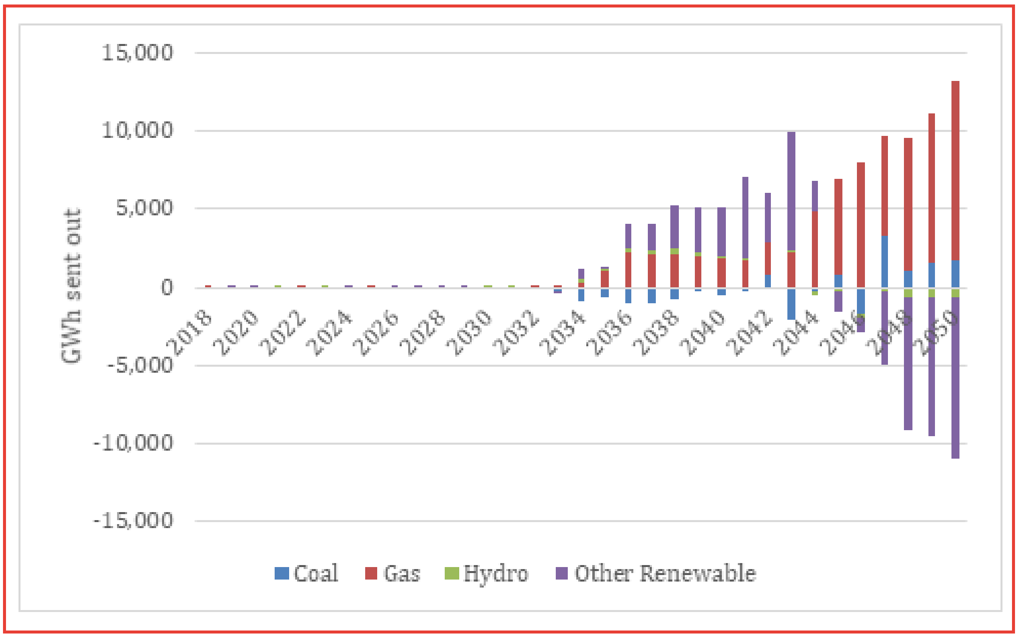


Figure 43 through Figure 45 show percentage deviations from Base Case levels in NSW's wholesale and average retail electricity prices through the projection period.

In the High Demand Scenario (Figure 43), electricity prices rise and fall relative to Base Case levels through to around 2034. For example, in 2020 the wholesale price is 22 per cent above its Base Case level, while in 2021 it is 14 per cent below. Between 2034 and 2045 prices progressively rise. In 2045 the wholesale price has increased by 66 per cent, while the average retail price is up 18 per cent. After 2045, prices rapidly fall back to their Base Case levels.

Figure 44 shows deviations in prices for the Alternate Coal Price Scenario. The revisions to fuel prices only affect electricity prices after 2032. In 2033, 2034 and 2035 electricity prices in NSW jump above their Base Case levels. In 2034 and 2035, the wholesale price rises by 26 per cent and the average retail price is up 11 per cent. After 2035 through to almost the end of the simulation period, wholesale and retail prices fall back to levels that are between 10 per cent and -10 per cent of their Base Case values. In the final two years, prices fall away. In 2050, the wholesale price is down 24 per cent (relative to the Base Case), while the average retail price is down 12 per cent.

Electricity price deviations for the High Solar Thermal Cost Scenario are given in Figure 45. Similar to the Alternate Coal Price Scenario, the changed assumptions have little impact for the first 15 or so years. Then, wholesale and retail prices steadily rise relative to their Base Case levels. The peak year is 2043, with the wholesale price projected to be 42 per cent higher than in the Base Case, and the average retail price up 18 per cent. After 2043, the price increases moderate, but in an uneven way with jumps occurring in 2046 and 2048.

Figure 43: Average Price of Electricity in NSW (% deviations from Base Case for High Demand Scenario)

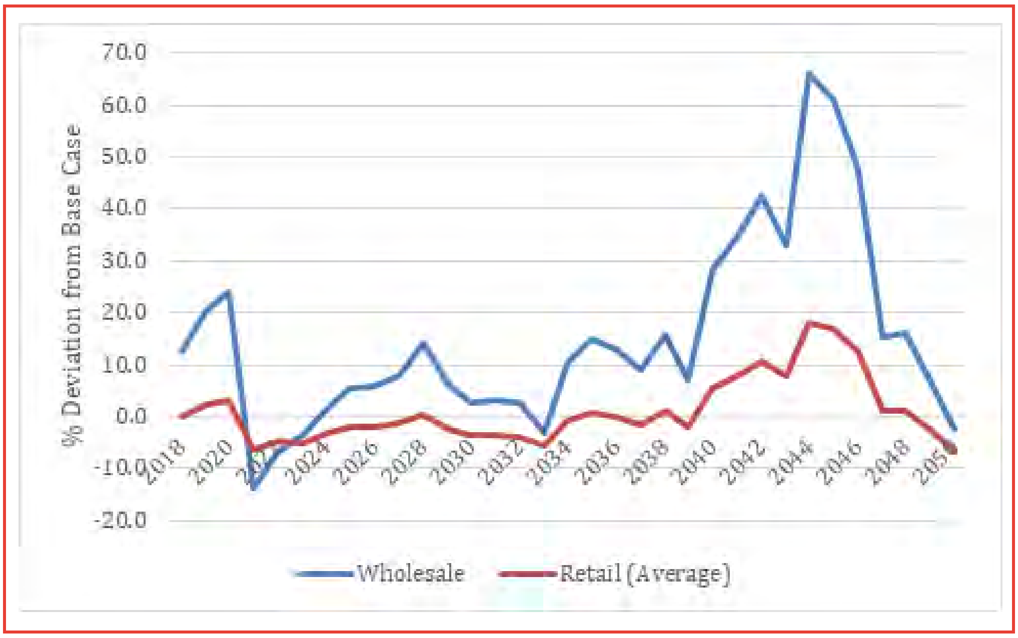


Figure 44: Average Price of Electricity in NSW (% deviations from Base Case for Alternate Coal Price Scenario)

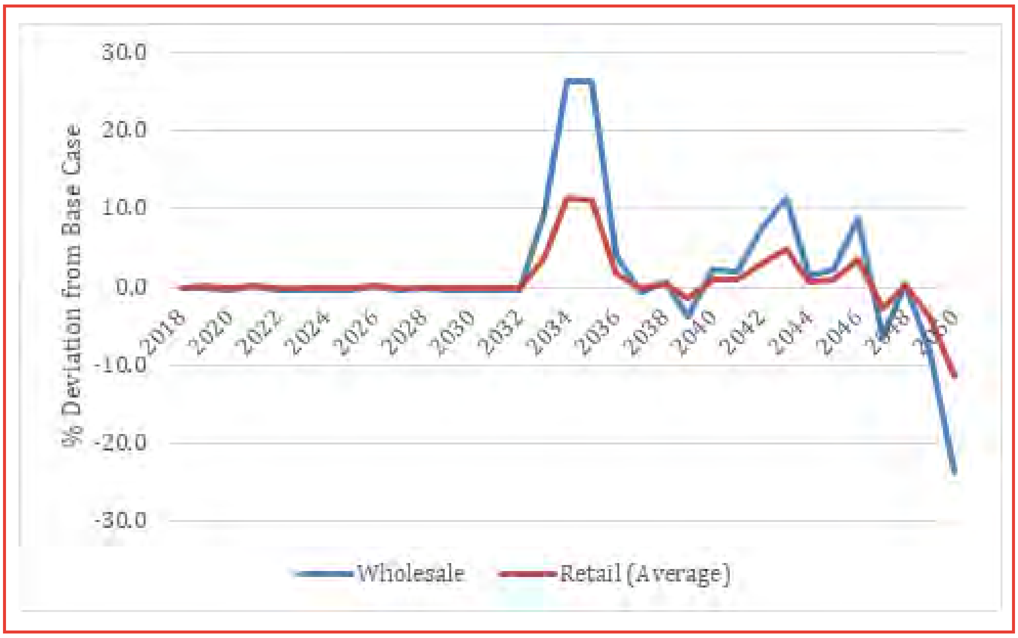
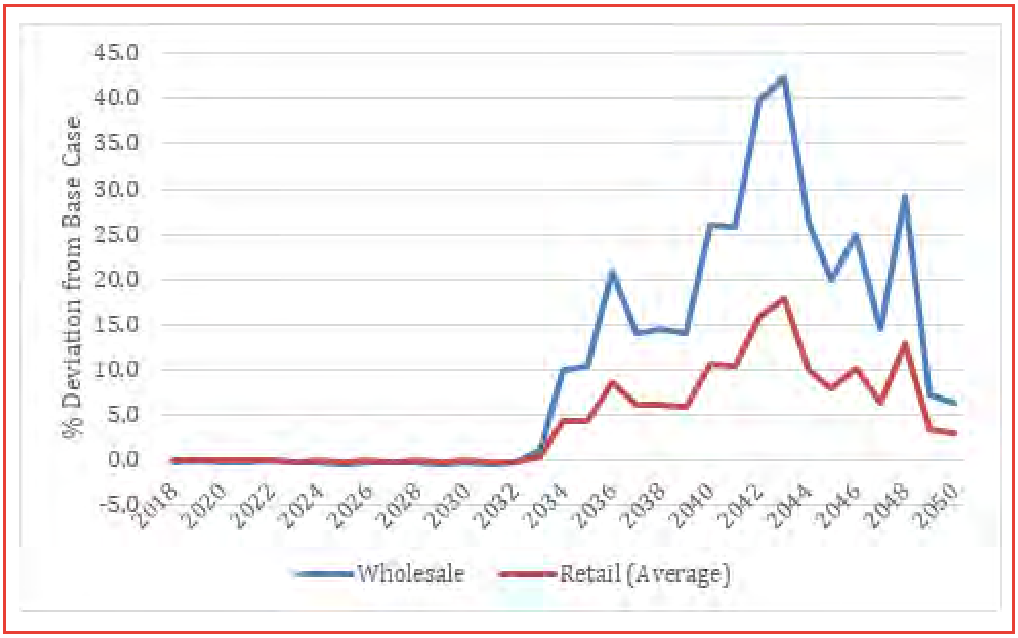


Figure 45: Average Price of Electricity in NSW (% deviations from Base Case for High Solar Thermal Cost Scenario)



Assumptions for the Macro-economy

The following assumptions are made for key aspects of the macro economy in the three policy simulations.

Labour markets

In the Base Case, the national real wage rate is endogenous and moves to reconcile growth in employment demand with exogenously imposed growth in labour supply.

In a policy simulation, the real *after-tax* wage rate is assumed sticky in the short-run and flexible in the long-run. Thus, relative to the Base Case, favourable actions generate short-run gains in aggregate employment, and long-run gains in the national real wage rate. This labour market assumption is consistent with conventional macro-economic modelling, in which the national unemployment rate and the size of the labour force (the unemployment-rate denominator) are either fixed or partly dependent on the real *after-tax* wage level.

At the regional level, labour is assumed mobile between state economies. Labour is assumed to move between regions to maintain inter-state unemployment-rate differentials at their reference-case levels. Accordingly, regions that are favorably affected by a change in the economy will experience increases in their labour forces as well as in employment, at the expense of regions that are less favorably affected.

Private consumption and investment

In the policy simulation, private consumption expenditure is determined *via* a relationship that links nominal consumption to nominal household disposable income (**HDI**). The major part of HDI is Gross National Income (**GNI**), with an allowance for payments of personal income tax.

In the policy simulation, the coefficient of proportionality (called the average propensity to consume (**APC**)) is an endogenous variable that moves to ensure that the balance on current account in the balance of payments remains at its reference-case level. Thus, domestic saving adjusts to accommodate any change in investment brought about by the policy, leaving Australia's call on foreign savings unchanged.

Investment in the electricity sector is determined based on inputs from the Frontier Economics model. Investment in most other industries is allowed to deviate from its Base Case value in line with deviations in expected rates of return. In the policy scenarios, VURM allows for short-run divergences in rates of return from their Base Case levels. These cause divergences in investment and hence capital stocks that gradually erode the initial divergences in rates of return. Provided there are no further shocks, rates of return revert to their reference-case levels in the end. The exceptions to this rule are the industries with capacity constraints in the Base Case – oil mining, iron and steel and aluminium.

Government consumption and fiscal balances

VURM contains no theory to explain changes in real public consumption. In the policy simulations, real public consumption is fixed at its Base Case level.

The fiscal balances of each jurisdiction (federal, state and territory) as a share of nominal GDP are fixed at their values in the Base Case. Endogenous movements in lump-sum payments to households accommodate these budget-balance constraints.

Production technologies and household tastes

VURM contains many variables to allow for shifts in technology and household preferences. In the policy scenarios, most of these variables are exogenous and have the same values as in the reference-case projection. The exceptions are technology variables that are made endogenous to allow for changes in the fuel intensity of electricity generation, based on data from the electricity supply modeling.

5.4.2 High Demand Scenario

Results are presented as deviations away from Base Case values:

- NSW real Gross State Product (GSP) (Figure 46), NSW employment (Figure 47) and NSW Greenhouse Gas emissions (Figure 48); and

- NSW industry real value added (a measure of industry production) (Table 8).[24]

Results for other macroeconomic and microeconomic variables are available on request.

For the High Demand Scenario, we impose on the model changes away from Base Case in total electricity demand in each of the NEM regions in line with inputs provided by the Frontier Economics modelling. These changes were implemented by forcing all electricity users (industries and household) to use more electricity per unit of activity in each year. For example, if in some year demand were to increase by 1 per cent relative to Base Case levels, then in that year every user of electricity would use 1 per cent more electricity.

Requiring more use of electricity per unit of activity imposes a cost on industries and on the residential sector that has a significant macroeconomic effect. This would dominate anything that might occur through changes in the electricity supply system, which is the focus of this work. Therefore, in forcing users to buy more electricity we also allow reductions in inputs of other items to the point where the *ex-ante* unit cost of production for industries and the *ex-ante* unit cost of consumption for households are unchanged. In effect, to model higher electricity demand we impose cost neutral switches in industry production and household consumption towards electricity and away from other inputs.

Figure 46 shows deviations away from Base Case values for real GSP in NSW due to increased electricity demand. The deviations are expressed in terms of percentages (line) and as absolute changes in $m (column).

The key message from Figure 46 is that the real GSP effects of increased demand achieved through cost-neutral switches in spending are small. Nearly all of the increased real GSP is created by switching towards electricity which has a relatively high local content and away from non-electricity inputs that have, on average, a lower local content. By 2050, relative to Base Case levels, real GSP has increased by 0.15 per cent, which is equivalent to $945 million in constant 2018 prices.

Employment also rises in line with the increase in real economic activity generally (Figure 47). Relative to Base Case values, in 2050 employment is up 0.07 per cent, which is equivalent to around 2,300 new jobs (full and part-time) in that year.

The final chart of results the High Demand Scenario is Figure 48, which shows trajectories for greenhouse gas emissions in NSW. Comparing these with the Base Case paths shown in Figure 39 reveal very little change. This is because in both the

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[24] In reporting results for industry production, we show results for two representative years – 2035 and 2050. Also,, we aggregate results for the 70 industries identified in the model to results for 21 broad industry groups. These correspond to the 17 industry sectors identified in the Australian National Accounts, with the electricity sector broken into five parts corresponding to the four sources of generation and the one source of overall supply.

High Demand Scenario and the Base Case we impose the same overall reduction in total NSW emissions.

Figure 46: Real GSP for NSW, High Demand Scenario (deviations from Base Case)

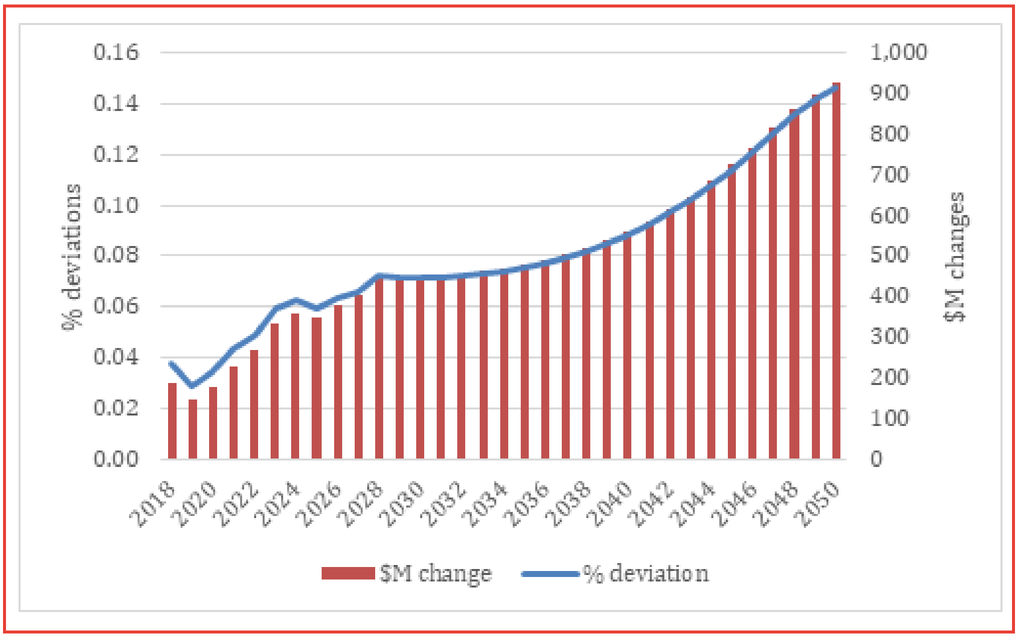


Figure 47: NSW Employment, High Demand Scenario (deviations from Base Case)

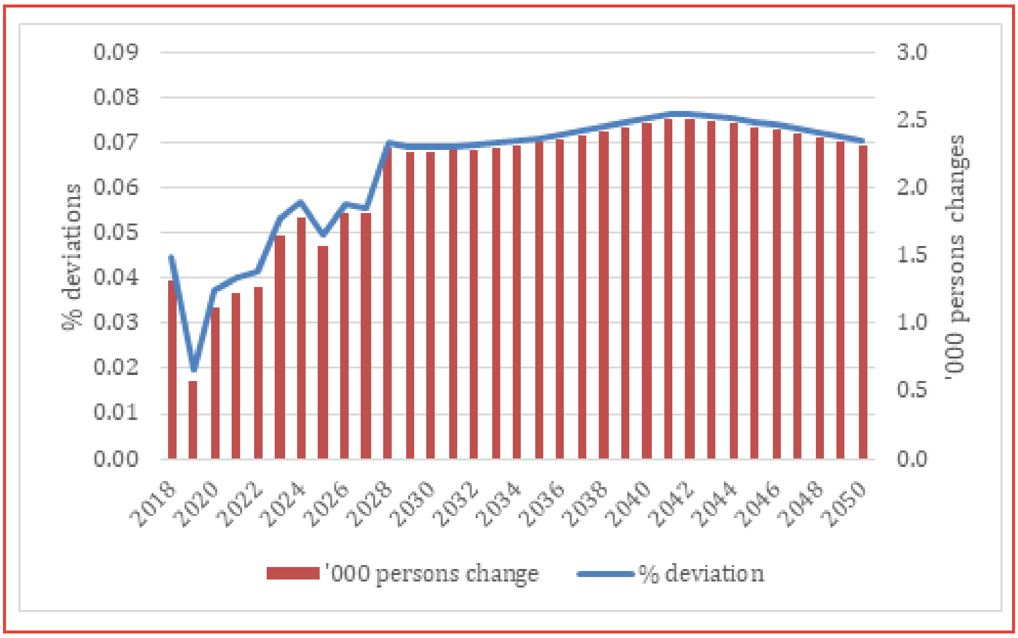


Figure 48: Greenhouse Gas Emissions in NSW, High Demand Scenario (relative to Base Case)

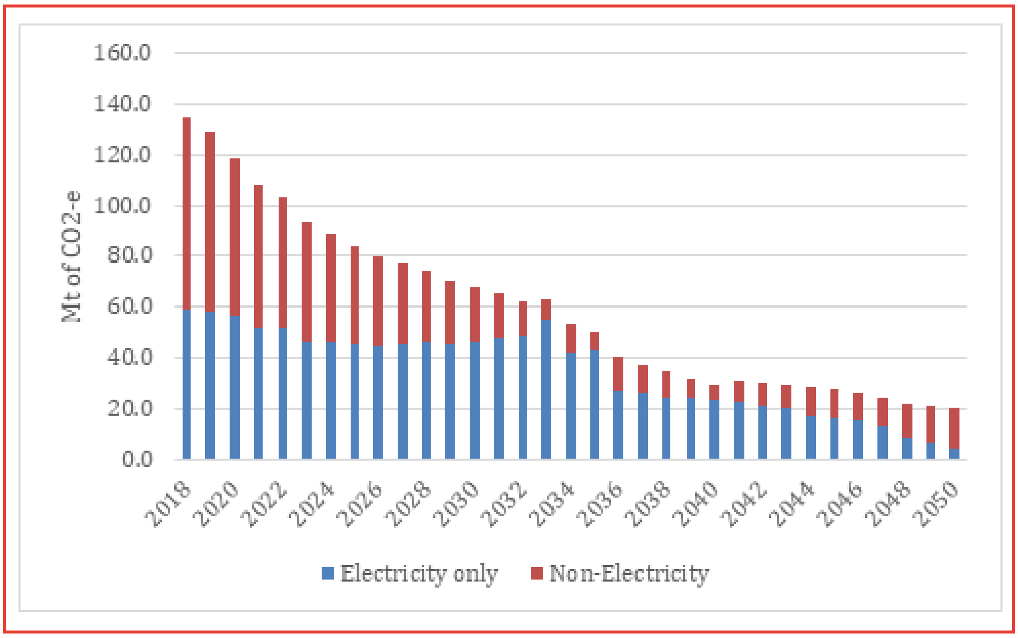


Table 8 shows projections of real value added (or output) in 2035 (a representative mid-point) and 2050 for broad industry groups and the electricity generation and supply industries. The clear message here is that in terms of deviations away from Base Case values, the High Demand Scenario has relatively little effect on the industrial structure of the economy outside of the electricity sector. The key non-service sectors experience minor reductions in output largely due to the switch in demand away from their productions and towards electricity. The service sectors (5-17) generally are projected to experience small increases in output, reflecting the general increase in size of the economy (see Figure 46).

The changes in production for the electricity generation and supply industries (4a – 4f) are imposed using inputs from the Frontier Economics modelling.

Table 8: NSW Real Value Added by Broad Industry Group: High Demand Scenario (percentage deviations in 2035 and 2050)

Industry	2035 % deviation	2050 % deviation
1. Agriculture, forestry and fishing	-0.09	-0.06
2. Mining	0.22	-0.13
3. Manufacturing	-0.02	-0.09
4a. Electricity generation – coal	-2.49	-20.75
4b. Electricity generation – gas	233.71	98.67
4c. Electricity generation – hydro	4.70	-3.76
4d. Electricity generation – other	91.32	18.80
4f. Electricity supply	31.98	58.78
5. Construction	1.30	0.61
6. Wholesale trade	0.31	0.19
7. Retail trade	0.13	0.01
8. Accommodation and food services	0.13	0.02
9. Transport, postal and warehousing	0.15	0.21
10. Information, media and telecommunications	0.00	0.00
11. Financial and insurance services	0.18	0.13
12. Business services	0.12	-0.05
13. Public administration and safety	0.01	-0.02
14. Education and training.	0.00	0.00
15. Health care and social assistance	0.06	0.02
16. Other services (including other utility services)	0.15	0.03
17. Dwelling services	0.20	0.02

5.4.3 Alternate Coal Price Scenario

Results are presented as deviations away from Base Case values:

- NSW real Gross State Product (GSP) (Figure 49), NSW employment (Figure 50) and NSW Greenhouse Gas emissions (Figure 51); and
- NSW industry real value added (a measure of industry production) (Table 4).

Results for other macroeconomic and microeconomic variables are available on request.

The key driver in this scenario are the deviations from Base Case values in the wholesale and retail prices of electricity in NSW, as shown in Figure 44. Relative to Base Case, if the retail price of electricity rises relative to elsewhere, then there is pressure for businesses to move activity out of the state to avoid increased energy costs. Conversely, if the retail price falls relative to elsewhere, then there is pressure for activity to move into the state.

In general, the coal fuel price update increases electricity prices in NSW relative to the average NEM price in years 2033, 2034 and 2035, and lowers the relative price of electricity in the final few years of the projection. This is reflected in the deviations from Base Case for real GSP and employment in NSW shown in Figure 49 and Figure 50.

Essentially, there is little to no impact on economic activity outside of these two periods. In the first period, real GSP and employment dip. At their low point in 2034, relative to Base Case levels, real GSP is down 0.06 per cent (or almost $500 million), and employment is down 0.08 per cent (equivalent to a loss of around 3,000 full and part-time jobs). At their high point in 2049, relative to Base Case, real GSP is up 0.06 per cent ($770 million) and employment is up 0.05 per cent (2,300 jobs)

Greenhouse gas emissions, shown in Figure 51 hardly change from their Base Case paths given in Figure 39.

In terms of changes to the industrial structure of the NSW economy (Table 4), outside of the electricity sector, where the changes are imposed using inputs from the Frontier Economics modelling), there is little change in line with the deviations in real GSP.

Figure 49: Real GSP for NSW, Alternate Coal Price Scenario (deviations from Base Case)

Figure 50: NSW Employment, Alternate Coal Price Scenario (deviations from Base Case)

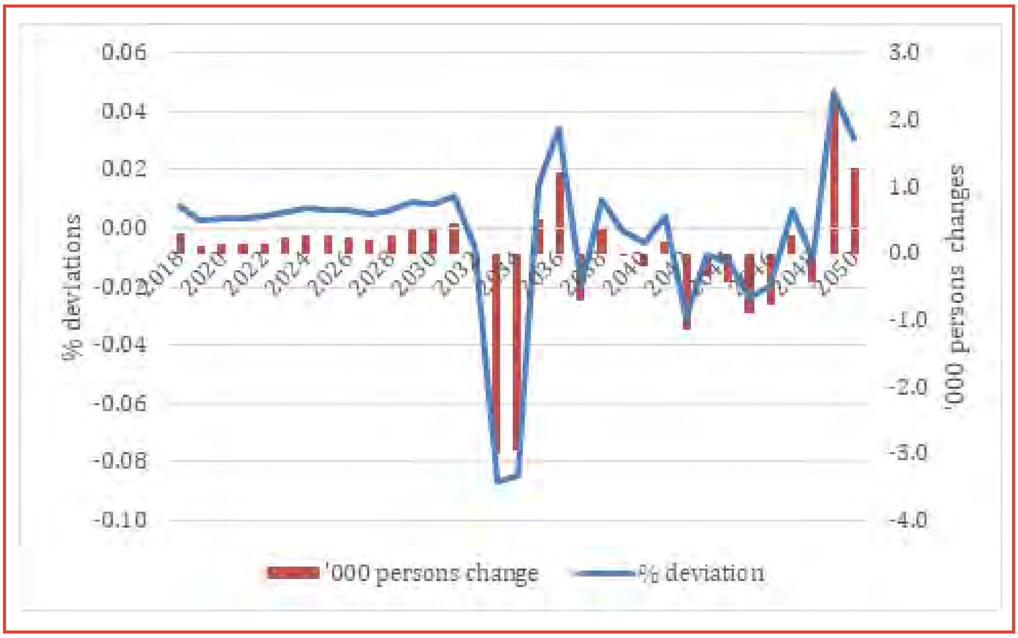


Figure 51: Greenhouse Gas Emissions in NSW, Alternate Coal Price Scenario (relative to Base Case)

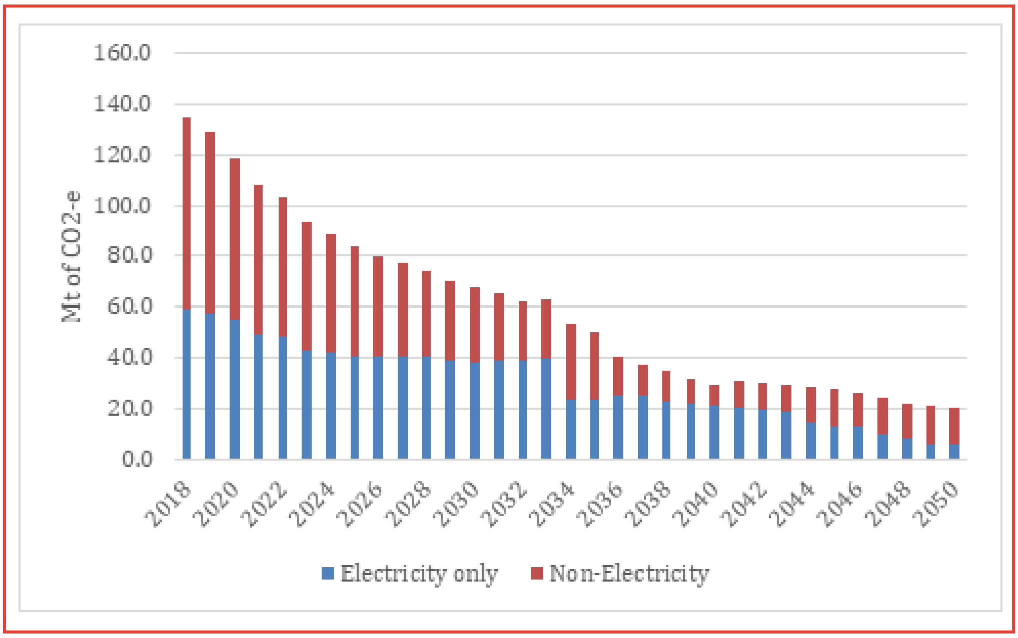


Table 9: NSW Real Value Added by Broad Industry Group: Alternate Coal Price Scenario (percentage deviations in 2035 and 2050)

Industry	2035 % deviation	2050 % deviation
1. Agriculture, forestry and fishing	-0.12	-0.05
2. Mining	-0.30	-0.33
3. Manufacturing	-0.37	-0.02
4a. Electricity generation – coal	-51.20	-62.56
4b. Electricity generation – gas	129.46	76.28
4c. Electricity generation – hydro	2.86	-2.71
4d. Electricity generation – other	199.03	-5.68
4f. Electricity supply	32.14	56.91
5. Construction	0.96	0.80
6. Wholesale trade	0.14	0.26
7. Retail trade	-0.07	0.08
8. Accommodation and food services	-0.11	0.09
9. Transport, postal and warehousing	-0.10	0.18
10. Information, media and telecommunications	0.00	0.00
11. Financial and insurance services	-0.03	0.07
12. Business services	-0.05	0.07
13. Public administration and safety	-0.02	-0.01
14. Education and training.	0.00	0.00
15. Health care and social assistance	0.00	0.04
16. Other services (including other utility services)	-0.02	0.08
17. Dwelling services	0.05	0.09

5.4.4 High Solar Cost

Results are presented as deviations away from Base Case values:

- NSW real Gross State Product (GSP) (Figure 52), NSW employment (Figure 53) and NSW Greenhouse Gas emissions (Figure 54); and
- NSW industry real value added (Table 10)

Results for other macroeconomic and microeconomic variables are available on request.

The key driver of change in this scenario is different from those in in the first two policy simulations. Here, changes from Base Case values are driven by economy-wide effects flowing through to states and territories. In the Base Case, from 2030 solar generation becomes the main source of non-hydro renewable generation in all of the NEM states. Thus increasing the cost of delivering electricity *via* this technology effectively imposes a significant technological deterioration on all of the economies. Technological deterioration directly reduces national and state GDP/GSP and employment.

Figure 52 and Figure 53 show the dampening effects of increased solar costs on GSP and employment in NSW. After the higher costs begin in 2034, relative to Base Case levels there are falls in real GSP and employment in NSW that persist through the projection period. However, these falls are small. They are largest in 2043 when real GDP has fallen (relative to Base) by 0.04 per cent (or $359 million) and employment has fallen by 0.02 per cent (or 700 full and part-time jobs).

Figure 52: Real GSP for NSW, High Solar Thermal Cost Scenario (deviations from Base Case)

Figure 53: NSW Employment, High Solar Thermal Cost Scenario (deviations from Base Case)

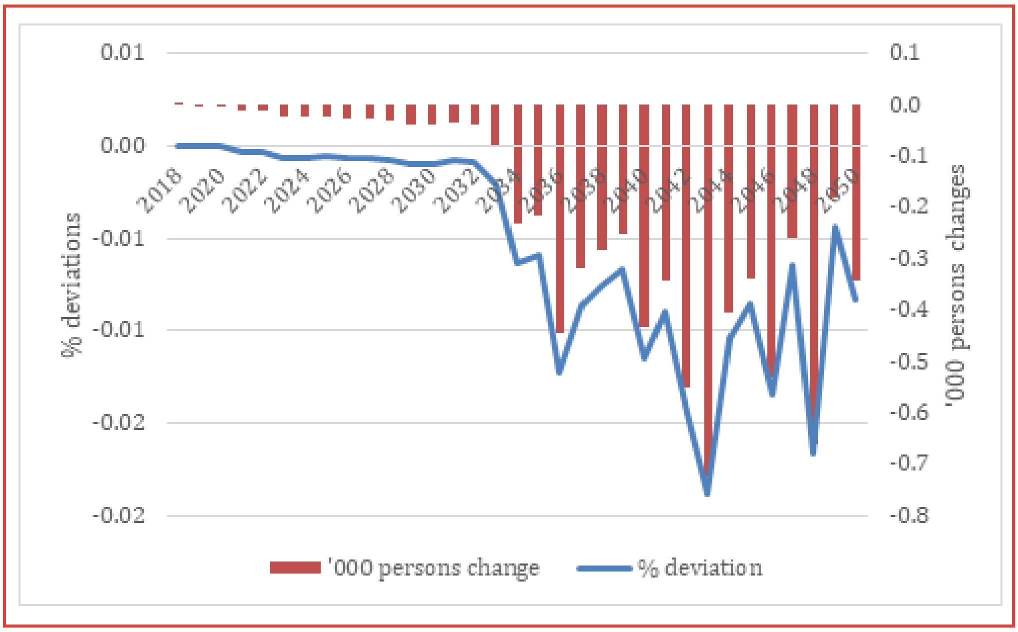


Figure 54: Greenhouse Gas Emissions in NSW, High Solar Thermal Cost Scenario (relative to Base Case)

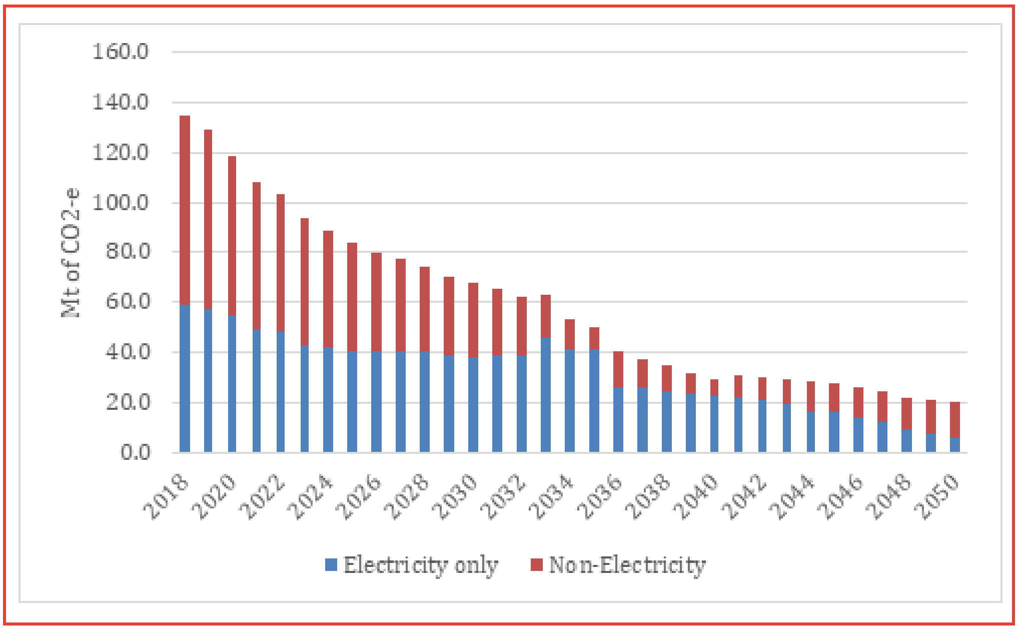


Table 10: NSW Real Value Added by Broad Industry Group: High Solar Thermal Cost Scenario (percentage deviations in 2035 and 2050)

Industry	2035 % deviation	2050 % deviation
1. Agriculture, forestry and fishing	-0.01	-0.05
2. Mining	-0.03	-0.31
3. Manufacturing	-0.07	-0.23
4a. Electricity generation – coal	-1.31	-48.73
4b. Electricity generation – gas	55.58	108.67
4c. Electricity generation – hydro	3.89	-8.91
4d. Electricity generation – other	1.56	-15.95
4f. Electricity supply	0.66	-0.05
5. Construction	-0.04	-0.05
6. Wholesale trade	-0.04	-0.09
7. Retail trade	-0.03	-0.05
8. Accommodation and food services	-0.03	-0.08
9. Transport, postal and warehousing	0.01	0.21
10. Information, media and telecommunications	0.00	0.00
11. Financial and insurance services	0.00	-0.05
12. Business services	-0.03	-0.05
13. Public administration and safety	0.00	-0.01
14. Education and training.	0.00	0.00
15. Health care and social assistance	0.00	-0.01
16. Other services (including other utility services)	-0.01	-0.04
17. Dwelling services	0.00	-0.05

5.5 Summary or macroeconomic modelling

The deviations from the Base Case of the three scenarios that we have undertaken CGE modelling for are small:

- The High Demand Scenario sees increased real GSP (by 0.15 per cent in 2050 compared to the Base Case) and increased employment (by 0.07 per cent in 2050 compared to the Base Case). This is due to switching towards electricity, which has a relatively high local content, away from non-electricity inputs, which have, on average, a lower local content.
- The Alternate Coal Price Scenario sees small increases in GSP and employment when prices are lower than the Base Case and small decreases in GSP and employment when prices are higher than the Base Case.
- The High Solar Thermal Cost Scenario sees small reductions in GSP and employment as a result of what is effectively a significant technological deterioration.

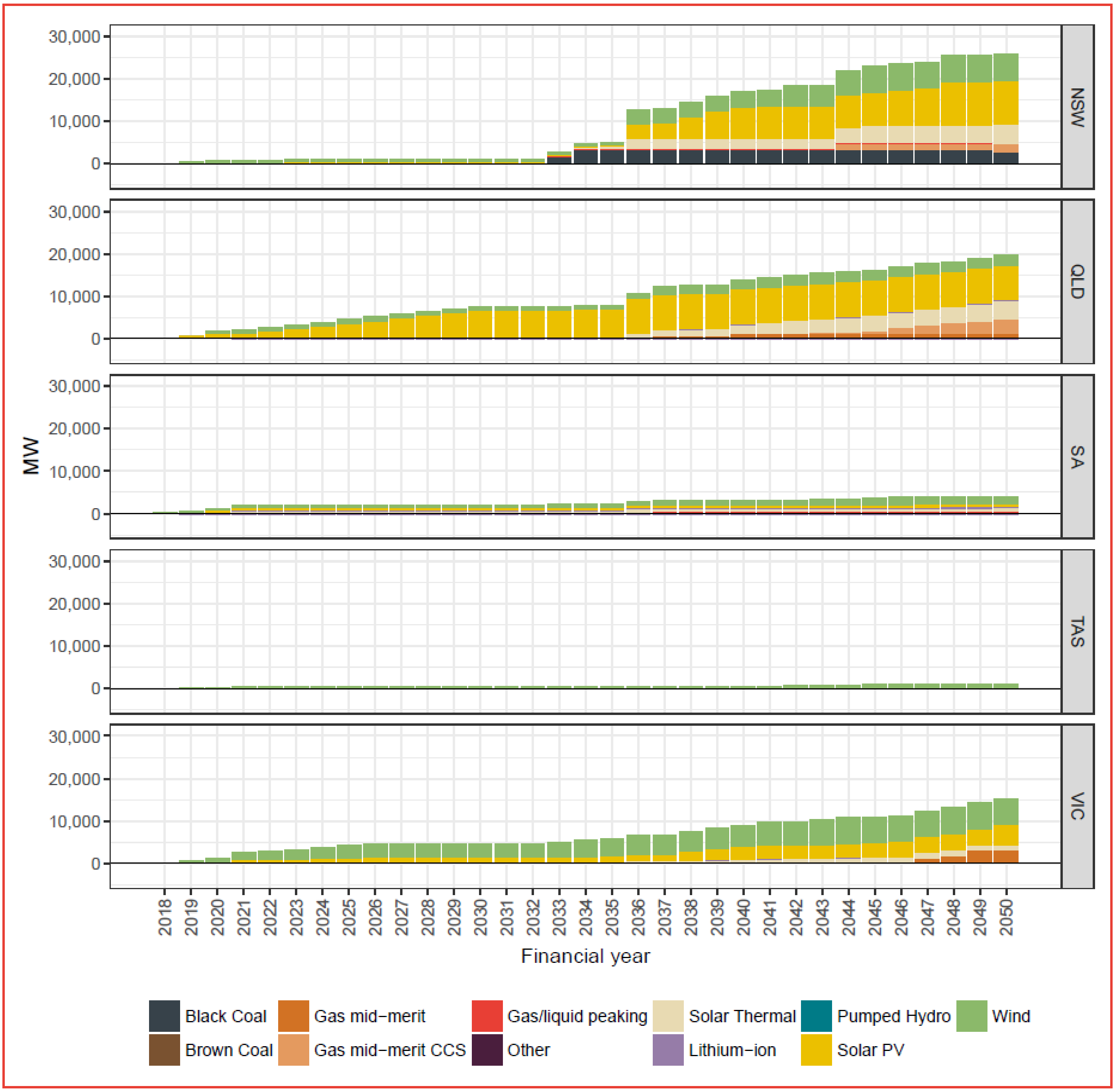
Given that we have undertaken macroeconomic modelling of scenarios that saw some of the largest differences in the energy sector, this suggests that the macroeconomic consequences of the energy scenarios that we have investigated will be small. So, for instance, the macroeconomic consequences of a difference between building new coal plant in NSW in the 2030s, or building a mix of other plant instead of coal, would be small.

Appendix A – regional results

This Appendix presents selected results for all regions in the NEM.

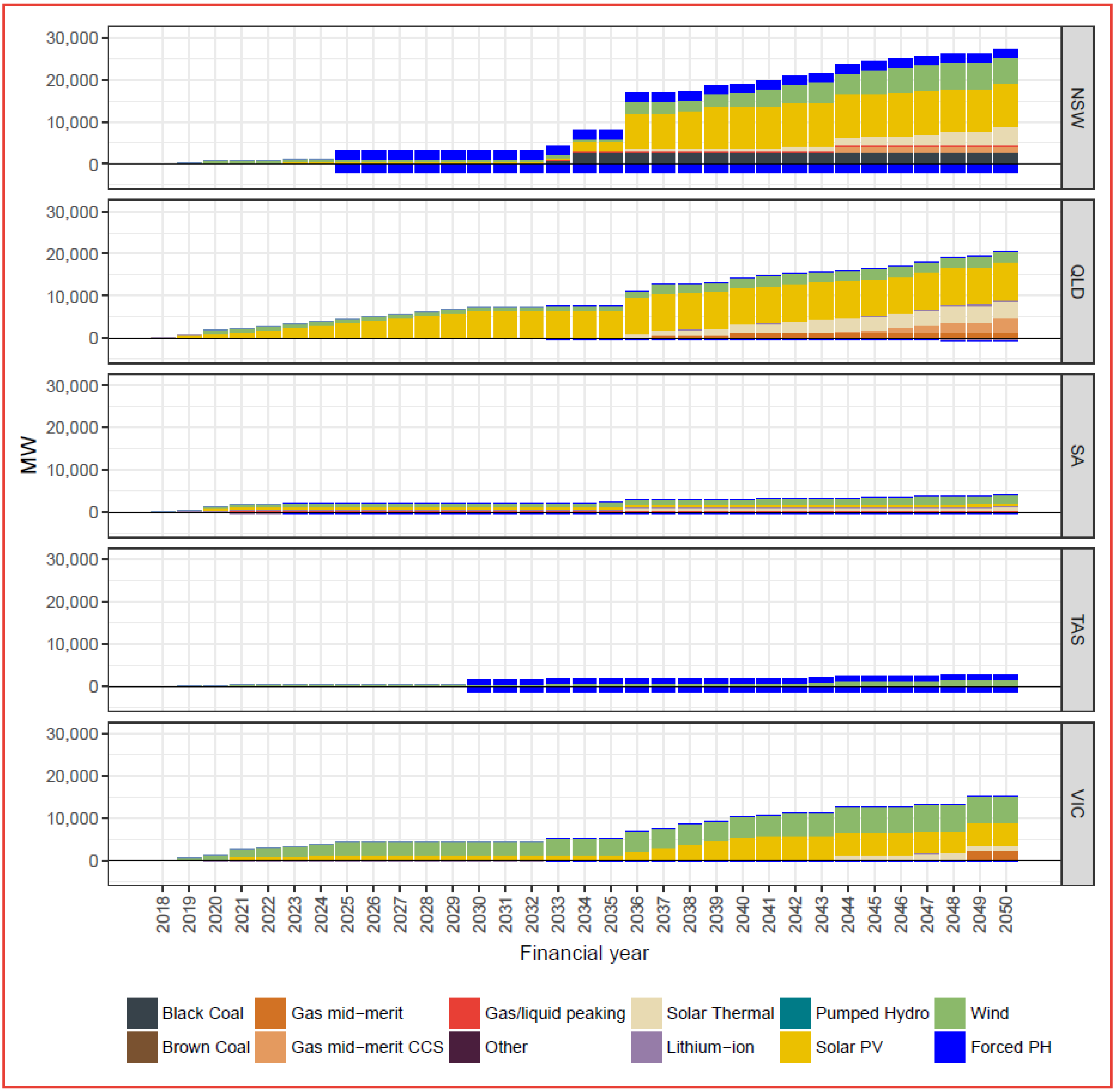
Regional investment results

Figure 55: Base Case – new investment, all regions



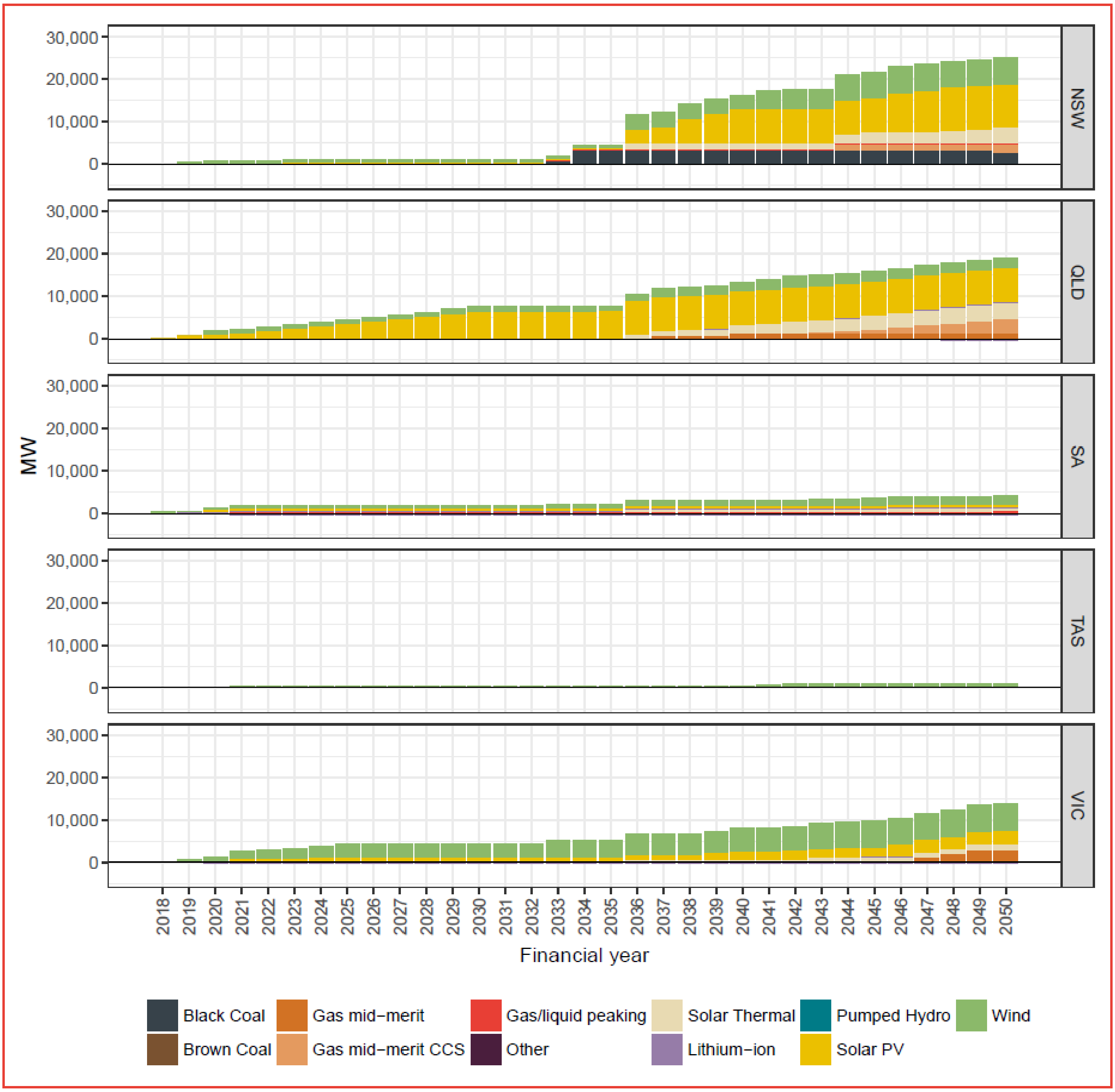
Source: Frontier Economics

Figure 56: Grid Storage Scenario – new investment, all regions



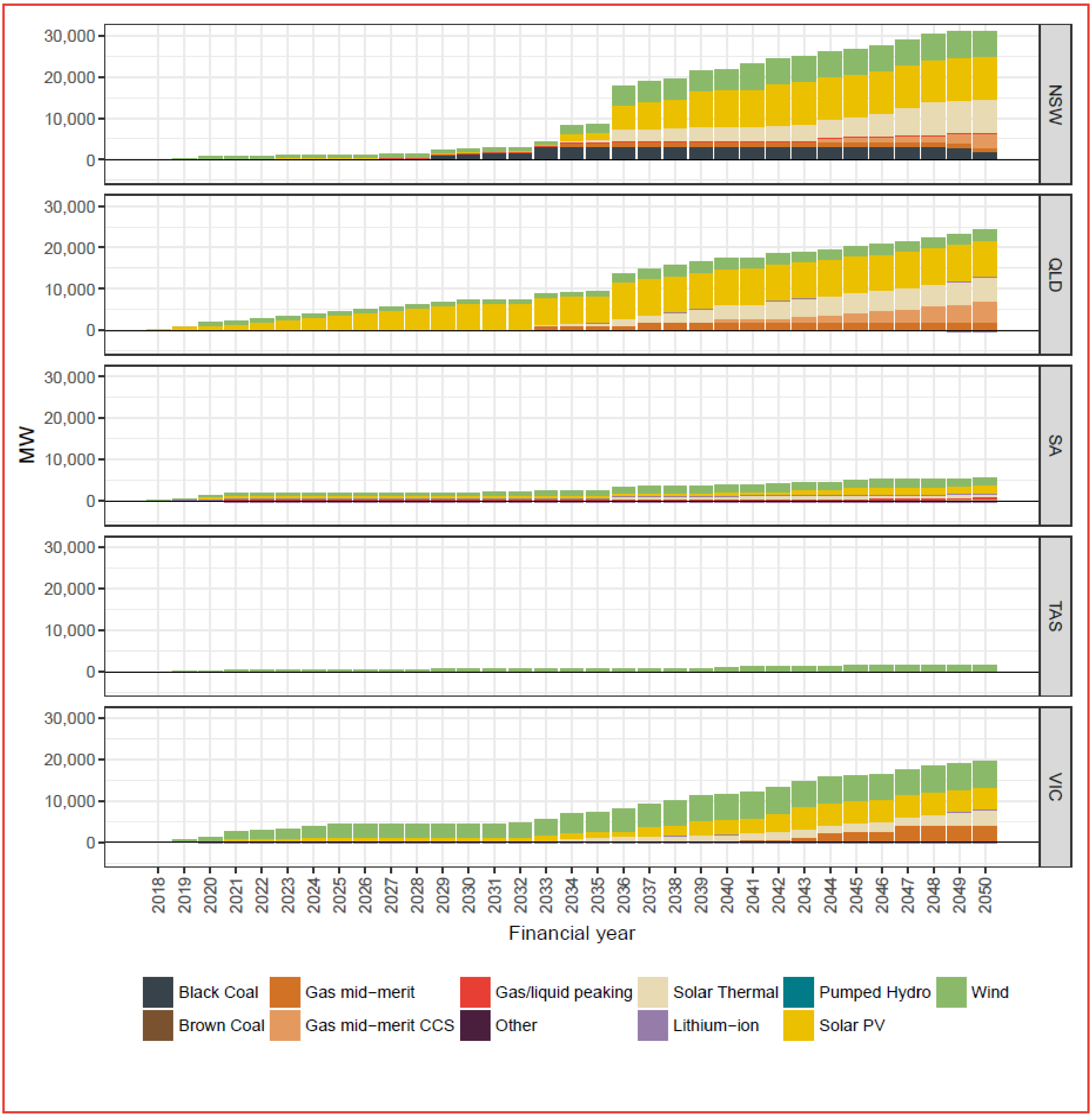
Source: Frontier Economics

Figure 57: Rooftop PV Scenario – new investment, all regions



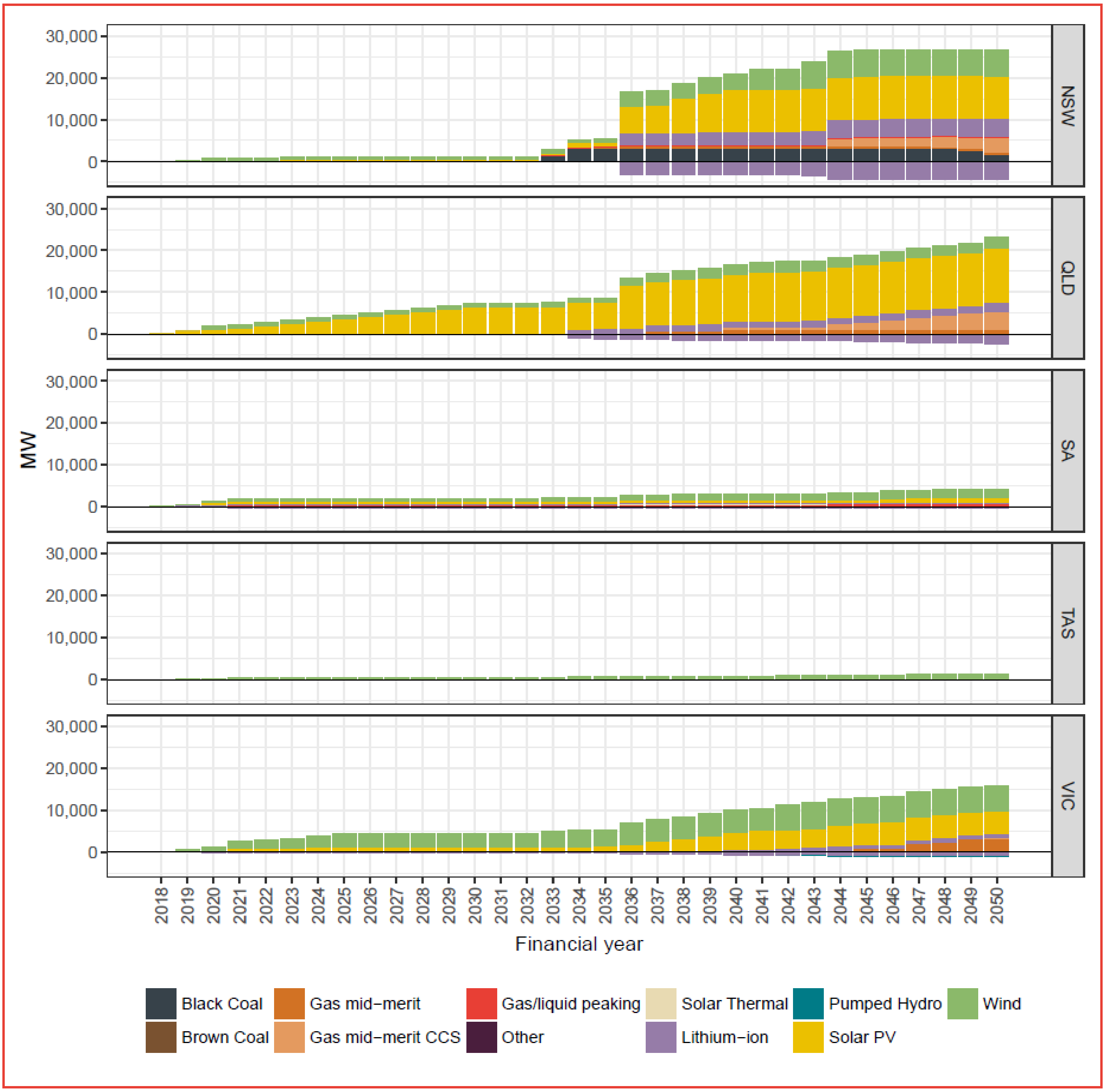
Source: Frontier Economics

Figure 58: High Demand Scenario – new investment, all regions



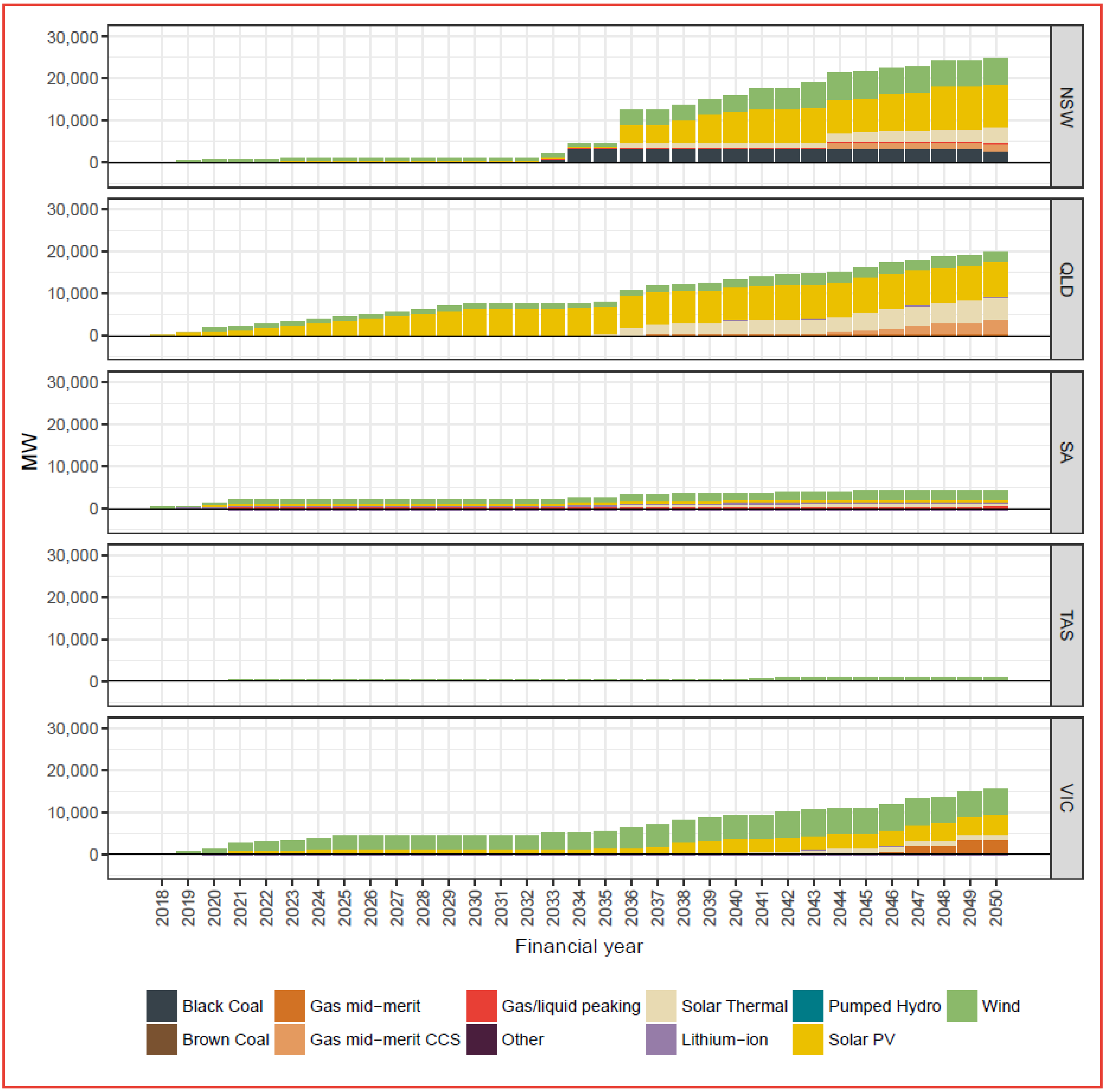
Source: Frontier Economics

Figure 59: High Solar Thermal Cost Scenario – new investment, all regions



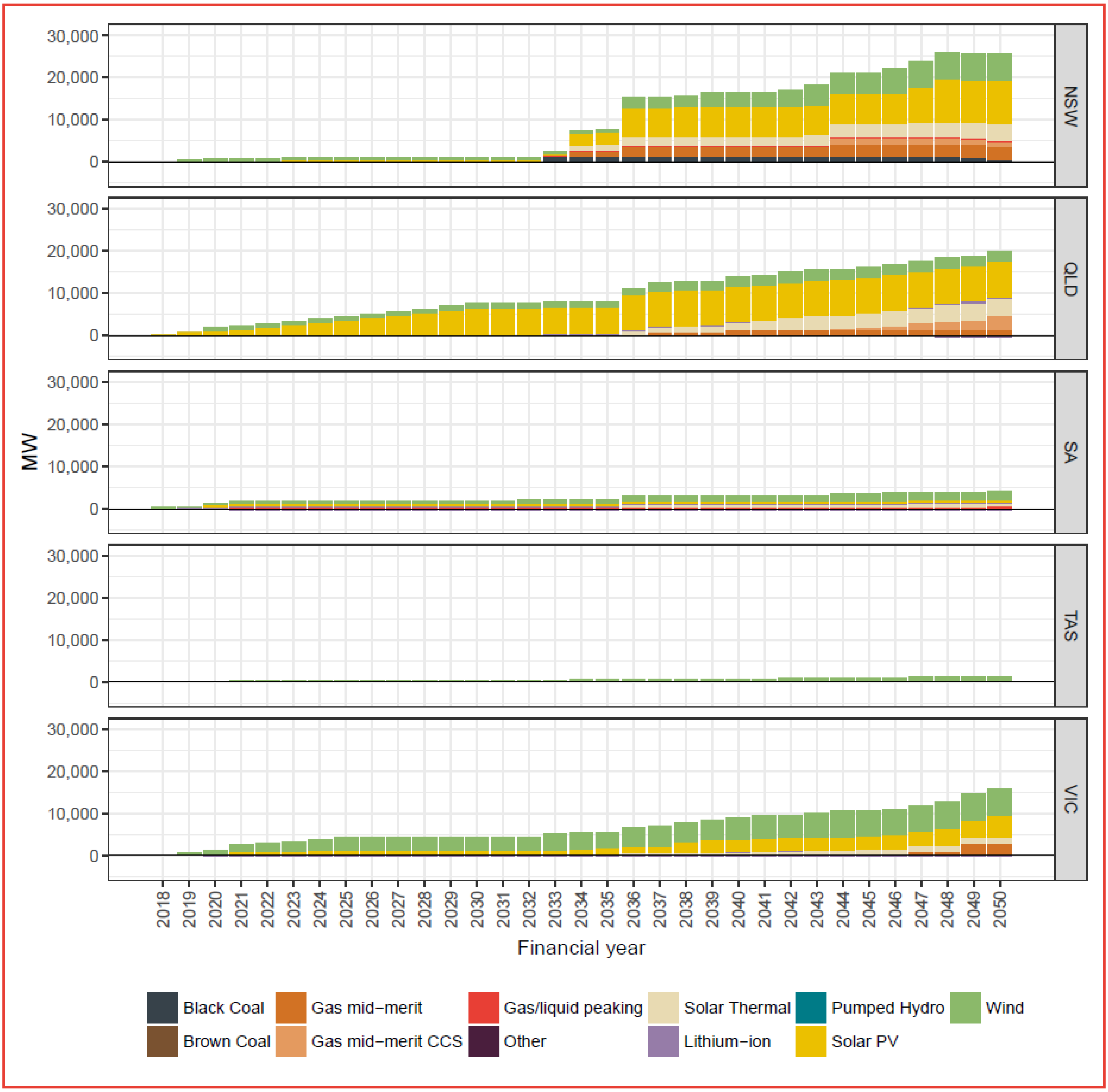
Source: Frontier Economics

Figure 60: Interconnector Expansions Scenario – new investment, all regions



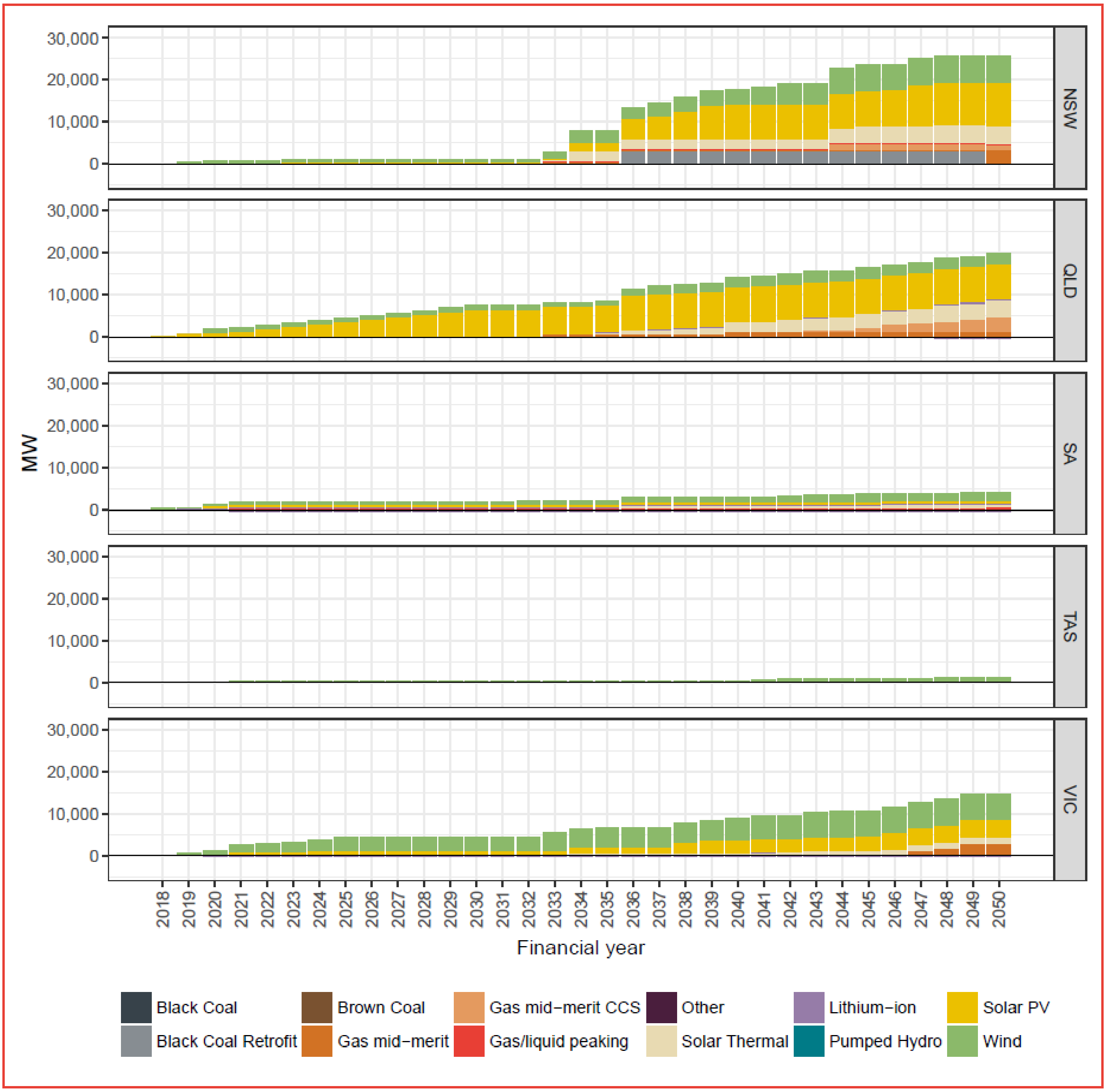
Source: Frontier Economics

Figure 61: Updated Entrant Fuel Cost Scenario – new investment, all regions



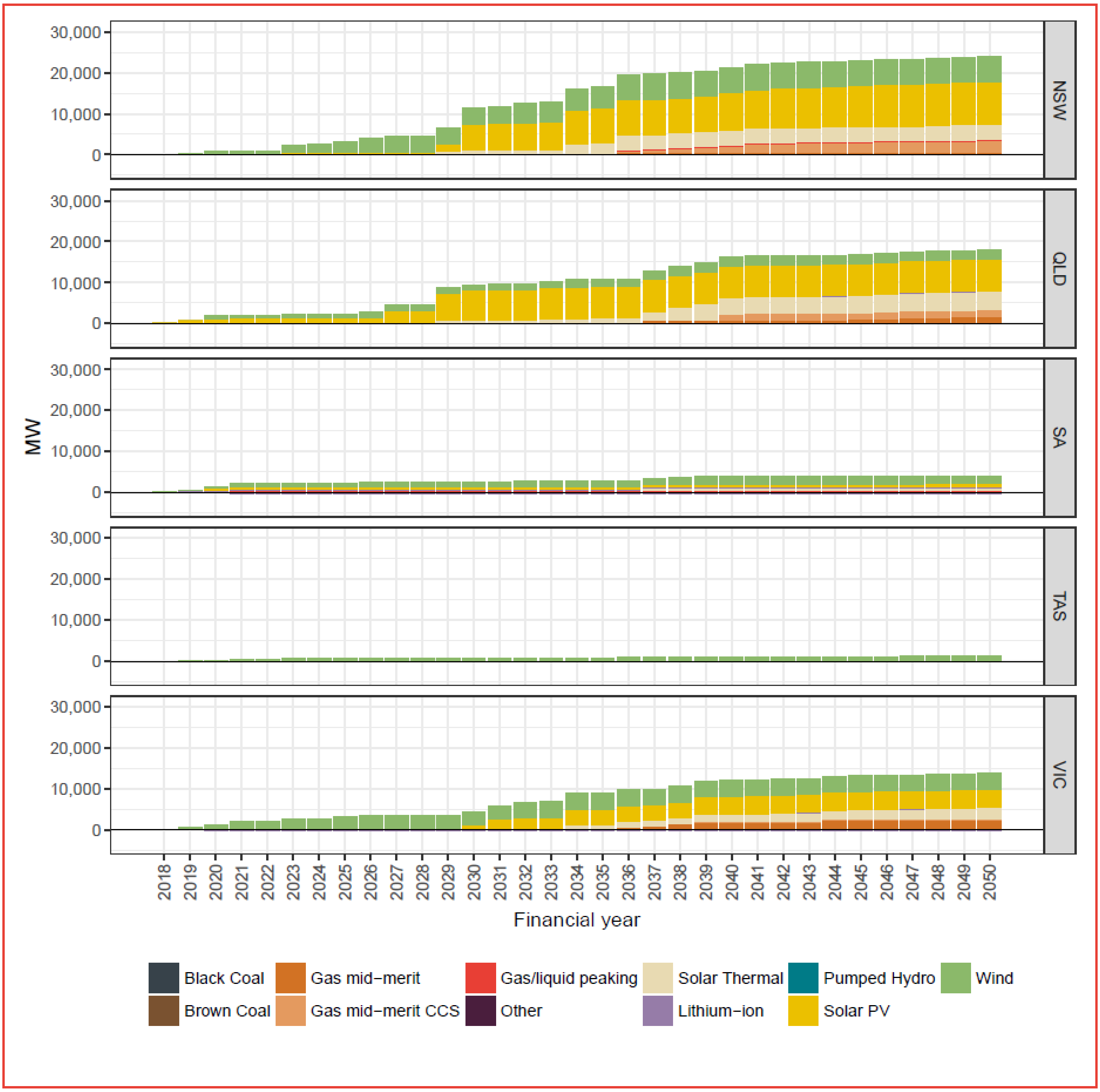
Source: Frontier Economics

Figure 62: Updated Entrant Fuel Cost HELE Scenario – new investment, all regions



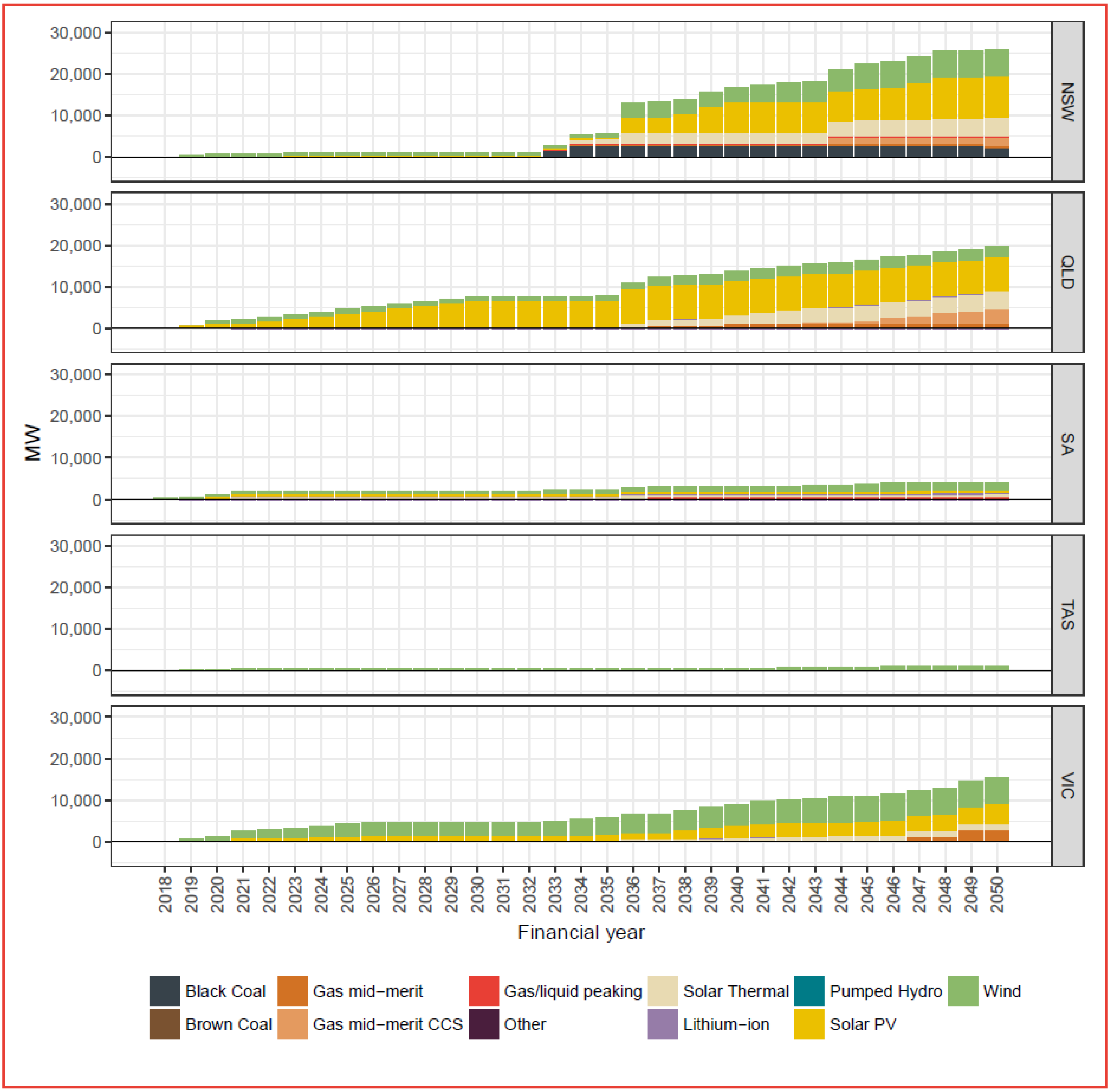
Source: Frontier Economics

Figure 63: High Emissions Reduction Scenario – new investment, all regions



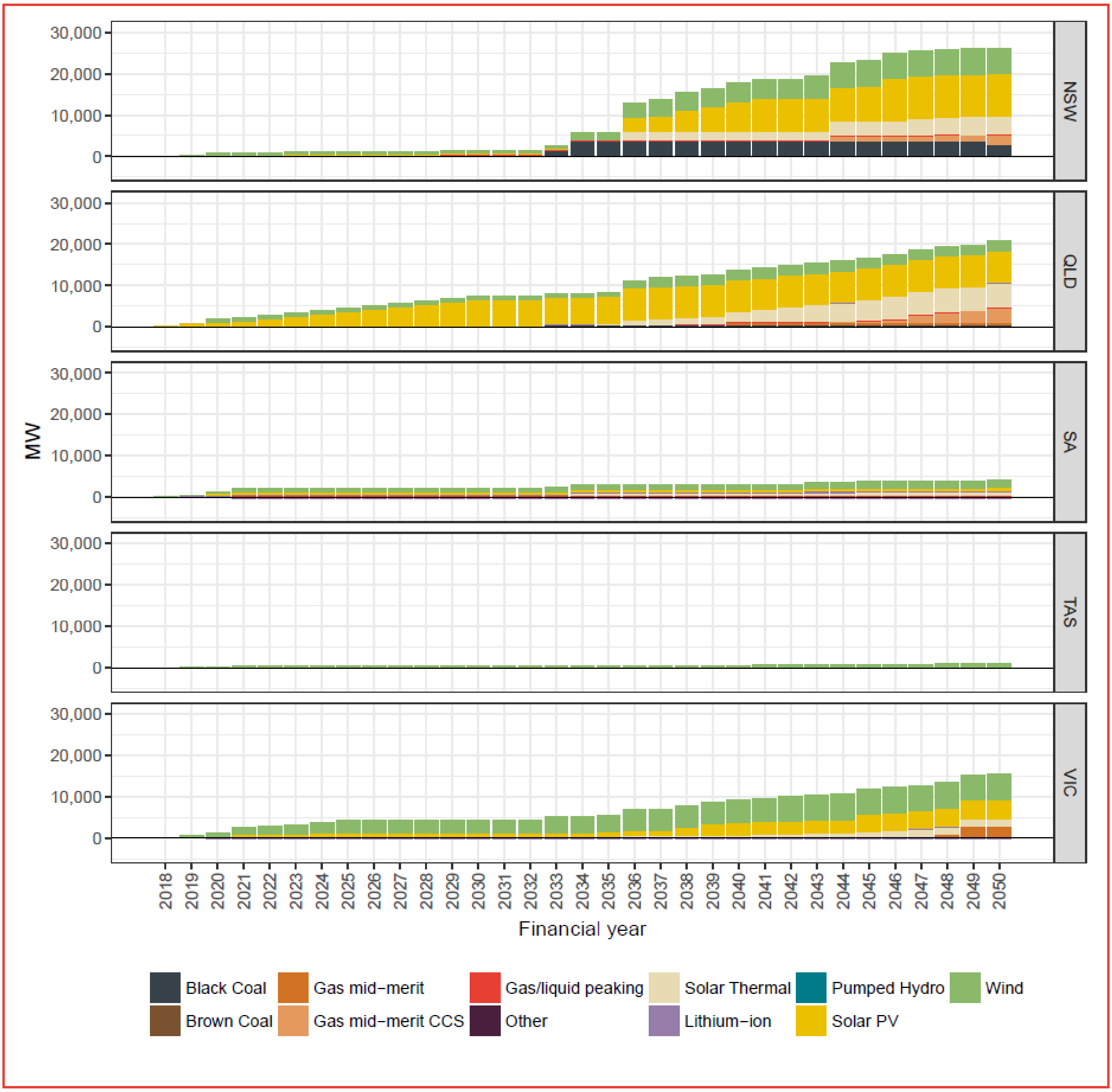
Source: Frontier Economics

Figure 64: Alternate Coal Price Scenario – new investment, all regions



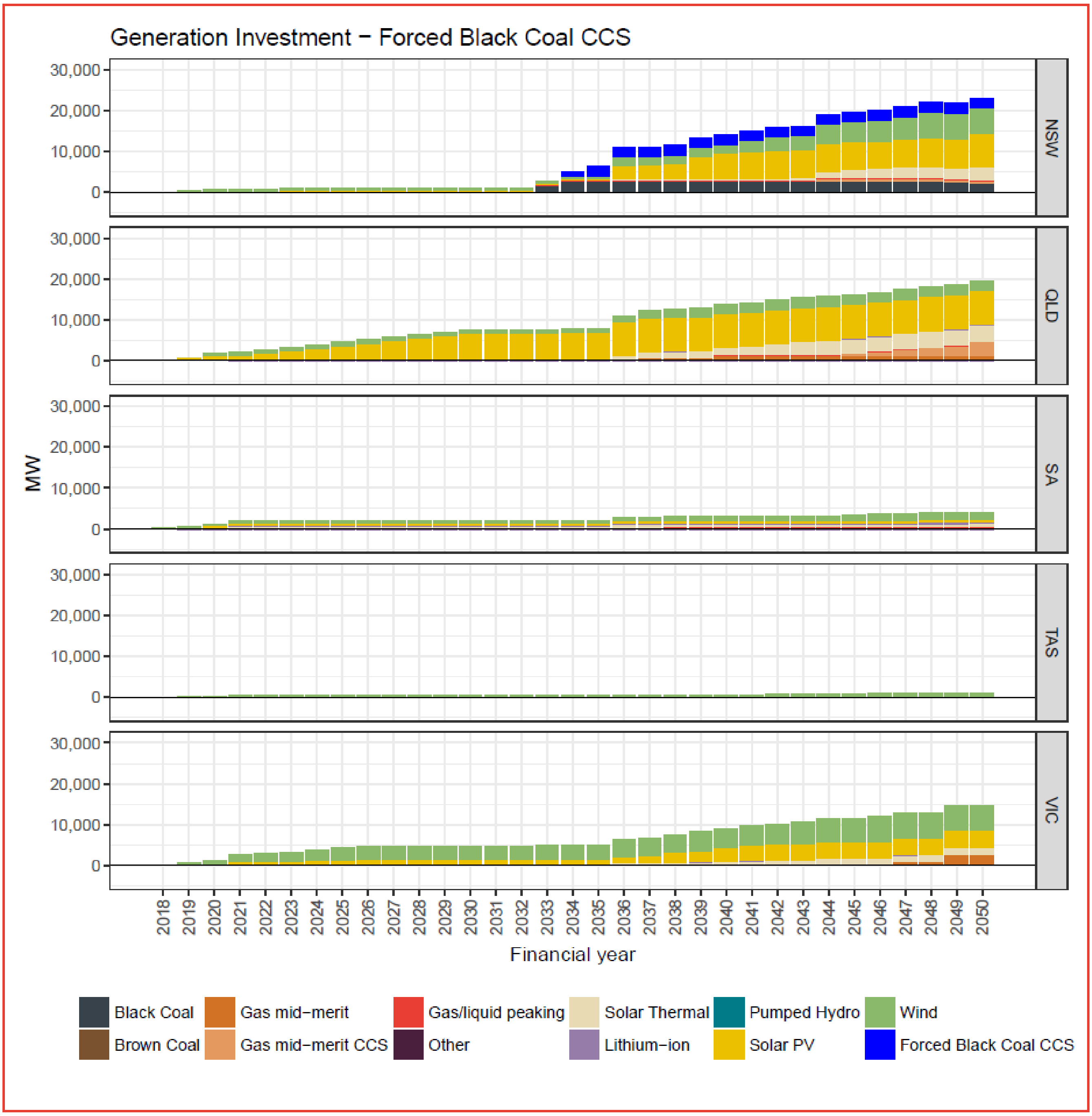
Source: Frontier Economics

Figure 65: High Gas Price Scenario – new investment, all regions



Source: Frontier Economics

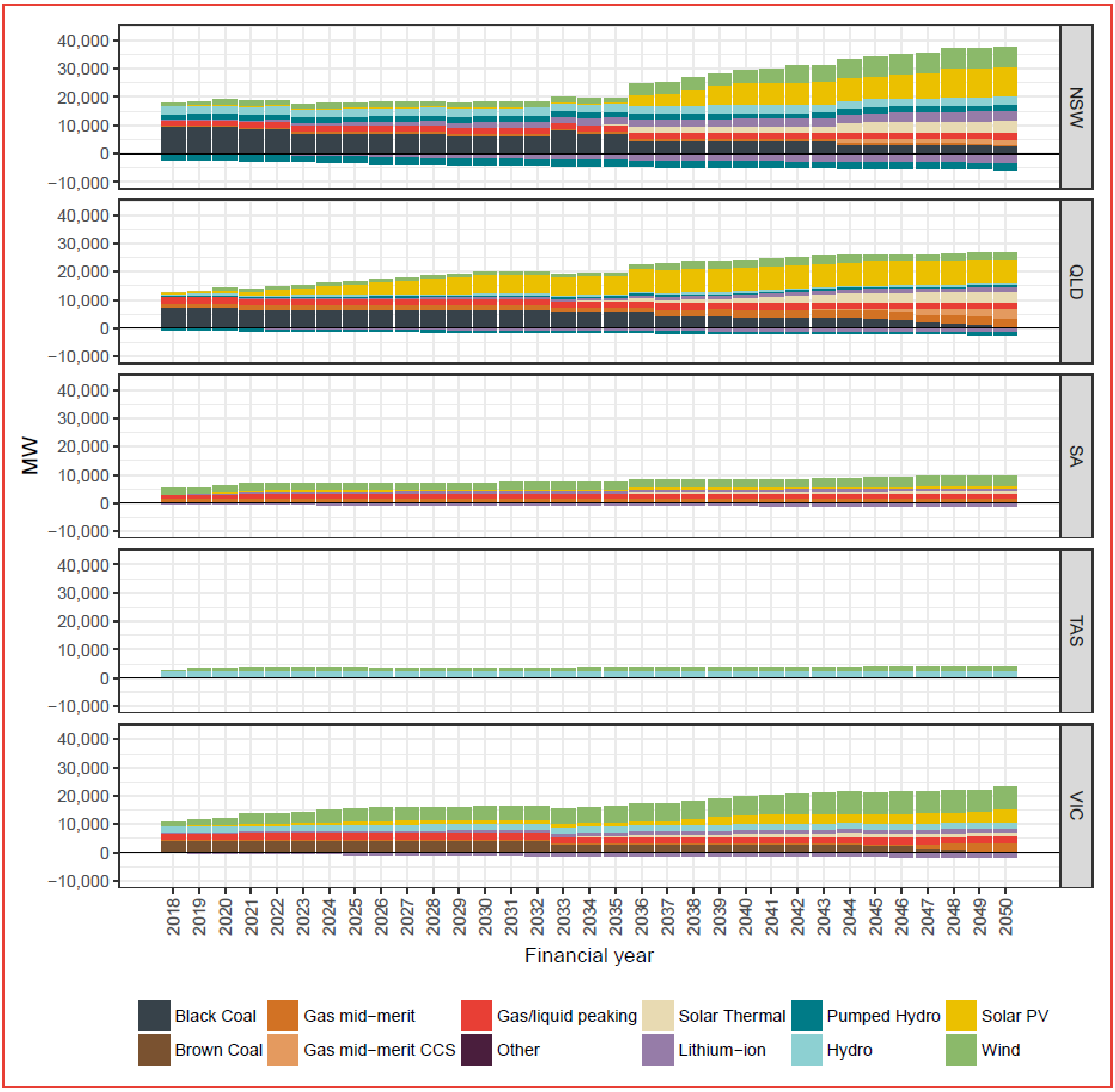
Figure 66: Forced Black Coal CCS – new investment, all regions



Source: Frontier Economics

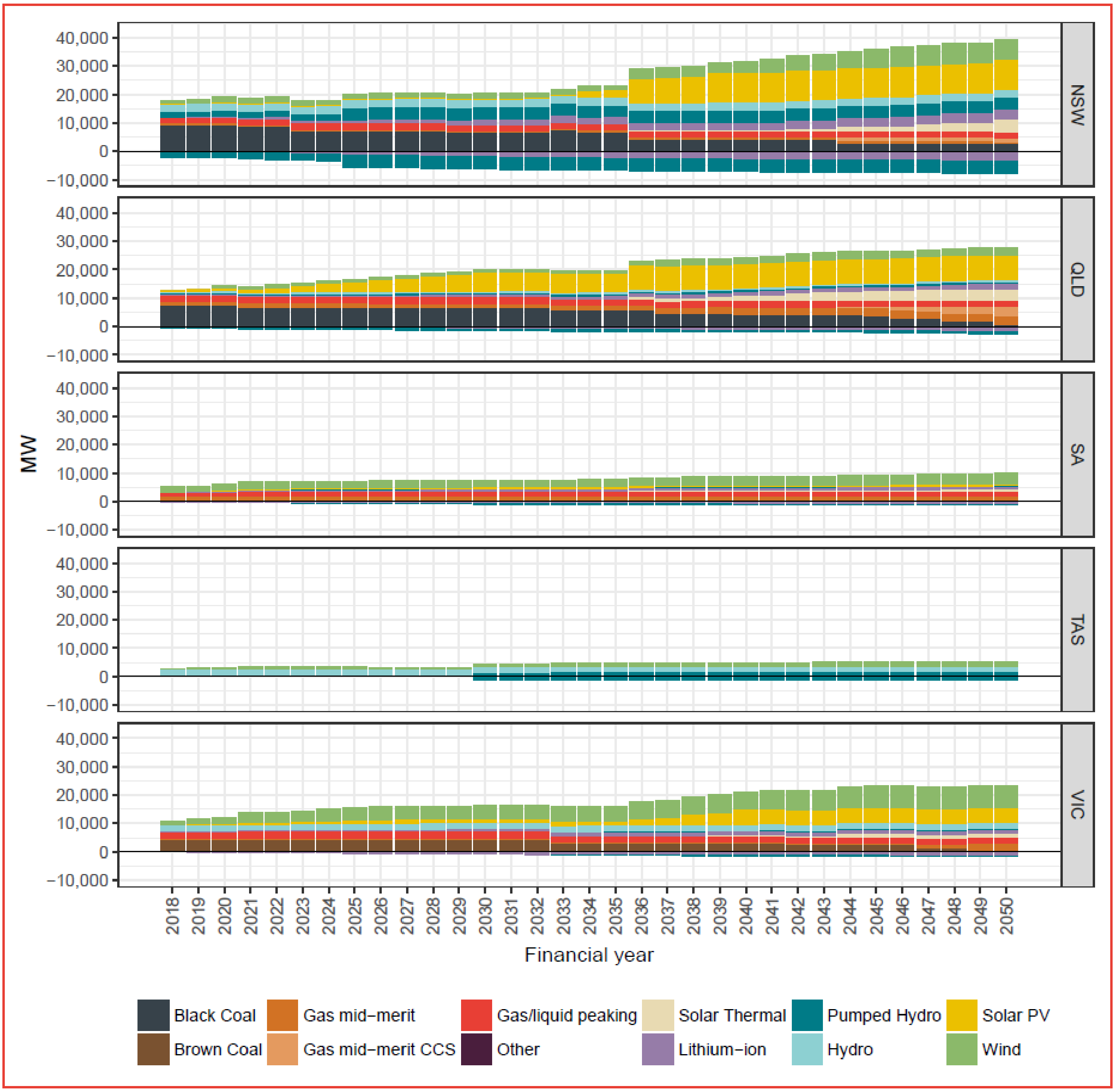
Regional generation capacity results

Figure 67: Base Case – generation capacity, all regions



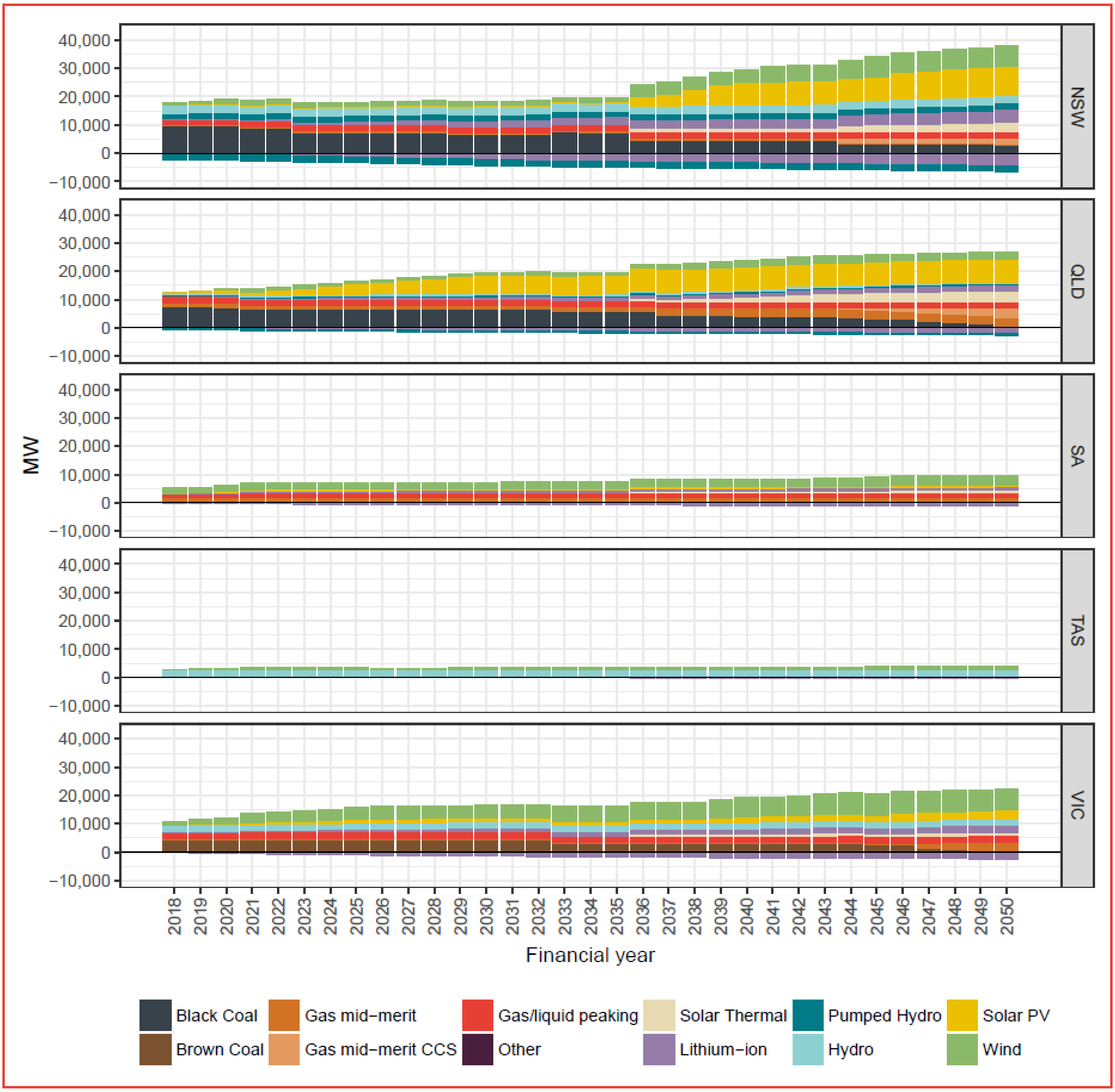
Source: Frontier Economics

Figure 68: Grid Storage Scenario – generation capacity, all regions



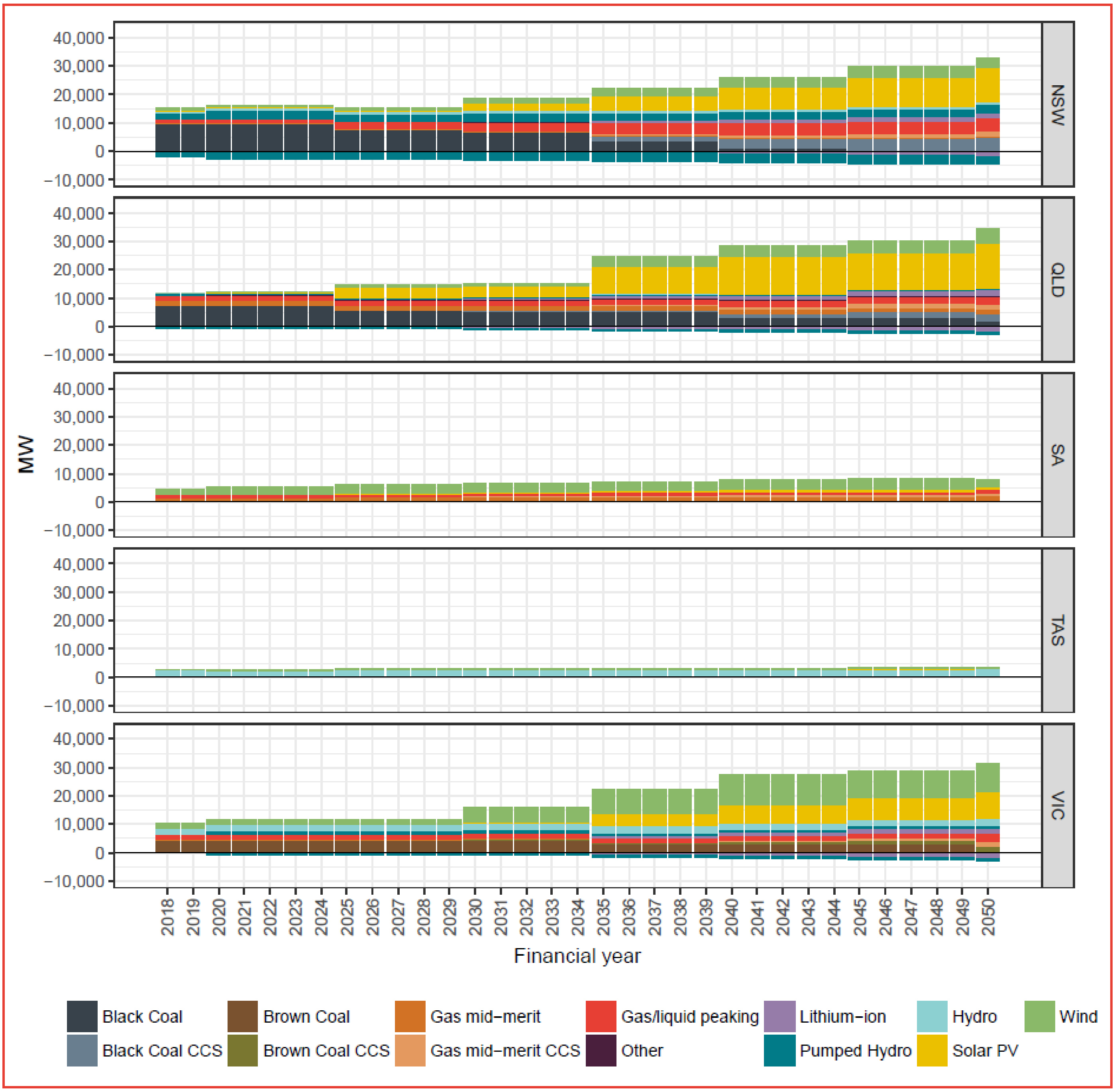
Source: Frontier Economics

Figure 69: Rooftop PV Scenario – generation capacity, all regions



Source: Frontier Economics

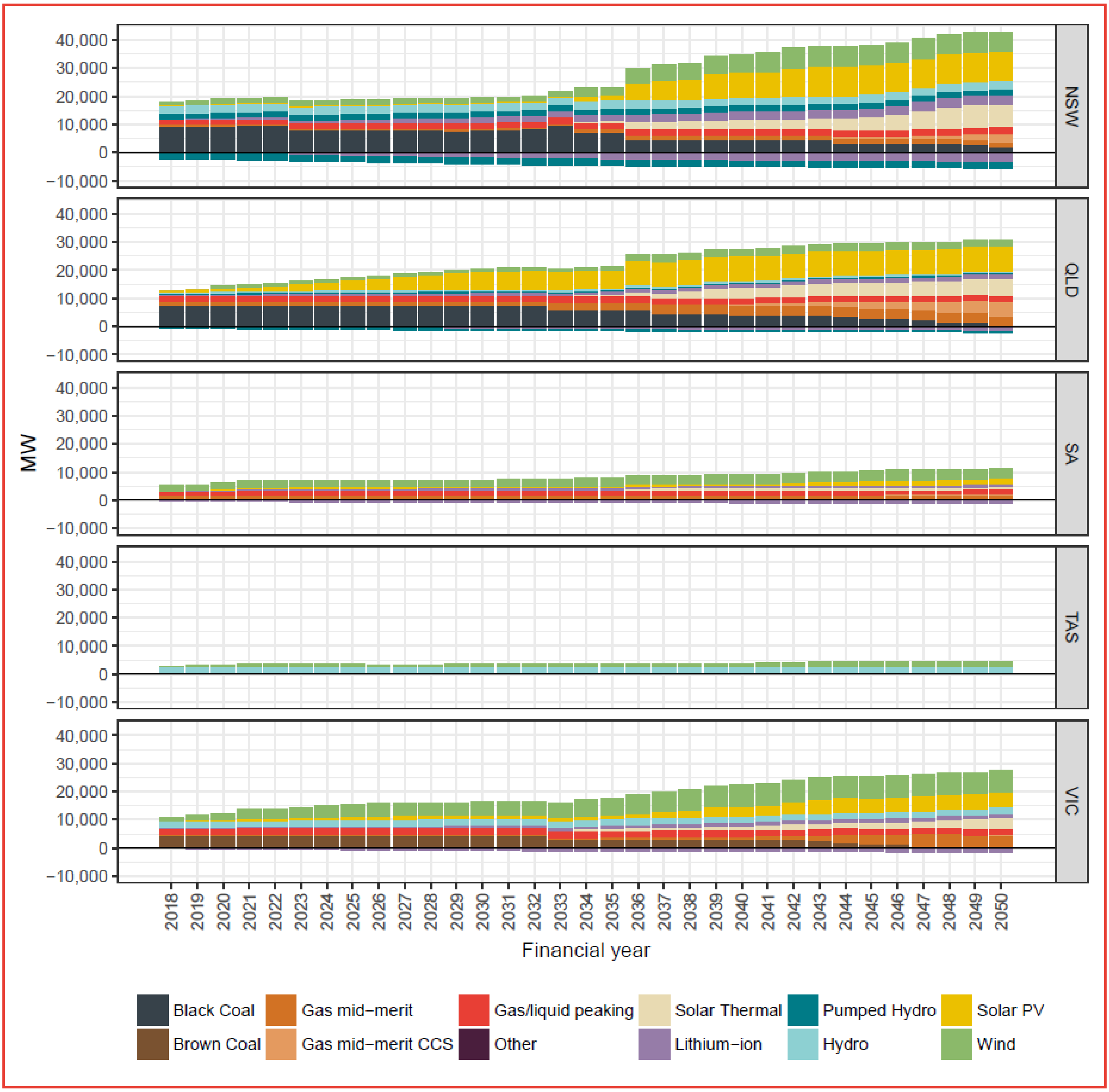
Figure 70: MEGS Scenario – generation capacity, all regions



Source: Frontier Economics

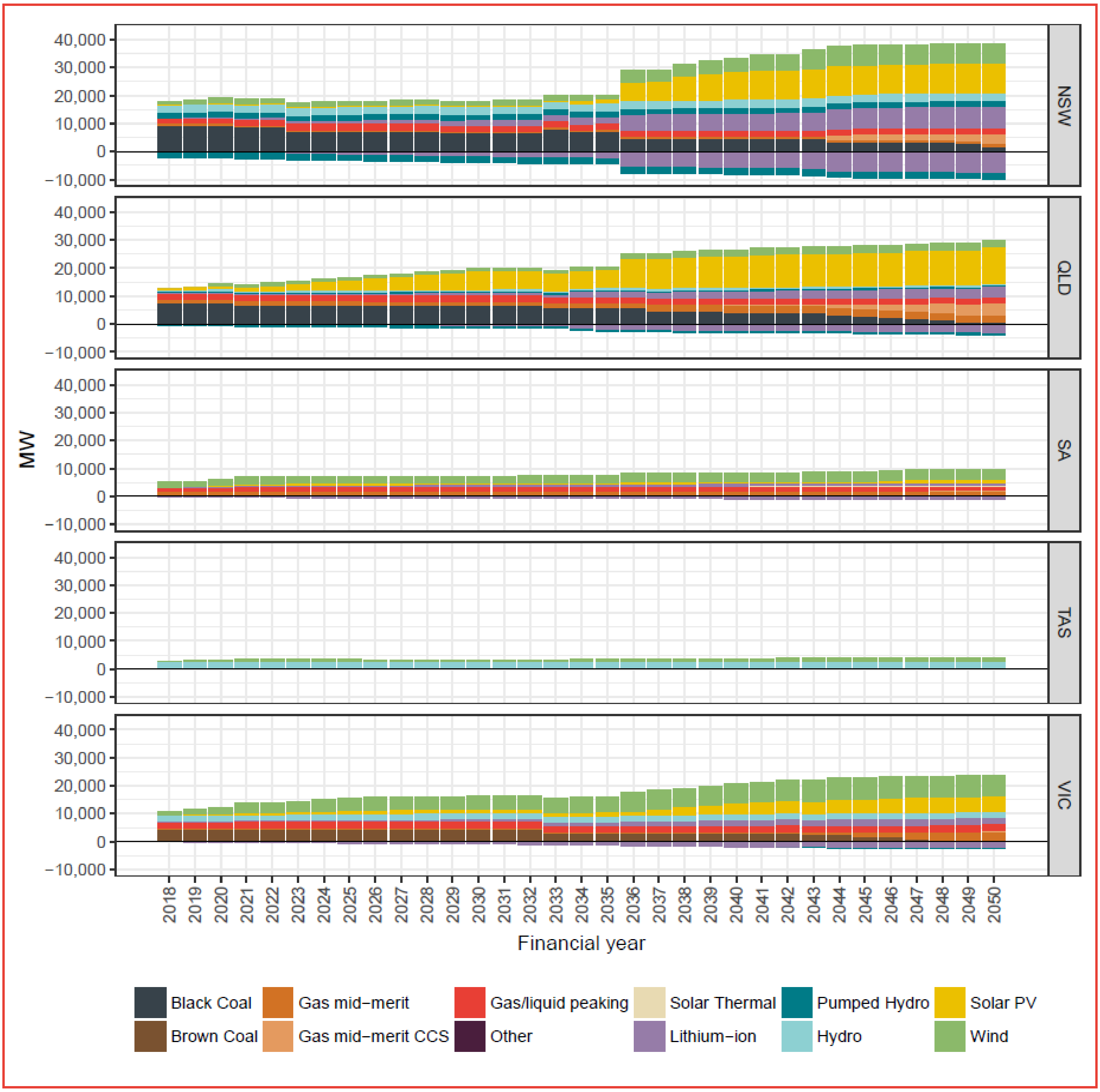
Note: Results shown for 5-year periods for MEGS Scenario, because this is the granularity of the results provided by Red Vector.

Figure 71: High Demand Scenario – generation capacity, all regions



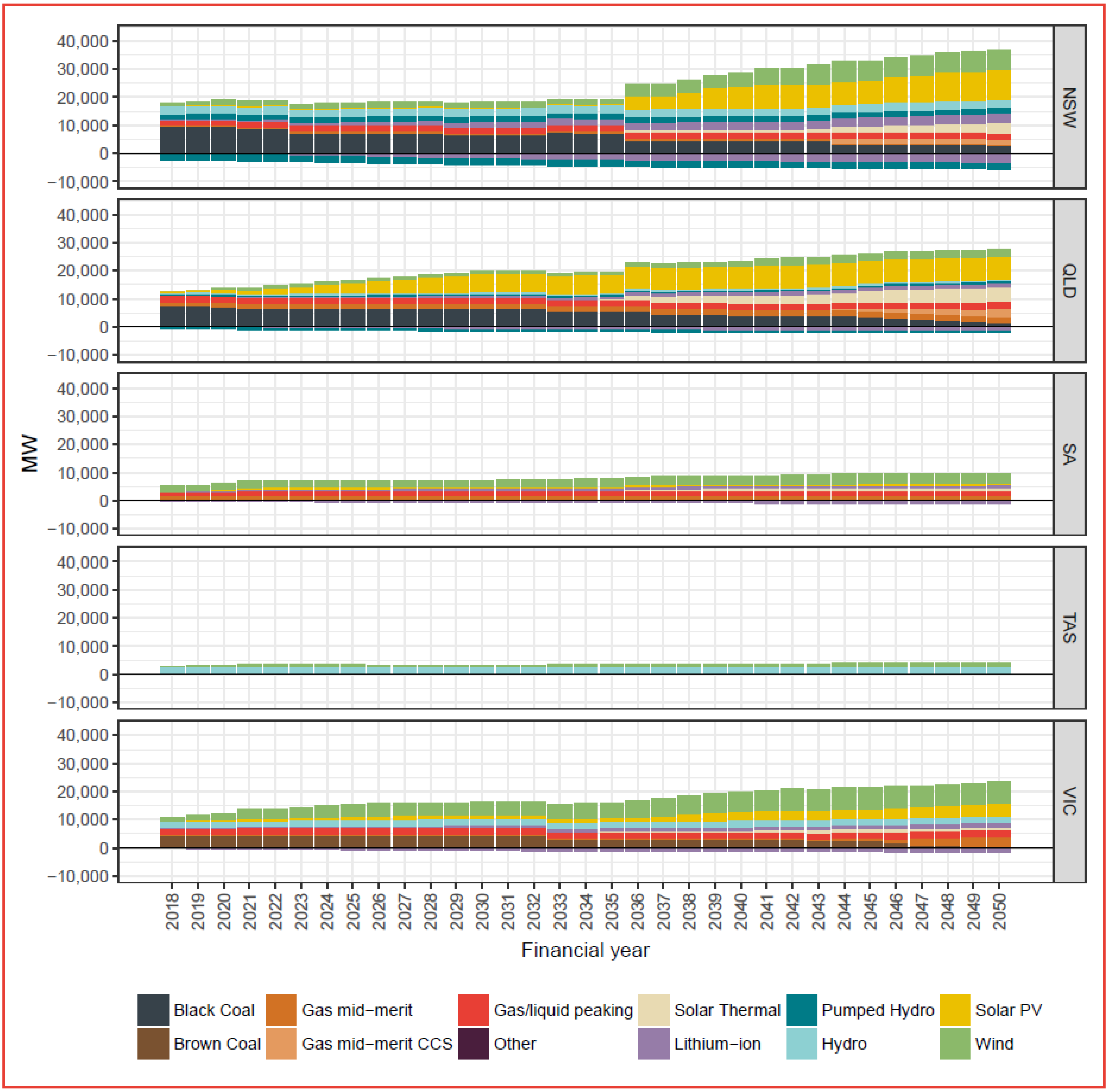
Source: Frontier Economics

Figure 72: High Solar Thermal Cost Scenario – generation capacity, all regions



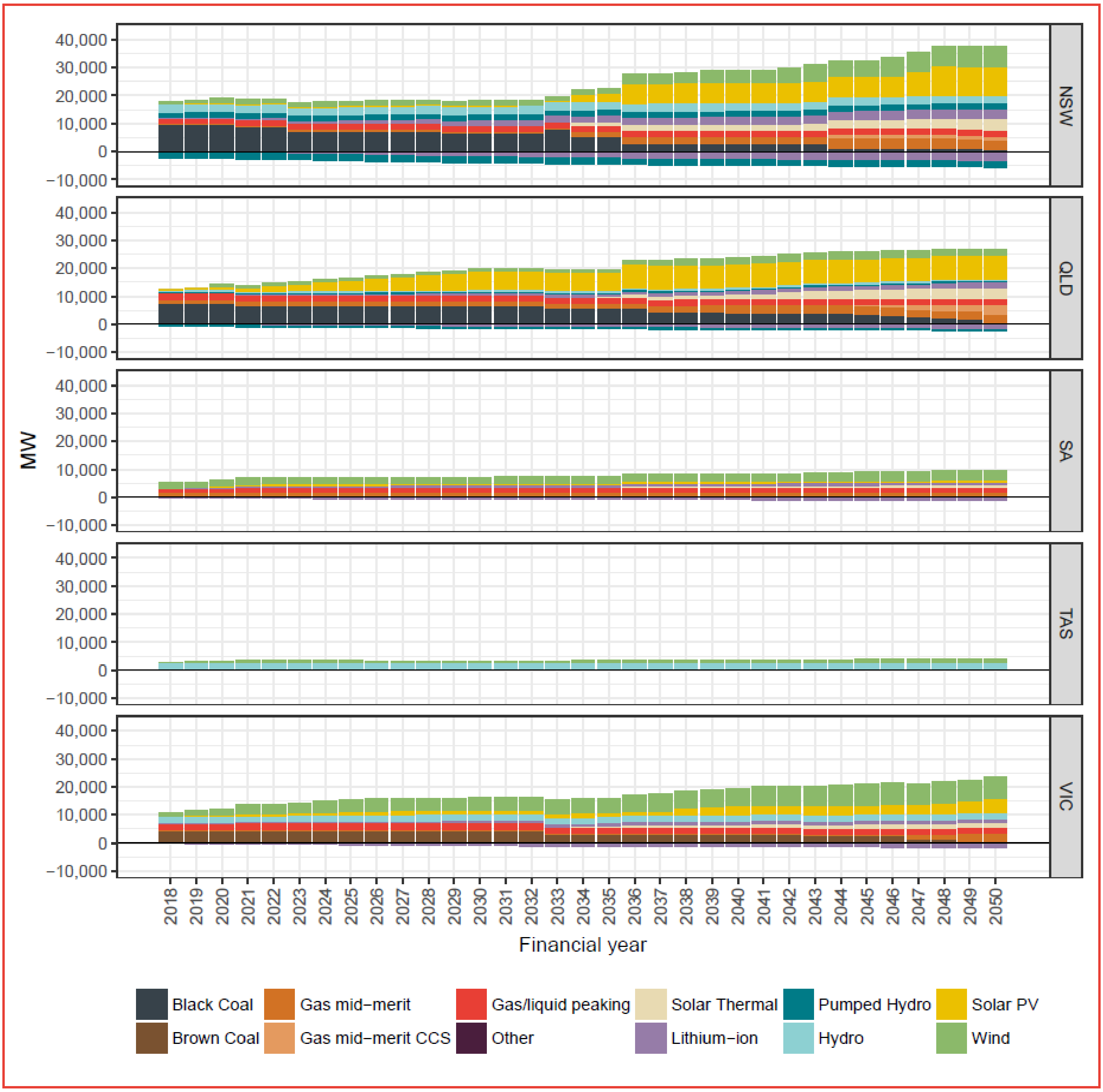
Source: Frontier Economics

Figure 73: Interconnector Expansions Scenario – generation capacity, all regions



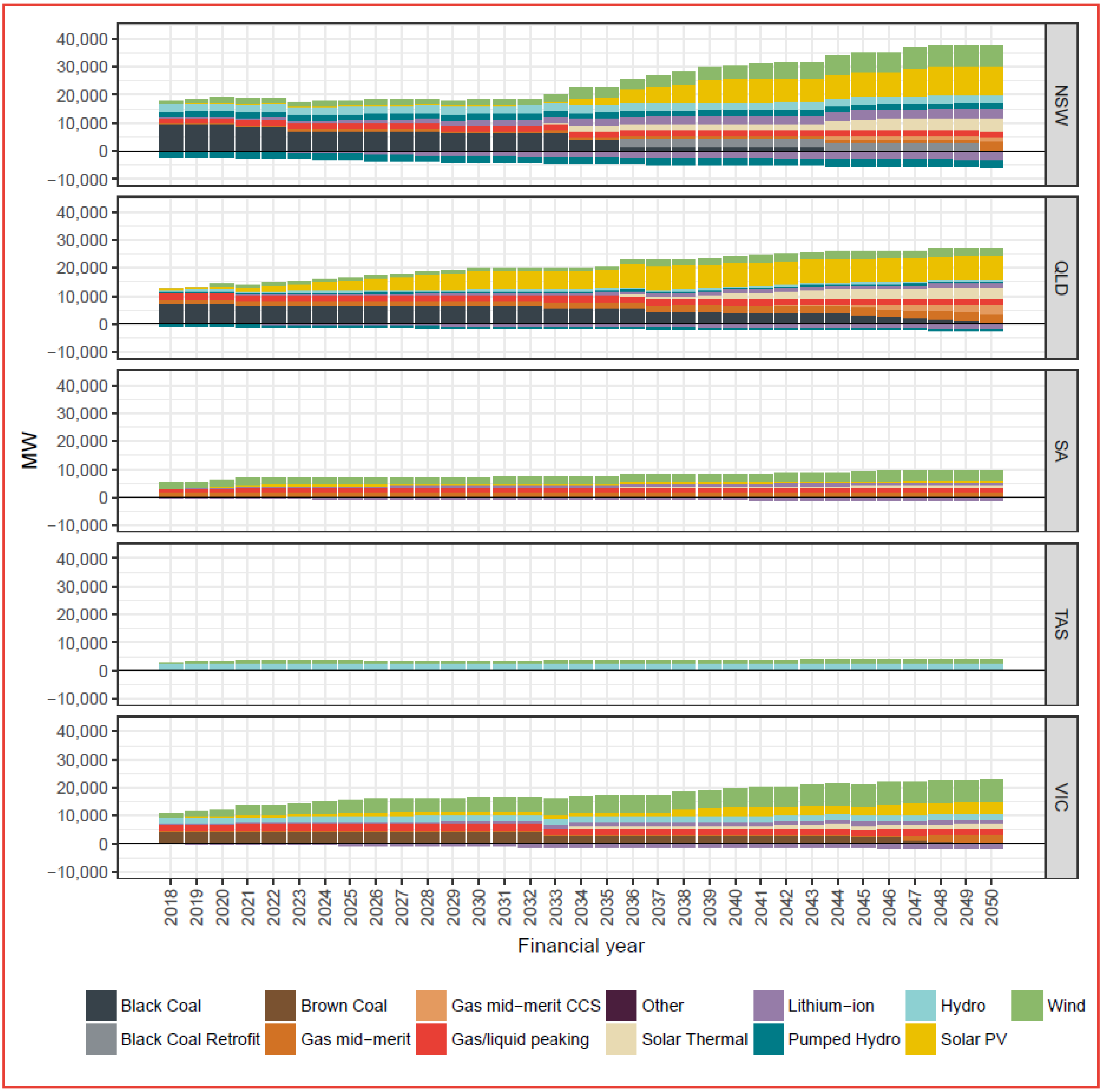
Source: Frontier Economics

Figure 74: Updated Entrant Fuel Cost Scenario – generation capacity, all regions



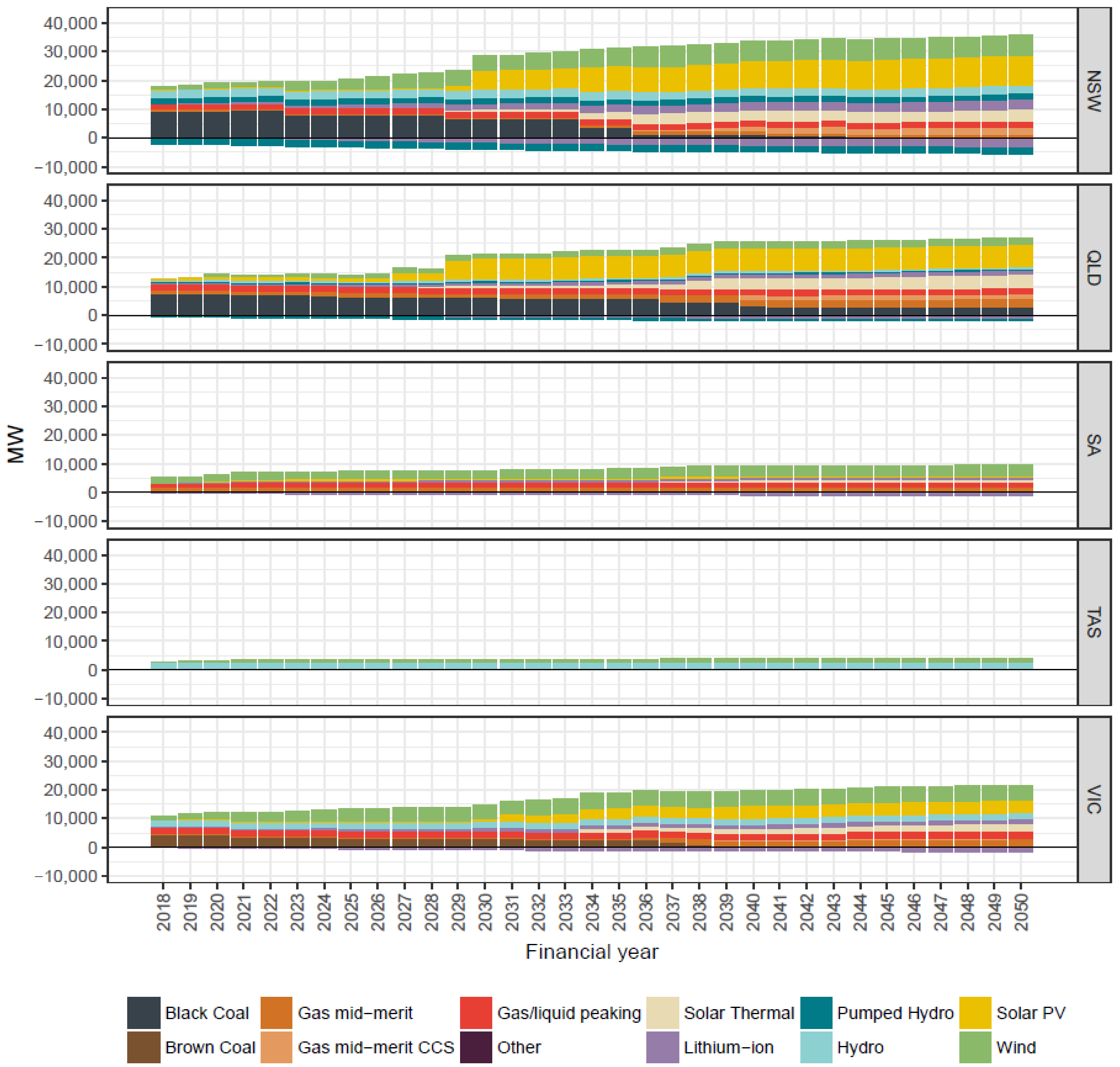
Source: Frontier Economics

Figure 75: Updated Entrant Fuel Cost HELE Scenario – generation capacity, all regions



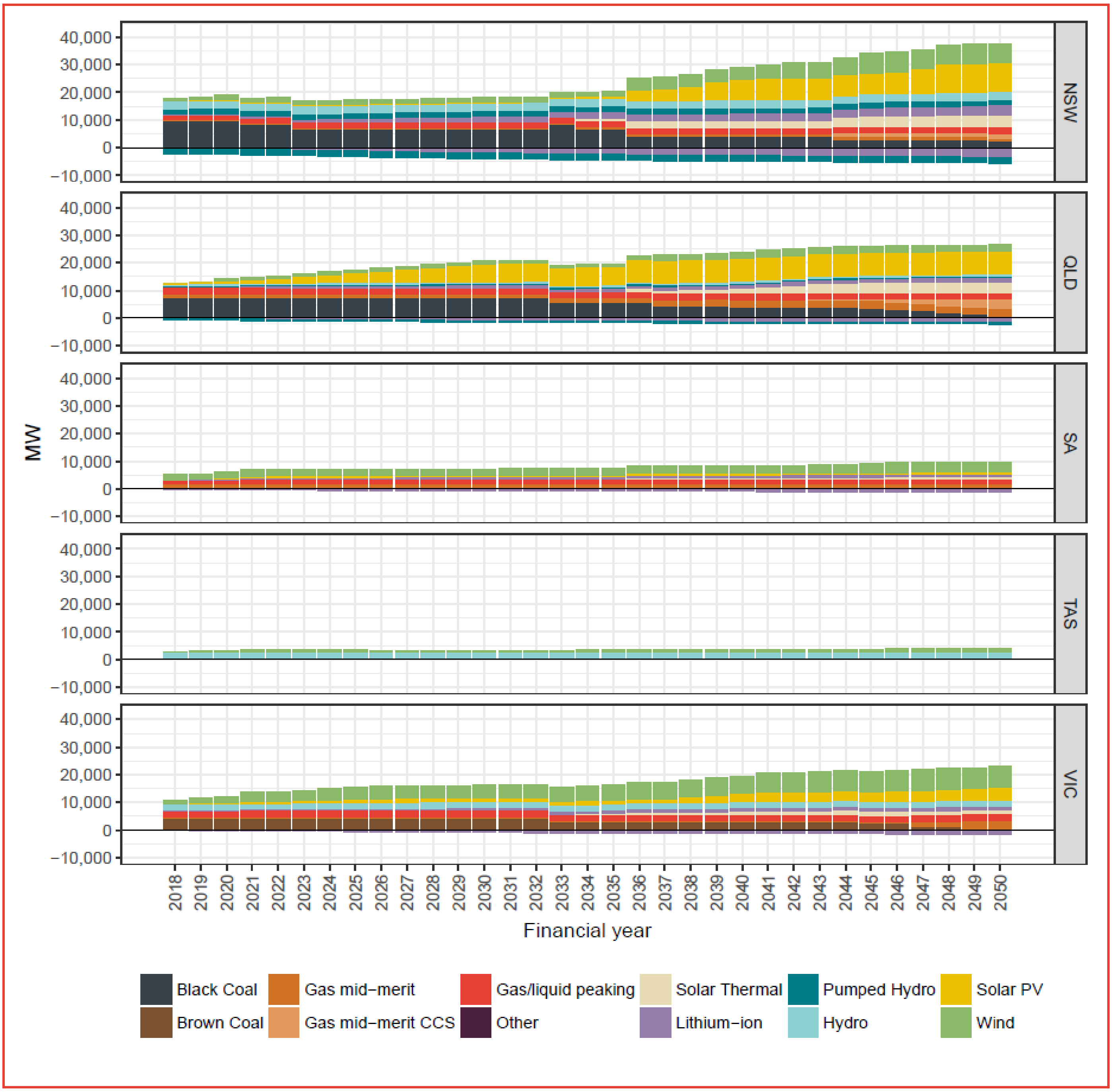
Source: Frontier Economics

Figure 76: High Emissions Reduction Scenario – generation capacity, all regions



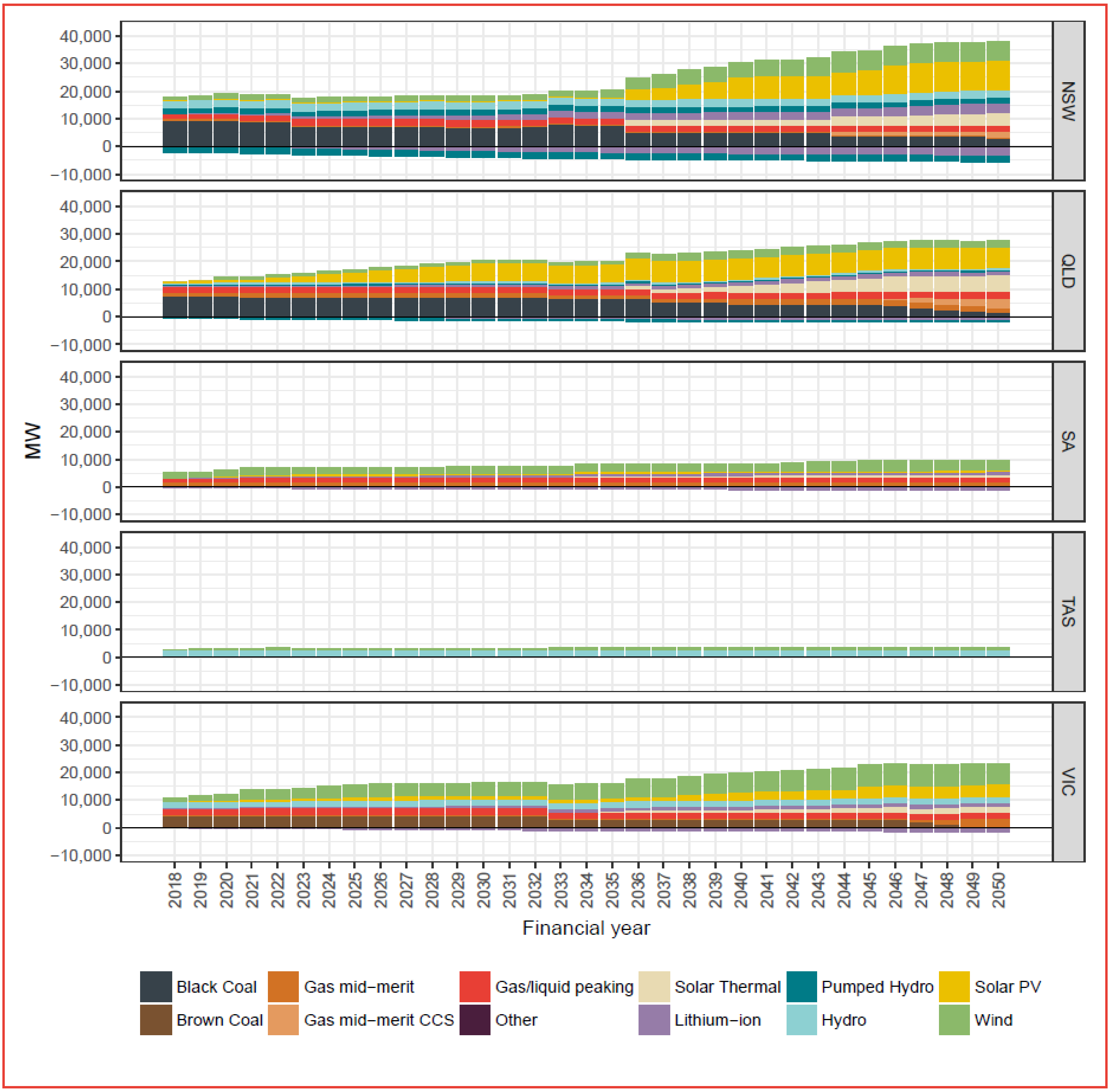
Source: Frontier Economics

Figure 77: Alternate Coal Price Scenario – generation capacity, all regions



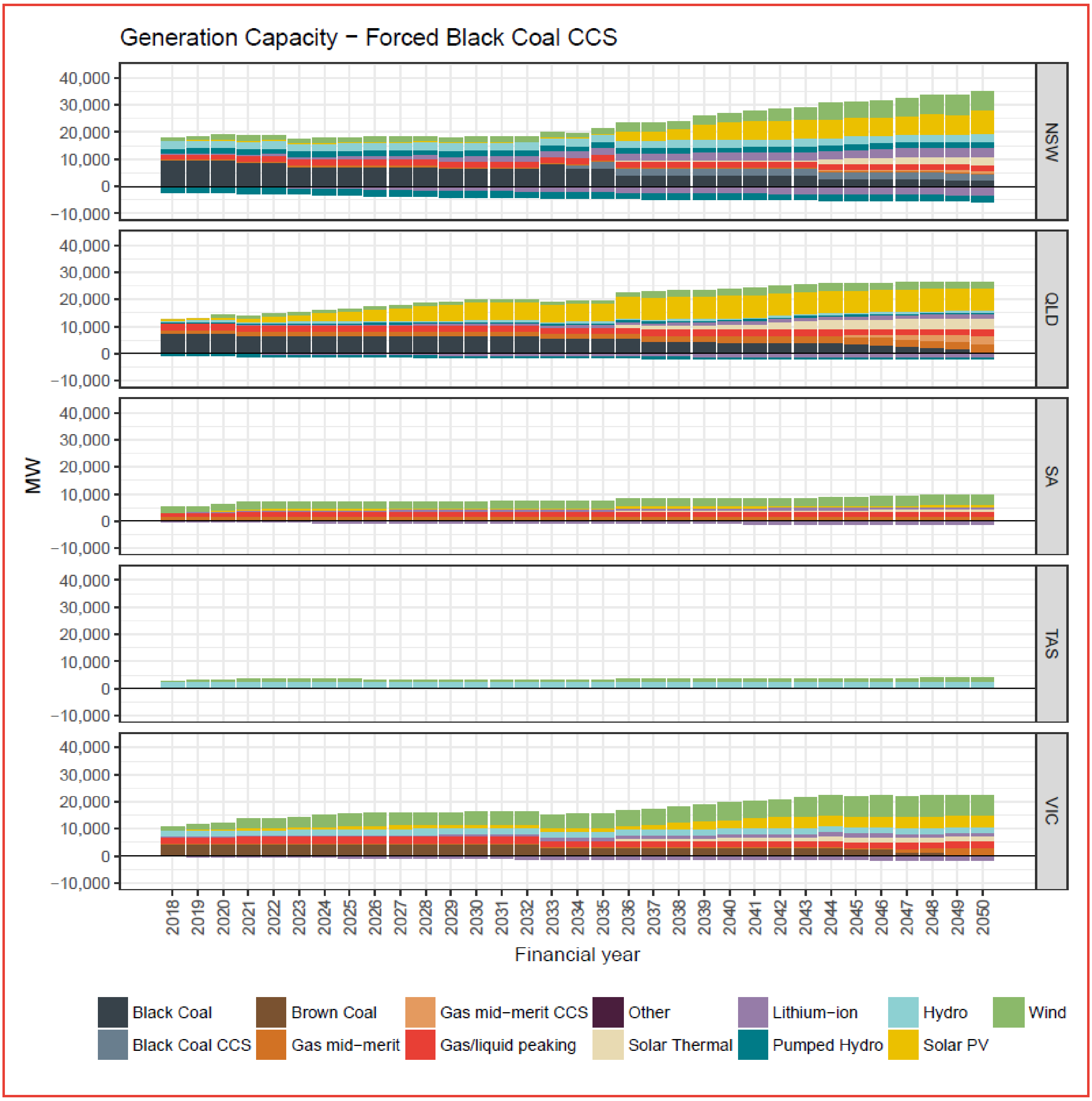
Source: Frontier Economics

Figure 78: High Gas Price Scenario – generation capacity, all regions



Source: Frontier Economics

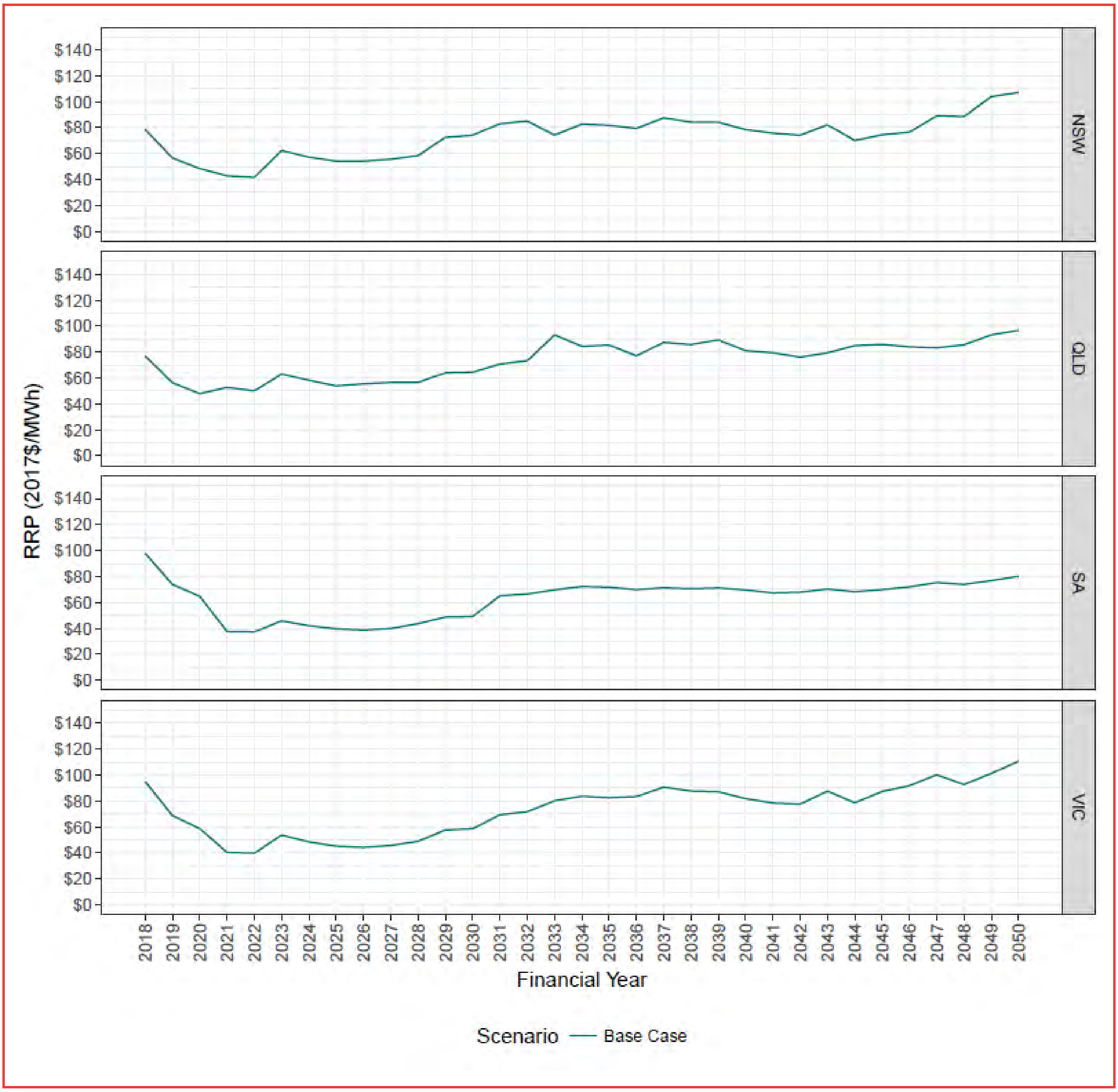
Figure 79: Forced Black Coal CCS Scenario – generation capacity, all regions



Source: Frontier Economics

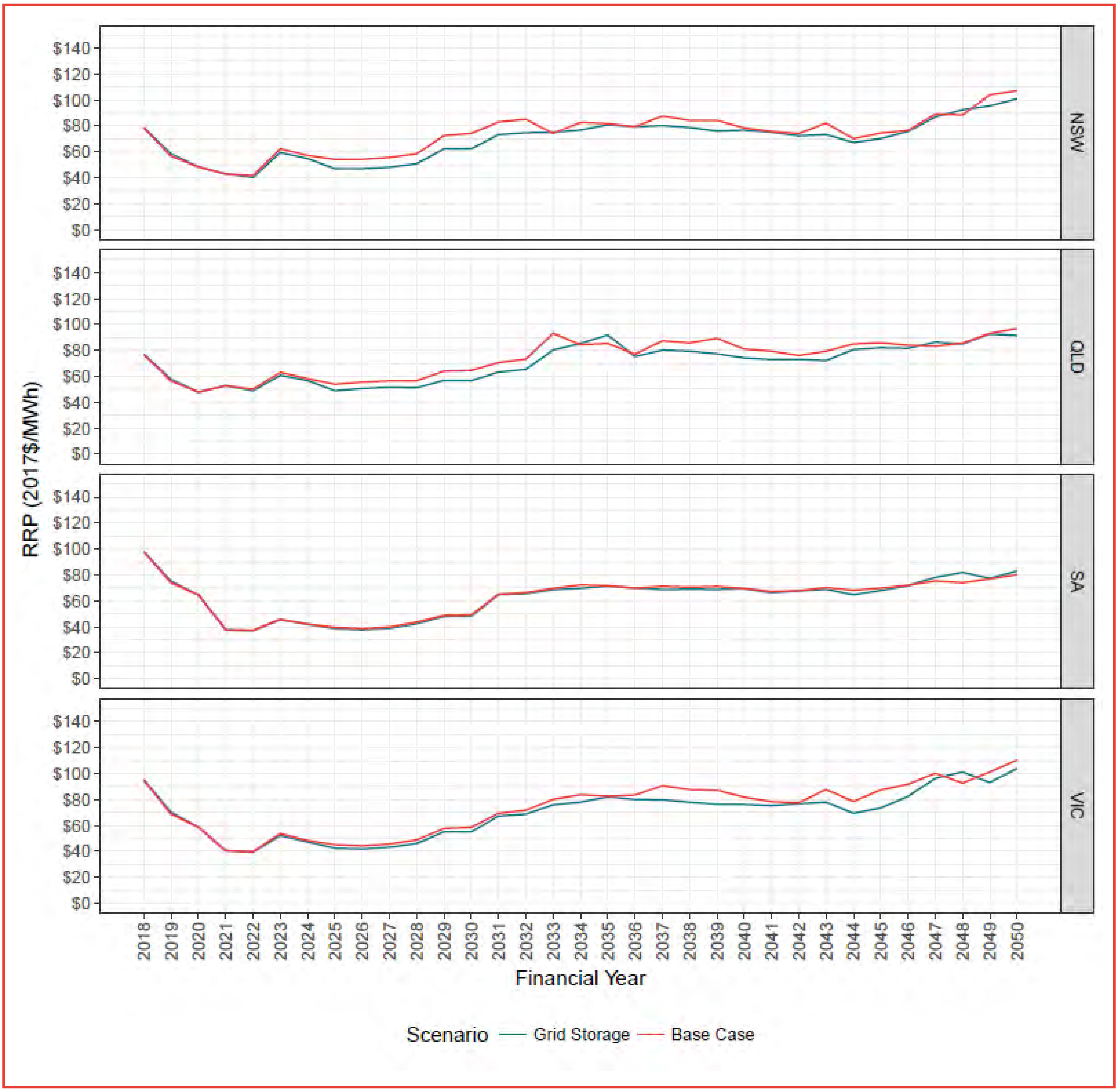
Regional price results

Figure 80: Base Case – annual average wholesale prices, all regions



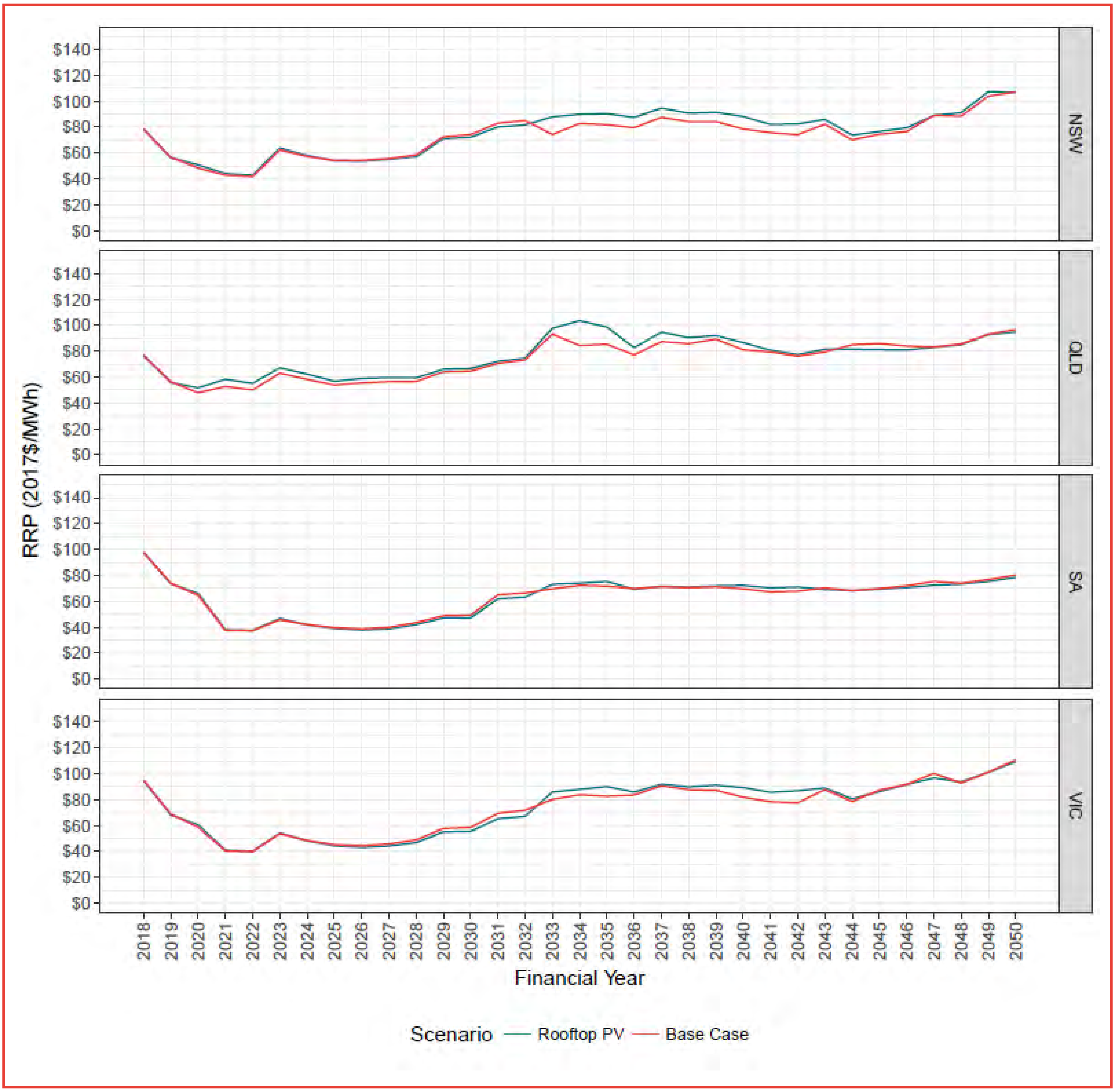
Source: Frontier Economics

Figure 81: Grid Storage Scenario– annual average wholesale prices, all regions



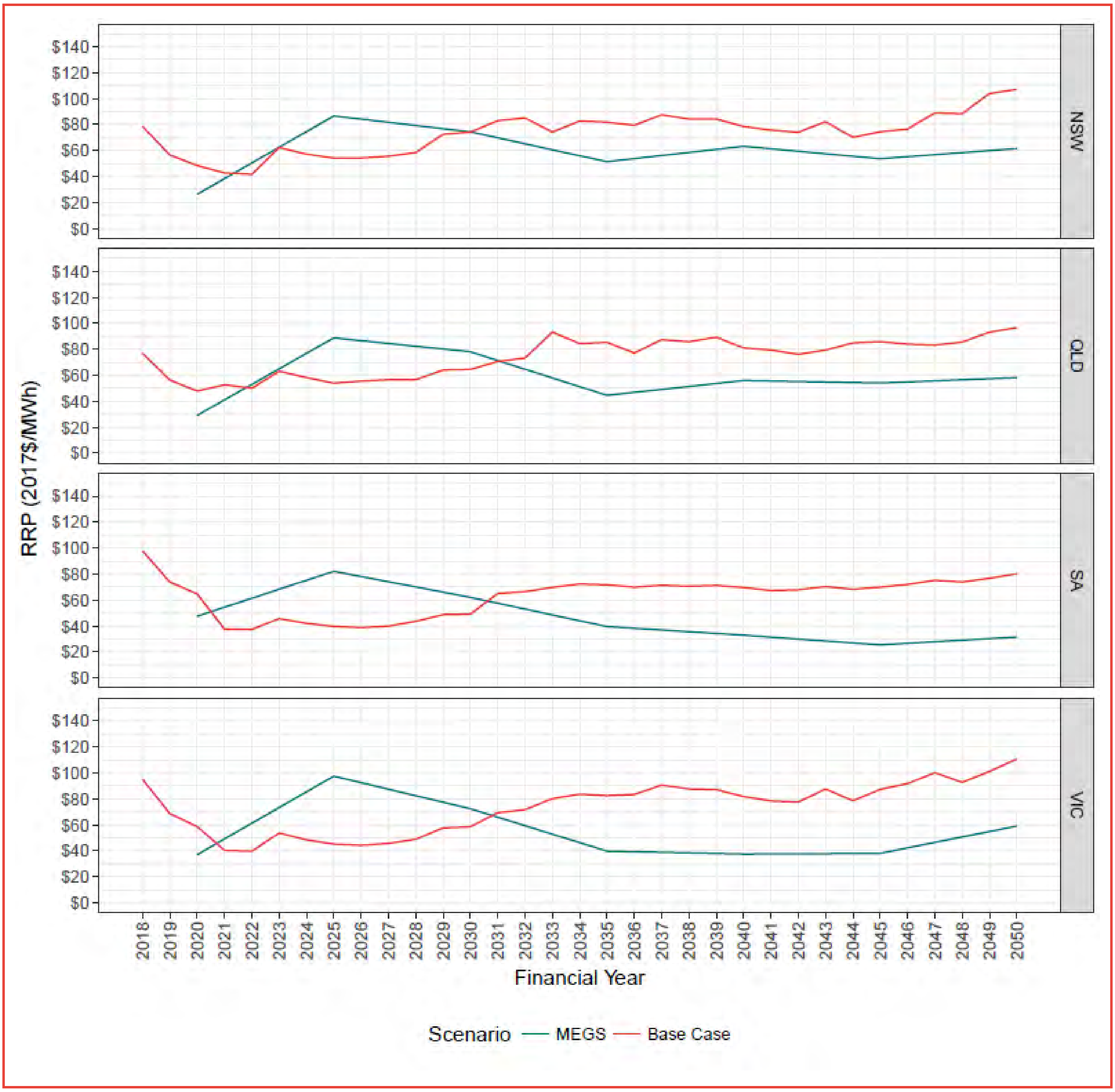
Source: Frontier Economics

Figure 82: Rooftop PV Scenario – annual average wholesale prices, all regions



Source: Frontier Economics

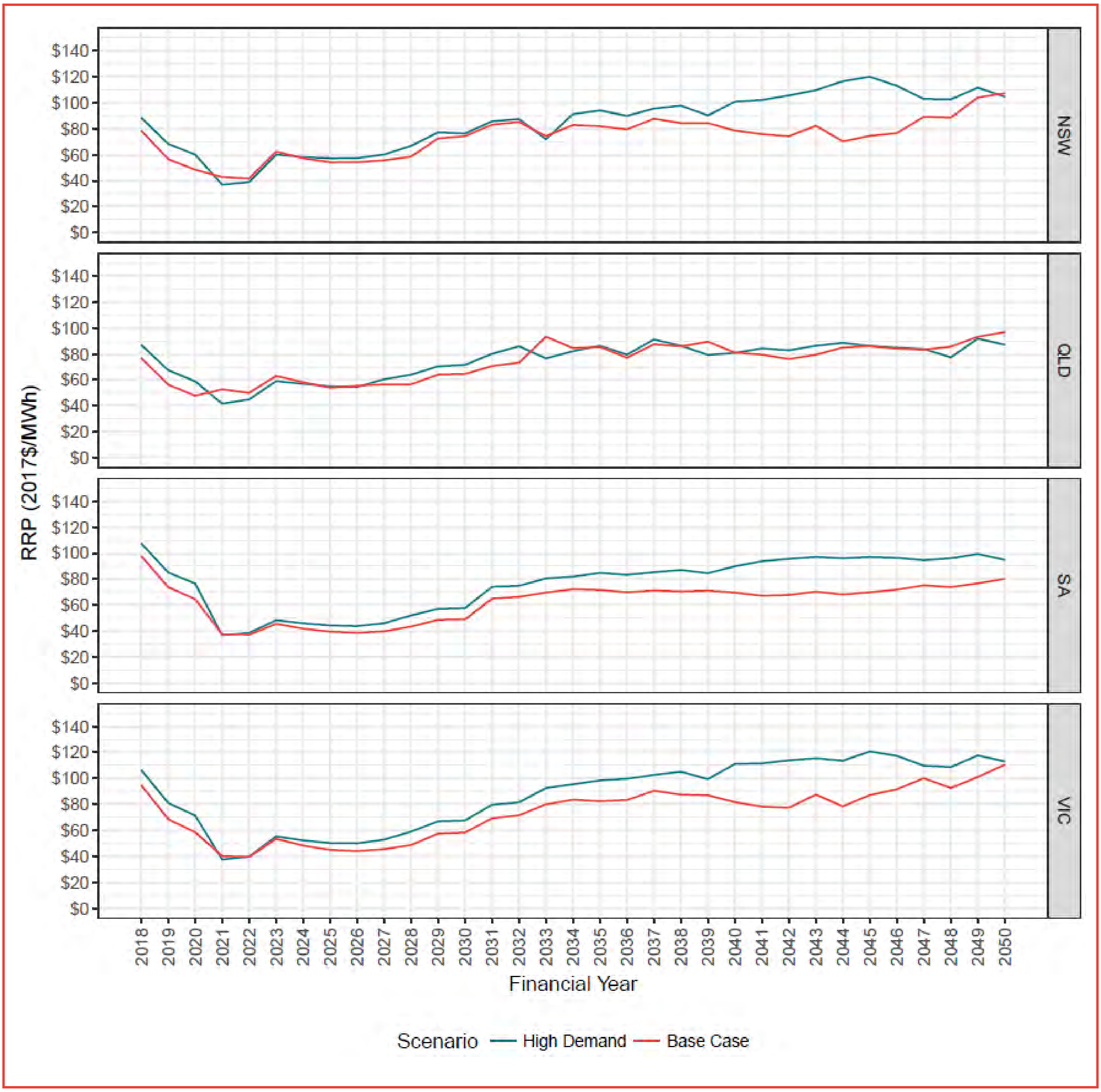
Figure 83: MEGS Scenario – annual average wholesale prices, all regions



Source: Frontier Economics

Note: Results shown for 5-year periods for MEGS Scenario, because this is the granularity of the results provided by Red Vector.

Figure 84: High Demand Scenario – annual average wholesale prices, all regions

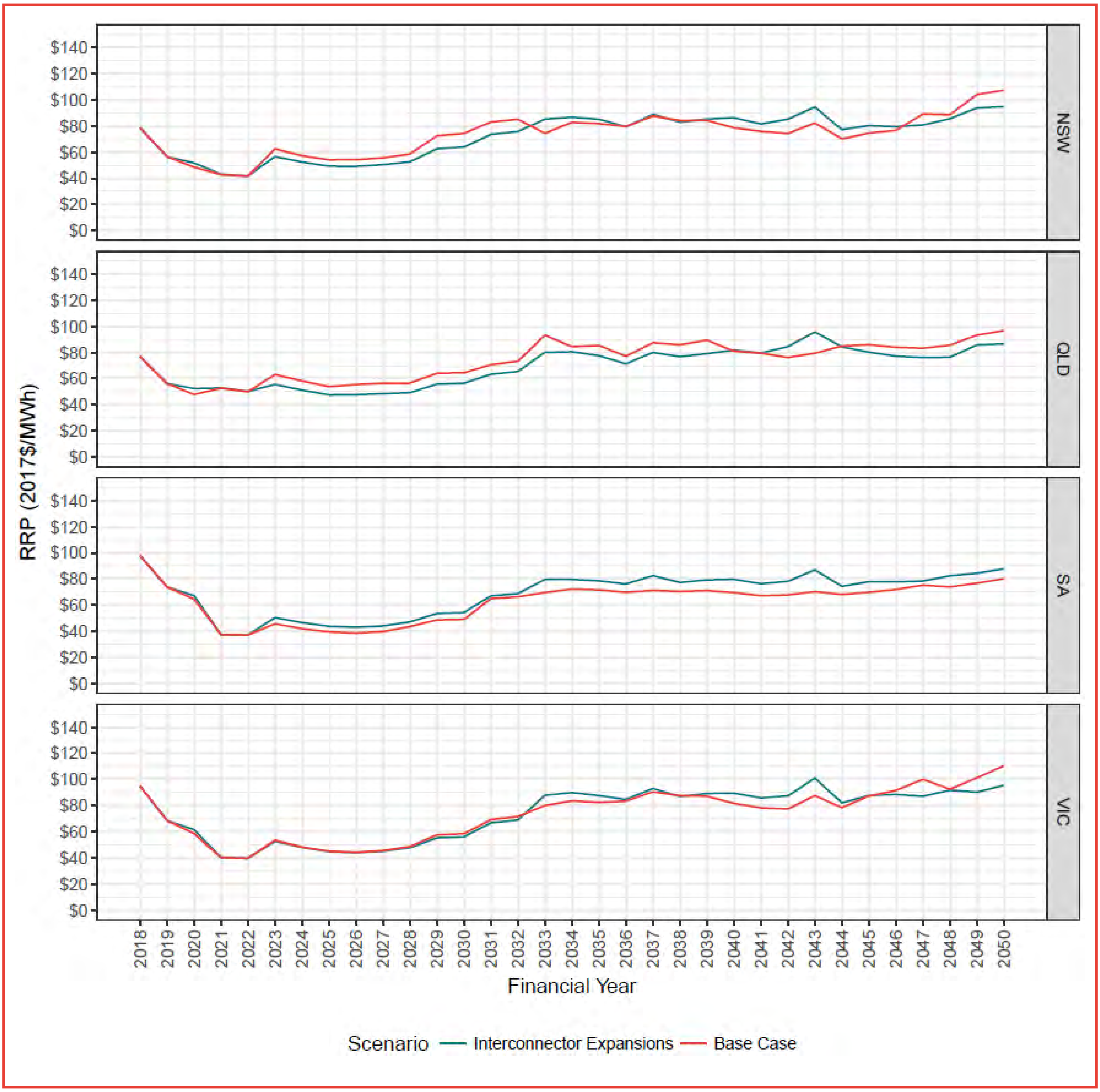


Source: Frontier Economics

Figure 85: High Solar Thermal Cost Scenario – annual average wholesale prices, all regions

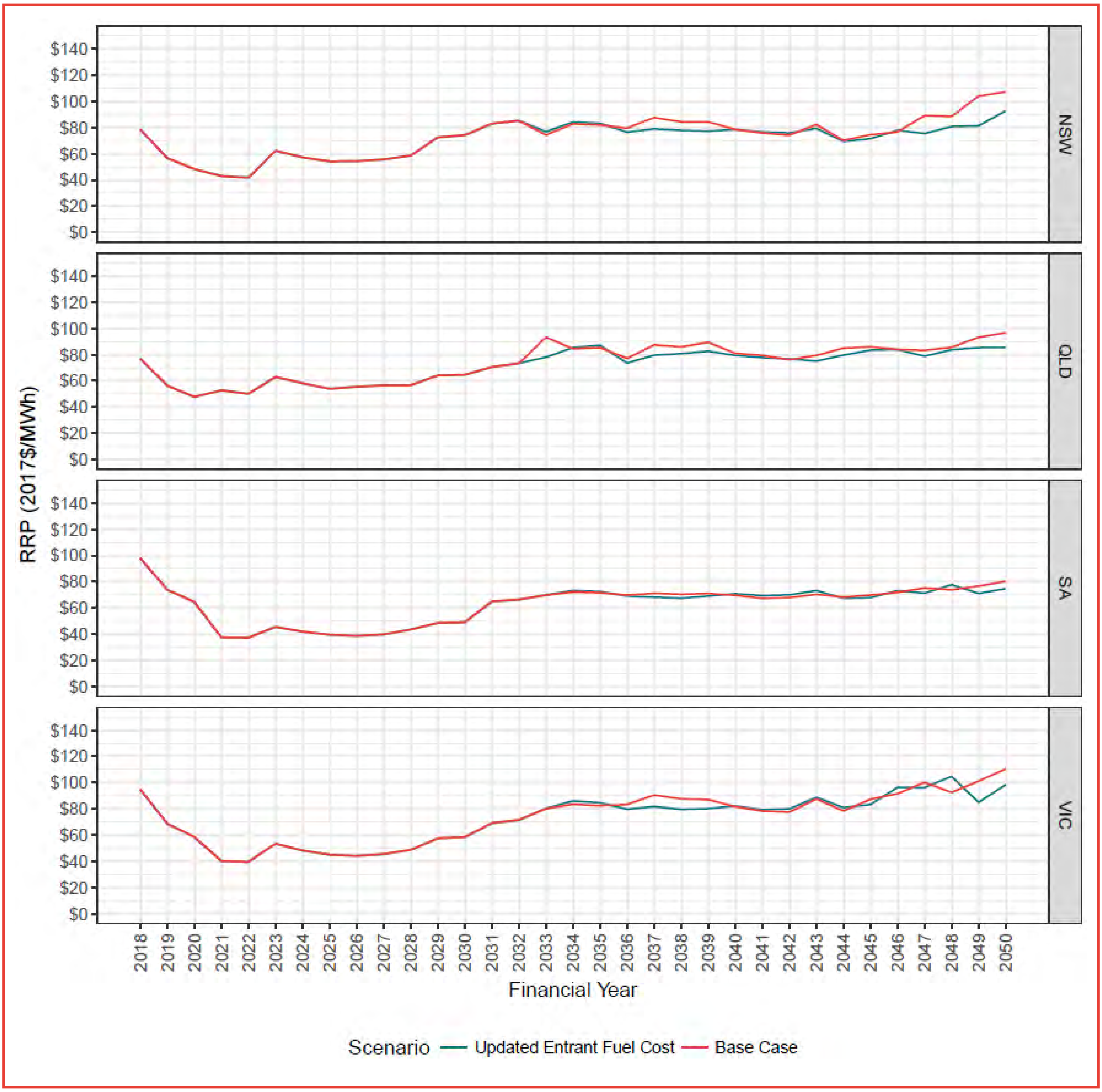
Source: Frontier Economics

Figure 86: Interconnector Expansions Scenario – annual average wholesale prices, all regions



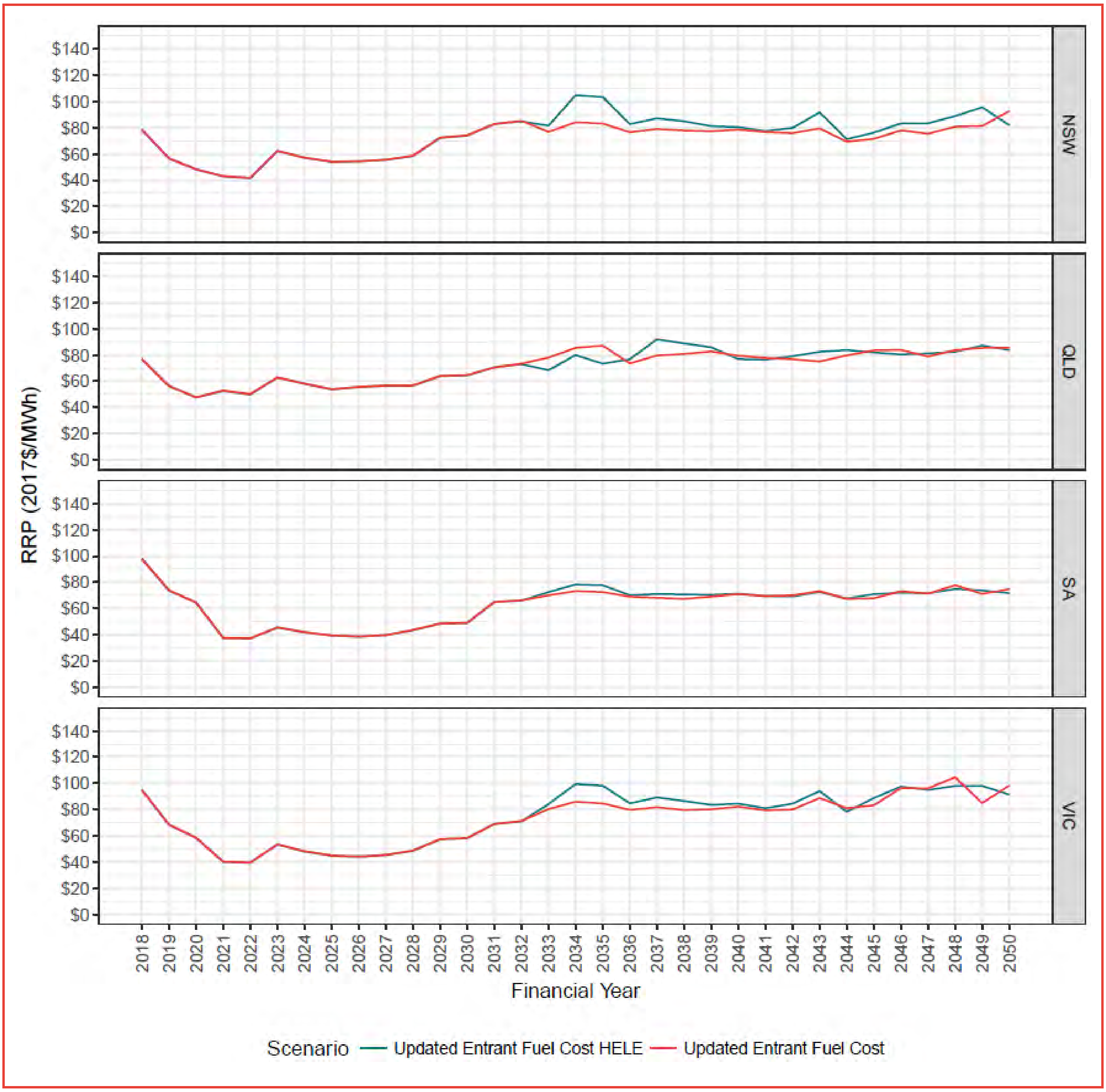
Source: Frontier Economics

Figure 87: Updated Entrant Fuel Cost Scenario – annual average wholesale prices, all regions



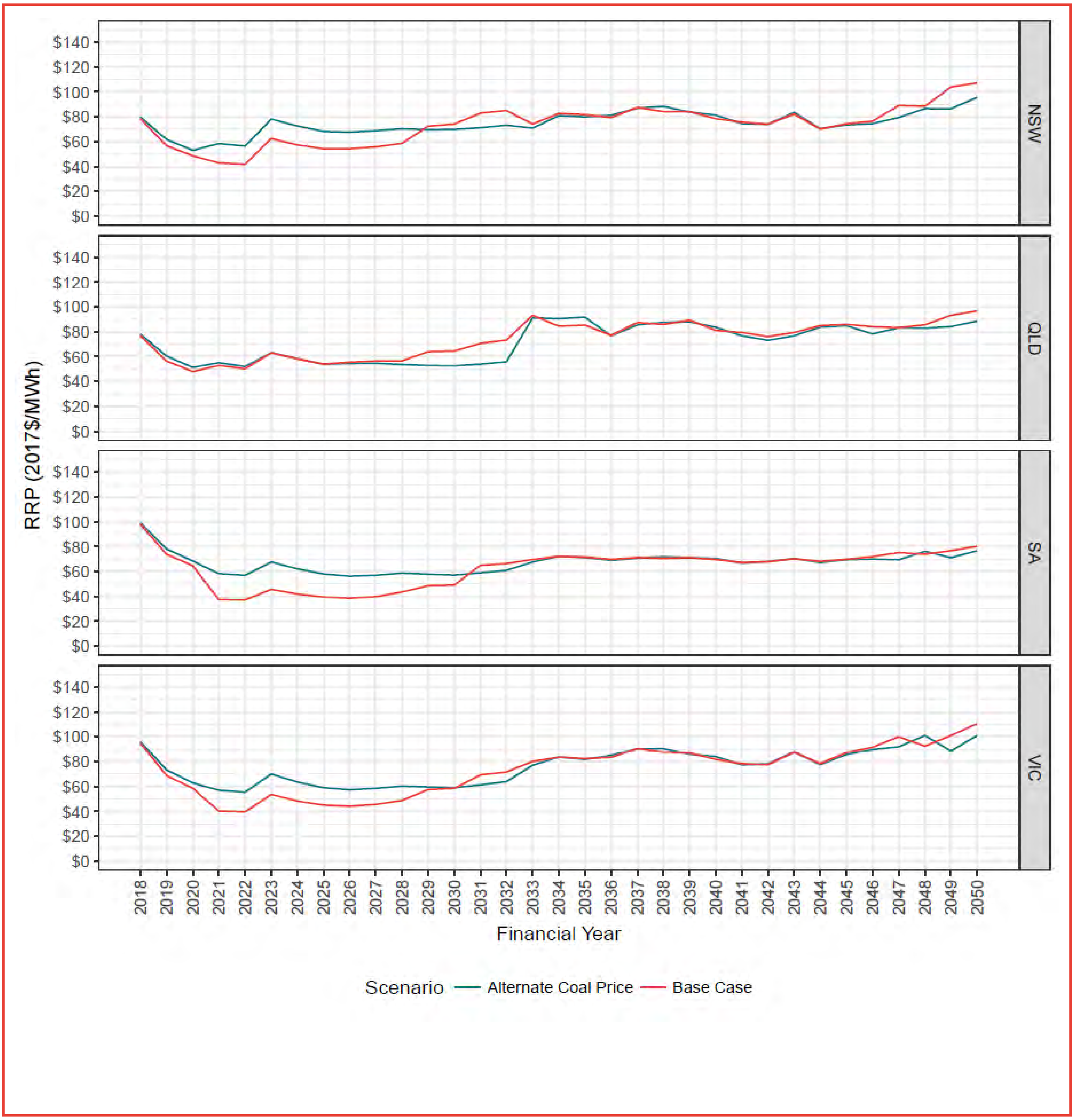
Source: Frontier Economics

Figure 88: Updated Entrant Fuel Cost HELE Scenario – annual average wholesale prices, all regions



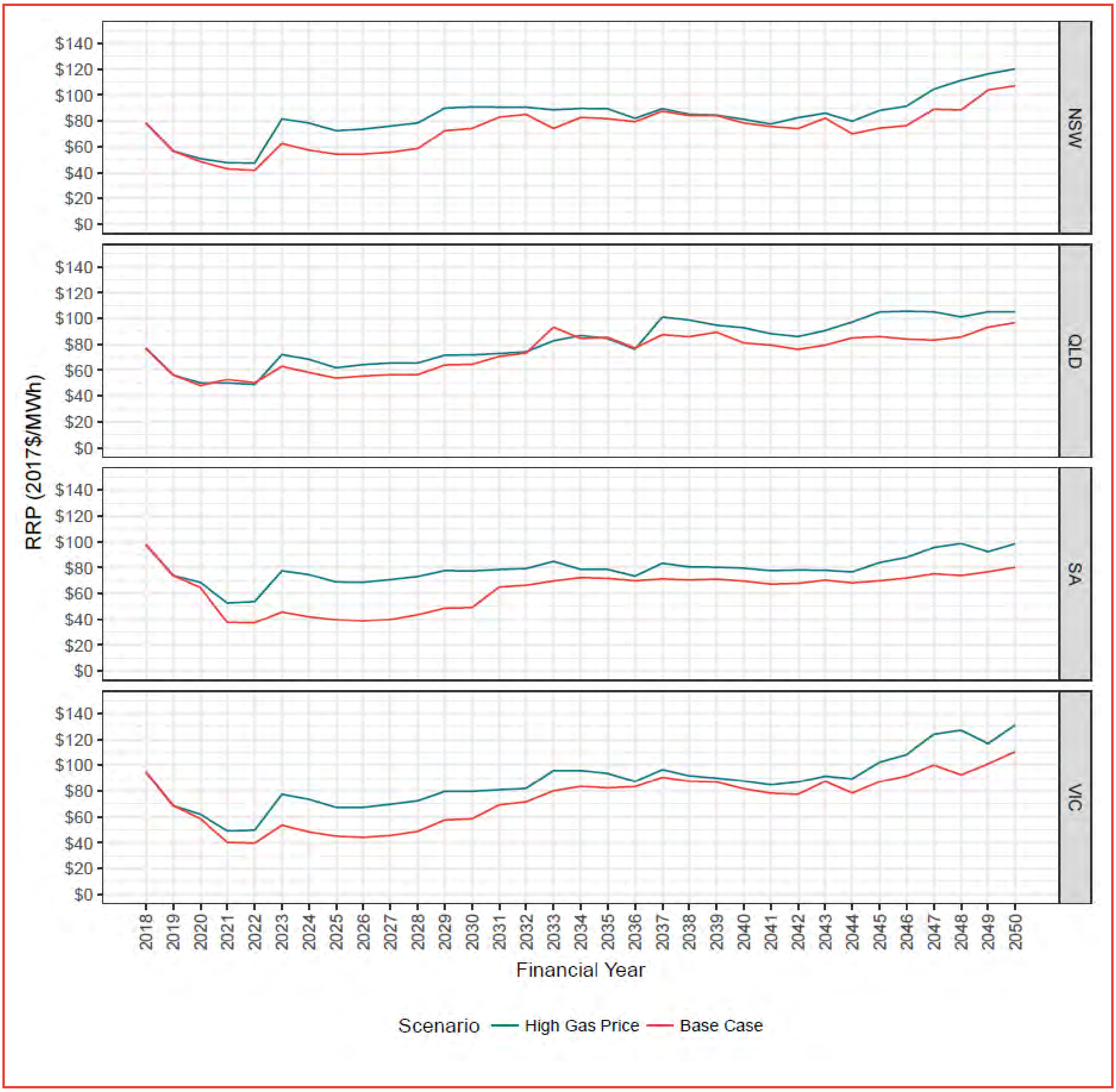
Source: Frontier Economics

Figure 89: Alternate Coal Price Scenario – annual average wholesale prices, all regions



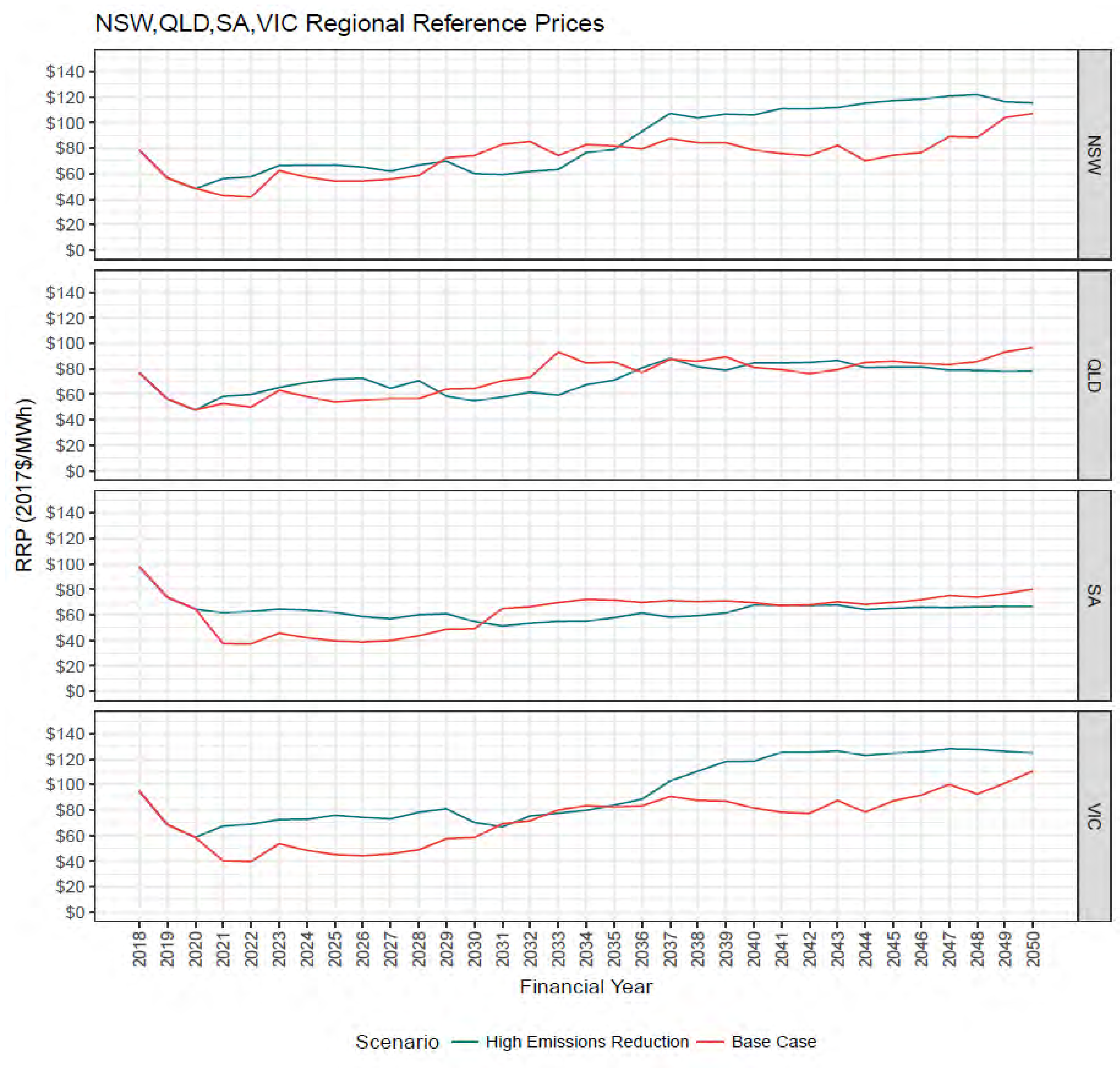
Source: Frontier Economics

Figure 90: High Gas Price Scenario – annual average wholesale prices, all regions



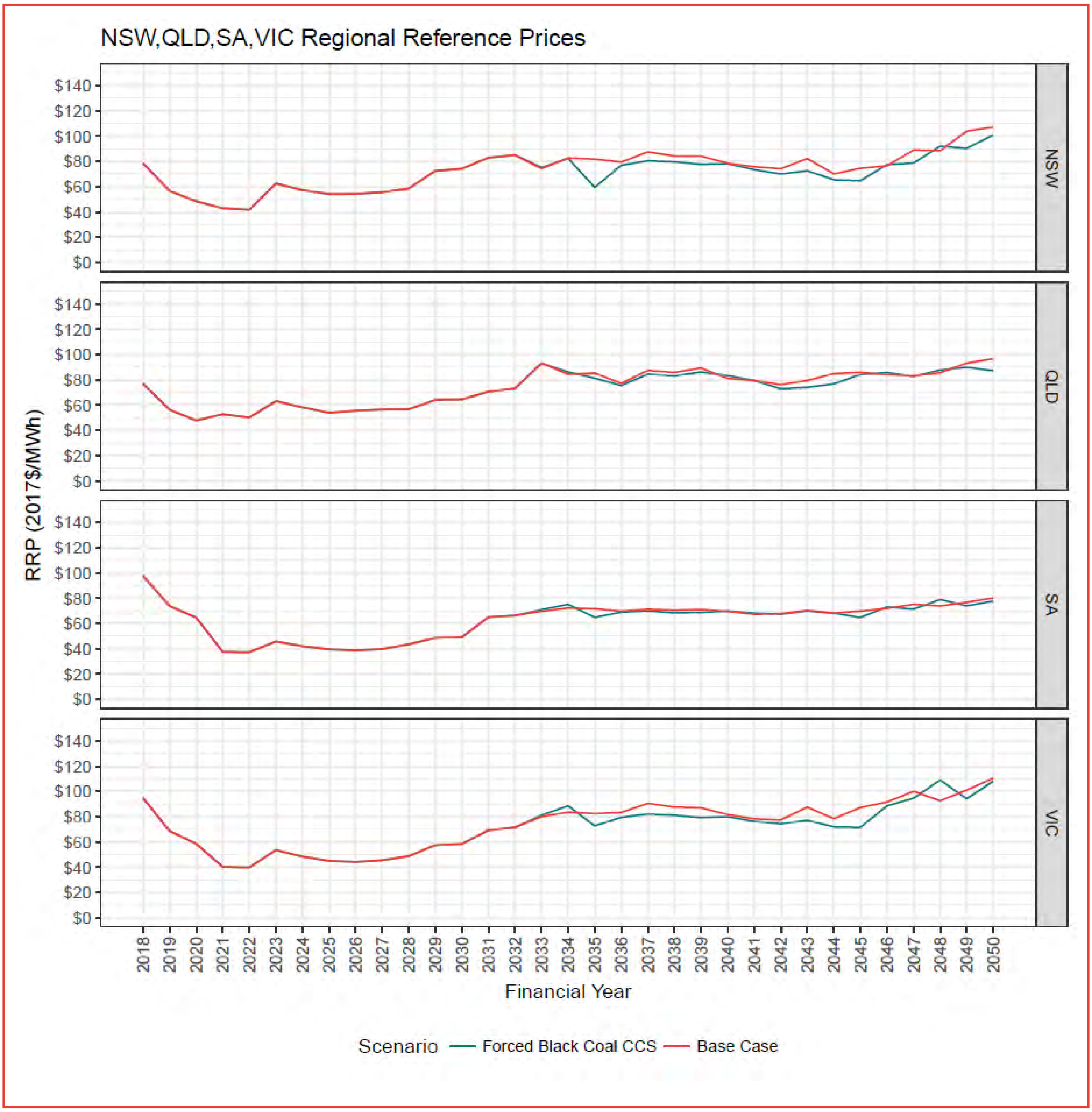
Source: Frontier Economics

Figure 91: High Emissions Reduction Scenario – annual average wholesale prices, all regions



Source: Frontier Economics

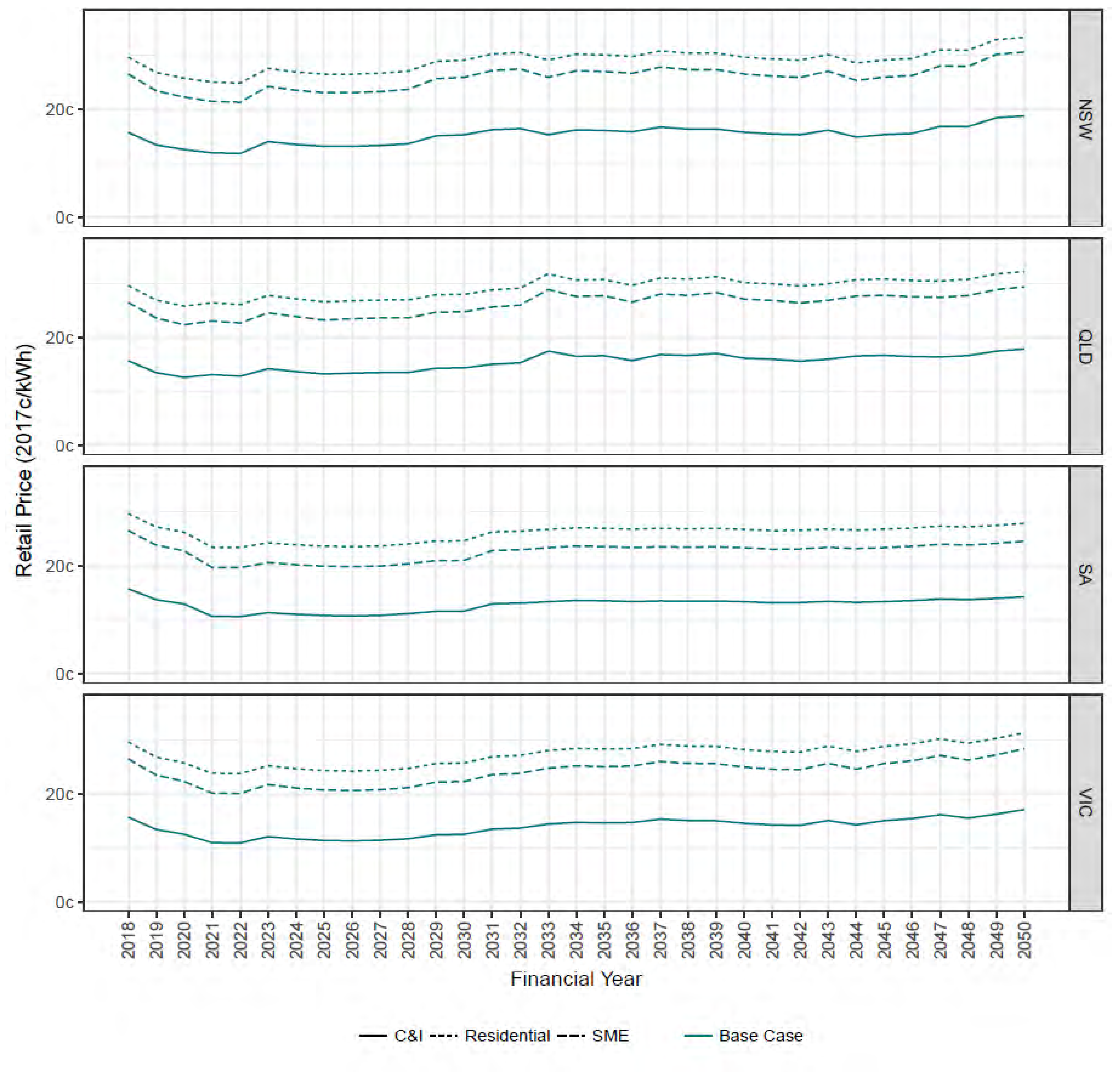
Figure 92: Forced Black Coal CCS Scenario – annual average wholesale prices, all regions



Source: Frontier Economics

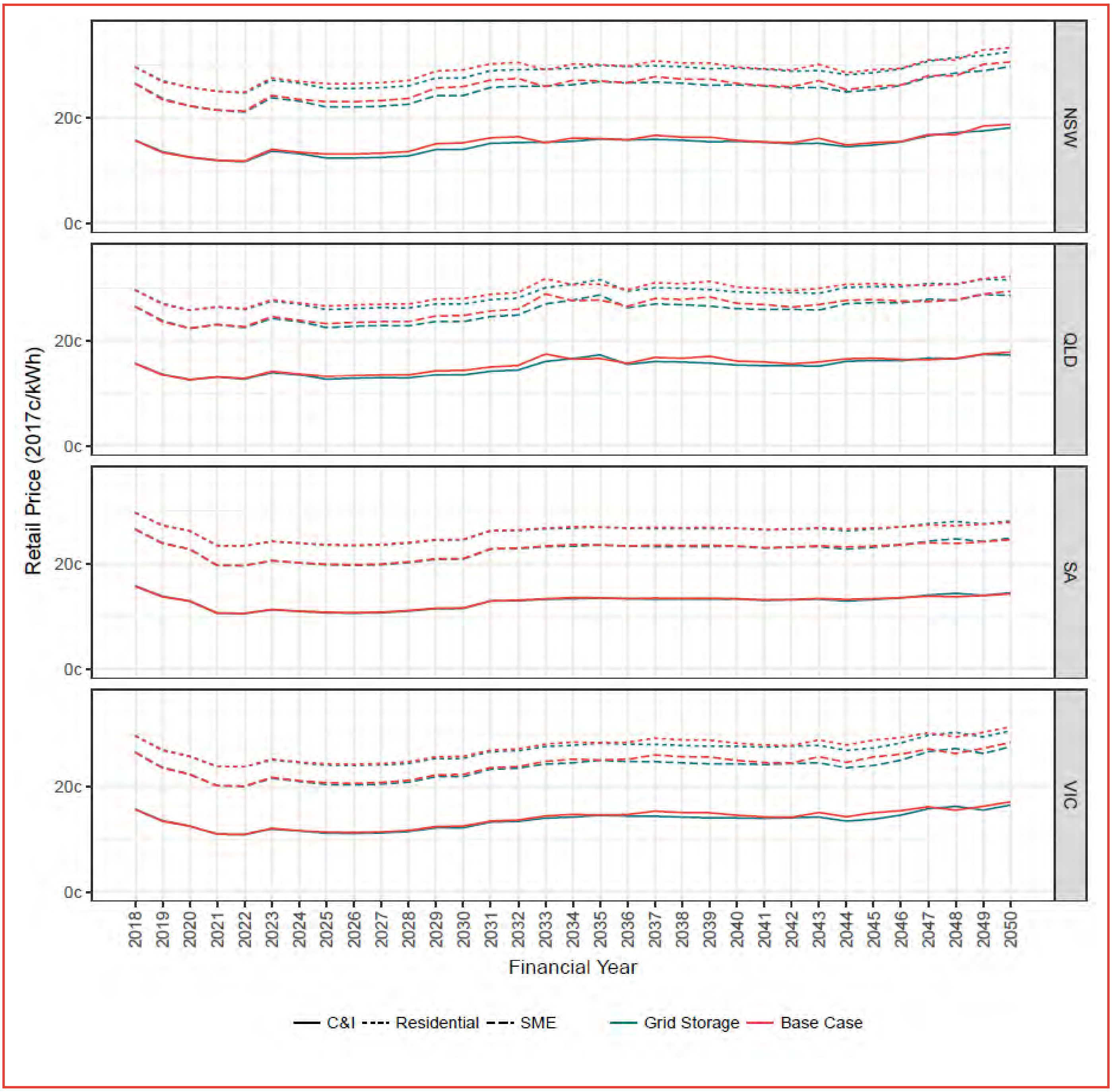
Retail price results

Figure 93: Base Case – annual average retail prices, all regions



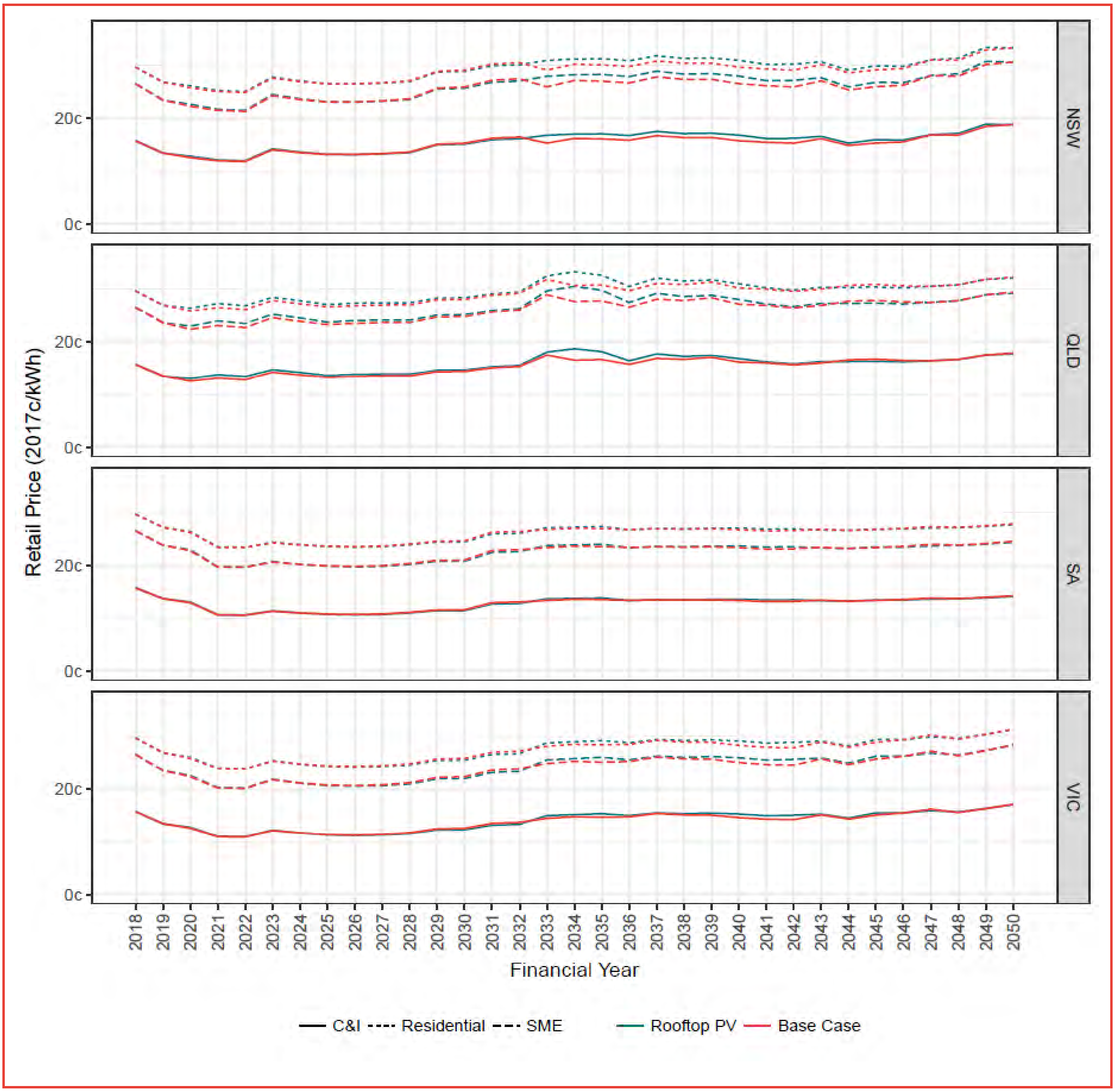
Source: Frontier Economics

Figure 94: Grid Storage Scenario – annual average retail prices, all regions



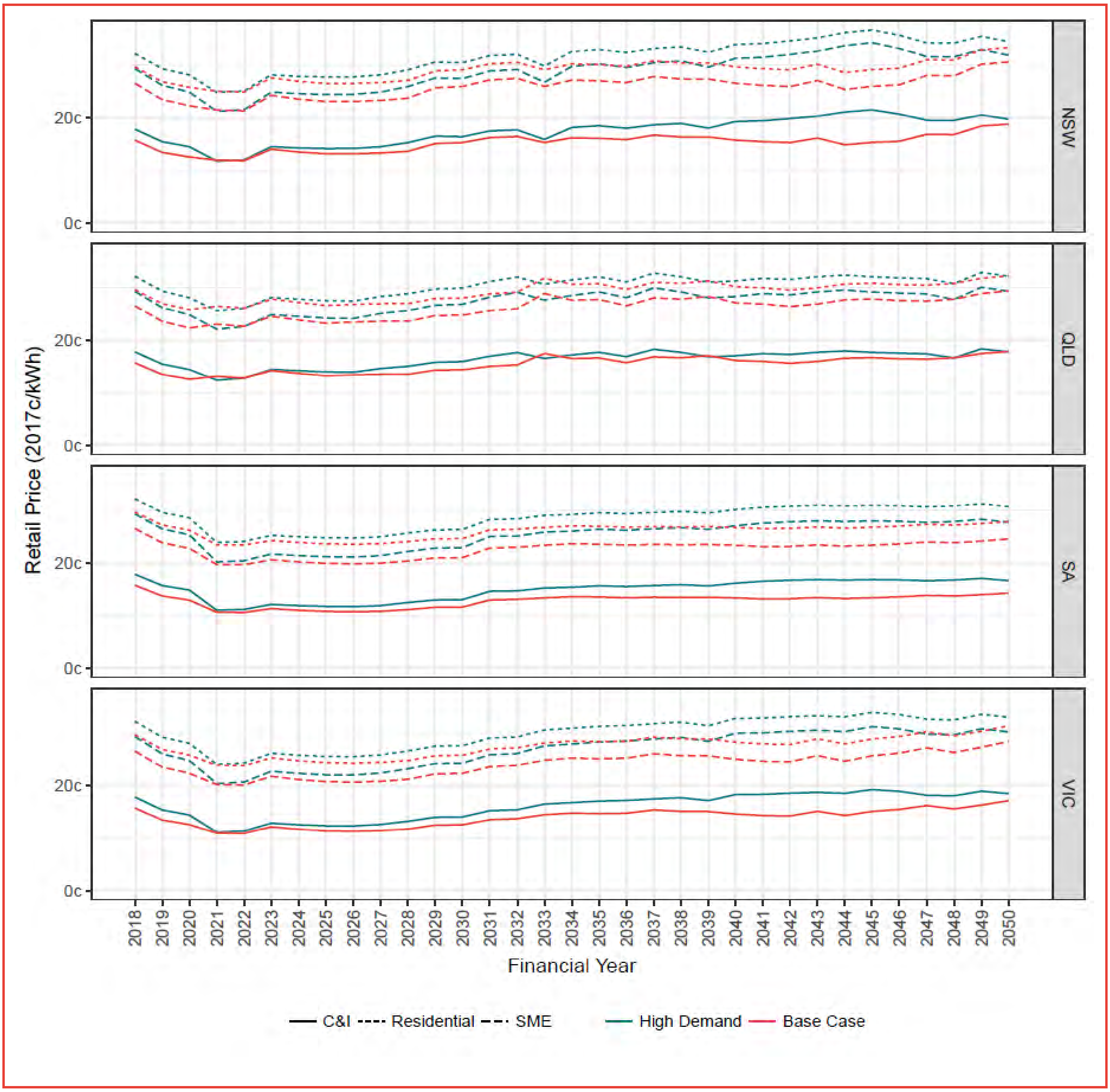
Source: Frontier Economics

Figure 95: Rooftop PV Scenario – annual average retail prices, all regions



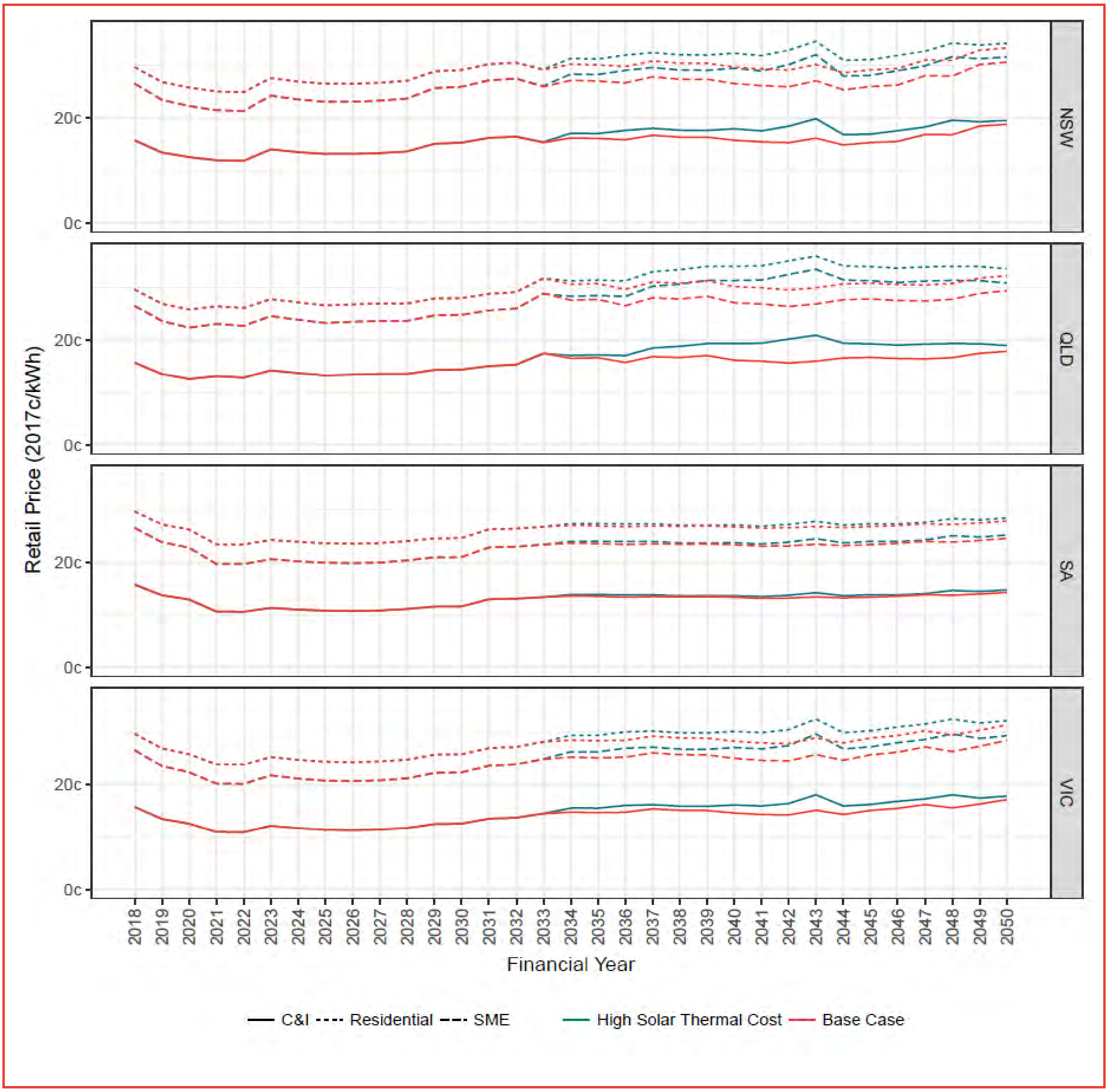
Source: Frontier Economics

Figure 96: High Demand Scenario – annual average retail prices, all regions



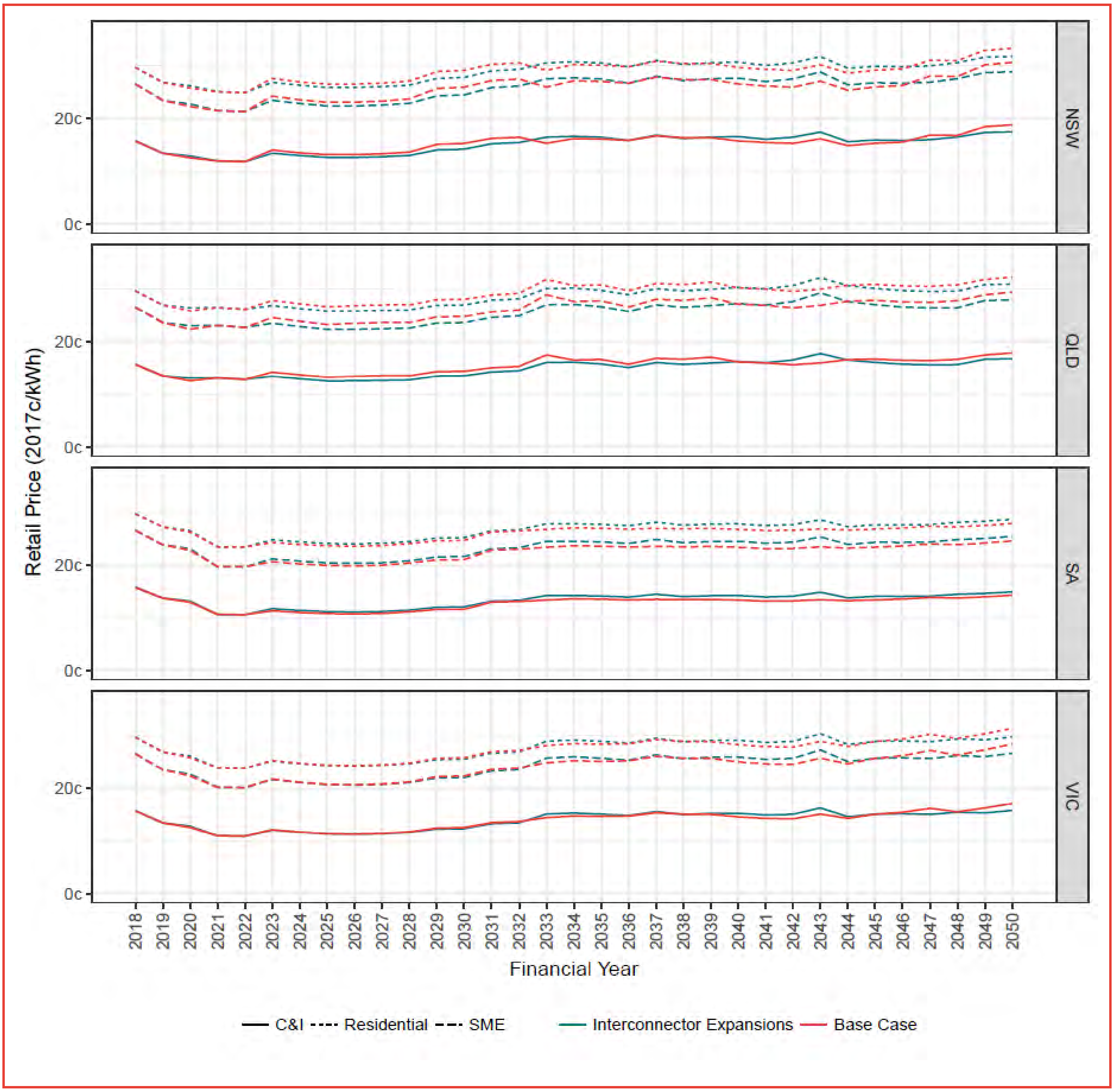
Source: Frontier Economics

Figure 97: High Solar Thermal Cost Scenario – annual average retail prices, all regions



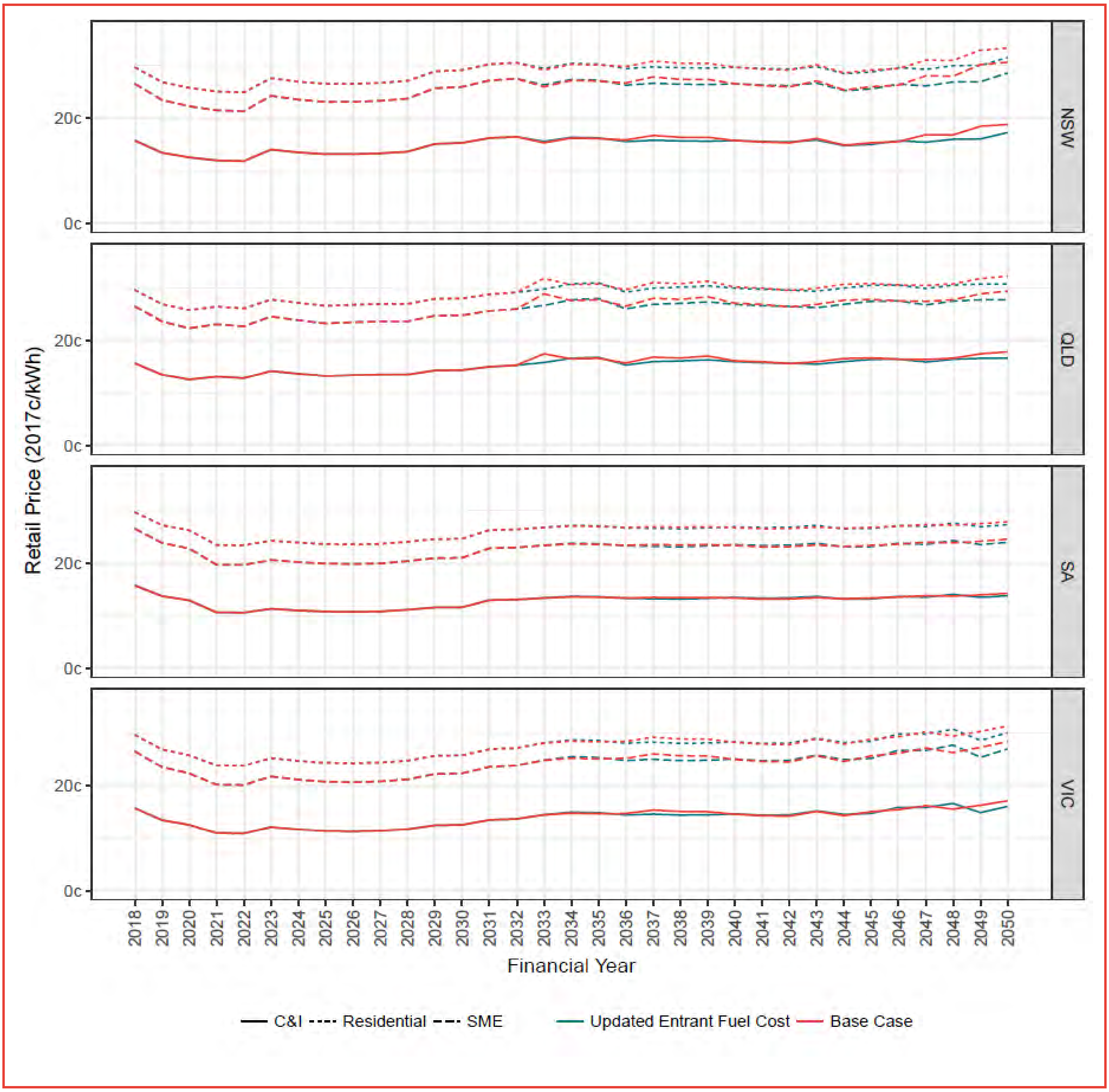
Source: Frontier Economics

Figure 98: Interconnector Expansions Scenario – annual average retail prices, all regions



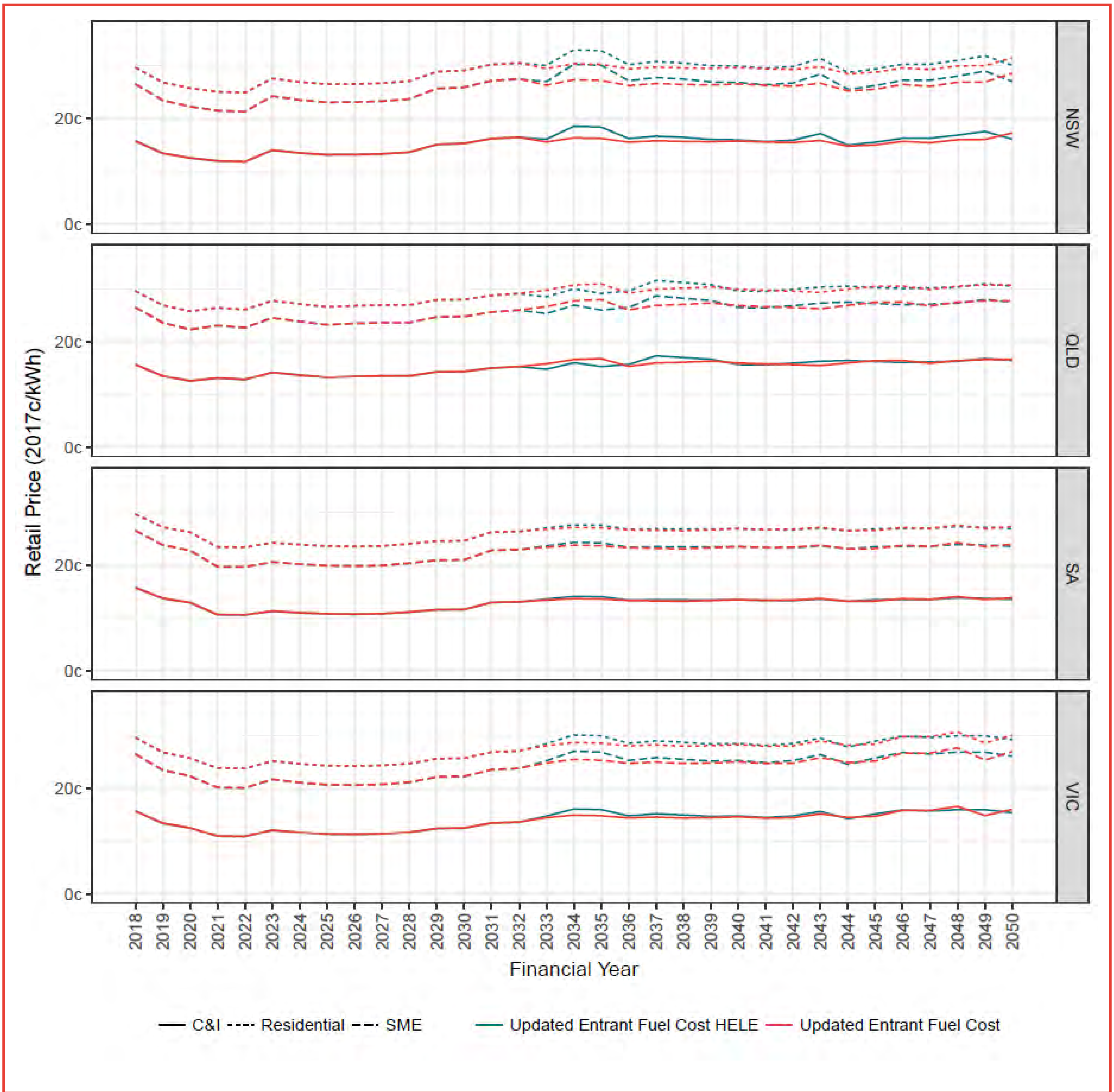
Source: Frontier Economics

Figure 99: Updated Entrant Fuel Cost Scenario – annual average retail prices, all regions



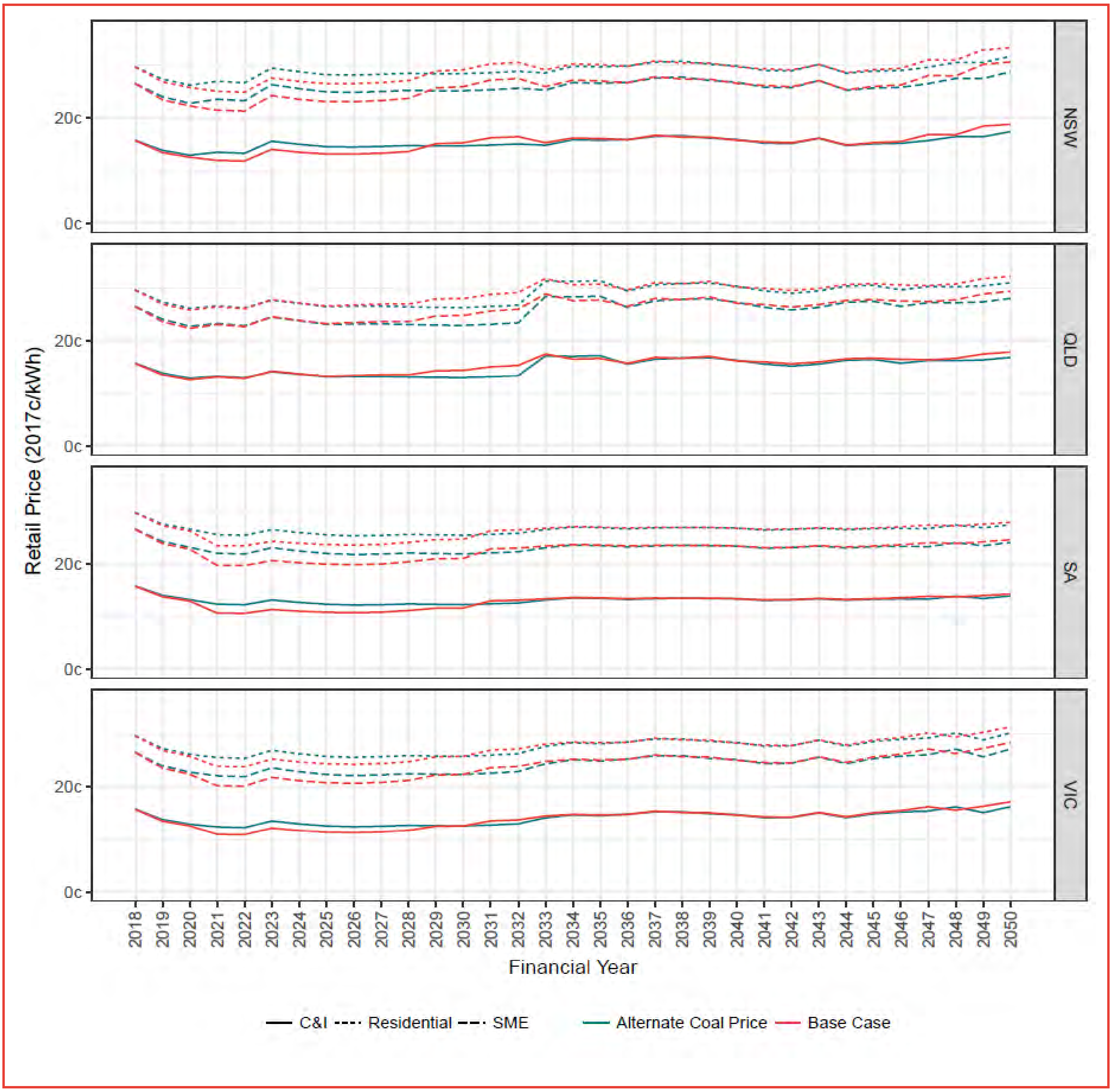
Source: Frontier Economics

Figure 100: Updated Entrant Fuel Cost HELE Scenario – annual average retail prices, all regions



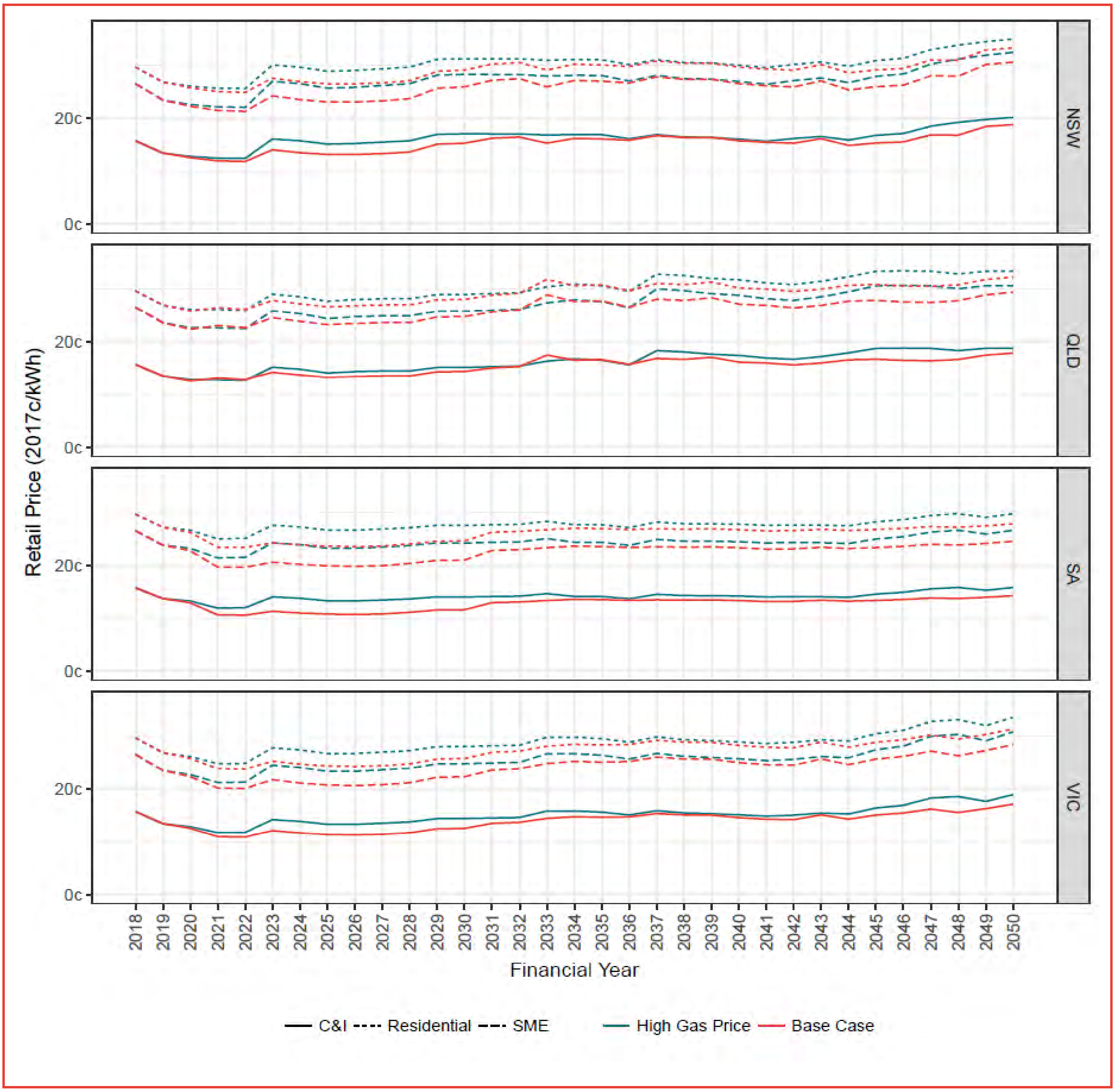
Source: Frontier Economics

Figure 101: Alternate Coal Price Scenario – annual average retail prices, all regions



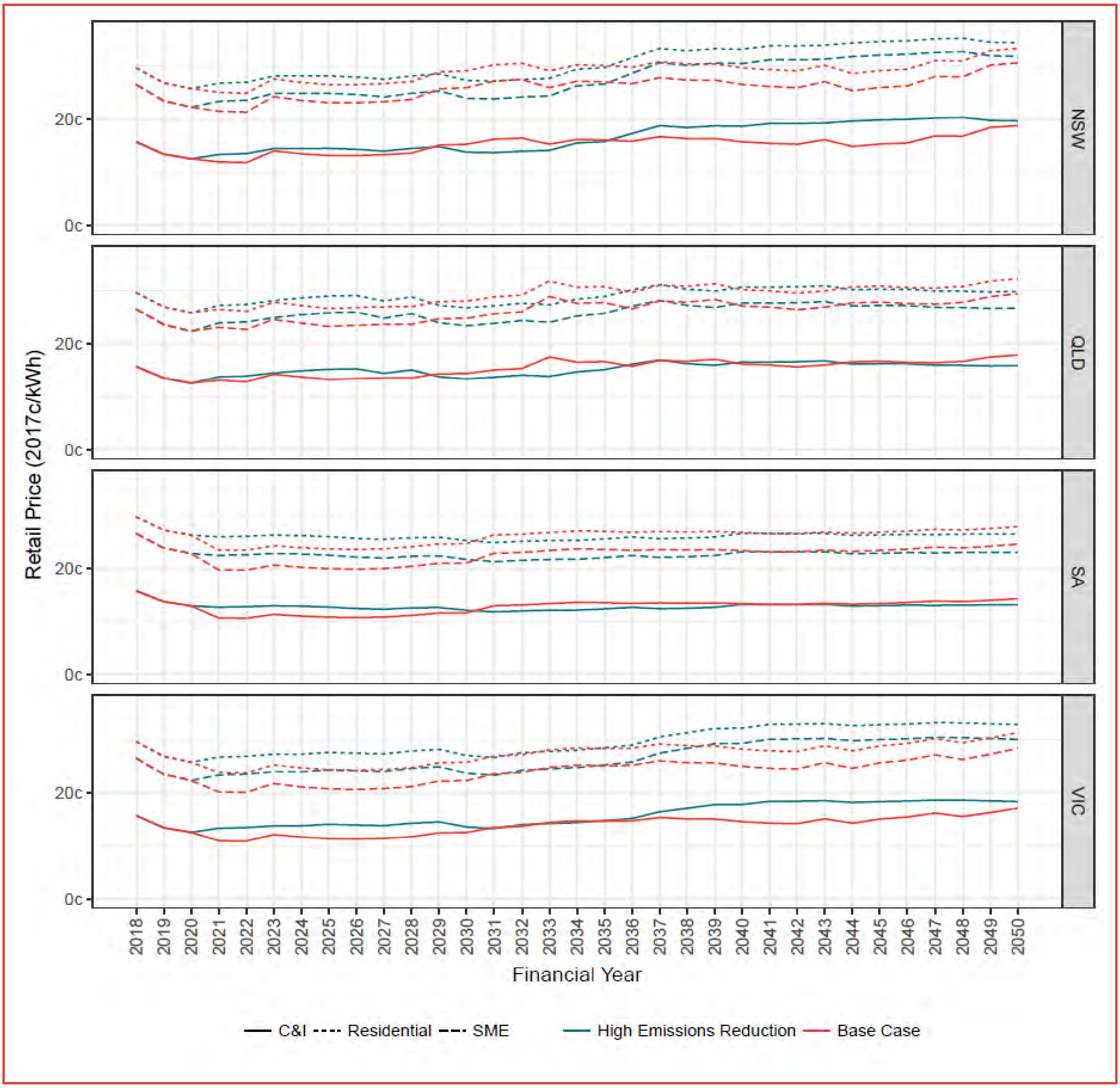
Source: Frontier Economics

Figure 102: High Gas Price Scenario – average annual retail prices, all regions



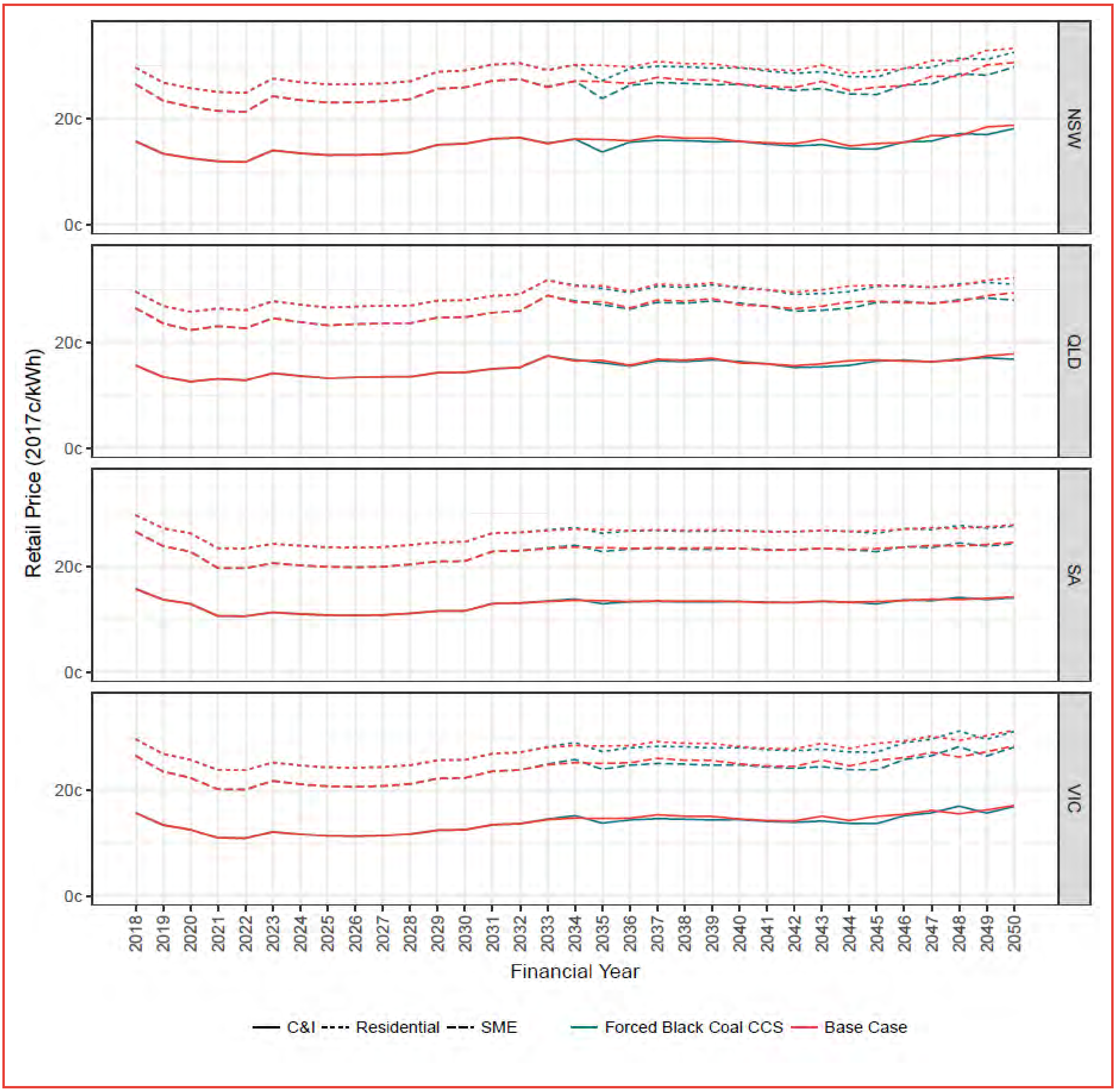
Source: Frontier Economics

Figure 103: High Emissions Reduction Scenario – average annual retail prices, all regions



Source: Frontier Economics

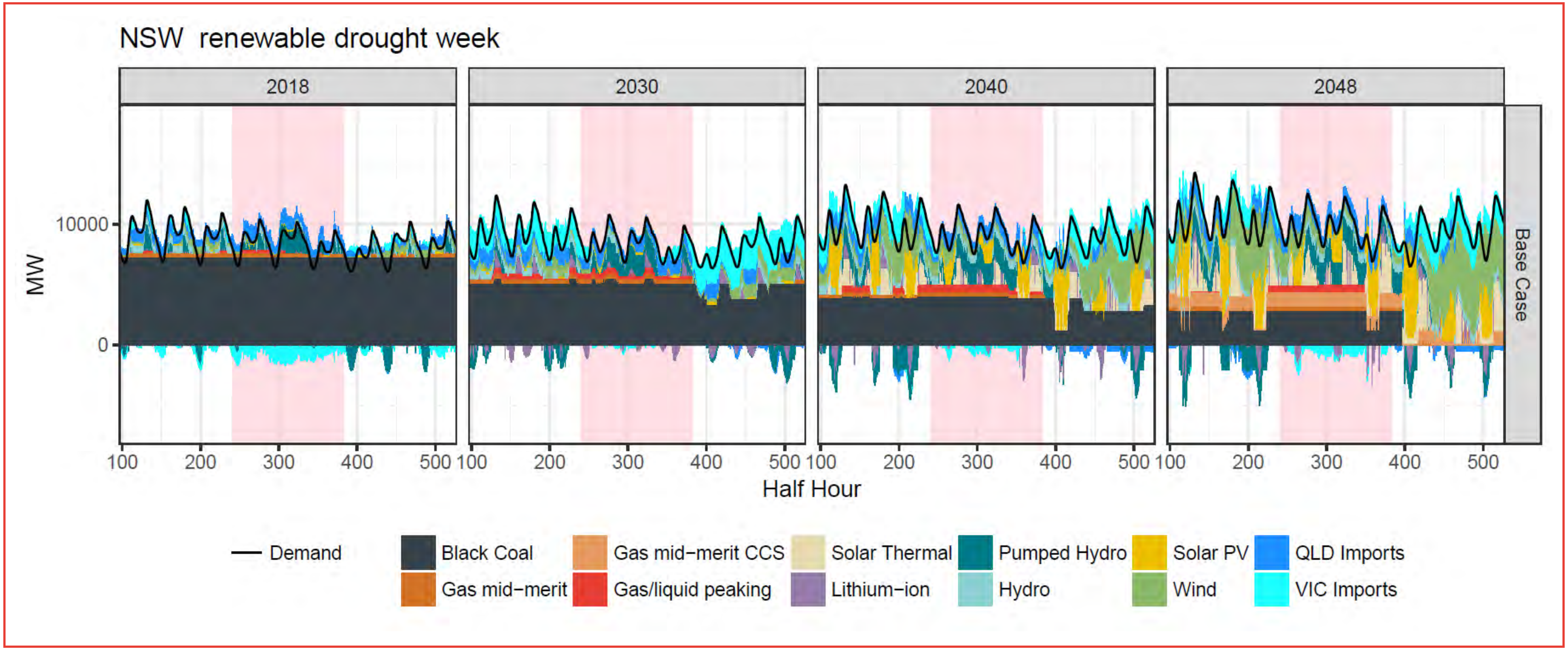
Figure 104: Forced Black Coal CCS Scenario – average annual retail prices, all regions



Source: Frontier Economics

NSW half-hourly dispatch results for week of lowest renewable generation (which occurs in early July)

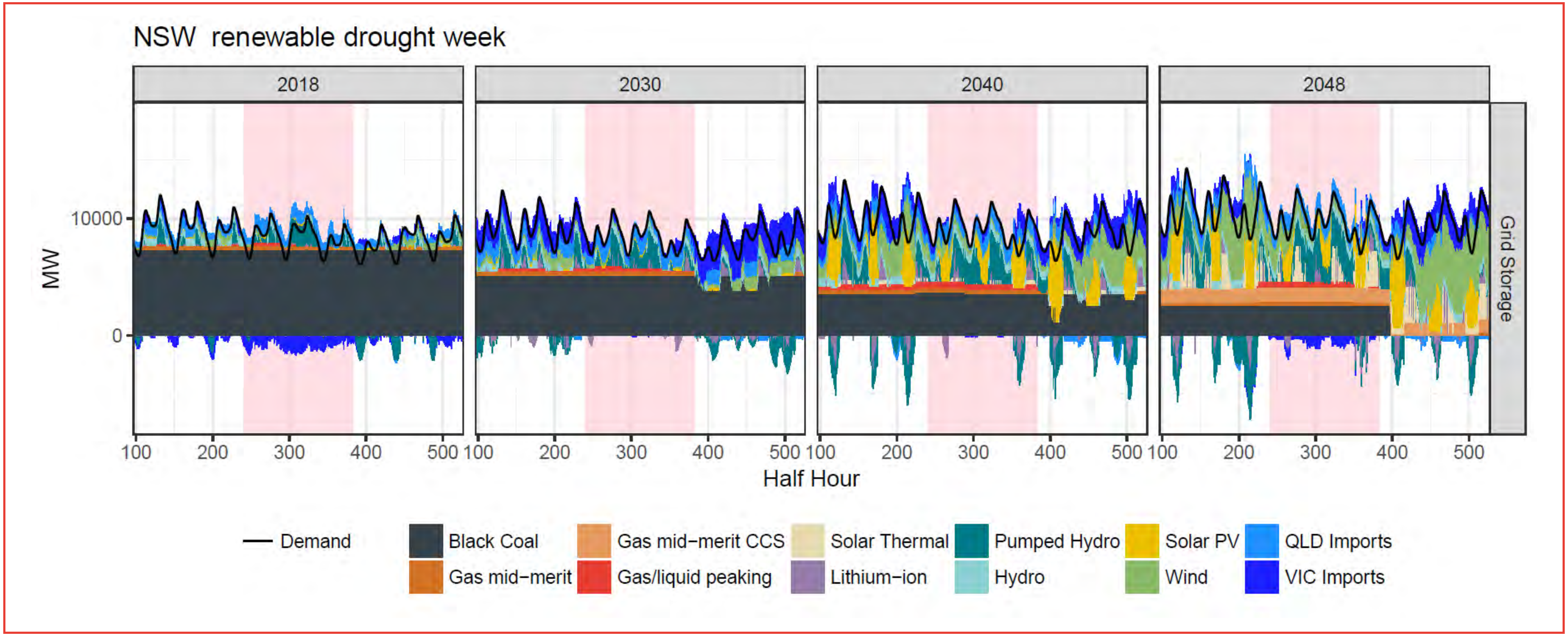
Figure 105: Base Case – half-hourly dispatch for week of lowest renewable



Source: Frontier Economics

Note: the x-axis records the numbered sequence of half-hours that this week represents. This is a sequence from Sunday to Sunday very early in the financial year; that is, a week in early July.

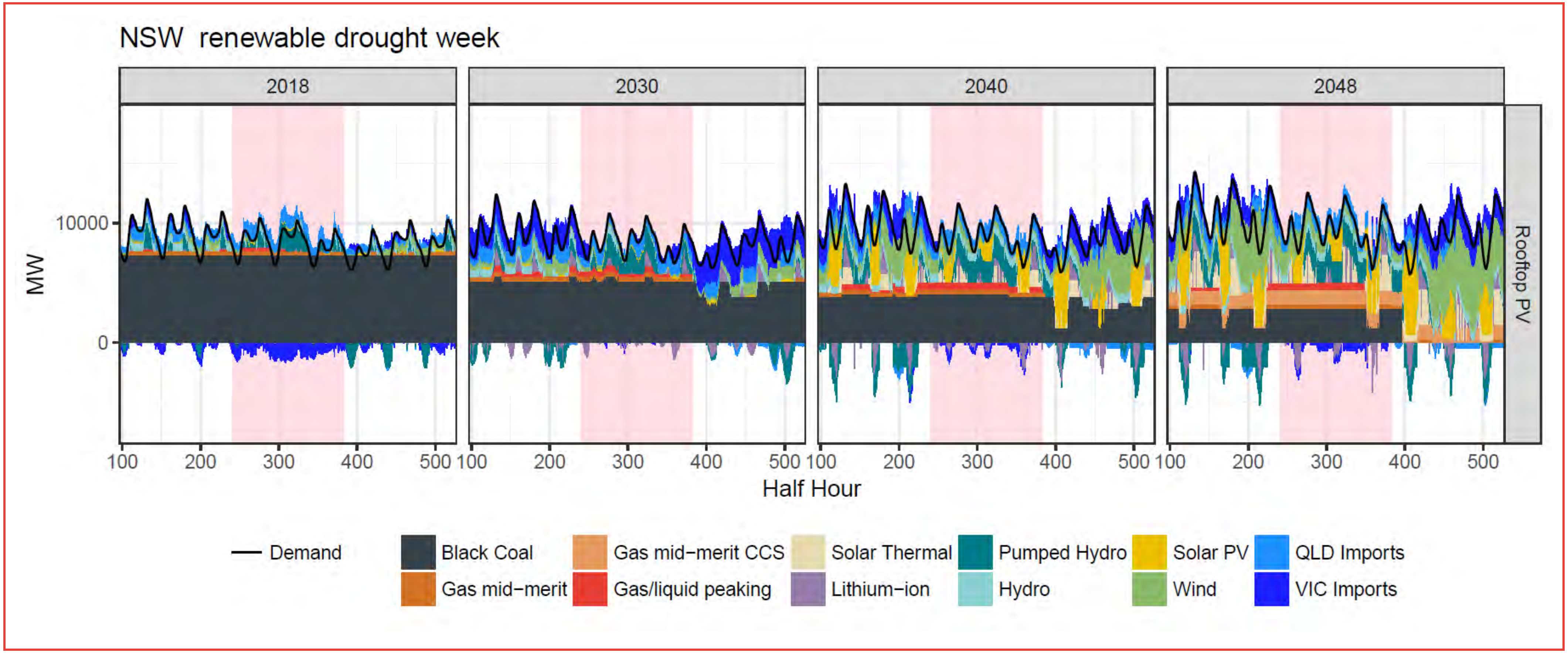
Figure 106: Grid Storage Scenario – half-hourly dispatch for week of lowest renewable



Source: Frontier Economics

Note: the x-axis records the numbered sequence of half-hours that this week represents. This is a sequence from Sunday to Sunday very early in the financial year; that is, a week in early July.

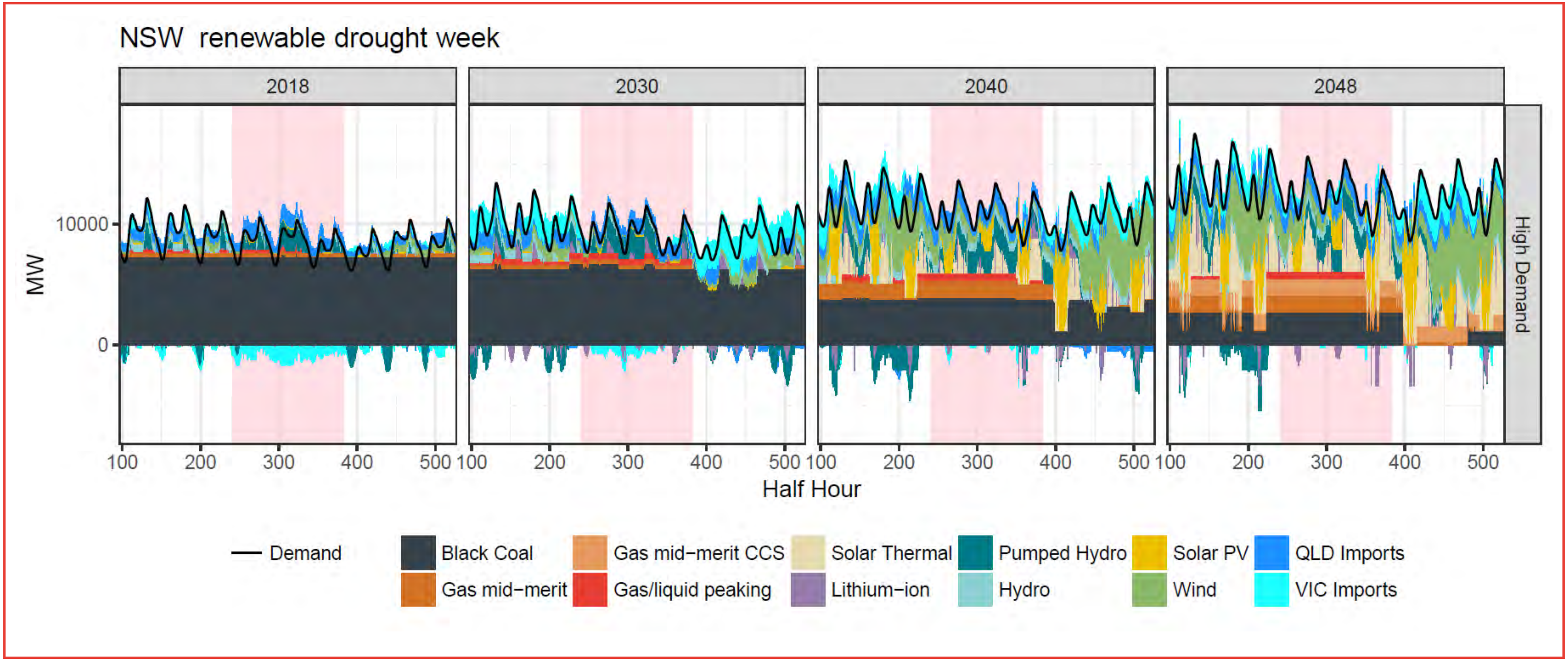
Figure 107: Rooftop PV Scenario – half-hourly dispatch for week of lowest renewable



Source: Frontier Economics

Note: the x-axis records the numbered sequence of half-hours that this week represents. This is a sequence from Sunday to Sunday very early in the financial year; that is, a week in early July.

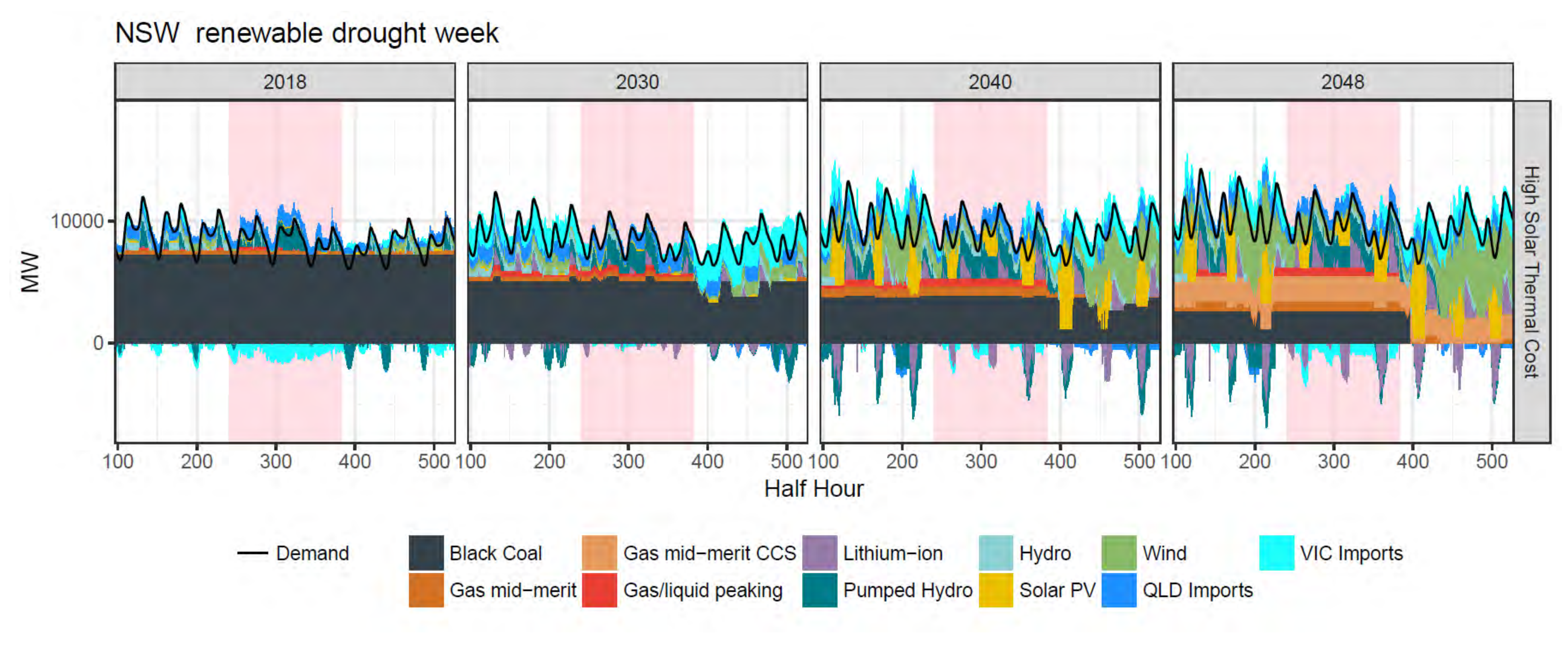
Figure 108: High Demand Scenario – half-hourly dispatch for week of lowest renewable



Source: Frontier Economics

Note: the x-axis records the numbered sequence of half-hours that this week represents. This is a sequence from Sunday to Sunday very early in the financial year; that is, a week in early July.

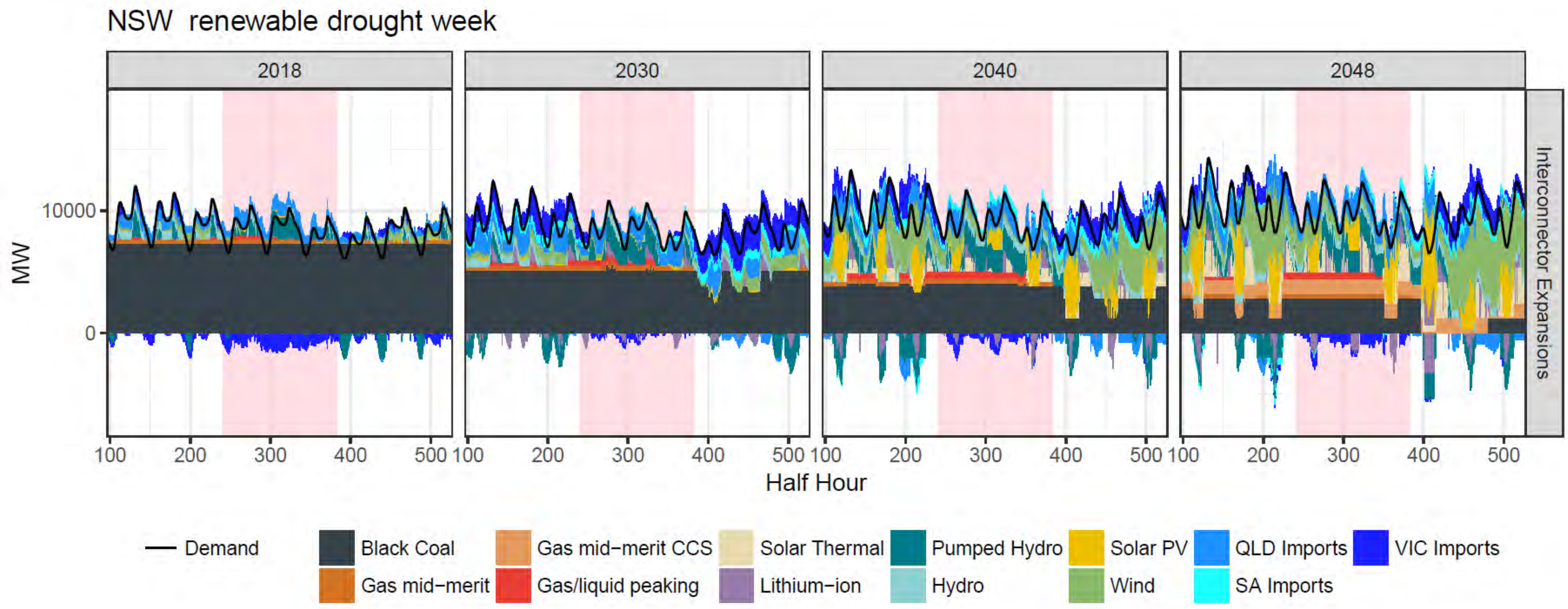
Figure 109: High Solar Thermal Cost Scenario – half-hourly dispatch for week of lowest renewable



Source: Frontier Economics

Note: the x-axis records the numbered sequence of half-hours that this week represents. This is a sequence from Sunday to Sunday very early in the financial year; that is, a week in early July.

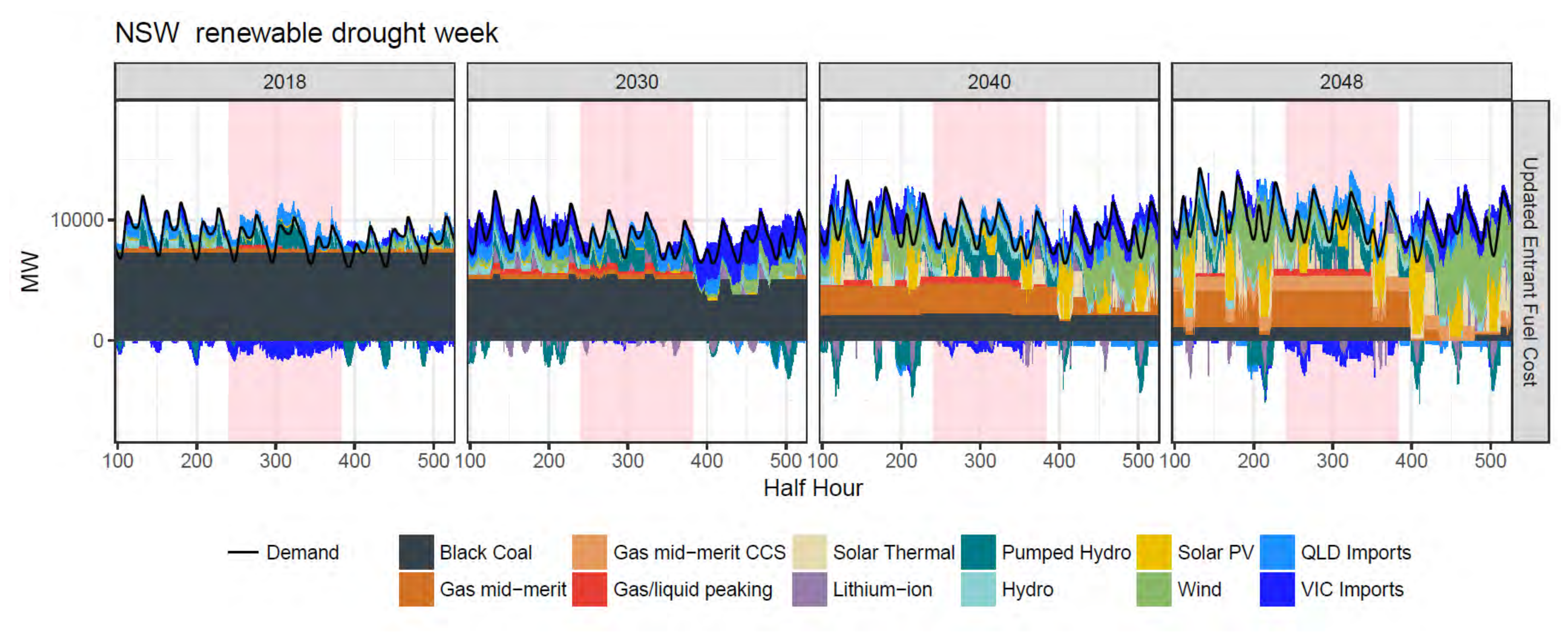
Figure 110: Interconnector Expansions Scenario – half-hourly dispatch for week of lowest renewable



Source: Frontier Economics

Note: the x-axis records the numbered sequence of half-hours that this week represents. This is a sequence from Sunday to Sunday very early in the financial year; that is, a week in early July.

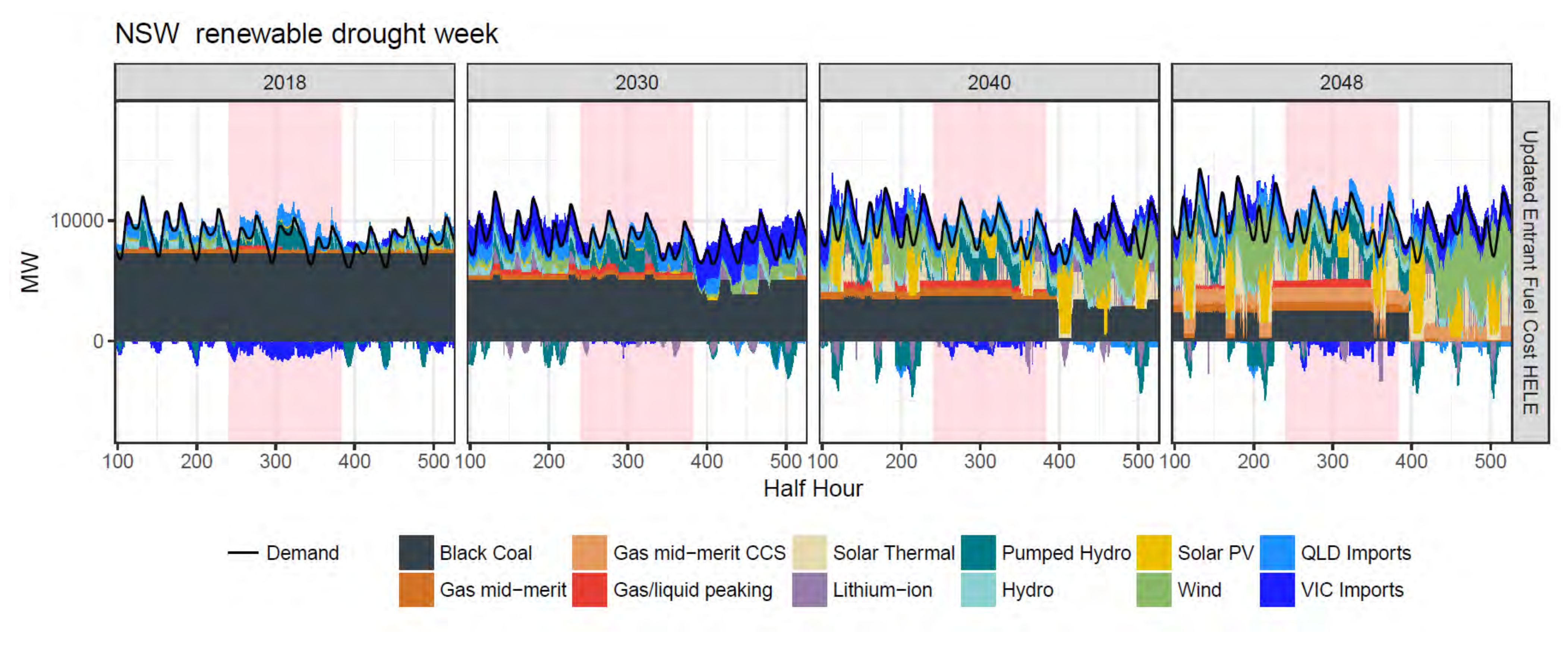
Figure 111: Updated Entrant Fuel Cost Scenario – half-hourly dispatch for week of lowest renewable



Source: Frontier Economics

Note: the x-axis records the numbered sequence of half-hours that this week represents. This is a sequence from Sunday to Sunday very early in the financial year; that is, a week in early July.

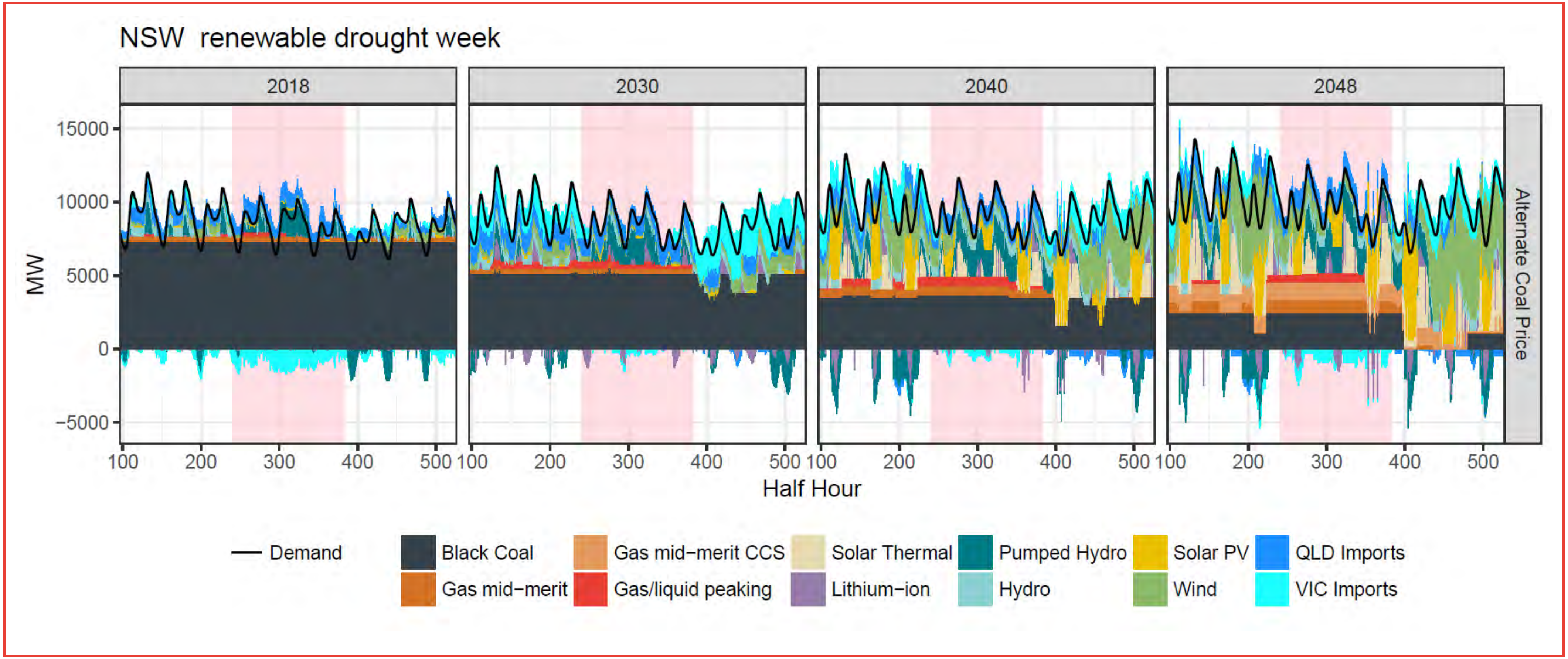
Figure 112: Updated Entrant Fuel Cost HELE Scenario – half-hourly dispatch for week of lowest renewable



Source: Frontier Economics

Note: the x-axis records the numbered sequence of half-hours that this week represents. This is a sequence from Sunday to Sunday very early in the financial year; that is, a week in early July.

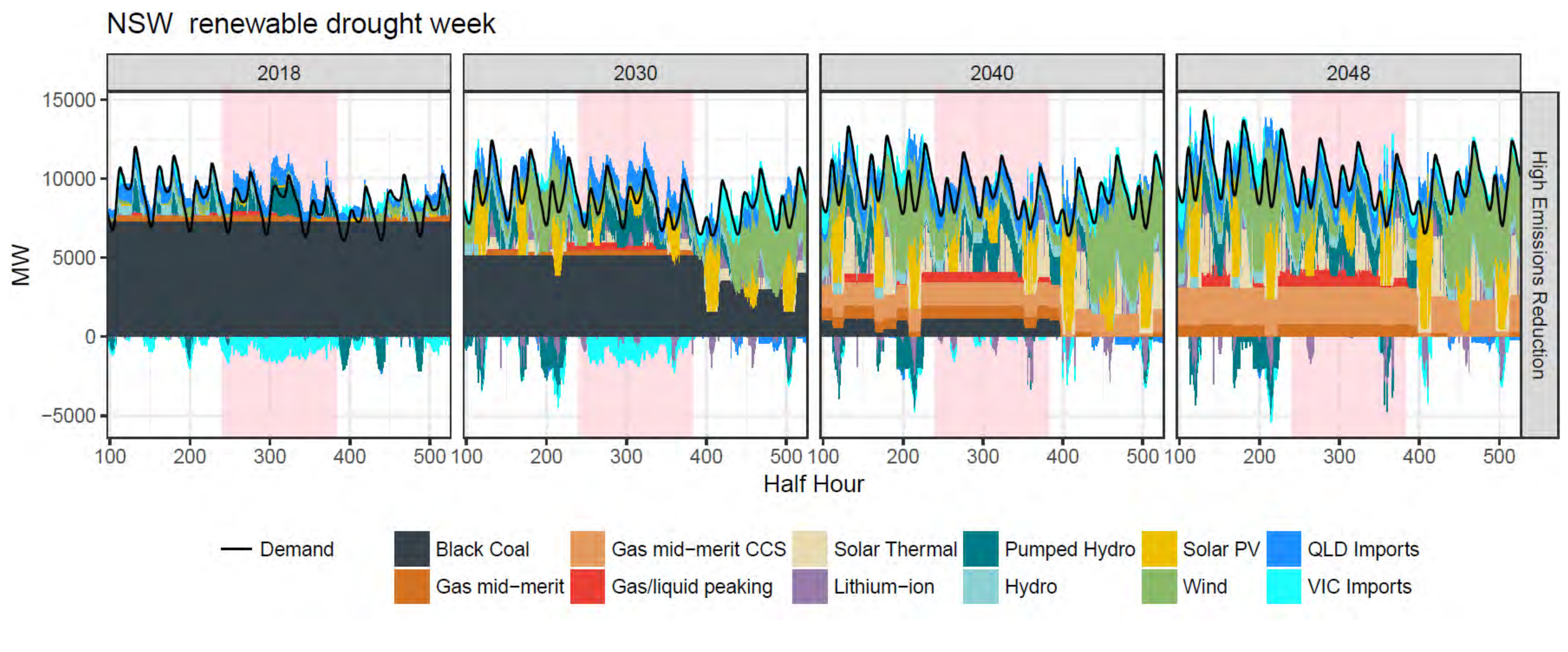
Figure 113: Alternate Coal Price Scenario – half-hourly dispatch for week of lowest renewable



Source: Frontier Economics

Note: the x-axis records the numbered sequence of half-hours that this week represents. This is a sequence from Sunday to Sunday very early in the financial year; that is, a week in early July.

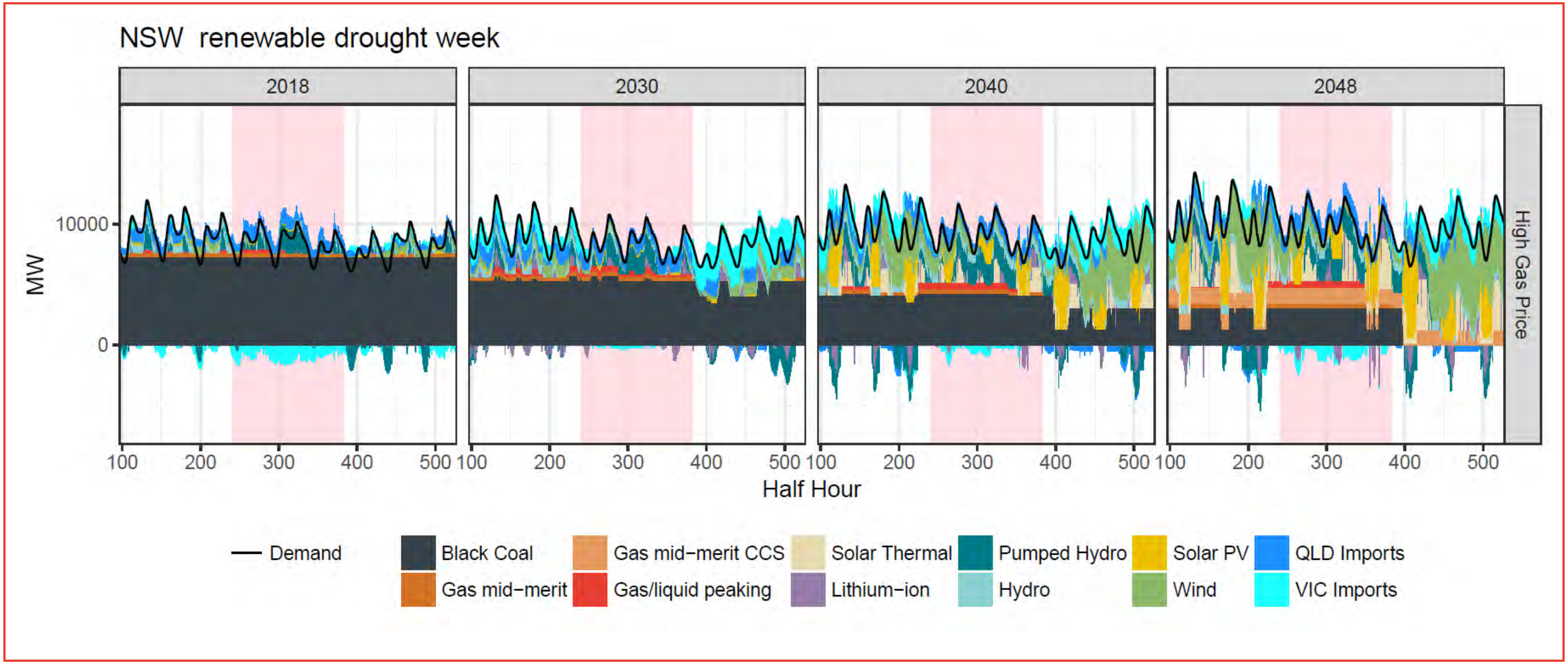
Figure 114: High Emissions Reduction Scenario – half-hourly dispatch for week of lowest renewable



Source: Frontier Economics

Note: the x-axis records the numbered sequence of half-hours that this week represents. This is a sequence from Sunday to Sunday very early in the financial year; that is, a week in early July.

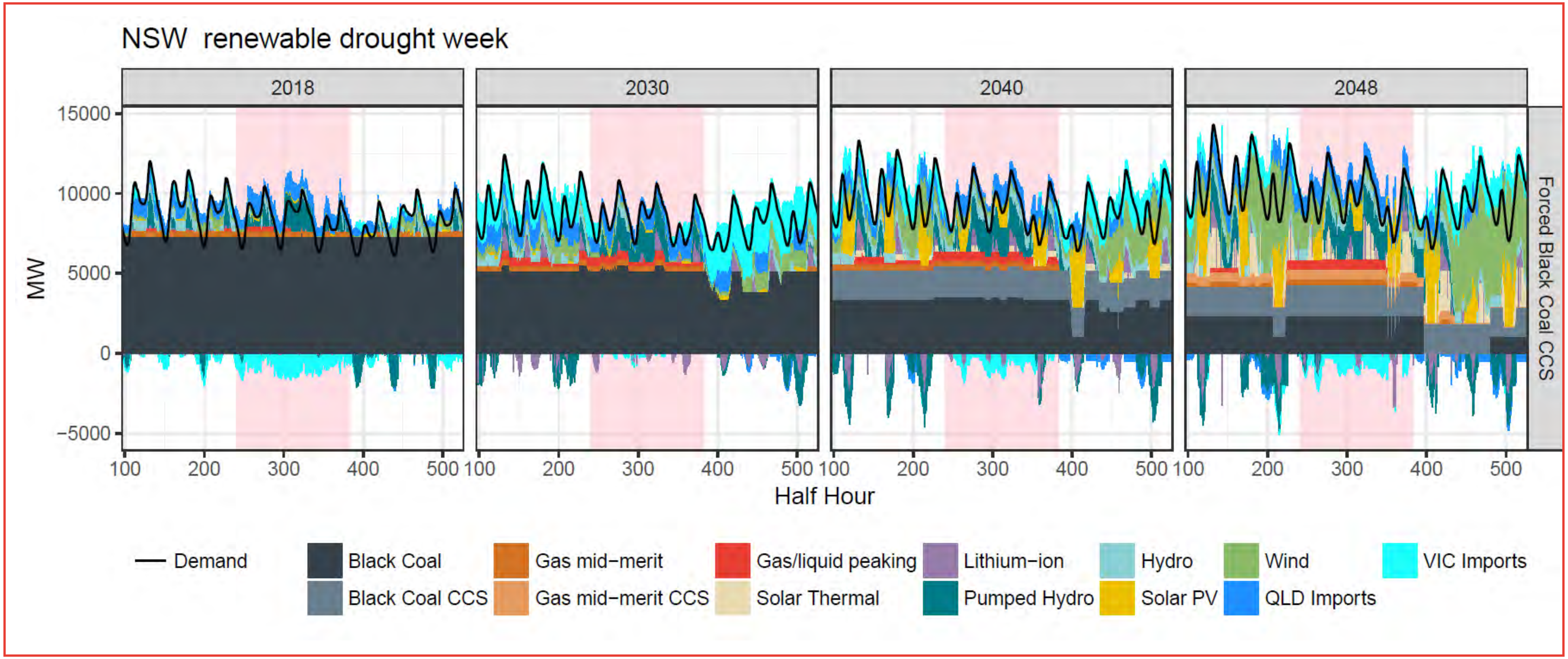
Figure 115: High Gas Price Scenario – half-hourly dispatch for week of lowest renewable



Source: Frontier Economics

Note: the x-axis records the numbered sequence of half-hours that this week represents. This is a sequence from Sunday to Sunday very early in the financial year; that is, a week in early July.

Figure 116: Forced Black Coal CCS Scenario – half-hourly dispatch for week of lowest renewable



Source: Frontier Economics

Note: the x-axis records the numbered sequence of half-hours that this week represents. This is a sequence from Sunday to Sunday very early in the financial year; that is, a week in early July.

Figure 117: Base case capacity factors of OCGT and other peaking plants

Source: Frontier Economics

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