2020 ISP Appendix 4. Energy Outlook

July 2020

Important notice

PURPOSE

This is Appendix 4 to the Final 2020 Integrated System Plan (ISP), available at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp.

AEMO publishes this 2020 ISP pursuant to its functions under section 49(2) of the National Electricity Law (which defines AEMO's functions as National Transmission Planner) and its broader functions under the National Electricity Rules to maintain and improve power system security. In addition, AEMO has had regard to the National Electricity Amendment (Integrated System Planning) Rule 2020 which commenced on 1 July 2020 during the development of the 2020 ISP.

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VERSION CONTROL

Version	Release date	Changes
1.0	30/7/2020	Initial release

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2020 ISP Appendices

Summary

This Energy Outlook appendix presents the generation outcomes and capacity expansion outlook for each scenario for its respective least-cost development path. This appendix details the evolution of the NEM under these various scenarios and provides analysis on the least cost mix of generation and storage under the development paths.

The appendix also details the impact to generation developments of various sensitivities examined in the ISP.

The appendix presents a predominantly NEM-wide view of generation development, with some regional insights. The content here is complemented by:

- Appendix 2, which provides the cost benefit assessment of the candidate development paths.
- Appendix 6, which provides greater detail on regional outlooks and other intra-year analyses, identifying opportunities and challenges addressed by the capacity developments of the ISP.

In this appendix, all dates are indicative, and on a financial year basis. For example, 2023-24 represents the financial year ending June 2024.

All values presented are 30 June 2019 real dollars unless stated otherwise. Net Present Value (NPV) outcomes are discounted back to 30 June 2019 based on a discount rate equivalent to the WACC assumed for each scenario[1].

[1] Further information on inputs and assumptions is available in the 2020 ISP inputs and assumptions workbook, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/scenarios-inputs-assumptions-methodologies-and-guidelines.

A4.1. Future energy supplies for a resilient power system

The ISP forecasts the NEM evolving from a generation mix dominated by coal-fired generation, to a generation mix dominated by renewable generation supported by energy storage, transmission, hydro power, GPG, and DER.

The most efficient replacement portfolio for aging power stations is projected to be a combination of:

- **Renewable energy** – a mixture of diversely located VRE (solar and wind) and DER, firmed by storage, GPG and supported by network augmentations.
- **Energy storage** – to firm the production of renewable energy and provide backup supply and peaking support, as well as a range of essential power system security services including fast frequency response and frequency control ancillary services (FCAS). Energy storages of varying depths and technologies are expected to be part of the efficient replacement portfolio.
- **GPG** – to provide backup supply and peaking support.
- **Increased transmission, including interconnection** – to support the integration of significant quantities of dispersed VRE across the grid and DER, and facilitate the efficient sharing of renewable energy, storage, and backup and firming services.

The generation mix is expected to be technologically and geographically diverse. This future technology mix may diversify further than current projections, if forecast technology cost reductions in emerging and maturing technologies occur more rapidly than current expectations, however the appropriate market arrangements will need to be in place to incentivise this investment.

This projected resource portfolio provides a lower overall cost to deliver the energy and peak capacity needed than developing like-for-like replacement of existing thermal generation and also supports large reductions in emissions.

A faster pace of transformation would hasten the need for the development of flexible supply options that can firm and support a renewable energy mix. Furthermore, the prospects of a highly decentralised energy mix will not replace the need for grid scale, controllable supplies to maintain grid reliability and security.

A4.2. Unlocking VRE through REZs

REZs are high-resource areas in the NEM where clusters of large-scale renewable energy projects can capture economies of scale as well as geographic and technological diversity in renewable resources. In the 2020 ISP, AEMO has identified and mapped 35 areas across Australia as candidate REZs across the NEM through consideration of a mix of resource, current and future transmission network capacities and cost, and other technical and engineering considerations.

REZ developments in the ISP therefore represent an economically efficient means to coordinate the access and development of the renewable energy developments forecast to be needed as the NEM transforms the supply mix away from aging thermal generators.

Since 2016, the NEM has installed a total of about 7 GW of VRE technologies, many encouraged by various state and federal government policies. The relatively low cost of renewable generation technologies and the assumed future availability of storage technologies – particularly embedded and large-scale batteries and the prospect of strategic expansions of larger pumped-hydro storage schemes – result in this ISP projecting development of between 26 GW and 50 GW of new large-scale VRE sources by 2039-40, beyond what is already committed and anticipated.

Table 1 presents the total additional renewable energy projected to be developed by 2039-40 for all five core scenarios: Central, Fast Change, High DER, Step Change and Slow Change, above what is already committed and anticipated. In the Fast Change and Step Change scenarios, the drivers for VRE developments are carbon budgets incentivising the exit of higher emissions generation, while significant amounts of VRE are also forecast to be required to replace retiring thermal generation in the Central and High DER scenarios. In the Slow Change scenario, coal-fired generation refurbishments moderate the amount of VRE developed relative to the other scenarios.

Table 1 Renewable energy developed by 2039-40 for all scenarios' least-cost development path

Technology	Central	Fast Change	High DER	Step Change	Slow Change*
Wind	17,843	20,320	15,043	27,417	2,425
Solar PV	13,297	15,202	11,420	22,225	3,522
Total VRE development	**31,140**	**35,523**	**26,463**	**49,641**	**5,947**
Distributed PV	10,926	10,926	22,218	21,262	6,425
Total renewable energy development	**42,066**	**46,449**	**48,681**	**70,903**	**12,372**

* The Slow Change scenario is based on the least-cost development path with low-regret developments of Project Energy Connect, Hume Link and both QNI Medium and QNI Large.

A4.2.1 NEM-wide developments

The timing and scale of REZ developments is driven initially by the VRE expansions needed to meet state-based renewable energy schemes up to 2029-30, and the need to replace thermal generator retirements from 2029-30 to 2041-42. Each region is forecast to develop several REZs to enable the scale of VRE developments, providing an opportunity for diversely located renewable developments and storage projects to meet the needs of future customer demand. More information on regional developments is available in Appendix 6.

The ISP co-optimises generation and transmission expansion to identify the most cost-effective mix of VRE and associated REZ network developments. Table 2 presents the REZs that are developed in the Central scenario's least-cost development path (DP1) with VNI West and Marinus Link's first cable developed in 2035-36 and 2036-37 respectively.

In this first decade, the highest amount of VRE developed that require dedicated REZ access is expected in Victoria and Queensland to meet the VRET and QRET respectively. By 2039-40, significant new VRE is forecast with a notable increase in VRE for Queensland, New South Wales (and South Australia, via Project EnergyConnect) to replace impending black coal retirements. The total REZ capacity requirement increases in all scenarios (apart from Slow Change) in both 2029-30 and 2039-40. Data for these other scenarios can be accessed from Appendix 5 and further details on the various candidate development paths analysed can be found in Appendix 2.

Table 2 REZ developments to 2029-30 and 2039-40 for the least-cost development path in the Central scenario

Region	Capacity (MW) by 2029-30	REZ development opportunities by 2029-30	Capacity (MW) by 2039-40	REZ development opportunities by 2039-40
NSW[2]	-	N1 North West NSW, N2 New England, N3 Central West NSW, N4 Southern Tablelands	11,843	N1 North West NSW, N2 New England, N3 Central West NSW, N4 Southern Tablelands, N6 South West NSW, N7 Wagga Wagga, N9 Cooma-Monaro
QLD	4,171	Q1 Far North QLD, Q4 Isaac, Q6 Fitzroy, Q8 Darling Downs	10,043	Q1 Far North QLD, Q4 Isaac, Q6 Fitzroy, Q7 Wide Bay, Q8 Darling Downs
SA	-	-	3,737	S1 South East SA, S2 Riverland, S3 Mid-North, S4 Yorke Peninsula, S7 Roxby Downs
TAS	43	T3 Tasmania Midlands	1,212	T3 Tasmania Midlands
VIC	3,040	V2 Murray River, V3 Western VIC, V4 South West VIC, V5 Gippsland, V6 Central North VIC	4,305	V2 Murray River, V3 Western VIC, V4 South West VIC, V5 Gippsland, V6 Central North VIC

Victorian REZ developments are, to some degree, influenced by the choice of route for VNI West (Central North Victoria REZ and Western Victoria REZ with the Shepparton route, and Murray River REZ and Western Victoria REZ with the Kerang route). Compared to DP1, early delivery of VNI West by 2027-28 (DP8) results in:

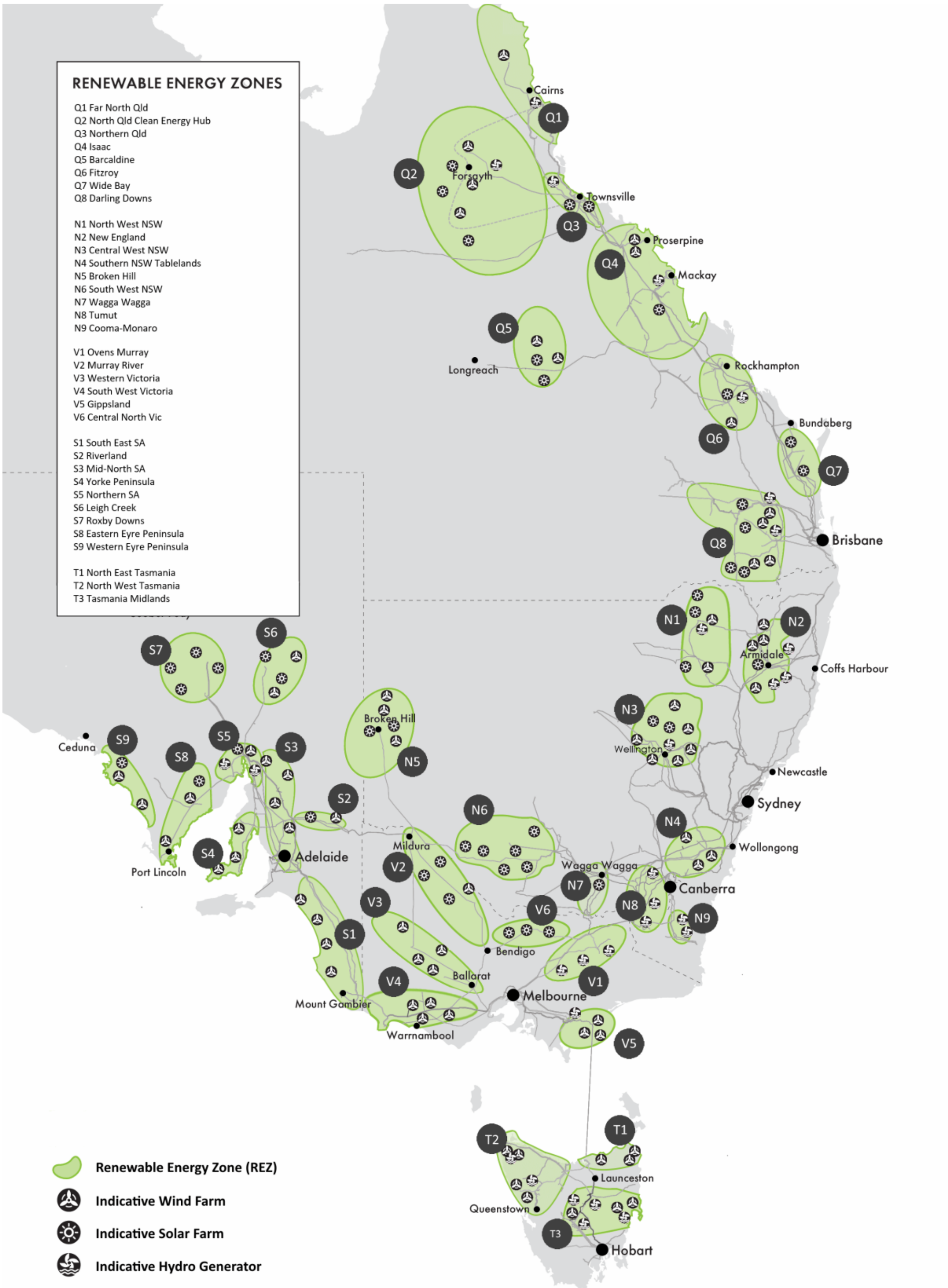
- more VRE capacity built in Western Victoria (V3) if the Shepparton route is selected; and
- more VRE capacity built in both Western Victoria (V3) and Murray River if the Kerang route is selected.

[2] Capacity development in this Central scenario does not value the investor confidence provided by the New South Wales Electricity Strategy.

If the TRET is legislated, additional VRE is projected to be built in Tasmania Midlands (T3), in North East Tasmania (T1) and North West Tasmania (T2).

The location of each of the REZs in Table 2 are presented in Figure 1; this figure is also presented in Section C2.2 of the ISP report body.

Figure 1 Identified potential Renewable Energy Zones (REZs) across the NEM



A4.3. Managing variable energy supplies through energy storages and firming technologies

The ISP has identified the most efficient way to firm VRE to maintain reliability is with a combination of new energy storages and transmission developments (both within and between NEM regions). Existing hydropower, GPG and coal-fired generation also continue to play important roles in meeting power system needs.

Table 3 presents the spread of different levels of firming technologies forecast to be required for each of the five scenarios for their respective least-cost development paths.

Table 3 Total dispatchable capacity for the least-cost development path in 2039-40 across the ISP scenarios (existing and new)

Technology	Central	Fast Change	High DER	Step Change	Slow Change*
Retired dispatchable capacity	19,380	21,500	19,380	25,950	14,230
Black coal	5,216	3,096	5,216	2,016	10,366
Brown coal	3,370	3,370	3,370	0	3,370
CCGT	1,509	1,509	1,509	1,509	1,509
Peaking gas + liquids	5,047	5,047	5,047	5,047	5,502
Hydro	7,210	7,210	7,210	7,210	6,820
Shallow storage	4,609	5,866	16,639	5,115	1,874
Medium storage	5,088	5,031	1,189	4,645	2,417
Deep storage	2,040	3,063	2,178	4,535	2,040
DSP	1,287	1,287	1,287	2,244	475
Total dispatchable capacity	35,375	35,478	43,644	32,320	34,373

* The Slow Change scenario is based on the least-cost development path with low-regret developments of Project EnergyConnect, Hume Link and both QNI Medium and QNI Large.

While VRE penetration is relatively low, and incumbent dispatchable thermal capacity remains operational, the ISP identifies that lower-cost shallow energy storages can efficiently complement the VRE developments encouraged by state government policies. With increasing dispatchable DER capacity in the Fast Change and

Step Change scenarios, deep and medium scale storages are projected to be needed to complement the shallow storages.

The total installed dispatchable capacity presented in Table 3 is forecast to provide sufficient firm capacity to meet the reliability standard (no more than 0.002% unserved energy in a region in any given year). Appendix 6 provides more details and also presents how storages and GPG, along with availability of other thermal generators, are forecast to respond to VRE production under weather variability.

While energy storages play a key role in supporting and firming VRE expansion, continued GPG availability is forecast to provide grid security and stability, particularly in the medium term (see Appendix 6). With an increasingly aging coal fleet that is becoming less reliable, it is important to have alternate dispatchable capacity to manage system security and reliability. Transmission developments will also have an important role in ensuring the access and capacity to share energy from VRE developments inter-regionally. This increased ability to share resources is not solely beneficial for energy from VRE – the role transmission can play in avoiding the need for investment in local dispatchable capacity is a key saving identified in the total system cost savings discussed in Appendix 2.

A4.3.1 Storage requirements

To meet future requirements for reliable and secure power supply, the future energy mix must provide an ability to store, shift and firm energy produced from VRE. The NEM currently has approximately 2.5 GW of large-scale storages (both deep and shallow storages). Additional storage capacity is expected to be required to provide a dispatchable, firm source of capacity, complementing the variability of VRE.

The NEM requires an assortment of backup supplies to provide peaking support during periods of extreme demands or capacity shortfalls, as well as supplies of a range of essential power system security services including fast frequency response and FCAS. Assuming costs continue to reduce as expected, and assuming the market appropriately incentivises investment, the ISP has forecast storage technologies to provide much of this role, including pumped hydro and battery technologies. A range of storage depths[3] are forecast to be needed; storage depth variability allows for a distribution of storages across the NEM. AEMO has defined the following storage depth classes:

- **Shallow storage**, which includes VPP battery and 2-hour large-scale batteries. The value of this category of storage is more for capacity, fast ramping and FCAS (not included in AEMO's modelling) than for its energy value.
- **Medium storage**, which includes 4-hour batteries, 6-hour pumped hydro, 12-hour pumped hydro, and the existing pumped hydro stations Shoalhaven and Wivenhoe. The value of this category of storage is in its intra-day energy shifting capabilities, driven by demand and solar cycles.
- **Deep storage**, which includes 24-hour pumped hydro, 48-hour pumped hydro, Snowy 2.0, and Tumut 3. The value of this category of storage is in covering VRE "droughts" (long periods of lower-than-expected VRE availability) and seasonal smoothing of energy over weeks or months.

To aid readability, at times only two categories of storage are reported in charts: Dispatchable storage, which includes all dispatchable storage of any depth (including VPP); and Behind the Meter storage, which includes all customer-driven distributed storage that is not dispatchable.

Existing and new-entry GPG and hydropower may also provide backup supply, security services (such as inertia) and peaking support. Given the relatively high cost of natural gas, the ISP identifies limited value in the development of new large, high-utilisation GPG facilities – particularly if transmission access enables development of VRE and storage technologies. Transmission developments also enable the sharing of firming resources across the NEM, reducing the overall capacity required to meet peak demands (subject to the non-coincidence of peak loads).

[3] Storage depth refers to the amount of time that a storage may take to charge or discharge. The 'deeper' the depth of storage, the longer that the storage facility can discharge at full capacity for before it runs out of stored energy.

Table 4 presents new dispatchable capacity additions by 2039-40 for the least-cost development path under five scenarios. As shown in Table 3, the main drivers that change the level and types of firm capacity developments across the scenarios are coal retirements and the penetration of distributed shallow storage uptake. Advanced coal retirements to meet carbon budget in the Fast Change and Step Change scenarios will result in higher uptake of deep storages compared to other scenarios. Due to high uptake of VPP and other distributed storage in the High DER scenario, there will be lower requirements for grid-scale storage development compared to other scenarios.

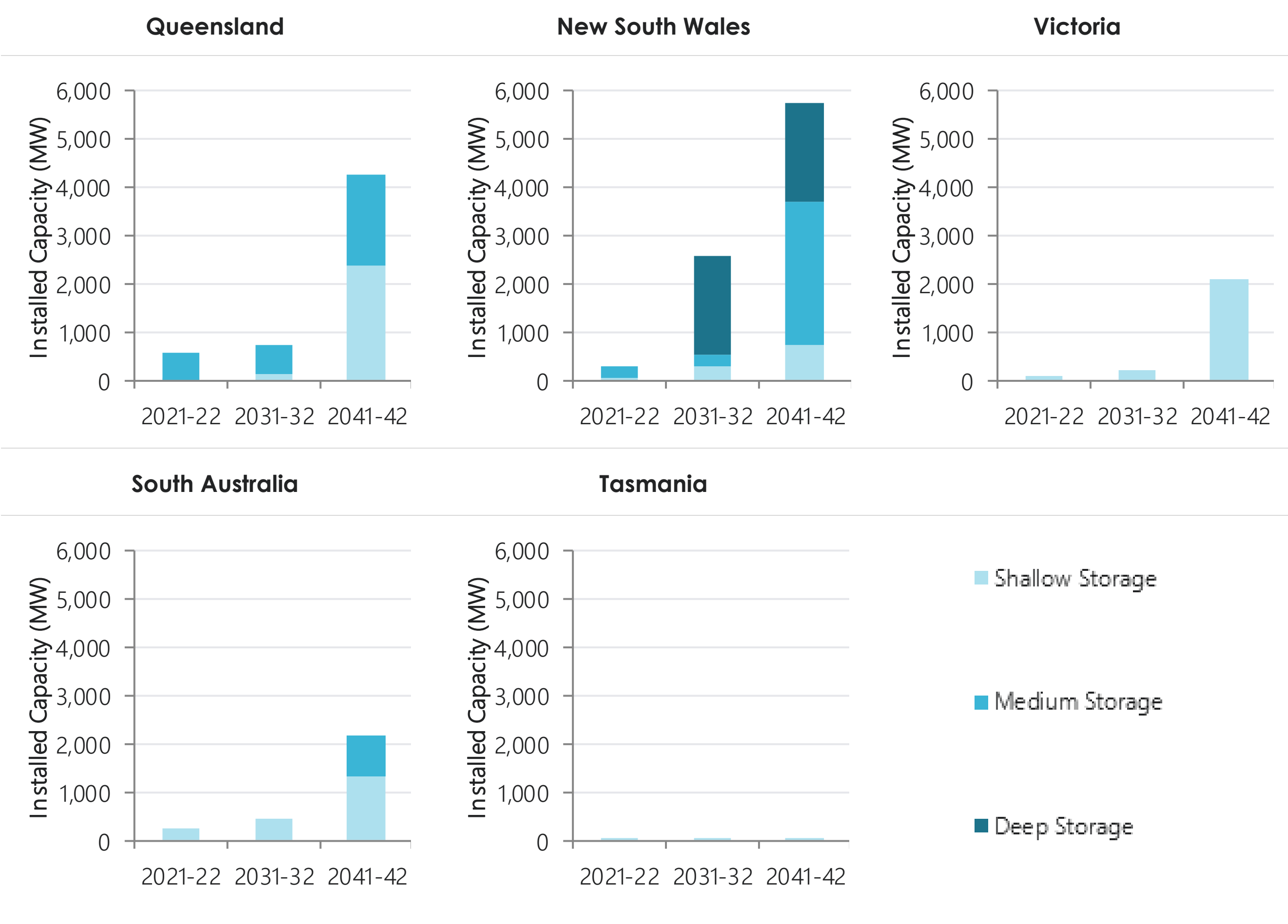
Table 4 New dispatchable capacity development opportunities by 2039-40 in the least-cost development path under five scenarios (MW)

Technology	Central	Fast Change	High DER	Step Change	Slow Change*
CCGT	0	0	0	0	0
Peaking Gas+Liquids	0	0	0	0	455
Hydro	390	390	390	390	0
Shallow Storage	4,379	5,550	15,403	4,698	1,627
Medium Storage	4,278	4,221	379	3,835	1,607
Deep Storage	2,040	3,063	2,178	4,535	2,040
DSP	744	744	744	1,702	-68
Total	11,830	13,969	19,094	15,159	5,662

* The Slow Change scenario is based on the least-cost development path with low-regret developments of Project Energy Connect, Hume Link and both QNI Medium and QNI Large.

Figure 2 presents the storage capacity forecast to be built across NEM regions in selected years under the Central scenario. As shown in the figure, except the committed deep storage built in New South Wales (Snowy 2.0 committed project), no significant storage capacity developments are expected until Eraring retires in 2032-33.

Figure 2 New storage capacity development opportunities across NEM regions in selected years in the least-cost development path under the Central scenario (MW)



A4.4. Development outlooks across scenarios

A4.4.1 Central scenario

The Central scenario demonstrates a moderate pace of change, with new developments required to replace aging assets in the next 20 years across the NEM and support existing federal and state government policies.

The Central scenario forecasts some regional concentration of large-scale renewable generation development over the near term, with renewable energy targets in Queensland and Victoria driving developments in those regions. New transmission augmentations to increase the connectivity of South Australia and Queensland into New South Wales will increase the capability of energy sharing to Australia's most populated state, reducing the need for significant local resources in the near term.

Should New South Wales develop additional resources locally in the next decade (as in the Central-West Orana REZ sensitivity), value remains in the transmission developments identified in the least-cost development path to maintain system reliability efficiently, to share geographically diverse resources, and to lower overall consumer costs. This is also the case for the other sensitivities analysed in the Central scenario (details in Section A4.4.1.4 to A4.4.1.9) where the least-cost timing and selection of transmission developments remain the same, except for the case where TRET is introduced (in this case both stages of Marinus Link are required).

This section describes in detail the evolution of the NEM for the least-cost development path that is forecast to maximise market benefits (minimise cost) in the Central scenario.

In the Central scenario, the outlook for generation developments includes:

- To 2029-30:
  - Renewable energy policies in Victoria and Queensland will drive development of VRE in those regions.
  - The commissioning of the Snowy 2.0 project, and transmission projects, will reduce the need for new dispatchable investments beyond existing commitments to meet the current reliability standard unless demand forecasts change materially.
  - In the event Yallourn retires earlier than anticipated, additional investments are required, either in transmission projects, or additional dispatchable capacity, to maintain reliability.
- By 2039-40:
  - The expected closure of coal capacity across the NEM will require significant replacement investment. Aging assets are forecast to be progressively replaced by VRE, complemented by energy storages of various depths. Generation retirements also drive the need for efficient investment in transmission augmentations, which reduce the need for new local dispatchable capacity and, in particular, maximise the operational efficiency of renewable developments and the remaining thermal fleet.

– The development of increased transmission infrastructure and DER operating as VPPs will allow a marginal reduction in overall dispatchable capacity.

These grid-scale developments are also complemented by growth in demand side participation (DSP), distributed PV and behind-the-meter battery storages. These include VPPs that provide some degree of dispatchability, as well as consumer-managed home-battery storages, which largely are expected to offset household energy developments and balance exports from distributed PV systems.

Figure 3 presents the forecast capacity mix for the NEM across the outlook period to 2041-42

Figure 3 Forecast NEM generation capacity 2041-42, Central scenario

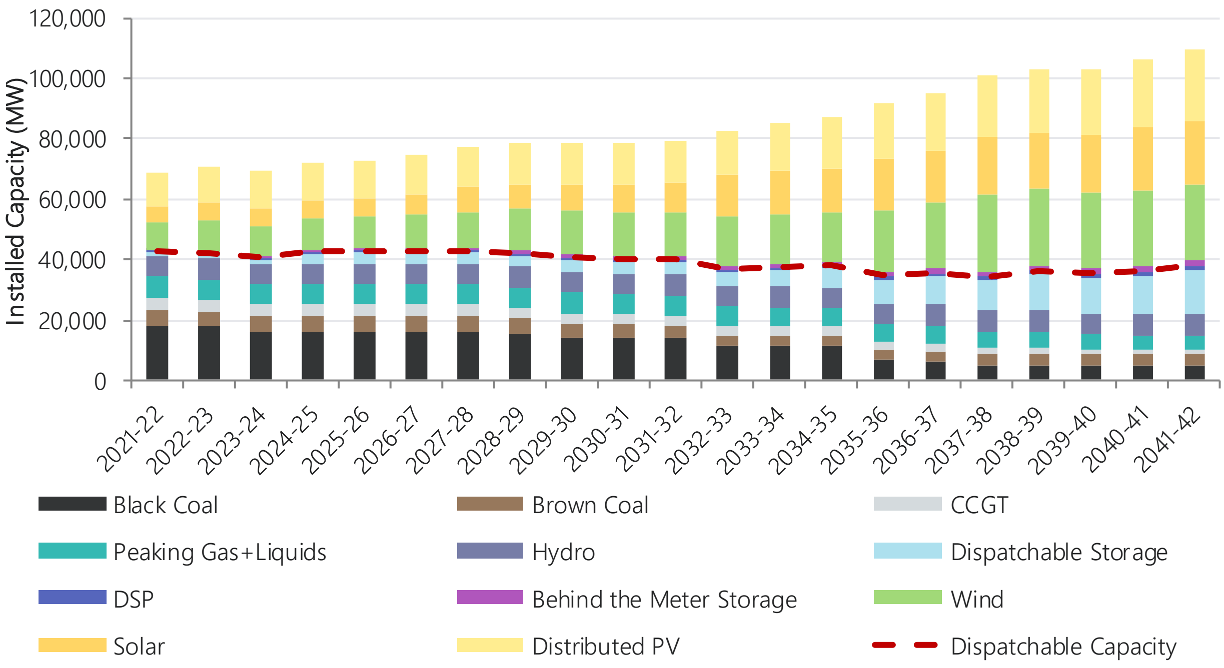
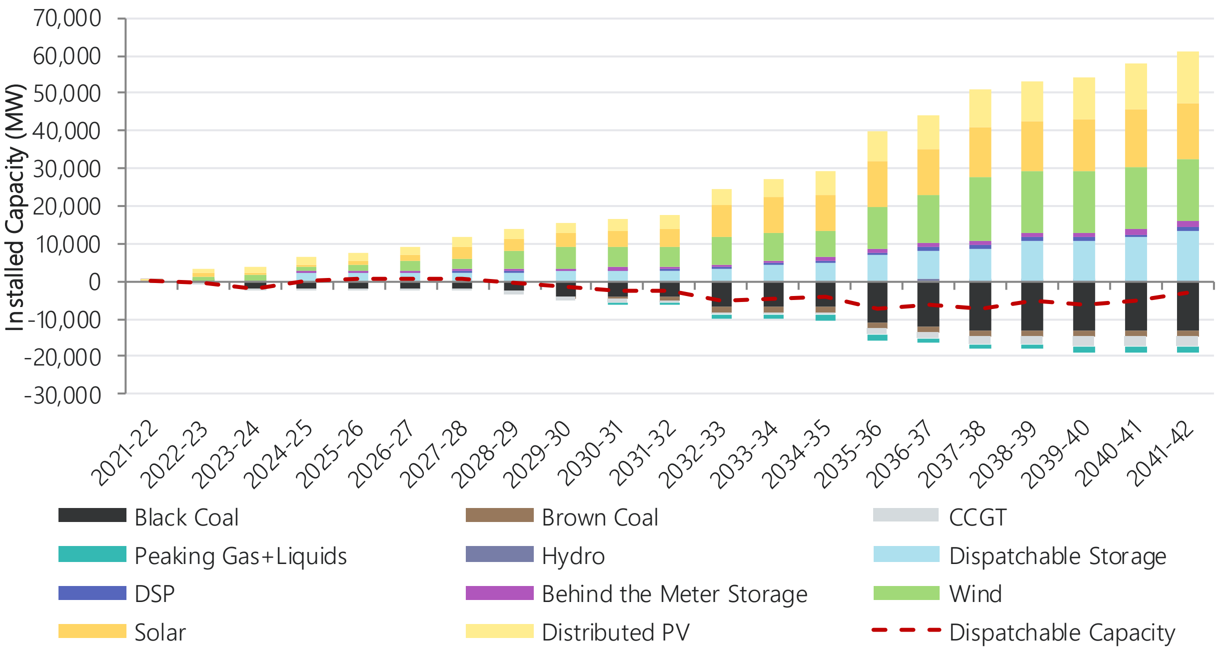


Figure 4 shows the cumulative change in investment and withdrawal by fuel and technology type over time. A positive value in the chart indicates a net addition in installed capacity, while a negative value indicates a net deduction due to economic retirement (if applicable in the scenario definition) or end of technical life. The figure demonstrates three major periods of investment for the Central scenario:

- Initial developments of renewable generation occur in the period **before 2029-30**, driven by existing policies.
- **Before 2034-35**, initial retirements of coal-fired generation are replaced by disperse VRE, with some additional energy storage capacity required to complement the Snowy 2.0 project, and existing storages. Given the development of Snowy 2.0, shallower projects are built across the NEM (in all regions except Tasmania); these assist in the firming of the growing VRE fleet.
- **After 2035-36**, as aging coal generator retirements accelerate, transmission investment enables a much greater transformation of the power system than in the counterfactual scenario without transmission development (as discussed in the following section). By 2039-40, a total of approximately 31 GW of new VRE (in addition to committed and anticipated projects) is developed to support consumption growth and replace the energy production provided by retired coal plants. This is complemented by approximately 9 GW of additional grid-scale energy storage and another 1.4 GW of new VPP capacity.

- Overall, dispatchable capacity[4] reduces, but dispatchability is maintained in all hours through greater interconnection, and therefore sharing of geographically and technologically diverse resources. Due to the varying degrees of flexibility in the replacement dispatchable capacity, this perfectly optimised system may be more challenging to operate in reality when perfect foresight is not possible. Intra-day operability and risks are discussed in more detail in Appendix 6.

Figure 4 Forecast relative change in installed capacity to 2041-42, Central scenario

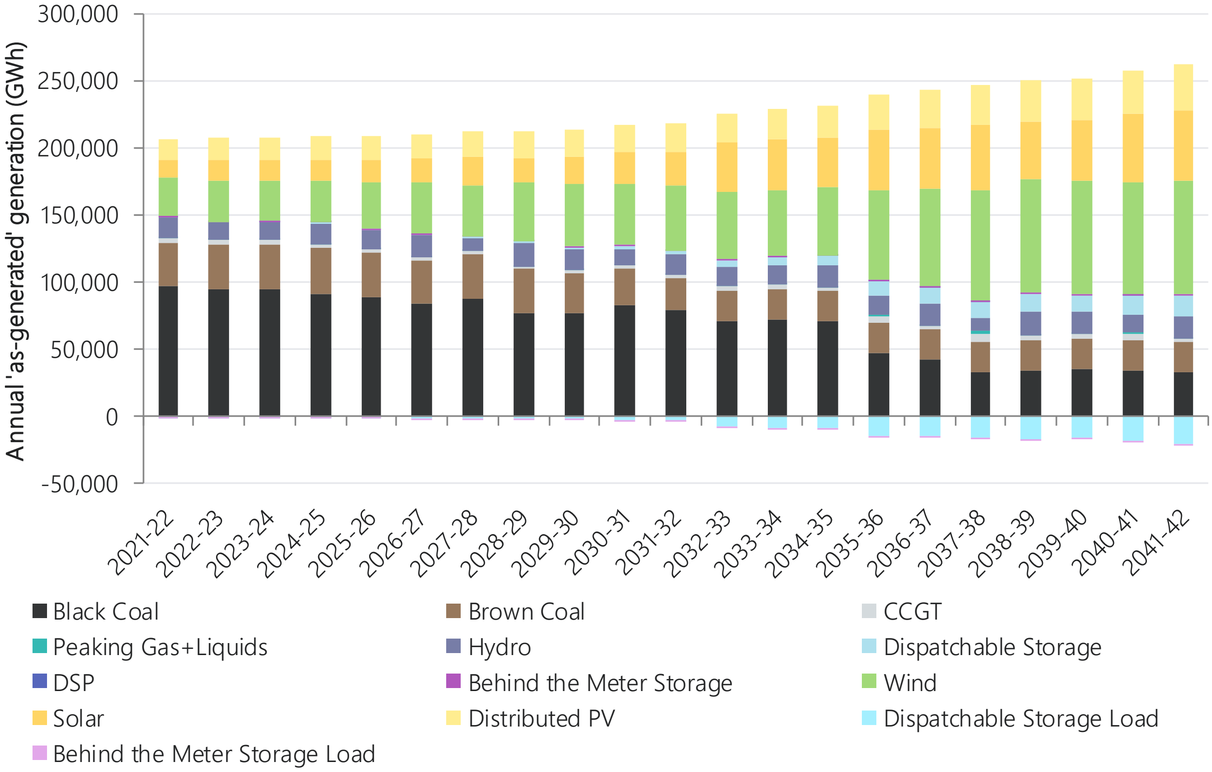


In terms of energy production, Figure 5 demonstrates the forecast change in the energy mix from coal generation to VRE. It also demonstrates the scale of energy required to operate energy storages, represented by the energy storage load beneath the x-axis. Renewable energy is forecast to expand from approximately 36% of energy generated to approximately 74% of energy generated by 2040. The projected mix of VRE generation favours wind at a split of 52% wind, 29% large-scale solar PV, and 19% distributed PV[5].

[4] Dispatchable capacity is defined as coal-fired generation, gas-powered generation, hydro generation, grid-scale storages, demand-side participation, and aggregated behind-the-meter batteries (VPP). This aggregation has been made to aid in presenting the relative differences in dispatchable technology types within the NEM. The Dispatchable Capacity line does not intend to imply an equal level of reliability between the two scenarios as each generation technology type has unique operational constraints.

[5] Distributed PV development is based on the scenario definitions and detailed in the ISP Assumptions Workbook.

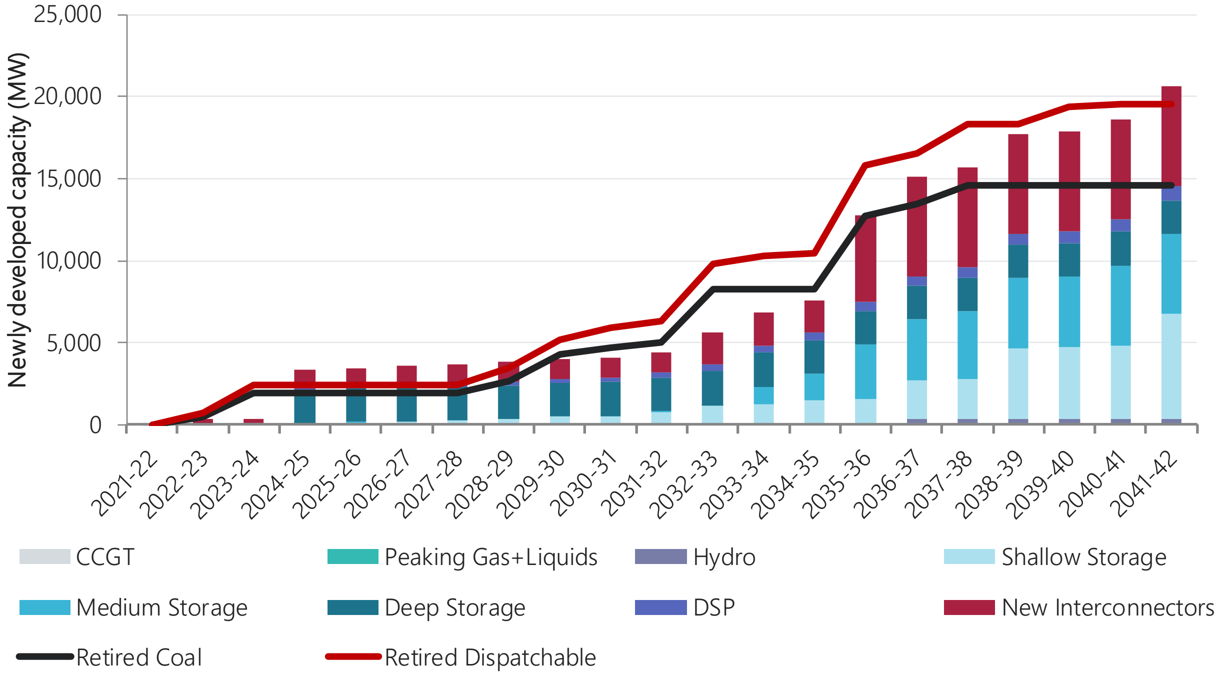
Figure 5 Forecast annual generation to 2041-42, Central scenario



A4.4.1.1 Firm dispatchable developments in the Central scenario

To complement the development of renewable energy, dispatchable capacity is necessary. With the introduction of Snowy 2.0 and a number of transmission augmentations, the need for significant additional storage developments is not observed in the forecast until the 2030s (Figure 6), unless Yallourn retires early (presented in Section A4.4.1.6). After 2029-30, the schedule of expected retirements drives the projected development need for storages across the NEM.

Figure 6 Forecast dispatchable capacity development to 2041-42, least-cost development path, Central scenario



Note: Includes 2,060 MW of committed and anticipated developments.

A4.4.1.2 Regional deployment of the Central scenario generation mix

Across the NEM, the forecast evolution of the supply mix in regions varies, in terms of size, technology and timing. Generation developments in NEM regions will depend on a number of factors including the scale of retirements, the quality of local wind and solar resources, the potential for storage capacity to complement VRE, and access to transmission to share energy. Figure 7 shows forecast regional evolution to 2041-42.

By 2039-40, all regions are projected to have developed new VRE capacity (10-12 GW each in Queensland and New South Wales, and 4 GW in Victoria, in addition to committed and anticipated projects). South Australia is forecast to feature the highest share of renewable energy of all NEM regions. Tasmania is also forecast to continue to rely heavily on hydro generation, complemented by increased wind and a smaller amount of distributed PV. In this scenario, the TRET is not included; were it to be included (as is observable in other scenarios), VRE development is expected to grow more significantly, offsetting mainland developments (more details are in Section A4.4.1.5).

Figure 7 Forecast annual 'as-generated' generation for each NEM region to 2041-42, Central scenario

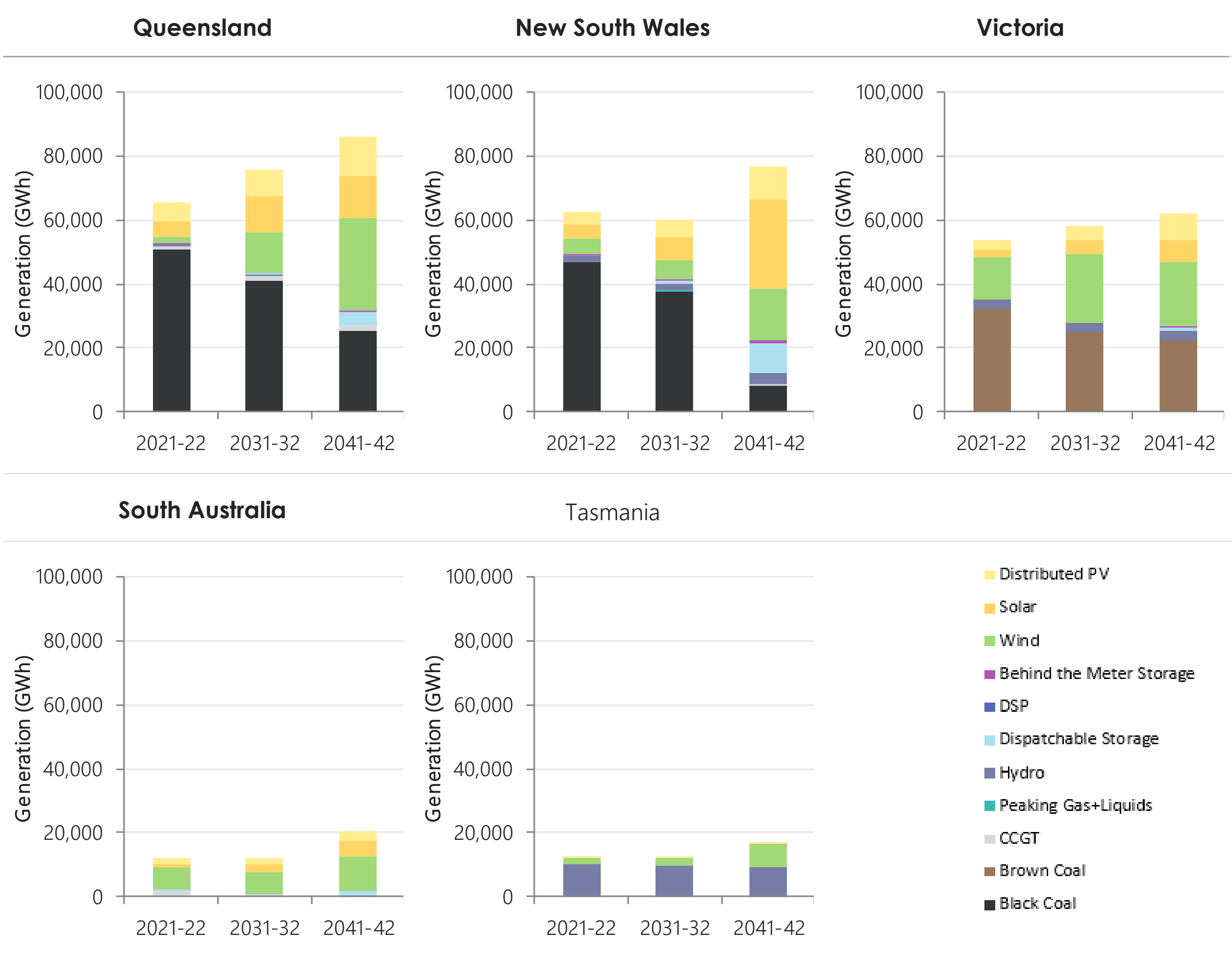
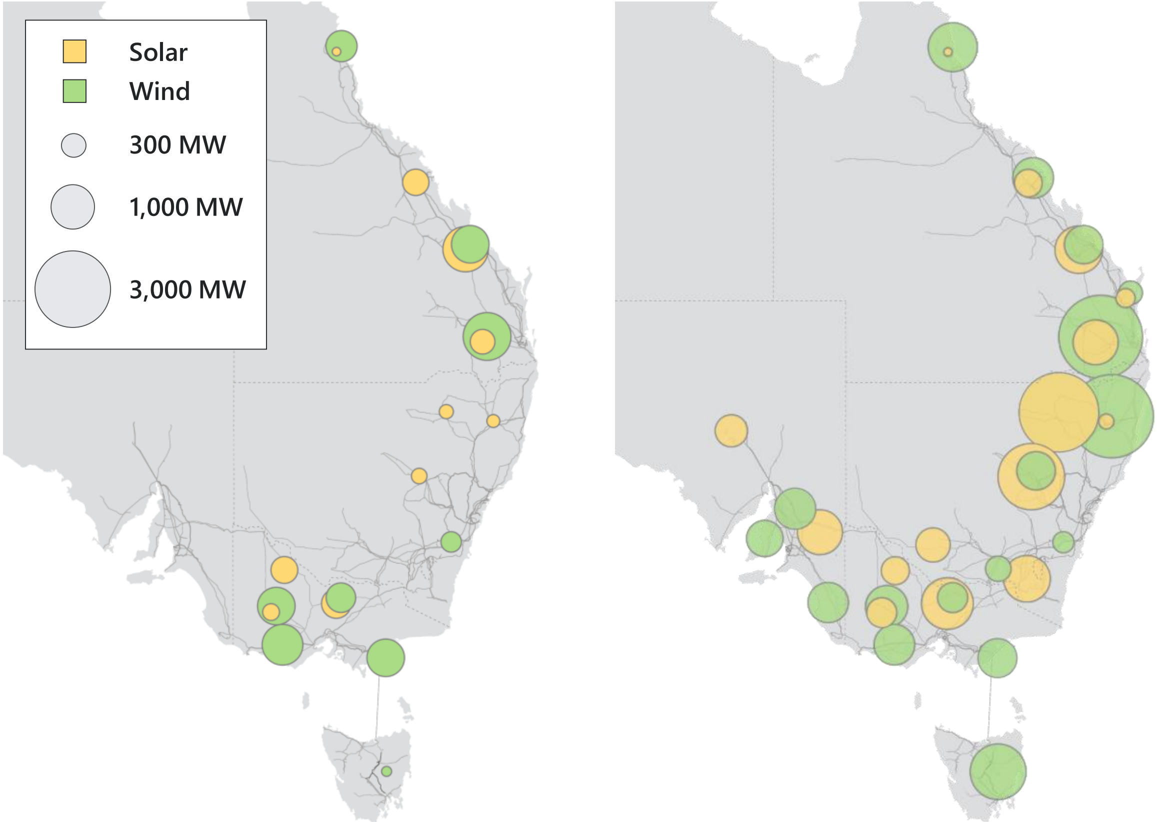


Figure 8 shows the forecast diversity of new large-scale renewable generation across the NEM. Geographic and technical diversity will be important to maximise resilience and fuel security associated with weather events in a future energy system with high VRE.

Figure 8 Forecast geographic dispersion of new VRE developments by 2029-30 (left) and 2039-40 (right), Central scenario



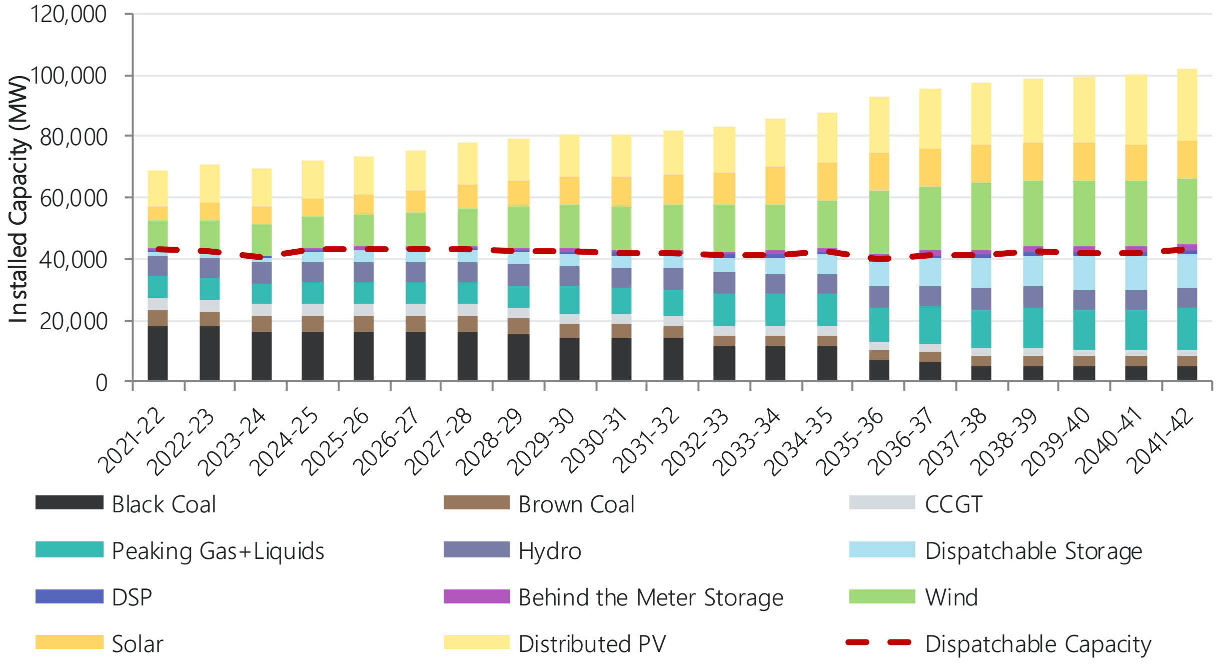
A4.4.1.3 Future generation mix in the Central scenario without the benefit of transmission development

Without transmission investment, the Central scenario's counterfactual demonstrates a much greater requirement for new entrant GPG. Although GPG running baseload or mid-merit is a higher cost energy technology at this time, GPG would be necessary because development of VRE beyond the existing hosting capacity of the NEM requires new network assets to liberate these production sources.

Figure 9 presents the capacity development outlook for the Central scenario in the absence of transmission developments and augmentations beyond the existing and committed network infrastructure.

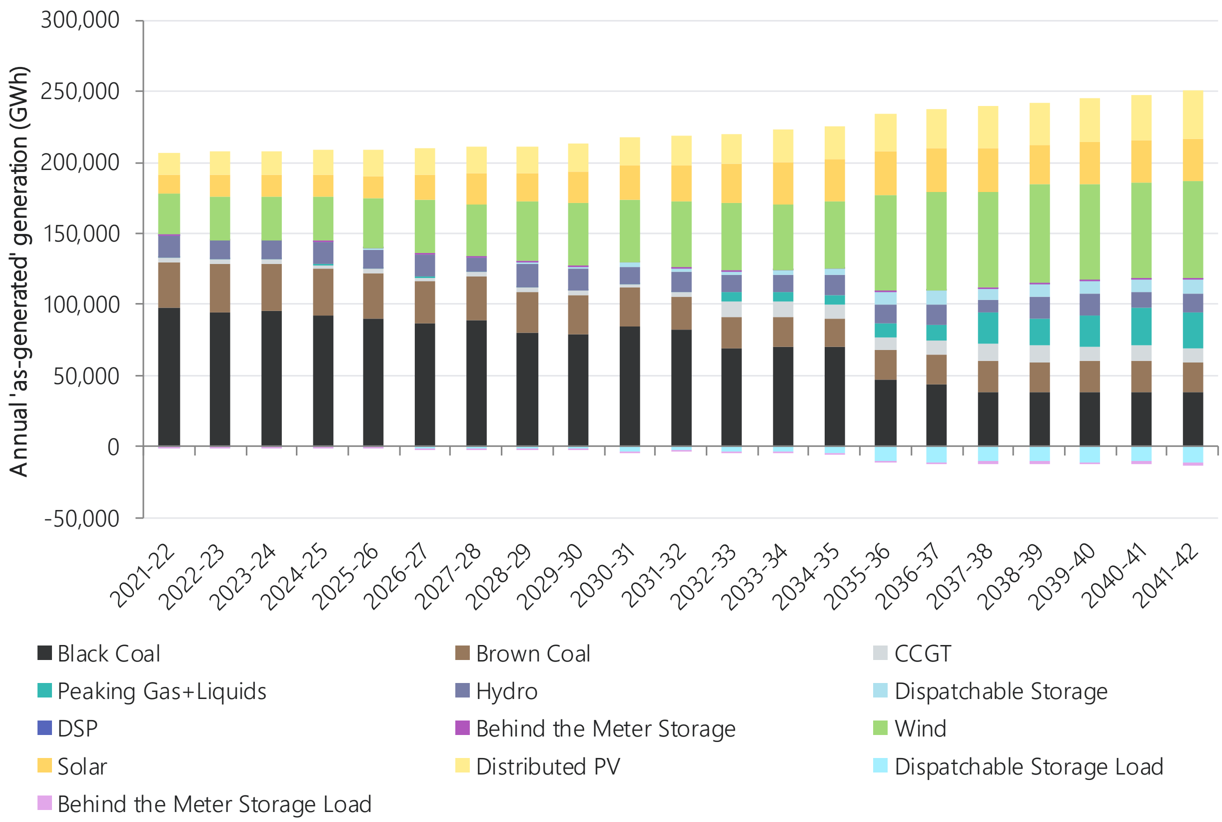
By 2039-40, a total of approximately 19 GW of new VRE (in addition to committed and anticipated projects) is developed to support consumption growth, approximately 12 GW lower than that which is enabled by the least-cost development path (DP1). This is complemented by approximately 8 GW of grid-scale energy storage, a 1 GW reduction relative to DP1, due to the reduced need for energy shifting as a result of having lower amounts of VRE in the counterfactual scenario). A higher overall level of GPG is also required in the counterfactual scenario, with an additional 8 GW by 2039-40 (note that the Central scenario does not require new GPG in any of the candidate development paths).

Figure 9 Forecast NEM generation capacity 2041-42 in counterfactual, Central scenario



Additionally, Figure 10 below presents the change in production outlook for the Central scenario counterfactual. Consistent with the observations in capacity development, GPG plays a greater role in achieving the required level of production to address the material reduction in capacity of the incumbent thermal generation due to end of life retirements.

Figure 10 Forecast annual generation to 2041-42 in counterfactual, Central scenario



For comparison, Figure 11 presents the difference in installed capacity between the least-cost development path and the counterfactual, where a positive value indicates higher total installed capacity in DP1 relative to the counterfactual. Similarly, a negative value indicates a greater contribution in the counterfactual outlook, for example in the counterfactual there is a net increase of 7 GW of dispatchable capacity in 2039-40 as depicted by the dotted red line.

It is evident that interconnection enables the development of more renewable resources which are complemented by large-scale storage in DP1, while there is a significantly higher need for GPG to provide firming capacity without interconnection to share geographically diverse renewable resources in the counterfactual scenario, as well as to provide additional energy that VRE cannot provide without increased transmission access. Up to 8 GW of peaking gas is required by 2039-40 to maintain system reliability and demand requirements.

Figure 11 Comparison of generation capacity developed with and without ISP transmission developments, Central scenario

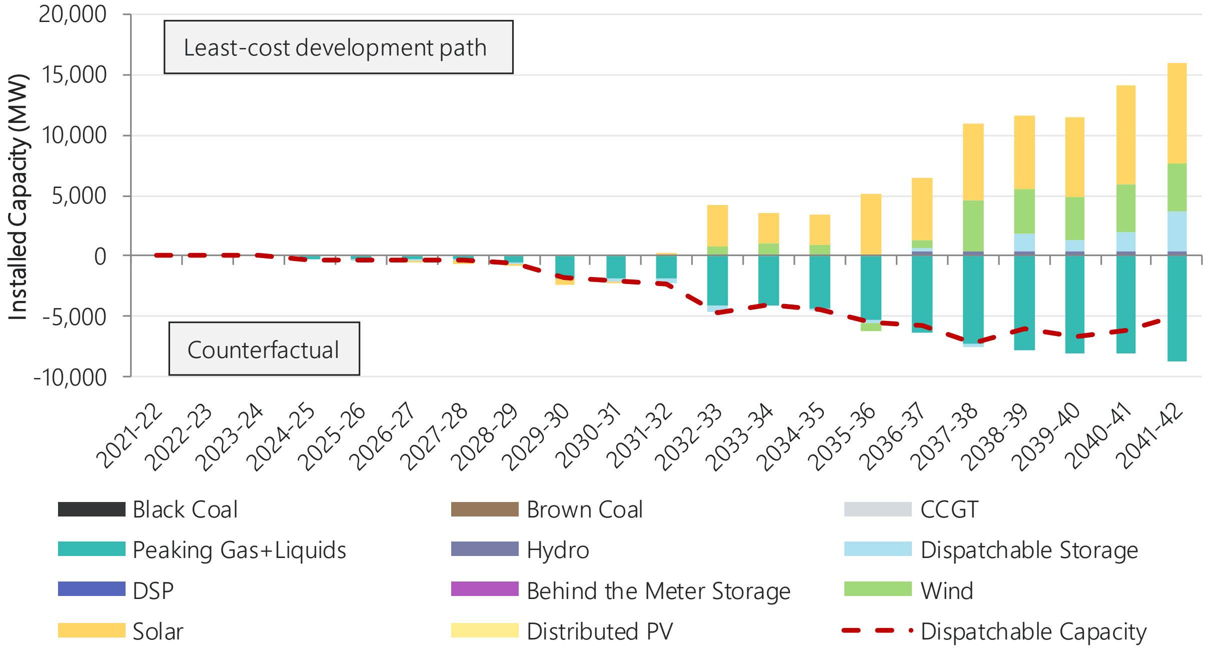
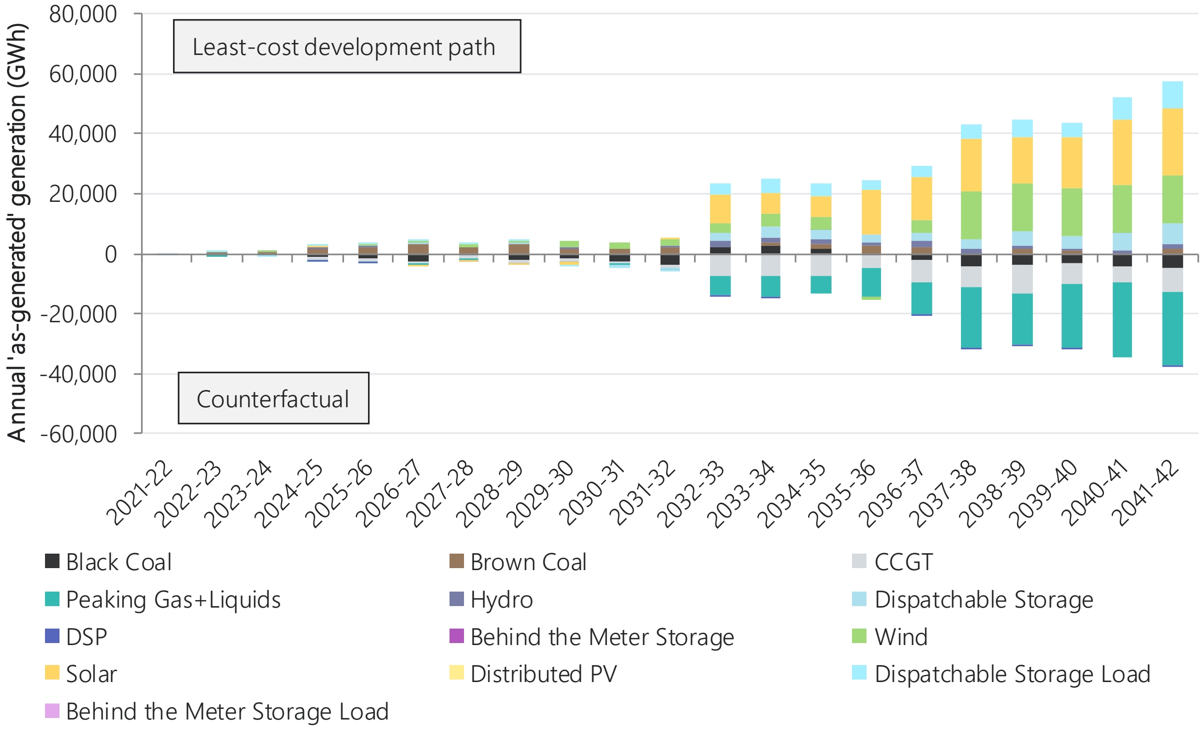


Figure 12 presents the generation production outcomes between the two pathways, and highlights – through the greater use of lower-cost fuel sources – the benefits forecast to be associated with further interconnection. For further discussion on the cost benefit analysis for the respective scenarios please refer to Appendix 2. Positive values in this figure mean there is more generation of that technology type in DP1; conversely, negative values represent greater production in the counterfactual.

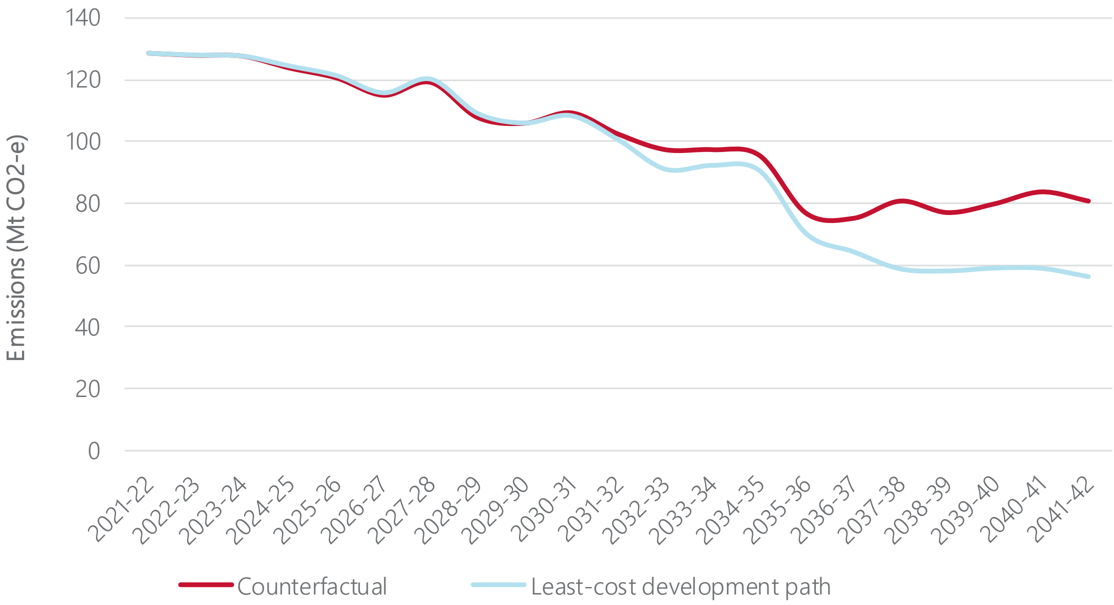
From 2032-33 to 2041-42, as more coal generation retires, greater utilisation of GPG is needed in the counterfactual (both from CCGTs and peaking gas), while DP1 would enable more efficient use of solar and wind generation.

Figure 12 Comparison of energy generated with and without ISP transmission developments, Central scenario



As a result of this material shift from VRE to GPG, emissions under the counterfactual outlook increase comparatively from 2032-33. Ultimately the complementary use of transmission infrastructure with VRE leads to both a lower-cost and less emission-intensive system. Figure 13 presents the emissions outcomes for the respective outlooks.

Figure 13 Comparison of emissions with and without transmission developments, Central scenario



A4.4.1.4 Generation developments in the updated demand sensitivity

The effects of both the COVID-19 pandemic and record sales of distributed PV systems observed in calendar year 2019 are projected to result in material reductions in electricity consumption and regional minimum demand levels into the future. As such, with the higher DER capacity forecast, the amount of additional VRE installed in the NEM is lower under this sensitivity compared to the Central scenario.

As shown in Figure 14, differences in installed capacity are borne out through significantly increased distributed PV capacity and corresponding reductions in large-scale wind and solar build across the NEM. Up to 2029-30, these reductions are present in Victoria and Queensland, with less large-scale VRE required to meet the respective state-based targets due to higher DER contributions. For example, while approximately 3.1 GW of new wind and solar (in addition to committed and anticipated projects) is expected to be required to meet the VRET under the Central scenario, only 1.3 GW would be required based on the revised DER projections, with significantly more distributed PV generation in Victoria.

Beyond the early 2030s, there are relative reductions in large-scale solar development forecast in New South Wales, Victoria and South Australia, which corresponds to the regions with the largest upward revision of distributed PV uptake. This effectively highlights that a trade-off occurs between large-scale PV and distributed PV in these regions. Meanwhile, wind generation capacity remains largely unchanged compared to the Central scenario, indicating a relative preference for wind to complement increased installations of distributed PV. In 2039-40, wind is projected to comprise 61% of all large-scale VRE capacity using updated demand forecasts, compared to 57% in the Central scenario.

Also observed in later years is an increase in forecast capacity of large-scale storage. These are required to provide firming and energy shifting services as the gap between minimum and maximum demand widens and peak demand shifts to after sunset.

Figure 14 Forecast differences in installed capacity in the NEM to 2041-42 in sensitivity with updated demand, Central scenario

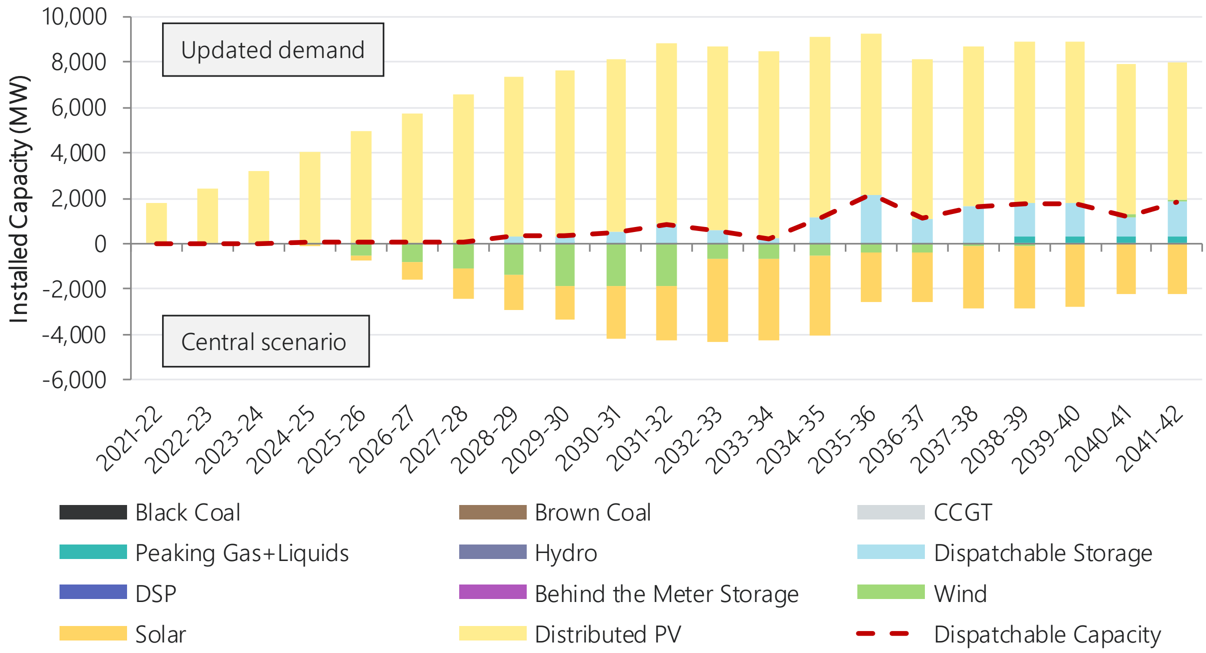
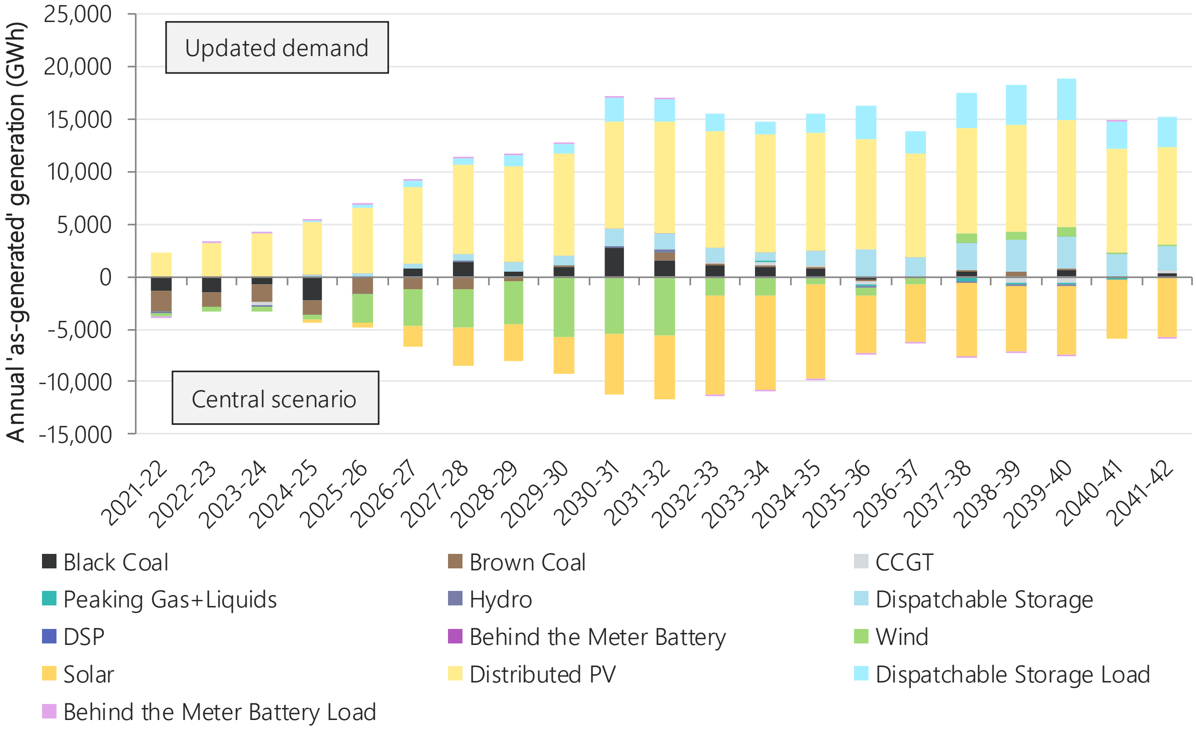


Figure 14 shows that using updated demand assumptions, additional storage capacity developments are not expected until major coal retirements commence from 2028-29.

The differences in generation (Figure 15) are broadly aligned with the differences in installed capacity observed above, with more distributed PV generation and less large-scale VRE generation. However, due to the proportionally lower production from distributed PV in comparison to large-scale VRE, a greater reliance on a combination of storages and thermal generation is observed for the updated demand scenario from 2026-27.

Declining consumption due to COVID-19 in the short term is expected to result in lower generation output from thermal generators, particularly coal-fired power stations. However, utilisation of thermal generators, transmission and large-scale storages are projected to be higher than in the Central scenario past the mid-2020s, as more flexible supply is required to support increasingly variable demand. Lower minimum demand provides greater opportunity for medium-depth storages to charge during daylight hours and perform intra-day or overnight energy shifting.

Figure 15 Forecast differences in generation in the NEM to 2041-42 in sensitivity with updated demand, Central scenario



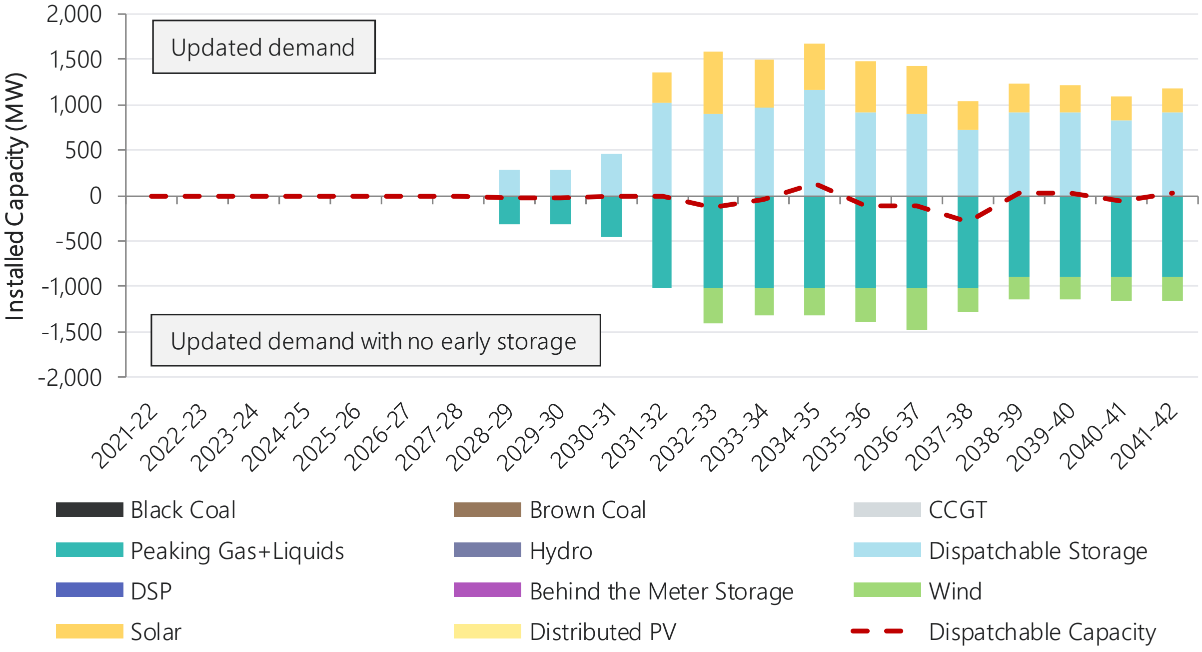
An additional sensitivity exploring the response to the delay of storage developments until 2032-33 under the updated demand scenario was examined to quantify the outlook for GPG and transmission under these conditions.

In this sensitivity, storage development was restricted until 2032-33 as development uncertainty in large storage schemes was expected to preclude investment until major thermal retirements provided sufficient price volatility for profitable development of technologies trading arbitrage opportunities. With major coal retirements across NEM regions, price volatility from this time would be likely to materially increase.

Figure 16 shows that, additional GPG capacity would be required if VNI West is delivered in 2035-36 (DP1) without the option to develop storages.

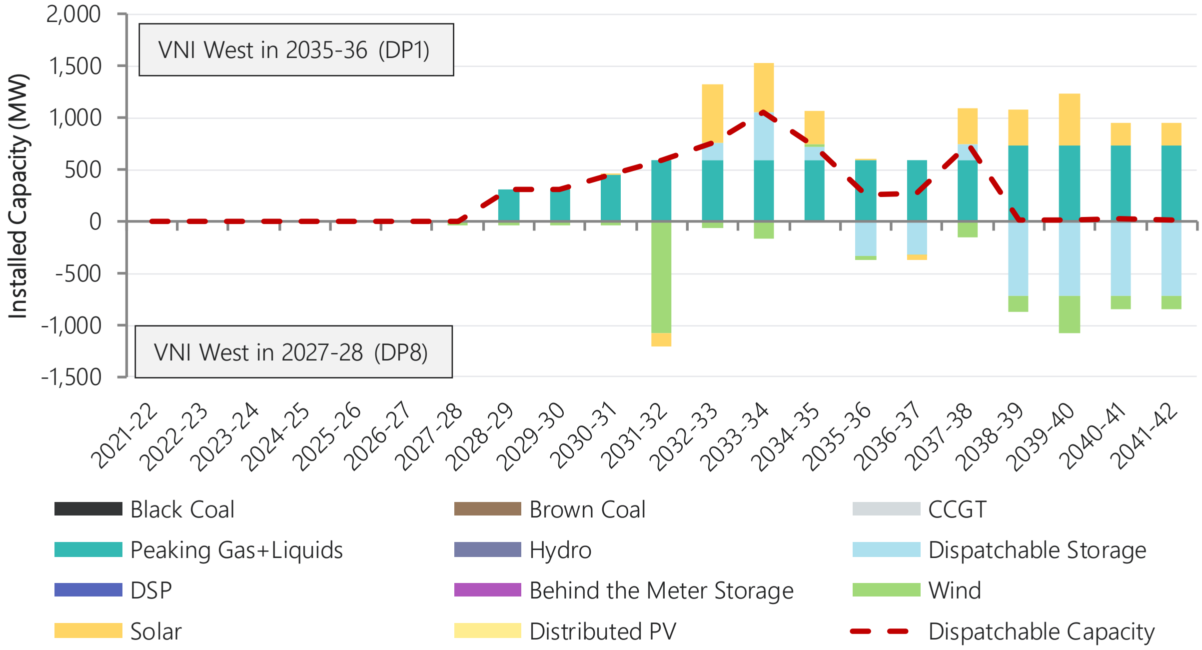
This additional GPG capacity is progressively built from 2028-29 to 2032-33 to provide firming capacity following the staged retirement of Yallourn Power Stations and the retirement of Eraring in the early 2030s. Once storage is available the development outlook for both scenarios stabilises.

Figure 16 Forecast differences in installed capacity in the NEM to 2041-42 in sensitivity with updated demand and no new market-based dispatchable storage until 2032, Central scenario



To quantify the impact of increased transmission, early delivery of VNI West (DP8) under the updated demand with delayed market-based dispatchable storage was modelled. Figure 17 shows that early delivery of VNI West will reduce the requirement for firming GPG and highlights the ability for an early VNI West to mitigate against the risks of deferred deployment of storages.

Figure 17 Forecast difference in installed capacity in the NEM to 2041-42 between development paths with VNI West built in 2035-36 (DP1) and VNI West built in 2027-28 (DP8) in Central scenario with updated demand and no new market-based dispatchable storage until 2032



A4.4.1.5 Generation developments in the inclusion of TRET sensitivity

The announced TRET is not yet legislated by the Tasmanian Government to meet 200% renewable energy by 2039-40 but may be in the near future. AEMO has conducted this sensitivity on the Central scenario to explore, and prepare for, the potential impact of this policy on the renewable resource developments, particularly across Tasmania and Victoria, and the development of interconnectors, mainly Marinus Link.

With the TRET implementation, this sensitivity:

- Projects Tasmania having higher VRE developments, with an additional 1,240 MW of wind and 150 MW solar by 2039-40 compared with the least-cost development path.
- Advances the development of Marinus Link first stage and develops a second stage Marinus link to export the additional renewable energy in Tasmania to the mainland.
- Advances the repurposing of an additional 390 MW of hydro resources in Tasmania in line with the development of Marinus Link.

The potential impact of this policy on the NEM renewable resource development is shown in Figure 18, with a shift from solar resources to more wind resources if TRET is legislated. Additionally, with greater access to the hydro assets from Tasmania, the mainland requires less development of storages to complement the uptake of VRE across the NEM.

Figure 18 Forecast differences in installed capacity in NEM to 2041-42 in TRET implementation, Central scenario

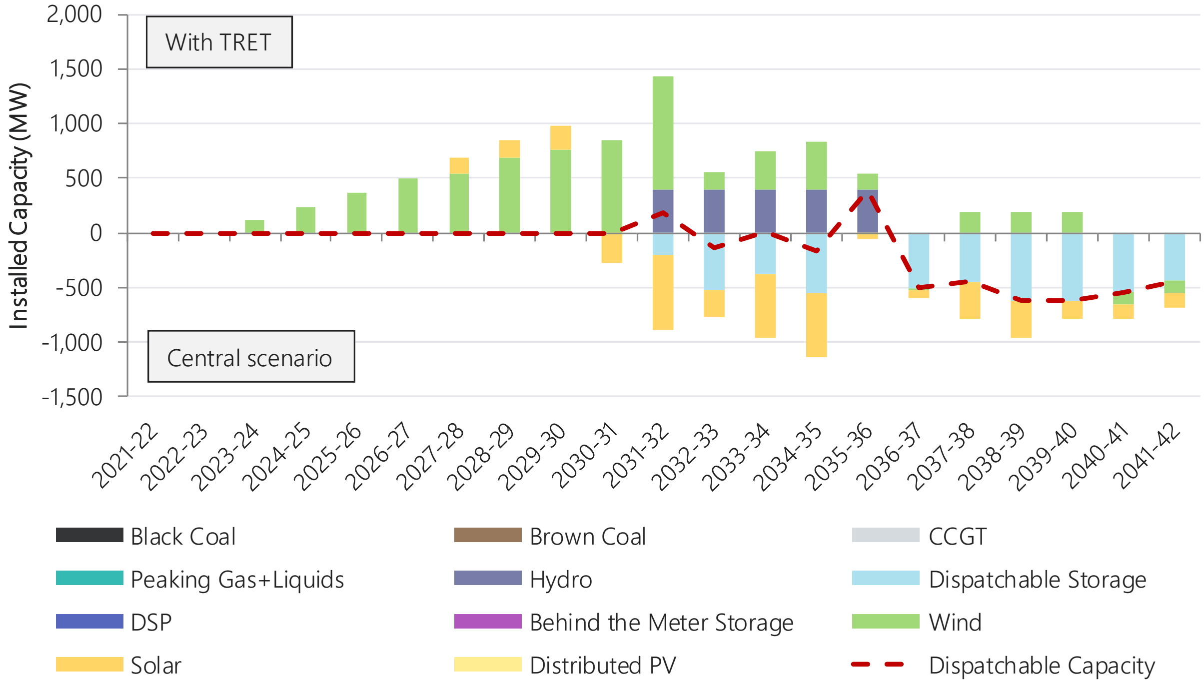


Figure 19 demonstrates the difference in the forecast generation for each NEM region and the renewable energy uptake in Tasmania. AEMO's modelling indicates that while the TRET legislation will increase local wind production, there is also a corresponding reduction in the generation of coal, mainly in New South Wales and Victoria, as this additional renewable energy is exported to the mainland. In the TRET sensitivity, Tasmania reaches 209% and 164% renewable energy with and without Marinus Link respectively by 2039-40. Without the legislation of TRET, the renewable energy share still reaches 161% of the region's underlying demand in the Central scenario, supported by development of Marinus Link first cable in the mid 2030s (DP1).

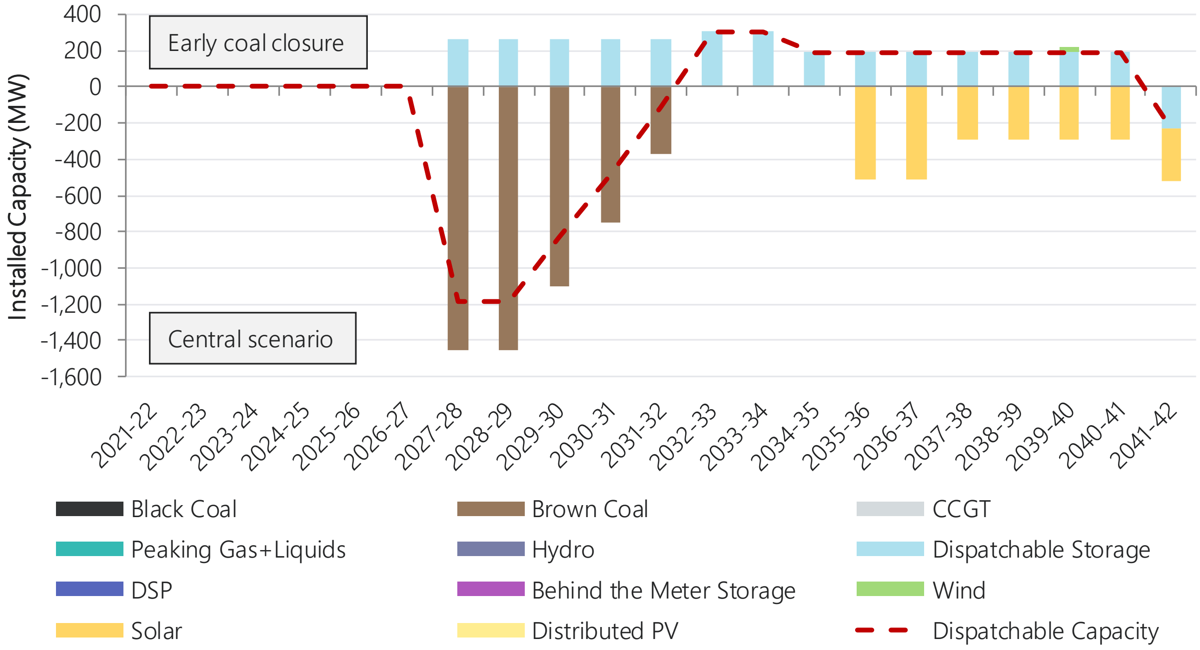
The development of Marinus Link is essential to meet the TRET without a local consumption response. The greater net energy production of Tasmania with increased VRE development impacts the region's export to the mainland, increasing the appetite to develop Marinus Link earlier.

Figure 19 Difference in forecast annual 'as-generated' generation for each NEM region to 2041-42 (top) and renewable energy uptake in Tasmania (bottom) in sensitivity with TRET legislation, Central scenario

A4.4.1.6 Generation developments in the early coal closure sensitivity

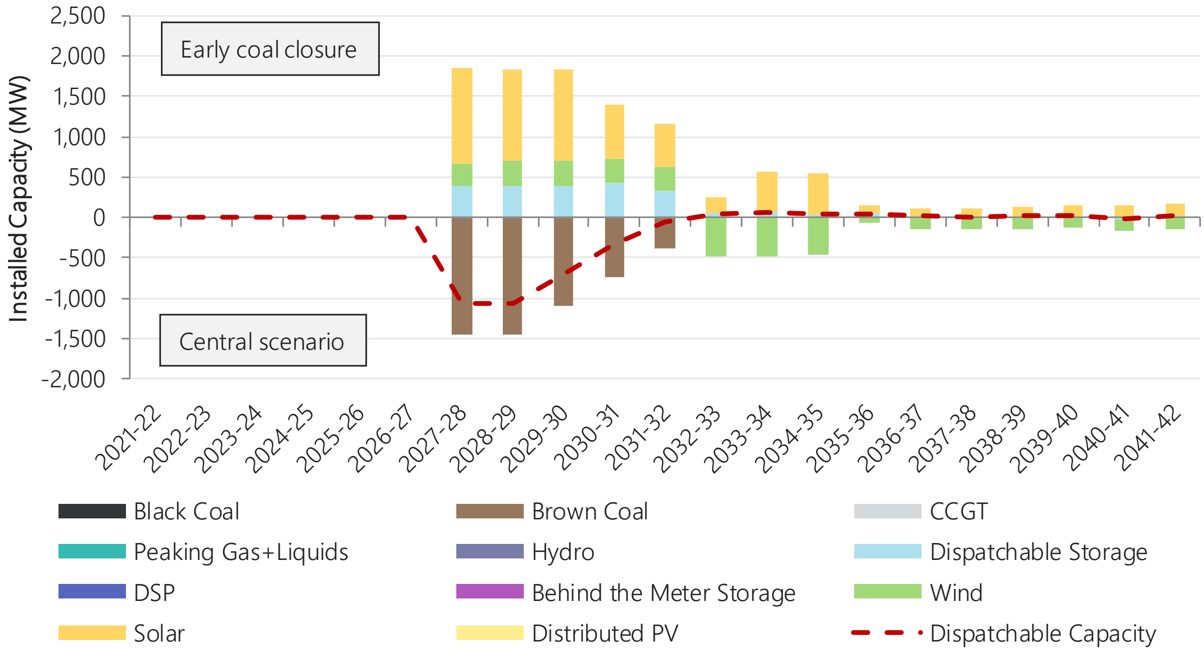
The ISP modelling considered the risk of unplanned early retirements. As a market event sensitivity, AEMO assumed the entire Yallourn brown coal power station in Victoria closes in 2027-28, several years earlier than the next planned retirement. The impact on the Victorian development outlook is presented in Figure 20. With the withdrawal of Yallourn, the local regional requirement is for 265 MW of storages from 2027-28.

Figure 20 Forecast differences in installed capacity in Victoria to 2041-42 in sensitivity with early coal closure, Central scenario



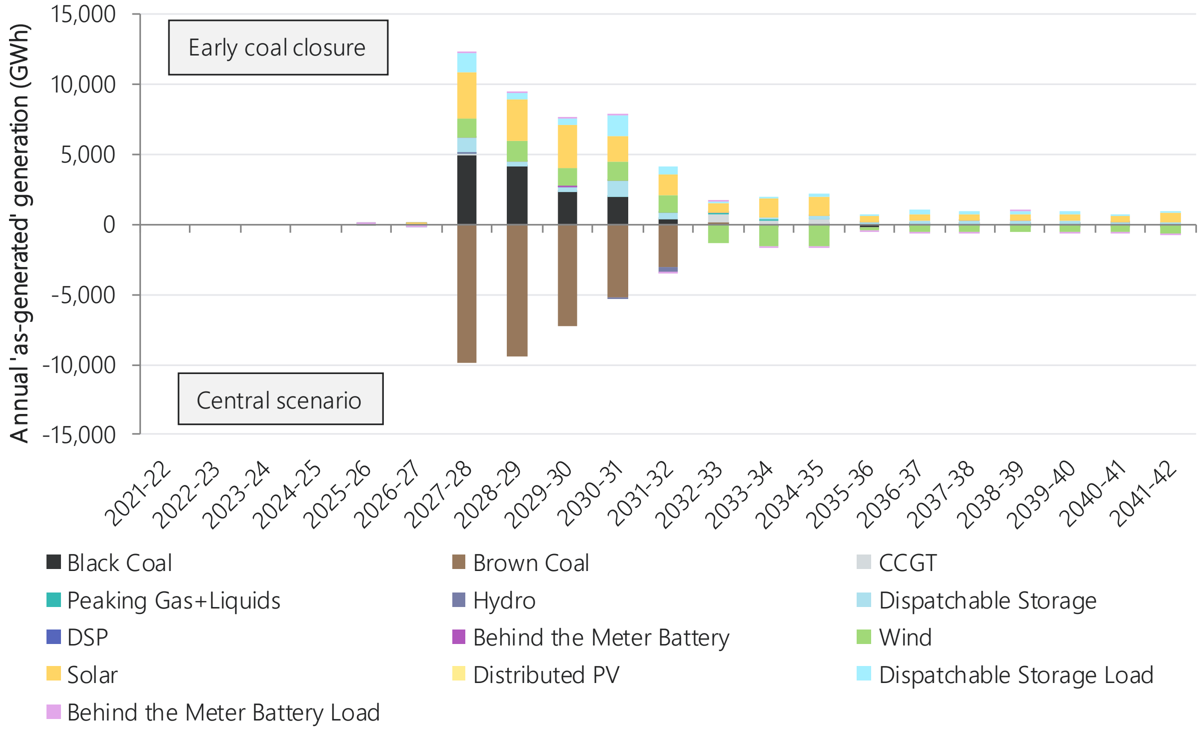
This sudden loss of brown coal capacity would affect generation investments across the NEM, since Victoria is no longer able to export as much energy to neighbouring regions. Under the Central scenario, and in the absence of an early transmission solution that would strengthen the Victoria – New South Wales corridor, this closure is projected to require additional investments in approximately 390 MW of large-scale storage (in both South Australia and Victoria) and is complemented by approximately 1.2 GW of solar (in New South Wales and South Australia) and almost 300 MW of wind (in Tasmania) (Figure 21).

Figure 21 Forecast differences in installed capacity in NEM to 2041-42 in sensitivity with early coal closure, Central scenario



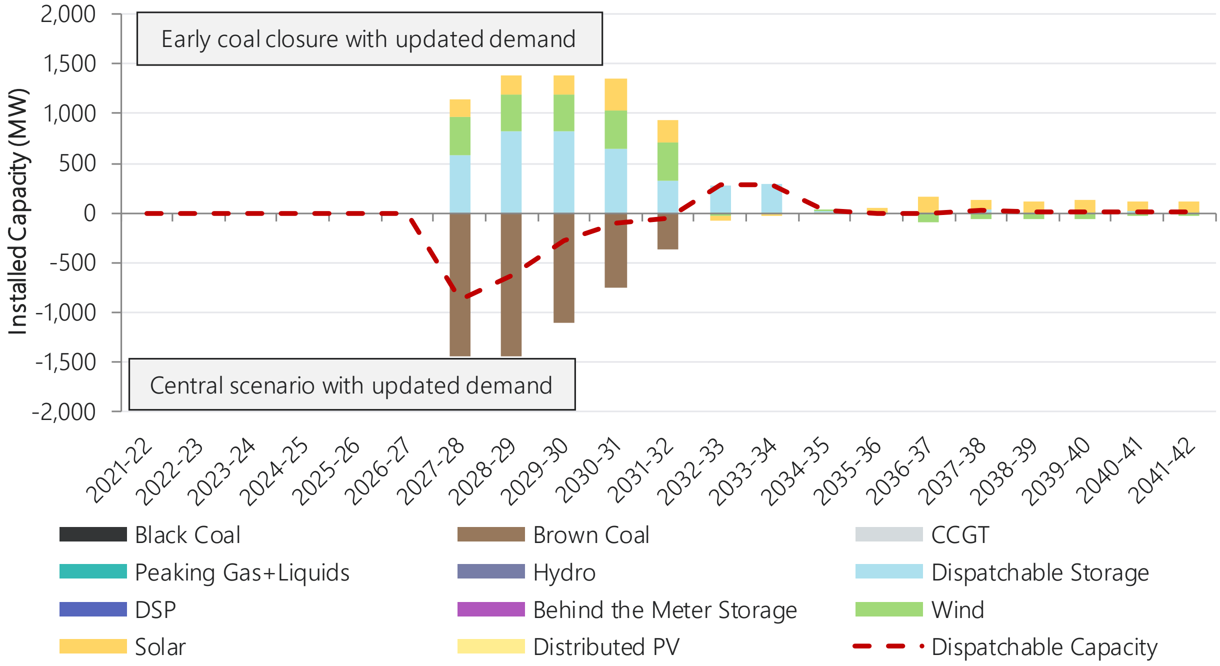
The differences in generation response to an early closure are projected to gradually reduce over time and mostly resolve with the delivery of VNI West in 2035-36 (based on least-cost timing), although there remains residual 'regret' associated with building solar in New South Wales and South Australia that would otherwise not have been needed for some time. Greater utilisation of the remaining black coal fleet, as well as increased operation of VRE, is forecast to offset the lost energy production due to the closure, as seen in Figure 22.

Figure 22 Forecast differences in generation in the NEM to 2041-42 in sensitivity with early coal closure, Central scenario



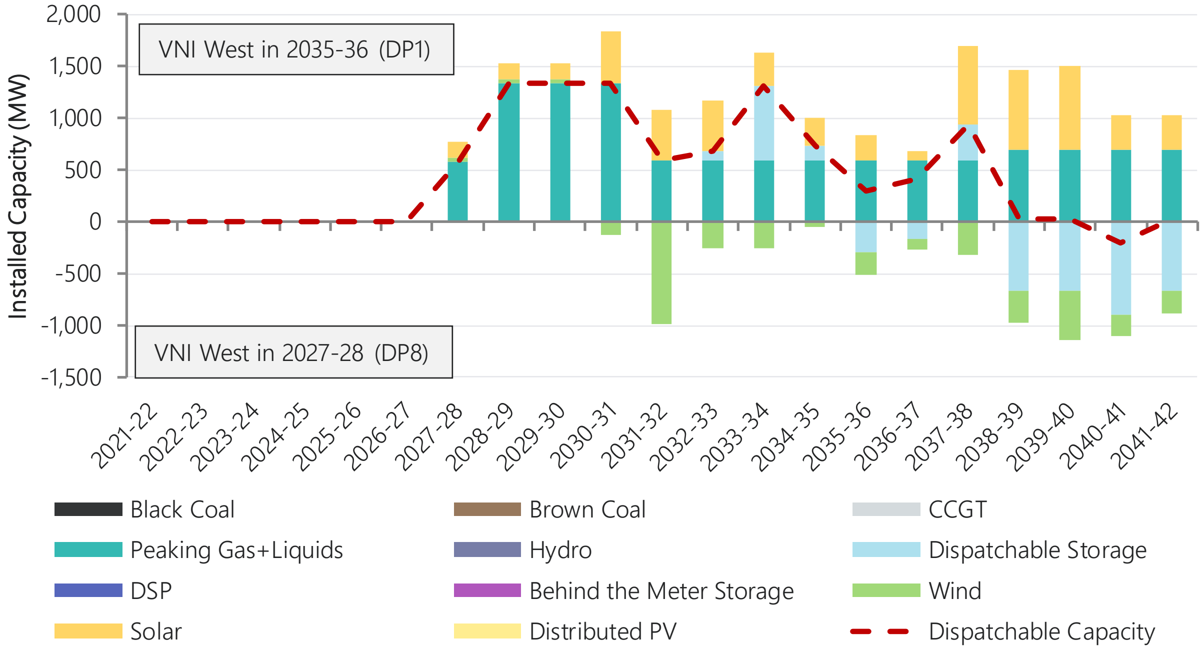
As shown in Figure 23, if Yallourn were to retire early under the Central scenario with updated demand, this closure is projected to increase the need for storage by approximately 820 MW (in Victoria mainly) with additional VRE also developed, primarily in New South Wales and Tasmania. The variability of operational demand under the updated demand sensitivity would increase the need for dispatchable capacity in Victoria if Yallourn were to retire early, consistent with the outcomes presented in Section A4.4.1.4. Consequently, with earlier retirements, a tendency to favour candidate development paths with early development of interconnectors connecting Victoria to other regions (VNI West and Marinus Link) is observed.

Figure 23 Forecast differences in installed capacity in NEM to 2041-42 in sensitivity with early coal closure, Central scenario with updated demand



This outcome is heavily reliant on the market providing the appropriate signals to incentivise at-scale energy storage development to perform an energy shifting role. There is no evidence of this having occurred in history under current market arrangements and relying on changes in market design to incentivise this investment in the next decade is risky. Therefore, an additional sensitivity for the Central scenario explored the value of early delivery of VNI West under the updated demand sensitivity in the Central scenario with an early brown coal generator closure, assuming no new market-based dispatchable storage until after 2031-32. As shown in Figure 24, under these settings, if VNI West is delivered in 2035-36 (DP1), this closure will require an additional GPG capacity response of 1,340 MW to be built by 2031-32. An early delivery of VNI West (DP8) will reduce the requirement of dispatchable capacity build until major coal retirements post 2035-36.

Figure 24 Forecast difference in installed capacity in the NEM between Interconnector paths with VNI West built in 2035-36 (DP1) and VNI West built in 2027-28 (DP8) under early Yallourn closure sensitivity with updated demand and no new market-based dispatchable storage until 2032, in Central scenario



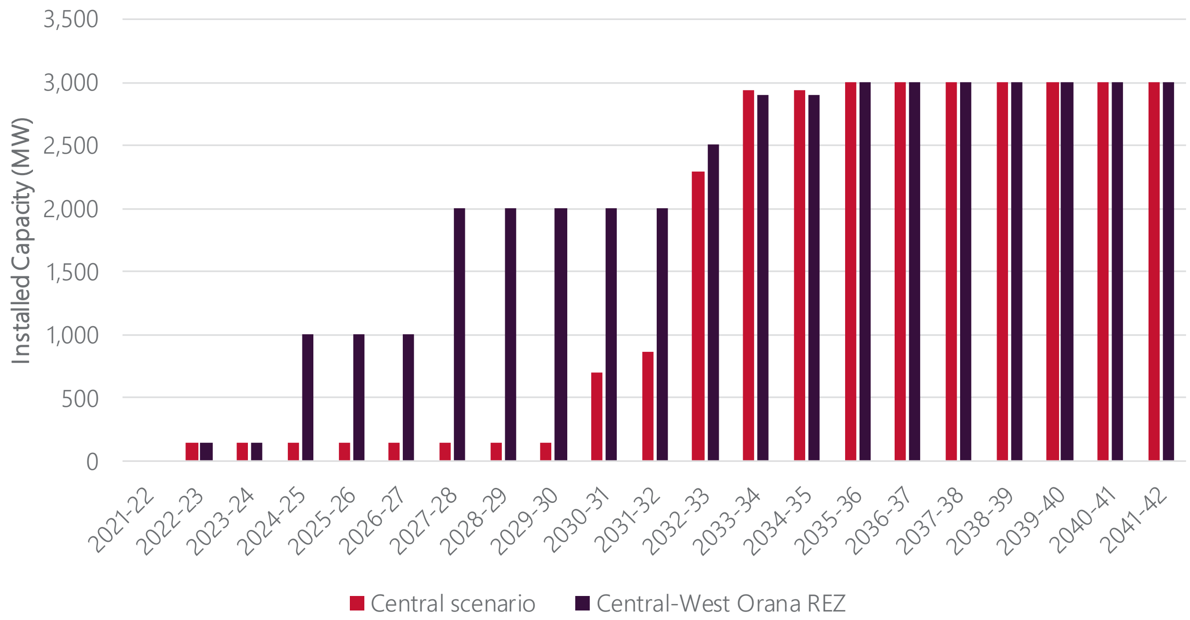
A4.4.1.7 Generation developments in the Central-West Orana REZ sensitivity

The New South Wales Electricity Strategy intends to coordinate investments in new generation capacity with transmission access in key areas of New South Wales, particularly the Central-West Orana REZ.

AEMO has carried out a market event sensitivity under the Central scenario to assess how the Electricity Strategy impacts selection of the optimal development path. In this market event sensitivity, AEMO has assumed development of at least 2 GW of new entrant VRE in the REZ by 2027-28, earlier than projected under the Central scenario, assuming that the Central-West Orana Transmission Link incentivises early VRE development in the REZ. This sensitivity effectively assumes that the New South Wales Electricity Strategy will accelerate the development of VRE projects in the region by eight years, in order to increase the region's renewable generation proportion.

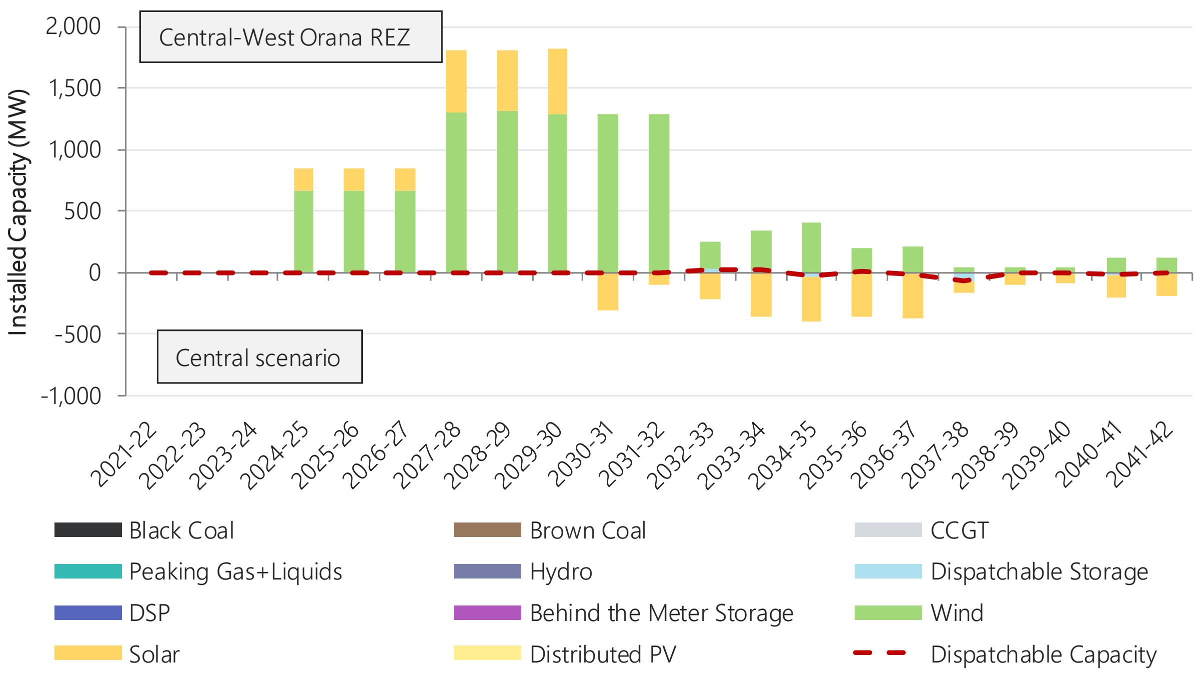
Figure 25 presents the differences in capacity installed in the Central-West Orana REZ, with and without an accelerated market response. By 2033-34, the sensitivity re-aligns to the VRE magnitude of the Central scenario.

Figure 25 Forecast differences in installed capacity in Central-West Orana REZ with and without assumed accelerated development



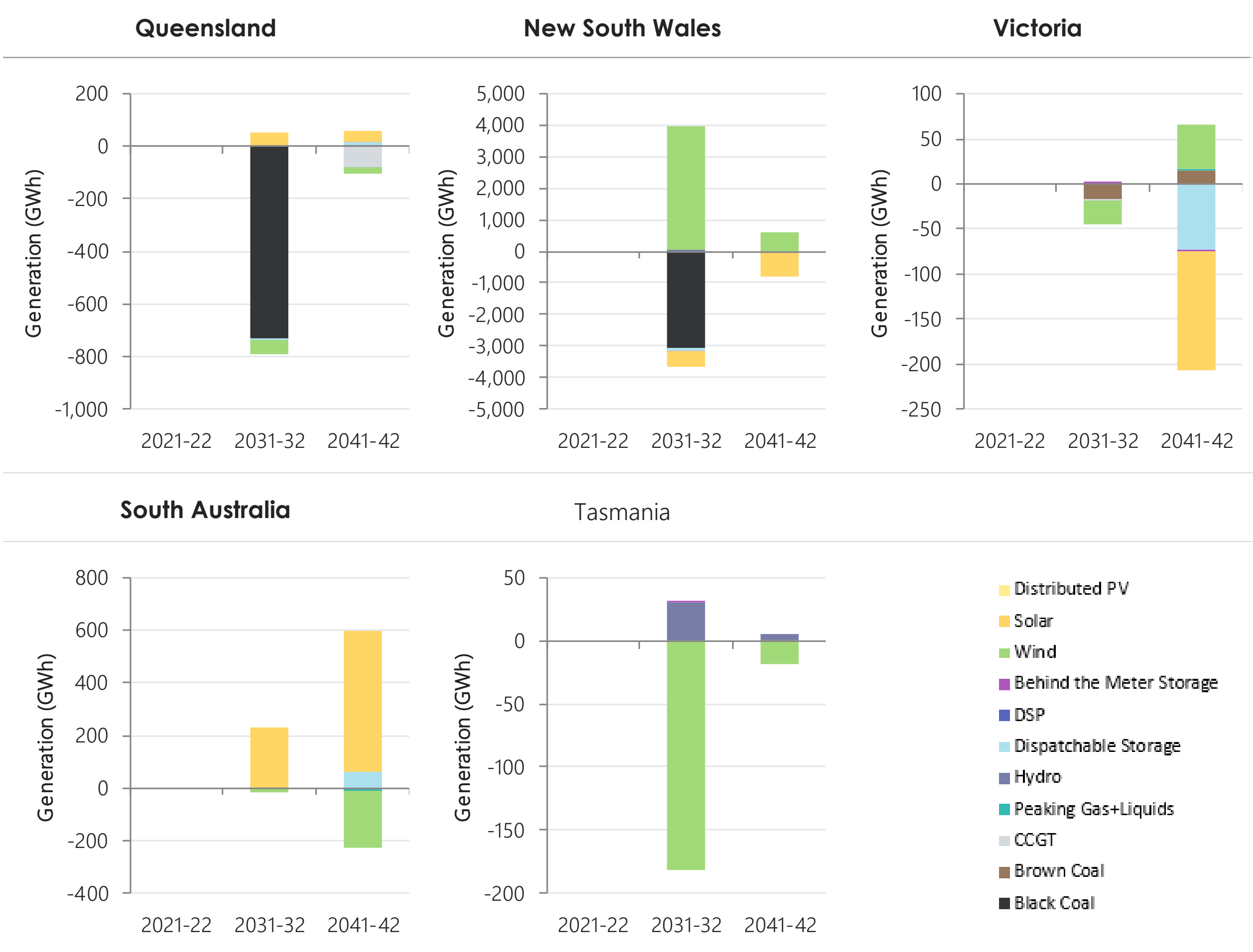
Overall, the assumption that 2 GW of VRE is built in Central-West Orana REZ by 2027-28 leads to earlier investments in wind generation in New South Wales, as seen in Figure 26. The assumption that wind developments would be the predominant technology candidate to advance under this scheme is based on developer interest and stakeholder feedback.

Figure 26 NEM-wide installed capacity impact of coordinated generation and transmission access in New South Wales



Increased VRE developments in this sensitivity are forecast to reduce coal generation, particularly in New South Wales. The net energy production of the New South Wales energy mix, however, is greater with this earlier VRE development, meaning there is slightly less reliance on imports to meet regional demand. The accelerated VRE development in Central-West Orana REZ has impacted the forecast evolution of other regions as well as shown in Figure 27, with minor VRE differences forecast in Queensland and Victoria across the outlook period particularly after 2030.

Figure 27 Difference in forecast annual 'as-generated' generation for each NEM region to 2041-42, with and without accelerated Central-West Orana REZ development

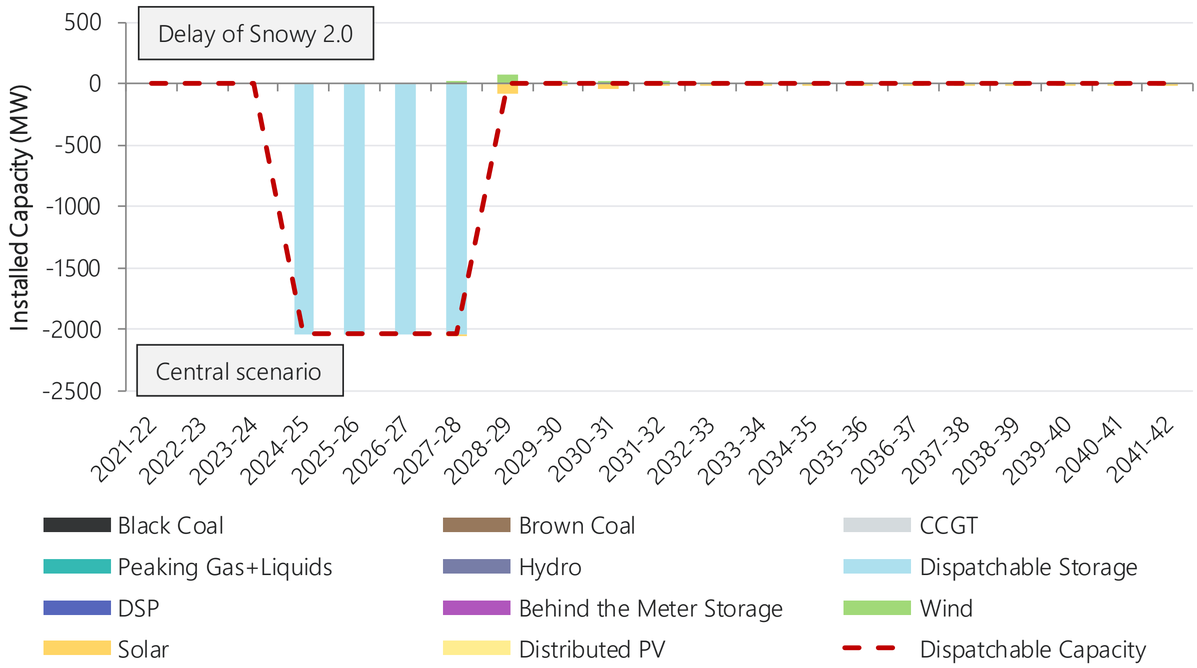


A4.4.1.8 Generation developments in the delay Snowy 2.0 sensitivity

The Snowy 2.0 project is expected to provide firming capacity to support the projected changing supply mix of the NEM. A delay of four years to the Snowy 2.0 project was considered as a market event sensitivity in the modelling under the Central scenario.

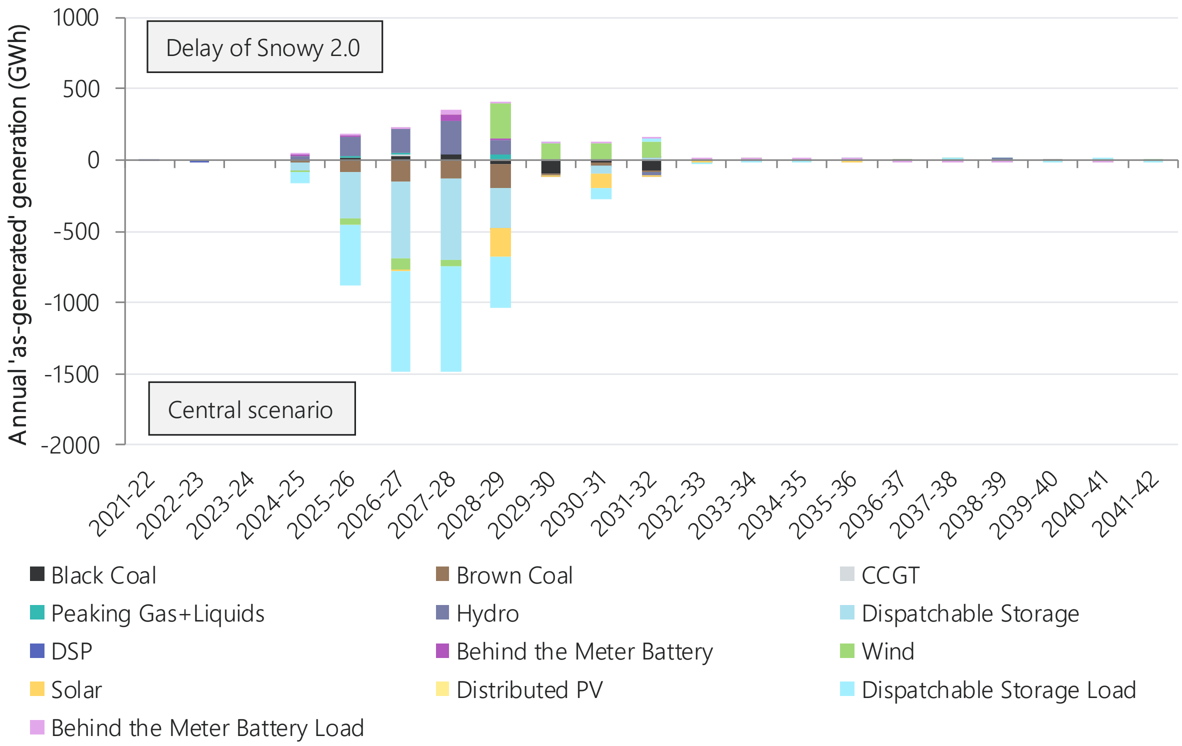
Figure 28 highlights that a Snowy 2.0 delay is not forecast to lead to alternative firming capacity, provided the low-regret ISP projects are progressed to enable more efficient sharing of resources across regions. With the delay of Snowy 2.0, there is minimal shift in the VRE development outlook across the NEM.

Figure 28 Forecast capacity differences to 2041-42 in sensitivity where Snowy 2.0 is delayed by four years, Central scenario



The generation response to the Snowy 2.0 delay is observed in Figure 29, where hydro generation in New South Wales facilitated through pumping at Tumut 3 covers the pumped hydro role between 2024-25 and 2028-29.

Figure 29 Forecast differences in generation in the NEM to 2041-42 in sensitivity where Snowy 2.0 is delayed by four years, in the Central scenario



While the long-term development models do not build firming generation in the interim, suggesting there is enough dispatchable capacity with the additional interconnector support in New South Wales and the broader NEM to maintain the reliability standard, supply scarcity risks would increase. Additional resources would be required to cover these risks (in line with the Interim Reliability Measure or equivalent) after the retirement of Liddell if Snowy 2.0 was delayed. The impact of a delay of more than four years is very likely to be much more severe as further power stations retire from 2029-30 onwards. At this point, additional dispatchable capacity would be essential to maintain reliability. This is evidenced by the additional storage capacity developments post 2029-30, even with Snowy 2.0 being built.

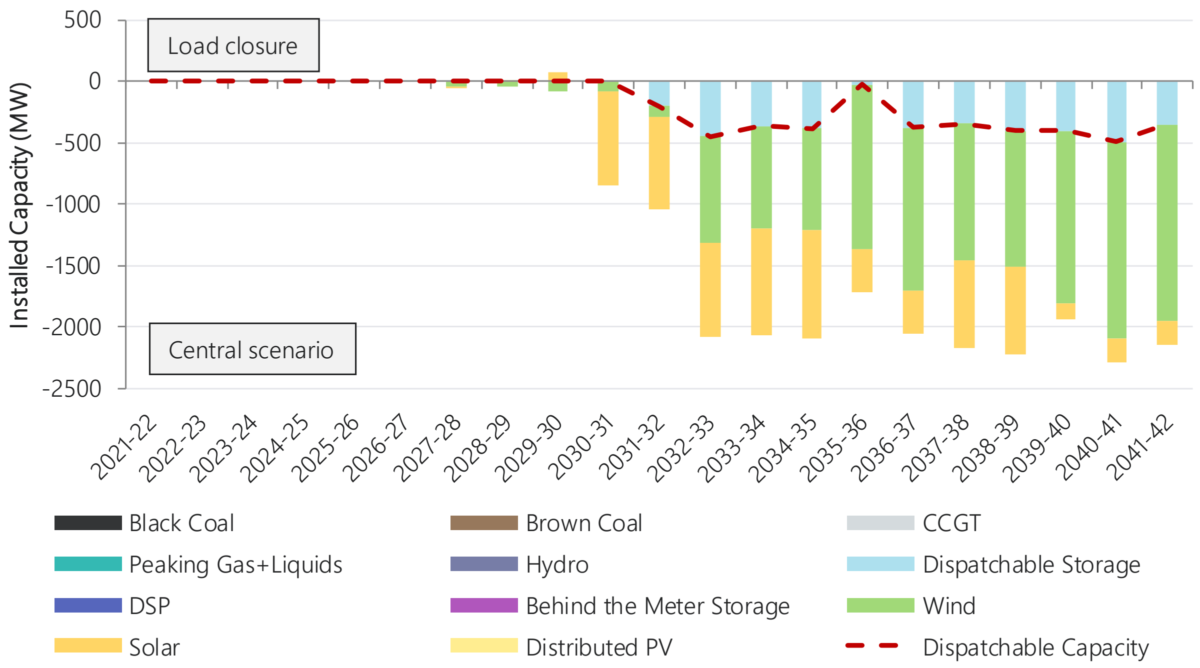
A4.4.1.9 Generation developments in the closure of industrial load sensitivity

The closure of industrial load is projected to impact the future supply mix, as lower generation development requirements would be expected to supply the remaining consumption requirements of the power system. This market event sensitivity assessed the impact of an industrial load closure in Victoria and Tasmania, assumed to represent approximately 10% of Victorian energy and 9% of Tasmanian energy.

Victoria's VRET is linked to local generation, therefore the load closure would not materially reduce the local VRE development needed in absolute terms, unless total Victorian generation (including exports) reduced. This may occur if the load closure led to a coal generator closure or significant constraint on export (not included in this sensitivity). Provided a load closure does not trigger an early coal closure, in the short to medium term, the assumed load closure is projected to increase the availability of brown coal generation to export to neighbouring regions, displacing black coal generation in New South Wales and Queensland[6].

As the existing coal fleet exits, less new generation is needed in this sensitivity, since the industrial load closure has reduced total consumption. Therefore, from 2031-32, a suite of VRE and large-scale storage developments is projected to be deferred, as shown in Figure 30. Fewer large-scale solar developments are projected in South Australia, New South Wales and Victoria while wind generation capacity is reduced in all regions. With fewer projected VRE developments in this sensitivity, energy storage developments are also projected to be lower.

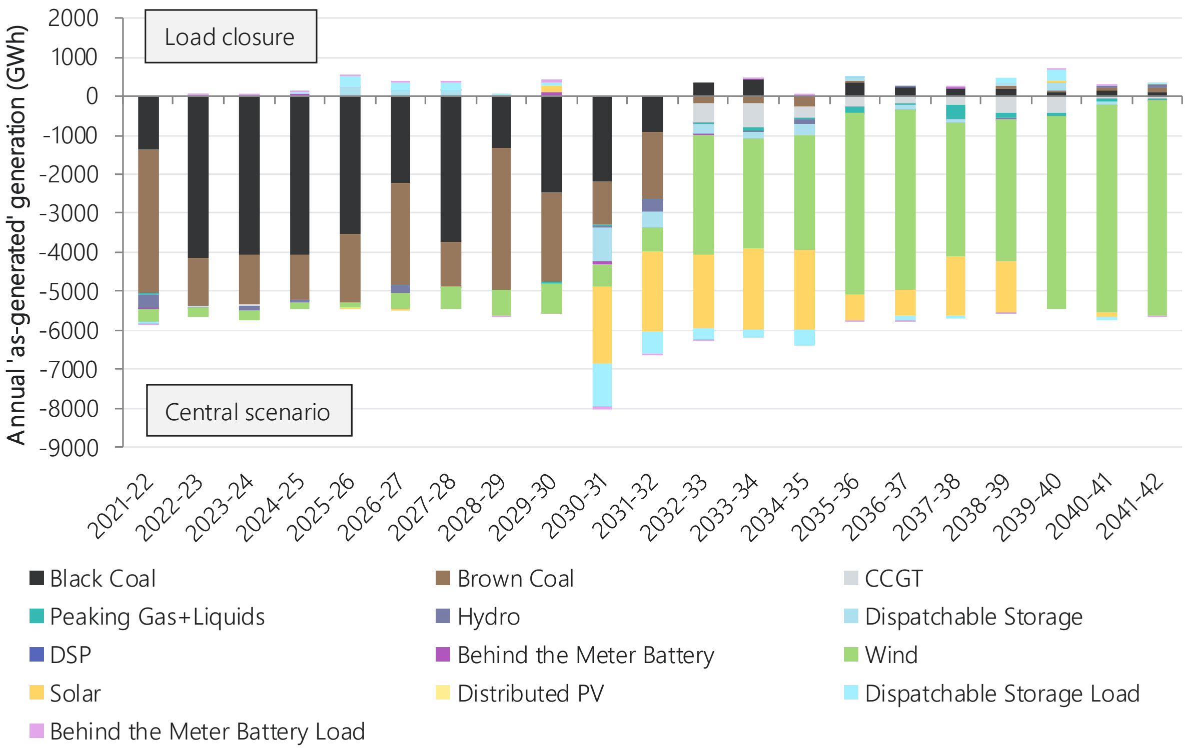
Figure 30 Forecast difference in capacity to 2041-42 in sensitivity with load closure, Central scenario



[6] The loss of major industrial load would typically impact the generation portfolio that services the load. For the 2020 ISP, AEMO has not conducted extensive portfolio analysis to determine with confidence whether sufficient revenue streams are available to the incumbent energy provider to avoid a local generator closure. The coal fleet is assumed to continue to operate until announced retirement dates.

Figure 31 shows the projected reduction in black coal production in New South Wales and Queensland, and brown coal generation in Victoria, in the 2020s in the absence of these industrial loads, and also the reduction in VRE generation beyond 2029-30, predominantly in New South Wales, Queensland, and South Australia.

Figure 31 Forecast difference in generation production to 2041-42 in sensitivity with load closure, Central scenario



A4.4.2 Slow Change scenario

The Slow Change scenario forecasts lower economic growth and lower overall grid consumption, with less DER and less ambition to decarbonise the energy sector, compared to the Central scenario. With reduced decarbonisation ambition, there is increased value in refurbishing aging coal-fired generators as they approach the end of technical life.

This section describes the resource mix that is forecast, in combination with transmission development, to optimally reduce total system costs, maximising market benefits of an efficiently operating power system.

The generation capacity forecast projects that:

- To 2029-30:
  - There will be little change in the near-term generation mix beyond committed project developments. Several coal-fired generators have life extensions for a period of 10 years (Bayswater in New South Wales and Gladstone in Queensland) to minimise system costs.
  - In the near term, renewable developments also stall, with the VRET policy assumed to be the only regional RET providing VRE stimulus.
- By 2039-40:
  - Generators that retire are replaced with distributed and large-scale PV and energy storage, especially in New South Wales and South Australia.

- These developments are also complemented by relatively slow growth in DER and behind-the-meter battery storages.

Figure 32 presents the forecast NEM generation capacity in the Slow Change scenario. Coal is forecast to remain a significant part of the generation mix in this scenario, with solar, batteries and storage increasing slightly in the later years, particularly in the late 2030s. Dispatchable capacity softens over the forecast period in line with a reduction in energy consumption. By 2039-40, in addition to the assumed 7 GW of new distributed PV, the NEM needs an additional 6 GW of VRE to replace major coal plant exits, excluding anticipated projects. This is complemented by approximately 5 GW of additional grid-scale energy storage and 150 MW of new VPP capacity.

Figure 32 Forecast NEM generation capacity to 2041-42, Slow Change scenario

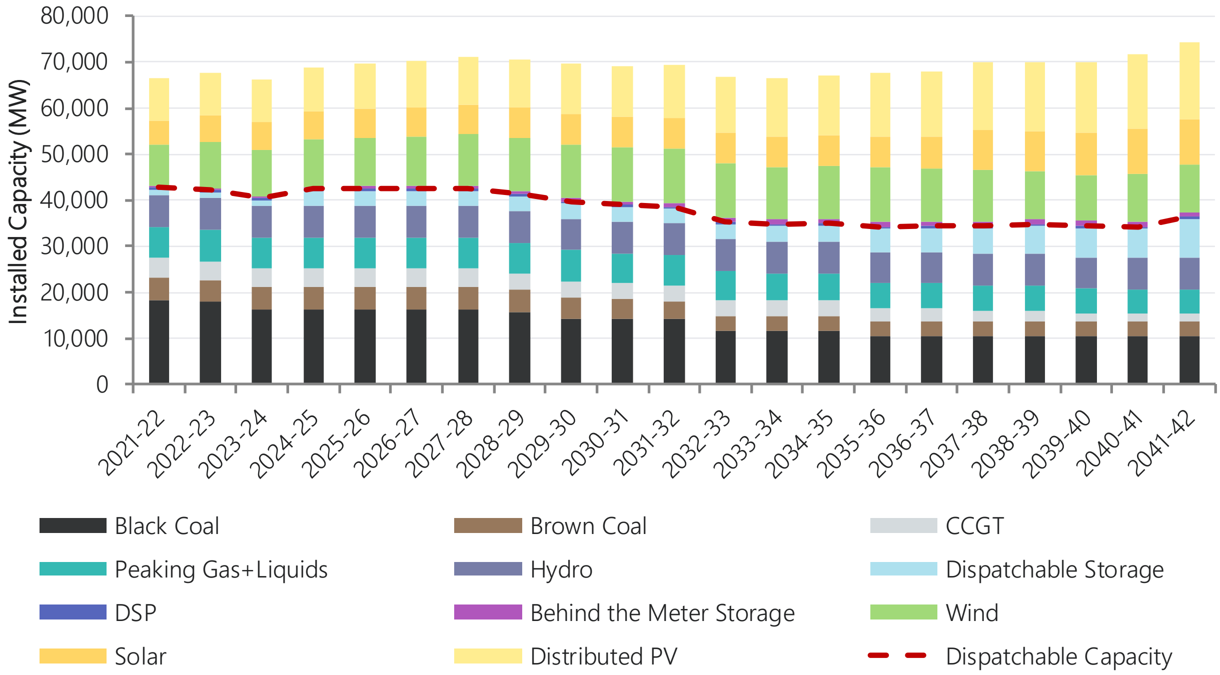
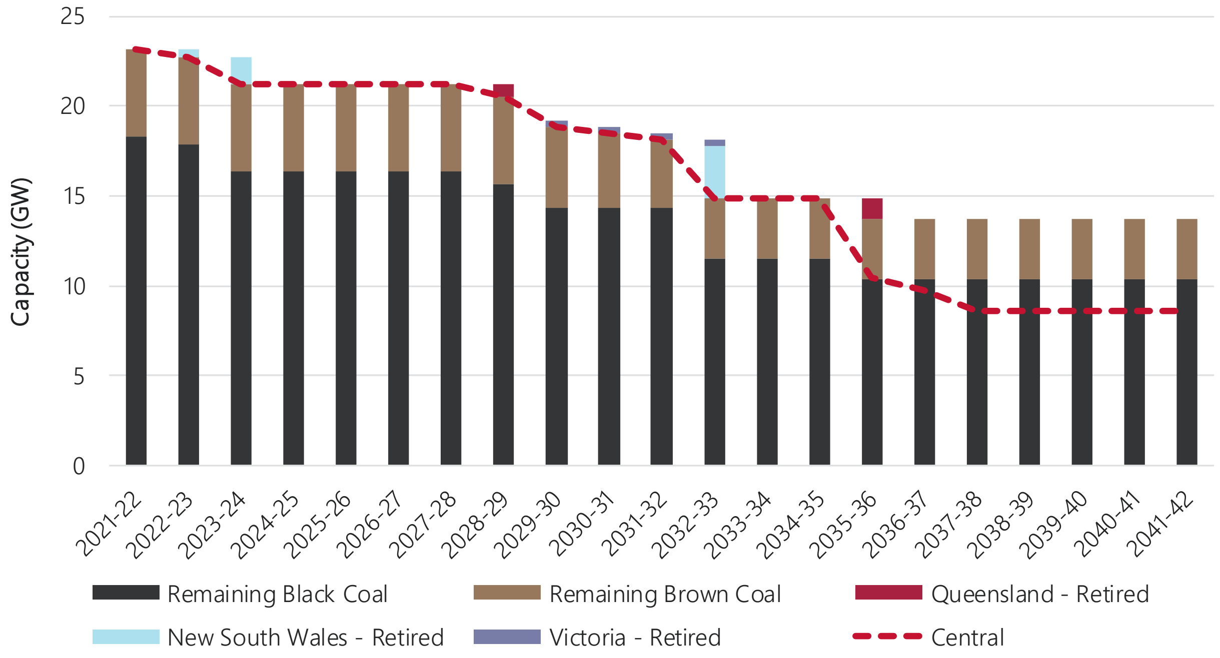


Figure 33 presents the difference in forecast coal retirements between the Slow Change scenario and the Central scenario, with the delayed retirements in the Slow Change scenario evident beyond 2035-36.

Figure 33 Forecast coal retirements to 2041-42, Slow Change scenario relative to the Central scenario



In Figure 34, a positive value indicates an addition in installed capacity while a negative value indicates a deduction due to retirement. This figure shows the forecast relative change in installed capacity in the Slow Change scenario, where the shift from coal to renewable energy is significantly slower than in the Central scenario. In the Slow Change scenario, new renewable energy is forecast to be provided by both solar (mainly in New South Wales, Queensland, South Australia) and wind (mainly in Queensland and Victoria), complemented with shallow storages in addition to the Snowy 2.0 project. It is also important to note that some wind generation is forecast to retire due to the end of the generators' technical life. These end of technical life retirements are considered in all scenarios but are more pronounced in the Slow change scenario with minimal new VRE developments offsetting these closures.

Figure 34 Forecast relative change in installed capacity to 2041-42, Slow Change scenario

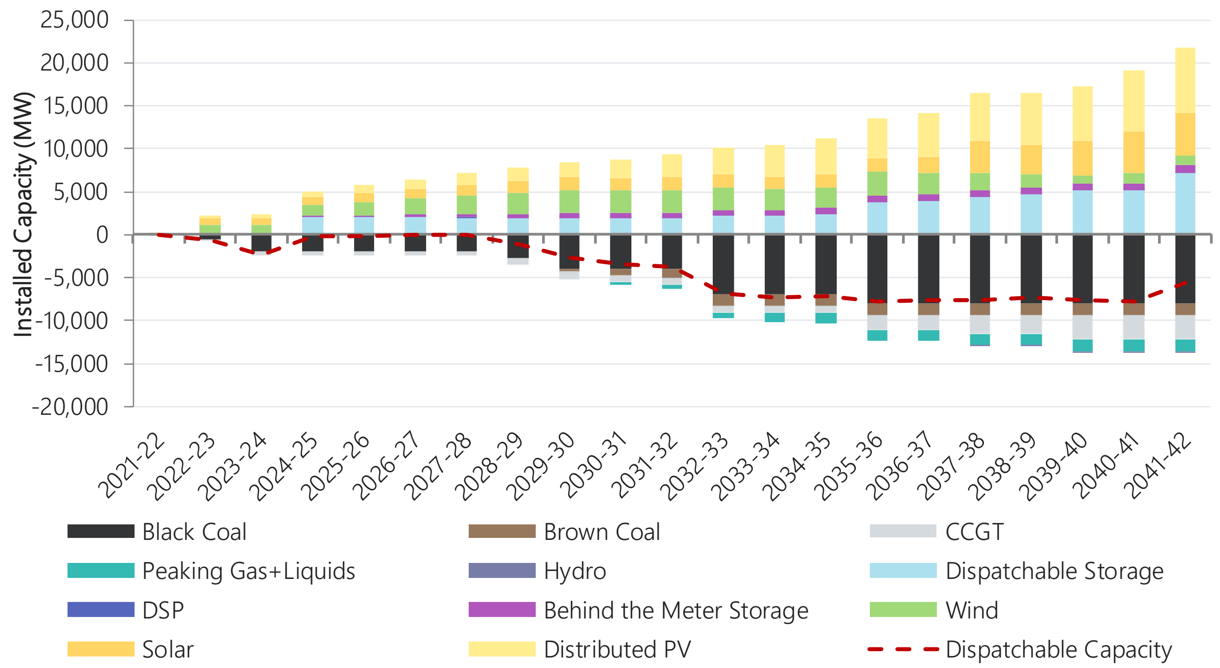
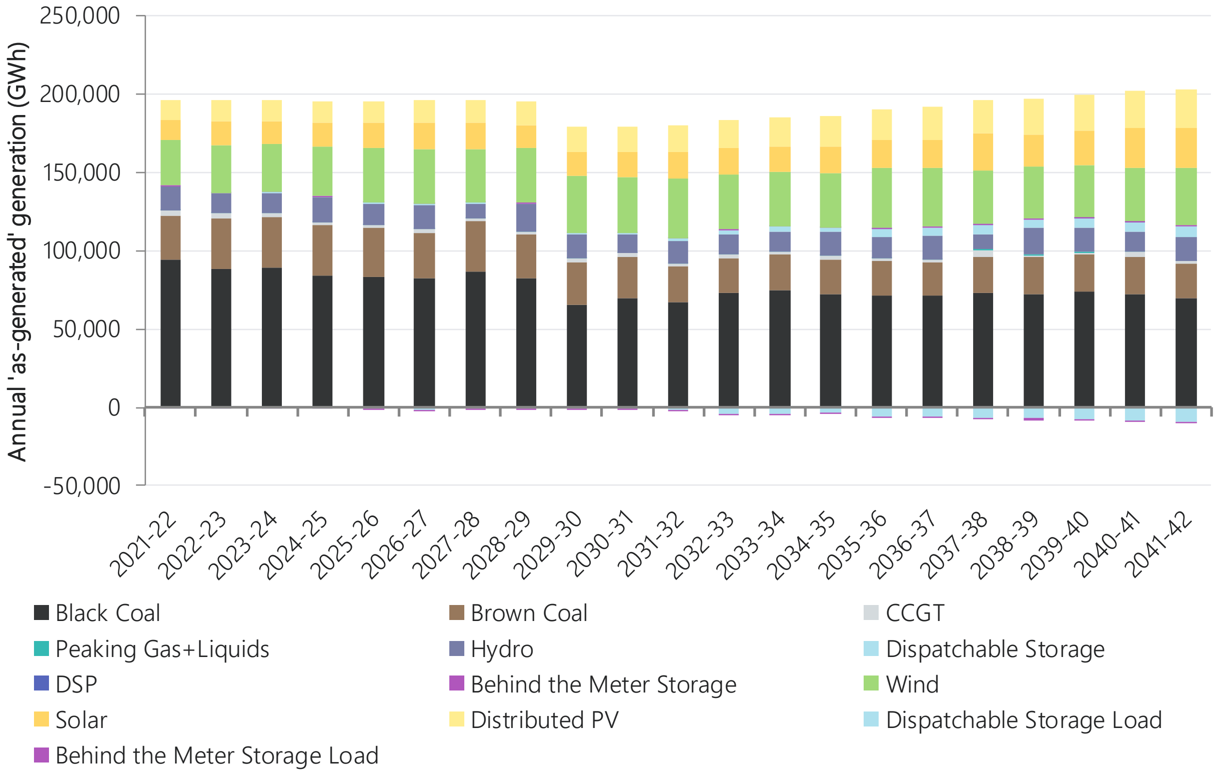


Figure 35 presents the slight change in the generation mix for energy production over time. In this scenario, energy production is forecast to be dominated by coal generation over the outlook period. Renewable energy is forecast to expand from approximately 36% of generation in 2021-22 to 49% of energy generated by 2039-40. The projected mix of VRE generation by 2039-40 is 42% wind, 29% large-scale solar PV, and 29% distributed PV.

Figure 35 Forecast annual generation to 2041-42, Slow Change scenario



A4.4.2.1 Regional deployment of the Slow Change scenario generation mix

Generation transformation is projected to be slow in all NEM regions across the forecast horizon in this scenario, as shown in Figure 36 and Figure 37, which present the generation in each region and the geographic and technological dispersion of new developments by 2039-40, respectively. By 2039-40, all regions except Tasmania are projected to have new VRE capacity (in addition to committed and anticipated projects) totalling 6 GW across the NEM.

Figure 36 Forecast annual 'as-generated' generation for each NEM region to 2041-42, Slow Change scenario

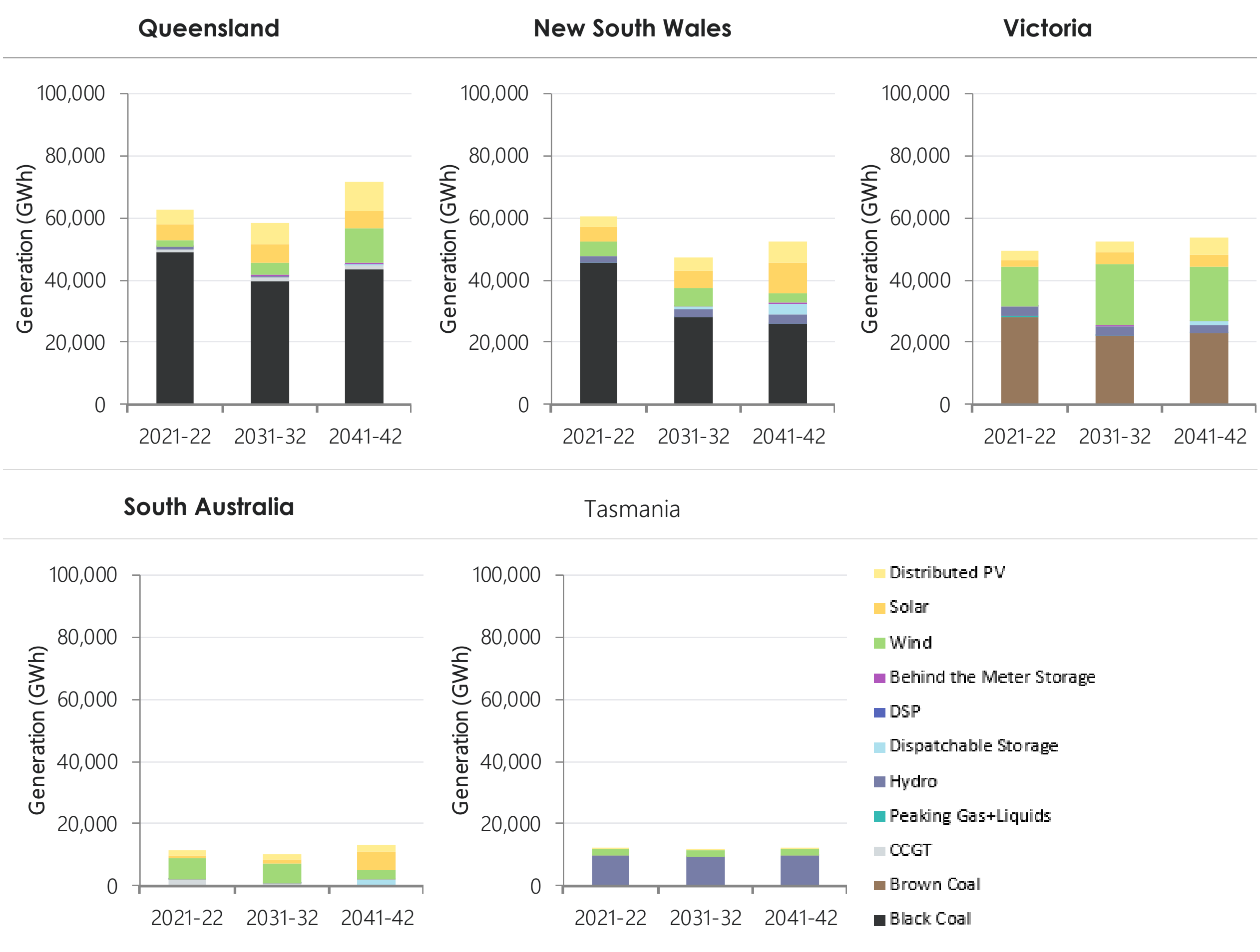
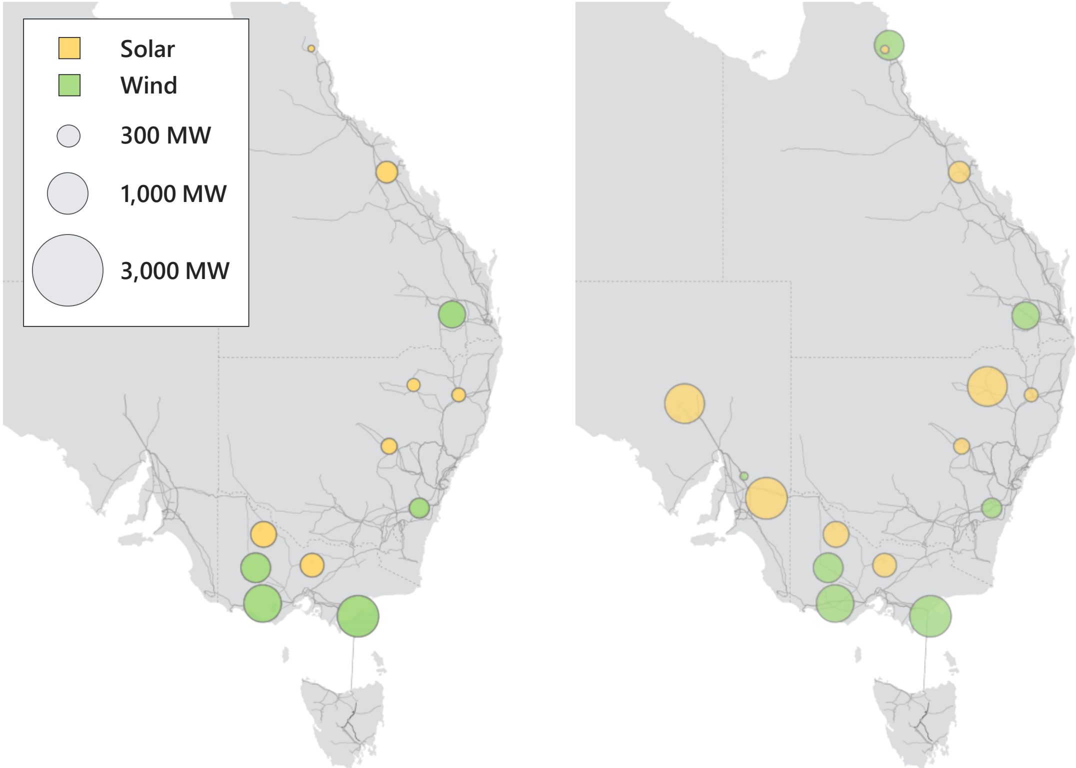


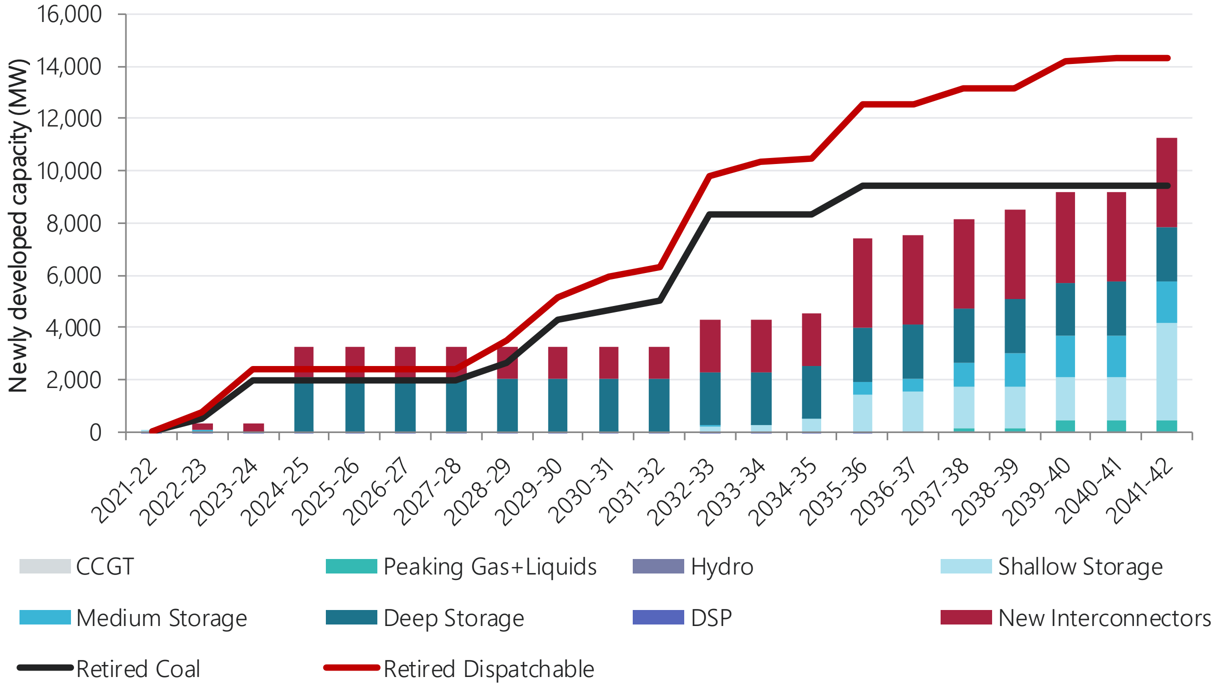
Figure 37 Forecast geographic and technological dispersion of renewable energy by 2029-30 (left) and 2039-40 (right), Slow Change scenario



A4.4.2.2 Firm dispatchable developments in the Slow Change scenario

Given the lack of renewable generation in this scenario, dispatchable capacity developments are also projected to be limited. Where storages do develop, shallow and medium depth storage is preferred to smooth solar generation; there is no forecast need for additional deep storages beyond the Snowy 2.0 project as shown in Figure 38, due to the low amount of VRE resources.

Figure 38 Forecast dispatchable capacity development to 2041-42, Slow Change scenario

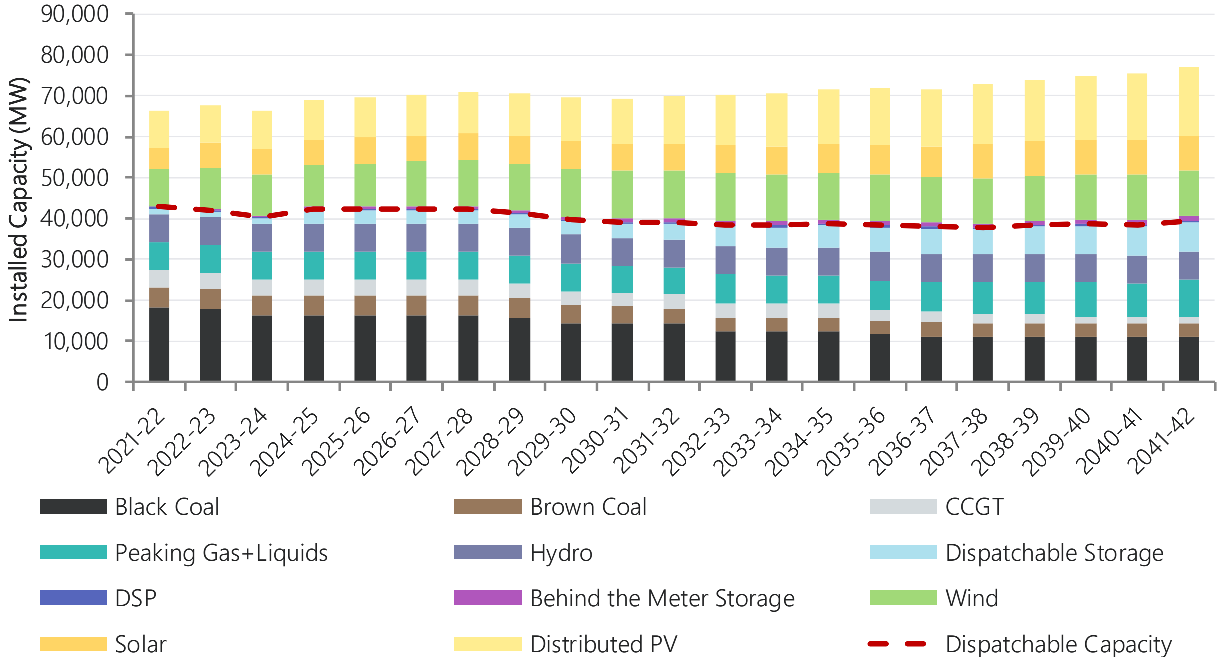


A4.4.2.3 Future generation mix in the Slow Change scenario without the ISP transmission developments

Under the Slow Change scenario, the development outlook for the NEM is relatively subdued, due to a range of factors such as, minimal change in consumption outlook, life extensions of existing power stations and lower ambition with respect to renewable energy targets. This leads to a moderated growth rate in VRE development up to 2039-40 with minimal non-network solutions to facilitate this VRE response.

Figure 39 presents the capacity development outlook for the Slow Change scenario in the absence of transmission developments and augmentations.

Figure 39 Forecast capacity mix to 2041-42 in the counterfactual, Slow Change scenario



Additionally, Figure 40 below presents the change in production outlook for the Slow Change scenario counterfactual. Consistent with the observations in capacity development, there is minimal change in generation production with the prospect of life extensions to existing plant. The shift in production from 2029-30 is a result of large industrial load closures assumed under this scenario.

Figure 40 Forecast annual generation to 2041-42 in the counterfactual, Slow Change scenario

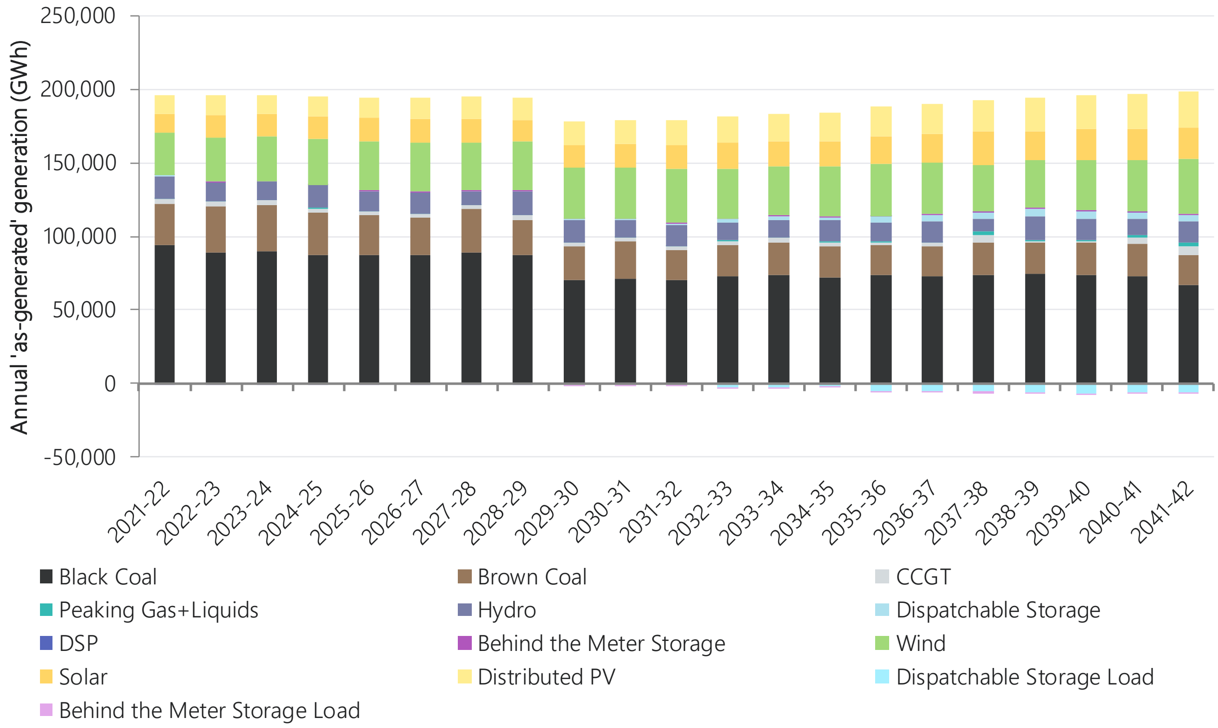


Figure 41 presents the projected capacity development outlook differences between the least-cost development path and counterfactual outcomes for the Slow Change scenario. As outlined previously, without transmission investment additional local generation resources are projected to replace coal retirements, with up to 2.9 GW of peaking thermal and 1.9 GW of storage technologies over the period to 2039-40 required. There is also an increase in local wind resource from 2038-39 to compensate for the lack of interconnection between regions. Coal retirements are also shifted slightly, with additional life extensions of coal generators in the counterfactual scenario. These subtle generation and storage changes across the horizon are timed and located to most efficiently use the existing transmission resources available to the generation and storage fleet. Due to the slow pace of system transition under the Slow Change scenario, a focus on utilising existing assets to complement the extended life of a number of thermal generation units is a key consideration.

Figure 41 Forecast capacity developments to 2041-42 for the least-cost development path (DP2) compared to counterfactual, Slow Change scenario

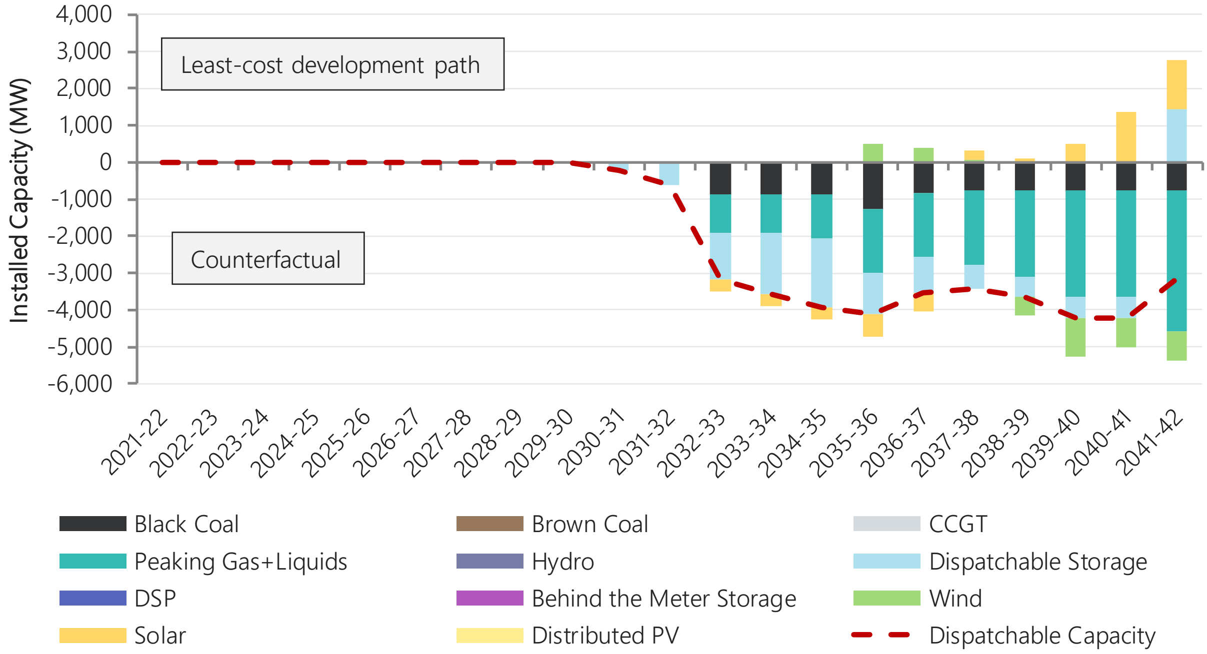
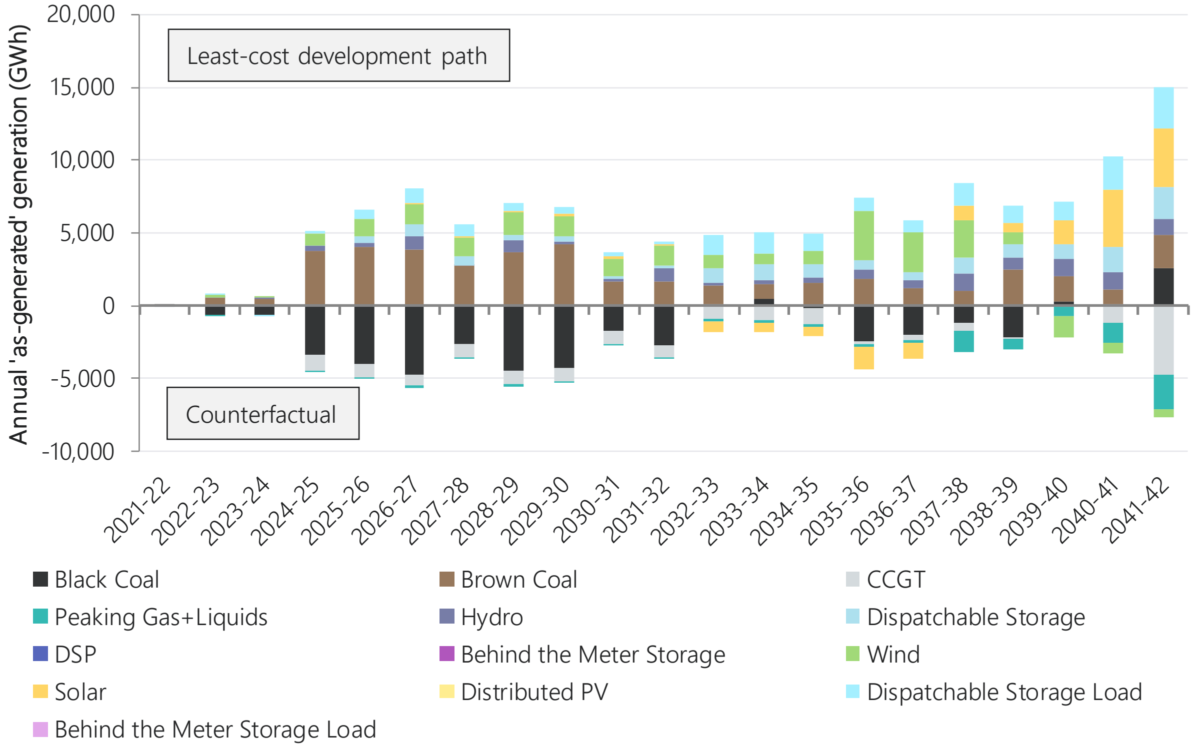


Figure 42 presents the generation production for the counterfactual relative to the least-cost development path (DP2). It is evident that interconnection allows for more low-cost brown coal generation at the expense of black coal generation in the least-cost development path. However, due to additional coal life extensions in the counterfactual scenario, there is an increase in black coal generation relative to brown coal generation from 2031-32. With transmission developed in the least-cost development path, lower cost energy from brown coal and VRE is available to share between regions, offsetting higher cost black coal generation and GPG.

Figure 42 Forecast generation outcomes to 2041-42 for the least-cost development path (DP2) compared to counterfactual, Slow Change scenario



A4.4.3 Fast Change scenario

The Fast Change scenario considers a rapid technology-led transition, particularly at grid scale, where advancements in large-scale technology improvements support a reduction in the economic barriers of the energy transition.

Key differences to the Central scenario include:

- Accelerated decarbonisation of the stationary energy and transport sectors, which in turn may result in advanced retirements of existing generators, to achieve emissions abatement targets.
- Consolidation of regional renewable development schemes, allowing greater national diversity of large scale VRE developments.

This section describes the developments, excluding network, that are forecast to maximise market benefits in the Fast Change scenario.

The generation capacity forecast projects that:

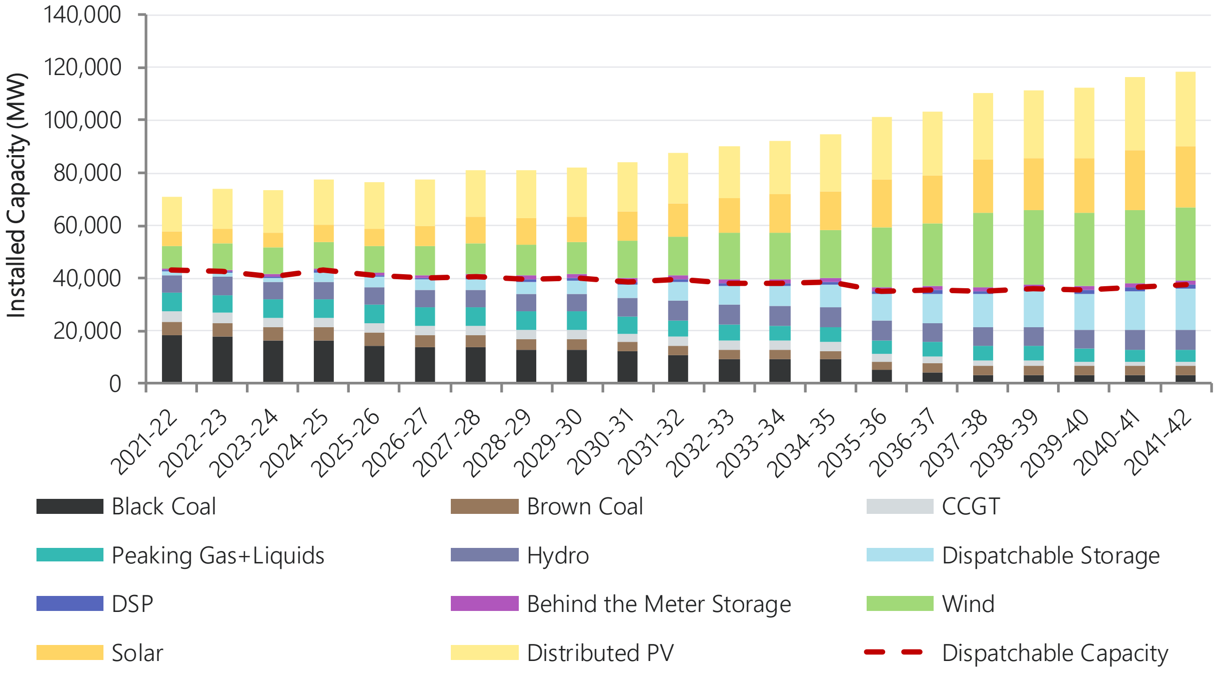
- To 2029-30:
  - The Fast Change scenario's carbon budget will advance coal power station retirements ahead of the current expected closure schedule. Although not as aggressive as the Step Change scenario, the forecast of coal retirements demonstrates the least-cost approach to achieving emissions abatement is to advance retirements into the mid-2020s.
  - Renewable investments will be made across all NEM regions from the beginning to the mid-2020s, even in Queensland despite there being no state-based renewable policy in this scenario.
- By 2039-40:
  - Installed coal capacity will reduce to 6.5 GW, 72% lower than existing capacity. Fossil fuel generation will be progressively replaced by renewable energy complemented by additional energy storages.

- Storage development will be needed in all mainland regions to support the renewable developments across each region in a future with less thermal generation available to smooth and firm VRE.

These grid-scale developments are also complemented by high growth in DER and behind-the-meter battery storages, including VPPs that provide some degree of dispatchability, as well as consumer-managed home battery storages, which largely are expected to offset household energy developments and balance exports from distributed PV systems.

Figure 43 presents the large-scale capacity outlook for the NEM under the Fast Change scenario. With the accelerated rate of retirements from thermal generation to meet emissions requirements, the new entrant VRE and storage build materially increases throughout the horizon, compared to the Central scenario.

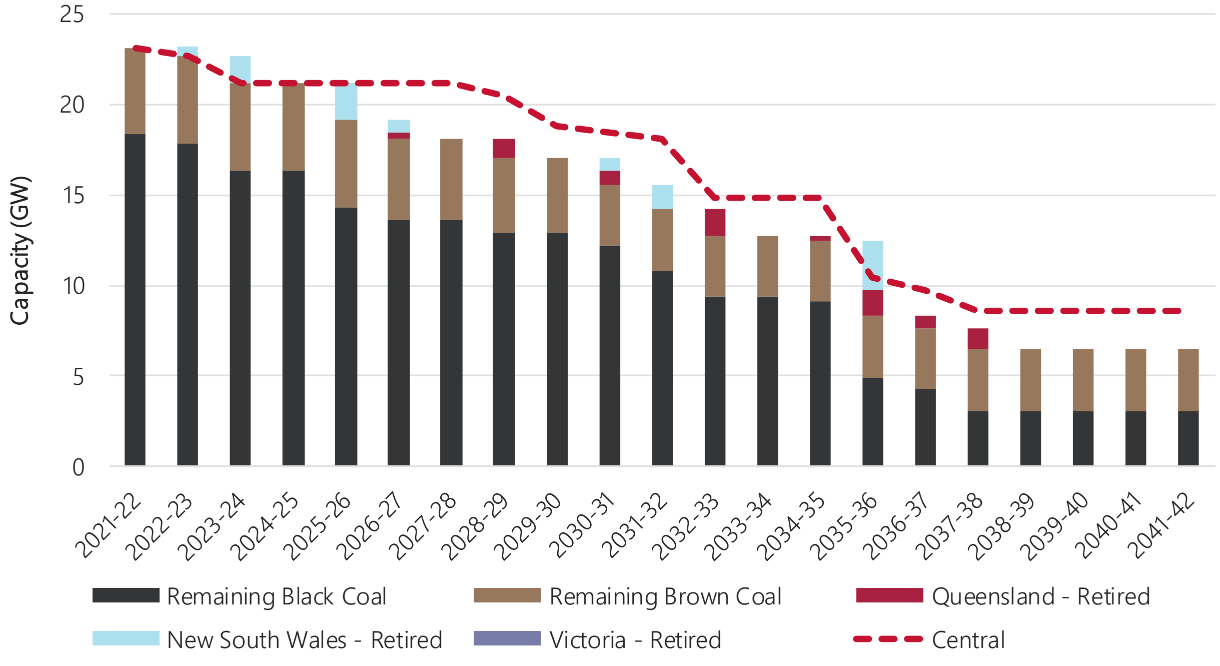
Figure 43 Forecast NEM installed capacity to 2041-42, Fast Change scenario



In the Fast Change scenario, the emissions budget impacts the NEM supply mix, promoting a shift from fossil fuel to renewable generation. Coal retirement in the Fast Change scenario is accelerated compared to the Central scenario, especially between 2025-26 and 2031-32. In 2021-22, fossil fuel generators are projected to account for 64% of total generation, while in 2039-40 this decreases to 20% of the total generation, as shown in Figure 46.

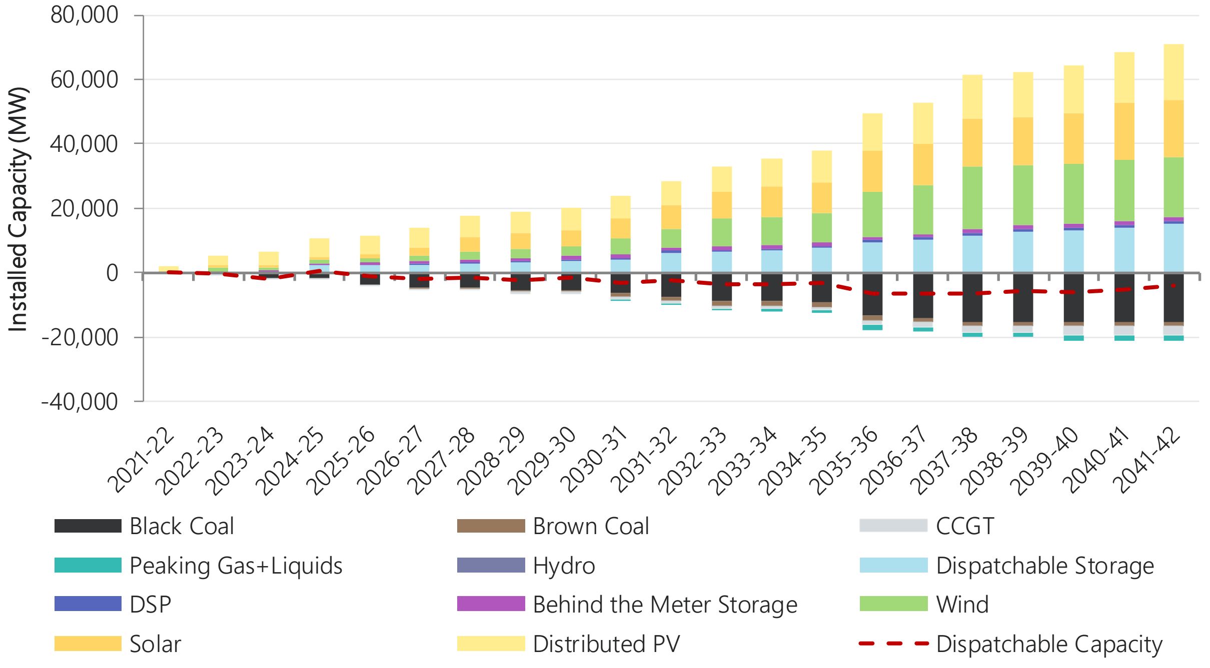
Black coal-fired generation in New South Wales and Queensland has higher marginal costs than brown coal-fired generation in Victoria and is therefore more cost-efficient to retire within the objectives of the carbon budget, despite having a lower relative emission intensity. The cost advantage brown coal generation has over all other thermal generation forms means that these more emission-intensive generators are preferred in the modelling to continue to operate to end of life but would present a means for deeper emissions abatement if retired earlier. The Fast Change scenario retirements are presented in Figure 44.

Figure 44 Forecast coal retirements to 2041-42, Fast Change scenario



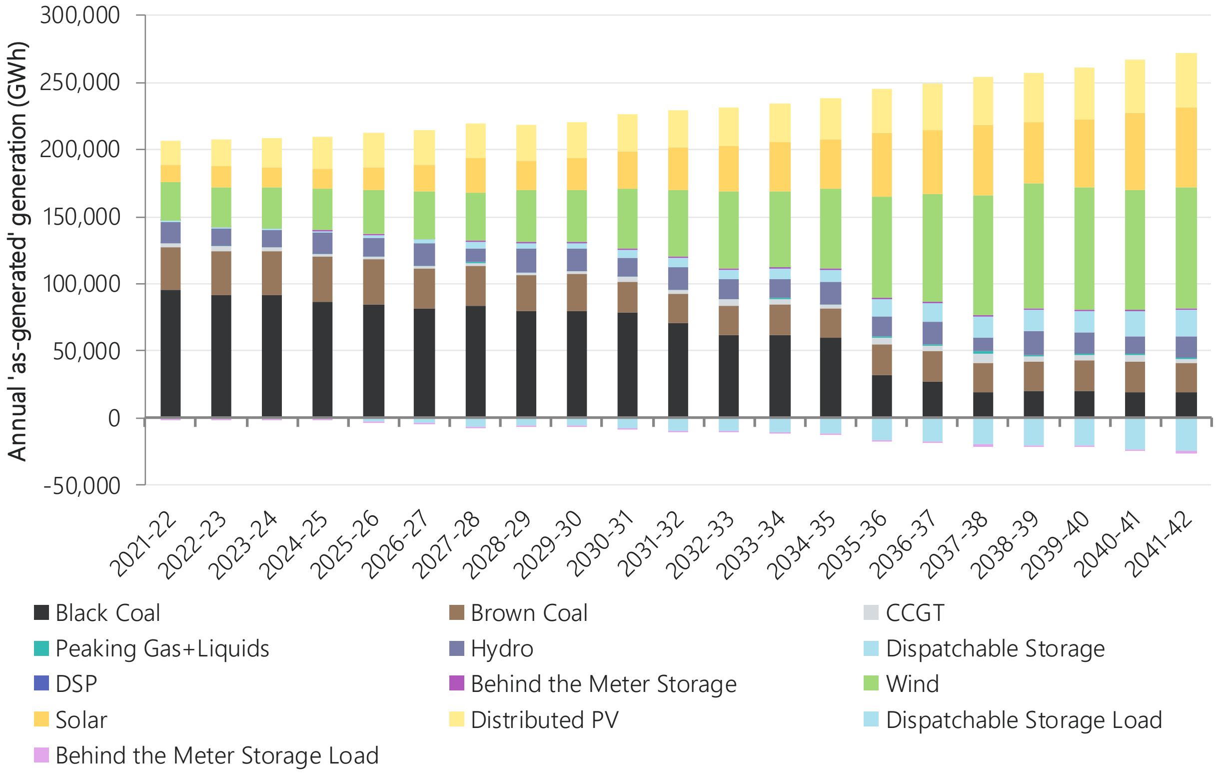
As shown in Figure 45, advanced thermal retirements in the Fast Change scenario are forecast to be offset by a combination of VRE, storages, and DER. By 2039-40, in addition to the assumed 28 GW of DER, primarily distributed PV, the NEM needs an additional 36 GW of VRE to replace major coal plant exits, in addition to committed and anticipated projects. This is complemented by approximately 6 GW of additional grid-scale energy storage and 5 GW of new VPP capacity.

Figure 45 Forecast relative change in installed capacity to 2041-42, Fast change scenario



This loss of energy production due to coal retirements will need to be replaced by investment in renewable generators, storages *and* transmission solutions, leading to a supply mix that is different both technologically and geographically to today's energy system, as shown in Figure 46. Renewable energy is forecast to expand from approximately 36% of generation to approximately 80% of energy generated by 2039-40. The projected mix of grid-scale wind and solar generation by 2039-40 is 53% wind, 29% large scale solar and 18% distributed PV.

Figure 46 Forecast annual generation to 2041-42, Fast Change scenario



A4.4.3.1 Regional deployment of the Fast Change scenario generation mix

Generation transformation in Queensland, New South Wales, and Victoria is forecast to be influenced by early coal retirements in each of those regions, as shown in Figure 47. New South Wales is forecast to have the most significant transformation with most coal-fired generation capacity forecast to be retired by 2039-40 under this scenario. This significant transformation in New South Wales is enabled by interconnector construction and energy storage technology development Appendix 7 details the security considerations for operation of the NEM under these prevailing conditions.

For the Fast Change scenario, the development outlook for the NEM is slightly muted in the short to medium term without all state-based renewable energy targets considered. However, the Fast Change scenario does consider an emissions budget which leads to a reduction in high emissions generation production complemented by a suite of VRE and GPG responses.

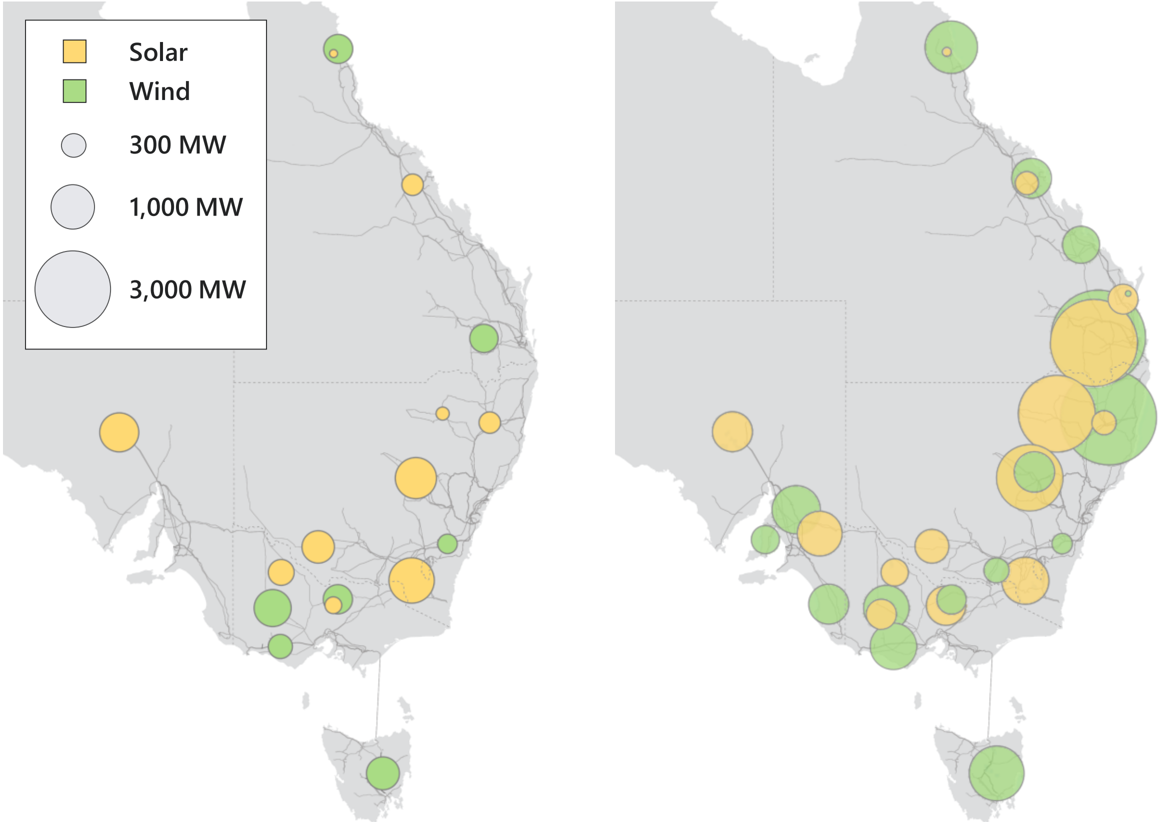
Without the 50% QRET policy, renewable generation in Queensland is forecast to be proportionally lower in the Fast Change scenario compared to the Central scenario.

By 2039-40, all regions are projected to have new VRE capacity (13 GW each in Queensland and New South Wales, and 4GW in Victoria), in addition to committed and anticipated projects, to replace retiring assets.

Figure 47 Forecast annual 'as-generated' generation for each NEM region to 2041-42, Fast Change scenario

Figure 48 demonstrates the forecast geographic diversity of new developments in the generation portfolio. Consistent with all scenarios with material VRE development; northern and south-western Victoria, southern and northern New South Wales and south west Queensland continue to be key renewable development locations.

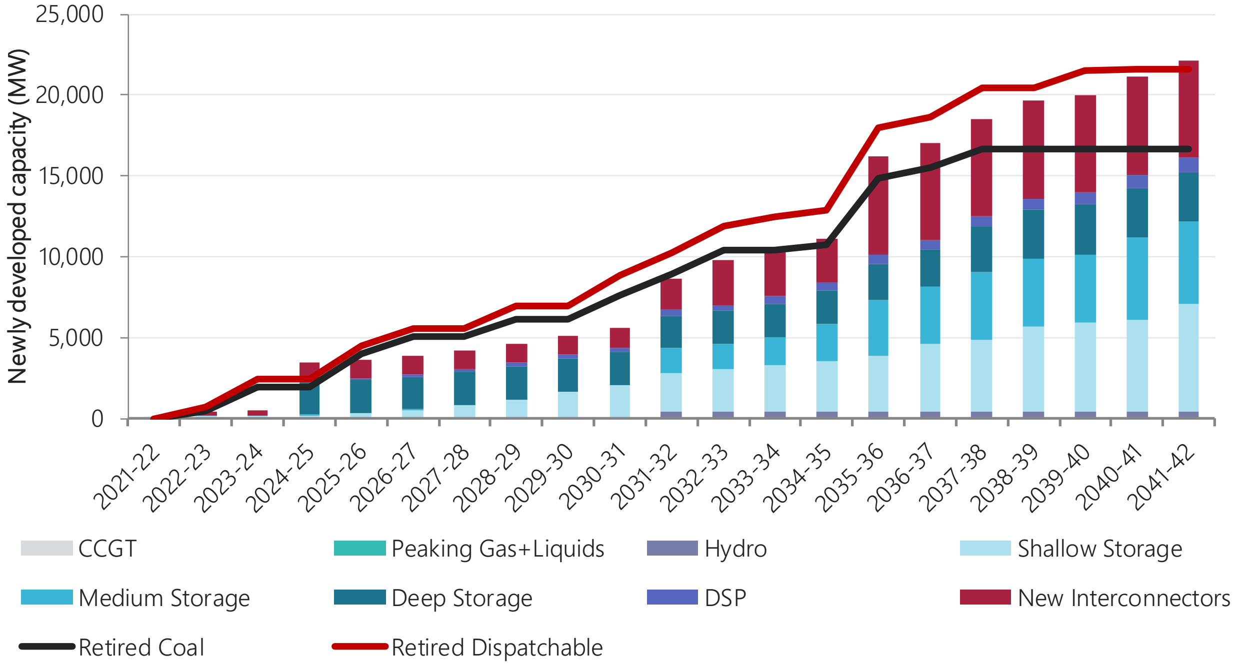
Figure 48 Forecast geographic and technological dispersion of new developments by 2029-30 (left) and 2039-40 (right), Fast Change scenario



A4.4.3.2 Firm dispatchable developments in the Fast Change scenario

In this scenario, storage and dispatchable capacity uptake is projected to be larger than in the Central scenario to offset the advanced coal retirements. Figure 49 shows the projected development of new storage and dispatchable capacity in the NEM for the Fast Change scenario.

Figure 49 Forecast dispatchable capacity development to 2041-42, Fast Change scenario



A4.4.3.3 Future generation mix in Fast Change without the ISP transmission project developments

Figure 50 presents the capacity development outlook for the Fast Change scenario for the counterfactual, without transmission developments and augmentations. While the Fast Change scenario applies a carbon budget to hasten the transformation of the NEM, the total installed dispatchable capacity across the NEM remains constant at approximately 40 GW, with dispatchable storage developments and GPG offsetting thermal closures.

Additionally, Figure 51 below presents the change in production outlook for the Fast Change counterfactual scenario. As with other scenarios, this counterfactual relies on GPG to provide a greater energy production role as coal generation retires earlier with the assumed carbon budget.

Figure 50 Forecast capacity mix to 2041-42 in counterfactual, Fast Change scenario

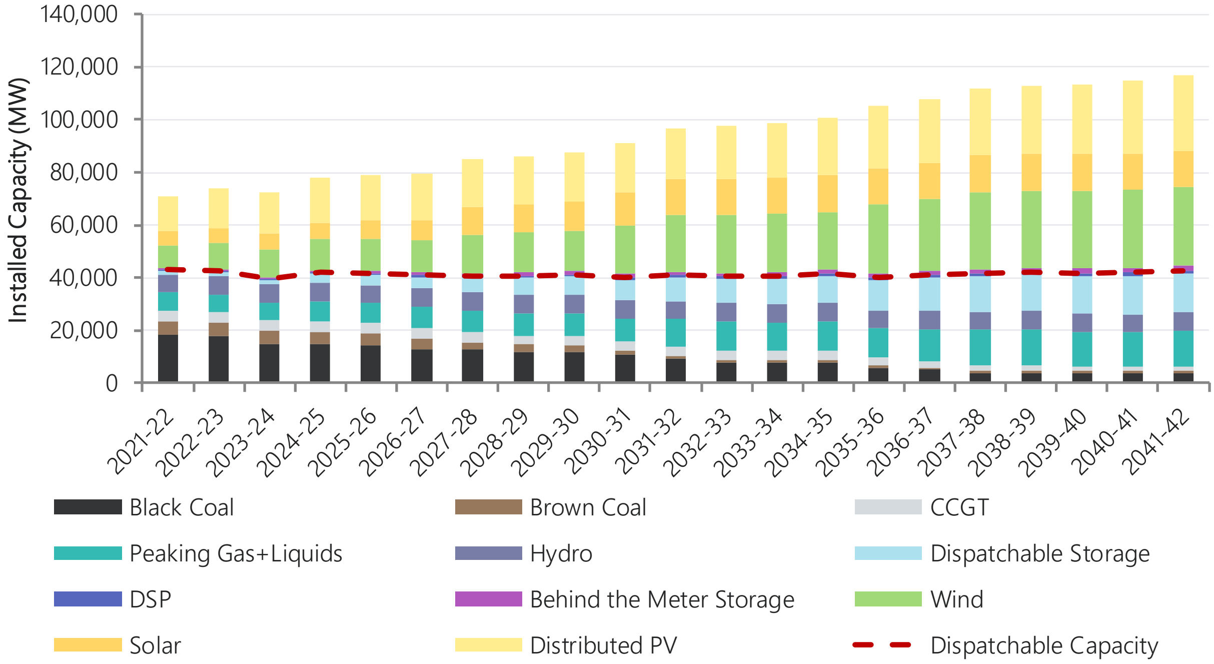


Figure 51 Forecast annual generation to 2041-42 in counterfactual, Fast Change scenario

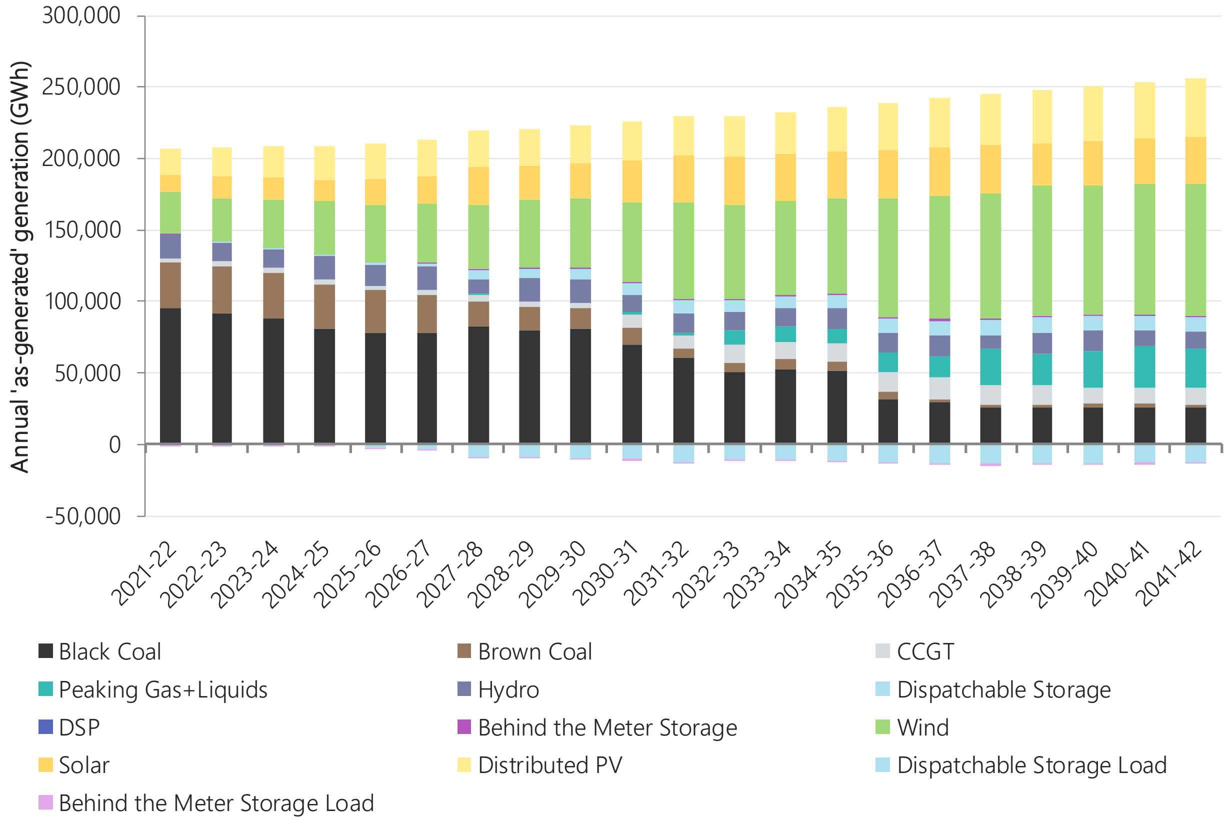


Figure 52 presents the capacity development outlook differences between the least-cost development path and counterfactual outcomes for the Fast Change scenario. The difference is attributed to the need for approximately 8.4 GW of new peaking gas in the counterfactual scenario in 2039-40, to replace aging coal generation. Coal retirements are also shifted in the counterfactual scenario, to allow for more GPG and VRE within the scenario's emission budget. With the reduced ability to share firming resources across regions in the counterfactual, and restrictions on the total amount of VRE that can be developed within the limits of the existing hosting capacity, there is also a greater reliance on a combination of wind and storage early in the counterfactual to meet the carbon budget.

Figure 52 Forecast capacity developments to 2041-42 for the least-cost development path (DP3) compared to counterfactual, Fast Change scenario

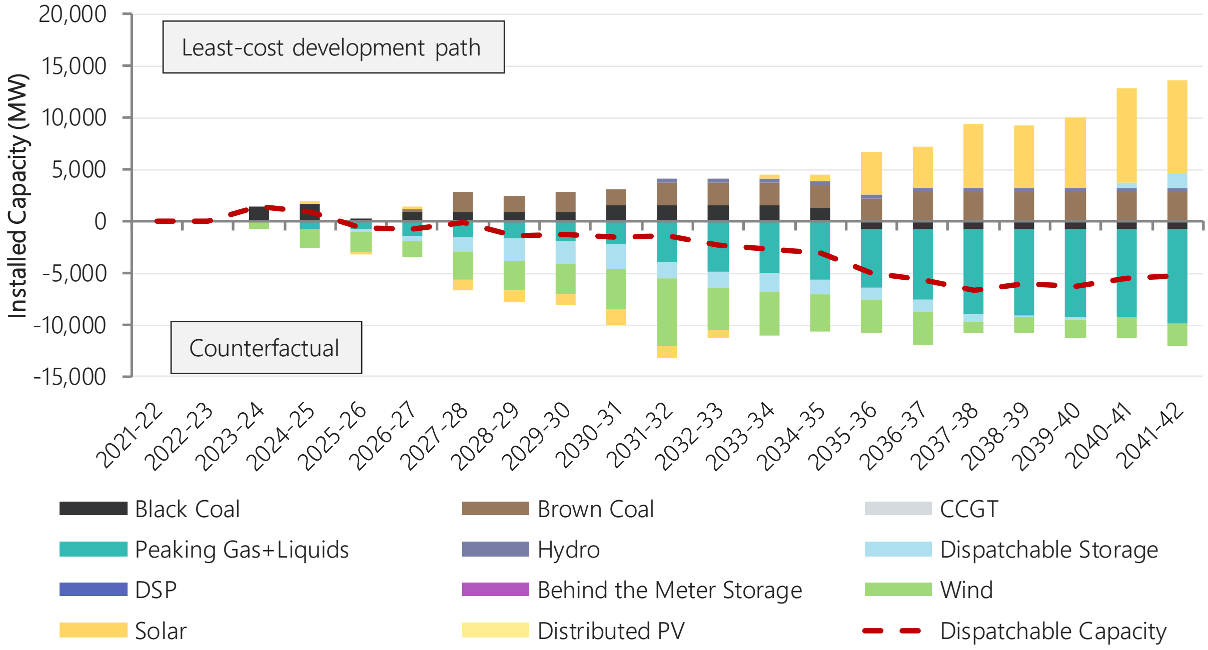
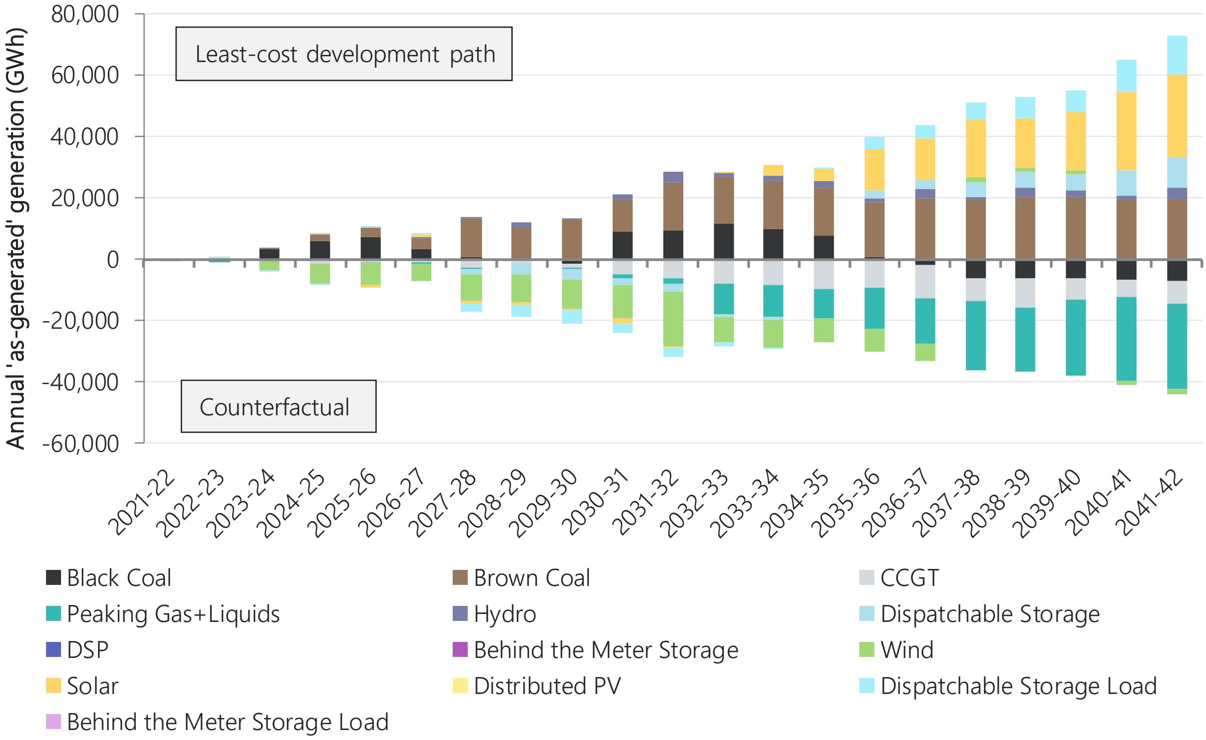


Figure 53 presents the generation production outcomes between the least-cost development path (DP3) and the counterfactual. In this scenario, the least-cost development path enables greater diversity of VRE, more low-cost brown coal and solar generation, and significantly less need for GPG to operate.

Figure 53 **Forecast generation outcomes to 2041-42 for the least-cost development path (DP3) compared to counterfactual, Fast Change scenario**



A4.4.4 Step Change scenario

The Step Change scenario considers stronger growth with aggressive action to address climate risks. In this scenario, commitment to aggressive decarbonisation is forecast to lead to accelerated exits of existing thermal generation.

This scenario includes faster technological improvements leading to a greater electrification of the transport sector, energy digitalisation, and consumer-led innovation.

Key differences to the Central scenario include:

- Higher population and economic growth.
- Most aggressive decarbonisation goals.
- Technology innovation and increased DER uptake, including greater EV uptake and stronger role for energy management solutions, including vehicle-to-home opportunities.
- Stronger role for energy efficiency measures.

The generation capacity forecast projects that:

- To 2029-30:
  - Similar to the Central scenario, VRE developments initially are incentivised by regional RETs. However, due to the higher requirement for decarbonisation, an increase in VRE development is observed.
  - With a more aggressive emissions abatement target, retirements of both black and brown coal across the NEM is projected to be accelerated. This reduction in generation production will be primarily addressed by a combination of VRE, DER, storage and transmission.
  - With larger volumes of VRE to achieve the assumed carbon budget there is heightened value in energy storages of all storage depths.

- Tasmania has higher VRE developments, driven by the inclusion of TRET in this scenario, with an additional 1.1 GW of wind by 2029-30 and 2.8 GW by 2041-42.
- With such rapid transformation, there is a greater need for transmission development – both intra- and inter-regional – to improve access to REZs and share energy and capacity between regions.

- By 2039-40:
  - Generator retirements will continue to partially drive developments in VRE, complemented by a suite of shallow, medium and deep storages.
  - The total installed capacity of coal fired power stations in the NEM is expected to be just above 2 GW, leading to the need for low emission firming technologies such as storage complemented by VRE, and additional system services (see Appendix 7). As presented in Table 4 and Figure 60, approximately 15 GW of new dispatchable capacity would be required to address this reduction in coal power stations by 2039-40.

These grid-scale developments are also complemented by high growth in DER and distributed battery storages, including VPPs that provide some degree of dispatchability, as well as consumer-managed home-battery storages, which largely are expected to offset household energy consumption and balance exports from distributed PV systems.

Figure 54 presents the large-scale capacity outlook for the NEM across the outlook period for the Step Change scenario. Of note is the accelerated retirements of black and brown coal generators to meet this scenario's carbon budget. To compensate for these retirements, there is an influx of new VRE capacity, both large-scale technologies and DER. Providing firm capacity are new builds of storages, and VPPs.

Figure 54 Forecast NEM generation capacity to 2041-42, Step Change scenario

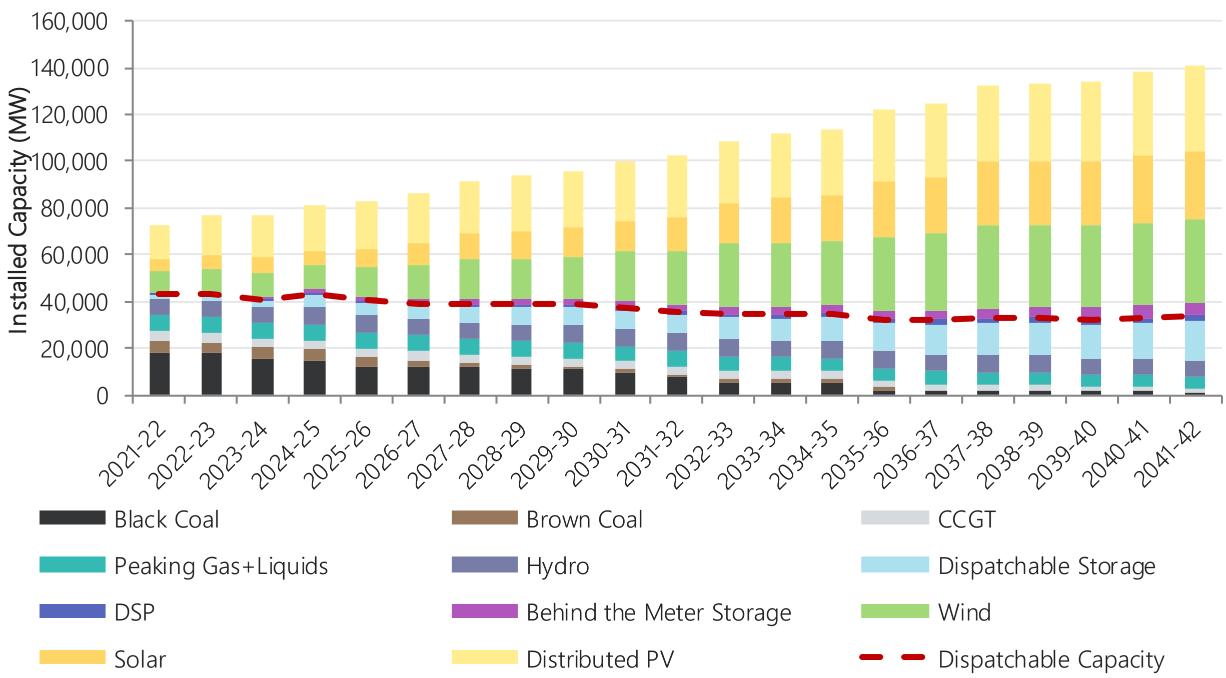
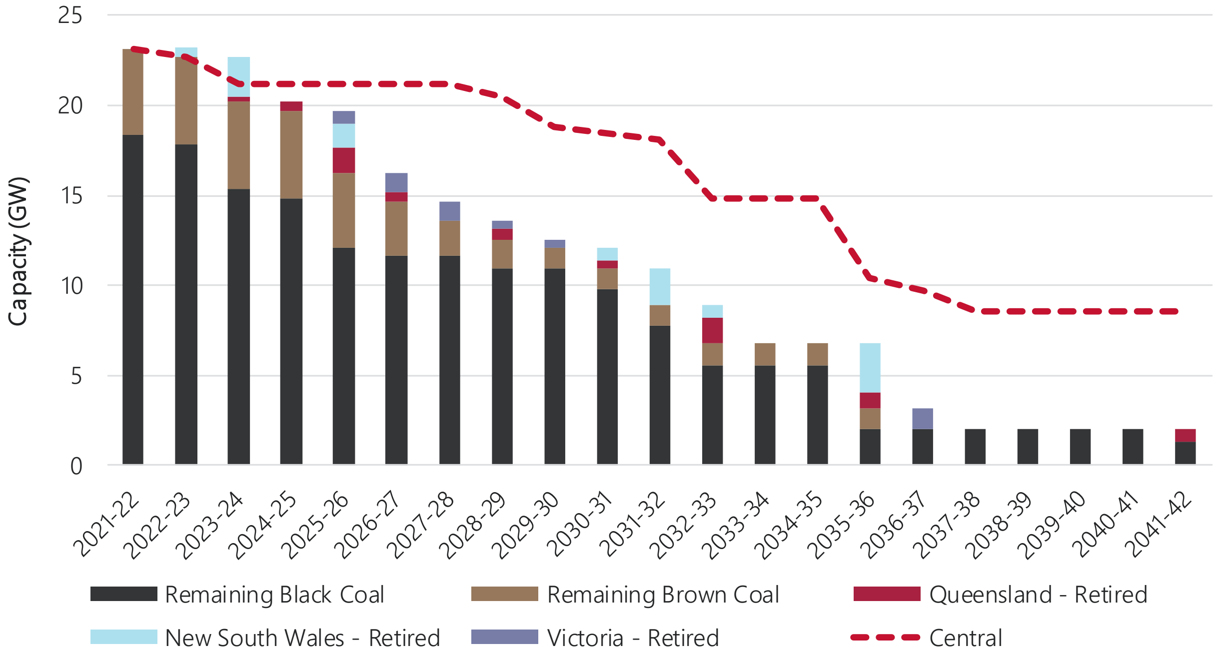


Figure 55 shows the rapid retirements that are modelled outcomes in this scenario, needed to meet a tight carbon budget, relative to the current expected closure years applied in the Central scenario. The greatest period of thermal capacity withdrawal occurs during the mid-2020s, effectively advancing retirements on average by six to seven years. By retiring early, emissions are reduced more efficiently over the forecast horizon than if action to abate emissions was left until later. By delaying retirements to post 2029-30, a significant proportion of the emissions budget would be eroded in the 2020s, causing significant challenge and increased costs under a retirement schedule that attempts to catch-up at a later date.

Figure 55 Forecast coal retirements to 2041-42, Step Change scenario

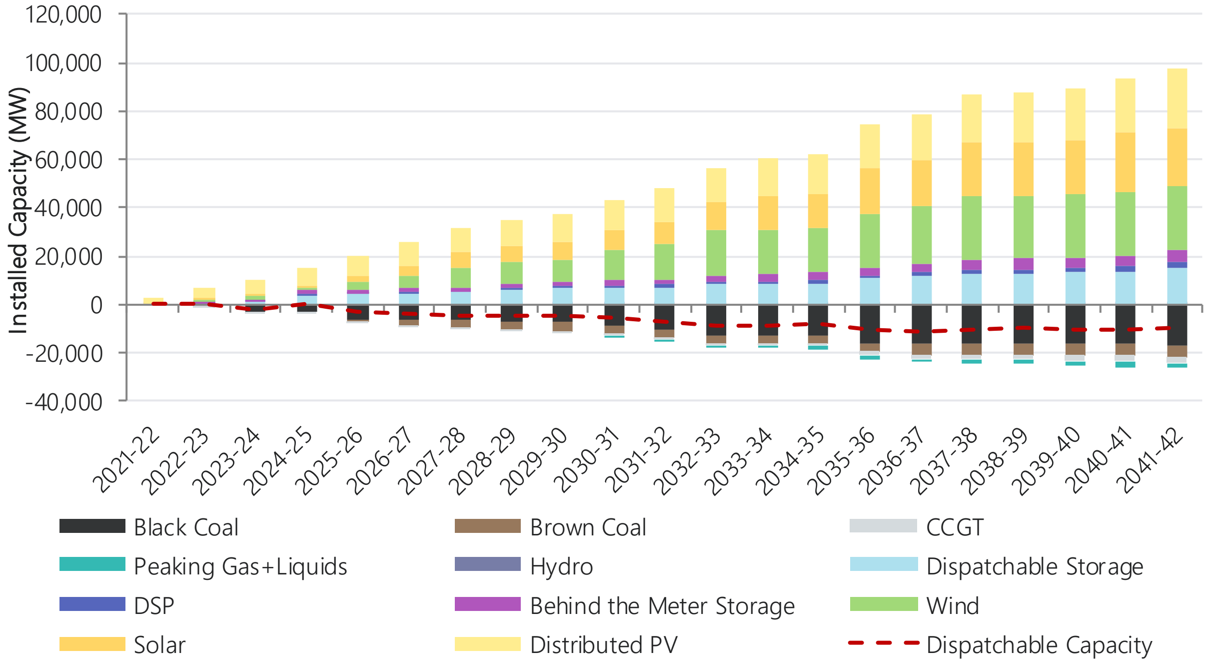


By 2039-40, in addition to the assumed 30 GW of distributed PV, the NEM needs 50 GW of further VRE to replace major coal plant exits, in addition to committed and anticipated projects. This is complemented by approximately 8 GW of new grid-scale energy storage and 5 GW of new VPP capacity.

As shown in Figure 56, the development of VRE increases in this scenario throughout the outlook period, facilitated by the accelerated retirements in comparison to the Central scenario. Aggregated VPPs in this scenario provide a significant proportion of new firm capacity. Storages predominately in New South Wales and Queensland supplemented by Victoria and Tasmania, is built to provide a suite of energy storage solutions and replace retired assets.

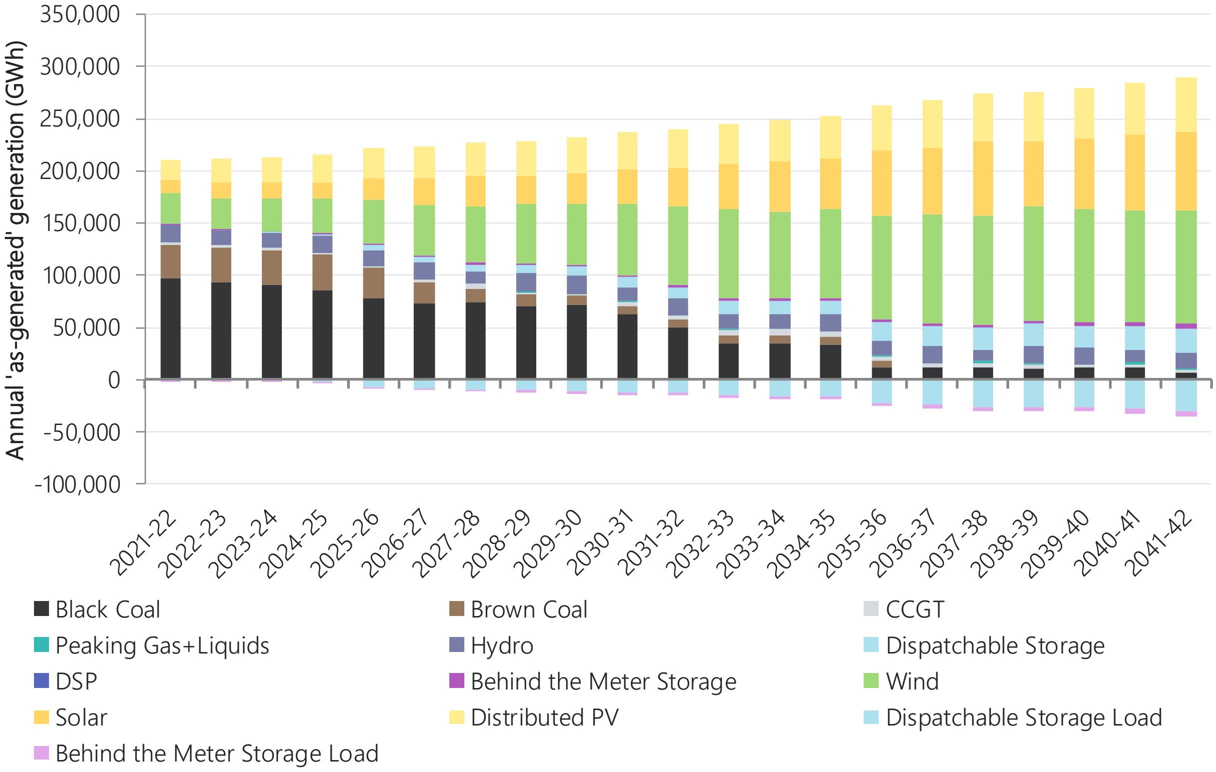
Figure 56 shows the change in installed capacity in the Step Change scenario, demonstrating the shift from coal to renewable energy, that requires a much larger capacity footprint. While total dispatchable capacity declines in this scenario, dispatchability is maintained in all hours through greater storage flexibility and sharing of resources across the NEM (see Appendix 6).

Figure 56 Forecast relative change in installed capacity to 2041-42, Step Change scenario



In terms of energy production, Figure 57 highlights the projected change in the energy mix from coal generation to VRE. It also demonstrates the scale of energy required to operate energy storages, through the load associated with the operation of energy storages shown beneath the x-axis. Renewable energy is forecast to expand from approximately 37% of generation in 2021-22 to approximately 63% by 2030 and 94% of energy generated by 2039-40, and the pace of this transformation is more rapid than in any other scenario considered. The projected mix of VRE generation by 2039-40 is 49% wind, 30% large scale solar PV and 22% distributed PV. For further discussion on the operability and security considerations for the NEM under this development outlook, refer to Appendices 6 and 7.

Figure 57 Forecast annual generation to 2041-42, Step Change scenario



A4.4.4.1 Regional deployment of the Step Change scenario generation mix

Figure 58 demonstrates the regional transformation of the NEM, with the projected distribution of VRE across NEM regions. By 2039-40, all regions are projected to have new VRE capacity: over 16 GW each in Queensland and New South Wales, 8 GW in Victoria, and approximately 3-4 GW in Tasmania and South Australia respectively, over and above what is already committed and anticipated. Significantly, in this scenario, all coal capacity in New South Wales is forecast to have retired by 2041-42, but local generation production is still expected to grow, with stronger VRE penetration to compensate complemented by over 22 GW of new storage and DSP technologies. Geographic and technological diversity will be critical to increase power system resilience to weather events. Appendix 7 details the security considerations for operation of the NEM under these prevailing conditions.

Figure 58 Forecast annual 'as-generated' generation for each NEM region to 2041-42, Step Change scenario

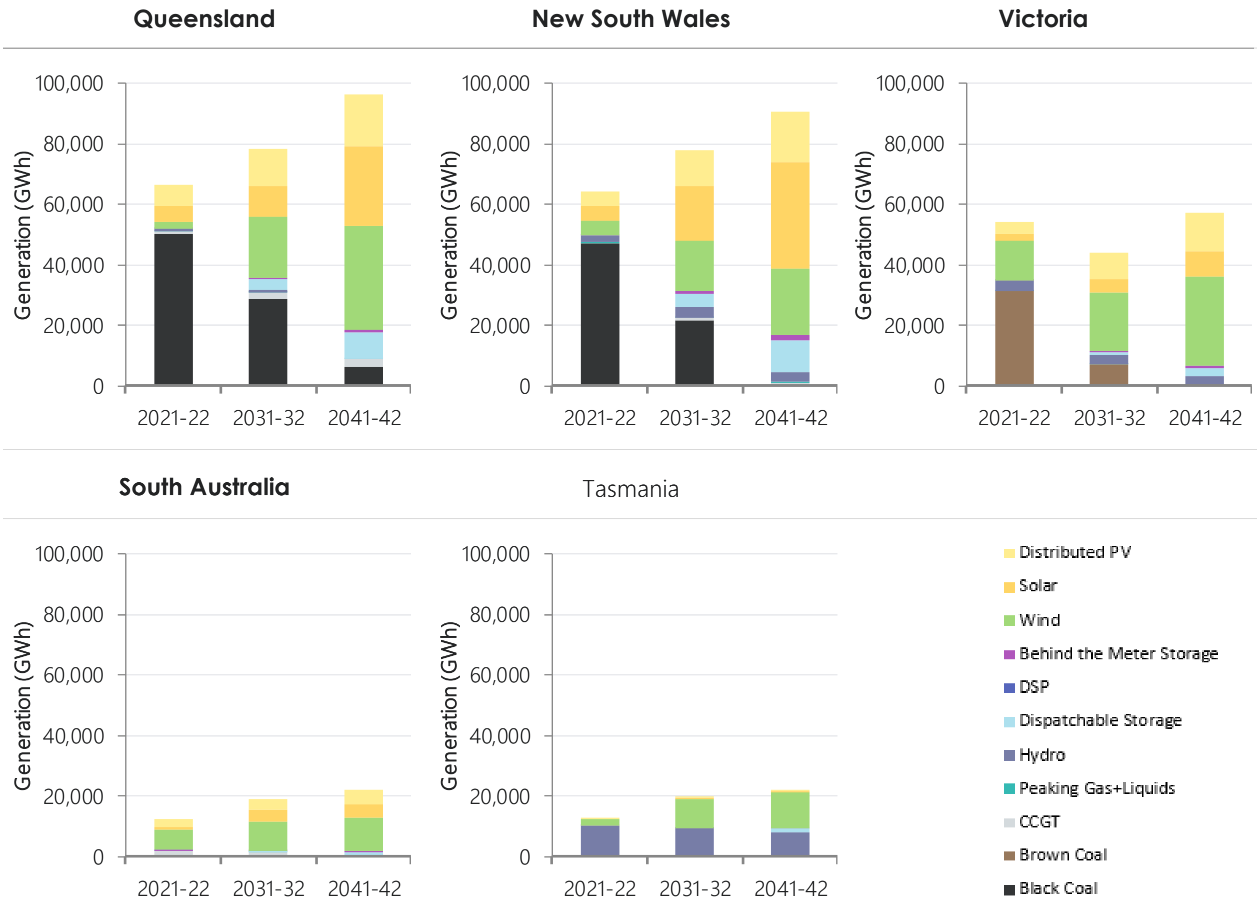
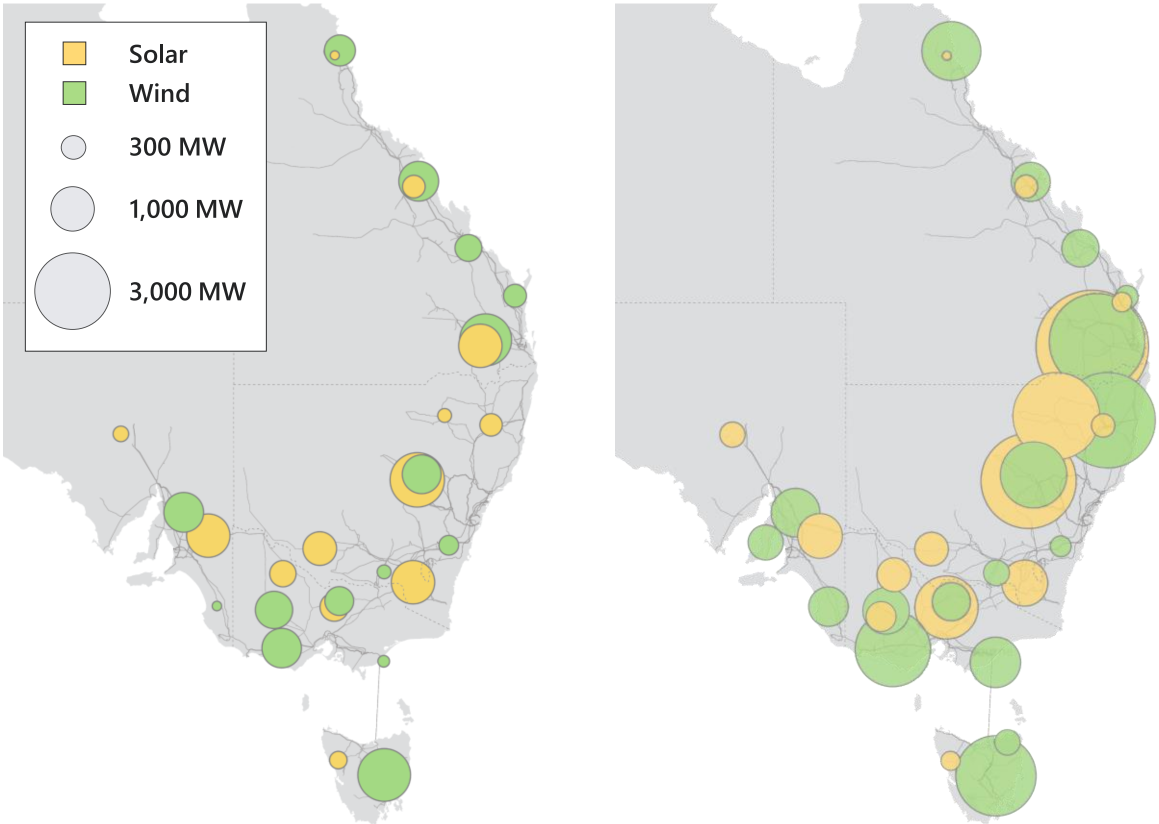


Figure 59 shows the projected diversity of renewable generation across the NEM, including existing and committed capacity.

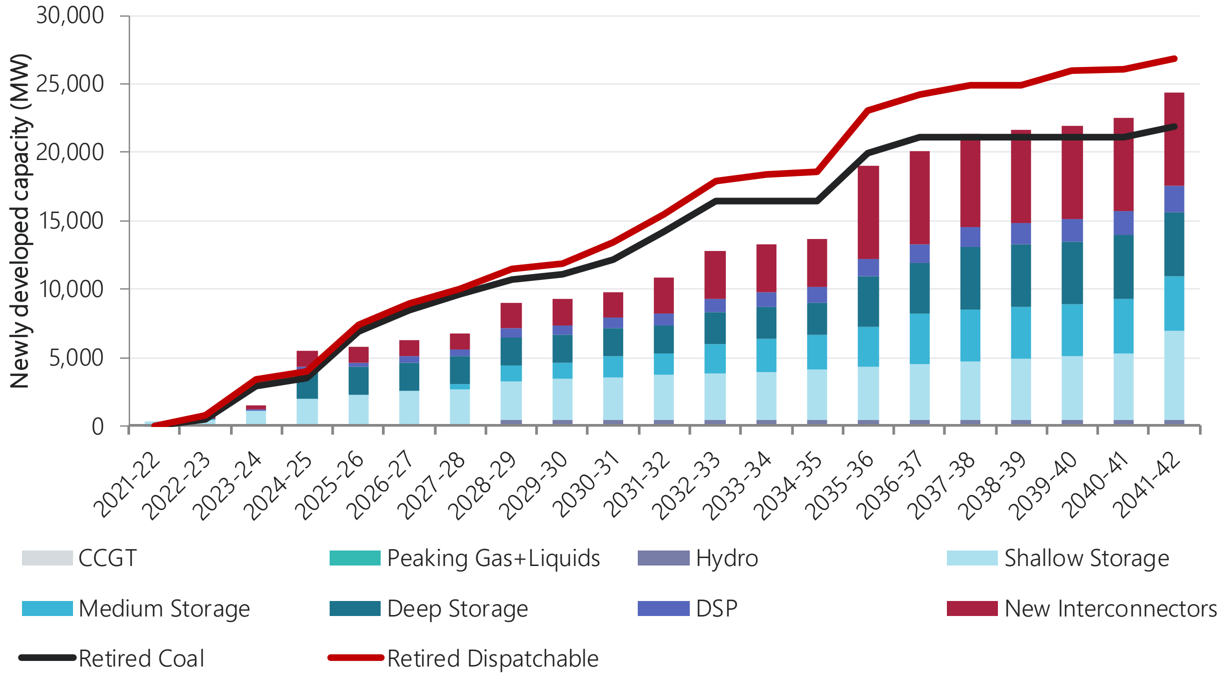
Figure 59 Forecast geographic and technological dispersion of new developments by 2029-30 (left) and 2039-40 (right), Step Change scenario



A4.4.4.2 Firm dispatchable developments in the Step Change scenario

To complement the development of renewable energy, energy storage development is critical. Figure 60 shows the projected development of new dispatchable capacity in the NEM for the Step Change scenario. Deeper storages are required to replace the accelerated retirements of dispatchable capacity and are forecast for development from the early 2030s. Shallow depth storage needs are mostly filled by the growth of VPP, leading to less medium duration storages that can hold up to six hours of energy storage.

Figure 60 Forecast dispatchable capacity development to 2041-42, Step Change scenario

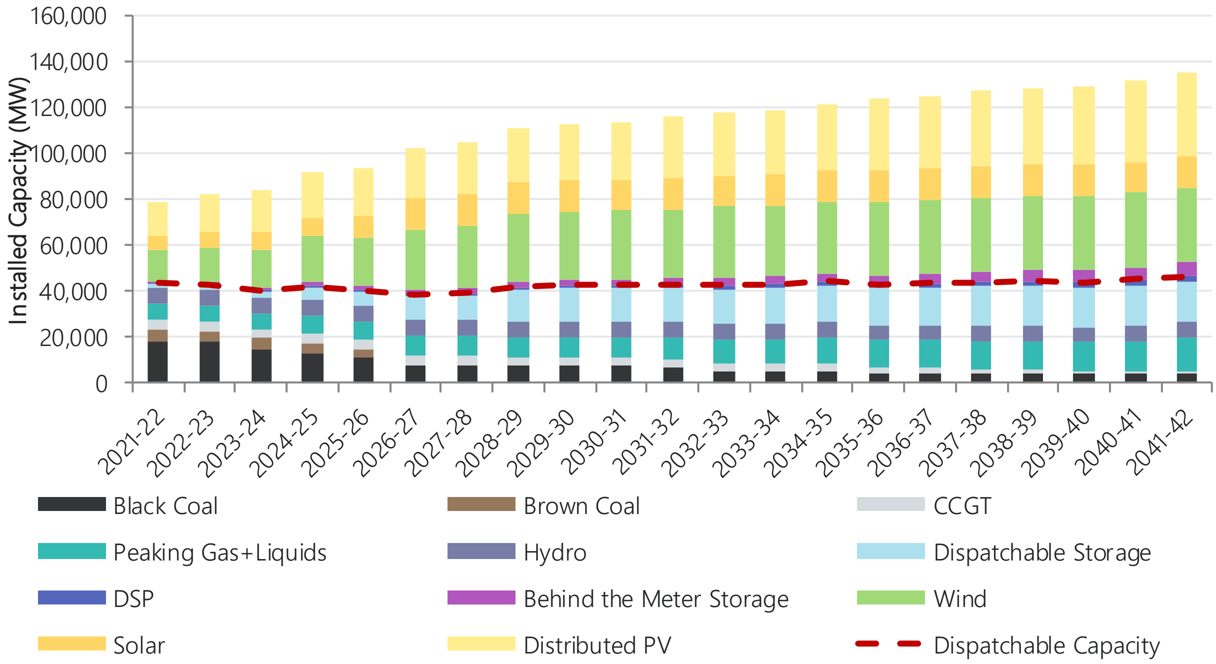


A4.4.4.3 Future generation mix in the Step Change scenario without the ISP transmission developments

For the Step Change scenario, the development outlook for the NEM is accelerated in comparison to the alternative scenarios in the short to medium term, primarily due to the emissions budget assumed in this scenario. Retired thermal capacity is replaced by a suite of GPG, VRE and storage developments. All brown coal generation is retired by 2036-37 and by 2030 only 11 GW of black coal capacity remains on the system.

Figure 61 presents the capacity development outlook for the Step Change scenario for the counterfactual without new transmission developments and augmentations.

Figure 61 Forecast capacity mix to 2041-42 in counterfactual, Step Change scenario



Additionally, Figure 62 below presents the change in production outlook for the Step Change scenario counterfactual. GPG plays a greater role in achieving the required level of production to address the material reduction in output of the incumbent thermal generation (changes in merit order dispatch) as a response to the emissions budget.

Figure 62 Forecast annual generation to 2041-42, Step Change scenario counterfactual

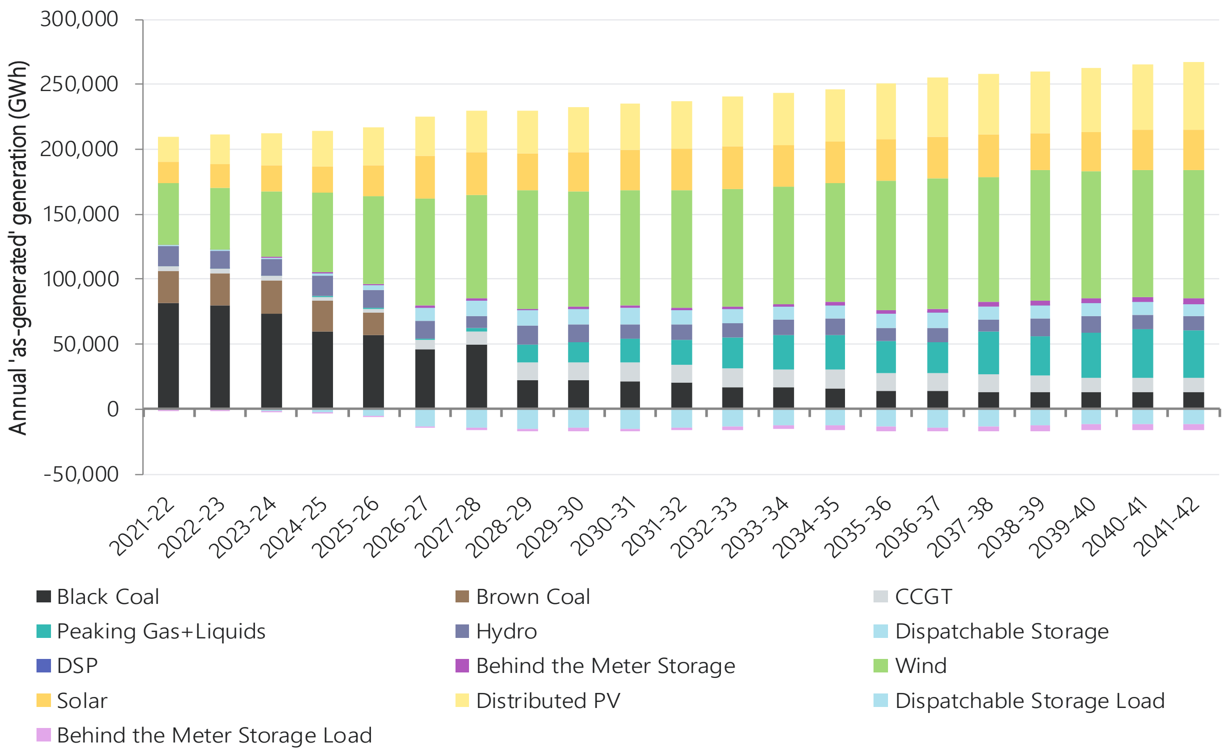
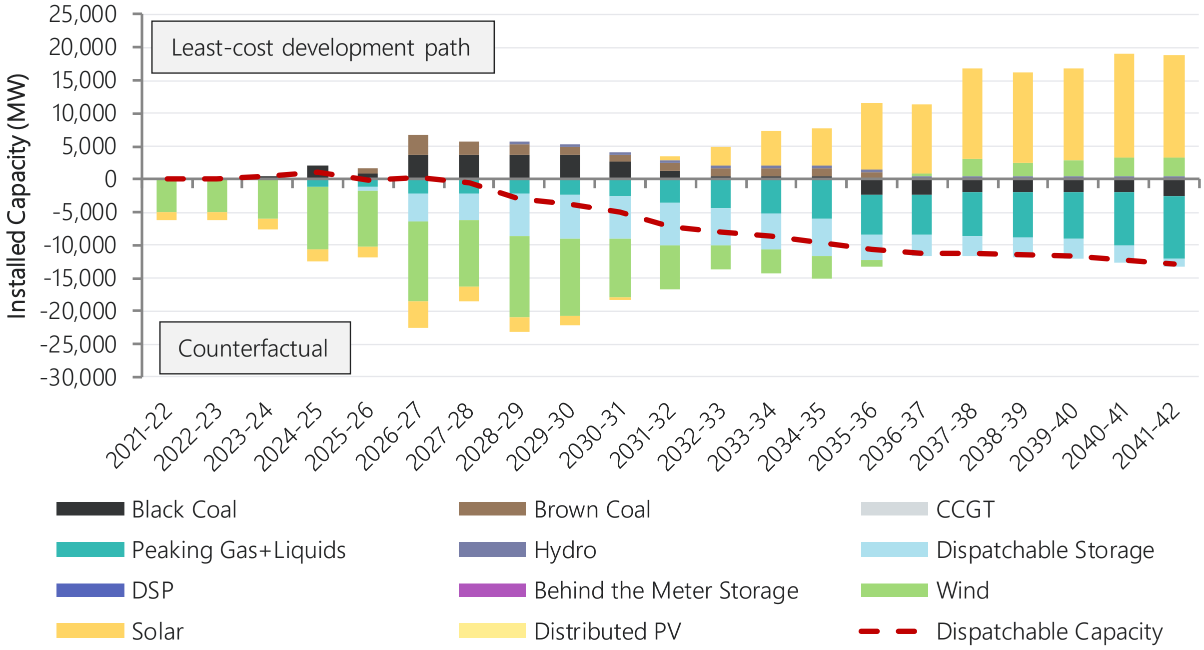


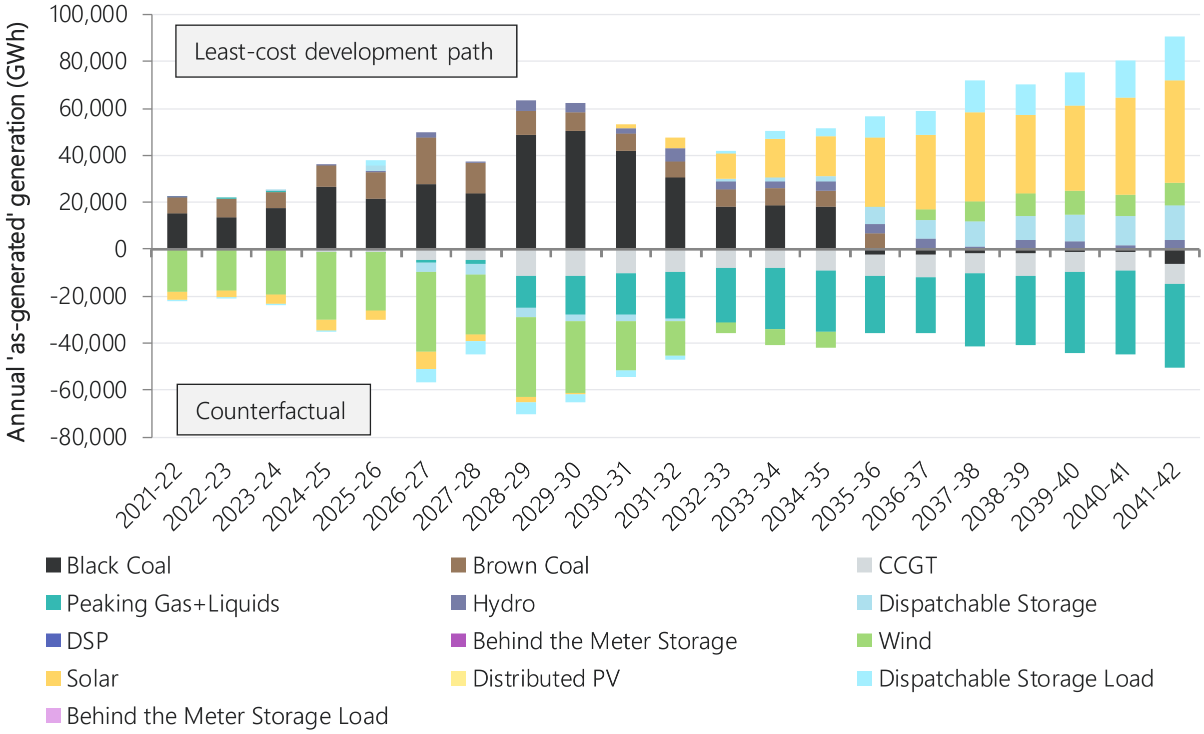
Figure 63 presents the differences in forecast capacity development under the Step Change scenario between the least-cost development path and the counterfactual. Under the least-cost development path, complemented by interconnectors, generation expansion is projected to rely on a higher share of solar, especially from 2033-34 onwards. Conversely, in the counterfactual there is increased need for local wind and solar capacity from 2021-22 to 2034-35 and GPG from 2035-36 onwards. There is also a need for a suite of storage depths to complement additional local VRE from 2026-27 onwards in the counterfactual outlook.

Figure 63 Forecast capacity developments to 2041-42 for the least-cost development path compared to counterfactual, Step Change scenario



The differences in capacity are reflected in the generation mix. Figure 64 shows projected year-on-year differences in generation between the least-cost development path and the counterfactual in the Step Change scenario. With the least-cost development path (DP4), reliance on coal is forecast to decrease and be replaced by higher contributions from solar as well as hydro generation and energy storages from 2031-32. Conversely, in the counterfactual, the mix is projected to increasingly feature a higher share of wind in the earlier years and a combination of wind and GPG from 2028-29.

Figure 64 Forecast generation outcomes to 2041-42 for the least-cost development path (DP4) compared to counterfactual, Step Change scenario



A4.4.5 High DER scenario

The High DER scenario considers a future where there is stronger growth in distributed PV generation, embedded battery storages, and other demand-based resources installed by consumers and industry – stronger than any other scenario. Other key scenario settings are broadly consistent with the Central scenario, leading to a development outlook that has an increased share of the transformation borne by consumers and industry as they develop resources behind-the-meter to meet their energy needs.

DER uptake – particularly if controllable through VPP technologies – reduces the need for grid-scale capacity, as the energy needs of consumers and industry are met at the point of consumption. For this outlook to be effective, technological and communication development is necessary to ensure coordination of DER efficiently lowers total system costs.

The generation capacity forecast projects that:

- To 2029-30:
  - Similar to the Central scenario, new capacity developments will consist of a portfolio of wind and solar developments, particularly in Victoria and Queensland. However, due to the decreased utilisation factor of DER compared to efficiently located large-scale VRE, there will be a greater number of generation assets in the NEM on an installed capacity basis.
  - The proportion of large-scale renewable developments across the NEM will be lower than in the Central scenario forecast, as DER plays a much greater role in energy production and management, resulting in a more even distribution of energy resources near load centres throughout the NEM.
  - Accelerated uptake of behind the meter battery storages, particularly the deployment of aggregated VPP, will limit the need for further dispatchable capacity across the NEM beyond the Snowy 2.0 project.
- By 2039-40:

– Generator retirements will drive continued development in VRE, complemented by deeper large-scale storages.
– Overall capacity expansion in both VRE and energy storages will be lower when compared to other scenarios except Slow Change, as a result of the increased development of DER deferring the requirement of generation and storage.

Figure 65 presents the forecast capacity mix for the NEM across the outlook period to 2041-42 for the High DER scenario. Of note is the material development of dispatchable storage driven primarily by strong DER uptake, providing a significant proportion of the NEM's firming requirements. As these and other consumer-managed behind-the-meter storages are at the point of consumption, the need for transmission and large-scale energy storage to provide energy sharing and firming of peak demands is reduced, but nonetheless they still have a vital role in effectively managing, and delivering, the inherently variable VRE to the load centres.

Figure 65 Forecast NEM generation capacity to 2041-42, High DER scenario

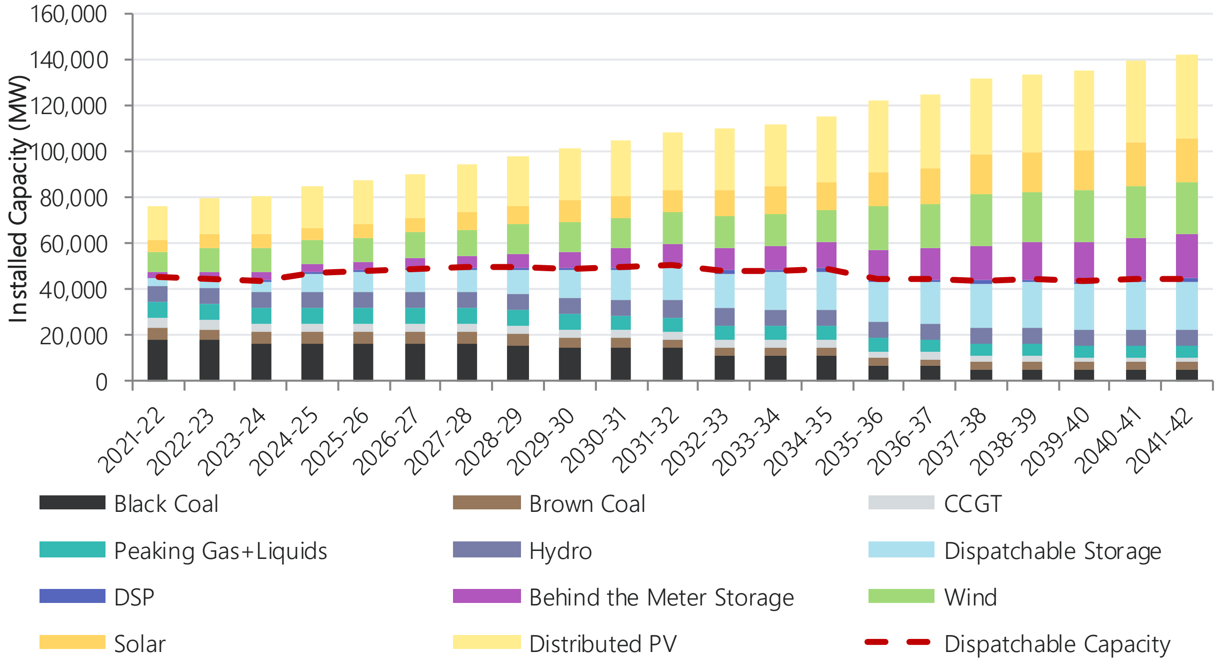
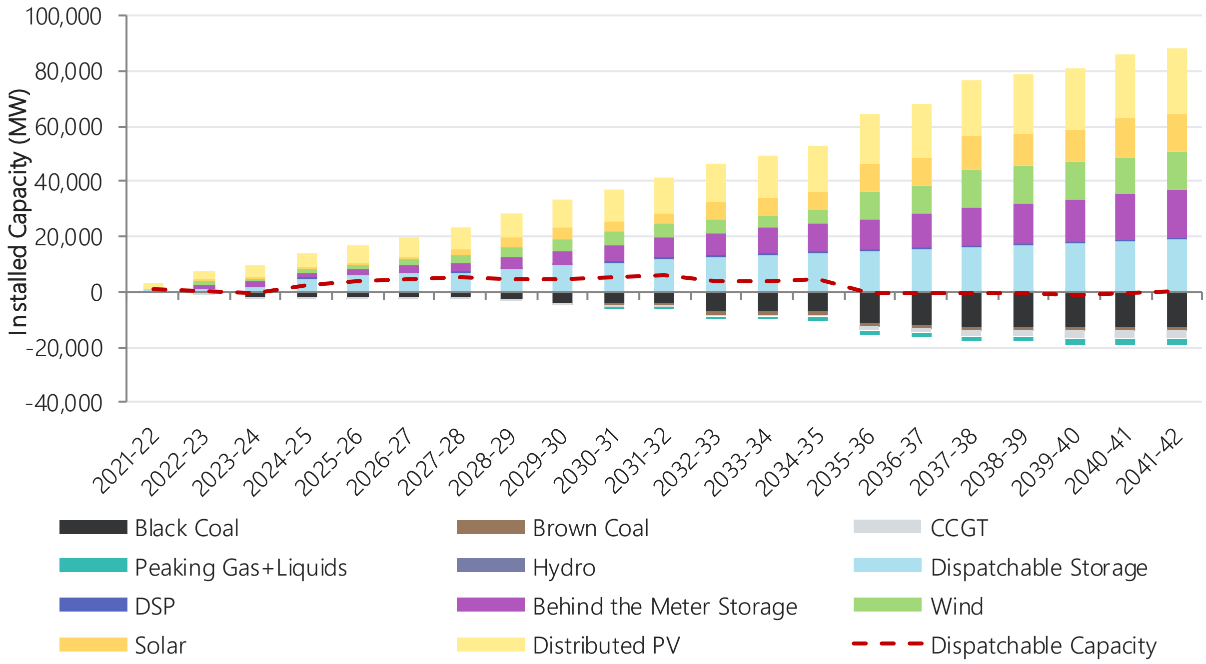


Figure 66 also reflects the significance of the DER uptake in this scenario. By 2039-40, allowing for the stronger growth in DER, the NEM will need 26 GW of new VRE over and above what is already committed and anticipated. This VRE development requires approximately 500 MW of additional grid-scale energy storage, complementing the 16 GW of new VPP capacity.

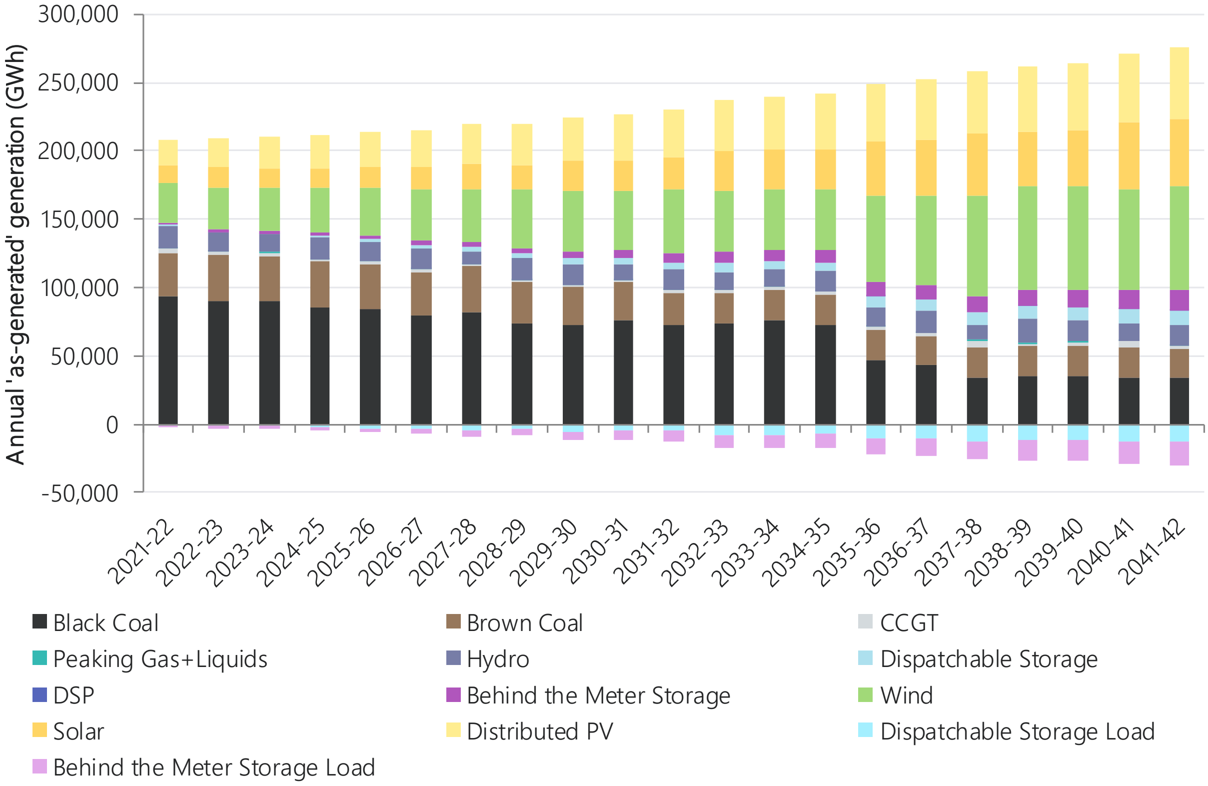
Figure 66 Forecast relative change in installed capacity to 2041-42, High DER scenario



Compared to the Central scenario, the forecast level of dispatchable capacity over time is relatively static in the High DER scenario, due to the greater proportion of distributed battery storages operating as VPPs in this scenario.

DER is also assumed to play a greater role in contributing to overall electricity generation, approximately doubling in energy contribution from 9% of generation in 2021-22 to 20% in 2039-40. The contribution from all renewable energy sources – VRE and DER – is expected to be approximately 75% of total energy production by 2039-40. The forecast mix of wind and solar generation at that time is expected to be fairly even, with a split of approximately 46% wind and 54% solar (25% large scale PV and 29% distributed PV).

Figure 67 Forecast annual generation to 2041-42, High DER scenario



A4.4.5.1 Regional deployment of the High DER scenario generation mix

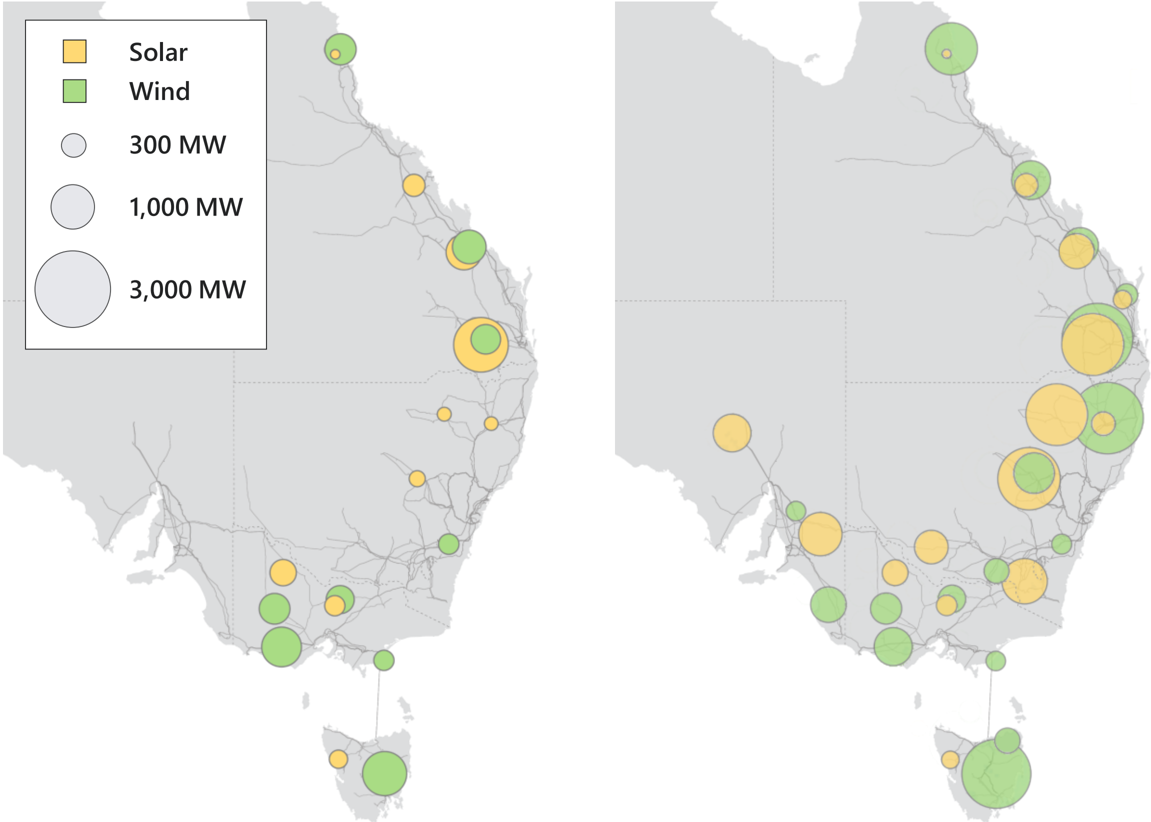
Across NEM regions, the forecast evolution of the supply mix varies in a similar manner to the Central scenario, particularly with regards to the timing and therefore urgency of the transformation (Figure 68). Large-scale VRE developments both in Queensland and Victoria are forecast to be lower than in the Central scenario, with the increased role of DER assisting in achieving state-based targets, and also increasing behind-the-meter solar generation in regions without renewable energy targets. This increased contribution of distributed PV in the generation mix subsequently reduces the projected interconnection requirement between New South Wales and Victoria, tipping the preference towards local generation developments rather than a larger VNI augmentation in the least-cost development path (see Appendix 2).

By 2039-40, all regions are projected to have new VRE capacity (10 GW each in Queensland and New South Wales, and 2 GW in Victoria), over and above what is already committed and anticipated. An additional 2 GW of grid-scale VRE is also expected to be required in Tasmania to meet the TRET assumed in this scenario.

Figure 68 Forecast annual 'as-generated' generation for each region in the NEM for the High DER scenario

Figure 69 shows the forecast VRE diversity across the NEM. Given the scale of DER developments, this scenario represents reduced diversity of large-scale generation, although the nature of DER is that it will be naturally distributed across each region's population centres.

Figure 69 Forecast geographic and technological dispersion of new developments by 2029-30 (left) and 2039-40 (right), High DER scenario

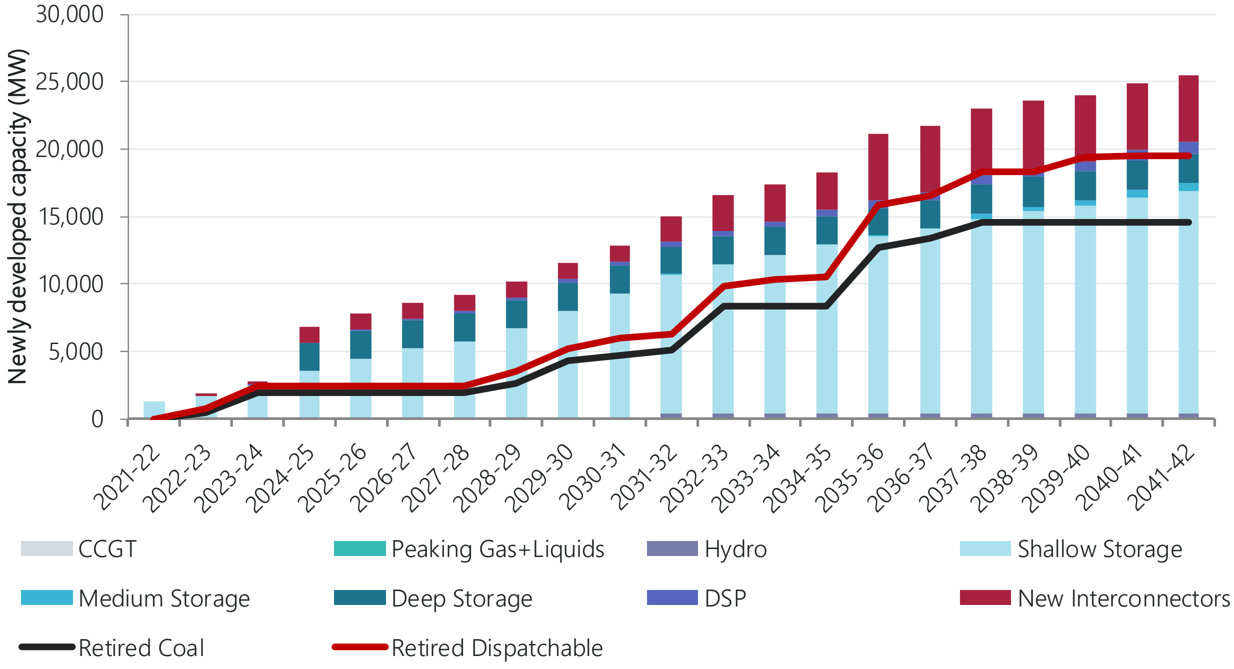


A4.4.5.2 Firm dispatchable developments in the High DER scenario

In this scenario, distributed battery storages largely fulfil the requirement for daily peak storage management, shifting distributed PV generation to assist in covering the evening peak demand periods. When required in the 2030s, some medium-depth storages are projected to be developed in New South Wales and Queensland to complement the shallow batteries, particularly after coal retirements lead to an increased need for flexibility and peaking support, as presented in Figure 70.

Also worth noting is the higher level of shallow storage in the High DER scenario relative to the other scenarios. Together with the increased levels of distributed PV, there is slightly less benefit from interconnector developments in this scenario, in particular, VNI West, as more of the variability in renewable energy output is managed through distributed storage solutions.

Figure 70 Forecast dispatchable capacity development to 2041-42, High DER scenario

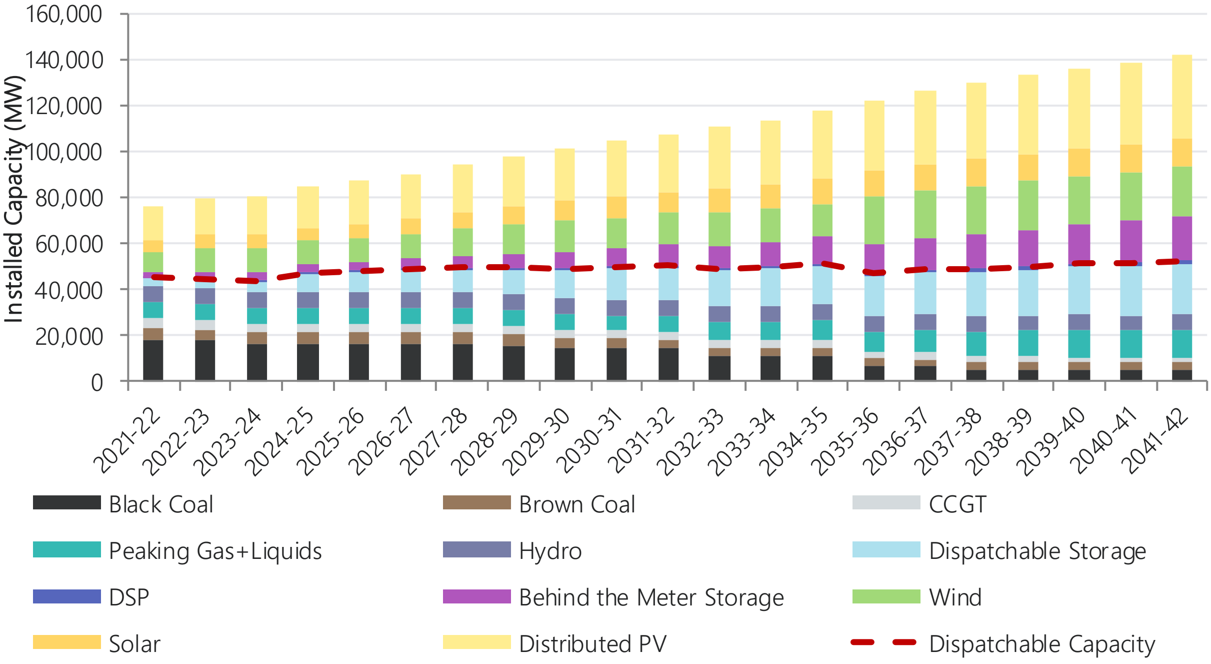


A4.4.5.3 Future generation mix in the High DER scenario without the ISP transmission developments

Under the High DER scenario, the development outlook for the NEM – much like under the Central scenario – is primarily driven by state-based renewable energy targets in the short to medium term. This leads to a measured growth rate in VRE development complemented by DER up to 2029-30 with minimal dispatchable capacity to facilitate this VRE uptake. Post 2032-33 coal fleet retirements lead to a need for new entrant GPG.

Figure 71 presents the capacity development outlook for the High DER scenario in the counterfactual, without any new transmission developments and augmentations. As per the Central scenario, there is a lower level of VRE penetration in the counterfactual scenario, approximately 3.4 GW less (by 2039-40) than the least-cost development path due to the absence of transmission developments and augmentations. This value is slightly lower than the Central scenario because of the higher levels of distributed energy assumed in the High DER scenario.

Figure 71 Forecast capacity mix to 2041-42 in counterfactual, High DER scenario



Additionally, Figure 72 below presents the change in production outlook for the High DER counterfactual scenario. Consistent with the observations in capacity development, GPG plays a greater role in achieving the required level of production to address the material reduction in capacity of the incumbent thermal generation due to end of life retirements. In addition to GPG development, the distribution led uptake of distributed solar production reduces the need for additional large-scale solar developments, allowing proportionately more large-scale wind generation to exploit the existing transmission hosting capacity.

Figure 72 Forecast annual generation to 2041-42, High DER scenario counterfactual

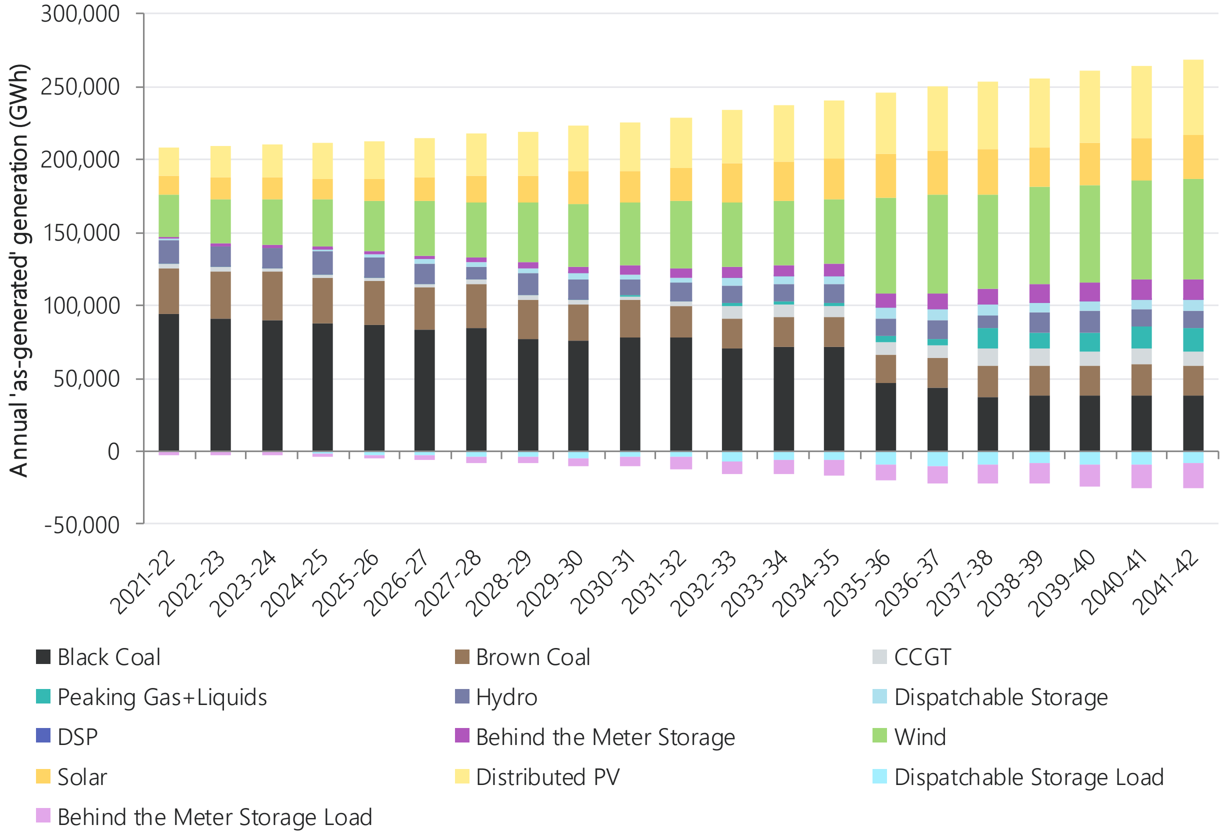
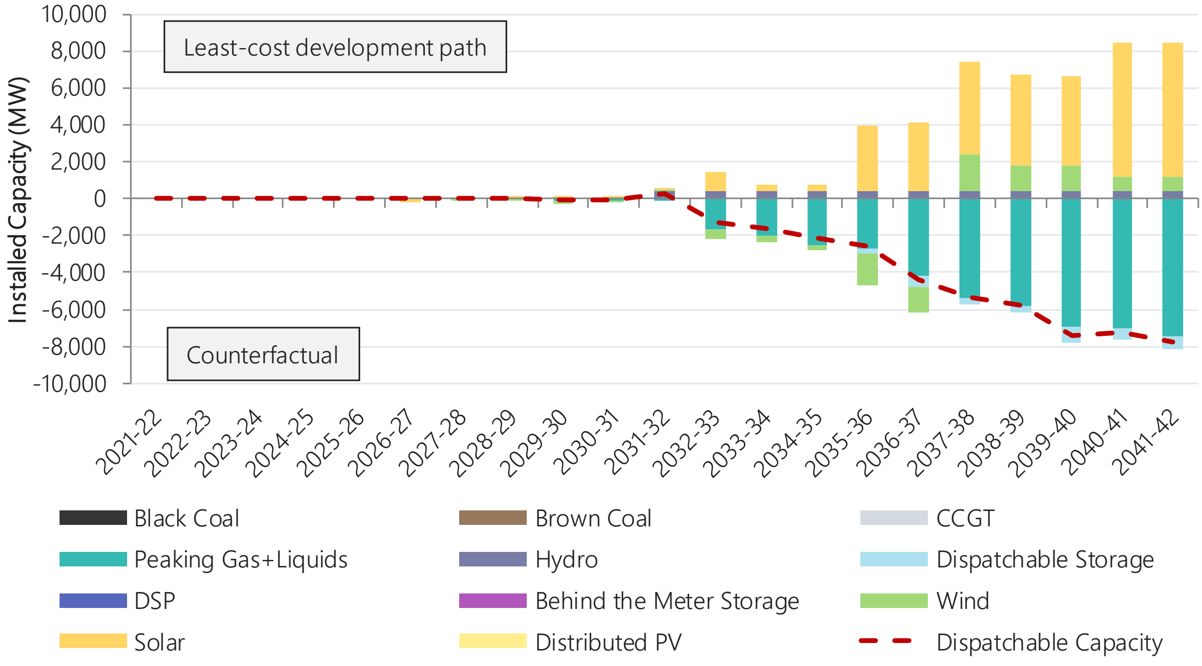


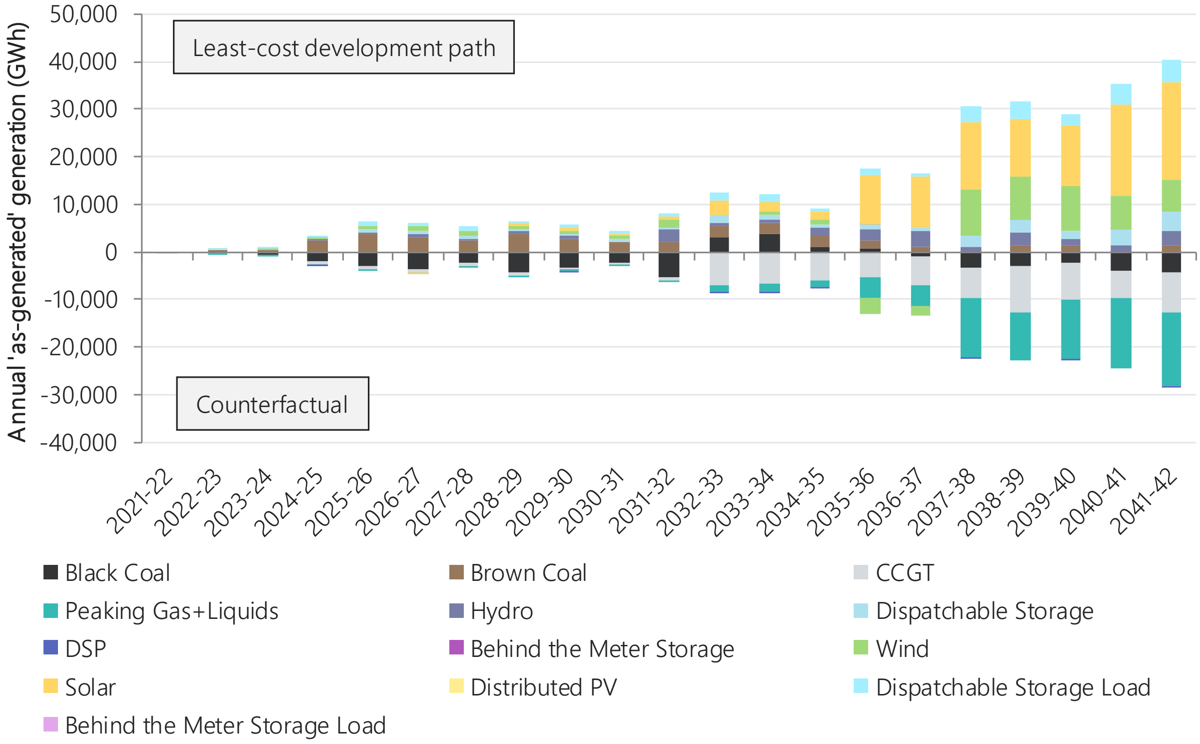
Figure 73 presents the differences in projected installed capacity in the least-cost development path for the High DER scenario against the counterfactual. The forecast capacity response is more muted than other scenarios, given the much higher level of consumer developments, reducing some need for grid-scale solutions. Consistent with the Central scenario, there is an increased need for GPG in the counterfactual outlook to compensate for the lack of interconnection between regions.

Figure 73 Forecast capacity developments to 2041-42 for least-cost development path (DP5) compared to counterfactual, High DER scenario



The projected impact on the generation mix is outlined in Figure 74. In the first years of the study period, the least-cost development path (DP5) is forecast to enable increased operation from the low-cost brown coal fleet and solar/wind from 2032-33. In the counterfactual, coal retirements drive the increase in gas generation from both CCGTs and peaking gas fleets from 2032-33.

Figure 74 Forecast generation outcomes to 2041-42 for the least-cost development path (DP5) compared to counterfactual, High DER scenario



A4.5. NEM emission intensity with the least-cost development paths

The emissions intensity of the NEM is forecast to reduce with the projected uptake of VRE, driven by lowest-cost replacement of retiring generation and existing state and federal policies on emission reduction affecting the energy sector, including regulated, state-based renewable energy targets. In addition, the Fast Change scenario and Step Change scenario assume explicit cumulative NEM electricity sector emissions budgets to 2050.

Figure 75 below demonstrates the reduction in emissions forecast to 2041-42 for the five core ISP scenarios. As the transformation of the NEM is already underway with the existing policies and low cost of VRE, NEM emissions by 2029-30 are forecast to be below the 26% emissions reduction target, in all five scenarios including the Slow Change scenario. However, the 2020 ISP shows that faster and deeper emissions reductions would require targeted direction by governments of Australia, or voluntary action by participants to retire plant earlier than currently expected.

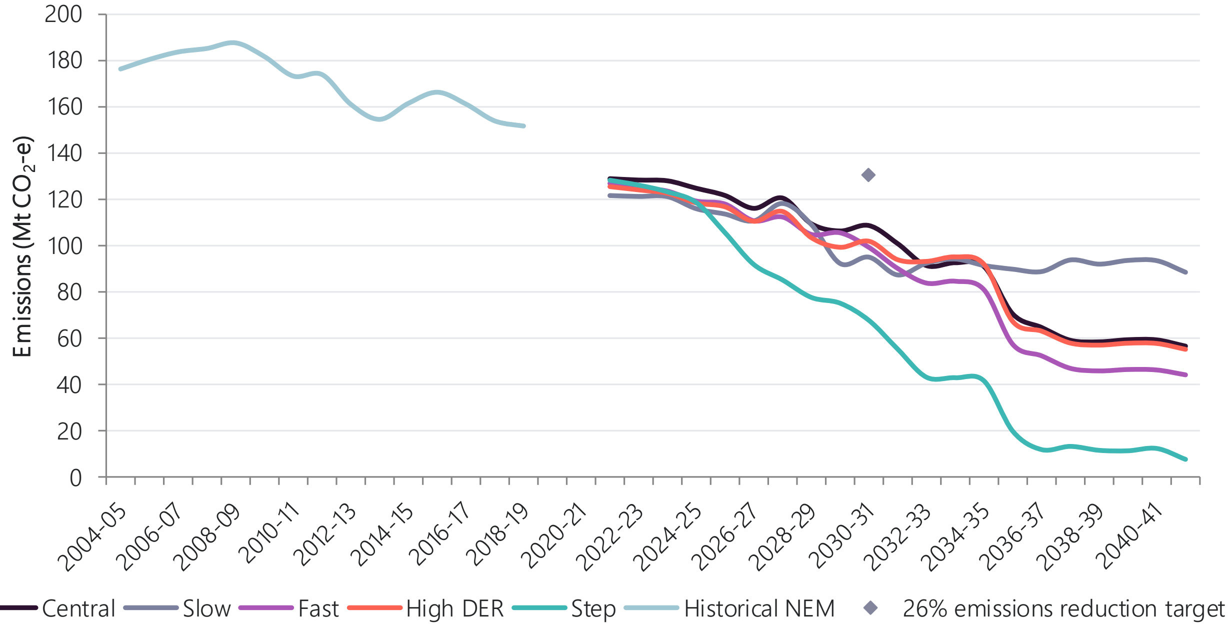
As shown in Figure 75, in the **Central scenario**, emissions are forecast to reduce given the expected schedule of generator retirements. While the higher DER production in the **High DER scenario** offsets some emissions-intensive generation, the emissions forecast in the High DER scenario is not significantly different to the Central scenario.

With a more aggressive emissions abatement target in the **Step Change scenario**, retirements of both black and brown coal across the NEM will be accelerated. To meet the carbon budget, emissions in the Step Change scenario would have to decrease 91%, from 128 Mt CO_2-e in 2021-22 to just over 11 Mt CO_2-e by 2039-40. This reduction in emissions intensive generation will be primarily addressed by a combination of VRE, DER, storage and transmission (Section A4.4.4). The greatest period of thermal capacity withdrawal occurs during the mid-2020s, effectively advancing retirements on average by six to seven years. During this period the system is more able, at an efficient cost, to materially reduce emissions over the forecast horizon. By delaying retirements to after 2030, a significant proportion of the emissions budget would be eroded in the 2020s, causing significant challenge and increased costs under a retirement schedule that attempts to catch up at a later date.

The carbon budget applied to the **Fast Change scenario** is forecast to advance coal power station retirements ahead of the current expected closure schedule. Although not as aggressive as the Step Change scenario, coal retirements in the mid-2020s achieve a lower cost approach to achieving emissions abatement than delayed action. Cumulative NEM emissions for the Fast Change scenario are forecast to be 9% lower than the Central scenario, declining progressively with coal retirements. To meet the carbon budget, emissions in the Fast Change scenario would have to decrease 63%, from 126 Mt CO_2-e in 2021-22 to just over 46 Mt CO_2-e by 2039-40, with most of the emissions cuts (relative to the Central scenario) being made from late 2020s to mid-2030s from advanced coal retirements.

Emissions in the **Slow Change scenario** are forecast to be higher than in all other scenarios in the long term. However, emissions in this scenario until the mid-2030s are forecast to be lower than the Central scenario due to the assumed softer consumption outlook. After 2032-33, emissions in the Slow Change scenario are forecast to remain flat due to several coal-fired generators having their life extended for a period of 10 years.

Figure 75 Annual emissions by scenario for each least-cost development path



The emissions outlook of the updated demand and TRET sensitivities (Figure 76) have a very similar trend to that observed in the Central scenario. If the TRET were legislated in the Central scenario, emissions are forecast to be similar to the Central Scenario as the policy implementation acts to promote VRE development in Tasmania, but less is then developed on the mainland (beyond what is required to meet state RETs).

The updated demand sensitivity shows short-term demand impacts of lower consumption from the effects of COVID-19 and increase in distributed PV, reducing emissions until 2028-29. From 2030, despite greater DER penetration emissions in this sensitivity, emissions converge with the Central scenario, as distributed PV offsets VRE.

Figure 76 Annual emissions for the TRET and updated demand sensitivities compared to the Central scenario