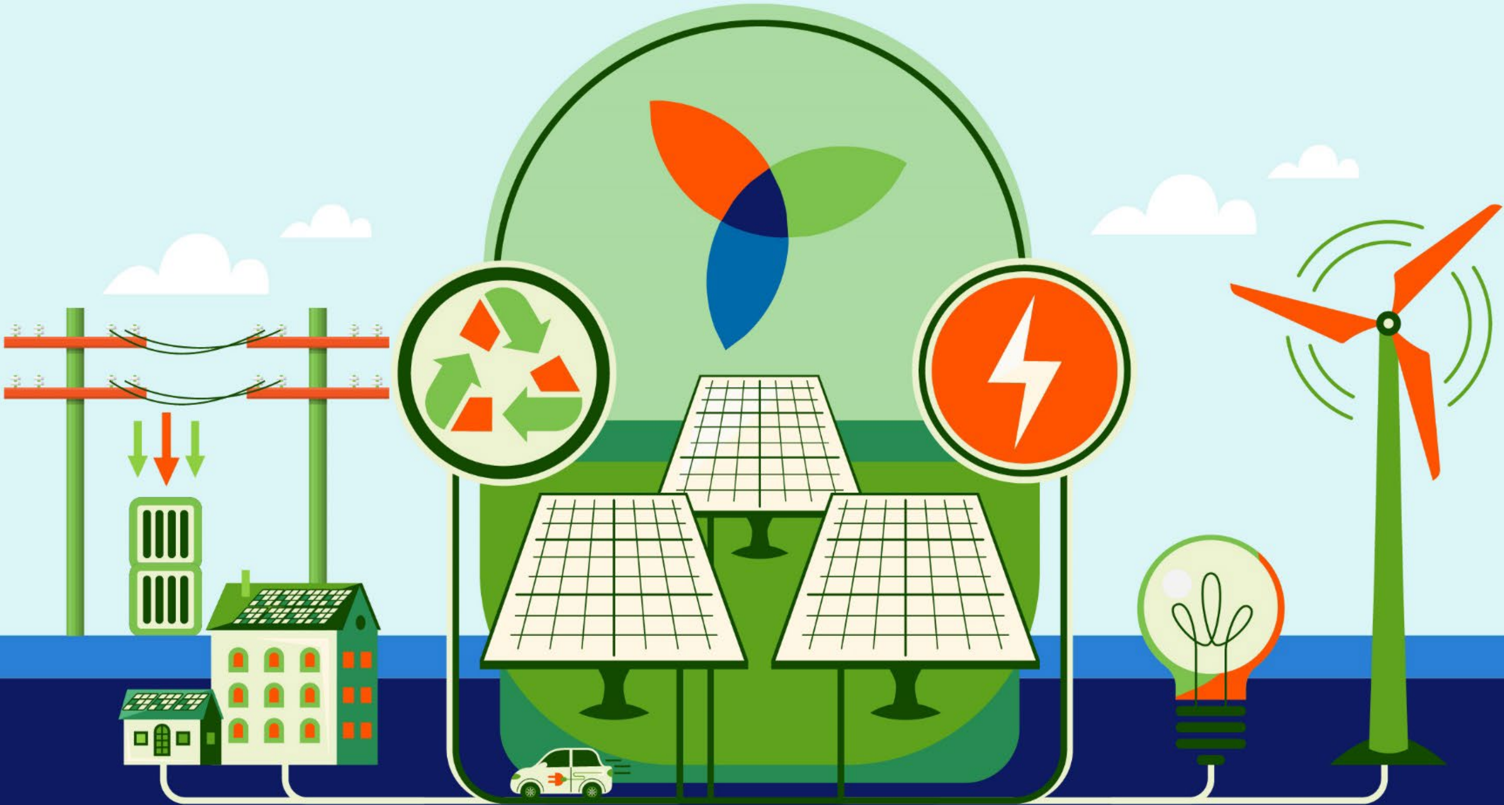
Ausgrid Endeavour Energy Essential Energy

Distribution System Plan

Opportunities Report



November 2025

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Executive Summary

The Distribution System Plan (DSP) Opportunities Report is a landmark, Australia-first roadmap that outlines the value that distribution networks can deliver to support Australia's energy transition. The three distribution businesses serving New South Wales (NSW) – Ausgrid, Endeavour Energy and Essential Energy – have come together to understand the value of unlocking opportunities across the NSW distribution network. This report outlines the opportunities and actions to de-risk the transition to renewable energy and improve customer participation in the energy system, while reducing cost pressure for households and businesses.

Challenges and opportunities

The energy transition in NSW faces increasing and interconnected challenges, which are exacerbated by a fragmented approach to long-term system planning that does not adequately consider the end-to-end system.

- At the low voltage level, the rapid uptake of Consumer Energy Resources (CER) provides opportunities to lower system costs for all electricity customers, not just those that can afford CER. However, challenges relating to CER forecasting and understanding customer behaviour complicate its integration into strategic planning. This is compounded by market structures that do not incentivise coordination of CER, deployment of community batteries and the co-location of load and generation within commercial and industrial (C&I) precincts in a way that benefits the broader system.
- In the sub-transmission network, there is latent capacity that can be leveraged to support a lower-cost and more efficient transition. However, existing strategic planning overlooks the role of the sub-transmission network, missing opportunities to rapidly unlock utility-scale generation and Battery Energy Storage Systems (BESS).
- At the transmission-level, delays, cost and social licence challenges have the potential to put at risk the state's ability to deliver sufficient replacement capacity prior to the closure of coal-fired generators.

These challenges underscore the need to integrate distribution networks (both the sub-transmission network, and medium and low-voltage distribution network) into system-wide planning and enable anticipatory distribution-level investments, recognising their critical role in supporting customers through the energy transition.

A new approach is required

The importance of integrating the distribution network opportunities and challenges into the strategic planning process is now widely recognised by policymakers and industry. The recent NSW Government's Transmission Planning Review Final Report highlights that planning for distribution networks, customer load growth, and CER are not sufficiently integrated into transmission planning, and recommends stronger integration through coordinated planning across NSW.[1] For the National Electricity Market (NEM), the next iteration of the Australian Energy Market Operator's (AEMO) Integrated System Plan (ISP) is required to consider distribution network capacity, CER and demand-side factors.[2] Whilst the need to integrate distribution opportunities into system planning is clear, how this can be achieved remains a key challenge.

To bridge this planning gap, the NSW Distribution Network Service Providers (DNSPs) have come together to develop a single, unified view of distribution network opportunities in NSW at the medium and low-voltage distribution level as well as the sub-transmission level. This planning exercise is underpinned by a consistent methodology and supported by analysis that incorporates insights from their networks, assets and customers. The resulting DSP Opportunities Report demonstrates how, in practice, distribution-level opportunities can be incorporated into whole-of-system planning. It establishes an integrated strategic planning and modelling methodology that co-optimises across distribution and transmission-level opportunities using granular DNSP demand and network capacity data.

The DSP Opportunities Report complements AEMO's ISP and AusEnergy Services Ltd Infrastructure Investments Objectives Report. Traditionally, system planning considers a top-down approach focusing on the coordination of transmission and utility-scale generation and storage to meet NEM demand. In contrast, the DSP Opportunities Report adopts a bottom-up approach, leveraging localised data from within the distribution networks. By offering higher resolution insight into emerging demand patterns and infrastructure needs at the distribution level, the DSP Opportunities Report supports the integration of distribution network opportunities and customer investments in CER into whole-of-system planning.

The purpose of this report is to provide an assessment of how DNSPs can support the NSW energy transition. The role of DNSPs is rapidly evolving as the energy system decarbonises, decentralises and becomes increasingly dynamic. The DSP Opportunities Report seeks to understand and shape the evolving role of DNSPs to ensure the electricity system remains reliable, affordable and capable of meeting NSW's legislated emissions reductions targets.

[1] Farrier Swier Consulting (2025). *NSW Transmission Planning Review – Final Report.* NSW Department of Climate Change, Energy, the Environment and Water.
[2] Australian Energy Market Operator (2025). *ISP Methodology*

The modelling approach

There are two overarching distribution network opportunities where DNSPs can play a larger role in supporting customers: opportunities to better utilise available capacity in distribution networks, and opportunities to optimise the use of CER. Both opportunities represent untapped potential within the distribution network where there is scope to do more. These opportunities can be considered both as standalone opportunities and together to understand the 'size of the prize':

- **Opportunity 1 – Unlocking available capacity:** Considers the potential for connecting utility-scale generation and storage into the sub-transmission network where it provides least-cost system outcomes. It also looks at targeted investment in distribution-connected Battery Energy Storage Systems (DBESS) and mid-scale solar in the medium and low-voltage distribution network to defer augmentation.
- **Opportunity 2 – Unlocking CER:** Considers how improved coordination and integration of CER, including rooftop and mid-scale solar, batteries and electric vehicles (EVs) can reshape load profiles and contribute to whole-of-system cost savings.
- **All opportunities unlocked**: Combines Opportunity 1 and Opportunity 2, pulling on all levers to understand the total 'size of the prize' for distribution network opportunities – both at the sub-transmission level, and the medium and low-voltage level.

To explore how the benefits of each opportunity might vary under different uncertain future conditions, three scenarios have been developed reflecting varying levels of decarbonisation ambition, customer behaviour, and infrastructure delivery:

- **Customer transformation**: This scenario represents a future where decarbonisation progresses rapidly, driven by high levels of customer and societal behavioural change. Customers adopt new technologies including EVs, rooftop solar and electrified appliances quicker and more extensively. Despite this, there are delays to transmission projects and constraints on the annual generation build limits for utility-scale projects, reflecting ongoing challenges in infrastructure delivery at the transmission-level.
- **Falling short**: This scenario reflects a future where decarbonisation progresses slowly and there is lower societal and customer appetite for behavioural change. Technology adoption is slower, leading to more gradual electrification. At the same time, further challenges are encountered at the transmission-level, with increased delays to transmission projects and tighter constraints on annual generation build limits.
- **Optimistic case**: This scenario broadly mirrors *Customer transformation,* but supply-side assumptions align with AEMO's Step Change scenario with ideal infrastructure delivery, e.g. no delays to transmission build out or annual generation build limits. It assumes stronger policy support, effective coordination and smooth delivery of the optimal development path.

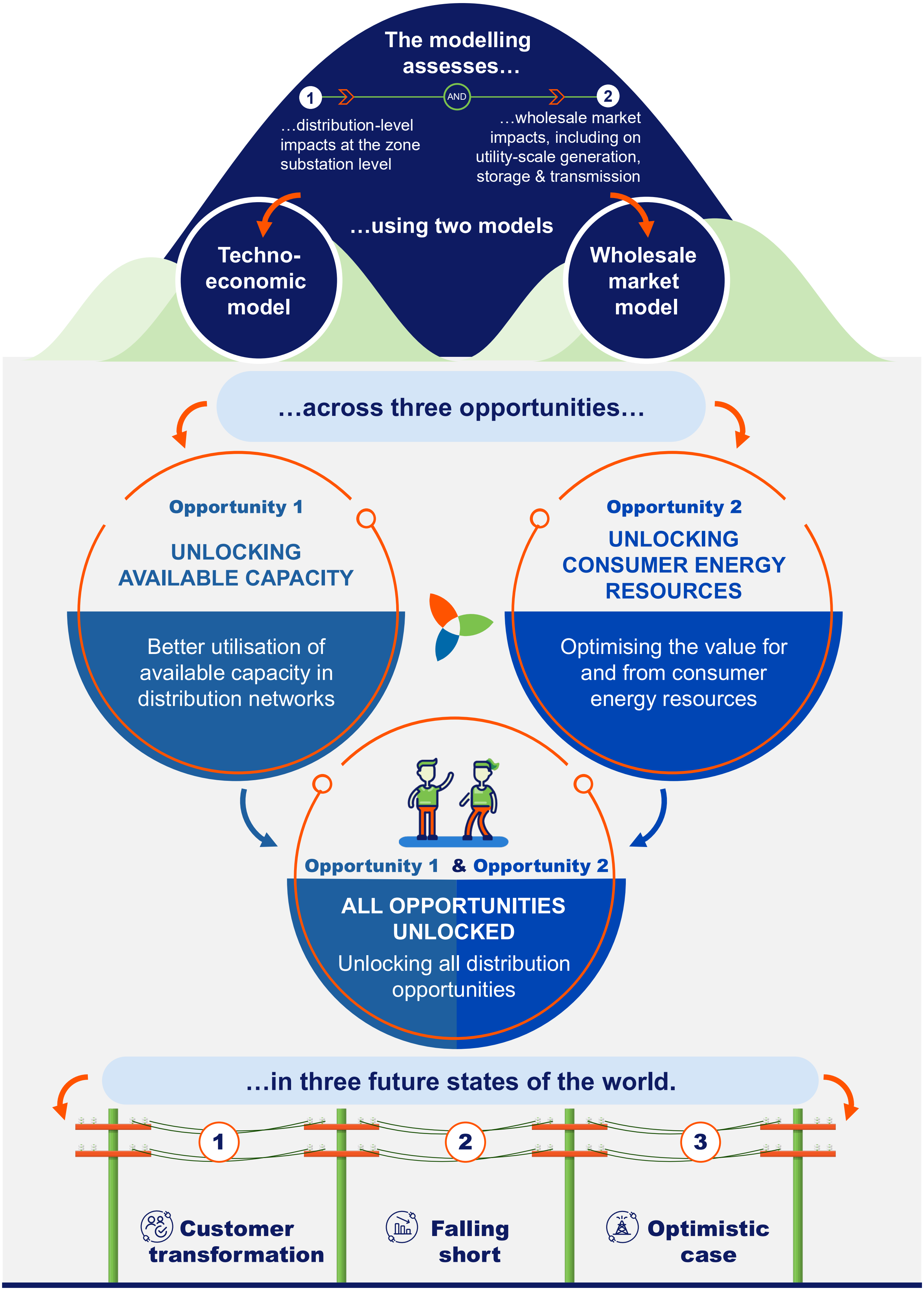
For the first iteration of the DSP, the modelling in the techno-economic model was undertaken at the zone substation level. There are additional constraints and opportunities at lower voltage levels deeper into the distribution network that are not captured in this report.

Beyond this, the wholesale market modelling incorporates 16 GW of hosting capacity for utility-scale resources (predominantly in the sub-transmission network) identified by the three networks in previous studies. Further opportunities within the sub-transmission network are likely to emerge with more detailed area planning.

As a first-of-its-kind initiative, the modelling in this report is strategic in nature. While further work is required to refine assumptions and address limitations, the process itself is as valuable as the outputs. A deliberate focus has been placed on learning – about data, methodologies and modelling capabilities – with the understanding that these insights will shape future iterations and inform broader planning reforms. Central to this is a recognition that strategic system planning is a whole-of-enterprise endeavour, requiring new skills, systems, and ways of working. Accordingly, internal capability building has been a core outcome of the project.

The modelling approach is summarised in Figure ES1.

Figure ES1: Summary of modelling approach



This complements AEMO's efforts to integrate sub-transmission and medium and low-voltage distribution network opportunities into the 2026 ISP in three ways:

- **Representation of the distribution network:** As a NEM-wide system plan focused on the bulk transmission network, the ISP's sub-regional model – with four sub-regions used to characterise NSW – necessarily requires significant simplification and aggregation to represent the distribution network. In reality, NSW has over 690 zone substations, reflecting a combination of meshed and linear network. By considering the distribution network at this more granular level, the DSP Opportunities Report builds on the assessment being undertaken by AEMO, ensuring the distribution network is represented with greater fidelity.
- **Scenario design**: While AEMO's scenarios are required to focus only on futures that achieve net zero targets and meet jurisdictional policy objectives, the modelled scenarios in this project were able to explore a broader range of outcomes – including futures where transmission development is delayed or coal retirements occur later than AEMO projects. Although the scenarios considered in this report are distinct from AEMO's, there are areas of alignment.

  On the supply-side, the timing of transmission projects in the *Optimistic case* scenario aligns most closely with AEMO's Optimal Development Path (ODP). This scenario also assumes no constraints on the speed or scale of renewable generation delivery, consistent to AEMO's ISP methodology. In contrast, the *Customer transformation* and *Falling short* scenarios limit early-stage generation to reflect delivery challenges faced by utility-scale generation projects at the transmission-level.
- **Bottom-up demand forecasting**: The modelling also uses bottom-up demand forecasts for NSW. These forecasts were developed by the DNSPs at the zone substation level, informed by customer and load data including uptake and coordination projections for CER (both household and C&I) and EVs.

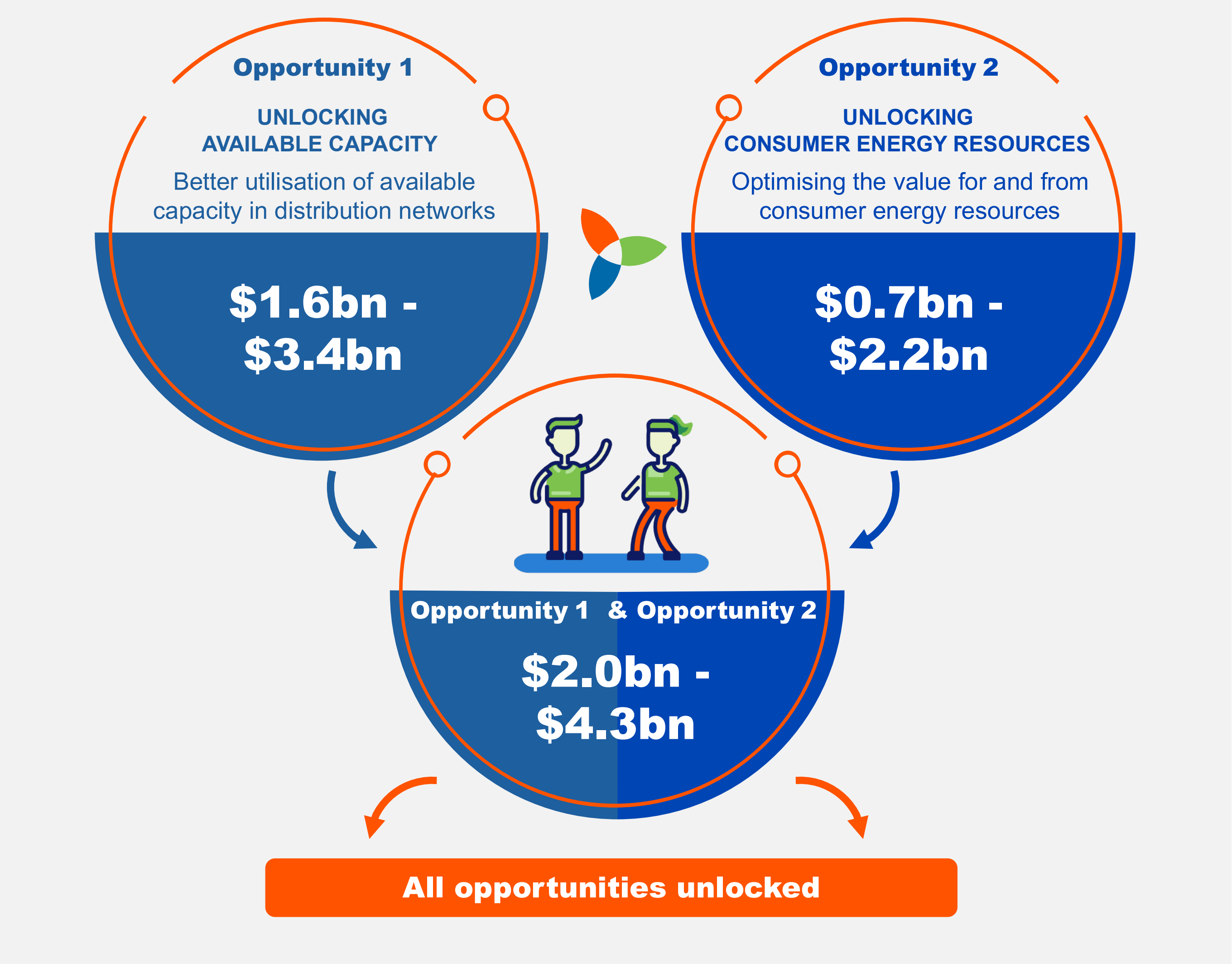
  NSW data centre load in the *Customer transformation* and *Optimistic case* scenarios is also derived from DNSP forecasts, using a probability-weighted estimate of expected growth, based on connection enquiries likely to proceed by 2030. A linear 'ramping' profile that gradually increases data centre load into the late 2030s is also used. While this approach is considered conservative, these forecasts project significantly higher demand than AEMO's Electricity Statement of Opportunities (ESOO) Central scenario.

  However, to consider the impact of different demand futures, the *Falling short* scenario includes a lower demand forecast – due to lower electrification and data centre growth – which is comparable to AEMO's 2025 ESOO Central forecast.

The value of distribution-level opportunities

There is significant value in unlocking distribution-level opportunities across NSW – estimated at $2.0 - $4.3 billion across scenarios.[3] The modelling highlights a clear need to do more at the distribution level, under all future demand scenarios, to deliver cost savings for households and businesses, de-risk the energy transition and improve customer participation in the energy system.

Figure ES2: The size of the prize[4]



Whilst modelling at the zone substation level was considered appropriate for this first of its kind planning exercise, there are additional constraints and opportunities at lower voltage levels as outlined above. Further work and time is required to standardise data collection and analysis across the networks before these can be fully assessed.

As a result, benefits in the medium low-voltage network are not captured in this report. The economic benefits are therefore considered conservative. Table ES1 and Table ES2 summarise the underlying drivers of this value for the *Customer transformation* scenario. This scenario most closely aligns with the DNSPs' view of future demand and infrastructure delivery.

[3] The benefits outlined are the net present value. The five value categories considered are Distribution Network benefits, Transmission Network benefits, Generation benefits, Social benefits (emission reductions) and Residual value. For a detailed breakdown see Appendix F.
[4] The range reflects the result across all modelled scenarios.

Table ES1: Key insights in Opportunity 1 – Unlocking available capacity

	Opportunity 1 - Key Insights: Demonstrates the value of distribution-connected generation, DBESS and co-location
Distribution-connected generation	• Distribution-connected wind and solar can make a significant contribution to managing NSW's load growth, driven by population, electrification and data centres. This value comes from: – **Unlocking solar generation in, or close to, major load centres** in Sydney, Newcastle and Wollongong – whether on rooftops or utility-scale connections. The solar investment is co-located with utility-scale storage. – **Providing additional wind capacity across NSW**. By 2050, this reduces the need for gas-powered generation by over 50 TWh – a key driver of electricity prices – and displaces over 500 PJ of gas consumption – almost four times NSW's current annual gas use. It also decreases the reliance on interconnection to service NSW demand by 65 per cent. Together, these outcomes derisk dependency on other sectors and states, while driving down greenhouse gas emissions by over 30 MtCO2-e across the NEM. • By leveraging both existing distribution network hosting capacity and the additional capacity unlocked through $3.2 billion (real, FY25) in targeted anticipatory investments, 14.7 GW of solar and 5.8 GW of wind is enabled by 2050 – at approximately $0.15 million per MW of hosting capacity. • This accounts for a quarter of NSW's total electricity generation by 2050, enough to power all NSW households (excluding EVs). • Transmission investment is still critical, but unlocking distribution-connected generation and storage de-risks the energy transition and buys the equivalent of 2 years for New England Renewable Energy Zone (REZ) and 5 years for Stage 2 of Central West Orana REZ.
Distribution-connected storage	• The deployment of DBESS connected at the zone substation can cost-effectively defer expensive zone substation upgrades. • Co-locating distribution-connected generation and storage further drives these benefits by maximising the utilisation of these assets. At the distribution-level, pairing 690 MW of storage with 180 MW of mid-scale solar creates an opportunity to defer zone substation augmentation by 12 years. By producing and storing electricity closer to load, co-location buys time for upstream network augmentations. • DBESS also promote customer participation in the system – enabling more equitable outcomes through community batteries, reducing curtailment, and facilitating greater investment in rooftop and mid-scale solar.

Table ES2: Key insights in Opportunity 2 – Unlocking CER

	Opportunity 2 - Key Insights: Demonstrates the value of coordination in an increasingly decentralised system
Coordination of CER	• Significant value can be derived from how customers use their flexible assets. Ensuring the coordination of CER – battery storage, EV charging and vehicle-to-grid – and unlocking local, mid-scale solar can deliver up to $2.2 billion in benefits. • It is critical that all customers benefit, through increased participation in the energy system, reduced curtailment and greater return on CER assets, and through a more reliable and lower-cost system for all. • Transport decarbonisation is a key priority for NSW. A proactive DNSP-led rollout of low-capacity kerbside EV charging infrastructure could accelerate the uptake of EVs for NSW households without off street parking by half a million by the late 2040s.[5] • As EV uptake grows, the orchestration of EV charging will be critically important to managing peak load growth and keeping costs down for customers.

The value drivers from *Unlocking available capacity* and *Unlocking CER* are complementary: distribution-connected wind and solar remain key to servicing NSW demand, while greater coordination of CER assets help to flatten the load profile and reduce the need for utility-scale storage. Together, these factors support a least-cost electricity system and deliver higher economic benefits.

[5] EBDM, Appendix G

Calls to action and reform considerations

The NSW DNSPs are actively pursuing initiatives across the key value drivers identified above, which has surfaced barriers to unlocking value at the distribution level. While DNSPs are committed to supporting customers through the energy transition, their ability to act is constrained under status quo regulatory arrangements.

To overcome these barriers, the DSP Opportunities Report outlines three critical reform priorities, each accompanied by targeted calls to action.

1 Strategic system planning

The NSW Transmission Planning Review highlights the need for end-to-end system planning that adequately captures opportunities within the distribution network. To support this, the DSP Opportunities report proposes that each DNSP develops a bottom-up, DNSP-led Distribution System Plan which is shared with an independent NSW system planner for co-optimisation across both distribution and transmission networks.

- Enable bottom-up DNSP-led strategic planning
- NSW system planner to co-optimise across distribution and transmission, informed by individual DNSP plans

This approach would help identify lower cost Generation Rich Zones (GRZs) and empower DNSPs to support co-location of load, generation and storage in Local Energy Precincts (LEPs) - delivering benefits not only to local customers but also to the broader electricity market. Longer-term planning at the distribution level would also enable greater consideration of demand-side solutions, CER coordination and battery storage deeper within the network, unlocking further whole-of-system benefits.

2 Project approvals

Current project approval timelines risk the achievement of NSW's 2030 and 2035 emissions targets. The shift to an integrated strategic planning approach must be complemented by reforms that facilitate and streamline approval processes for anticipatory distribution-level investments. This includes linking project approval processes to the NSW integrated system plan, and broader reforms to enable DNSPs to invest in projects that deliver system-wide benefits.

- Align approval pathway to NSW integrated system plan
- Develop fit-for-purpose appraisal framework suited to capturing and assessing the complexities of the distribution network under the *Electricity Infrastructure Investment Act*
- Improve the ability to invest in anticipatory projects by extending the time horizon over which demand is considered under the National Electricity Rules (NER)
- Introduce changes to NER uncertainty mechanisms to allow for more flexible application, as well as the potential introduction of new mechanisms to allow for new load connections within period

These reforms will support investment in the strategic network infrastructure required to unlock GRZ and LEP opportunities – both for investments included in the NSW integrated system plan and those that sit outside of it.

3 DBESS regulatory and market settings

The modelling demonstrates that additional DBESS can reduce system costs and put downward pressure on electricity prices. However, current regulatory and market factors result in unequal treatment of functionally similar systems, creating barriers to connecting at the distribution level.

To unlock the value of DBESS, these differences need to be addressed – by aligning the treatment of NSW Roadmap charges between distribution- and transmission-connected storage systems and addressing inequities in Transmission Use of System (TUoS) charges for developers of larger DBESS (typically greater than 5 MW).

- Address inequities in TUoS charges for large DBESS
- Align treatment of NSW Roadmap charges for DBESS connections with transmission-connected counterparts

Beyond these specific calls to action, there are broader areas in the electricity system that require further consideration. These include both challenges that require reform and emerging opportunities to unlock value for customers and the network. Adopting a more integrated approach that optimises all components of the electricity system, not just at the transmission level, will enable NSW to deliver on its renewable energy targets in a manner that minimises costs for all electricity users.

Cost allocation

Electricity customers will pay for the majority of the energy transition – including through their own investments in CER and through their electricity bills. Careful consideration is required to ensure the costs of the transition are borne equitably. In particular, this report highlights specific cost-recovery issues that need to be tackled to ensure Essential Energy's regional customers do not unfairly bear a greater share of the burden by paying for distribution REZ developments that benefit all NSW consumers.

Consumer energy resources and community assets

Customer choices around energy resources – what they invest in, how they are used, and the extent of participation in the trading of energy and services – will play a significant role in the energy transition. Coordinating these assets is critical to reduce costs for all electricity customers and support the needs of the system. With the right information, choices and incentives, CER can be used to help balance supply and demand.

Importantly, optimising the coordination of CER also delivers equity benefits by enabling fairer access to lower energy costs and increased participation opportunities for all customers. Shared infrastructure such as community batteries and public EV charging will play a critical role in supporting equitable access. For example, community batteries could offer significant equity and social benefits by making energy storage accessible to a broader range of households, including renters, apartment dwellers, and those unable to afford their own systems. By pooling resources at the neighbourhood level, these batteries provide an avenue to share the benefits of rooftop solar across the community.

Reforms should be considered to address how this infrastructure can be deployed at the speed required for the transition, as current regulatory frameworks and private market settings do not support the required pace of rollout.

At the household level, DNSPs are already developing capabilities to support an increasingly decentralised system characterised by two-way power flows, playing a critical facilitation role in supporting participation in the energy system. DNSPs will continue to partner with retailers and work with governments to progress actions in the National CER Roadmap and support their customers with CER investments.

While these reforms will support CER integration, further progress requires more localised energy planning and a deeper understanding of customer preferences. DNSPs are uniquely placed to support with this planning exercise as they have the best view of how customers are using CER assets and how this impacts the local network.

To effectively integrate CER into the strategic planning process, additional investment is required in advanced hardware and software – such as smart meters, analytics programs and distributed energy resource management systems – to better understand how CER are being used. Further development of tools, such as the Energy Behavioural Demand Model used in this report, is also needed to improve understanding of how customers respond to initiatives and incentives designed to encourage use of these assets in a way that delivers whole-of-system benefits.

Data centres

Data centres present a significant opportunity for the NSW economy that will put new demands on the electricity system. A more proactive approach to data centre planning, supported by anticipatory investments to deliver network capacity required for this growing demand category, is needed. Strategic planning and projects to support data centres would encourage connections in locations that work best from a whole-of-system perspective, including potential co-location with distribution-connected generation. Cost allocation mechanisms for anticipatory investments require careful consideration to protect against equity issues and stranded asset risk in the event of data centre closure.

Beyond the NSW DSP Opportunities Report

Developed as a first-of-its-kind, the DSP Opportunities Report provides valuable insights into the integration of distribution-level opportunities within whole-of-system planning. While it marks a significant step forward, it also highlights that much more work is needed to fully understand and unlock the potential for distribution networks to support customers through the energy transition.

To this end, Ausgrid, Endeavour Energy and Essential Energy are committed to working with government, market bodies, retailers and customers to address the challenges identified in this report and enhance outcomes across the energy system.

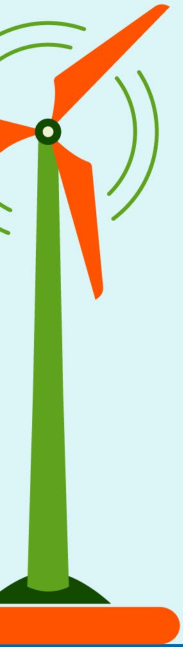
As part of this commitment, the DNSPs will continue to work closely with the NSW Government and actively support changes to how network infrastructure is planned in NSW. In parallel, and as part of a coordinated approach to developing their individual Distribution System Plans, the DNSPs will continue to collaborate on shared elements of their respective plans – building on the insights gained and challenges encountered through this planning exercise. This includes:

- Refining bottom-up demand forecasts, including building on and integrating the methodology to projecting data centre load developed as part of this project
- Improving understanding of customer behaviour and preferences, to optimise CER coordination in a way that maximises system value and supports more equitable participation in the energy system
- Improving understanding of reverse-flow and voltage constraints that drive corrective action across the network, particularly at low-voltage parts of the network below the zone substation. This will include undertaking detailed power systems modelling of the investments identified through the plan for thermal overloading, voltage profiles, power flow, contingency, reactive power compensation, fault analysis and system strength.
- Continued analysis of the sub-transmission network to identify and develop distribution REZ opportunities
- Improving characterisation of meshed network impacts in the modelling
- Incorporating this planning exercise with on-the-ground knowledge of replacement schedules to further drive integration of network activities.

Additionally, the DNSPs will continue to engage with government and regulators to share lessons learnt, and consider how these findings can inform any current rule changes or provide scope for new reforms. These efforts aim to adapt the regulatory framework in response to a rapidly changing energy landscape where decentralised energy and the distribution networks that host them will play an increasingly important role.

Importantly, the value that can be unlocked from the distribution network is not unique to NSW – it exists across the NEM. This report provides a framework for other jurisdictions to demonstrate the value of distribution network opportunities, and the proposed reforms to support the realisation of this value. The NSW DNSPs can share lessons learnt with other jurisdictions, helping to build collective momentum and capability across the NEM – accelerating Australia's energy transition and delivering benefits for all customers.

1. Introduction



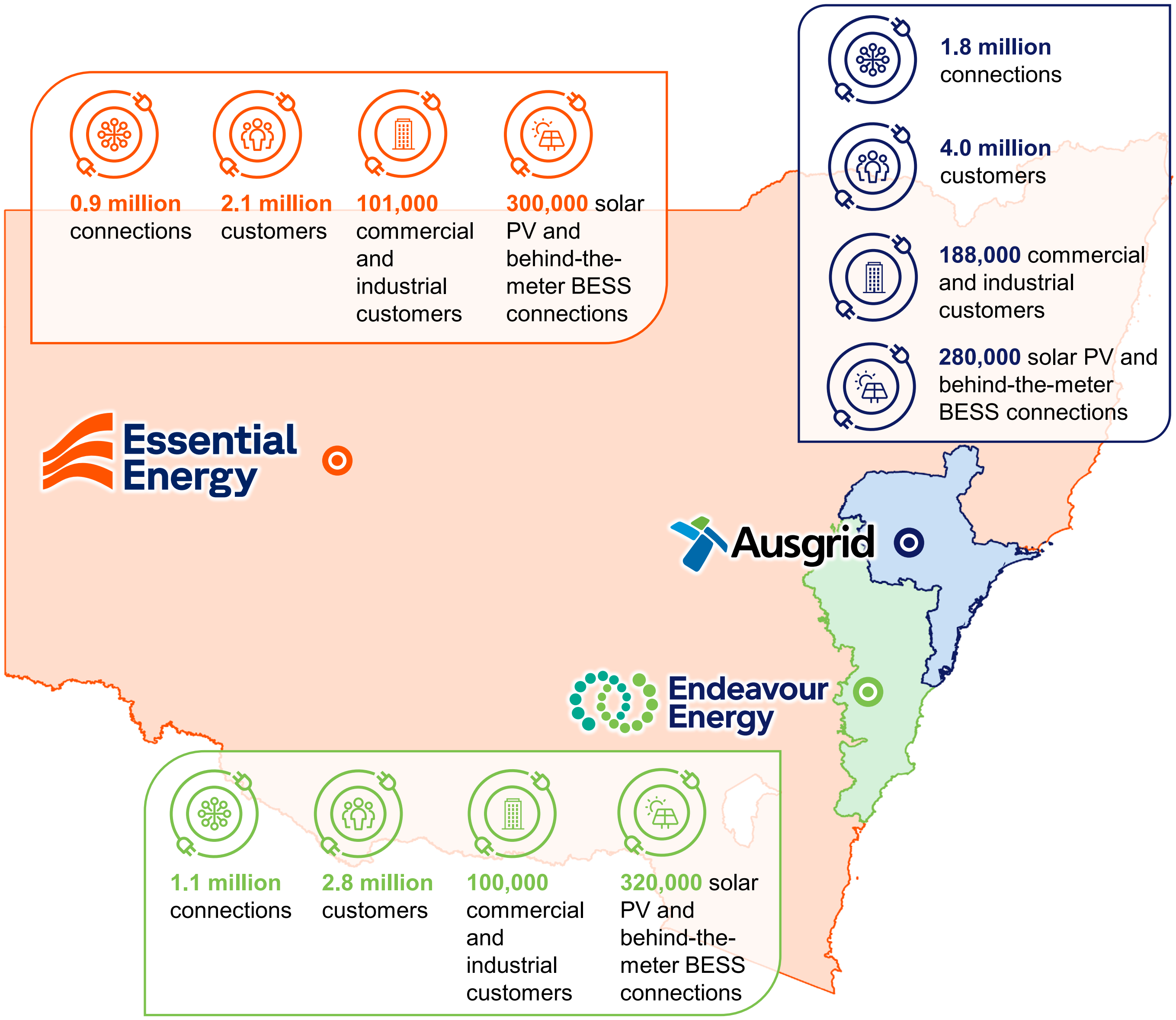
1.1 Background

As part of its transition to a low-emissions economy, New South Wales (NSW) has committed to ambitious climate targets – including a legislated 50 per cent reduction in greenhouse gas emissions by 2030, 70 per cent by 2035 and net zero by 2050.[6] These goals align with national commitments to reach net zero by 2050, and exceed Australia's interim targets of a 43 per cent reduction by 2030 and 62-70 per cent by 2035.[7]

Electricity distribution networks will play an increasingly important role in transforming the NSW energy system. As the key link between transmission networks and customers, they are central to delivering clean, reliable and affordable electricity across both urban and regional areas of the state.

Across NSW, the three Distribution Network Service Providers (DNSPs) – Ausgrid, Essential Energy and Endeavour Energy – provide electricity to nearly 4 million households and businesses, collectively supporting approximately 8.9 million customers and 30 per cent of Australia's GDP.

Figure 1: Key statistics for Endeavour Energy, Ausgrid and Essential Energy



[6] *Climate Change (Net Zero Future) Act 2023*
[7] Department of Climate Change, Energy, the Environment and Water (2025). *Australia's Net Zero Plan*

In aggregate, the networks distributed over 55 TWh of energy in FY2024.As the state's energy transition progresses, electricity demand is expected to grow significantly. This increase will be driven by two key trends: the electrification of households – particularly for heating, cooking, hot water and vehicles – and the emergence of new large-scale loads such as data centres. These changes will place greater pressure on the electricity system, which must evolve and do more to meet changing consumption patterns, while maintaining reliability and affordability.

At the same time, the energy system is rapidly evolving into a decentralised grid with two-way energy flows. This customer-led transformation has seen an unprecedented investment in Consumer Energy Resources (CER) such as rooftop solar, behind-the-meter batteries and electric vehicles (EVs). In a system originally designed for centralised, top-down energy flows, these technologies are creating both challenges and opportunities.

The distribution network has latent capacity, due to necessary network design to meet technical performance needs, and seasonal and daily variations in demand and CER behaviours. Increasing utilisation of the existing distribution network in a way that supports network performance will accelerate renewable development, de-risk delays to large scale generation and transmission projects, and support NSW to meet its *Electricity Infrastructure Investment Act* (EII Act) 'minimum objectives' – all while minimising whole-of-system costs.[8]

The critical role of distribution networks in supporting the energy transition is being increasingly recognised by regulators, policy makers, stakeholders and industry groups. A number of key reforms are underway nationally – from planning, to demand forecasting, to new ways of delivering energy (such as stand-alone power systems at the distribution level), as well as reforms to establish new responsibilities in managing operating networks in high CER environments (such as the role out of the emergency backstop mechanism in each National Electricity Market (NEM) jurisdiction).

Leveraging these distribution-level opportunities to respond to evolving generation and consumption patterns is essential to the success of the energy transition. However, even though distribution networks play a critical role, strategic system planning often overlooks how these networks can be used to reduce costs for households and businesses and to enhance customer participation in the energy system.

1.2 Purpose

The NSW Distribution System Plan (DSP) Opportunities Report is the result of a coordinated planning effort by the NSW DNSPs to support the NSW energy transition. The three NSW DNSPs have recognised the value in coming together to develop a united methodology underpinned by robust analysis to understand the value of opportunities within the NSW distribution network. It is a landmark, Australia-first study that seeks to integrate distribution network opportunities into system planning to reduce overall costs and support customer outcomes by recognising the opportunity to do more with the distribution network.

The DSP Opportunities Report is designed to complement AEMO's Integrated System Plan (ISP) and AusEnergy Services Ltd (ASL) Infrastructure Investments Objectives Report (IIO Report). Traditionally, system planning considers a top-down approach focusing on the coordination of transmission and utility-scale generation and storage to meet NEM demand. In contrast, the DSP Opportunities Report uses a bottom-up approach with detailed localised data from within the distribution networks. By offering higher resolution insight into emerging demand patterns, available capacity for new connections, as well as future infrastructure needs at the distribution level, the DSP Opportunities Report supports the integration of distribution network opportunities and customer investments in CER into whole-of-system planning.

The purpose of this report is to provide a comprehensive assessment of how DNSPs can support the NSW energy transition. The role of DNSPs is rapidly evolving as the state's energy system decarbonises, decentralises and becomes increasingly dynamic. The DSP Opportunities Report seeks to understand and shape the evolving role of distribution networks to ensure the electricity system remains reliable, affordable and capable of meeting NSW's legislated emissions reductions targets.

[8] NSW Government (2020). *Electricity Infrastructure Investment Act 2020 No 44*

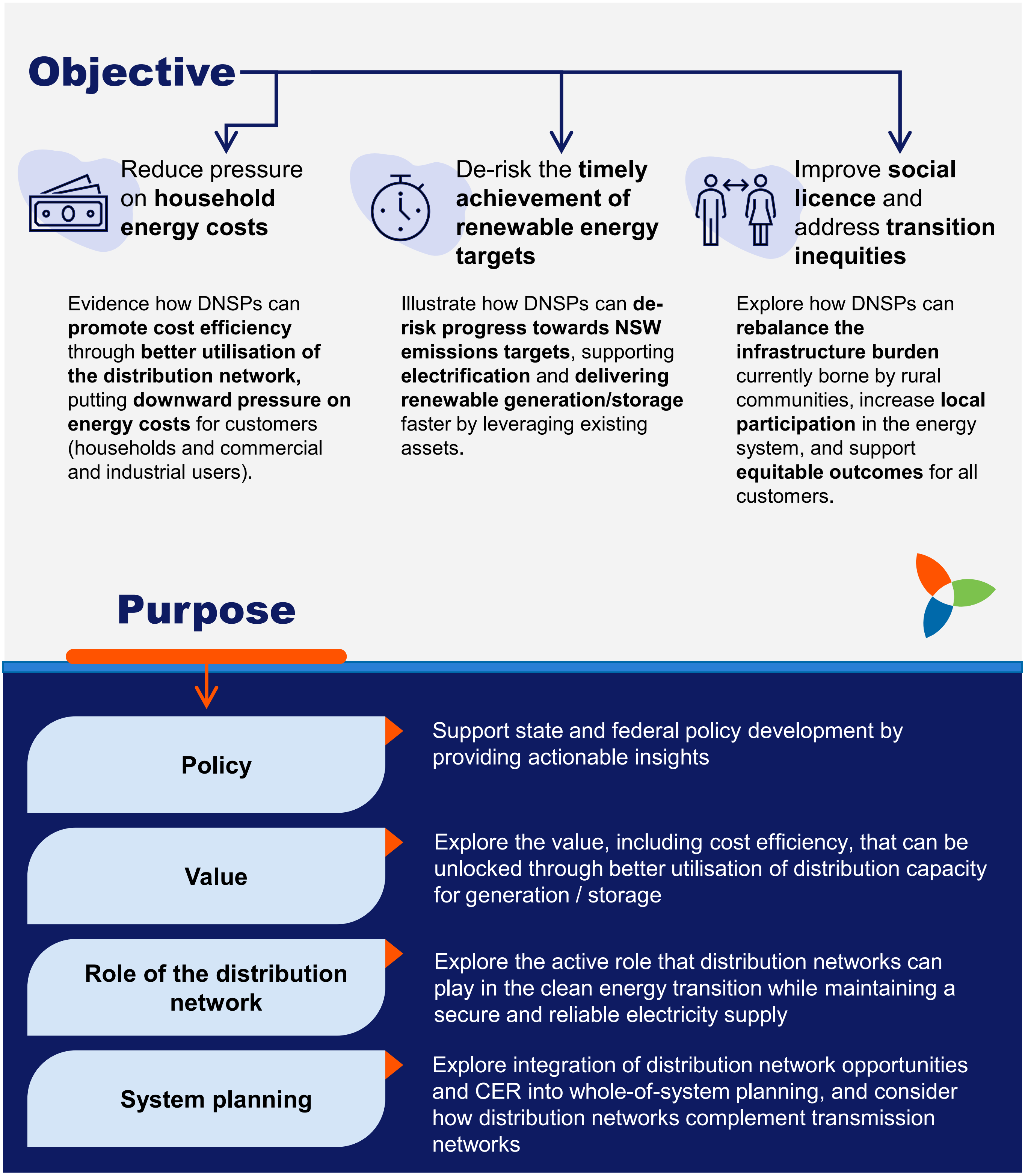
The DSP Opportunities Report is underpinned by three core objectives:

- reduce pressure on household energy costs
- de-risk the timely achievement of renewable energy targets
- improve social licence and address transition inequities.

By identifying high-impact opportunities, aligning community and stakeholder priorities, and identifying priority calls to action, the report aims to support DNSPs in delivering a faster, fairer, and more affordable decarbonisation pathway for NSW. However, there are still barriers to unlocking the full value of the distribution network. The purpose of the DSP Opportunities Report is to inform policy reform needed the address these barriers, highlight the benefits of doing so, and provide insights into the evolving role of the distribution network and system planning.

The objectives and purpose of the DSP Opportunities Report is summarised in Figure 2.

Figure 2: Objectives and purpose of the DSP Opportunities Report



The DSP Opportunities Report explores how distribution-level planning can complement transmission-level planning to support a whole-of-system planning approach. Focusing on the distribution level fills a critical gap in current planning processes by ensuring that distribution-level constraints, opportunities, and insights inform broader strategies for decarbonisation, grid reliability, and affordability across the NSW energy system. Figure 3 provides an overview of how the DSP Opportunities Report relates to these other state and national processes and reports.

Figure 3: Distribution networks are the 'missing middle' in the NSW energy transition

	Document	Coverage	Scope
AEMO	Integrated System Plan		NEM-wide generation, storage and transmission
Independent Planning Body (EnergyCo proposed)	NSW System Plan (proposed)		Integrated plan for distribution & transmission projects
Ausgrid, Endeavour Energy, Essential Energy	Distribution System Plan		Unlocking value in the distribution network
AusEnergy Services Ltd	Infrastructure Investment Objectives Report		State-wide generation and storage infrastructure
EnergyCo	Network Infrastructure Report		REZ design and downstream augmentation

1.3 Structure

The DSP Opportunities Report:

- identifies the problems facing the electricity system (**Section 2**)
- details the approach undertaken within this report and quantifies the benefits of unlocking distribution network opportunities (**Section 3** and **Section 4**)
- considers how this value can be realised, and the barriers that need to be addressed (**Section 5** and **Section 6**).

The report is structured as follows:

Section 2: Problem definition

This section outlines the challenges facing the electricity system from the customer to the bulk system and reinforces the need for integrated, whole-of-system planning.

Section 3: The modelling approach

This section outlines the journey undertaken by the three NSW DNSPs to develop a unified methodology for integrating distribution-level opportunities into strategic planning. It covers modelling tools, scenario development and data requirements, and introduces the two distribution network opportunity categories assessed in the modelling:

- Better utilisation of available distribution network capacity
- Optimising the value for and from CER.

Section 4: The value of distribution-level opportunities

This section draws on the modelling to quantify the 'size of the prize' from unlocking the value of the distribution network opportunities modelled.

Section 5: Value pathways

This section identifies and explores four pathways that can be readily supported by DNSPs to deliver the value identified in Section 4:

- Generation Rich Zones
- Local Energy Precincts
- Battery energy storage connected to all levels of the distribution network
- Optimising the coordination of CER.

These four areas are considered through the network and customer benefits that they deliver, supported by specific case studies which illustrate the role that the distribution network can play in unlocking value.

Section 6: Barriers to unlocking value and calls to action

This section explores emerging issues and the barriers that need to be addressed to unlock the value pathways identified in Section 5 across six key reform areas:

- strategic system planning
- project approvals
- DBESS regulatory and market settings
- cost allocation
- CER and community assets
- data centres.

Targeted calls to action are proposed for the first three reform areas, while the remaining areas are highlighted as needing further exploration to fully realise the value of opportunities within the distribution network.

Section 7: Beyond the NSW DSP Opportunities Report

This section outlines how the DNSPs will continue working together to build on the learnings from this planning exercise as they develop Distribution System Plans. It also highlights the ongoing collaboration with government, regulators, and industry to support the proposed reforms.

2. Problem definition

2.1 Problem statement

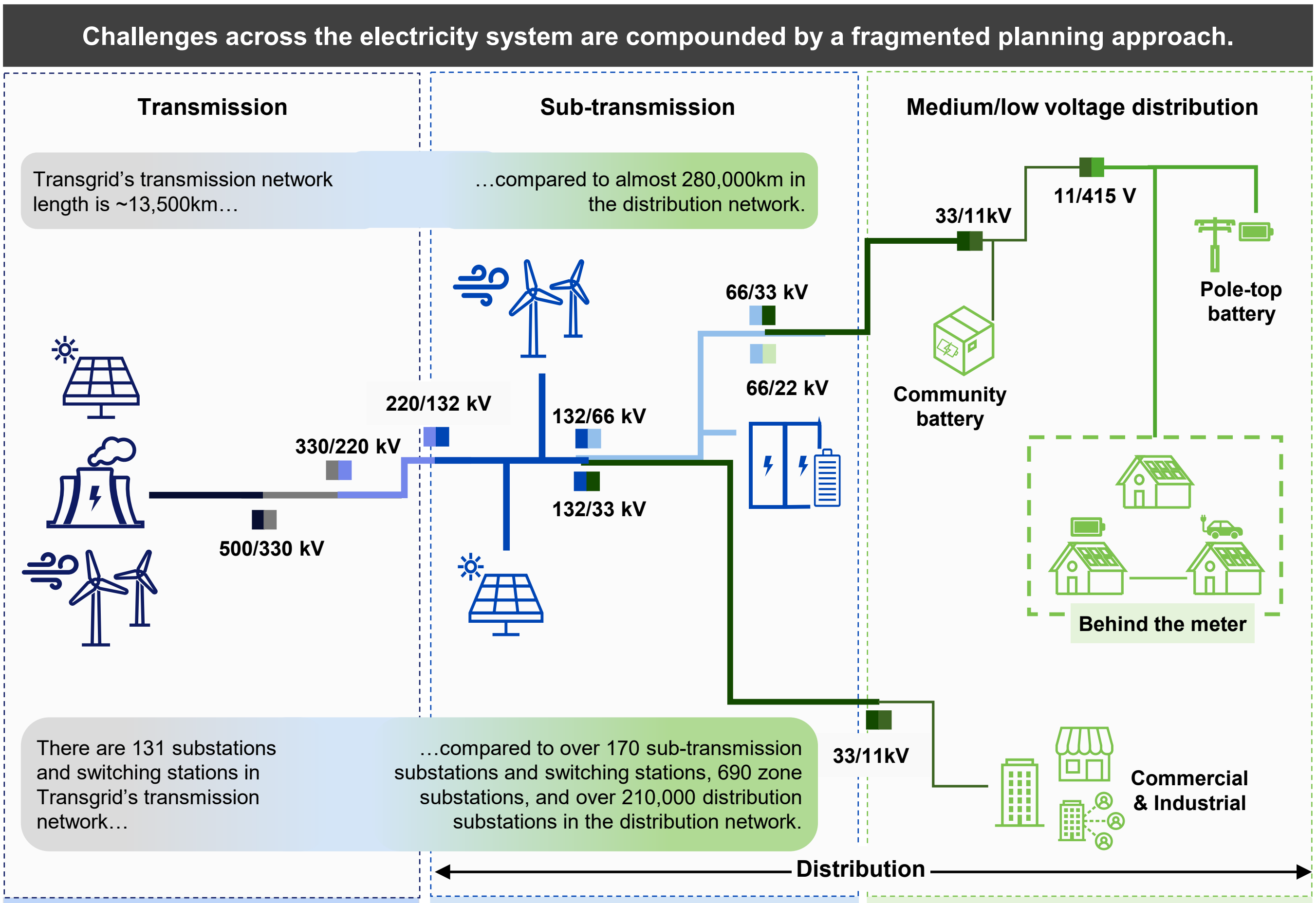
The energy transition in NSW faces a range of significant and inherently interconnected challenges across all levels of the electricity system. These challenges are made more difficult by a fragmented planning approach to long-term planning. At present, strategic system planning does not adequately consider the end-to-end system, especially the complexities found deeper within the distribution network. However, a more integrated approach is imperative to deliver a lower-cost, resilient energy system that aligns with community expectations.

The electricity network can be broadly conceptualised in three components:

- Transmission network (typically between 132 kV and 500 kV) and utility-scale, transmission-connected generation and Battery Energy Storage Systems (BESS)
- Sub-transmission network (typically between 33 kV and 132 kV) and utility-scale generation and distribution-connected Battery Energy Storage Systems (DBESS)
- Medium and low-voltage distribution network (typically less than 33 kV) and Distributed Energy Resources (DER), including DBESS and CER.

Each level of the network faces unique challenges, outlined in Figure 4. In particular, the distribution network's challenges arise from the dispersed nature and scale of network assets compared to the transmission network. This complexity creates data challenges that necessitate a different approach to planning and integration.

Figure 4: Components of the electricity network and associated problem statements



Problem 1

Challenges in forecasting CER and understanding customer behaviour complicate their integration into strategic planning. This is compounded by market structures that do not incentivise uptake and coordination of CER in a way that lowers system costs for all electricity customers.

Problem 2

Current planning processes do not adequately consider latent network capacity within the sub-transmission network, resulting in missed opportunities to rapidly unlock new utility-scale generation and BESS where it provides least-cost system outcomes.

Problem 3

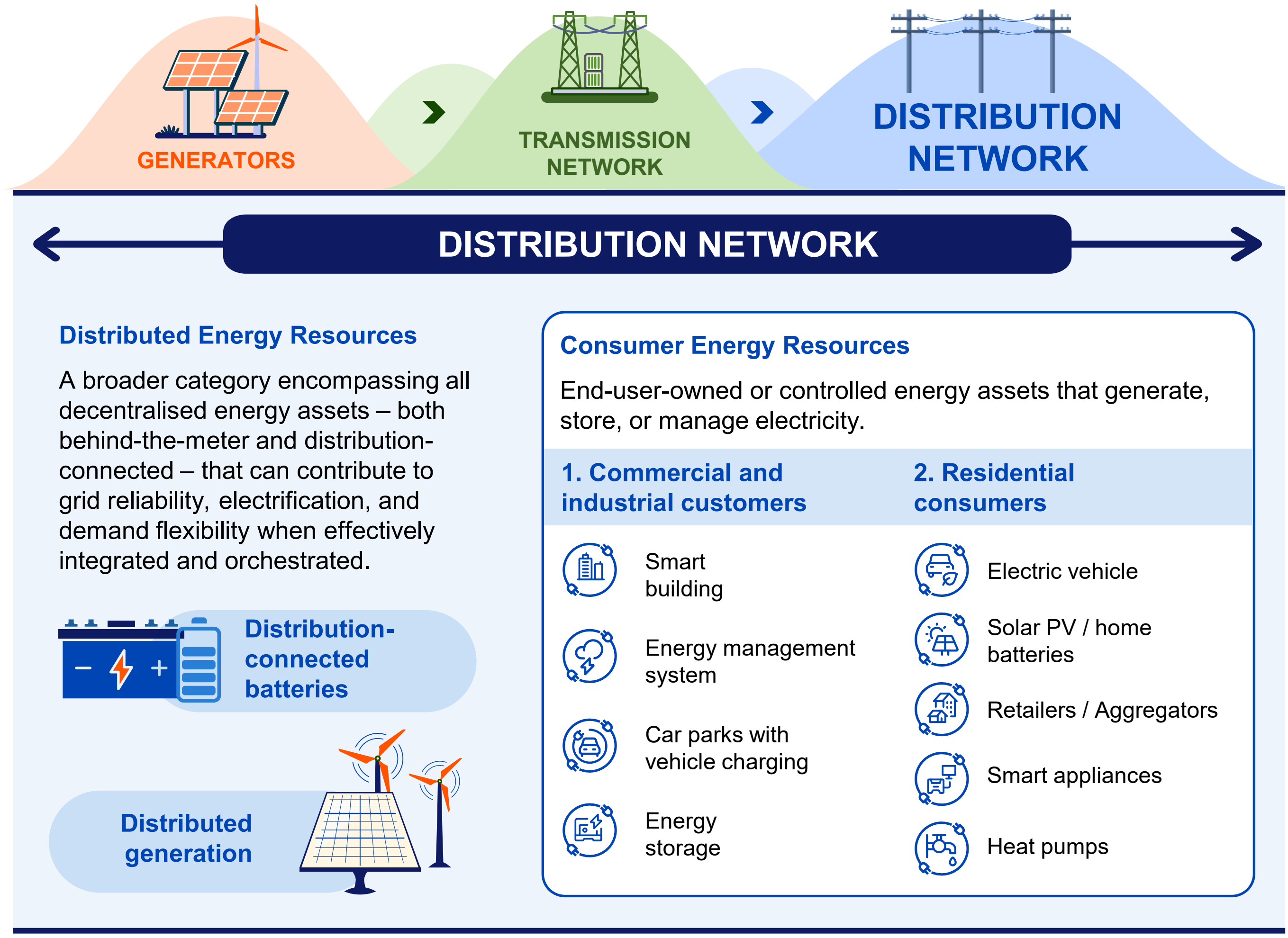
Delays, cost and social licence challenges facing transmission-level projects may jeopardise the state's ability to deliver sufficient replacement capacity prior to closure of coal-fired generators.

2.2 Problem 1: Challenges in forecasting CER and understanding customer behaviour complicate their integration into strategic planning. This is compounded by market structures that do not incentivise uptake and coordination of CER in a way that lowers system costs for all electricity customers.

The national interconnected electricity system is undergoing a significant transformation – from a coal-dependent grid to one powered by renewable energy and storage technologies. At the same time, the system is becoming increasingly decentralised, with customers at the centre of this transition. This presents new opportunities to support the energy transition at lower voltage parts of the electricity network, but also introduces challenges around system design and equity. Realising these opportunities requires active reform of market and regulatory frameworks to enable the effective integration of decentralised energy assets. Without this, there is a risk that the uptake and coordination of CER does not occur in a manner that maximises system benefits and reduces cost for all electricity customers.

As shown in Figure 5, large, centralised electricity systems are increasingly being complemented by smaller and more dispersed sources of generation and storage closer to load – namely CER and DER. CER includes behind the meter customer-owned or controlled energy assets that generate, store or manage electricity. CER is a subset of DER – a broader category which encompasses all decentralised energy assets including both behind-the-meter and distribution-connected assets.

Figure 5: DER and CER in the electricity system



These decentralised energy assets are changing the way electricity is generated, consumed and managed across the state at rapid pace. This is evidenced by the ISP, which forecasts that by 2050 in NSW, the capacity of:

- distributed solar will rise from 10.3 GW today to 37.5 GW
- coordinated CER storages will rise from 0.5 GW today to 17.9 GW.[9]

[9] AEMO (2024). ISP generation and storage outlook

A more decentralised energy system can enhance grid resilience, reduce transmission losses, and empower customers to actively participate in the energy market. It also supports the integration of additional renewable energy, contributing to emissions reduction and increased energy security at both local and national levels.

CER can deliver a range of benefits for customers, the network and the environment. This includes increased energy autonomy, downwards pressure on bills for customers and, when managed effectively, improved grid stability and reliability. For example, at a system level, rooftop solar is reducing daytime operational demand and assists in the displacement of emissions-intensive generation. Behind-the-meter batteries are supporting self-sufficiency and enabling greater load flexibility, while EVs and smart appliances are introducing new controllable loads that can respond to dynamic price signals and network needs.

The medium and low-voltage distribution network also presents opportunities to co-locate load and generation within commercial and industrial (C&I) precincts, further reducing transmission losses and the need for costly network augmentations.

Table 1: The state of play for CER and DER in NSW

Rooftop solar	Rooftop solar in NSW has experienced significant growth with over a million households now having rooftop solar installed - around 38 per cent of all households.[10] Overall, NSW has the highest level of total installed capacity in Australia at around 7.5 GW, making up over a quarter of total rooftop solar capacity.[11]
Residential battery storage	Around 85,000 batteries were installed in Australia in the first half of 2025, more than the total number of installations in 2024.[12] This growth has been driven by the Federal Government's Cheaper Home Batteries Program – in over three months since its launch, more than 95,000 home batteries have been installed.[13] NSW has also introduced a Virtual Power Plants (VPP) incentive that provides an upfront payment for connecting a battery to a VPP.[14]
Electric vehicles	NSW has seen a significant increase in EV sales, making up 13 per cent of new car sales – a 150 per cent increase from 2022.[15, 16] The NSW Government is aiming for EVs to represent 50 per cent of all new car sales by 2030. To complement this goal, the NSW Government is investing in EV charging infrastructure (EVCI), including a $209 million investment for charging coverage across the state. A major focus of this has been expanding fast and ultra-fast charging stations, with plans to have chargers at 100km intervals on major highways and every 5km in metropolitan areas.[17]
Community battery storage	Community batteries offer a shared energy solution for neighbourhoods, particularly to those without access to rooftop solar. The Community Batteries for Household Solar program is delivering grants to support over 420 community batteries across Australia through two grant programs: the Department of Industry, Science and Resources' Business Grants Hub and Australian Renewable Energy Agency's (ARENA) Community Batteries Funding. The former has provided grants for 15 DNSP-led community batteries in NSW, with the latter targeting a further 95 batteries.[18, 19]
Commercial & Industrial	NSW's commercial and industrial DER, particularly medium scale rooftop solar (systems over 100 kW), behind the meter batteries, and flexible demand assets, are gaining prominence as integral components of the energy transition. There is currently ~4,150 MW of C&I rooftop solar – 43 per cent of NSW's installed rooftop solar capacity – reflecting the substantial uptake in larger commercial systems.[20] The NSW Digital Infrastructure for Energy Flexibility project, funded under the Net Zero Plan, is deploying digital infrastructure to aggregate 5 MW of flexible load across over 200 commercial and industrial buildings, enabling these assets to be registered and orchestrated as deployable grid services.[21, 22]

[10] Rooftop solar data calculated using Australian PV Institute, Mapping Australian Photovoltaic installations (2025)
[11] Clean Energy Council (2025). Rooftop solar and storage report: January—June 2025
[12] Ibid.
[13] Department of Climate Change, Energy, the Environment and Water (2025). Australia's Net Zero Plan
[14] NSW Government (2025). Connect your battery to a Virtual Power Plant (VPP)
[15] Australian Automobile Association (2025). Electric Vehicle Index
[16] Electric Vehicle Council (2024). State of EVs report media release
[17] NSW Government (2021). NSW Electric Vehicle Strategy
[18] Department of Climate Change, Energy, the Environment and Water (2025). Community Batteries for Household Solar program
[19] Australian Renewable Energy Agency (2024). ARENA funds national community battery roll out
[20] NEXA Advisory (2024). Accelerating Commercial & Industrial Demand Side Participation in NSW
[21] Race for 2030 (2025). NSW Digital Infrastructure for Flexibility
[22] AEMO' 2023 Integrating Price Responsive Resources into the NEM reforms enable distributed and price-responsive assets to provide deployable grid services by integrating them into NEM dispatch.

While CER deliver important benefits to customers who invest in them, they also introduce new challenges in managing both peak and minimum demand. For example, rooftop solar is increasingly pushing parts of the network beyond safe operating limits at certain times of day, leading to voltage management and thermal overload issues.

The Australian Energy Market Commission (AEMC) pricing review also highlights that current electricity market structures – including price signals and incentives – are misaligned with customer interests and are driving inefficiencies for CER asset owners.[23] As a result, CER are used in ways that do not always support the needs of the system or help reduce costs for all electricity customers.

These issues are widely recognised. As part of the Federal Government's retail energy market reforms, a new regulated electricity offer called Solar Sharer will be introduced next year through the Default Market Offer. This initiative provides customers with smart meters three hours of free electricity during the middle of the day, encouraging load shifting to when solar energy is abundant.[24] While such measures are a step in the right direction, improving the coordination and integration of CER remains critical to maximising the benefits for both customers and the broader energy system. Without better coordination, customers will experience higher levels of curtailment, which limits their ability to participate in the energy system and reduces the value from their investments. Over time, customers will face increased costs from network upgrades required to host more CER.

These challenges are further compounded by difficulties in forecasting CER – driven by limited visibility of behind-the-meter assets, as well as the variability and complexity of customer behaviour. Addressing this requires new approaches and high-quality revealed preference survey data to better understand customer decision-making. One such approach considered in this planning exercise is the Energy Behavioural Demand Model (EBDM) - a modelling framework based on consumer choice theory that accounts for financial factors, individual preferences, social influences and technology adoption theory to simulate customer responses to pricing, policy and infrastructure initiatives.

These factors complicate the integration of CER into strategic planning. Despite this complexity, CER will play an increasingly important role in energy supply and security, making it critical to understand how these assets interact with the network. The impacts of CER are not limited to a local area – their uptake, use and coordination can influence upstream needs for generation, storage and transmission. This highlights the need to adequately consider CER and local networks in end-to-end system planning to deliver a lower-cost, lower-emissions and more resilient energy system for all customers.

2.3 Problem 2: Current planning processes do not adequately consider latent network capacity within the sub-transmission network, resulting in missed opportunities to rapidly unlock new utility-scale generation and BESS where it provides least-cost system outcomes.

The challenges facing large scale transmission and transmission-connected generation projects (discussed in Section 2.4) can be mitigated by capturing opportunities within the sub-transmission network. Whilst there is untapped capacity between the 33 kV and 132 kV parts of network, current strategic planning does not adequately consider this when designing the system.

The planning of the NEM in Australia has evolved significantly since its inception in 1998. At the NEM's inception, the key planning documents included:

- the Distribution Annual Planning Report (DAPR) – prepared annually by each distribution network, and focused on a 10-year planning horizon;
- the Transmission Annual Planning Report (TAPR) – prepared annually by each transmission network, and focused on a 10-year planning horizon;[25] [26]
- the National Transmission Network Development Plan (NTNDP) – a planning document prepared bi-annually by AEMO that focused on new developments required across the bulk system; and
- the Electricity Statement of Opportunities – an annual planning document focused on the outlook of supply and demand across a 10-year period.

In 2018, reforms were introduced to replace the NTNDP with the ISP. The approach to planning in the ISP recognised the significant new infrastructure required as coal-fired power stations retire and variable renewable energy projects connect to the grid. For the first time, planning also incorporated the concept of 'renewable energy zones', which are areas of the grid developed in anticipation of new renewable energy connecting.

[23] AEMC (2024). *The pricing review: Electricity pricing for a consumer-driven future*
[24] Department of Climate Change, Energy, the Environment and Water (2025). *Solar Sharer Offer (SSO)*
[25] NER 9A.9.5 reduces the scope of the TAPR to be prepared by NSW Transmission Network Service Providers in respect of their "*IP planned REZ networks*"
[26] NER 5.1A.1 (e) removes this obligation from Transmission Network Service Providers in Victoria, and assigns this responsibility to AEMO instead.

The reforms that heralded the ISP also recognised important changes in operational demand as a result of economic conditions, energy efficiency and CER/DER. Like the NTNDP, the ISP took a 20-year planning horizon. Also like the NTNDP, the ISP focused on the required new transmission projects across the national interconnected electricity system. The ISP sought to optimise opportunities for new variable renewable generation to connect across the interconnected electricity network.

In NSW, the next significant reform to strategic system planning occurred with the introduction of the NSW Electricity Infrastructure Roadmap (NSW Roadmap). The roadmap heralded the commencement of a bi-annual IIO Report, prepared by ASL as the Consumer Trustee, and stipulated under the EII Act. The IIO sets out a 20-year development pathway to meet NSW's legislated objectives and a 10-year tender plan to inform energy infrastructure investors.[27]

The key difference between the strategic planning undertaken in these documents and other planning documents (like the DAPR and TAPR) include:

- **The planning timeframe**. Taking a 20-year time horizon, rather than a 10-year, ensures longer-term planning considerations including demand growth and emissions objectives can be reckoned with, and supports improved efficiency in planning through better alignment of infrastructure development with long-term policy goals and market needs.
- **The role of economic assessment frameworks to optimise across multiple choices and scenarios**. These frameworks enable a comprehensive evaluation of costs, benefits, and risks across various scenarios, ensuring that the most efficient and effective solutions are selected to meet future energy demand. For the ISP, this includes those projects that minimise overall system cost, and for the IIO report includes those projects that are in the long-term financial interests of NSW electricity customers.

These factors create opportunities to plan projects in advance of need, and sends locational signals to developers on where new network capacity will be unlocked to support the coincident development of renewable generation, storage and transmission projects.

To date, in focusing on transmission level opportunities, the strategic planning in the ISP has not optimised for opportunities that support the transition by connecting new renewable generation and storage at the distribution level. Similarly, there is no formal requirement or process to systematically assess and compare distribution network or non-network options at the state level by EnergyCo's development of the Network Infrastructure Strategy or ASL's development of the IIO Report.

The current approach overlooks the significant contribution made by distribution networks and distribution-connected assets to the electricity system, and risks missing further opportunities for how they can support the energy transition. Analysis completed through this project has identified over 16 GW of available capacity within the sub-transmission network. Leveraging this capacity with new generation and storage will de-risk the energy transition and accelerate progress towards emissions reduction targets.

2.4 Problem 3: Delays, cost and social licence challenges facing transmission-level projects may jeopardise the state's ability to deliver sufficient replacement capacity prior to closure of coal-fired generators.

The success of NSW's energy transition is contingent on the timely delivery of Renewable Energy Zones (REZs) and associated transmission projects identified in the ISP and IIO Report. This is to prepare the system ahead of the closure of major coal generators, including Eraring Power Station – the largest in the NEM. However, despite policy alignment at both state and federal levels, the scale and pace of infrastructure development required is facing significant headwinds. These include:

- Sustained supply chain pressures on the delivery of materials and equipment, as well as workforce and skills shortages, driven by market competition both in Australia and abroad as other economies look to decarbonise.
- Social licence challenges and opposition from communities impacted by generation and transmission infrastructure who cite visual and noise impacts, environmental impacts, disruption to agricultural operations and concerns related to benefits flowing to developers, investors and urban centres while local communities bear the costs.
- Lack of clarity around coal retirements, firming capacity and long-term revenue frameworks to support renewable generation. The complexity and interrelatedness of these factors contribute to risk premiums, further driving up project costs and delaying final investment decisions.

[27] EnergyCo separately prepares the Network Infrastructure Strategy. Whilst not required under the EII Act, this report identifies network infrastructure options to connect generation and storage within NSW's five REZs over the next 20 years. This includes options for REZ network infrastructure projects and priority network infrastructure projects.

Together, these factors are resulting in major project delays and cost overruns. The challenges faced by several major energy transition projects are summarised in Table 2.

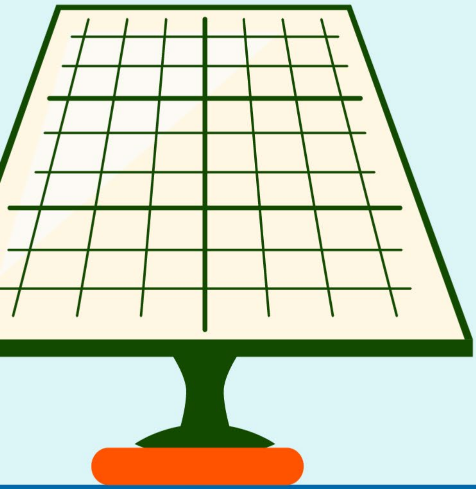
Table 2: Large-scale renewable energy projects and their associated delivery challenges

Project	Purpose	Challenges
Project Energy Connect	Interconnector between NSW and South Australia to improve grid resilience	Significant cost overruns from an initial cost of $2.1 billion to $3.6 billion. Project timeline deferral from July 2026 until late 2027.[28]
HumeLink	Connects Snowy Hydro 2.0 to the grid and enables the REZs	Significant cost overruns from an initial cost of $1.3 billion to $4.9 billion. Completion date estimated by 2027 but is contingent on the progress of Snowy Hydro 2.0.[29]
Snowy Hydro 2.0	Major pumped hydro project providing long duration storage	Significant cost overruns from an initial cost of $2 billion to over $12 billion. Initially expected to be completed in 2026, has now been pushed out to December 2028, commissioning by 2029.[30]

These challenges are placing the NSW energy transition at risk. Without timely REZ development and transmission upgrades, NSW may not be able to deliver sufficient replacement capacity before the closure of coal-fired generation. Reliance on gas, higher wholesale electricity prices and reliability gaps would undermine public confidence, and impact broader energy goals.

[28] Australian Broadcasting Corporation (2025). *$1.5 billion blowout for Australia's largest energy transmission project*
[29] Renew Economy (2024). *Is HumeLink worthwhile? The $5 billion dilemma facing the energy regulator*
[30] Renew Economy (2025). *Cost to build first renewable energy zone in NSW blows out to $5.5 billion*

3. The modelling approach



3.1 Development context

There has been increasing discussion both globally and nationally about the importance of better integrating distribution-level considerations within existing planning and approvals processes.

For the NEM, the next iteration of AEMO's ISP will look to consider distribution network capacity, CER and demand-side factors. Furthermore, the NSW Transmission Planning Review has recommended adopting a more integrated approach to strategic planning – one that better recognises and captures opportunities within the distribution network to support the transition. This focus on integrated, forward-looking distribution system planning is further supported by the recent rule change request submitted by Energy Consumers Australia to the AEMC.[31] The proposed Integrated Distribution System Planning rule aims to modernise and enhance distribution system planning and improve data transparency, sharing and use.

Globally, the UK's updated 'Revenue = Incentives + Innovation + Outputs' framework and integrated system planning approach offer a leading example of how regulatory models are adapting to support more flexible and forward-looking infrastructure development.

Table 3 provides a summary of recent reports that highlight the growing recognition that end-to-end system planning is needed to support an increasingly decentralised energy system.

Table 3: Summary of reports that emphasise the role of distribution networks and CER in system planning

Report title	Author	Publication date	Key considerations
2026 Integrated System Plan	AEMO	Expected June 2026	In response to the 2024 Review of the ISP and the subsequent AEMC rule determination, the 2026 ISP will formally consider distribution network capabilities and opportunities for CER and DER in its capacity outlook modelling. This includes consideration of: • distribution network capacity data • network augmentation costs to integrate more CER • network augmentation options to connect utility-scale generation and storage options to the distribution network.[32]
NSW Transmission Planning Review – Final Report[33]	NSW Minister for Energy and Department of Climate Change, Energy, the Environment and Water (DCCEEW). Prepared by Farrier Swier Consulting Pty Ltd.	October 2025	Assesses NSW's transmission planning framework, ensuring it is fit-for-purpose to deliver REZs, support system reliability, and align with the state's clean energy targets. The report highlights inefficiencies and governance challenges in the current dual planning regimes under the NER and the EII Act, with overlapping roles among multiple entities. The review finds that planning for distribution networks, customer load growth, and CER is not sufficiently integrated into transmission planning, and recommends better integration and coordination between transmission and distribution planning.
National CER Roadmap[34]	CER Working Group	July 2024	Outlines a coordinated national approach to integrating consumer-owned energy assets (including rooftop solar, batteries, and EVs) into Australia's energy system. Its purpose is to unlock the full value of CER by enabling smarter, more equitable participation in the grid, supporting decarbonisation, and lowering energy costs.

[31] Australian Energy Market Commission (2025). Integrated distribution system planning
[32] Australian Energy Market Operator (2025). 2025 Electricity Network Options Report
[33] Farrier Swier Consulting (2025). NSW Transmission Planning Review – Final Report. NSW Department of Climate Change, Energy, the Environment and Water.
[34] Energy and Climate Change Ministerial Council (2024). National Consumer Energy Resources Roadmap

Report title	Author	Publication date	Key considerations
Time is Now[35]	Energy Networks Australia / L.E.K. Consulting Partners	August 2024	Demonstrates how smarter, more proactive use of local distribution networks can accelerate Australia's clean energy transition, drive down costs for consumers, and help the nation meet its 2030 renewable energy targets. It makes the case that the local grid is under-utilised and has untapped potential to contribute substantially to the energy transformation.
Enhanced System Planning Project[36]	C4Net	June 2025	Develops a bottom-up modelling methodology using Victorian DNSP data for integrating active distribution networks and CER into Australia's electricity system planning, aiming to reduce system-wide costs and improve reliability through coordinated DER orchestration and flexibility. The project was specific to Victoria and supported by the near-universal adoption of smart meters in Victoria.

3.2 Building on other studies

The DSP Opportunities Report builds on the findings of previous studies – particularly those outlined in Section 3.1 – by drawing on their insights to enhance the analysis and identify emerging gaps and opportunities for further development. Whilst the need to integrate distribution opportunities into system planning is clear, how this can be achieved remains a key challenge. The DSP Opportunities Report builds on these developments, helping to bridge the gap between top-down planning frameworks and the customer-led energy transformation. This includes:

- Leveraging local DNSP data and insights to support bottom-up demand forecasts at the zone substation level
- Using DNSP voltage and thermal constraints data to understand network augmentation triggers and hosting capacity at zone substation level
- Assessing both the distribution and wholesale market benefits of distribution level solutions, including distribution-connected utility-scale generation and storage, as well as better coordination of household and C&I CER
- Developing an aligned approach with consistent methodologies and data definitions across all three DNSPs
- Combining modelling insights with calls to action that overcome barriers to unlocking value.

Whilst this report has been published after substantive components of the 2026 ISP,[37] the NSW DNSPs understand their important role in supporting system planning by helping to understand and define distribution-level opportunities. To this end, the modelling in this report aligns with and builds on AEMO's work in integrating distribution network opportunities into the 2026 ISP. As a NEM-wide system plan focused on the bulk transmission network, the ISP's sub-regional model – with four sub-regions used to characterise NSW – requires significant simplification and aggregation to represent the distribution network, overlooking location specific constraints and opportunities. In reality, NSW has over 690 zone substations, reflecting a combination of meshed and linear network. By considering the distribution network at the more granular zone substation level, the DSP Opportunities Report builds on the assessment being undertaken by AEMO, ensuring the distribution network is captured with greater fidelity.

[35] Energy Networks Australia (2024). *The Time is Now*
[36] C4NET (2025). *Enhanced System Planning Project*
[37] The *2025 Electricity Network Options Report*, *2025 Input Assumptions and Scenarios Report* and *ISP Methodology* were release in mid-2025.

3.3 Summary of approach

3.3.1 Design principles

The development of the DSP Opportunities Report has been guided by foundational principles of learning, capability building and speed – recognising both the novelty of the exercise, its broader strategic purpose and the importance of timeliness to the impact of the work.

As a first-of-its-kind initiative, the modelling in this report is strategic in nature, seeking to identify and quantify the 'size of the prize' as it relates to distribution network opportunities over a 24-year planning horizon. While further work is required to refine assumptions and address limitations, the process itself is as valuable as the outputs. A deliberate focus has been placed on learning – about data, methodologies and modelling capabilities – with the understanding that these insights will shape future iterations and inform broader planning reforms. Central to this is a recognition that strategic system planning is a whole-of-enterprise endeavour, requiring new skills, systems, and ways of working. Accordingly, internal capability building has been a core outcome of the project.

Speed and timeliness are also critical. The urgency of the net zero transition requires planning processes that are not only robust but also rapid enough to inform real-world decisions. As such, the findings and learnings from this initial report have been developed with a view to immediate relevance and impact.

Recognising these design principles and acknowledging that this is a first-of-its kind exercise – emphasis has been placed on enabling the testing and refinement of assumptions, focusing on the most critical areas of learning and value, and ensuring outputs remained fit-for-purpose to deliver insight and impact for end-to-end system planning. The report is framed as an 'opportunities report' rather than a 'plan' in the first instance. While the initial intent was to develop a plan, the exercise has demonstrated that key distribution network opportunities are currently constrained by barriers that need to be addressed before they can be meaningfully integrated into a plan.

Importantly, the DSP Opportunities Report does not replace existing planning activities such as the Distribution Annual Planning Report or replacement expenditure modelling. Rather, it complements these processes by taking a longer-term perspective – focusing on the larger-scale anticipatory investments and identifying opportunities that drive system-wide value, rather than addressing immediate network needs. The findings of this report provide valuable insights for these other planning exercises.

3.3.2 Modelling tools

The project uses two models to assess the 'size of the prize' as summarised in Figure 6.

Figure 6: Modelling distribution and transmission

The distribution techno-economic model assesses benefits in the distribution network at the zone-substation level.	The market model assesses benefits in the wholesale market, including impacts on utility-scale generation, storage and transmission.
It determines the least-cost resource combination to meet customer demand within each zone substation, including through the uptake and coordination of CER and/or investment in network augmentation and distribution-connected BESS.	It evaluates the benefits from connecting utility-scale generation and storage to the distribution network, and the wholesale market impacts from a smoothed NSW system load profile driven by DER and CER investments identified in the techno-economic model.

See Appendix C to Appendix E for further detail on the techno-economic model (TEM) and wholesale market model.

3.3.3 Distribution network opportunities

The study focused on two overarching distribution network opportunities where DNSPs can and should play a larger role in supporting customers: opportunities to better utilise available capacity in distribution networks, and opportunities to optimise the use of CER. Both opportunities represent untapped potential within the distribution network and the scope to do more.

These opportunities (summarised in Figure 7) are modelled in the TEM and wholesale market model, and can be considered both as standalone opportunities and together to understand the 'size of the prize'.

Figure 7: Opportunities to unlock value within the distribution network

Opportunity 1: Unlocking available capacity

Better utilisation of available capacity in distribution networks

This opportunity considers the potential for connecting **utility-scale generation and storage into the distribution network** where it provides least-cost system outcomes, as well as **targeted investment in DBESS** and **mid-scale solar** to defer network augmentation.

Opportunity 2: Unlocking CER

Optimising the value for and from consumer energy resources

This opportunity considers how **improved coordination and integration of CER**, including rooftop and mid-scale solar, batteries and EVs can reshape load profiles and contribute to whole-of-system cost savings.

All opportunities unlocked

Pulling on all levers to understand the total '**size of the prize**' for distribution network opportunities.

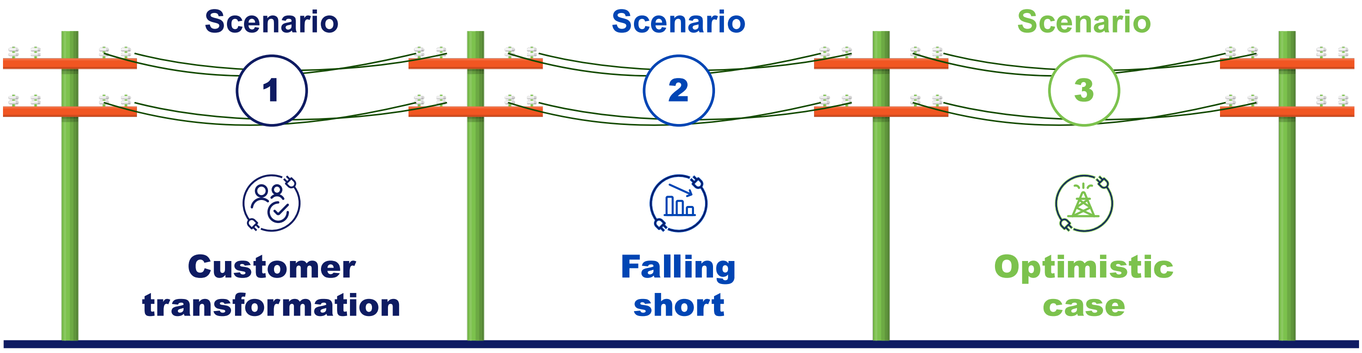
These opportunities are assessed against a **status quo**. Without intervention, coordination of CER is expected to fall short of AEMO's Step Change scenario. This is reflected in the status quo where CER coordination is limited. Additionally, the status quo considers the impacts of not proactively investing in distribution-connected batteries, and there are no opportunities to leverage hosting capacity in the distribution network.

See Appendix B for further detail on the modelled opportunities.

3.3.4 Scenario design

To explore how the benefits of each opportunity might vary under different uncertain future conditions, three scenarios have been developed reflecting varying levels of decarbonisation ambition, customer behaviour, and infrastructure delivery. Figure 8 outlines the three scenarios considered in the modelling and Table 4 provides a summary of the key variables within each. Further details on the scenarios and underlying assumptions are provided in Appendix B.

Figure 8: Summary of the modelled scenarios



This scenario represents a future where decarbonisation progresses rapidly, driven by high levels of customer and societal behavioural change. Customers adopt new technologies including EVs, rooftop PV and electrified appliances quicker and more extensively. Despite this, there are delays to transmission projects and constraints on the annual generation build limits for utility-scale projects, reflecting ongoing challenges in infrastructure delivery at the transmission-level.

This scenario reflects a future where decarbonisation progresses slowly and there is lower societal and customer appetite for behavioural change. Technology adoption is slower, leading to more gradual electrification. At the same time, further challenges are encountered at the transmission-level, with increased delays to transmission projects and tighter constraints on annual generation build limits.

This scenario broadly mirrors Customer transformation, but supply-side assumptions align with AEMO's Step Change scenario with ideal infrastructure delivery, e.g., no delays to transmission build out or annual generation build limits. It assumes stronger policy support, effective coordination and smooth delivery of the optimal development path

Table 4: Key scenario variables

	Customer transformation	Falling short	Optimistic case
Consumption	NSW: DNSP forecasts Rest of NEM: Electricity Statement of Opportunities (ESOO) 2024 Central		
EVs and electrification	NSW: DNSP forecasts Rest of NEM: ESOO 2024 Central	ESOO 2024 Progressive Change	NSW: DNSP forecasts Rest of NEM: ESOO 2024 Central
NSW data centre load	DNSP forecasts	ESOO 2025 Central	DNSP forecasts (in line with *Customer transformation)*
Transmission	Delays to 2024 ISP Optimal Development Path (ODP)	Further delays relative to Customer Transformation	2024 ISP ODP
Build limits	Wind limits in NSW and NEM	Wind and solar limits in NSW and NEM	No build limits
Coal retirement	Delays to 2024 ISP coal retirement schedule		

Whilst the assumptions underpinning the modelling broadly align with AEMO's ISP, deliberate departures have been made where distribution-level data provided more localised insights – including NSW consumption, EV charging coordination and data centre load growth (discussed further in Appendix B). This approach balances alignment with the ISP while recognising the need for greater consistency in data collection and treatment across DNSPs to support future planning maturity.

Further, while AEMO's scenarios are required to focus only on futures that achieve net zero targets and meet jurisdictional policy objectives, the modelled scenarios in this project were able to explore a broader range of outcomes – including futures where transmission development is delayed or coal retirements occur later than AEMO projects. Although the scenarios considered in this report are distinct from AEMO's, there are areas of alignment. For example, the timing of transmission projects in the *Optimistic case* scenario aligns most closely with AEMO's ODP, and AEMO's demand projections align most closely with those considered in the *Falling short* scenario.

3.3.5 Data requirements and challenges

For the first time, the three NSW DNSPs have modelled whole-of-system network impacts down to the zone substation level. This involved bringing together network capacity, network augmentation cost data and bottom-up demand forecasts to model the distribution network opportunities outlined in Section 3.3.3:

- **Network capacity:** DNSP data on available network capacity at the zone substation level, considering both thermal and voltage network constraints. Network capacity is shaped by two key types of constraints: import and export constraints. Import constraints limit how much electricity can be drawn from the grid, and export constraints restrict how much electricity can be sent back into the grid from distributed sources like rooftop solar. Import constraint data is essential for evaluating initiatives that reduce peak demand such as DBESS and CER coordination. In contrast, export constraint data is critical for identifying where there is available capacity to host new distribution-connected generation and/or CER.
- **Cost of addressing network constraints:** DNSP data on zone substation augmentation costs. The costs considered reflect specific zone substation configurations, including the size and space for transformers at each zone substation.
- **Demand forecasting:** DNSP bottom-up demand forecasts at the zone substation level. These are informed by customer and load data and include uptake and coordination projections for CER (both household and C&I) and EVs. The approach to demand forecasting is discussed in further detail in Appendix B.

NSW data centre load in the *Customer transformation* and *Optimistic case* scenarios is also derived from DNSP forecasts. These forecasts use a probability-weighted estimate of expected growth, based on connection enquiry data for projects likely to proceed by 2030. A conservative linear 'ramping' profile that gradually increases data centre load into the late 2030s is also used.

While there is a risk of duplication in connection requests – such as enquiries by the same proponent across DNSPs – the approach taken on which projects to include and how their energy needs grow over time is intentionally conservative. It also does not consider potential future enquiries or unforeseen connection requests. Even so, the resulting demand centre load forecasts indicate significantly higher demand than AEMO's ESOO Central scenario (i.e. Step Change).

While data centres often have behind-the-meter (BTM) resources that can provide flexibility, their operational models place a premium on energy reliability. As such, the modelling assumes flat data centre load in the absence of a more consistent and considered approach across the NEM. Further work is required to better understand the load profile of data centres to inform forecasting.

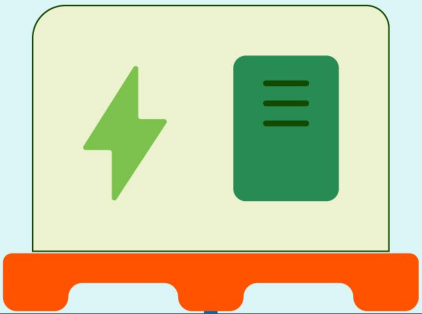
Data at the zone substation level was considered appropriate for this first-of-its-kind planning exercise, providing sufficient granularity in the modelling without imposing significant additional data and computational requirements. The complexity of this challenge is evident in the sheer volume of assets deeper in the distribution network. While there are around 690 zone substations, there are over 210,000 distribution substations across NSW. Though there are additional constraints and opportunities at lower voltage levels, further work and time is required to standardise data collection and analysis across the networks before these can be fully assessed. As a result, benefits in the medium and low-voltage network are not captured in this report. The findings are therefore considered conservative – appropriate for this first report as it reduces the risk of overstating benefits. The low-voltage network will be considered in future iterations, and reinforces the role that DNSPs must necessarily play in an integrated strategic planning process.

Additionally, the modelling draws on existing analysis of the sub-transmission network. Each DNSP provided transfer capacities to the transmission network, with wind and solar resource limits derived by considering land power density and available suitable land within the vicinity of the network. This information was used in the wholesale market model to co-optimise between connecting new utility-scale generation and BESS to the transmission and distribution network.

A key modelling challenge was the characterisation of parts of the network as a mesh. A meshed network provides multiple flow paths connecting substations to feeders and ultimately customers. This provides flexibility by allowing load to be redistributed in the case of network congestion or system faults which can defer the need to upgrade a zone substation that may be at capacity as load can be directed elsewhere. For this report, the impact of meshing has been proxied; further work is required to understand and characterise meshed network impacts in future iterations.

The modelling undertaken highlights the complexity of distribution-level strategic planning, driven largely by the scale and dispersed nature of the distribution network compared to transmission. This is further compounded by differences in data availability and assessment approaches across the three NSW DNSPs. To undertake effective and integrated strategic planning, a consistent approach to demand forecasting – and its key drivers such as behind-the-meter generation, EV uptake, data centre growth and electrification – is critical. As DNSPs transition toward a system operator model and take on a more strategic planning role, there is a growing need to invest in improved data systems and analytical capabilities. To support this, there is an opportunity to establish an integrated modelling and data coordination group across the networks, aimed at realising efficiencies, improving data quality, and ensuring consistency across datasets to better support whole-of-system planning.

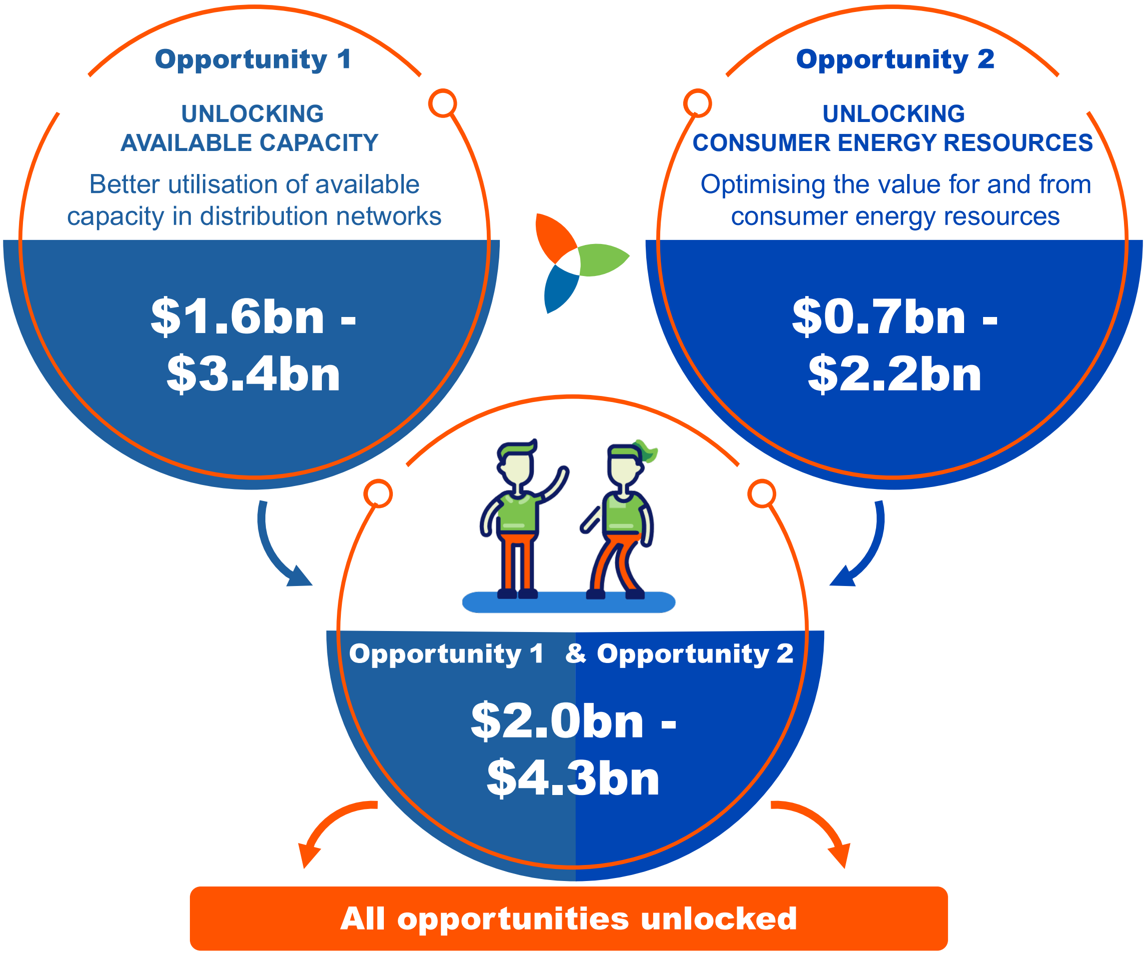
4. The value of distribution-level opportunities



4.1 Overview

There is significant value in unlocking distribution-level opportunities across NSW – estimated at $2.0 – $4.3 billion across scenarios. The modelling highlights a clear need to do more at the distribution level, under all future demand scenarios, to deliver cost savings for households and businesses, help de-risk the energy transition and improve customer participation in the energy system. The economic value of benefits for each modelled opportunity is summarised in Figure 9.

Figure 9: Economic benefits of unlocking NSW distribution-level opportunities[38]



The economic benefits are considered conservative for several reasons:

- The economic appraisal considers a 24-year evaluation period to align with the market modelling. This compares to a 28-year evaluation period considered in the 2024 ISP. A shorter evaluation period captures benefits over a shorter period of time.
- As outlined in Section 3, while modelling is undertaken at the zone substation level, there are additional constraints and opportunities at lower voltage levels. Benefits in the medium and low-voltage network are not captured in this report.

This section explores the key value drivers for the *Customer transformation* scenario. This scenario most closely aligns with the DNSPs' view of future demand and infrastructure delivery.

The *Customer transformation* and *Optimistic case* scenarios produce similar economic results across all the opportunities. This is due to both scenarios using the same demand input assumptions and having a similar overall build out of generation capacity and generation mix. In contrast, the *Falling short* scenario features a lower demand profile, along with further transmission delays and stricter build limits (compared to the *Customer transformation* scenario). As a result, the overall pattern remains consistent but *Unlocking available capacity* and *All opportunities unlocked* deliver lower benefits under the *Falling short* scenario.[39]

Further detail on the economic benefits, distribution network impacts and wholesale market impacts for all scenarios is provided in Appendix D, Appendix E and Appendix F respectively.

[38] The range incorporates the economic results across all three modelled scenarios.
[39] The lower demand in the *Falling short* scenario leads to a unique benefit profile for *Opportunity 2 – Unlocking CER*. In this scenario, the CER orchestration displaces investment in utility-scale BESS, resulting in reduced capital expenditure on new renewable capacity but increased reliance on existing gas generation. This contrasts with other opportunities, where new renewable capacity plays a larger role in meeting generation needs for the NEM.

4.2 Value drivers in Opportunity 1 – *Unlocking available capacity*

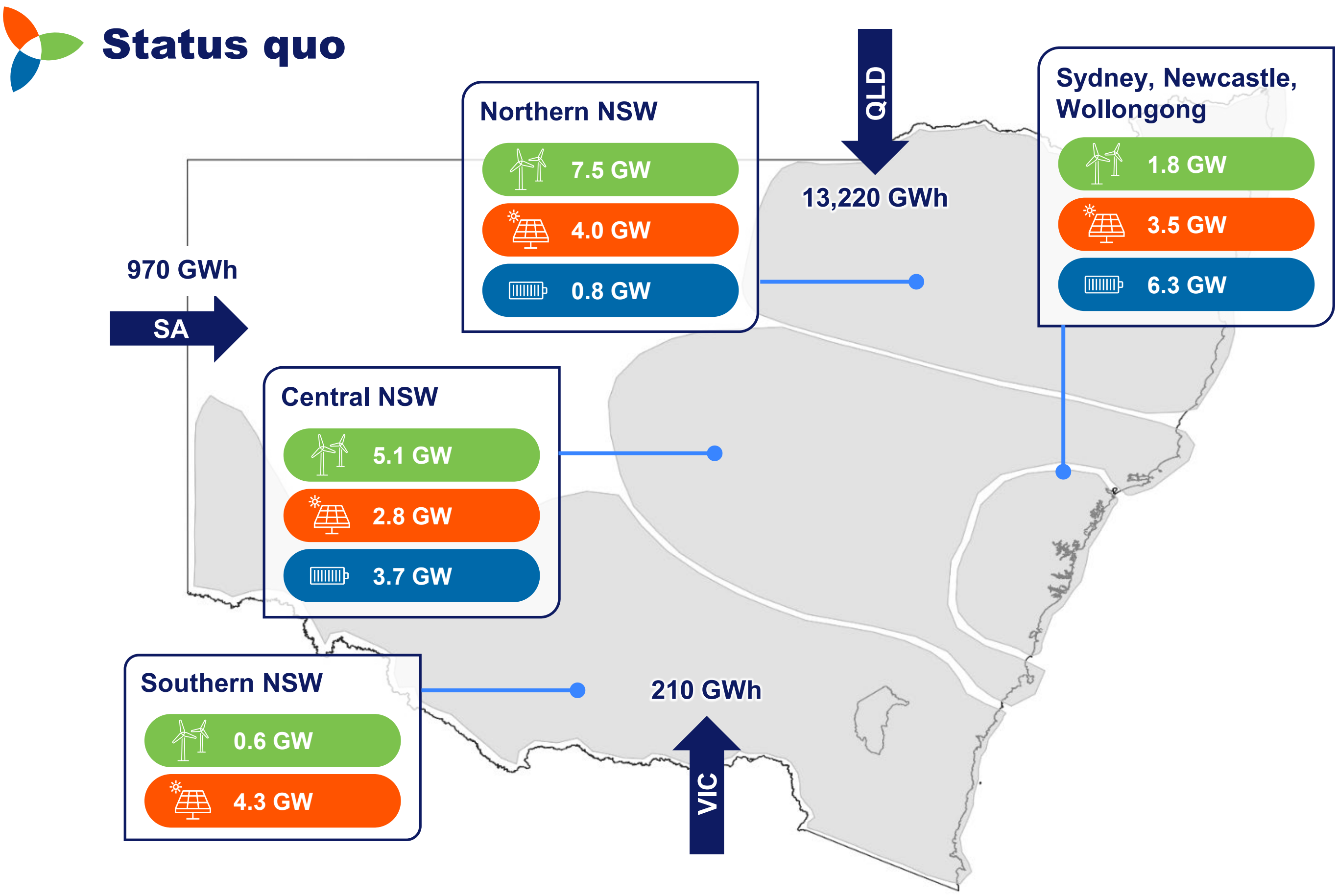
Enabling new generation opportunities through distribution-connected wind and solar can make a significant contribution to managing NSW's rapid load growth, driven by population, electrification and data centres. This value comes from:

- **Unlocking solar generation in or near major load centres** in Sydney, Newcastle and Wollongong – whether on C&I rooftops or utility-scale connections. Locating solar generation closer to where electricity is used helps bypass transmission constraints into Sydney and reduces the need to build new solar projects in REZs that have limited access rights early in the planning process. This approach also allows for more wind generation to be developed over the longer term. The solar investment is co-located with utility-scale storage.
- **Providing additional wind capacity across NSW**. By 2050, this reduces the need for gas-powered generation by over 50 TWh – a key driver of electricity prices – and displaces over 500 PJ of gas consumption[40] – almost four times NSW's current annual gas use.[41] It also decreases the reliance on interconnection to service NSW demand by 65 per cent. Together, these outcomes derisk dependency on other sectors and states, while driving down greenhouse gas emissions by over 30 MtCO2-e across the NEM.

By leveraging both existing distribution network hosting capacity and the additional capacity unlocked through $3.2 billion (real, FY25) in targeted anticipatory investments, 14.7 GW of solar and 5.8 GW of wind is deployed as part of the least-cost system – at approximately $0.15 million per MW. This accounts for a quarter of NSW's total electricity generation by 2050, enough to power all NSW households.[42]

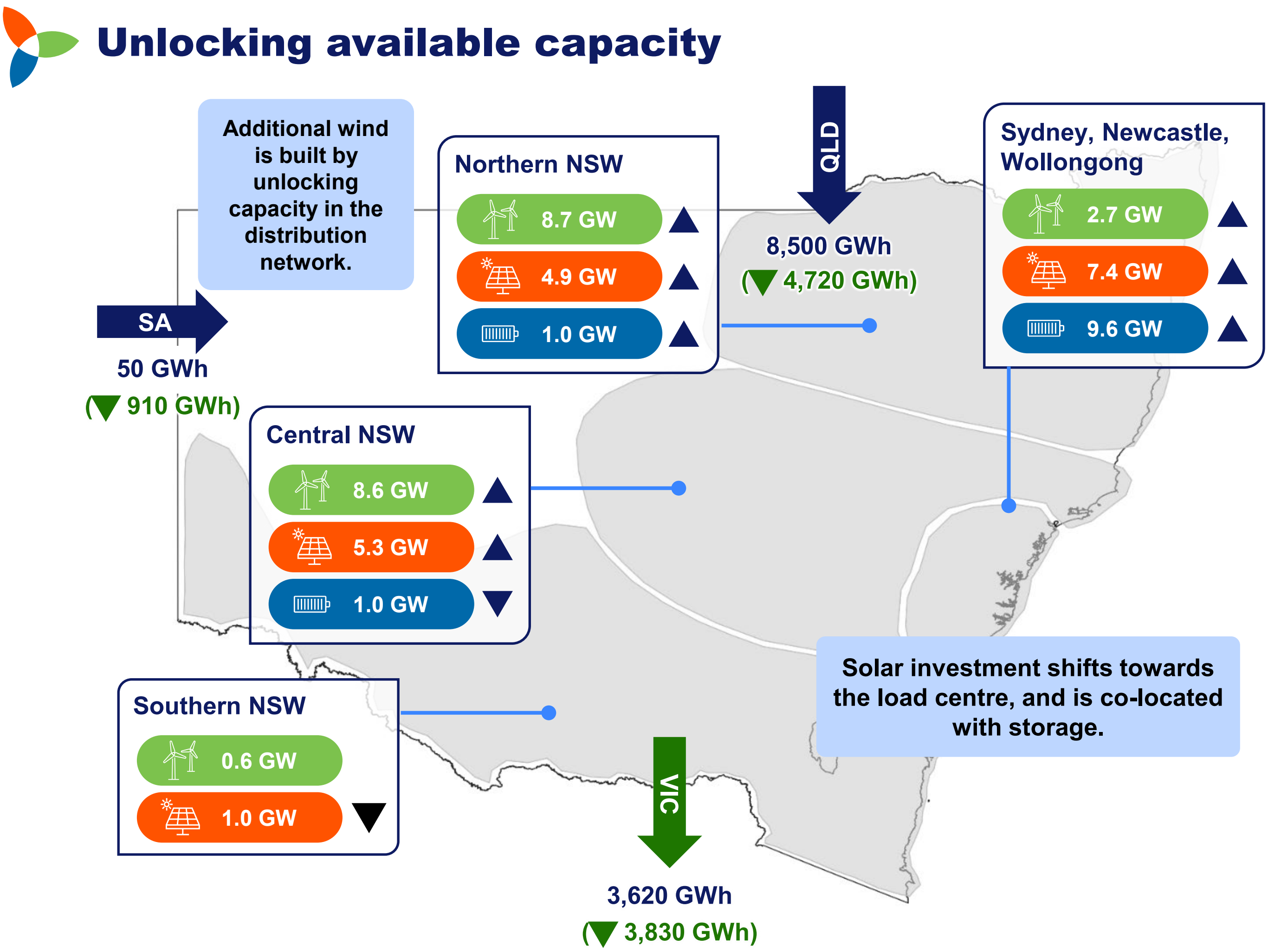
The location of new wind, solar (utility and mid-scale) and utility storage, as well as net imports/exports of electricity to/from NSW for *Status quo* and *Unlocking available capacity* are shown in Figure 10 and Figure 11 respectively.[43]

Figure 10: New wind, solar and utility-scale storage build in NSW in Status quo – Customer transformation



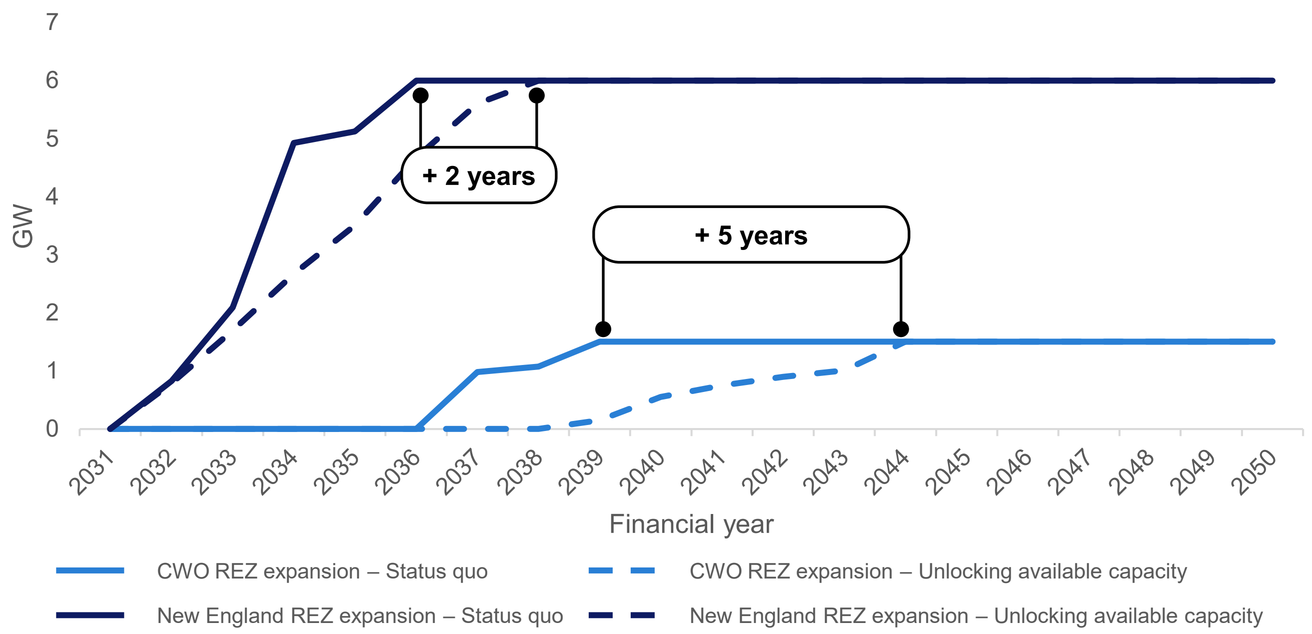
[40] Based on a heat rate of 10 GJ/MWh.
[41] NSW Environment Protection Authority (2024). *Energy consumption 2024*. Primary energy consumption by gas in 2022-23 used.
[42] This reflects underlying residential consumption and includes all non-transport electrification, such as electrification of heating, hot water and cooking, but does not include EV load.
[43] Note that the capacity numbers reflect new generation and storage build that is additional to projects already in the pipeline. The regions shown reflect AEMO's sub-regional topology for NSW.

Figure 11: New wind, solar and utility-scale storage build in NSW in Unlocking available capacity – Customer transformation[44]



Transmission investment is still critical, but unlocking distribution-connected generation and storage de-risks the energy transition in NSW by buying time. In the *Status quo*, both Central West Orana (CWO) REZ Stage 2 and New England REZ see rapid expansion, reaching their full capacity within 5 years to manage persistent load growth alongside retiring coal generation. Using the distribution network too buys the equivalent of 2 years for New England REZ and 5 years for CWO REZ as shown in Figure 12.

Figure 12: Transmission network augmentation – Customer transformation



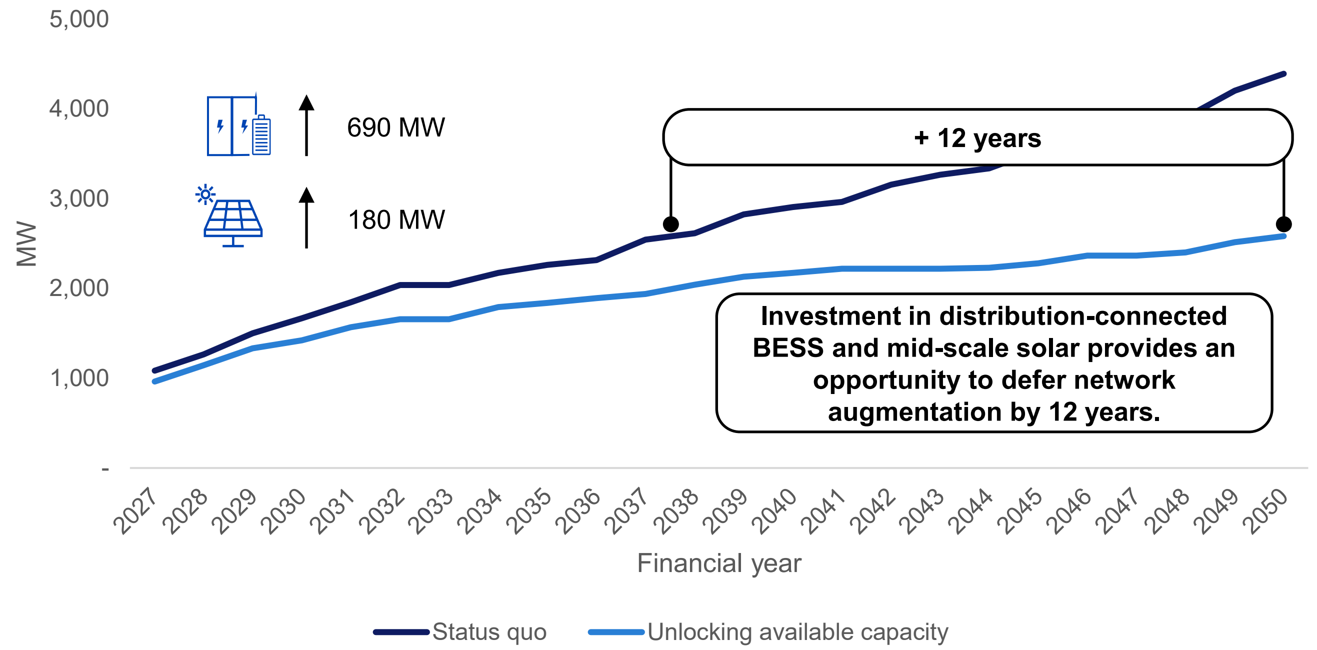
[44] Note that the differences in interconnection numbers shown may not add up due to rounding.

Moreover, the deployment of DBESS at the zone substation has the potential to cost-effectively defer expensive zone substation upgrades due to their:

- **Ability to time-shift generation and provide network support.** By charging during periods of excess solar, DBESS can support the system during periods where import capacity is constrained, reducing the need for network augmentation
- **Participation in the wholesale market.** By participating in wholesale market arbitrage, DBESS reduces the need to draw energy from the grid when costs are high, typically to meet evening and overnight demand
- **Flexibility in scale.** Unlike traditional distribution investments, which tend to be "lumpier" in nature, batteries can be built in smaller increments over time, which can significantly reduce capital expenditure.

Co-locating distribution-connected generation and storage further drives these benefits by maximising the utilisation of these assets. At the distribution-level, pairing 690 MW of storage with 180 MW of mid-scale solar provides an opportunity to defer zone substation augmentation by 12 years. Mid-scale solar is particularly important later in the planning horizon when midday EV charging becomes a significant driver of distribution load profiles. In the *Status quo,* the constrained midday import capacity prevents batteries in the distribution network – both DBESS and BTM BESS – from being fully charged to meet evening demand. Mid-scale solar investment provides an additional generation source to charge these batteries in the distribution network. Co-located with DBESS, this provides opportunity to defer the need for distribution network investment. This is highlighted in Figure 13.

Figure 13: NSW distribution network augmentation – Customer transformation scenario



DBESS also promotes customer participation in the system – enabling more equitable outcomes through community batteries, reducing curtailment, and facilitating greater investment in rooftop and mid-scale solar. This is discussed further in Section 6.6.

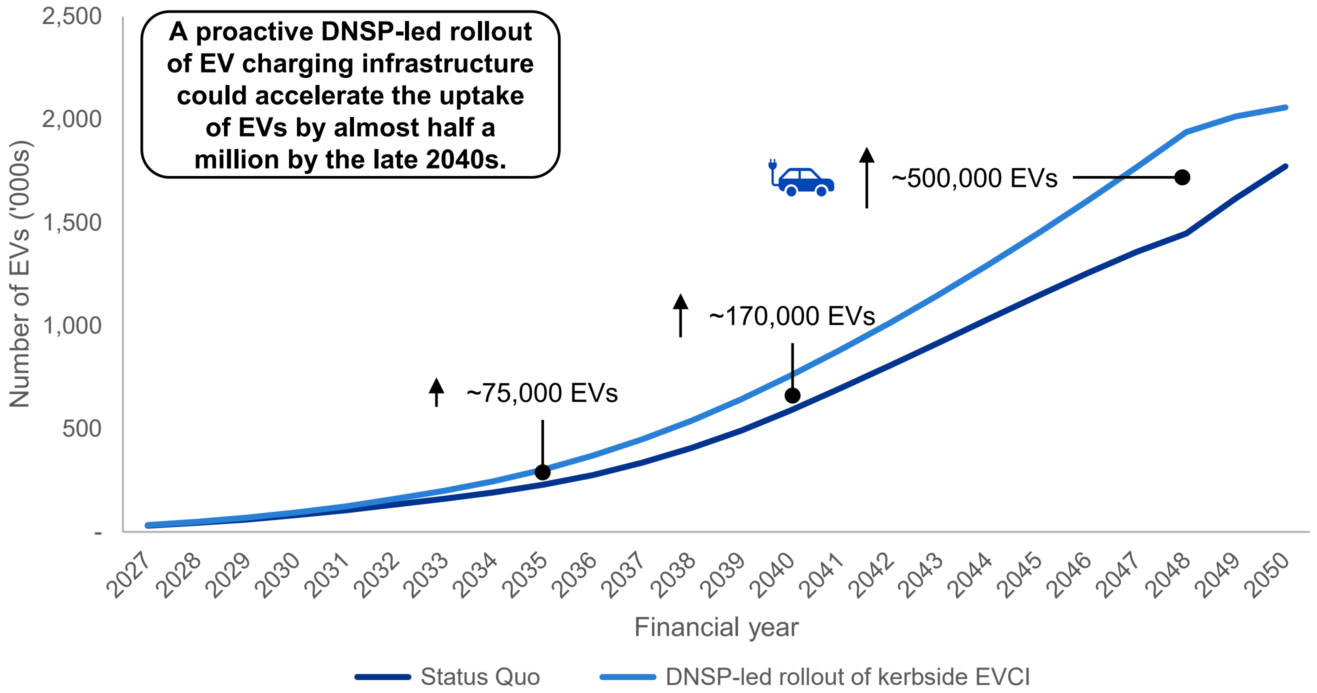
4.3 Value drivers in Opportunity 2 – *Unlocking CER*

Unlocking CER highlights the value of coordination in an increasingly decentralised system. By better orchestrating CER – battery storage, EV charging and vehicle-to-grid – and leveraging local, mid-scale solar, up to $2.2 billion in benefits can be unlocked.

Coordinated CER can respond more effectively to network cost signals, providing an opportunity to defer the need for distribution network augmentation. Further value is created in the wholesale market through coordinated CER storage – BTM BESS and vehicle-to-grid – which reduces the need for utility-scale storage. When combined with orchestrated midday EV charging, this also contributes to a flatter load profile. All customers will benefit – those with CER through increased participation in the energy system, reduced curtailment and a greater return on their assets; and all customers from a more reliable and lower-cost energy system.

As more of the vehicle fleet becomes electric, the coordination of EV charging will become increasingly critical to managing peak load growth and keeping costs down for customers. In line with its Net Zero and Climate Change policy, NSW is aiming for a net zero transport sector by 2050.[45] Central to this is supporting the rollout of public EVCI. DNSPs can play an important role in supporting the state's transport decarbonisation journey. A proactive DNSP-led rollout of low-capacity pole mounted kerbside EVCI could accelerate the uptake of EVs by almost half a million by the late 2040s as shown in Figure 14.

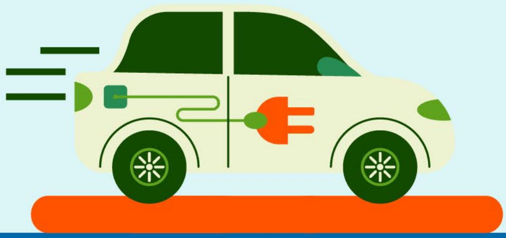
Figure 14: NSW EV uptake for households without dedicated off street parking – Customer transformation



Source: EBDM, Appendix G

[45] NSW Government (2023). *Net Zero and Climate Change Policy*

5. Value pathways

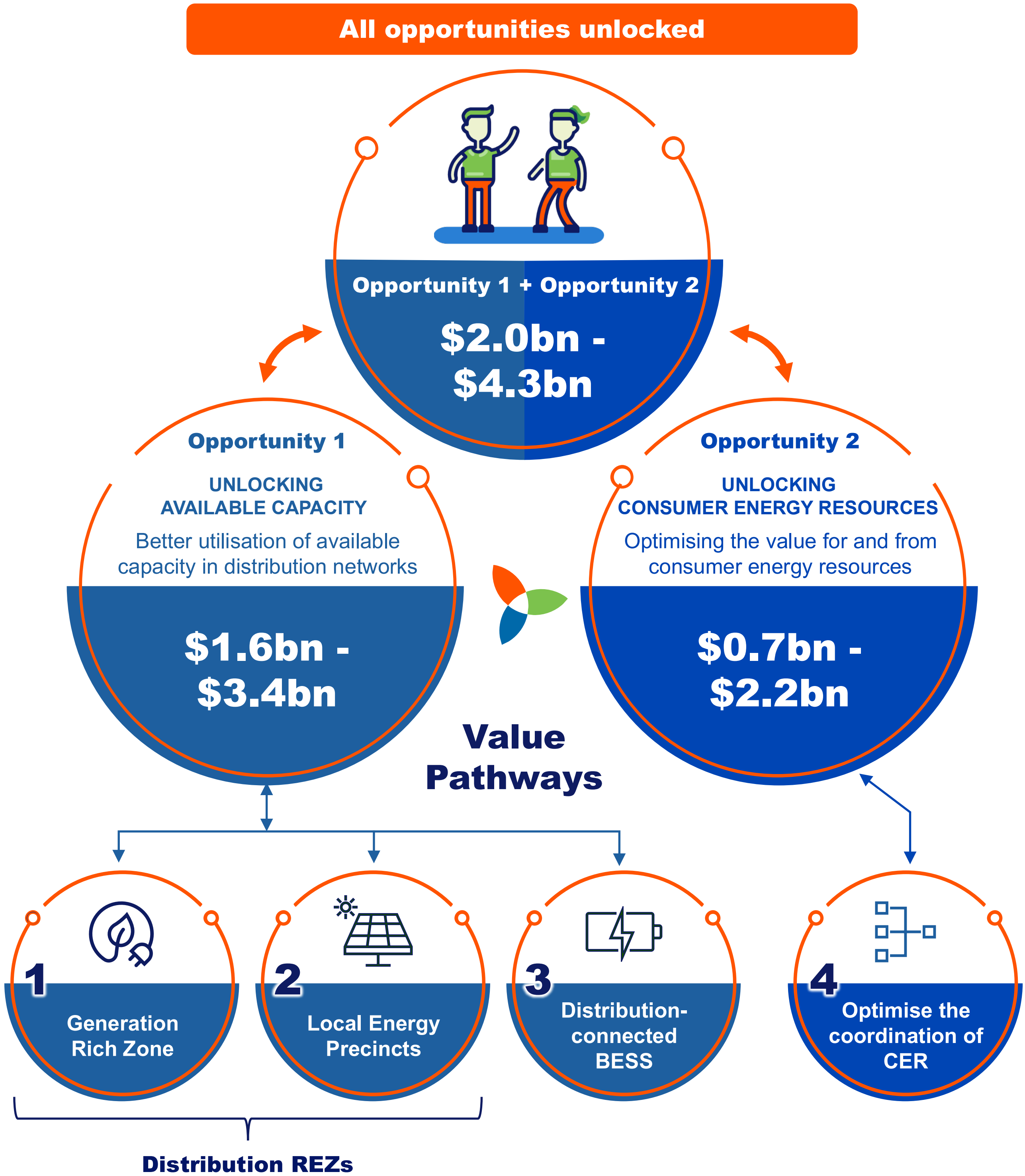


5.1 Introduction

While Section 4 outlines the economic benefits that can be unlocked through better utilisation of available distribution network capacity and optimising the value for and from CER, this section outlines how that value can be realised in practice.

The modelling demonstrates the value of wind and solar generation connected to the distribution network, co-location of generation, storage and load, DBESS and coordination of CER. The DSP Opportunities Report focuses on four pathways that have greatest potential to unlock this value and can be readily supported by DNSPs. This is illustrated in Figure 15.

Figure 15: Pathways to unlock value



This section explores these four value pathways. Each value pathway is supported by case studies of ongoing projects and initiatives across the NSW DNSPs, and serve as illustrative examples of the benefits and value that can be unlocked through successful implementation of the pathways.

5.2 Generation Rich Zone

A Generation Rich Zone (GRZ) is an area within the footprint of the distribution network that is strategically planned and developed to support the integration of utility-scale generation and storage projects. These zones leverage available hosting capacity in the sub-transmission levels of the distribution network and can produce energy to support the needs of the local community as well as the broader electricity market.

Distribution networks already accommodate a substantial amount of utility-scale wind and solar generation. However, there is still latent capacity within the network that could support even more utility-scale storage and generation. Much of this potential remains untapped, but could be unlocked through targeted, anticipatory investments.

What is the case for Generation Rich Zones?

GRZs provide a cost-effective and efficient way to deploy generation and storage at scale. Typically, the network augmentation cost associated with distribution network upgrades is many times less than the costs associated with transmission network projects, subject to any upstream augmentation works. GRZs can also be delivered more readily as sub-transmission systems are serviced by a broader range of contractors, equipment suppliers and workforce capabilities compared to higher voltage systems, enabling faster mobilisation and shorter construction timelines.

Moreover, by making use of existing land, and minimising greenfield development, GRZs limit the impact on host communities and can mitigate social licence challenges. They also create less disruption to existing networks as distribution-level connections require fewer complex outages or interface works with critical backbone transmission assets, thereby reducing risks to system stability during construction.

From a system perspective, GRZs can provide greater generation diversification and contribute to system resilience. Distribution-level solutions enable geographic diversification of renewable generation across the network footprint. This spatial diversity improves energy security and output stability, particularly important in variable conditions such as cloud cover or localised weather events.

In aggregate, GRZs provide a range of timing and cost advantages associated with avoiding greenfield development and utilising existing infrastructure. These present an opportunity to deliver meaningful and rapid contributions to NSW Roadmap targets by 2030.

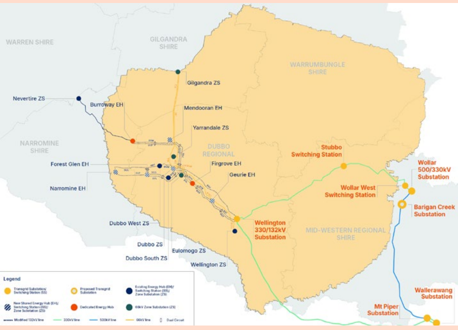
GRZs do not replace the need for large-scale generation and the supporting transmission infrastructure, which remain key for the energy transition. However, these larger projects will take time to develop and deliver. Instead, strategically planned distribution-connected generation and storage may mitigate or delay the need for certain transmission network investments and utility-scale generation and storage, providing flexibility and progressing Australia’s path to decarbonisation.

The Dubbo Distribution Project shown in Figure 16 below is an example of a distribution GRZ that is supporting the connection of significant new renewable energy generation to support the transition.

Figure 16: Case study - Dubbo Distribution Project

Essential Energy

Dubbo Distribution Project



Case study overview

- The Dubbo Distribution Project (DDP) is located within the CWO REZ geographical boundary, with phase 1 of the project currently under construction and expected to deliver first energy in 2026 with full realisation of generator connections by 2030.
- CWO REZ is the first transmission REZ to be initiated under the NSW Roadmap.
- Essential Energy owns and operates a broad network of existing sub-transmission and distribution infrastructure across the CWO REZ and beyond, as illustrated in the map adjacent.
- The network augmentation to be undertaken by Essential Energy for DDP spans new 'Energy Hubs', augmentation of existing switching stations, upgrades to existing zone substations, 132 kV sub-transmission line and protection upgrades, as well as an upgrade to the Wellington supply point.
- The DDP supports the connection of renewable energy projects by enabling energy flows from Essential Energy's 132 kV network.
- Its primary objective is to transfer energy to Transgrid's 132/330 kV bulk supply point, ensuring the benefits reach electricity customers across NSW.
- The DDP will exclusively host large scale renewable projects which are required to be registered with AEMO. The projects will connect via the Chapter 5 process as detailed in the NER.

Benefits and rationale

- Supports the **additional connection of approximately 2.3 GW of generation capacity by 2030** with a targeted Essential Energy export capacity of 750 MW and a transfer capacity of 1.1 GW
- **Enhanced investment certainty** by aligning infrastructure delivery with generator timelines and complementing major transmission projects
- **System reliability and resilience improvements** by uplifting Essential Energy existing 132 kV infrastructure and increasing network operability
- Ability to utilise existing assets, facilities and easements to **minimise cost**
- **Social licence and local community benefits** stemming from an established Essential Energy presence and minimising construction of new infrastructure
- Environmental characteristics including the Dubbo region's **prime location for wind, solar and DBESS** projects
- The DDP focuses on augmentation of existing network assets and line routes, **deferring the need for greenfield construction and creating new generation connection points** in the critical 2028-32 period.

5.3 Local Energy Precinct

Local Energy Precincts (LEPs), also referred to as “local energy hubs”, refer to designated areas within the distribution network that capitalise on available rooftops and other available land to generate local energy, supported by local storage. LEPs accelerate the deployment of DER in a local network area that both produces and consumes clean energy. Surplus energy generated within the LEP – typically the middle of the day – is stored in batteries to meet demand during non-generation periods. Any additional surplus energy can be exported to the wider NSW network, lowering energy costs for all customers.

DNSPs are uniquely suited to plan and coordinate these precincts. They can identify areas with additional rooftop solar potential and network hosting capacity, and strategically locate storage across the network to maximise benefits from the energy generated.

What is the case for a local energy precinct?

Despite the significant uptake of rooftop photovoltaic systems (PV) in NSW, there is untapped solar potential on both residential, C&I rooftops and government-owned land. LEPs can capitalise on this potential by increasing renewable generation in the local area. In isolation, a significant increase in rooftop solar can pose challenges for the stability of the grid. As rooftop solar penetration grows, integrating it into the electricity system becomes increasingly important. LEPs play a role in mitigating these minimum load challenges, balancing local generation with demand and storage solutions, and helping to enhance grid stability.

By integrating storage solutions with onsite renewables, LEPs provide opportunities for C&I customers to maximise self-consumption, whilst also generating a return on exported energy. This provides an incentive for C&I customers to increase solar installations beyond their immediate consumption needs, as excess generation can be stored and used later for the benefit of the system and customers, improving the financial viability of solar investments.

Over time, the additional renewable generation provided by LEPs may stimulate local economic development by attracting investment from load intensive industries such as data centres, certain types of manufacturing and technology intensive healthcare facilities to these areas to capitalise on the local generation. Section 6.7 explores the opportunities presented by data centres, particularly the co-location of these high-load assets with DER in LEPs, and highlights the potential for optimised network utilisation and reduced infrastructure costs through strategic planning.

Overall, by focusing on local interventions and existing infrastructure, LEPs will enable more renewable energy to connect to the distribution network, whilst avoiding upstream network upgrades and reducing dependence on the transmission network. Storage solutions will also play a critical role, reducing curtailment and maximising value from the renewable energy generated.

Figure 17 below is one example of an LEP that leverages load co-location opportunities and storage solutions to support faster deployment of CER and DER. Additionally, Figure 18 presents a further example of a potential Sandbox trial, which would enable DNSPs to create a market for excess solar through battery orchestration, to deliver equitable benefits to customers.[46]

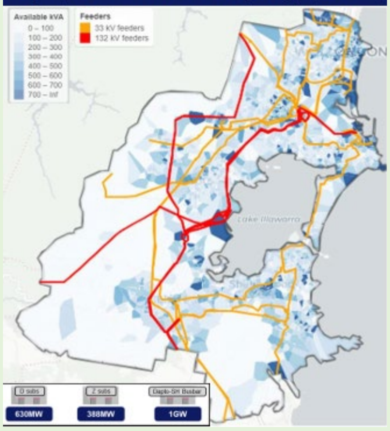
[46] At the time of publication, Community Power Networks was in initial stages under the AER’s Sandbox trial process. Accordingly, some information on this project may not fully reflect subsequent developments or outcomes arising from the project’s progression or implementation.

Figure 17: Case study - Illawarra REZ

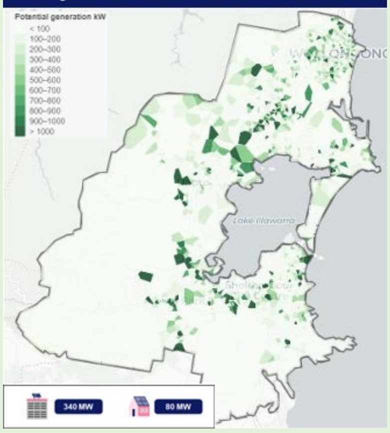
Endeavour Energy

Illawarra REZ

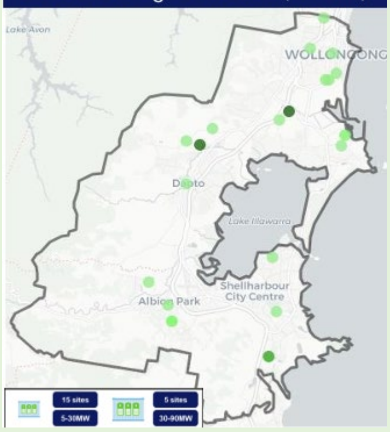
Repurposed Network Capacity (1GW+)



Ready Generation Potential (420MW+)



Smart Storage Potential (1.5GW)



Case study overview

- Endeavour Energy has signed a memorandum of understanding and is working with EnergyCo to jointly develop innovative network and battery solutions as part of plans for NSW's first urban REZ within the region.
- The Illawarra REZ is one of the five REZs under the NSW Roadmap and has unique features including being distinctively urban, with high demand, many existing customers, and significant rooftop PV and local storage potential. The region already hosts major energy, port and transport infrastructure, a skilled workforce and strong demand for future renewable energy projects.
- The Illawarra region currently lacks the energy storage needed to move solar from midday to evening peaks. New community and utility-scale batteries (third-party owned) will address this and incentivise local generation.
- The overarching approach is focused on incremental upgrades, leveraging existing networks and deploying smart/grid-flexible assets, rather than building new large-scale generation/transmission infrastructure.

Benefits and rationale

- Faster deployment **reduces reliance on coal and cuts CO_2 emissions** sooner than other generation or network augmentation options, accelerating progress towards net zero targets
- **Optimises solar generation by leveraging storage solutions** to reduce curtailment and maximise energy use
- **Supercharges local generation** beyond self-consumption and incentivises the sharing of surplus energy with the community
- **Avoids the scale of transmission network augmentation** required for utility-scale generation projects
- Reduces costs for customers by **increasing the utilisation of existing network assets**
- **Delivers equitable access** to clean, low-cost energy to all communities.

Figure 18: Case study - Community Power Networks

Ausgrid

Community Power Networks (CPN)

Case study overview

- Ausgrid has submitted a trial waiver application to the Australian Energy Regulator (AER) under the sandboxing framework.
- The trial tests the hypothesis that DNSP-led orchestration of batteries can deliver superior benefit for customers by leveraging the following innovations:
  1. Making a local market for surplus solar
  2. Making a more efficient grid by orchestrating batteries
  3. Delivering equitable benefits to all customers
- The CPN trial would take place in two NSW regions – Charmhaven (residential) and Botany-Mascot (mixed C&I / apartment settings):
  - Botany-Mascot (2 zone substations)
  - Charmhaven (1 zone substation)
- The trial involves pooling surplus solar from rooftops (especially C&I buildings) and pairing this with local battery storage to store excess solar energy. The battery sizes are expected to be around 400 kWh each, totalling 130 MWh.
- The batteries are owned and directly controlled by Ausgrid for the pilot (other ownership models and orchestration solutions will be explored as a long-term solution). The solar is owned and operated by third parties, e.g. property owners, commercial solar and retailers (Ausgrid will only step in to solar ownership and operation if commercial markets do not respond).
- Customers with rooftop solar benefit from higher feed-in-tariffs, increasing by an estimated 50 per cent to provide a better return on excess solar produced.
- Once costs are netted off, the remaining benefits are equitably shared with all customers in the CPN catchment as an annual dividend – even if that customer doesn't have CER assets.

Benefits and rationale

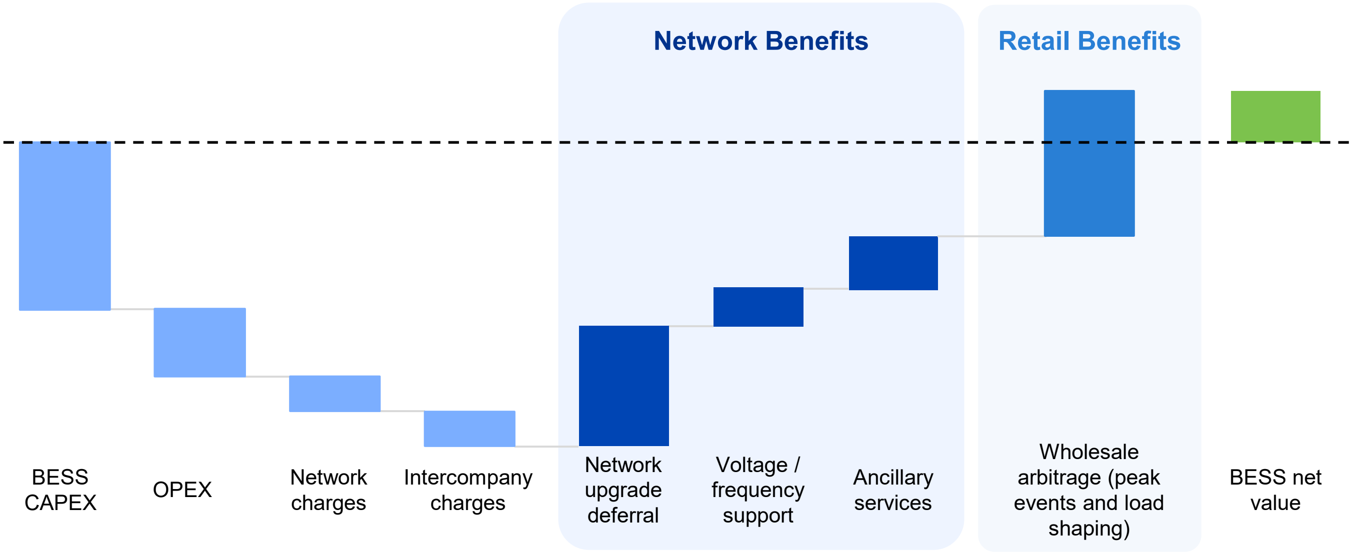
- **Customer savings shared equitably amongst all customers**, equating to around $150-$200 per customer per annum for a typical household once fully operational
- **Additional savings accrue to solar owners** from higher feed-in tariffs than currently exist
- Over **420,000 tonnes of CO_2 removed** from energy generation (equivalent of 8,350 cars)
- $84m of batteries added to the network, with **130MWh of additional storage** and **70MW of additional solar**, relative to base case
- Estimated to be over **20% cheaper than building firmed renewable generation** via traditional large-scale infrastructure
- Will reduce peak demand by more than 20% at the zone substation level, creating capacity for more load and ultimately **higher network utilisation**
- Ausgrid is underwriting the pilot, meaning no losses will be recovered from customers if the pilot doesn't achieve a positive return and has to be unwound, **supporting equitable outcomes without shifting risk to customers.**

5.4 Distribution-connected BESS

As the energy system evolves, the role of distribution networks is also changing. The distribution network of the future needs to be able to transfer energy not only over distance, but across time as well. DBESS will play a critical role in time-shifting energy and helping to balance supply and demand. From a system planning perspective, DBESS offers flexibility by providing a longer window of time before further network investment is required. This puts downward pressure on electricity bills for all customers and can help de-risk the energy transition.

DBESS can be used in different ways, at different scales, and under different business models, to create value for customers and support the grid. This is reflected in the diverse value stack for DBESS, which spans network and retail value streams as illustrated in Figure 19. These benefits streams are currently realised through partnership models between DNSPs, retailers, and aggregators, who share value streams and operational responsibilities under varying regulatory and commercial frameworks.

Figure 19: Illustrative value stack of DBESS (not to scale)



Network upgrade deferral
Provides an opportunity to defer costly network upgrades by time-shifting generation, placing downwards pressure on consumer energy bills.

Voltage and frequency support
Enhances grid stability, reducing the need for ancillary services.

Provision of ancillary services, including fast frequency response
Provide support services such as frequency control and voltage control. The fast response time of battery projects can provide opportunities to capture greater revenue from the market.

Wholesale arbitrage
Generate revenue by charging during low price periods and discharging during peak demand hours, placing downwards pressure on electricity prices.

Benefit to remote/off-grid locations*
Enable remote/off-grid regions to be more self-sufficient by using DBESS in conjunction with solar generation, reducing reliance on expensive gas/diesel generators.

Improving customer participation*
Reduces curtailment of CER assets like rooftop solar.

** Benefits not reflected in illustrative value stack*

Distribution-connected storage includes:

- Batteries connected to the sub-transmission network
- Batteries located deeper in the distribution network and closer to the customer – for example, around zone substations, community batteries and batteries that support LEPs.

The modelling demonstrates that placing storage assets deeper within the distribution network – typically connected at or below the zone substation level – offers additional benefits. These storage systems act as a flexible resource, helping to optimise network investment and enabling the network to capture a broader range of value streams (illustrated in Figure 19). These systems primarily store excess rooftop solar and discharge it during the evening peak, helping to minimise renewable energy curtailment, facilitate increased solar penetration, manage localised voltage and thermal constraints and defer the need for network augmentation. These batteries are more efficient than BTM BESS, allow for greater control by market participants and networks, and can be delivered at scale and speed by DNSPs. While demand-side initiatives – such as those modelled in EBDM – can support increased uptake and coordination of BTM BESS, the majority of these systems remain uncoordinated, limiting the benefits that can be provided to all customers relative to front-of-the-meter systems.

When located at zone substations, DBESS can smooth demand peaks and troughs, reducing the amount of headroom that needs to be built into upstream network assets. This enables DNSPs to delay upgrades to critical infrastructure such as transformers, high-voltage busbars, and incoming feeders until demand increases can no longer be offset by the battery system. By improving utilisation of existing network assets in this way, DBESS can provide cost savings for all customers.

There are currently several models for ownership and operation of DBESS in NSW, each influencing the degree to which the value streams in Figure 19 can be unlocked. These models also impact the speed of deployment, which is often constrained by challenges like investment incentives, regulatory approval processes and the alignment of commercial interests among stakeholders. To achieve the necessary scale and speed of DBESS, deployment will require a mix of ownership and operation models tailored to individual use cases.

In addition, ownership models can also impact how value from community assets are shared with local customers. Community batteries as an example offer significant equity and social benefits by making energy storage accessible to a broader range of households, including renters, apartment dwellers, and those unable to afford their own systems. By pooling resources at the neighbourhood level, these batteries provide an avenue to share the benefits of rooftop solar across the community. They also help address energy inequity by ensuring that vulnerable or low-income communities can participate in the energy system.

One approach is being implemented through Project Bolster (Figure 20), where Essential Energy is deploying DBESS at zone substations to accelerate the integration of new renewable energy generation. As shown in Figure 21, the Ausgrid Community Battery program is an example of accelerating DBESS connection deeper in the distribution network to promote customer affordability and equity.

Figure 20: Case study – Project Bolster

Essential Energy

Project Bolster

Case study overview

- Project Bolster is a zone substation battery storage program - part of Essential Energy's broader strategy to enhance energy storage capabilities and support the transition to renewable energy sources.
- The project involves the development of 10 sites in Tranche 1, with a total capacity of ~368 MW and an energy storage capacity of 736 MWh in a two-hour configuration.
- Essential Energy leases the land to third-parties who build, own and operate the DBESS. There are established partnerships between Essential and leading renewable energy companies to support system deployment and operation, essential for Tranche 1's success and market expansion. The partnerships involve negotiation on the extent to which Essential Energy can use the storage for network services.
- The sites for Tranche 1 span Essential Energy's network and were chosen based on strategic criteria including proximity to renewable energy sources, existing infrastructure, and potential market demand.
- The project involves implementing next-gen lithium-ion battery technology to improve energy density and reduce charging times, testing performance and reliability in real-world conditions

Benefits and rationale

- Accelerates the transition to renewable energy generation by **rapidly expanding BESS capacity across the network** and enabling 3rd party access to Essential Energy land for DBESS deployments
- Enables **better management of the system** by using distributed storage across the network as more localised generation enters the grid, delivering whole-of-network benefits
- Serves as an **alternative to traditional network augmentation**, helping to manage peak demand and deferring network investments
- Leverages Essential Energy **land holdings in proximity to existing zone substations**, selected based on proximity to renewable energy sources, existing infrastructure, and potential market demand
- Competitive pricing for larger sites will result in **cost savings and improved financial outcomes over the project lifespan.**

Figure 21: Case study – Community batteries

Ausgrid

Community Batteries

Case study overview

- Ausgrid has an existing portfolio of community batteries, with future expansion plans (illustrated below).

Existing portfolio | *Future*

	Ausgrid innovation trial (Feb 19-Dec 21)	**DCCEEW Pilot** (Feb 19 – Dec 21)	**ARENA scale-up** (Jun 24 – Feb 26)	**Future expansion** (Feb 26+)
Batteries	**3**	**6**	**16**	**32+**
Battery Size	Pole top batteries, 30-50 kW, 1-2hr	Small community batteries 100-200 kW, 1-2hr	Large community batteries ~5 MW, 1-2hr	Large community batteries ~5 MW, 2-4hr
Total MW	0.2 MW 0.4 MWh	1.2 MW 2.6 MWh	40.4 MW 85.1 MWh	250 MW 500+ MWh

- The ownership model for these community batteries is based on a network-led model, whereby Ausgrid develops and owns the DBESS, and leases capacity to a third-party, as per the below:
  1. Ausgrid develops and owns the battery, retaining some control for network use
  2. Ausgrid leases capacity to third party market participants (e.g. retailers)
  3. Commercial partner operates battery in energy and ancillary markets
  4. Retailer offers eligible customers virtual storage.

Benefits and rationale

- **Provides energy bill savings** to support customer affordability, enabled by discounted **Local-Use-Of-System tariffs**
- **Promotes equity** by allowing eligible customers to benefit from community batteries in a similar way to a household battery but without the upfront costs
- Available to customers that might face barriers installing household batteries, including **customers living in apartments, renters, and low-income households**
- **Supports the integration of more rooftop solar** by storing surplus energy and feeding it back into the network during peak periods, helping to **reduce curtailment** and putting **downward pressure on energy bills**
- Given Ausgrid's experience in deploying community batteries, future tranches are expected to achieve **significant cost reductions through delivery efficiencies and economies of scale**
- **Substantial network benefits** from DBESS built in the most constrained parts of the Ausgrid network.

5.5 Optimise the coordination of CER

DNSPs are well placed to support the coordination of CER, providing a platform for customers to trade energy and services while continuing to build capabilities to support the electricity system of the future. Improved coordination of CER helps to reduce strain on supply and demand balance, network infrastructure, support customer energy choices, improve grid stability and resilience and ultimately put downwards pressure on costs for customers.

There are several tools DNSPs can use to facilitate the use of CER to benefit customers and the overall energy system. Three examples of these tools are summarised in Figure 22.

Figure 22: Key tools DNSPs can use to support the coordination of CER[47]

Dynamic Operating Envelopes

- Dynamic operating envelopes are flexible, location and time-specific export and import limits for CER that are adjusted in near real-time based on local network conditions.
- They provide benefits by maximising available network capacity, reducing curtailment of customer exports, and enabling more equitable access to the grid without costly infrastructure upgrades.

Dynamic Pricing

- Dynamic pricing refers to electricity tariffs that vary based on time, demand, or network conditions (e.g. time-of-use tariffs, demand tariffs, real-time pricing and critical peak pricing).
- This approach provides benefits by incentivising CER owners to shift consumption or exports to times when it is most valuable to the system.
- This helps to reduce peak demand, lower system costs, and support more efficient investment in network and generation infrastructure.

What is the opportunity for CER?

The opportunity for CER to support Australia's transition to net zero is immense. The 2024 ISP forecasts coordinated CER/DER to comprise 66 per cent of the NEM's storage capacity by 2050, with CER modelled to reach ~45 per cent of total NEM generation capacity.[48]

DNSPs are already playing a critical facilitation role in enabling households to connect and participate in the energy system through CER, and ensuring households can fully realise the value of their assets by contributing to and benefiting from a more flexible, decentralised energy system. There is a continued need and potential for NSW to trial, deploy and ultimately scale long-term solutions through dynamic operating envelopes and cost-reflective network tariffs to better integrate CER while maintaining network stability.

To safely and efficiently connect increasingly decentralised energy resources, DNSPs are developing capabilities to link and aggregate embedded generation and flexible demand as active market participants. These capabilities will allow them to balance loads, deliver essential network services and manage two-way energy flows. By leveraging existing networks, optimising data flows, and enabling more dynamic, responsive grid operations and pricing, DNSPs can support and optimise the uptake and coordination of CER.

At the same time, customer choices around energy resources – what they invest in, how they are used, and the extent of participation in the trading of energy and services – will play a significant role in the energy transition. Coordinating these assets is critical to reduce costs for all electricity customers and support the needs of the system. With the right information, choices and incentives, CER can be used to help balance supply and demand.

Importantly, optimising the coordination of CER also delivers equity benefits by enabling fairer access to lower energy costs and increased participation opportunities for all customers, including those in vulnerable or underserved communities. Shared infrastructure such as community batteries (that enable energy storage as a service) and public EVCI will play a critical role in supporting equitable access, helping to ensure all customers can benefit from a decentralised energy system regardless of their housing type or income level.

Table 5 summarises key initiatives currently being trialled by NSW DNSPs to optimise the coordination of CER.

[47] Source of insights 1-3: EBDM, Appendix G
[48] AEMO (2024). *Integrated System Plan*

Table 5: CER initiatives undertaken by NSW DNSPs

Project	DNSP	Description	Benefits
Project Edith	Ausgrid	Project Edith is a network pricing trial that provides fairer pricing for customers who modify their energy usage to support network stability and electricity demand. The trial explores how 5-minute dynamic network prices can be considered alongside 5-minute market prices, and showcases how dynamic pricing can help facilitate the participation of solar, battery and EVs in the energy market, while remaining within distribution network capacity limits.	• Removes barriers to the participation of CER in energy markets through efficient pricing. • Makes network value available to retailers to optimise for market price signals on behalf of customers. • Provides fairer pricing for customers who modify their energy usage to support network stability and electricity demand. • Promotes lower network costs through flexible, real-time incentives, translating to downwards pressure on customer bills.
Electrify 2515	Endeavour	Electrify 2515 is a community-led pilot that removes barriers to electrifying homes and enables integration with the grid at a local level, to accelerate electrification at the national level. The pilot is supported by ARENA funding, which offers subsidies to ~500 homes to reduce emissions and energy bills.	• Provides equity benefits by offering households subsidies to update their appliances to efficient, electric versions, and finance to help afford the difference. • Enables household savings when appliances are switched to electric, combined with rooftop solar and a household battery.
Hot water dynamic controlled load	Ausgrid	Dynamic controlled load trials are being conducted to reduce the impact of peak demand from residential electric hot water systems. Around 450,000 Ausgrid customers have electric hot water systems connected to controlled load network tariffs. These trials involve partnering with retailers to dynamically orchestrate controlled load. The insights gained from these trials could inform broader opportunities for demand flexibility, helping expand demand flexibility beyond hot water systems to include other CER and load management approaches.	• Provides opportunity to reduce peak demand through electric water heaters, which are one of the largest electricity using appliances in a typical home. • Allows dynamic orchestration without negative impacts on the network or customers. • Enables cost savings to be shared with customers by passing on wholesale price savings.
Flexible exports	Endeavour	Endeavour Energy's flexible exports trial allows eligible rooftop solar customers to export up to 10 kW of energy to the grid (double the standard limit), by using smart inverters and real-time network data. The trial, running through to June 2026, aims to unlock significant additional solar export capacity with minimal curtailment (~5 per cent annually), offering increased value to customers and enhancing grid resilience.	• Improves grid stability through use of dynamic controls to adjust exports. • Provides additional network capacity for solar, supporting broader decarbonisation goals. • Enables greater feed-in-tariff earnings by reducing solar export limitations.

DNSPs are continuing to innovate in this space. Endeavour's Energy's Flex Together pilot program, outlined in Figure 23, is one of many forward-looking NSW DNSP pilots and trial proposals that are looking to challenge the boundaries of the regulatory framework to test if better outcomes can be achieved for all customers under different settings in the future.[49]

[49] At the time of publication, Flex Together was in initial stages of the AER's Sandbox trial process. Accordingly, some information on this project may not fully reflect subsequent developments or outcomes arising from the project's progression or implementation.

Figure 23: Case study – Flex Together

Endeavour Energy

“Flex Together” Sandbox Trial

Case study overview

- FlexTogether is an AGL and Endeavour Energy collaborative initiative.
- This pilot serves as a proof-of-concept. The initial study is designed to enable data sharing that informs system planning and lays the groundwork for future market development that optimises CER coordination. Insights from this phase will be applied in subsequent stages.
- The initial phase aims to develop and propose a standardised approach for short and long-range data sharing and publication.
- This includes data sharing approaches for: VPP resource availability, cost of activation, confidence and expected performance criteria, network constraints and opportunities for flexibility service mechanisms to support more efficient network operations.
- Improved data sharing in this phase aims to support the AER sandboxing objective of “Network data visibility as an enabler” and the key principle of “Facilitating deployment and orchestration” of CER.
- The initiative also seeks to standardise the procurement and delivery of flexibility services in the NEM, including their definition and how flexibility can be procured in an equitable manner. This will provide consistency across market participants and avoid the development of bespoke requirements across networks.
- Future phases of the initiative propose a desktop study on efficient network incentives to scale flexibility, considering reforms to incentive schemes and potential regulatory changes.
- Final phases will consider trial expansion and knowledge sharing to maximise benefits and support continued competition in the market.

Benefits and rationale

FlexTogether aims to deliver the following outcomes:

- **Promote CER adoption** through incentives and price signals in key locations that reduce costs for all customers
- **Enable equitable CER access**, including renters and low-income households, leaving no customer behind. This will consider targeted support programs for all customers including funding CER assets, providing data driven-insights, and offering flexible options for asset ownerships
- **Orchestrate CER assets** to maximise wholesale and network value to benefit customers
- **Optimise retailer orchestration to alleviate network capacity constraints** by ensuring transparency in short to long range pricing signals and empowering customers to respond effectively
- **Identify efficient network incentives to scale flexibility** by exploring alternative network incentives that prioritise flexibility services procurement over network augmentation
- **Enhance competition** amongst energy retailers/aggregators to provide Flexibility Services, and additional choice and opportunities for energy customers
- **Increase transparency of benefit sharing** between retailers and customers and value accrued, exploring market and network needs in order to incentivise participation.

6. Barriers to unlocking value and calls to action

6.1 Overview

Following the 'size of the prize' modelling and identification of value pathways, the project sought to understand which opportunities could be delivered by DNSPs under status quo regulatory arrangements, and which opportunities sit behind barriers that prevent value from being unlocked. Addressing these barriers and adopting a more integrated approach that optimises all components of the electricity system – not just at the transmission level – will enable NSW to deliver on its renewable energy targets in a manner that minimises costs for all electricity customers.

The DSP Opportunities Report identifies six reform areas that are critical to realising the full potential of distribution network opportunities. Of these, three areas - strategic system planning, project approvals, and DBESS regulatory and market settings - have well-defined solutions and are accompanied by specific calls to action. The remaining three areas - cost allocation, CER and community assets, and data centres - are highlighted as emerging issues requiring further exploration and reform consideration.

Unlocking the distribution-level opportunities requires:

- **Integrated strategic planning** such that each DNSP develops a bottom-up Distribution System Plan, shared with an independent NSW system planner for co-optimisation across both distribution and transmission networks. Such an approach helps identify lower-cost opportunities for distribution-connected generation opportunities and empower DNSPs to support co-location of load, generation and storage – delivering benefits to local customers and reducing whole-of-system costs. Longer-term planning at the distribution level would also enable greater consideration of how DBESS and CER coordination can deliver lower-cost demand-side solutions.
- **Streamlined project approval processes** for distribution-level anticipatory investments that support renewable generation connections and de-risk the energy transition.
- **Reform of regulatory and market settings for DBESS** to reduce system costs and put downward pressure on electricity prices. Current regulatory and market factors result in unequal treatment of functionally similar systems connected to transmission versus distribution, creating barriers to connecting at the distribution level. These differences need to be addressed to incentivise investment and unlock the value of DBESS for customers and networks.
- **Equitable cost allocation frameworks** that ensure the costs and benefits of new infrastructure are fairly distributed among all beneficiaries.
- **Realising the full value of CER** through more localised energy planning and a deeper understanding of customer preferences. To effectively integrate CER into the strategic planning process, additional investment is required in advanced hardware and software, such as smart meters, analytics platforms and distributed energy resource management systems, to better understand how CER are being used.
- **Continued support for CER uptake and coordination**, including DNSPs continuing to actively collaborate with industry, retailers and regulators to scale trials, embed CER Taskforce initiatives and ensure CER are integrated in a way that maximises customer and system benefits.
- **Increased investment in community assets**, and further consideration of the role of shared assets, such as community batteries and public EVCI, that promote customer participation in the energy system and enable equitable access to the benefits of the transition for all customers.
- **Strategic planning for data centre integration** to attract investment and maximise the economic opportunity for NSW while effectively managing the associated electricity system challenges.

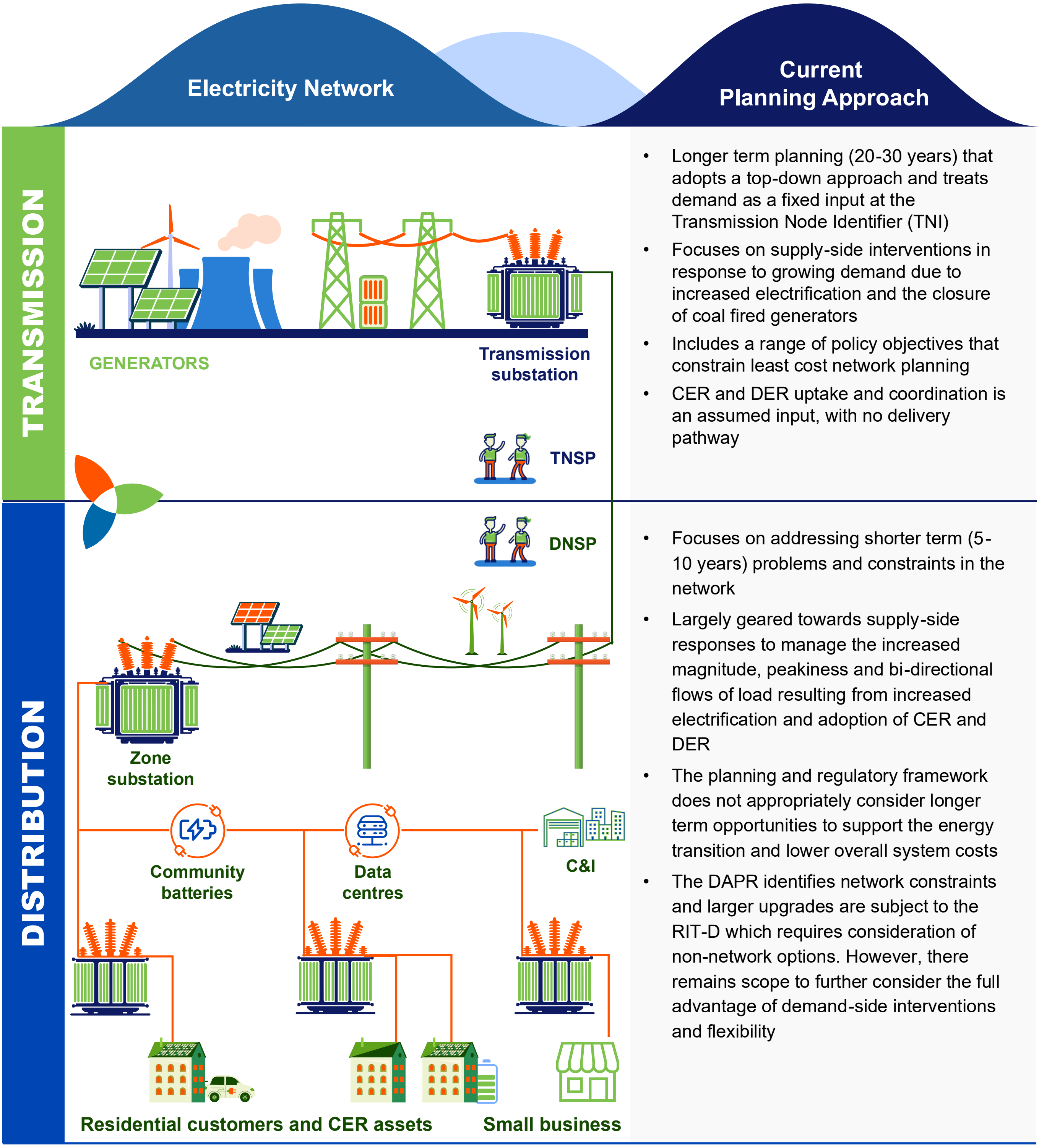
This section outlines the challenges associated with each of the above and highlights where targeted change or further consideration is needed to fully realise the value of distribution-level opportunities.

6.2 Strategic system planning

6.2.1 Barriers in the status quo

Current electricity system planning considers household demand and the expected contribution of DER as an exogenous input as part of broader demand forecasts. The planning process is largely driven by utility-scale generation, firming and transmission investment to support the transition of the NEM to meet this future demand. Whilst system planning acknowledges the critical role of distribution, in practice, electricity distribution networks and the resources connected to them have been treated as an afterthought by policymakers, to be considered only after the 'big pieces' of transmission and large-scale generation and storage have been put in place. The current approach to system planning is shown in Figure 24. With large-scale generation and the transmission network facing delays, cost overruns and social licence challenges, local networks are at a risk of being the 'missing' part of the energy solution despite their potential to enable a cheaper and faster energy transition.

Figure 24: Current approach to system planning



Integrated strategic planning across the entire network is necessary to maximise overall system benefits. Under an integrated approach, generation connected at the distribution level (including renewable energy projects), DBESS and generation from CER are treated as dynamic components to system planning rather than inputs. Rather than optimising at the transmission level, this approach seeks to solve for the lowest system costs by considering the full spectrum of generation and storage options across both the distribution and transmission networks. By incorporating these resources into the core planning process, the integrated model enables more efficient investment decisions, utilisation of existing infrastructure, optimisation of behind the meter assets and a more equitable pathway to decarbonisation.

Integrating distribution and behind-the-meter assets into the strategic planning process will be challenging and requires a different approach that accounts for the uniqueness and complexities of the distribution network. For example, NSW distribution networks operate over 690 zone substations collectively and over 210,000 distribution substations, while the transmission network has only 131 bulk supply substations[50]. Modelling frameworks and appraisal methodologies need to evolve to capture this complexity and appropriately capture the value of distribution level solutions.

Table 6 outlines the key problems with system planning today that limit the ability to realise value at the distribution level.

Table 6: System planning – barriers to unlocking value at the distribution level

System planning		
Integrated strategic planning across the entire network is necessary to maximise overall system benefits, however it presents a range of challenges, especially in capturing the unique characteristics of the distribution network. This is leading to missed opportunities at the distribution level and behind the meter. These are typically lower cost opportunities that make greater use of existing assets to provide overall system benefits and support the energy transition.	**i.**	Current system-wide strategic planning does not systematically consider opportunities to better utilise existing distribution network infrastructure and locate generation closer to current and projected large load centres. While this is maturing, opportunities are considered on an ad hoc basis.
	ii.	The strategic planning framework involves taking demand as a fixed input at the transmission connection point and identifying supply side transmission-level investments to meet that demand. This does not allow for an equal consideration of demand side and flexible energy solutions that could lower overall system costs.
	iii.	Current planning does not adequately reckon with the uniqueness of the distribution network, particularly the significantly greater volume of assets and customers compared to transmission.

6.2.2 Solution considerations

As outlined in Section 3.1, there are a range of iterative improvements to demand-side and distribution planning in-train. System planning could continue down this path, with DNSPs continuing to participate in these improvements, working collaboratively with AEMO and other planners. However, this centralised, top-down planning risks missing the true value of distribution-level opportunities. A bottom-up approach that reflects the importance of distribution-level strategic planning, and incorporates this into an integrated system plan at the state level is needed. This new NSW Integrated System Plan is consistent with an option recommended as part of the NSW Transmission Planning Review, which recommends to consolidate all NSW planning documents into a single overarching infrastructure planning document.[51] This is also echoed by the Enhanced System Planning project (complementary to the CER Roadmap), which emphasises that distribution system considerations should be included in whole-of-system planning to enable a more efficient transformation. It makes recommendations for bodies including AEMO, DNSPs, policymakers and regulators to support collaborative bottom-up integrated planning.[52]

CALL TO ACTION

Enable bottom-up DNSP-led strategic planning

[50] Transgrid (2024). *2025 Transmission Annual Planning Report*
[51] Farrier Swier Consulting (2025). *NSW Transmission Planning Review – Final Report.* NSW Department of Climate Change, Energy, the Environment and Water.
[52] Centre for New Energy Technologies (2025). *Enhanced System Planning Project*

There are three broad options for incorporating distribution-level strategic planning into the NSW Integrated System Plan, with differences in the role and remit of DNSPs and the NSW system planner as outlined in Figure 25.

Figure 25: Options for distribution-level strategic planning

	01 DNSPs	02 NSW system planner
Option 1: Data provision	Provide all required data to system planner in standardised form based on common methodology and data requirements (as defined in collaboration with system planner) across DNSPs	• Develops demand forecasts and CER uptake projections • Optimises for level of investment in distribution network between network and non-network options • Identifies distribution REZ candidates • Co-optimises distribution REZ candidates against identified transmission-level opportunities • Develops a single, overarching NSW Integrated System Plan
Option 2: Individual DNSP planning	Establish common methodology and data requirements across DNSPs (as defined in collaboration with system planner) to separately: • Develop demand forecasts and CER uptake projections • Optimise for level of investment in distribution network between network and non-network options • Identify distribution REZ candidates	• Takes distribution REZ candidates identified in DNSP-led planning and co-optimises these against identified transmission-level opportunities • Develops a single, overarching NSW Integrated System Plan
Option 3: Combined DNSP planning	DNSP strategic collaboration to: • Establish common methodology and data requirements (as defined in collaboration with system planner) • Develop demand forecasts and CER uptake projections • Optimise for level of investment in distribution network between network and non-network options • Identify distribution REZ candidates	• Takes distribution REZ candidates identified in joint DNSP-led planning and co-optimises these against identified transmission-level opportunities • Develops a single, overarching NSW Integrated System Plan

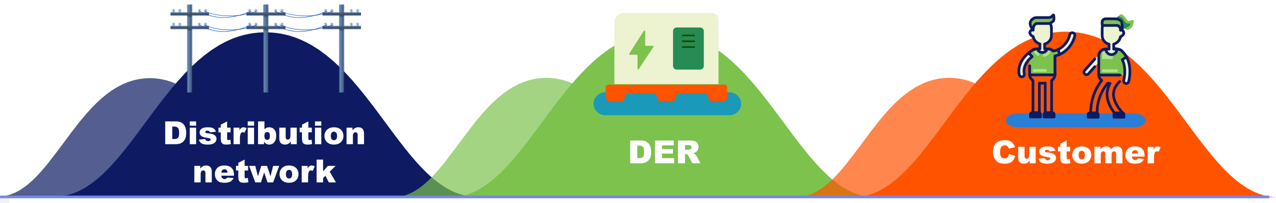
Individual DNSP strategic planning (Option 2) is the recommended pathway. It provides greater level of control for DNSPs to identify and optimise value in their networks to support the broader energy transition, based on their in-depth understanding and 'on the ground' knowledge of network constraints and opportunities. Whilst DNSP strategic planning (Option 3) provides a more collaborative approach between DNSPs, it diminishes the level of control and oversight for the central planner which is key to a credible and robust system plan.

Under this approach, the integrated transmission and distribution planning process would be split into two stages:

- **Stage 1**: Targeted solutions to local constraints – similar scope to existing DAPR but with a greater focus on localised demand projections as well as lower cost demand-side solutions to address network constraints
- **Stage 2**: Co-optimising transmission and distribution REZ opportunities to support the transition based on demand forecasts informed by Stage 1 – DNSPs provide distribution REZ candidate areas to the state system planner for co-optimisation against transmission level opportunities.

This methodology facilitates a whole-of-system approach by linking modelling and opportunities at the distribution level to modelling and opportunities at the transmission level. At the distribution level, the techno-economic modelling undertaken during this project has highlighted significant challenges – primarily driven by data volume and complexity. These challenges stem from the large number of nodes (zone substations and distribution substations) and dispersed nature of the distribution network which creates complexity in data collection, collation and computation. A summary of the relevant data considerations to enable effective distribution-level planning are summarised in Figure 26.

Figure 26: Distribution network data requirements



	Distribution network	DER	Customer
Components	• Distribution network topology (single-line diagrams, GIS data) • Asset data (age, type, capacity, condition, ratings) • Substation and feeder-level loads • Switching configurations and meshed networks • Voltage and thermal constraints • Network losses • Network augmentation cost • Operational limits and flexibility (e.g., voltage control)	• DER connections (size, location, inverter settings) • DER potential • Inverter capabilities (export limits, volt-var control, dynamic response) • Community energy projects / microgrids • Forecast DER uptake (incl. AEMO ISP, CSIRO, DNSP scenarios) • Hosting capacity analysis data	• Historical load data • Customer connection data (location, type) • Connection forecasts • Forecast demand profiles (residential, commercial, industrial) • Peak demand • Customer usage patterns (time-of-use, seasonal variation) • Customer segment forecasts (population, electrification, embedded networks)
Challenges	• Limited visibility and monitoring at the LV level • Capturing real-time network conditions and constraints • Volume of potential solutions to address localised constraints	• Forecast of DER uptake • DER bidding behaviour	• Limited visibility and monitoring at the LV level • Understanding customer behaviour and decision-making

In contrast, modelling at the transmission level requires less data, by orders of magnitude. Given the complexities associated with distribution-level modelling, it is critical that DNSPs are closely integrated in the system planning process.

CALL TO ACTION

NSW system planner to co-optimise across distribution and transmission, informed by individual DNSP plans

6.3 Project approvals

6.3.1 Barriers in the status quo

Different approval processes apply to different projects in NSW, including:

- Actionable ISP projects under the National Electricity Rules (NER)
- REZ network infrastructure projects (RNIPs) and priority network infrastructure projects (PNIPs) under the EII Act
- Other transmission and distribution projects under the NER, including the Regulatory Investment Test for Transmission (RIT-T) and Regulatory Investment Test for Distribution (RIT-D) respectively.

Table 7 includes an overview of the planning process, approval pathways and responsible parties under both the national and NSW frameworks.

Table 7: Current planning process, approval pathways and responsible parties[53, 54]

	Strategic NSW transmission planning		Strategic national transmission planning	Transmission projects (other)		Distribution projects	
Projects	**REZ network infrastructure projects**	**Priority network infrastructure projects**	**Actionable ISP projects**	**Capex less than $8 million**	**Capex exceeds $8 million**	**Capex less than $7 million**	**Capex exceeds $7 million**
Identify need	ASL via IIO Report	Energy Security Target Monitor (ESTM) via ESTM report) or any report prepared under or published in accordance with the Chapter 5, 6, or 6A of the NER	AEMO via ISP	Transmission Network Service Provider (TNSP) via TAPR	TNSP via TAPR	DNSP via DAPR	DNSP via DAPR
Identify options	Infrastructure Planner	No formal options assessment or recommendation process.	Relevant TNSP (usually Transgrid) via RIT-T	Internal asset management plans	TNSP via RIT-T	Internal asset management plans	DNSP via RIT-D
Assessment of options (cost and benefits)	Infrastructure Planner and ASL via IIO Report						
Determine preferred option	Infrastructure Planner						
Regulatory confirmation	ASL via authorisation or Minister via direction (ASL recommends Ministerial direction)	Minister via authorisation or direction of a network operator	AER via contingent project process	AER via revenue determination process			
Cost recovery mechanism	AER makes a revenue determination for the Network Operator, based on contestability arrangement. This feeds into AER's contribution determination, followed by the Scheme Financial Vehicle issuing contribution orders to NSW DNSPs						
Cost recovery base	All NSW distribution-connected customers	All NSW distribution-connected customers	All electricity customers in NSW and ACT	All electricity customers in NSW and ACT	All electricity customers in NSW and ACT	All DNSP electricity customers	All DNSP electricity customers

Anticipatory investment refers to making investments in the electricity network that address long-term needs at the lowest possible cost. Unlike reactive investments, anticipatory investment involves planning and building infrastructure ahead of time – based on forecasts of future demand – rather than waiting to respond to existing needs. In recognition of the significant infrastructure need required as the energy system transitions away from coal, the ISP and EII Act were introduced nationally and in NSW respectively to facilitate this investment.

The EII Act approval pathway is primarily focused on transmission network projects. Where distribution projects are similar in nature or present an alternative to transmission projects, they can more readily be considered under the existing EII Act pathway as RNIPs. This includes, for example, the Hunter Central Coast REZ. Recent amendments to the EII Act have also broadened the scope of strategic infrastructure planning by replacing the term "priority transmission infrastructure projects" with "priority network infrastructure projects". This change allows projects

[53] Note that the table is not exhaustive, but illustrative of the multiple approval pathways.
[54] Note that EnergyCo is the Infrastructure Planner for the first five NSW REZs but may not be the Infrastructure Planner for future NSW REZs.

related to distribution, storage, and generation to be formally recognised within the same streamlined planning and delivery framework. However, PNIPs are primarily projects that address reliability or system security challenges, rather than opportunities to support the energy transition.

Whilst EnergyCo and ASL are exploring opportunities to better understand distribution network options, there is no formal requirement or process to systematically assess and compare distribution network, CER or non-network options by:

- EnergyCo's development of the Network Investment Strategy or making RNIP or PNIP recommendations
- ASL's development of the IIO Report.

This narrow focus may result in missed opportunities to deliver infrastructure more efficiently or effectively via the distribution network. To this end, the NSW Transmission Planning Review recommends establishing clearer criteria or guidelines for the RNIP and PNIP tests, including whether a distribution or non-network solution would better meet the objectives.[55]

Under the national framework, TNSPs and AEMO are obliged to consider all network and non-network options in developing the ISP, TAPR and through RIT-T assessments. In practice however, distribution solutions are rarely identified through transmission or system planning due to limited understanding of distribution network capabilities, complexity of data requirements and the need for modelling capabilities beyond traditional market modelling.

Whilst existing frameworks support anticipatory investment at the transmission level, the current regulatory framework does not allow for timely and efficient levels of anticipatory investment in the distribution network. In developing their regulatory proposals, DNSPs must include total forecast capital expenditure required to meet demand over the regulatory control period, comply with regulations and meet network performance obligations. The AER then makes a distribution determination by assessing what it would cost a prudent and efficient operator to achieve these objectives, ensuring that these costs are based on realistic expectations of future demand and expenses. This framework makes anticipatory investment proposals challenging, placing the focus for distribution investment primarily on addressing short-term network needs, rather than identifying opportunities to more efficiently use the distribution network and to lower the overall cost of energy provision over the long term.

In aggregate, the existing frameworks do not support longer-term distribution-level anticipatory investments and integration opportunities that drive broader system-wide benefits and support the transition.

Moreover, the current regulatory framework lacks the flexibility to respond efficiently to uncertainties that emerge during a 5-year regulatory period. In an environment of unprecedented change, there is increasing uncertainty around demand growth driven by EVs and electrification, large load connections like data centres and undiversifiable cost risks driven by the energy transition. The inability to respond efficiently to rapidly emerging or changing expenditure limits the ability for DNSPs to provide timely solutions for customers and results in delays to the energy transition.

Table 8 outlines the key problems with project approvals today that limit the ability to realise value at the distribution level.

Table 8: Project approvals - barriers to unlocking value at the distribution level

Project approvals		
The lack of integration with strategic planning discussed under Action Theme 1 makes it challenging for existing project approval processes to consider costs and benefits within a whole-of-system context. Currently, different approval processes apply to different projects in NSW. In aggregate, these frameworks do not effectively support longer-term distribution-level anticipatory investments and integration opportunities.	**i.**	The EII Act approval pathway is primarily focused on transmission network projects. This narrow focus may result in missed opportunities to deliver infrastructure more efficiently or effectively via the distribution network. In addition, there is a lack of transparency as to how EnergyCo will fairly and efficiently assess the benefits of distribution projects under this approval pathway.
	ii.	Under the national framework, distribution solutions are rarely identified through transmission/system planning by TNSPs and AEMO due to limited understanding of distribution network capabilities, complexity of data requirements and the need for modelling capabilities beyond traditional market modelling. For DNSPs, the NER focuses on addressing shorter-term network needs, limiting the ability to make anticipatory investments.
	iii.	The current regulatory framework lacks the flexibility to respond to in-period uncertainties, limiting the ability for DNSPs to provide timely solutions for customers and delaying the energy transition.

[55] Farrier Swier Consulting (2025). NSW Transmission Planning Review – Final Report. NSW Department of Climate Change, Energy, the Environment and Water.

6.3.2 Solution considerations

The shift to an integrated strategic planning approach needs to be complemented by reforms that facilitate and streamline approval processes for anticipatory distribution-level investments.

In line with the call to action in Section 6.2, there is a need to recognise the new NSW integrated system plan in the legislation as the state's overarching electricity infrastructure planning document. Projects identified under this plan would be streamlined through the approvals process – the NSW integrated system plan would serve as the vehicle to establish the need for anticipatory distribution-level projects, and the need for these projects would not be re-prosecuted again as part of the approvals process. Rather, the approvals pathway would solely focus on assessing and identifying the best project option to deliver on that strategic need. This is akin to other strategic planning processes, including actionable projects identified by AEMO in the ISP and priority projects identified by Ofgem in the Centralised Strategic Network Plan.

CALL TO ACTION

Align approval pathway to NSW integrated system plan

As outlined in Table 7, the EII Act provides an approval pathway for anticipatory projects in NSW, which could also be applied to projects identified in the NSW integrated system plan. To enable this, the assessment framework needs to be updated to ensure the appraisal of distribution-level projects by the infrastructure planner and ASL (as consumer trustee) appropriately reflect whole-of-system benefits and support more balanced infrastructure planning. This would include development of a modelling framework that better incorporates distribution network capabilities and data to inform the assessment of projects, akin to the approach adopted in this project.

CALL TO ACTION

Develop fit-for-purpose appraisal framework suited to capturing and assessing the complexities of the distribution network under the EII Act

Distribution-level projects identified under the NSW integrated system plan are likely to be those that are similar in nature, or an alternative, to transmission-level projects. There are however wider opportunities in the distribution network. For anticipatory investments or programs of work that are not included in the NSW integrated system plan, but are identified through the individual strategic DNSP plans, additional reforms are required. A key enabling solution involves changes to the forecasting capital expenditure[56] and operating expenditure[57] objectives in the NER. These should be updated to remove reference to meeting demand "over that period", enabling planning over a longer-term horizon to support strategic anticipatory investment. There is also a need to insert requirements into capital expenditure and operating expenditure criteria that require the AER to have regard to:

- demand in future periods
- minimising the full lifecycle costs of investments
- the relative consequences of over- vs under-investment.

These changes would ensure that electricity networks can make investment decisions based on whole-of-life considerations, minimising costs for customers overall.[58]

Moreover, the timing of anticipatory investments are not necessarily tied to the regulatory period. Complementary mechanisms for off-cycle capital expenditure that allow these investments to be assessed within period would provide greater flexibility – akin to the speculative capex framework in the National Gas Rules which allows gas companies to build ahead of the coming Access Arrangement period.[59]

CALL TO ACTION

Improve the ability to invest in anticipatory projects by extending the time horizon over which demand is considered under the NER

[56] NER Clause 6.5.7(a)(1)
[57] NER Clause 6.5.6(a)(1)
[58] This is aligned with the National Energy Objective to promote the long-term interests of consumers. AEMC (2023) *National Energy Objectives*
[59] National Gas Rules 80/84

Beyond strategic planning, uncertainty mechanisms that allow for revenue adjustment in period are also required. These mechanisms provide benefits by:

- **Increasing certainty**: Improved uncertainty mechanisms help de-risk the demand forecast, reducing the level of cost and risk that needs to be factored into DNSP regulatory period allowances.[60] This protects customer interests by ensuring costs are only incurred when conditions justify.
- **Unlocking demand**: Enabling timely capital investment to respond to developments can unlock new demand (such as a data centre connection), increasing overall network utilisation. This spreads total costs over more demand, lowering network charges for all customers.
- **Simplifying assessments**: By reducing the need to fully capture the complex dynamics and uncertainties of the energy transition in advance of the regulatory period, the capital expenditure assessment process can be simplified – both for networks to forecast and for the AER to assess. A less onerous process lowers administrative and regulatory burden, lowering operating expenditure costs passed on to customers.

There are a range of uncertainty mechanism types as summarised in Table 9.

Table 9: Summary of uncertainty mechanisms

Uncertainty mechanism	Purpose
Contingent project	Pre-approved as part of revenue determination but can only be used if trigger event occurs during regulatory period. Trigger event needs to be ‘reasonably specific’ and ‘probable’.[61]
Reopeners	Allow certain cost categories to be reopened mid-period if conditions change significantly. It requires events to be unforeseeable and the hurdle is very high.[62]
Cost pass through	Enable recovery of costs for events outside of DNSP control (e.g. policy changes, natural disaster impacts, etc.).[63]
Capital Expenditure Sharing Scheme (CESS)	Networks share in capital expenditure overspends and underspends with customers, incentivising networks to pursue efficiency gains within the regulatory control period.
Ex-post reviews	Allows the AER to assess the efficiency and prudency of capital expenditure after it is incurred and adjust the regulatory asset base (RAB).[64]

Re-openers and contingent projects are most suited to address uncertainty within the context of the national framework. In Australia, re-opener thresholds are set to ensure they are rarely triggered. This contrasts with the United Kingdom and New Zealand, where re-openers are a standard part of the framework rather than a last-resort mechanism. For contingent projects, New Zealand does not require the network service provider to anticipate what and where the event/project will be at the beginning of the period, whereas under the NER, the trigger event needs to be ‘reasonably specific’ and ‘probable’.

Changes to the NER are required to provide greater flexibility for in-period uncertainty that reflects the nature of energy-transition related uncertainties. This includes lowering the reopener materiality threshold and introducing an equivalent ‘foreseeable’ reopener. Additionally, greater flexibility would be achieved, particularly for large connections, by removing the ‘probable’ requirement from the contingent project mechanism, allowing them to apply to foreseeable projects which are not necessarily “probable” or specific in location. Both reforms would protect DNSPs from cost overruns outside their control while also ensuring that customers do not pay for projects that do not materialise.

Consideration should also be given to complementary mechanisms that target more specific problems. This could include the introduction of a Large Connection Contract mechanism which allows electricity networks to connect large new customers outside of the RAB through a commercially-negotiated agreement. This could then trigger a re-opener to determine if investment beyond the capacity requirements of the connecting party would be an anticipatory investment in line with the call to action above, with any additional amount added to the RAB.

CALL TO ACTION

Introduce changes to NER uncertainty mechanisms to allow for more flexible application, as well as the potential introduction of new mechanisms to allow for new load connections within period

[60] While the AER’s 2025 amendments to the CESS Guidelines introduces some flexibility – for example through discretionary treatment of large individual projects, targeted ex post reviews, and the potential exclusion of small connection capex – the scheme continues to rely on ex ante demand forecasts as a key input to regulatory period allowances. As such, forecasting demand risks remains critical to avoid unintended financial outcomes under the CESS framework.
[61] NER Clause 6.6A.1
[62] NER Clause 6.6.5
[63] NER Clause 6.6.1
[64] AER (2025). *Capital Expenditure Incentive Guidelines for Electricity Network Service Providers – Draft Guidelines for consultation*

6.4 DBESS regulatory and market settings

6.4.1 Barriers in the status quo

The modelling undertaken as part of this project highlights the opportunity to connect more storage into the distribution network to reduce overall system costs. However, current regulatory and market factors are a handbrake on the deployment of DBESS on both the sub-transmission and medium and low-voltage parts of the distribution network.

6.4.1.1 Unequal treatment based on point of connection

For utility-scale DBESS connecting at the sub-transmission level, DNSPs are obligated to pass through Transmission Use of System (TUoS) charges calculated at the Transmission Node Identifier where the DBESS contributes to maximum monthly half-hour demand. These costs can be significant and vary across time. Without transparency and certainty on how these costs are calculated and the potentially significant impact on project financials, there are risks to the commercial viability of DBESS. In contrast, for transmission-connected BESS, TNSPs can provide a higher degree of cost certainty.

In addition, the application of NSW Roadmap charges create further discrepancies in regulatory treatment. NSW Roadmap charges are recovered from distribution-connected customers only.[65] These charges are a significant impediment for BESS proponents looking to connect to the distribution network, whereas transmission-connected BESS are exempt from these charges.

In aggregate, these factors incentivise BESS developers to install on the transmission network even where a distribution network connected battery would otherwise reduce overall system costs and provide greater system benefits. This pricing framework creates a potential misalignment between commercial value for BESS proponents and least-cost energy system outcomes by favouring transmission-connected storage.

6.4.1.2 Challenges for community batteries and LEPs

At lower voltages – typically between 30 kW and 5 MW systems – third party developers are not building batteries at the pace and scale required to support equitable access to flexible energy through community batteries and/or the development of LEPs.

The lack of storage on the distribution network creates a ‘chicken and egg’ challenge for the development of LEPs. Whilst there is significant potential for landlords to install rooftop PV systems on rental properties and for C&I customers to scale up their rooftop solar investments beyond self-consumption, there is limited incentive and limited ability to unlock the value of this energy without complementary storage. For C&I customers, this is driven by tariff arrangements, where surplus energy is exported at very low feed-in tariffs and in some cases, at a cost to the customer. As a result, areas of the distribution network with the potential to host significant local generation have little to no incentive to capture this opportunity. Targeted storage solutions with appropriate value sharing arrangements are essential to overcoming barriers for renters and C&I customers, and are central to the development of LEPs.

DNSPs view batteries as being both a network and market-led intervention. The network-led model provides greater network benefits via deployment in strategic locations and maintenance of operational control. This vertical integration of network and battery allows for a quicker development pathway, access to substation co-located sites and greater technical integration. Where speed of deployment is important, the network-led model provides distinct advantages.

Table 10 outlines the key problems with DBESS regulatory and market settings that limit the ability to realise value at the distribution level.

[65] NSW Government (2020). *What the Roadmap means for you*

Table 10: DBESS regulatory and market settings – barriers to unlocking value at the distribution level

DBESS regulatory and market settings		
The modelling highlights the need for a rapid acceleration in DBESS. Existing market structures and network tariffs disincentivise DBESS, even where they are providing overall network benefits when co-located with load. In turn, this creates challenges for developing LEPs.	**i.**	Inequities in the current regulatory framework discourage BESS from connecting at the distribution network relative to the transmission network. For large BESS connecting at the sub-transmission level, use of system charges based on network connection point results in unequal cost exposure for functionally similar assets. Additionally, NSW Roadmap charges apply only to DBESS, further disincentivising BESS investment in the distribution network.
	ii.	Third party developers are not building batteries at the pace and scale required to support equitable access to flexible energy through community batteries and/or the development of LEPs.
	iii.	Current market signals - such as very low feed-in-tariffs and connection costs - discourage C&I customers from installing PV systems, supported by privately-owned BESS, that are larger than their behind the meter consumption. This limits opportunities to maximise efficient use of distribution network infrastructure, as well as broader system benefits, from locating generation near load.

6.4.2 Solution considerations

Regulatory and tariff reforms that address barriers to DBESS are critical to minimising system costs, supporting community batteries and unlocking LEPs.

To incentivise investment in sub-transmission connected BESS, the approach to calculating TUoS charges for DBESS needs to be reviewed and reformed to appropriately reflect the overall system benefits they provide.[66] As outlined in Section 6.4.1, these TUoS charges for large DBESS can be both significant and uncertain, whereas transmission-connected BESS benefit from greater cost certainty.

CALL TO ACTION

Address inequities in TUoS charges for large DBESS connections

Further to this, a level playing field is needed for NSW Roadmap charges, which currently apply only to DBESS, placing them at a disadvantage relative to their transmission-connected counterparts. Addressing these inequities will ensure that siting decisions are not driven by unequal cost exposure.

CALL TO ACTION

Align treatment of NSW Roadmap charges for DBESS connections with transmission-connected counterparts

These reforms, together with the actions DNSPs are taking to improve the visibility of their networks,[67] will support third-party proponents connecting storage systems to the distribution network.

DNSPs are exploring new models (such as Project Bolster, Community Power Networks and Community Batteries outlined in the case studies in Section 5.4 that may require deeper regulatory reform to unlock the full value of storage deeper in the distribution network. Enabling these models is critical to supporting DBESS deployment at lower voltage levels – facilitating community batteries that address equity issues by providing flexible energy options for customers unable to invest in CER, and addressing barriers to installing PV systems larger than behind-the-meter consumption that are central to lower cost localised matching of supply and demand in LEPs.

[67] For example, the network hosting capacity opportunities map published on the NSW Spatial Collaboration Portal.

6.5 Cost allocation

The current cost recovery framework results in an inequitable allocation of costs among DNSP customers. This is particularly pertinent for large load projects (such as data centres, discussed in Section 6.7), and areas with high levels of distribution-connected generation, where the existing approach fails to reflect the broader benefits these projects deliver.

As outlined in Table 7, under the NER DNSPs can only recover costs from their customer base, even where investments – such as those enabling GRZs – provide benefits to customers across NSW. This places a disproportionate cost on the DNSP's customers and structurally disadvantages large-scale distribution-connected generation. This is particularly prominent in Essential Energy's network, which hosts half of the capacity to connect utility-scale generation and storage, but serves less than a quarter of the customers in NSW – who would be burdened with the cost of enabling this capacity unless alternative cost recovery pathways are established for GRZs. These inequities undermine efficient investment and will result in missed opportunities for the distribution network to support the energy transition.

In addition, NSW Roadmap charges are recovered solely from distribution customers, not from transmission-connected users or exporting generators. Charges are based on where you are connected, not on how much you use, benefit, or contribute to the need for infrastructure. This creates a significant inequity in how the costs of new energy infrastructure, such as REZs and certain transmission upgrades (under the NSW Roadmap), are shared.

Many of the key beneficiaries of these investments, including large-scale generators and industrial users connected at the transmission level, are exempt from contributing, while residential and small business customers bear the full financial burden through their electricity bills. This approach does not reflect the distribution of benefits, undermining both equity and economic efficiency. Moreover, the scale of the inequity is growing: the AER's contribution determination increased from $138.14 million in 2023-24 to $341.24 million in 2024-25, and further to $493.18 million in 2025-26.[68] Without changes to the cost-recovery methodology, distribution customers will bear an increasingly unfair share of costs as Roadmap charges continue to rise.

6.5.1 Reform considerations

The costs of the energy transition are predominantly falling on customers – either through direct investment in CER assets and rising retail and network charges. While this report is focused on opportunities to deliver the energy transition at lowest total cost through utilising the distribution network, it is important to also consider how the costs of the transition will be borne by customers.

Reforms to current cost allocation frameworks or alternative cost recovery pathways are required to ensure equitable outcomes for anticipatory investments that support new generation connected to the sub-transmission network. Enabling negotiated distribution services could also introduce additional flexibility in how cost is recovered from data centres and utility-scale batteries.

DNSPs are committed to working with government, market bodies, retailers and customers to ensure cost allocation is equitable. This may involve revising cost allocation principles under the NER to better recognise shared benefits across customer classes and geographies and/or enabling cost socialisation for projects with system-level value.

To improve the fairness of the NSW Electricity Infrastructure Roadmap charges, and better align with the Roadmap's objectives, the cost recovery framework should be broadened to include other beneficiaries of the infrastructure investment - specifically, transmission-connected customers and generators. These users also benefit from enhanced grid capacity, access to REZs and improved reliability, yet do not contribute to the associated costs. A revised model based on a beneficiary-pays or a cost-reflective approach would ensure that charges more accurately reflect who drives and benefits from infrastructure investment. This would avoid an inequitable share of costs falling solely on distribution customers.

[68] AER (2025). *Contribution determination for 2025-26 under NSW Roadmap released*

6.6 CER and community assets

As outlined in Section 5.5, CER is fundamentally changing the future energy system, and customers sit at the heart of this transformation. This shift creates a compelling need for regulatory frameworks, coordinated energy planning, and targeted investments to respond to an increasingly decentralised energy system. Optimising the coordination of these assets will become increasingly important. These measures are essential to ensure that all customers continue to have access to reliable, secure, and affordable energy as the system transitions.

The importance of national coordination and effort across industry and government is recognised in the National CER Roadmap.[69] DNSPs are actively involved with, and supporting, the implementation of the roadmap's recommendations. In July 2025, DCCEEW began consulting on two key workstreams in the roadmap:[70]

- **M3 – Redefine roles for market operations:** Define the roles and responsibilities of distribution level market operation and drive alignment of incentives between market participants for CER integration.
- **P5 – Redefine roles for power system operators:** Define the roles and responsibilities of power system operation with high CER and drive alignment of incentives between industry actors for CER integration.

The Roadmap recognises that – in addition to their traditional role as distribution network owner, planner and operator – DNSPs also perform the role of a Distribution System Operator (DSO) and are the natural entity to continue in this capacity going forward. The DSO role is consistent with the identified need for distribution networks to undertake longer-term, strategic planning, actively manage two-way power flows and recognises the increased role for distribution networks in incentivising, procuring and coordinating CER.[71]

6.6.1 Reform considerations

While there are many positive reforms underway in the context of consumer energy participation and policy, increased maturity of localised energy planning and a deeper understanding of customer preferences is needed to support end-to-end system planning. DNSPs are already developing capabilities to operate the system of the future and are uniquely placed to support with this planning exercise, given their visibility into how customers are deploying and using their CER assets and how this behaviour impacts the local network.

However, effectively integrating CER into strategic planning requires additional investment to enhance visibility, monitoring and control at the low voltage level – through both hardware and software, such as smart meters, analytics platforms and distributed energy resource management systems. It will also involve further development of modelling tools that recognise the range of individual decisions that customers make, considering differences in financial considerations, individual preferences, social factors and technology adoption. The EBDM used in this report is one such tool, helping to capture how pricing, policy and infrastructure initiatives interact to shape both customer investment decisions and subsequent asset use.

Further reform is needed to ensure that community energy assets, including community batteries and public EVCI, are a key feature of local networks, promoting equitable access to all customers. These assets can help ensure that all customers – including those in vulnerable or underserved communities – can participate in and benefit from the energy transition. By leveraging their existing networks, workforce and experience in promoting customer participation and addressing energy inequity, DNSPs are well placed to support the deployment of community assets.

To ensure network incentives align with the emerging requirements and associated capability required, – broader reforms are also required to formalise the DNSP role as a DSO. This could include allowing full cost recovery of AER-approved innovation activities through pricing, rather than the partial recovery currently available under demand management incentive arrangements. Further reform may be needed to align regulatory treatment with the increasing role of CER. This could include establishing a total expenditure model that treats operating and capital expenditure equally, ensuring that investment in flexibility and orchestration is not disadvantaged compared to traditional network augmentation.

To illustrate the type of analysis required to support strategic planning and highlight the value of shared assets, this report examines the impact of additional EVCI installed on existing poles. Kerbside EVCI increases the availability of public charging infrastructure, benefitting customers that own EVs, and helping to accelerate EV uptake. The EBDM modelling estimates that pro-active investment in kerbside chargers by DNSPs could add nearly half a million EVs in NSW by the late 2040s.[72] While EBDM is an emerging modelling framework, it demonstrates the type of analysis needed to understand customer behavioural choices, and the role this will play in better integrating CER and shared infrastructure into strategic planning.

[69] Department of Climate Change, Energy, the Environment and Water (2025). *Redefining roles and responsibilities for power system and market operations in a high CER future: Consultation Paper to progress M3/P5 workstreams of the National CER Roadmap*
[70] Ibid.
[71] Ibid.
[72] EBDM, Appendix G. Assumes around 160,000 kerbside chargers by 2050 in the modelled scenario (*Kerbside EVCI*) compared to around 15,000 in *Status quo*.

6.7 Data centres

Data centres present a significant economic opportunity for NSW that will put new demands on the electricity system. Analysis of DNSP customer and connection enquiry information shows that by 2040, data centres are projected to account for approximately 30 per cent of total operational load in NSW.[73] This surge in demand coincides with a critical period in the energy transition, marked by the retirement of coal-fired generation.

The scale and speed at which data centres are seeking to connect to the grid puts pressure on the system and complicates strategic system planning. To ensure NSW can respond effectively to this load growth, there is a need for greater collaboration between data centre developers, network businesses, and system planners. Timely access to reliable, forward-looking insights on data centre developments – including location, capacity requirements, and timing of connection – is essential to inform coordinated anticipatory investment decisions. DNSPs are well-positioned to provide this insight, given they hold the most up-to-date knowledge of connection enquiries and project pipelines through direct engagement with proponents and visibility into emerging demand. Additionally, there is available capacity in the distribution network to connect storage and generation to alleviate some of this demand pressure.

6.7.1 Types of data centres

Data centres fall into three broad categories based on their power consumption patterns:

- Enterprise and co-location facilities
- Hyperscale and cloud data centres
- Artificial intelligence (AI) and large language model (LLM) data centres.

In NSW, the leading data centre operators – such as AirTrunk, Canberra Data Centres, NEXTDC and Amazon Web Services – primarily operate hyperscale or co-location facilities.

Table 11 provides a more detailed comparison of the different types of data centres by power usage.

Table 11: Data centre types by power usage – description and overview

Data centre type by power usage	Description and demand growth pattern	Customer	Power usage	Location
Enterprise and co-location *Flexible load patterns and lower power consumption*	• Enterprise: Smaller facilities, directly operated by a specific company to manage its own information technology systems and data. • Co-location: Similar but operator provides the infrastructure, while customers lease and manage own servers (multiple companies hosted in a facility). • Demand for these data centres is steadily increasing due to ongoing digital transformation and the need for scalable data management solutions.	A variety of organisations of diverse sizes and types that use information technology infrastructure	• Low to moderate (~1 MW - 5 MW)[74] • Flexible load patterns, varying by tenant demand / may peak during business hours	Suburban areas where electricity prices are lower OR near HQs / business districts for low-latency data processing.[75]

[73] NSW DNSP load projections under the Customer transformation and Optimistic case scenarios. Further detail on these assumptions are provided in Appendix B.
[74] Mordor Intelligence (2025). *Australia Data Center Market SIZE & SHARE ANALYSIS - GROWTH TRENDS & FORECASTS UP TO 2030*
[75] Macquarie Data Centres (2025). *Our Data Centre Locations.*

Data centre type by power usage	Description and demand growth pattern	Customer	Power usage	Location
Cloud and hyperscale *Flexible load patterns and higher power consumption*	• Larger facilities than enterprise and co-location, designed to support cloud service providers, web hosting and enterprise applications. • Their growth is accelerating, due to increasing cloud adoption and the rising demand for globally distributed digital services.	Big tech cloud service providers, large data platforms	• High or very high (5 MW - 100+ MW)[76] • Elastic and fluctuating loads, scaling with user demand and time of day • Steady load growth rates (over 5-10 years)	Require proximity to end users or enterprise hubs for latency-sensitive services – often near urban load centres and require reliable, flexible grid access.
AI and LLM *Constant load and very high power consumption*	• Very high-density facilities purpose-built or retrofitted for AI training and inference; often co-located within hyperscale infrastructure but have dense configurations, requiring enhanced power, advanced cooling and energy delivery systems. • AI/LLM data centres are growing at a significantly faster rate than traditional cloud and enterprise facilities, driven by the rapid expansion of generative AI applications and model training, which demand greater energy infrastructure investment.	AI labs and cloud AI platforms	• Very high (100+ MW)[77] • Sustained, flat load profiles • Faster load growth rates (over 1-3 years)	Regional or remote locations. Their latency-tolerant workloads require sitting near stable and high energy supply, but are less reliant on flexible or load-following grid infrastructure. They can be located some distance from demand – including at transmission REZ sites.

6.7.2 The opportunity

Data centres offer substantial economic potential for Australia, with the national market projected to reach $12.1 billion by 2033.[78,79] NSW is leading this growth, hosting over 90 operational data centres and positioning Sydney as the country's largest data centre hub.[80]

This growth is translating into significant economic and employment outcomes at both state and regional levels. For example, the regional data centre in Dubbo is projected to generate more than $100 million annually in economic benefits and support around 600 local jobs.[81,82]

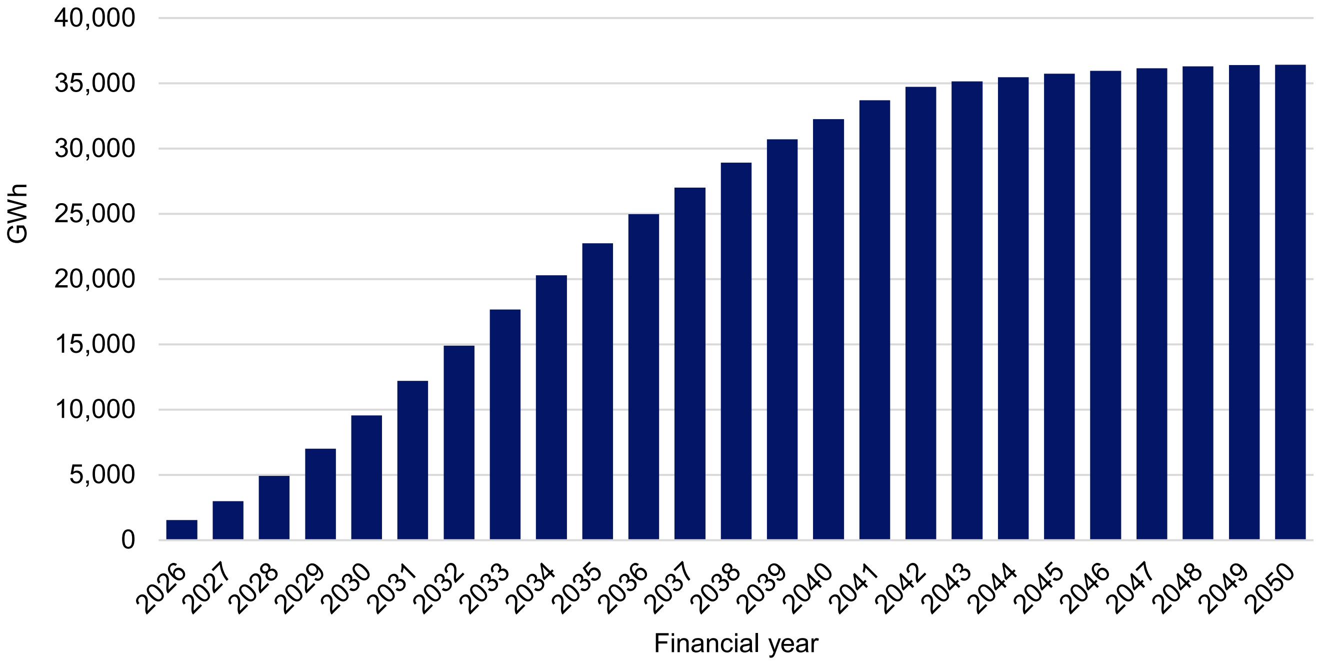
NSW is well placed to attract continued data centre investment, supported by a skilled workforce and government initiatives. The 2025-26 NSW budget includes funding to drive digital infrastructure investment,[83] and the classification of data centres as a 'State Significant Development' enables faster and more streamlined approval processes.[84]

[76] International Energy Agency (2024). Global electricity demand rose moderately in 2023 but is set to grow faster through 2026
[77] IEA (2024). What the data centre and AI boom could mean for the energy sector
[78] The term "Australia Data Center Market Size", as used by IMARC, refers to the total annual revenues in Australia in the data centre sector, covering both solutions and services components (under their definitions).
[79] IMARC Group (2025). Australia Data Center Market Size and Growth Report 2033
[80] Property Council of Australia (2025). NSW Needs a Data Centres Strategy to Unlock Digital Growth
[81] This includes benefits to businesses through decreased network costs, reduction of network outages, increased productivity, unlocking new business opportunities, as well as benefits through averted CO2 and wider economy contributions.
[82] Dubbo Regional Council (2023). Data centre paves the way for jobs and $106M in economic growth
[83] NSW Government (2025). Investment Delivery Authority to turbocharge business investment in NSW
[84] NSW Government (2021). State significant development warehouses and data centres

6.7.3 The challenge

The rapid growth of data centres – particularly hyperscale and AI data centre facilities – is driving step-changes in electricity demand. AEMO is projecting significant growth in data centre demand out to 2050.[85] NSW DNSPs anticipate even steeper growth, as illustrated in Figure 27, based on current and forecast connection enquiries and applications. NSW DNSPs data centre demand forecasts are derived using probability weighted estimate of expected growth using current and forecast connection enquiries, and only includes connection requests before and up to 2030 that are likely to proceed.[86] Even with a higher projected growth in demand than AEMO, this is still considered a conservative forecast by DNSPs, as only 4 GW of the current 20 GW connection pipeline is assumed to eventuate and future growth is not considered.

Figure 27: NSW DNSP data centre load projections (GWh)



This large increase in data centre demand exerts pressure on the wholesale market, putting upwards pressure on electricity prices. Further, these large users have high-reliability requirements (near 100 per cent), which increases the strain on distribution networks and the electricity system more broadly, often requiring significant network augmentation and advanced load management to support their connections.[87] This highlights the need for system-wide strategic planning which consider opportunities to better utilise existing distribution network infrastructure to manage this surge in demand and resulting network and bill impacts, including opportunities to locate generation closer to current and projected large load centres.

Ensuring these large load users can be optimally located within the network is further complicated by the inequities in network charges. Reflecting similar characteristics to the DBESS inequities in network charges described in Section 6.4, there are imbalances between transmission and distribution charges (across both TUoS charges and NSW roadmap charges) for data centre connections which distort investment decisions.

Compounding these challenges is the unpredictability of data centre deployment – driven by limited transparency and coordination between DNSPs and hyperscale data centre operators who are often global players with private planning cycles. This makes load forecasting significantly more challenging – complicating network augmentation and anticipatory investment decisions, increasing the risk of over or under-investment.

Cost allocation mechanisms for network investments that support data centre connections also require careful consideration. As illustrated in Table 12, there are a range of cost allocation approaches available for integrating data centres into the electricity network. Some approaches give greater weight to the economic development benefits that data centres can bring, while others focus on reducing the risk of stranded network assets – a risk that, if not managed appropriately, may result in higher costs being borne by the broader customer base. This raises equity concerns, particularly for customers who may not directly benefit from data centre developments.

[85] AEMO (2024). *Integrated System Plan (ISP)*
[86] Refer to Appendix B.1.1.5 for DNSP data centre demand forecast assumptions.
[87] NEXTDC advertises its facilities in Australia as guaranteeing “100% uptime”

Table 12: Data centre investment – models and cost allocation options

Model	Investment responsibility	Cost allocation mechanism	Pros	Cons
Proponent-led with partial cost recovery	Proponent pays upfront	A portion of the cost can be recovered by the proponent from other customers that connect to the asset	Minimises risk to DNSP and broader customer base by reducing stranded asset risk	• High upfront capital requirement may deter data centre investment • Cost recovery depends on uncertain future connections • May create access/competition barriers
DNSP-led with customer cost recovery	DNSP pays upfront	DNSP recovers the cost over time from customers that connect to the asset	Encourages proactive system planning by DNSPs Incentivises data centre investment	• May delay / disincentivise data centre investment if DNSPs cannot recover costs confidently through inclusion in the RAB, particularly given the uncertainty surrounding success of reopener/contingent project applications • Stranded asset risk if data centre becomes insolvent prior to paying off asset (e.g. if a new customer does not purchase the site)
Shared investment (Proponent + DNSP)	Split between proponent and DNSP	DNSP recovers their portion of the cost over time from customers that connect to the asset	Risk-sharing encourages partnership and balanced incentives Can accelerate delivery of enabling infrastructure	• Potentially complex commercial arrangements • Still exposed to future customer uptake uncertainty (and stranded asset risk)
DNSP pays and recovers from customer base	DNSP pays upfront	Costs recovered over time from entire customer base	Simplifies recovery process; supports public-good arguments	• Equity concerns - socialises costs to all customers regardless of benefit

6.7.4 Reform considerations

As data centre demand continues to grow, action is required to ensure that these facilities are integrated in a way that captures the economic benefits while effectively managing the associated risks and network challenges. The key areas of focus for reform considerations (items 1-5 below) are aligned with the broader reforms proposed in Sections 6.2.2, 6.3.2, 6.4.2 and 6.5.1.

1. Forecasting data centre demand

Effective forecasting of data centre electricity demand is critical to ensure reliable and efficient operation of the distribution network, and to guide longer term planning and anticipatory investments that support load growth. To this end, there is a need to establish a consistent, standardised methodology for forecasting data centre demand, incorporating factors such as varying scales of operation, technological improvements, and potential demand management measures. These forecasts should be underpinned by DNSP data on connection enquiries and customer insights.

A uniform approach would enable DNSPs to better anticipate connection requirements, optimise network investments, and coordinate with data centre operators on load management strategies. Moreover, improved forecasting frameworks can support more transparent and proactive engagement between DNSPs, regulators, and industry stakeholders – facilitating sustainable growth while maintaining grid stability and reliability.

2. Planning: Integrated strategic planning and driving co-location with distribution-connected generation

Once a more consistent approach to data centre demand projections is established, analysis is required to identify optimal locations from a whole-of-system perspective. This should consider existing network capacity, the presence of distribution-connected generation and storage, land use impacts and opportunities for co-location with new generation assets.

DNSPs have direct insights into connection enquiries and local network conditions. They are uniquely placed to support with the strategic planning required to maximise the economic opportunities that come with data centre investment, while effectively managing challenges associated with their integration into the grid.

3. Inequities with transmission: TUoS and NSW Roadmap charges

Reform considerations that address these inequities will remove a barrier to siting data centres in what would otherwise be an optimal location from an investor and a whole of system perspective.

4. Project approvals: Enabling anticipatory investments for data centres

As outlined in Section 6.3, the current regulatory framework presents barriers to anticipatory investment in distribution network infrastructure. This limits the ability for DNSPs to invest in network assets that encourage data centre connections towards areas of the network that work best form a whole-of-system perspective. Reforms to the regulatory framework that support proactive DNSP planning should be considered, and will help to unlock opportunities to site data centres in locations that improve network utilisation and minimise augmentation costs. These reforms could also be considered in the context of broader land use planning for cities and regions, including planning for industrial areas (such renewable energy industrial precincts) to ensure alignment between energy infrastructure development, strategic urban growth and economic development objectives.

5. Cost allocation: Stranded asset risks

The allocation of costs associated with network investments to support data centre connections is important for ensuring equitable customer outcomes. Determining who should bear these costs: whether network businesses, data centre proponents, or a combination of both, has implications for investment certainty, network efficiency, and broader system planning. As such, these cost allocation methods require careful consideration, both in response to the growing volume of data centre connection applications and in the context of anticipatory investments aimed at supporting future connections.

7. Beyond the NSW DSP Opportunities Report

Developed as a first-of-its-kind, the DSP Opportunities Report provides valuable insights into the integration of distribution-level opportunities within whole-of-system planning. While it marks a significant step forward, it also highlights that much more work is needed to fully understand and unlock the potential for distribution networks to support customers through the energy transition.

To this end, Ausgrid, Endeavour Energy and Essential Energy are committed to working with government, market bodies, retailers and customers to address the challenges identified in this report and enhance outcomes across the energy system.

As part of this commitment, the DNSPs will continue to work closely with the NSW Government and actively support changes to how network infrastructure is planned in NSW. In parallel, and as part of a coordinated approach to developing their individual Distribution System Plans, the DNSPs will continue to collaborate on shared elements of their respective plans – building on the insights gained and challenges encountered through this planning exercise. This includes:

- Refining bottom-up demand forecasts, including establishing a consistent methodology to projecting data centre load
- Improving an understanding of customer behaviour and preferences, to optimise CER coordination in a way that maximises system value and supports more equitable participation in the energy system
- Improving understanding of thermal and voltage constraints that drive corrective action across the network, particularly at low-voltage parts of the network below the zone substation. This will include undertaking detailed power systems modelling of the investments identified through the plan for thermal overloading, voltage profiles, power flow, contingency, reactive power compensation, fault analysis and system strength
- Continued analysis of the sub-transmission network to identify and develop distribution REZ opportunities
- Improving the characterisation of meshed network impacts in the modelling
- Incorporating this planning exercise with on-the-ground knowledge of replacement schedules to further drive integration of network activities.

Additionally, the DNSPs will continue to engage with government and regulators to share lessons learnt, and consider how these findings can inform any current rule changes or provide scope for new reforms. These efforts aim to adapt the regulatory framework in response to a rapidly changing energy landscape where decentralised energy and the distribution networks that host them will play an increasingly important role.

Importantly, the value that can be unlocked from the distribution network is not unique to NSW – it exists across the NEM. This report provides a framework for other jurisdictions to demonstrate the value of distribution network opportunities, and the proposed reforms to support the realisation of this value. The NSW DNSPs can share lessons learnt with other jurisdictions, helping to build collective momentum and capability across the NEM – accelerating Australia's energy transition and delivering benefits for all customers.

Glossary

Term	Definition
ABS	Australian Bureau of Statistics
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AI	Artificial intelligence
ARENA	Australian Renewable Energy Agency
ASL	AusEnergy Services Limited
BESS	Battery Energy Storage System
BTM	Behind-the-meter
CER	Consumer Energy Resources
CESS	Capital Expenditure Sharing Scheme
C&I	Commercial and industrial
CO2	Carbon dioxide
CO2-e	Carbon dioxide equivalent
CPI	Consumer Price Index
CPN	Community Power Networks
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CWO	Central West Orana
DAPR	Distribution Annual Planning Report
DBESS	Distribution-connected Battery Energy Storage System
DCCEEW	Department of Climate Change, Energy, the Environment and Water
DDP	Dubbo Distribution Project
DER	Distributed Energy Resources
DNSP	Distribution Network Service Provider
DSP	Distribution System Plan
DSO	Distribution System Operator
EBDM	Energy Behavioural Demand Model
EII Act	*Electricity Infrastructure Investment Act*
ESOO	Electricity Statement of Opportunities
ESTM	Energy Security Target Monitor
EV	Electric vehicles
EVCI	Electric vehicle charging infrastructure
GPG	Gas-powered generation
GW	Gigawatt
GWh	Gigawatt-hour
GRZ	Generation Rich Zone
IA	Infrastructure Australia
IASR	Input Assumptions and Scenarios Report
IIO Report	Infrastructure Investment Objectives Report
IPART	Independent Pricing and Regulatory Tribunal

Term	Definition
ISP	Integrated System Plan
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
LEP	Local Energy Precinct
LLM	Large language model
MtCO2-e	Million tonnes of carbon dioxide equivalent
MVA	Megavolt-ampere
MW	Megawatt
MWh	Megawatt-hour
NEM	National Electricity Market
NER	National Electricity Rules
NPV	Net present value
NSW	New South Wales
NSW Roadmap	NSW Electricity Infrastructure Roadmap
NTNDP	National Transmission Network Development Plan
ODP	Optimal Development Path
PJ	Petajoule
PNIP	Priority network infrastructure project
POE	Probability of Exceedance
PV	Photovoltaic
RAB	Regulatory asset base
REZ	Renewable Energy Zone
RIT-D	Regulatory Investment Test for Distribution
RIT-T	Regulatory Investment Test for Transmission
RNIP	REZ network infrastructure project
TAPR	Transmission Annual Planning Report
TCO	Total cost of ownership
tCO2-e	Tonnes of carbon dioxide equivalent
TEM	Techno-economic model
TNSP	Transmission Network Service Provider
TOU	Time of Use
TUoS	Transmission Use of System
TWAP	Time-Weighted Average Price
TWh	Terawatt-hour
TZP24	Travel Zone Projections 2024
V2G	Vehicle-to-grid
VCR	Value of Customer Reliability
VPP	Virtual power plant
V	Volt

Ausgrid

Endeavour Energy

Essential Energy