Sydney Ring South

Market modelling report for Transgrid's Project Assessment Draft Report (PADR)

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Non-Reliance Disclaimer

Scope and Purpose

At the request of Transgrid, EPEC Engineering ("EPEC") has completed wholesale electricity market modelling to assess the gross market benefits of credible options for the Sydney Ring South Project for the purposes of the Regulatory Investment Test for Transmission (RIT-T) Project Assessment Draft Report (PADR). This report presents EPEC's analysis and findings, including modelling outcomes for counterfactual Base Cases and options assessed under three AEMO Draft 2026 Integrated System Plan (ISP) scenarios.

Limitations and Currency

This report has been prepared exclusively for Transgrid's use. All analysis and forecasts are current only to 26 June 2026; EPEC accepts no responsibility for subsequent events or changes. EPEC has not conducted any supplementary work to update the analysis since this date.

Data Sources and Verification

The report incorporates data from the Draft 2026 ISP, AEMO's 2025 Inputs, Assumptions and Scenarios Report (IASR), and information supplied by Transgrid. Whilst EPEC has made reasonable efforts to ensure the quality of this information, it has not independently verified, audited or validated any supplied data and makes no warranty regarding accuracy or completeness.

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Executive Summary

EPEC Engineering ("EPEC") was engaged by Transgrid to undertake wholesale electricity market modelling to assess the gross market benefits of credible options for the Sydney Ring South Project for the purposes of the Regulatory Investment Test for Transmission (RIT-T) Project Assessment Draft Report (PADR). The Sydney Ring South Project was identified as an actionable ISP project in AEMO's 2024 Integrated System Plan (ISP) and Draft 2026 ISP.

This report assesses the gross market benefits of credible network options over a 24-year outlook from 2026-27 to 2049-50, using EPEC's integrated PLEXOS® & PSS®E modelling framework.

Following the Cost Benefit Analysis (CBA) Guidelines for Actionable ISP projects[1], inputs are aligned with AEMO's Draft 2026 ISP and 2025 Inputs, Assumptions and Scenarios Report (IASR), except where targeted refinements were required to better represent the Sydney Ring network and local operating conditions.

The modelling was designed to assess how each credible option for the Sydney Ring South Project changes market outcomes under the three ISP scenarios: *Slower Growth*, *Step Change and Accelerated Transition*. It quantifies gross market benefits across the key categories relevant to the PADR, including:

- Changes in fuel consumption arising through different patterns of generation dispatch
- Changes in voluntary load curtailment (DSP)
- Changes in involuntary load shedding, estimated as unserved energy (USE) costed at the value of customer reliability (VCR)
- Changes in costs for parties, other than the RIT-T proponent (that is, changes in investment in generation and storage capital and fixed and variable operating and maintenance costs)
- Differences in the timing of other network expenditure
- Changes in Australia's greenhouse gas emissions (VER)

Several augmentation options are modelled as part of the Sydney Ring South PADR. Table 1 summarises these options and their planned commissioning dates.

Table 1: Options assessed for the Sydney Ring South PADR

Option	Description	Commissioning date
Option 2	New South Creek 500/330 kV substation	1/7/2030
Option 2d	Install power flow technology in the existing 330 kV network (2024 ISP candidate option)	1/7/2030
Option 3	Staged delivery of a high-capacity transmission line from Bannaby in the Southern Tablelands to South Western Sydney:	Stage 1: 1/7/2033 Stage 2: 1/7/2040

[1] AER, Cost Benefit Analysis guidelines, available at: Cost Benefit Analysis guidelines | Australian Energy Regulator (AER)

Option	Description	Commissioning date
	• Stage 1: 500 kV double-circuit line from Bannaby, initially operated at 330 kV, plus a South Creek 330 kV switching station • Stage 2: Upgrade South Creek to a 500/330 kV substation, and upgrade line operation to 500 kV	
Option 4	High-capacity transmission link from Bannaby to South Western Sydney, including a new South Creek 500/330 kV substation. • Stage 1: New South Creek 500/330 kV substation • Stage 2: 500 kV double-circuit line from Bannaby	Stage 1: 1/7/2030 Stage 2: 1/7/2033
Option 5	Power flow control plus a deferred high-capacity transmission link from Bannaby in the Southern Tablelands to South Western Sydney and a new South Creek 500/330 kV substation (Draft 2026 ISP optimal development path): • Stage 1: Install power flow control technology in the existing 330 kV network • Stage 2: New South Creek 500/330 kV substation and a 500 kV double-circuit line from Bannaby to South Western Sydney	Stage 1: 1/7/2030 Stage 2: 1/7/2037
Option 6	Option 5 scope, delivered to an earliest in-service schedule: • Stage 1: Install power flow control technology in the existing 330 kV network, plus a new South Creek 500/330 kV substation • Stage 2: 500 kV double-circuit line from Bannaby to South Western Sydney	Stage 1: 1/7/2030 Stage 2: 1/7/2033

Market modelling is conducted to assess how each option relieves emerging transmission bottlenecks into the Sydney, Newcastle, and Wollongong load centres and therefore delivers market benefits relative to the Base Case (also called the counterfactual), which assumes that no investment is made in the Sydney Ring South Project.

A key feature of EPEC's market modelling assessment is the more detailed representation of the Sydney Ring transmission network than is available in the Draft 2026 ISP model. This additional granularity is important because it captures the specific constraints affecting supply into the Sydney, Newcastle, and Wollongong region and enables meaningful differentiation between the Sydney Ring South Project options.

Without investment in the Sydney Ring South Project, the Base Case shows material and persistent congestion on the transmission corridor south of Sydney, especially the Bannaby to Sydney West 330 kV corridor (Line 39), with increasing pressure also emerging on the corridor supplying Wollongong and the Illawarra (via 330 kV Lines 8 and 16). As demand grows and coal power stations retire, these constraints increasingly limit the ability to move lower-cost energy into Sydney, Newcastle, and Wollongong from regional NSW and from interconnectors, forcing greater reliance on higher-cost local generation, storage, gas and, in some scenarios, offshore wind development in the Hunter and Illawarra regions.

The Sydney Ring South Project options are forecast to alleviate congestion on the southern corridor of the Sydney Ring network, particularly on 330 kV Lines 39, 8 and 16. The increased transfer capacity enabled by the Sydney Ring South Project options is forecast to allow more efficient utilisation of lower-cost renewable generation and storage resources, both current and future generation capacity, resulting in lower wholesale electricity costs, benefitting the NEM parties including those who produce, consume and transport electricity in the market.

Table 2: presents estimated gross market benefits of the Sydney Ring South Project options assessed in the PADR across the three core scenarios. Gross benefits over the assessment period (2026-27 to 2049-50, inclusive) are presented in present value terms, discounted to 30 June 2025 by applying 7% discount rate (real, pre-tax) consistent with the discount rate in the 2025 IASR.

Gross market benefits for all Sydney Ring South Project options are lowest under Slower Growth, higher under Step Change and highest under Accelerated Transition, reflecting the increasing value of higher transfer capability as demand growth, electrification and emissions constraints intensify. The dominant driver of benefits is the reduced capital expenditure across the broader power system, complemented by lower total fixed operating costs and, in some cases, reductions in fuel costs and reliability-related costs.

Transgrid's PADR has identified Option 6 as the preferred option at the PADR stage of the RIT-T process[2]. The net benefits are calculated on a weighted average basis across all scenarios, considering the weightings of 46% for Step Change, 27% for Slower Growth and 27% for Accelerated Transition, consistent with the Draft 2026 ISP.

Option 6 comprises a new 500 kV transmission line from Bannaby in the Southern Tablelands to South Western Sydney, planned for 2033-34, together with a new South Creek substation and installation of series reactors as power flow controllers on the 330 kV network in 2030-31. While this option is estimated to deliver the highest expected net market benefit of all options on a weighted average across all scenarios, the PADR highlights that all options that plan the delivery of a new high-capacity transmission line achieve the highest market benefits.

As shown in Table 2:, Option 6 also delivers the highest gross market benefits in each scenario, at approximately $1.5 billion under Slower Growth, $4.4 billion under Step Change and $6.6 billion under Accelerated Transition. Other Sydney Ring South Project options involving transmission upgrades are estimated to have similar benefits to Option 6, while the incremental upgrades proposed under Option 2 and Option 2d deliver materially lower gross market benefits.

Table 2: Gross market benefits of Sydney Ring South Project options – Core scenarios ($ million, real 30 June 2025 discounted to 30 June 2025)

Option	Slower Growth	Step Change	Accelerated Transition
Option 2	202	212	1,179
Option 2d	948	1,495	2,257
Option 3	1,402	4,212	5,810
Option 4	1,452	4,277	6,155
Option 5	1,450	4,162	5,714
Option 6	1,537	4,390	6,584

In addition to the scenario analysis, a variety of sensitivities have been tested to assess the robustness of gross market benefits to changes in key assumptions about the trajectory of the energy transition. Table 3 outlines the sensitivities modelled for the Sydney Ring South PADR.

[2] Transgrid, Sydney Ring South, available at: [Sydney Ring South | Transgrid]

Table 3: Sydney Ring South PADR sensitivities

Sensitivity No.	Sensitivity Name	Description
1	Alignment with NSW Electricity Infrastructure Roadmap development	Generation projects that have been awarded with South West REZ and Central West Orana REZ Access Rights are treated as 'anticipated' projects. Stage 2 of the New England REZ transmission project is treated as an actionable project progressing under the NSW Electricity Infrastructure Roadmap framework.
2	Constrained use of diesel as a back-up fuel	Ability for existing gas-fired generators in the Hunter and Central Coast regions to run on diesel as a backup fuel is limited to the conditions of relevant environmental and planning permits and assume that future facilities are required to meet equivalent standards.
3	NSW Electricity Infrastructure Roadmap aligned development & constrained use of diesel as a back-up fuel	Combination of Sensitivities 1 and 2.
4a	High data centre growth	Add 1 GW by 2050 to the baseline Draft 2026 ISP Step Change data centre demand forecast for the Sydney, Newcastle and Wollongong region. Match growing data centre demand with equivalent local demand management mechanisms which could include demand flexibility agreements or local generation and storage. For modelling purposes, this flexibility is modelled as additional dispatchable demand side participation Alignment with NSW Electricity Infrastructure Roadmap developments (as above). Constrained use of diesel as a backup fuel (as above). Inclusion of LTESA Tender 6 outcomes, consistent with treatment of other policy supported projects. Disable modelled targets set by the 2025 NSW Infrastructure Investment Objective (IIO) Report and 82% of electricity generation from renewable energy sources under the Commonwealth Government's Powering Australia Plan. These adjustments are made to ensure that this large increase in electricity demand is met by a realistic capacity mix which still observes longer term carbon reduction objectives.
4b	Very high data centre growth	Same as Sensitivity 4a but add 2 GW data centre demand by 2050 to the baseline Draft 2026 ISP Step Change data centre demand forecast for the Sydney, Newcastle and Wollongong region.
5	Low data centre growth	Limits data centre capacity and growth to only existing facilities in the Sydney, Newcastle, and Wollongong region. This results in data centre demand growing from approximately 0.5 GW in 2026 to approximately 0.9 GW by the late 2030s (compared to over 2 GW by the end of the assessment period in the Step Change scenario).
6	Higher adoption of distributed and consumer energy resources	Increase year-on-year uptake of behind-the-meter storage by approximately 50% for 10 years to 2035-36, relative to the AEMO forecast adopted in the Draft 2026 ISP Step Change scenario. This

Sensitivity No.	Sensitivity Name	Description
		results in an additional 760 MW (1,490 MWh) of behind-the-meter storage installed in the Sydney, Newcastle, and Wollongong region by 2035/36, in addition to the forecast 2,000 MW (3,960 MWh) forecast by this date. Increase generation hosting capacity of distribution networks in the Sydney, Newcastle, and Wollongong region from 0.9 GW to 5.3 GW, consistent with the 2025 Distribution System Plan assuming that this capacity would be available to solar generation only.
7	Negligible non-zero variable cost for renewable generation and storage	Revert adoption of a negligible non-zero variable cost ($0.10 per MWh) for renewable generation and storage to the ISP parameter ($0 per MWh).

Across the modelled sensitivities, the options that include new high-capacity transmission lines materially outperform the options that only deliver incremental network upgrades. Table 4 shows that Option 6 delivers the highest gross market benefits in every modelled sensitivity, ranging from approximately $1.9 billion in the low data centre growth case (Sensitivity 5) to $10.8 billion in the 2 GW data centre growth sensitivity (Sensitivity 4b). Option 4 and Option 3 also perform strongly, with benefits ranging from approximately $1.8 billion to $10.6 billion, while the smaller Option 2d remains materially lower where assessed. Given the outcomes from the core scenarios, Transgrid only tested Option 2d in the sensitivities where it was plausible to expect that it could become preferred.

Table 4: Gross market benefits of Sydney Ring South Project options – Sensitivities ($ million, real 30 June 2025 discounted to 30 June 2025)

Option	Sensitivity 1	Sensitivity 2	Sensitivity 3	Sensitivity 4a	Sensitivity 4b	Sensitivity 5	Sensitivity 6	Sensitivity 7
Option 2d	-	-	-	-	-	861	1,362	-
Option 3	4,856	4,443	5,368	7,951	10,392	1,797	2,961	4,091
Option 4	4,956	4,487	5,468	8,111	10,592	1,815	3,009	4,134
Option 5	4,755	4,340	5,265	7,570	9,048	1,743	2,816	3,987
Option 6	5,082	4,556	5,590	8,253	10,825	1,859	3,031	4,202

1. Introduction

1.1 Background

EPEC Engineering ("EPEC") was engaged by Transgrid to undertake wholesale electricity market modelling to assess the gross market benefits of credible options for the Sydney Ring South Project for the purposes of the Regulatory Investment Test for Transmission (RIT-T) Project Assessment Draft Report (PADR). The Sydney Ring South Project was identified as an actionable ISP project in AEMO's 2024 Integrated System Plan (ISP) and Draft 2026 ISP.

As an actionable ISP project, Transgrid is required to apply the RIT-T in accordance with the National Electricity Rules (NER). The RIT-T process requires Transgrid to identify and assess credible options that address the identified need, and to demonstrate that the preferred option maximises net market benefits relative to a Base Case in which no credible option is implemented.

1.2 Purpose of this Report

This report is a supporting document to Transgrid's PADR for the Sydney Ring South Project which details the market modelling inputs and assumptions, methodology, scenarios, sensitivities and results. The regulatory context, identified need, scope of credible options, and net market benefit outcomes are documented in Transgrid's PADR document[3]. The applicable classes of market benefits and the regulatory framework governing the assessment are also set out in the PADR.

1.3 Relationship to AEMO's Draft 2026 ISP

The market modelling in this assessment is aligned with AEMO's Draft 2026 ISP and most recent Inputs, Assumptions and Scenarios Report (IASR), except for specific circumstances as outlined in this report.

EPEC's Integrated PLEXOS® & PSS®E Model builds on the Draft 2026 ISP PLEXOS® model, with the key improvement being the representation of the flow paths into Sydney, Newcastle, and Wollongong, which is implemented in more detail to capture the network limitations and differentiate the benefits between Sydney Ring South Project options.

1.4 Report Structure

This report is structured as follows:

- Section 2 sets out the inputs and assumptions underpinning the market modelling.
- Section 3 describes the market modelling methodology, including the network constraint formulation.
- Section 4 outlines the options, scenarios and sensitivities that were assessed in Transgrid's PADR
- Section 5 presents the gross market benefits for each option relative to the Base Case.
- Section 6 analyses the key drivers of benefits in each scenario, including analysis of sensitivities undertaken to assess the robustness of findings.

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[3] Transgrid, Sydney Ring South, available at: Sydney Ring South | Transgrid

2. Market modelling inputs and assumptions

This section sets out the inputs and assumptions underpinning the market modelling undertaken for the Sydney Ring South PADR.

2.1 Inputs and assumptions for core scenario assessments

Table 5 summarises the key assumptions adopted for the Sydney Ring South PADR market modelling across the Slower Growth, Step Change and Accelerated Transition scenarios. The assumptions draw primarily on AEMO's Draft 2026 ISP and the 2025 IASR and cover key modelling inputs including technical and financial parameters for generation and storage development, coal retirement dates, gas operation limits, representation of hydroelectric schemes, demand, forecast uptake of consumer energy resources, hydrogen demand, limits for renewable energy zones, emissions limits, capital costs and committed transmission developments. These assumptions provide the basis for assessing how the relative market benefits of the Sydney Ring South Project options vary under different transition pathways and system conditions.

Table 5: Key input parameters for modelled scenarios

Assumption	Source for inputs and assumptions		
	Slower Growth	Step Change	Accelerated Transition
Generators and storage projects	All existing, committed and anticipated projects from the AEMO Generation Information July 2025. Market modelling is used to develop long-term capacity plan.		
Coal generator limits	Minimum annual capacity factors – consistent with the AEMO Draft 2026 PLEXOS® model.		
Coal retirement dates	AEMO Draft 2026 ISP outcomes – Slower Growth least cost development plan; except for Eraring retirement date, being updated to the announced date (April 2029)	AEMO Draft 2026 ISP – Step Change least cost development plan; except for Eraring retirement date, being updated to the announced date (April 2029)	AEMO Draft 2026 ISP – Accelerated Transition least cost development plan; except for Eraring retirement date, being updated to the announced date (April 2029)
Gas operation limits	AEMO Draft 2026 ISP - Daily limits determined by the Gas Statement of Opportunity (GSOO). Some OCGTs can operate on secondary liquid fuel, consistent with AEMO Draft 2026 ISP PLEXOS® model.		
Generation and storage build limits	AEMO Draft 2026 ISP		
Hydro representation and inflows	Hydro scheme representation consistent with the 2025 IASR. Reservoir inflow data consistent with the AEMO Draft 2026 ISP model, except for the Snowy Hydro scheme which was redacted from the modelling package supplied to Transgrid ahead of its public release. As a result, inflows from the 2024 IASR were used to ensure alignment with rolling reference year cycle used for other weather dependent assumptions.		
Demand	AEMO Draft 2026 ISP, Operational sent out (OPSO) PV LITE POE10 Slower Growth Note: Distributed PV is explicitly modelled in PLEXOS	AEMO Draft 2026 ISP, OPSO PV LITE POE10 Step Change Note: Distributed PV is explicitly modelled in PLEXOS	AEMO Draft 2026 ISP, OPSO PV LITE POE10 Accelerated Transition Note: Distributed PV is explicitly modelled in PLEXOS
Uptake of Consumer Energy Resources (CER) - Aggregated virtual power plants and vehicle to grid	IASR workbook v7.5 – Slower Growth	IASR workbook v7.5 – Step Change	IASR workbook v7.5 – Accelerated Transition

Assumption	Source for inputs and assumptions		
Hydrogen demand	IASR workbook v7.5 – Slower Growth Electrolyser locations and capacities consistent with AEMO Draft 2026 ISP Slower Growth least cost DP	IASR workbook v7.5 – Step Change Electrolyser locations and capacities consistent with AEMO Draft 2026 ISP Step Change least cost DP	IASR workbook v7.5 – Accelerated Transition Electrolyser locations and capacities consistent with AEMO Draft 2026 ISP Accelerated Transition least cost DP
REZ resource limits	IASR workbook v7.5		Accelerated Transition scenario-specific land limits as outlined in IASR workbook v7.5
REZ transmission limits	IASR workbook v7.5		
Interconnectors and subregional flow path limits	IASR workbook v7.5, except for the limit for the flow path between Sydney, Newcastle, and Wollongong (SNW) and Central NSW (CNSW), which was replaced with more detailed network constraints.		
NEM emissions budget	727 Mt CO2-e	583 Mt CO2-e	303 Mt CO2-e
State emissions budgets	NSW: 126 Mt from 2026-27 to 2029-30, 228 Mt from 2030-31 to 2049-50 QLD: 175 Mt from 2026-27 to 2029-30, 248 Mt from 2030-31 to 2049-50 SA: 7 Mt from 2026-27 to 2029-30, 15Mt from 2030-31 to 2049-50 VIC: 123 Mt from 2026-27 to 2029-30, 139 Mt from 2030-31 to 2049-50		
Capacity Investment Scheme (CIS)	Variable renewable generation targets: NSW: 7,100 MW by 2029-30 SA: 1,200 MW by 2029-30 VIC: 1,500 MW solar and 3,500 MW wind by 2029-30 TAS: 1,200 MW by 2029-30 Dispatchable targets: NEM: 10,994 MW by 2029-30 NSW: 1,300 MW by 2028-29 SA: 1,249 MW by 2027-28 VIC: 1,700 MW by 2028-29		
Powering Australia Plan	82% of total NEM production from renewable sources by 2030		
NSW Energy Infrastructure Roadmap (EIR)	33.6 TWh of additional renewable generation capacity by 2029-30. 16 GWh of long duration storage (8h+) by 2029-30 and 28 GWh by 2033-34.		
	Not applicable	88 TWh of additional renewable generation capacity by 2036-37. 42.4 GWh of long duration storage (8h+) by 2036-37.	
Victorian Renewable Energy Target (VRET)	65% renewable generation by 2029-30 95% renewable generation by 2034-35		
Victorian Offshore Wind Target (VOWT)	2 GW by 2031-32 4 GW by 2034-35 9 GW by 2039-40		
Victorian Storage Target	2.6 GW of utility scale storage by 2029-30 6.3 GW of utility scale storage by 2034-35		
South Australian Renewable Energy Target (SRET)	Net renewable energy generation by 2027-28		
South Australian Firming	2.3 GW of firm capacity by 2028-29		
Tasmanian Renewable Energy Target (TRET)	15.75 TWh of renewable generation by 2029-30 21 TWh of renewable generation by 2039-40		

Assumption	Source for inputs and assumptions		
Capital costs for new entrant generation and storage	IASR workbook v7.5 – Slower Growth	IASR workbook v7.5 – Step Change	IASR workbook v7.5 – Accelerated Transition
Committed, Anticipated and Actionable Transmission Projects	Timing as per the Optimal Development Plan (ODP) in the AEMO Draft 2026 ISP		
Future Transmission Projects	Timing as per the AEMO Draft 2026 ISP Slower Growth least cost development plan	Timing as per the AEMO Draft 2026 ISP Step Change least cost development plan	Timing as per the AEMO Draft 2026 ISP Accelerated Transition least cost development plan

Given the ISP's scope as a long-term, whole-of-system roadmap for the whole National Electricity Market, AEMO makes necessary simplifications to its representation of the power system to accommodate the breadth of factors that must be taken into consideration. As a result, the ISP parameters designated may not be sufficiently granular to capture the nuanced wholesale market benefits of different options in a RIT-T assessment. Therefore, EPEC market modelling assessment for the Sydney Ring South Project PADR develops and considers the following additional details:

- More detailed representation of the Sydney Ring transmission network;
- Updated representation of consumer energy resources (CER) and demand side participation (DSP) within the Sydney, Newcastle, and Wollongong region;
- More granular representation of new generation and storage build options;
- Application of updated parameters from the AEMO Draft 2026 ISP;
- Updated closure date of Eraring Power Station;
- Changes to the Snowy Hydro inflow data; and
- Application of non-zero variable operating and maintenance (VOM) costs to variable renewable energy (VRE) and battery storage.

The following section describes each of these aspects and the rationale for the additional detail.

2.1.1 More detailed representation of the Sydney Ring transmission network

The AEMO Draft 2026 ISP represents the Sydney Ring network using three cut-set constraints, one from the north and two from the south (a cut-set represents aggregated transfer capacity across a section of the transmission network). To better capture the locational dynamics relevant to the Sydney Ring South Project, EPEC has developed a more detailed set of network constraint equations, formulated in accordance with AEMO's Constraint Formulation Guidelines[4].

This added granularity allows the influence of existing, committed and anticipated generation, storage and loads on the network constraint equations to more accurately reflect where the generation, storage and loads are connected within the network. Generic, region-wide build options for the Sydney, Newcastle, and Wollongong region are by default mapped to the subregional reference node at Sydney West, which does not adequately reflect the differing network impacts of candidate developments at more plausible connection locations. To address this, technology build options have been explicitly

[4] AEMO, Congestion information resource, available at: AEMO | Congestion information resource

mapped to specific connection points within the region (for example, separate 4-hour BESS options have been defined at Vales Point and Dapto). The full set of location-specific build options within Sydney, Newcastle, and Wollongong is listed in Table 6.

Table 6: Sydney, Newcastle, and Wollongong specific asset assumptions

Generation or storage build option	Modelled connection point
Sydney, Newcastle, and Wollongong OCGT	Vales Point 330 kV
WOO OCGT (New gas-powered generation in the Illawarra)	Dapto 330 kV
CNSW OCGT	Marulan 330 kV
2-hour BESS Vales Point	Vales Point 330 kV
4-hour BESS Vales Point	Vales Point 330 kV
8-hour BESS Vales Point	Vales Point 330 kV
1-hour BESS Kemps Creek	Kemps Creek 330 kV
2-hour BESS Kemps Creek	Kemps Creek 330 kV
4-hour BESS Kemps Creek	Kemps Creek 330 kV
2-hour BESS Dapto	Dapto 330 kV
4-hour BESS Dapto	Dapto 330 kV
8-hour BESS Dapto	Dapto 330 kV

Importantly, this modelling makes available all the same build options for the Sydney, Newcastle and Wollongong subregion as in the Draft 2026 ISP, only represented with greater nuance on plausible connection locations.

2.1.2 Updated representation of CER and DSP within Sydney, Newcastle, and Wollongong

The representation of distributed energy resources within the Sydney, Newcastle, and Wollongong region has also been disaggregated from the Draft 2026 ISP, which represents all distributed energy resources in the region to be connected at the subregional reference node (Sydney West). The Draft 2026 ISP models Distributed PV and consumer energy resources (CER), including vehicle-to-grid (V2G), across two distribution network service provider (DNSP) areas: Ausgrid and Endeavour Energy. While this provides some locational detail, the geographic extent of these DNSP areas means the resulting injections do not align closely with the connection points that influence the Sydney Ring network constraint equations. To address this, the Ausgrid and Endeavour Energy aggregates have been reallocated across three zones, i.e. Newcastle, Sydney and Wollongong (Dapto), to better reflect the distribution of these resources relative to the network elements of interest. The resulting mapping is shown in Table 7.

Table 7: Sydney, Newcastle, and Wollongong CER and Distributed PV assumptions

Object	Allocation	Connection point
Newcastle Distributed PV / CER / V2G	40% of Ausgrid capacity	Newcastle
Sydney Distributed PV / CER / V2G	60% of Ausgrid capacity 80% of Endeavour capacity	Sydney West
Wollongong Distributed PV / CER / V2G	20% of Endeavour capacity	Dapto

2.1.3 Changes to the Snowy Hydro inflow data

The natural inflow data for the Snowy Hydro scheme was redacted in the version of the Draft 2026 ISP model provided to Transgrid by AEMO prior to its public release, for the purposes of conducting market modelling for the Sydney Ring South PADR.

To address this, inflow data from the 2024 ISP dataset was substituted. However, the sequence of reference years used in the rolling weather trace differs between the 2024 ISP and the Draft 2026 ISP. The substituted inflow data was therefore re-sequenced to ensure consistency with other weather-dependent inputs, including variable renewable energy (VRE) availability and demand traces. Inflow data for the 2023-24 reference year was not available in the 2024 ISP dataset; in its place, the median hydrological reference year (2017-18) was applied.

2.1.4 Non-zero VOM costs applied to VRE and batteries

A non-zero variable operating and maintenance (VOM) cost of $0.1/MWh has been applied to variable renewable energy (VRE) generators and battery energy storage systems (BESS). The Draft 2026 ISP applies a zero marginal cost to these technologies, reflecting the absence of fuel costs and the limited variable component of their operating expenses. While this is a reasonable representation of their true short-run marginal cost, it can introduce numerical and behavioural issues in dispatch models.

When generation and storage are modelled with zero marginal cost, the optimiser is indifferent between many dispatch combinations that yield the same objective function value. This degeneracy can result in arbitrary cycling of energy between storage assets, or spatial and temporal shifting of energy without any economic penalty. Where network constraint equations are included in the formulation, zero-cost cycling can also be used to satisfy constraints in ways that are mathematically valid but do not reflect realistic operation of the power system.

Introducing a small positive VOM ensures that dispatch and cycling decisions occur only where there is an economic benefit, breaks the degeneracy in the objective function, and produces more stable and interpretable results. The value applied is sufficiently small that it does not materially influence the merit order or the calculation of gross market benefits; rather, it removes unrealistic dispatch behaviour that would otherwise distort the underlying outcomes. Confidence in the gross benefits is improved as a result, since they are derived from economically meaningful dispatch decisions.

2.2 Materiality of key inputs and assumptions

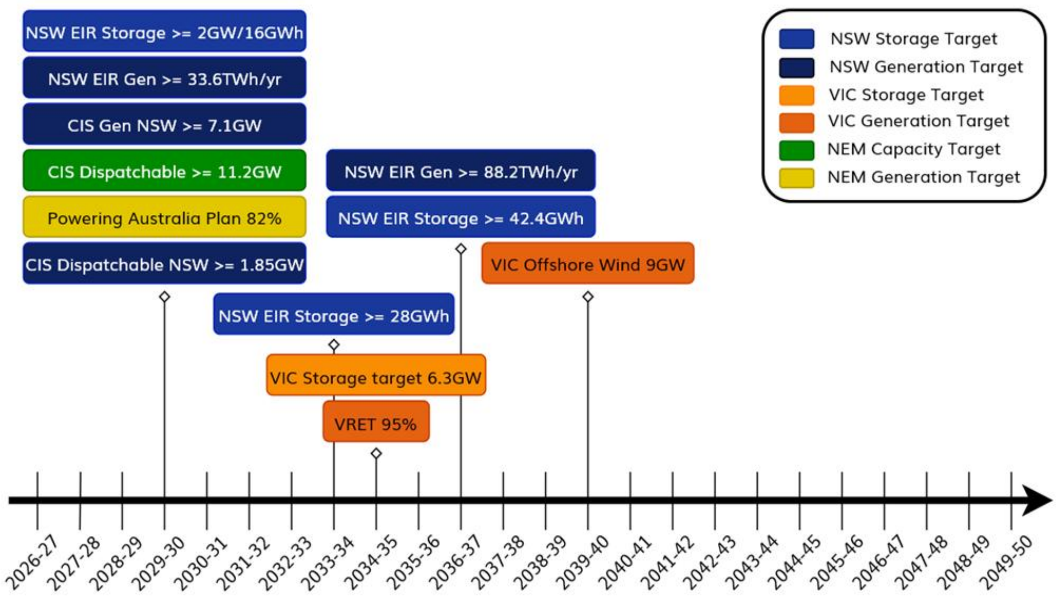
This section provides details of key assumptions influencing benefits for the Sydney Ring South Project across all scenarios.

2.2.1 Government policies and targets for renewable energy generation and storage developments

Renewable generation and storage policies and targets are a key driver for the short to medium term capacity build out, which also impacts the longer-term capacity mix. Figure 1 shows the assumed policies in all scenarios. All scenarios have the same policy assumptions, apart from the Slower Growth scenario which does not assume extended targets for the NSW EIR based on the Infrastructure Investment Objectives (IIO). Key targets and policies are outlined below:

- By 2029-30, NSW is required to deliver 16 GWh of long-duration storage and 33.6 TWh of renewable generation per year under the NSW Electricity Infrastructure Roadmap (EIR).
- At the NEM level, renewable generation is assumed to reach 82% of total generation by 2030 under the Powering Australia Plan, enabled by a target of 11.2 GW of dispatchable capacity under the Capacity Investment Scheme (CIS), of which 1.85 GW is allocated for NSW.
- Following that and by 2033-34, application of the NSW Infrastructure Investment Objective (IIO) targets in the Draft 2026 ISP, requires an additional 12 GWh of storage to be built in NSW, bringing the total to 28 GWh.
- The following year (2034-35) Victoria is required to reach 95% of electricity from renewable sources and 6.3 GW of storage capacity.
- By 2036-37, the NSW IIO targets applied in the Draft 2026 ISP model for the Step Change and Accelerated Transition scenarios require 14.4 GWh of further long duration storage in NSW, totalling 42.4 GWh, and total renewable generation greater than 88.2 TWh per year.
- Lastly, by 2039-40, Victoria is assumed to reach 9 GW of offshore wind capacity according to the legislated Victorian offshore wind target.

Figure 1: Timeline of key renewable energy and storage development policies applied to all scenarios (Slower Growth is not required to meet the 2036-37 EIR targets)



2.2.2 Coal retirements

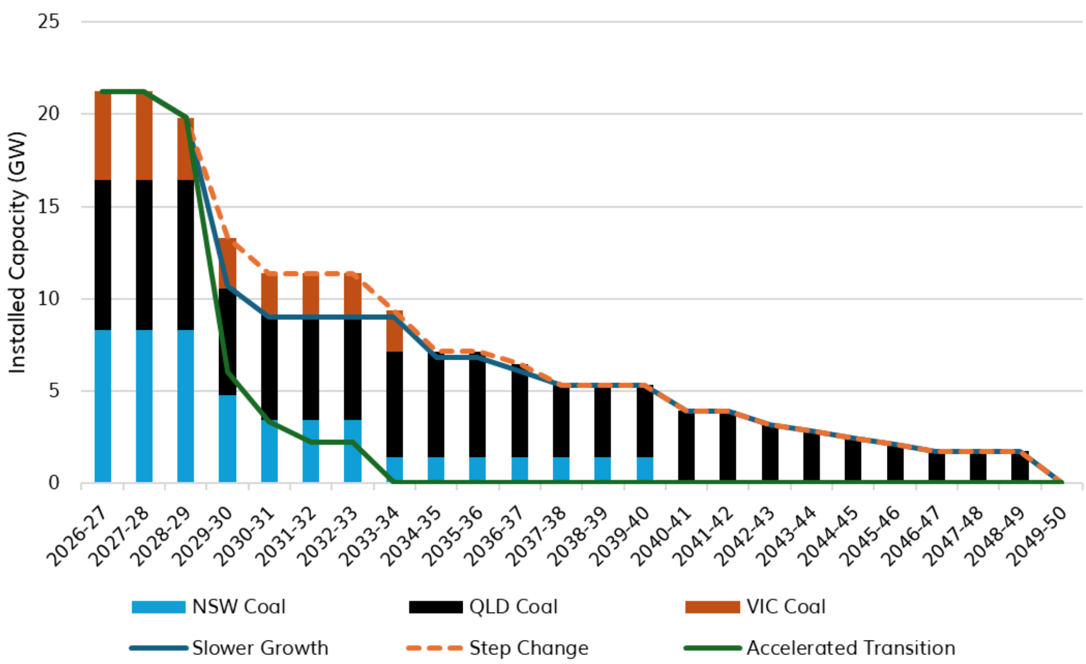
Across the NEM, installed coal fired generation capacity totals approximately 21.3 GW in 2026-27, reducing modestly to 19.8 GW by 2028-29 before declining from 2029-30, when a wave of retirements reduces capacity to 13.3 GW under the Step Change scenario, 10.7 GW under Slower Growth, and 6.0 GW under Accelerated Transition (refer to Figure 2).

Notably, more coal capacity retires in the near term in the Slower Growth scenario, compared to Step Change. Under the Accelerated Transition scenario, coal exits the NEM entirely by 2033-34, approximately 16 years earlier than under Slower Growth and Step Change, both of which retain residual coal capacity through to 2049-50.

In the Step Change scenario, the state-level breakdown illustrates the sequence of retirements that are most relevant to the Sydney Ring South Project:

- NSW coal capacity declines from 8.3 GW in 2026-27 to 4.8 GW by 2029-30 - a reduction of 43 % in two years - and continues declining to 1.4 GW by 2033-34 (following retirement of Vales Point and the last Bayswater units) before exiting entirely by 2040-41 when Mt Piper retires.
- Victorian coal exits by 2034-35, and
- Queensland coal remains through to 2049-50 under the Step Change and Slower Growth scenarios.

Figure 2: Coal retirements across all scenarios



2.2.3 Emissions and carbon budgets

In its ISP modelling, AEMO applies carbon budget constraints to ensure that the optimal development pathway reflects the need to limit cumulative emissions over time rather than just annual outcomes.

Cumulative NEM-wide emissions budgets are applied over six-year periods across the modelling horizon, with the PLEXOS® model able to optimise the timing and profile of emissions within each six-year window.

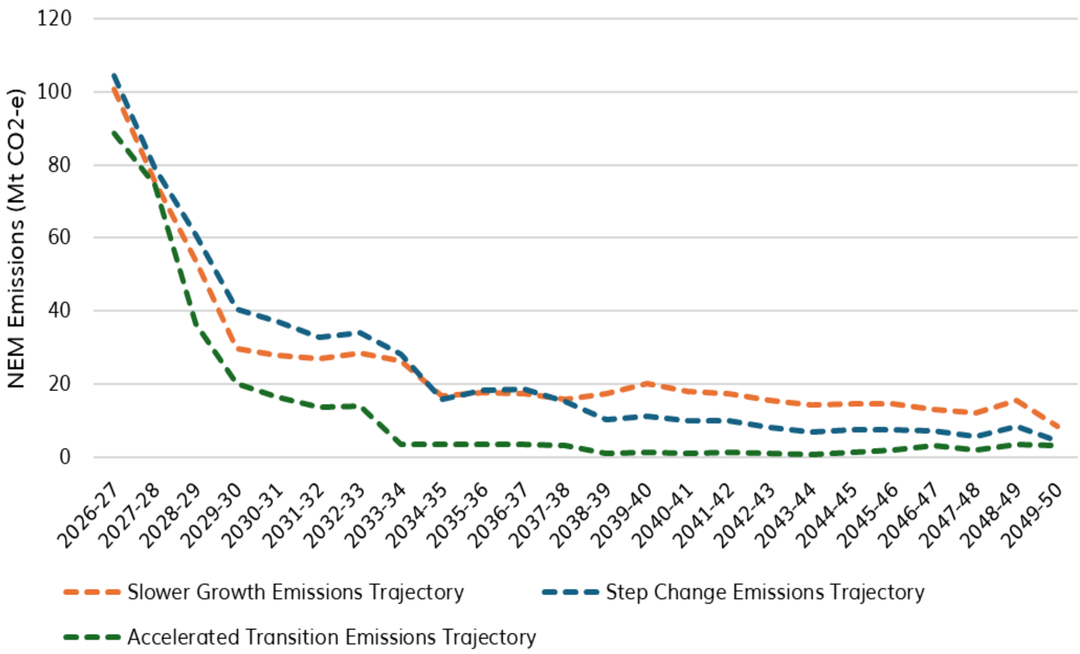
In the first window covering years 2026-27 to 2031-32, emissions budgets are broadly similar across Slower Growth and Step Change scenarios at 351 Mt CO2-e and 355 Mt CO2-e respectively, while the allowance in the Accelerated Transition scenario is materially lower at 250 Mt CO2-e. Scenario divergence widens significantly in subsequent periods.

Over the period from 2032-33 to 2037-38, the Accelerated Transition budget of 31 Mt CO2-e is less than one fifth of the Slower Growth budget of 168 Mt CO2-e. The Step Change scenario follows a steady declining trajectory across all four periods, reaching 40 Mt CO2-e in the final window covering years 2044-45 to 2049-50, while Slower Growth declines more gradually to 78 Mt CO2-e over the same period. Under Accelerated Transition, the budget of 15.2 Mt CO2-e for the window covering years 2044-45 to 2049-50 is slightly higher than the preceding period (6.6 Mt CO2-e between 2038-39 and 2043-44), an outcome derived from AEMO's Single Stage Long-Term (SSLT) model.

Application of these emissions budgets places limits the ability to utilise carbon-emitting generation such as coal and gas fired generation, driving the need to build out a least-cost renewable energy and storage mix to supply the bulk energy needs of the NEM.

Figure 3 shows the annual emissions trajectories across all scenarios, based on modelled outcomes that satisfy the applicable emissions budgets.

Figure 3: Emissions trajectory to meet carbon budget across all scenarios



2.2.4 NEM and NSW electricity demand

NEM-wide and NSW native demand (underlying demand excluding net effects of Distributed PV) varies materially across the three modelled scenarios, representing different assumptions about the pace of industrial electrification, consumer electrification, and the development of renewable export industries (refer to Figure 4).

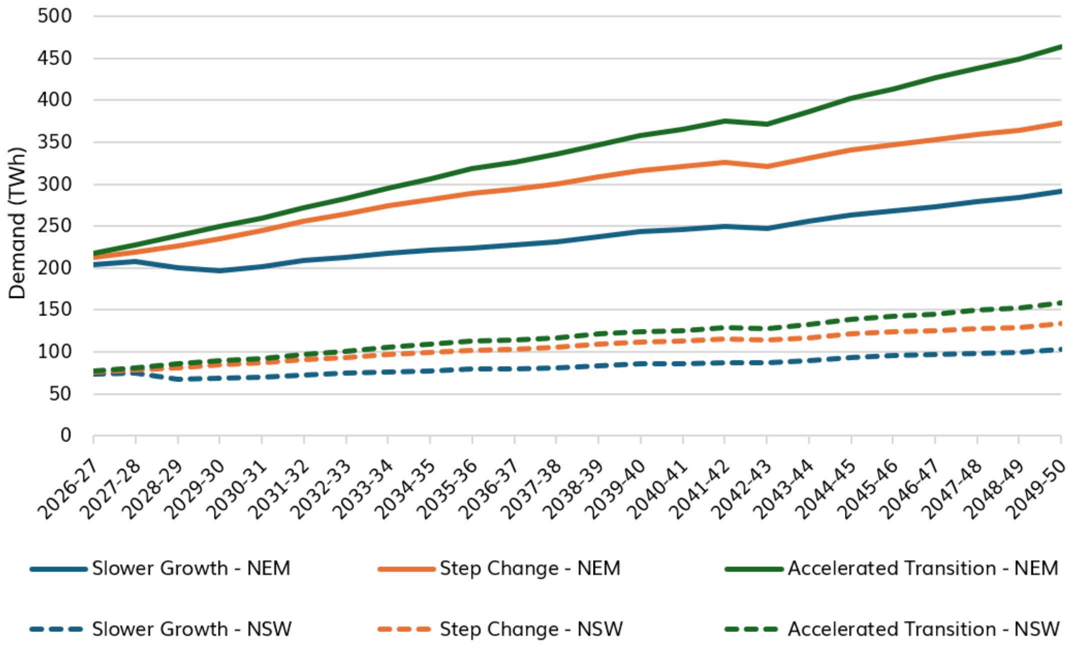
By the end of the assessment period in 2049-50, native electricity demand in the NEM in the Slower Growth scenario reaches 292 TWh (a 42.6 % increase over the modelling horizon, equivalent to a compound annual growth rate of approximately 1.6 %), while demand in the Step Change scenario reaches 373 TWh (75.6 %; 2.5 % p.a.), and demand in the Accelerated Transition scenario reaches 464 TWh (112.9 %; 3.3 % p.a.). This represents a spread of approximately 173 TWh between the upper and lower bounds by the end of the study period.

Under Slower Growth, native demand declines to a trough of approximately 196.4 TWh in 2029-30, before recovering to a sustained growth trajectory from the early 2030s.

In Step Change and Accelerated Transition, demand growth is more continuous across the horizon, with the divergence between the two scenarios widening from approximately 6.5 TWh in 2026–27 to around 91 TWh by 2049–50.

For NSW specifically, demand is projected to follow a similar trajectory to the broader NEM. By 2050, NSW demand is expected to roughly double under the Slower Growth scenario and almost triple under Accelerated Transition, with Step Change sitting between these two outcomes.

Figure 4: NEM and NSW native demand across all scenarios



2.2.5 Distributed PV and Coordinated Energy Resources (CER)

Across the NEM, Distributed PV is projected to be broadly similar across scenarios at the start of the modelling horizon before diverging materially, reaching 53 GW, 87 GW and 109 GW under Slower Growth, Step Change and Accelerated Transition, respectively, by 2049-50 (refer to Figure 5). As for NSW, Distributed PV growth in this region is significant and expected to roughly account for 40% of NEM Distributed PV under all scenarios.

Figure 5: NEM and NSW Distributed PV across all scenarios

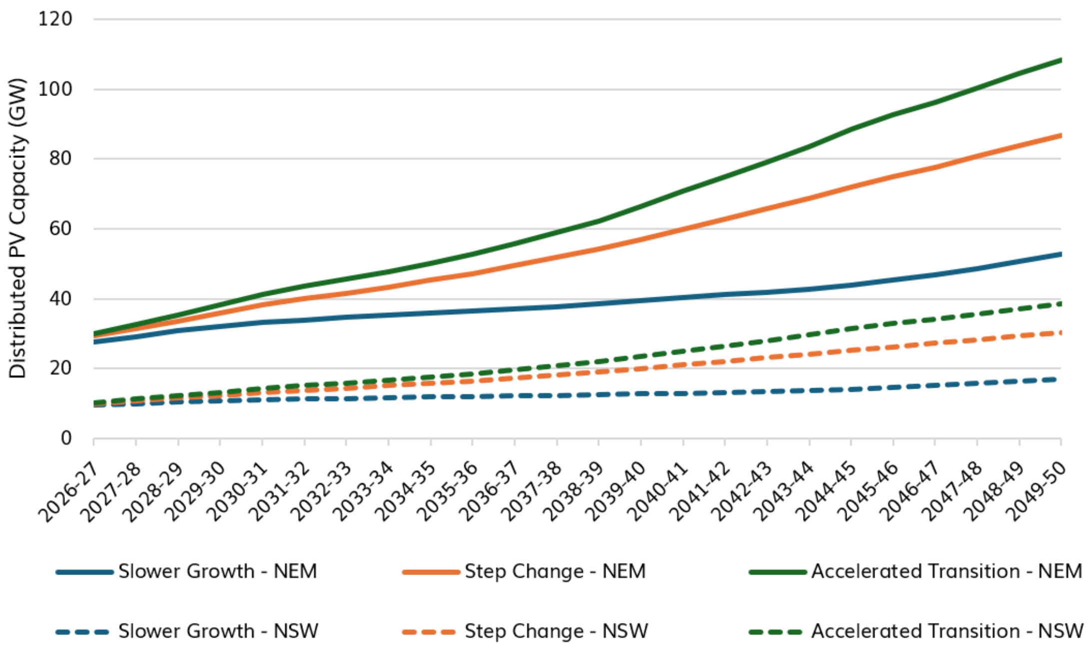
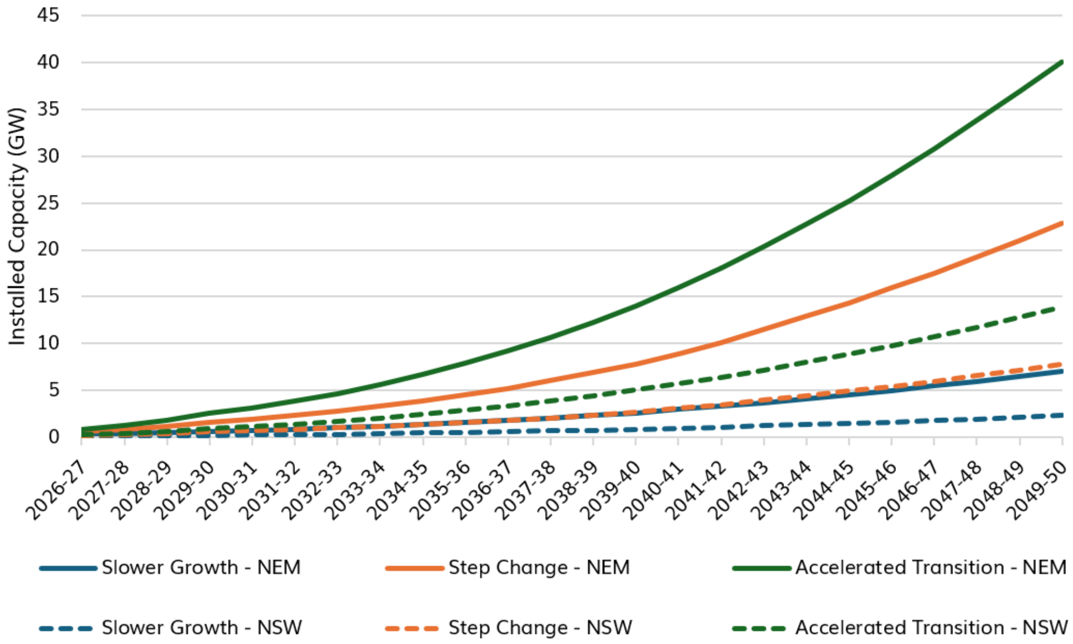


Figure 6 shows the forecast installed capacity of coordinated consumer energy resources (CER) which includes aggregated consumer energy storage (such as home batteries) and vehicle-to-grid (V2G) technology which are modelled as centrally coordinated generators that discharge capacity in the NEM. NEM capacity is low initially, reflecting the relatively low current uptake rates, but grows rapidly to 7.1 GW, 22.8 GW, and 40.1 GW by 2049-50 for Slower Growth, Step Change and Accelerated Transition, respectively. A similar growth trend is seen in NSW, accounting for around 30% of NEM coordinated CER by the end of modelling horizon.

The extent to which the charging and discharging cycles of coordinated consumer energy resources are able reduce evening peak requirements is therefore highly scenario dependent. Under Accelerated Transition, the scale of coordinated CER relative to distributed PV suggests a material shift of daytime generation surplus into the evening peak. By contrast, under Slower Growth, the coordinated storage-to-PV ratio remains modest across the modelling horizon, limiting this effect.

Note that uncoordinated consumer batteries are not modelled as a separate input since they are instead embedded within the native demand traces, consistent with AEMO's approach in the 2025 IASR. Only coordinated consumer batteries and V2G resources, which can be actively dispatched in response to market conditions, are represented explicitly in the market modelling.

Figure 6: NEM and NSW coordinated CER (VPP and V2G) across all scenarios



2.2.6 Hydrogen demand

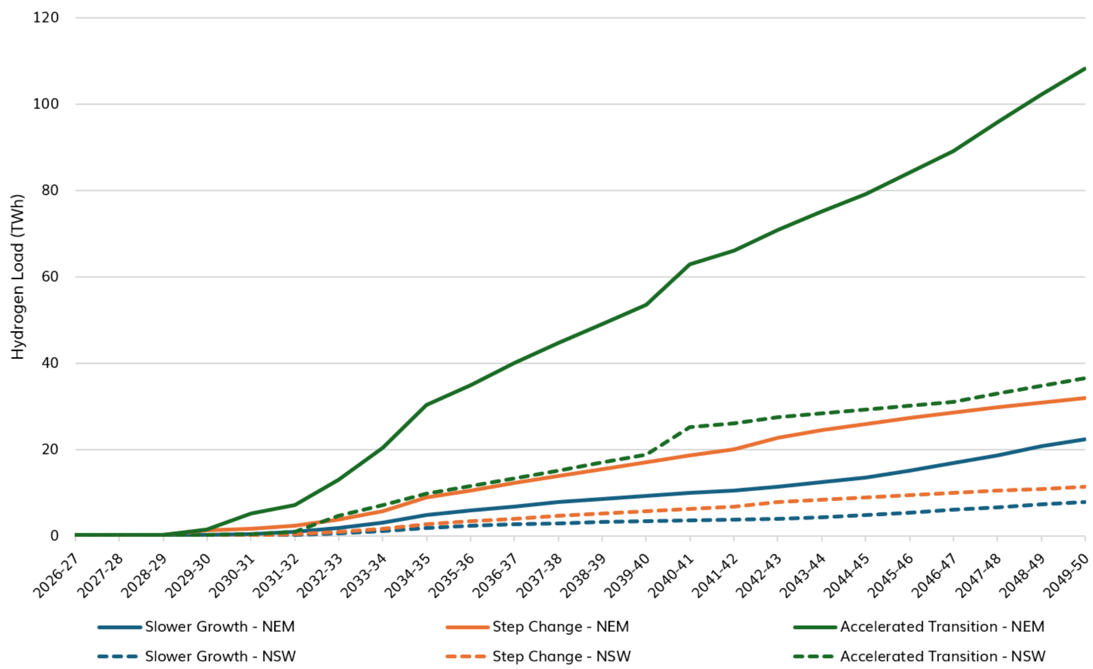
Electricity demand for hydrogen electrolysis is modelled as a separate input and is not included in the native demand figures presented earlier.

Figure 7 presents NEM and NSW hydrogen demand assumptions in each scenario.

Hydrogen demand is negligible at the start of the modelling horizon in all scenarios, before increasing from 2029–30. Growth is lowest under the Slower Growth scenario, slightly stronger under the Step Change scenario, and materially higher under the Accelerated Transition scenario. While hydrogen demand in the Slower Growth and Step Change scenarios is expected to be just under 30 TWh by the end of modelling horizon, it reaches just above 100 TWh in the Accelerated Transition scenario. Consistent with the Draft 2026 ISP, the majority of NSW green hydrogen production is modelled in Sydney, Newcastle, Wollongong region, primarily in the Illawarra region, where the 70% of NSW electricity demand for green hydrogen production is modelled.

In NSW, relatively low hydrogen demand growth is seen in the Slower Growth and Step Change scenarios, while it is forecast to grow significantly in Accelerated transition scenario, reaching just under 40 TWh by 2050.

Figure 7: Electricity demand for hydrogen production in the NEM and NSW across all scenarios



2.2.7 Sydney, Newcastle, and Wollongong gas supply limits

Gas-fired generation in the Sydney, Newcastle, and Wollongong region is modelled within AEMO's East Coast Gas Market (ECGM) gas supply zone framework, as set out in the 2025 IASR and 2025 GSOO.

Daily gas fuel limits are applied at the supply zone level and, where applicable, at the pipeline zone level (such as for the Colongra and Kurri Kurri pipelines in the Newcastle area). All daily limits are treated as exogenous inputs to the model, sourced from AEMO's gas supply modelling undertaken for the GSOO and provided alongside the Draft 2026 ISP PLEXOS® model. Each zone's daily limit represents the gas available to gas-powered generation after residential, commercial, and industrial demand has been met.

As Figure 8 shows, all Sydney, Newcastle, and Wollongong gas units are located within the Southern zone, which spans Victoria (VIC), South Australia (SA), Tasmania (TAS), and New South Wales (NSW). Within the Southern zone, units are further allocated to supply zones: the Newcastle units fall within the Newcastle supply zone, and the Wollongong units fall within the Gippsland supply zone (which also covers Victorian and Tasmanian gas units).

Figure 8: AEMO's Supply and Pipeline zones for the ECGM[5]

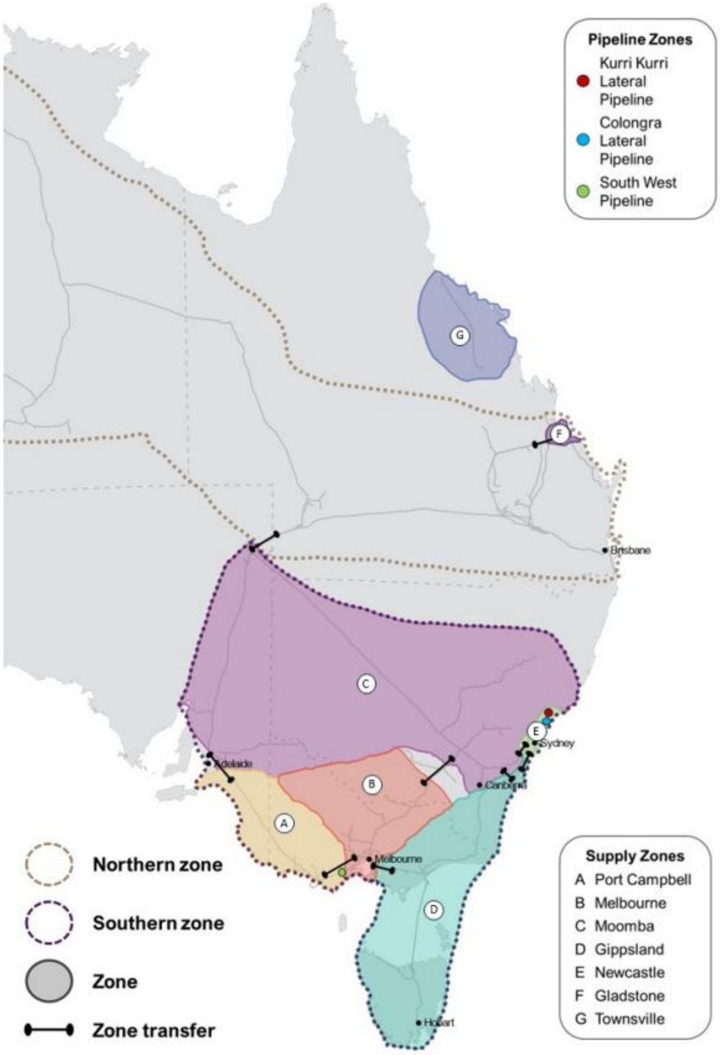


Table 8 summarises the units modelled in each Sydney, Newcastle, and Wollongong cluster, their pipeline constraints, and their fuel options; the detail follows.

Table 8: Sydney, Newcastle, and Wollongong Gas Unit Summary

Power Station	Modelled Location	Pipeline Constraints	Alternative Fuel(s)
Colongra	Newcastle	Southern + Newcastle + station level	Liquid fuel
Hunter (Kurri Kurri)	Newcastle	Southern + Newcastle + station level	Liquid fuel; Hydrogen (Accelerated Transition only)

5 AEMO, 2025 Gas Infrastructure Options Report, available at: [AEMO| 2025 Gas Infrastructure Options Report]

Power Station	Modelled Location	Pipeline Constraints	Alternative Fuel(s)
Tallawarra A	Wollongong	Southern + Gippsland	None
Tallawarra B	Wollongong	Southern + Gippsland	Hydrogen (Accelerated Transition only)
Generic new-build OCGT (Newcastle)	Newcastle	Southern + Newcastle	Liquid fuel; Hydrogen (Accelerated Transition only)
Generic new-build OCGT (Wollongong)	Wollongong	Southern + Gippsland	Liquid fuel; Hydrogen (Accelerated Transition only)

The Southern zone constraint sets an upper bound on aggregate gas withdrawal across all gas units in Victoria (VIC), South Australia (SA), Tasmania (TAS), and New South Wales (NSW) combined. Supply zone constraints sit beneath this, for example, the Newcastle supply zone constraint covers the existing Colongra and Hunter (Kurri Kurri) power stations, plus any new-build OCGTs modelled at Newcastle, and the Gippsland supply zone constraint covers the existing Tallawarra A and Tallawarra B power stations, plus any new-build OCGTs modelled at Wollongong (Dapto). Either the Southern zone constraint or the applicable local supply zone constraint can bind in any given period.

The Colongra and Hunter (Kurri Kurri) power stations are additionally subject to station-level pipeline constraints (the Colongra Pipeline and the Kurri Kurri Pipeline respectively) that cap each station's gas withdrawal. When the Southern zone, Newcastle supply zone, or station-level pipeline constraint binds, the affected units can switch to liquid fuel as a backup, albeit at a materially higher short-run marginal cost. The Hunter (Kurri Kurri) power station is additionally configured to run on hydrogen as an alternative fuel (this option is only available in the Accelerated Transition scenario).

The Gippsland supply zone represents gas supplied via the East Coast Gas Pipeline (ECGP) and intersects with the Sydney, Newcastle, and Wollongong transmission node modelling in the Draft 2026 ISP. The Tallawarra A and Tallawarra B power stations share the Gippsland constraint with VIC and TAS gas powered generation units, on top of the Southern zone constraint. The Tallawarra B power station is configured as a dual-fuel unit with hydrogen as its secondary fuel rather than liquid fuel, although as with the Hunter (Kurri Kurri) power station, hydrogen is only made available in the Accelerated Transition scenario.

Generic new-build OCGT options are made available in both supply zones and if built, contribute to their respective supply zone constraint as well as the Southern zone constraint. New-build OCGTs have access to both liquid fuel and hydrogen as alternative fuels. To use liquid fuel, they must build dedicated liquid fuel storage, which is modelled as refilling on a fortnightly cycle and effectively caps the duration of liquid fuel operation between refills.

Hydrogen, where available under the Accelerated Transition scenario, is supplied from a shared Sydney, Newcastle, and Wollongong-wide pool subject to a daily offtake limit. All hydrogen-capable units in the region (Hunter (Kurri Kurri), Tallawarra B, and any generic new-build OCGTs that elect to use hydrogen, draw from this common pool, so the daily limit effectively allocates hydrogen availability across competing units rather than guaranteeing each unit a separate entitlement.

3. Methodology

This section describes the classes of benefits assessed in the Sydney Ring South PADR, the wholesale market modelling methodology developed for the PADR and details of the more detailed network representation for the flow paths towards Sydney, Newcastle, and Wollongong.

3.1 Classes of benefits assessed in the Sydney Ring South PADR

Under the AER Cost Benefit Analysis (CBA) guidelines, to calculate market benefits for each credible option, a RIT-T proponent must derive the states of the world with and without the credible option in place under each relevant scenario or adopt the states of the world determined through the ISP if applicable. A state of the world is a detailed description of all the relevant market supply and demand characteristics and conditions likely to prevail if a credible option proceeds or in the Base Case[6]. For the Sydney Ring South PADR, the three scenarios from the Draft 2026 ISP (Slower Growth, Step Change and Accelerated Transition) are adopted as the states of the world in which each credible option is assessed.

Assessed against the Base Case, for each credible option the RIT-T proponent must quantify all classes of market benefits identified in the relevant ISP that are considered to be material and may also consider other classes of market benefits in accordance with the CBA guidelines [7]. The classes of market benefits considered in this assessment are:

- changes in costs for parties, other than the RIT-T proponent (that is, changes in investment in generation and storage capital and fixed and variable operating and maintenance costs)
- changes in fuel consumption in the NEM arising through different patterns of generation dispatch
- changes in involuntary load curtailment
- changes in voluntary load curtailment
- differences in timing of other network expenditure
- changes in greenhouse gas emissions
- changes in network losses.

The benefits regarding changes in network losses are captured indirectly in the modelling through other market benefit classes such as fuel costs. Changes in network losses will result in a corresponding change in the total level of generation required and the costs associated with its production. The classes of benefits assessed are consistent with the AEMO ISP[8]. Also consistent with AEMO's Draft 2026 ISP methodology, the ancillary services costs and competition benefits market benefit classes are not considered material.

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[6] AER, Cost Benefit Analysis guidelines, available at: Cost Benefit Analysis guidelines | Australian Energy Regulator (AER)

[7] AER, Cost Benefit Analysis guidelines, available at: Cost Benefit Analysis guidelines | Australian Energy Regulator (AER)

[8] A RIT-T proponent has discretion when considering whether to quantify a market benefit class set out in section 3.3.4 that AEMO did not include in the ISP.

As outlined in Transgrid's PADR, benefits related to option value may arise for flexible, staged options (Options 3 and 5), but this has not been assessed at this stage of the RIT-T.

All gross market benefits are estimated on a 30 June 2025 real dollars basis ($2024-25). Present value (NPV) outcomes are discounted back to 30 June 2025 by applying 7% discount rate (real, pre-tax) consistent with the discount rate in the 2025 IASR. All NPVs consider a 24-year outlook period from 2026-27 to 2049-50, inclusive.

3.2 Wholesale market modelling

The Sydney Ring South PADR market modelling has been conducted using EPEC's Integrated PLEXOS® and PSS®E Model for a 24-year modelling outlook period covering 2026-27 to 2049-50, inclusive.

To meet the requirements of the CBA guidelines, the market modelling for this assessment has been aligned with AEMO's Draft 2026 ISP by adopting the Draft 2026 ISP PLEXOS® model as the starting point for EPEC's long term capacity expansion model.

The PLEXOS® long-term (LT) model was used to develop the least-cost generation and storage build-out over the modelling horizon. The LT model applies a linear optimisation that minimises total system costs, subject to constraints including supply-demand balance, renewable energy and storage policy targets, emissions budgets, transmission limits, energy-limited resource availability, and generator technical constraints.

Consistent historical weather reference years are used for wind, solar and demand profiles as well as hydro inflows. The modelling applies a 'rolling reference year' approach (using data from 2010-11 to 2024-25) across the modelling horizon, consistent with the ISP modelling methodology. The use of multiple reference years allows the modelling to capture a broad range of weather patterns affecting the coincidence of customer demand, wind, solar and hydro generation outputs. All half hourly profiles are based on data published with the Draft 2026 ISP[9] or as provided by Transgrid.

The Sydney Ring network constraint representation in AEMO's Draft 2026 ISP model reflects a high level of aggregation and abstraction suitable for NEM-wide capacity expansion modelling, but it does not resolve the transfer limit differences between the credible options under assessment for this PADR. To ensure network limitations in the Base Case are accurately modelled and that market benefits of each option are properly differentiated, the Sydney Ring South PADR market modelling develops individual N and N-1 line and transformer constraint equations for the flow paths to Sydney, Newcastle, and Wollongong, from north, west and south. This refinement reflects the RIT-T's role, as set out in the CBA guidelines, of exploring credible options at a more granular technical level than the ISP.

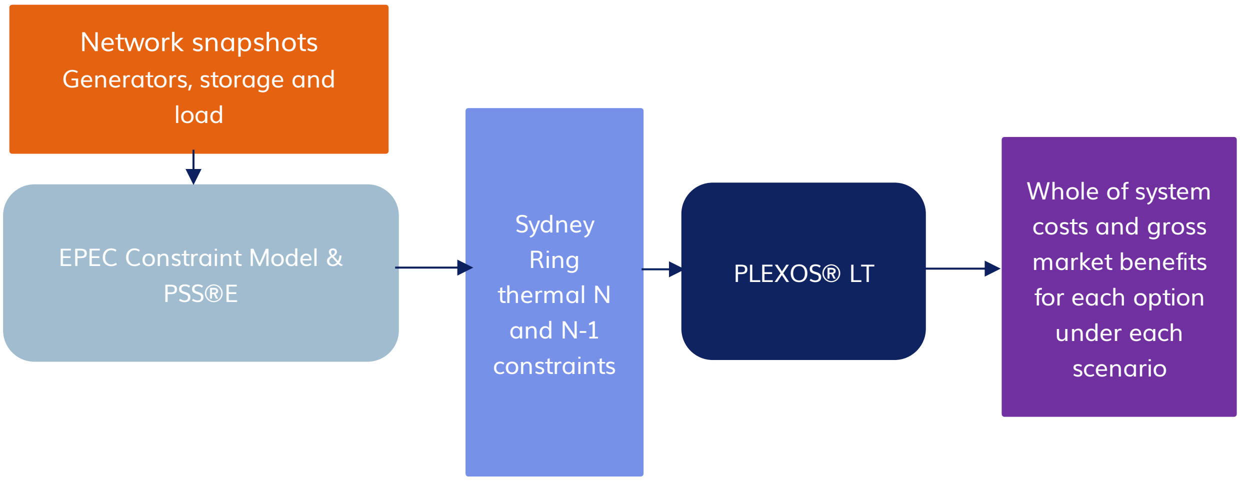
To develop the Sydney Ring network constraints, EPEC applied its Integrated PSS®E & PLEXOS® modelling framework, with the Draft 2026 ISP model forming the basis of the PLEXOS® component.

Network snapshots of the Base Case and each credible option were developed in PSS®E, from which constraint equations were formulated consistent with AEMO's Constraint Formulation and Constraint

[9] AEMO, 2026 Integrated System Plan (ISP), available at: AEMO | 2026 Integrated System Plan (ISP)

Implementation guidelines[10]. The resulting network constraint equations were then implemented in the PLEXOS® model in place of the simplified Sydney Ring network representation used in the Draft 2026 ISP model. Figure 9 shows the market modelling approach applied for the Sydney Ring South PADR.

Figure 9: Market modelling approach for the Sydney Ring South PADR

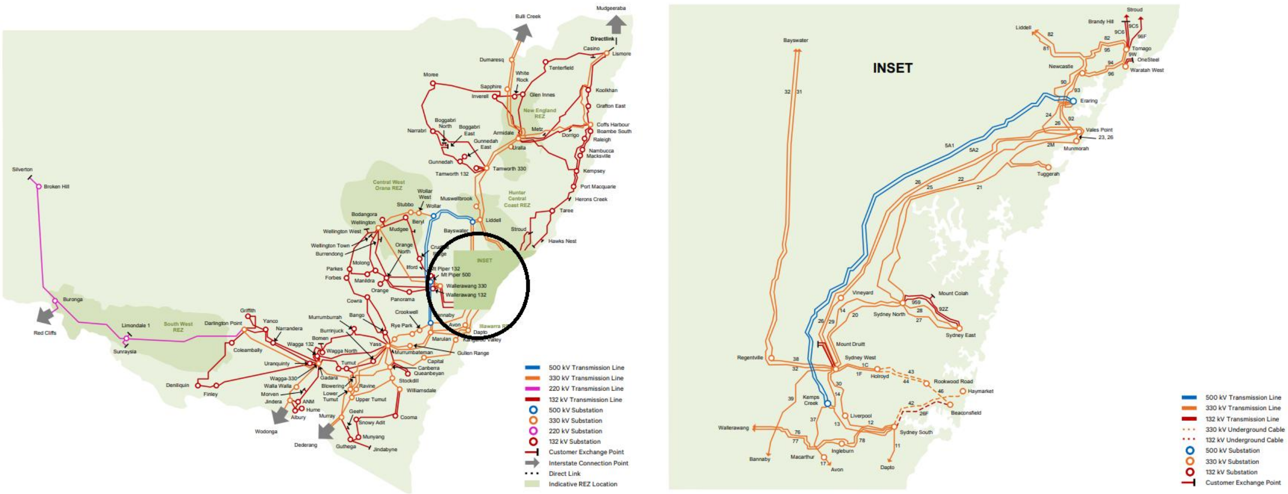


3.3 Network constraint modelling

EPEC modelled N and N-1 network constraints for key transmission lines and transformers which supply the Sydney, Newcastle, and Wollongong demand centres. The geographic extent of the modelled network is illustrated in Figure 10, with all 330 kV and 500 kV lines intersected by the black circle represented by network constraint equations in PLEXOS®. Additional network constraints within the Sydney, Newcastle, and Wollongong region, including thermal limits from Eraring to Kemps Creek, and around Eraring, as well as thermal limits on the southern side near Sydney such as Sydney South to Liverpool 330 kV line are also modelled, as these have been found to be limiting factors in supplying demand in the Greater Sydney region.

[10] AEMO, Congestion information resource, available at: AEMO | Congestion information resource

Figure 10: Electricity network map of NSW[11]



Constraints are formulated following AEMO's Constraint Formulation and Constraint Implementation guidelines. EPEC applied its Constraints Model which uses PSS®E to create constraint equations for N and N-1 conditions. Constraint equations include left-hand side and right-hand side terms. We note that for the right-hand side terms, AEMO's pre-dispatch formulation methodology is used. Details of modelled constraints are provided in Table 37 in Appendix A.

To accurately capture the evolution of the network over the modelling horizon, network constraints are reformulated following each major augmentation. When projects such as Project EnergyConnect (PEC), HumeLink, or the Hunter Transmission Project (HTP) are commissioned, updated constraint sets, including any new lines introduced by those projects, are applied. Each updated constraint set supersedes the preceding set from the point of commissioning onward, with the final constraint set remaining in effect for the remainder of the modelling horizon.

The full list of individual constraint sets applied across the Base Case modelling horizon is shown in Table 37. All Draft 2026 ISP upgrades including QNI Connect and Stage 1 of the New England REZ transmission project are reflected in the Sydney Ring South PADR modelling. However, unlike the upgrades listed in Table 9, these projects are not expected to materially affect the left-hand-side coefficients of the relevant constraint equations and therefore were not modelled explicitly in the network snapshots used for constraints.

Table 9: Constraint sets – Base Case

Constraint set	Description	Date from	Date to
Set 1	Existing NEM network, before Project EnergyConnect (PEC)	1/07/2026	30/06/2027
Set 2	Project EnergyConnect commissioned	1/07/2027	30/11/2028
Set 3	HumeLink commissioned	1/12/2028	31/10/2029
Set 4	Hunter Transmission Project (HTP) commissioned	1/11/2029	30/06/2030

[11] Transgrid, Transmission Annual Planning Report, available at: NSW Transmission Annual Planning Report 2024

Constraint set	Description	Date from	Date to
Set 5	End of Waratah System Integrity Protection Scheme (SIPS) ratings	1/07/2030	31/10/2031
Set 6	Victoria – New South Wales Interconnector West (VNI West) commissioned	1/11/2031	30/06/2033
Set 7	Updated load distribution allocations, reflecting locational uneven demand growth trends in the Sydney, Newcastle and Wollongong region, as advised by Transgrid.	1/07/2033	

Table 38 in Appendix A shows the constraints modelled in the 500 kV upgrade options. Constraints are reformulated using PSS®E modelling with the option scope in place. Furthermore, additional constraints are modelled to ensure all network limitations for each credible option are represented.

For each individual Sydney Ring South Project option, a new set of constraints is formulated and applied. For example, for Option 6, constraint set 5 from 1/07/2030 includes the power flow control and the South Creek substation, and constraint set 7 from 1/07/2033 includes the scope for the new 500 kV transmission line. This differs from the Base Case constraint sets which do not include the power flow control, South Creek substation or the 500 kV component. Table 10 below shows the individual constraint sets applied when modelling Option 6.

Table 10: Constraint sets – Option 6

Constraint set	Description	Date from	Date to
Set 1	Existing NEM network, before Project EnergyConnect	1/07/2026	30/06/2027
Set 2	Project EnergyConnect commissioned	1/07/2027	30/11/2028
Set 3	HumeLink commissioned	1/12/2028	31/10/2029
Set 4	Hunter Transmission Project (HTP) commissioned	1/11/2029	30/06/2030
Set 5	End of Waratah System Integrity Protection Scheme (SIPS) ratings; South Creek substation and power flow control solution commissioned.	1/07/2030	31/10/2031
Set 6	Victoria – New South Wales Interconnector West (VNI West) commissioned	1/11/2031	30/06/2033
Set 7	New 500 kV transmission line from Bannaby to South Western Sydney commissioned; Updated load distribution allocations, reflecting locational uneven demand growth trends in the Sydney, Newcastle and Wollongong region.	1/07/2033	

Beyond the more detailed constraints on the flow paths to Sydney, Newcastle, and Wollongong, the modelling adopts the same subregional nodal representation of the NEM as the Draft 2026 ISP, comprising four subregions for QLD, four for NSW, three for SA, and three for VIC. Intra-regional transfer limits and REZ transmission network constraints are also applied consistently with the Draft 2026 ISP. The nodal structure of the model is illustrated in Figure 11.

Figure 11: Nodal representation of the market model[12]

[12] Draft 2026 ISP Inputs and Assumptions workbook, available at: https://www.aemo.com.au/consultations/current-and-closed-consultations/draft-2026-isp-consultation

4. Options, scenarios and sensitivities considered in the Sydney Ring South PADR

This section provides an overview of the market modelling scenarios, the credible options assessed for the PADR, and sensitivities undertaken to assess the robustness of the gross market benefits.

4.1 Modelled scenarios

The RIT-T is focused on identifying the top-ranked credible option that maximises expected net benefits. However, uncertainty exists about how quickly the energy transition will occur, including the scale of future distributed energy resource uptake, as well as the level of demand growth as other sectors electrify or consider use of alternate zero-emission fuels.

To deal with this uncertainty, the actionable ISP framework requires AEMO to direct the use of specific scenarios for each RIT-T. The costs and market benefits for each credible option are estimated across these scenarios and then weighted based on the likelihood-based weightings identified in the ISP for each scenario to determine a weighted net benefit. It is this weighted net benefit that is used to rank credible options and identify the preferred option.

Consistent with the CBA guidelines, market modelling for the Sydney Ring South PADR adopts the set of scenarios published in the AEMO's 2025 IASR and applied in the 2026 Draft ISP: Slower Growth, Step Change and Accelerated Transition.

4.2 Credible options assessed for the Sydney Ring South PADR

The four credible options identified in the 2025 Electricity Network Options Report (ENOR), which were tested in AEMO's Draft 2026 ISP, are assessed in the Sydney Ring South PADR (Options 2, Option 2d, Option 3 and Option 4). Two additional options (Option 5 and Option 6) which combine and stage components of the 2025 ENOR options have also been assessed. The objective of assessing various staging options is to test the scope and timing of the project and identify which option best positions NSW and the NEM for a range of credible futures, maximising the net economic benefit across the market.

A summary of the credible options assessed in the PADR, and the modelled commissioning date for each, is presented in Table 11. Further detail about the scope and cost assumptions for each option is documented in Transgrid's PADR[13].

Table 11: Options assessed for the Sydney Ring South PADR

Option	Description	Commissioning date
Option 2	New South Creek 500/330 kV substation	1/7/2030
Option 2d	Install power flow technology in the existing 330 kV network (2024 ISP candidate option)	1/7/2030

[13] Transgrid, Sydney Ring South, available at: Sydney Ring South | Transgrid

Option	Description	Commissioning date
Option 3	Staged delivery of a high-capacity transmission line from Bannaby in the Southern Tablelands to South Western Sydney: • Stage 1: 500 kV double-circuit line from Bannaby, initially operated at 330 kV, plus a South Creek 330 kV switching station • Stage 2: Upgrade South Creek to a 500/330 kV substation, and upgrade line operation to 500 kV	Stage 1: 1/7/2033 Stage 2: 1/7/2040
Option 4	High-capacity transmission link from Bannaby to South Western Sydney, including a new South Creek 500/330 kV substation. • Stage 1: New South Creek 500/330 kV substation. • Stage 2: 500 kV double-circuit line from Bannaby.	Stage 1: 1/7/2030 Stage 2: 1/7/2033
Option 5	Power flow control plus a deferred high-capacity transmission line from Bannaby in the Southern Tablelands to South Western Sydney and a new South Creek 500/330 kV substation (Draft 2026 ISP optimal development path): • Stage 1: Install power flow technology in the existing 330 kV network • Stage 2: New South Creek 500/330 kV substation and a 500 kV double-circuit line from Bannaby to South Western Sydney	Stage 1: 1/7/2030 Stage 2: 1/7/2037
Option 6	Option 5 scope, delivered to an earliest in-service schedule: • Stage 1: Install power flow technology in the existing 330 kV network, plus a new South Creek 500/330 kV substation • Stage 2: 500 kV double-circuit line from Bannaby to South Western Sydney	Stage 1: 1/7/2030 Stage 2: 1/7/2033

4.3 Modelled sensitivities

Several sensitivities were conducted to assess the robustness of market benefit results and ranking of options under various credible trajectories for the energy transition in NSW. Table 12 summarises the sensitivities assessed in the Sydney Ring South PADR.

Sensitivities requiring electricity market modelling to be undertaken have only been performed relative to the Step Change scenario, being the central (highest weighted) scenario assessed. The options including scope for a transmission line (Options 3, 4, 5 and 6) are tested in all sensitivities, given the closeness of the results on a weighted net market benefits basis, and Option 2d is tested in cases where it has reasonable potential to become preferred.

Table 12: Sydney Ring South PADR sensitivities

Sensitivity No.	Sensitivity Name	Description
1	Alignment with NSW Electricity Infrastructure Roadmap development	Generation projects that have been awarded with South West REZ and Central West Orana REZ Access Rights are treated as 'anticipated' projects. Stage 2 of the New England REZ transmission project is treated as an actionable project progressing under the NSW Electricity Infrastructure Roadmap framework.
2	Constrained use of diesel as a back-up fuel	Ability for existing gas-fired generators in the Hunter and Central Coast regions to run on diesel as a backup fuel is limited to the conditions of relevant environmental and planning permits and

Sensitivity No.	Sensitivity Name	Description
		assume that future facilities are required to meet equivalent standards.
3	NSW Electricity Infrastructure Roadmap aligned development & constrained use of diesel as a back-up fuel	Combination of Sensitivities 1 and 2.
4a	High data centre growth	Add 1 GW of additional data centre demand by 2050 to the baseline Draft 2026 ISP Step Change data centre demand forecast for the Sydney, Newcastle and Wollongong region. Match growing data centre demand with equivalent local demand management mechanisms which could include demand flexibility agreements or local generation and storage. For modelling purposes, this flexibility is modelled as additional dispatchable demand side participation Alignment with NSW Electricity Infrastructure Roadmap developments (as above). Constrained use of diesel as a backup fuel (as above). Inclusion of LTESA Tender 6 outcomes, consistent with treatment of other policy supported projects. Disable modelled targets set by the 2025 NSW Infrastructure Investment Objective (IIO) Report and 82% of electricity generation from renewable energy sources under the Commonwealth Government's Powering Australia Plan. These adjustments are made to ensure that this large increase in electricity demand is met by a realistic capacity mix which still observes longer term carbon reduction objectives.
4b	Very high data centre growth	Same as Sensitivity 4a but add 2 GW of additional data centre demand by 2050 to the baseline Draft 2026 ISP Step Change data centre demand forecast for the Sydney, Newcastle and Wollongong region.
5	Low data centre growth	Limits data centre capacity and growth to only existing facilities in the Sydney, Newcastle, and Wollongong region. This results in data centre demand growing from approximately 0.5 GW in 2026 to approximately 0.9 GW by the late 2030s (compared to over 2 GW by the end of the assessment period in the Step Change scenario).
6	Higher adoption of distributed and consumer energy resources	Increase year-on-year uptake of behind-the-meter storage by approximately 50% for 10 years to 2035-36, relative to the AEMO forecast adopted in the Draft 2026 ISP Step Change scenario. This results in an additional 760 MW (1,490 MWh) of behind-the-meter storage installed in the Sydney, Newcastle, and Wollongong region by 2035/36, in addition to the forecast 2,000 MW (3,960 MWh) forecast by this date. Increase generation hosting capacity of distribution networks in the Sydney, Newcastle, and Wollongong region from 0.9 GW to 5.3 GW, consistent with the 2025 Distribution System Plan assuming that this capacity would be available to solar generation only.

Sensitivity No.	Sensitivity Name	Description
7	Negligible non-zero variable cost for renewable generation and storage	Revert adoption of a negligible non-zero variable cost ($0.10 per MWh) for renewable generation and storage to the ISP parameter ($0 per MWh).

5. Estimated gross market benefits

This section provides a summary of key gross market benefit results for the core simulations and sensitivities for each credible option assessed, over the modelled 24-year horizon.

The estimated gross market benefits for each credible option under each scenario are derived from the electricity market modelling. The PADR, Transgrid has separately assessed gross market benefits against the corresponding option costs to determine the forecast net market benefit of each option. The options are then comparatively ranked to identify the preferred option that maximises net market benefits.

Consistent with the CBA guidelines, Transgrid has identified Option 6 as the preferred option at the PADR stage of the RIT-T process. Option 6 comprises a new 500 kV transmission line from Bannaby in the Southern Tablelands to South-West Sydney, delivered in 2033-34, together with a new South Creek substation and the installation of series reactors for power flow control on the 330 kV network in 2030-31. This option is estimated to deliver the highest expected net market benefit of all options considered. While Option 6 is estimated to deliver the highest expected net market benefit of all options on a weighted average across all scenarios, the PADR highlights that all options that plan the delivery of a new high-capacity transmission line achieve the highest market benefits.

For further details on the net market benefits assessment, refer to the Sydney Ring South PADR[14].

5.1 Estimated gross market benefits in core scenarios

Table 13 shows the estimated gross market benefits across the modelled horizon for each modelled scenario and each credible option, compared to the Base Case. All gross market benefits are presented on a 30 June 2025 real dollars basis ($2024-25). Present value outcomes are discounted to 30 June 2025 by applying 7% discount rate (real, pre-tax) consistent with the discount rate in the 2025 IASR. All results consider the outlook period from 2026-27 to 2049-50.

Table 13 shows that options which deliver a new 500 kV transmission line deliver materially higher gross market benefits than the options which only propose incremental upgrades. Option 6 delivers the highest forecast gross market benefits in each scenario, followed closely by Option 4, Option 3 and Option 5, while Option 2 delivers the lowest benefits across all scenarios.

Benefits are lowest under Slower Growth, higher under Step Change and highest under Accelerated Transition, indicating that the value of the Sydney Ring South Project increases as demand growth and transition pressures intensify. Under Step Change, options which deliver a new 500 kV transmission line are forecast to deliver between $4.2 billion and $4.4 billion in gross market benefits in present value terms, increasing to approximately $5.7 billion to $6.6 billion under the Accelerated Transition scenario.

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[14] Transgrid, Sydney Ring South, available at: [Sydney Ring South | Transgrid]

Table 13: Estimated gross market benefits: Core scenarios ($ millions, real 30 June 2025 discounted to 30 June 2025)

Option	Slower Growth	Step Change	Accelerated Transition
Option 2	202	212	1,179
Option 2d	948	1,495	2,257
Option 3	1,402	4,212	5,810
Option 4	1,452	4,277	6,155
Option 5	1,450	4,162	5,714
Option 6	1,537	4,390	6,584

Figure 12 to Figure 14 show breakdowns of estimated gross market benefits of each option assessed under the Step Change, Slower Growth and Accelerated Transition scenarios.

Across all three scenarios, the largest share of benefits is driven by avoided or deferred capital expenditure, with fixed operating cost savings also contributing significantly, while reductions in costs related to fuel, USE/DSP, VOM and other categories are comparatively lower.

A notable difference in the Slower Growth scenario is that higher VER costs partially offset gross market benefits relative to the Step Change and Accelerated Transition scenarios, reflecting greater reliance on emissions-intensive generation in that scenario.

Figure 12: Estimated gross market benefits – Step Change scenario ($m, real 30 June 2025 discounted to 30 June 2025)

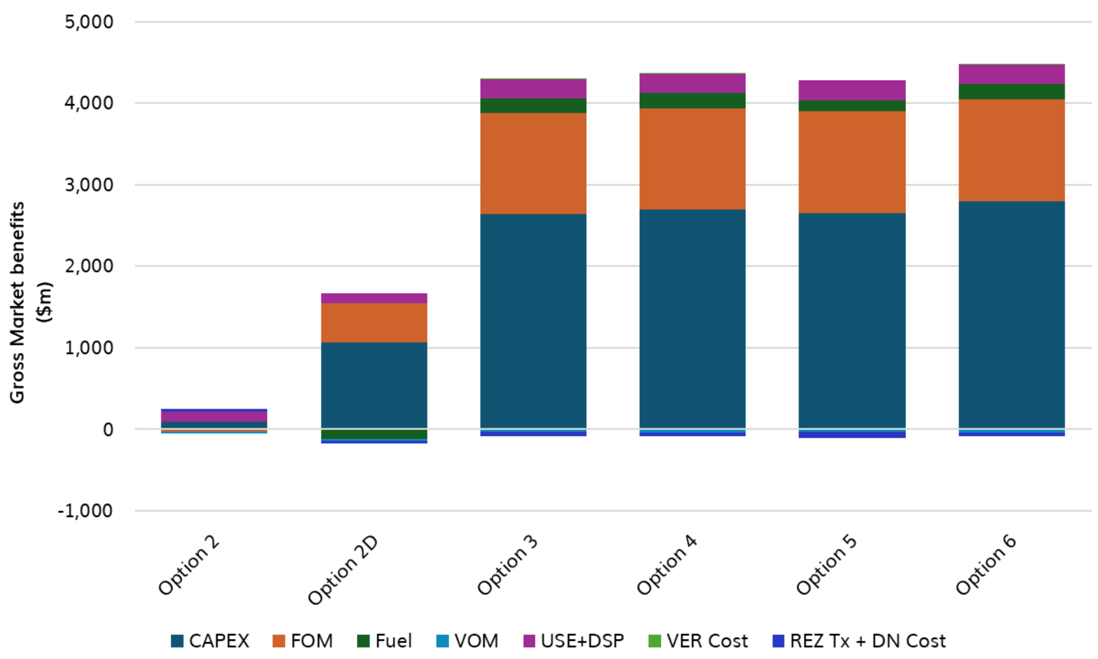


Figure 13: Estimated gross market benefits – Slower Growth scenario ($m, real 30 June 2025 discounted to 30 June 2025)

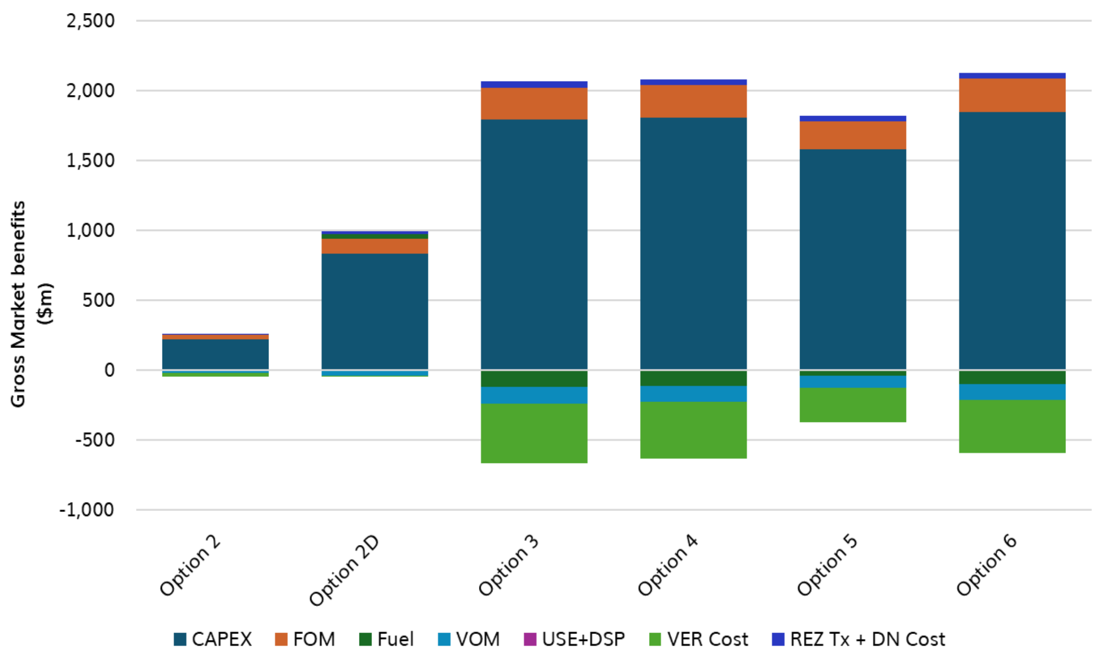
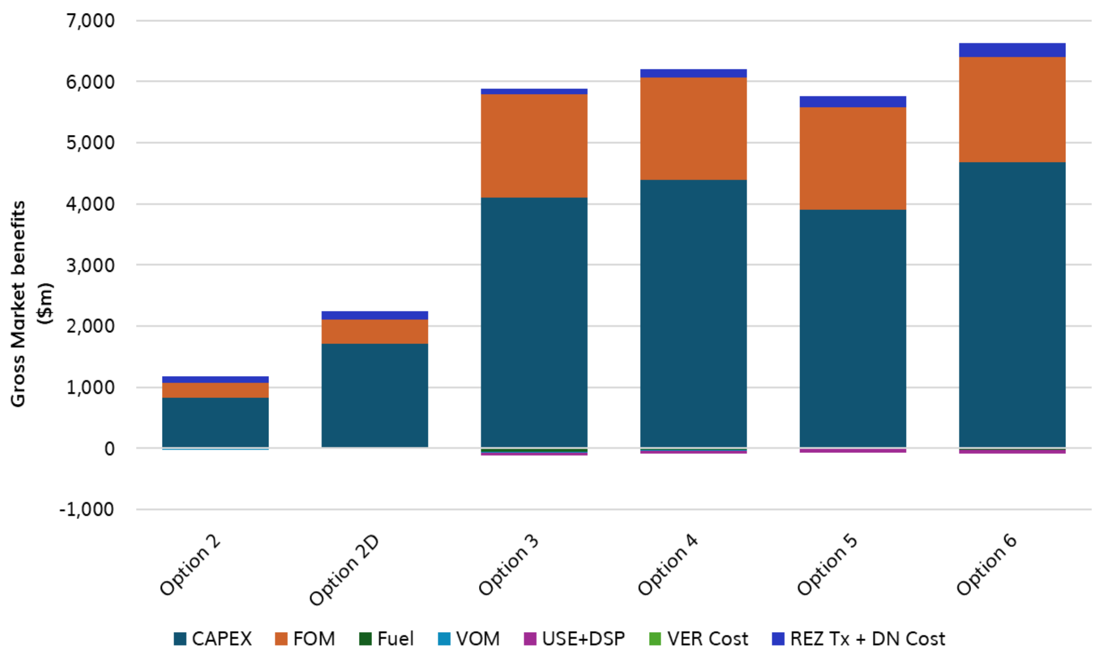


Figure 14: Estimated gross market benefits – Accelerated Transition scenario ($m, real 30 June 2025 discounted to 30 June 2025)



5.2 Estimated gross market benefits in sensitivity assessments

Table 14 shows the estimated gross market benefits across the modelled horizon for each credible option assessed compared to the Base Case. All gross market benefits are presented on a 30 June 2025 real dollars basis ($2024-25). Present value outcomes are discounted to 30 June 2025 by applying 7% discount rate (real, pre-tax) consistent with the discount rate in the 2025 IASR. All NPVs consider an outlook period from 2026-27 to 2049-50.

Table 14 demonstrates that Option 6 delivers the highest gross market benefits in every modelled sensitivity, ranging from approximately $1.9 billion in the low data centre growth case (Sensitivity 5) to $10.8 billion in the very high data centre growth sensitivity (Sensitivity 4b) (in present value terms). Option 4 and Option 3 also perform strongly, with benefits ranging from approximately $1.8 billion to $10.6 billion, while benefits for the more incremental upgrades proposed in Option 2d remain materially lower in the cases where it was assessed, at around $0.9 billion in Sensitivity 5 and $1.4 billion in Sensitivity 6.

Table 14: Estimated gross market benefits: Sensitivities ($m, real 30 June 2025 discounted to 30 June 2025)

Option	Sensitivity 1	Sensitivity 2	Sensitivity 3	Sensitivity 4a	Sensitivity 4b	Sensitivity 5	Sensitivity 6	Sensitivity 7
Option 2d	-	-	-	-	-	861	1,362	-
Option 3	4,856	4,443	5,368	7,951	10,392	1,797	2,961	4,091
Option 4	4,956	4,487	5,468	8,111	10,592	1,815	3,009	4,134
Option 5	4,755	4,340	5,265	7,570	9,048	1,743	2,816	3,987
Option 6	5,082	4,556	5,590	8,253	10,825	1,859	3,031	4,202

6. Key insights from market modelling for the PADR

6.1 Step Change scenario

This section provides insights into the drivers of benefits for the Sydney Ring South Project under the Step Change scenario. We first discuss the key outcomes observed in the Base Case, where no investment is made in the Sydney Ring South Project, then focus on the benefits of the preferred option identified in Transgrid's PADR (Option 6). Results from the assessment of all other options can be found in the accompanying results workbook.

6.1.1 Analysis of modelling outcomes for the Base Case

The Step Change scenario is described by AEMO as achieving the objectives of Australia's government policies in transitioning the energy system and reflects a scale of global and domestic action that limits global temperature rise to below 2°C compared to pre-industrial levels.

Figure 15 and Figure 16 present the forecast generation and storage capacity for the NEM and NSW in the Base Case. It is forecast that total NEM capacity will grow rapidly from around 110 GW in 2026-27 to approximately 160 GW by 2028-29, before more steadily increasing to 299 GW in 2049-50. Meanwhile, NSW capacity is forecast to grow from around 37 GW in 2026-27 to approximately 110 GW by 2049-50.

For both the NEM and NSW, renewable generation, utility scale battery storage (BESS) and gas generation are forecast to be dominant in the capacity growth. Utility scale batteries are forecast to be mostly built in the short to medium-term, with some capacity forecast to retire over the longer term which is partially replaced with new build. In addition, while most offshore wind capacity is expected to be built in Victoria in response to government policy, network limitations combined with emissions budget constraints also drives the need for some offshore wind capacity to be developed in NSW.

Figure 15: Generation and storage capacity outlook for the NEM in the Step Change scenario

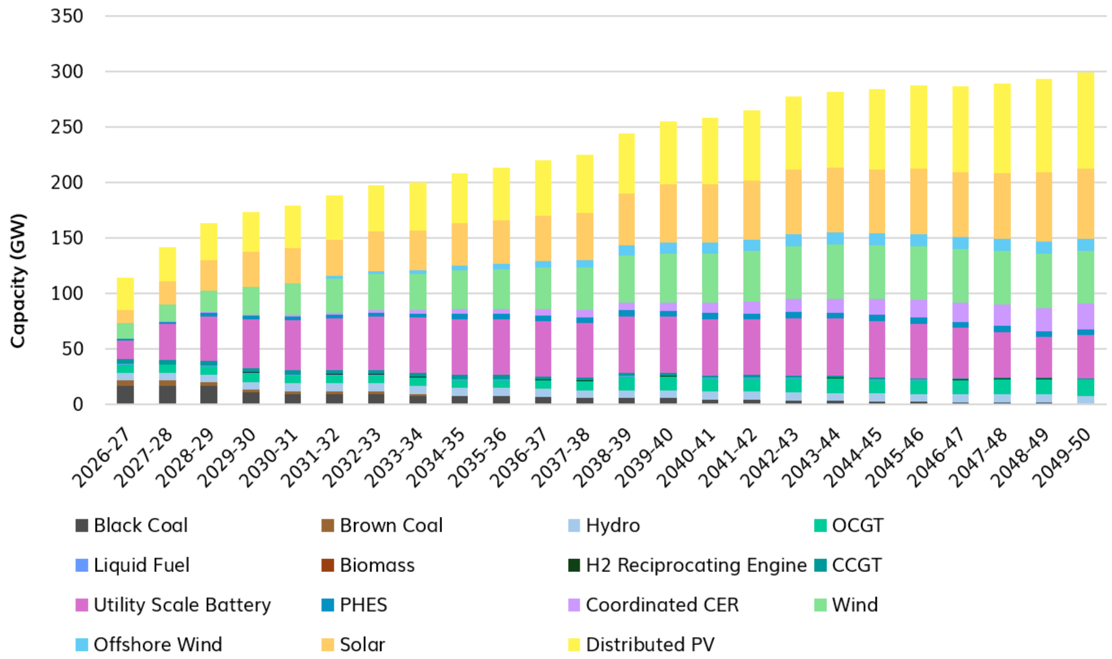
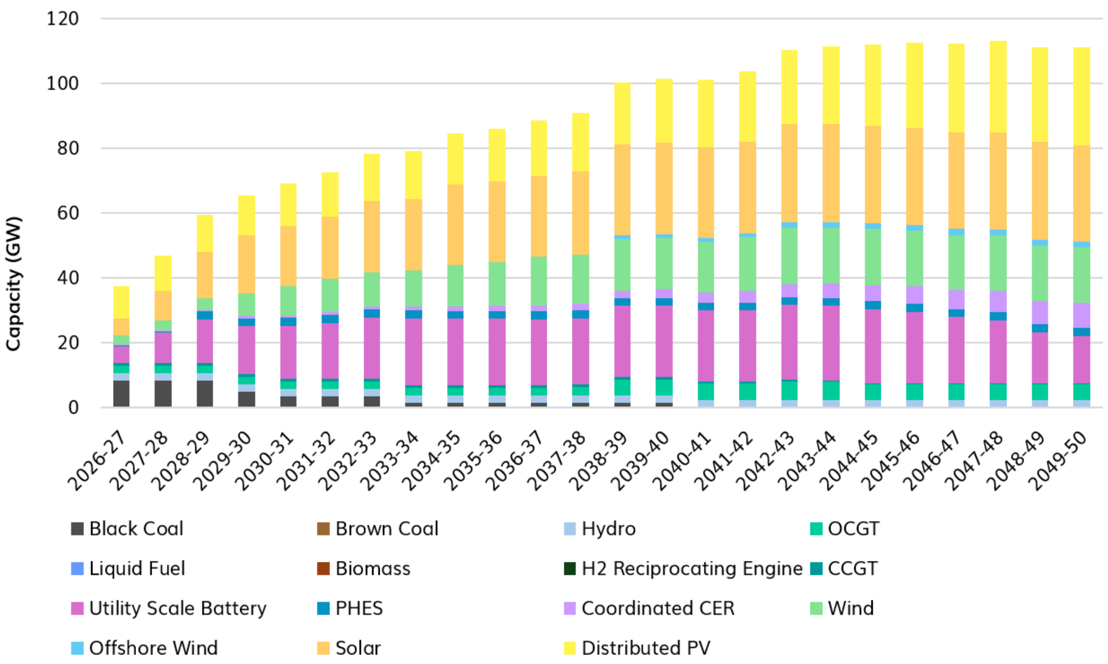


Figure 16: Generation and storage capacity outlook for NSW in the Step Change scenario



The detailed network representation for the flow paths into Sydney, Newcastle, and Wollongong modelled for the Sydney Ring South PADR enables a clear assessment of how individual network constraints will limit power system operation in the future. Table 15 shows how frequently (expressed as a percentage of modelled half-hourly intervals) the most limiting constraints will bind over the modelled horizon. In the Base Case, where there is no investment in the Sydney Ring South Project, significant congestion on the existing Bannaby to Sydney West 330 kV line (Line 39) is forecast to limit generation in Southern NSW as well as imports to NSW via the Victoria to NSW Interconnector (VNI) and from South Australia via Project EnergyConnect (PEC).

The Line 39 N-0 system normal thermal constraint (Avoid overload of 330 kV Line 39 Bannaby to Sydney West) binds 7.8% of dispatch intervals in the near term to 2029-30 (inclusive), before declining to around 1% from 2030-31 onwards. This pattern reflects the modelled treatment of the Waratah Super Battery System Integrity Protection Scheme (WSB SIPS), which increases the N-1 (contingency) rating of Line 39 but not its N-0 (system normal) rating, and is modelled to end in June 2030. With the WSB SIPS in place, the N-0 limit is the more restrictive of the two limits and binds more often. Once contracts enabling the WSB SIPS end in 2030, the N-1 contingency limit becomes more binding.

From 2030 onwards, the most material constraint on the southern corridor of the Sydney Ring is "Avoid overload of 330 kV Line 39 Bannaby to Sydney West on trip of 330 kV Line 17 Avon to Macarthur" which binds in 23.8% of dispatch intervals over the period from 2030-31 to 2032-33, increasing to an average of 35.0% over the period from 2033-34 to 2036-37 as renewable build-out in Southern NSW and import flows via VNI and PEC increasingly push power onto Line 39. The binding frequency moderates to 24.9% (2037-38 to 2039-40) and 19.3% (2040-41 to 2049-50) due to a combination of factors including CER and Distributed PV growth in Sydney, Newcastle, and Wollongong as well as brown coal retirements in Victoria.

The results also demonstrate increased congestion on the Marulan to Dapto and Avon 330 kV flow paths (330 kV Lines 8 and 16) from the mid-2030s. This is driven by demand growth in the Illawarra region and limits the ability to supply Illawarra and Wollongong demand using generation sourced from Southern NSW. The constraint "Avoid overload of 330 kV Line 8 Marulan to Dapto on trip of 330 kV Line 16 Avon to Marulan" binding percentage is expected to increase from 4.3% in over the period from 2030-31 to 2032-33 to 13.3% (2033-34 to 2036-37), 25.8% (2037-38 to 2039-40) and 26.8% (2040-41 to 2049-50). The companion constraint "Avoid overload of 330 kV Line 16 Marulan to Avon on trip of 330 kV Line 8 Dapto to Marulan" binds at a lower but persistent 3% to 5% across the same period.

Other constraints on transmission lines supplying the Sydney, Newcastle, and Wollongong region are not forecast to bind significantly over the modelling horizon. While EPEC has modelled all constraints on the flow paths to Sydney, Newcastle, and Wollongong, the table below only shows the key binding constraints.

Table 15: Step Change scenario – key binding network constraints in the Base Case

Constraint name	2026-27 to 2029-30	2030-31 to 2032-33	2033-34 to 2036-37	2037-38 to 2039-40	2040-41 to 2049-50
Avoid overload of 330 kV Line 39 Bannaby to Sydney West on trip of 330 kV Line 17 Avon to Macarthur	0.0%	23.8%	35.0%	24.9%	19.3%
Avoid overload of 330 kV Line 16 Marulan to Dapto on trip of 330 kV Line 8 Avon to Marulan	0.0%	4.3%	13.3%	25.8%	26.8%
Avoid overload of 330 kV Line 8 Marulan to Avon 330 kV on trip of 330 kV Line 16 Dapto to Marulan	0.7%	3.0%	5.4%	4.9%	5.0%
Avoid overload of 330 kV Line 39 Bannaby to Sydney West	7.8%	1.0%	1.7%	1.0%	0.8%
Avoid overload of 330 kV Line 76 Wallerawang to Sydney South on trip of 330 kV Line 77 Ingleburn to Wallerawang	0.0%	0.0%	1.0%	2.4%	4.9%

With significant congestion on these flow paths, the Sydney, Newcastle, and Wollongong load centres are forecast to rely more heavily on local costly generation and storage capacity within Sydney, Newcastle, and Wollongong, as well as on supply from Northern NSW and Queensland. Line 39 remains the primary bottleneck, particularly for flows from Southern NSW, but also for flows from Central NSW and, to a lesser extent, from Northern NSW and Queensland.

Figure 17 to Figure 20 present the forecast generation and storage capacities for the NSW subregions (nodes) in the Base Case. The notable generation and storage developments in each node are summarised below:

- Generation and storage capacity in Northern NSW is forecast to increase from 3 GW to 14 GW over the modelling horizon. The majority of this capacity is forecast to be wind, followed by solar (large-scale and distributed) and BESS. New England REZ in this subregion is expected to account for the majority of capacity with around 8 GW wind and solar build out.
- Generation and storage capacity in Central NSW is projected to increase from 9 GW to 36 GW over the modelling horizon. Significant solar is forecast to be developed in Central NSW, while wind and BESS capacity is also notable. The Base Case forecasts significant capacity build of up to 18 GW in the Central-West Orana REZ and up to 5 GW in the Hunter Central Coast REZ, which are both modelled in the Central NSW region.
- The modelling forecasts Sydney, Newcastle, and Wollongong capacity to grow from 13 GW to 34 GW over the modelling horizon, with the largest increase occurring in the late 2030s as demand grows, emissions budgets tighten and the last coal fired capacity in NSW (Mt Piper)

retires. Due to congestion on the network supplying Sydney, Newcastle, and Wollongong in the Base Case, significant BESS, approximately 1.8 GW of offshore wind and approximately 5 GW gas powered generation capacity is forecast to be required in Sydney, Newcastle, and Wollongong.

- The generation and storage capacity mix in Southern NSW is forecast to be comprised of mainly solar, wind and hydro/pumped hydro. Capacity in Southern NSW is forecast to increase from 9 GW to 20 GW over the modelling horizon, with a majority of new capacity expected in the late 2020s to early 2030s. The forecast congestion on 330 kV Lines 39, 8 and 16 supplying Sydney, Newcastle, and Wollongong from the mid-2030s is expected to become a limiting factor to further renewable and battery developments in Southern NSW.

Figure 17: Generation and storage capacity outlook for Northern NSW in the Base Case, Step Change scenario

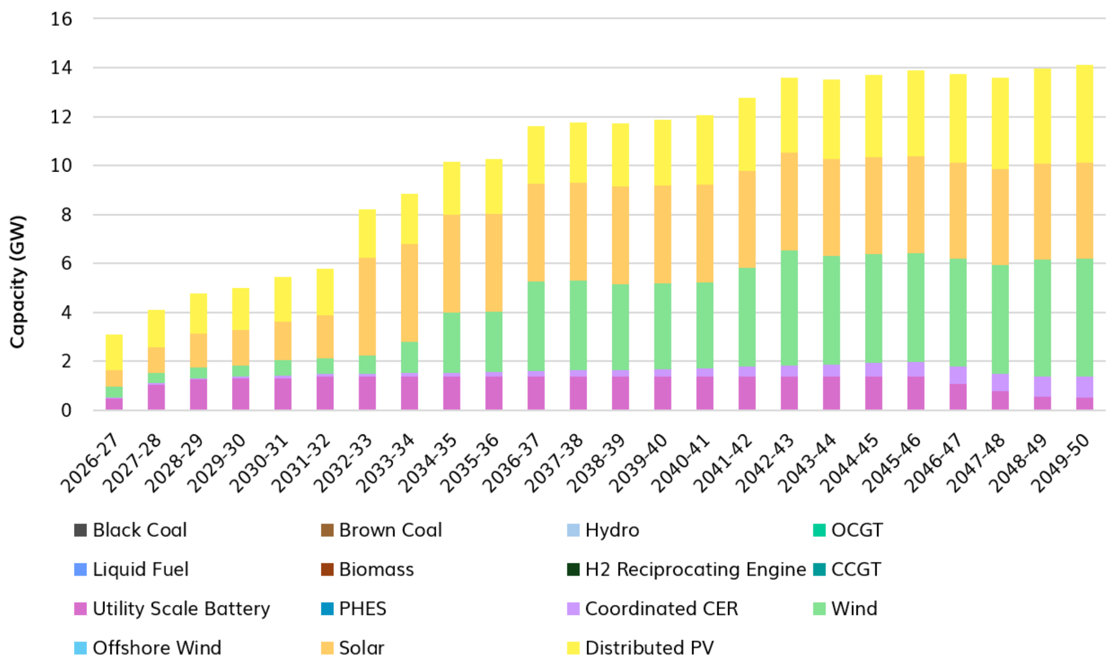


Figure 18: Generation and storage capacity outlook for Central NSW in the Base Case, Step Change scenario

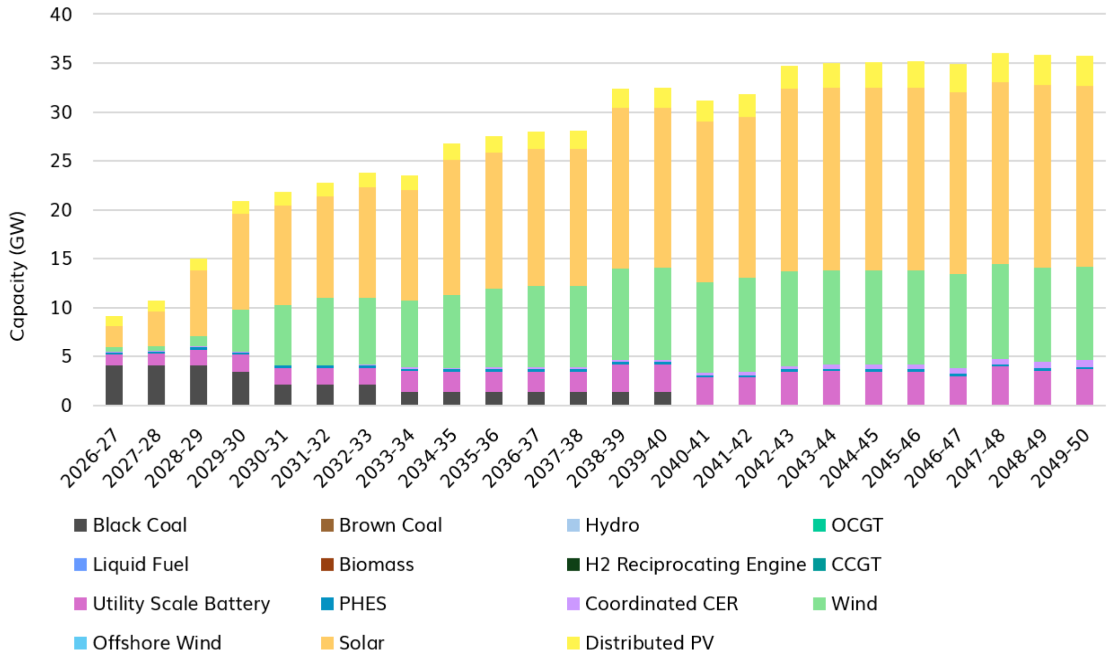


Figure 19: Generation and storage capacity outlook for Sydney, Newcastle and Wollongong in the Base Case, Step Change scenario

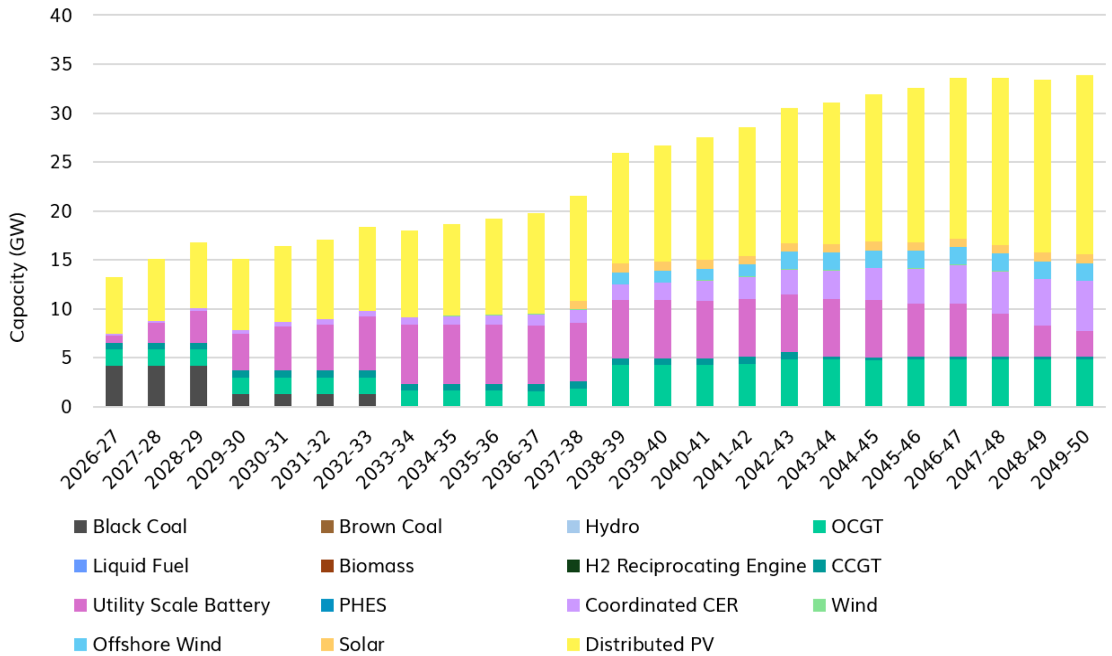
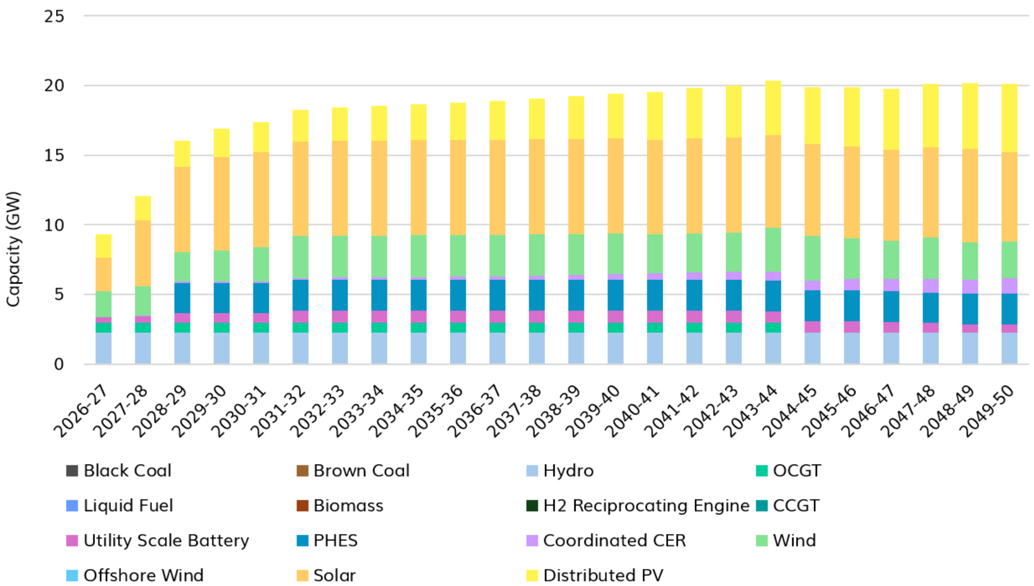
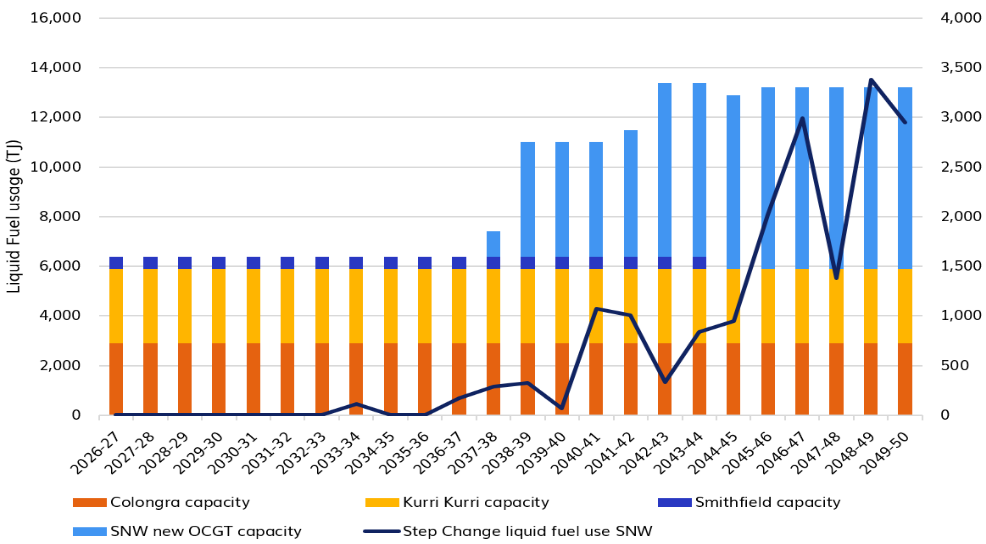


Figure 20: Generation and storage capacity outlook for Southern NSW in the Base Case, Step Change scenario



Increased reliance on gas powered generation in the Newcastle region is forecast to result in periods where the Newcastle gas pipeline reaches its capacity limits. In the Base Case, constrained gas supply is expected to require gas-fired generation in the Newcastle area to increasingly switch to higher-cost liquid fuel alternatives, such as diesel, particularly from the early 2040s (refer to Figure 21). While opportunities exist for new gas generation to be developed around Wollongong and Marulan which avoid constraints on the Newcastle gas pipeline by tapping into pipelines with greater supply, network congestion (particularly on 330 kV Line 39) limits the ability of these units to support the load in Sydney, Newcastle, and Wollongong in the Base Case.

Figure 21: Liquid fuel usage and development trajectory for new gas-powered generation in Sydney, Newcastle and Wollongong (SNW) in the Base Case, Step Change scenario



6.1.2 Analysis of modelling outcomes for the PADR preferred option analysis

This section presents more detailed analysis regarding benefits of the preferred option in the Step Change scenario at the PADR stage of the RIT-T (Option 6). On a net benefits basis, Transgrid has determined under the Step Change scenario, Option 3 is top ranked, while Option 6 is found to be the preferred option on a weighted net benefits basis across all scenarios.

Table 16 shows how frequently (expressed as a percentage of modelled intervals) the most limiting constraints will bind over the modelled horizon if Option 6 is delivered. Key constraints towards Sydney, Newcastle, and Wollongong load centres are expected to be marginally alleviated after the South Creek substation and power flow control solution are commissioned in 2030-31 and fully alleviated after the 500 kV upgrades are commissioned in 2033-34. In addition, constraints on the flow path towards Wollongong (specifically, "Avoid overload of 330 kV Line 8 Marulan to Dapto on trip of 330 kV Line 16 Avon to Marulan") are also expected to be significantly alleviated as compared to the Base Case.

While EPEC has modelled all constraints on the flow paths to Sydney, Newcastle, and Wollongong, the table below only shows the key binding constraints.

Table 16: Step Change scenario – key binding network constraints – Option 6

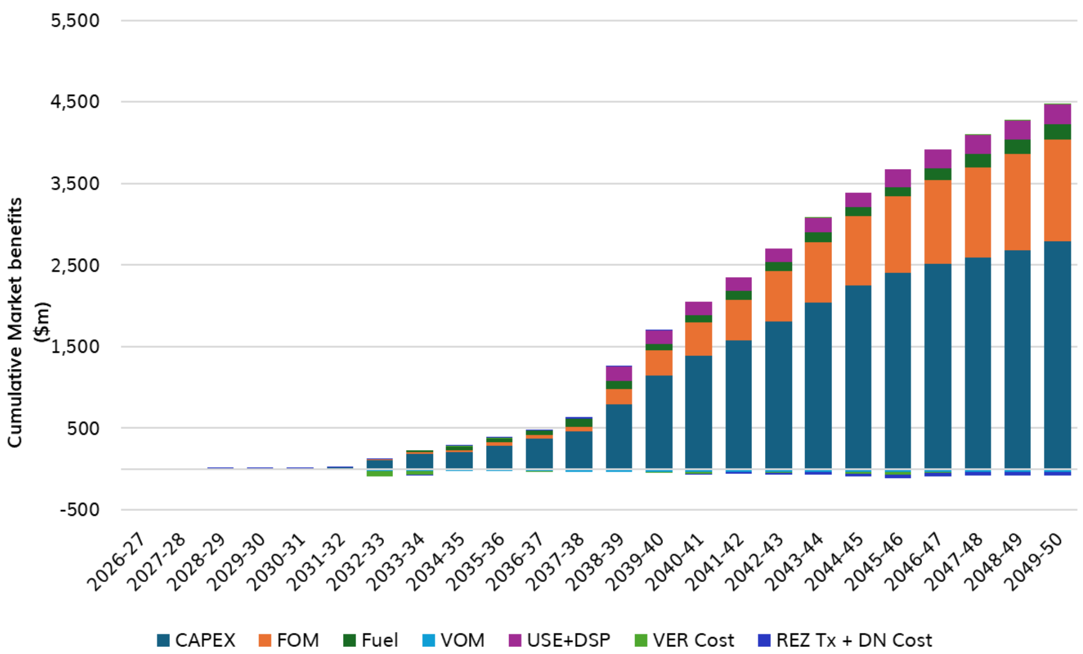
Constraint	2026-27 to 2029-30	2030-31 to 2032-33	2033-34 to 2036-37	2037-38 to 2039-40	2040-41 to 2049-50
Avoid overload of 330 kV Line 8 Avon to Marulan (Reverse) on trip of 330 kV Line 16 Dapto to Marulan	2%	5%	0%	0%	0%
Avoid overload of 330 kV Line 39 Bannaby to Sydney West	8%	0%	0%	0%	0%
Avoid overload of 330 kV Line 39 Bannaby to South Creek on trip of 330 kV Line 17 Avon to Macarthur	0%	11%	0%	0%	0%

The additional network capacity into Sydney, Newcastle, and Wollongong provided by Option 6 is expected to improve utilisation of existing and new generation and storage capacity across the NEM, thereby delivering gross market benefits. The new transmission capacity achieved by this option enables access to a lower-cost, geographically diverse mix of generation including on shore wind and solar to supply growing demand in Sydney, Newcastle, and Wollongong.

The estimated gross market benefits of Option 6, relative to the Base Case, are shown in Figure 22. Option 6 is estimated to deliver in approximately $4.4 billion of gross market benefits under the Step Change scenario (in present value terms, ($2024-25). It is forecast that capex benefits arising from deferred or avoided investments in generation and storage account for the largest portion of gross market benefits ($2.5 billion), followed by FOM and USE+DSP benefits.

Benefits are expected to accrue gradually from 2032-33, with a significant increase from the late 2030s onwards, when the option is found to avoid or defer significant alternative investments in new offshore wind and gas-powered generation capacity in Sydney, Newcastle and Wollongong. FOM benefits increase most over the 2040s (these benefits are also related to avoided or deferred generation or storage investments), while USE and DSP benefits are primarily accumulated in the late 2030s.

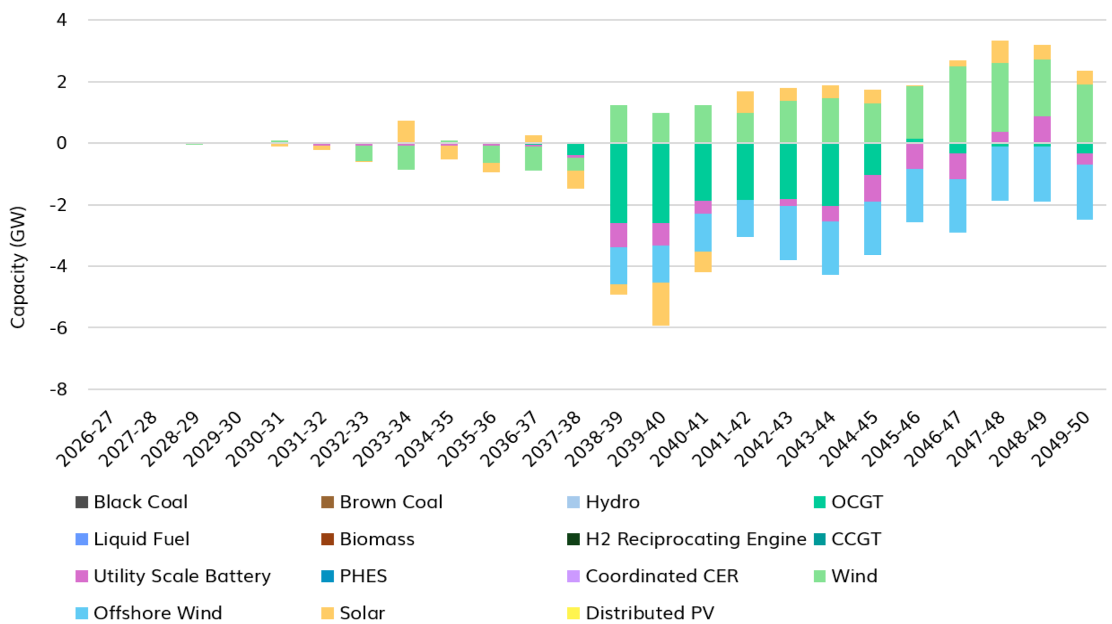
Figure 22: Discounted cumulative gross market benefits for Option 6 – Step Change scenario ($2024-25)



To better understand the drivers of the capex benefits under Option 6, Figure 23 shows the NEM-wide capacity difference between this option and the Base Case across the modelled horizon. Capacity above the X-axis indicates net capacity built in the case where the option is delivered, whereas bars below the X-axis indicate net capacity needed in the Base Case, relative to one another.

Option 6 is forecast to result in avoided/deferred gas, utility scale storage (BESS) and offshore wind capacity, while enabling some additional lower cost onshore wind capacity in the NEM. Specifically, up to around 2.5 GW gas powered generation capacity is deferred, while approximately 2 GW of offshore wind is avoided altogether across the NEM.

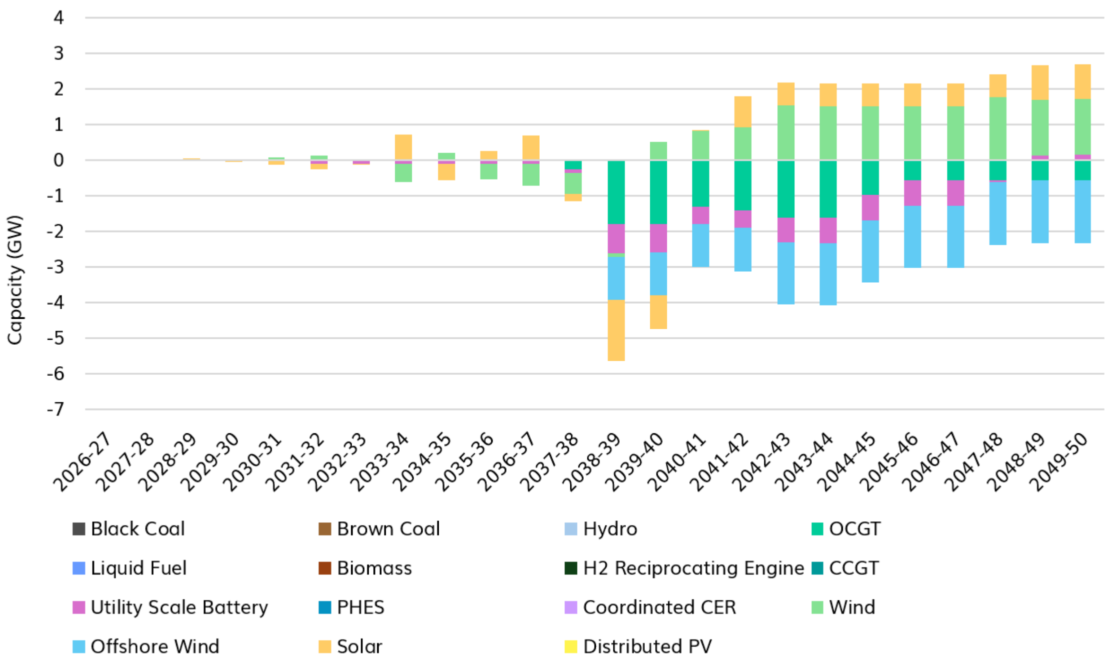
Figure 23: Generation and storage capacity outlook for the NEM in the Step Change scenario – Option 6 vs Base Case



A more detailed assessment of NSW identifies the following key findings.

- The majority of differences in generation and storage capacity build are due to changes in NSW, as shown in Figure 24.
- As a result of additional transmission capacity into Sydney, Newcastle, and Wollongong, Option 6 is expected to avoid the need for approximately 1.8 GW of offshore wind capacity and 500 MW OCGT capacity in NSW.
- Option 6 enables better utilisation of existing generation and storage capacity, and access to lower cost onshore wind and solar capacity. Specifically, the Sydney Ring South upgrades are expected to alleviate network congestion and unlock additional capacity in Southern NSW, resulting in approximately 4.5 GW of additional wind and solar capacity being developed.

Figure 24: Generation and storage capacity outlook for NSW in the Step Change scenario – Option 6 vs Base Case



6.1.3 Key insights for options that include scope for a new 500 kV transmission line

While the options that include scope for a new 500 kV transmission line differ in their specific configurations and commissioning timing, they share a common set of drivers for the gross market benefits.

A new 500 kV transmission line delivered under the Sydney Ring South Project is forecast to relieve the congestion on the existing 330 kV Line 39 from Bannaby to Sydney West, as well as the flow paths to Wollongong (330 kV Lines 8 and 16). Relieving these bottlenecks is expected to enable greater transfer of electricity from lower-cost generation and storage resources by increasing access to capacity in Southern NSW and increasing imports from South Australia and Victoria to supply demand in Sydney, Newcastle, and Wollongong. As a result, a new 500 kV transmission line is forecast to reduce the need to build higher-cost generation capacity in Sydney, Newcastle, and Wollongong, or over-build capacity in Central NSW, Northern NSW and Queensland, which is able to make use of the northern corridor of the Sydney Ring via the Hunter Transmission Project.

Specifically, the options that include scope for a new 500 kV transmission line are forecast to avoid the need for offshore wind capacity off the Hunter and Illawarra coasts, as well as additional gas fired generation capacity in the pipeline-restricted Newcastle area. These options are also forecast to enable more strategic placement of new gas fired generation capacity across NSW, allowing a shift of capacity from Newcastle to Marulan and Wollongong, where there is better access to high-capacity gas networks. This is expected to improve utilisation of existing gas infrastructure, reduce constraints on the Newcastle gas pipeline and support more efficient usage of gas fired generation resources.

As with Option 6, the majority of benefits for options that include scope for a new 500 kV transmission line accrue from the mid to late 2030s. Consequently, the timing of the commissioning of a 500 kV line (whether commissioned in 2033-34 or deferred to 2037-38 consistent with the ODP of the Draft 2026 ISP), is not found to significantly impact the gross market benefits. This is also the case for Option 3, which involves initial 330 kV operation of the transmission from Bannaby to South Western Sydney, followed by an upgrade to operate at 500 kV in 2040-41.

Overall, in the Step Change scenario, benefits from capex and Fixed Operation and Maintenance (FOM) costs associated with deferred or avoided investments in storage and generation capacity account for the majority of gross market benefits provided by all options that include scope for a new 500 kV transmission line.

6.1.4 Key insights for options that propose incremental network upgrades

The benefits of the smaller-scale network options which include scope for incremental network upgrades only (Option 2 and Option 2d), differ from the options that include scope for a new 500 kV transmission line discussed in the previous section.

These incremental network upgrades are not expected to alleviate congestion on the flow paths into Sydney, Newcastle, and Wollongong. Specifically, with Option 2 (delivering only the South Creek substation) and Option 2d (delivering a power flow control solution) the network is still expected to experience congestion on Line 39 up to 20% of the time from the mid-2030s through to the end of the study period. While these options incrementally increase the dispatch of lower-cost generation to meet Sydney's growing electricity demand, Newcastle and Wollongong demand centres, the persistence of these network bottlenecks will continue driving high reliance on more expensive sources of energy at peak times to supply demand, raising wholesale prices and increasing bills for consumers.

For example, Table 17 shows that if Option 2d is built, constraints on 330 kV Lines 39, 8, 16 as well as constraints on the flow path from west (Lines 76 and 77, and via the 500/330 kV transformers at Mt Piper) are likely to continue binding frequently into the future.

Table 17: Step Change scenario – key binding network constraints - Option 2d

Constraint	2026-27 to 2029-30	2030-31 to 2032-33	2033-34 to 2036-37	2037-38 to 2039-40	2040-41 to 2049-50
Avoid overload of 330 kV Line 16 Marulan to Dapto on trip of 330 kV Line 8 Avon to Marulan	0.0%	1.8%	6.1%	14.8%	19.9%
Avoid overload of 330 kV Line 39 Bannaby to Sydney West on trip of 330 kV Line 17 Avon to Macarthur	0.0%	11.4%	19.8%	15.8%	12.3%
Avoid overload of 330 kV Line 39 Bannaby to Sydney West	7.8%	2.2%	4.1%	2.8%	1.7%

Constraint	2026-27 to 2029-30	2030-31 to 2032-33	2033-34 to 2036-37	2037-38 to 2039-40	2040-41 to 2049-50
Avoid overload of 330 kV Line 76 Wallerawang to Sydney South on trip of 330 kV Line 77 Ingleburn to Wallerawang	0.0%	0.1%	2.4%	3.6%	6.5%
Avoid overload of 330 kV Line 8 Marulan to Avon on trip of 330 kV Line 16 Dapto to Marulan	1.5%	2.2%	5.6%	6.0%	5.5%
Avoid overload of 330 kV Line 39 Bannaby to Sydney West on trip of 330 kV Line 8 Avon to Marulan	0.0%	0.3%	1.3%	5.1%	4.9%
Avoid overload of Mt Piper 500/330 kV transformer on trip of Mt Piper 500/330 kV transformer	0.1%	0.8%	1.4%	1.2%	3.7%

As a result, these options, particularly Option 2, are not expected to materially improve access to lower cost generation resources to supply Sydney, Newcastle, and Wollongong demand. This results in significantly lower benefits compared to the options that include scope for a new 500 kV transmission (refer to Figure 25 and Figure 26). With Option 2 and Option 2d, there is still a need to develop higher-cost generation such as offshore wind within Sydney, Newcastle, and Wollongong to meet growing demand is forecast.

In the Step Change scenario, Option 2 is estimated to have gross market benefits of approximately $200 million (in present value terms, $2024-25), and USE & DSP are forecast to account for the majority its benefits. Gross market benefits for Option 2d are estimated to be $1.5 billion, with approximately $1 billion of this derived from avoided/ deferred generation and storage capex.

Figure 25: Discounted cumulative gross market benefits for Option 2 – Step Change scenario ($2024-25)

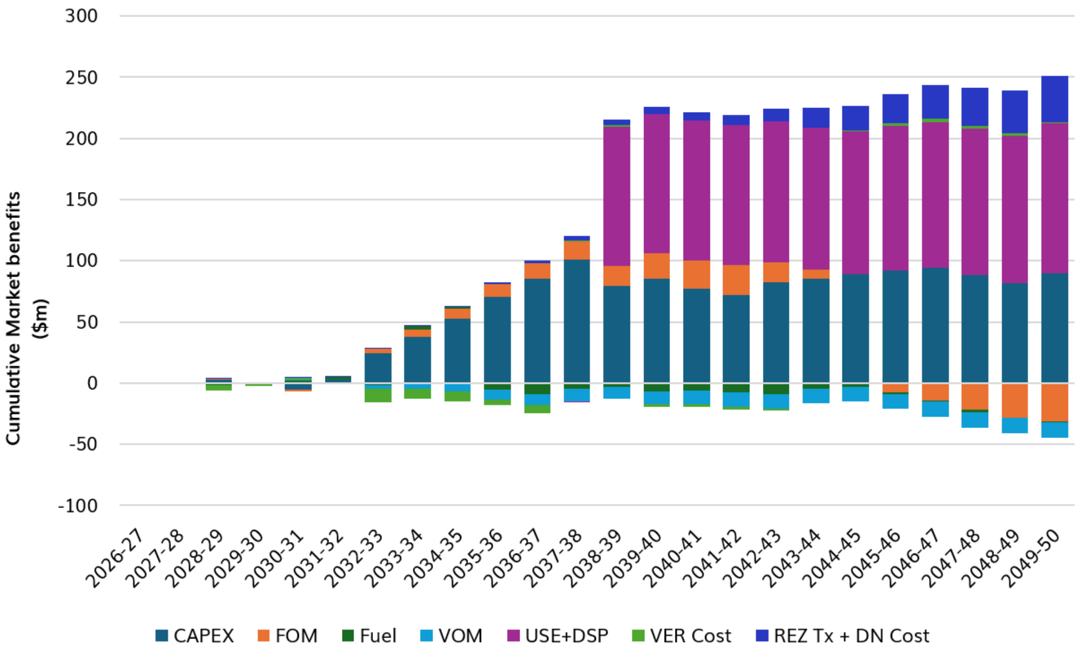
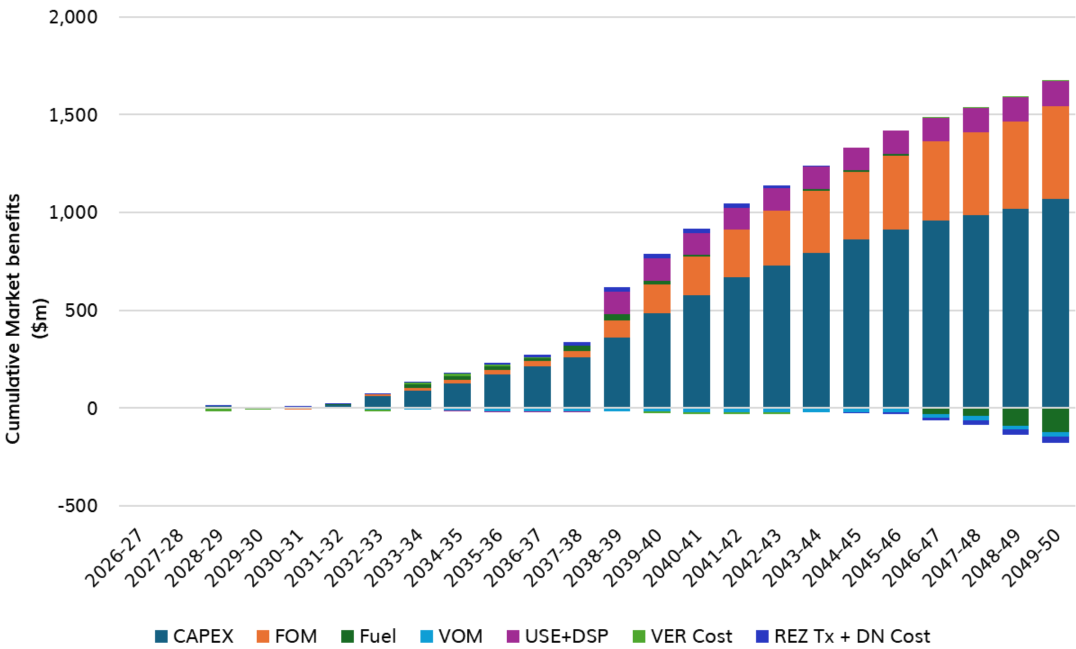


Figure 26: Discounted cumulative gross market benefits for Option 2d – Step Change scenario ($2024-25)



6.2 Slower Growth scenario

This section provides insights into the drivers of benefits for the Sydney Ring South Project under the Slower Growth scenario. We first discuss the challenges observed in the Base Case, where no investment is made in the Sydney Ring South Project, then focus on the benefits of the preferred option identified in Transgrid's PADR (Option 6). Results from the assessment of all other options can be found in the accompanying results workbook.

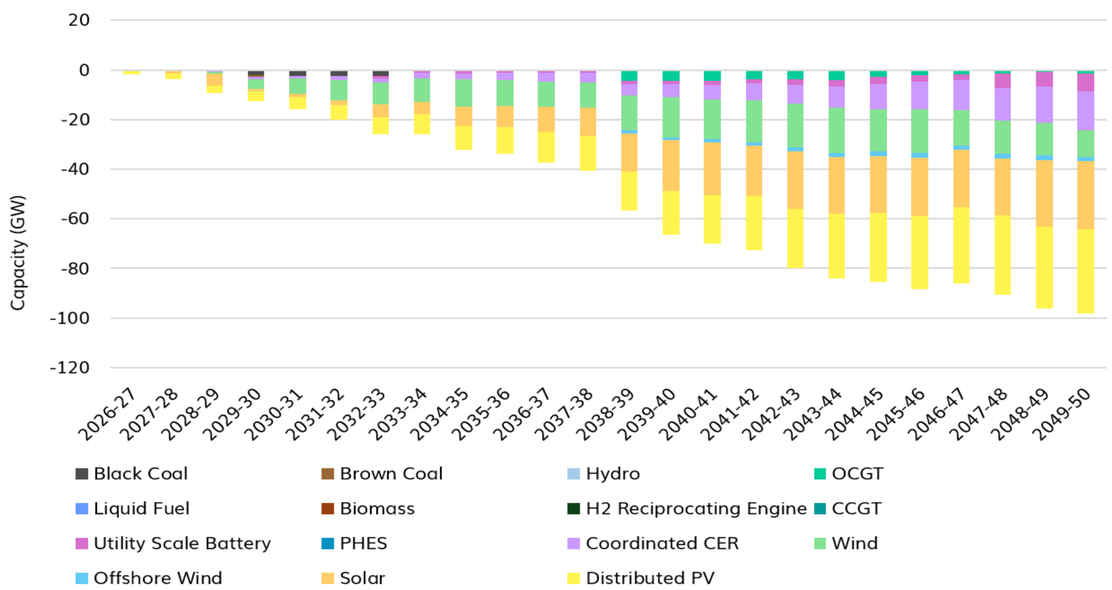
6.2.1 Analysis of modelling outcomes for Base Case

As discussed earlier in the input assumptions section, the Slower Growth scenario differs to the Step Change scenario in its underlying assumptions about the trajectory of the energy transition including demand growth and the pace of decarbonisation.

The Slower Growth scenario is described by AEMO as achieving the objectives of Australia's government policies in transitioning the energy system, despite challenges posed by slower economic growth and lesser continued action beyond current commitments. In this scenario, weaker domestic and international economic conditions mean Australia's energy intensive industry and businesses are at greater operating risk, causing a proportion of the business sector to close in the short to medium term. Investments in energy efficiency, consumer energy resources such as rooftop solar and home batteries are also naturally lower due to the weaker economic circumstances.

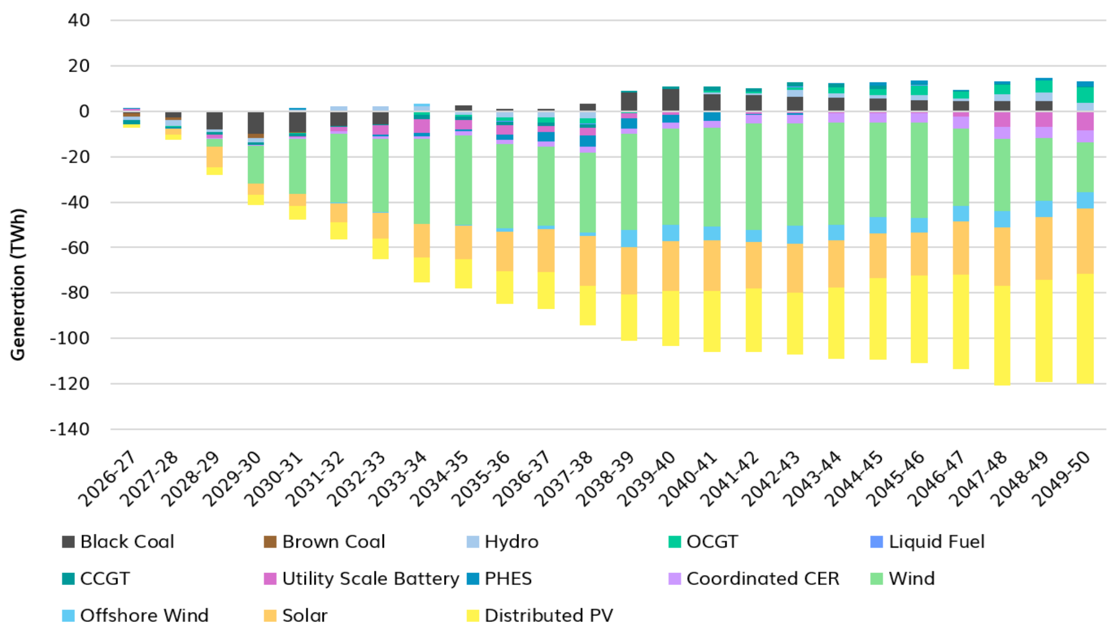
These underlying assumptions are expected to result in a lesser need for new generation and storage capacity development as well as reducing the immediate pressure to transition the generation mix to a low-emissions profile in the Slower Growth scenario. As shown in Figure 27 up to around 98 GW less generation and storage capacity is forecast in the Base Case in this scenario compared to the Step Change scenario over the modelling period to 2050. This includes approximately 34 GW less Distributed PV and 16 GW less coordinated CER capacity (which are exogenous inputs to the modelling applied from the 2025 IASR), along with 1.8 GW less offshore wind. At the utility scale, the Slower Growth scenario is still expected to require significant solar, onshore wind and utility-scale battery storage developments.

Figure 27: Difference in generation and storage capacity outlook for the NEM in the Base Case, Slower Growth vs Step Change scenarios



The lower capacity build requirement in the Slower Growth scenario is also reflected in the lower generation, as shown in Figure 28. A key insight from the forecast generation outlook is that coal and gas-fired generators are expected to be utilised more in the second half of the modelling horizon, compared with the same period in the Step Change scenario. This is particularly the case for Queensland coal generation as a more relaxed emissions budget in this allows greater utilisation of the remaining coal fleet from the late 2030s and through the 2040s.

Figure 28: Difference in generation outcomes for the NEM in the Base Case, Slower Growth vs Step Change scenarios



Nonetheless, in this scenario additional generation capacity is required to ensure reliable supply to growing demand and efficiently replace retiring capacity, both across the NEM and in NSW. Total installed generation and storage capacity (including rooftop solar and CER storage) is expected to reach approximately 194 GW, while that of NSW is approximately 70 GW by the end of modelling horizon.

Similar to the Step Change scenario, increased future congestion on the existing Bannaby to Sydney West 330 kV line (Line 39) is forecast in the Base Case under the Slower Growth scenario. Table 18 shows how frequently (expressed as a percentage of modelled intervals) the most limiting constraints will bind over the modelled horizon.

Line 39 constraints are expected to bind up to 60% of the time in the period of 2032-33 to 2036-37, representing the peak congestion period across the modelling horizon. This is primarily driven by the contingency constraint associated with a trip of the Avon to Macarthur 330 kV line (Line 17), which sees binding frequency increases significantly from 26% in 2030-31 to 2032-33 before moderating to 56% in 2037-38 to 2039-40 and declining further to 32% by the 2040s, likely reflecting a combination of growing distributed PV and consumer energy resource (CER) capacity suppressing daytime and peak demand reducing pressure on the transmission corridor, as well as load growth occurring increasingly in regions outside of southern NSW that shifts the aggregate dispatch pattern away from flows through Line 39.

Starting in the mid-2030s, the modelling forecasts an increasing level of congestion on the Marulan to Dapto and Avon 330 kV flow paths (Lines 8 and 16), partly driven by demand growth in the Illawarra region. Congestion on this path grows steadily from 4% of the time in 2030-31 to 2032-33 to 25% by the 2040s, suggesting that this corridor becomes an increasingly binding transmission bottleneck over the longer term.

The Mt Piper 500 kV/330 kV transformer constraint also remains a minor but persistent binding constraint, binding at 3% to 4% from the mid-2030s onward, reflecting the ongoing role of Mt Piper in supplying load in the Central West. While EPEC has modelled all constraints on the flow paths to Sydney, Newcastle, and Wollongong, the table below only shows the key binding constraints.

Table 18: Slower Growth Scenario – binding constraints, Base Case

Constraint	2026-27 to 2029-30	2030-31 to 2032-33	2033-34 to 2036-37	2037-38 to 2039-40	2040-41 to 2049-50
Avoid overload of 330 kV Line 39 Bannaby to Sydney West on trip of 330 kV Line 17 Avon to Macarthur 330 kV	0%	26%	60%	56%	32%
Avoid overload of 330 kV Line 39 Bannaby to Sydney West	7%	1%	1%	1%	1%
Avoid overload of 330 kV Line 16 Marulan to Dapto on trip of 330 kV Line 8 Avon to Marulan	0%	4%	9%	18%	25%
Avoid overload of 330 kV Line 8 Marulan to Avon on trip of 330 kV Line 16 Dapto to Marulan	1%	3%	10%	12%	8%
Avoid overload of Mt Piper transformer 500 kV/330 kV on trip of Mt Piper transformer 500 kV/330 kV	0%	1%	3%	3%	4%

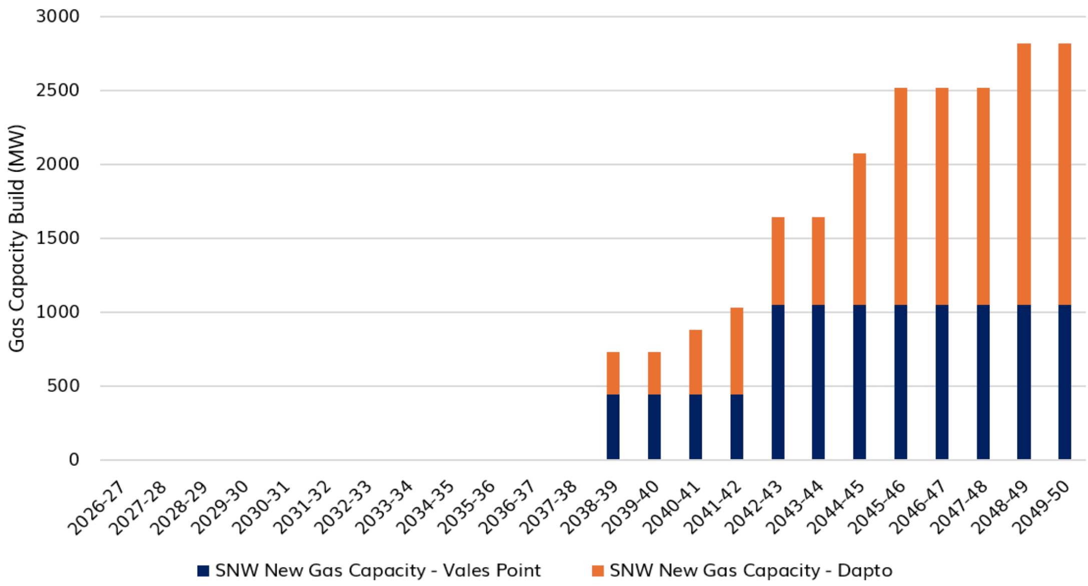
The forecast congestion on the southern corridor of the Sydney Ring network is expected to limit generation in Southern NSW as well as the capacity for energy imports into NSW via the Victoria to NSW Interconnector (VNI) and Project Energy Connect (PEC) (from South Australia). These flow path constraints are also forecast to limit the ability to supply growing demand in the Illawarra/Wollongong region with generation from Southern NSW, meaning demand centres rely increasingly on generation from Central NSW, Northern NSW (NNSW) and Queensland.

Consequently, the Base Case forecasts the largest capacity builds in the Central-West Orana (CWO) and New England (NE) Renewable Energy Zones (REZs), with moderate development in the Hunter-Central Coast (HCC) REZ. Approximately 9 GW solar and 6 GW wind is forecast in the CWO REZ. NE and HCC REZs are expected to have a similar level of capacity. Wind generation capacity is forecast to be more dominant in the NE REZ, while the HCC REZ sees approximately equal wind and solar generation capacity development.

Even with the development of the capacity in the NSW REZs, Sydney, Newcastle, and Wollongong is forecast to require additional gas generation build in Newcastle and Wollongong to meet demand at times of network congestion. Figure 29 shows the required gas capacity development in Sydney, Newcastle, and Wollongong, indicating the need for approximately 2.8 GW of new gas fired generation to supply demand in the region. This includes approximately 1 GW at the Newcastle region modelled at Vales Point and 1.8 GW at the Illawarra region modelled at Dapto.

A notable difference from the Step Change scenario is that no offshore wind capacity is forecast to be required in Sydney, Newcastle, and Wollongong in the Base Case.

Figure 29: Slower Growth scenario – New gas capacity in the Sydney, Newcastle, and Wollongong region in the Base Case



6.2.2 Analysis of modelling outcomes for the PADR preferred option

This section presents the more detailed analysis regarding benefits of the preferred option at the PADR stage of the RIT-T (Option 6) in the Slower Growth scenario. On a net benefits basis, Transgrid has determined under the Slower Growth scenario, Option 2d is top ranked, while Option 6 is found to be the preferred option on a weighted net benefits basis across all scenarios. Insights from the modelling outcomes for Option 2d are discussed in the next section.

Table 19 shows how frequently (expressed as a percentage of modelled intervals) the most limiting constraints will bind over the modelled horizon if Option 6 is delivered. Key constraints towards Sydney, Newcastle, and Wollongong load centres are expected to be marginally alleviated after the South Creek substation and power flow control solution are commissioned in 2030-31 and fully alleviated after the 500 kV upgrades are commissioned in 2033-34. Unlike in the Step Change scenario, in the Slower Growth scenario Option 6 is expected to almost fully alleviate congestion on the transmission corridor towards Wollongong.

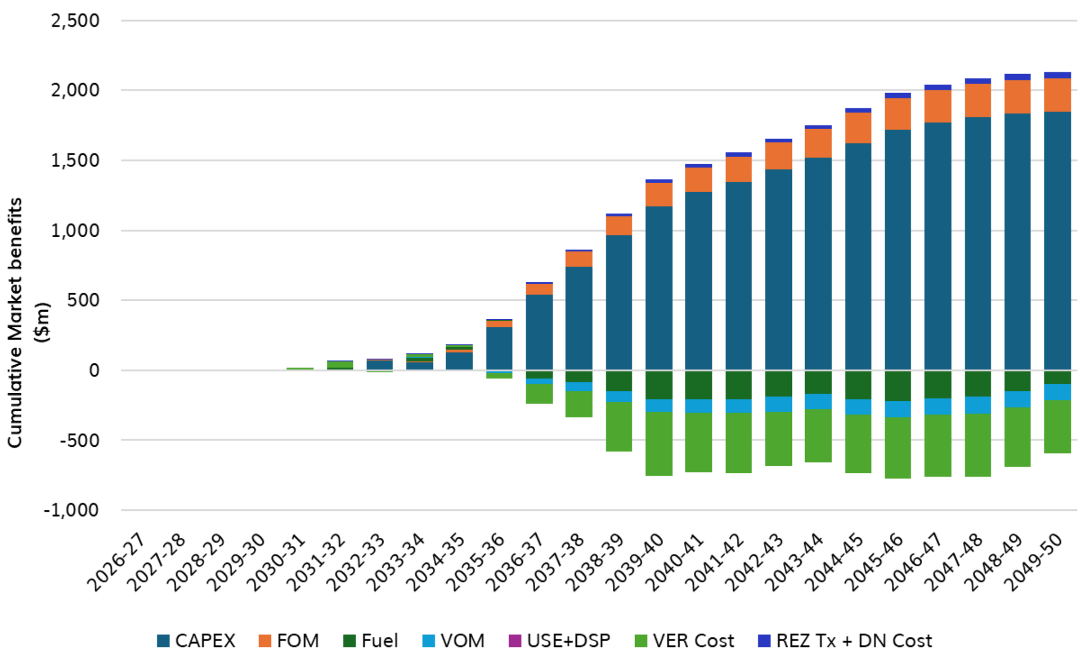
Table 19: Slower Growth scenario – key binding network constraints - Option 6

Constraint	2026-27 to 2029-30	2030-31 to 2032-33	2033-34 to 2036-37	2037-38 to 2039-40	2040-41 to 2049-50
Avoid overload of 330 kV Line 39 Bannaby to Sydney West on trip of 330 kV Line 17 Avon to Macarthur	0%	24%	0%	0%	0%
Avoid overload of 330 kV Line 8 Marulan to Avon 330 kV on trip of 330 kV Line 16 Dapto to Marulan	2%	6%	0%	1%	1%
Avoid overload of 330 kV Line 39 Bannaby to Sydney West	7%	0%	0%	0%	0%

Estimated gross market benefits for Option 6 are shown in Figure 30. This option is estimated to deliver approximately $1.5 billion in gross market benefits (present value terms, $2024-25), with capex benefits accounting for the majority of benefits ($1.7 billion). Notably, in the Slower Growth scenario, strong positive gross benefits are partially offset by approximately $500 million of increased system costs (negative benefits) arising from higher fuel costs, variable operating and maintenance (VOM) costs and the economic costs of increased carbon emissions (valued at VER).

Benefits are expected to gradually increase from the mid-2030s, with a significant increase from the late 2030s. The higher utilisation of coal and gas fired thermal generation enabled by Option 6 is expected to result in higher emissions (VER) and fuel costs in Option 6, compared to the Base Case. Consistent with the ISP methodology, unlike other financial and economic parameters, costs related to carbon emissions (valued at VER), are not included in the market modelling optimisation process when determining a least-cost generation mix, and are calculated based on the outputs of the optimisation.

Figure 30: Discounted cumulative gross market benefits for Option 6 - Slower Growth scenario ($2024-25)



To better understand the drivers of the capex benefits under Option 6, Figure 31 shows the NEM-wide capacity difference between this option and the Base Case across the modelled horizon. Capacity above the X-axis indicates net capacity built in the case where the option is delivered, whereas bars below the X-axis indicates net capacity needed in the Base Case, relative to one another.

Figure 31 shows how alleviating constraints on the southern corridor of the Sydney Ring network as a result of Option 6 enables higher utilisation of the Mt Piper coal power station and Snowy Hydro generation, offsetting the need for additional capacity which is otherwise required in the Base Case.

In the longer term, this option is forecast to reduce the need for new gas-fire and solar generation while enabling additional utility-scale BESS development from the mid-2040s. Approximately 2.5 GW of wind capacity is expected to be deferred from the mid-2030s to the early 2040s, while approximately 1GW of solar capacity and 1 GW of gas capacity are forecast to be avoided.

Figure 31: Slower Growth scenario – Option 6 NEM capacity difference to the Base Case

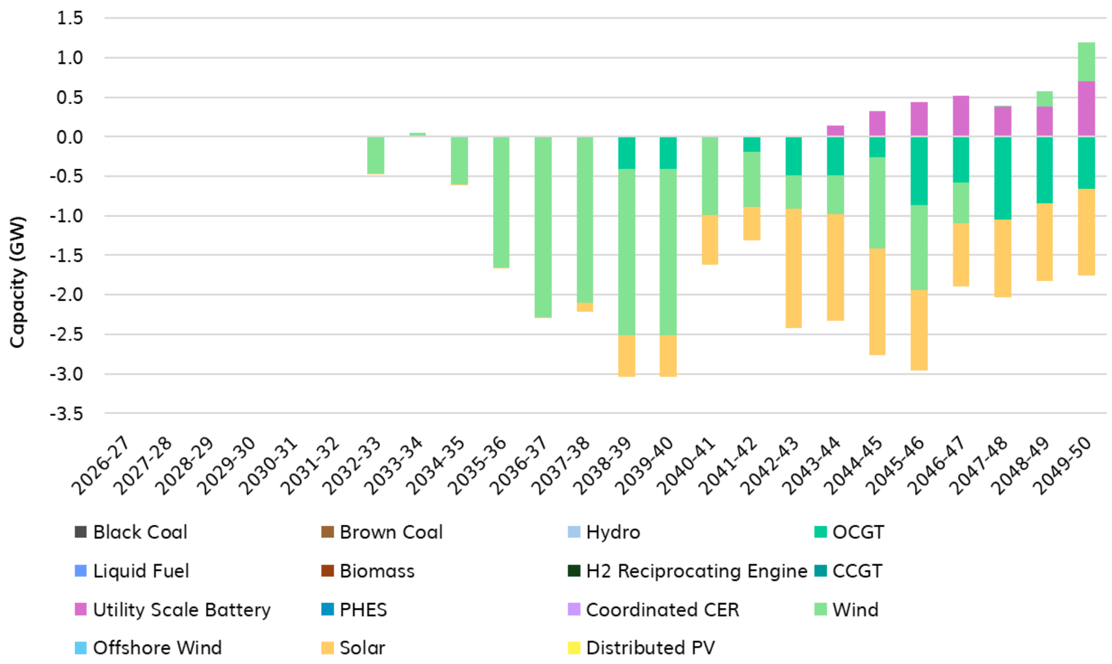
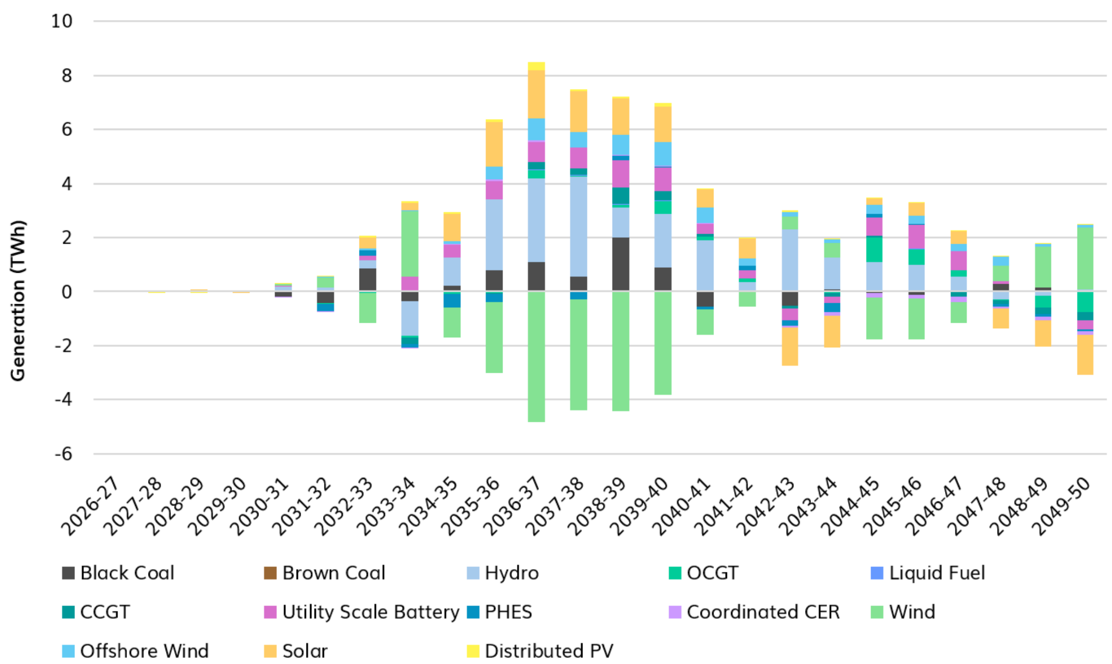


Figure 32: Slower Growth scenario – Option 6 NEM generation difference to the Base Case

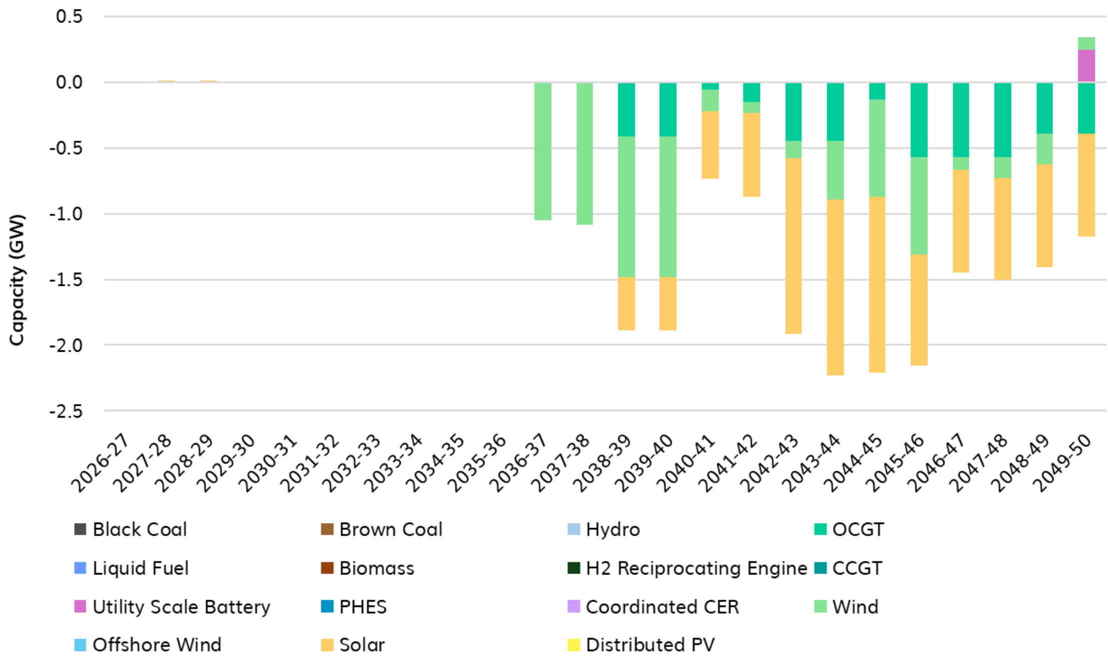


A more detailed assessment of the results for NSW highlights the following key insights:

- The majority of differences in generation and storage capacity build between Option 6 and the Base Case are due to changes in NSW.
- Figure 33 shows that up to 1GW of onshore wind is deferred from the mid-2030s, and approximately 800 MW solar generation is avoided in NSW. Furthermore, Option 6 allows approximately 400 MW new gas-powered generation capacity to be avoided in NSW.

- In NSW, the avoided or deferred wind generation capacity is predominantly in Northern NSW, while development of 1.2 GW wind generation capacity is enabled in Southern NSW is unlocked by Option 6. Central NSW is expected to require less wind and solar generation capacity over the longer term, while 400 MW gas fired generation capacity and up to 200 MW of solar generation capacity is avoided in Sydney, Newcastle, and Wollongong.

Figure 33: Generation and storage capacity outlook for NSW in the Slower Growth scenario – Option 6 vs Base Case



6.2.3 Key insights for options that include scope for a new 500 kV transmission line

As in the Step Change scenario, while the options that include scope for a new 500 kV transmission line differ in their specific configurations and commissioning timing, they share a common set of drivers for the gross market benefits. These options are forecast to relieve congestion on Line 39, as well as the flow paths serving the Wollongong region (Lines 8 and 16). Relieving these bottlenecks enables greater sharing of generation resources between NSW and Queensland, specifically allowing increased generation from NSW hydro and the Mt Piper power station to offset the need for additional capacity build in both Queensland and NSW.

Options that include scope for a new 500 kV transmission line are forecast to avoid the need for building additional wind generation capacity in Queensland, as well as solar and gas fired generation capacity in NSW. Increased flows across the southern interconnectors also enhances resource sharing between South Australia, Victoria, and NSW.

Consistent with the Step Change scenario, the majority of gross market benefits for these options are estimated to accrue from the mid-to-late 2030s, and are similar across options, irrespective of the staging and sequencing of commissioning of the new 500 kV transmission line.

Overall, capex and FOM are expected to account for the majority of the gross market benefits for the options that include scope for a new 500 kV transmission line, while additional emissions-related (VER) costs are forecast with these upgrades in place. While capex and FOM benefits are due to avoided wind, solar and gas capacity, additional VER costs are mainly due to increased generation from Mt Piper in the option cases.

6.2.4 Key insights for options that propose incremental network upgrades

As with the Step Change scenario, the smaller-scale network options which include scope for incremental network upgrades only (Option 2 and Option 2d) are not expected to fully alleviate the congestion on the flow paths into Sydney, Newcastle, and Wollongong. Unlike the Step Change scenario, gross market benefits for Option 2d are estimated to be closer to the options that include scope for a new 500 kV transmission line (albeit still $500 million lower, in present value terms). Option 2, however, is estimated to deliver far fewer benefits (refer Figure 34 and Figure 35).

Specifically, with Option 2d (delivering a power flow control solution) the network is still expected to experience congestion on Line 39, despite enabling incrementally higher utilisation of NSW hydro and coal generation capacity, as well as higher imports from Victoria and South Australia. The gross market benefits for Option 2d follow a similar trajectory to options that include scope for a new 500 kV transmission line, albeit to a lesser extent. Unlike for the transmission line options, the standalone power flow control solution proposed in Option 2d is not expected to enable higher utilisation of Mt Piper, relative to the Base Case, and therefore does not incur the same higher emissions-related (VER) costs.

Option 2 (delivering only the South Creek substation) is not expected to materially improve the congestion on Lines 39, 8 and 16. Therefore, gross market benefits for this option are relatively low, and are driven by enabling a small amount of new gas fired generation capacity to be avoided.

Figure 34 and Figure 35 show the cumulative gross market benefits for Option 2 and Option 2d. In both options, the majority of benefits result from capex savings. Option 2 delivers approximately $200 million in gross market benefits in present value terms ($2024-25), while Option 2d delivers almost five times more gross market benefits in this scenario.

Figure 34: Discounted cumulative gross market benefits for Option 2 – Slower Growth scenario ($2024-25)

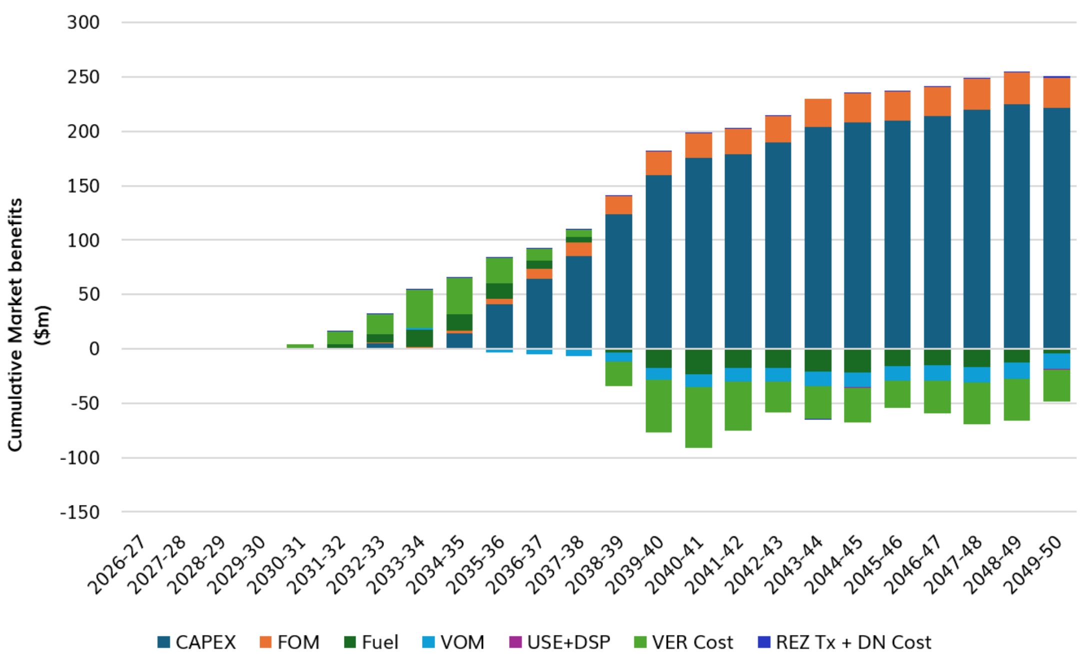
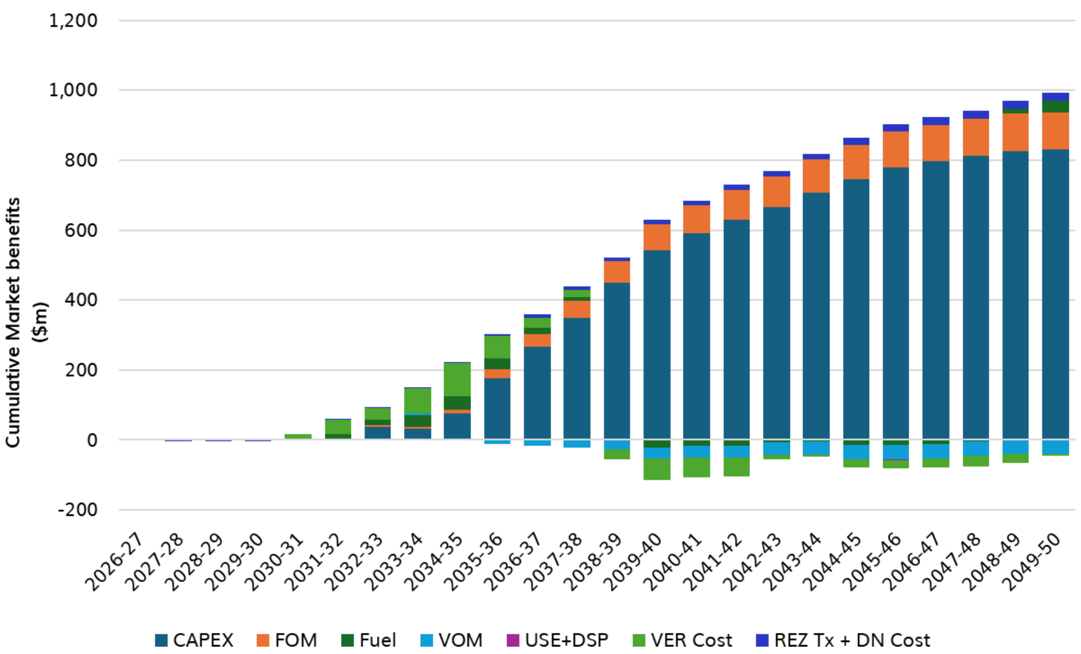


Figure 35: Discounted cumulative gross market benefits for Option 2d – Slower Growth scenario ($2024-25)



6.3 Accelerated Transition scenario

This section provides insights into the drivers of benefits for the Sydney Ring South Project under the Accelerated Transition scenario. We first discuss the challenges observed in the Base Case, where no investment is made in the Sydney Ring South Project, then focus on the benefits of the preferred option identified in Transgrid's PADR (Option 6). Results from the assessment of all other options can be found in the accompanying results workbook.

6.3.1 Analysis of modelling outcomes for the Base Case

The Accelerated Transition scenario is described by AEMO as a future defined by rapid transformation of Australia's energy sectors at a rate greater than that required by current domestic and global decarbonisation commitments, to limit temperature rise to 1.5°C above pre-industrial levels.

The largest drivers of the differences in outcomes between the Accelerated Transition and Step Change scenarios are the higher electricity demand forecasts, both operational and new demand for hydrogen electrolysis, and the stricter carbon budgets aligned to more ambitious long term decarbonisation targets. Together, these assumptions result in a greater need for new generation capacity and ensure the generation mix transitions to a low-emissions profile more quickly.

Figure 36 and Figure 37 show differences in the least-cost capacity build outcomes for Base Case between the Accelerated Transition and Step Change scenarios. Evidently, significantly more renewable generation capacity (most notably being significantly more solar generation and some new offshore wind) and storage, plus some additional gas fired generation, is required in the Accelerated Transition scenario. By 2050, the Accelerated Transition scenario sees approximately 80 GW more large-scale solar built, plus approximately 18 GW more onshore wind, 6 GW more offshore wind and 30 GW more utility-scale battery storage. From 2040, the significant increase in electricity demand for hydrogen production combined with the constraints of a more restrictive emissions budget drives the need for materially more generation capacity than in the Step Change scenario.

The trends and drivers for more generation and storage capacity Step Change scenario in NSW is consistent with those observed at the NEM-wide level. Notably, coal fired generation retires sooner in the Accelerated Transition scenario (largely by the early 2030s), with the remainder of NEM coal power stations retiring through the 2030s.

In the modelling for the PADR, the Base Case for the Accelerated Transition scenarios sees the need for approximately 400 GW of additional capacity to be built in the NEM by 2050, resulting in a system wide capacity of approximately 500 GW.

Figure 36: Accelerated Transition vs Step Change - Base Case NEM capacity difference forecast

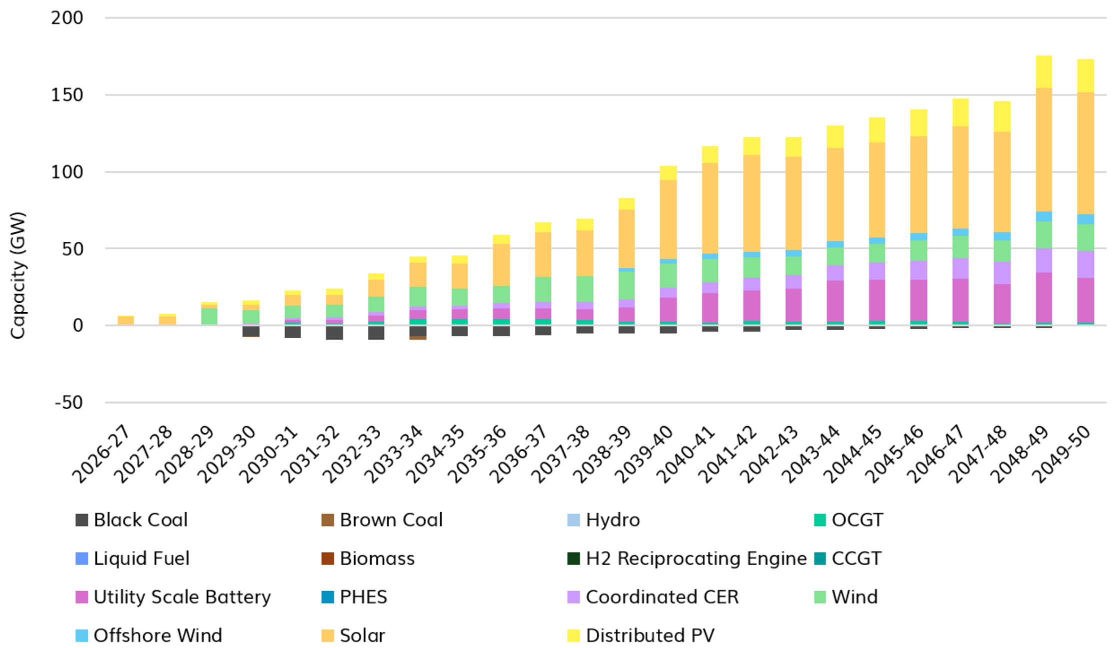
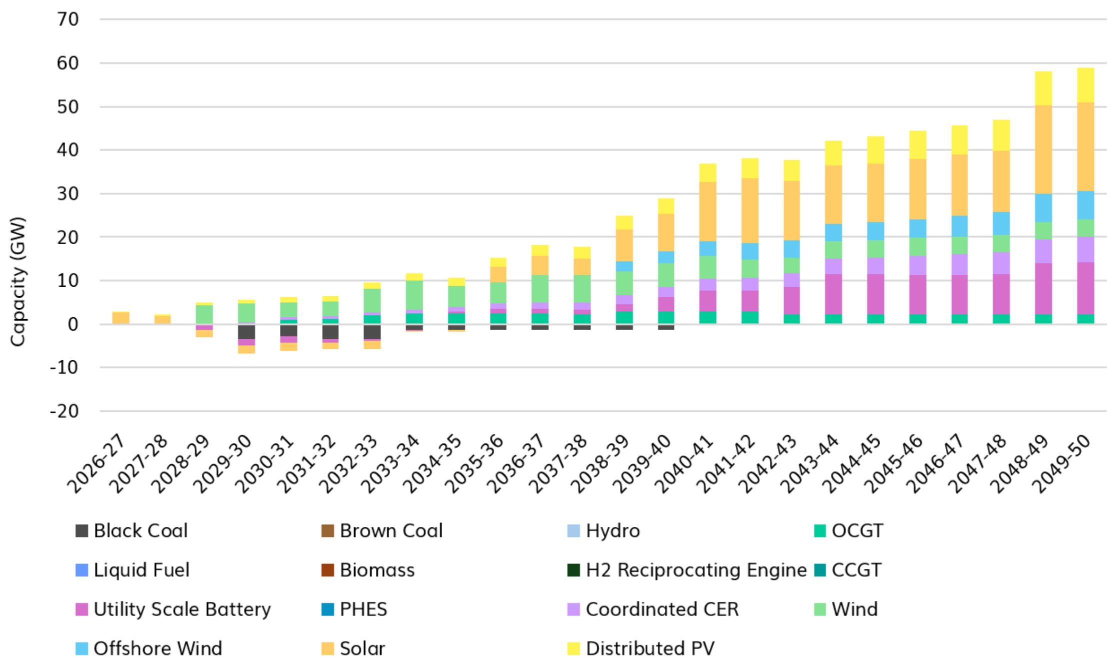


Figure 37: Accelerated Transition scenario Base Case vs Step Change Base Case NSW capacity difference forecast



In the Accelerated Transition scenario, increased future congestion on the existing Bannaby to Sydney West 330 kV line (Line 39), and on corridors supplying Sydney, Newcastle and Wollongong from the north and west, is forecast in the Base Case. Table 20 shows how frequently (expressed as a percentage of modelled half-hourly intervals) the most limiting constraints will bind over the modelled horizon).

In the Base Case, congestion on the existing Bannaby to Sydney West 330 kV line (Line 39) is forecast to increase to 23% in the early 2030s, before a moderate reduction from the late 2030s, mainly due to an increased level of distributed generation and storage in SNW. Modelling also forecasts increasing congestion on the Marulan to Dapto and Avon 330 kV flow paths (Lines 8 and 16).

Unlike in the Step Change scenario, this scenario forecasts relatively high congestion on the Bayswater to Sydney West 330 kV flow path (Lines 31 and 32) and the Kemps Creek transformers starting in the mid-2030s, increasing to approximately 12% by the end of the modelling horizon. This is driven by significant demand growth in Sydney, Newcastle, and Wollongong, requiring significant capacity in the CWO and HCC REZs and to a lesser extent the NE REZ, with power flowing from the north and west to supply load in the Sydney, Newcastle, and Wollongong load centres.

Congestion on Lines 8 and 16 is driven by demand growth in the Illawarra region, specifically the development of hydrogen electrolyser loads, and is forecast to limit the ability to supply Illawarra/Wollongong demand using generation from Southern NSW.

Table 20: Accelerated Transition scenario – Base Case binding network constraints

Constraint	2026-27 to 2029-30	2030-31 to 2032-33	2033-34 to 2036-37	2037-38 to 2039-40	2040-41 to 2049-50
Avoid overload of 330 kV Line 39 Bannaby to Sydney West on trip of 330 kV Line 17 Avon to Macarthur	0%	23%	16%	9%	12%
Avoid overload of 330 kV Line 16 Marulan to Dapto on trip of 330 kV Line 8 Avon to Marulan	0%	1%	15%	22%	17%
Avoid overload of 330 kV Line 31 Bayswater to Regentville on trip of 330 kV Line 32 Bayswater to Sydney West 330 kV	0%	0%	4%	7%	11%
Avoid overload of Kemps Creek 500 kV/330 kV transformer on trip of Kemps Creek 500 kV/330 kV transformer	0%	0%	0%	3%	12%
Avoid overload of 330 kV Line 39 Bannaby to Sydney West 330 kV	10%	0%	1%	1%	1%

As a result of congestion on the southern corridor of the Sydney Ring network supplying Sydney, Newcastle, and Wollongong, significant capacity build is required across NSW, particularly in Central NSW and Sydney, Newcastle, and Wollongong, in the Base Case (refer to Figure 38 to Figure 41).

A considerable capacity of solar in excess of 30 GW, followed by wind and utility-scale storage, each around 10 GW, is modelled in CNSW, most of which is expected to be developed in Central NSW in the CWO and HCC REZs. These REZ are expected to host around 20 GW of new generation and storage each, with CWO REZ modelled to host an almost equal share of solar and wind generation, while solar generation is dominant in the HCC REZ.

Sydney, Newcastle, and Wollongong region is forecast to require a total of approximately 55 GW capacity, which comprises significant gas-powered generation, utility-scale storage and offshore wind in Hunter and Illawarra REZs, in addition to the forecast uptake Distributed PV and CER (both of which are higher in the Accelerated Transition scenario). In Northern NSW and Southern NSW, new solar generation capacity is found to be the key component of the modelled energy mix, with each region hosting approximately 10-15 GW of solar capacity.

By the end of the modelling horizon, Northern NSW hosts approximately 19 GW of capacity, of which 7 GW is modelled within the NE REZ, while Southern NSW hosts a total capacity of 25 GW. Figure 38 to Figure 41 below show the modelled capacity mix in each NSW subregion under the Base Case for the Accelerated Transition scenario.

Figure 38: Accelerated Transition scenario – Base Case: NNSW capacity forecast

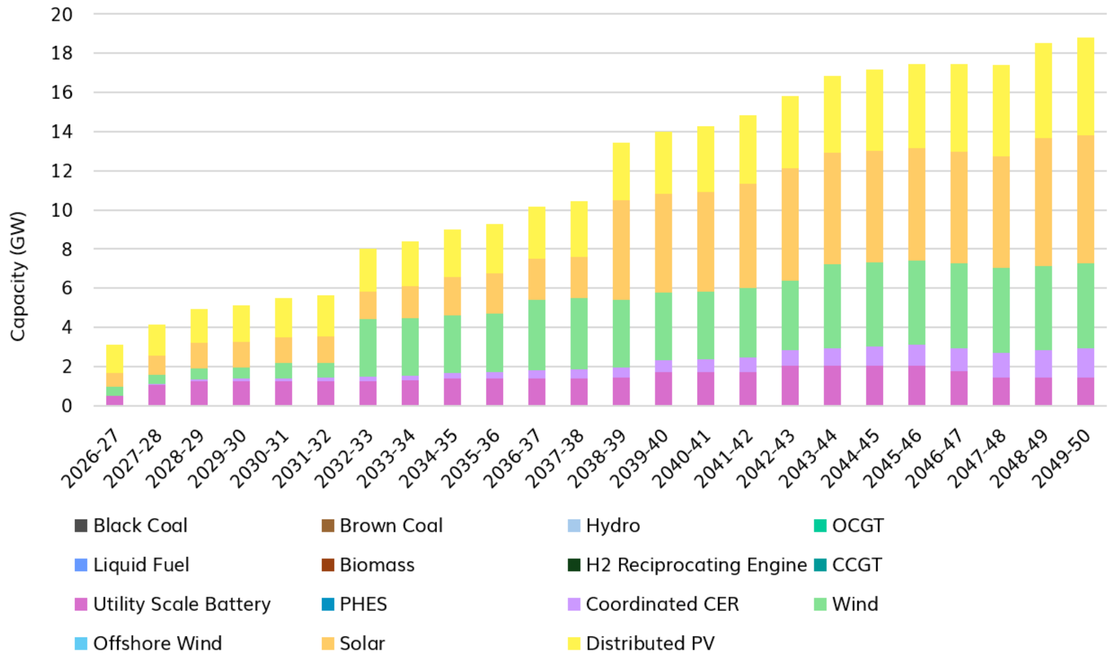


Figure 39: Accelerated Transition scenario – Base Case: CNSW capacity forecast

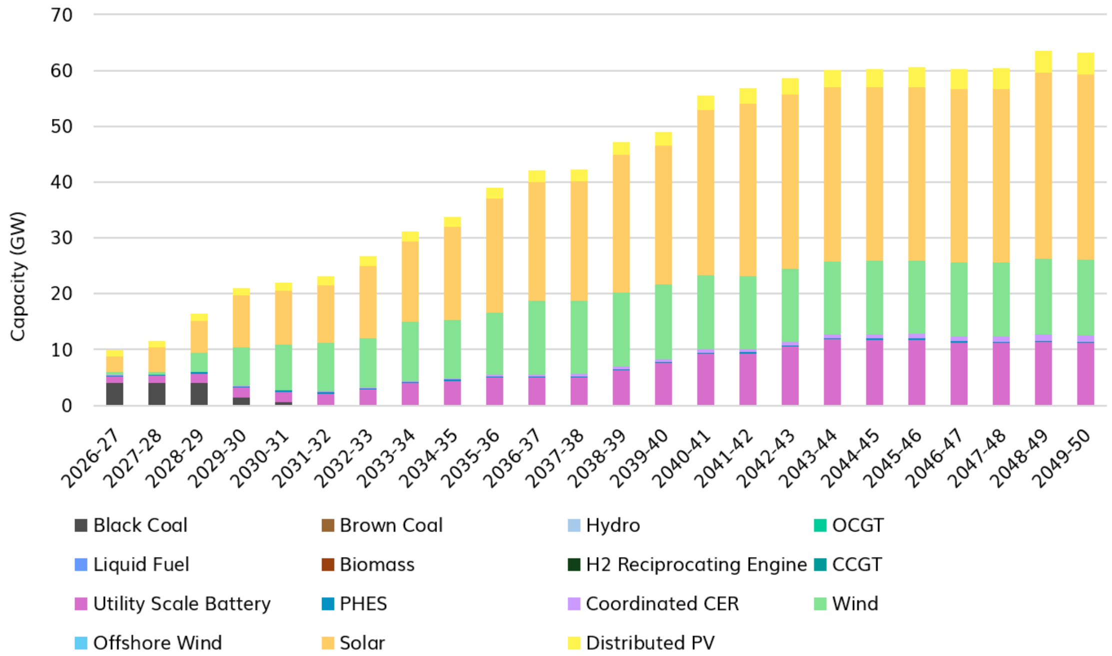


Figure 40: Accelerated Transition scenario – Base Case: Sydney, Newcastle, and Wollongong capacity forecast

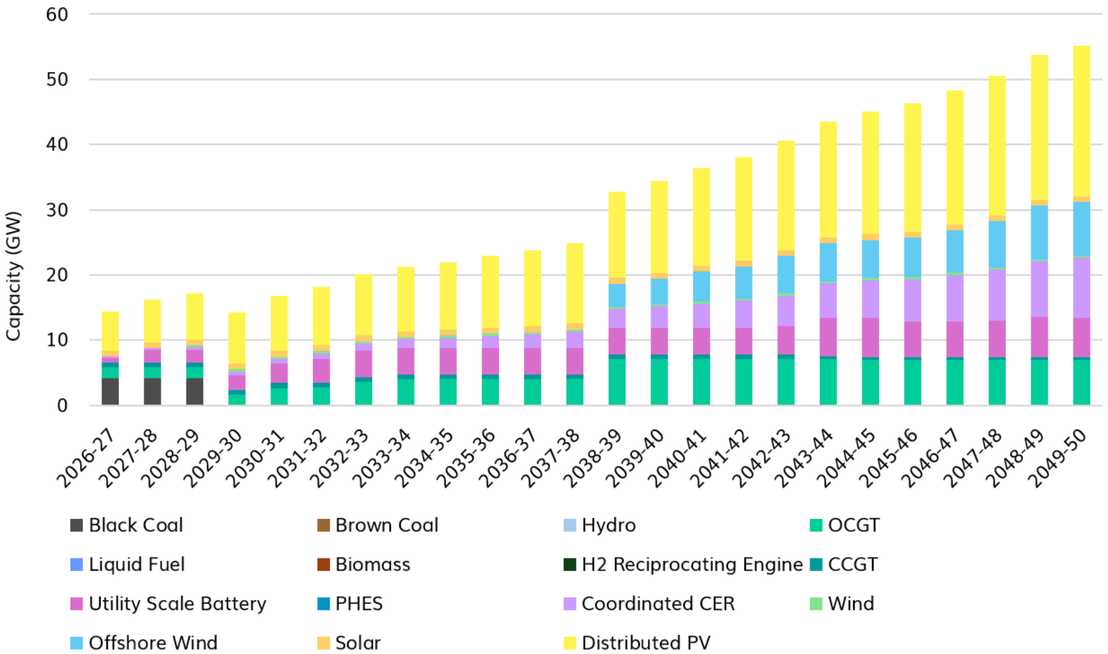
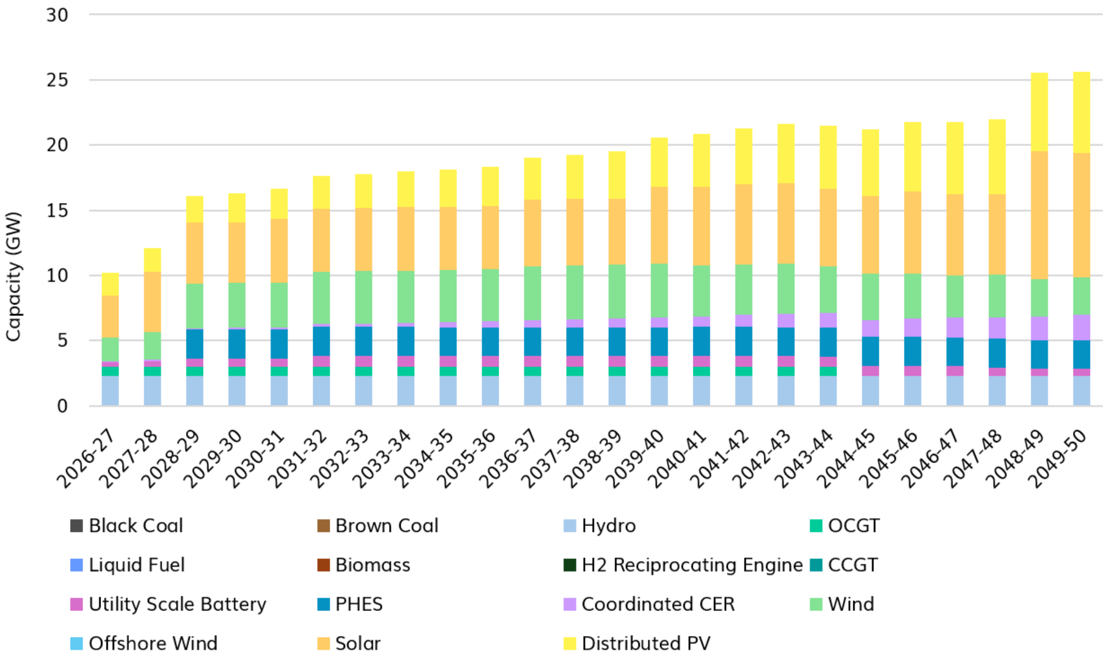


Figure 41: Accelerated Transition scenario – Base Case: SNSW capacity forecast



6.3.2 Analysis of modelling outcomes for the PADR preferred option analysis

This section presents the more detailed analysis regarding benefits of the preferred option at the PADR stage of the RIT-T (Option 6) in the Accelerated Transition scenario. On a net benefits basis, Transgrid has determined that Option 6 is also the top ranked option in the Accelerated Transition scenario.

Option 6 delivers benefits by enabling more efficient resource sharing across NSW and the broader NEM, particularly with the southern NEM regions. In the Base Case, generation and storage capacity in NSW, particularly Sydney, Newcastle, and Wollongong, needs to be overbuilt to supply growing demand, since constraints on the southern corridor of the Sydney Ring network limit generation in Southern NSW, and imports from Victoria and South Australia. By delivering new transmission capacity, Option 6 alleviates the network constraints into Sydney from the south, enabling a more geographically diverse generation mix to supply growing demand in Sydney, Newcastle, and Wollongong, reducing the need for new capacity.

Table 21 shows how frequently (expressed as a percentage of modelled intervals) the most limiting constraints will bind over the modelled horizon if Option 6 is delivered. Key constraints towards Sydney, Newcastle, and Wollongong load centres are expected to be marginally alleviated after the South Creek substation and power flow control solution are commissioned in 2030-31 and fully alleviated after the 500 kV upgrades are commissioned in 2033-34.

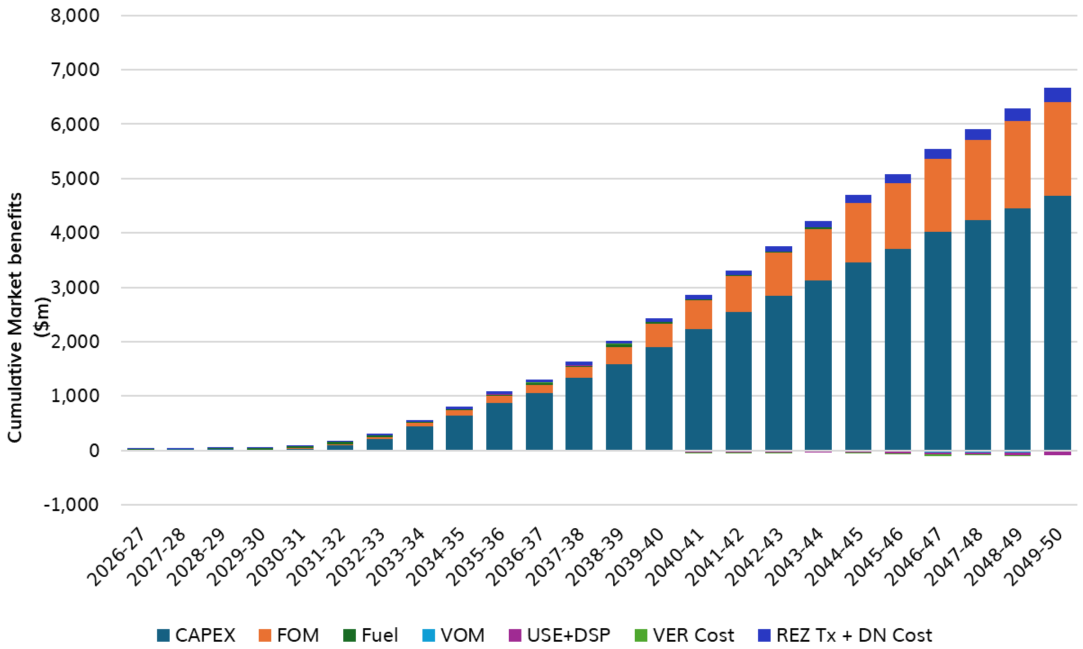
Table 21: Accelerated Transition scenario – Option 6 binding network constraints

Constraint	2026-27 to 2029-30	2030-31 to 2032-33	2033-34 to 2036-37	2037-38 to 2039-40	2040-41 to 2049-50
Avoid overload of 330 kV Line 39/1 Bannaby to South Creek on trip of Avon to Macarthur	0%	20%	0%	0%	0%
Avoid overload of 330 kV Line 16 Marulan to Dapto on trip of 330 kV Line 8 Avon to Marulan	0%	0%	1%	3%	7%
Avoid overload of 330 kV Line 39 Bannaby to Sydney West	10%	0%	0%	0%	0%
Avoid overload of 330 kV Line 8 Marulan to Avon on trip of 330 kV Line 16 Dapto to Marulan	0%	4%	0%	0%	1%
Avoid overload of 330 kV Line 32/1 Bayswater to South Creek on trip of 330 kV Line 31 Bayswater to Regentville	0%	0%	0%	1%	4%

Alleviating congestion on the southern corridor of the Sydney Ring network supplying Sydney, Newcastle, and Wollongong results in more efficient resource utilisation, and thus gross market benefits. Forecast cumulative gross market benefits for Option 6 in the Accelerated Transition are shown in Figure 42

Benefits are primarily comprised of reduced capex and FOM costs, with some benefits also arising from avoided or deferred REZ transmission and distribution network (DN) costs. Total cumulative gross market benefits of the PADR preferred option under the Accelerated Transition scenario are estimated to be approximately $6.6 billion in present value terms ($2024-25), of which $4.5 billion are capex benefits associated with avoided or deferred investments in generation and storage.

Figure 42: Discounted cumulative gross market benefits for Option 6 - Accelerated Transition scenario ($2024-25)



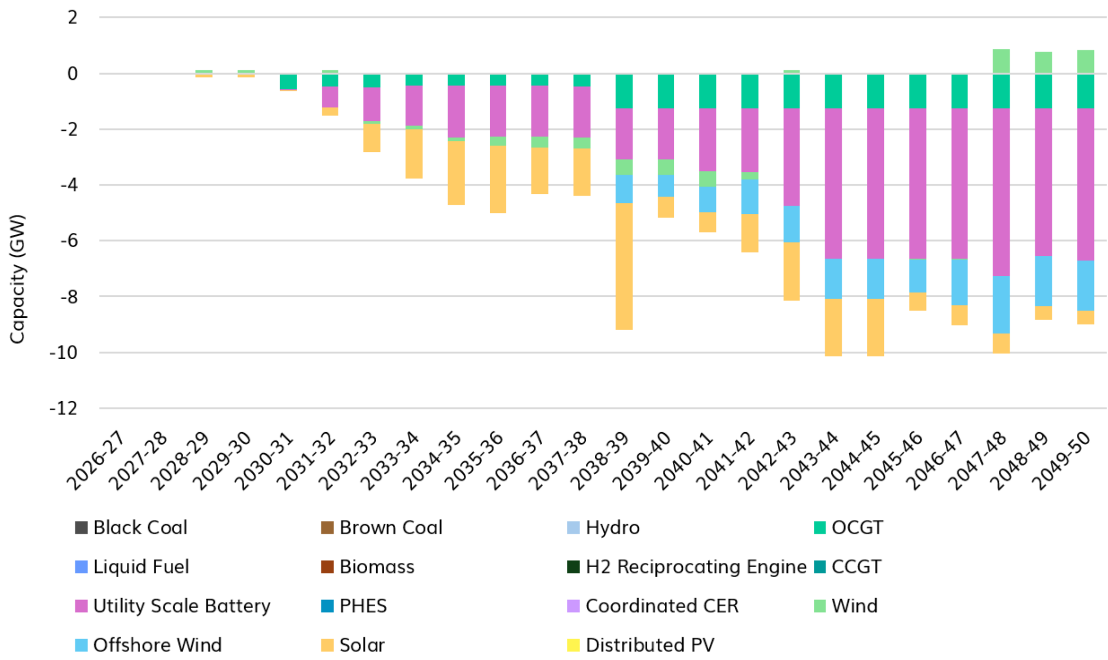
Focusing on capacity avoided by developing Option 6, Figure 43 shows the differences in capacity between the least cost generation mix in the option case and the Base Case. Option 6 is modelled to reduce the amount of new gas fired generation capacity in NSW by approximately 1 GW by the end of the modelling period. The required offshore wind capacity is also reduced from the late 2030s onwards, resulting in a reduction of approximately 2 GW by 2050. Utility scale battery build is also forecast to be avoided as a result of developing Option 6, with a reduced need for storage seen through the 2030s and resulting in a total capacity reduction of approximately 5.5 GW by the end of study period. The need for new solar capacity is reduced throughout the 2030s but is approximately equal to the Base Case by the mid-2040s under this option.

A more detailed assessment of the results for NSW highlights the following key insights:

- In the Sydney, Newcastle, and Wollongong region, the total capacity build under Option 6 in the Accelerated Transition scenario is modelled to be 8 GW lower than the Base Case by 2050, with this reduction comprising approximately 1.2 GW of gas fired generation (OCGT), 1.7 GW of offshore wind and 4.6 GW of utility-scale battery storage capacity. The reduction in forecast OCGT capacity appears in the late 2030s, aligning with a sharp increase in hydrogen demand under this scenario. The reduced utility-scale battery capacity forecast in this option begins in the early 2030s and offshore wind is avoided from the late 2030s.
- Option 6 is found to reduce the need for wind, solar and large-scale battery capacity in Central NSW. By 2050, this option avoids approximately 3 GW of capacity in this region, including 2 GW of battery storage, 1 GW of solar and plus some wind generation capacity.
- In Northern NSW, capacity build under Option 6 is modelled to be approximately 1 GW lower than in the Base Case, primarily due to reduced solar capacity while approximately 500 MW more wind capacity is required by 2050. This capacity difference is first forecast in the late 2030s and remains consistent until the end of the modelling period.

- Option 6 is modelled to increase capacity in Southern NSW, relative to the Base Case by 2050, owing to the improved transfer capability between Southern NSW and Sydney, Newcastle, and Wollongong. By the end of the modelling horizon, approximately 1.5 GW of additional utility-scale battery capacity, 500 MW of additional wind capacity and around 2 GW of additional solar capacity is modelled to be developed in Southern NSW. The additional solar and wind capacity is required from the mid-2030s, while the extra battery capacity is largely required from the late 2040s.

Figure 43: Accelerated Transition scenario – Option 6 NSW capacity difference to the Base Case



6.3.3 Key insights for options that include scope for a new 500 kV transmission line

Similar to the outcomes for Option 6, all options that include scope for a new 500 kV transmission line are anticipated to relieve congestion on Line 39, as well as on the flow paths to Wollongong (i.e. Lines 8 and 16), and to some extent the northern corridor of the Sydney Ring constrained by Lines 31 and 32 and the Kemps Creek 500/330 kV transformers.

Relieving these bottlenecks enables more efficient use of generation capacity by avoiding the need to overbuild storage and solar generation capacity in Central NSW and Sydney, Newcastle, and Wollongong, as less energy needs to be time shifted to overcome network constraints.

A 500 kV transmission line is also expected to avoid more expensive generation within Sydney, Newcastle, and Wollongong, specifically new gas fired and offshore wind capacity. Notably, even with a 500 kV transmission line option developed, some offshore wind capacity is still seen in the Hunter and Illawarra areas, largely due to prevailing congestion on Lines 8, 16, 31 and 32 in the late 2030s and 2040s.

Gross market benefits for the options that include scope for a new 500 kV transmission line are expected to accrue steadily from the early 2030s, with some differences in gross market benefits observed between the options that plan for earlier commissioning of the transmission line (Option 3, Option 4 and Option

6) and Option 5 which plans for the transmission line in 2037-38. Specifically, in this scenario, earlier commissioning of the transmission line is expected to result in higher benefits.

Overall, in the Accelerated Transition scenario, benefits from capex and Fixed Operation and Maintenance (FOM) costs associated with deferred or avoided investments in storage and generation capacity account for the majority of gross market benefits provided by all options that include scope for a new 500 kV transmission line.

6.3.4 Key insights for options that propose incremental network upgrades

As with the Step Change scenario, the smaller-scale network options which include scope for incremental network upgrades only (Option 2 and Option 2d) are not expected to fully alleviate the congestion on the flow paths into Sydney, Newcastle, and Wollongong. Specifically, with Option 2 (delivering only the South Creek substation) and Option 2d (delivering a power flow control solution) the network is still expected to experience congestion on Line 39 up to 16% of the time from the mid-2030s until the end of the modelling horizon.

As a result, these options, particularly Option 2, are not expected to materially improve access to lower-cost generation resources to supply growing Sydney, Newcastle, and Wollongong demand, leading to lower capex savings compared to the options that include scope for a new 500 kV transmission line. Figure 44 and Figure 45 show the cumulative gross market benefits for Option 2 and Option 2d of approximately $1.2 billion and $2.2 billion respectively in present value terms ($2024-25). In both options, most benefits arise from capex savings related to avoided or deferred generation and storage investments, with Option 2 delivering approximately $800 million of benefits in this category, compared with approximately $1.3b for Option 2d. In both options, there is still a need to develop higher-cost generation such as offshore wind within Sydney, Newcastle, and Wollongong.

Figure 44: Discounted cumulative gross market benefits for Option 2 - Accelerated Transition scenario ($2024-25)

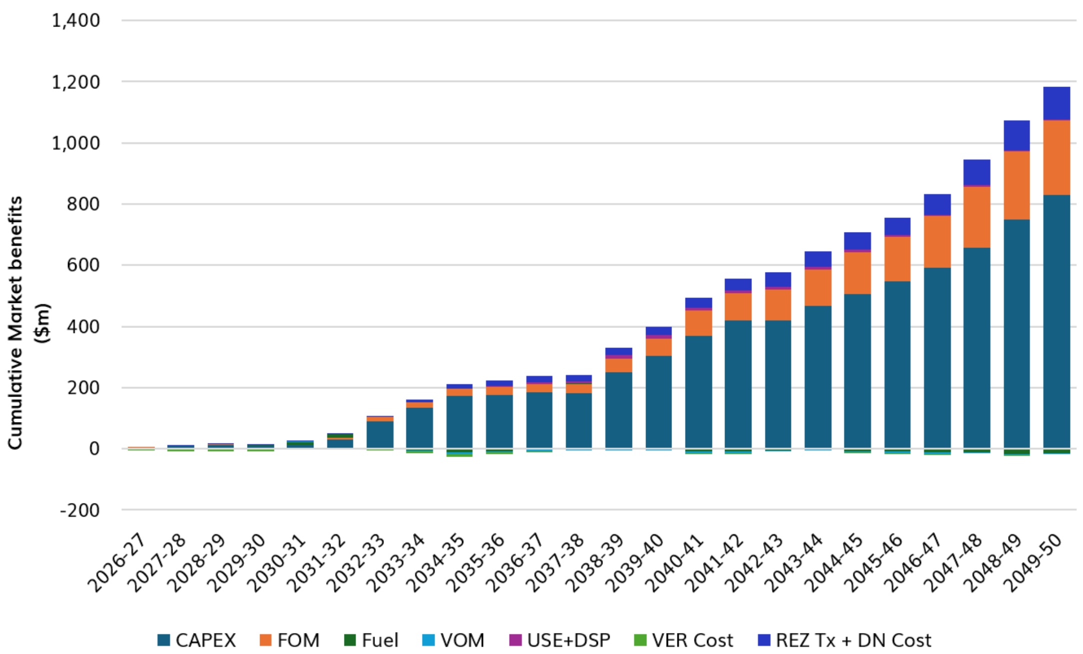
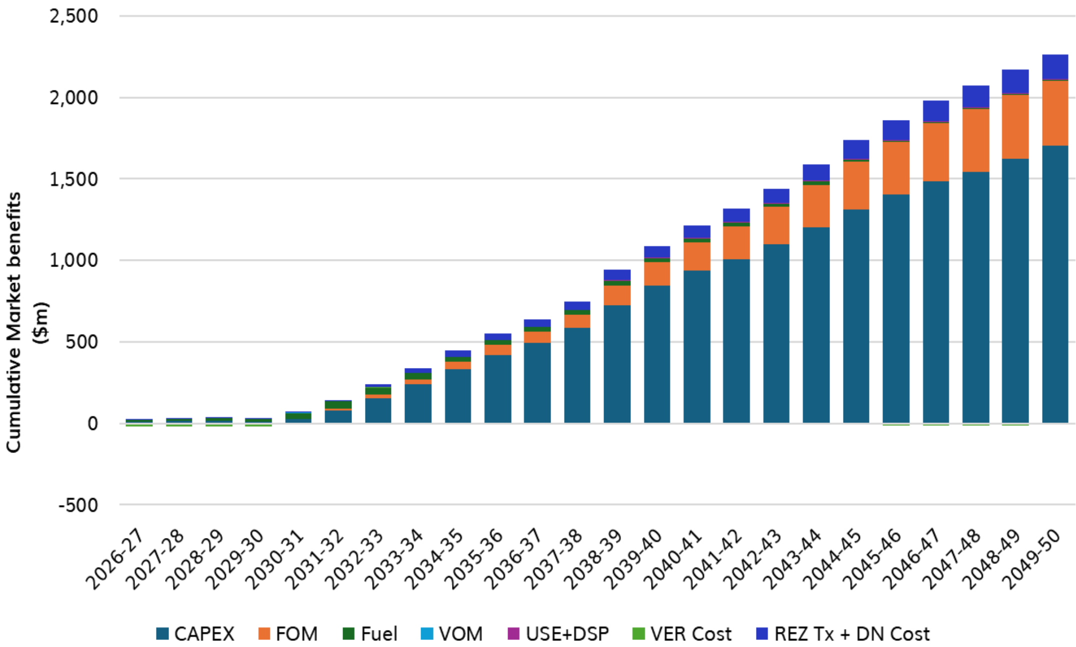


Figure 45: Discounted cumulative gross market benefits for Option 2d - Accelerated Transition scenario ($2024-25)



6.4 Sensitivities

In addition to the scenario analysis, a variety of sensitivities have been tested to assess the robustness of gross market benefits to changes in key assumptions about the trajectory of the energy transition. This section provides a summary of key results and findings for the sensitivities modelled for the Sydney Ring South PADR.

Sensitivities requiring electricity market modelling to be undertaken have only been performed relative to the Step Change scenario, being the central (highest weighted) scenario assessed. The options including scope for a transmission line (Options 3, 4, 5 and 6) are tested in all sensitivities, given the closeness of the results on a weighted net market benefits basis, and Option 2d is tested in cases where it has reasonable potential to become preferred.

All gross market benefits are presented on a 30 June 2025 real dollars basis ($2024-25). Present value outcomes are discounted to 30 June 2025 by applying 7% discount rate (real, pre-tax) consistent with the discount rate in the 2025 IASR. All NPVs consider an outlook period from 2026-27 to 2049-50.

6.4.1 Sensitivity 1: Alignment with NSW Electricity Infrastructure Roadmap development

This sensitivity examines the impact of treating NSW REZ Access Rights holder projects in the Central-West Orana (CWO) and South-West (SW) REZs as anticipated and including Stage 2 of the New England (NE) transmission project, which were not considered in the core scenario modelling. Key assumptions for this sensitivity are outlined below.

Table 22 shows the increase in the Central NSW (CNSW) to Northern NSW (NNSW) limits due to NE REZ Stage 2, as reported in the 2025 IASR. This upgrade also increases the NE REZ transmission hosting capacity by 3,600 MW. Table 23 and Table 24 show the commissioned capacity of Access Right holder projects in CWO REZ and SW REZ modelled for this sensitivity

Table 22: CNSW-NNSW line limits (typical summer ratings)

	Southerly limit (MW)	Northerly Limit (MW)
Without New England REZ Stage 2	-3,330	3,310
With New England REZ Stage 2	-6,930	6,910

Table 23: Commissioned Central-West Orana REZ Access Right holder generation capacity

	BESS (MW)	Wind (MW)	Solar (MW)
2029-30	600	460	600
2030-31	1,500	1,269	1,800
2031-32	2,200	2,951	2,500

Table 24: Commissioned South West REZ Access Right holder generation capacity

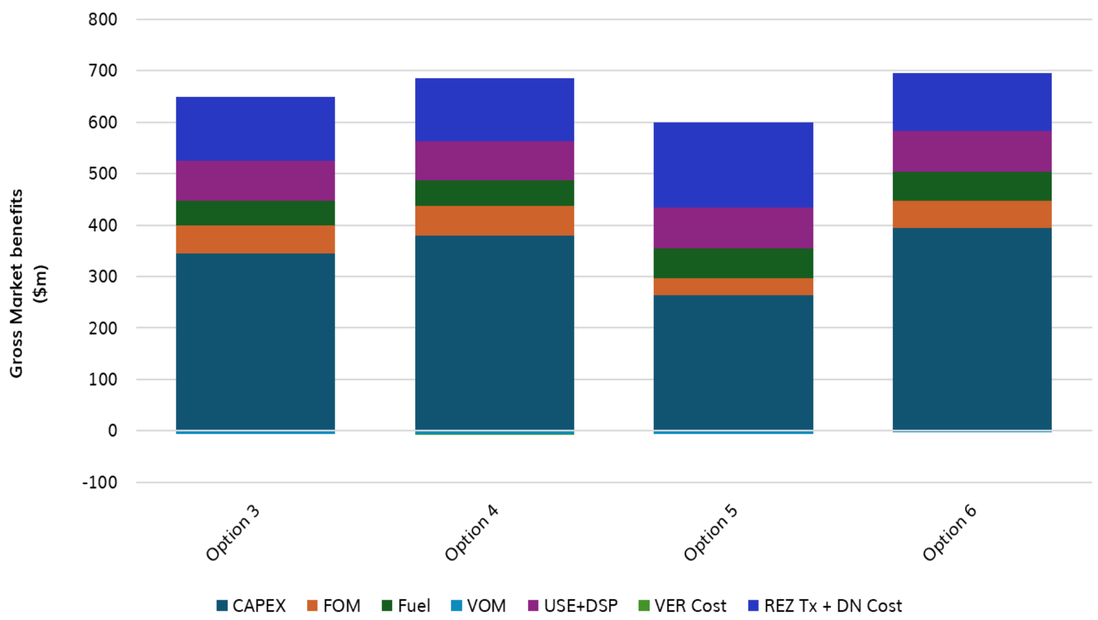
	BESS (MW)	Wind (MW)	Solar (MW)
2028-29	200	41	0
2029-30	400	687	0
2030-31	495	2,529	95
2031-32	710	3,069	308
2032-33	710	3,328	308

In the Base Case, congestion on the southern corridor of the Sydney Ring network results in underutilisation (curtailment) of generation from the REZ Access Right holder projects, particularly those in SW REZ. The Sydney Ring South Project options that include scope for a new 500 kV transmission enable more efficient utilisation of these projects by increasing access to the demand centres in Sydney, Newcastle, and Wollongong. Options 3, 4, 5 and 6 deliver between approximately $590 million and $690 million of additional gross market benefits in present value terms ($2024-25), relative to the core Step Change scenario. The most significant changes in gross market benefits come from capex and FOM cost savings, since fewer alternative generation and storage projects are needed when the REZ Access Right holder projects are efficiently utilised, followed by savings from alternative network investments (REZ and distribution (DN) network) required to host this alternative capacity. Table 25 and Figure 46 show the gross market benefits of the options assessed in this sensitivity and the relative changes from the Step Change scenario.

Table 25: Gross market benefits – Sensitivity 1 ($m, real 30 June 2025 discounted to 30 June 2025)

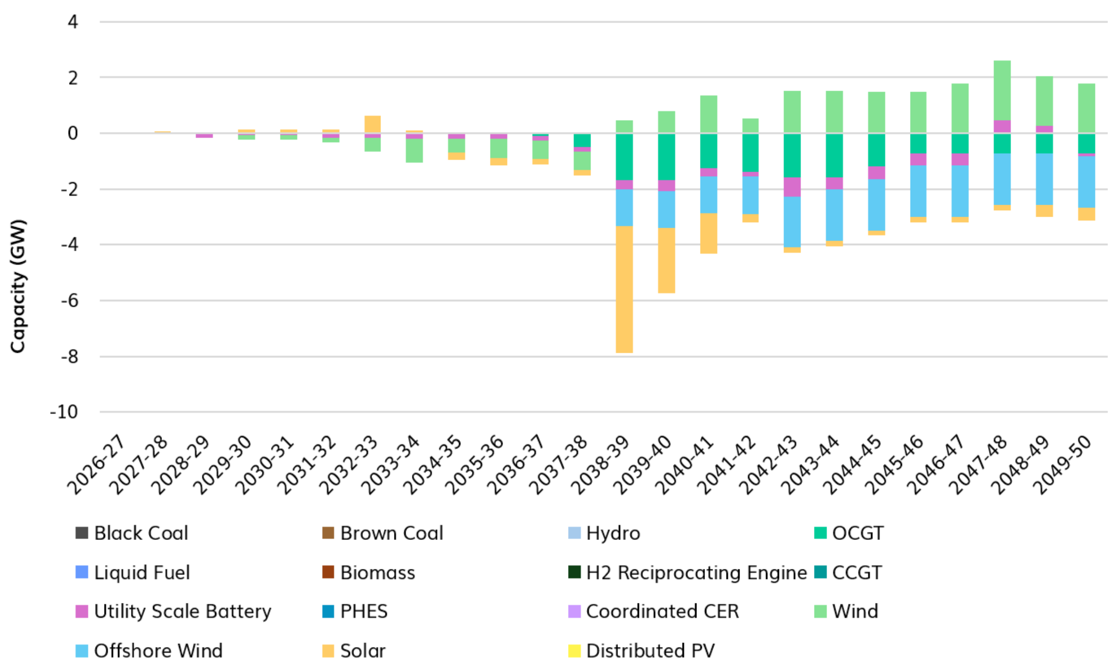
	Option 3	Option 4	Option 5	Option 6
Gross market benefits	4,856	4,956	4,755	5,082

Figure 46: Change in gross market benefits of Sydney Ring South options – Sensitivity 1 vs Step Change ($m, real 30 June 2025 discounted to 30 June 2025)



The Sydney Ring South Project options enable better utilisation of generation from REZ Access Right holder projects, avoiding/deferring additional generation and storage capacity that is otherwise needed in the Base Case due to transmission network congestion. This is particularly evident in the early-late 2030s where some wind capacity is avoided with Option 6 (refer to Figure 47). This deferral of wind capacity is the primary driver for additional capex benefits in this sensitivity compared to the core Step Change scenario outcomes.

Figure 47: Sensitivity 1 – Change in NSW capacity Option 6 vs Base Case



6.4.2 Sensitivity 2: Constrained use of diesel as backup fuel

This sensitivity tests the impact of applying liquid fuel constraints limiting the ability for gas fired generators in the Newcastle region to use backup fuels when gas pipeline capacity is exhausted. These limits have been designed to align with conditions of relevant environmental and planning permits and physical capabilities (e.g. onsite diesel storage limits).

Access to backup fuel is particularly important in Sydney, Newcastle, and Wollongong, where the interaction of reciprocal transmission and gas network constraints have material implications for planning new gas-powered generation to support reliability as coal power stations retire. The liquid fuel limits applied for each gas generator in this sensitivity are shown in Table 26.

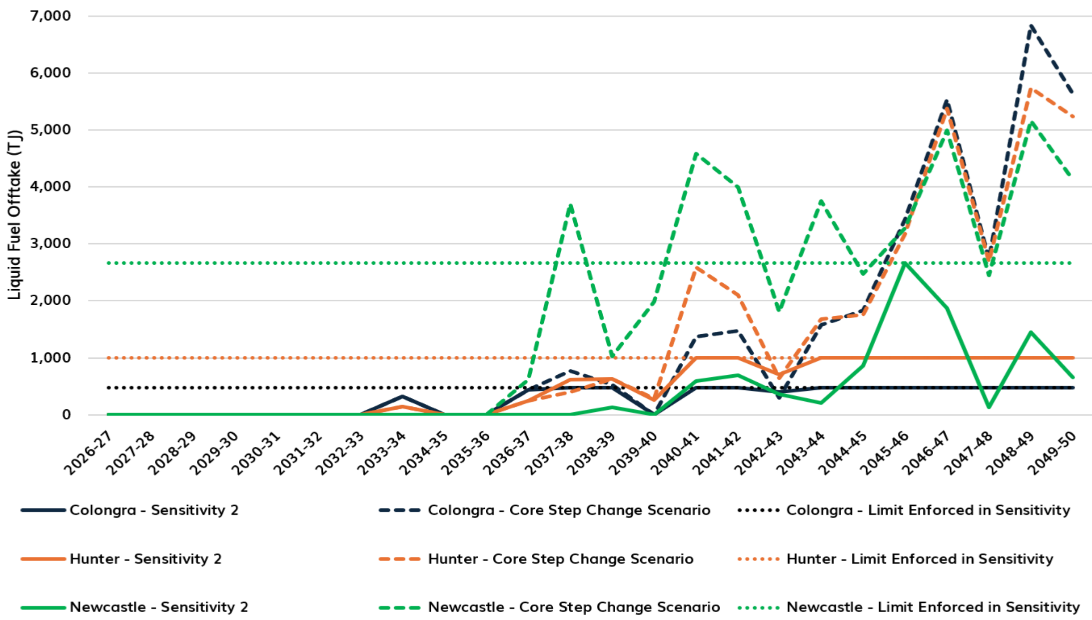
Table 26: Liquid fuel limit assumption (TJ/Year)

	Sensitivity 2	Core modelling - Step Change
Colongra Power Station	482 TJ per year	Unlimited
Hunter Power Station	1000 TJ per year	Unlimited
New OCGT build in the Newcastle gas supply region	1334 TJ per year per GW of new capacity developed	Unlimited

Figure 48 shows the liquid fuel offtake at the existing Colongra and Hunter Power Stations and at the new gas plant built by the model at the Newcastle region in Sensitivity 2 Base Case and the core Step

Change scenario Base Case. It is observed that the sensitivity significantly limits the level of liquid fuel usage in the Newcastle area, particularly in the last decade of the modelling horizon. The Colongra and Hunter Power Stations are expected to use up to approximately 7,000 and 6,000 TJ liquid fuel in the Base Case in the Step Change scenario, whereas they are limited according to the values in Table 26 for the sensitivity.

Figure 48: Liquid fuel offtake –Step Change Base Case vs Sensitivity Base Case

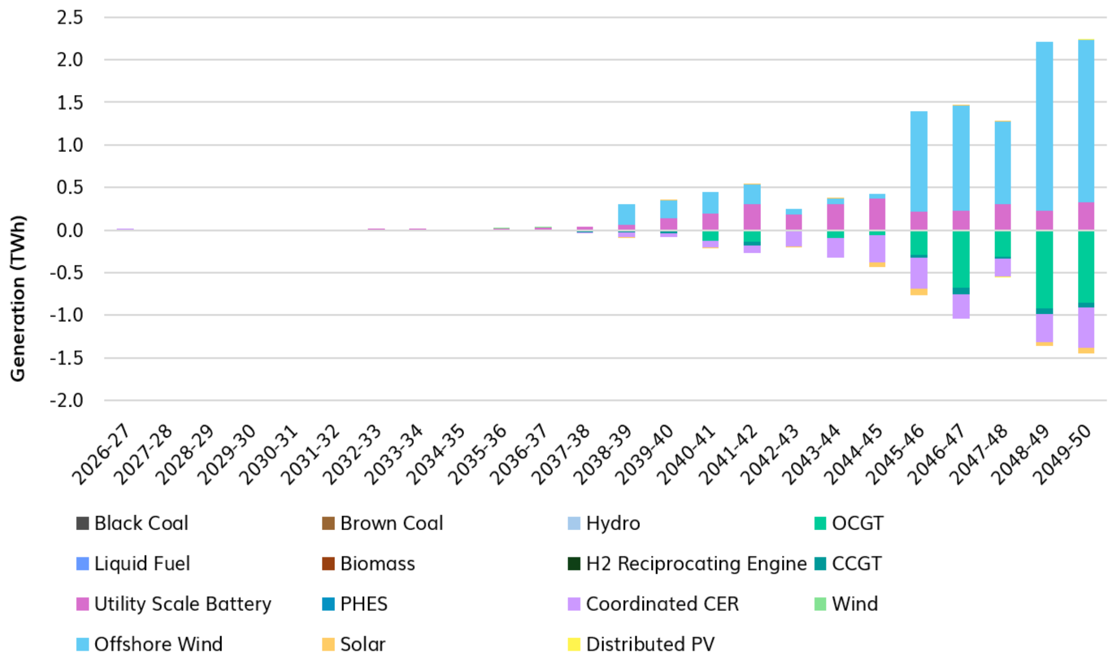


When the additional liquid fuel constraints are applied to the Base Case, total generation output from the gas fired generators in the Newcastle region declines as compared with the generation in the core Step Change Base Case. As shown in Figure 49, the difference starts to show in 2040-41 and increases to approximately 1 TWh by the end of the modelling horizon.

Figure 49: Base Case aggregate Newcastle gas generation

Figure 50 shows the change in generation in Sydney, Newcastle, and Wollongong between the Base Case in Sensitivity 2 and the core Step Change scenario. The results show that the reduction in gas fired generation from the Newcastle area is made up for by additional generation from offshore wind generation. The need for additional offshore wind capacity within Sydney, Newcastle, and Wollongong indicates that the system modelled in this sensitivity is more strained than in the core Step Change scenario modelling.

Figure 50: Difference in Sydney, Newcastle, and Wollongong Generation Sensitivity 2 Base Case minus Step Change Base Case



With the development of Option 6, the added capacity on the southern corridor of the Sydney Ring network relieves congestion into Sydney, Newcastle, and Wollongong, reducing the need to rely on local gas generation in Sydney, Newcastle, and Wollongong, and generally decreases the need for higher cost generation capacity within Sydney, Newcastle, and Wollongong.

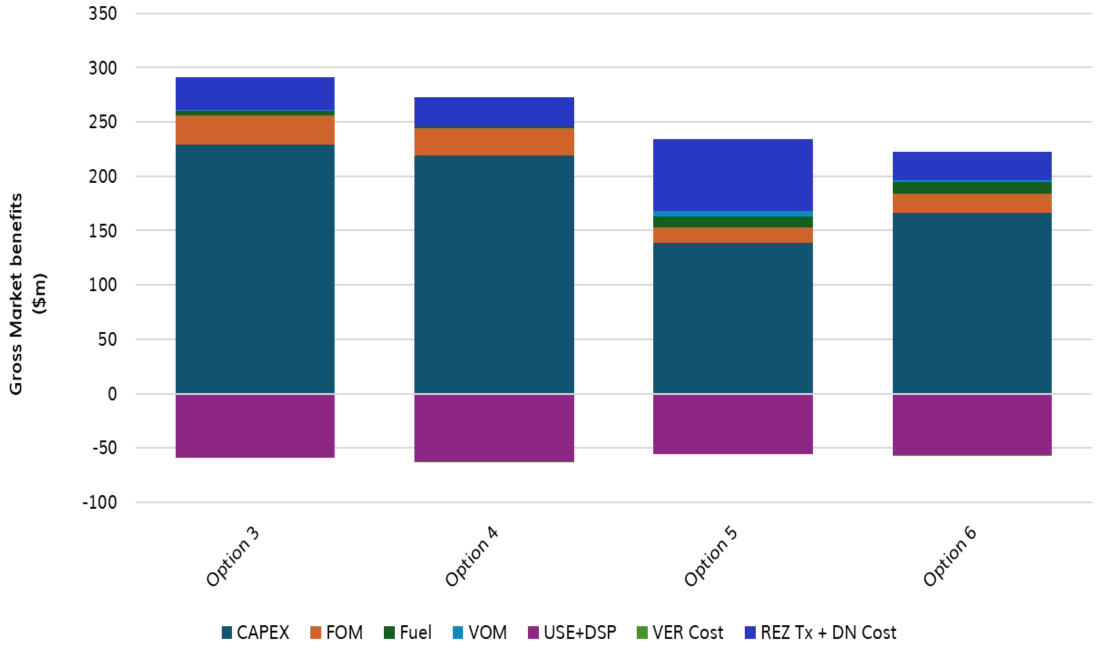
Relative to the Base Case, Option 6 reduces new gas fired generation build in the Newcastle area (modelled at Vales Point) by 1.3 GW and in Wollongong (modelled at Dapto) by 250 MW, with most of this (900 MW) relocating south of Sydney (modelled at Marulan) where there is better access to high-capacity gas pipelines, resulting in a net reduction of new gas fired generation capacity of approximately 650 MW. All options that include scope for a new 500 kV transmission line enable greater access to generation from Southern and Central NSW to meet growing demand, lowering the overall gas fired generation build required. The increased ability to supply growing demand with energy from outside of Sydney, Newcastle, and Wollongong also reduces the need for approximately 1.8 GW of offshore wind within Sydney, Newcastle, and Wollongong.

Table 27 shows the total gross market benefits of the options assessed in this sensitivity, which are found to be greater than in the core scenario, and Figure 51 shows the relative changes from the Step Change scenario show total benefits and the difference between benefits in this sensitivity to the Step Change scenario. It is forecast that the constrained fuel usage applied for this sensitivity increases the benefits relatively modestly across all options.

Table 27: Gross market benefits – Sensitivity 2 ($m, real 30 June 2025 discounted to 30 June 2025)

	Option 3	Option 4	Option 5	Option 6
Gross market benefits	4,443	4,487	4,340	4,556

Figure 51: Change in gross market benefits of Sydney Ring South options – Sensitivity 2 vs Step Change ($m, real 30 June 2025 discounted to 30 June 2025)



6.4.3 Sensitivity 3: NSW Electricity Infrastructure Roadmap aligned development & constrained use of diesel as a back-up fuel

This sensitivity combines the assumptions of the NSW Infrastructure Roadmap alignment sensitivity (Sensitivity 1) and the liquid fuel constraint sensitivity (Sensitivity 2), and finds that all options assessed deliver higher estimated gross market benefits relative to the core modelling, driven primarily by higher capex benefits.

The results follow a similar pattern to the individual sensitivities discussed in previous sections: the Sydney Ring South Project options avoid development of offshore wind and new gas fired generation capacity while enabling more efficient utilisation of the anticipated Access Right holder generation projects in the SW and CWO REZs.

Figure 52: Sensitivity 3 –NEM capacity - Option 6 vs the Base Case

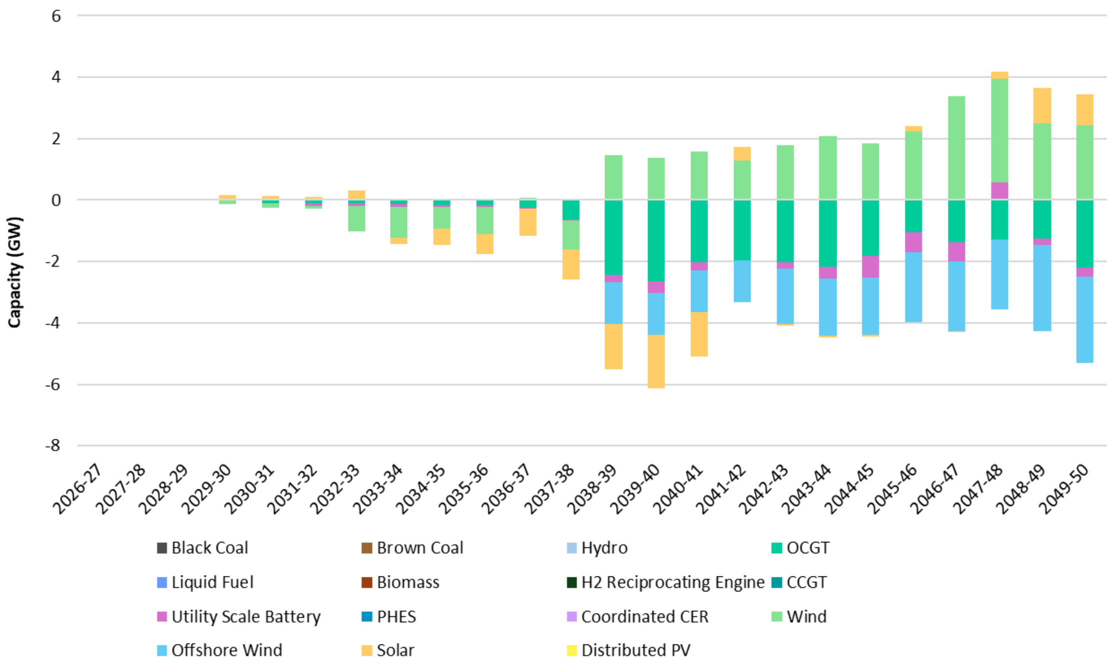


Table 28 shows the total gross market benefits of the options assessed in this sensitivity, which are found to be greater than in the core scenario, and Figure 53 shows the relative changes from the Step Change scenario.

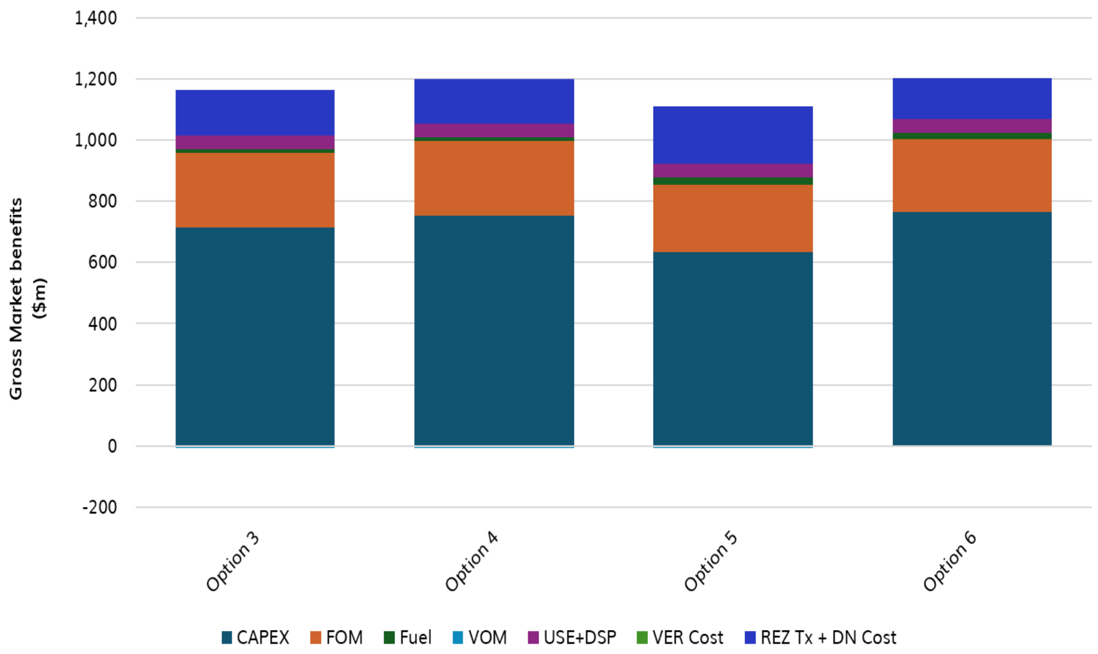
The results show that the combined sensitivity yields gross market benefits exceeding the sum of the incremental benefits seen in Sensitivity 1 and Sensitivity 2, reflecting a complementary interaction between the two assumptions, both of which rely on the ability for additional network capacity to relieve the binding network constraints into the Sydney, Newcastle, and Wollongong load centre.

In the first sensitivity, the augmentation allows the model to make better use of anticipated REZ generation capacity, particularly in the SW REZ, that would otherwise sit behind a network bottleneck. In the second sensitivity, the liquid fuel limits constrain Newcastle gas generation and would, in the Base Case, require costly local substitution from offshore wind and BESS. With the augmentation in place, lower-cost onshore renewables from outside Sydney, Newcastle, and Wollongong can instead be imported to offset the constrained gas. When the two assumptions are applied together, these effects reinforce one another: the additional committed REZ capacity introduced in the first sensitivity provides the low-cost generation that the added transmission capacity can deliver into Sydney, Newcastle, and Wollongong to replace output that was restricted from gas fired generation in the Newcastle region in the second. A 500 kV transmission line augmentation therefore unlocks more combined value than either assumption captures in isolation, producing benefits greater than their sum.

Table 28: Gross market benefits –Sensitivity 3 ($m, real 30 June 2025 discounted to 30 June 2025)

	Option 3	Option 4	Option 5	Option 6
Gross market benefits	5,368	5,468	5,265	5,590

Figure 53: Change in gross market benefits of Sydney Ring South options – Sensitivity 3 vs Step Change ($m, real 30 June 2025 discounted to 30 June 2025)



6.4.4 Sensitivity 4a: High data centre growth

This sensitivity adds 1 GW of data centre load to the forecast data centre demand modelled in Sydney, Newcastle, and Wollongong under the Step Change scenario in the Draft 2026 ISP. This additional demand is added linearly between 2027-28 through to 2044-45 and is modelled with a flat load profile.

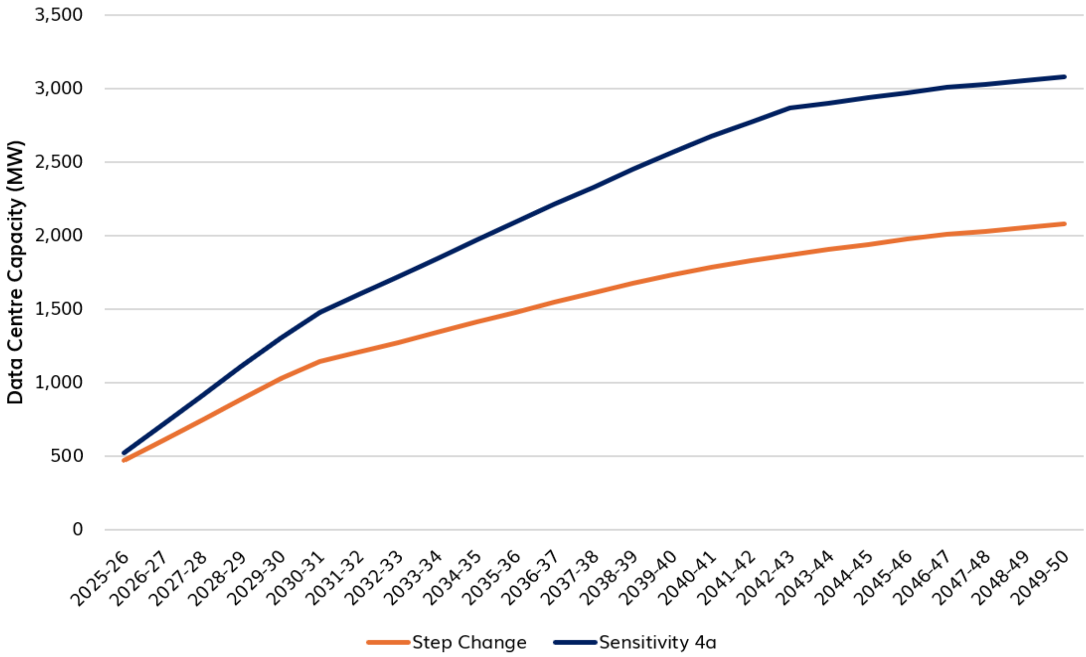
Figure 54 shows the data centre demand growth modelled in this sensitivity relative to a the flat-load profile equivalent of the data centre demand forecast in the 2025 IASR for the Step Change scenario.

In addition to the higher data centre demand, this sensitivity also includes a range of supply-side adjustments to the inputs and assumptions of the Draft 2026 ISP Step Change scenario to ensure that the additional demand does not overly strain the system, ensuring that the estimated market benefits are based on a realistic development trajectory for the NSW power system. These demand-side adjustments are:

- Match growing data centre demand with equivalent local demand management mechanisms which could include demand flexibility agreements or local generation and storage. For modelling purposes, this flexibility is modelled as additional dispatchable demand side participation, whereby new data centres have the capability to reduce demand at a price of $1000/MWh. This value has been chosen to set a high dispatch threshold for demand reduction, forcing it to be used as a last resort. It is not considered to be reflective of the market value of data centre demand flexibility.
- Alignment with NSW Electricity Infrastructure Roadmap developments (as in Sensitivity 1).
- Constrained use of diesel as a backup fuel (as in Sensitivity 2).
- Inclusion of LTESA Tender 6 outcomes, consistent with treatment of other policy supported projects.

- Disable modelled targets set by the 2025 NSW Infrastructure Investment Objective (IIO) Report and the target to achieve 82% of electricity generation from renewable energy sources under the Commonwealth Government's Powering Australia Plan. These adjustments are made to ensure that this large increase in electricity demand is met by a realistic capacity mix which still observes longer term carbon reduction objectives.

Figure 54: Sensitivity 4a – Comparing data centre demand growth trajectories: Step Change scenario vs Sensitivity 4a (modelled as flat load)



Under the Base Case, network constraints on 330 kV Lines 12, 39, 32, 93 and the Kemps Creek transformers are expected to be materially binding, requiring significant new capacity to be developed in Sydney, Newcastle, and Wollongong and Central NSW to supply the additional demand, primarily comprising 8-hour BESS and offshore wind in Sydney, Newcastle, and Wollongong alongside 8-hour BESS and solar in Central NSW.

The Sydney Ring South Project for options that include scope for a new 500 kV transmission line alleviate this congestion and deliver substantial benefits by avoiding the need to overbuild of storage and high-cost offshore wind that would otherwise be required.

Table 29 shows gross market benefits for the options assessed under this sensitivity. Figure 55 and Figure 56 show the changes in benefits in this sensitivity as compared to the Step Change benefits.

Options 3, 4 and 6, which deliver a high capacity transmission line in 2033-34, yield higher gross market benefits than Option 5 (which delivers the 500 kV transmission line scope in 2037-38), as they relieve congestion on the southern corridor of the Sydney Ring network sooner, reducing the need to build out generation and storage capacity in the interim to meet growing demand. Option 5 is found to deliver approximately $680 million fewer gross market benefits in present value terms ($2024-25) compared with Option 6, which is the top ranked option in this sensitivity.

Table 29: Gross market benefits – Sensitivity 4a ($m, real 30 June 2025 discounted to 30 June 2025)

	Option 3	Option 4	Option 5	Option 6
Gross market benefits	7,951	8,111	7,570	8,253

Figure 55: Change in gross market benefits of Sydney Ring South options – Sensitivity 4a vs Step Change ($m, real 30 June 2025 discounted to 30 June 2025)

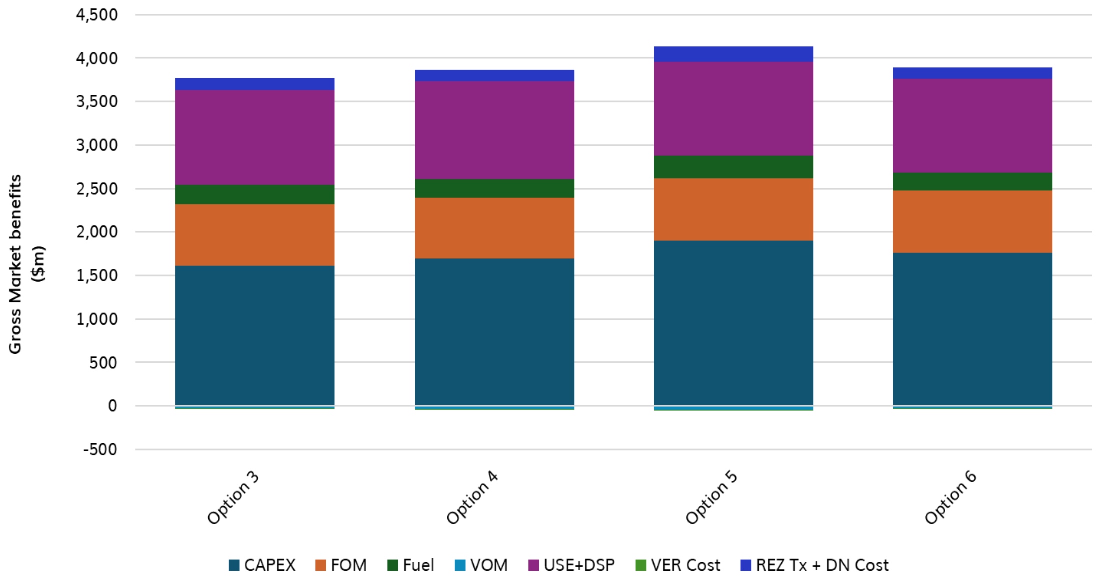
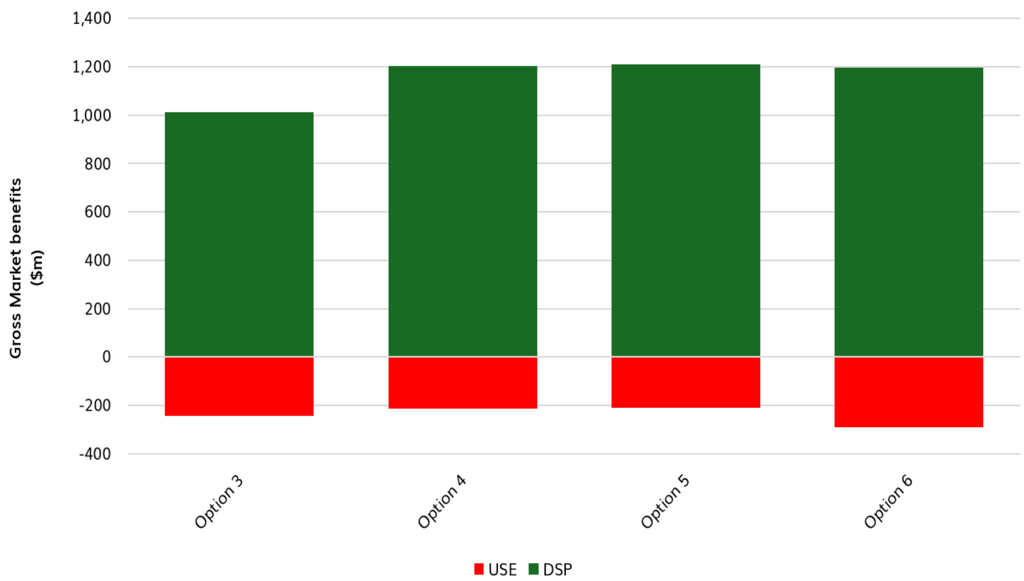


Figure 56: Change in USE and DSP benefits – Sensitivity 4a vs Step Change ($m, real 30 June 2025 discounted to 30 June 2025)

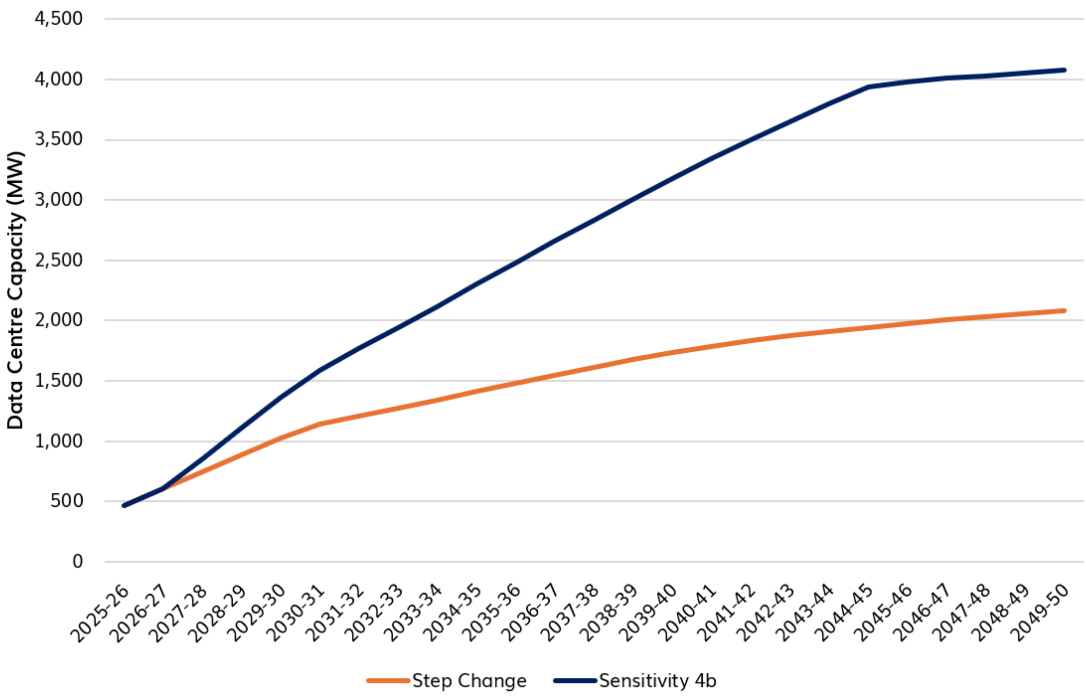


6.4.5 Sensitivity 4b: Very high data centre growth

This sensitivity adds 2 GW of data centre load to the forecast data centre demand modelled in Sydney, Newcastle, and Wollongong under the Step Change scenario in the Draft 2026 ISP. This additional demand is added linearly between 2028 through to 2045 and is modelled with a flat load profile. Figure 57 shows the additional data centre demand growth modelled in this sensitivity relative to a the flat-load profile equivalent of the data centre demand forecast in the 2025 IASR for the Step Change scenario.

Similar to Sensitivity 4a, this sensitivity also includes a range of supply-side adjustments to the inputs and assumptions of the Draft 2026 ISP Step Change scenario to ensure that the additional demand does not overly strain the system, ensuring that the estimated market benefits are based on a realistic development trajectory for the NSW power system.

Figure 57: Comparing data centre demand growth trajectories: Step Change scenario vs Sensitivity 4b



In the Base Case, network constraints on 330 kV Lines 12, 39, 32, 93 and the Kemps Creek transformers are expected to be materially binding (refer to Table 30), requiring significant new capacity to be developed in Sydney, Newcastle, and Wollongong and Central NSW to supply the additional demand, primarily comprising 8-hour BESS and offshore wind in Sydney, Newcastle, and Wollongong alongside 8-hour BESS and solar in Central NSW. The Sydney Ring South Project for options that include scope for a new 500 kV transmission line alleviate this congestion and deliver substantial benefits by avoiding the need to overbuild of storage and high-cost offshore wind that would otherwise be required.

Table 30: Sensitivity 4b – Base Case binding network constraints

Constraint	2026-27 to 2029-30	2030-31 to 2032-33	2033-34 to 2036-37	2037-38 to 2039-40	2040-41 to 2049-50
Avoid overload of 330 kV Line 39 Bannaby to Sydney West on trip of 330 kV Line 17 Avon to Macarthur	0%	53%	57%	26%	19%
Avoid overload of 330 kV Line 30 Liverpool to Sydney South (Reverse) on trip of 330 kV Line 39 Bannaby to Sydney West	0%	0%	13%	27%	24%
Avoid overload of 330 kV Line 8 Avon to Marulan (Reverse) on trip of 330 kV Line 8 Dapto to Marulan 330 kV	0%	2%	3%	1%	2%

Constraint	2026-27 to 2029-30	2030-31 to 2032-33	2033-34 to 2036-37	2037-38 to 2039-40	2040-41 to 2049-50
Avoid overload of 330 kV Line 31 Bayswater to Regentville on trip of 330 kV Line 32 Bayswater to Sydney West	0%	0%	1%	8%	12%
Avoid overload of 330 kV Line 39 Bannaby to Sydney West on trip of 330 kV Line 8 Avon to Marulan	0%	0%	6%	13%	7%
Avoid overload of 330 kV Line 39 Bannaby to Sydney West 330 kV on trip of 330 kV Line 8 Dapto to Marulan	0%	0%	0%	9%	8%
Avoid overload of 330 kV Line 39 Bannaby to Sydney West on trip of NIL	15%	1%	5%	8%	7%
Avoid overload of 330 kV Line 76 Sydney South to Wallerawang (Reverse) on trip of 330 kV Line 77 Ingleburn to Wallerawang	0%	0%	1%	5%	9%
Avoid overload of 330 kV Line 8 Dapto to Marulan (Reverse) on trip of 330 kV Line 8 Avon to Marulan	0%	1%	7%	16%	17%
Avoid overload of 330 kV Line 90 Eraring to Newcastle (Reverse) on trip of 330 kV Line 90 Eraring to Newcastle line 2	0%	0%	0%	0%	6%
Avoid overload of Kemps Creek 500 kV/330 kV Transformer 1 (2L) on trip of Kemps Creek 500 kV/330 kV Transformer 2 (3L)	0%	0%	0%	1%	16%
Avoid overload of Mt Piper 500 kV/330 kV Transformer (2TL) on trip of Mt Piper 500 kV/330 kV Transformer (1TL)	0%	0%	0%	2%	5%

Options 3, 4 and 6, which deliver a high capacity transmission line in 2033-34, yield higher gross market benefits than Option 5 (which delivers the 500 kV transmission line scope in 2037-38), as they relieve congestion on the southern corridor of the Sydney Ring network sooner, reducing the need to build out generation and storage capacity in the interim to meet growing demand.

Table 31 shows the total gross market benefits of the options assessed in this sensitivity, which are found to be greater than in the core scenario, and Figure 58 and Figure 59 shows the relative change in gross market benefits from the Step Change scenario.

Relative to the core Step Change scenario, significantly higher benefits are expected for all options in this sensitivity, mainly driven by higher avoided costs of demand reduction (DSP) when the options are developed. With the modelled assumption that new data centre demand comes with equivalent local demand management mechanisms which could include demand flexibility agreements or local generation and storage, the model has access to a mechanism that avoids the need to overbuild generation capacity, resulting in gross market benefits of over $4 billion in present value terms ($2024-25) for all options that include scope for a 500 kV transmission line.

Table 31: Gross market benefits – Sensitivity 4b ($m, real 30 June 2025 discounted to 30 June 2025)

	Option 3	Option 4	Option 5	Option 6
Gross market benefits	10,392	10,591	9,048	10,825

Figure 58: Change in gross market benefits of Sydney Ring South options – Sensitivity 4b vs Step Change ($m, real 30 June 2025 discounted to 30 June 2025)

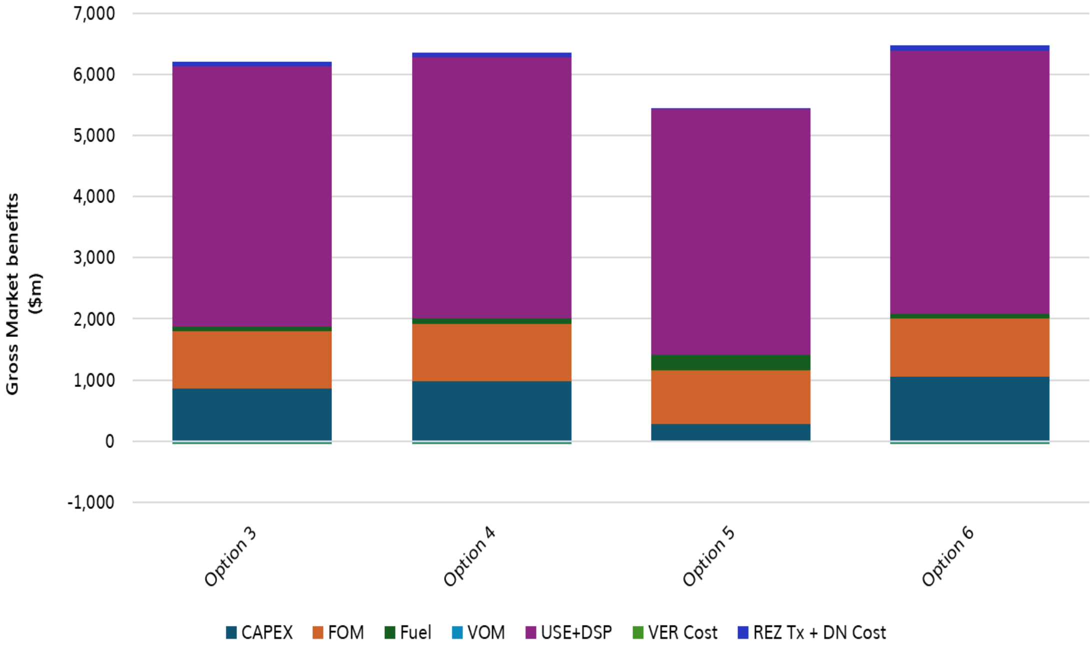
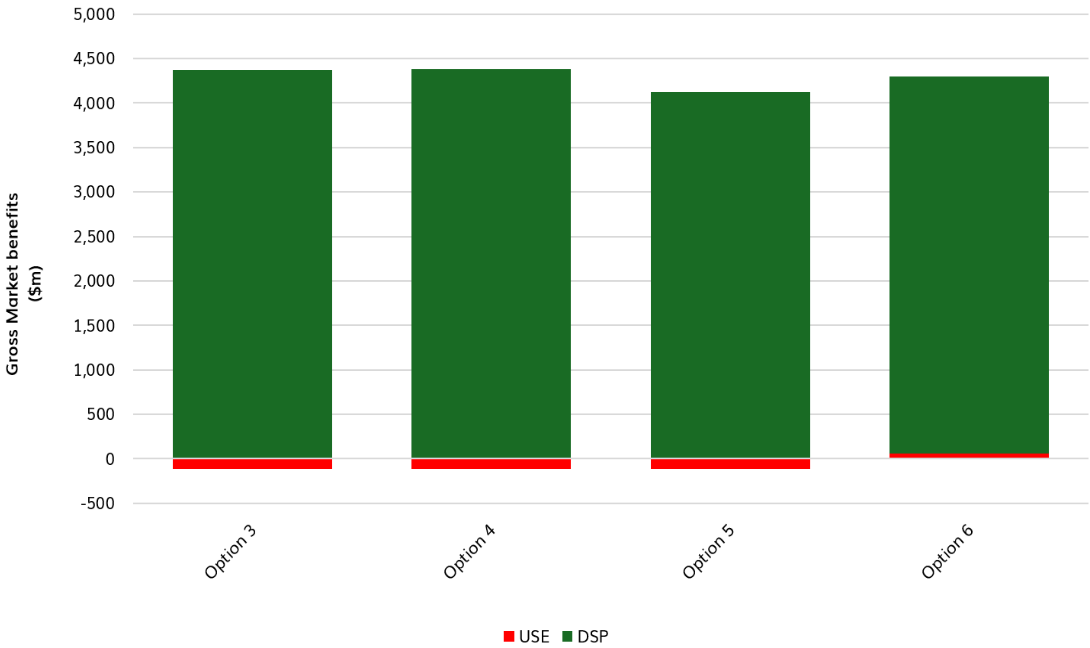


Figure 59: Change in USE and DSP benefits – Sensitivity 4b vs Step Change ($m, real 30 June 2025 discounted to 30 June 2025)



With the development of Option 6, commissioning the 500 kV transmission line in 2033-34 allows nearly 7 GW of wind, solar and utility-scale storage to be deferred through the 2030s and from the late 2030s, displaces offshore wind in Sydney, Newcastle, and Wollongong and utility-scale battery altogether in favour of lower cost onshore wind and solar. Significant DSP benefits related to avoiding costly demand flexibility services also accrue from the late 2030s as data centre demand is curtailed less frequently with a 500 kV transmission line in service.

Figure 60: Sensitivity 4b –NEM capacity - Option 6 vs the Base Case

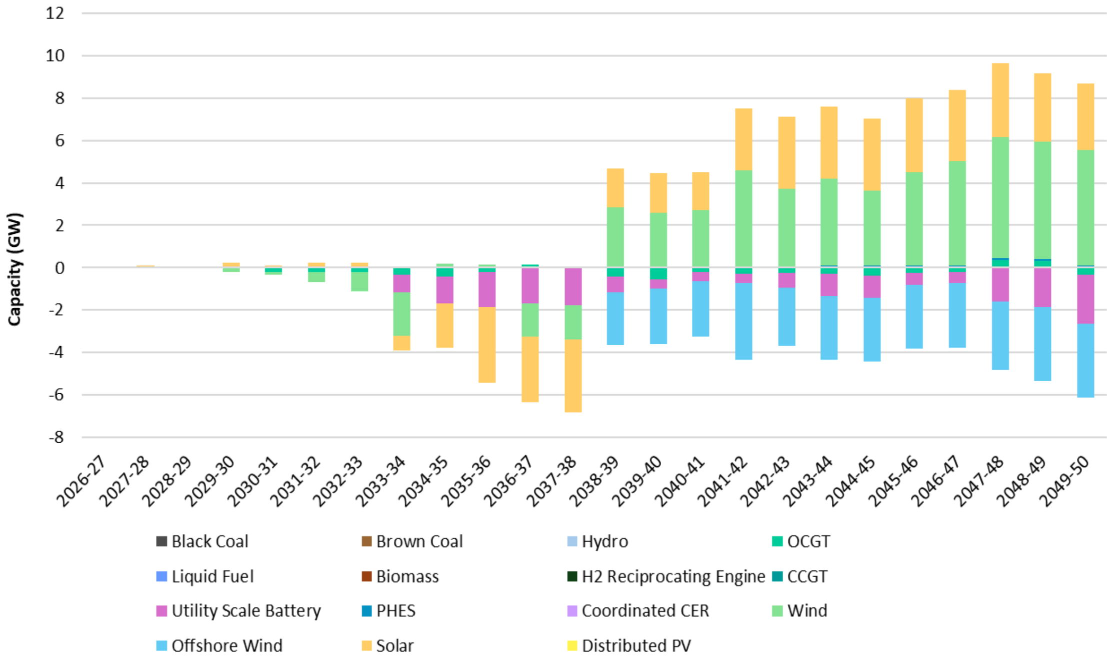
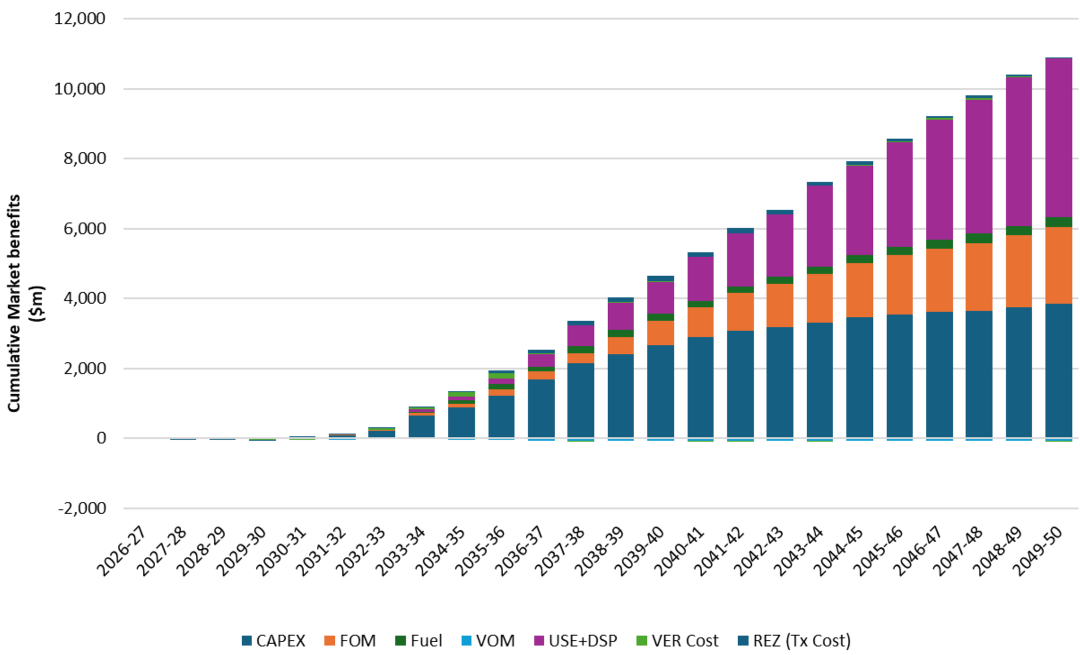


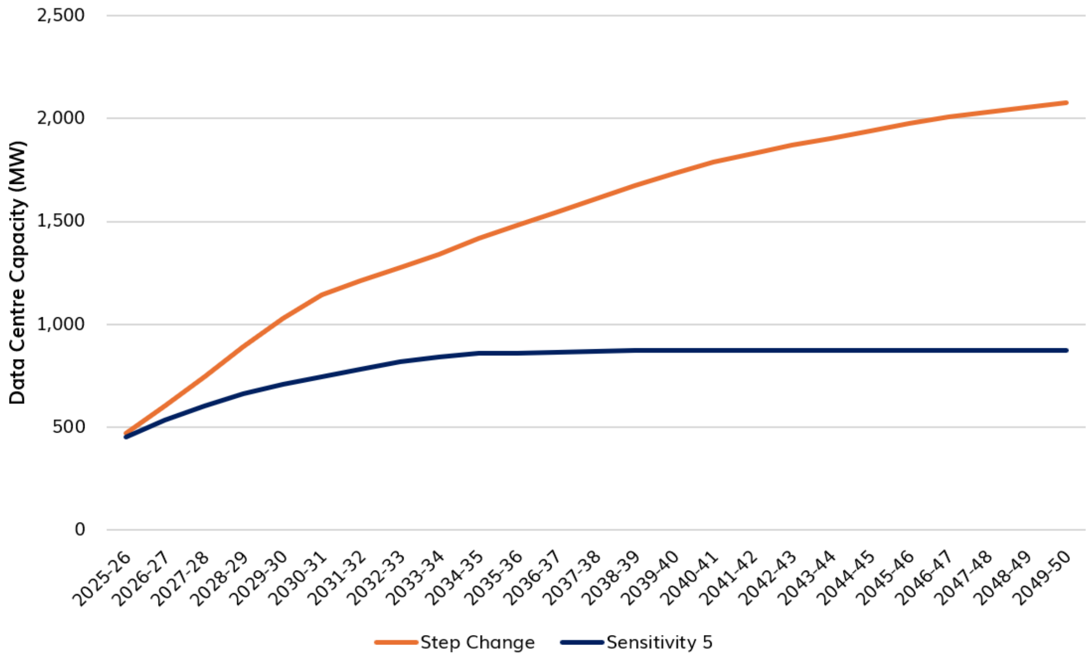
Figure 61: Sensitivity 4b – Option 6 cumulative gross market benefits



6.4.6 Sensitivity 5: Low data centre growth

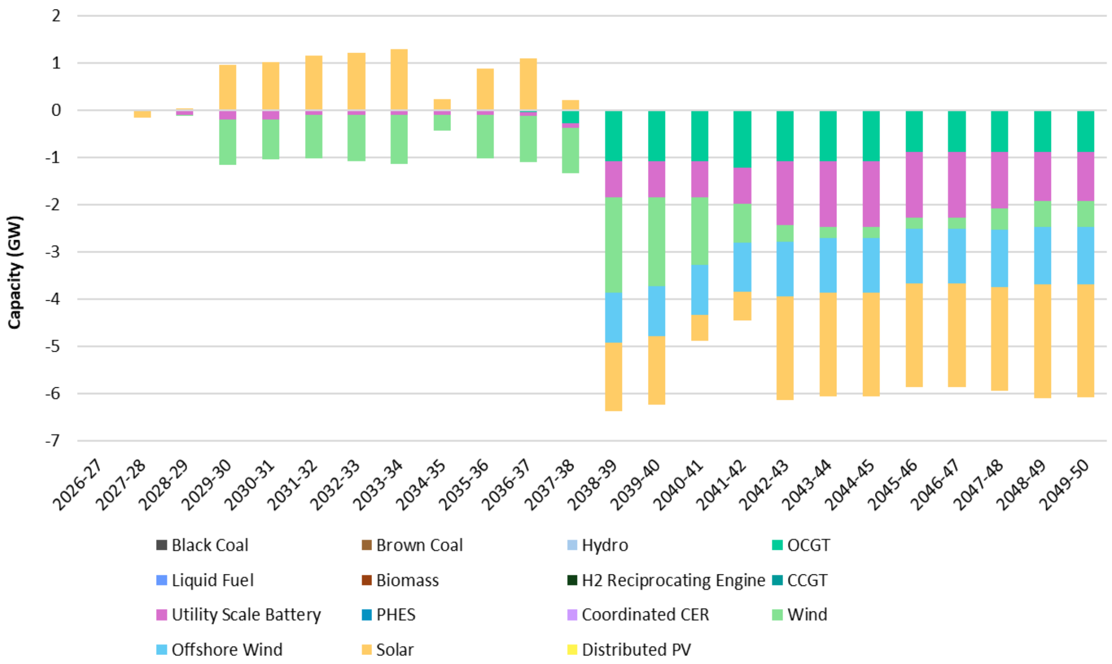
This sensitivity models a scenario where no new data centres are built, and the only growth in data centre electricity demand comes from existing facilities that are already connected to distribution networks, but which have not reached full utilisation. In this case, data centre demand plateaus at approximately 0.9 GW by the late 2030s, compared with the Step Change scenario, where data centre demand in Greater Sydney reaches over 2 GW by the end of the assessment period. Figure 62 shows the data centre demand growth modelled in this sensitivity relative to a the flat-load profile equivalent of the data centre demand forecast in the 2025 IASR for the Step Change scenario.

Figure 62: Sensitivity 5 – Data centre demand modelled in Sensitivity 5, compared to the core Step Change scenario



Under this sensitivity, the lower overall electricity demand in materially reduces need for new generation and storage capacity in the Base Case, both in Sydney, Newcastle and Wollongong, and also more broadly across NSW. Relative to the Base Case in the core Step Change scenario, the Base Case under this sensitivity requires less onshore and offshore wind, gas, battery and solar capacity to be developed across NSW, with the need for offshore wind in the Hunter and Illawarra regions almost completely avoided (refer to Figure 63). As a result, the Sydney Ring South Project options have less scope to deliver major capex savings from avoided or deferred generation and storage investments, translating to lower gross market benefits compared to the core Step Change scenario.

Figure 63: Sensitivity 5 – Base Case NSW capacity difference to the Core Base Case



Under the lower data centre demand sensitivity, the gross market benefits for the options that include scope for a new 500 kV transmission line are lower by a greater margin than those of the standalone power flow control option. This reflects the differing scale of congestion relief each option provides. The power flow control option delivers a more modest level of headroom on the existing network, primarily addressing the highest-value congested hours where redirecting flows across the existing 330 kV network yields the greatest dispatch efficiency gains. These core benefits are relatively robust to changes in demand, as the underlying congestion in the peak hours persists even under lower demand growth.

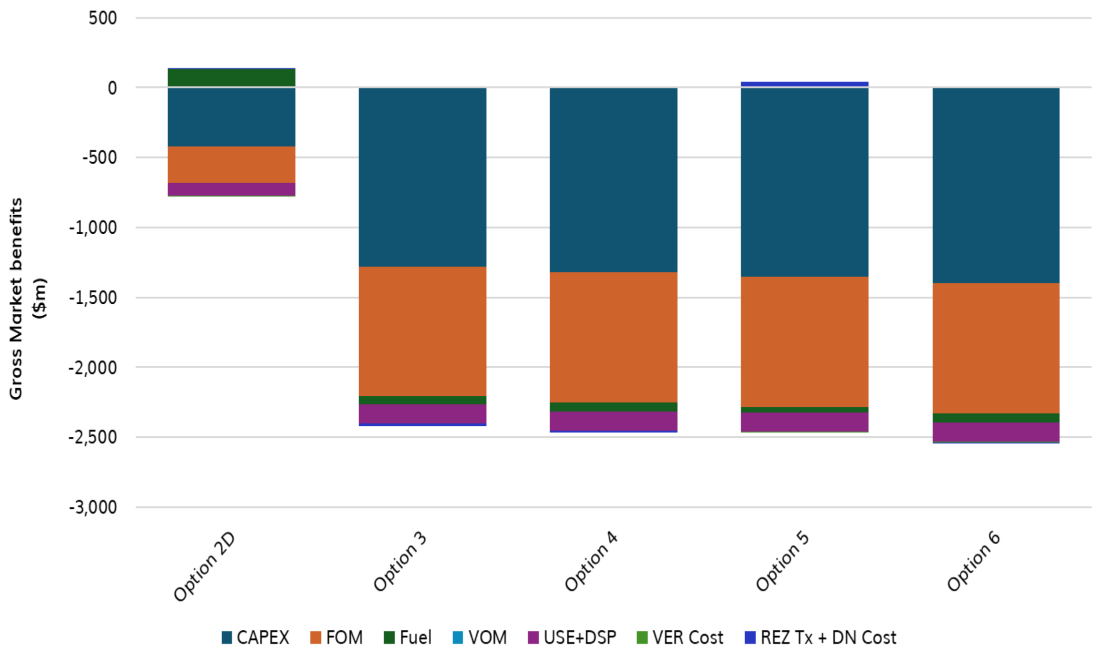
The options that include a new 500 kV transmission line, however, provide a substantially larger increase in transfer capability, which under the core Step Change scenario unlocks additional benefits across a broader range of operating conditions including hours of moderate congestion that the smaller option cannot economically address. Under a lower data centre demand scenario, the frequency and severity of these moderately congested hours reduce, eroding the incremental benefit that a new transmission line captures over the standalone power flow control option. The benefits for the standalone power flow control option are therefore more resilient to the lower demand sensitivity because its value was concentrated in the most heavily congested periods, which remain binding even with reduced data centre demand.

Table 32 shows the total gross market benefits of the options assessed in this sensitivity, which are found to be lower than in the core scenario, and Figure 64 shows the relative change in gross market benefits from the Step Change scenario.

Table 32: Gross market benefits – Low data centre load sensitivity ($m, real 30 June 2025 discounted to 30 June 2025)

	Option 2d	Option 3	Option 4	Option 5	Option 6
Gross market benefits	861	1,797	1,815	1,743	1,859

Figure 64: Change in gross market benefits of Sydney Ring South options – Sensitivity 5 vs core Step Change scenario ($m, real 30 June 2025 discounted to 30 June 2025)



6.4.7 Sensitivity 6: Higher adoption of distributed and consumer energy resources

This sensitivity assesses a scenario where there is higher than forecast uptake of consumer batteries across Sydney, Newcastle, and Wollongong and opportunities to build out small and medium scale solar well in excess of what AEMO forecasts.

In this sensitivity, the distributed solar build limit in Sydney, Newcastle, and Wollongong is increased from 890 MW (per the 2025 IASR for the Step Change scenario) to 6.2 GW, reflecting potential hosting capacity for new renewables in the region reported by the NSW Distribution Network Service Providers (DNSP) in their 2025 Distribution Network System Plan. The modelled allocation of this additional capacity within the broader Sydney, Newcastle and Wollongong region is outlined in Table 33, which is based on an the DNSP level allocations outlined in Table 34. These allocations were determined by Transgrid as a proportionate to the relative size, density and populations of each region.

Table 33: Modelled build limits for new solar generation capacity in the Sydney, Newcastle and Wollongong region, Sensitivity 6 vs Step Change scenario

Region	Sensitivity 6 Build Limit (MW)	Core Step Change Build Limit (MW)
Newcastle	1160	148
Sydney West	4380	638
Dapto	660	104

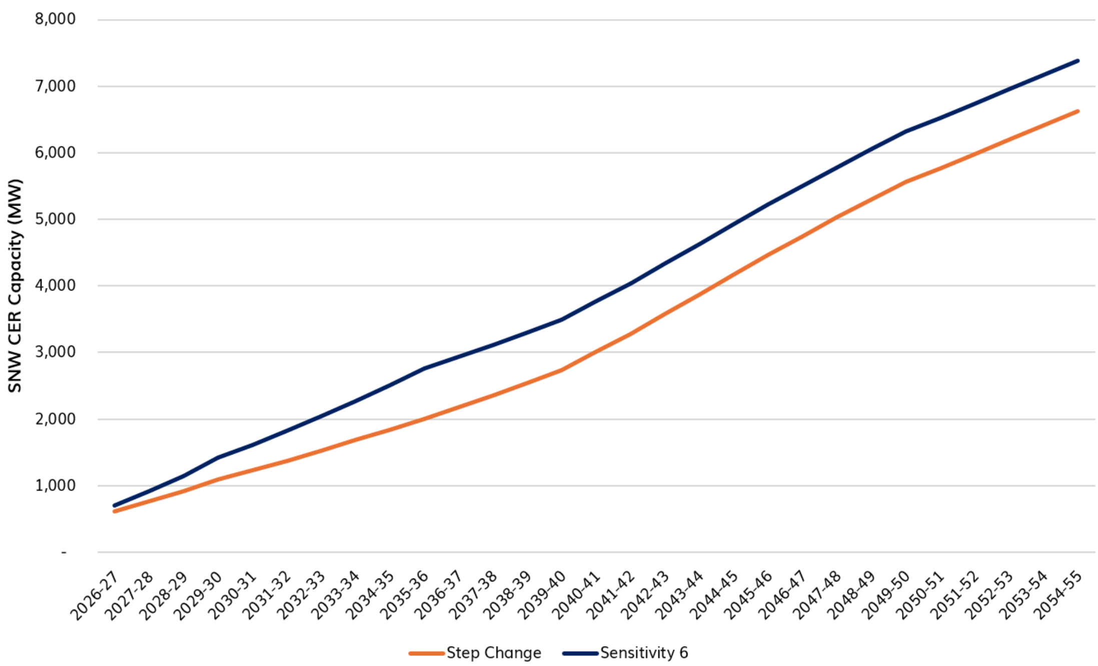
Table 34: Locational allocation of coordinated CER capacity within the distribution networks

DNSP	Allocation
Newcastle	40% Ausgrid hosting capacity

DNSP	Allocation
Sydney West	60% Ausgrid + 80% Endeavour Energy hosting capacity
Dapto	20% Endeavour Energy hosting capacity

Additionally, this sensitivity also models higher uptake of consumer energy resource (CER) storage (aggregated VPP). For this sensitivity, the year-on-year uptake of home batteries is increased approximately 50 per cent for the next 10 years to 2035-36, relative to the AEMO forecast adopted in the Draft 2026 ISP Step Change scenario, which was modelled as a 100% increase to the forecast year-on-year uptake of 'aggregated' (coordinated) embedded energy storage capacity in the Sydney, Newcastle, and Wollongong region. This results in an additional 760 MW (1,490 MWh) of dispatchable behind-the meter storage installed in the Sydney, Newcastle, and Wollongong region by 2035-36, in addition to the forecast 2,000 MW (3,960 MWh) forecast by this date. The CER storage capacity modelled in this sensitivity, relative to the Step Change scenario is shown in Figure 65.

Figure 65: CER storage in the Sydney, Newcastle and Wollongong region modelled in Sensitivity 6, compared to the core Step Change scenario



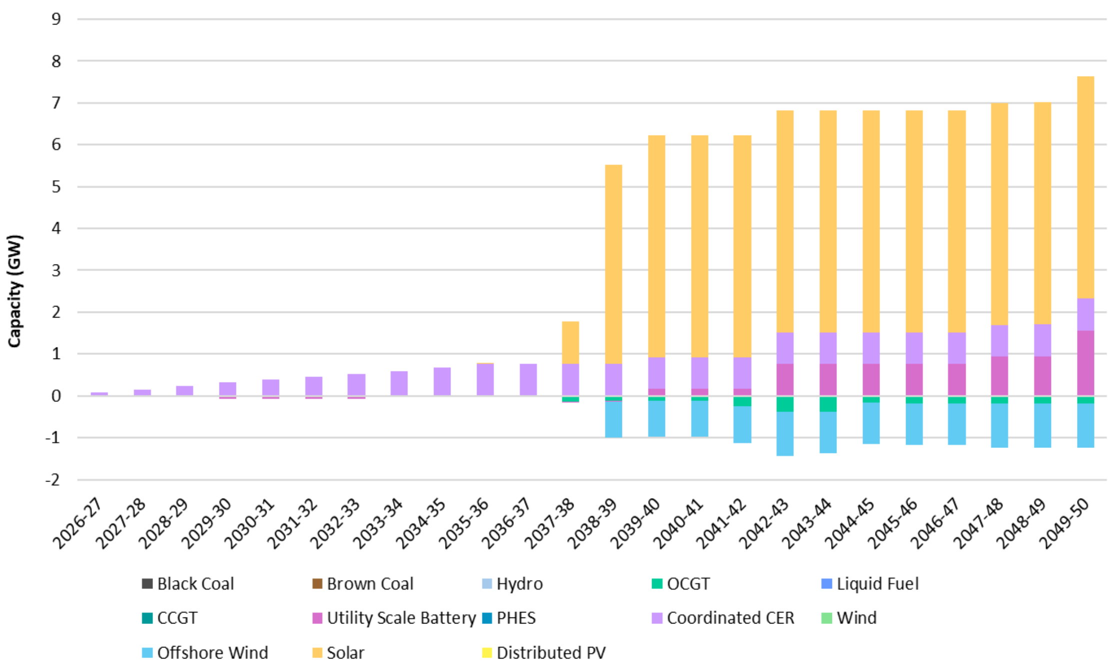
In the Draft 2026 ISP, utility solar and storage capacity connecting to distribution networks (referred to in the IASR as Distributed PV and Distributed BESS) are modelled behind a network constraint representing each DNSP service area. These constraints limit the net generation from these resources. Specifically, the sum of Distributed PV and net Distributed BESS output is capped at a fixed limit for each DNSP region, reflecting the limited capacity of distribution networks to export distributed generation into the transmission network. The Draft 2026 ISP model allows this network limits can be increased at a cost, as set out this IASR workbook, allowing the optimisation to determine if it is economic to do so.

Within the Sydney, Newcastle, and Wollongong region, two separate constraints are applied corresponding to the Ausgrid and Endeavour Energy distribution network areas respectively.

Under this sensitivity, the option to build Distributed PV in the Sydney, Newcastle and Wollongong region is fully utilised in both the Base Case and Option cases, indicating the high value of maximising generation close to demand centres, even when a new 500 kV transmission line is built. In each case, the relevant distribution network constraints for each of the Ausgrid (Distributed PV + Distributed BESS ≤ 3,124 MW) and Endeavour Energy (Distributed PV + Distributed BESS ≤ 6,819 MW) areas do not trigger costs for distribution network augmentations to accommodate the higher capacity build. The Endeavour Energy constraint is not expected to bind, and the Ausgrid constraint would only bind if Distributed BESS was also built by the model, which is unlikely given the alternative transmission-level storage options available in Sydney, Newcastle, and Wollongong.

Relative to the Base Case in the core Step Change scenario, the option to build significantly more solar generation within Sydney, Newcastle and Wollongong, combined with higher and CER storage uptake, reduces the need for offshore wind generation capacity. The results also show that the additional solar capacity in Sydney, Newcastle, and Wollongong promotes the need for complementary 8-hour battery in Sydney, Newcastle, and Wollongong, which was otherwise built in Central NSW in the core Step Change scenario. Figure 66 shows the change in generation and storage capacity in the Sydney, Newcastle and Wollongong region for the Base Case under this sensitivity, compared to the core Step Change scenario results.

Figure 66: Sydney, Newcastle, and Wollongong capacity - Sensitivity 6 Base Case vs the Core Base Case



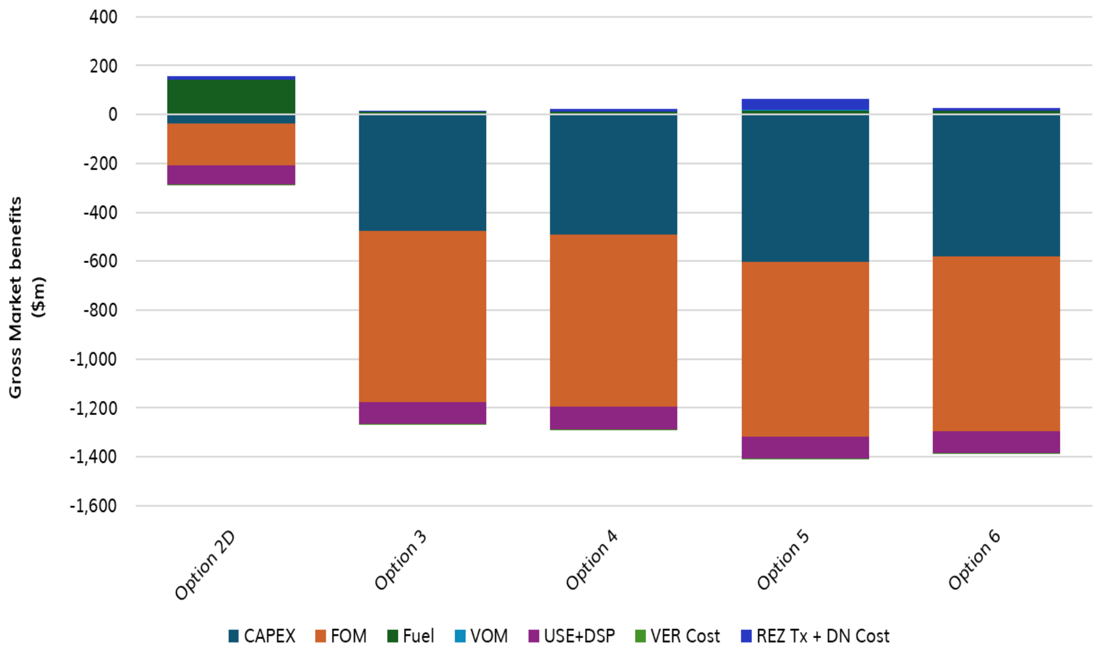
The Sydney Ring South Project options assessed for this sensitivity follow a similar pattern of benefits to those seen for the core Step Change scenario but at a reduced scale, largely reflecting the lower offshore wind capacity build in the Base Case. Relative to the gross market benefits estimated for the core Step Change scenario, benefits for the options that include scope for a new 500 kV transmission reduce more materially than the benefits for the standalone power flow control option (Option 2d), as their benefits include the cost savings from avoiding offshore wind developed, an opportunity that is more limited under this sensitivity, whereas benefits for Option 2d relied less on this factor to begin with.

Table 35 shows the total gross market benefits of the options assessed in this sensitivity, which are found to be lower than in the core scenario, and Figure 67 shows the relative change in gross market benefits from the Step Change scenario.

Table 35: Gross market benefits – Sensitivity 7 ($m, real 30 June 2025 discounted to 30 June 2025)

	Option 2d	Option 3	Option 4	Option 5	Option 6
Gross market benefits	1,362	2,961	3,009	2,816	3,031

Figure 67: Change in gross market benefits of Sydney Ring South options – Sensitivity 7 vs Step Change ($m, real 30 June 2025 discounted to 30 June 2025)



6.4.8 Sensitivity 7: Negligible non-zero variable cost for renewable generation and storage

As set out in the 2025 IASR, the Draft 2026 ISP applies a variable operating and maintenance (VOM) cost of $0/MWh for VRE generation and battery storage. For the purposes of this assessment, a small positive VOM cost of $0.10/MWh has been applied to these technologies to improve the numerical stability of the optimisation. A sensitivity has been undertaken to confirm that adopting this non-standard modelling parameter has not materially affected the gross benefits or the ranking of credible options assessed for the Sydney Ring South PADR.

With zero variable cost for renewable generation and storage, the numerical optimisation problem becomes highly degenerate, meaning that many dispatch solutions yield equivalent objective function values because generating, storing, or cycling energy carries no economic penalty. In this state, the solver may arbitrarily cycle energy between storage assets or shift energy spatially and temporally without any cost signal to discourage it. When detailed network constraint equations are included - as in this assessment - degenerate dispatch can be used to satisfy constraints in ways that are mathematically valid but not physically or economically realistic representations of power system operation.

Introducing a small positive VOM cost breaks degeneracy in the objective function, ensures that dispatch decisions reflect genuine economic merit, and produces more stable and interpretable outcomes. The $0.10/MWh value is sufficiently small to remain immaterial relative to the marginal cost of alternative higher cost generation (such as coal and gas fired generation) while being large enough to discipline the solver.

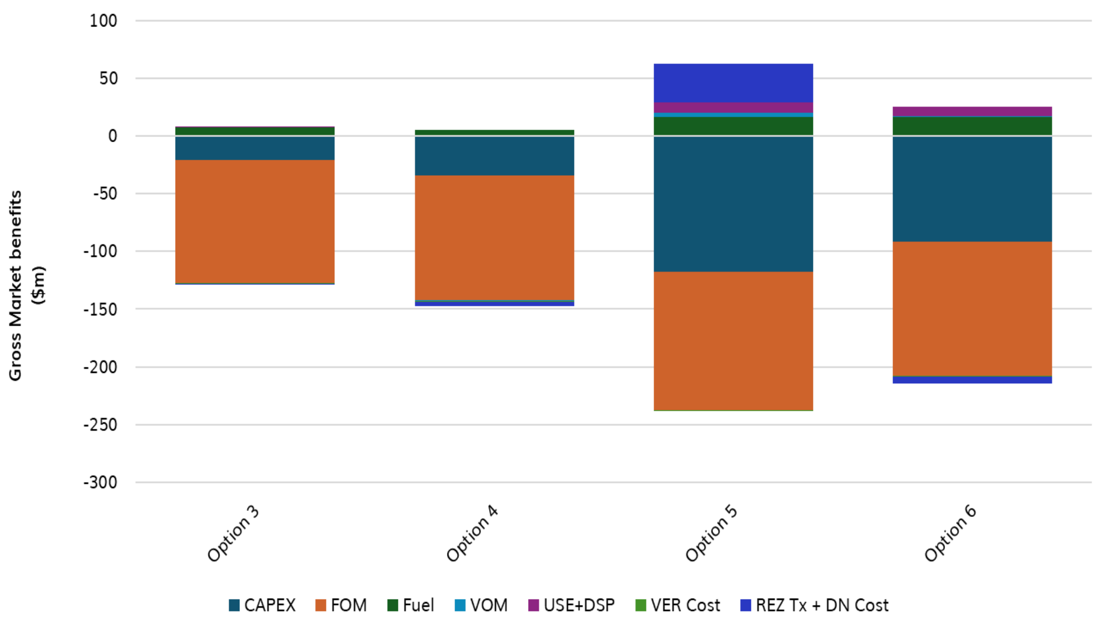
The application of a $0.10/MWh VOM cost to VRE, and storage is found to have no material impact on the gross benefits or the ranking of credible options. Where small differences in gross benefits do arise, they reflect the removal of degenerate dispatch behaviour rather than the new cost that was introduced - that is, the adjustment ensures gross benefits are derived from economically realistic dispatch outcomes.

Table 36 shows the total gross market benefits of the options assessed in this sensitivity, which are found to be marginally lower than in the core scenario, and Figure 68 shows the relative change in gross market benefits from the Step Change scenario.

Table 36: Gross market benefits under Sensitivity 7 ($ millions, real 30 June 2025 discounted to 30 June 2025)

	Option 3	Option 4	Option 5	Option 6
Gross market benefits	4,091	4,134	3,987	4,202

Figure 68: Change in gross market benefits of Sydney Ring South options - Sensitivity 7 relative to the Step Change scenario ($m, real 30 June 2025 discounted to 30 June 2025)



Appendix A Network constraints

Table 37 lists the detailed network constraints modelled to represent the Sydney Ring network in the Base Case for the Sydney Ring South PADR.

Table 37: Detailed network constraints modelled to represent the Sydney Ring network in Base Case

Constraint	Description
N >> 11_17	To avoid overload of 330 kV Line 11 Dapto to Sydney South on trip of 330 kV Line 17 Avon to Macarthur
N >> 12_14_R	To avoid overload of 330 kV Line 12 Liverpool to Sydney South (Reverse) on trip of 330 kV Line 14 Kemps Creek to Sydney North
N >> 12_39_R	To avoid overload of 330 kV Line 12 Liverpool to Sydney South (Reverse) on trip of 330 kV Line 39 Bannaby to Sydney West
N >> 16_8_R	To avoid overload of 330 kV Line 16 Avon to Marulan 330 kV (Reverse) on trip of 330 kV Line 8 Dapto to Marulan
N >> 17_11	To avoid overload of 330 kV Line 17 Avon to Macarthur on trip of 330 kV Line 11 Dapto to Sydney South
N >> 18_5_R	To avoid overload of 330 kV Line 18 Dapto to Kangaroo Valley 330 kV (Reverse) on trip of 330 kV Line 5 Marulan to Yass
N >> 31_32	To avoid overload of 330 kV Line 31 Bayswater to Regentville on trip of 330 kV Line 32 Bayswater to Sydney West
N >> 32_31	To avoid overload of 330 kV Line 32 Bayswater to Sydney West 330 kV on trip of 330 kV Line 31 Bayswater to Regentville
N >> 39_11	To avoid overload of 330 kV Line 39 Bannaby to Sydney West on trip of 330 kV Line 11 Dapto to Sydney South
N >> 39_16	To avoid overload of 330 kV Line 39 Bannaby to Sydney Weston trip of 330 kV Line 16 Avon to Marulan
N >> 39_17	To avoid overload of 330 kV Line 39 Bannaby to Sydney Weston trip of 330 kV Line 17 Avon to Macarthur
N >> 39_3W	To avoid overload of 330 kV Line 39 Bannaby to Sydney Weston trip of 330 kV Line 3W Capital to Kangaroo Valley 330 kV
N >> 39_5A6	To avoid overload of 330 kV Line 39 Bannaby to Sydney West on trip of 500 kV Line 5A6 Bannaby to Mt Piper 500 kV line 1
N >> 39_8	To avoid overload of 330 kV Line 39 Bannaby to Sydney Weston trip of 330 kV Line 8 Dapto to Marulan 330 kV
N >> 39_NIL	To avoid overload of 330 kV Line 39 Bannaby to Sydney Weston trip of NIL
N >> 5A5_5P1	To avoid overload of 500 kV Line 5A5 Barigan Creek to Wollar on trip of 500 kV Line 5P1 Barigan Creek to Mt Piper
N >> 5H5_5H6	To avoid overload of 500 kV Line 5H5 Bayswater to Olney line 1 on trip of 500 kV Line 5H6 Bayswater to Olney line 2
N >> 5P1_5A5	To avoid overload of 500 kV Line 5P1 Barigan Creek to Wollar on trip of 500 kV Line 5A5 Barigan Creek to Mt Piper
N >> 5P1_5P2	To avoid overload of 500 kV Line 5P1 Barigan Creek to Mt Piper line 2 on trip of 500 kV Line 5P2 Barigan Creek to Mt Piper line 1

Constraint	Description
N >> 76_77_R	To avoid overload of 330 kV Line 76 Sydney South to Wallerawang (Reverse) on trip of 330 kV Line 77 Ingleburn to Wallerawang
N >> 8_16_R	To avoid overload of 330 kV Line 8 Dapto to Marulan (Reverse) on trip of 330 kV Line 16 Avon to Marulan
N >> 81_82	To avoid overload of 330 kV Line 81 Liddell to Newcastle on trip of 330 kV Line 82 Liddell to Tomago
N >> 82_81	To avoid overload of 330 kV Line 82 Liddell to Tomago on trip of 330 kV Line 81 Liddell to Newcastle
N >> 93_90_R	To avoid overload of 330 kV Line 93 Eraring to Newcastle (Reverse) on trip of 330 kV Line 90 Eraring to Newcastle line 2
N >> KEMPS_CK_2H1_2_KEMPS_CK_3H1_2	To avoid overload of Kemps Creek 500 kV/330 kV Transformer 1 (2L) on trip of Kemps Creek 500 kV/330 kV Transformer 2 (3L)
N >> MT_PIPER_2TH1_2_MT_PIPER_1TH1_2	To avoid overload of Mt Piper 500 kV/330 kV Transformer (2TL) on trip of Mt Piper 500 kV/330 kV Transformer (1TL)

Table 38 shows all constraints modelled in options that include scope for a new 500 kV transmission line.

Table 38: Constraints modelled for options that include scope for a new 500 kV transmission li

Constraint	Description
N >> 11_17	To avoid overload of 330 kV Line 11 Dapto to Sydney South on trip of 330 kV Line 17 Avon to Macarthur
N >> 11_BAN_SCRK_1	To avoid overload of 330 kV Line 11 Dapto to Sydney South on trip of 500 kV Line BAN_SCRK_1 Bannaby to South Creek
N >> 12_14_R	To avoid overload of 330 kV Line 12 Liverpool to Sydney South (Reverse) on trip of 330 kV Line 14 Kemps Creek to Sydney North
N >> 12_39-1_R	To avoid overload of 330 kV Line 12 Liverpool to Sydney South (Reverse) on trip of 330 kV Line 39-1 Bannaby to Sydney West
N >> 12_39/1_R	To avoid overload of 330 kV Line 12 Liverpool to Sydney South (Reverse) on trip of 330 kV Line 39/1 Bannaby to Sydney West (post augmentation)
N >> 12_BAN_SCRK_1_R	To avoid overload of 330 kV Line 12 Liverpool to Sydney South (Reverse) on trip of 500 kV Line BAN_SCRK_1 Bannaby to South Creek
N >> 16_8_R	To avoid overload of 330 kV Line 16 Avon to Marulan (Reverse) on trip of 330 kV Line 8 Dapto to Marulan
N >> 16_BAN_SCRK_1_R	To avoid overload of 330 kV Line 16 Avon to Marulan (Reverse) on trip of 500 kV Line BAN_SCRK_1 Bannaby to South Creek
N >> 17_11	To avoid overload of 330 kV Line 17 Avon to Macarthur on trip of 330 kV Line 11 Dapto to Sydney South
N >> 17_BAN_SCRK_1	To avoid overload of 330 kV Line 17 Avon to Macarthur on trip of 500 kV Line BAN_SCRK_1 Bannaby to South Creek
N >> 18_5	To avoid overload of 330 kV Line 18 Dapto to Kangaroo Valley on trip of 330 kV Line 5 Marulan to Yass
N >> 18_5_R	To avoid overload of 330 kV Line 18 Dapto to Kangaroo Valley (Reverse) on trip of 330 kV Line 5 Marulan to Yass
N >> 31_32	To avoid overload of 330 kV Line 31 Bayswater to Regentville on trip of 330 kV Line 32 Bayswater to Sydney West
N >> 32_31	To avoid overload of 330 kV Line 32 Bayswater to Sydney West on trip of 330 kV Line 31 Bayswater to Regentville

Constraint	Description
N >> 32/2_31	To avoid overload of 330 kV Line 32/2 Bayswater to South Creek on trip of 330 kV Line 31 Bayswater to Regentville
N >> 32/2_38/2	To avoid overload of 330 kV Line 32/2 Bayswater to South Creek on trip of 330 kV Line 38/2 Regentville to South Creek
N >> 38/1_32/1_R	To avoid overload of 330 kV Line 38/1 Sydney West to South Creek (Reverse) on trip of 330 kV Line 32/1 Sydney West to South Creek
N >> 38/2_32/2	To avoid overload of 330 kV Line 38/2 Regentville to South Creek on trip of 330 kV Line 32/2 Bayswater to South Creek
N >> 39-1_11	To avoid overload of 330 kV Line 39-1 Bannaby to Sydney West on trip of 330 kV Line 11 Dapto to Sydney South
N >> 39-1_16	To avoid overload of 330 kV Line 39-1 Bannaby to Sydney West on trip of 330 kV Line 16 Avon to Marulan
N >> 39-1_17	To avoid overload of 330 kV Line 39-1 Bannaby to Sydney West on trip of 330 kV Line 17 Avon to Macarthur
N >> 39-1_3W	To avoid overload of 330 kV Line 39-1 Bannaby to Sydney West on trip of 330 kV Line 3W Capital to Kangaroo Valley
N >> 39-1_5A6	To avoid overload of 330 kV Line 39-1 Bannaby to Sydney West on trip of 500 kV Line 5A6 Bannaby to Mt Piper 500 kV
N >> 39-1_8	To avoid overload of 330 kV Line 39-1 Bannaby to Sydney West on trip of 330 kV Line 8 Dapto to Marulan
N >> 39-1_NIL	To avoid overload of 330 kV Line 39-1 Bannaby to Sydney West on trip of NIL
N >> 39/1_11	To avoid overload of 330 kV Line 39/1 Bannaby to South Creek on trip of 330 kV Line 11 Dapto to Sydney South
N >> 39/1_16	To avoid overload of 330 kV Line 39/1 Bannaby to South Creek on trip of 330 kV Line 16 Avon to Marulan
N >> 39/1_17	To avoid overload of 330 kV Line 39/1 Bannaby to South Creek on trip of Avon to Macarthur
N >> 39/1_5A6	To avoid overload of 330 kV Line 39/1 Bannaby to South Creek on trip of 500 kV line 5A6 Bannaby to Mt Piper 500 kV line 1
N >> 39/1_8	To avoid overload of 330 kV Line 39/1 Bannaby to South Creek on trip of Dapto to Marulan
N >> 39/1_BAN_SCRK_1	To avoid overload of 330 kV Line 39/1 Bannaby to South Creek on trip of 500 kV Line BAN_SCRK_1 Bannaby to South Creek 500 kV line 1
N >> 39/1_NIL	To avoid overload of 330 kV Line 39/1 Bannaby to South Creek on trip of NIL
N >> 5A5_5P1	To avoid overload of 500 kV Line 5A5 Barrigan Creek to Wollar 500 kV on trip of 500 kV Line 5P1 Barrigan Creek to Mt Piper 500 kV
N >> 5H5_5P1	To avoid overload of 500 kV Line 5H5 Bayswater to Olney 500 kV line 1 on trip of 500 kV Line 5P1 Barrigan Creek to Mt Piper 500 kV
N >> 5P1_5A5	To avoid overload of 500 kV Line 5P1 Barrigan Creek to Mt Piper 500 kV on trip of 500 kV Line 5A5 Barrigan Creek to Wollar 500 kV
N >> 5P1_5P2	To avoid overload of 500 kV Line 5P1 Barrigan Creek to Mt Piper 500 kV on trip of 500 kV Line 5P2 Barrigan Creek to Mt Piper 500 kV line 2
N >> 76_77_R	To avoid overload of 330 kV Line 76 Sydney South to Wallerawang (Reverse) on trip of 330 kV Line 77 Ingleburn to Wallerawang
N >> 76_BAN_SCRK_1_R	To avoid overload of 330 kV Line 76 Sydney South to Wallerawang (Reverse) on trip of 500 kV Line BAN_SCRK_1 Bannaby to South Creek
N >> 8_16_R	To avoid overload of 330 kV Line 8 Dapto to Marulan (Reverse) on trip of 330 kV Line 16 Avon to Marulan 330 kV
N >> 8_BAN_SCRK_1_R	To avoid overload of 330 kV Line 8 Dapto to Marulan (Reverse) on trip of 500 kV Line BAN_SCRK_1 Bannaby to South Creek
N >> 81_82	To avoid overload of 330 kV Line 81 Bayswater to Newcastle on trip of 330 kV Line 82 Liddell to Tomago
N >> 81-0_82	To avoid overload of 330 kV Line 81-0 Liddell to Newcastle on trip of 330 kV Line 82 Liddell to Tomago

Constraint	Description
N >> 82_81	To avoid overload of 330 kV Line 82 Liddell to Tomago on trip of 330 kV Line 81 Bayswater to Newcastle 330 kV
N >> 82_81-0	To avoid overload of 330 kV Line 82 Liddell to Tomago on trip of 330 kV Line 81-0 Liddell to Newcastle
N >> 93_90_R	To avoid overload of 330 kV Line 93 Eraring to Newcastle line 1 (Reverse) on trip of 330 kV Line 90 Eraring to Newcastle line 2
N >> BAN_SCRK_1_11	To avoid overload of 500 kV Line BAN_SCRK_1 Bannaby to South Creek on trip of 330 kV Line 11 Dapto to Sydney South
N >> BAN_SCRK_1_16	To avoid overload of 500 kV Line BAN_SCRK_1 Bannaby to South Creek on trip of 330 kV Line 16 Avon to Marulan
N >> BAN_SCRK_1_17	To avoid overload of 500 kV Line BAN_SCRK_1 Bannaby to South Creek on trip of 330 kV Line 17 Avon to Macarthur
N >> BAN_SCRK_1_5A6	To avoid overload of 500 kV Line BAN_SCRK_1 Bannaby to South Creek on trip of 500 kV Line 5A6 Bannaby to Mt Piper line 1
N >> BAN_SCRK_1_8	To avoid overload of 500 kV Line BAN_SCRK_1 Bannaby to South Creek on trip of 330 kV Line 8 Dapto to Marulan
N >> BAN_SCRK_1_BAN_SCRK_2	To avoid overload of 500 kV Line BAN_SCRK_1 Bannaby to South Creek line 1 on trip of 500 kV Line BAN_SCRK_2 Bannaby to South Creek line 2
N >> BANNABY_1TH1_2_BAN_SCRK_1	To avoid overload of Bannaby 500 kV/330 kV Transformer on trip of 500 kV Line BAN_SCRK_2 Bannaby to South Creek
N >> KEMPS_CK_2H1_2_KEMPS_CK_3H1_2	To avoid overload of Kemps Creek 500 kV/330 kV Transformer 2 (Tx2) on trip of Kemps Creek 500 kV/330 kV Transformer 3 (Tx3)
N >> MT_PIPER_2TH1_2_BAN_SCRK_1	To avoid overload of Mt Piper 500 kV/330 kV Transformer (Tx2) on trip of 500 kV Line BAN_SCRK_1 Bannaby to South Creek
N >> MT_PIPER_2TH1_2_MT_PIPER_1TH1_2	To avoid overload of Mt Piper 500 kV/330 kV Transformer 2 (Tx2) on trip of Mt Piper 500 kV/330 kV Transformer 1(Tx1)
N >> SCRK_1TH1_2_SCRK_2TH1_2_R	To avoid overload of South Creek 500 kV/330 kV Transformer (Tx1) (Reverse) on trip of South Creek 500 kV/330 kV Transformer (Tx2)

Appendix B Abbreviations

Table 39: Abbreviations

Abbreviation	Meaning
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
BESS	Battery Energy Storage System
CBA	Cost Benefit Analysis
CER	Consumer Energy Resources
CIS	Capacity Investment Scheme
CNSW	Central New South Wales
CO2-e	Carbon dioxide equivalent
CWO	Central-West Orana
DNSP	Distribution Network Service Provider
DP	Development Path
DSP	Demand Side Participation
ECGM	East Coast Gas Market
EIR	Energy Infrastructure Roadmap
ENOR	Electricity Network Options Report
FOM	Fixed Operating and Maintenance
GSOO	Gas Statement of Opportunities
GW	Gigawatt
GWh	Gigawatt-hour
HCC	Hunter-Central Coast
HTP	Hunter Transmission Project
IASR	Inputs, Assumptions and Scenarios Report
IIO	Infrastructure Investment Objective
ISP	Integrated System Plan
kV	Kilovolt
LT	Long-term
LTESA	Long-Term Energy Service Agreement
Mt	Million tonnes
MWh	Megawatt-hour
MW	Megawatt
NE	New England
NEM	National Electricity Market
NER	National Electricity Rules
N-0	Normal operating condition
N-1	Single contingency condition

Abbreviation	Meaning
NNSW	Northern New South Wales
NSW	New South Wales
OCGT	Open Cycle Gas Turbine
ODP	Optimal Development Path
PADR	Project Assessment Draft Report
PEC	Project EnergyConnect
POE10	Probability of Exceedance 10%
PV	Photovoltaic
QLD	Queensland
QNI	Queensland–New South Wales Interconnector
QNI Connect	Queensland–New South Wales Interconnector Connect
REZ	Renewable Energy Zone
RIT-T	Regulatory Investment Test for Transmission
SA	South Australia
SIPS	System Integrity Protection Scheme
SNSW	Southern New South Wales
SNW	Sydney, Newcastle and Wollongong
SRET	South Australian Renewable Energy Target
SRS	Sydney Ring South
SSLT	Single Stage Long-Term
TAS	Tasmania
TRET	Tasmanian Renewable Energy Target
USE	Unserved Energy
V2G	Vehicle-to-Grid
VCR	Value of Customer Reliability
VER	Value of Emissions Reduction
VIC	Victoria
VNI	Victoria–New South Wales Interconnector
VNI West	Victoria–New South Wales Interconnector West
VOM	Variable Operating and Maintenance
VOWT	Victorian Offshore Wind Target
VPP	Virtual Power Plant
VRE	Variable Renewable Energy
VRET	Victorian Renewable Energy Target
WOO	Wollongong OCGT