Expanding NSW-QLD transmission transfer capacity PADR market modelling report

TransGrid and Powerlink

9 October 2019

Building a better working world

Release Notice

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Readers are advised that the outcomes provided are based on many detailed assumptions underpinning the scenarios, and the key assumptions are described in the Report. These assumptions were selected by TransGrid and Powerlink after public consultation. The modelled scenarios represent several possible future options for the development and operation of the Nation Electricity Market, and it must be acknowledged that many alternative futures exist. Alternative futures beyond those presented have not been evaluated as part of this Report and could be considered and analysed to have a more comprehensive understanding of sensitivities and options.

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1. Executive summary

TransGrid and Powerlink have jointly engaged EY to evaluate the potential market benefits of expanding the transmission transfer capacity between New South Wales and Queensland in the near term. This work supports the Regulatory Investment Test for Transmission (RIT-T) currently in progress for the expansion of interconnector capacity.[1,2] The RIT-T is a cost-benefit analysis used to assess the viability of investment options in electricity transmission assets.

This Report forms a supplementary report to the broader Project Assessment Draft Report (PADR) published by TransGrid and Powerlink.[3] It describes the key assumptions, input data sources and methodologies that have been applied in this modelling as well as outcomes of our analysis and key insights. It is accompanied by market modelling workbooks which contain summaries of key outcomes.

EY applied a cost-benefit analysis based on the change in least-cost generation dispatch and capacity development plan with an augmentation.

EY has computed the least-cost generation dispatch and development plan for the National Electricity Market (NEM) associated with five Queensland-New South Wales Interconnector (QNI) augmentation options across a range of scenarios and sensitivities. This is an independent study and the modelling methodology follows the RIT-T guidelines published by the Australian Energy Regulator.[4]

To determine the least-cost solution, the model makes decisions for each hourly trading interval in relation to:

- The generation dispatch level for each power plant along with the charging and discharging of storage. Stations are assumed to bid at their short-run marginal cost (SRMC), which is derived from their Variable Operation and Maintenance (VOM) and fuel costs. The generation for each trading interval is subject to the modelled availability of power stations in each hour (those that are not on planned or un-planned outages), network limitations and energy limits (e.g., storage levels).

- Commissioning new entrant capacity for wind, solar PV[5] SAT, CCGT, OCGT, large-scale storage and pumped storage hydro (PSH).

These hourly decisions take into account operational constraints that include:

- supply must equal demand in each region for all trading intervals plus a reserve margin, with unserved energy (USE) costed at the value of customer reliability (VCR)[6],

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[1] TransGrid RIT-T website available at: https://www.transgrid.com.au/what-we-do/projects/current-projects/ExpandingNSWQLDTransmissionTransferCapacity. Accessed 26 September 2019.
[2] Powerlink RIT-T website available at: https://www.powerlink.com.au/expanding-nsw-qld-transmission-transfer-capacity. Accessed 26 September 2019.
[3] 30 September 2019. Available at: https://www.transgrid.com.au/what-we-do/projects/current-projects/ExpandingNSWQLDTransmissionTransferCapacity or https://www.powerlink.com.au/expanding-nsw-qld-transmission-transfer-capacity. Accessed 30 September 2019.
[4] 14 December 2018, *RIT-T and RIT-D application guidelines 2018*. Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rit-t-and-rit-d-application-guidelines-2018. Accessed 26 September 2019.
[5] PV = photovoltaics, SAT = Single Axis Tracking, CCGT = Closed-Cycle Gas Turbine, OCGT = Open-Cycle Gas Turbine
[6] Set to $33,460/MWh based on AEMO, September 2014, *Value of customer reliability review: final report*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Value-of-Customer-Reliability-review. Accessed 24 September 2019.

- minimum loads for generators,
- transmission interconnector flow limits (between regions),
- intra-regional flow limits (between zones in New South Wales and central/south zone for Queensland),
- maximum and minimum storage (conventional storage hydro, PSH and large-scale battery storage) reservoir limits and cyclic efficiency,
- new entrant capacity build limits for wind and solar for each Renewable Energy Zone (REZ) where applicable, and PSH in each region,
- emission constraints in applicable scenarios,
- renewable energy targets where applicable by region or NEM-wide in applicable scenarios.

From the hourly time-sequential modelling we computed the following costs, as defined in the RIT-T:

- capital costs of new generation capacity installed,
- total Fixed Operation and Maintenance (FOM) costs of all generation capacity,
- total VOM costs of all generation capacity,
- total fuel costs of all generation capacity,
- total cost of voluntary (demand-side participation, DSP) and involuntary load curtailment (USE),
- transmission expansion costs associated with REZ development.

For each simulation with a QNI augmentation option and in a matched existing QNI counterfactual (referred to as the Base case) we compute the difference between the sum of these components. The changes in costs are the gross market benefits due to the QNI augmentation, as defined in the RIT-T.

The market benefits also capture the impact on transmission losses to the extent that losses across interconnectors and intra-connectors affect the generation that is needed to be dispatched in each trading interval. The market benefits also capture the impact of differences in losses in storages, including PSH and large-scale battery storage between each QNI augmentation option and matched Base case.

Market benefits were forecast for five QNI augmentation options across four scenarios covering a broad range of reasonable possible futures for the NEM.

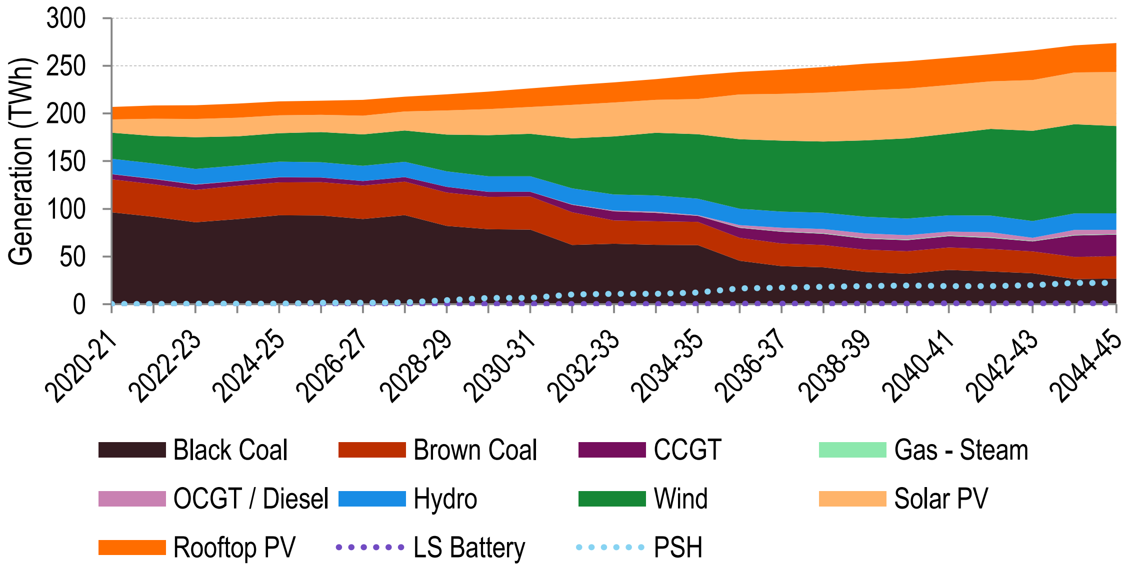
Market benefits were forecast for five QNI augmentation options across four scenarios covering a broad range of reasonable possible futures for the NEM. The augmentation options were defined by TransGrid and Powerlink and are described in detail in the PADR.[7] The scenarios were: Neutral, Neutral + lower emissions, Slow change and Fast change. In all scenarios, QNI predominantly flows

[7] TransGrid and Powerlink, 30 September 2019. Available at: https://www.transgrid.com.au/what-we-do/projects/current-projects/ExpandingNSWQLDTransmissionTransferCapacity or https://www.powerlink.com.au/expanding-nsw-qld-transmission-transfer-capacity. Accessed 30 September 2019.

to the South due to load growth in New South Wales coupled with large coal-fired generator retirements.

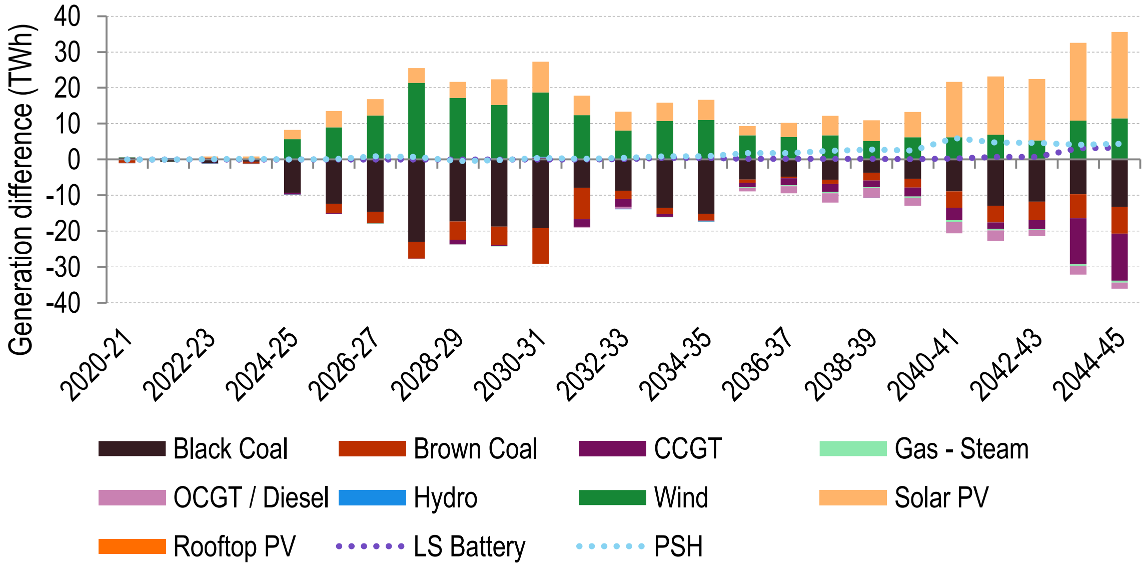
The Neutral scenario reflects a view on the evolution of the market going forward selected by TransGrid and Powerlink as a central view after public consultation following publication of the Project Specification Consultation Report (PSCR). It includes the Australian Energy Market Operator's (AEMO's) 'Neutral' demand forecasts, new generator/storage capital and fuel costs, as well as a national emissions reduction of around 28 % below 2005 levels by 2030. This generation mix forecast is shown in Figure 1. The NEM gradually shifts towards increasing capacity of wind, solar, gas generation and storage, both PSH and large-scale battery storage.

Figure 1: NEM generation mix forecast for Neutral scenario without QNI upgrade



The Neutral + low emissions scenario applies all the same assumptions as the Neutral scenario with the exception of a stronger emissions reduction target and assumed earlier retirement of coal generators as a result. The change in generation mix forecast in this scenario relative to the Neutral scenario is shown in Figure 2. It shows that the earlier coal generator retirements are replaced by wind and solar generation, with some additional PSH and large-scale battery storage.

Figure 2: Difference in NEM generation forecast between Neutral + low emissions scenario and Neutral scenario without QNI upgrade

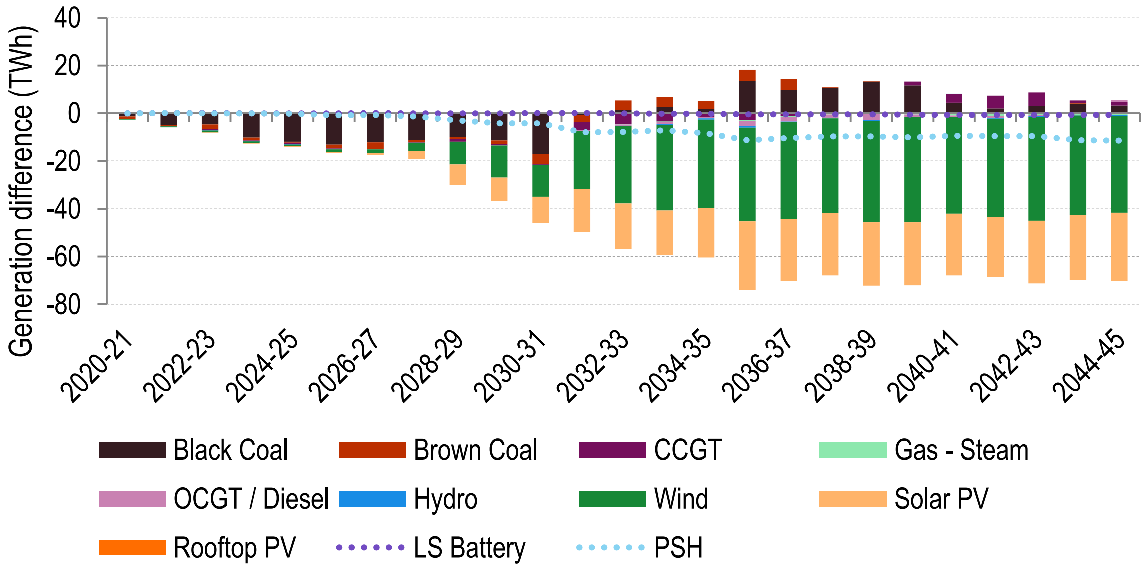


The Slow change scenario applies a set of assumptions reflecting a future world of lower demand forecasts, lower fuel costs, and later coal plant retirements relative to the Neutral scenario. The Slow change scenario also excludes the Victoria to New South Wales interconnector (VNI) upgrade, as well as the planned Snowy 2.0 generation, HumeLink and KerangLink developments. The Slow change scenario is intended to represent the lower end of the potential range of realistic net market benefits associated with the various options.

The change in generation mix forecast in this scenario relative to the Neutral scenario is shown in Figure 3. Overall, there is less capacity installed in this scenario due to lower demand growth. Further differences in the generation mix are an outcome of several factors including:

- Reduced build and dispatch of new wind and solar due to existing coal fleet operating for longer and reduced ability to share renewables with reduced interconnection.
- More CCGT generation due to lower gas prices in the later years.

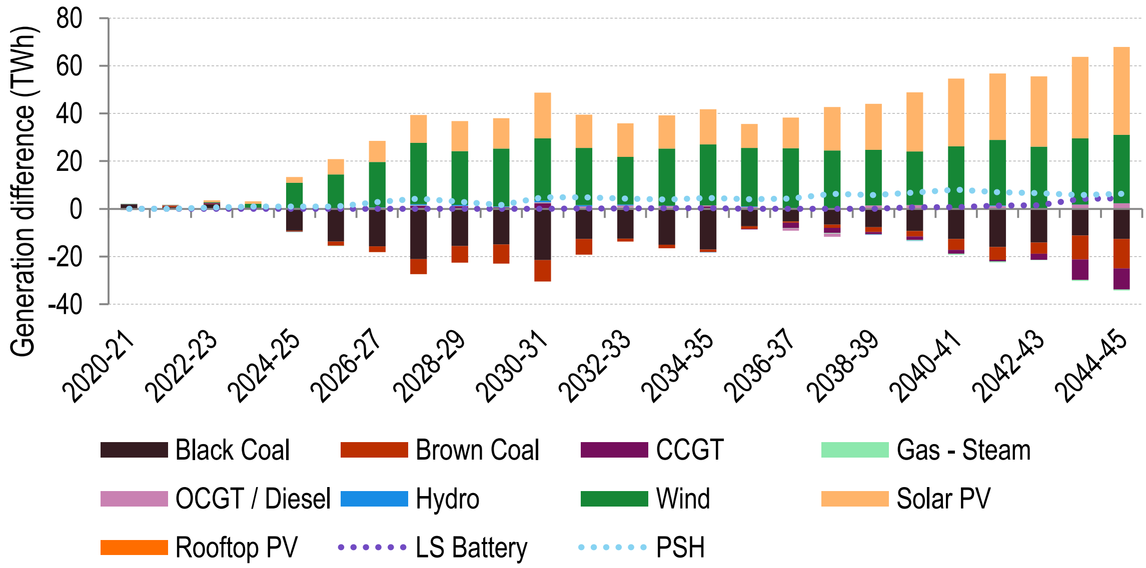
Figure 3: Difference in NEM generation forecast between Slow change scenario and Neutral scenario without QNI upgrade



The Fast change scenario applies a set of assumptions reflecting a future world of high demand forecasts, gas costs, a more stringent national emissions reduction target of around 52 % below 2005 levels by 2030, and earlier coal plant retirements compared to the Neutral scenario. The Fast change scenario also assumes that the MarinusLink and Battery of the Nation are commissioned (and is the only scenario investigated to do so). The Fast change scenario represents the upper end of the potential range of realistic net market benefits associated with the various options.

The change in generation mix forecast in this scenario relative to the Neutral scenario is shown in Figure 4. Overall, there is more capacity in this scenario due to higher demand growth. There is also less gas capacity installed in the later years due to the stronger emissions constraint applied.

Figure 4: Difference in NEM generation forecast between Fast change scenario and Neutral scenario without QNI upgrade



The robustness of market benefits was also explored in several sensitivities:

- deferring the retirement of three of Liddell's units and bringing one unit forward, as recently announced by AGL,[8]
- the impact of line outages during the line uprating work (specific to Option 1A and Option 1B),
- the impact of assuming Wood Mackenzie's 'Fast' coal prices for the Fast change scenario,[9]
- New South Wales CCGT minimum load and minimum run time operational parameters.

[8] AGL, 2 August 2019, *Schedule for the closure of AGL plants in NSW and SA* [press release]. Available at: https://www.agl.com.au/about-agl/media-centre/asx-and-media-releases/2019/august/schedule-for-the-closure-of-agl-plants-in-nsw-and-sa. Accessed 24 September 2019.

[9] Wood Mackenzie, July 2019, *Coal cost projections: approach to coal cost projections*. Available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/WoodMackenzie_AEMO_Coal_cost_projections_Approach_20190711.pdf. Accessed 24 September 2019.

Forecast gross market benefits changes across options and scenarios and must be compared to augmentation costs to determine the preferred option.

Table 1 shows the forecast gross market benefits associated with the change in the least-cost development plan with each augmentation option over the modelled 25-year horizon.

Table 1: Summary of forecast gross market benefits, millions real June 2019 dollars discounted to 2019-20

Option	Scenario			
	Slow change	Neutral	Neutral + low emissions	Fast change
1A	240	379	382	451
1B	71	179	230	284
1C	159	146	94	112
1D	115	95	59	67
5B	438	499	462	532

The gross modelled market benefits of each QNI augmentation option computed in each scenario need to be compared to the relevant QNI augmentation cost to determine whether there is a positive net market benefit. The determination of Option 1A as the preferred option is dependent on option costs and was conducted outside of this Report by TransGrid and Powerlink.[10] All references to the preferred option in this Report are in the sense defined in the RIT-T as "the credible option that maximises the net economic benefit across the market, compared to all other credible options." [11]

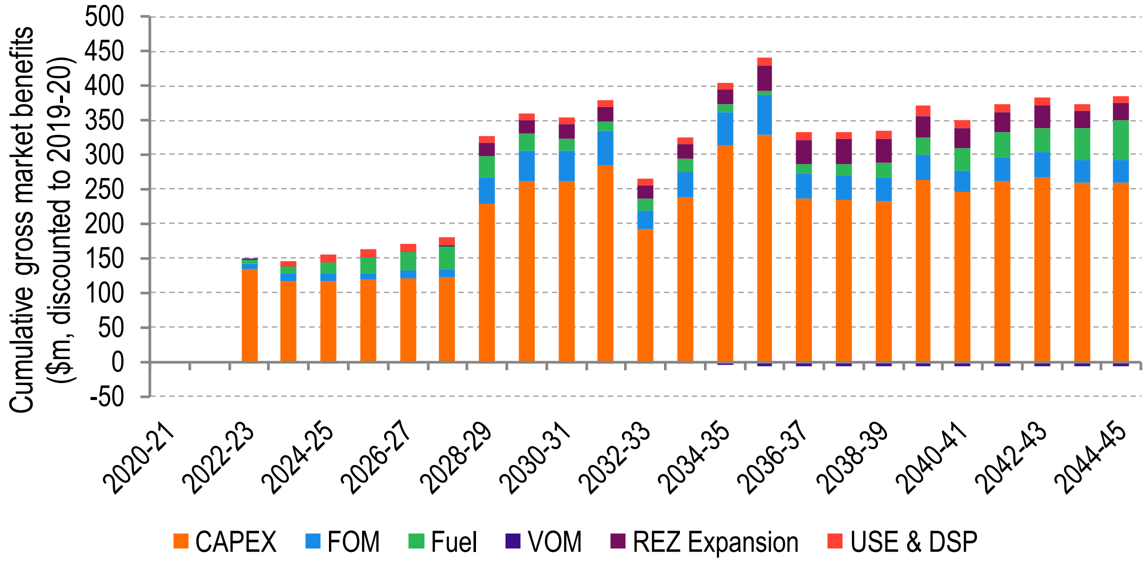
Deferred or avoided capex is the main source of benefits for the Option 1A.

The forecast cumulative gross market benefits for Option 1A in the Neutral scenario are shown in Figure 5. Capex savings associated with deferred or avoided build of new capacity are the dominant source of benefits. The timing of capex benefit accrual is associated with New South Wales coal retirements starting with Liddell in 2022-23. This outcome holds across all scenarios, although the technology deferred varies with each scenario. In the Neutral and Slow change scenarios OCGT capacity is deferred, while in the Neutral + low emissions and Fast change scenarios, OCGT and PSH capacity is deferred.

[10] 30 September 2019. Available at: https://www.transgrid.com.au/what-we-do/projects/current-projects/ExpandingNSWQLDTransmissionTransferCapacity or https://www.powerlink.com.au/expanding-nsw-qld-transmission-transfer-capacity. Accessed 30 September 2019.

[11] 14 December 2018, *RIT-T and RIT-D application guidelines 2018*. Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rit-t-and-rit-d-application-guidelines-2018. Accessed 26 September 2019.

Figure 5: Forecast cumulative gross market benefit[12,13] for Option 1A under the Neutral scenario, millions real June 2019 dollars discounted to 2019-20



As the Neutral + low emissions and Fast change scenarios have more capacity built in the Base case, there is more opportunity for Option 1A to defer or avoid capex and better share generation between regions. This drives higher benefits in these scenarios. The inverse is true in the Slow change scenario.

The other augmentation options have gross benefits that scale with their effectiveness in unlocking the full QNI flow path and ability to serve New South Wales peak demand.

In general, the forecast sources and timing of market benefits for the other augmentation options are similar to Option 1A in all scenarios. The main source of forecast benefits are capex benefits associated with avoided or deferred need for new generation and storage capacity. The expected magnitude of benefits scales with each option's ability to serve the Central New South Wales zone (NCEN) during high demand periods after large retirements of coal capacity in NCEN.

Options 1B, 1C and 1D do not unlock the full flow path and consequently are forecast to have reduced gross market benefits relative to Option 1A. Option 1D is the smallest augmentation improving the Southern Queensland to Northern New South Wales (SQ-NNS) southerly stability limit only and no Northern New South Wales to New South Wales Central (NNS-NCEN) line upgrades. Consequently, it has the smallest benefits.

A general observation of note is that in terms of works and costs Option 1A is equivalent to Option 1B plus 1C. However, gross market benefits of Option 1A are higher than the sum of the gross benefits of Option 1B and 1C. This indicates that there are synergies in gross market benefits which are achieved by combining the two work components of Option 1A.

[12] Note, while all generator and storage capital costs have been included in the market modelling on an annualised basis, this annual market benefits chart, and all charts of this nature in the Report, present the entire capital costs of these plant in the year avoided to highlight the timing of capacity changes that drive expected capex benefits. This is purely a presentational choice that TransGrid and Powerlink have made to assist with relaying the timing of expected benefits (i.e., when thermal plant retire) and does not affect the overall gross benefits of the options.

[13] Since this figure shows the cumulative gross market benefits in present value terms, the height of the bar in 2044-45 equates to the gross benefits for Option 1A shown in Table 1 above.

Option 5B is the largest augmentation in magnitude of improvement of SQ-NNS and NNS-NCEN limits, and furthermore also increases Central Queensland to Southern Queensland (CQ-SQ) limits. Consequently, it has the largest gross market benefits; however, the PADR[14] notes it is also the highest cost option.

[14] TransGrid and Powerlink, 30 September 2019. Available at: https://www.transgrid.com.au/what-we-do/projects/current-projects/ExpandingNSWQLDTransmissionTransferCapacity or https://www.powerlink.com.au/expanding-nsw-qld-transmission-transfer-capacity. Accessed 30 September 2019.

2. Introduction

TransGrid and Powerlink have jointly engaged EY to evaluate the potential market benefits of expanding the transmission transfer capacity between New South Wales and Queensland in the near term. This work supports the Regulatory Investment Test for Transmission (RIT-T) currently in progress for the expansion of interconnector capacity.[15,16] The RIT-T is a cost-benefit analysis used to assess the viability of investment options in electricity transmission assets.

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EY has computed the least-cost generation dispatch and development plan for the National Electricity Market (NEM) associated with five Queensland-New South Wales Interconnector (QNI) augmentation options across a range of scenarios and sensitivities. The augmentation options were defined by TransGrid and Powerlink and are described in detail in the PADR.[18] This is an independent study and the modelling methodology follows the RIT-T guidelines published by the Australian Energy Regulator.[19]

The descriptions of outcomes in this Report are focussed on identifying and explaining the key sources of market benefits across scenarios and sensitivities. The categories of market benefits modelled are changes in:

- capital costs of new generation capacity installed,
- total Fixed Operation and Maintenance (FOM) costs of all generation capacity,
- total Variable Operation and Maintenance (VOM) costs of all generation capacity,
- total fuel costs of all generation capacity,
- total cost of voluntary and involuntary load curtailment,
- transmission expansion costs associated with renewable energy zone (REZ) development.

Each category of market benefits is computed annually across a 25-year study period from 2020-21 to 2044-45. Benefits are presented in real June 2019 dollars discounted to 2019-20 using a 5.9 % real, pre-tax discount rate as selected by TransGrid and Powerlink. This value is sourced from the commercial discount rate calculated in the *RIT-T Economic Assessment Handbook* published by Energy Networks Australia[20] and is consistent with the value to be applied by the

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[15] TransGrid RIT-T website available at: https://www.transgrid.com.au/what-we-do/projects/current-projects/ExpandingNSWQLDTransmissionTransferCapacity. Accessed 26 September 2019.

[16] Powerlink RIT-T website available at: https://www.powerlink.com.au/expanding-nsw-qld-transmission-transfer-capacity. Accessed 26 September 2019.

[17] 30 September 2019. Available at: https://www.transgrid.com.au/what-we-do/projects/current-projects/ExpandingNSWQLDTransmissionTransferCapacity or https://www.powerlink.com.au/expanding-nsw-qld-transmission-transfer-capacity. Accessed 30 September 2019.

[18] TransGrid and Powerlink, 30 September 2019. Available at: https://www.transgrid.com.au/what-we-do/projects/current-projects/ExpandingNSWQLDTransmissionTransferCapacity or https://www.powerlink.com.au/expanding-nsw-qld-transmission-transfer-capacity. Accessed 30 September 2019.

[19] 14 December 2018, *RIT-T and RIT-D application guidelines 2018*. Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rit-t-and-rit-d-application-guidelines-2018. Accessed 26 September 2019.

[20] 15 March 2019. Available at: https://www.energynetworks.com.au/rit-t-economic-assessment-handbook. Accessed 24 September 2019.

Australian Energy Market Operator (AEMO) in most scenarios in the 2019-20 Integrated System Plan (ISP)[21].

The gross modelled market benefits of each QNI augmentation option forecast in each scenario need to be compared to the relevant QNI augmentation cost to determine whether there is a positive net market benefit. The determination of the preferred option is dependent on option costs and was conducted outside of this Report by TransGrid and Powerlink. All references to the preferred option in this Report are in the sense defined in the RIT-T as "the credible option that maximises the net economic benefit across the market, compared to all other credible options." [22]

The Report is structured as follows:

- Section 3 gives an overview of the methodology applied in the modelling and computation of market benefits.
- Section 4 gives an overview of scenario settings and sensitivities.
- Section 5 outlines model aspects and input data related to representation of the transmission network and transmission losses and demand.
- Section 6 gives an overview of model inputs and methodologies related to supply of energy.
- Section 7 describes the forecast generation and capacity outlooks in each of the scenarios without any QNI augmentation.
- Section 8 gives an overview of gross market benefits forecast for each option across scenarios and sensitivities. It is focussed on identifying and explaining the key sources of market benefits with Option 1A, the preferred QNI augmentation option based on TransGrid's and Powerlink's analysis of net market benefit.

[21] AEMO, 13 September 2019, *2019 Input and Assumptions workbook, v1.2*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2019-Integrated-System-Plan. Accessed 24 September 2019.

[22] 14 December 2018, *RIT-T and RIT-D application guidelines 2018*. Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rit-t-and-rit-d-application-guidelines-2018. Accessed 26 September 2019.

3. Methodology

3.1 Long-term investment planning

EY has used linear programming techniques to perform hourly time-sequential, least-cost, long-term NEM development optimisation modelling spanning 25 years from 2020-21 to 2044-45. The modelling methodology follows the RIT-T guidelines published by the Australian Energy Regulator.[23]

Based on the full set of input assumptions, the Time-Sequential Integrated Resource Planning (TSIRP) model makes decisions that minimise the overall cost to supply the electricity demand for the NEM over the entire study period, with respect to:

- capital expenditure for generation and storage (capex),
- FOM,
- VOM,
- fuel usage,
- demand-side participation (DSP) and unserved energy (USE),
- transmission expansion costs associated with REZ development,
- transmission and storage losses which form part of the demand to be supplied, which are calculated dynamically within the model.

To determine the least-cost solution, the model makes decisions for each hourly[24] trading interval in relation to:

- The generation dispatch level for each power plant along with the charging and discharging of storage. Stations are assumed to bid at their short-run marginal cost (SRMC), which is derived from their VOM and fuel costs. The generation for each trading interval is subject to the modelled availability of power stations in each hour (those that are not on planned or un-planned outages), network limitations and energy limits (e.g., storage levels).
- Commissioning new entrant capacity for wind, solar PV[25] SAT, CCGT, OCGT, large-scale storage and pumped storage hydro (PSH).

These hourly decisions take into account constraints that include:

- supply must equal demand in each region for all trading intervals, while maintaining a reserve margin, with USE costed at the value of customer reliability (VCR)[26],
- minimum loads for some generators,

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[23] 14 December 2018, *RIT-T and RIT-D application guidelines 2018*. Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rit-t-and-rit-d-application-guidelines-2018. Accessed 26 September 2019.

[24] Whilst the NEM is dispatched on five-minute intervals, the model resolution is hourly as a compromise between managing computation time while still capturing the renewable and storage resources in sufficient detail for the purposes of the modelling.

[25] PV = photovoltaics, SAT = Single Axis Tracking, CCGT = Closed-Cycle Gas Turbine, OCGT = Open-Cycle Gas Turbine

[26] Set to $33,460/MWh based on AEMO, September 2014, *Value of customer reliability review: final report*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Value-of-Customer-Reliability-review. Accessed 24 September 2019.

- transmission interconnector flow limits (between regions),
- intra-regional flow limits (between zones in New South Wales and central/south zone for Queensland),
- maximum and minimum storage reservoir limits (for conventional storage hydro, PSH and large-scale battery storage),
- new entrant capacity build limits for wind and solar for each REZ where applicable, and PSH in each region,
- emission constraints in applicable scenarios,
- renewable energy targets where applicable by region or NEM-wide in applicable scenarios.

The model includes key intra-regional constraints in New South Wales and Queensland through the modelling of zones with intra-regional limits and loss equations. Within these zones and within regions, no further detail of the transmission network is considered.

The model incorporates as inputs the assumed fixed retirement dates for existing generation. It also factors in the annual costs, including capital costs for all new generator capacity and the model decides how much new capacity to build in each region to deliver the least-cost market outcome.

The model meets the specified emissions trajectory in applicable scenarios, at least cost, which may be by either building new lower emissions plant or reducing operation of higher emissions plant, or both.

There are three main types of generation that are scheduled by the model:

- Dispatchable generation, typically coal, gas and liquid fuel which is assumed to have unlimited energy source in general. The running costs for these generators is the sum of the VOM and fuel costs. Coal generators and some CCGTs have minimum loads to reflect operational stability limits and high start-up costs and this ensures they are always online when available. This is consistent with the self-commitment nature of the design of the NEM. On the other hand, peaking generators have no minimum operating level and start whenever their variable costs will be recovered.
- Semi-scheduled and non-scheduled wind and solar generators are fully dispatched according to their available resource in each hour, unless constrained by oversupply, when they may be curtailed.
- Storage plant of all types (conventional hydro generators with storages, PSH and large-scale battery storages) are operated so as to minimise the overall system costs. This means they tend to generate at times when the demand for power is high, and so dispatching energy-limited generation will lower system costs. Conversely, at times when there is a surplus of capacity, storage hydro preserves energy and PSH and large-scale battery storage operate in pumping or charging mode.

3.1.1 Reserve constraint in long-term investment planning

The TSIRP model ensures there is sufficient dispatchable capacity in each region to meet peak demand in the region, allowing for generation contingences which can occur at any time by enforcing regional minimum reserve levels.

All dispatchable generators in each region are eligible to contribute to reserve (except new PSH and large-scale batteries installed by the model as part of least-cost plan[27]) and headroom that is available from interconnectors. The hourly modelling accounts for load diversity and sharing of reserves across the NEM and so minimises the amount of reserve carried, and provides reserve from the lowest cost providers, including allowing for each region to contribute to its neighbours' reserve requirements through interconnectors.

In the modelling presented in this Report, a consecutive contingency reserve requirement was applied with a high penalty cost. This amount of reserve ensures there is sufficient capacity for operational reliability in the event that conditions vary from the perfect-foresight optimisation model (e.g. variability in production from variable renewable energy sources, different forced outage patterns).

This constraint is applied to only a subset of simulation hours (highest 1 % demand) to reduce the optimisation problem size. We do not expect this to affect outcomes as a reserve constraint is unlikely to bind in lower demand intervals.

There are three geographical levels of reserve constraints applied:

- Reserve constraints are applied to each region.
- The model ensures that interconnector headroom is backed by spare capacity in the neighbouring region through an additional reserve constraint covering New South Wales, Victoria and South Australia. Tasmania and Queensland do not feature in this constraint because they have surplus dispatchable capacity and therefore can export reserve.
- In New South Wales, where the major proportion of load and dispatchable generation is concentrated in the Central New South Wales (NCEN) zone, the same rules are applied as for the New South Wales region except headroom on intra-connectors between adjacent zones does not contribute to reserve.[28]

3.1.2 Losses in long-term investment planning

Interregional losses are captured in the TSIRP model through explicit modelling of dynamic interconnector loss equations. More detail on these equations is given in Section 5.2.

Most intra-regional losses in Queensland and New South Wales are captured in the TSIRP model through explicit modelling of intra-connector dynamic loss equations between the defined zones. More detail on these equations is given in Section 5.2.

Additional losses within the Queensland and New South Wales zones and within the remaining NEM regions are captured through an estimate of loss factors for existing and new entrant generators. To estimate these loss factors, the TSIRP model is interfaced with an AC power flow program. Hourly generation dispatch outcomes from the model are transferred to nodes in a network snapshot. These estimated loss factors are then returned to the TSIRP model and used in a further refining pass to ensure new entrant developments are least-cost when accounting for changing load and generation patterns. Loss factors are estimated based on hourly outcomes for a year, once

[27] PSH and large-scale batteries are usually fully dispatched during the peaks and thus will be unable to contribute to reserve. In the event that they are not dispatched fully, it is likely due to insufficient energy in storage.

[28] This is because even if there is headroom on the NCEN intra-connectors, in the Northern New South Wales (NNS) zone there is no reserve available and in the Canberra (CAN) zone reserve is limited by CAN-NCEN intra-connector limit which is likely to be binding during peak demand periods. However, intra-connectors (and, in particular, the NCEN-NNS line upgrades in applicable options) still implicitly contribute to reserve because increased flow can displace dispatchable generators within NCEN allowing them to contribute to reserve.

every five years.[29] This method of estimating and incorporating loss factors is sufficient to give a geographic investment signal related to transmission network utilisation. The reduced energy delivered from generators to serve load as a result of the loss factors is incorporated in the modelling.

3.1.3 Cost-benefit analysis

From the hourly time-sequential modelling we computed the following categories of costs defined in the RIT-T:

- capital costs of new generation capacity installed,
- total FOM costs of all generation capacity,
- total VOM costs of all generation capacity,
- total fuel costs of all generation capacity,
- total cost of voluntary and involuntary load curtailment, DSP and USE,
- transmission expansion costs associated with REZ development.

For each simulation with a QNI augmentation option and in a matched existing QNI counterfactual (referred to as the Base case) we compute the difference between the sum of these components. The changes in costs are the gross market benefits due to the QNI augmentation, as defined in the RIT-T.

The market benefits also capture the impact on transmission losses to the extent that losses across interconnectors and intra-connectors affect the generation that is needed to be dispatched in each trading interval. The market benefits also capture the impact of differences in losses in storages, including PSH and large-scale battery storage between each QNI augmentation option and matched Base case.

Each component of market benefits is computed annually over the 25-year study period. In this Report, we summarise the benefit and cost streams using a single value computed as the Net Present Value (NPV)[30], discounted to 2019-20 at a 5.9 % real, pre-tax discount rate as selected by TransGrid and Powerlink. This value is sourced from the commercial discount rate calculated in the *RIT-T Economic Assessment Handbook* published by Energy Networks Australia[31] and is consistent with the value to be applied by AEMO in most scenarios in the 2019-20 ISP[32].

The gross modelled market benefits of each QNI augmentation option forecast in each scenario need to be compared to the relevant QNI augmentation cost to determine whether there is a positive net market benefit. The determination of the preferred option is dependent on option costs and was conducted outside of this Report by TransGrid and Powerlink.[33] All references to the

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[29] The final computation of loss factors is in 2030-31 since at this time significant REZ transmission upgrade costs have been incurred as part of the least-cost generation development plan in all scenarios except the Slow change scenario. There is insufficient detail to reflect these transmission upgrades in the network snapshot to sensibly compute loss factors after this time.

[30] We use the term net present value rather than present value as there are positive and negative components of market benefits captured; however, we do not consider augmentation costs.

[31] 15 March 2019. Available at: https://www.energynetworks.com.au/rit-t-economic-assessment-handbook. Accessed 24 September 2019.

[32] AEMO, 13 September 2019, *2019 Input and Assumptions workbook, v1.2*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2019-Integrated-System-Plan. Accessed 24 September 2019.

[33] 30 September 2019. Available at: https://www.transgrid.com.au/what-we-do/projects/current-projects/ExpandingNSWQLDTransmissionTransferCapacity or https://www.powerlink.com.au/expanding-nsw-qld-transmission-transfer-capacity. Accessed 30 September 2019.

preferred option in this Report are in the sense defined in the RIT-T as "the credible option that maximises the net economic benefit across the market, compared to all other credible options." [34]

3.2 Short-term market dispatch simulation

The TSIRP model computes the least-cost generation development plan with perfect foresight based on a single pre-determined forced outage pattern. This creates the possibility that there is insufficient capacity in the optimal plan to meet the reliability standard when assessed against multiple different forced outage patterns.

We validated the generation development plan using a short-term market dispatch simulation. The short-term model takes the generation development plan computed by the long-term TSIRP model and dispatches it at SRMC with multiple Monte Carlo samples of forced outage patterns. The expected annual USE is then calculated and compared against the reliability standard. This check was done for the Neutral scenario Base case and Option 1A for sample years which coincided with assumed thermal generator retirements. No adjustments were made to the generation development plan based on these simulations.

[34] 14 December 2018, *RIT-T and RIT-D application guidelines 2018*. Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rit-t-and-rit-d-application-guidelines-2018. Accessed 26 September 2019.

4. Scenarios and sensitivity assumptions

4.1 Scenarios

The credible options have been assessed under four scenarios selected by TransGrid and Powerlink after public consultation following publication of the Project Specification Consultation Report (PSCR). These are summarised in Table 2. As noted in Table 2, most input data were sourced from AEMO's February 2019 planning and forecasting assumptions workbook which formed the initial consultation for the 2019-20 ISP.[35] This was the most up-to-date data source available at the time of modelling for this assessment.

Table 2: Overview of key input parameters that vary across scenarios[36]

Key drivers input parameter	Scenario			
	Fast change	Neutral	Neutral + low emissions	Slow change
Underlying consumption	AEMO 2018 ESOO strong[37]	AEMO 2018 ESOO neutral	AEMO 2018 ESOO neutral	AEMO 2018 ESOO weak
New entrant capital cost for wind, solar SAT, OCGT, CCGT, PSH, and large-scale batteries	AEMO Feb 2019 '2 degree' scenario. '4 degree' scenario for PSH.	AEMO Feb 2019 '4 degree' scenario.		
Retirements of coal-fired power stations	Half of stations' capacity retired 5 years earlier than Neutral. Liddell 2022 fixed	AEMO Feb 2019 announced retirement date or end-of-technical-lives, except Eraring 2031. Liddell 2022 fixed	Half of stations' capacity retired 2 years earlier than Neutral. Liddell 2022 fixed	Half of stations' capacity retired 5 years later than Neutral. Liddell 2022 fixed
Gas fuel cost	AEMO Feb 2019 Fast Change forecast	AEMO Feb 2019 Neutral forecast		AEMO Feb 2019 Slow Change forecast
Coal fuel cost	AEMO Aug 2019 Neutral forecasts[38]			AEMO Aug 2019 Slow Change forecasts
Federal Large-scale Renewable Energy Target (LRET)	33 TWh by 2020 to 2030 (including GreenPower and ACT scheme)			

[35] AEMO, 5 February 2019, *2019 Input and Assumptions workbook, v1.0*. No longer available online. Available on request from TransGrid or Powerlink.

[36] Ibid, unless otherwise stated in table.

[37] AEMO, August 2018, *2018 Electricity Statement of Opportunities*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities/2018-NEM-ESOO. Accessed 24 September 2019.

[38] AEMO, 13 September 2019, *2019 Input and Assumptions workbook, v1.2*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2019-Integrated-System-Plan. Accessed 24 September 2019.

Key drivers input parameter	Scenario			
	Fast change	Neutral	Neutral + low emissions	Slow change
COP21 commitment (Paris agreement)	52 % reduction from 2005 by 2030, then a linear extrapolation beyond 2030 to 90 % reduction of 2005 emissions by 2050	28 % reduction from 2005 by 2030, then a linear extrapolation beyond 2030 to 70 % reduction of 2016 emissions by 2050	52 % reduction from 2005 by 2030, then a linear extrapolation beyond 2030 to 90 % reduction of 2005 emissions by 2050	28 % reduction from 2005 by 2030, then a linear extrapolation beyond 2030 to 70 % reduction of 2016 emissions by 2050
Victoria Renewable Energy Target (VRET)	25 % renewable energy by 2020[39], 40 % renewable energy by 2025 and 50 % renewable energy by 2030			
Queensland Renewable Energy Target (QRET)	50 % by 2030			
South Australia Energy Transformation RIT-T	NSW to SA interconnector (Project EnergyConnect[40]) is assumed commissioned by July 2023[41] Project EnergyConnect 800 MW bi-directional Heywood 750 MW bi-directional Combined Heywood + Project EnergyConnect 1,300 MW bi-directional			
Western Victoria Renewable Integration RIT-T	The ISP 2018 preferred option is assumed commissioned by July 2023			
Marinus Link and Battery of the Nation	Assumed commissioned by July 2033 600 MW bi-directional[42]	Excluded		
Victoria to NSW Interconnector Upgrade	The preferred option is assumed commissioned by July 2020 North 870 MW, South 400 MW[42]			Excluded
Snowy 2.0, HumeLink and KerangLink	Snowy 2.0 and HumeLink will be included by July 2025 The KerangLink ISP 2018 preferred option is assumed commissioned by July 2026[43] North 2,800 MW, South 2,200 MW[42]			Excluded

[39] All successful reverse auction projects are included as listed in the AEMO February 2019 assumptions.

[40] New South Wales to South Australia interconnector referred to in this Report as Project EnergyConnect is also known as NSW-SA, NSI or Riverlink.

[41] ElectraNet, 13 February 2019. *SA Energy Transformation RIT-T: Project Assessment Conclusions Report*. Available at: https://www.electranet.com.au/projects/south-australian-energy-transformation/. Accessed 24 September 2019. There are options for commissioning between 2022 and 2024. Limits also from this document.

[42] AEMO, 5 February 2019, *2019 Input and Assumptions workbook, v1.0*, VIC-TAS Second IC - Option 1. No longer available online. Available on request from TransGrid or Powerlink.

[43] Consistent with: AEMO, July 2019, *Building power system resilience with pumped hydro energy storage – An Insights paper following the 2018 Integrated System Plan for the National Electricity Market*, p.16. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan. Accessed 24 September 2019

4.2 Sensitivities

A number of sensitivities to the market modelling have been selected by TransGrid and Powerlink which test the robustness of the gross market benefits in light of additional or updated information on input parameters. Specifically, the four sensitivities undertaken in the market modelling were:

- deferring the retirement of three of Liddell's units and bringing one unit forward, as recently announced by AGL,[44]
- the impact of line outages during the line uprating work (specific to Option 1A and Option 1B),
- the impact of assuming Wood Mackenzie's 'Fast' coal prices for the Fast change scenario,[45]
- the impact of various operating modes for New South Wales CCGTs.

4.2.1 Liddell retirement timing

In August, AGL announced that the first unit of Liddell will close in April 2022 and the remaining three units will close in April 2023 to support system reliability throughout the 2022-23 summer months.[44] This announcement came after the modelling of scenarios presented in this Report was finalised.

Previously AGL had indicated that all four units of Liddell would retire in July 2022 and this is what was assumed by TransGrid and Powerlink across the core modelling scenarios.

To assess the robustness of outcomes to this change, a sensitivity was performed across all scenarios for Option 1A.

4.2.2 Outages during line uprating

A sensitivity was performed to capture the impact on forecast gross market benefits of scheduled lines outages that are required to complete the work for an option. Line outages are only applicable to Option 1A and Option 1B which require the uprating of lines 88 (Tamworth – Muswellbrook), 84 (Tamworth – Liddell) and 83 (Muswellbrook - Liddell). To estimate the associated outage cost, constraints on the Central New South Wales to Northern New South Wales (NCEN-NNS) intra-regional link and QNI were applied in the TSIRP model during the periods line work is to be undertaken.

TransGrid and Powerlink informed EY of the following information which underpins the assumptions around deratings applied in this sensitivity:

- all line works will take a total of 14 months and will be scheduled over 2020 and 2021,
- constraints will be applied on QNI and NCEN-NNS intra-regional link for twelve hours a day, five days a week over the 14 months and outside these periods the lines will be restored back to full service,

[44] AGL, 2 August 2019, *Schedule for the closure of AGL plants in NSW and SA* [press release]. Available at: https://www.agl.com.au/about-agl/media-centre/asx-and-media-releases/2019/august/schedule-for-the-closure-of-agl-plants-in-nsw-and-sa. Accessed 24 September 2019.

[45] Wood Mackenzie, July 2019, *Coal cost projections: approach to coal cost projections*. Available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/WoodMackenzie_AEMO_Coal_cost_projections_Approach_20190711.pdf. Accessed 24 September 2019.

- no work will be scheduled during peak demand periods and there is the capability for daily recall on these line outages to minimise the risk of USE.

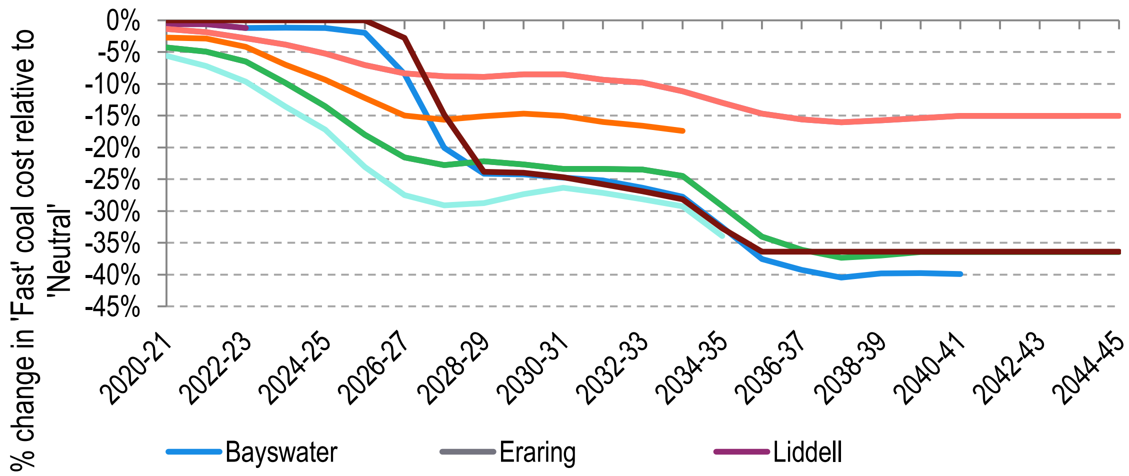
4.2.3 Coal price forecast

A sensitivity has been performed using the 'Fast' coal cost scenario from Wood Mackenzie on the Fast change scenario to assess the impact on gross market benefits for Option 1A.

Wood Mackenzie provide three coal price trajectories[46] that are to be used by AEMO in the 2019-20 ISP modelling[47]. The core scenario settings for the PADR modelling presented in this Report apply the Wood Mackenzie 'Neutral' fuel cost scenario for all scenarios except the Slow change scenario which utilises the 'Slow' coal cost price trajectory. In the September update of the assumptions to be used by AEMO for the 2019-20 ISP, the 'Fast' coal cost scenario was introduced and applied only in AEMO's 'Step change' scenario; hence, the coal price trajectories selected by TransGrid and Powerlink and applied across scenarios in this Report align with AEMO's scenario settings. Despite this, the impact of applying the 'Fast' coal cost scenario in the most appropriate scenario in this Report, the Fast change, was tested.

As shown in Figure 6 below, the 'Fast' coal cost scenario relative to the 'Neutral' cost scenario has a lower coal price outlook for Callide, Gladstone, Stanwell and all New South Wales coal-fired generators. This is reflective of the fact the 'Fast' cost scenario from Wood Mackenzie refers to the fast economic assumptions underpinning the trajectory and not the coal prices itself.

Figure 6: Percentage change in coal price forecast between Wood Mackenzie's 'Fast' and 'Neutral' coal cost scenarios



4.2.4 New South Wales CCGT operation

Gas-fired generators (and indeed all dispatchable fossil-fuelled generators) can be subject to a minimum load, or start operation on a price signal. They can also be subject to a minimum run time, where the generator operates when price exceeds its SRMC, but must operate for a specified

[46] Wood Mackenzie, July 2019, *Coal cost projections: approach to coal cost projections*. Available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/WoodMackenzie_AEMO_Coal_cost_projections_Approach_20190711.pdf. Accessed 24 September 2019.

[47] AEMO, 13 September 2019, *2019 Input and Assumptions workbook, v1.2*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2019-Integrated-System-Plan. Accessed 24 September 2019.

minimum number of hours once started. CCGTs may at times choose to operate more like an OCGT at lower efficiency.

Modelling assumptions around these operational constraints as applied to CCGTs in the NEM have varied. This is discussed further in Section 6.3.2. Since operational constraints for New South Wales CCGTs may be impactful on the forecast of gross market benefits, we performed two sensitivities to the Neutral scenario for Option 1A as described in Table 3. The minimum run time option in the TSIRP model is computationally expensive and not possible to apply across many simulations.

Table 3: Input assumptions for New South Wales CCGT operation sensitivities

Sensitivity	Neutral scenario assumption	Sensitivity assumption
Tallawarra and Smithfield minimum load	Tallawarra minimum load = 0 MW Smithfield minimum load = 0 MW	Tallawarra minimum load = 190 MW Smithfield minimum load = 30 MW
Tallawarra minimum run time	Tallawarra minimum run time = 0 hours	Tallawarra minimum run time = 6 hours

5. Transmission and demand

5.1 Regional and zonal definitions

TransGrid and Powerlink elected to split Queensland and New South Wales into sub-regions or zones in the modelling presented in this Report, as listed in Table 4. This enables better representation of intra-regional network limitations and losses through dynamic loss equations.

Table 4: Regions, zones and reference nodes

Region	Zone	Zonal Reference Node
Queensland	Central Queensland (CQ)	Ross 275 KV
	South Queensland (SQ)	South Pine 275 kV
New South Wales	Northern New South Wales (NNS)	Armidale 330 kV
	Central New South Wales (NCEN)	Sydney West 330 kV
	Canberra (CAN)	Canberra 330 kV
	South-West New South Wales (SWNSW)	Darlington Point 330 kV
Victoria	Victoria (VIC)	Thomastown 66 kV
South Australia	South Australia (SA)	Torrens Island 66 kV
Tasmania	Tasmania (TAS)	Georgetown 220 kV

The loss factors for generators (as discussed in Section 3.1.2) are computed with respect to the zonal reference node they are mapped to, which for Queensland and New South Wales are the reference nodes defined in Table 4 rather than the regional reference nodes as currently defined in the NEM.

The borders of each zone or region are defined by the cut-sets listed in Table 5. Dynamic loss equations are defined between reference nodes across these cut sets.

Table 5: Cut-sets between zones

Border	Lines
CQ-SQ	Line 819 Teebar Creek – Wurdong Line 814 Gin Gin – Calliope River Line 813 Gin Gin – Calliope River Line 8810 Halys – Calvale Line 8811 Halys - Calvale
SQ-NNS	Line 8M Dumaresq – Bulli Creek (QNI) Line 8L Dumaresq – Bulli Creek (QNI) Line 757 Terranora – Mudgeeraba (Terranora Interconnector) Line 758 Terranora – Mudgeeraba (Terranora Interconnector)
NNS-NCEN	Line 88 Muswellbrook – Tamworth Line 84 Liddell – Tamworth Line 96T Hawks Nest – Taree Line 9C8 Stroud – Brandy Hill

Border	Lines
NCEN-CAN	Line 61 Gullen Range - Bannaby Line 3W Kangaroo Valley - Capital Line 4/5 Yass - Marulan Line 973 Yass - Cowra Line 999 Yass - Cowra Line 98J Shoalhaven - Evans Lane Line 28P West Tomerong - Evans Lane New 500 kV Wagga - Bannaby (after assumed commissioning of HumeLink) New 500 kV Maragle - Bannaby (after assumed commissioning of HumeLink)
CAN-SWNSW	Line 63 Wagga - Darlington Pt Line 994 Yanco - Wagga Line 99F Yanco - Uranquinty Line 99A Finley - Uranquinty Line 997/1 Corowa - Albury New second 330 kV from Wagga - Darlington Pt (after assumed commissioning of Project EnergyConnect) New 500kV double circuit from Wagga - Darlington Pt (after assumed commissioning of KerangLink)
VIC-CAN	Line 060 Jindera - Wodonga (VNI) Line 65 Upper Tumut - Murray (VNI) Line 66 Lower Tumut - Murray (VNI)
VIC-SWNSW	Line 0X1 Red Cliffs - Buronga (VNI) New Red Cliffs - Buronga (after assumed commissioning of Project EnergyConnect) New 500 kV double circuit from Kerang - Darlington Pt (after assumed commissioning of KerangLink)
SWNSW-SA	New 330 kV double circuit from Buronga - Robertstown (after assumed commissioning of Project EnergyConnect)
VIC-SA	As defined by AEMO (Heywood + Murraylink Interconnectors).[48]
VIC-TAS	As defined by AEMO (Basslink Interconnector).

5.2 Interconnector and intra-connector loss models

Dynamic loss equations were computed where:

- a new link was defined e.g. NNS-NCEN, SA-SWNSW (Project EnergyConnect[49]),
- interconnector definitions changed with the additional of new reference nodes e.g. the Victoria to New South Wales interconnector (VNI) now spans VIC-SWNSW and VIC-CAN instead of VIC-NSW,
- future upgrades involving conductor changes were modelled e.g. KerangLink.

The network snapshots were provided by TransGrid and Powerlink to compute the loss equations. These were the same snapshots used for the estimation of generator loss factors.

[48] AEMO, June 2019, Updated Regions and Marginal Loss Factors: FY 2019-20. Available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Loss_Factors_and_Regional_Boundaries/2019/Marginal-Loss-Factors-for-the-2019-20-Financial-year.pdf. Accessed 30 September 2019.

[49] New South Wales to South Australia interconnector referred to in this Report as NSI is also known as NSW-SA, EnergyConnect or Riverlink.

5.3 Interconnector and intra-connector capabilities

The notional limits imposed on interconnectors are reflected in Table 6. The following interconnectors are included in the left-hand side of constraints which may restrict them below the notional limits specified in this table:

- Terranora is limited in the northerly and southerly directions.[50]
- Heywood + Project EnergyConnect has a combined bi-directional transfer limit of 1,300 MW. The model will dispatch them to minimise costs.
- VIC-CAN which forms part of VNI has a limit which considers the Snowy cut-set constraint.[51]

Table 6: Notional interconnector capabilities used in modelling

Interconnector (From node – To node)	Import[52] notional limit	Export[53] notional limit
QNI	More detail in Section 5.3.1	More detail in Section 5.3.1
Terranora[50] (NNS-SQ)	-180 MW	180 MW
VIC-NSW[54] (VIC-CAN)	-250 MW	550 MW (Base) 720 MW (after VNI minor upgrade)
VIC-NSW (VIC-SWNSW)	-150 MW (Base) -1,950 MW (after KerangLink)	150 MW (Base) 2,080 MW (after KerangLink)
Project EnergyConnect (SWNSW-SA)	-800 MW	800 MW
Heywood (VIC-SA)	-650 MW (before Project EnergyConnect) -750 MW (after Project EnergyConnect)	650 MW (before Project EnergyConnect) 750 MW (after Project EnergyConnect)
Murraylink (VIC-SA)	-220 MW	200 MW
Basslink (TAS-VIC)	-478 MW	478 MW

[50] Rather than use the notional limits of 50 MW (export) and -150 MW (import) as listed in the AEMO February 2019 planning and forecasting assumptions workbook, a constraint has been imposed in both the northerly and southerly direction considering the load at Terranora and ratings of limiting elements as directed by Powerlink and TransGrid. This allows Terranora interconnector to at times be clamped down below the specified notional limits in Table 6.

[51] This is an intra-regional constraint based on input from TransGrid which is imposed within the CAN zone. It limits northerly flows along VIC-CAN to be <= 2870 - Snowy generation + CAN-SWNSW flow. This constraint is no longer imposed after HumeLink is assumed to be commissioned.

[52] Import refers to power being transferred from the ‘To node’ to the ‘From node’ and follows NEM convention where the ‘From node’ is the most southerly or easterly node, and the ‘To node’ is the most northerly or westerly node. e.g. import along QNI implies southerly flow and import along Heywood implies easterly flow.

[53] Export refers to power being transferred from the ‘From node’ to the ‘To node’ and follows NEM convention where the ‘From node’ is the most southerly or easterly node, and the ‘To node’ is the most northerly or westerly node. e.g. export along QNI implies northerly flow and export along Heywood implies westerly flow.

[54] The modelling of zones within New South Wales necessitated that VIC-NSW is split across two zones on the New South Wales side of the border. The VIC-NSW transfer path is a combination of VIC-SWNSW and VIC-CAN and have their limits proportioned based on input from TransGrid.

Interconnector (From node – To node)	Import[52] notional limit	Export[53] notional limit
Marinus Link[55] (TAS-VIC)	-600 MW	600 MW

Queensland and New South Wales have been broken down into zones as outlined in Section 5.1 with the following limits imposed between the zones defined in Table 7.

Table 7: Intra-connector notional limits imposed in modelling for Queensland and New South Wales

Intra-connector (From node – To node)	Import notional limit	Export notional limit
SQ-CQ	-2,100 MW (Base) -2,300 MW (after Option 5B)[56]	N/A
NCEN-NNS	-1,000 MW (Base) -1,177 MW (after Option 1A / Option 1B)	1,200 MW (Base) 1,377 MW (after Option 1A / Option 1B)
CAN-NCEN	-2,700 MW (Base) -5,000 MW (after HumeLink)	2,700 MW (Base) 5,000 MW (after HumeLInk)
CAN-SWNSW	-700 MW (before Project EnergyConnect) -1,400 MW (after Project EnergyConnect, before KerangLink) -3,000 MW (after KerangLink)	700 MW (before Project EnergyConnect) 1,400 MW (after Project EnergyConnect, before KerangLink) 3,000 MW (after KerangLink)

5.3.1 QNI capabilities

For QNI which is defined between the NNS and SQ node, more detailed thermal and stability constraints are imposed to capture seasonal and time-of-day thermal ratings, stability limitations based on generation level of relevant generators, and demand variations. Further details and a summary of the detailed power system studies performed by TransGrid and Powerlink to inform the stability and thermal limits used in our market modelling can be found in Appendix D of the PADR.[57]

5.4 Demand

The TSIRP model captures peak period diversity across regions by basing the overall shape of hourly demand on eight historical years ranging from 2010-11 to 2017-18.

Specifically, the key steps in creating the hourly demand forecast are as follows:

- the historical underlying demand has been calculated as the sum of historical metered demand and the estimated rooftop PV generation based on historical rooftop PV capacity and solar insolation,
- the eight-year hourly pattern has been projected forward to meet future forecast annual peak demand and energy in each region (scenario-dependent),

[55] Proposed interconnector for a second DC interconnector between Tasmania and Victoria. With Marinus Link still undergoing the RIT-T process, TransGrid and Powerlink have assumed Option 1 from the AEMO February 2019 planning and forecasting assumptions workbook as the preferred option for the Fast change scenario.
[56] To maximise gross market benefits, TransGrid and Powerlink have assumed for Option 5B that the northern battery will be located at Calvale to also extend the CQ-SQ stability limit.
[57] TransGrid and Powerlink, 30 September 2019. Available at: https://www.transgrid.com.au/what-we-do/projects/current-projects/ExpandingNSWQLDTransmissionTransferCapacity or https://www.powerlink.com.au/expanding-nsw-qld-transmission-transfer-capacity. Accessed 30 September 2019.

- the eight reference years are repeated sequentially throughout the modelling horizon as shown in Figure 7,
- the future hourly rooftop PV generation has been estimated based on insolation in the corresponding reference year and the projection of future rooftop PV capacity, which is subtracted from the forecast underlying demand along with other behind-the-meter components (e.g., electric vehicles and domestic storage) to get a projection of hourly operational demand.

TransGrid and Powerlink selected demand forecasts from the AEMO 2018 ESOO[58] in all scenarios (see Section 4.1).

This method ensures the timing of peak demand across regions reflects historical patterns, while accounting for projected changes in rooftop PV generation and other behind-the-meter loads and generators that may alter the size of peaks and diversity of timing of peaks across regions. Overall, due to rooftop PV uptake, we generally see the peak operational demand intervals shifting later in the day throughout the forecast.

The reference year pattern is also consistent with site-specific hourly wind and solar availability (see Section 6.1). This maintains correlations between weather patterns, demand, wind, large-scale solar and rooftop PV availability.

The AEMO 2018 ESOO demand forecasts that were used as inputs to the modelling were provided on a regional level and were split into the various zones that have been defined for New South Wales and Queensland, as described in Section 5.1. TransGrid and Powerlink obtained from AEMO half-hourly scaling factors to convert regional load to connection point loads which were used to split the regional demand into the zones. Doing so captures the diversity of demand profiles between the different zones in New South Wales and Queensland.

[58] AEMO, August 2018, *2018 Electricity Statement of Opportunities*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities/2018-NEM-ESOO. Accessed 24 September 2019.

6. Supply

6.1 Wind and solar energy projects and REZ representation

Several generators not yet built were committed in all simulations, both Base case and with each QNI augmentation option. The source of this list varied with region:

- In South Australia, AEMO Generation Information May 2019[59], Committed and Com* status.
- In Victoria, AEMO Generation Information May 2019, Committed and Com* status. This includes all the successful projects for the Victorian Renewable Energy Auction Scheme.
- In Tasmania, AEMO Generation Information May 2019, Committed and Com* status.
- In Queensland, AEMO Generation Information 18 July 2019, Committed and Com* status and several additional generators anticipated by Powerlink based on the maturity of the connection applications as listed in Table 8. These projects are anonymised in our modelling.
- In New South Wales, AEMO Generation Information 18 July 2019, Committed and Com* status and several additional generators anticipated by TransGrid based on the maturity of the connection applications as listed in Table 8. These projects are anonymised in our modelling.

Table 8: Capacity anticipated by TransGrid and Powerlink in addition to AEMO information

Region	Zone	Solar capacity (MW)	Wind capacity (MW)
Queensland	CQ	1,333	1,010
	SQ	523.5	0
NSW	NNS	320	0
	NCEN	640	0
	CAN	50	331
	SWNSW	40	0

Existing and new wind and solar projects are modelled based on eight years of historical weather data. The methodology for each category of wind and solar project is summarised in Table 9 and explained further in this section of the Report.

Table 9: Summary of wind and solar availability methodology

Technology	Category	Capacity factor methodology	Reference year treatment
Wind	Existing	Specify long-term target based on eight-year average in AEMO ESOO 2018 traces[60] where available, otherwise past meteorological performance	Capacity factor varied with reference year based on site-specific, historical, near-term wind speed forecasts.

[59] AEMO, *Generation Information Page*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information. Accessed 24 September 2019

[60] AEMO, 2018, *2018 Electricity Statement of Opportunities: 2018 REZ Wind Traces* and *2018 REZ Solar Traces*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities/2018-NEM-ESOO. Accessed 23 September 2019.

Technology	Category	Capacity factor methodology	Reference year treatment
	Committed new entrant	Specify long-term target based on average of AEMO ESOO 2018 traces (seven years) of nearest REZ, medium quality tranche.	
	Generic REZ new entrants	Specify long-term target based on average of AEMO ESOO 2018 traces (seven years). One high quality option and one medium quality trace per REZ.	
Solar PV FFP	Existing	Annual capacity factor based on technology and site-specific solar insolation measurements.	Capacity factor varied with reference year based on historical, site-specific insolation measurements.
Solar PV SAT	Existing		
	Committed new entrant		
	Generic REZ new entrant		
Rooftop PV and small non-scheduled solar PV	Existing and new entrant	Long-term average capacity factor based on past meteorological performance.	Capacity factor varied with reference year based on historical insolation measurements.

All existing and committed large scale wind and solar farms in the NEM were modelled on an individual basis i.e. each project has a location-specific availability trace based on historical resource availability. The availability traces are derived using eight years of historical weather data covering financial years between 2010-11 and 2017-18 (inclusive), consistent with the hourly shape of demand.[61] Wind and solar availability traces used in the modelling reflect generation patterns occurring in the eight historical years, and these generation patterns are repeated throughout the study period as shown in Figure 7.

Figure 7: Sequence of wind, solar and demand reference years applied to forecast

Modelled year	Reference year
2020-21	2011-12
2021-22	2012-13
2022-23	2013-14
2023-24	2014-15
2024-25	2015-16
2025-26	2016-17
2026-27	2017-18
2027-28	2010-11
2028-29	2011-12
2029-30	2012-13
2030-31	2013-14
2031-32	2014-15

[61] Bureau of Meteorology weather data prior to 2010-11 is from a different source and is inferior in quality.

Modelled year	Reference year
2032-33	2015-16
2033-34	2016-17
2034-35	2017-18
...	...
2040-41	2015-16
2041-42	2016-17
2042-43	2017-18
2043-44	2010-11
2044-45	2011-12

The availability traces for wind are derived using the methodology of EY's electricity market modelling team, which uses simulated wind speeds and directions from the Australian Bureau of Meteorology's Numerical Weather Prediction systems[62] at a representative hub height. Wind speeds are converted into power using a generic wind farm power curve. The traces are scaled to achieve the average target capacity factor across the eight historical years. The traces reflect inter-annual variations, but at the same time achieve long-term capacity factors in line with historical performance (existing wind farms) or the values for each REZ used in the AEMO 2018 ESOO and 2018 ISP[63] for each REZ (new entrant wind farms, as listed in Table 10).

Table 10: REZ wind and solar target average capacity factors over eight reference years

Region	REZ	Wind		Solar SAT
		High quality	Medium quality	
Queensland	North Queensland Clean Energy Hub	48 %	38 %	31 %
	Northern Queensland	Tech not available	Tech not available	29 %
	Isaac	46 %	34 %	30 %
	Barcaldine	42 %	35 %	32 %
	Fitzroy	45 %	35 %	30 %
	Darling Downs	45 %	38 %	30 %
New South Wales	North West New South Wales	27 %	25 %	30 %
	New England	38 %	38 %	29 %
	Central West New South Wales	33 %	30 %	30 %
	Southern New South Wales Tablelands	42 %	41 %	26 %
	Broken Hill	36 %	32 %	31 %

62 As described by Australian Government Bureau of Meteorology, *ACCESS NWP Data* Information. Available at: http://www.bom.gov.au/nwp/doc/access/NWPData.shtml. Accessed 8 November 2018.

63 AEMO, 2018, *2018 Electricity Statement of Opportunities: 2018 REZ Wind Traces* and *2018 REZ Solar Traces*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities/2018-NEM-ESOO. Accessed 23 September 2019.

Region	REZ	Wind		Solar SAT
		High quality	Medium quality	
	Murray River (NSW)	31 %	30 %	29 %
	Riverland (NSW)	30 %	30 %	29 %
Victoria	Murray River (VIC)	31 %	30 %	29 %
	Western Victoria	Tech not available	34 %	Tech not available
	Moyne	Tech not available	37 %	Tech not available
	Gippsland	30 %	31 %	Tech not available
South Australia	South East South Australia	38 %	36 %	Tech not available
	Riverland (SA)	30 %	30 %	28 %
	Mid-North South Australia	37 %	37 %	Tech not available
	Yorke Peninsula	37 %	34 %	Tech not available
	Northern South Australia	Tech not available	Tech not available	30 %
	Leigh Creek	41 %	40 %	32 %
	Roxby Downs	Tech not available	Tech not available	31 %
	Eastern Eyre Peninsula	37 %	36 %	28 %
	Western Eyre Peninsula	36 %	32 %	29 %
Tasmania	North West Tasmania	48 %	43 %	Tech not available
	Tasmania Midlands	51 %	44 %	Tech not available
	North East Tasmania	44 %	43 %	Tech not available

The availability traces for solar are derived using solar irradiation data derived from satellite imagery processed by the Australian Bureau of Meteorology. Similarly to wind traces, the solar traces reflect inter-annual variations over eight historical years, but at the same time achieve long-term capacity factors in line with historical performance (existing solar farms) or close to[64] AEMO expectations for each REZ (generic new entrant solar farms[65], as listed in Table 10).

Wind and solar capacity expansion in each REZ was limited by three parameters based on the AEMO February 2019 planning and forecasting assumptions workbook.[66]

- Transmission-limited total build limit (MW) representing the amount of capacity supported by current intra-regional transmission infrastructure.
- A transmission expansion cost ($/MW) representing an indicative linear network expansion cost to develop a REZ beyond current capabilities and connect the REZ to the nearest major load centre.

[64] For solar farms, we could not efficiently produce availability traces that achieved exactly AEMO's long-term capacity factor. The traces derived by EY are up to 3 % higher than the AEMO ESOO 2018 solar traces, depending on REZ.

[65] AEMO, 2018, *2018 Electricity Statement of Opportunities: 2018 REZ Wind Traces* and *2018 REZ Solar Traces*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities/2018-NEM-ESOO. Accessed 23 September 2019.

[66] AEMO, 5 February 2019, *2019 Input and Assumptions workbook, v1.0*. No longer available online. Available on request from TransGrid or Powerlink.

- Resource limits (MW) representing the maximum amount of capacity expected to be feasibly developed in a REZ based on topography, land use etc. TransGrid and Powerlink elected to double the resource limits in the February 2019 assumptions workbook for the purpose of this modelling on the expectation that higher resource limits were to be applied in the 2019-20 ISP.

The TSIRP model will incur the additional transmission expansion cost to build more capacity up to the resource limit if it is part of the least-cost development plan.

6.2 Forced outage rates and maintenance

Forced outage rates for coal generators were based on EY analysis of historical performance. The AEMO 2018 ESOO[67] provided the forced outage rates for the coal generators as a regional aggregate. EY's analysis instead gives generator-specific full forced outage rates. TransGrid and Powerlink elected to deviate from the 2018 ESOO full forced outage rates for coal generators to capture more granular observations of the apparent availability of the existing coal fleet. Table 11 below summarises the full forced outage rates outlined in the 2018 ESOO along with the rate applied in modelling presented in this Report. Partial outage rates used in the modelling were the same as the 2018 ESOO.

Table 11: Coal-fired power station full forced outage rates

Generator	AEMO 2018 ESOO full forced outage rate[67]	Full forced outage rate applied in modelling in this Report
Bayswater	6.56 % (until 2022) 3.88 % (after 2022)	5.11 %
Callide B	2.42 %	8.58 %
Callide C	2.42 %	5.24 %
Eraring	6.56 % (until 2022) 3.88 % (after 2022)	8.83 %
Gladstone	2.42 %	16.49 %
Kogan Creek	2.42 %	5.02 %
Liddell	6.56 %	24.93 %
Loy Yang A	5.34 %	3.71 %
Loy Yang B	5.34 %	0.86 %
Mount Piper	6.56 % (until 2022) 3.88 % (after 2022)	10.78 %
Millmerran	2.42 %	3.40 %
Stanwell	2.42 %	0.59 %
Tarong	2.42 %	4.39 %
Tarong North	2.42 %	7.60 %

[67] AEMO, August 2018, *2018 Electricity Statement of Opportunities*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities/2018-NEM-ESOO. Accessed 24 September 2019.

Generator	AEMO 2018 ESOO full forced outage rate[67]	Full forced outage rate applied in modelling in this Report
Vales Point	6.56 % (until 2022) 3.88 % (after 2022)	7.53 %
Yallourn	5.34 %	11.20 %

To calculate coal generator-specific forced outage rates, we counted zeros in historical dispatch from 2013-14 to 2018-19 based on AEMO's market data database.[68] This records dispatch level at the start of each half-hourly trading interval for each DUID[69]. This was divided by the number of half-hours of historical records to give a total full unavailability rate reflecting historical planned and unplanned outages.[70] Station average outage rates were computed as the average across units in each station. The planned maintenance rate of 20 days per unit[71] was then subtracted to estimate full forced outage rates for each station.[72]

All unplanned forced outage patterns are set by a random number generator for each existing generator. The seed for the random number generator is set such that the same forced outage pattern exists between the Base case and the various interconnector upgrade options. New entrant generators are de-rated by their equivalent forced outage rate as defined in the AEMO February 2019 planning and forecasting assumptions workbook.[73]

Planned maintenance events for existing generators are scheduled during low demand periods and the number of days required for maintenance is set based on the AEMO February 2019 planning and forecasting assumptions workbook.[73]

6.3 Generator technical parameters

In general, all technical parameters are as detailed in the AEMO February 2019 planning and forecasting assumptions workbook[73], except where noted in this section.

6.3.1 Coal-fired generators

Coal-fired generation is treated as dispatchable between its minimum load and its maximum load. Must run generation is dispatched whenever available at least at its minimum load. In line with the AEMO February 2019 assumptions workbook[73], maximum loads vary seasonally. This materially reduces the amount of available capacity in the summer periods.

An assumed energy limit was placed on coal-fired power stations approximately equal to the maximum annual energy generated between 2013-14 and 2017-18 to reflect limitations on annual

[68] Market Data NEMWEB, Daily trading interval data, INITIALMW. Available at: http://nemweb.com.au/Reports/CURRENT/Daily_Reports/. Accessed 12 July 2019.

[69] Dispatchable Unit Identifier. For coal generators each DUID corresponds to a single genset.

[70] Two stations had prolonged outages on units which caused data anomalies and excluded from the analysis. One unit of Callide B, CALL_B_1, experienced a prolonged outage in 2014 due to fuel supply issues; data for this this unit before 27 November 2014 has been excluded. The Tarong outage rate was based on only units 1 and 3 since units 2 and 4 (TARONG#2, TARONG#4) were mothballed within the analysis period.

[71] AEMO, 5 February 2019, *2019 Input and Assumptions workbook, v1.0*. No longer available online. Available on request from TransGrid or Powerlink.

[72] Loy Yang A and Stanwell had lower annual unavailability than what is assigned to maintenance giving a negative forced outage rate after maintenance was subtracted from unavailability. For these stations, we assumed maintenance wouldn't be scheduled over the summer period and hence computed the outage rates using only data from December, January and February.

[73] AEMO, 5 February 2019, *2019 Input and Assumptions workbook, v1.0*. No longer available online. Available on request from TransGrid or Powerlink.

coal deliveries. Prior to its retirement the Liddell power station annual capacity factor was limited to 50 % in accordance with the AEMO February 2019 assumptions workbook.[74]

6.3.2 Gas-fired generators

Gas-fired CCGT plant also typically have a must-run component and so are dispatched at or above their minimum load. Minimum loads were applied to several gas generators as listed in Table 12. These assumptions were generally in line with the AEMO February 2019 planning and forecasting assumptions workbook.[74]

Table 12: Minimum loads applied to gas-fired power stations

Generator	Value in AEMO February 2019 assumptions (MW)	Value applied in this Report (MW)
Condamine	60	60
Darling Downs	109	109
Yarwun	120	120
Tallawarra	190	0
Swanbank E	0	120
Yabulu	0	141

The AEMO February 2019 assumptions listed a minimum load for Tallawarra and no minimum loads for Swanbank E and Yabulu. Historically Tallawarra and Swanbank E tend to operate with a minimum load when they are available, but have large periods of time when they were withdrawn from the market, presumably related to expected seasonal demand, gas contracting or portfolio management. In the TSIRP model, applying a minimum load gives dispatch outcomes with a capacity factor much higher than observed historically. Conversely, not applying a minimum load gives dispatch outcomes with a capacity factor much lower than observed historically.

Ultimately, weighing up the approximations made in the model, Powerlink chose to depart from AEMO's assumed zero minimum load for Swanbank E and Yabulu. The updated AEMO assumptions[75] released since making this decision now list minimum loads for these two stations.

Meanwhile, TransGrid elected not to apply a minimum load to Tallawarra or Smithfield in the core scenarios. The updated AEMO assumptions[75] released since making this decision still lists a minimum load for Tallawarra and adds a minimum load for Smithfield. Since reducing the output of Tallawarra may provide more favourable conditions for a QNI upgrade, application of minimum loads to Tallawarra and Smithfield and a minimum run time to Tallawarra were investigated as sensitivities (see Section 4.2.4). The minimum run time option in the TSIRP model is computationally expensive and not possible to apply across all simulations under the required timeframes.

TransGrid and Powerlink assumed a minimum load of 50 % for all new CCGTs to reflect minimum load conditions for assumed efficient use of gas and steam turbines in CCGT operating mode.

OCGTs operate with no minimum load level and so start and are dispatched when the cost of supply is at or above their SRMC.

[74] AEMO, 5 February 2019, *2019 Input and Assumptions workbook, v1.0*. No longer available online. Available on request from TransGrid or Powerlink.

[75] AEMO, 13 September 2019, *2019 Input and Assumptions workbook, v1.2*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2019-Integrated-System-Plan. Accessed 24 September 2019.

6.3.3 Wind, solar and run-of-river hydro generators

Intermittent renewables, in particular solar PV, wind and run-of-river hydro are dispatched according to their resource availability as they cannot store energy. Intermittent renewable production levels are based on eight years of hourly measurements and weather observations across the NEM including all REZ zones. Using historical reference years preserves correlations in weather patterns, resource availability and demand. Modelling of wind and solar PV is covered in more detail in Section 6.1.

Solar PV and wind generation are dispatched at their available resource limit unless curtailed economically, when the cost of supply falls to less than their VOM, or by other constraints such as transmission limits.

6.3.4 Storage-limited generators

Conventional hydro with storages, PSH and batteries are dispatched in each trading interval such that they are most effective in reducing the costs of generation up to the limits of their storage capacity.

Hourly hydro inflows to the reservoirs and ponds were computed from monthly values sourced from the AEMO 2018 Integrated System Plan assumptions workbook[76] due to this information not being included in the more recent February 2019 planning and forecasting assumptions workbook[77]. The Tasmanian hydro schemes were modelled using a simplified six pond model.

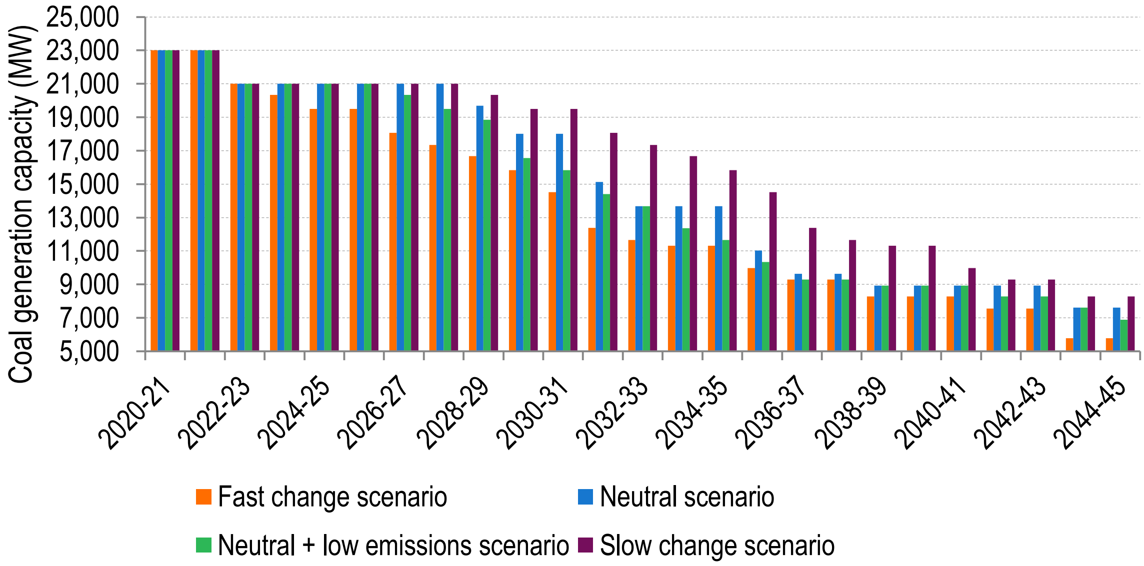
6.4 Retirements

According to the scenario settings selected by TransGrid and Powerlink after public consultation following publication of the PSCR, thermal retirements in the model are fixed. Retirement dates for the Neutral scenario were sourced from AEMO's February 2019 planning and forecasting assumptions workbook based on announced retirements and end-of-technical life at that time.[77] Other scenarios were varied from these dates as noted in Table 2. Coal retirements across scenarios is illustrated in Figure 8.

[76] AEMO, 21 August 2018, *2018 Integrated System Plan Modelling Assumptions v2.4*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2018-Integrated-System-Plan. Accessed 30 September 2019.

[77] AEMO, 5 February 2019, *2019 Input and Assumptions workbook, v1.0*. No longer available online. Available on request from TransGrid or Powerlink.

Figure 8: Coal capacity across NEM by year across all scenarios



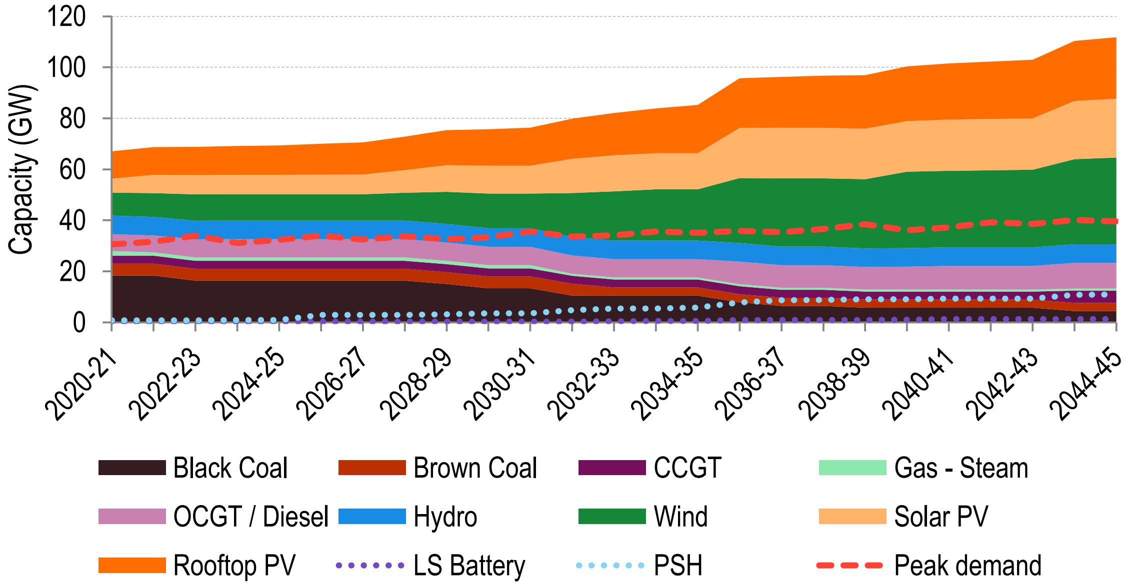
7. NEM outlook across scenarios without upgrade to QNI transfer capacity

Before considering the benefits of increasing the transfer capacity between New South Wales and Queensland under the augmentation options, it is useful to understand the differences between the generation and capacity forecast outlooks in each of the scenarios.

7.1 Neutral scenario without increase to QNI transfer capacity

The NEM-wide capacity mix forecast in the Neutral scenario without any increase to QNI transfer capacity is shown in Figure 9. Without any upgrade to QNI, the forecast generation capacity of the NEM gradually shifts towards increasing capacity of wind, solar, gas generation and storage, both PSH and large-scale battery storage.

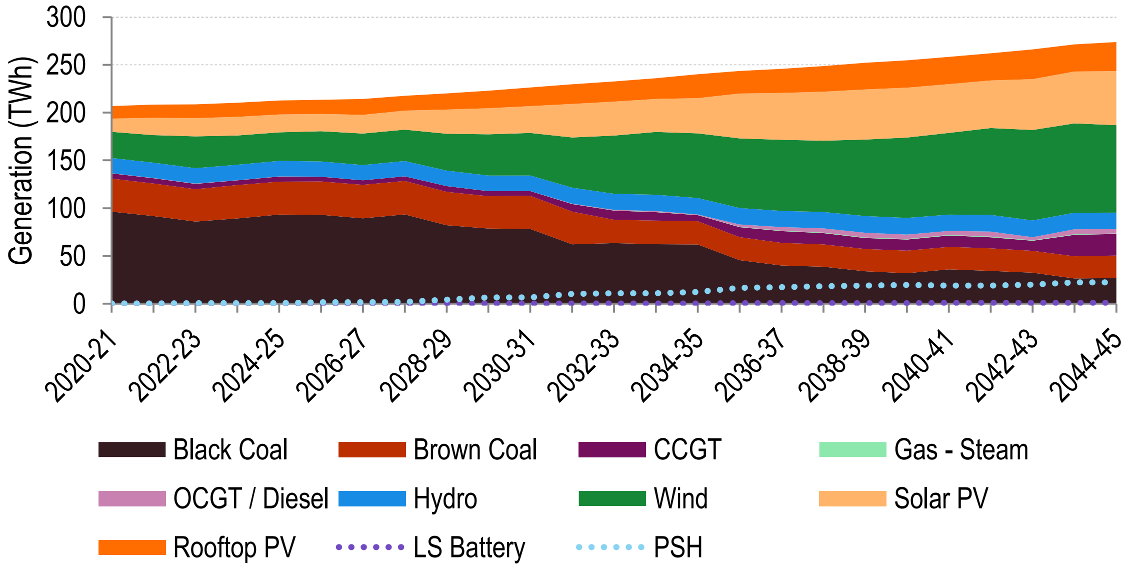
Figure 9: NEM capacity mix forecast for Neutral scenario without QNI upgrade



The first new capacity installed by the model as part of the least-cost development plan to meet demand is 513 MW of new OCGT capacity in NCEN in 2022-23 when Liddell is assumed to retire.

The energy supplied to the grid, as shown in Figure 10, gradually increases throughout the modelling period due to the modest demand growth of the AEMO 2018 ESOO Neutral demand assumed in this scenario. The concurrent forecast growth in installed capacity shown in Figure 9 is much faster, due to the relatively lower annual assumed capacity factors available from wind and solar generation compared with the coal-fired generation that is assumed to retire at fixed dates. However, the assumed cost of developing storage, solar and wind resources trends below that of a gas plant, so the forecast mix of generation favours solar, wind and storage over OCGT and CCGT gas-fired plant, except as needed to meet the need for dispatchable peaking generation when solar and wind are not available and furthermore to maintain reserve requirements within each region. The balance of OCGT and CCGT capacity is influenced by the imposition of a 50 % minimum load on new CCGTs and no minimum load requirement on new OCGTs.

Figure 10: NEM generation mix forecast for Neutral scenario without QNI upgrade



Without an upgrade to QNI under the Neutral scenario, the forecast overall energy production in the NEM, as shown in Figure 10, is an outcome of several factors in the input assumptions including but not limited to:

- modest demand growth,
- retirements of major coal and gas generators due to age,
- the declining cost of renewable generation relative to the cost of fossil generation.

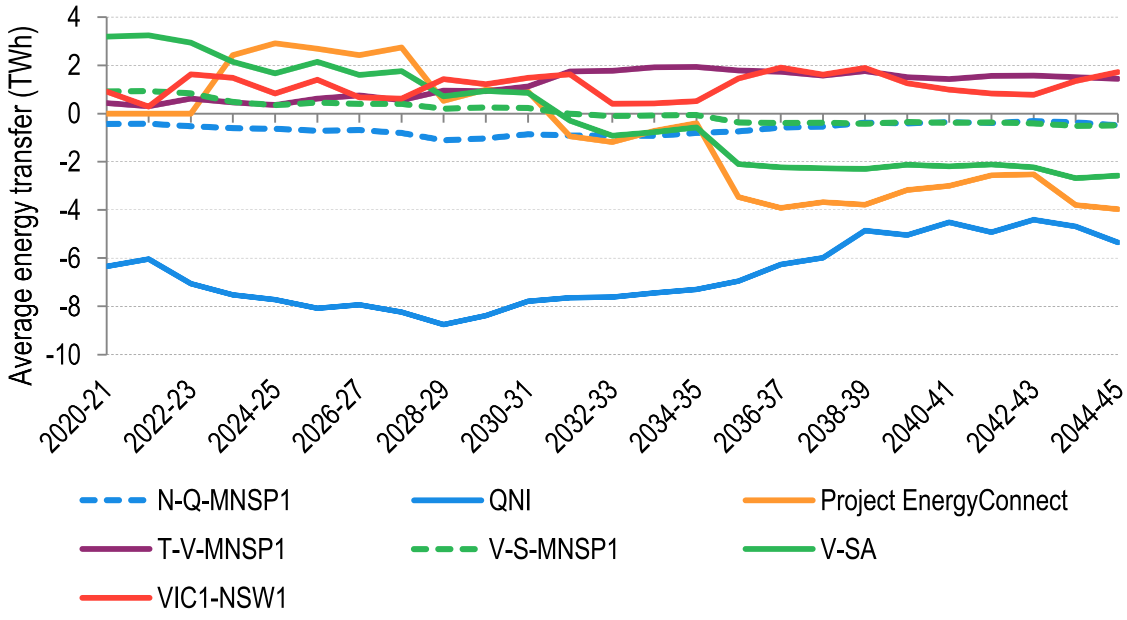
The forecast average net energy transfers by year across all existing and assumed committed interconnectors is shown in Figure 11 for the Neutral scenario without any upgrade to QNI. This shows that some interconnectors are forecast to transfer more energy between regions than others and the following key changes can be observed in the transfers:

- QNI flows are southerly due to the 5.2 GW of assumed committed[78] wind and solar projects in Queensland by 2022-23. Transfers are forecast to increase from Queensland towards New South Wales until the peak southerly energy flow in 2028-29 when Vales Point is assumed to retire in the Neutral scenario. From 2028-29 onwards, there are several assumed age-based retirements of coal generators in Queensland that slightly reduce the southerly energy transfer forecast across QNI.
- Transfers from Victoria towards New South Wales are forecast to tend to increase over the VIC-NSW interconnector until 2030-31 primarily due to the assumed KerangLink[79] interconnector upgrade and retirement of coal-fired generation in Queensland and New South Wales. Northerly energy transfers across VIC-NSW are expected to reduce in 2032-33 when Yallourn is assumed to retire.

[78] Committed projects refers to the project list based on AEMO data as well as the anticipated projects provided by TransGrid and Powerlink (see Section 6.1).

[79] KerangLink is assumed to be commissioned by July 2026 and is assumed to increase the VIC-NSW transfer capability to 2,800 MW North, and 2,200 MW South.

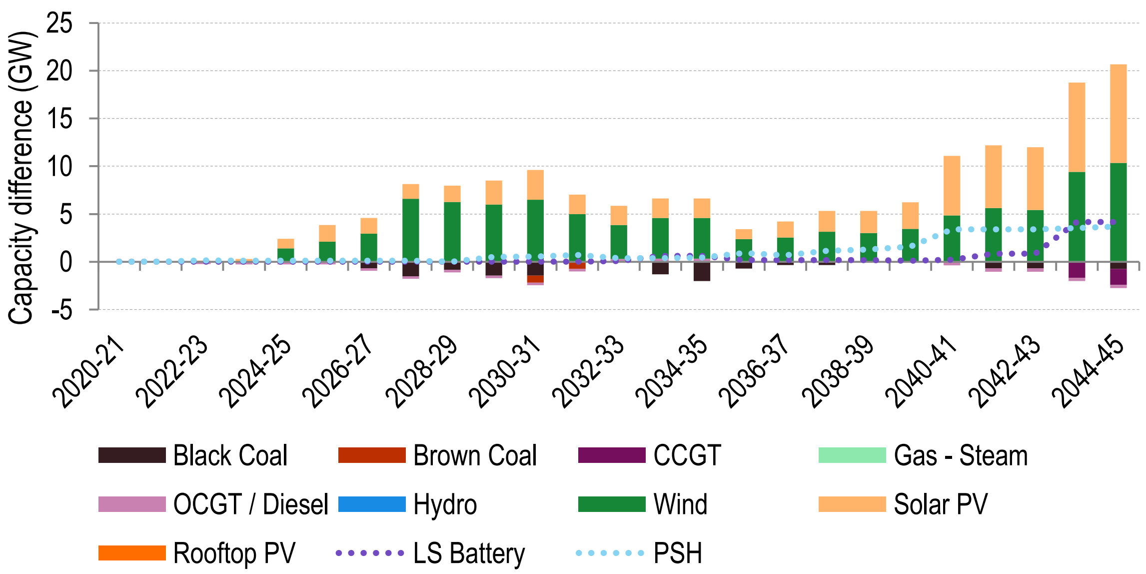
Figure 11: Average annual interconnector energy transfer forecast for Neutral scenario without QNI upgrade



7.2 Neutral + low emissions scenario without increase to QNI transfer capacity

The change in the NEM-wide capacity mix forecast between the Neutral + low emissions scenario and the Neutral scenario without any increase to QNI transfer capacity is shown in Figure 12. The forecast increase in installed wind, solar PV, PSH and large-scale battery storage capacity in the Neutral + low emissions scenario relative to the Neutral scenario is primarily driven by the assumption that half of the coal-fired power stations retire two years earlier and the application of a stronger emissions reduction target.

Figure 12: Difference in NEM capacity forecast between Neutral + low emissions scenario and Neutral scenario without QNI upgrade



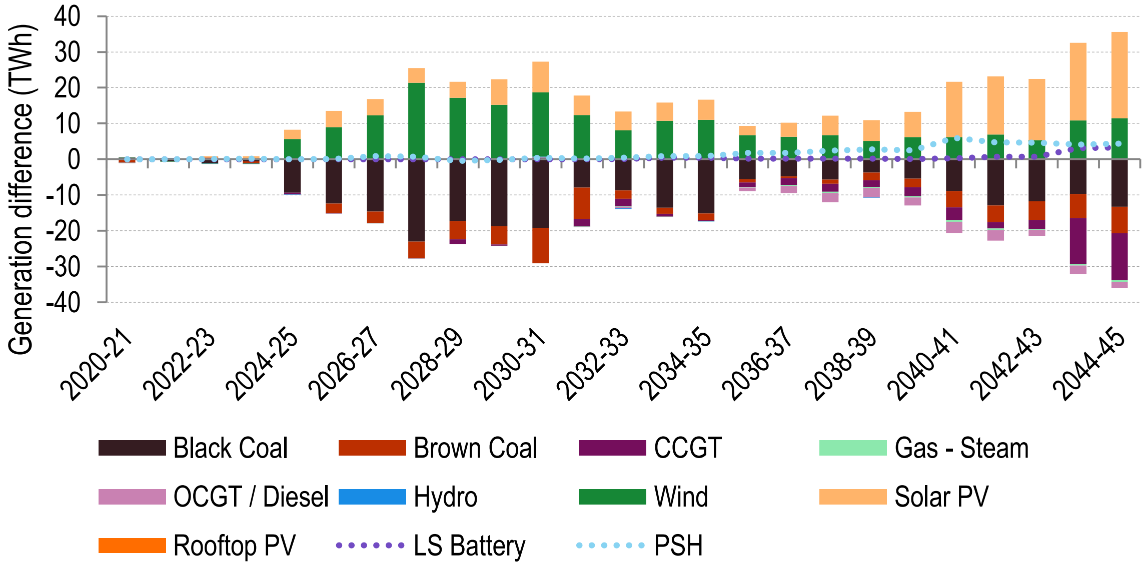
The first new capacity installed by the model as part of the least-cost development plan to meet demand is in 2022-23 when Liddell is assumed to retire. The new capacity is 282 MW of OCGT capacity, 133 MW of solar PV capacity and 140 MW of PSH capacity in NCEN.

The difference in forecast generation between the Neutral + low emissions scenario relative to the Neutral scenario without an upgrade to QNI, as shown in Figure 13, is an outcome of several input assumptions including but not limited to:

- A stronger emissions target requiring a 52 % reduction from 2005 levels by 2030 and a 90 % reduction by 2050. In the model, this constraint begins binding in 2024-25 in this scenario which results in a forecast reduction in output from existing coal-fired generators, which is forecast to be replaced by new entrant wind and solar.

- The 50 % minimum load requirement imposed on CCGTs combined with the assumed stronger emissions reduction constraint results in less CCGT generation forecast for the later years. With reduced expected gas generation, there is increased generation expected from batteries and PSH.

Figure 13: Difference in NEM generation forecast between Neutral + low emissions scenario and Neutral scenario without QNI upgrade

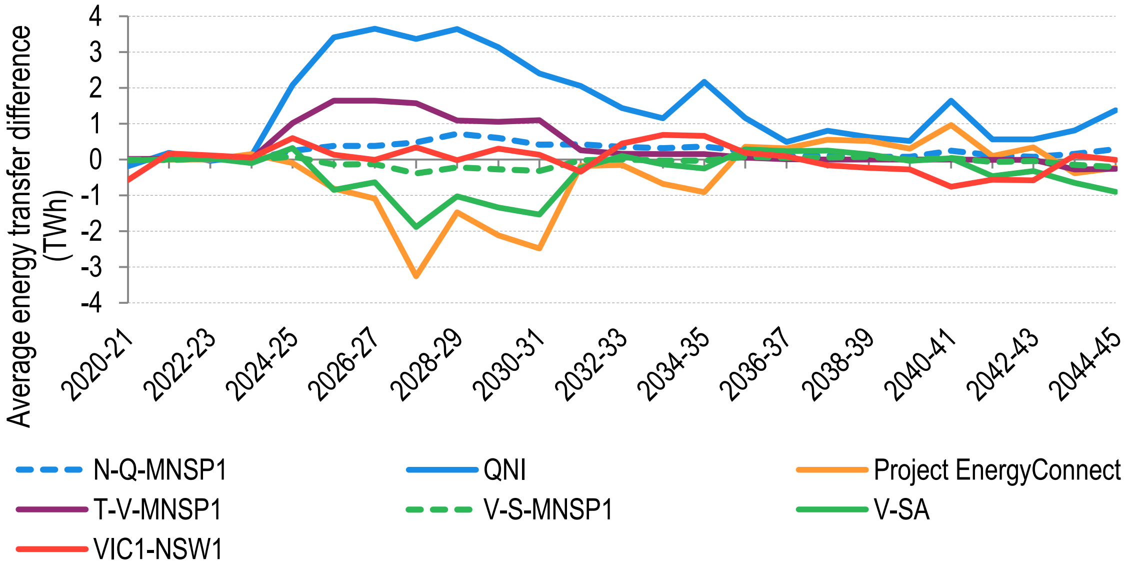


The forecast difference between the Neutral + low emissions scenario and the Neutral scenario for the average net energy transfers across all existing and assumed committed interconnectors is shown below in Figure 14. Changes to forecast energy transfers across interconnectors between the two scenarios are driven by the following:

- Reduced expected southerly flow on QNI from 2024-25 which is driven by the higher proportion of new entrant wind and solar forecast to come into New South Wales over Queensland to satisfy the assumed stronger emissions constraint.

- Higher expected exports from South Australia along Heywood and Project EnergyConnect as a result of forecast increased wind and solar capacity in South Australia.

Figure 14: Difference in forecast average annual interconnector energy transfer between Neutral + low emissions scenario and Neutral scenario without QNI upgrade

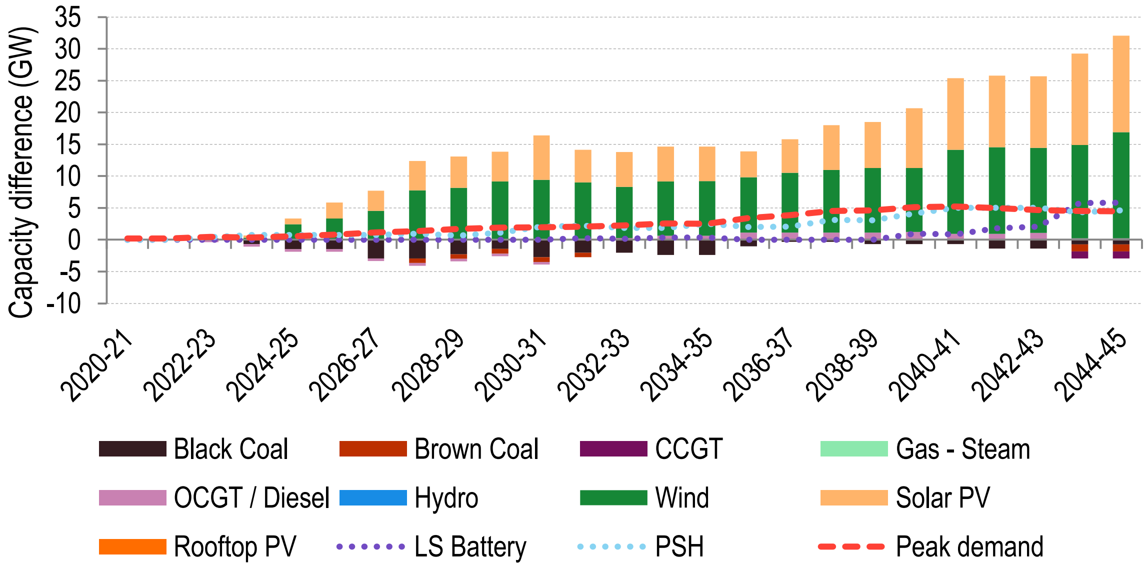


7.3 Fast change scenario without increase to QNI transfer capacity

The forecast change in the NEM-wide capacity mix between the Fast change scenario and the Neutral scenario without any increase to QNI transfer capacity is shown in Figure 15. Key drivers for the forecast increase in installed capacity in the Fast change scenario relative to the Neutral are the following input assumptions:

- the 2018 ESOO Fast Change demand scenario which has higher demand growth relative to the Neutral demand scenario,
- retiring half of the coal power stations capacity five years earlier than the assumed end of technical life,
- a stronger emission reduction constraint leading to less installed gas capacity forecast in the later years.

Figure 15: Difference in NEM capacity forecast between Fast change scenario and Neutral scenario without QNI upgrade

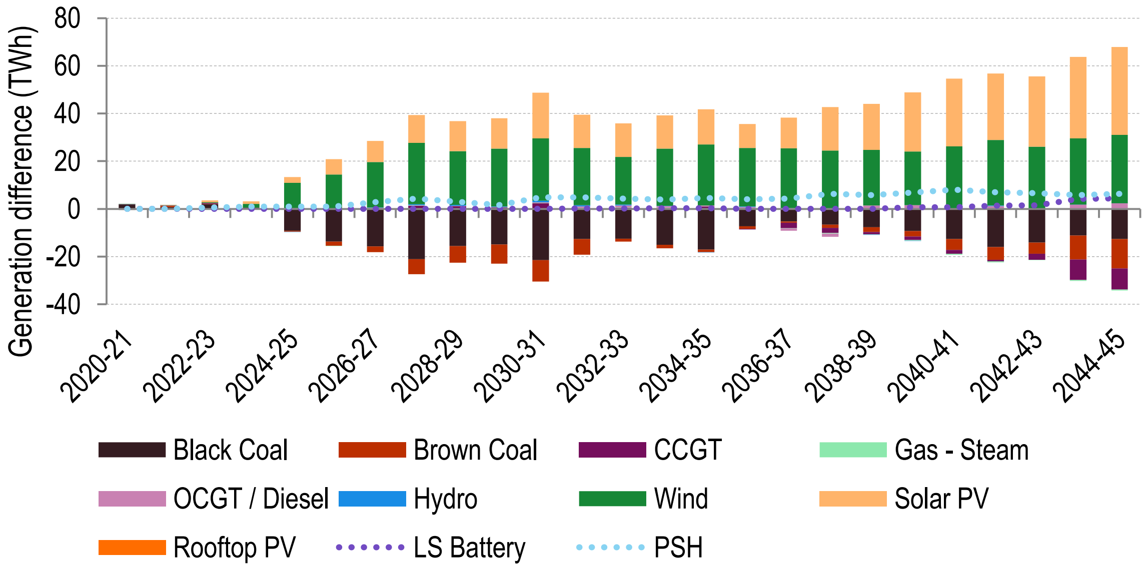


The assumed high load growth means new OCGT capacity is forecast to be built in New South Wales before Liddell retires. In 2020-21, 34 MW of OCGT is forecast to be built and a further 104 MW in 2021-22. By 2022-23 when Liddell is assumed to retire, the model forecasts 142 MW of new OCGT capacity, 297 MW of new solar PV capacity and 403 MW of new PSH capacity in NCEN.

The forecast difference in generation between the Fast change scenario relative to the Neutral scenario without an upgrade to QNI, as shown in Figure 16, is an outcome of several factors including but not limited to:

- A stronger emissions target requiring a 52 % reduction from 2005 levels by 2030 and a 90 % reduction from 2016 levels by 2050. Given the higher demand growth in this scenario, the emissions constraint is forecast to begin binding as early as 2023-24 leading to early build of wind, mainly in Tasmania.
- In 2024-25, which is a year following the assumed retirement of half the capacity of Vales Point, a large build of wind capacity in New South Wales is forecast.

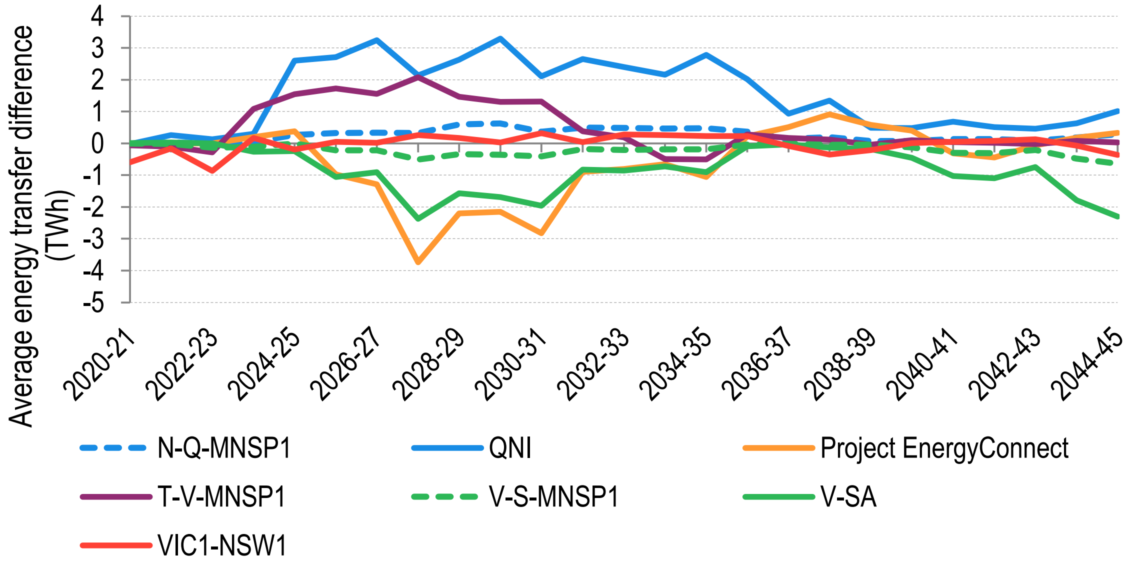
Figure 16: Difference in NEM generation forecast between Fast change scenario and Neutral scenario without QNI upgrade



The difference in average net energy transfers between the Fast change scenario and the Neutral scenario for the across all existing and assumed committed interconnectors is shown below in Figure 17. Key features are:

- Forecast increased energy transfer from South Australia into New South Wales across Project EnergyConnect from the mid-2020s to the mid-2030s primarily driven by forecast increased wind and solar PV capacity installed and assumed earlier retirements of coal capacity in New South Wales.
- Forecast reduced energy transfer from Queensland to New South Wales across QNI due to forecast increased new entrant capacity coming into New South Wales relative to Queensland.
- Forecast increased energy transfer from Tasmania to Victoria across Basslink until the assumed commissioning of Marinus Link in 2033. In the years prior to Marinus Link, the forecast increased exports from Tasmania are driven by increased wind capacity installed in Tasmania.

Figure 17: Difference in forecast average annual interconnector energy transfer between Fast change scenario and Neutral scenario without QNI upgrade

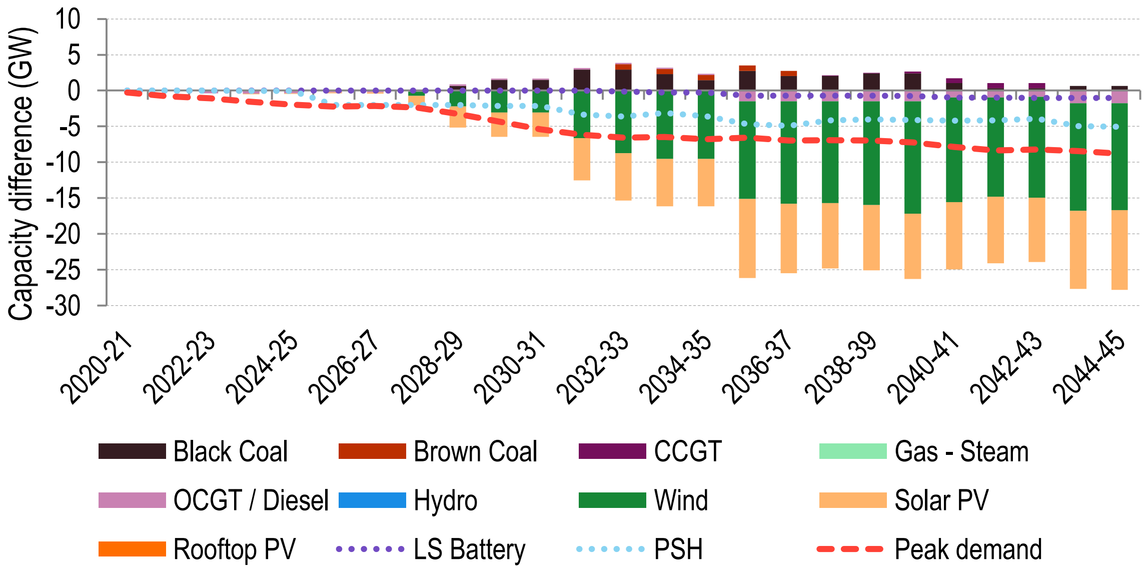


7.4 Slow change scenario without increase to QNI transfer capacity

The forecast change in the NEM-wide capacity mix between the Slow change scenario and the Neutral scenario without any increase to QNI transfer capacity is shown in Figure 18. Key input assumptions that drive the forecast reduction in install capacity in the Slow change scenario relative to the Neutral are:

- lower demand outlook in the utilised 2018 AEMO ESOO slow change demand forecast,
- extending half of the coal power stations capacity five years beyond the end of the technical life,
- Snowy 2.0 and associated network augmentations are not commissioned.

Figure 18: Difference in NEM capacity forecast between Slow change scenario and Neutral scenario without QNI upgrade

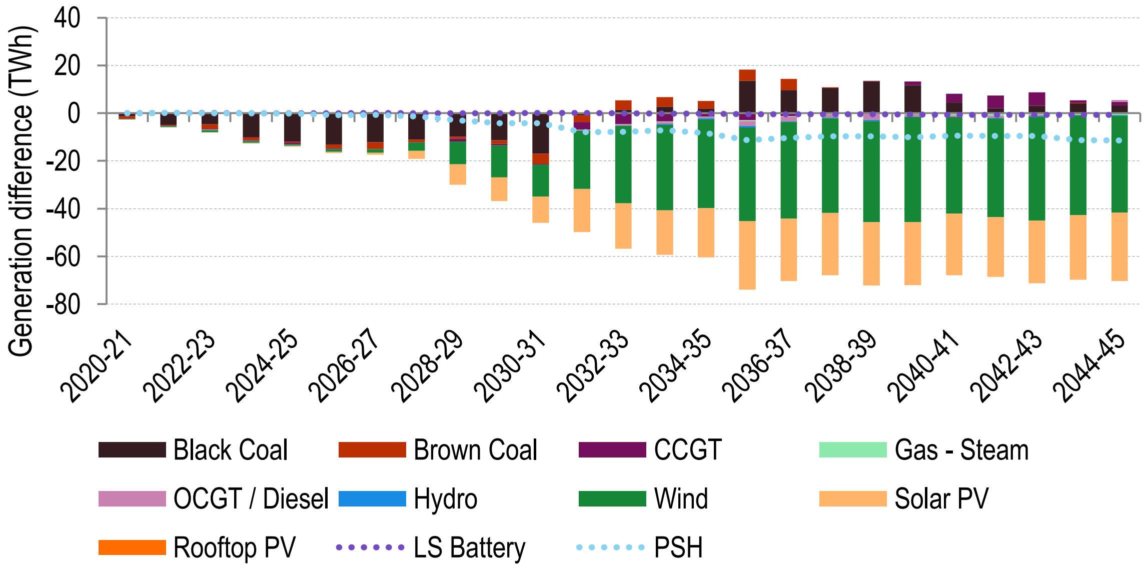


The first new capacity installed by the model as part of the least-cost development plan to meet demand is 138 MW of new OCGT capacity in NCEN in 2022-23 when Liddell is assumed to retire.

The forecast difference in generation between the Slow change scenario relative to the Neutral scenario without an upgrade to QNI, as shown in Figure 19, is an outcome of several factors including but not limited to:

- the existing coal fleet is assumed to be operational for longer,
- no development of Snowy 2.0 and associated network augmentations assumed,
- interconnection between regions are assumed not to be developed, except for Project EnergyConnect.

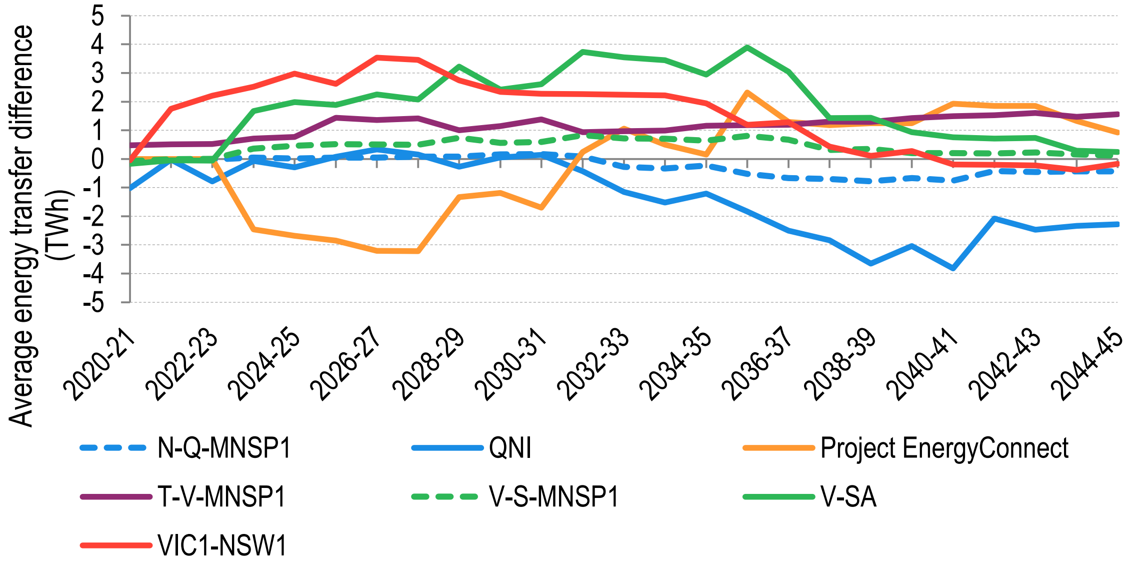
Figure 19: Difference in NEM generation forecast between Slow change scenario and Neutral scenario without QNI upgrade



The forecast difference between the Slow change scenario and the Neutral scenario for the average net energy transfers across all existing and assumed committed interconnectors is shown below in Figure 20. Forecast changes to energy transfers across interconnectors between the two scenarios are driven by the following:

- reduced northerly transfers on VIC-NSW due to KerangLink not assumed to be commissioned by July 2026,
- shift in energy transfers under the assumption that half the coal fleet retires five years later and the assumed reduced demand growth relative to the Neutral scenario.

Figure 20: Difference in forecast average annual interconnector energy transfer between Slow change scenario and Neutral scenario without QNI upgrade



8. Market benefit outcomes

8.1 Summary of market benefits

Table 13 shows the gross market benefits over the modelled 25-year horizon for all options across the four scenarios. The gross modelled market benefits of each QNI augmentation option computed in each scenario need to be compared to the relevant QNI augmentation cost to determine whether there is a positive net market benefit. The determination of Option 1A as the preferred option is dependent on option costs and was conducted outside of this Report by TransGrid and Powerlink. All references to the preferred option in this Report are in the sense defined in the RIT-T as "the credible option that maximises the net economic benefit across the market, compared to all other credible options." [80]

Table 13: Summary of forecast gross market benefits, millions real June 2019 dollars discounted to 2019-20

Option	Scenario			
	Slow change	Neutral	Neutral + low emissions	Fast change
1A	240	379	382	451
1B	71	179	230	284
1C	159	146	94	112
1D	115	95	59	67
5B	438	499	462	532

The rest of Section 8 will explore the timing and sources of these benefits, with a focus on Option 1A.

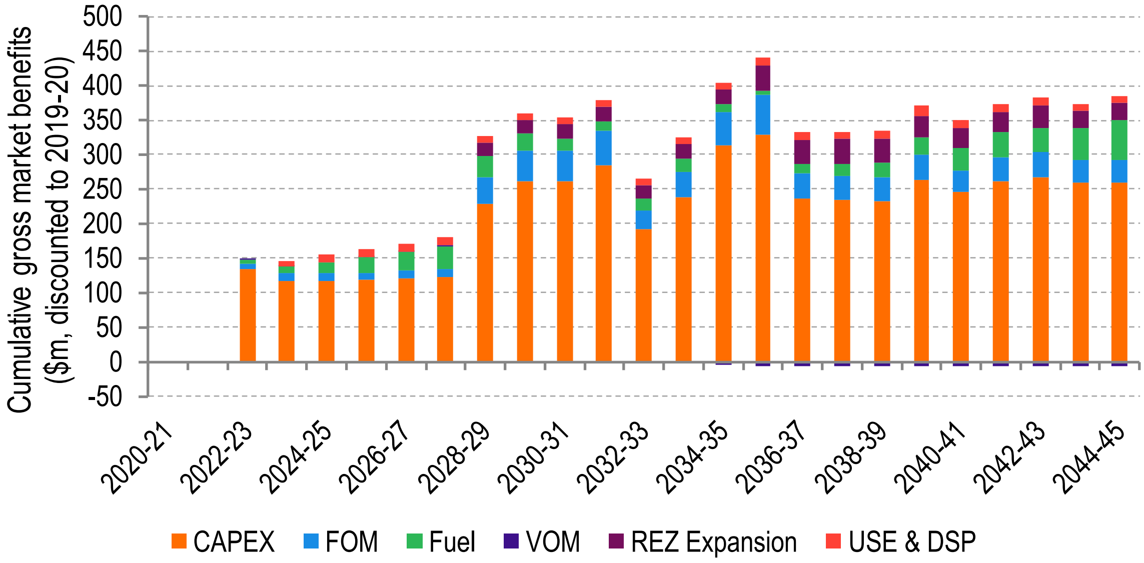
[80] 14 December 2018, *RIT-T and RIT-D application guidelines 2018*. Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rit-t-and-rit-d-application-guidelines-2018. Accessed 26 September 2019.

8.2 Neutral scenario benefits for Option 1A

8.2.1 Market benefits with Option 1A

The forecast cumulative gross market benefits for Option 1A in the Neutral scenario are shown in Figure 21.

Figure 21: Forecast cumulative gross market benefit[81,82] for Option 1A under the Neutral scenario, millions real June 2019 dollars discounted to 2019-20



The primary source of market benefits is avoided and deferred capex for new generation and storage. The timing and source of this benefits are attributable to the following:

- The large capex benefit of $134m in 2022-23 comes from a forecast avoidance of 171 MW of OCGT build in NCEN in the same year Liddell is assumed to retire.
- Capex benefit is forecast to decrease to $118m in 2023-24 due to some of the avoided OCGT build from 2022-23 being deferred to 2023-24.
- In 2028-29 capex benefit is forecast to increase to $228m following the assumed retirement of Vales Point.
- The forecast decrease in capex benefit in 2032-33 is due to more investment with Option 1A than in the Base case. This indicates that a portion of the capex savings in earlier years was due to deferred rather than avoided capacity.
- Capex benefits are forecast to shift over time as major generators begin to retire and new entrant generation is either avoided or deferred.
- By 2044-45, capex benefits are forecast to accrue to $259m.

[81] Note, while all generator and storage capital costs have been included in the market modelling on an annualised basis, this market benefits chart, and all charts of this nature in the Report, present the entire capital costs of these plant in the year avoided to highlight the timing of capacity changes that drive expected capex benefits. This is purely a presentational choice that TransGrid and Powerlink have made to assist with relaying the timing of expected benefits (i.e., when thermal plant retire) and does not affect the overall gross benefits of the options.

[82] Since this figure shows the cumulative gross market benefits in present value terms, the height of the bar in 2044-45 equates to the gross benefits for Option 1A shown in Table 13 above.

Other smaller magnitude sources of benefits are:

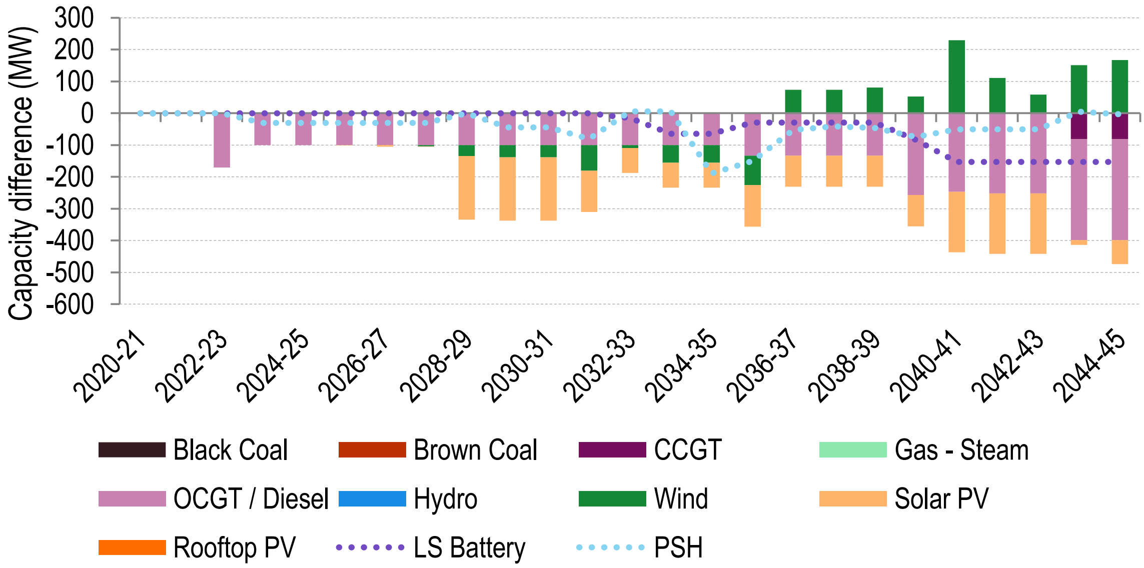
- FOM benefits are associated with the forecast avoided capacity built and accrue to $33m in 2044-45.
- Fuel benefits accrue over time to an expected $58m in 2044-45 due to Queensland generation displacing higher cost New South Wales generation.

The subsequent section discusses in further detail the shifts in capacity as well as changes in generation under Option 1A relative to the Base case for the Neutral scenario.

8.2.2 Generation development plan with Option 1A

The difference in capacity across the NEM between Option 1A and the Base case in the Neutral scenario is shown in Figure 22. Comparison to Figure 21 shows that avoided and deferred investment visible on this chart (negative movements) are associated with increased capex benefit in Figure 21.

Figure 22: Difference in NEM capacity forecast between Option 1A and Base case in the Neutral scenario



In the near term, the key observations for the forecast are as follows:

- 171 MW of avoided OCGT build in NCEN in 2022-23 when Liddell is assumed to retire, with 71 MW of this OCGT capacity deferred until 2023-24.
- 30 MW of PSH deferred in NNS from 2023-24 to 2028-29 when Vales Point is assumed to retire.
- 157 MW of solar PV capacity is avoided in New South Wales in 2028-29 when Vales Point is assumed to retire, with some of this capacity deferred until additional coal capacity retires from the market later in the forecast.

Over the longer outlook, the key observations are as follows:

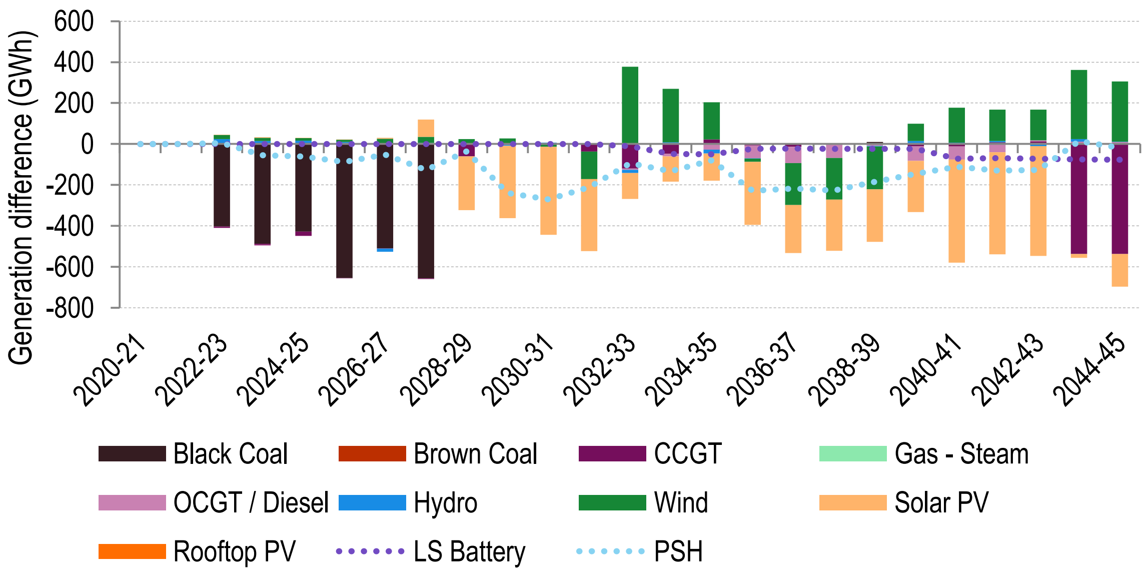
- Approximately 400 MW of gas build (OCGT and CCGT) is forecast to be avoided by 2044-45 across the NEM, with 124 MW of this build avoided in NCEN. Increase in forecast avoided gas build in 2043-44 coincides with the assumed retirement of Mt Piper. This demonstrates the continued value of Option 1A over the whole study period.

- A forecast 75 MW of solar PV and 154 MW of large-scale battery storage capacity is avoided by 2044-45 across the NEM, with a large proportion of this being in New South Wales. This capacity is forecast to be replaced by primarily Queensland wind and some New South Wales wind. Overall, more wind capacity is forecast to be built with Option 1A leading to an associated small increase capex cost which offsets capex savings of other technologies.

The augmentation opens up transfer capacity between Queensland and New South Wales which allows for better utilisation of existing generation before new capacity is required and better exploitation of diverse resources when new capacity is required. The avoidance and deferral of capacity with Option 1A drive the capex benefits illustrated in Figure 21.

To illustrate how the fuel benefits identified in Figure 21 accrue overtime, the shifts in forecast generation between New South Wales and Queensland are presented in Figure 23 and Figure 24 respectively. Prior to the retirement of Vales Point, the modelling forecasts that higher cost New South Wales coal-fired generation is displaced by lower cost Queensland coal-fired generation. Queensland coal-fired generation[83] (and energy from Queensland coal overall) is forecast to be higher in the Option 1A case until the assumed retirement of Tarong in 2036-37 which is then replaced with primarily Queensland wind. In the longer-term the least-cost development plan is forecast to have less large-scale solar generation in New South Wales with Option 1A.

Figure 23: Difference in New South Wales generation forecast between Option 1A and Base case in the Neutral scenario



[83] Queensland coal-fired power stations generally have lower fuel costs on a $/GJ basis because they are mine-mouth operations with their own mine or a captive independent supply. Furthermore, the thermal efficiency of coal-fired power stations in Queensland is generally better than those in New South Wales.

Figure 24: Difference in Queensland generation forecast between Option 1A and Base case in the Neutral scenario

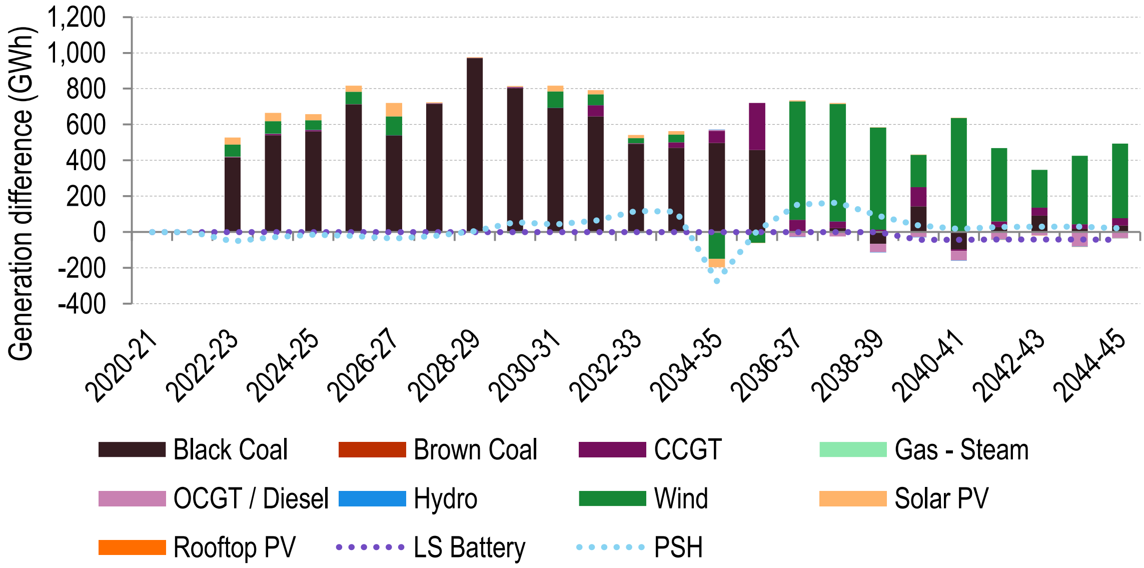
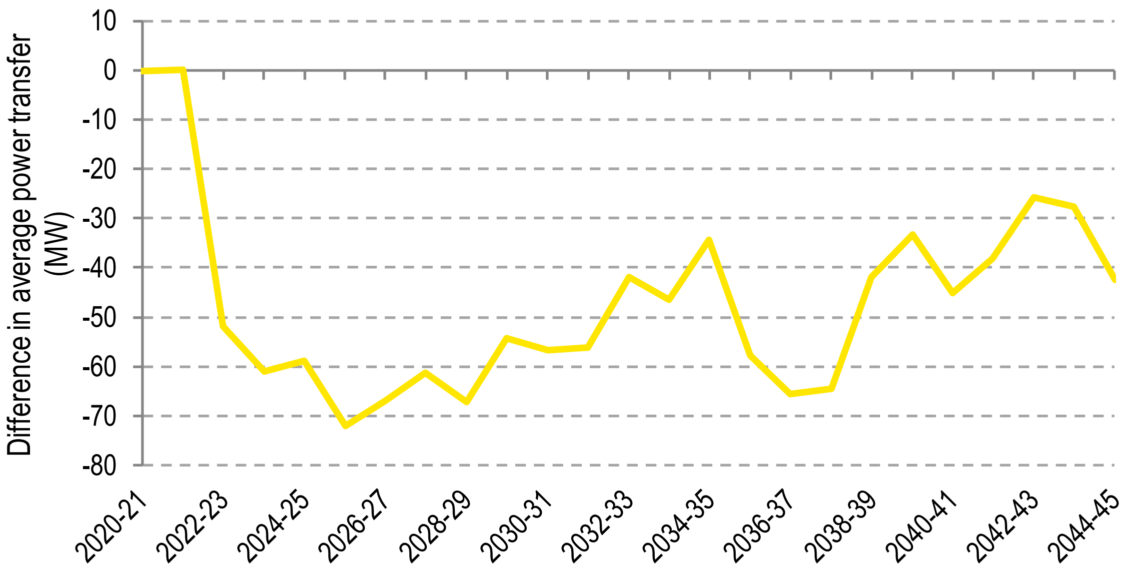


Figure 25 illustrates the difference in forecast average power transfer with Option 1A relative to the Base case. It shows that from 2022-23 when Option 1A is assumed to be commissioned, QNI flows are forecast to increase on average in the southerly direction when compared to the Base case. While the average flow is more southerly, Option 1A is not forecast to change the proportion of time that the flow is to the south. Option 1A increases transfer capacity on QNI to the north and south and this additional range is utilised in both directions in the forecast; that is when flow is to the south, it tends to be at higher magnitude, and when flow is to the north it also tends to be a higher magnitude.

Figure 25: Difference in forecast average power transfer on QNI between Option 1A and Base case in the Neutral scenario

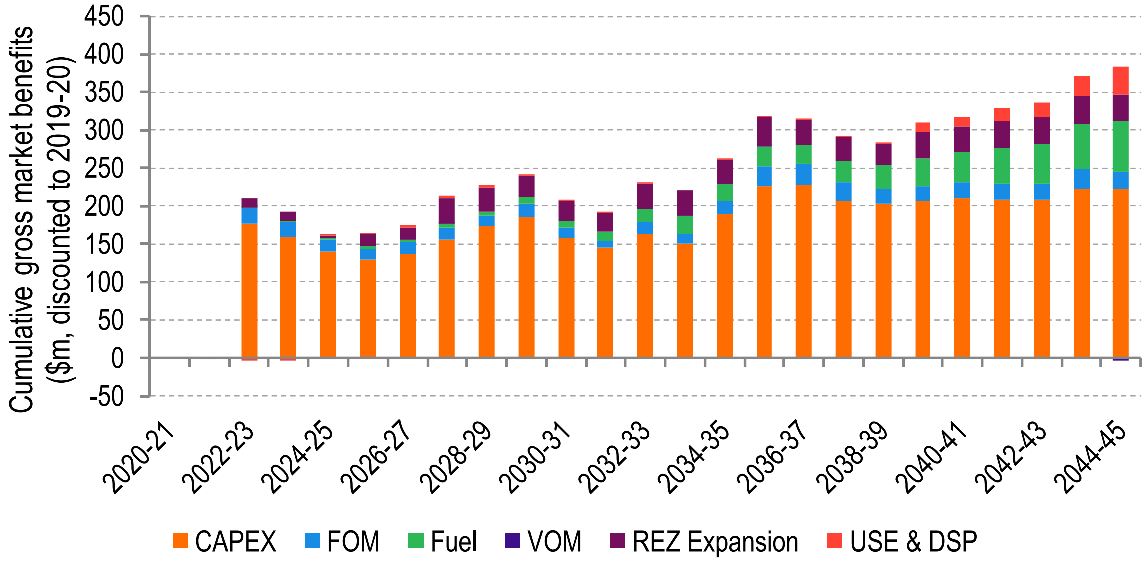


8.3 Neutral + low emissions scenario for Option 1A

8.3.1 Market benefits with Option 1A

The forecast cumulative gross market benefits for Option 1A in the Neutral + low emissions scenario are shown in Figure 26.

Figure 26: Forecast cumulative gross market benefit[84] for Option 1A in the Neutral + low emissions scenario, millions real June 2019 dollars discounted to 2019-20



The sources and timing of gross market benefits presented for the Neutral + low emissions scenario in Figure 26 relative to benefits for the Neutral scenario in Figure 21 are:

- Capex benefits are still forecast to be the dominant source of benefits, but the technologies deferred or avoided are different due to scenario settings (see Section 8.3.2 for more detail). This avoided or deferred capacity leads to a larger forecast capex benefits in 2022-23 of $177m compared to the forecast capex benefit of $134m observed in the Neutral scenario.
- The large step change in forecast capex benefits observed in the Neutral scenario in 2028-29 when Vales Point is retired is not seen in this scenario. This is due to the Neutral + low emissions scenario settings which assumes that half of Vales Point retires two years earlier than what has been assumed in the Neutral scenario.

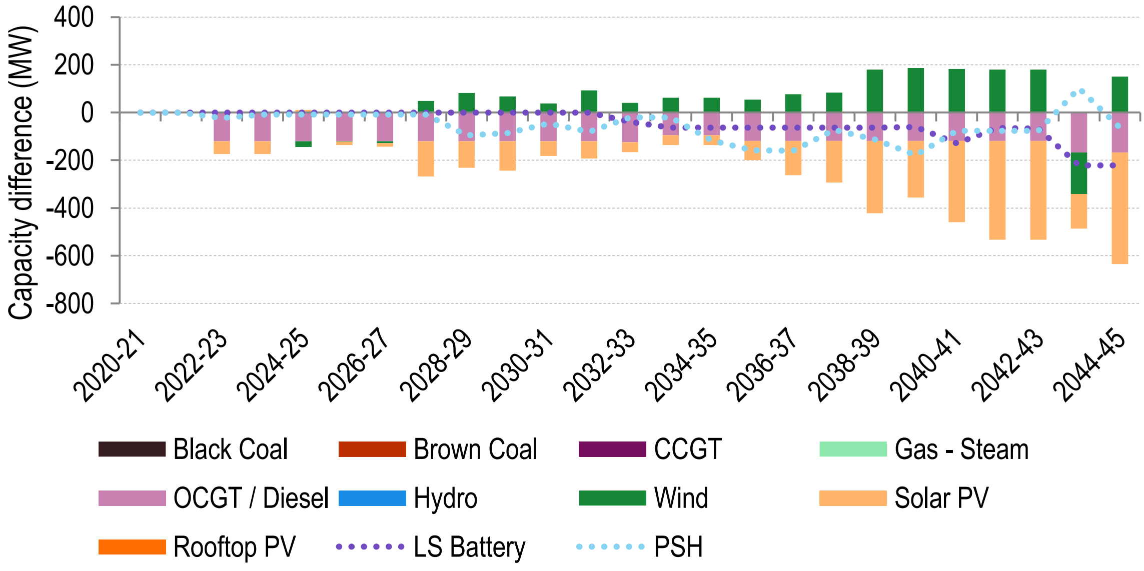
The subsequent section discusses in further detail the shifts in capacity as well as changes in generation under Option 1A relative to the Base case for the Neutral + low emissions scenario.

8.3.2 Generation development plan with Option 1A

The difference in capacity across the NEM between Option 1A and the Base case in the Neutral + low emissions scenario is shown in Figure 27.

[84] Note this market benefits chart presents the entire capital costs of these plant in the year of avoided or deferred capacity to highlight the timing of capacity changes that drive expected capex benefits.

Figure 27: Forecast NEM capacity difference between Option 1A and Base case in the Neutral + low emissions scenario



There are several key differences in the forecast capacity outlook relative to the Neutral scenario (Figure 22).

- In the near term, Option 1A is forecast to avoid or defer a combination of OCGT, solar PV and PSH capacity. A combination of these three technologies is forecast to be installed in the Base case in 2022-23 when Liddell retires due to the assumed stronger emissions constraint, and some of each technology is forecast to be avoided by Option 1A. Overall, the model forecasts that Option 1A defers or avoids the installation of 121 MW of OCGT capacity, 53 MW of solar PV capacity and 23 MW of PSH capacity in 2022-23.
- In the long-term, the trend is similar to the Neutral scenario. Option 1A is forecast to reduce solar, OCGT, PSH and large-scale battery storage while building slightly more wind capacity in Queensland. There is no avoided CCGT capacity forecast in this scenario as there was in the Neutral scenario in 2043-44 when Mt Piper is assumed to retire, because no CCGT is forecast to be built in the Base case. In this scenario, the model installs less OCGT, wind, solar PV and large-scale battery storage in 2043-44 with Option 1A, but more PSH.

The differences in forecast generation in New South Wales (Figure 28) and Queensland (Figure 29) shows that the displacement of New South Wales coal-fired generation by Queensland coal-fired generation is greatly reduced compared to the Neutral scenario. This is because coal-fired generation in general is forecast to be lower due to the more stringent emissions reduction trajectory assumed. Queensland coal-fired generation is forecast to displace New South Wales coal-fired generation from only 2022-23 until 2024-25. From 2025-26 until the late 2030s, Queensland wind displaces New South Wales wind and solar PV generation.

Figure 28: Difference in New South Wales generation forecast between Option 1A and Base case in the Neutral + low emissions scenario

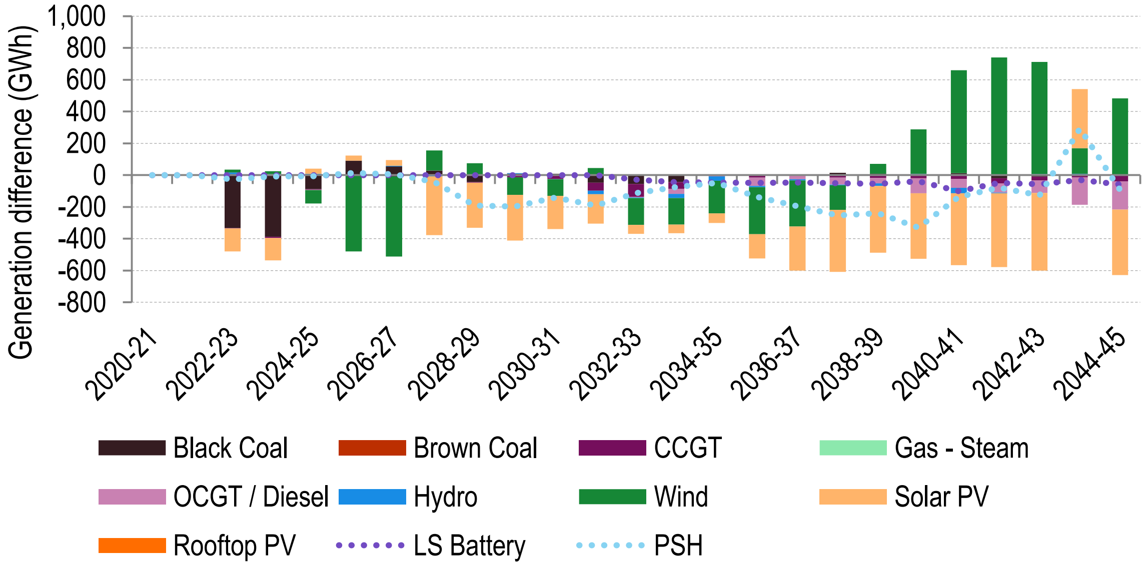
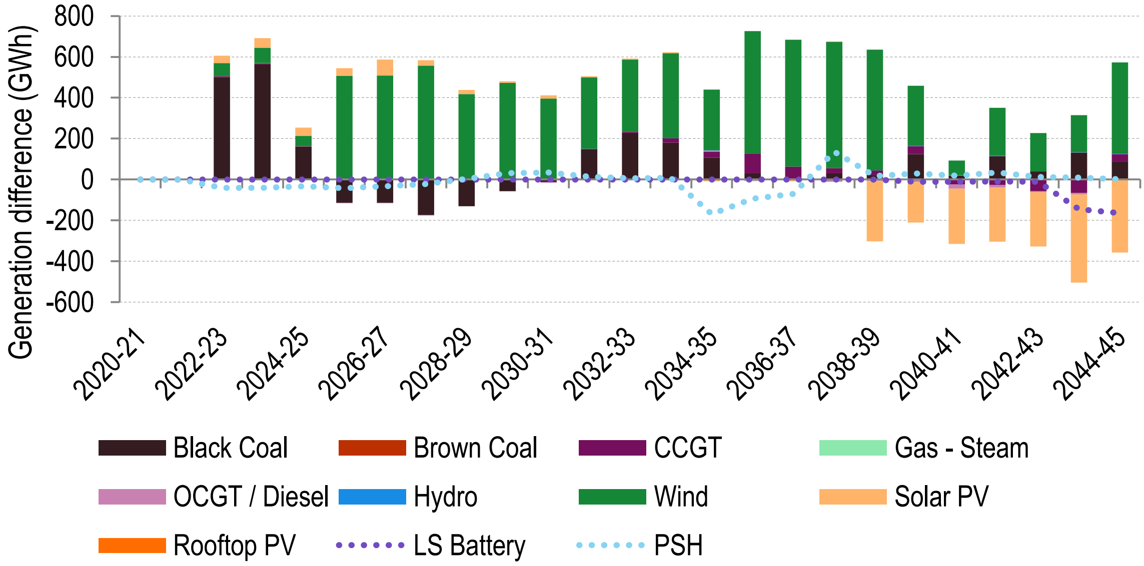


Figure 29: Difference in Queensland generation forecast between Option 1A and Base case in the Neutral + low emissions scenario

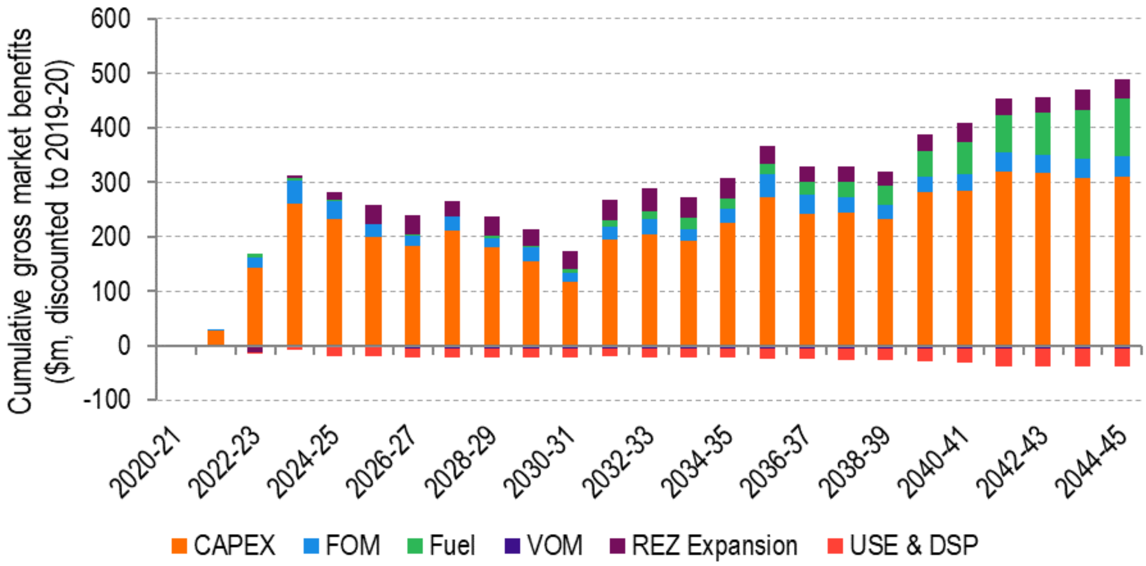


8.4 Fast change scenario for Option 1A

8.4.1 Market benefits with Option 1A

The forecast cumulative gross market benefits for Option 1A in the Fast change scenario are shown in Figure 30.

Figure 30: Forecast cumulative gross market benefit[85] for Option 1A in the Fast change scenario, millions real June 2019 dollars discounted to 2019-20



As in all other scenarios, benefits associated with avoided or deferred capex are forecast to be the dominant source of benefits. Forecast capex benefits in 2022-23 are $143m compared to $134m forecast in the Neutral scenario. Benefits, including capex benefits, are forecast to accrue a year before the augmentation is in operation due to the perfect foresight of the TSIRP model. The Fast change scenario is the only modelled scenario which forecasts OCGT build prior to Liddell retirement in 2022-23. As the model is optimised over the full 25-year outlook, it 'knows' that an augmentation operational in 2022-23 will reduce the lifetime utilisation of OCGT capacity built in 2020-21 and 2021-22. Hence, some of this capacity is not built in the forecast.

The large step change in forecast capex benefits observed in the Neutral scenario in 2028-29 when Vales Point is retired is not seen in this scenario. This is due to the scenario settings which have assumed that half of Vales Point retires five years earlier than what has been assumed in the Neutral scenario.

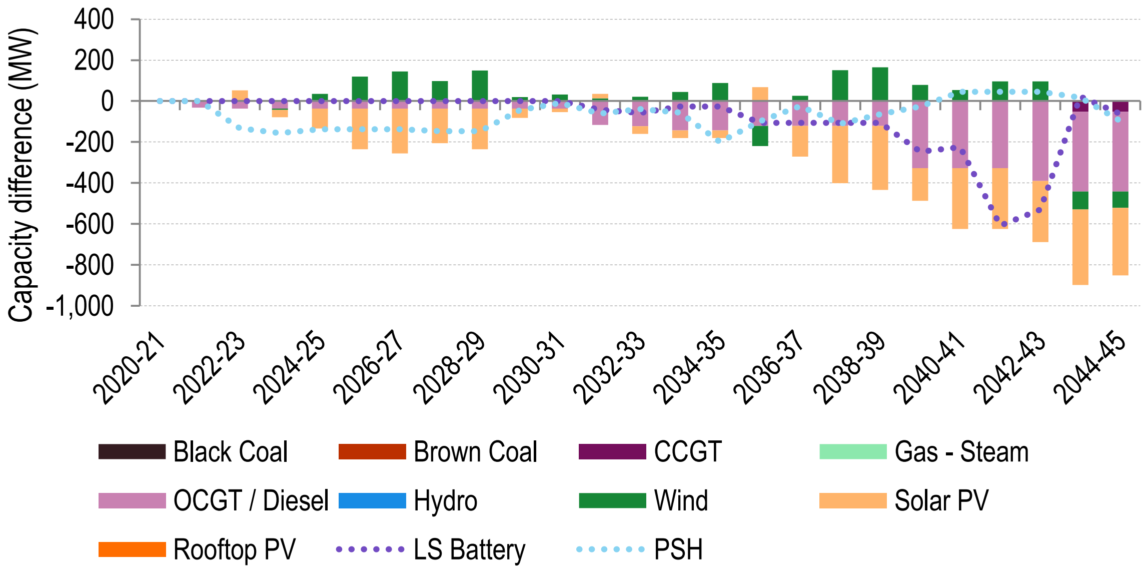
There is a modest increase in DSP dispatch and USE forecast in NCEN under this scenario with Option 1A relative to the Base case. This forecast increase is concentrated in New South Wales where demand growth is the highest. Relative to the Neutral scenario, the Fast change scenario is forecast to have a large need for high cost storage capacity due to high demand growth and the (binding) stringent emissions reduction constraint assumed. Option 1A is forecast to generate large savings by deferring some of this investment, at the cost of an increase in USE when storages occasionally run short of energy. The increase in USE is at a total cost of $33m by 2044-45 compared to the $451m benefit over the study period.

[85] Note this market benefits chart presents the entire capital costs of these plant in the year of avoided or deferred capacity to highlight the timing of capacity changes that drive expected capex benefits.

8.4.2 Generation development plan with Option 1A

The difference in capacity across the NEM between Option 1A and the Base case in the Fast change scenario is shown in Figure 31.

Figure 31: Forecast NEM capacity difference between Option 1A and Base case in the Fast change scenario



There are several key differences in the forecast capacity outlook relative to the Neutral scenario (Figure 22):

- In the near term to Liddell retirement in 2022-23, Option 1A is forecast to avoid or defer a combination of OCGT and PSH, but build more solar PV. In the Base case, a combination of these three technologies is forecast to be installed by 2022-23 in New South Wales due to the stronger emissions constraint assumed, and some of both OCGT and PSH are forecast to be avoided with Option 1A. Overall, by 2022-23, Option 1A is forecast to defer or avoid the installation of 36 MW OCGT, 133 MW PSH while installing 53 MW more solar PV.
- Over the study period, the forecast large capex benefits are principally associated with deferred or avoided solar PV, large-scale battery storage, PSH and OCGT capacity. In this scenario, more wind capacity is forecast to be built with Option 1A leading to an associated increased forecast capex cost which offsets capex savings of other technologies.

The fact that more new capacity is forecast to be built in the Fast change scenario (due to higher assumed load growth, earlier assumed coal retirement and a more stringent emission reduction trajectory) gives more opportunity for Option 1A to generate savings in the forecast by avoiding or deferring capacity.

The differences in forecast generation in New South Wales and Queensland are shown in Figure 32 and Figure 33 respectively. Trends are very similar to those forecast in the Neutral + low emissions scenario described in Section 8.3.2. Primarily, the displacement of New South Wales coal-fired generation by Queensland coal-fired generation is greatly reduced compared to the Neutral scenario forecast, because coal-fired generation in general is forecast to be reduced due to the more stringent emissions reduction trajectory assumed. As occurred in the Neutral + low emissions scenario forecast, Queensland coal-fired generation is forecast to displace New South Wales coal-fired generation from only 2022-23 until 2024-25. From 2025-26 until the late 2030s, Queensland wind is forecast to displace New South Wales wind and solar PV generation.

Figure 32: Difference in New South Wales generation forecast between Option 1A and Base case in the Fast change scenario

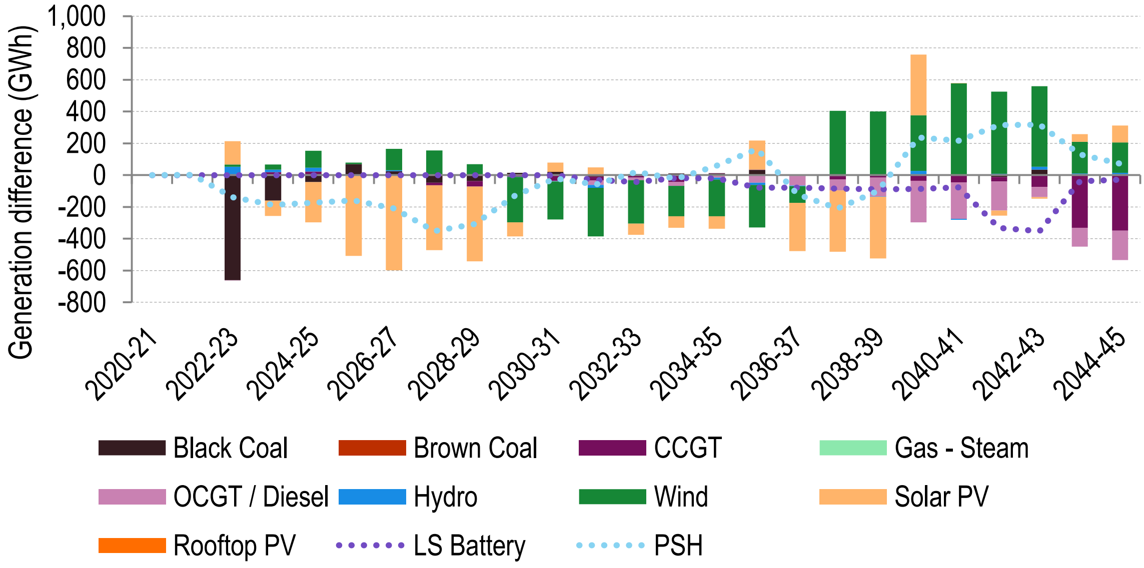
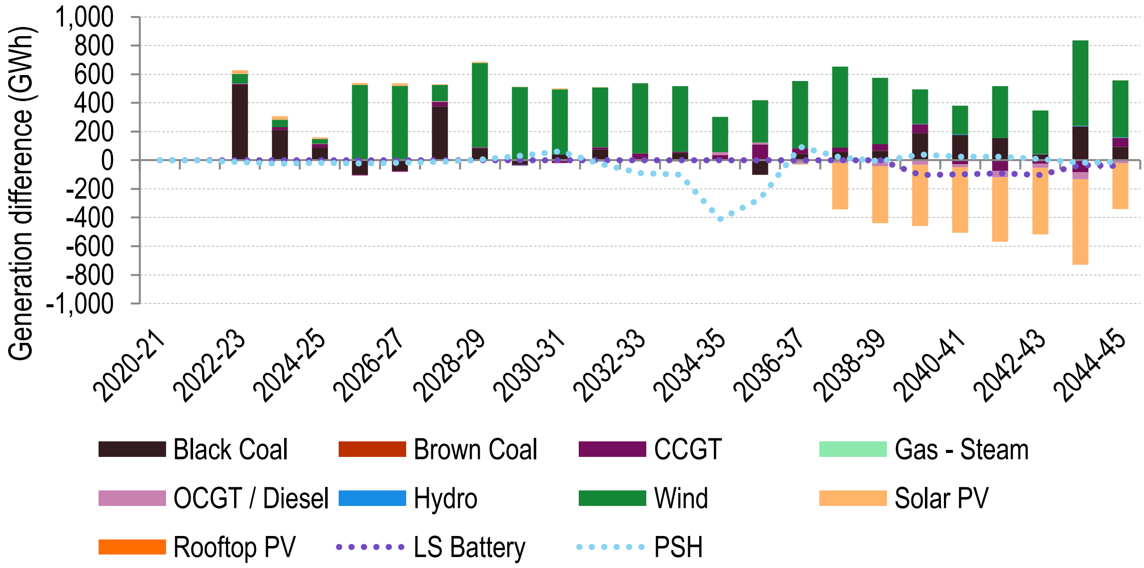


Figure 33: Difference in Queensland generation forecast between Option 1A and Base case in the Fast change scenario

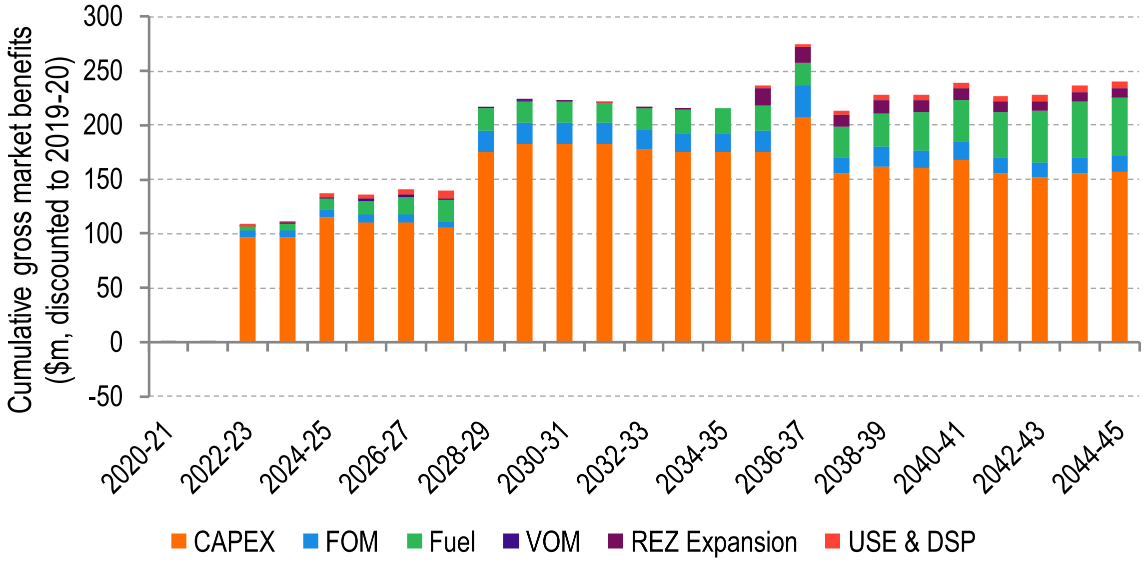


8.5 Slow change scenario for Option 1A

8.5.1 Market benefits with Option 1A

The forecast cumulative gross market benefits for Option 1A in the Slow change scenario are shown in Figure 34.

Figure 34: Forecast cumulative gross market benefit[86] for Option 1A in the Slow change scenario, millions real June 2019 dollars discounted to 2019-20



As in the Neutral scenario forecast, capex savings from deferred or avoided investment are forecast to be the dominant source of market benefits. These benefits are forecast to start accruing from when Liddell is assumed to retire in 2022-23. The magnitude of the capex savings is expected to be smaller overall in 2022-23 and throughout the forecast as the need for additional capacity in the long term is lower than in the Neutral scenario due to lower assumed demand growth and delayed coal-fired generator retirements.

Overall, less need for new capacity forecast in this scenario means less opportunity for Option 1A to generate savings and total expected gross market benefits are consequently reduced relative to the Neutral scenario.

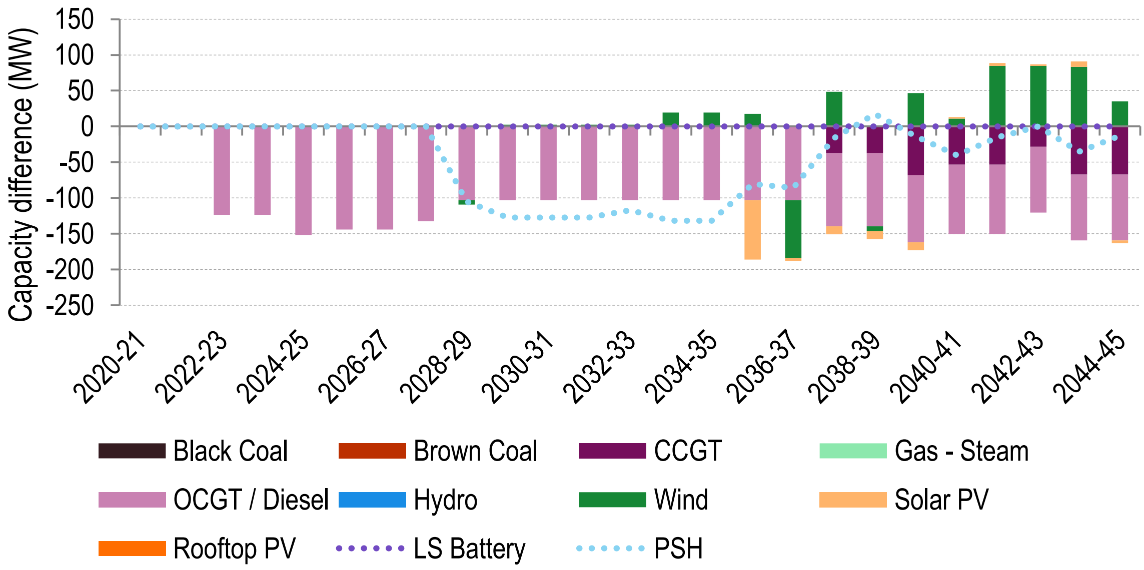
Fuel cost savings form a larger portion of the overall benefits in this scenario relative to the Neutral scenario due to the assumption that coal-fired generators remain operational for longer. As a result, less new entrant capacity is developed under this scenario to displace coal generation, as highlighted in Figure 19. Option 1A is able to derive a larger portion of its benefits from fuel cost savings by allowing Queensland generation to displace higher cost New South Wales generation.

[86] Note this market benefits chart presents the entire capital costs of these plant in the year of avoided or deferred capacity to highlight the timing of capacity changes that drive expected capex benefits.

8.5.2 Generation development plan with Option 1A

The difference in capacity across the NEM between Option 1A and the Base case in the Slow change scenario is shown in Figure 35.

Figure 35: Forecast NEM capacity difference between Option 1A and Base case in the Slow change scenario



Relative to the Neutral scenario (Figure 22), there are several key differences in the forecast capacity outlook.

- In 2022-23 when Liddell is assumed to retire, the model forecasts 123 MW of avoided OCGT build in NCEN. This is less than the amount avoided in the Neutral scenario forecast (171 MW).
- Avoided OCGT built is forecast to dominate over the whole study period (all in NCEN), with deferred PSH from the late 2020s to late 2030s (New South Wales and Queensland), and avoided CCGT build from 2037-38 (all in NCEN). By the study end there is forecast to be slightly more wind capacity relative to the Base case which offsets the forecast capex savings from the other technologies.
- Almost all the change in capacity build due to Option 1A is forecast to occur in New South Wales. There are small differences in forecast PSH in Queensland from the late 2020s (less than 30 MW) and a small increase in Queensland forecast wind capacity concentrated on 2041-42 to 2043-44 (less than 150 MW). Forecast differences in other regions are small and transient.

The differences in forecast generation in New South Wales and Queensland are shown in Figure 36 and Figure 37 respectively. Key trends are:

- As in the Neutral scenario, Queensland coal-fired generation is forecast to displace higher cost New South Wales coal-fired generation from when Liddell is assumed to retire in 2022-23. This trend is forecast to persist for longer under assumed later coal retirements in the Slow change scenario.
- These figures also illustrate that the forecast deferral of PSH capacity from the late 2020s to late 2030s occurs in both New South Wales and Queensland.
- In addition to forecast reduced CCGT build overall from the 2030s, there is a movement in CCGT generation from New South Wales to Queensland with Option 1A.

Figure 36: Difference in New South Wales generation forecast between Option 1A and Base case in the Slow change scenario

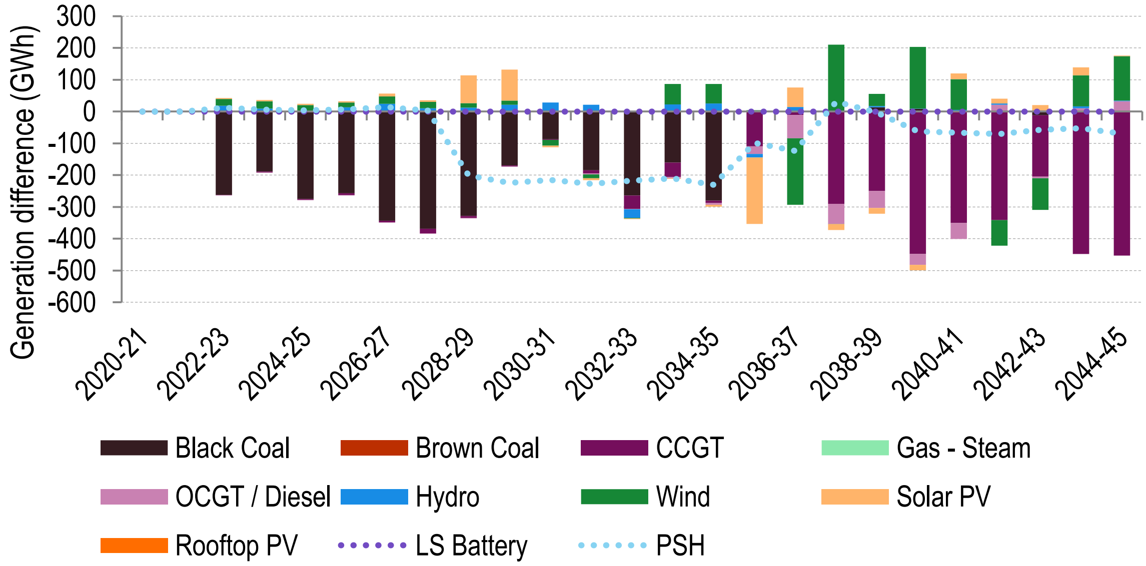
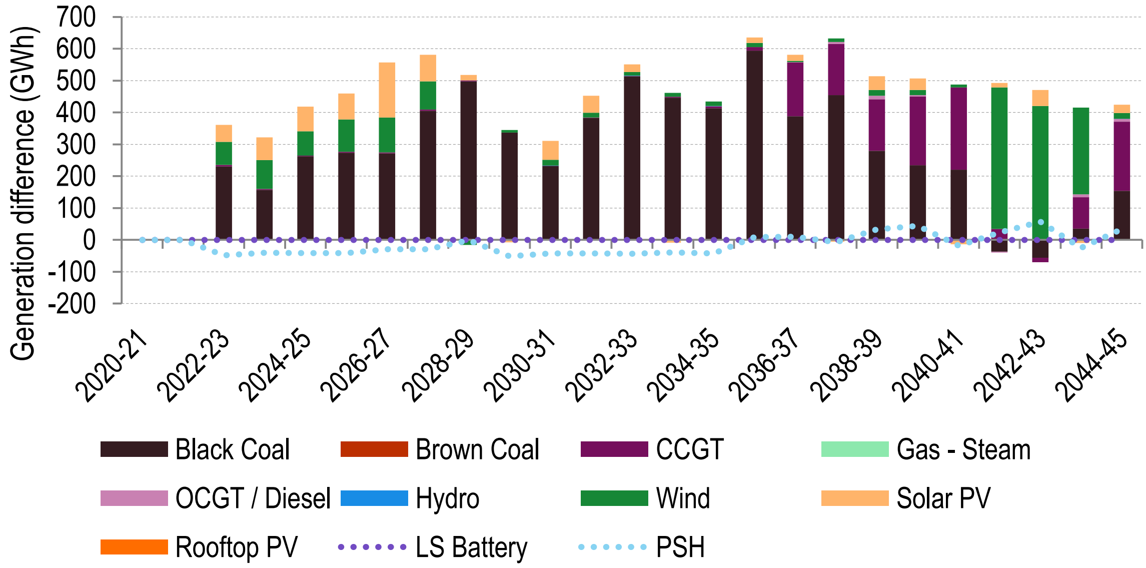


Figure 37: Difference in Queensland generation forecast between Option 1A and Base case in the Slow change scenario



8.6 Other QNI augmentation options

In general, the sources and timing of market benefits for the other augmentation options are forecast to be similar to Option 1A in all scenarios.

The main source of forecast benefits are capex benefits associated with avoided or deferred need for new capacity. In the 2020s, the assumed large retirements of coal capacity in NCEN create an opportunity for capex savings for augmentation options with the ability to serve NCEN during high demand periods. The magnitude of forecast gross benefits scales with each option's ability to do this. The exception is the Slow change scenario where Options 1B and 1C are not forecast to create significant capex savings. This will be discussed further in Sections 8.6.1 and 8.6.2.

A general observation to note is that in terms of works and costs Option 1A is equivalent to Option 1B plus 1C. However, forecast gross market benefits of Option 1A are greater than the sum of the forecast gross benefits of Option 1B plus 1C as shown in Table 14. This indicates that the two components of Option 1A are complementary and provide synergies in achieving gross market benefits.

Table 14: Comparison of forecast gross market benefits for Options 1A, 1B and 1C, millions real June 2019 dollars discounted to 2019-20

Option	Scenario			
	Slow change	Neutral	Neutral + low emissions	Fast change
1A	240	379	382	451
1B	71	179	230	284
1C	159	146	94	112
1B + 1C	230	325	325	396
1A - (1B + 1C)	10	54	57	55

8.6.1 Option 1B

Option 1B works are line upgrades which increase the NCEN-NNS limit, but do not provide additional reactive support to QNI. This option does not fully unlock the transmission corridor between Queensland and New South Wales generation and load centres which means Option 1B has reduced ability to serve NCEN peak relative to Option 1A (which does provide reactive support). Consequently, in all scenarios, Option 1B is forecast to deliver less benefit from avoided or deferred capex compared to Option 1A.

In the Neutral + low emissions and Fast change scenarios Option 1B has increased forecast benefits relative to Neutral, similar to Option 1A.

Forecast gross market benefits decrease in the Slow change scenario relative to Neutral because the expected reduced need for new capacity in the Slow change Base case means reduced opportunity for Option 1B to avoid or defer that capacity. In the Slow change scenario forecast, Option 1B is associated with primarily only small fuel cost savings on retirement of Liddell in 2022-23, and no capex cost savings until retirement of Vales Point in 2028-29. From 2037-38, Option 1B is also associated with a forecast increase in capex spend as wind and solar are built in New South Wales instead of gas (CCGT and OCGT). This forecast increase in capex is least-cost overall due to the large fuel cost savings from expected reduced gas dispatch.

8.6.2 Option 1C

Option 1C involves reactive support to increase QNI limits to the North and South, but does not have line upgrades to increase the NCEN-NNS intra-connector limit. This means that Option 1C has limited ability to serve NCEN during times of high demand when the NCEN-NNS intra-connector is at maximum flow. This reduces the ability of Option 1C to create capex benefits in the 2020s through avoiding or deferring the need for new NCEN capacity on retirement of Liddell and Vales Point. Instead capacity is forecast to be built locally in NCEN in both the Base case and Option 1A; this is forecast to be a combination of OCGT, solar and PSH depending on the scenario. Overall, Option 1C is forecast to have lower market benefits than Option 1A across all scenarios.

In the Neutral + low emissions and Fast change scenarios, gross market benefits are forecast to decrease relative to the Neutral scenario, while benefits are forecast to increase in the Slow change scenario. This is opposite to the forecast trend observed for Options 1A, 1B and 5B. It is related to the expected amount of solar built in the Base case in each scenario and the amount avoided by Option 1C relative to 1A.

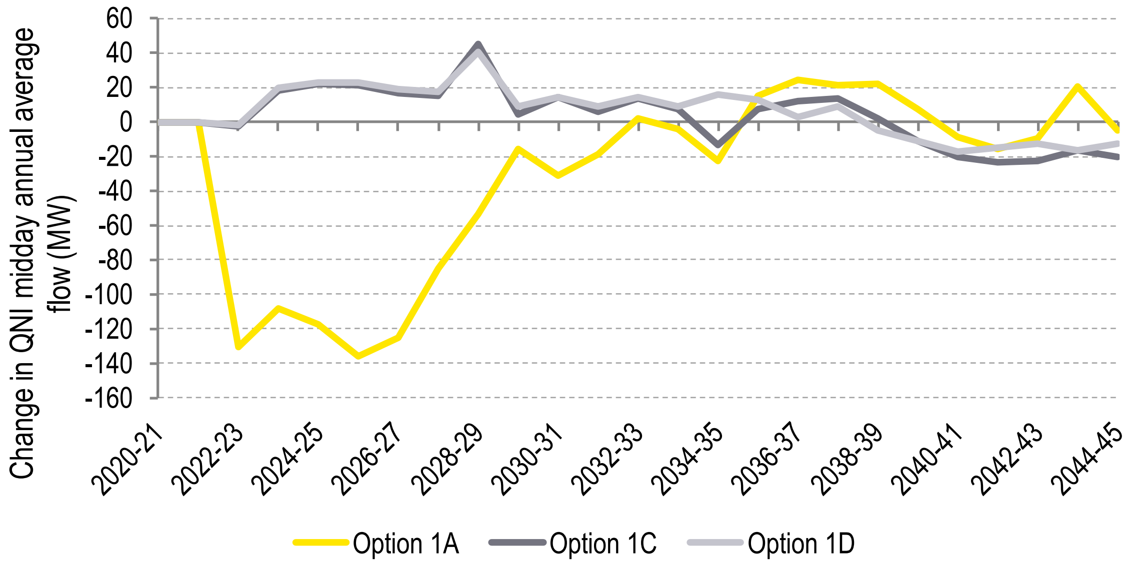
- In the Neutral scenario, Option 1A is forecast to defer significant solar capacity in NCEN in 2028-29 on retirement of Vales Point; this is not avoided by Option 1C.

- The Neutral + low emissions and Fast change scenarios are forecast to build more solar and storage than the Neutral scenario instead of gas, as the utilisation of gas in the long-term forecast is limited by the more stringent emissions reduction constraint assumed. Again, Option 1A is forecast to defer some of this capacity while Option 1C is not.

- In the Slow change scenario, there is not much need for new solar capacity due to assumed low demand growth and later coal retirements. Option 1A is forecast to defer slightly more capacity than Option 1C but the difference is small and only from the mid-2030s.

Overall, Option 1C is forecast to have the same or more solar installed in NCEN than Option 1A across all years of all scenarios. The forecast capex benefits associated with Option 1C are minimal and furthermore the solar built as part of the least-cost way to meet NCEN peak demand in the forecast actually erodes fuel cost benefits. While solar is built as part of the least-cost way to meet NCEN peak demand, particularly in the Neutral + low emissions and Fast change scenarios, it generates every day. This erodes the ability of Queensland coal and later wind to displace New South Wales coal during non-peak periods. This is illustrated in Figure 38 which shows the change in midday to 1pm QNI average flows in the Neutral scenario with various augmentation options. While average QNI flow is to the South in this hour across all years of the forecast, the *change* in forecast midday flow with Option 1C is to the North. This stands in contrast to the change in forecast midday flows with Option 1A which is to the South until the mid-2030s.

Figure 38: Difference in forecast average midday power transfer on QNI between augmentation options and Base case under the Neutral scenario



The Neutral + low emissions and Fast change scenarios are forecast to have more NCEN solar than the Neutral scenario and so lower benefits.

8.6.3 Option 1D

Similar to Option 1C, Option 1D improves QNI stability limits, but does not have line upgrades to increase the NCEN-NNS intra-connector limit. This means that Option 1D also has limited ability to serve NCEN during times of high demand when the NCEN-NNS intra-connector is at maximum flow. Option 1D only increases QNI limits to the south, while Option 1C increases limits in both directions.

Overall, this is the smallest upgrade in terms of increase in availability of QNI. Consequently, it is forecast to deliver to lowest market benefits of all augmentation options in the Neutral, Neutral + low emissions and Fast change scenarios. In the Slow change scenario, it is forecast to have the second lowest gross benefits.

Similar to Option 1C, forecast benefits decrease relative to the Neutral scenario in the Neutral + low emissions and Fast change scenarios, and increase in the Slow change scenario. The reasoning is the same as Option 1C discussed in Section 8.6.2.

8.6.4 Option 5B

Option 5B is forecast to deliver the largest gross market benefits of all the QNI augmentation options across all scenarios. This is because it has the largest increase in transfer capacity of all options along the highest number of flow paths, from CQ through SQ and NNS to NCEN. The categories, timing and drivers of trends in gross market benefits across scenarios are forecast to be similar to Option1A but the magnitude of forecast benefits is larger.

8.7 Sensitivities

All sensitivities were selected by TransGrid and Powerlink to test the robustness of their findings that Option 1A had positive net market benefits after consideration of augmentation costs. Hence, we did not perform exhaustive simulations across options and scenarios. All sensitivities had a minor impact on overall gross market benefits. Conclusions regarding the impact of sensitivities on net market benefits are presented in the PADR published by TransGrid and Powerlink[87].

8.7.1 Liddell retirement timing

The core scenarios assumed all four units of Liddell retire on 1 July 2022. These sensitivities assume Liddell retirements align with AGL's August announcement[88] advising that the first unit of Liddell is assumed to close in April 2022 and the remaining three units in April 2023.

Table 15 summarises the outcomes of these sensitivities. The assumed later retirement of three of the four Liddell units reduces forecast gross market benefits of Option 1A across all scenarios by less than $12m.

Table 15: Forecast gross market benefits for Option 1A in Liddell retirement sensitivity, millions real June 2019 dollars discounted to 2019-20

Scenario/sensitivity	Scenario			
	Slow change	Neutral	Neutral + low emissions	Fast change
Core scenarios	240	379	382	451
Liddell retirement sensitivity	228	375	371	442
Change in benefit	-12	-4	-11	-9

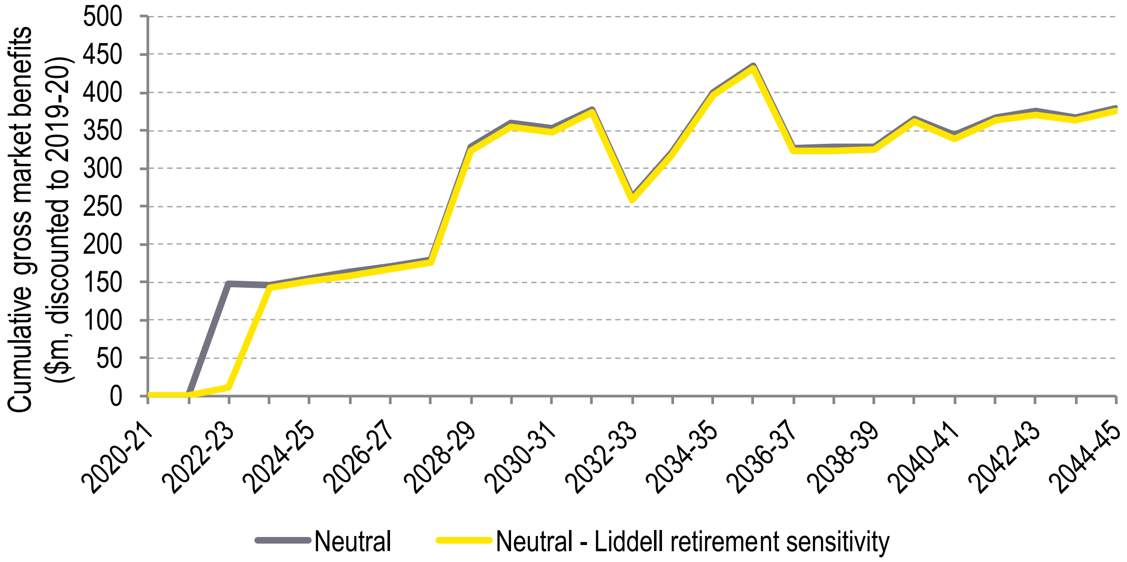
Figure 39 shows an example of the forecast change in timing of benefits for Option 1A in this sensitivity to the Neutral scenario. The date benefits start to accrue is forecast to be delayed by a year, as expected given the forecast capex benefit is associated with Liddell retirement. However, the amount of avoided NCEN capacity in 2023-24 is similar to the matched earlier retirement

[87] 30 September 2019. Available at: https://www.transgrid.com.au/what-we-do/projects/current-projects/ExpandingNSWQLDTransmissionTransferCapacity or https://www.powerlink.com.au/expanding-nsw-qld-transmission-transfer-capacity. Accessed 30 September 2019.

[88] AGL, 2 August 2019, *Schedule for the closure of AGL plants in NSW and SA* [press release]. Available at: https://www.agl.com.au/about-agl/media-centre/asx-and-media-releases/2019/august/schedule-for-the-closure-of-agl-plants-in-nsw-and-sa. Accessed 24 September 2019.

scenario so that the effect on market benefits is confined to 2022-23. Sensitivities to other scenarios are expected to follow a similar trend.

Figure 39: Forecast cumulative gross market benefit for Option 1A in the Liddell sensitivity to the Neutral scenario, millions real June 2019 dollars discounted to 2019-20



8.7.2 Outages during line upratings

This sensitivity tested the robustness of gross market benefits of Options 1A and 1B in the Neutral scenario to the line outages that are required to complete the line uprating work for these options. Details of these outages are listed in Section 4.2.2.

In this sensitivity there was a reduction in the forecast gross market benefits of $12m as shown in Table 16. This represents an increase in fuel costs due to limiting the access of lower cost Queensland generation to New South Wales during the line works, and running higher cost New South Wales generation instead. All changes are confined to the time of the outages. System conditions are identical for the two options during the outage, therefore, the same decrease occurs for both Option 1A and 1B.

Table 16: Forecast gross market benefits for Option 1A and 1B in line outage sensitivities, millions real June 2019 dollars discounted to 2019-20

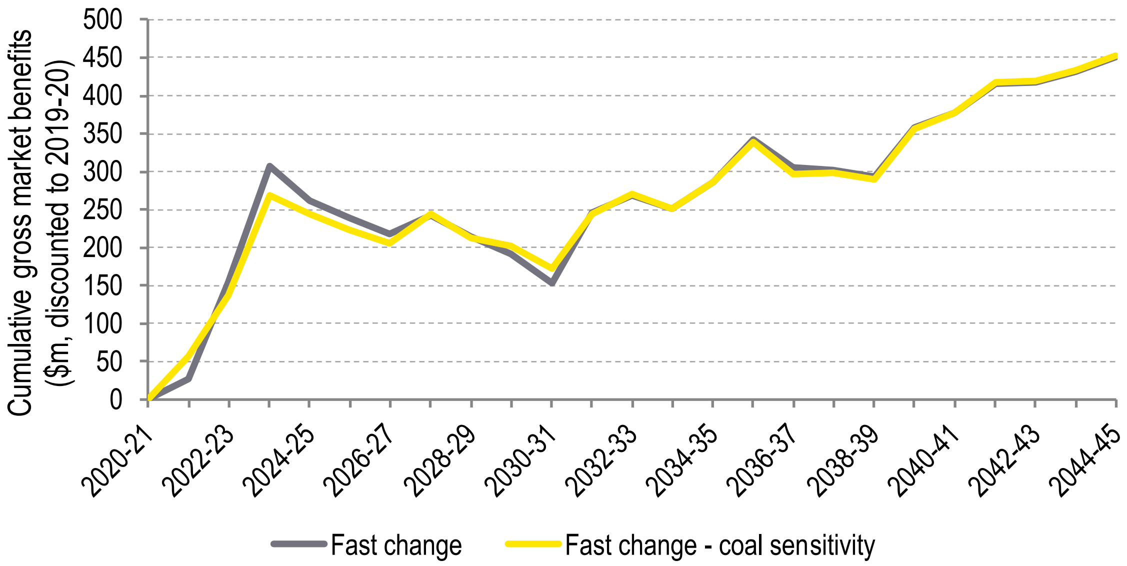
Option	Neutral scenario	Line outage sensitivity	Cost of outage
1A	379	367	12
1B	179	167	12

8.7.3 Coal price forecast

This sensitivity tested the robustness of gross market benefits of Option 1A in the Fast change scenario to a change in the coal cost for the Wood Mackenzie 'Fast' scenario as shown in Figure 6.[89] This coal price is applied by AEMO in the 'Step change' scenario of the 2019-20 ISP.[90]

In this sensitivity there was a small change in the forecast gross market benefits from $451m to $452m, an increase of $1.3m. Figure 40 shows the forecast change in timing of benefits for Option 1A in this sensitivity to the Fast change scenario.

Figure 40: Forecast cumulative gross market benefit for Option 1A in the coal price sensitivity to the Fast change scenario, millions real June 2019 dollars discounted to 2019-20



8.7.4 New South Wales CCGT operation

This sensitivity tested the robustness of gross market benefits of Option 1A in the Neutral scenario to various operating modes for New South Wales CCGTs. Specifically:

- a minimum load sensitivity applied minimum loads to Tallawarra and Smithfield,
- a minimum run time sensitivity applied a minimum run time to Tallawarra.

More detail is given is Section 4.2.4.

The change in forecast gross market benefits in these sensitivities is summarised in Table 17. The changes in gross benefits are small.

[89] Wood Mackenzie, July 2019, *Coal cost projections: approach to coal cost projections*. Available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/WoodMackenzie_AEMO_Coal_cost_projections_Approach_20190711.pdf. Accessed 24 September 2019.

[90] AEMO, 13 September 2019, *2019 Input and Assumptions workbook, v1.2*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2019-Integrated-System-Plan. Accessed 24 September 2019.

Table 17: Forecast gross market benefits for Option 1A in New South Wales CCGT operation sensitivities, millions real June 2019 dollars discounted to 2019-20

Sensitivity	Neutral scenario	Sensitivity	Change in benefit
Tallawarra and Smithfield minimum load	379	371	-8.4
Tallawarra minimum run time		379	-0.1

Appendix A Glossary of terms

Abbreviation	Meaning
AEMO	Australian Energy Market Operator
AC	Alternating Current
CAN	Canberra (NEM zone)
CCGT	Closed-Cycle Gas Turbine
CQ	Central Queensland (NEM zone)
DSP	Demand side participation
FOM	Fixed Operation and Maintenance
GW	Gigawatt
GWh	Gigawatt-hour
ISP	Integrated System Plan
LRET	Large-scale Renewable Energy Target
LS Battery	Large-Scale battery storage (as distinct from behind-the-meter battery storage)
MW	Megawatt
MWh	Megawatt-hour
NCEN	Central New South Wales (NEM zone)
NEM	National Electricity Market
NNS	Northern New South Wales (NEM zone)
NPV	Net Present Value
NSW	New South Wales
OCGT	Open-Cycle Gas Turbine
PADR	Project Assessment Draft Report
PSCR	Project Specification Consultation Report
PSH	Pumped Storage Hydro
PV	Photovoltaic
QLD	Queensland
QNI	Queensland-New South Wales interconnector
QRET	Queensland Renewable Energy Target
REZ	Renewable Energy Zone
RIT-T	Regulatory Investment Test for Transmission
SA	South Australia
SAT	Single Axis Tracking

Abbreviation	Meaning
SQ	Southern Queensland (NEM zone)
SRMC	Short-Run Marginal Cost
SWNSW	South West New South Wales (NEM zone)
TAS	Tasmania
TSIRP	Time-sequential integrated resource planner
TW	Terawatt
TWh	Terawatt-hour
USE	Unserved Energy
VCR	Value of Customer Reliability
VIC	Victoria
VNI	Victoria-New South Wales Interconnector
VOM	Variable Operation and Maintenance
VRET	Victoria Renewable Energy Target