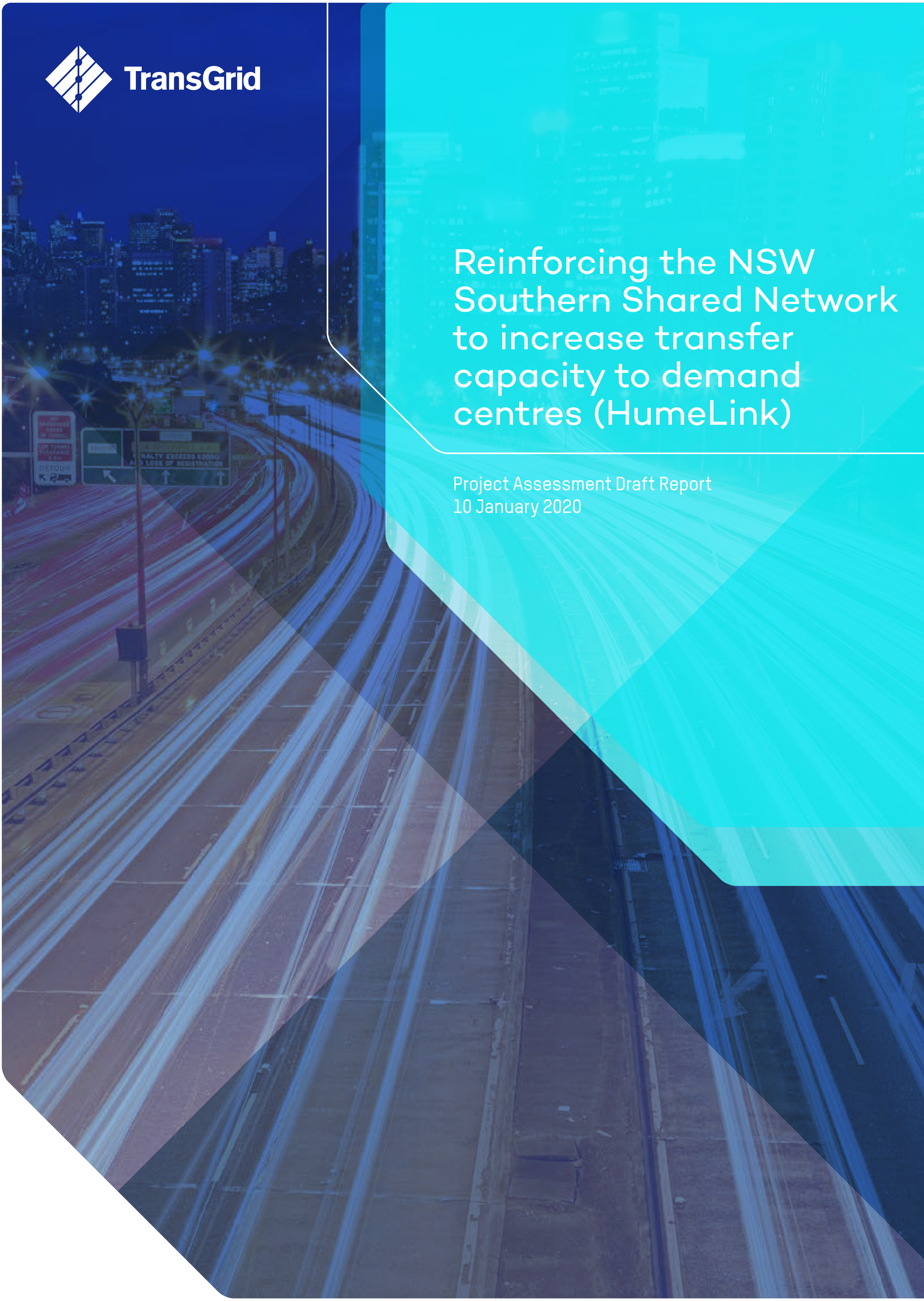


TransGrid

Reinforcing the NSW Southern Shared Network to increase transfer capacity to demand centres (HumeLink)

Project Assessment Draft Report
10 January 2020

Executive summary

TransGrid is investigating options for reinforcing the New South Wales (NSW) Southern Shared Network to increase transfer capacity to the state's major load centres of Sydney, Newcastle and Wollongong.

The driver for reinforcing the Southern Shared Network is to deliver a net economic benefit to consumers and producers of electricity and support energy market transition through:

- increasing the transfer capacity and stability limits between the Snowy Mountains and major load centres of Sydney, Newcastle and Wollongong;
- enabling greater access to lower cost generation to meet demand in these major load centres; and
- facilitating the development of renewable generation in high quality renewable resource areas in southern NSW, which will further lower the overall investment and dispatch costs in meeting NSW demand, whilst also ensuring that emissions targets are met at the lowest overall cost to consumers.

This analysis builds on the assessment in the 2018 Integrated System Plan (ISP) prepared by the Australian Energy Market Operator (AEMO) that transmission reinforcement provides net benefits, as well as the 2019 AEMO Electricity Statement of Opportunities (ESOO). Its findings are consistent with both of these studies as well as the draft 2020 ISP results recently released by AEMO.

Expanded transmission capacity from southern NSW to major demand centres was listed as a priority in the NSW Transmission Infrastructure Strategy, released in November 2018.[1]

We are applying the Regulatory Investment Test for Transmission (RIT-T)[2] to this identified need based on expected net market benefits, rather than a reliability corrective action. Reliability of supply has been considered as one class of market benefits in the overall benefits assessment. This Project Assessment Draft Report (PADR) has been prepared as the second formal step in the 'reinforcing the NSW Southern Shared Network to increase transfer capacity to demand centres' RIT-T process and follows the Project Specification Consultation Report (PSCR) released in June 2019.

Overview

This PADR assessment finds that the 500 kV options going between Maragle and Bannaby via Wagga Wagga (i.e., Option 2C and Option 3C[3]) provide the greatest net benefits of all options.

Option 3C is the preferred option as it provides additional unquantified benefits over Option 2C on account of its topology involving more opportunity for route diversity, which translates to a greater risk reduction in terms of 'high impact low probability' events (such as lightning strikes, bushfires or extreme wind events).

The analysis shows that the preferred option is expected to:

- deliver net benefits of approximately $1.1 billion over the assessment period to 2044/45 (in present value terms);
- lower the aggregate generator fuel costs required to meet demand in the National Electricity Market (NEM) going forward;
- reduce the need for new dispatchable generation investment to meet demand going forward;
- avoid capital costs that would otherwise be required associated with enabling greater integration of renewables in the NEM; and
- generate sufficient benefits to recover the project capital costs three years after the option is commissioned.

1 https://energy.nsw.gov.au/media/1431/download
2 The Regulatory Investment Test for Transmission (RIT-T) is the economic cost benefit test that is overseen by the AER and applies to all major network investments in the NEM.
3 Option 2C has two lines passing through Wagga Wagga, while Option 3C has one line passing through Wagga Wagga and one directly between Maragle and Bannaby.

This RIT-T examines reinforcing the Southern Shared Network to increase transfer capacity to demand centres

TransGrid operates and maintains the transmission network in NSW. The shared transmission network between the Snowy Mountains and Bannaby carries power from all generation across southern NSW to the major load centres of Sydney, Newcastle and Wollongong. It also carries all electricity that is imported from Victoria (VIC) to the major load centres in NSW. The main transmission lines in this area are heavily congested at times of high demand and will become more congested as new generation connects in southern NSW.

In NSW, where the existing coal-fired generators are retiring progressively from 2022, there is a pressing need for new sources of supply to meet the community's growing energy demand.

Existing congestion at times of high demand limits access to the existing generation capacity of the Snowy Mountains Scheme at times of peak demand. Access to the additional 1,900 MW of new renewable generation and 2,000 MW capacity of Snowy 2.0 in southern NSW would be severely limited, without reinforcement to the Southern Shared Network.[4]

Snowy 2.0 will provide a new source of generation to meet future demand in the major load centres of NSW and 'firm' supply from new renewable generation which is anticipated in southern NSW. This includes renewables projects in construction or under development totalling 1,900 MW. Reinforcement of the Southern Shared Network will be required to allow the transfer of energy to demand centres.

Benefits from reinforcing the Southern Shared Network compared to the status quo

The RIT-T must demonstrate that there is an overall net market benefit to the NEM from increasing the transfer capacity of the transmission network – the Southern Shared Network between southern NSW and the major demand centres of Sydney, Newcastle and Wollongong.

Increasing access to generation capacity in southern NSW has the potential to benefit the market and consumers through lowering the overall dispatch and investment costs required to meet the demand from households and businesses in NSW for reliable and safe electricity, as existing generators in NSW are expected to progressively retire.

The investments to be considered in this RIT-T have the potential to:

- open up additional capacity for new generation (primarily renewable generation) in areas of southern NSW, which have recognised high-quality wind and solar resources;
- increase the transfer capacity between VIC and NSW, which would provide NSW with access to additional generation from VIC; and
- allow the additional transfer capacity between South Australia (SA) and NSW provided by the proposed SA–NSW interconnector, Project EnergyConnect, to flow to Sydney.

In the absence of investment under this RIT-T, alternative investment by market participants in peaking plant and other generation technologies in NSW would be needed to continue to meet the State's demand and system stability requirements, as existing dispatchable generation in NSW retires.

The RIT-T tests whether the net cost to the market, (and therefore ultimately to consumers), would be higher under the 'do nothing' path, than if investment under this RIT-T proceeds.

The PADR analysis has benefited from extensive stakeholder consultation

TransGrid published the PSCR for this RIT-T in June 2019, along with an accompanying input and methodology consultation paper and assumptions workbook. The input and methodology documents provided additional detail on the proposed economic and wholesale market modelling to be undertaken, as well as further information on the specification of the credible options assessed.

In September 2019, TransGrid held its Transmission Annual Planning Report (TAPR) public forum and, as part of this, ran a consultation session on this RIT-T.

Formal submissions from six parties were subsequently received, all of which have been published on our website. While formal submissions and points raised in the consultation session covered a range of topics, there were three broad topics that were most commented on, namely:

- the modelling approach, assumptions, scenarios and sensitivities;
- options considered and the proposal of alternative options; and
- the provision of information to support the PADR and modelling that has been undertaken.

In addition, prior to, as well as after, receiving submissions, we held bilateral meetings with interested parties in order to further discuss the RIT-T assessment. These have played a pivotal role in being able to define and undertake the assessment in this PADR.

We have taken all feedback raised in submissions and stakeholder feedback sessions into account in undertaking our PADR analysis, as explained throughout this document (together with an appendix providing a comprehensive list of key points raised through stakeholder engagement and responses to each).

4 New generators will connect to the transmission network at various locations. The connection works are funded by the respective generator and are outside the scope of this RIT-T, which examines reinforcing the shared network.

Twelve options have been developed and assessed in this PADR

This PADR assesses twelve different network options to provide additional transfer capacity on the NSW Southern Shared Network between the Snowy Mountains and the major load centres. These are the same options as presented in the PSCR.

The network options considered reflect four alternative topologies for greenfield developments, reflecting:

1. a 'direct' path between Maragle[5] and Bannaby ('route 1');
2. a path between Maragle and Bannaby via Wagga Wagga that would open up additional capacity for new renewable generation in southern NSW ('route 2');
3. a wider footprint via Wagga Wagga, that would open up both direct and additional capacity for new renewable generation in southern NSW ('route 3'); and
4. a wider Maragle-Wagga Wagga-Bannaby footprint plus additional capacity between Bannaby and Sydney, to further relieve constraints on that portion of the network ('route 4').

Each topology has been modelled using three different operating capacities:

- construction and operation at 330 kV with high capacity conductor (referred to as the 'fixed 330 kV' options);
- construction to 500 kV and initial operation at 330 kV, with the option to augment substation equipment in the future to operate to 500 kV (referred to as the 'flexible 500 kV' options); and
- construction and operation at 500 kV (referred to as the 'fixed 500 kV' options).

These network options are summarised in Table E 1, which shows the additional network capacity that each provides between southern NSW and the major load centres of Sydney, Newcastle and Wollongong. We have also considered a staged variant of Option 3C as a standalone sensitivity in response to submissions.

Table E.1 Summary of the twelve credible options assessed in this PADR

TOPOLOGY	A. FIXED 330 KV	B. FLEXIBLE 500 KV	C. FIXED 500 KV
ROUTE 1 Two new transmission lines between Maragle and Bannaby (and power flow control between Bannaby and Sydney where needed to provide 2,000 MW capacity)	**Option 1A** Two new 330 kV high capacity transmission lines, switchgear and phase shifting transformer **Additional firm capacity** 2,050 MW **Indicative capex** $790m	**Option 1B** Two new 500 kV transmission lines operated at 330 kV, switchgear and phase shifting transformer **Additional firm capacity** 2,170 MW initially 2,570 MW if upgraded to 500 kV **Indicative capex** $950m initially Plus $117m for upgrade to 500 kV	**Option 1C** Two new 500 kV transmission lines, tie transformers and switchgear **Additional firm capacity** 2,510 MW **Indicative capex** $1,060m
ROUTE 2 New transmission lines between Maragle, Wagga Wagga and Bannaby (and power flow control between Bannaby and Sydney where needed to provide 2,000 MW capacity)	**Option 2A** Four new 330 kV high capacity transmission lines, switchgear and phase shifting transformers **Additional firm capacity** 2,000 MW **Indicative capex** $1,240m	**Option 2B** Four new 500 kV transmission lines operated at 330 kV, switchgear and phase shifting transformers **Additional firm capacity** 2,000 MW initially 2,500 MW if upgraded to 500 kV **Indicative capex** $1,420m initially Plus $208m for upgrade to 500 kV	**Option 2C** Four new 500 kV transmission lines, tie transformers and switchgear **Additional firm capacity** 2,500 MW **Indicative capex** $1,380m
ROUTE 3 New transmission lines in a 'loop' between Maragle, Bannaby and Wagga Wagga (and power flow control between Bannaby and Sydney where needed to provide 2,000 MW capacity)	**Option 3A** Three new 330 kV high capacity transmission lines, switchgear and phase shifting transformer **Additional firm capacity** 2,000 MW **Indicative capex** $1,010m	**Option 3B** Three new 500 kV transmission lines operated at 330 kV, switchgear and phase shifting transformer **Additional firm capacity** 2,030 MW initially 2,570 MW if upgraded to 500 kV **Indicative capex** $1,220m initially Plus $166m for upgrade to 500 kV	**Option 3C** Three new 500 kV transmission lines, tie transformers and switchgear **Additional firm capacity** 2,570 MW **Indicative capex** $1,350m
ROUTE 4 New transmission lines in a 'loop' between Maragle, Bannaby and Wagga Wagga and direct between Bannaby and Sydney	**Option 4A** Four new 330 kV high capacity transmission lines and switchgear **Additional firm capacity** 2,000 MW **Indicative capex** $1,330m	**Option 4B** Four new 500 kV transmission lines operated at 330 kV and switchgear **Additional firm capacity** 2,030 MW initially 3,100 MW if upgraded to 500 kV **Indicative capex** $1,570m initially Plus $343m for upgrade to 500 kV	**Option 4C** Four new 500 kV transmission lines, tie transformers and switchgear **Additional firm capacity** 3,100 MW **Indicative capex** $1,890m

Note: While the indicative additional firm capacities in this table assume an average level of import from VIC to NSW of 200 MW and average wind generation in southern NSW of 265 MW and zero SA-NSW imports, the market modelling dynamically models both of these key sources of supply for NSW.

5 Maragle is approximately 85 km south of Tumut, in the Snowy Mountains. This is the connection point to the shared network for Snowy 2.0.

The costs provided here must not be interpreted as a cap or maximum cost but rather as the midpoint of a range of possible cost outcomes. The costs have been prepared through desktop studies, utilising preliminary plant and material cost data available at the date of preparation for inter-option comparison. An extensive range of factors will affect the final project cost including (but not limited to) environmental factors affecting line route, land acquisition or easement requirements and cost, environment offset costs, construction cost, implications arising from route dynamics, currency fluctuations and construction contractor costs during the proposed construction period. As such, the costs specified are indicative only and will be further refined during the PACR stage of the project.

Construction for all options is expected to take 3-4 years, with commissioning in 2024-25, subject to obtaining necessary environmental and development approvals. The exception to this is Options 4A, 4B and 4C, in which the Bannaby to Sydney link is expected to take 4-5 years to construct (with commissioning expected in 2025-26). The future upgrades associated with the flexible 500 kV options are expected to take two years and the timing differs by scenario.

The 500 kV options going between Maragle and Bannaby via Wagga Wagga provide the greatest net benefits across all scenarios

Uncertainty is captured under the RIT-T framework through the use of scenarios, which reflect different assumptions about future market development, and other factors that are expected to affect the relative market benefits of the options being considered.

Four core scenarios have been considered as part of this PADR, which are intended to cover a wide range of possible futures and are generally aligned with the AEMO proposed 2020 ISP 'central', 'slow-change', 'fast-change' and 'step-change' scenarios. The four scenarios differ in relation to key variables expected to affect the market benefits of the options considered, including demand outlook, DER uptake, assumed generator fuel prices, assumed emissions targets, retirement profiles for coal-fired power stations, and generator and storage capital costs.

The results of the PADR assessment find that the 500 kV options going between Maragle and Bannaby via Wagga Wagga (i.e., Option 2C and Option 3C) are found to provide the greatest net benefits of all credible options across all four scenarios. The net benefits for these two options range from around $370 million to $1.4 billion across the four scenarios.

Under the central and step-change scenarios, the benefits are primarily driven by avoided generator fuel costs, with avoided or deferred costs associated with generation and storage providing the second largest source of benefit. Under the fast-change scenario, the benefits are driven equally by both avoided generator fuel costs and avoided or deferred costs associated with generation and storage. Under the slow-change scenario, market benefits are almost completely driven by avoided or deferred costs associated with generation and storage.

On a weighted-basis, Option 2C and Option 3C are expected to deliver approximately $1.1 billion of net benefits and are ranked equal-first (Option 3C has approximately 2 per cent greater net benefits than Option 2C), which is around 7 per cent greater net benefits than the third-ranked option (Option 3B).

Figure E.1 Estimated net benefits for each scenario

Note: The top-ranked option under each scenario (and any other options within 5 per cent of the top-ranked option) are shown in green above.

The 500 kV 'loop' reinforcement is the preferred option due to the additional risk reduction benefits it provides

While Option 2C and Option 3C are effectively ranked equal-first, the new circuits under Option 3C have lower capital cost than Option 2C due to shorter circuit length, and marginally higher net benefits. They have more route diverse paths than for Option 2C due to their topology. In particular, the new lines under Option 3C provide greater route diversity opportunity (forming a 'loop') while the new lines under Option 2C run in parallel for the length of the line.

Option 3C is therefore expected to provide a greater risk reduction than Option 2C in terms of avoiding 'high impact low probability' events (such as lightning strikes, bushfires or extreme wind events) affecting multiple lines simultaneously. While recognising the low probability of two lines going down simultaneously under both options, TransGrid has undertaken indicative power system studies that estimate the value of load at risk to be approximately $450 million (in present value terms). Option 3C is consequently the preferred option identified as part of this PADR as it provides the lowest chance of this occurring due to its multiple route diversity solutions.

For the purposes of the options assessed in this PADR, route diversity consideration may not apply to the entire route lengths. Final decisions regarding route diversity will be based on assessment of network risks and mitigation strategies having regard to the relative cost of diversity options.

We have tested the robustness of the assessment to a range of sensitivities including the retirement of existing plant based on economic viability, Snowy 2.0 not proceeding, higher DER uptake, QNI Stage 2, VNI West timing, staged development of the preferred option and 50 per cent POE demand forecasts. All tests confirm the conclusion that Option 3C is the optimal investment.

We have also assessed the ability of demand response to provide net benefits prior to Option 3C being commissioned. Specifically, modelling has shown that if demand response is enabled to respond within 5 minutes of loss of a transmission line between the Snowy Mountains and Sydney, the use of 5-minute transmission line ratings can provide approximately $2.4 million in gross market benefits (in present value terms).

Although no submissions to the PSCR offered demand response, we encourage parties who consider they can assist with providing this service to contact us, so a more fulsome assessment of whether this is likely to be efficient can be undertaken in the PACR.

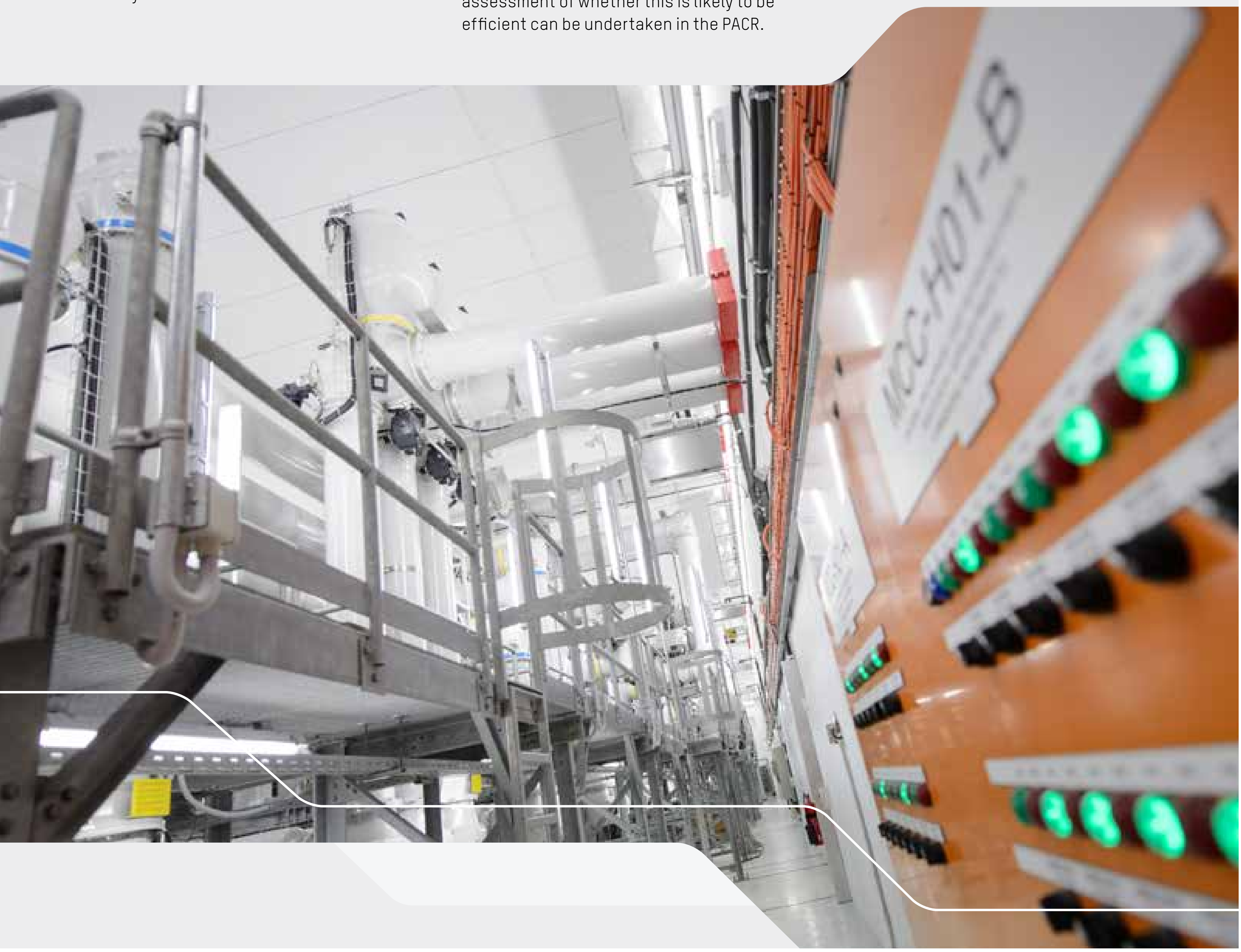
Submissions and next steps

TransGrid welcomes written submissions on this PADR. Submissions are due on or before 24 February 2020.

Submissions should be emailed to regulatory. regulatory.consultation@transgrid.com.au

Submissions will be published on the TransGrid website. If you do not wish for your submission to be made publicly available, please clearly specify this at the time of lodgement.

The next formal stage of this RIT-T is the Project Assessment Conclusions Report (PACR). The PACR will address PADR consultation responses and determine the final preferred option and is expected to be published in the first half of 2020.



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01 Introduction

The National Electricity Market (NEM) is currently undergoing rapid change as the sector transitions to lower carbon emissions and greater uptake of new technologies. In NSW, coal-fired generators are expected to close going forward and this capacity is expected to be replaced with new generation.

The inaugural Integrated System Plan (ISP), released by the Australian Energy Market Operator (AEMO) in July 2018, demonstrated the economic value of network investment to efficiently support the transition to a lower emissions power system, including in response to the expansion of generation and storage capacity at the Snowy Mountains Hydroelectric Scheme ('Snowy 2.0').

Snowy 2.0 is a project to install new pumped hydro generation using existing dams in the Snowy Mountains for storage. The Snowy 2.0 expansion is proposed to have peak generation and pumping capacity of 2,000 MW, and total storage of 350 GWh.

In June 2019, TransGrid released a Project Specification Consultation Report (PSCR) and initiated a Regulatory Investment Test for Transmission (RIT-T) to progress the assessment of investments that increase transfer capacity of the shared network between southern New South Wales and the major load centres within the state.

This Project Assessment Draft Report (PADR) is the second formal step in the RIT-T process and follows the PSCR.

There have been a number of key developments since the release of the PSCR, including:

- the updating of market modelling assumptions so they closely align with those to be used for the 2020 ISP, which were consulted on by AEMO during early 2019 and published in August 2019;
- updates from NSW coal generators regarding the operation of these plants going forward;
- the release of the 2019 AEMO Electricity Statement of Opportunities (ESOO) reconfirming the need to provide additional transmission capacity to enable Snowy 2.0 generation to best serve load centres; and[6]
- the release of the draft 2020 ISP that identifies HumeLink, an augmentation to reinforce the NSW Southern Shared Network and increase transfer capacity between Snowy Hydro and the state's demand centres, as a Group 1 priority grid project and 'no regret' action.[7]

This report presents the draft findings of the RIT-T assessment, including identifying that new 500 kV lines, from Maragle to Bannaby, Maragle to Wagga Wagga and Wagga Wagga to Bannaby ('Option 3C') is the preferred option, which is expected to maximise overall net benefits. This finding is consistent with the 2018 ISP and the draft 2020 ISP findings.

This RIT-T process is being undertaken in consultation with consumers, AEMO, Registered Participants and other interested parties regarding the investment options under consideration.

6 AEMO, *2019 Electricity Statement of Opportunities*, August 2019, pp.4, 12 & 79.
7 AEMO, *Draft 2020 Integrated System Plan*, 12 December 2019, p. 50.

1.1 Role of this report

This PADR continues the consultation on options for reinforcing the Southern Shared Network of New South Wales to best serve load centres in New South Wales.

This report:

1. identifies and confirms the market benefits expected from reinforcing the Southern Shared Network of New South Wales;
2. summarises points raised in submissions to the PSCR and the accompanying consultation material, and highlights how these have been addressed in the RIT-T analysis;
3. describes the options being assessed under this RIT-T;
4. presents the results of the NPV analysis for each of the credible options assessed;
5. describes the key drivers of these results, and the assessment that has been undertaken to ensure the robustness of the conclusion; and
6. identifies the preferred option at this stage of the RIT-T, i.e., the option that is expected to maximise net benefits.

Overall, a key purpose of this PADR, and the RIT-T more broadly, is to provide interested stakeholders the opportunity to review the analysis and assumptions, provide input to the process, and have certainty and confidence that the preferred option has been robustly identified as optimal.

TransGrid is also releasing supplementary reports on its website to complement this PADR. Detailed cost benefit results are included as a spreadsheet appendix to this report.

1.2 Submissions and next steps

TransGrid welcomes written submissions on this PADR. Submissions are due on or before 24 February 2020.

Submissions should be emailed to regulatory. regulatory.consultation@transgrid.com.au

Submissions will be published on the TransGrid website. If you do not wish for your submission to be made publicly available, please clearly specify this at the time of lodgement.

The next formal stage of this RIT-T is the Project Assessment Conclusions Report (PACR). The PACR will address PADR consultation responses and determine the final preferred option and is expected to be published in the first half of 2020.

02 Key developments since the PSCR

Summary of key points:

- The market modelling assumptions have been updated to reflect the most recent information, so they closely align with those to be used for the 2020 ISP, which were consulted on by AEMO during early 2019, as well as the 2019 ESOO.
- The assessment no longer includes a 'neutral + low emissions' scenario and, instead, includes AEMO's 'step-change' scenario, which is designed to reflect strong action on climate change that leads to a step change reduction of greenhouse gas emissions.
- Updates from NSW coal generators made after the PSCR was released regarding the operation of these plant going forward have been captured in the PADR market modelling.
- The 2019 AEMO ESOO and draft 2020 ISP results have reconfirmed the need to provide additional transmission capacity in line with what is being considered in this RIT-T.

2.1 Market modelling assumptions have been updated to closely align with those to be used for the 2020 ISP, as well in the latest ESOO

The market modelling assumptions and approaches have been updated since the PSCR based on more recent information and to closely align with those to be used for the 2020 ISP, which were consulted on by AEMO during early 2019, as well as the latest ESOO (published by AEMO in August 2019).

In addition, the credible options have been assessed under four scenarios as part of this PADR assessment, which are based on four of the scenarios to be used in the 2020 ISP.[8] The assessment no longer includes a 'neutral + low emissions' scenario and, instead, includes AEMO's 'step-change' scenario, which is designed to reflect strong action on climate change that leads to a step change reduction of greenhouse gas emissions.[9]

The assessment departs from the 2020 ISP assumptions for the following three sets of assumptions:

- retirement of coal-fired power stations;
- the implications of the COP21 commitment; and
- the implications of the VRET/QRET.

These three sets of assumptions have been adopted to further stress test the expected net market benefits from the twelve options considered in this PADR. Table 6 1 summarises the exact assumption departures from the 2020 ISP assumptions, along with the reasons why, under each of the four scenarios investigated.

In addition, the upgrades to the interconnection transfer capacity between New South Wales and Queensland have been updated since the PSCR, reflecting the latest assessment of these investments (i.e., that in the QNI RIT-T PADR released on 30 September 2019). Specifically, in all scenarios modelled in this PADR:

- the Stage 1 QNI investment is assumed to be in place from July 2022; and
- the Stage 2 QNI investment has been removed as it is not currently under assessment (we have undertaken a sensitivity test on this however, outlined in section 8.7.4).

VNI West (previously referred to as 'KerangLink') has also been removed from the slow-change scenario, recognising that it is not committed at this stage, which extends the slow-change scenario to be a more robust test of the net economic benefits that might be expected from the credible options considered.

8 The fifth scenario used in the 2020 ISP, High DER, is tested in this RIT-T as a sensitivity.
9 AEMO, *2019 forecasting and planning scenarios, inputs, and assumptions*, August 2019, p. 4.

2.2 Announcements regarding the operation of NSW coal plants

Since the PSCR was published, there have been a number of company announcements regarding the operation of coal power plants in the NEM. Specifically:

- in July 2019, EnergyAustralia announced it will invest more than $80 million in operational upgrades at its Mt Piper power station to expand the plant's capacity by 60 MW;[10]
- AGL announced on 2 August 2019 that it plans to defer the retirement of three of Liddell's four units until April 2023 (the one other unit is still scheduled to retire in April 2022);[11] and
- AGL stated it is continuing with plans for a $200 million upgrade of the Bayswater Power Station.[12]

All market modelling in this PADR reflects this updated information.

2.3 The 2019 ESOO and draft 2020 ISP results have reconfirmed the need to reinforce the Southern Shared Network

The 2019 ESOO, released by AEMO in August 2019, states that the full benefits of Snowy 2.0 will not be realised without an associated transmission development as is being considered in this RIT-T. Specifically, the 2019 ESOO states that:[13]

- the introduction of Snowy 2.0 does little to improve reliability outcomes without the associated transmission needed to utilise the increase in firm capacity; and
- network capability to transfer electricity between the Snowy Mountains and the load centre in Sydney remains a limiting factor in supplying peak demand in New South Wales.

The draft 2020 ISP, released by AEMO on 12 December 2019, recommended Option 3C in this PADR as a 'no regret' action. Specifically, AEMO has recommended that new 500 kV circuits from Maragle to Bannaby, Bannaby to Wagga Wagga, and Wagga Wagga to Maragle, with associated works at Maragle, Wagga Wagga, and Bannaby, is required to reinforce the New South Wales Southern Shared Network to increase transfer capacity to the state's demand centres.[14]

This RIT-T is not focussed on the benefits from connecting Snowy 2.0 and assesses a range of benefits, including the uptake of renewables in southern NSW and increasing the transfer capacity between Victoria and NSW. We have investigated sensitivities that assume Snowy 2.0 does not go ahead (as outlined in section 8.7.2), which confirm that:

- there are expected to be positive net benefits associated with the preferred option in the central scenario; and
- there is a negligible net cost associated with the preferred option in the slow-change scenario.

The latter sensitivity provides an indication of a boundary condition at which the preferred option would no longer deliver a net benefit.

10 https://www.energyaustralia.com.au/about-us/media/news/energyaustralia-commits-lithgow-region-mt-piper-upgrades
11 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
12 https://www.abc.net.au/news/2019-08-02/agl-delays-defers-power-plant-closures-to-avoid-summer-blackouts/11377876
13 AEMO, *2019 Electricity Statement of Opportunities, August 2019*, pp. 79, 80 & 110.
14 AEMO, *Draft 2020 Integrated System Plan,* 12 December 2019, pp. 50 & 55.

03 Investment benefits

Summary of key points:

- Investment considered under this RIT-T will allow future New South Wales demand and NEM emissions targets to be met at the lowest cost.
- The driver for the options considered in this PADR is to deliver a net economic benefit to consumers and producers of electricity and support energy market transition through:
  - increasing the transfer capacity and stability limits between the Snowy Mountains and major load centres of Sydney, Newcastle and Wollongong;
  - enabling greater access to lower cost generation to meet demand in these major load centres; and
  - facilitating the development of renewable generation in high quality renewable resource areas in southern NSW as well as southern states, which will further lower the overall investment and dispatch costs in meeting NSW demand whilst also ensuring that emissions targets are met at the lowest overall cost to consumers.
- This is therefore a 'market benefit' RIT-T (as opposed to a 'reliability corrective action' RIT-T).

The planned expansion of generation in southern New South Wales provides sources of generation that can be used to meet demand in the major load centres as existing New South Wales coal-fired generation retires. However, access to existing capacity from southern New South Wales is currently limited by constraints on the transmission network between the Snowy Mountains and Sydney, Newcastle and Wollongong at times of peak demand. Access to additional generation capacity would be similarly limited under the existing network configuration.

Investment to increase the transfer capacity between southern New South Wales and these major load centres will both relieve constraints that currently limit the use of existing generation capacity to supply these load centres and enable greater access to new generation as it develops.

In addition, the dispatchable generation that can be provided via the expanded storage capacity at Snowy Hydro can be used to 'firm' renewable generation and is expected to support the development of additional renewable generation in NSW, SA and VIC, as the NEM transitions to low-emission generation technologies.

Depending on the route adopted, the investments being considered in this RIT-T also have the potential to:

- open up additional capacity for new generation (primarily renewable generation) in areas of southern NSW, which has recognised high-quality wind and solar resources;
- increase the transfer capacity between VIC and NSW, which would provide NSW with access to additional generation in VIC; and
- allow the additional transfer capacity between SA and NSW which will be provided by the proposed new SA-NSW interconnector (which is proposed to terminate at Wagga Wagga), to also flow to Sydney.

Opening up additional capacity in areas of the NEM for renewable generation investment will also facilitate geographical diversity in renewable generation and lead to less variability in output as a result of local weather effects.

Within the context of the RIT-T assessment, greater output from renewable generation can be expected to primarily deliver the following classes of market benefit:

- further reductions in total dispatch costs, by enabling lower cost renewable generation to displace higher cost conventional generation;
- reduced generation investment costs, resulting from more efficient investment and retirement decisions, due to wind, solar and pumped hydro generation being able to locate at optimal high-quality locations rather than inferior locations; and
- avoided/lower intra-regional transmission investment associated with the development of Renewable Energy Zones (REZ).

The modelling in this PADR shows that, in the absence of investment under this RIT-T, alternative additional investment by market participants in solar, gas-fired generation and pumped hydro in NSW would be needed in the next fifteen years, in order to continue to meet New South Wales demand and system stability requirements, as existing dispatchable generation in New South Wales retires. Overall, the net cost to the market (and therefore ultimately to consumers) is expected to be higher under the 'do nothing' path, than if investment under this RIT-T proceeds. These benefits are expected from as soon as the options are commissioned in the mid-2020s.

The expectation that investment to increase transfer capacity between the Snowy Mountains and major New South Wales load centres is expected to increase net market benefits is consistent with AEMO's findings in its 2018 ISP. In particular, the 2018 ISP analysis included a scenario that assumed that the Snowy 2.0 expansion went ahead (i.e. the 'neutral with storage' scenario). AEMO's analysis found that under this scenario 'a new link consistent with 'Option 3C' in this PADR (which AEMO referred to as 'SnowyLink North') would provide system benefits.[15]

In addition, the draft 2020 ISP, released by AEMO on 12 December 2019, recommended Option 3C in this PADR as a 'no regret' action. Specifically, AEMO has recommended that new 500 kV circuits from Maragle to Bannaby, Bannaby to Wagga Wagga, and Wagga Wagga to Maragle, with associated works at Maragle, Wagga Wagga, and Bannaby, is required to reinforce the New South Wales Southern Shared Network to increase transfer capacity to the state's demand centres.[16]

Under the existing regulatory framework, this RIT-T is the means by which further consideration of options identified in the ISP is undertaken.

15 Integrated System Plan July 2018, Australian Energy Market Operator, page 9.
16 AEMO, *Draft 2020 Integrated System Plan,* 12 December 2019, pp. 50 & 55.

04 Consultation on the PSCR

Summary of key points:

- We have undertaken extensive stakeholder consultation to investigate the potential credible options for reinforcing the Southern Shared Network of New South Wales to enable Snowy 2.0 generation to best serve load centres in New South Wales and ensure the robustness of the RIT-T findings.
- This consultation has included publication of a separate detailed market modelling and assumptions report, a consultation session at the TAPR public forum, briefing our Customer Panel, bilateral discussions with interested stakeholders, and the release of detailed analysis in response to stakeholder requests.
- The analysis presented in this PADR has consequently been shaped by this consultation, which has helped test the conclusions reached and ensure the robustness of the analysis.
- We thank all parties for their valuable input to the consultation process and encourage parties to continue to engage with us over the course of this RIT-T.

TransGrid published the PSCR for this RIT-T in June 2019, along with an accompanying input and methodology consultation paper and assumptions workbook. The input and methodology documents provided additional detail on the proposed economic and wholesale market modelling to be undertaken, as well as further information on the specification of the credible options assessed.

In September 2019, TransGrid held its Transmission Annual Planning Report (TAPR) public forum and, as part of this, ran a consultation session on the HumeLink RIT-T.

Formal submissions from six parties were subsequently received, all of which have been published on our website.[17]

While formal submissions and points raised in the consultation session covered a range of topics, there were three broad topics that were most commented on, namely:

- the modelling approach, assumptions, scenarios and sensitivities;
- options considered and the proposal of alternative options; and
- the provision of information to support the PADR and modelling that has been undertaken.

In addition, prior to, as well as after, receiving submissions, we held bilateral meetings with interested parties in order to further discuss the RIT-T assessment. These have played a pivotal role in being able to define and undertake the assessment in this PADR.

The key matters raised in submissions and stakeholder feedback sessions relevant to the RIT-T assessment are summarised in the following subsections, as well as the TransGrid responses and how the matters raised have been reflected in the PADR assessment. Appendix B provides a full summary of all points raised as part of consultation on the PSCR.

4.1 Modelling approach, assumptions, scenarios and sensitivities

Stakeholders have raised a range of points in relation to the modelling approach, assumptions, scenarios and sensitivities to be applied and investigated. These include:

- alignment with the latest ISP and ESOO assumptions;
- risk of Snowy 2.0 not going ahead, or being delayed;
- assumptions about coincident transmission developments;
- the modelled retirement of coal generators;
- impact of additional new renewable generation in New South Wales;
- weighting of scenarios and demand forecasts;
- assumptions regarding distribution energy resources; and
- the use of least-cost market modelling.

A summary of the points raised, along with responses from TransGrid, is provided in the sections below.

17 https://www.transgrid.com.au/what-we-do/projects/current-projects/Reinforcing%20the%20NSW%20Southern%20Shared%20Network

4.1.1 Alignment with the latest ISP and ESOO assumptions

EnergyAustralia[18] expressed a view that TransGrid should use the proposed 2020 ISP assumptions where possible and explain any deviations from these assumptions.

The assumptions and approaches used in this PADR assessment have been updated from those proposed as part of the PSCR and the June 2019 market modelling inputs and methodology consultation paper. Specifically, the market modelling assumptions and approaches used in this PADR are based on the 2020 ISP assumptions and the latest views on committed and anticipated generation developments (including recently announced delayed date for Liddell retirement and the Bayswater and Mount Piper upgrades).

As outlined in section 2.1, the assumptions depart from the 2020 ISP assumptions for the following three sets of assumptions, namely:

- retirements of coal fired power stations;
- the implications of the COP21 commitment; and
- the implications of the VRET/QRET.

These three sets of assumptions have been adopted to further stress test the expected net market benefits from the twelve options considered in this PADR. Table 6 1 summarises the three sets of exact assumption departures from the 2020 ISP assumptions, under each of the four scenarios investigated, and their rationale.

4.1.2 The risk of Snowy 2.0 not going ahead, or being delayed

Delta Electricity,[19] the National Parks Association of NSW[20] (NPA) and EnergyAustralia[21] noted that Snowy 2.0 has yet to obtain all the necessary approvals in order to go ahead. Particularly, the project has not yet received environmental approvals under the Environmental Planning and Assessment Act, which raises the possibility that Snowy 2.0 may be delayed or does not proceed at all.

TransGrid recognises that, at this point in time, Snowy 2.0 has not received all necessary approvals for the project to proceed. However, a Final Investment Decision (FID) has been made by the Snowy Hydro Board in December 2018. In addition, in response to a report by NPA in September 2019, Snowy Hydro announced that it has recently completed a competitive debt-raising process that resulted in the debt funding requirement being over-subscribed. Snowy Hydro also noted that this follows the approvals granted by Snowy Hydro's Board, which were endorsed by Macquarie Capital (for Snowy Hydro).[22]

TransGrid also notes that approval for the Exploratory Works stage was granted in February 2019, and public exhibition of the Environmental Impact Statement (EIS) for the Main Works stage was completed in November 2019. TransGrid will continue to monitor the status of approvals for Snowy 2.0.

EnergyAustralia[23] raised the possibility of considering a staged investment in transmission if Snowy 2.0 is delayed. The staging suggested involves completing Wagga Wagga to Bannaby/Sydney when Project EnergyConnect proceeds, with Maragle-Wagga Wagga and Maragle Bannaby/Sydney lines deferred until Snowy 2.0 is built.

In light of the points raised in consultation, we have run an extreme sensitivity test to assess the impacts on the net market benefits of Snowy 2.0 not going ahead under the central scenario. This sensitivity is presented in section 8.7.2 below and finds that the preferred option is still expected to deliver strongly positive expected net market benefits (despite gross market benefits falling by approximately 32 per cent). We have also investigated an even more extreme sensitivity where Snowy 2.0 is assumed to not go ahead under the slow-change scenario to further stress-test the results and find that Option 3C is expected to deliver effectively zero net market benefits under this set of assumptions (as outlined in section 8.7.2 below).

EnergyAustralia further questioned whether it is necessary to build all circuits shown in each option at the same time, or if these could be staged. We have investigated a sensitivity that involves staging the preferred option in this manner, with the timing of the two stages determined by when it is optimal to build each. This sensitivity is presented in section 8.7.5 and finds that expected gross market benefits fall by approximately 12 per cent, compared to when both stages are constructed at the same time.

18 EnergyAustralia, p 2.
19 Delta Electricity, pp 1-2.
20 NPA, p 1.
21 EnergyAustralia, p 2.
22 https://www.snowyhydro.com.au/our-scheme/snowy20/faqs20-2/
23 EnergyAustralia, p 5.

4.1.3 Assumptions around coincident transmission developments

Delta Electricity[24] and EnergyAustralia[25] raised the issue of assumptions regarding coincident transmission developments in the NEM. Specifically, the view was raised that not all planned transmission investments will proceed and should be carefully considered in estimating market benefits given the interaction between investments.

For the purposes of the assessment presented in this PADR, TransGrid has assumed the following state of coincident transmission projects:

- exclusion of QNI stage 2 in all scenarios, with investigation of its inclusion as a sensitivity;
- exclusion of VNI West in the slow-change scenario but included in the other scenarios (the timing of VNI West is assumed to be in July 2026 in these scenarios, based on the July 2019 AEMO Insights Paper[26]);[27]
- inclusion of QNI stage 1, VNI stage 1, Project EnergyConnect and Western Victoria in all scenarios, since these investments are ISP group 1 investments and the RIT-T has been completed or is well advanced; and
- inclusion of MarinusLink in the fast-change scenario (600 MW) and step-change (1,200 MW) scenario only.

We consider that, where these coincident developments have been included in the base case for a scenario, it removes the scope for duplication of benefits since the market modelling simultaneously models these developments and the options outlined in this PADR.

We have investigated the impact of assuming Stage 2 of QNI as a sensitivity in this PADR since it is excluded from the four core scenarios. This assessment finds that the expected net benefits of the preferred option remain positive and is presented in section 8.7.4.

Delta Electricity[28] also stated that the RIT-T for Project EnergyConnect assumed firm transfer between New South Wales and South Australia and that the economics of the options being considered as part of this RIT-T will include the benefits of providing firm capacity between New South Wales and South Australia. This is not a correct characterisation of the modelling undertaken as part of the Project EnergyConnect RIT-T, which assumed that the new interconnector to South Australia could be constrained. The options considered in this PADR investigate the benefits of relieving those constraints in the Southern Shared network of New South Wales only.[29]

4.1.4 Retirement of coal generators

Delta Electricity[30] stated that an assumed emissions reduction of 52 per cent by 2030 implies coal generator retirements outside the range considered by AEMO in its ISP modelling and would require very significant storage to be developed.

As outlined in section 6.1, the fast-change and step-change scenarios assume a 52 per cent reduction by 2030, while AEMO are planning to model a 26 per cent reduction and carbon budgets for these scenarios. The 52 per cent reduction has been assumed for these two scenarios in this PADR to thoroughly test the robustness of the market benefits expected from the options considered.

AEMO has recently published the draft 2020 ISP, which includes trajectories for electricity sector emissions reduction aligned with the respective emissions reduction policies and carbon budgets under each scenario.[31] An assumed emissions reduction of 52 per cent by 2030 falls within the range of those published by AEMO for the fast-change and step-change scenarios.

In addition, as set out in sections 8.3 and 8.4, the market modelling does not find significant amounts of storage is required to be developed under these scenarios.

Participants at the TAPR forum suggested assessing more aggressive coal generator retirement assumptions, such as all coal generators retiring by the late 2020s, to inform the impact of the early withdrawal of coal fired generation. We note that the four scenarios investigated in this PADR reflect a wide range of potential coal generator retirement dates and all yield the same conclusion regarding the top-ranked options. The retirement of coal generators is therefore not considered to be a material determinant of the preferred option for this RIT-T assessment.

EnergyAustralia[32] suggested that the retirement of existing power stations should be modelled on the basis on economic viability, rather than adopting fixed retirement dates. While the core modelling undertaken in this PADR does not explicitly model the economic viability of existing power plants, and instead assumes existing generator retirement dates depending on the scenario with reference to their standard technical lives (as set out in Table 6 1), we note that the scenarios modelled in this PADR have a range of assumed generator retirement dates and, as set out in section 8, all find the 500 kV options via Wagga Wagga are preferred.

In response to EnergyAustralia's submission, we have undertaken an explicit sensitivity that models the retirement of generators based on their economic viability. This sensitivity is set out in section 8.7.1 and shows that there are still expected to be significant net benefits associated with the preferred option.

24 Delta Electricity, pp 1-2.
25 EnergyAustralia, p 3.
26 AEMO, *Building power system resilience with pumped hydro energy storage – An Insights paper following the 2018 Integrated System Plan for the National Electricity Market*, July 2019, p. 15.
27 TransGrid and AEMO released a PSCR for this RIT-T on 13 December 2019, which states that delivery of all options assessed is expected to take six to eight years, with indicative completion by 2028-30. The expected impact of this latest timing assumption for VNI West is discussed in section 8.7.5.
28 Delta Electricity, p 2.
29 In particular, the methodology adopted provides flows on all lines in the Southern Shared network individually for both the base case and option cases, and ensures that that all the benefits of the existing lines are fully accounted for and only the benefits relative to the existing network are assessed.
30 Delta Electricity, p 2.
31 AEMO, Draft 2020 Integrated System Plan, 12 December 2019, p. 36.
32 EnergyAustralia, p 3.

4.1.5 Effect of additional renewable generation in NSW

Delta Electricity[33] queried how the expected benefits would be affected by the development of additional renewable generation in southern New South Wales.

We note that large scale storage (such as Snowy 2.0) and renewables are complementary and that the development of renewables is not precluded by Snowy 2.0 and/or HumeLink development. Instead, the usage of the transmission system enables excess generation from any source to be consumed or stored, whichever is optimal, and reduces the likelihood of congestion resulting in curtailment of renewable generation (this stored energy is then able to be accessed for peak demand periods). As outlined in section 8, the options considered allow for significant additional renewables to develop alongside Snowy 2.0.

This RIT-T has considered flexible options that can be scaled as needed in future, including in response to additional renewable generation in New South Wales. Any further future upgrade of transmission capacity in Southern New South Wales (e.g., due to the development of renewable generation in Southern New South Wales that leads to future transmission congestion) would be subject to a further RIT-T and would only proceed if there was a further positive net economic benefit.

The TAPR forum raised whether a sensitivity should be included in the modelling that incorporates a New South Wales renewable energy target/policy, as is the case in Victoria and Queensland. We note that the adoption of a NEM-wide emissions reduction trajectory of 52 per cent by 2030 in the fast-change and step-change scenarios is expected to lead to similar results as individual state based emissions reduction targets across the NEM.

4.1.6 Weighting of scenarios and demand forecasts

EnergyAustralia[34] suggested that a 25 per cent scenario weighting across all four scenarios appears aggressive as it locks in high demand forecast and electric vehicle (EV) projections, and early coal generator retirements.

We note that the construction of each scenario, based on the proposed 2020 ISP assumptions, results in only one scenario with high demand forecasts and EV projections (i.e., the 'step-change' scenario). We also note that the step-change scenario is the scenario that incorporates high DER, as the scenario in which it is the most internally consistent.

As set-out in section 8, the 500 kV options via Wagga Wagga are found to be robust across the four different scenarios investigated. The weights applied to the scenarios are therefore not material in identifying the preferred option.

Both EnergyAustralia and participants in the TAPR forum queried how TransGrid was to use and weight 10 per cent POE, 50 per cent POE or 90 per cent POE demand forecasts.

The 10 per cent POE has been used to cover both the 10 per cent and 50 per cent POE situations in the modelling, consistent with the common practice of providing transmission capacity for 10 per cent POE. This is consistent with the recently released NSW Government Energy Strategy, which sets an Energy Security Target at an amount equivalent to the peak demand experienced in NSW based on 10 POE.[35]

In addition, we note that the annual energy does not vary on a POE basis and the only difference in modelled demand is in relation to the shape of the demand curve, which informs provision of peaking capacity to cover the annual peak demands for one-in-ten year peaks, compared with only one-in-two year peaks. In response to EnergyAustralia's submission, we have investigated a sensitivity where the 50 per cent POE forecasts are used, which is found to have no impact on the finding that the preferred option is expected to deliver significant net market benefits (as set-out in section 8.7.7).

4.1.7 Distributed energy resource assumptions

Participants at the TAPR forum suggested that different levels of distributed energy resources (DER) should be tested.

The PADR modelling undertaken involves assumptions for each scenario that adopts different levels of DER. In particular:

- a high DER assumption under the step-change scenario;
- a moderate DER assumption under the neutral and fast-change scenarios; and
- a low DER in slow-change scenario.

These assumptions align with the AEMO proposed, and consulted on, 2020 ISP assumptions.

In addition, in response to the point raised at the TAPR forum, we have investigated a sensitivity that involves high DER uptake in the central scenario, which aligns with the 2020 ISP 'high DER' scenario, and is found to not affect the identification of the top-ranked option (as set out in section 8.7.3).

4.1.8 The use of least-cost market modelling

Delta Electricity queried whether using short run marginal cost (SRMC) bidding is adequate to properly capture market benefits and suggested it will affect the assessment of new entrant economics and dispatch outcomes. Delta Electricity asserts that this could lead to overstating the fuel switching benefits and distorting the modelled flows on transmission lines.[36]

We note that SRMC modelling is a feature of least-cost market development modelling, which is standard practice in projecting generation and investment requirements in wholesale electricity markets and a requirement under the RIT-T.[37] Similar approaches have been utilised by AEMO in the 2018 ISP (and is proposed to be applied for the 2020 ISP[38]), previous NTNDPs and RIT-Ts that have all assessed the relative expected benefits of alternative network investments.

TNSPs can also investigate other bidding strategies under the RIT-T, where they consider the additional work required (which can be extensive) is warranted by the likelihood of this analysis materially affecting the RIT-T assessment, which can include when competition benefits are expected.

33 Delta Electricity, p 2.
34 EnergyAustralia, p 2.
35 NSW Government, *NSW Electricity Strategy*, p. 23.
36 Delta Electricity, p 3.
37 AER, *Regulatory Investment Test for Transmission*, June 2010, pp. 8-9.
38 AEMO, *2019 Planning and Forecasting Consultation Paper*, February 2019, p. 59.

We do not consider that the additional work required to investigate market-driven market development modelling is warranted for this RIT-T, as we do not expect that it would materially affect the ranking of the options. More broadly, we consider that the market modelling undertaken as part of this PADR adequately mimics what can be expected to occur in the wholesale market, due to the calibration of the market modelling to actual outcomes undertaken by EY. The accompanying market modelling report details how the market model has been calibrated to ensure the results are realistic and in-line with how entities in the wholesale market can be expected to operate.

Moreover, we do not consider that SRMC bidding in least-cost modelling would necessarily overstate the fuel switching benefits, on account of the bidding type assumed feeding into both the base case for the RIT-T assessment and the option cases. This means that the effect of assuming least-cost modelling, over market-driven modelling, is ambiguous and may actually understate the estimated fuel switching benefits since, by definition, least-cost modelling assumes lower cost generators are dispatched than under market-driven modelling.

Delta Electricity also noted that the SRMC approach would not allow for competition benefits to be assessed.[39]

Competition benefits are only required to be assessed in the RIT-T where it is expected to be material in the context of the RIT-T (i.e., where it is expected to affect the identified preferred option). The PSCR noted that competition benefits may be important for this RIT-T, and that TransGrid would undertake a 'fit for purpose' assessment to see whether such benefits are likely to vary materially between options. However, in light of the core NPV results, we do not now expect that any competition benefits would be material in terms of identifying the preferred option for this RIT-T. This is on account of the PADR modelling finding that the largest capacity options are preferred, which can be expected to have the greatest impact on any competition benefits, and previous RIT-T findings that competition benefits do not add significantly to gross market benefits.[40]

4.2 Options considered and the proposal of alternative options

Consultation undertaken on the PSCR raised a number of potential additional options for meeting the identified need. These are summarised and commented on in the sections below.

4.2.1 Use of modular power flow control technology

Smart Wires,[41] a provider of modular power flow control solutions, has proposed that this technology could be used in place of phase shifting transformers.

TransGrid has met with Smart Wires to further understand their proposal. The premise is that modular power flow control technology would replace phase shifting transformers but maintain the same capacity with different costs.

The preferred option assessed in this PADR does not include phase shifting transformers, and as such, does not require a power flow control solution. Should further information become available prior to preparation of the PACR that leads to an option that includes a power flow control solution, we will seek further information from Smart Wires to assess modular power flow control solutions on an economic basis.

4.2.2 Staging the options

Snowy Hydro[42] and participants at the TAPR forum raised the possibility of a staged development and the moving forward of one of the circuits from Maragle to Bannaby prior to the completion of Snowy 2.0 to support load in New South Wales through improved access to existing generation at the Snowy scheme and Victorian generation.

TransGrid has not included this as a credible option in the assessment as it is not technically feasible to bring forward parts of the investment given that there is insufficient time to obtain the necessary environmental approvals to do so.

EnergyAustralia[43] and Snowy Hydro[44] both note that there could be considerable option value associated with flexible/staged options. TransGrid has modelled the option value associated with the flexible 500 kV options over the alternative scenarios (as is outlined in section 7.1.7). In addition, we have included a sensitivity that tests the option value of staged route construction for the preferred option (as outlined in section 8.7.5).

TransGrid has also investigated a sensitivity in which non-network solutions, such as demand management, could be used to deliver additional transmission capacity by operating the existing southern shared network to 5-minute transmission line ratings. This sensitivity is presented in section 8.7.9.

4.2.3 Separating Bannaby-Sydney West under Option 4

EnergyAustralia[45] queried whether the section between Bannaby and Sydney West should be separated from the route 4 options in order to make the option comparable with the other three options.

TransGrid notes that option routes 1A, 1B, 2A, 2B, 3A and 3B all include phase shifting transformers on the Bannaby-Sydney West line (which are required in light of this line not being upgraded under these options). The inclusion of Bannaby-Sydney West in the route 4 options should therefore not be separated out in order to compare the options on a like-for-like basis.

In addition, as shown in section 8, the PADR assessment has found that the options including delivery of the Bannaby-Sydney West component in the same timeframe as the other transmission lines (i.e., options 4A, 4B and 4C) result in lower expected net market benefits than the equivalent options that do not include the Bannaby-Sydney West component (i.e., options 3A, 3B and 3C). This shows that the Bannaby-Sydney West component is not expected to be incrementally net beneficial in the same timeframe as the other transmission lines.

39 Delta Electricity, p 3.
40 TransGrid and Powerlink, *Development of the Queensland-NSW Interconnector*, PACR, 13 November 2014, p. 45.
41 Smart Wires, pp 3-4.
42 Snowy Hydro, p 2.
43 EnergyAustralia, p 5.
44 Snowy Hydro, p 2.
45 EnergyAustralia, p 5.

4.3 Provision of information to support the PADR and modelling

EnergyAustralia[46] requested that TransGrid provide as much information as possible to support the PADR and to allow stakeholders to review modelling outcomes in a critical manner so as to assist them with understanding how benefits are realised.

TransGrid is endeavouring to provide sufficient information so that the PADR is as transparent and clear as possible. Sections 6 and 7 of this PADR provide detailed descriptions of the key modelling assumptions and approaches adopted, while section 8 outlines the results of the economic modelling for all options, across all scenarios and sensitivities undertaken.

In addition, we have released a range of supplementary material alongside the PADR to help interested stakeholders understand the drivers of the estimated net benefit, including:

- the cost-benefit NPV model;
- summaries of the market modelling outputs under each scenario; and
- a detailed market modelling report.

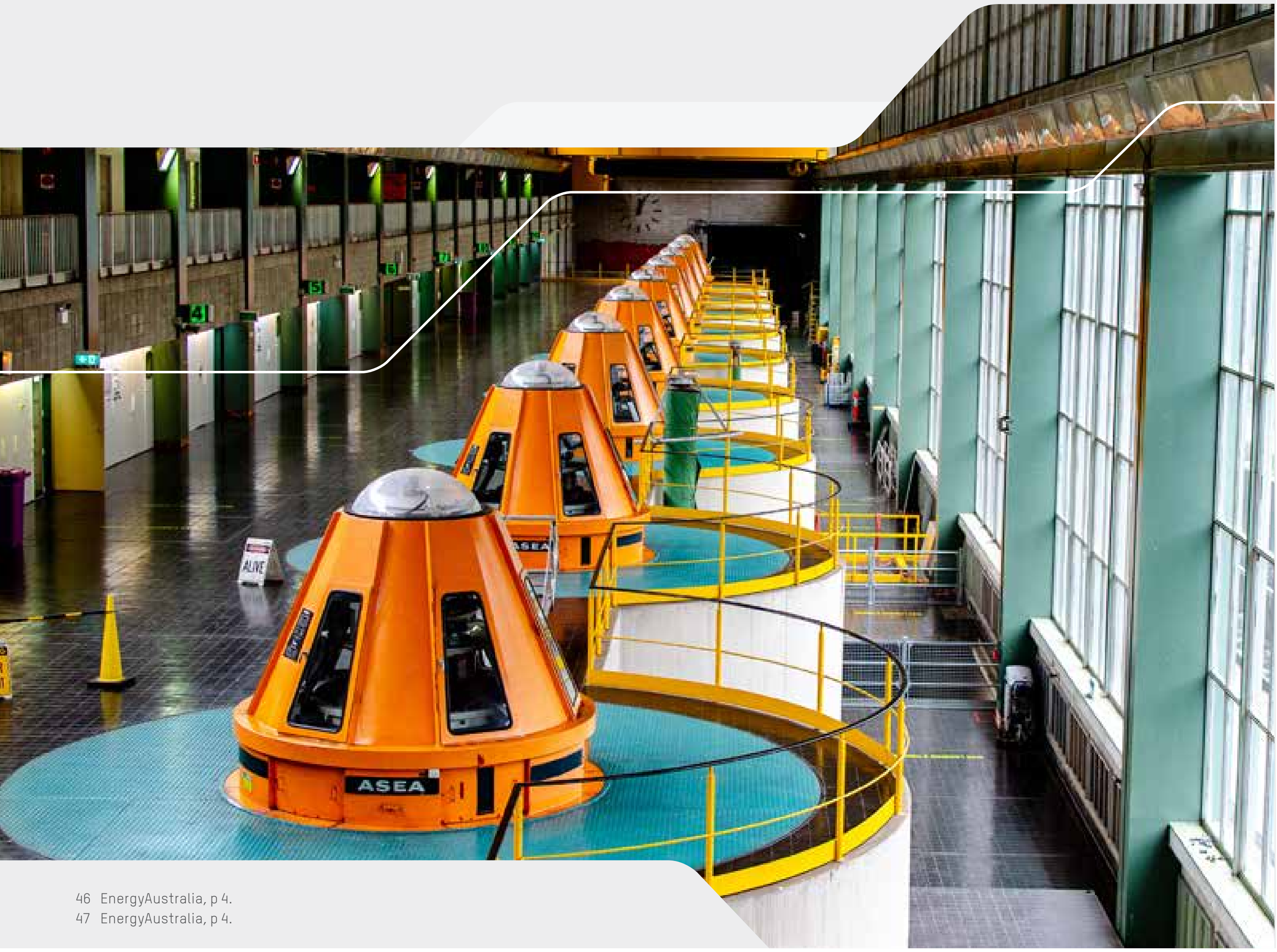
EnergyAustralia[47] also requested information regarding how existing Snowy generation, Snowy 2.0 and other pumped hydro and storage are modelled in the RIT-T assessment.

The operation of Snowy 2.0 (and all storage) is an outcome of the market modelling undertaken, as opposed to an input to it, and follows the same least cost approach as for all thermal generation in the NEM. At a high-level, the methodology for modelling storage involves:

- charging and discharging storages so as to minimise the cost of fossil fuel over the short and long term horizon (which is carried out taking into account the sizes of all storages);
- for pumped hydro and hydro storage, a 'water value' is computed for all storages, which is effectively the marginal cost below which it is economic to store energy and above which it is economic to release energy to the grid;
- taking account of the efficiency of each storage unit in making the assessment as to whether to store energy, discharge energy or remain switched off; and
- the marginal cost at which the storages neither charge nor discharge is a price band that reflects the unwillingness of the owner of the storage(s) to participate in the market because they would suffer losses from either storing or discharging in that band.

The methodology takes account of all storages (including hydro storage, pumped storage and battery storage) in all locations in the NEM. Incorporated in the model is the decision to invest in additional storage provided it can meet its investment and fixed and variable operating and maintenance costs from the time of the commissioning of the capacity through to the end of the assessment period. For the purpose of making the decision, the costs of investing in storage capacity is annualised, taking into account the investment discount rate for the lifetime of the plant, which may be different for each storage type and is specified in the ISP dataset.

The methodology for modelling storage is explained in detail in the market modelling methodology report that has been released alongside the PADR.



46 EnergyAustralia, p 4.
47 EnergyAustralia, p 4.

05

Network options

Summary of key points:

- This PADR considers twelve credible options for increasing transfer capacity between the Snowy Mountains and Sydney, Newcastle and Wollongong, reflecting a range of technologies, costs and capabilities.
- The twelve options assessed are the same as those presented in the PSCR.
- Stakeholder consultation on the PSCR has resulted in a staged variation on a credible option (i.e., Option 3C) being included as a sensitivity.

This PADR assesses twelve different network options to provide additional transfer capacity on the NSW Southern Shared Network between the Snowy Mountains and the major load centres of Sydney, Newcastle and Wollongong.

The network options considered reflect four alternative topologies for greenfield developments, reflecting:

1. a 'direct' path between Maragle[48] and Bannaby ('route 1');
2. a path between Maragle and Bannaby via Wagga Wagga that would open up additional capacity for new renewable generation in southern NSW ('route 2');
3. a wider footprint via Wagga Wagga, that would open up both direct and additional capacity for new renewable generation in southern NSW ('route 3'); and
4. a wider Maragle-Wagga Wagga-Bannaby footprint plus additional capacity between Bannaby and Sydney, to further relieve constraints on that portion of the network ('route 4').

Each topology has been modelled across three different operating capacities:

- construction and operation at 330 kV with high capacity conductor (referred to as the 'fixed 330 kV' options);
- construction to 500 kV and initial operation at 330 kV, with the optionality to augment substation equipment in the future to operate to 500 kV (referred to as the 'flexible 500 kV' options); and
- construction and operation at 500 kV (referred to as the 'fixed 500 kV' options).

These network options are summarised in Table 5.1, which shows the additional network capacity that each provides between southern NSW and the major load centres of Sydney, Newcastle and Wollongong.

Indicative cost estimates specified have been prepared from the desktop studies based on cost data available at the date of preparation. Data used in the options is consistent for the purposes of inter-option comparison. The specific route will only be confirmed during preparation of the PACR. An extensive range of factors may affect the project cost including (but not limited to) environmental factors affecting line route, biodiversity considerations, land acquisition or easement cost, construction cost implications arising from route dynamics, currency fluctuations and construction contractor costs in the proposed construction period. As such, the costs specified are indicative only at this stage and will be subject to further refinement.

While the capital costs shown below for all options align with those in the PSCR, the flexible 500 kV options now have the network upgrade costs required to go from 330 kV to 500 kV in the future if required also identified (these costs were not separately identified in the PSCR). All options are assumed to have annual operating costs equal to approximately 1 per cent of their capital costs.

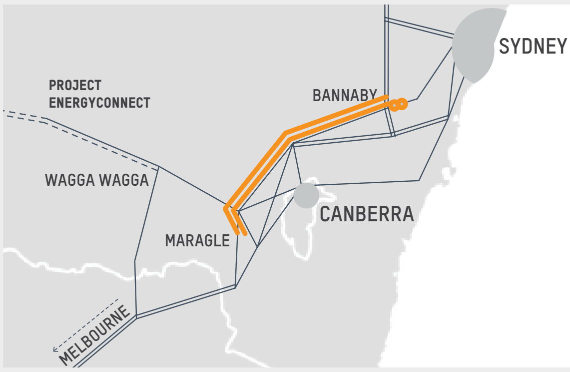
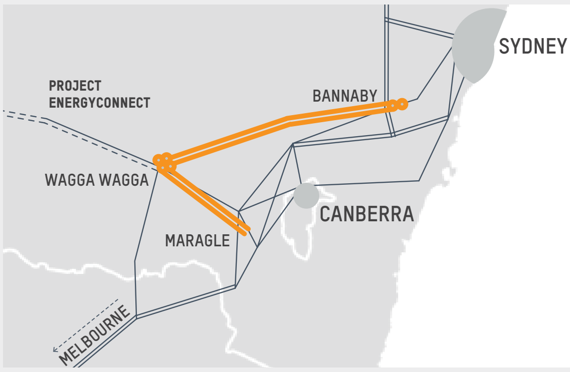
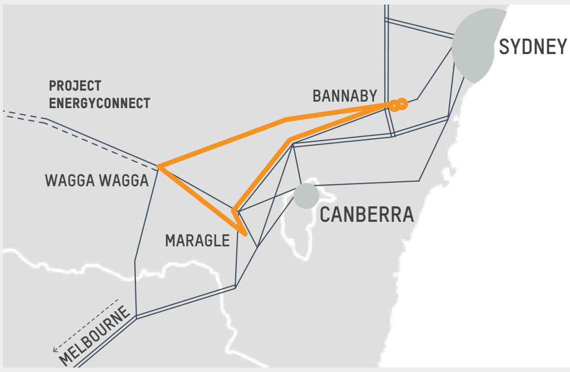
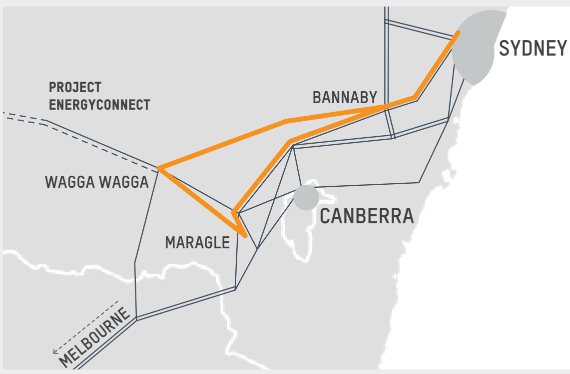
Construction for all options is expected to take 3-4 years, with commissioning in 2024-25, subject to obtaining necessary environmental and development approvals. The exception to this is Options 4A, 4B and 4C, in which the Bannaby to Sydney link is expected to take 4-5 years to construct (with commissioning expected in 2025-26). The future upgrades associated with the flexible 500 kV options are expected to take two years and the timing differs by scenario (as summarised in section 7.1.7).

The remainder of this section provides further detail on each of these options. It also outlines a number of network options that have been considered but not progressed (together with the reasons why).

For the purposes of the options assessed in this PADR (Table 5.1), route diversity consideration may not apply to the entire route lengths. Final decisions regarding route diversity will be based on assessment of network risks and mitigation strategies having regard to the relative cost of diversity options.

48 Maragle is approximately 85 km south of Tumut, in the Snowy Mountains. This is the connection point to the shared network for Snowy 2.0.

Table 5.1 Summary of the credible options assessed in this PADR

<table>
<tr><th>TOPOLOGY/OPERATING CAPACITY</th><th>A. FIXED 330 KV</th><th>B. FLEXIBLE 500 KV</th><th>C. FIXED 500 KV</th></tr>
<tr><td>1 Two new transmission lines between Maragle and Bannaby (and power flow control between Bannaby and Sydney where needed to provide 2,000 MW capacity)

</td>
<td>Option 1A
Two new 330 kV high capacity transmission lines, switchgear and phase shifting transformer
Additional firm capacity
2,050 MW
Indicative capex
$790m</td>
<td>Option 1B
Two new 500 kV transmission lines operated at 330 kV, switchgear and phase shifting transformer
Additional firm capacity
2,170 MW initially
2,570 MW if upgraded to 500 kV
Indicative capex
$950m initially
Plus $117m for upgrade to 500 kV</td>
<td>Option 1C
Two new 500 kV transmission lines, tie transformers and switchgear
Additional firm capacity
2,510 MW
Indicative capex
$1,060m</td></tr>
<tr><td>2 New transmission lines between Maragle, Wagga Wagga and Bannaby (and power flow control between Bannaby and Sydney where needed to provide 2,000 MW capacity)

</td>
<td>Option 2A
Four new 330 kV high capacity transmission lines, switchgear and phase shifting transformers
Additional firm capacity
2,000 MW
Indicative capex
$1,240m</td>
<td>Option 2B
Four new 500 kV transmission lines operated at 330 kV, switchgear and phase shifting transformers
Additional firm capacity
2,000 MW initially
2,500 MW if upgraded to 500 kV
Indicative capex
$1,420m initially
Plus $208m for upgrade to 500 kV</td>
<td>Option 2C
Four new 500 kV transmission lines, tie transformers and switchgear
Additional firm capacity
2,500 MW
Indicative capex
$1,380m</td></tr>
<tr><td>3 New transmission lines in a 'loop' between Maragle, Bannaby and Wagga Wagga (and power flow control between Bannaby and Sydney where needed to provide 2,000 MW capacity)

</td>
<td>Option 3A
Three new 330 kV high capacity transmission lines, switchgear and phase shifting transformer
Additional firm capacity
2,000 MW
Indicative capex
$1,010m</td>
<td>Option 3B
Three new 500 kV transmission lines operated at 330 kV, switchgear and phase shifting transformer
Additional firm capacity
2,030 MW initially
2,570 MW if upgraded to 500 kV
Indicative capex
$1,220m initially
Plus $166m for upgrade to 500 kV</td>
<td>Option 3C
Three new 500 kV transmission lines, tie transformers and switchgear
Additional firm capacity
2,570 MW
Indicative capex
$1,350m</td></tr>
<tr><td>4 New transmission lines in a 'loop' between Maragle, Bannaby and Wagga Wagga and direct between Bannaby and Sydney

</td>
<td>Option 4A
Four new 330 kV high capacity transmission lines and switchgear
Additional firm capacity
2,000 MW
Indicative capex
$1,330m</td>
<td>Option 4B
Four new 500 kV transmission lines operated at 330 kV and switchgear
Additional firm capacity
2,030 MW initially
3,100 MW if upgraded to 500 kV
Indicative capex
$1,570m initially
Plus $343m for upgrade to 500 kV</td>
<td>Option 4C
Four new 500 kV transmission lines, tie transformers and switchgear
Additional firm capacity
3,100 MW
Indicative capex
$1,890m</td></tr>
</table>

Note: While the indicative additional firm capacities in this table assume an average level of import from VIC to NSW of 200 MW and average wind generation in southern NSW of 265 MW and zero SA-NSW imports, the market modelling dynamically models both of these key sources of supply for NSW.

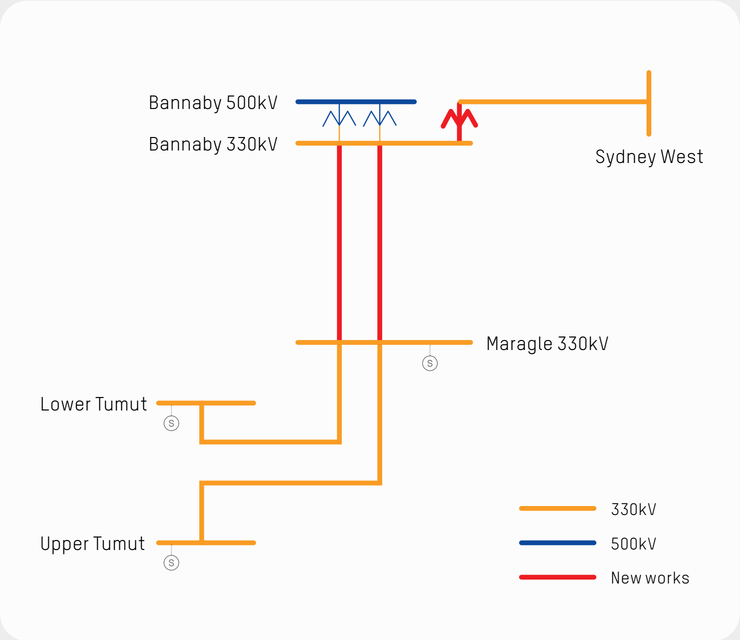
5.1 Two new route diverse lines between Maragle and Bannaby

5.1.1 Option 1A – Two new 330 kV route diverse lines from Maragle to Bannaby using high capacity conductor

This option involves constructing two new 330 kV route diverse lines from Maragle to Bannaby using a high capacity conductor and a phase shifting transformer on Bannaby – Sydney West 330 kV line to control power flows on existing transmission lines between Bannaby and Sydney. The new 330 kV circuits contain route diverse opportunity to mitigate the risk of 'high impact low probability' events (such as lightning strikes, bushfires or extreme wind events) affecting both lines simultaneously.

The high level scope includes:

- Constructing two 330 kV transmission lines using high capacity conductor:
  - Between Maragle Substation and Bannaby 330 kV Substation (260km)
- Phase shifting transformer on Bannaby-Sydney West 330 kV line
- Upgrade equipment at Lower Tumut and Upper Tumut Substations to accommodate increased fault levels
- Augment the Maragle Substation to accommodate the additional transmission lines
- Augment the existing Bannaby Substation to accommodate the additional transmission lines and phase shifting transformer



Preliminary modelling indicates that an additional 2,050 MW generation could be accommodated at times of average import from VIC and average renewable generation in southern NSW.

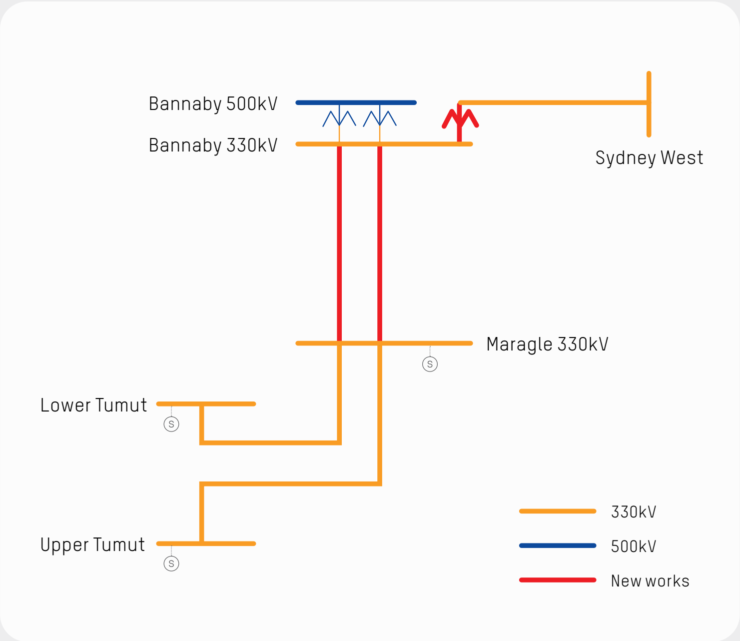
The estimated capital cost of this option is approximately $790 million.

5.1.2 Option 1B – Two new 500 kV route diverse lines initially operated at 330 kV between Maragle and Bannaby

This option involves constructing two new 500 kV route diverse lines initially operated at 330 kV between Maragle and Bannaby and a phase shifting transformer on Bannaby – Sydney West 330 kV line. The new circuits contain route diverse opportunity to mitigate the risk of 'high impact low probability' events (such as lightning strikes, bushfires or extreme wind events) affecting both lines simultaneously.

The high level scope includes:

- Construct two 500 kV transmission lines to be initially operated at 330 kV:
- Between Maragle Substation and Bannaby 330 kV Substation (260km)
- Phase shifting transformer on Bannaby-Sydney West 330 kV line
- Upgrade equipment at Lower Tumut and Upper Tumut Substations to accommodate increased fault levels
- Augment the Maragle Substation to accommodate the additional transmission lines
- Augment the existing Bannaby Substation to accommodate the additional transmission lines and phase shifting transformer



Preliminary modelling indicates that additional 2,170 MW generation could be accommodated at times of average import from VIC and average renewable generation in southern NSW.

The estimated capital cost of this option is approximately $950 million initially plus another $117 million in substation works when the lines are upgraded to 500 kV.

5.1.3 Option 1C – Two new 500 kV route diverse lines between Maragle and Bannaby

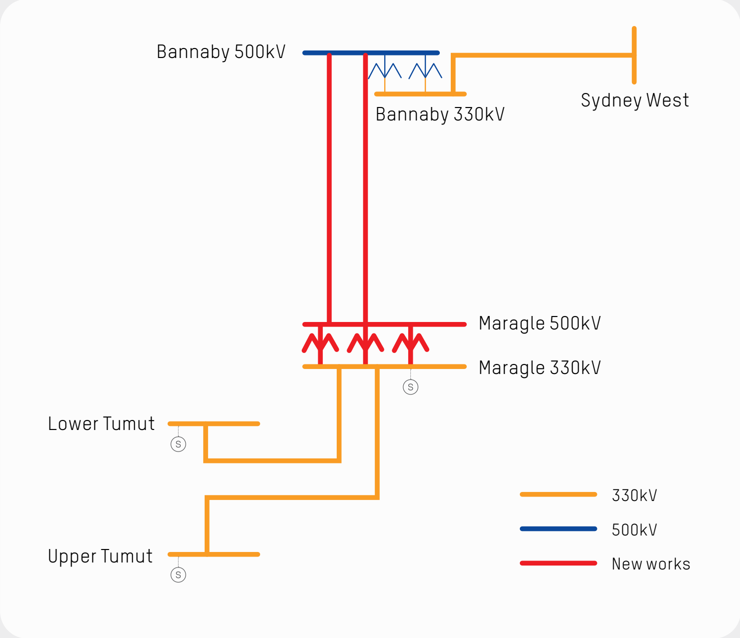
This option involves constructing two new 500 kV route diverse lines between Maragle and Bannaby. The new circuits contain route diverse opportunity to mitigate the risks of 'high impact low probability' events (such as lightning strikes, bushfires or extreme wind events) affecting both lines simultaneously.

The high level scope includes

- Construct two 500 kV transmission lines:
  - Between Maragle Substation and Bannaby 500 kV Substation (260km)
- Three new 500/330/33 kV 1,500 MVA transformers at Maragle Substation
- Upgrade equipment at Lower Tumut and Upper Tumut Substations to accommodate increased fault levels
- Augment the Maragle Substation to accommodate the additional transmission lines
- Augment the existing Bannaby Substation to accommodate the additional transmission lines

Preliminary modelling indicates that additional 2,510 MW generation could be accommodated at times of average import from VIC and average renewable generation in southern NSW.

The estimated capital cost of this option is approximately $1,060 million.



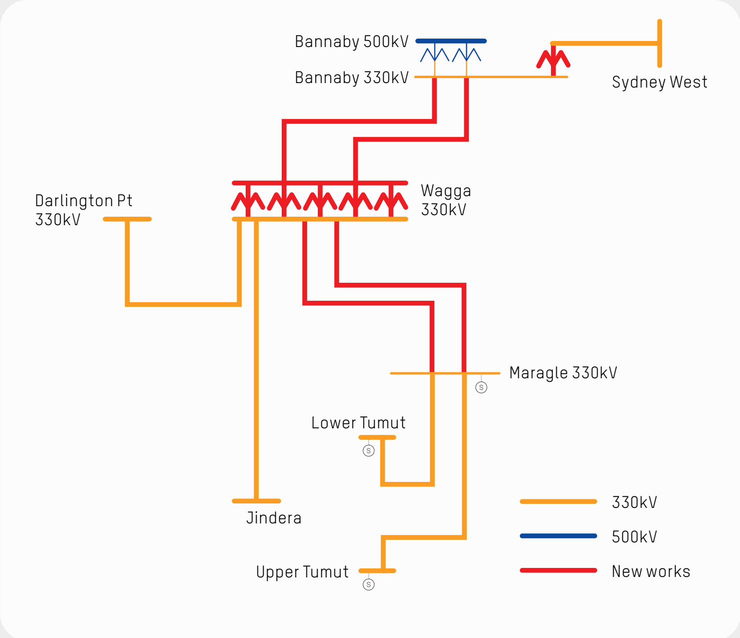
5.2 New route diverse lines between Maragle, Wagga Wagga and Bannaby using high capacity conductor

5.2.1 Option 2A – New 330 kV route diverse lines between Maragle, Wagga Wagga and Bannaby using high capacity conductor

This option involves constructing two new 330 kV route diverse lines between Maragle, Wagga Wagga and Bannaby using a high capacity conductor and a phase shifting transformer on Bannaby – Sydney West 330 kV line. The new 330 kV circuits contain route diverse opportunity to mitigate the risks of 'high impact low probability' events (such as lightning strikes, bushfires or extreme wind events) affecting multiple lines simultaneously.

The high level scope includes:

- Constructing four 330 kV transmission lines using high capacity conductor:
  - Two lines between Maragle Substation and Wagga Wagga 330 kV Substation (110km); and
  - Two lines between Wagga Wagga Substation and Bannaby 330 kV Substation (260km)
- Phase shifting transformer on Bannaby-Sydney West 330 kV line
- Phase shifting transformers on Wagga Wagga–Bannaby 330 kV line
- Upgrade equipment at Lower Tumut and Upper Tumut Substations to accommodate increased fault levels
- Augment the Maragle Substation to accommodate the additional transmission lines
- Augment the existing Substations at Wagga Wagga and Bannaby to accommodate the additional transmission lines



Preliminary modelling indicates that an additional 2,000 MW generation could be accommodated at times of average import from VIC and average renewable generation in southern NSW.

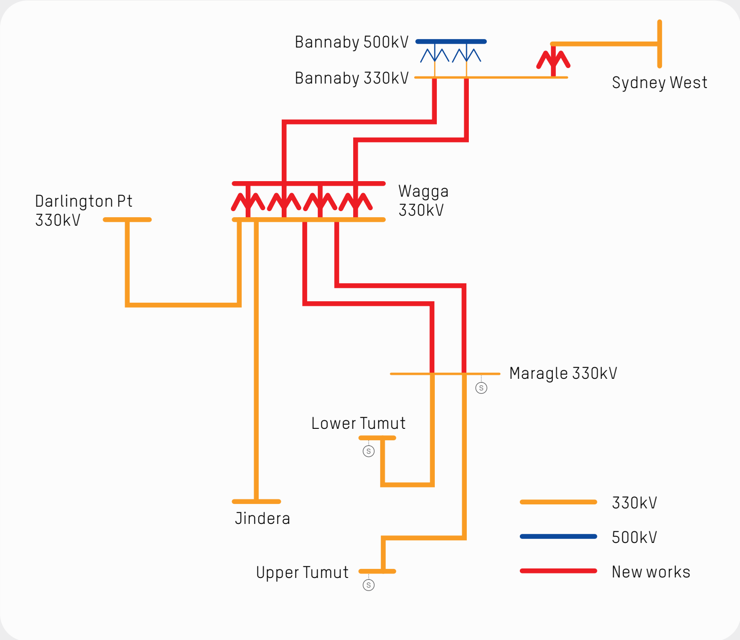
The estimated capital cost of this option is approximately $1,240 million.

5.2.2 Option 2B – New 500 kV route diverse lines initially operated at 330 kV between Maragle, Wagga Wagga and Bannaby

This option involves constructing new 500 kV route diverse lines initially operated at 330 kV between Maragle and Bannaby via Wagga Wagga and a phase shifting transformer on Bannaby – Sydney West 330 kV line. The new circuits contain route diverse opportunity to mitigate the risks of 'high impact low probability' events (such as lightning strikes, bushfires or extreme wind events) affecting multiple lines simultaneously.

The high level scope includes:

- Construct four 500 kV transmission lines to be initially operated at 330 kV:
- Two lines between Maragle Substation and Wagga Wagga 330 kV Substation (110km); and
- Two lines between Wagga Wagga Substation and Bannaby 330 kV Substation (260km)
- Phase shifting transformer on Bannaby-Sydney West 330 kV line
- Phase shifting transformers on Wagga Wagga–Bannaby 330 kV lines
- Upgrade equipment at Lower Tumut and Upper Tumut Substations to accommodate increased fault levels
- Augment the Maragle Substation to accommodate the additional transmission lines
- Augment the existing Substations at Wagga Wagga and Bannaby to accommodate the additional transmission lines



Preliminary modelling indicates that an additional 2,000 MW generation could be accommodated at times of average import from VIC and average renewable generation in southern NSW.

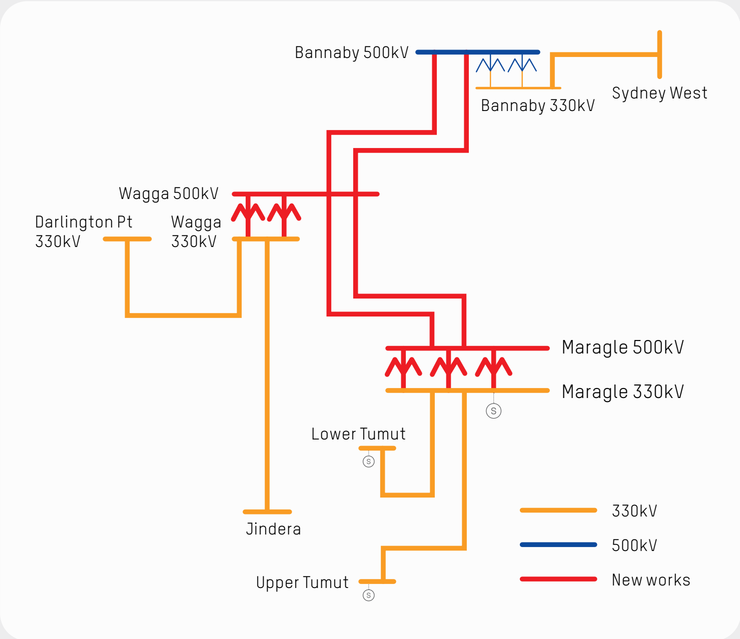
The estimated capital cost of this option is approximately $1,420 million initially plus another $208 million in substation works when the lines are upgraded to 500 kV. Option 2B is more expensive than its 500 kV counterpart (Option 2C) on account of the phase shifting transformers required to accommodate 2,000 MW of new generation at 330 kV (which are redundant at 500 kV).

5.2.3 Option 2C – New 500 kV route diverse lines between Maragle, Wagga Wagga and Bannaby

This option involves constructing new 500 kV route diverse lines between Maragle, Wagga Wagga and Bannaby. The new circuits contain route diverse opportunity to mitigate the risks of 'high impact low probability' events (such as lightning strikes, bushfires or extreme wind events) affecting multiple lines simultaneously.

The high level scope includes:

- New Wagga Wagga 500/330 kV Substation and 330 kV connection to the existing Wagga Wagga Substation
- Construct four 500 kV transmission lines:
  - Two lines between Maragle Substation and Wagga Wagga 500 kV Substation (110km); and
  - Two lines between Wagga Wagga Substation and Bannaby 500 kV Substation (260km)
- Three new 500/330/33 kV 1,500 MVA transformers at Maragle Substation and two new 500/330/33 kV 1,500 MVA transformers at Wagga Wagga Substation
- Upgrade equipment at Lower Tumut and Upper Tumut Substations to accommodate increased fault levels
- Augment the Maragle substation to accommodate the additional transmission lines
- Augment the existing Substations at Wagga Wagga and Bannaby to accommodate the additional transmission lines and transformers



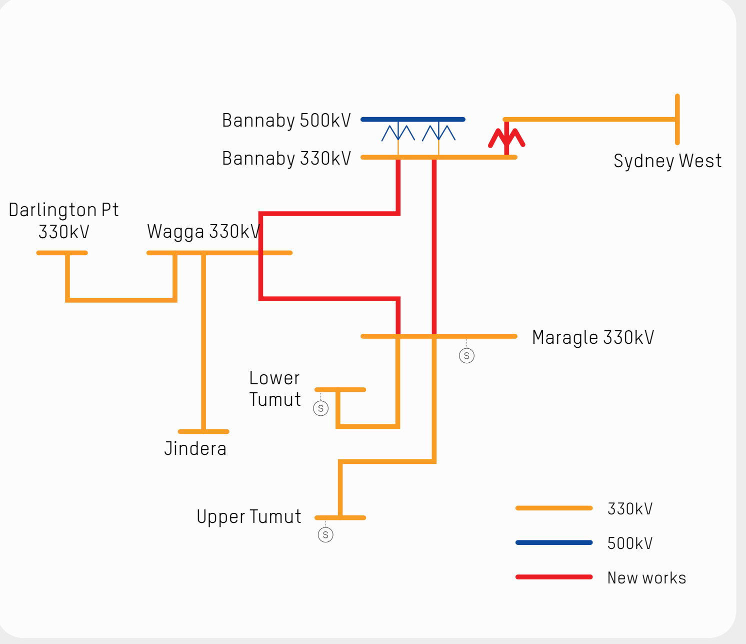
Preliminary modelling indicates that an additional 2,500 MW generation could be accommodated at times of average import from VIC and average renewable generation in southern NSW.

The estimated capital cost of this option is approximately $1,380 million.

5.3 New route diverse lines in a 'loop' between Maragle, Bannaby and Wagga Wagga using high capacity conductor

5.3.1 Option 3A – New 330 kV route diverse lines in a 'loop' between Maragle, Bannaby, Maragle and Wagga Wagga using high capacity conductor

This option involves constructing new 330 kV route diverse lines in a 'loop' between Maragle, Bannaby and Wagga Wagga using high capacity conductor and a phase shifting transformer on Bannaby – Sydney West 330 kV line. The new circuits under this option contain more route diverse opportunities than under the route 1 and route 2 options outlined above due to the 'loop' topology and so are expected to provide a greater risk reduction in terms of avoiding 'high impact low probability' events (such as lightning strikes, bushfires or extreme wind events) affecting multiple lines simultaneously.



The high level scope includes:

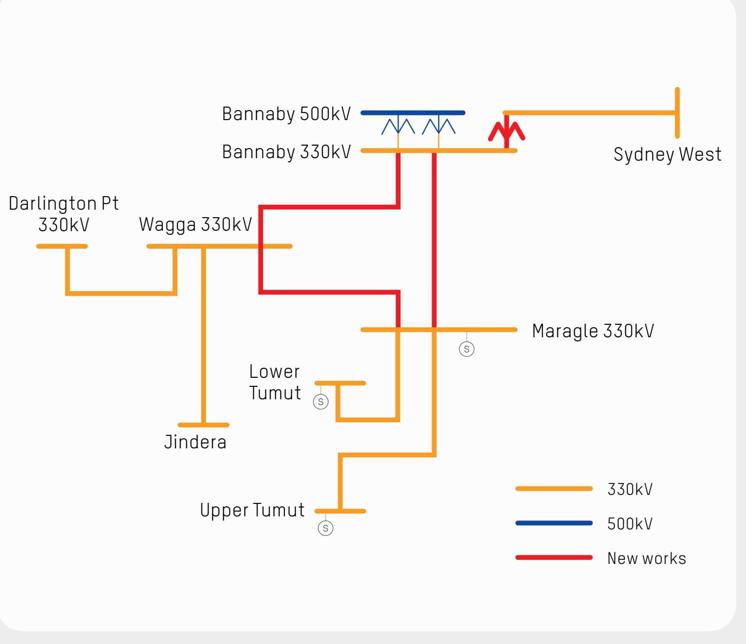
- Construct three 330 kV transmission lines using high capacity conductor:
  - Between Maragle and Bannaby 330 kV Substation (260km);
  - Between Maragle and Wagga Wagga 330 kV Substation (110km); and
  - Between Wagga Wagga and Bannaby 330 kV Substation (260km)
- Phase shifting transformer on Bannaby-Sydney West 330 kV line
- Upgrade equipment at Lower Tumut and Upper Tumut Substations to accommodate increased fault levels
- Augment the Maragle Substation to accommodate the additional transmission lines
- Augment the existing Substations at Wagga Wagga and Bannaby to accommodate the additional transmission lines.

Preliminary modelling indicates that additional 2,000 MW generation could be accommodated at times of average import from VIC and average renewable generation in southern NSW.

The estimated capital cost of this option is approximately $1,010 million.

5.3.2 Option 3B – New 500 kV route diverse lines in a 'loop' initially operated at 330 kV between Maragle, Bannaby and Wagga Wagga

This option involves constructing new 500 kV route diverse lines initially operated at 330 kV in a 'loop' between Maragle, Bannaby and Wagga Wagga, and a phase shifting transformer on Bannaby – Sydney West 330 kV line. The new circuits under this option contain more route diverse opportunities than under the route 1 and route 2 options outlined above due to the 'loop' topology and so are expected to provide a greater risk reduction in terms of avoiding 'high impact low probability' events (such as lightning strikes, bushfires or extreme wind events) affecting multiple lines simultaneously.



The high level scope includes:

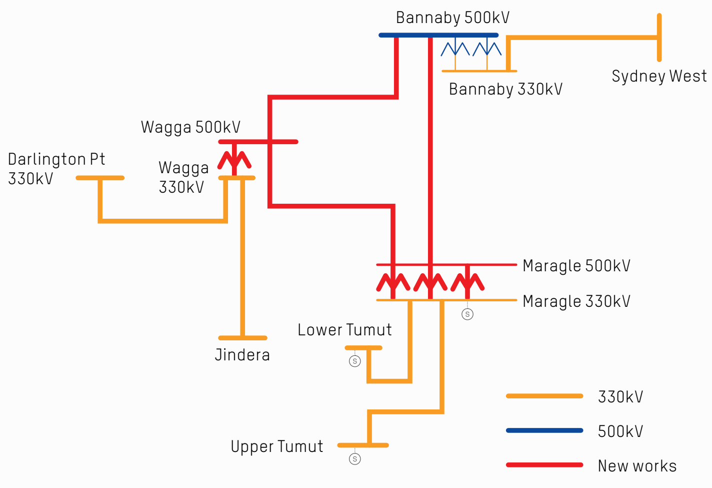
- Construct three 500 kV transmission lines:
  - Between Maragle and Bannaby 330 kV Substation (260km);
  - Between Maragle and Wagga Wagga 330 kV Substation (110km); and
  - Between Wagga Wagga and Bannaby 330 kV Substation (260km)
- Phase shifting transformer on Bannaby-Sydney West 330 kV line
- Upgrade equipment at Lower Tumut and Upper Tumut Substations to accommodate increased fault levels
- Augment the Maragle Substation to accommodate the additional transmission lines
- Augment the existing Substations at Wagga Wagga and Bannaby to accommodate the additional transmission lines.

Preliminary modelling indicates that additional 2,030 MW generation could be accommodated at times of average import from VIC and average renewable generation in southern NSW.

The estimated capital cost of this option is approximately $1,220 million initially plus another $166 million in substation works when the lines are upgraded to 500 kV.

5.3.3 Option 3C – New 500 kV route diverse lines in a 'loop' between Maragle, Bannaby and Wagga Wagga

This option involves constructing new 500 kV route diverse lines in a 'loop' between Maragle, Bannaby and Wagga Wagga. The new circuits under this option contain more route diverse opportunities than under the route 1 and route 2 options outlined above due to the 'loop' topology and so are expected to provide a greater risk reduction in terms of avoiding 'high impact low probability' events (such as lightning strikes, bushfires or extreme wind events) affecting multiple lines simultaneously.



The high level scope includes:

- New Wagga Wagga 500/330 kV Substation and 330 kV connection to the existing Wagga Wagga Substation
- Construct three 500 kV transmission lines:
  - Between Maragle and Bannaby 500 kV Substation (260km);
  - Between Maragle and Wagga Wagga 500 kV Substation (110km); and
  - Between Wagga Wagga and Bannaby 500 kV Substation (260km)
- Three new 500/330/33 kV 1,500 MVA transformers at Maragle Substation and one new 500/330/33 kV 1,500 MVA transformer at Wagga Wagga Substation
- Upgrade equipment at Lower Tumut and Upper Tumut Substations to accommodate increased fault levels
- Augment the Maragle Substation to accommodate the additional transmission lines
- Augment the existing Substations at Wagga Wagga and Bannaby to accommodate the additional transmission lines/transformers.

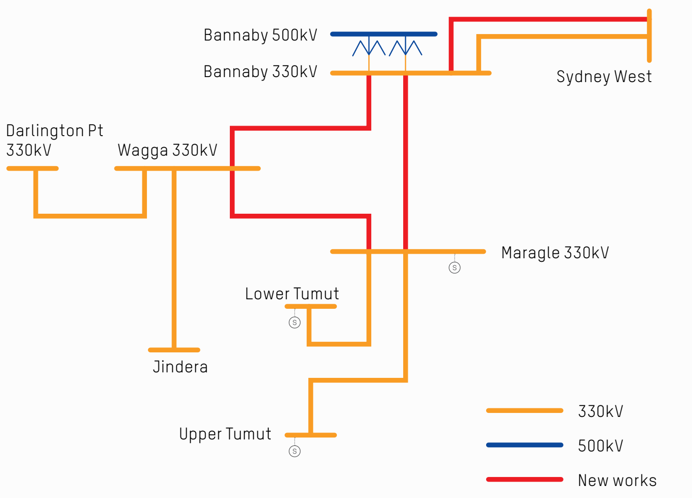
Preliminary modelling indicates that additional 2,570 MW generation could be accommodated at times of average import from VIC and average renewable generation in southern NSW.

The estimated capital cost of this option is approximately $1,350 million.

5.4 New route diverse lines in a 'loop', between Maragle, Bannaby and Wagga Wagga and direct between Bannaby and Sydney West via South Creek

5.4.1 Option 4A – New 330 kV route diverse lines in a 'loop' between Maragle, Bannaby and Wagga Wagga and direct between Bannaby and Sydney West via South Creek

This option involves constructing new 330 kV route diverse lines in a 'loop' between Maragle, Bannaby and Wagga Wagga and a new 330 kV line between Bannaby and Sydney West. The new circuits under this option contain more route diverse opportunities than under the route 1 and route 2 options outlined above due to the 'loop' topology and so are expected to provide a greater risk reduction in terms of avoiding 'high impact low probability' events (such as lightning strikes, bushfires or extreme wind events) affecting multiple lines simultaneously.



The high level scope includes:

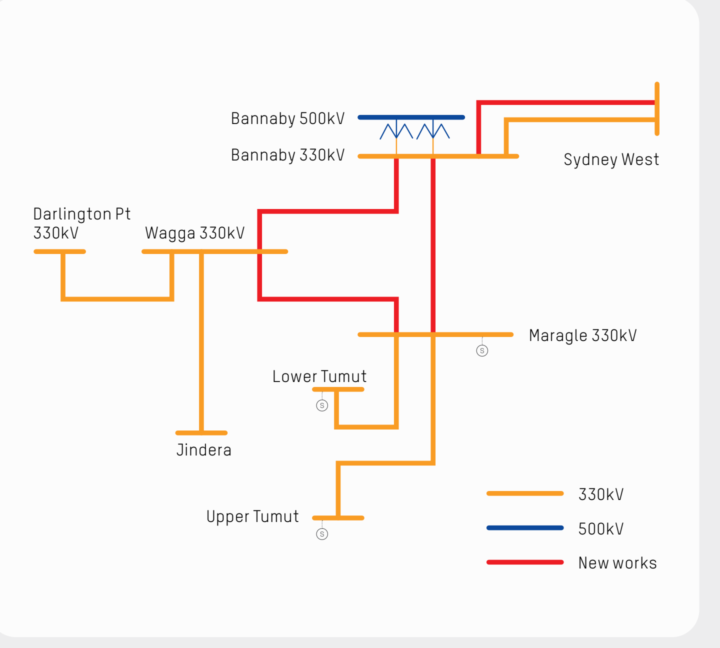
- Construct three 330 kV transmission lines using high capacity conductor:
  - Between Maragle and Bannaby 330 kV Substation (260km);
  - Between Maragle and Wagga Wagga 330 kV Substation (110km); and
  - Between Wagga Wagga and Bannaby 330 kV Substation (260km);
- Construct one 330 kV transmission line:
  - Between Bannaby and Sydney West 330 kV Substation (110km)
- Upgrade equipment at Lower Tumut and Upper Tumut Substations to accommodate increased fault levels
- Augment the Maragle connection Substation to accommodate the additional transmission lines
- Augment the existing Substations at Wagga Wagga, Bannaby and Sydney West to accommodate the additional transmission lines.

Preliminary modelling indicates that an additional 2,000 MW generation could be accommodated at times of average import from VIC and average renewable generation output in southern NSW.

The estimated capital cost of this option is approximately $1,330 million.

5.4.2 Option 4B – New 500 kV route diverse lines in a 'loop' initially operated at 330 kV between Maragle, Bannaby and Wagga Wagga and direct Bannaby to Sydney West via South Creek

This option involves constructing new 500 kV route diverse lines in a 'loop' initially operated at 330 kV between Maragle, Bannaby and Wagga Wagga and a new 330 kV line between Bannaby and Sydney West. The new circuits under this option contain more route diverse opportunities than under the route 1 and route 2 options outlined above due to the 'loop' topology and so are expected to provide a greater risk reduction in terms of avoiding 'high impact low probability' events (such as lightning strikes, bushfires or extreme wind events) affecting multiple lines simultaneously.



The high level scope includes:

- Construct three 500 kV transmission lines to be initially operated at 330 kV:
  - Between Maragle and Bannaby 330 kV Substation (260km);
  - Between Maragle and Wagga Wagga 330 kV Substation (110km); and
  - Between Wagga Wagga and Bannaby 330 kV Substation (260km);
- Construct 330 kV transmission line:
  - Between Bannaby and Sydney West 330 kV Substation 110km
- Upgrade equipment at Lower Tumut and Upper Tumut Substations to accommodate increased fault levels
- Augment the Maragle connection Substation to accommodate the additional transmission lines
- Augment the existing Substations at Wagga Wagga, Bannaby and Sydney West to accommodate the additional transmission lines.

Preliminary modelling indicates that an additional 2,030 MW generation could be accommodated at times of average import from VIC and average renewable generation output in southern NSW.

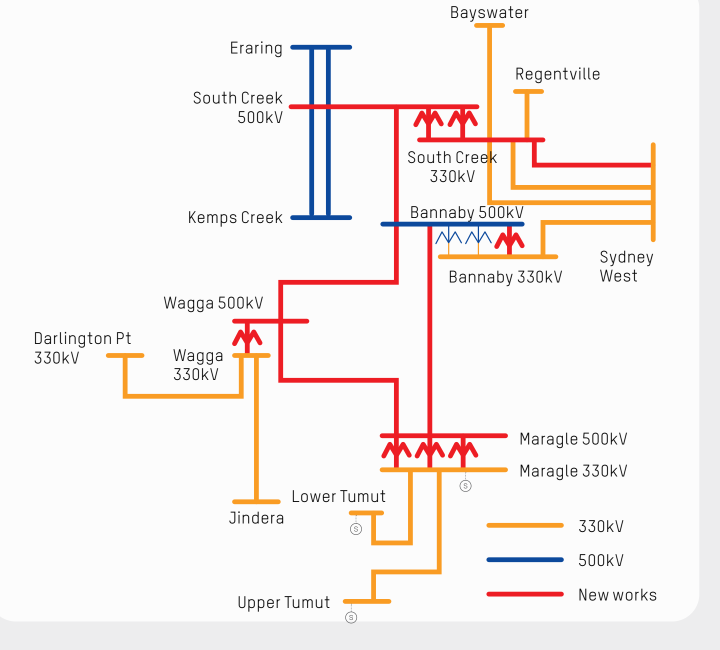
The estimated capital cost of this option is approximately $1,570 million initially plus another $343 million in substation works when the lines are upgraded to 500 kV.

5.4.3 Option 4C – New 500 kV route diverse lines in a 'loop' between Maragle, Bannaby and Wagga Wagga and direct between Bannaby and Sydney via South Creek

This option involves constructing new 500 kV route diverse lines in a 'loop' between Maragle, Bannaby and Wagga Wagga and direct between Bannaby and South Creek. The new circuits under this option contain more route diverse opportunities than under the route 1 and route 2 options outlined above due to the 'loop' topology and so are expected to provide a greater risk reduction in terms of avoiding 'high impact low probability' events (such as lightning strikes, bushfires or extreme wind events) affecting multiple lines simultaneously.

The high level scope includes:

- New Wagga Wagga 500/330 kV Substation and 330 kV connection to the existing Wagga Wagga Substation
- New 500/330 kV South Creek Substation connecting existing 330 kV lines 32/38 and 500 kV lines 5A1/5A2
- Construct four 500 kV transmission lines:
  - Between Maragle and Bannaby 500 kV Substation (260km);
  - Between Maragle and Wagga Wagga 500 kV Substation (110km);
  - Between Wagga Wagga and Bannaby 500 kV Substation (260km); and
  - Between Bannaby and South Creek 500 kV Substation (102km)
- Construct one 330 kV transmission line:
  - Between South Creek and Sydney West Substation (8km)
- Seven new 500/330/33 kV 1,500 MVA transformers: three transformers at Maragle Substation, one transformer at Wagga Wagga Substation, one transformer at Bannaby Substation and two transformers at South Creek Substation
- Upgrade equipment at Lower Tumut and Upper Tumut Substations to accommodate increased fault levels
- Augment the Maragle Substation to accommodate the additional transmission lines
- Augment the existing Substations at Wagga Wagga, Bannaby and Sydney West to accommodate the additional transmission lines/ transformers.



Preliminary modelling indicates that additional 3,100 MW generation could be accommodated at times of average import from VIC and average renewable generation in southern NSW.

The estimated capital cost of this option is approximately $1,890 million.

5.5 Options considered but not progressed

As outlined in section 4.2.2, Snowy Hydro[49] and participants at the TAPR forum raised the possibility of a staged development, bringing forward one of the circuits from Maragle to Bannaby prior to the completion of Snowy 2.0 to support load in New South Wales with improved access to existing generation at the Snowy scheme and Victorian generation. TransGrid has not included this as a credible option in the assessment as it is not technically feasible to move forward parts of HumeLink, given that there is insufficient time to obtain the necessary environmental approvals to do so.

TransGrid has also considered a range of other potential options as part of this RIT-T to-date but ceased to progress these as part of the PSCR on the grounds that they are not considered technically and/or economically feasible, and therefore are not credible options. A summary of each is provided in Table 5.2.

Table 5.2 Options considered but not progressed at the PSCR stage

OPTION	OVERVIEW	REASON(S) IT HAS NOT BEEN PROGRESSED
Brownfield options	TransGrid has considered options that re-use existing transmission line routes ("brownfield" options). These options may be, for example: • replacement of existing single circuit transmission lines with double circuit transmission lines; and • replacement of existing standard conductor transmission lines with high capacity conductor transmission lines. The scope of "brownfield" options includes demolition of existing transmission lines and construction of new single circuit high capacity or double circuit transmission lines on multiple existing transmission line routes.	The removal of several existing transmission lines for their demolition and construction periods would remove capacity from the transmission system and significantly increase constraints on generation and inter-regional transfers within the NEM. TransGrid will consider re-use of existing corridors where practical and cost-effective, where the impact of outages on the market is within TransGrid's reliability and network performance obligations.
HVDC options	TransGrid has also considered HVDC options following the topologies set out in options 1, 2, 3 and 4.[50] These would require the installation of two or three new HVDC transmission lines, tie transformers and switchgear	Preliminary estimation has found that HVDC options would be substantially more expensive than other potential greenfield options and would not provide materially higher capacities. These options have costs that are between 50 and 100 per cent higher than other options with comparable capacity. These options are therefore not considered economically feasible, as the higher costs are not expected to be outweighed by materially higher market benefits,[51] and have not been considered further as part of this RIT-T.

49 Snowy Hydro, p 2.
50 The topology of option 3D differs from the other options, with transmission lines from Snowy 2.0 to Wagga and Wagga to Sydney, to minimise the number of HVDC converter stations required.
51 AER, *Regulatory Investment Test for Transmission Application Guidelines*, December 2018, p13.

06
Scenario analysis

Summary of key points:

- The RIT-T assessment considers four reasonable scenarios, which differ in relation to demand outlook, DER uptake, assumed generator fuel prices, assumed emissions targets, retirement of coal-fired power stations, and generator and storage capital costs.
- The scenarios reflect a broad range of potential outcomes across the key uncertainties that are expected to affect the future market benefits of the investment options being considered and are largely aligned with the scenarios proposed by AEMO for the 2020 ISP.
- A range of sensitivity tests have also been investigated in order to further test the robustness of the outcome to key uncertainties.

The transmission investments considered as part of this RIT-T involve long-lived assets, and it is important that the recommended preferred option does not depend on a narrow view of future outcomes, given that the future is inherently uncertain.

Uncertainty is captured under the RIT-T framework through the use of plausible scenarios, which reflect different assumptions about future market development, and other factors that are expected to affect the relative market benefits of the options being considered. The adoption of different plausible scenarios tests the robustness of the RIT-T assessment to different assumptions about how the energy sector may develop in the future.

The robustness of the outcome is also investigated through the use of sensitivity analysis in relation to key input assumptions. We have identified the key factors driving the outcome of this RIT-T and sought to identify the 'threshold value' for these factors, beyond which the outcome of the analysis would change.

6.1 The assessment considers four 'reasonable scenarios'

The RIT-T is focused on identifying the top ranked credible option in terms of expected net benefits. However, uncertainty exists in terms of estimating future inputs and variables (termed future 'states of the world').

To deal with this uncertainty, the NER requires that costs and market benefits for each credible option are estimated under reasonable scenarios and then weighted based on the likelihood of each scenario to determine a weighted ('expected') net benefit.[52] It is this 'expected' net benefit that is used to rank credible options and identify the preferred option.

The credible options have been assessed under four scenarios as part of this PADR assessment, which are largely based on four of the scenarios identified by AEMO to be used in the 2020 ISP. The table below summarises the specific key variables that influence the net benefits of the options under each of the four scenarios considered.

As outlined in section 2.1, there are three sets of assumptions that differ slightly from those being used by AEMO in the 2020 ISP: i.e., retirements of coal-fired power stations, the implications of the COP21 commitment and the assumptions made in relation to VRET/QRET.

These differences have been adopted since:

- AEMO's specific ISP timing assumptions regarding the retirement of coal-fired generators were not available at the time the market modelling inputs for this PADR were required to be finalised – TransGrid and EY therefore adopted the range summarised below to reflect the expected range of outcomes for these assumptions, and tested sensitivities of retirement of generators based on economic viability;
- similarly, the specific implications of AEMO ISP assumptions on the COP21 commitment for emissions reduction trajectories were not available at the time the market modelling inputs for this PADR were required to be finalised – TransGrid and EY therefore adopted the same emissions constraints as applied in the QNI RIT-T (with the exception of the step-change scenario, which was not included in the QNI RIT-T, where the same methodology has been applied to derive emissions constraints); and
- a more conservative approach to VRET/QRET under the fast-change scenario has been adopted than is proposed for the 2020 ISP (i.e., the assumptions below for this scenario include greater renewable uptake in these two states than is proposed under the ISP assumptions).

Overall, TransGrid considers these departures serve to further stress test the expected net market benefits from the twelve options considered in this PADR. The 2020 ISP assumptions have been included in parentheses in the table below, for comparison.

Additional detail and discussion of each scenario is provided in the accompanying market modelling report released alongside this PADR.

52 The AER RIT-T Application Guidelines explicitly refer to the role of scenarios as the primary means of taking uncertainty into account. See: AER, RIT-T Application Guidelines, December 2018, p. 42.

Table 6.1 PADR modelled scenario's key drivers input parameters

KEY DRIVERS INPUT PARAMETER	SLOW-CHANGE SCENARIO	CENTRAL SCENARIO	FAST-CHANGE SCENARIO	STEP-CHANGE SCENARIO
Underlying consumption and consumer behaviour[53]	AEMO 2020 ISP slow-change	AEMO 2020 ISP central	AEMO 2020 ISP fast-change	AEMO 2020 ISP step-change
Generation technology cost projects	CSIRO GenCost 4 – degrees for solar and battery Weaker reductions than CSIRO GenCost 4 – degrees for wind, pumped hydro and solar thermal	CSIRO GenCost 4 – degrees for wind, solar, pumped hydro, battery and solar thermal	CSIRO GenCost 2 – degrees for wind, solar, pumped hydro, battery and solar thermal	CSIRO GenCost 2 – degrees for solar Stronger reductions than CSIRO GenCost 2 – degrees for wind, pumped hydro and solar thermal Faster than CSIRO GenCost 2 – degrees for battery
Retirements of coal fired power stations[54]	Half of coal power stations' capacity is retired 5 years later than end-of-technical-lives (ISP: Maintained at least until expected closure year, potentially extended if economic to do so).	Retired by announced retirement date or end-of-technical-lives (ISP: In line with expected closure years, or earlier if economic to do so).	Half of coal power stations' capacity is retired 2 years earlier than end-of-technical-lives (ISP: In line with expected closure year, or earlier if economic or driven from decarbonisation objectives).	Half of coal power stations' capacity is retired 5 years earlier than end-of-technical-lives (ISP: In line with expected closure year, or earlier if economic or driven from decarbonisation objectives).
Gas and coal fuel costs	AEMO 2019 slow forecasts	AEMO 2019 neutral forecasts		AEMO 2019 fast forecasts
Federal Large-scale Renewable Energy Target (LRET)	33 TWh by 2020 to 2030			
COP21 commitment (Paris agreement)	28% reduction from 2005 by 2030, then a linear extrapolation beyond 2030 to 70% reduction of 2016 emissions by 2050 (ISP: 26% reduction in emissions by 2030 with no coordinated carbon budget)		52% reduction from 2005 by 2030, then a linear extrapolation beyond 2030 to 90% reduction of 2005 emissions by 2050 (ISP: 26% reduction in emissions by 2030 and carbon budgets consistent with the degree of decarbonisation).	
VRET	40% by 2025	40% by 2025 and 50% by 2030	40% by 2025 and 50% by 2030 (ISP: 40% by 2025)	40% by 2025 and 50% by 2030
QRET	Q400 only[55]	50% by 2030	50% by 2030 (ISP: Q400 only)	50% by 2030
Snowy 2.0 generation	Included by 2025.			
Project EnergyConnect	The proposed SA to NSW interconnector is assumed constructed by 2023.			
Western Victoria Renewable Integration RIT-T	The preferred option is assumed constructed by 2025 (220 kV upgrade by 2024 and 500 kV to Sydenham by 2025).			
MarinusLink and Battery of the Nation[56]	Excluded		600MW capacity increase is assumed constructed by July 2033.	1,200MW capacity increase is assumed constructed by July 2033.
Victoria to NSW Interconnector Upgrade	The preferred option is assumed constructed by 2022.			
VNI West[57]	Excluded.	VNI West is assumed constructed by 2026.		
QNI upgrade	The preferred ISP option for QNI minor upgrade is assumed to be constructed by 2022. QNI major upgrade is excluded in all core scenarios.			

53 'Consumer behaviour' relates to rooftop PV, demand-side participation, EV penetration and small-scale battery penetration and charging and discharging pattern.

54 Higher levels of renewable energy generation create an oversupply during certain periods of the day, displacing conventional generation and result in earlier retirement. This phenomenon is amplified in a high load growth scenario, with correspondingly higher levels of renewable energy generation.

55 'Q400' is the name given to the reverse auction the Queensland government undertook for up to 400 megawatts of renewable energy capacity, including up to 100 megawatts of energy storage, under the Powering Queensland Plan. See: https://www.business.qld.gov.au/industries/mining-energy-water/energy/renewable/projects-queensland/renewables-400

56 TransGrid notes that the PADR for the MarinusLink was released on 5 December 2019 and finds that an initial 750 MW link in 2028, followed by a further 750 MW in 2032, is the preferred option. See: TasNetworks, Project Marinus RIT-T Project Assessment Draft Report, available at: https://www.marinuslink.com.au/wp-content/uploads/2019/12/rit-t-project-assessment-draft-report.pdf

57 TransGrid and AEMO released a PSCR for this RIT-T on 13 December 2019, which states that delivery of all options assessed is expected to take six to eight years, with indicative completion by 2028-30. The expected impact of this latest timing assumption for VNI West is discussed in section 8.7.5.

These variables do not reflect all future uncertainties that may affect future market benefits of the options being considered, but are expected to provide a broad enough 'envelope' of where these variables may reasonably be expected to fall. Moreover, the scenarios vary several variables at a time and do so in an internally consistent manner, consistent with the AER RIT-T Guidelines.[58]

6.2 Weighting the reasonable scenarios

We have weighted each of the above scenarios equally (i.e., 25 per cent each).

While the above probabilities have been applied to weight the estimated market benefits and identify the preferred option across scenarios (illustrated in section 8), we have also carefully considered the results in each scenario in section 8.

As outlined in section 8.5, the assessment in this PADR finds that the top ranked options are invariant to the scenarios investigated and so are independent of the weightings applied.

6.3 Sensitivity analysis

In addition to the scenario analysis, we have also considered the robustness of the outcome of the cost benefit analysis through undertaking a range of sensitivity testing.

The range of factors tested as part of the sensitivity analysis in this PADR are:

- the retirement of existing plant based on their economic viability;
- sensitivity to Snowy 2.0's development;
- higher DER uptake (as per the 2019 ISP assumption);
- development of QNI Stage 2 in 2028-29;
- development of VNI West in 2034-35;
- staged development of Option 3C;
- 50 per cent POE demand forecasts; and
- whether there are benefits from the use of demand management prior to commissioning of HumeLink.

The results of the sensitivity tests are discussed in section 8.7.

In addition, as part of the analysis, we have also identified the key factors driving the outcome of this RIT-T and sought to identify the 'threshold value' for key variables beyond which the outcome of the analysis would change.

The above list of sensitivities focuses on the key variables that could impact the identified preferred option.

58 AER, *Application guidelines for the regulatory investment tests*, Final decision, December 2018, p 42.

07
Market benefits

Summary of key points:

- Seven categories of market benefit under the RIT-T are considered material for this RIT-T and have been estimated as part of the economic assessment for the credible options within this PADR.
- 'Option value' has been estimated for both the flexible 500 kV options as well as going via Wagga Wagga.
- Wholesale market modelling has been used to estimate these categories of market benefits.
- The market modelling assumptions and inputs have been updated since the PSCR to align with those to be used for the 2020 ISP in most instances.
- A separate modelling report has been released alongside this PADR that provides greater detail on the modelling approaches and assumptions, including details on the technical constraints adopted.

As outlined in section 3, the key benefits expected from increasing transmission capacity are driven by anticipated changes in wholesale market outcomes going forward.

The RIT-T requires categories of market benefits to be calculated by comparing the 'state of the world' in the base case where no action is undertaken, with the 'state of the world' with each of the credible options in place, separately. The 'state of the world' is essentially a description of the NEM outcomes expected in each case, and includes the type, quantity and timing of future generation investment as well as unrelated future transmission investment (e.g., that is required to connect REZ).

A wholesale market modelling approach has been applied to estimate the market benefits associated with each credible option included in this RIT-T assessment.[59]

This section first outlines the specific categories of market benefit that are expected from reinforcing the Southern Shared Network of New South Wales, before providing an overview of the wholesale market modelling undertaken.

We are publishing a separate modelling report alongside this PADR that provides greater detail on the modelling approach and assumptions, to provide transparency to market participants.

7.1 Expected market benefits from expanding transfer capacity

The specific categories of market benefit under the RIT-T that have been modelled as part of this PADR are:

- changes in fuel consumption in the NEM arising through different patterns of generation dispatch;
- changes in costs for parties, other than the RIT-T proponent (i.e., changes in investment in generation and storage);
- differences in unrelated transmission investment (in particular, the cost of connecting REZ);
- changes in involuntary load curtailment;
- changes in voluntary load curtailment;
- changes in network losses; and
- option value associated with the flexible 500 kV options (i.e., options 1B, 2B, 3B and 4B).

The approach taken to estimating each of these market benefits is outlined below and discussed in greater detail in the accompanying market modelling report.

59 The RIT-T requires that in estimating the magnitude of market benefits, a market dispatch modelling methodology must be used, unless the TNSP(s) can provide reasons why this methodology is not relevant. See: AER, Final Regulatory Investment Test for Transmission, June 2010, version 1, paragraph 11, p. 6.

7.1.1 Changes in fuel consumption in the NEM

This category of market benefit is expected where credible options result in different patterns of generation and storage dispatch across the NEM, compared to the base case.

In particular, the primary effects of reinforcing the NSW Southern Shared Network come from enabling demand centres to be supplied by lower cost generation than can be expected if no upgrade is undertaken. The market modelling finds that new renewable generation avoids the need for gas-fired generation to operate. As outlined in section 8, this is the largest category of benefit estimated (except under the slow-change scenario).

7.1.2 Changes in costs for other parties in the NEM

This category of market benefit is expected where credible options result in different investment patterns of generators and large-scale storage across the NEM, compared to the base case.

In particular, the market modelling finds that there are large amounts of avoided new dispatchable generation in NSW compared to the base case. As shown in section 8, these avoided or deferred, costs associated with generation and storage are the second most material category of market benefit estimated across the options.

7.1.3 Differences in unrelated transmission costs

This benefit category relates to the costs of intra-regional transmission investment associated with the development of REZs that could be avoided if a credible option is pursued.

AEMO has identified a number of REZs in various NEM jurisdictions as part of the ISP and has included allowances for transmission augmentations that it considers would be required to develop those REZs. The credible options being considered in this RIT-T can allow development of some of these REZs without the need for additional intra-regional transmission investment (or less of it).

7.1.4 Changes in involuntary load curtailment

Increasing the transmission transfer capacity in southern New South Wales increases the generation supply availability from existing generation to meet New South Wales demand. This will provide greater reliability for each state by reducing the potential for supply shortages and the consequent risk of involuntary load shedding.

This market benefit involves quantifying the impact of changes in involuntary load shedding associated with the implementation of each credible option via the time sequential modelling component of the market modelling. Specifically, the modelling estimates the MWh of unserved energy (USE) in each trading interval over the modelling period, and then applies a Value of Customer Reliability (VCR, expressed in $/MWh) to quantify the estimated value of avoided USE for each option. We have adopted AEMO's standard assumptions for VCR for the purposes of this assessment.

This category of market benefit has been found to be relatively small within the market modelling. This is due to there not being a material difference in the quantity of involuntary load shedding between each option and the base case, under each of the scenarios.

7.1.5 Changes in voluntary load curtailment

Voluntary load curtailment is when customers agree to reduce their load once wholesale prices in the NEM reach a certain threshold. Customers usually receive a payment for agreeing to reduce load in these circumstances. Where the implementation of a credible option affects wholesale price outcomes, and in particular results in wholesale prices reaching higher levels in some trading intervals than in the base case, this may have an impact on the extent of voluntary load curtailment.

This class of market benefit has also been found to be relatively low within the market modelling, reflecting that the level of voluntary load curtailment currently present in the NEM is not significant.

7.1.6 Changes in network losses

The time sequential market modelling has taken into account the change in network losses that may be expected to occur as a result of the implementation of each of the credible options, compared with the level of network losses which would occur in the base case, for each scenario.

The benefit of changes to network losses is captured within the wholesale market modelling of dispatch cost benefits of avoided fuel costs and changes to voluntary and involuntary load shedding.

The reduction in network losses between the base case and the options is material for the options considered in this PADR (particularly for the 500 kV options) and reduces both the energy to be produced by fossil fuel generators to account for the losses, and a reduction in new capacity that has to be built to supply demand, particularly during peak periods.

7.1.7 Option value

This PADR investigates whether there is significant option value associated with flexible options, which would readily and cost-effectively increase the transfer capacity between the Snowy Mountains and Sydney in the future. This is investigated through inclusion of option variants that would be built at 500 kV but initially operated at 330 kV (options 1B, 2B, 3B, 4B). These options provide flexibility to 'scale up' transfer capacity at a later date, in response to changes in demand and/or the expansion of generation capacity along the transmission corridor, whilst avoiding upfront investment associated with higher capacity.

60 AER, RIT-T Application Guidelines, December 2018, pp. 59-60.

The modelling in this PADR estimates the option value associated with these flexible options as part of the scenario analysis, which is in line with the AER's RIT-T Guidelines.[60] Specifically, the flexible options are assumed to operate at 330 kV until the benefits from upgrading to 500 kV exceed the annualised upgrade cost. This means that the cost of upgrading these options to 500 kV is not incurred until it is expected to be net beneficial to do so.

Since the benefits from each of these flexible options differ across the scenarios, the PADR modelling finds it is optimal to upgrade these options to 500 kV at different times for each scenario. Specifically, the PADR modelling finds that it is optimal to upgrade these flexible options from 330 kV to 500 kV in the following years:

- 2029-30 in the central scenario;
- 2035-36 in the slow-change scenario;
- 2028-29 in the fast-change scenario; and
- 2026-27 in the step-change scenario.

As outlined in section 8, the flexible 500 kV options are found to provide lower net benefits than the fixed 500 kV options under all scenarios.

The same approach has been adopted to test the option value associated with route construction staging for the preferred option (i.e., the sensitivity presented in section 8.7.5).

7.2 Wholesale market modelling has been used to estimate market benefits

TransGrid engaged EY to undertake the wholesale market modelling to assess the market benefits expected to arise under each of the credible options and scenarios.

EY has applied a linear optimisation model and performed hourly, time-sequential, long-term modelling for the NEM to estimate categories of wholesale market benefits expected under each of the options. Specifically, EY has undertaken two separate market simulation exercises, namely:

- Long-term Investment Planning – identifies the optimum generation (including storage) and unrelated transmission infrastructure development schedule, while meeting reliability requirements, policy objectives, and technical generator and network performance limitations; and
- Market Dispatch Simulation – mimics AEMO's NEM Dispatch Engine ('NEMDE') embedded within a Monte Carlo random outage pattern of generator failures for a large number of iterations (simulation-years) and determining the half-hourly dispatch of generation for further verification of the reliability requirement assessment arising from the long-term model.

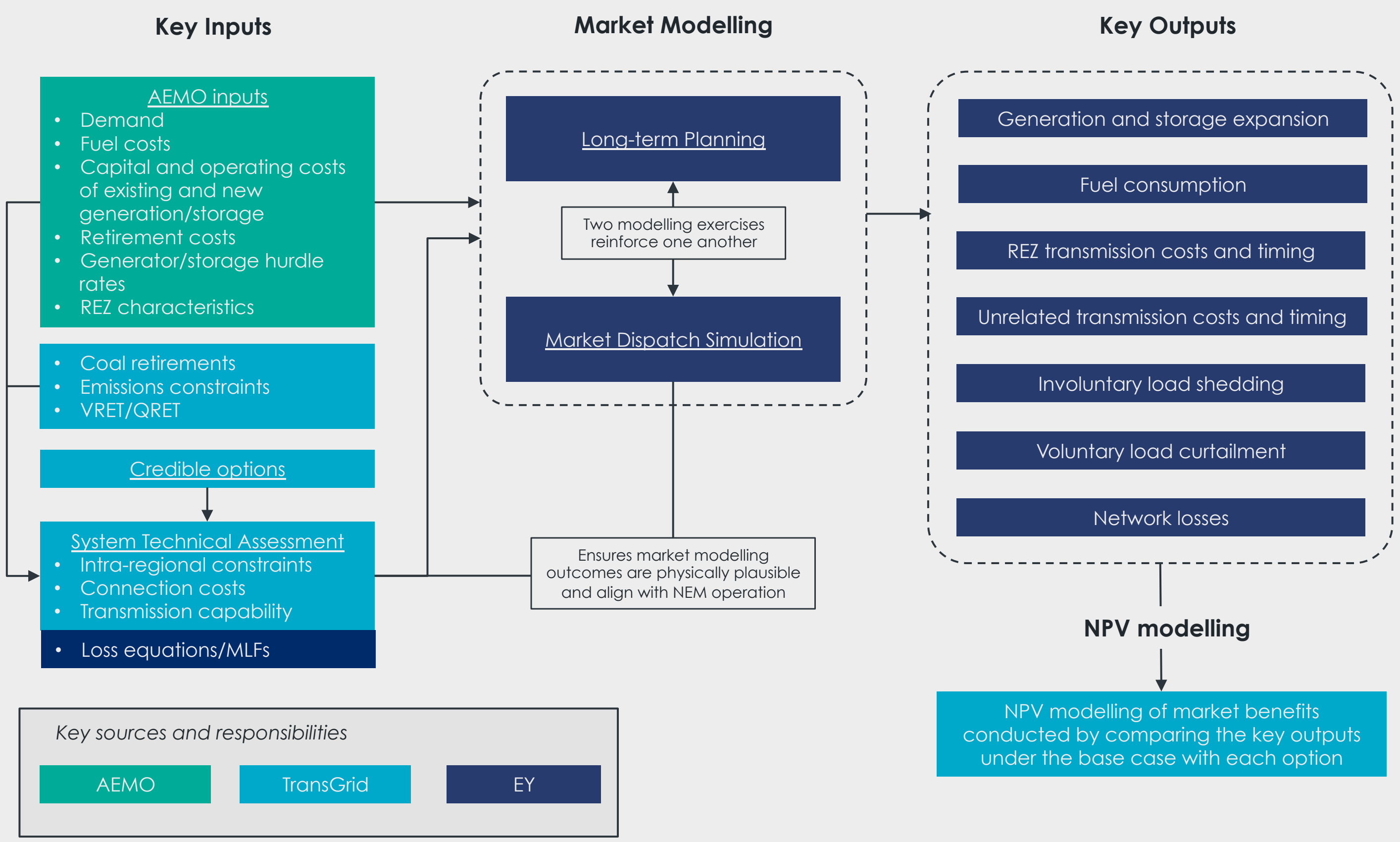
The first solves for the least-cost generation and transmission infrastructure development across the assessment period while meeting energy policies, whereas the second investigates the resulting generation and transmission infrastructure development from a deeper operational perspective. In short, the first creates an optimal investment plan, while the second explores the appropriateness of the investment schedule given the simplifications made in the linear optimisation due to computer processing power limitations.

TransGrid has undertaken a detailed System Technical Assessment, which evaluates the power system behaviour and performance under each credible option and ensures market modelling outcomes are physically plausible, follow the operation of the NEM, and that the benefits of credible options align with the changes to the power system under each credible option. This assessment serves as an input to the two wholesale market modelling exercises EY has undertaken (as outlined above).

These exercises are consistent with an industry-accepted methodology, including within AEMO's ISP.

Figure 2 illustrates the interactions between the key modelling exercises, as well as the primary party responsible for each exercise and/or where the key assumptions have been sourced.

Figure 2 Overview of the market modelling process and methodologies



60 AER, RIT-T Application Guidelines, December 2018, pp. 59-60.

As these modelling exercises investigate different aspects of the market simulation process, they necessarily interact and are executed iteratively using inputs and outputs. For example, the Market Dispatch Simulation uses the generation infrastructure development schedule from the Long-term Investment Planning exercise, the detailed network representations from the System Technical Assessment exercise, and other key input assumptions such as those from AEMO.

The two sub-sections below provide additional detail on the two key wholesale market modelling exercises EY have undertaken as part of this PADR assessment. The third sub-section details how intra-regional constraints have been modelled.

The accompanying market modelling report provides additional detail on these modelling exercises, as well as the key modelling assumptions and approach adopted more generally.

7.2.1 Long-term Investment Planning

The Long-term Investment Planning's function is to develop generation (including storage) and unrelated transmission infrastructure forecasts over the assessment period for each of the credible options and base cases.

This exercise determines the least-cost development schedule for each credible option and scenario drawing on assumptions regarding demand, reservoir inflows, generator outages, wind and solar generation profiles, and maintenance over the assessment period.

The generation and transmission infrastructure development schedule resulting from the Long-term Investment Planning is determined such that:

- it economically meets hourly regional and system-wide demand while accounting for network losses;
- it builds sufficient generation capacity to meet demand when economic while considering potential generator forced outages;
- the cost of unserved energy is balanced with the cost of new generation investment to supply any potential shortfall;
- generator's technical specifications such as minimum stable loading, and maximum capacity are observed;
- notional interconnector flows do not breach technical limits and interconnector losses are accounted for;
- hydro storage levels and battery storage state of charge do not breach maximum and minimum values and cyclic losses are accounted for;
- new generation capacity is connected to locations in the network where it is most economical from a whole of system cost;
- NEM-wide emissions constraints are adhered to;
- NEM-wide and state-wide renewable energy targets are met, or else penalties are applied;
- refurbishment costs are captured;
- generator maintenance outages are scheduled to represent planned generator outages;
- regional and mainland reserve requirements are met;
- energy-limited generators such as Tasmanian hydro-electric generators and Snowy Hydro-scheme are scheduled to minimise system costs; and
- the overall system cost spanning the whole outlook period is optimised whilst adhering to constraints.

The Long-term Investment Planning adopts the same commercial discount rates as used in the NPV discounting calculation in the cost benefit analysis. This is consistent with the approach being taken in the 2020 ISP (and was applied in the inaugural 2018 ISP).[61]

Coal-fired and gas-fired generation is treated as dispatchable between its minimum load and its maximum load in the modelling. Coal-fired 'must run' generation is dispatched whenever available at least at its minimum load, while gas-fired CCGT 'must run' plant is dispatched at or above its minimum load. Open cycle gas turbines are typically bid at their short run marginal cost with a zero minimum load level, and started and operated whenever the price is above that level. The accompanying market modelling report provides additional detail on how cycling constraints have been reflected in the analysis.

The Long-term Investment Planning model ensures there is sufficient dispatchable capacity in each region to meet peak demand in the region, plus a reserve level sufficient to allow for generation or transmission contingences which can occur at any time, regardless of the present dispatch conditions.

Due to load diversity and sharing of reserve across the NEM, the reserve to be carried is minimised at times of peak, and provided from the lowest cost providers of reserve including allowing for each region to contribute to its neighbours reserve requirements through interconnectors.

The market modelling report accompanying this PADR provides additional detail on the assumptions and methodological approaches adopted in the Long-term Investment Planning, including necessary model simplifications, sub-regional modelling and how new capacity has been modelled.

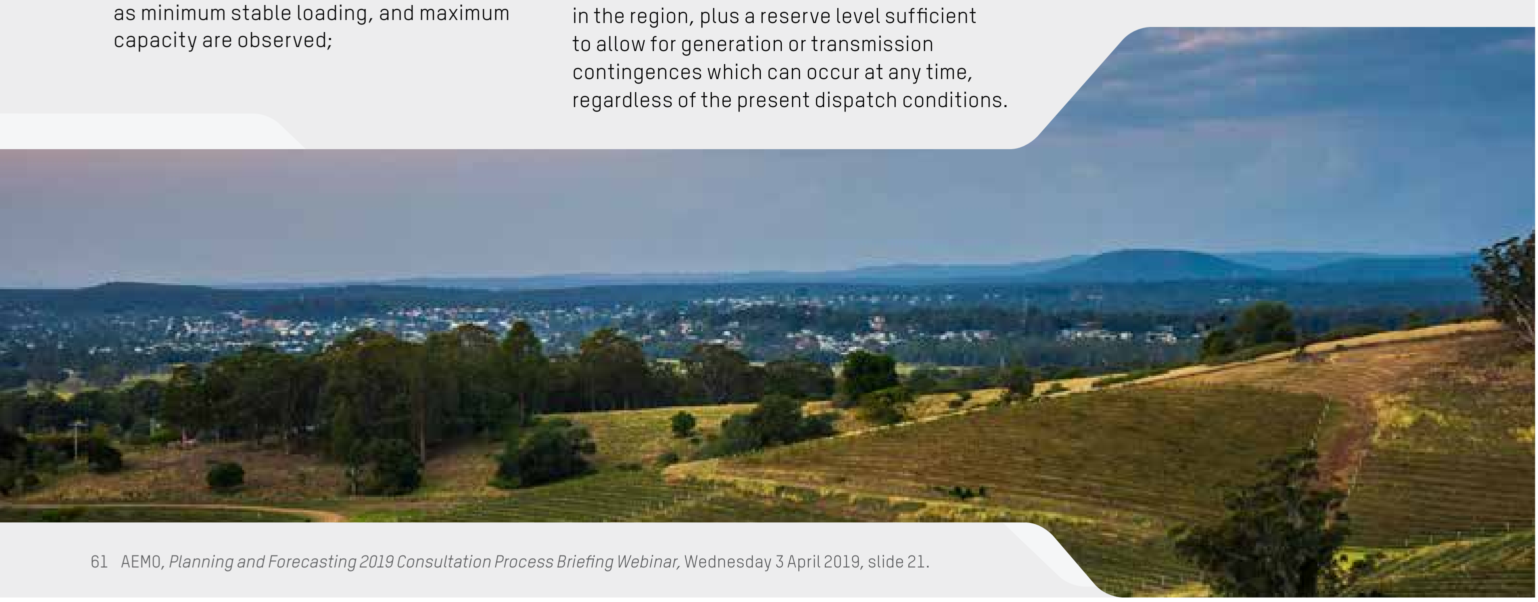
7.2.2 Market Dispatch Simulation

The Market Dispatch Simulation investigates the market and system operation using the resulting generation and transmission development schedule and the detailed network representation from the System Technical Assessment and the Long-term Investment Planning activities.

The model sequentially calculates the least variable cost half-hourly generation dispatch that observes inter-regional and intra-regional network technical and security limitations, where known, over the assessment period. This simulation is executed to validate the operational plausibility of the generation and transmission development schedule from the Long-term Investment Planning activity.

The Market Dispatch Simulation has been applied to obtain an assessment of involuntary load curtailment using Monte Carlo techniques to model the impacts of random forced generator outages.

This modelling evaluates whether simplifications made in the Long-term Investment Planning are valid in a more detailed model, indicating a need for an additional iteration of the Long-term Investment Planning and/or the System Technical Assessment.



61 AEMO, *Planning and Forecasting 2019 Consultation Process Briefing Webinar,* Wednesday 3 April 2019, slide 21.

7.2.3 Modelling of diversity in peak demand

The market modelling accounts for peak period diversification across regions by basing the overall shape of hourly demand on nine historical years ranging from 2010/11 to 2018/19.

Specifically, the key steps to accounting for this diversification 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 nine-year hourly pattern has been projected forward to meet future forecast annual peak demand and energy in each region;
- the nine reference years are repeated sequentially throughout the modelling horizon; and
- 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.

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 diversity of timing.

Additional detail on how peak period diversification has been modelled is provided in the market modelling report accompanying this PADR.

7.2.4 Modelling of intra-regional constraints

The wholesale market simulations include models for intra-regional constraints in addition to the inter-regional transfer limits.

Key intra-regional transmission constraints in New South Wales have been captured by splitting NSW into zones (NNS, NCEN, CAN and SWNSW), and explicitly modelling intra-regional connectors across boundaries or cut-sets between these zones. Bi-directional flow limits and dynamic loss equations were formulated for each intra-regional connector. To more accurately capture the benefit of the options being considered, the Canberra zone is split into further nodes and an equivalent network has been developed for this zone to accommodate the DC power flow with all transmission lines, both existing and defined in the options, explicitly modelled by its impedance and thermal limits.

In addition, loss factors for each generator were applied. These were computed from an AC power flow programme interfaced with the Long-term Investment Planning model. The loss factors for each generation investment plan were computed on a five-year basis up to 2030-31 and fed back into the Long-term Investment Planning model to capture both the impact on bids and intra-zonal losses.

Beyond 2030/31, the loss factors have been maintained at the same values as 2030-31, since network changes beyond that stage and additional renewable generation are becoming much less certain. However, this does not preclude generation investment if economic at any location.

7.3 General modelling parameters adopted

The RIT-T analysis spans a 25-year assessment period from 2020/21 to 2044/45.

Where the capital components of the credible options have asset lives extending beyond the end of the assessment period, the NPV modelling includes a terminal value to capture the remaining asset life. This ensures that the capital cost of long-lived options over the assessment period is appropriately captured, and that all options have their costs and benefits assessed over a consistent period, irrespective of option type, technology or asset life.

A real, pre-tax discount rate of 5.90 per cent has been adopted as the central assumption for the NPV analysis presented in this PADR. The RIT-T also requires that sensitivity testing be conducted on the discount rate and that the regulated weighted average cost of capital (WACC) be used as the lower bound. We have therefore tested the sensitivity of the results to a lower bound discount rate of 2.85 per cent,[62] and an upper bound discount rate of 8.95 per cent (i.e., a symmetrical adjustment upwards).

The same commercial discount rates have been adopted for both the NPV discounting calculation in the cost benefit analysis, as well as the generator hurdle rates in the wholesale market modelling, which is consistent with the approach proposed for the 2020 ISP (and which was applied in the inaugural 2018 ISP).[63]

7.4 Classes of market benefit not considered material

The NER requires that all categories of market benefit identified in relation to the RIT-T are included in the RIT-T assessment, unless the TNSP can demonstrate that a specific category (or categories) is unlikely to be material in relation to the RIT-T assessment for a specific option.[64]

The PSCR outlined how TransGrid consider that all categories of market benefit identified in the RIT-T have the potential to be material with the exception of changes in ancillary services costs, as well as the reasons why this category is not expected to be material. With the exception of competition benefits, we have not changed our view regarding these potential sources of market benefit, and no parties have commented on these as part of the PSCR consultation.

While the PSCR suggested that competition benefits may be important for this RIT-T, and that TransGrid would undertake a 'fit for purpose' assessment to see whether such benefits are likely to vary materially between options, we do not now expect that assessing competition benefits would be material in terms of identifying the preferred option for this RIT-T. This is on account of the PADR modelling finding that the largest capacity options are preferred, which can be expected to have the greatest impact on any competition benefits, and previous RIT-T findings that competition benefits do not add significantly to gross market benefits.[65]

62 This is equal to WACC (pre-tax, real) in the latest final decision for a transmission business in the NEM, see: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/tasnetworks-determination-2019-24

63 AEMO, *Planning and Forecasting 2019 Consultation Process Briefing Webinar,* Wednesday 3 April 2019, slide 21.

64 NER clause 5.16.1(c)(6).

65 TransGrid and Powerlink, *Development of the Queensland-NSW Interconnector,* PACR, 13 November 2014, p. 45.

08 Net present value

Summary of key points:

- The 500 kV options going between Maragle and Bannaby via Wagga Wagga (i.e., Option 2C and 3C) are found to provide the greatest net benefits of all credible options across all four scenarios – net benefits for these two options range from around $370 million to $1.4 billion across the scenarios.
- Under the central and step-change scenarios, the benefits are primarily driven by avoided generator fuel costs (with the exception of the route 1 options), with avoided, or deferred, costs associated with generation and storage build providing the second largest source of benefit.
- Under the slow-change scenario, market benefits are almost completely driven by avoided or deferred, costs associated with generation and storage build.
- Under the fast-change scenario, the benefits are driven equally by both avoided generator fuel costs and avoided, or deferred, costs associated with generation and storage build.
- On a weighted-basis, Option 2C and Option 3C are expected to deliver approximately $1.1 billion in net benefits and are ranked equal-first (Option 3C has approximately 2 per cent greater net benefits), which is around 7 per cent greater net benefits than the third-ranked option (Option 3B).
- While Option 2C and Option 3C are effectively ranked equal-first, TransGrid has identified Option 3C as the preferred option as it has lower capital cost than Option 2C due to shorter circuit length, and marginally higher net benefits. Option 3C also provides additional unquantified benefits over Option 2C on account of its topology involving more opportunity for route diverse paths that run in a 'loop', which mitigates the risk of 'high impact low probability' events (such as lightning strikes, bushfires or extreme wind events).
- These conclusions are found to be robust to a range of sensitivity tests and more extreme 'threshold tests'.

8.1 Central scenario

The central scenario reflects the best estimate of the evolution of the market going forward, including AEMO's moderate demand forecasts (including DSP), neutral gas and coal price forecasts, coal plants retiring when announced (or at the end of their technical lives), as well as a national emissions reduction of around 28 per cent below 2005 levels by 2030.

AEMO describes the central scenario as reflecting 'the current transition of the energy industry under current policy settings and technology trajectories, where the transition from fossil fuels to renewable generation is generally led by market forces and supported by current federal and state government policies'.[66]

The PADR assessment finds that Option 3C has the highest expected net benefit under these assumptions, although Option 2C is effectively ranked equal-first with Option 3C (with estimated net benefits that are approximately 1 per cent lower than Option 3C). Option 3C is estimated to deliver approximately $1.2 billion in net benefits under this scenario.

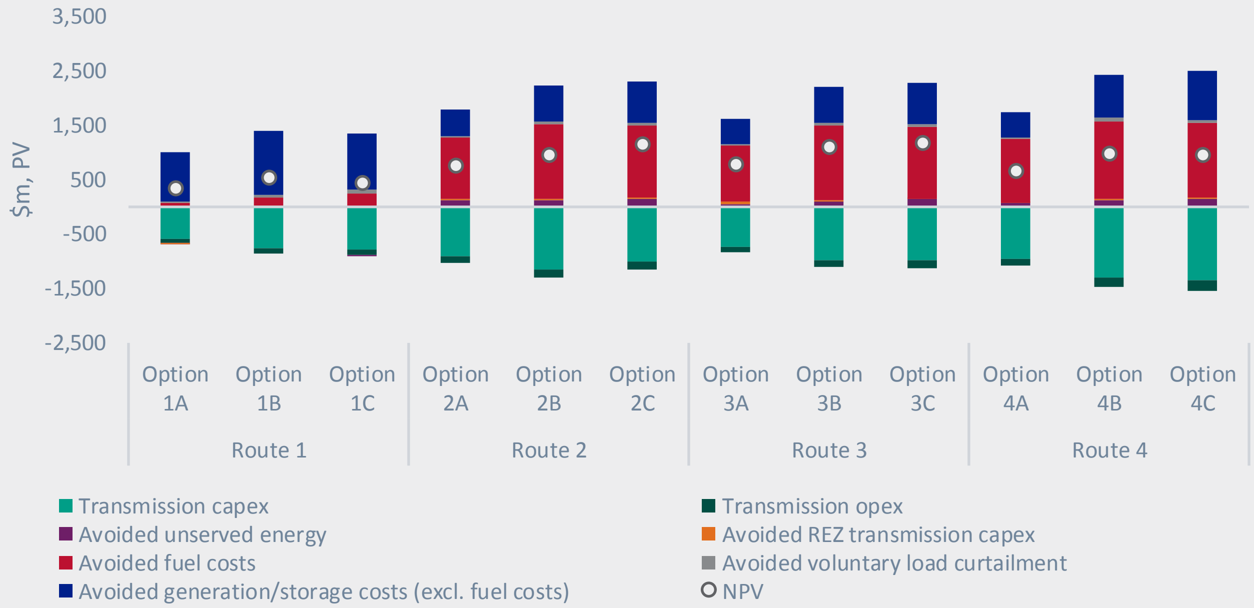
66 AEMO, 2019 forecasting and planning scenarios, inputs, and assumptions, August 2019, p. 3.

Figure 3 shows the overall estimated net benefit for each option under the central scenario.

Figure 3 Summary of the estimated net benefits under the central scenario

Figure 4 shows the composition of estimated net benefits for each option under the central scenario.

Figure 4 Breakdown of estimated net benefits under the central scenario



The key findings from the assessment of each option under the central scenario are that:[67]

- All credible options are found to deliver strongly positive net market benefits, ranging from approximately $330 million (Option 1A) to $1.2 billion (Option 3C).
- The fixed 500 kV options (i.e., the 'C' options) provide the greatest net benefit of all options considered on account of these options providing the greatest (and earliest) increase in transfer capacity.
  - The exception to this is for the route 1 options, where the flexible 500 kV option (i.e., Option 1B) provides the greatest estimated net benefit.
- The flexible 500 kV options are found to be upgraded from 330 kV to 500 kV in 2029-30, being the time at which the benefits from upgrading to 500 kV exceed the annualised upgrade cost under this scenario.
- Market benefits of all options are primarily derived from avoided fuel costs in the wholesale market (shown by the red bars in Figure 4).
  - This benefit arises since reinforcing the NSW southern shared network enables demand centres to be supplied by lower cost generation than can be expected if no upgrade is undertaken.
  - The exception to this is the route 1 options, which do not allow for material fuel costs to be avoided since these options do not facilitate additional renewable investment around Wagga Wagga or South Australian renewable exports (via Project EnergyConnect) compared to the base case.

67 The detailed descriptions of the drivers of the key market benefit categories below are based on the market modelling results for Option 3C. Please refer to the accompanying market modelling results, and report, released alongside this PADR for more detail on the market modelling results for all options.

- Avoided or deferred costs associated with generation and storage are the second most material category of market benefit estimated across the options (shown by the blue bars in Figure 4).
  - The market modelling finds that there are large amounts of solar, gas-fired generation (OCGT) and pumped hydro investment deferred in NSW compared to the base case in the first fifteen years (which is illustrated by the blue bars shown in Figure 5 below).
- This also allows REZ transmission costs to be avoided during this period (as shown by the orange bars in Figure 5 below).
  - From around 2037-38, while large investments in gas-fired generation (both OCGT and CCGT) in NSW continue to be avoided, there is significant additional new build of renewable generation (primarily NSW and SA solar and Victorian wind).
- This new investment results in a reduction in the 'avoided or deferred, costs associated with generation and storage' market benefit overall (and is illustrated by the step-down in the blue bars from 2037-38 in Figure 5 below).

Figure 5 below presents the estimated cumulative expected gross benefits for Option 3C for each year of the assessment period under the central scenario.[68] It shows the cumulative market benefits, in present value terms (and so the final year's stacked bars align with the overall breakdown of estimated market benefits shown in Figure 4 above).

Figure 5 Breakdown of cumulative gross benefits for Option 3C under the central scenario[69]

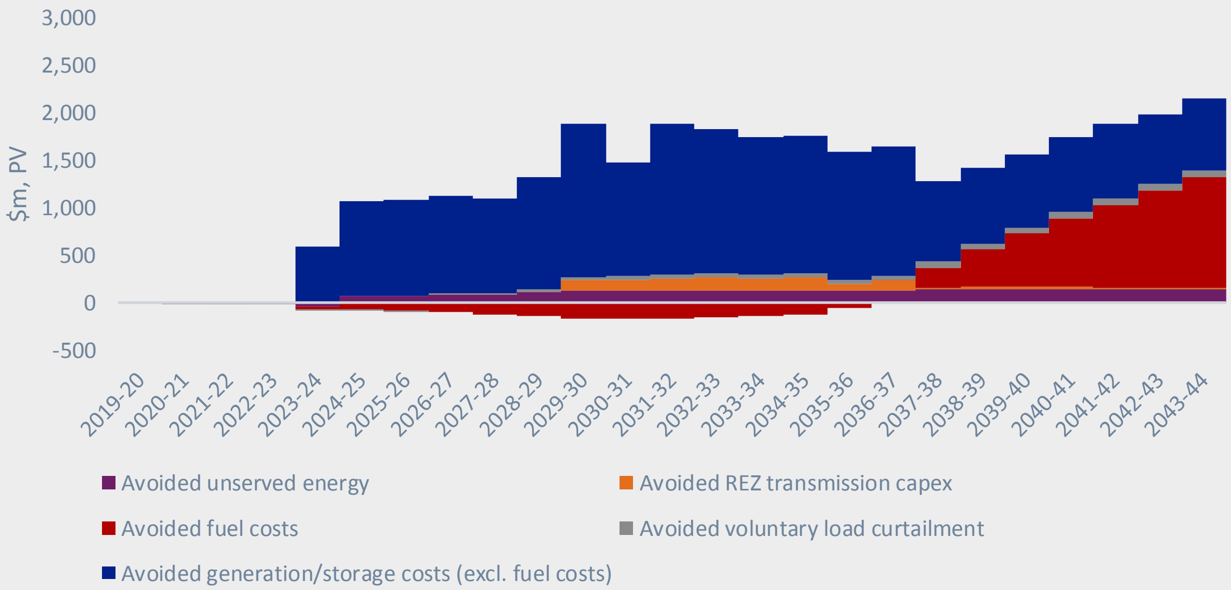
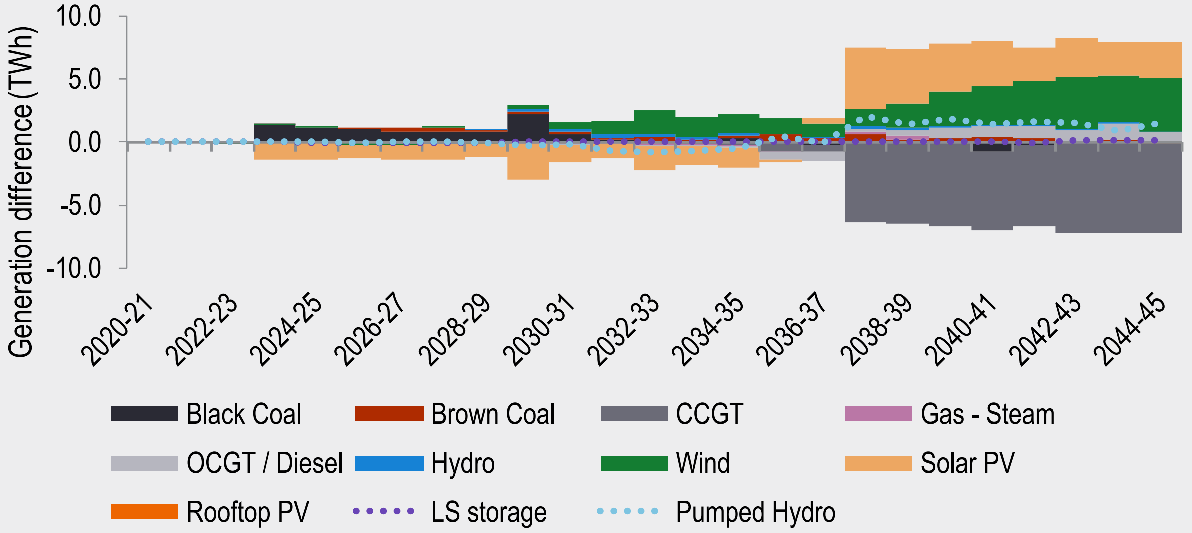


Figure 6 summarises the difference in generation and storage output modelled for Option 3C (in TWh), compared to the base case, i.e., what is found to be driving the avoided fuel cost benefit. The accompanying market modelling results workbook provides the data underpinning this chart, as well as the same data for all other options and scenarios (at both the technology and regional levels).

Figure 6 Difference in output with Option 3C, compared to the base case, under the central scenario

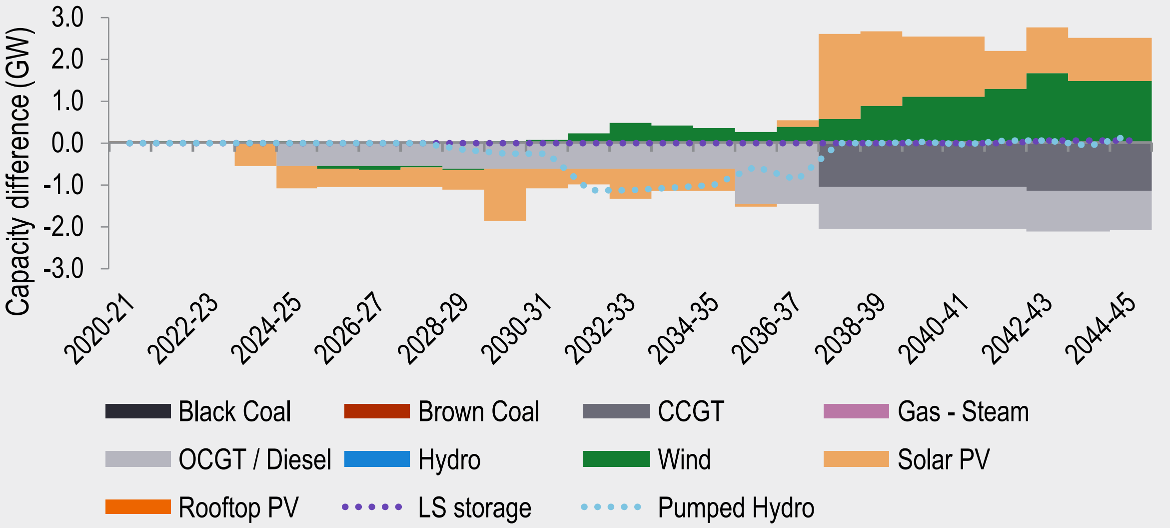


68 This figure only presents the annual breakdown of estimated gross benefits for the preferred option. The separately released spreadsheet presents an annual breakdown of costs and benefits for all options. Since this figure shows the cumulative gross benefits in present value terms, the height of the bar in 2043-44 equates to the gross benefits for Option 3C shown in Figure 4 above.

69 While all generator and storage capital costs have been included in the market modelling on an annualised basis, this chart, and all charts of this nature in the PADR, present the entire capital costs of these plant in the year avoided in order to highlight the timing of the expected market benefits. This is purely a presentational choice that TransGrid has made to assist with relaying the timing of expected benefits (i.e., when thermal plant retire) and does not affect the overall estimated net benefit of the options.

Figure 7 summarises the difference in generation and storage capacity modelled for Option 3C (in GW), compared to the base case, i.e., what is found to be driving the avoided or deferred costs associated with generation and storage benefit.

Figure 7 Difference in cumulative capacity built with Option 3C, compared to the base case, under the central scenario



While this section (as well as sections 8.2, 8.3 and 8.4) focusses on the drivers of market benefits for Option 3C, we note that the drivers are effectively the same for the other two top-ranked options under this scenario (i.e., Option 2C and Option 3B). The accompanying market modelling results workbook provides the modelled market outcomes for all options and this similarity can be seen there.

8.2 Slow-change scenario

The slow-change scenario is comprised of a set of conservative assumptions reflecting a future world of lower demand forecasts (including DSP), slow gas and coal price forecasts and coal plants retiring later than under the central scenario. While the slow-change scenario assumes the same national emissions reduction as the central scenario, it assumes lower state-based renewables commitments. The slow-change scenario also excludes VNI West going ahead.

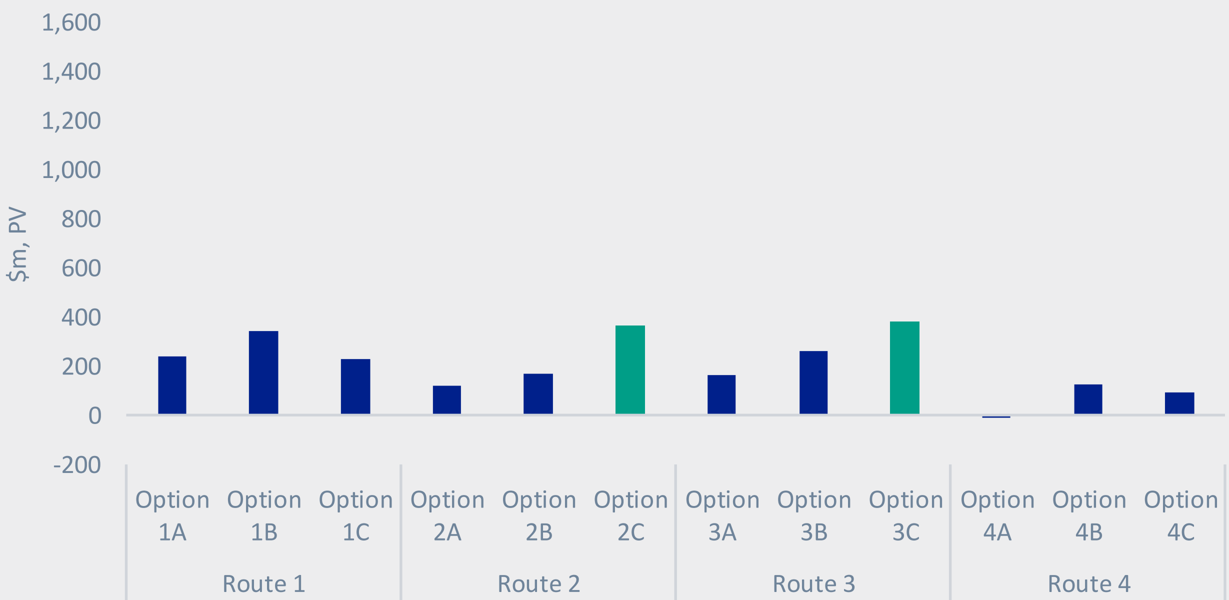
AEMO describe the slow-change scenario as reflecting 'a general slow-down of the energy transition. It is characterised by slower advancements in technology and reductions in technology costs, low population growth, and low political, commercial, and consumer motivation to make the upfront investments required for significant emissions reduction'.[70]

The slow-change scenario is therefore intended to represent the lower end of the potential range of realistic net benefits associated with the various options.

While Option 3C is found to have the highest estimated net benefit (approximately $380 million), Option 2C is effectively ranked equal-first with net benefits approximately 4 per cent lower than for Option 3C.

Figure 8 shows the overall estimated net benefit for each option under the slow-change scenario.

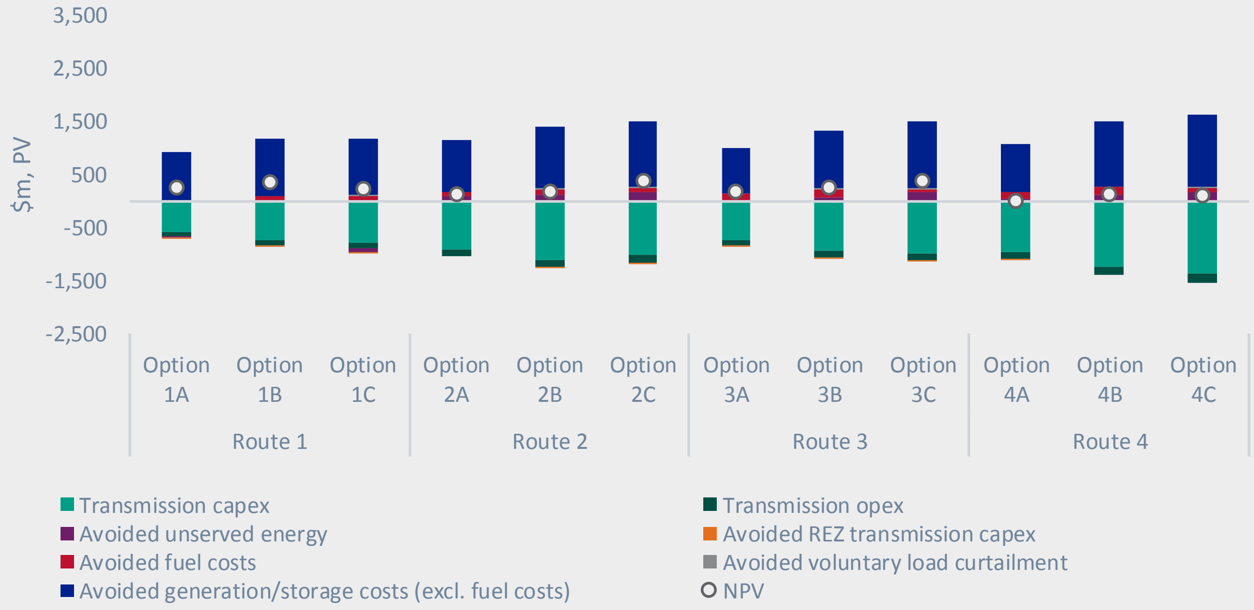
Figure 8 Summary of the estimated net benefits under the slow-change scenario



70 AEMO, *2019 forecasting and planning scenarios, inputs, and assumptions*, August 2019, p. 3.

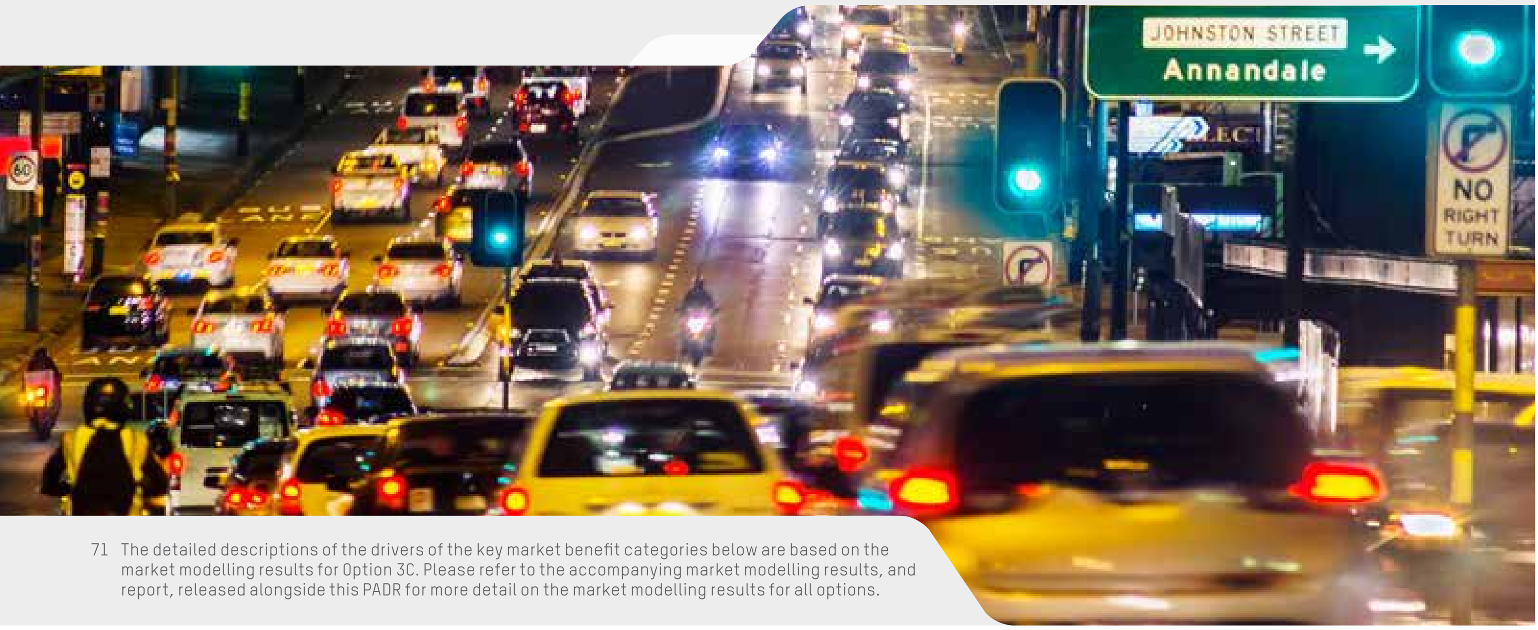
Figure 9 shows the composition of estimated net benefits for each option under the slow-change scenario.

Figure 9 Breakdown of estimated net benefits under the slow-change scenario



The key findings from the assessment of each option under the slow-change scenario are that:[71]

- While all options are expected to deliver strongly positive net benefits under these conservative assumptions (with the exception of Option 4A, which is found to deliver marginally negative net market benefits), the estimated net market benefits fall relative to the central scenario.
- The fixed 500 kV options (i.e., the 'C' options) provide the greatest net benefit of all options considered on account of these options providing the greatest (and earliest) increase in transfer capacity.
  - The exception to this is for the route 1 options, where the flexible 500 kV option (i.e., Option 1B) provides the greatest estimated net benefit.
- The flexible 500 kV options are found to be upgraded from 330 kV to 500 kV in 2035-36, being the time at which the benefits from upgrading to 500 kV exceed the annualised upgrade cost under this scenario.
  - The flexible 500 kV Option 3B is found to deliver net benefits that are approximately 31 per cent lower than Option 3C under this scenario (compared to 6 per cent under the central scenario).
  - The incremental benefits that Option 3C delivers over Option 3B in the early years are greater than the cost savings from committing to Option 3B initially or, put another way, the incremental benefits from 500 kV operation are greater than the incremental cost savings from operating at 330 kV.
- Avoided fuel costs are not found to be a material market benefit under the slow-change scenario.
  - This is due to a lower CCGT build under the base case in this scenario (and as such less CCGT generation offset by renewables in the upgrade options). The lower CCGT build is a result of a number of factors including lower demand forecast, delaying half of coal capacity retirement, and the exclusion of VNI West under this scenario.
- The market benefits for all options are almost completely driven by avoided or deferred costs associated with generation and storage (shown by the blue bars in Figure 4).
  - The market modelling finds that this is driven primarily by avoided OCGT build in NSW across the assessment period, as well as NSW pumped hydro from around 2034-35.
- Avoided unserved energy is the second most material category of market benefit for all options (but is immaterial compared to the avoided or deferred, costs associated with generation and storage).



71 The detailed descriptions of the drivers of the key market benefit categories below are based on the market modelling results for Option 3C. Please refer to the accompanying market modelling results, and report, released alongside this PADR for more detail on the market modelling results for all options.

Figure 10 below presents the estimated cumulative expected gross benefits for Option 3C for each year of the assessment period under the slow-change scenario. It shows that the majority of the overall benefits have accrued by 2024-25 under this scenario.

Figure 10 Breakdown of cumulative gross benefits for Option 3C under the slow-change scenario

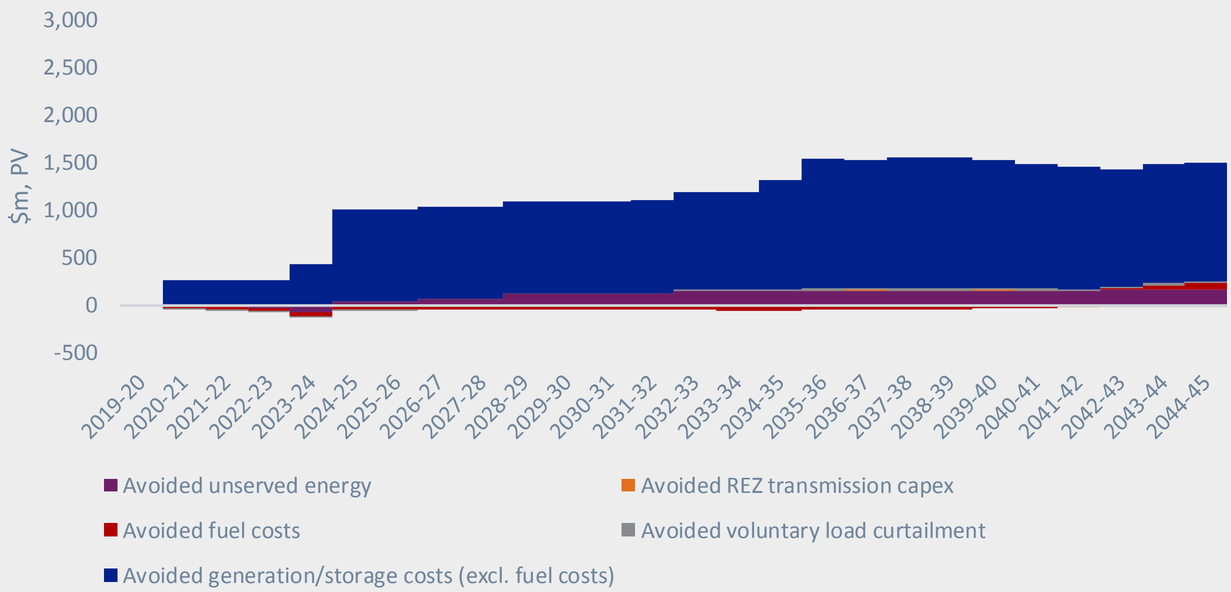


Figure 11 summarises the difference in generation and storage output modelled for Option 3C (in TWh), compared to the base case.

Figure 11 Difference in output with Option 3C, compared to the base case, under the slow-change scenario

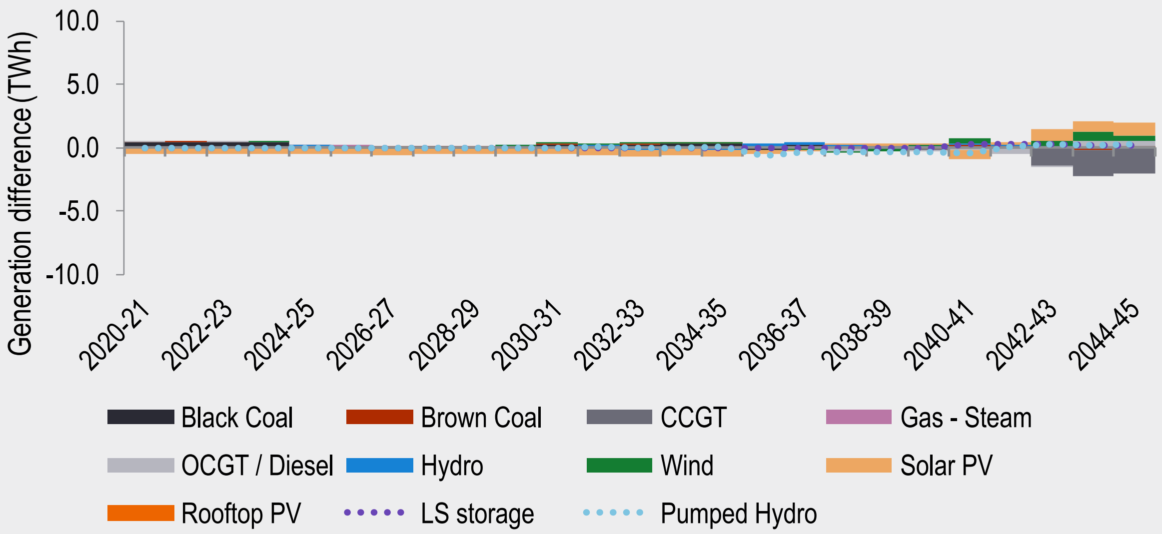
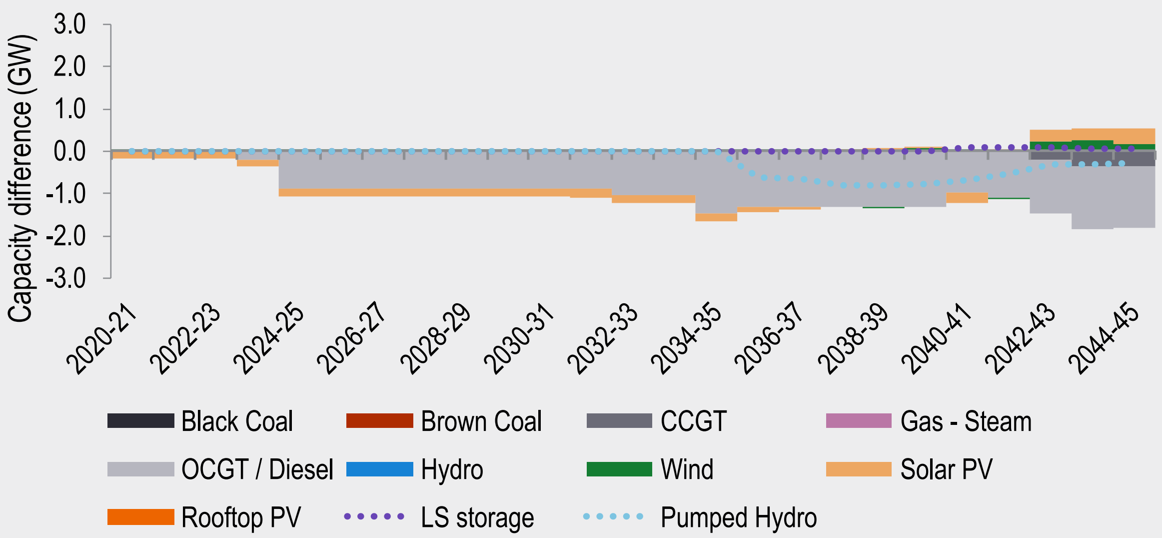


Figure 12 summarises the difference in generation and storage capacity modelled for Option 3C (in GW), compared to the base case.

Figure 12 Difference in cumulative capacity built with Option 3C, compared to the base case, under the slow-change scenario



8.3 Fast-change scenario

The fast-change scenario reflects a state of the world where there is a rapid technology-led transition of the power system and a 'fast-change' in emissions. Assumptions made in the fast-change scenario include AEMO's moderate demand forecasts (including DSP), neutral and coal price forecasts, coal plants retiring earlier than the central scenario, as well as a national emissions reduction of around 52 per cent below 2005 levels by 2030.

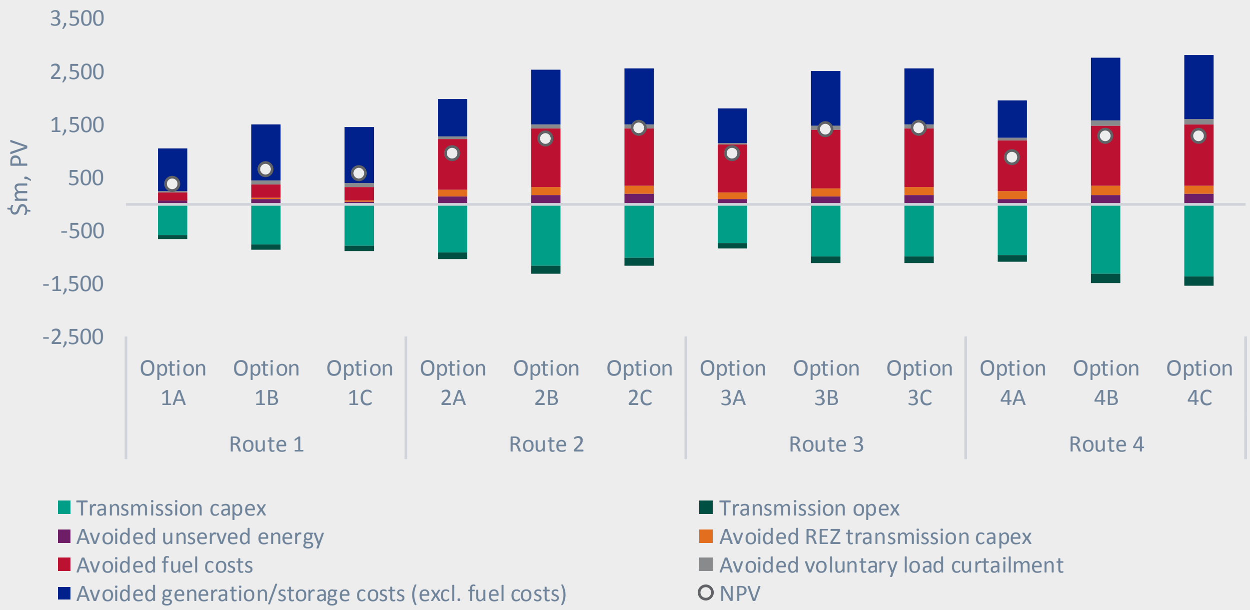
AEMO describes the fast-change scenario as reflecting a 'rapid technology-led transformation, particularly at grid scale, where advancements in large scale technology improvements and targeted policy support reduce the economic barriers of the energy transmission. In this scenario, coordinated national and international action towards achieving emissions reductions, leading to manufacturing advancements, automation, accelerated exist of existing generators, and integration of transport into the energy sector'.[72]

The PADR assessment finds that Option 3C has the highest expected net benefit under these assumptions, although Option 2C and Option 3B are effectively ranked equal-first with Option 3C (with estimated net benefits that are approximately 1 per cent and 3 per cent lower than Option 3C, respectively). Option 3C is estimated to deliver approximately $1.4 billion in net benefits under this scenario.

Figure 13 Summary of the estimated net benefits under the fast-change scenario

Figure 14 shows the composition of estimated net benefits for each option under the fast-change scenario.

Figure 14 Breakdown of estimated net benefits under the fast-change scenario



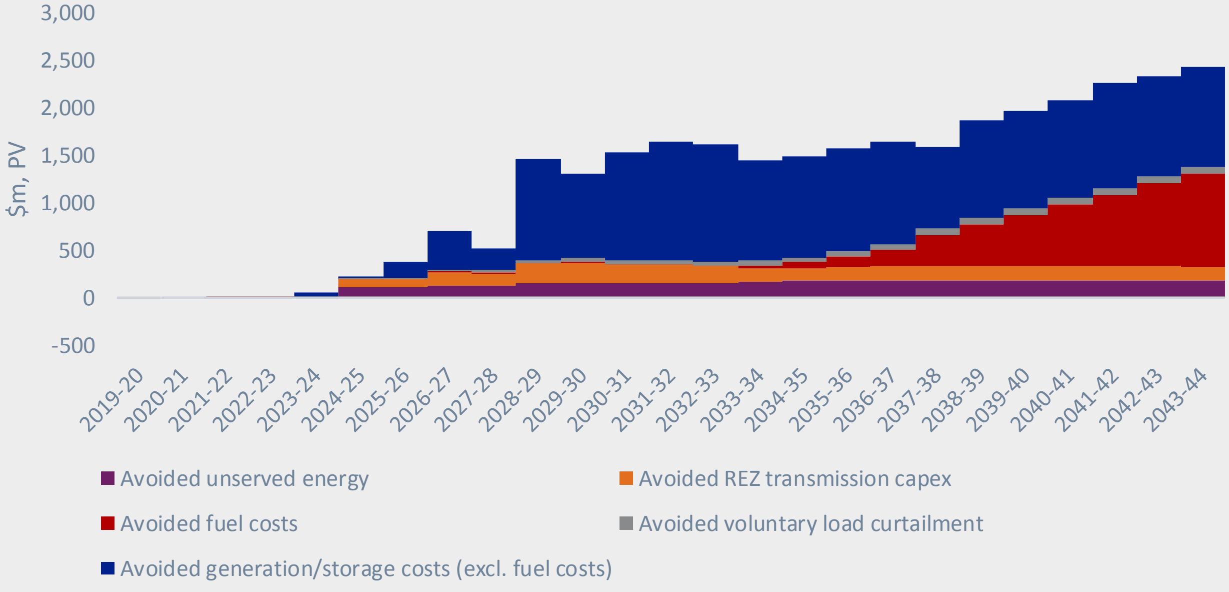
72 AEMO, *2019 forecasting and planning scenarios, inputs, and assumptions*, August 2019, p. 4.

The key findings from the assessment of each option under the fast-change scenario are that: [73]

- The fast-change scenario results in greater estimated net benefits for all options compared to the central scenario.
  - The fast-change scenario increases estimated net benefits compared to the central scenario by between approximately $50 million (Option 1A) and $320 million (Option 4B).
- The fixed 500 kV options (i.e., the 'C' options) continue to provide the greatest net benefit of all options considered on account of these options providing the greatest (and earliest) increase in transfer capacity.
  - As with the central scenario, the exception to this is for the route 1 options, where the flexible 500 kV option (i.e., Option 1B) provides the reatest estimated net benefit.
- The flexible 500 kV options are found to be upgraded from 330 kV to 500 kV in 2028-29, being the time at which the benefits from upgrading to 500 kV exceed the annualised upgrade cost under this scenario.
- Market benefits of all options (besides the route 1 options) are almost equally derived from avoided fuel costs in the wholesale market (shown by the red bars in Figure 14) and avoided generation and storage costs (shown by the blue bars in Figure 14).
  - Benefits expected from avoided generation and storage costs are accrued mostly in 2028-29, while benefits from avoided fuel costs in the wholesale market are expected to accrue starting from around 2033-34.
  - Avoided fuel costs are found to be most significant around the time large black coal generators are expected to retire and are driven by renewable generation (primarily NSW pumped hydro, NSW solar and SA and Victorian wind) avoiding gas-fired generation in NSW.
  - The market modelling finds that there are large amounts of solar and pumped hydro investment avoided in NSW compared to the base case in the first fifteen years (which is illustrated by the blue bars shown in Figure 15 below).
- This also allows REZ transmission costs to be avoided over the assessment period (as shown by the orange bars in Figure 15 below).
  - From around 2033-34, large investments in gas-fired generation (both OCGT and CCGT) in NSW are avoided and there is significant new build of renewable generation (primarily NSW and Victorian solar and SA and Victorian wind).

Figure 15 below presents the estimated cumulative expected gross benefits for Option 3C for each year of the assessment period under the fast-change scenario.

Figure 15 Breakdown of cumulative gross benefits for Option 3C under the fast-change scenario



73 The detailed descriptions of the drivers of the key market benefit categories below are based on the market modelling results for Option 3C. Please refer to the accompanying market modelling results, and report, released alongside this PADR for more detail on the market modelling results for all options.

Figure 16 summarises the difference in generation and storage output modelled for Option 3C (in TWh), compared to the base case.

Figure 16 Difference in output with Option 3C, compared to the base case, under the fast-change scenario

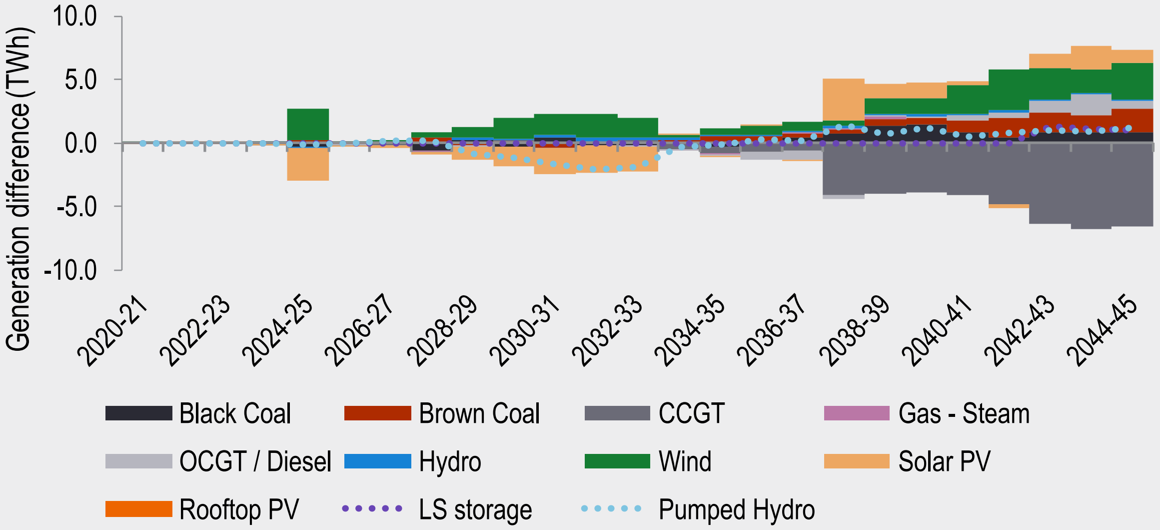
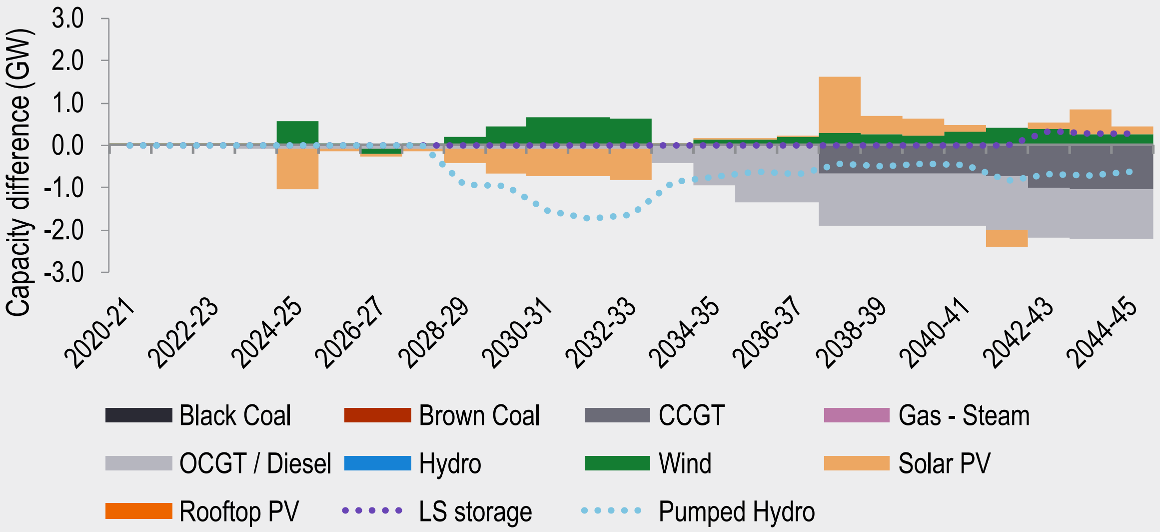


Figure 17 summarises the difference in generation and storage capacity modelled for Option 3C (in GW), compared to the base case.

Figure 17 Difference in cumulative capacity built with Option 3C, compared to the base case, under the fast-change scenario



8.4 Step-change scenario

The step-change scenario reflects a state of the world where there is strong action on climate change and a 'step-change' in emissions, including AEMO's high demand forecasts (including DSP), fast gas and coal price forecasts, coal plants retiring earlier than the central scenario, as well as a national emissions reduction of around 52 per cent below 2005 levels by 2030.

AEMO describe the step-change scenario as reflecting 'strong action on climate change that leads to a step change reduction of greenhouse gas emissions. In this scenario, aggressive global decarbonisation leads to faster technological improvements, accelerated exit of existing generators, greater electrification of the transport sector with increased infrastructure developments, energy digitalisation, and consumer-led innovation'.[74]

The PADR assessment yields similar results under the step-change scenario as under the central scenario. In particular, while Option 3C has the highest expected net benefit under these assumptions, Option 2C and Option 3B are effectively ranked equal-first with Option 3C (with estimated net benefits that are approximately 2 per cent and 4 per cent lower than Option 3C, respectively).

74 AEMO, *2019 forecasting and planning scenarios, inputs, and assumptions*, August 2019, p. 4.

Figure 18 shows the overall estimated net benefit for each option under the step-change scenario.

Figure 18 Summary of the estimated net benefits under the step-change scenario

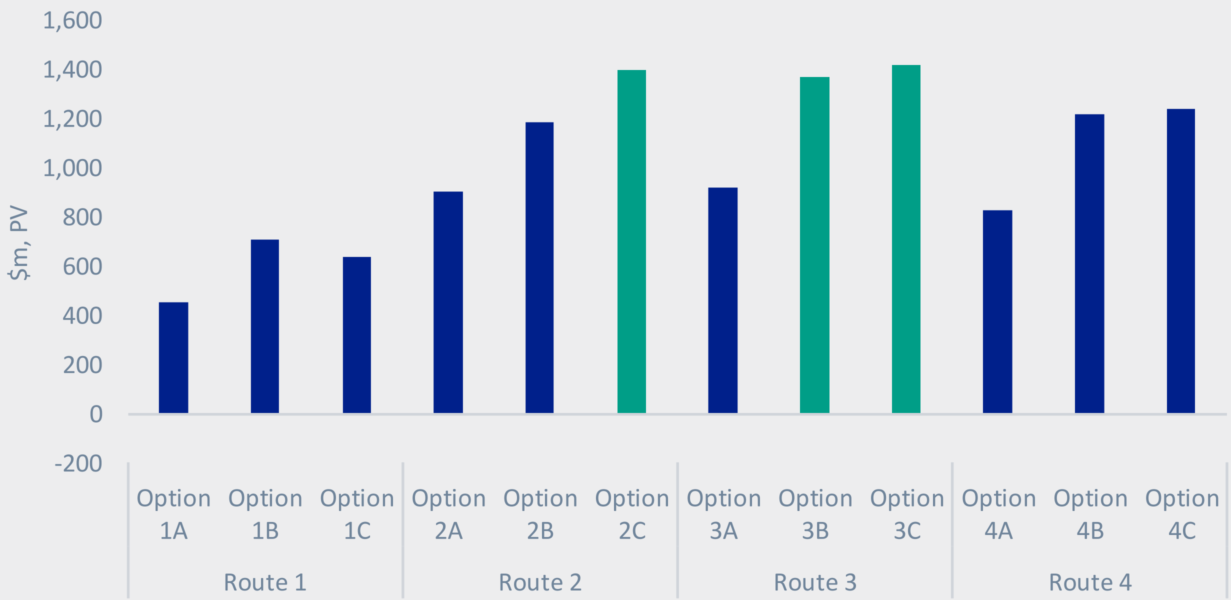
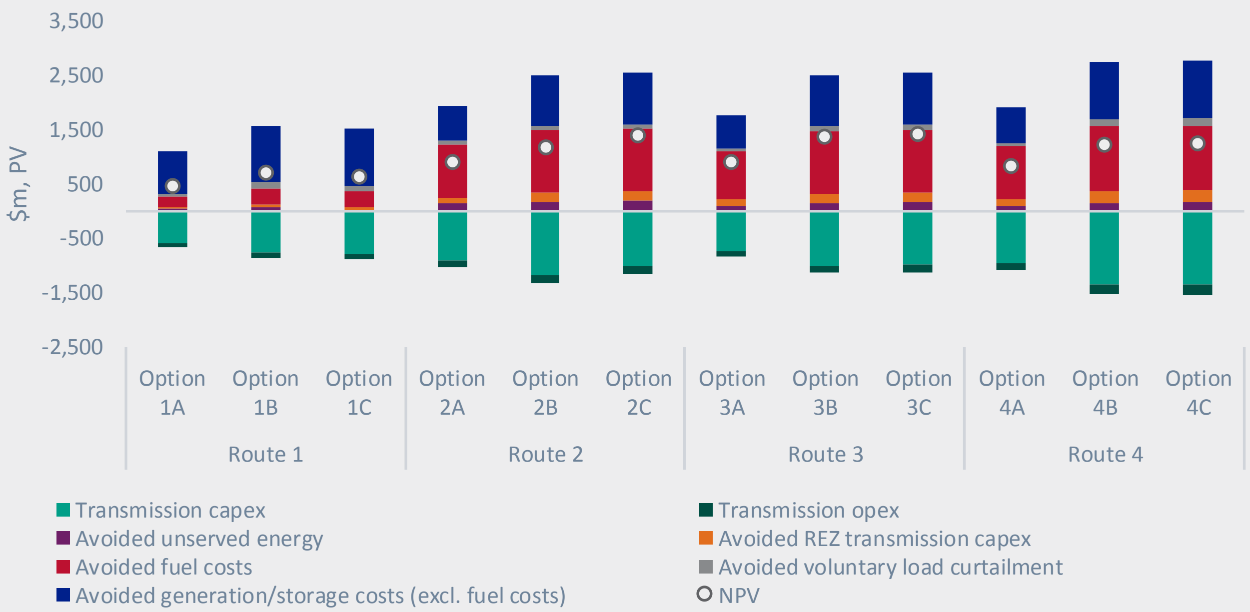


Figure 19 shows the composition of estimated net benefits for each option under the step-change scenario.

Figure 19 Breakdown of estimated net benefits under the step-change scenario



The key findings from the assessment of each option under the step-change scenario are that: [75]

- The step-change results in greater estimated net benefits for all options than under the central scenario, ranging from approximately $460 million (Option 1A) to $1.4 billion (Option 3C).
- The fixed 500 kV options (i.e., the 'C' options) continue to provide the greatest net benefit of all options considered on account of these options providing the greatest (and earliest) increase in transfer capacity.
  - As with the central scenario, the exception to this is for the route 1 options, where the flexible 500 kV option (i.e., Option 1B) provides the greatest estimated net benefit.
- The flexible 500 kV options are found to be upgraded from 330 kV to 500 kV in 2026-27, being the time at which the benefits from upgrading to 500 kV exceed the annualised upgrade cost under this scenario.
- Market benefits of all options are primarily derived from avoided fuel costs in the wholesale market (shown by the red bars in Figure 19) and are expected to accrue most significantly from around 2037-38 (as under the central scenario).
  - These benefits are found to be most significant around the time large black coal generators are expected to retire and are driven by renewable generation (primarily NSW pumped hydro, NSW solar and SA and Victorian wind) avoiding gas-fired generation in NSW.

75 The detailed descriptions of the drivers of the key market benefit categories below are based on the market modelling results for Option 3C. Please refer to the accompanying market modelling results, and report, released alongside this PADR for more detail on the market modelling results for all options.

- Avoided or deferred costs associated with generation and storage are the second most material category of market benefit estimated across the options (shown by the blue bars in Figure 19).
  - The market modelling finds that there are large amounts of solar and pumped hydro investment avoided in NSW compared to the base case in the first fifteen years (which is illustrated by the blue bars shown in Figure 20 below).
- This also allows REZ transmission costs to be avoided over the assessment period (as shown by the orange bars in Figure 20 below).
  - From around 2037-38, large investments in gas-fired generation (both OCGT and CCGT) in NSW are avoided and there is significant new build of renewable generation (primarily NSW and Victorian solar and SA and Victorian wind).

Figure 20 below presents the estimated cumulative expected gross benefits for Option 3C for each year of the assessment period under the step-change scenario.

Figure 20 Breakdown of cumulative gross benefits for Option 3C under the step-change scenario

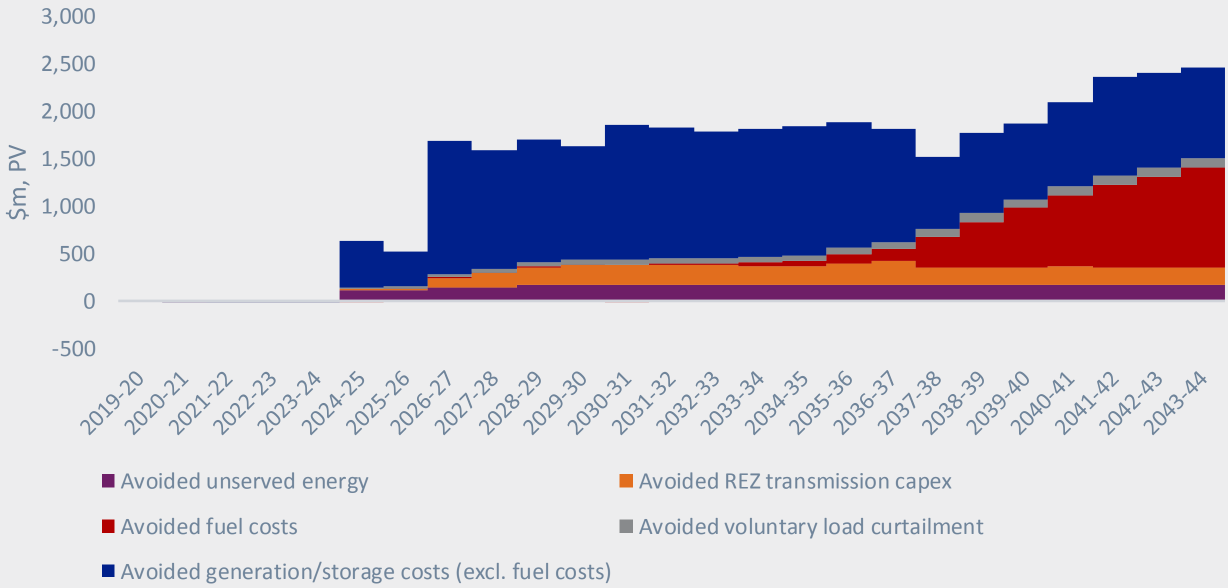


Figure 21 summarises the difference in generation and storage output modelled for Option 3C (in TWh), compared to the base case.

Figure 21 Difference in output with Option 3C, compared to the base case, under the step-change scenario

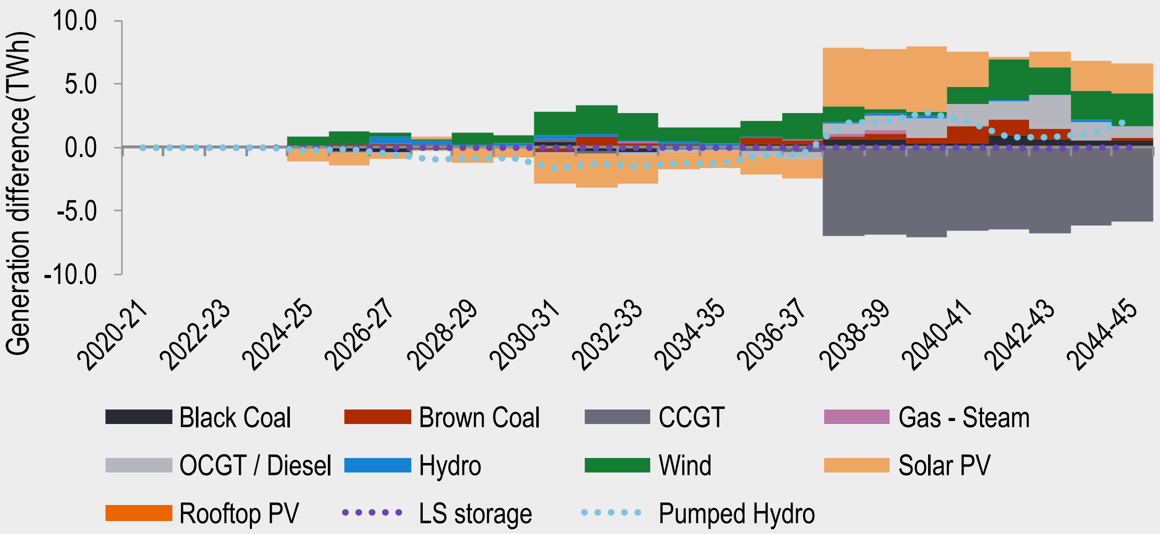
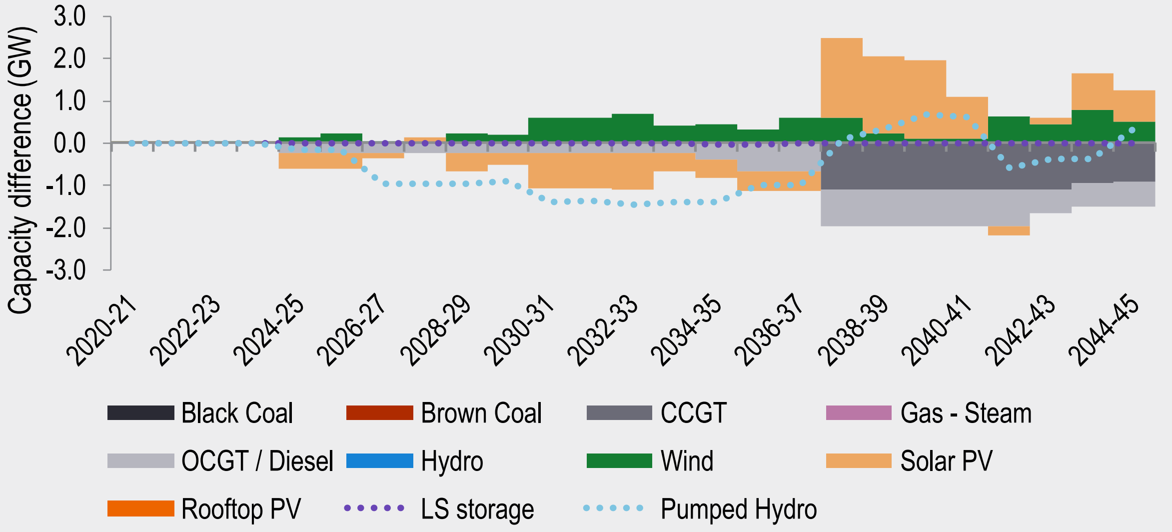


Figure 22 summarises the difference in generation and storage capacity modelled for Option 3C (in GW), compared to the base case.

Figure 22 Difference in cumulative capacity built with Option 3C, compared to the base case, under the step-change scenario

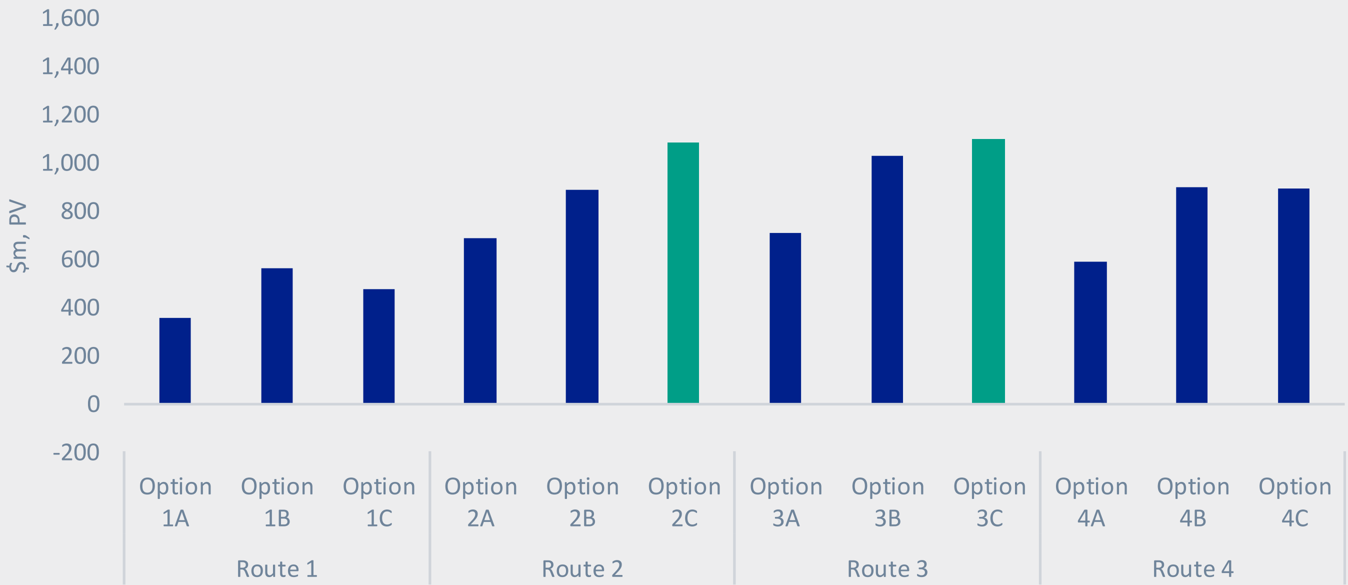


8.5 Weighted net benefits

Figure 23 shows the estimated net benefits for each of the credible options weighted equally across the four scenarios investigated (and discussed above).

On a weighted-basis, Option 2C and Option 3C are expected to deliver approximately $1.1 billion in net benefits and are ranked equal-first (Option 3C has approximately 2 per cent greater net benefits), which is around 7 per cent greater net benefits than the third-ranked option (Option 3B).

Figure 23 Summary of the estimated net benefits, weighted across the four scenarios



8.6 Unquantified benefits associated with route diversity

While Option 2C and Option 3C are effectively ranked equal-first, the new circuits under Option 3C have more route diverse opportunity than for Option 2C due to their topology.

Option 3C is therefore expected to provide a greater risk reduction than Option 2C in terms of avoiding 'high impact low probability' events (such as lightning strikes, bushfires or extreme wind events) affecting multiple lines simultaneously. While recognising the low probability of two lines going down simultaneously under both options, TransGrid has undertaken indicative power system studies that estimates the value of load at risk to be approximately $450 million (in present value terms). Option 3C is consequently the preferred option identified as part of this PADR as it provides the lowest chance of this occurring due its greater route ability.

8.7 Sensitivity analysis

A range of sensitivity analyses have been undertaken to test the robustness of the PADR modelling outcomes.

Specifically, we have assessed a number of sensitivities that involve additional market modelling, namely:

- the retirement of existing plants based on their economic viability;
- sensitivity to Snowy 2.0's development;
- higher DER uptake (as per the 2019 ISP assumption);
- development of QNI Stage 2 in 2028-29;
- development of VNI West in 2034-35;
- staged development of Option 3C;
- 50 per cent POE demand forecasts; and
- whether there are benefits from the use of demand management prior to commissioning of HumeLink.

Each of these sensitivity tests has been designed to test the robustness of the net benefit outcomes for Option 3C. The market modelling for each of the above sensitivities has not been undertaken for all credible options and scenarios. This is due to the computational time required to complete such an exercise and the fact that the four core scenarios outlined in the sections above already include significant variability in the underlying assumptions and find that Option 3C and Option 2C are the top-ranked options.

Two other sensitivity and threshold tests that do not require wholesale market modelling have also been investigated, namely:

- higher and lower network capital costs of the credible options; and
- alternate commercial discount rate assumptions.

Each of the sensitivity tests are discussed in the sections below.

8.7.1 Retirement of existing plants based on their economic viability

As outlined in section 4.1.4, EnergyAustralia suggested the retirement of existing power stations should be modelled on the basis on economic viability, rather than adopting fixed retirement dates.

TransGrid has investigated two different sensitivities for economic retirements for coal-fired power stations in the central scenario, namely:

- sensitivity (a) allows only earlier retirements;
- sensitivity (b) allows earlier retirements as well as life extensions of Vales Point, Eraring and Bayswater.

Both of these sensitivities re-run both the base case and the Option 3C case, allowing for a change in the gross market benefits estimated.

Compared to the core results for Option 3C, sensitivity (a) forecasts an increase of market gross benefits by $36 million, while sensitivity (b) results in a decrease of market gross benefit of $755 million. Under both sensitivities, Option 3C is still expected to have significant net benefits.

Under the base case for sensitivity (a), the market modelling finds that 1,150 MW of black coal in Queensland retires early. For sensitivity (b), the market modelling finds that 1,780 MW of black coal in Queensland and around 230 MW coal in NSW are forecast to retire early (however the remaining NSW coal generators' retirement is forecast to be deferred by 10 years).

With Option 3C in-place under sensitivity (a), 1,150 MW of black coal in Queensland and 570 MW of black coal in NSW are forecast to retire before their end-of-technical life. Similarly, under sensitivity (b), 1,690 MW of Queensland black coal and 800 MW pf NSW black coal are forecast to retire early (starting from 2023-24) with Option 3C in-place, while other NSW black coal generators' retirements are forecast to be deferred by 10 years compared to their end of technical life.

The accompanying detailed market modelling report outlines the assumptions and methodology that this sensitivity test draws on.

8.7.2 Sensitivity to Snowy 2.0's development

As outlined in section 4.1.2, a number of parties raised the prospect of Snowy 2.0 not going ahead or being delayed. While TransGrid considers this is highly unlikely, we have investigated a sensitivity where Snowy 2.0 does not go ahead.

This sensitivity finds that the estimated net benefits of Option 3C under the central scenario would decrease from $1.2 billion to $435 million if Snowy 2.0 were not to proceed. This indicates that Option 3C is expected to provide significant benefits irrespective of the development of Snowy 2.0, from the uptake of renewables in southern NSW and increasing the transfer capacity between Victoria and NSW.

We have also investigated an even more extreme sensitivity where Snowy 2.0 is assumed to not go ahead under the slow-change scenario, to further stress-test the results. This sensitivity reflects a future with sustained slow economic growth, low electricity demand, low ambition for emissions reduction, closure of major industrial electricity users and Snowy 2.0 not proceeding. Under these assumptions, Option 3C is no longer expected to deliver a net benefit (instead a small net cost of approximately $120,000). While this future is extremely unlikely, it provides an indication of a boundary condition at which the preferred option would no longer deliver a net benefit. However, Option 3C has strongly positive benefits under the core scenarios and other sensitivities, and this is sensitivity reflects the only condition studied under which Option 3C does not have a net benefit.

8.7.3 High DER uptake

As outlined in section 4.1.7, participants at the TAPR forum suggested that different levels of DER should be tested. While the modelling undertaken by TransGrid involves assumptions for each scenario that adopts different levels of DER (in line with the ISP assumptions), this sensitivity investigates high DER uptake in the central scenario.

Under this sensitivity, the NPV for Option 3C under the central scenario decreases from $1.2 billion to $1 billion, indicating that high DER uptake has only a limited effect on benefits accruing to Option 3C.

8.7.4 QNI Stage 2

As outlined in section 4.1.3, a number of parties raised the impact of the timing of potential coincident, and/or subsequent, network developments.

We consider that the most relevant such investment is the QNI Stage 2 upgrade and have modelled the largest new double-circuit line from NSW to Queensland considered in the earlier TransGrid and Powerlink QNI PSCR as a conservative sensitivity (ie, the largest capacity version of the 2018 ISP recommended Stage 2 option type).[76]

This sensitivity on the fast-change scenario[77] finds that Option 3C still provides positive net market benefits (in the order of $690 million). The reduction in net benefits is due to the expanded QNI capacity, which enables the NSW New England REZ to develop. This competes with southern renewables and contributes to the estimated gross benefits of Option 3C reducing by approximately 30 per cent, noting that the net benefits remain positive.

8.7.5 VNI West

Consistent with the July 2019 AEMO Insights Paper[78], the market modelling for this PADR has assumed VNI West in July 2026 in all scenarios modelled (with the exception of the slow-change scenario, which does not include VNI West). This represented the best information available regarding the assumed timing of this development at the time the PADR market modelling assumptions were finalised and updated the 2034-35 assumption from the 2018 ISP (and referenced in the HumeLink PSCR).

We have therefore investigated a sensitivity involving VNI West in 2034-35 in the central scenario. This sensitivity finds that the net benefits of Option 3C are not sensitive to the timing of VNI West (the gross market benefits are estimated to decline by around four per cent with VNI West assumed in 2034-35).

On 13 December 219, TransGrid and AEMO released a PSCR for the VNI West RIT-T, which states that delivery of all options assessed is expected to take six to eight years, with indicative completion by 2028-30. In light of the sensitivity undertaken, this latest expected timing for VNI West is not expected to have a material impact on the findings of this PADR.

76 Specifically, we have modelled 'Option 3C' from the QNI PSCR being commissioned in 2028/29 in this sensitivity, see: TransGrid and Powerlink, *Expanding NSW-QLD transmission transfer capacity*, Project Specification Consultation Report, November 2018, available at: https://www.transgrid.com.au/what-we-do/projects/regulatory-investment-tests/Documents/QNI%20PSCR%20November%202018.pdf

77 This sensitivity has been run on the fast-change scenario since the underlying characteristics of this scenario make it most likely to have QNI Stage 2 commissioned in it.

78 AEMO, *Building power system resilience with pumped hydro energy storage – An Insights paper following the 2018 Integrated System Plan for the National Electricity Market*, July 2019, p. 15.

8.7.6 Staged development of Option 3C

As outlined in section 4.1.2, EnergyAustralia questioned whether it is necessary to build all circuits shown in each option at the same time and suggested considering a staged investment in transmission. We have investigated sensitivities under all scenarios that involve completing the Bannaby to Wagga Wagga and Wagga Wagga to Maragle transmission lines first, with the Bannaby to Maragle transmission line built at a later stage.

This sensitivity finds that, compared to when both stages are constructed at the same time, the expected gross market benefits of Option 3C fall by approximately:

- 12 per cent under the central scenario (with the second stage commissioned 1 July 2029);
- 6 per cent under the fast-change scenario (with the second stage commissioned 1 July 2028);
- 5 per cent under the step-change scenario (with the second stage commissioned 1 July 2026); and
- 35 per cent under the slow-change scenario (with the second stage commissioned 1 July 2035).

Under each scenario, there are still expected to be significant net benefits (with the exception of the slow-change scenario, which has around $145 million net cost under these assumptions). Overall, these findings suggest that, while a staged development would defer capital expenditure, it would result in a greater value of market benefits being forgone during the period when the option is not fully developed.

8.7.7 Use of 50 per cent POE demand forecasts

As outlined in section 4.1.6, EnergyAustralia and participants at the TAPR forum queried how TransGrid was planning to use and weight 10 per cent POE, 50 per cent POE or 90 per cent POE demand forecasts.

While the 10 per cent POE has been used to cover both the 10 per cent and 50 per cent POE situations in the core modelling, consistent with the common practice of providing transmission capacity for the 10 per cent POE (which is consistent with the approach adopted in the recently released NSW Government Energy Strategy [79]), we have also investigated a sensitivity where the 50 per cent POE forecasts are used.

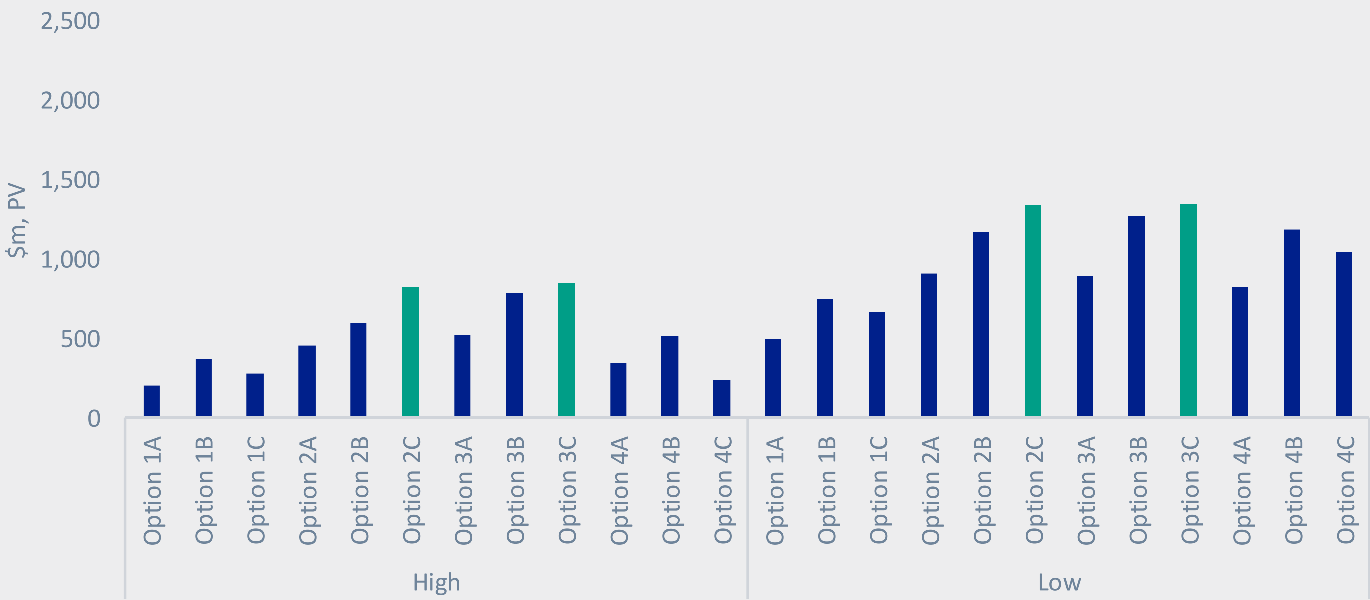
This sensitivity finds that the estimated gross benefits of Option 3C under the central scenario are expected to decrease by around 14 per cent but that there are still expected to be significant net benefits (in the order of $860 million).

8.7.8 Higher and lower network capital costs of the credible options

We have tested the sensitivity of the results to the underlying network capital costs of the credible options.

Figure 24 shows that Option 3C remains the top-ranked option under 25 per cent lower and higher network capital cost assumptions.

Figure 24 Impact of 25 per cent higher and lower network capital costs, weighted NPVs



We have extended this sensitivity testing and find that Option 3C's capital costs would need to be at least 111 per cent higher than the central estimates for it to no longer have positive estimated net benefits (on a weighted-basis).

8.7.9 Use of demand management prior to commissioning of HumeLink

We have tested a sensitivity of using non-network solutions, such as demand management, to increase the transfer capacity of the existing Southern Shared Network at times of peak demand before the network solution is in place.

Specifically, modelling has shown that non-network options that can be enabled to respond within 5 minutes of loss of a transmission line between the Snowy Mountains and Sydney would allow the use of 5-minute ratings on these transmission lines. This could provide up to 110 MW additional transfer capacity from existing generation in southern NSW to the major load centres of Sydney, Newcastle and Wollongong.

The results of this sensitivity indicate that 110 MW additional transfer capacity would provide approximately $2.4 million in gross market benefits (in present value terms). Requirements for non-network options are set out in Appendix C of this PADR.

79 NSW Government, *NSW Electricity Strategy*, p. 23.

8.7.10 Alternate commercial discount rate assumptions

Figure 25 illustrates the sensitivity of the results to different discount rate assumptions in the NPV assessment. In particular, it illustrates two tranches of net benefits estimated for each credible option – namely:

- a high discount rate of 8.95 per cent; and
- a low discount rate of 2.85 per cent.

Option 3C is the top-ranked option under all different discount rate assumptions. We have extended this sensitivity and do not find a realistic discount rate that would result in Option 3C having a negative estimated net benefit.

Figure 25 Impact of different assumed discount rates, weighted NPVs

09 Conclusion

This PADR assessment finds that the 500 kV options going between Maragle and Bannaby via Wagga Wagga (i.e., Option 2C and 3C) provide the greatest net benefits of all credible options across all four scenarios.

On a weighted-basis, Option 2C and Option 3C are expected to deliver approximately $1.1 billion of net benefits and are ranked equal-first (Option 3C has approximately 2 per cent greater net benefits), which is around 7 per cent greater net benefits than the third-ranked option (Option 3B).

While Option 2C and Option 3C are effectively ranked equal-first, Option 3C has a lower capital cost than Option 2C due to shorter circuit length, and marginally higher net benefits. Option 3C also has more route diverse opportunities than for Option 2C due to the 'loop' topology.

Option 3C is also expected to provide a greater risk reduction than Option 2C in terms of avoiding 'high impact low probability' events (such as lightning strikes, bushfires or extreme wind events) affecting multiple lines simultaneously. While recognising the low probability of two lines going down simultaneously under both options, TransGrid has undertaken indicative power system studies that estimates the value of load at risk to be approximately $450 million (in present value terms).

Option 3C is consequently the preferred option identified as part of this PADR as it provides the lowest chance of this occurring due its greater route ability.

Option 3C involves building a new 500 kV route, using route diverse lines, from Maragle to Bannaby, Maragle to Wagga Wagga and Wagga Wagga to Bannaby. Specifically, the high-level scope includes:

- New Wagga Wagga 500/330 kV substation and 330 kV connection to the existing Wagga Wagga substation
- Construct three 500 kV transmission lines:
  - Between Maragle and Bannaby 500 kV substation (260km);
  - Between Maragle and Wagga Wagga 500 kV substation (110km); and
  - Between Wagga Wagga and Bannaby 500 kV substation (260km).
- Three new 500/330/33 kV 1,500 MVA transformers at Maragle substation and one new 500/330/33 kV 1,500 MVA transformer at Wagga Wagga substation
- Upgrade equipment at Lower Tumut and Upper Tumut substations to accommodate increased fault levels
- Augment the Maragle substation to accommodate the additional transmission lines
- Augment the existing substations at Wagga Wagga and Bannaby to accommodate the additional transmission lines/transformers.

Preliminary modelling indicates that Option 3C could accommodate an additional 2,570 MW of generation at times of average import from Victoria and average renewable generation in southern NSW.

Option 3C is expected to provide net benefits to consumers and producers of electricity and to support energy market transition through:

- increasing the transfer capacity and stability limits between the Snowy Mountains and major load centres of Sydney, Newcastle and Wollongong;
- enabling greater access to lower cost generation to meet demand in these major load centres; and
- facilitating the development of renewable generation in high quality renewable resource areas in southern NSW, which will further lower the overall investment and dispatch costs in meeting NSW demand whilst also ensuring that emissions targets are met at the lowest overall cost to consumers.

The estimated capital cost of this option is approximately $1,350 million. Construction is expected to take 3-4 years, with commissioning commencing in 2024, subject to obtaining necessary environmental and development approvals.

The cumulative market benefits realised from Option 3C are expected to exceed the investment cost (in NPV terms) three years after the project is energised (on a weighted-basis).

We have also assessed the ability of demand response to provide net benefits prior to Option 3C being commissioned. Specifically, modelling has shown that if demand response is enabled to respond within 5 minutes of loss of a transmission line between the Snowy Mountains and Sydney, the use of 5-minute transmission line ratings can provide approximately $2.4 million in gross market benefits (in present value terms).

Although no submissions to the PSCR offered demand response, we encourage parties who consider they can assist with providing this service to contact us, so a more fulsome assessment of whether this is likely to be efficient can be undertaken in the PACR.

Appendix A Checklist of compliance clauses

This section sets out a compliance checklist which demonstrates the compliance of this PADR with the requirements of clause 5.16.4(b) of the National Electricity Rules version 128.

RULES CLAUSE	SUMMARY OF REQUIREMENTS	RELEVANT SECTION(S) IN THE PADR
5.16.4(k)	A RIT-T proponent must prepare a report (the assessment draft report), which must include:	–
	1) a description of each credible option assessed;	5
	2) a summary of, and commentary on, the submissions to the project specification consultation report;	4 & Appendix B
	3) a quantification of the costs, including a breakdown of operating and capital expenditure, and classes of material market benefit for each credible option;	8
	4) a detailed description of the methodologies used in quantifying each class of material market benefit and cost;	7
	5) reasons why the RIT-T proponent has determined that a class or classes of market benefit are not material;	7.4
	6) the identification of any class of market benefit estimated to arise outside the region of the Transmission Network Service Provider affected by the RIT-T project, and quantification of the value of such market benefits (in aggregate across all regions);	8
	7) the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results;	8
	8) the identification of the proposed preferred option;	8 & 9
	9) for the proposed preferred option identified under subparagraph (8), the RIT-T proponent must provide: (i) details of the technical characteristics; (ii) the estimated construction timetable and commissioning date; (iii) if the proposed preferred option is likely to have a material inter-network impact and if the Transmission Network Service Provider affected by the RIT-T project has received an augmentation technical report, that report; and (iv) a statement and the accompanying detailed analysis that the preferred option satisfies the regulatory investment test for transmission.	9

Appendix B Summary of consultation on the PSCR

This appendix provides a summary of points raised by stakeholders during the PSCR consultation process.

The points raised are grouped by topic and a response is provided to every point raised. All section references are to this PADR, unless otherwise stated.

Table 9.1 Summary of points raised in consultation on the PSCR

SUMMARY OF COMMENT(S)	SUBMITTER(S)	TRANSGRID RESPONSE
The modelling approach, assumptions, scenarios and sensitivities		
Modelling approach		
SRMC modelling is not adequate to properly capture the market benefits and will distort the assessment of new entrant economics and dispatch outcomes overstating the fuel switching benefits and distorting the modelled flows on transmission lines. SRMC bidding also doesn't allow competition benefits to be assessed.	Delta Electricity, p 3.	See section 4.1.8.
Assumptions used in market modelling		
TransGrid should use the proposed 2020 ISP assumptions where possible and provide a clear explanation for any deviation.	EnergyAustralia, p 2.	See section 4.1.1.
Modelling results must be realistic and sense-checked against historical outcomes. AEMO's 2019/20 ISP modelling is considering how to deal with minimum and maximum capacity factors on coal and gas units. TransGrid should include similar constraints.	EnergyAustralia, p 4.	There are limitations to using historical outcomes in the NEM to sense check modelling results going forward given new transmission investments will modify how the network operates. However, the market modelling in this PADR has adopted the majority of the proposed 2020 ISP. This includes assumptions around maximum and minimum capacity factors on coal and gas units. By adopting the 2020 ISP assumptions, it ensures assumptions adopted have an authoritative basis, accepted broadly and provide for reasonable outcomes. The accompanying market modelling report details how the market model has been calibrated to ensure the results are realistic and in line with how entities in the wholesale market can be expected to operate.
Adopting a 25 per cent scenario weighting across all scenarios appears aggressive as it locks in high demand forecasts and EV projections, plus 2-year and 5-year early coal retirements. It is unclear how TransGrid will use and weight 10 per cent POE, 50 per cent POE or 90 per cent POE forecasts.	EnergyAustralia, p 2. The POE point was also raised at the TAPR forum.	See section 4.1.6.
The retirement of existing power stations should be modelled on an economic viability basis, rather than adopting fixed closure dates	EnergyAustralia, p 3.	See section 4.1.4.
What is the impact of assuming more aggressive coal generator retirement dates (i.e., all retire by late 2020s)? Also, should the different scenarios apply a symmetric adjustment to retirement dates (as opposed to the two years earlier vs. five years later currently proposed).	TAPR forum.	See section 4.1.4.
Assumptions of emissions reducing 52 per cent by 2030 implies coal plant closures outside of the range being considered by AEMO in the ISP modelling and would require very significant storage to be developed. The modelling approach needs to properly account for the variability of demand, renewable generation, thermal plant cycling and outages.	Delta Electricity, p 2.	See section 4.1.4. The accompanying EY market modelling report provides additional detail on how variability of demand, renewable generation, thermal plant cycling and outages have been reflected in the analysis.

SUMMARY OF COMMENT(S)	SUBMITTER(S)	TRANSGRID RESPONSE
Consistency of modelling assumptions and outcomes across RIT-T applications is critical.	EnergyAustralia, p 3.	TransGrid's modelling is largely based on AEMO's 2020 ISP assumptions. There will inevitably be differences in specific modelling outcomes between RIT-Ts, as a variety of different models are utilised. The more salient issue is whether the identification of the preferred option is affected by the specifics of the modelling approach used, and that, where it is, the differences between the outcomes are understood. TransGrid has been working closely with AEMO as part of this RIT-T assessment to align the outcomes between this RIT-T and the draft ISP.
Different DER levels should be tested in scenarios.	TAPR forum.	See section 4.1.7.
A high DER scenario should be run (as opposed to a sensitivity as was proposed in the PSCR).	TAPR forum.	
Shared network component covered by the RIT-T should include Maragle 330 kV substation and the cut in line to Line 64 in order to capture all of the market benefits.	Snowy Hydro, p 7.	The shared network component covered by the RIT-T relates to all transmission assets up to but not including the connection point for a generator.
The assessment should not assume that all other coincident transmission developments also go ahead. TransGrid should provide clarity as to how it incorporates how other network developments are included in market modelling assumptions and option selection.	Delta Electricity, p 1-2. EnergyAustralia, p 3. PIAC, p 3. The interaction between, and timing assumed for, these developments was also raised at the TAPR forum.	See section 4.1.3.
Scenarios and sensitivities		
Snowy 2.0 has not yet received all required approvals and may still not proceed or may be delayed. TransGrid should test scenarios in which Snowy 2.0 is staged, delayed or does not proceed.	Delta Electricity, p 1-2. NPA, p 1. EnergyAustralia, p 2. The TAPR forum raised the scope for delay (given the project's size) and suggested delay be treated as a sensitivity.	This PADR includes sensitivities where Snowy 2.0 is assumed to not go ahead. These sensitivities are presented and discussed in section 8.7.2.
Staging of the transmission investment if Snowy 2.0 delayed: Wagga Wagga to Bannaby/Sydney completed first if PEC proceeds, with Maragle-Wagga Wagga and Maragle Bannaby/Sydney lines deferred until Snowy 2.0 built.	EnergyAustralia, p 5.	Staged development of the transmission investment has been considered in the modelling as a sensitivity. This sensitivity is presented and discussed in section 8.7.5.
There could be considerable option value associated with the flexible/staged options.	EnergyAustralia, p 5. Snowy Hydro, p 2.	See section 7.1.7.
PADR should test the impact of varying multiple assumptions in parallel as part of the sensitivity testing.	EnergyAustralia, p 4.	The scenarios have been designed to test the impact of varying multiple assumptions at once, and in an 'internally consistent' manner.
It is expected that wide capital cost sensitivities will be tested given the uncertainty around capital cost estimates.	EnergyAustralia, p 4.	Sensitivity testing of capital costs undertaken in the PADR adopts a ±25 per cent on central estimates for capital cost. Threshold testing has also been undertaken to stress test how much capital costs under the preferred option would need to increase to reduce net market benefits to zero and for net market benefits to equal the second ranked option. These tests are presented and discussed in section 8.7.8.

SUMMARY OF COMMENT(S)	SUBMITTER(S)	TRANSGRID RESPONSE
A scenario that is worse than the slow-change scenario should be investigated (e.g., constraints on committed generation, recession, investment drought etc).	TAPR forum.	The scenarios investigated largely align with the 2020 ISP scenarios and already include significant variability in the underlying assumptions. The slow-change scenario takes into account reduction in demand from closure of major industrial electricity users, as well as slow economic conditions. No new scenario has been developed.
Could there be a sensitivity included in the modelling that incorporates a NSW renewable energy target/policy, as is the case with Victoria and Queensland	TAPR forum.	See section 4.1.5.
Options considered and the proposal of alternative options		
Staged development with an advancement of one of the circuits from Maragle to Bannaby to support NSW load from the south from existing Snowy scheme or Victoria following the closure of Liddell, and before Snowy 2.0 completed.	Snowy Hydro, p 2. EnergyAustralia, p 5. TAPR forum.	It is not possible to move parts of HumeLink forward as there is insufficient time to obtain all the necessary environmental approvals to do so (and so the option is not considered technically feasible). However, staged/flexible options have been included in the RIT-T analysis.
Build each circuit separately, rather than double circuit from the beginning in order to minimise or eliminate the possibility of double circuit trip and single contingency reclassification.	EnergyAustralia, p 5. Snowy Hydro, p 6	Options proposed in the PADR are considered as route diverse as described in Section 5.
Should the inclusion of Bannaby-Sydney West in Option 4 be separated out so that all options are considered on a like-for-like basis?	EnergyAustralia, p 5.	As shown in section 8, the options including the Bannaby-Sydney West component in the same timeframe as the other transmission lines (i.e., options 4A, 4B and 4C) result in lower expected net market benefits than the equivalent options that do not include the Bannaby-Sydney West component (i.e., options 3A, 3B and 3C). This shows that delivery of the Bannaby-Sydney West component in the same timeframe as the other transmission lines is not expected to be incrementally net beneficial.
Proposal to use modular power flow control technology.	Smart Wires, p 3-4.	See section 4.2.1.
The need to provide information to support the PADR and modelling that has been undertaken		
TransGrid should provide as much information as possible to support the PADR to allow stakeholders to critically review modelling outcomes and understand how benefits are realised.	EnergyAustralia, p 4.	Sections 6 and 7 of this PADR provide detailed descriptions of the key modelling assumptions and approaches adopted, while section 8 outlines results of the economic modelling for all options, across all scenarios and sensitivities undertaken. In addition, we have released a range of supplementary material alongside the PADR to help interested stakeholders understand the drivers of the estimated net benefit. The operation of Snowy 2.0 (and all storage) is an outcome of the market modelling undertaken, as opposed to an input to it.
Providing insights into how Snowy, Snowy 2.0 and other pumped hydro and storage are modelled and how they are dispatched would build confidence in the modelling.	EnergyAustralia, p 4	
Regional price outcomes should be published for all scenarios and sensitivities.	EnergyAustralia, p 4.	The objective of this RIT-T process is to identify the transmission investment option that provides the greatest net benefit to consumers, given the FID that has been made by the Snowy Board. Publication, or providing insights into, regional pricing outcomes or how prospective projects affects TransGrid's regulated asset base would require substantial additional modelling that would not be consistent with the objective of the RIT-T process and is outside the scope of the RIT-T process.
Providing insights into how the Humelink project and other projects anticipated in each scenario would affect TransGrid's regulated asset base.	EnergyAustralia, p 4.	
Other points raised		
Additional renewable generation developed in southern NSW would require further increased capacity of the Southern NSW transmission. It would also reduce the benefits of the transmission to Snowy 2.0 (and the SA-NSW interconnector).	Delta Electricity, p 2.	The RIT-T is considering flexible options that can be scaled up as needed in future to operate at 500 kV. Any further future upgrade of transmission capacity in Southern NSW (e.g., due to the development of renewable generation in Southern NSW that erodes the capacity available for Snowy 2.0 or the SA-NSW interconnector) would be subject to a further RIT-T and would only proceed if there was a further positive net economic benefit. The market modelling finds that the preferred option facilitates significant amounts of new renewable generation in southern NSW.

SUMMARY OF COMMENT(S)	SUBMITTER(S)	TRANSGRID RESPONSE
PSCR states that Snowy 2.0 is committed and that final approval occurred in February 2019. NPA asserts that it would be more correct to state that Snowy 2.0 has yet to receive all necessary approvals, including environmental approvals under the Environmental Planning and Assessment Act.	NPA, p 1.	The PADR has been drafted to recognise that Snowy 2.0 has not received all necessary approvals and has not yet received final approval, but also noting that it has progressed past Final Investment Decision in December 2018. TransGrid also notes that approval for the Exploratory Works stage was granted in February 2019, and public exhibition of the Environmental Impact Statement (EIS) for the Main Works stage was completed in November 2019. TransGrid will continue to monitor the status of approvals for Snowy 2.0.
If Snowy 2.0 does not proceed, then the requirement for transmission assets and associated costs would be different. Snowy Hydro should pay for the majority of the capital contributions towards the difference in transmission augmentation costs.	NPA, p 1-2.	The RIT-T identifies where transmission investment is expected to provide an overall net benefit to the market. That is, investments as a result of which customers will benefit in the long-run by more than the cost of the transmission investment they incur. We note that the RIT-T is required to look at market benefits across the NEM as a whole to find the optimal solution, without assessing inter-regional impacts. Cost allocation, and the sharing of risk, sit outside of the RIT-T process and changes to the regulatory framework in this regard are currently being considered by governments and regulators. Under the NER, where transmission assets in one region are used to supply customers in another region, part of the cost of those assets are charged to customers in the importing region through an 'inter-regional TUOS' or 'IR-TUOS' charge. The current arrangements for determining IR-TUOS have been in place since February 2013 and were intended to make TUOS charges more reflective of the actual costs incurred in providing transmission services. However, the current regime only takes into account peak annual usage for each asset and does not consider the extent of energy flows between regions, or the contribution assets make to providing system strength or contributing to system stability in other ways. The appropriateness of the current IR-TUOS arrangements is an issue that is separate to this RIT-T application, is currently being reviewed, and modifications to the arrangements are not precluded by the outcome of this RIT-T.
The share of benefits from the investment that accrue directly to Snowy 2.0 and those that accrue directly to consumers should be determined. Material imbalances should be highlighted by TransGrid and examine options to address this proposed, including Snowy 2.0 being required to directly fund a commensurate portion of the investment, as part of the HumeLink RIT-T.	PIAC, p 2.	
The relative accrual of expected benefits to consumers in different NEM regions should be examined and a comparison made to how the consumers' portion of costs will be recovered through TUOS. If there is a material imbalance, PIAC recommends that TransGrid highlight this fact and examine options to address this as part of the HumeLink RIT-T, including reallocating regulated revenue recovery across NEM regions in line with their share expected benefit accrual.	PIAC, p 3.	
Alternative options to Snowy 2.0 may not require the same extent of augmentation to the grid.	NPA, p 2.	This RIT-T is not considering alternative options for generation and storage to meet future NEM reliability standards. Under the NEM market arrangements, there is no centralised cost benefit analysis prior to decisions being made to invest in generation or storage projects. Rather, TransGrid's focus in this RIT-T is to identify the transmission investment option that provides the greatest net benefit to consumers, given the FID that has been made by the Board of Snowy Hydro.
Snowy 2.0 is expected to result in substantial, permanent damage to Kosciuszko National Park.	NPA, p 3.	The development of Snowy 2.0, and any impact it has on the Kosciuszko National Park, is a matter that sits outside of this RIT-T.
TransGrid should use experienced gained through the HumeLink RIT-T to inform broader policy and regulatory reforms.	PIAC, p 4.	TransGrid actively participates in broader policy and regulatory reforms through industry associations, submissions and consultations. Experience and insight gained through projects, including the HumeLink RIT-T, informs TransGrid's engagement in policy and regulatory reforms.

Appendix C Requirements for non-network options

Non-network options may provide net benefits prior to the preferred option for HumeLink being commissioned.

Specifically, modelling has shown that non-network options that can be enabled to respond within 5 minutes of loss of a transmission line between the Snowy Mountains and Sydney would allow the use of 5-minute ratings on these transmission lines. This could provide up to 110 MW additional transfer capacity from existing generation in southern NSW to the major load centres of Sydney, Newcastle and Wollongong. Sensitivity modelling has indicated that 110 MW additional transfer capacity would provide approximately $2.4 million in gross market benefits (in present value terms). This corresponds with a value of approximately $700,000 per year for non-network options to be economic.

For this application, non-network options would need to allow the transfer capacity between the Snowy Mountains and Sydney to be increased at times of high power transfer using short-time thermal ratings under system normal conditions. A successful implementation relies on reducing the loading on several transmission lines, from short-time thermal ratings to acceptable continuous levels, immediately following a critical network contingency. Within five minutes following a critical network contingency:

- generation would be tripped or runback in the Snowy Mountains or south or west of the Snowy Mountains; and
- a corresponding amount of load would be tripped or run-back north of Bannaby.

The tripped or run-back generation and load would need to remain in this state until AEMO is able to re-secure the power system (within 30 minutes) but would then be free to resume normal operation within the new secure envelope.

TransGrid invites proponents of non-network solutions that can contribute to submit binding offers.

Required technical characteristics of the non-network option

Size of the non-network solution

The transfer capacity of the transmission lines from Snowy Mountains and Sydney following commissioning of the VNI upgrade project will be approximately 2,870 MW. By utilising short-term ratings, this transfer capacity can be increased by up to 110 MW.

Table C1 Non-network support required

SIZE OF NON-NETWORK OPTION (REQUIRES BOTH GENERATION AND LOAD)	2020/2021 TO 2024/2025
Runback or tripped generation	up to 110 MW
Runback or tripped load	up to 110 MW

We note that this option requires both generation and load components to be runback or tripped together in equal magnitudes. TransGrid will consider individual loads or individual generation, however, this would require TransGrid securing equal amounts of generation or load on the opposite side of the transmission constraint.

TransGrid will consider minimum capacities of 1 MW in either load or generation.

Duration

The non-network solutions will only be required to be enabled when the existing transfer capacity between the Snowy Mountains and Bannaby becomes constrained. This typically occurs at times of peak NSW demand when high amounts of peaking generation is dispatched in southern New South Wales. Historically, this has occurred on 1-2 days, or approximately 5-10 hours cumulatively, per year.

Table C2 Indicative frequency and timing

TIME SCALE	TARGET
Time of year	Summer (December to February)
Time of day	11am to 8pm
Day type	Weekdays
Duration	<10 hours per annum
Failure Rate	0.29 events per annum

Location

TransGrid requires participating generation and load to be located on both sides of the transmission constraint.

Table C3 Location of non-network support required

NON-NETWORK COMPONENT	LOCATION
Runback generation	Lower Tumut, Upper Tumut, Murray, Wagga Wagga area
Runback load	North of Bannaby and South of Liddell

Notice Periods

Given the nature of peak demand days in NSW, TransGrid may provide notice to non-network providers up to 12 hours in advance for them to be enabled. Once enabled, within five minutes following a critical network contingency the generation and load must be runback or tripped.

Please note that participation would preclude that generator or load from providing contingency FCAS (raise/lower) for that period.

Table C4 Notification periods of non-network support

NON-NETWORK COMPONENT	CALL NOTICE PERIOD	DISPATCH
Runback generation	up to 12 hours	within 5 minutes
Runback load	up to 12 hours	within 5 minutes

Information to be provided by proponents

PARAMETER	DESCRIPTION
Block ID	Block Identifier (e.g. Block 1) of non-network solution
Block Capacity	Discrete amount of the non-network option (runback load or generation) capacity in MW.
Location	Address, and/or
Where does the generation/load connect?	
Technology	e.g. Synchronous generation, battery/thermal energy storage, load curtailment.
Details	Details of equipment, service, technology and any other relevant information describing the demand/generation reduction on the transmission network
Availability Period	Period for that Block is available
Call Notice Period	Minimum period of time before the Block can be dispatched
Is this Block participating in other Demand Management programs?	Is this load or generation contracted to another party, e.g. for demand management or setup for the provision of contingency FCAS?
Establishment Fee	Setup payment that applies to enabling a Block, e.g. capex for new equipment and opex to participate, including control systems to enable dispatch within 5 minutes.
Availability Fee	A fee per month for a Block to be made available to be dispatched.
Dispatch Fee	Fee for a Block to be dispatched per MWh
Timeframe for project delivery	When the Block will be available for dispatch. Time required to implement these measures
Communications	Proposed dispatch mechanism with TransGrid's control room. Please provide the communications latency?
Metering	Metering equipment installed or to be installed to measure and record the data to be verified

TransGrid