C4NET

Australian Energy Market Commission (AEMC)

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24 July 2025

C4NET Submission: AEMC Consultation – National Electricity Amendment (Integrated Distribution System Planning) Rule 2026 ERC0410

C4NET welcomes the opportunity to provide feedback on the consultation of *National Electricity Amendment (Integrated Distribution System Planning) Rule 2026 ERC0410* (the Rule Change).

C4NET delivers multi-disciplinary solutions to the challenges the energy industry is facing. Working with complexity requires diverse skills, reliable data and new approaches, which C4NET facilitates by bringing together governments, industry and universities, creating strong links across the sector.

As a leading collaborator and proponent for the inclusion of distribution network considerations into the Australian Energy Market Operator's (AEMO) Integrated System Plan (ISP), C4NET is well positioned to contribute to the consideration of the proposed Rule Change. C4NET is supportive of the intent behind the amendments proposed by the Energy Consumers Australia (ECA) and the approach AEMC has taken to consult more broadly on the matter.

It is well-timed that this consultation is shortly after the release of our ESP research program's final report: *Enhanced System Planning Project - Australia's electricity networks beyond 2030* (ESP Final Report), published on our website and attached to this submission. The ESP was a $3.6M multi-year research program with over 100 contributors across 5 universities, 11 partner organisations from industry and government, including the ECA.

As the ESP Final Report highlights, the ESP project delivered bottom-up electricity distribution network modelling, scalable tools and methodologies to assess future residential load, CER/DER and electrification impacts, repeatable data-sharing methods and planning frameworks using DNSP data. It also compared flexible and traditional infrastructure pathways to lower system costs. It is deliberately open source for public access and use and is specifically designed to support and integrate into the ISP's evolutionary pathway. C4NET has published the many ESP research reports, summary reports, data, models and methodologies on our website; an overview of the information available is provided in the Appendix to this submission.

Case studies using AEMO renewable energy zone (REZ) data have illustrated that directional savings of over 25% may be achieved through applying the methodologies developed in the ESP, which would represent multi-billion-dollar savings if valid more broadly across the NEM (noting that model parameters and investment costs would need to be verified with industry for an expanded implementation). There appear to be further savings from applying a similar approach down through each nodal hierarchy within distribution systems, ultimately efficiently harnessing the value of capacity and flexibility from CER.

Importantly, these significant cost and efficiency savings won't be realised through a business-as-usual scenario. The research outcomes showed that distribution system considerations are critical for whole of system planning and must be integrated as a priority to avoid over-investment in the energy system: the process and regulatory changes to support this evolution should start now.

The ESP provides a Roadmap and recommendations for key stakeholders to consider that are focused on identifying, evaluating, incentivising and planning for distribution network opportunities that have the potential to deliver co-optimised benefits from a whole of system perspective.

The proposed ESP Roadmap (see *Figure 1*), explained in detail in chapter 5.5 of the ESP Final Report, consists of five main elements, where the first four follow a bottom-up, physics-based, techno-economic approach, and the fifth revolves around policy development, operational and regulatory reforms required to make the approach effective.

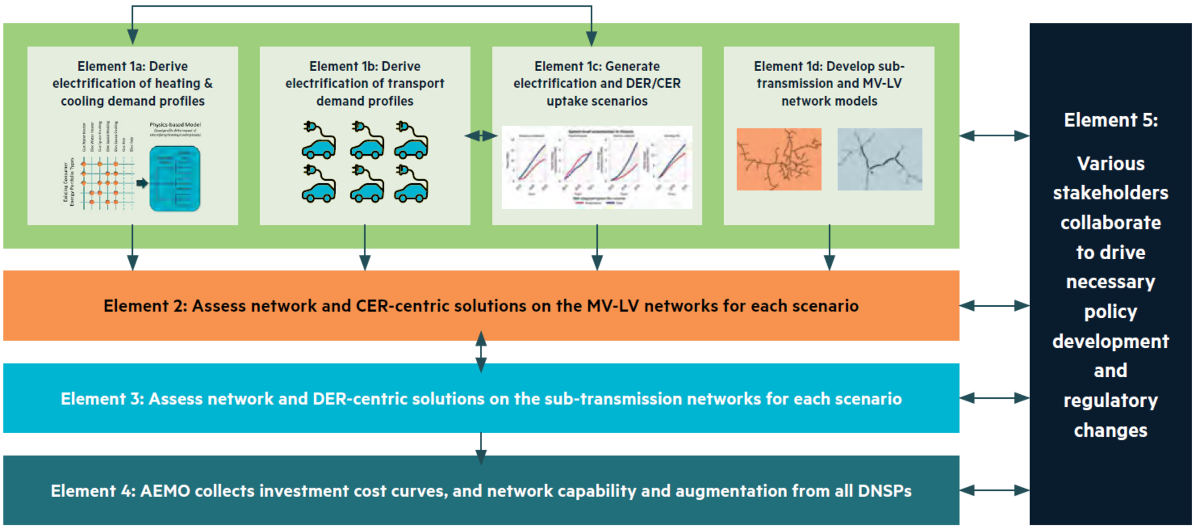

Figure 1 – ESP Roadmap

The adoption of the ESP is not the subject of the Rule Change, however given the close subject matter and relevance to addressing many of the issues raised within the Rule Change and fit with other directives to AEMO in relation to evolution of the ISP, C4NET encourages the AEMC to consult with both AEMO and the System Planning Working Group (of which the Commonwealth Department of Climate Change, Energy, Environment and Water is the secretariat for) to inform views on ESP adoption (or alternate demand-side inclusion) because if recommended there would be subsequent rule changes needed that would intersect with the proposed Rule Change.

C4NET has recommended the Roadmap to the System Planning Working Group and AEMO for consideration to enhance implementation of the ECMC's ISP action for co-optimisation through incorporation of active distribution systems into future ISPs as a suitable approach to assess cost trade-offs of unlocking increasing tranches of orchestrated CER and DER against other investment options.

In its *Draft 2025 Electricity Network Options Report*, AEMO has identified the potential and significance for advanced power flow modelling to provide optimisation and evaluation of distribution network opportunities via allowing DNSPs to adopt an alternate pathway approach. This is consistent with, and provides a pathway for, the application and ongoing refinement of methodologies, tools and insights developed from the ESP research program.

C4NET's response to many of the questions posed by the AEMC in its consultation paper will stem back to common points which C4NET addresses in the following paragraphs. Additional points for select questions are then provided as an addendum to the common points noted.

To a large degree, transmission and transmission system-connected generation/storage planning done within the ISP is separate from distribution system planning. There is next to no co-optimisation across the systems and this risks overinvestment in infrastructure and operational inefficiency. The ISP considers distribution systems as unconstrained which limits the value of the ISP objective of informing the optimal pathway. This does not serve consumers well considering that distribution systems will host material generation and storage assets through the ISP planning period. From the distribution system planning perspective, there is no current mechanism to capture or incentivise asset planning to contribute to broader system benefits to lower the cost for all users beyond the boundary of each individual distribution patch.

While C4NET agrees with the ECA's premise that distribution system planning will need to further evolve commensurate to the changing CER and DER hosting forecasts, doing so without a common planning and operational endpoint being targeted risks driving activity and cost in the provision of data and planning effort without the means to capture the benefit. It is only with this endpoint in mind that the shortcomings in the current planning process can be evaluated. The direction of the ISP changes in response to the ECMC's ISP review has started us on this path, the ESP provides a comprehensive and deeply researched Roadmap and methodologies to put in place to achieve this by the 2030 ISP.

With most relevance to the proposed Rule Change, the ESP:

+ Lays out how distribution systems can be incorporated into the existing ISP frameworks and modelling as *Active Distribution Systems*, which helps then define the data needed to be published in planning and exchanged in operation for co-optimised longer-term planning at a whole-of-system level, and for that to be harmonised across all distribution.
+ Delivers the foundational physics-based mechanisms to ensure the adequate incorporation of the uptake of CER into both the ISP and distribution system planning when integrated (as proposed in the ESP Roadmap), in particular to facilitate power flow modelling to inform asset impact.
+ Has the use of nodal operating envelopes underlying its methodologies, which then provide a framework for the optimisation of modern systems with high penetration of inverter-based power electronics - in particular the harnessing of reactive power and storage to maximise the operating envelope for any given set of DER/CER at any localised node within the system that identifies and values both upstream and downstream impacts of any non-network solution vs alternatives.
+ Strongly advocates for the integration of distribution system planning into broader system planning. There is a recognition of how shorter-term (such as existing distribution planning considerations with minimum 5-year horizon) and longer-term more strategic integrated planning can work together to address their differing objectives, but it is not to say that only one or the other is needed.

+ Identifies the lack of alignment of incentives for actors to invest in an optimised manner. If we wish distribution businesses to invest in assets and coordinate operations to increase storage or generation connected to their system, much of which has been shown to be considerably lower cost than alternatives from a system perspective, then the behaviour needs to be encouraged and impediments removed.
+ Roadmap adoption would integrate biennial strategic reviews within the well-established ISP cycle.

The adoption of the Roadmap would address many of the issues raised in the Rule Change holistically while seamlessly fitting with the CER roadmap objectives and the ECMC's recommended actions for AEMO from their most recent ISP Review.

Question 1: What are the shortcomings of the current distribution annual planning process?

The current distribution annual planning process in rule 5.13 does not require reference to the broader system impacts of any planning consideration. This means any proposed solution risks being sub-optimal from the broader system perspective. Unless common integrated planning frameworks, such as those proposed in the ESP Roadmap and consistent with the better representation of demand-factors sought by the ECMC are in place though it would be impossible to identify. If done so, many of the issues raised by the ECA are addressed. If not, some actions proposed in the Rule Change are at risk of adding cost without value.

Question 6: Is a new consultation process needed for the distribution annual planning review?

While the ESP points above are relevant to most questions posed by the AEMC and included some consumer research, we just note that community consultation needs were not included within the ESP scope and not addressed in this submission.

Question 10: Are the existing performance metrics for distribution networks no longer useful with the increasing adoption of CER?

C4NET directly supports the adoption of the network asset utilisation measures as proposed by the ECA through the addition of Total Energy Throughput Utilisation and Two-way Power Flow Utilisation. These should be applied across all network level assets in both transmission and distribution systems. This will assist transparency of new market and network optimisation opportunities as storage is further adopted. This should be designed to be delivered with existing data wherever possible to minimise cost.

Question 14: Assessment Framework

Given the "integrated" aspect behind the Rule Change, the AEMC may consider including in its evaluation criteria the degree to which the Rule Change contributes to the ISP objective of identification of the optimal development pathway. The ECMC ISP review identified the shortcomings of the ISP process in regard to improved incorporation of demand-side factors – should the Rule Change make a significant contribution to this then that would influence its appeal.

C4NET is generally positive to the publication and availability of data. However, where this is resource intensive to do so or generates noise and distraction that requires resource to address it can be counter-productive no matter how well intentioned. There is considerable data already required to be published as part of distribution annual planning requirements – the AEMC may consider:

1. Commissioning an assessment of the extent to which such data is currently being used/adding value, and
2. If the Rule Change or similar were to proceed, building in some form of regular review of the value of data being provided to ensure ongoing relevance and cost, including a process to remove redundant/superseded data provision.

C4NET welcomes deeper engagement on any of the points it has raised in this submission – you are welcome to contact us at any time via james.seymour@c4net.com.au or 0427 386 933.

Yours Sincerely,

James Seymour

Chief Executive Officer

Centre for New Energy Technologies (C4NET)

Appendix

About the Enhanced System Planning Project

The ESP project is a major research project aimed at informing electricity planning below the transmission level beyond 2030. Over the course of the last two years, C4NET has brought together over 100 academic, industry and government personnel to deliver 15 research projects that involved sophisticated electricity distribution network simulations and techno-economic modelling using Victorian distribution network data in a unique collaboration to update infrastructure utilisation modelling. The Victorian Government Department of Energy Environment and Climate Action (DEECA) and AEMO have also participated to ensure that system planning, policy and regulation are informed by project outcomes, and vice versa.

Enhanced System Planning Project - Australia's electricity networks beyond 2030 is the ESP research program's final report. It is attached to this submission and also available for download from our website. *Figure 2* shows the many documents under the ESP program also published on our website, including research reports authored by universities, summary reports for these work packages authored by C4NET, along with assumptions books and associated data and methodologies.

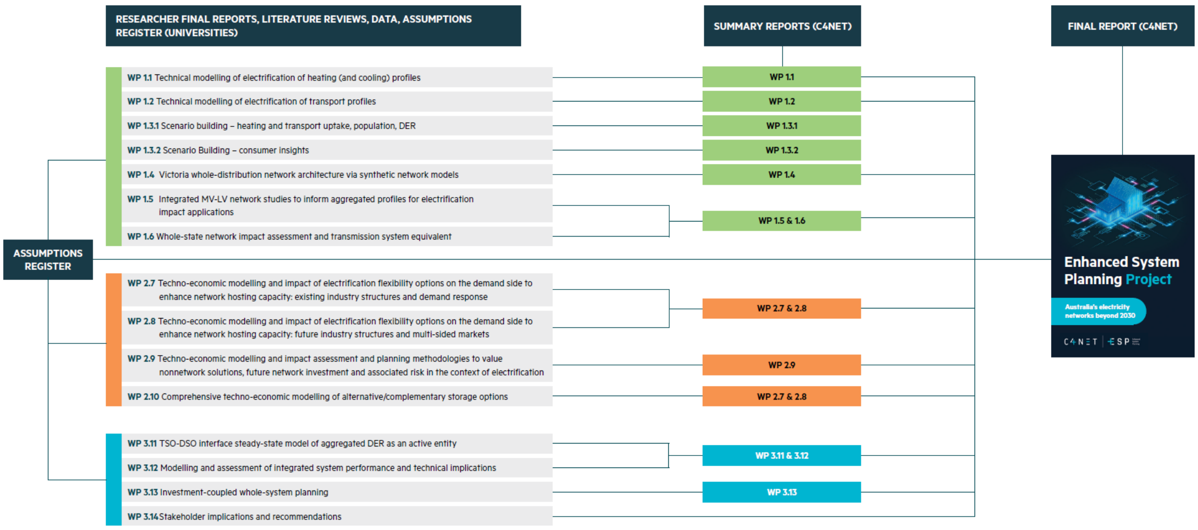

Figure 2 – structure of publicly available documents under the ESP

The ESP Final Report contains a number of recommendations for AEMO , DNSPs and regulatory bodies. For reference, these are repeated on the following pages.

1. The System Planning Working Group and AEMO to:
    a. consider the ESP findings to address optimisation for the demand side, and the roadmap as a key means for implementation of the ECMC ISP action for co-optimisation through incorporation of active distribution systems into future ISPs as a suitable approach to assess cost trade-offs of unlocking increasing tranches of orchestrated CER and DER against other investment options; and in parallel
    b. identify priority issues and actions needed to permit AEMO and DNSPs to implement, including roles and responsibilities, regulatory requirements, consultation and rule changes to permit and allocate costs
2. Should the adoption of the roadmap be supported, the System Planning Working Group and AEMO to:
    a. Commission the development of frameworks for integrated system operation which recognises the future "active" nature of distribution network operations, as well as regulatory and market development to align incentives, and
    b. propose the implementation into the next appropriate ISP review framework, such as any post-2026 ISP review or the AEMC's scheduled ISP review to be published in 2027.
3. AEMO to coordinate common methodologies for characterisation of the electrification of space heating/cooling, domestic hot water, EV charging in active distribution systems for planning purposes, including evaluation of the frameworks developed under the ESP. This work could be conducted by consultants or researchers under guidance of AEMO rather than having to be done by AEMO or the DNSPs.
4. AEMO and transmission planners such as VicGrid to ensure large scale assets are evaluated against comparative opportunities that utilise the capacity, complementary assets and flexibility available in respective distribution networks.
5. AEMO, TNSPs and DNSPs to develop common frameworks for the integrated operation of assets connected to sub-transmission networks along with the necessary rule change requests.
6. DNSPs should work collaboratively to address areas where AEMO will benefit from harmonisation. This is likely to include:
    a. Consistent representation of distribution networks across an expanded set of regional nodes or transmission system connection points
    b. Development of a manageable number of scalable network archetypes for modelling long-term planning outcomes
    c. Provision of standardised data to inform modelling
    d. Common approaches to the characterisation of flexibility.
7. DNSPs should develop the capability to produce accurate parametric representations of their networks suitable for the proposed whole-system planning approach.

8. DNSPs work with AEMO for the development of a co-optimised DSO-TSO framework, incorporating both data exchange and value sharing.
9. DNSPs should evaluate the tools developed under the ESP for use in their own planning.
10. DNSPs should work with AEMC and AER to foster the development of the ESP framework for non-network solution assessment – navigating uncertainties, planning risks and facilitating investment decisions.
11. DNSPs to consider working collaboratively within jurisdictions to harmonise communication to customers and minimise difference in CER connection policies and opportunities to participate in network service opportunities.
12. DNSPs to work with policy makers to help communicate the role of DOEs and their advantage for all system users.
13. DNSPs to work with policy makers to build trust with consumers for better engagement of their CER, understanding the benefits of doing so and convey with them how they benefit, ideally with aligned incentives.
14. AEMC to consider, as part of its upcoming ISP review, whether the current regulations are adequate to allow for this work to progress in accordance with ECMC's expectations for the co-optimisation ISP recommendation.
15. AEMC to accelerate the development comprehensive DSO frameworks in anticipation of broader inclusion of active distribution systems in integrated system planning and operation including associated market development for flexibility, consistent with the CER Roadmap.
16. AEMC could build a program to pro-actively develop better holistic approaches to incentive alignment needs of the future. DNSPs, the ECA and transmission planners could all assist in identifying current and emerging gaps to be addressed. Include both market and non-market means to address.
17. Regulators and governments to adopt stop-gap measures to address the immediate opportunity for preferential connection of large-scale assets to the sub-transmission system where there is a strong economic case to do so.
18. Ensure all transmission expansion cases are compared to viable alternatives in the sub-transmission networks in case a lower cost alternate can be identified.
19. Adopt the recommended additional asset utilisation reporting for all major electricity network assets in transmission and distribution networks, as proposed by the ECA in their rule change proposal.
20. Policy makers to consider longitudinal consumer sentiment studies relating to CER and develop a better understanding of their adoption of CER services.
21. Policy makers to facilitate the adoption of DOEs in conjunction with DNSP's increasing the inverter size to 10kW that can be connected without further engineering studies. Together with this policy makers should help communicate the value of DOEs to customers and consider

differentiated offerings where storage is paired with the solar installation (such as DHW, home battery or EV with degrees of control).

22. Facilitate data access – both to DNSPs for the information they need to best manage the system and from DNSPs to help planners and investors identify opportunities once mechanisms are in place to realise those values.

23. Policymakers and regulatory bodies should consider the additional insights and recommendations contained in Appendix 6 [of the ESP Final Report].

Enhanced System Planning Project

Australia's electricity networks beyond 2030

C4NET | ESP Enhanced System Planning

June 2025

Enhanced System Planning by C4NET

This report is the result of a significant and collaborative research project aimed at informing sub transmission level electricity planning in Australia beyond 2030. The Enhanced System Planning (ESP) research project was developed with a focus on building methodologies and approaches for bottom-up modelling and to highlight the opportunities presented through the distribution system and integrating Consumer Energy Resources (CER) and Distributed Energy Resources (DER) to inform whole-of-system planning.

This report recognises the contribution of organisations and individuals who have contributed to the development of the ESP and the benefits the ESP has identified across the National Electricity Market for an integrated energy system.

The ESP project was generously supported by the project partners listed below.

See Appendix 1 for background on C4NET.

Partners

C4NET Centre for New Energy Technologies
Monash University – Monash Energy Institute
The University of Melbourne
Federation University
RMIT University
Deakin University
AusNet
Jemena – bringing energy to life
CitiPower
iMOVE
AEMO – Australian Energy Market Operator
Powercor Australia
united energy
RACE for 2030 – Reliable Affordable Clean Energy
Energy Consumers Australia
Victoria State Government – Energy, Environment and Climate Action

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SECTION ONE

Executive summary

1 Executive summary

Background

The transformation facing Australia's National Electricity Market (NEM) over the next 30 years is without precedent. As power systems evolve, traditional approaches to transmission network (TN) planning are being challenged by the increasing uptake of consumer energy resources (CERs) and distributed energy resources (DERs) embedded in electricity distribution networks, in conjunction with a substantial increase in demand due to electrification. In addition, the connection of data centres over the next decade could be transformational. These challenges are further exacerbated by the shift from conventional to renewable energy generation that is less responsive to demand variation. This shift will necessitate the development of new coordination systems, the emergence of new market structures, and significant changes to the regulatory environment to ensure reliability, affordability, and equity throughout the transition.

The impacts of the electrification of residential gas and transport and the increase in adoption of CER and DER in distribution networks will push many low voltage electricity network assets in the NEM beyond their present limits and solar curtailment will become material within the next decade. Major electricity network augmentation will be required to accommodate electrification and broader CER connections, which without coordinated infrastructure planning will push up the costs of electrification and the energy transition. The electricity distribution system is experiencing challenges but also holds solutions to the changing grid needs - the Australian Energy Market Operator (AEMO) has estimated a $4.1 billion deferment in grid-scale investment if CER is properly coordinated.[1] Uncertainty in CER and DER adoption rates and demand growth presents risks of both under- and over-investment in long-life electricity network assets, reinforcing the importance of scenario-based planning.

AEMO currently undertakes an Integrated System Plan (ISP) process every two years to provide an integrated roadmap for the efficient development of the NEM over the next 20 years and beyond. The primary objective of the ISP is to optimise value to end consumers by designing the lowest cost, secure and reliable energy system capable of meeting any emissions trajectory determined by policy makers at an acceptable level of risk.[2]

The Energy and Climate Change Ministerial Council's (ECMC) Review of the Integrated System Plan supports enhanced demand forecasting including "that the System Planning Working Group and AEMO work with the relevant stakeholders, including DNSPs [distribution network service providers], to develop a suitable approach to trade off the cost of unlocking increasing tranches of orchestrated CER and distributed resources against other investment options for use in the earliest ISP practicable".[3] The goal posts have clearly been set - while in the past the distribution system could be thought of as simply a net load, it is now a critical priority to include this increasingly "active" electricity network[4] in an updated, coordinated, whole of electricity system planning and operation approach to enable an efficient, cost-effective evolution of our electricity grid.

1 AEMO, 2024 Integrated System Plan, June 2024

2 https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp, accessed 23 May 2025

3 ECMC 2024, Review of the Integrated System Plan: ECMC Response, Energy and Climate Change Ministerial Council, Canberra. CC BY 4.0

4 Proactive, pre-emptive and responsive control using real-time monitoring and management of the network, user loads and power generation, compared to traditional "passive" networks where control is restricted to network components.

AEMO is recognising the potential benefits and making initial steps towards a more whole-of-system planning approach. The challenge is that there is currently no roadmap for integrating bottom-up electricity distribution system considerations into an integrated, sector-wide framework for system planning and operation. There are no established methods for effectively modelling the uncertainties of that evolution, or to co-optimise the most efficient infrastructure investment across transmission and distribution networks that accounts for differences in DNSP planning approaches. C4NET's Enhanced System Planning (ESP) project provides methodologies, models and a roadmap to support this evolution.

Project design and methodology

The ESP project is a major research project aimed at informing electricity planning below the transmission level beyond 2030. Over the course of the last two years, C4NET has brought together over 100 academic, industry and government personnel to deliver 15 research projects that involved sophisticated electricity distribution network simulations and techno-economic modelling using Victorian distribution network data in a unique collaboration to update infrastructure utilisation modelling. The Victorian Government Department of Energy, Environment and Climate Action (DEECA), and AEMO have also participated to ensure that system planning, policy and regulation are informed by project outcomes, and vice versa.

The ESP was delivered over three work packages:

+ **Work package one:** Key inputs, methodologies, and demand network implications of electrification to inform foundational elements of bottom-up modelling.
+ **Work package two**: Impact of flexibility options within distribution networks and techno-economic assessments of future architectures.
+ **Work package three:** Active distribution network considerations for whole-of-system planning implications: technical, economic and policy.

The ESP study was conducted using AEMO's 2024 ISP "Step Change" scenario as the foundation for forecast timings and in the context of current regulatory frameworks, with some adaptation to inform the 100% electrification of residential gas. The models and outcomes generated by the ESP are designed to cover both network and non-network solutions at all levels of distribution networks (high, medium and low voltage), be nationally relevant and support and feed into the ISP process to inform whole of system planning.

Findings, observations and key outputs

The ESP delivered bottom-up electricity distribution network modelling, scalable tools and models to assess future residential load, CER/DER and electrification impacts, repeatable data-sharing methods and planning frameworks using DNSP data. It also compared flexible and traditional infrastructure pathways to lower system costs.

The approach outlined in the ESP builds practical foundations for cost-effective, integrated, coordinated, system-wide energy planning across the NEM. It enables better system coordination and policy alignment, reducing duplication and delays, and informs more timely, cost-effective infrastructure investment and a reduction of total energy system costs for consumer benefit.

Key findings from the ESP include:

+ **Planning**: Long-term, bottom-up planning within the electricity distribution network was shown to facilitate better management of overall system uncertainty by introducing flexibility via active distribution sub-systems and coordinated DER/CER.
+ **Operation**: A combination of electricity network and CER/DER management solutions can lower overall cost impacts across the "active" distribution network.
+ **Connections**: When coupled with an "active" electricity distribution system, the connection of solar and wind generation combined with storage in the sub-transmission network can ease the investment challenge in the transmission network and reduce overall system costs by utilising existing and lower-cost hosting capacity.
+ **Flexibility**: Upstream system investment could be lowered by implementing and sequencing added "flexibility" created by active distribution networks and regulatory incentives within the distribution system.
+ **Cost savings**: Case studies using AEMO renewable energy zone (REZ) data have illustrated that directional savings of over 25% may be achieved through applying the framework and methodologies developed in the ESP, which would represent multi-billion dollar savings if valid more broadly across the NEM (noting that model parameters and investment costs would need to be verified with industry as just shown in a research modelling context to date).

These significant cost and efficiency savings won't be realised through a business-as-usual scenario. The research outcomes showed that distribution system considerations are critical for whole of system planning and must be integrated as a priority to avoid over-investment in the energy system: the process and regulatory changes to support this evolution should start now.

A roadmap for the implementation the ESP approach to integrated whole-of-system planning has been developed.. The proposed roadmap consists of five main elements, where the first four follow a bottom-up, physics-based, techno-economic approach, and the fifth revolves around policy development, operational and regulatory reforms required to make the approach effective. Given the complexity and lengthy timeframes for implementing the approach outlined in the ESP, a staged approach has been outlined to fit the iterative nature of successive ISPs.

The ESP has highlighted the criticality of incorporating distribution system considerations in whole of system planning to deliver the lowest cost system. It is recommended:

1. The System Planning Working Group and AEMO to:
   a. consider the ESP findings to address optimisation for the demand side, and the roadmap as a key means for implementation of the ECMC ISP action for co-optimisation through incorporation of active distribution systems into future ISPs as a suitable approach to assess cost trade-offs of unlocking increasing tranches of orchestrated CER and DER against other investment options; and in parallel
   b. identify priority issues and actions needed to permit AEMO and DNSPs to implement, including roles and responsibilities, regulatory requirements, consultation and rule changes to permit and allocate costs.

Stakeholder considerations, recommendations and next steps

Key recommendations from the ESP include:

+ **ESP adoption:**. The System Planning Working Group and AEMO should consider the ESP findings and roadmap adoption to address the ECMC's ISP review action relating to optimising for the demand side. Identify the priority issues and actions needed to permit AEMO and DNSPs to implement the roadmap. Building on their recent collaborations, AEMO and DNSPs should continue transitioning ESP methodologies from a research context into real-world application. A crucial component of this transition involves adopting a bottom-up modelling framework across all networks, extending to at least the medium-voltage (MV) transformer level. This ensures that network archetypes adequately reflect the diversity, configuration, and topology of Australia's evolving energy grid, allowing for more precise and scalable decision-making.
+ **Harmonisation:** A fundamental priority is achieving harmonisation across whole-of-system planning, creating a practical and efficient framework that integrates distribution and transmission networks seamlessly. Policymakers and regulators must align investment assessment frameworks to encourage greater collaboration between consumers and electricity network operators.

This alignment will ultimately lead to lower network service costs and reduced overall system expenditure, particularly as the NEM increasingly relies on distribution-connected resources.

+ **Alignment:** To support this transition, it is essential to align incentives and remove existing regulatory and commercial impediments that do not support DNSPs investing in infrastructure and operational practices that enable higher CER adoption and reduced energy export curtailment. While these investments benefit individual customers, they also generate wider economic value across the NEM by improving systemwide coordination. Current incentive structures do not adequately reward DNSPs for enabling systemwide access to lower cost renewable energy, rather than simply focusing on localised network costs.
+ **Regulation:** Looking to international best practices, policymakers should consider global regulatory examples where distribution network assets—alone or combined with coordinated CER—are effectively integrated into broader system activities, allowing benefits to be shared with consumers through new market mechanisms. Additionally, regulatory arrangements should be expanded to allow DNSPs and market participants to capture the full range of network and market benefits from distribution system storage, reducing overall electricity system costs.
+ **Frameworks:** The Australian Energy Regulator (AER) and the Australian Energy Market Commission (AEMC), in collaboration with DNSPs, should develop common model frameworks aligned with the illustrative prototypes established under the ESP project. These frameworks will enable efficient asset and solution assessments while incorporating uncertainty into investment planning. For example, critically, regulatory assessments must allow total system benefits—including CER-driven efficiencies—to be included in the Regulatory Investment Test for Distribution (RIT-D).
+ **Investment:** Additionally, several structural reforms will help facilitate a more integrated and cost-effective electricity transition. Removing investment barriers will allow for the development of coordinated planning and operational roles between market participants. Evaluating all generation and large-scale storage connection options against sub-transmission alternatives will ensure that investments align with broader system needs and avoid unnecessary infrastructure costs.
+ **Reporting:** Improved reporting of asset utilisation at both peak demand and energy levels is required for transmission and distribution network infrastructure. Increased visibility into network performance will support better-informed whole-of-system planning and investment decisions as well as policy decisions with respect to new markets.
+ **Consumers:** As consumers will be both the beneficiaries and enablers of a whole-of-system planning approach using an active distribution system, and their uptake of CER and willingness to participate in CER orchestration is key to the success of the modelled scenarios, consider longitudinal consumer sentiment studies relating to CER and develop a better understanding of their adoption of CER services.

Through these collaborative efforts, Australia's energy sector can move toward a more resilient, cost-efficient, and consumer-centric future, ensuring that electricity network investments are optimised, market structures are reformed, and planning approaches are harmonised to support the long-term evolution of the grid.

1.1 Consolidated list of recommendations

Detailed recommendations, their context and interdependency are laid out in Section 6. A full list is provided here for quick reference.

1 The System Planning Working Group and AEMO to:

a. Consider the ESP findings to address optimisation for the demand side, and the roadmap as a key means for implementation of the ECMC ISP action for co-optimisation through incorporation of active distribution systems into future ISPs as a suitable approach to assess cost trade-offs of unlocking increasing tranches of orchestrated CER and DER against other investment options; and in parallel

b. Identify priority issues and actions needed to permit AEMO and DNSPs to implement, including roles and responsibilities, regulatory requirements, consultation and rule changes to permit and allocate costs.

2 Should the adoption of the roadmap be supported, the System Planning Working Group and AEMO to:

a. Commission the development of frameworks for integrated system operation which recognises the future "active" nature of distribution network operations, as well as regulatory and market development to align incentives, and

b. Propose the implementation into the next appropriate ISP review framework, such as any post-2026 ISP review or the AEMC's scheduled ISP review to be published in 2027.

3 AEMO to coordinate common methodologies for characterisation of the electrification of space heating/cooling, domestic hot water, EV charging in active distribution systems for planning purposes, including evaluation of the frameworks developed under the ESP. This work could be conducted by consultants or researchers under guidance of AEMO rather than having to be done by AEMO or the DNSPs.

4 AEMO and transmission planners such as VicGrid to ensure large scale assets are evaluated against comparative opportunities that utilise the capacity, complementary assets and flexibility available in respective distribution networks.

5 AEMO, TNSPs and DNSPs to develop common frameworks for the integrated operation of assets connected to sub-transmission networks along with the necessary rule change requests.

6 DNSPs should work collaboratively to address areas where AEMO will benefit from harmonisation. This is likely to include:

a. Consistent representation of distribution networks across an expanded set of regional nodes or transmission system connection points.

b. Development of a manageable number of scalable network archetypes for modelling long-term planning outcomes.

c. Provision of standardised data to inform modelling.

d. Common approaches to the characterisation of flexibility.

7 DNSPs should develop the capability to produce accurate parametric representations of their networks suitable for the proposed whole-system planning approach.

8 DNSPs work with AEMO for the development of a co-optimised DSO-TSO framework, incorporating both data exchange and value sharing.

9 DNSPs should evaluate the tools developed under the ESP for use in their own planning.

10 DNSPs should work with AEMC and AER to foster the development of the ESP framework for non-network solution assessment – navigating uncertainties, planning risks and facilitating investment decisions.

11 DNSPs to consider working collaboratively within jurisdictions to harmonise communication to customers and minimise difference in CER connection policies and opportunities to participate in network service opportunities.

12 DNSPs to work with policy makers to help communicate the role of DOEs and their advantage for all system users.

13 DNSPs to work with policy makers to build trust with consumers for better engagement of their CER, understanding the benefits of doing so and convey with them how they benefit, ideally with aligned incentives.

14 AEMC to consider, as part of its upcoming ISP review, whether the current regulations are adequate to allow for this work to progress in accordance with ECMC's expectations for the co-optimisation ISP recommendation.

15 AEMC to accelerate the development of comprehensive DSO frameworks in anticipation of broader inclusion of active distribution systems in integrated system planning and operation including associated market development for flexibility, consistent with the CER Roadmap.

16 AEMC could build a program to pro-actively develop better holistic approaches to incentive alignment needs of the future. DNSPs, the ECA and transmission planners could all assist in identifying current and emerging gaps to be addressed. Include both market and non-market means to address.

17 Regulators and governments to adopt stop-gap measures to address the immediate opportunity for preferential connection of large-scale assets to the sub-transmission system where there is a strong economic case to do so.

18 Ensure all transmission expansion cases are compared to viable alternatives in the sub-transmission networks in case a lower cost alternate can be identified.

19 Adopt the recommended additional asset utilisation reporting for all major electricity network assets in transmission and distribution networks, as proposed by the ECA in their rule change proposal.

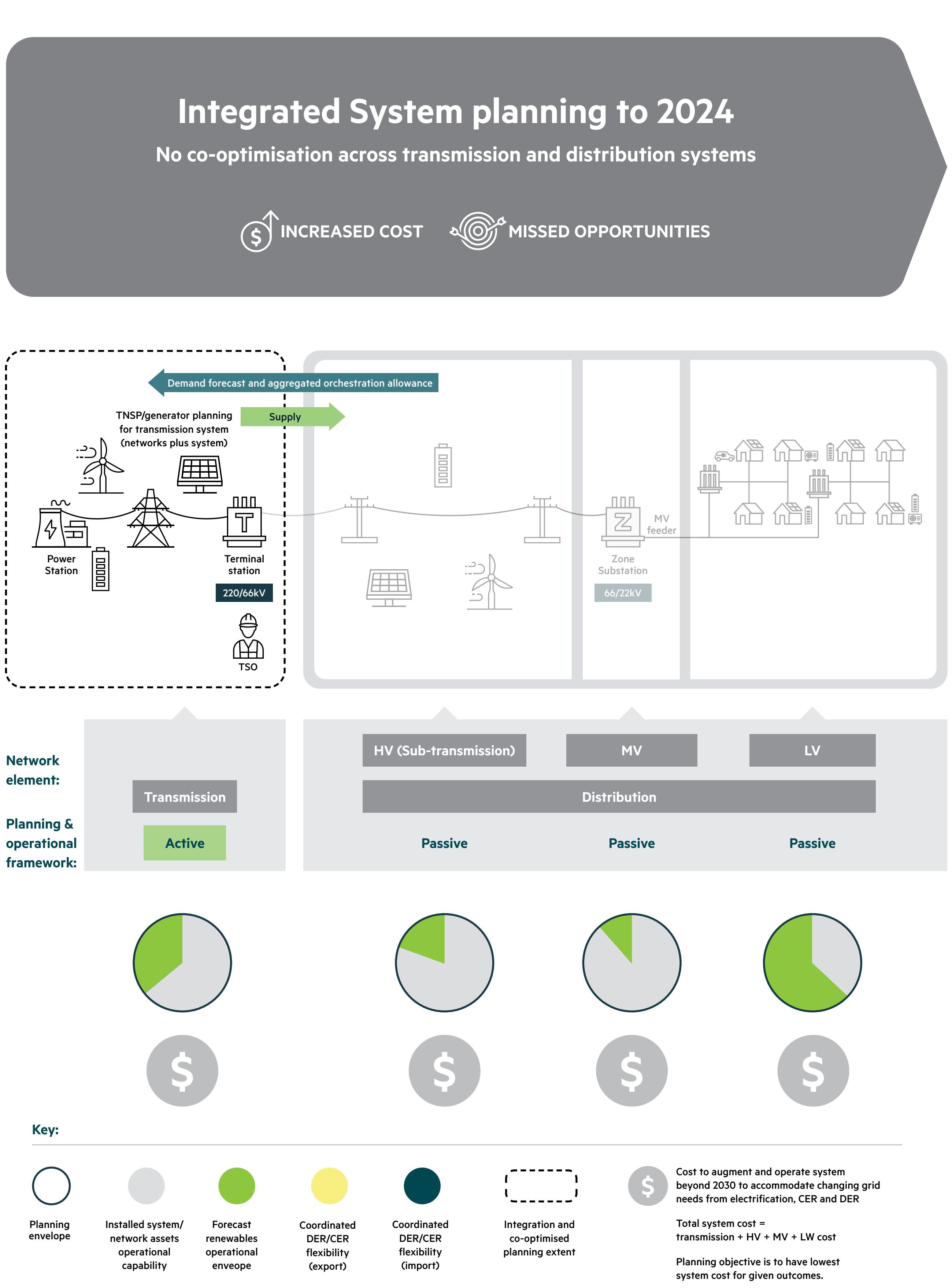
20 Policy makers to consider longitudinal consumer sentiment studies relating to CER and develop a better understanding of their adoption of CER services.

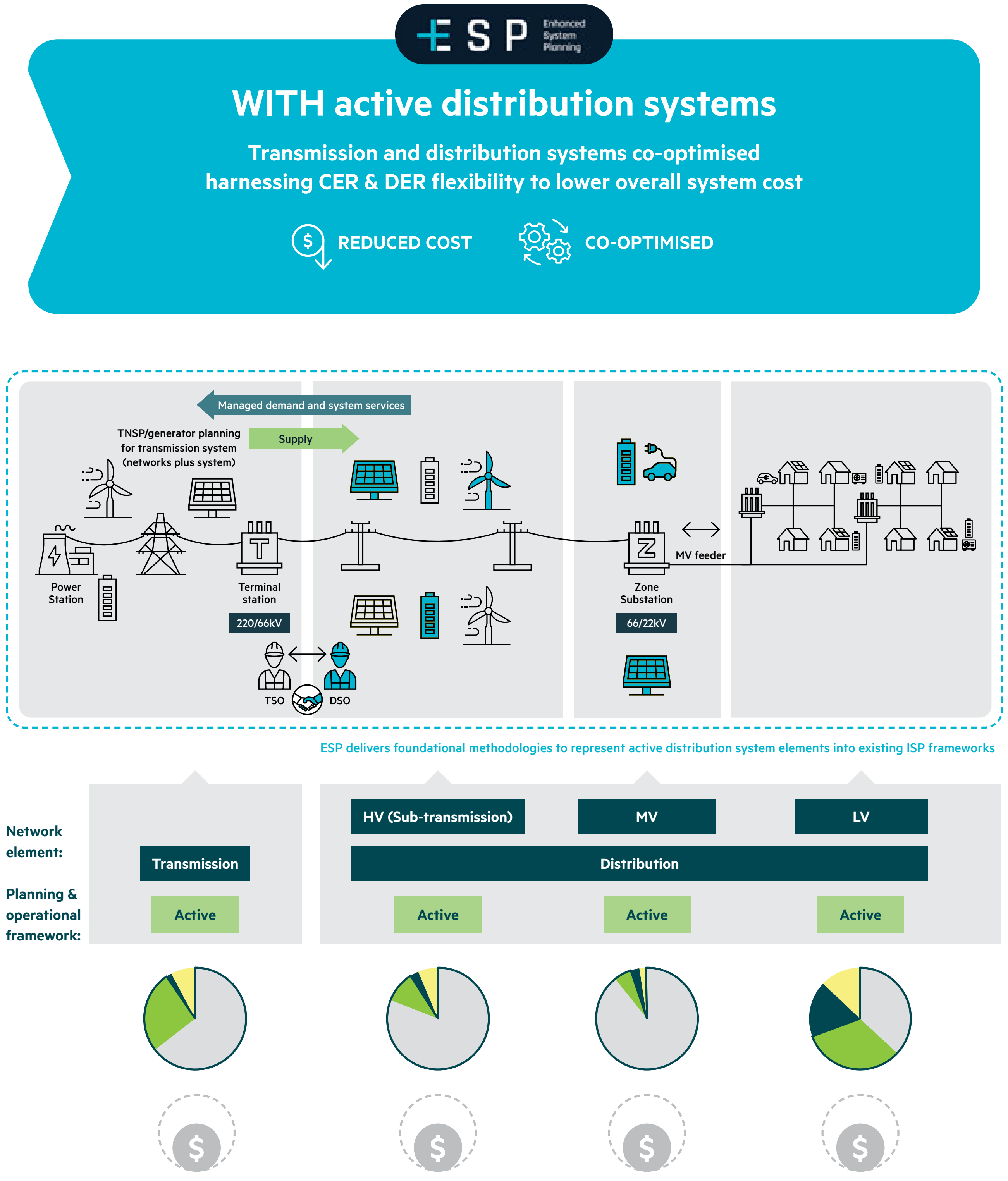
21 Policy makers to facilitate the adoption of DOEs in conjunction with DNSP's increasing the inverter size to 10kW that can be connected without further engineering studies. Together with this policy makers should help communicate the value of DOEs to customers and consider differentiated offerings where storage is paired with the solar installation (such as DHW, home battery or EV with degrees of control).

22 Facilitate data access – both to DNSPs for the information they need to best manage the system and from DNSPs to help planners and investors identify opportunities once mechanisms are in place to realise those values.

23 Policymakers and regulatory bodies should consider the additional insights and recommendations contained in Appendix 6.

Figure 1: How the ESP compares to business as usual





Integrated planning and operating extensive CER and DER across both transmission and distribution networks from a whole-of-system perspective can reduce the operational envelope to be served at each level of the transmission and distribution networks, reducing future asset investment. It is recognised there are some inherent reductions in the operating windows from the passive inclusion of CER and DER across both transmission and distribution, but there is an opportunity to capture the full potential of these by shifting to more integrated planning as proposed in the ESP adoption roadmap.

SECTION TWO

Project Reporting Structure

2 Project reporting structure

ASSUMPTIONS REGISTER

RESEARCHER FINAL REPORTS, LITERATURE REVIEWS, DATA, ASSUMPTIONS REGISTER (UNIVERSITIES)

- **WP 1.1** Technical modelling of electrification of heating (and cooling) profiles
- **WP 1.2** Technical modelling of electrification of transport profiles
- **WP 1.3.1** Scenario building – heating and transport uptake, population, DER
- **WP 1.3.2** Scenario building – consumer insights
- **WP 1.4** Victoria whole-distribution network architecture via synthetic network models
- **WP 1.5** Integrated MV-LV network studies to inform aggregated profiles for electrification impact applications
- **WP 1.6** Whole-state network impact assessment and transmission system equivalent
- **WP 2.7** Techno-economic modelling and impact of electrification flexibility options on the demand side to enhance network hosting capacity: existing industry structures and demand response
- **WP 2.8** Techno-economic modelling and impact of electrification flexibility options on the demand side to enhance network hosting capacity: future industry structures and multi-sided markets
- **WP 2.9** Techno-economic modelling and impact assessment and planning methodologies to value nonnetwork solutions, future network investment and associated risk in the context of electrification
- **WP 2.10** Comprehensive techno-economic modelling of alternative/complementary storage options
- **WP 3.11** TSO-DSO interface steady-state model of aggregated DER as an active entity
- **WP 3.12** Modelling and assessment of integrated system performance and technical implications
- **WP 3.13** Investment-coupled whole-system planning
- **WP 3.14** Stakeholder implications and recommendations

SUMMARY REPORTS (C4NET)

- WP 1.1
- WP 1.2
- WP 1.3.1
- WP 1.3.2
- WP 1.4
- WP 1.5 & 1.6
- WP 2.7 & 2.8
- WP 2.9
- WP 2.10
- WP 3.11 & 3.12
- WP 3.13

FINAL REPORT (C4NET)

SECTION THREE

Enhanced System Planning project overview

3 Enhanced System Planning project overview

3.1 Background

As power systems evolve, traditional approaches to transmission network (TN) planning are being challenged by the increasing uptake of consumer energy resources (CERs) and distributed energy resources (DERs) embedded in electricity distribution networks, in conjunction with a substantial projected increase in demand due to electrification. These challenges are further exacerbated by the shift from conventional generation to renewable energy generation that is less responsive to demand variation.

The following section provides an overview of power system planning in Australia, the need to shift from a supply-centric model to a whole-of-system approach to respond to these challenges, and the ESP project's purpose to support this evolution by incorporating distribution network considerations into forecasting and policy frameworks to ensure a more responsive, efficient and cost-effective future grid.

3.1.1 Traditional planning of power systems: The supply-centric paradigm

Traditionally, electricity distribution networks (DNs), which are predominantly *radial* in topology, were designed based on after-diversity maximum demand (ADMD)[5], with an additional allowance for loss of diversity. Although this generally ensured reliability by minimising congestion, it came at the expense of a relatively low asset utilisation. On the other hand, the predominantly meshed topology of electricity transmission networks is the result of system reliability requirements, which relate to the potentially widespread consequences of failure. The built-in redundancies (i.e. N-1 security) and robust designs reduce what would have been a higher asset utilisation and congestion is managed through supply-side market arrangements.[6]

Moreover, the demand in traditional DNs was generally inflexible, and the flow of power was largely unidirectional. As a result, all the dispatchability, and therefore flexibility, was provided from the generation side through the TNs. Power system security was also provided primarily from the side of TNs. Consequently, traditional TNs and large-scale generation were planned *simultaneously* to ensure reliability and security. The inflexibility of demand therefore meant that flexibility had to be appropriately considered in the *joint planning* of transmission and generation under a *centralised* paradigm.

In summary, traditional electricity network design was largely centred around servicing the (after-diversity) peak demand with little consideration of demand management options except in extreme circumstances (e.g., brownouts, industrial level etc.). In doing so, the potential flexibility within the system beyond the control of power flows on the transmission level was ignored. However, as will be discussed below, increased visibility of demand, through advanced metering infrastructure, SCADA systems, and real-time monitoring and control, and the emergence of CER with embedded storage can now greatly influence demand profiles of the power system and in turn influence future design choices at all levels of the grid.

3.1.2 The energy transition: From supply-centric to consumer-centric

The energy transition is underpinned by two main drivers, each presenting its own set of challenges and opportunities, being:

1. The shift from coal-fired generation (CFG) to renewable generation,
2. A significant increase in electricity demand mainly due to electrification of transport, hot water heating, cooling,[7] and cooking.[8]

These trends are acknowledged in the Australian Energy Market Operator's (AEMO) 2024 Integrated System Plan (ISP),[9] which forecasts a significant scale-up in renewable generation. Utility-scale wind and solar capacity is projected to triple by 2030, targeting a national renewable energy share of 82%, and increase six-fold by 2050, growing from 21 gigawatts (GW) in 2024 to 127 GW (Figure 2 a). In parallel, AEMO forecasts a two-fold increase in residential electricity consumption by 2050, driven by the uptake of electric vehicles (EVs) and electrification of household heating, cooling, and cooking, as shown in Figure 2 b.

Over the next 20 to 30 years, the energy landscape, and the roles of consumers within it, is expected to undergo substantial transformation. While it is difficult to imagine exactly how it will look, reflecting the scale of change from the past 25 years one can see that change was not predictably linear.

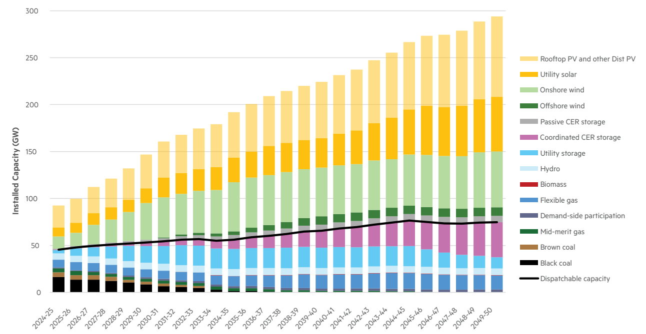
5 ADMD is the measure of the highest demand averaged across all consumers at peak time

6 Congestion on the TNs gives rise to price arbitrage opportunities between different regions.

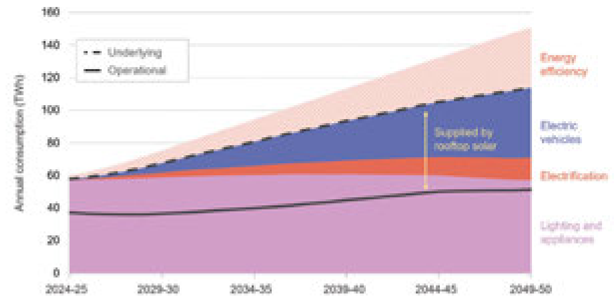
7 While cooling in isolation is not considered to be affected by electrification, gas heating units are often replaced with electric-powered ones that also provide a cooling function that impacts demand.

8 Data centres are also envisaged to contribute to a significant increase in demand.

9 AEMO, 2024 Integrated System Plan, June 2024



a) Forecast capacity in the NEM



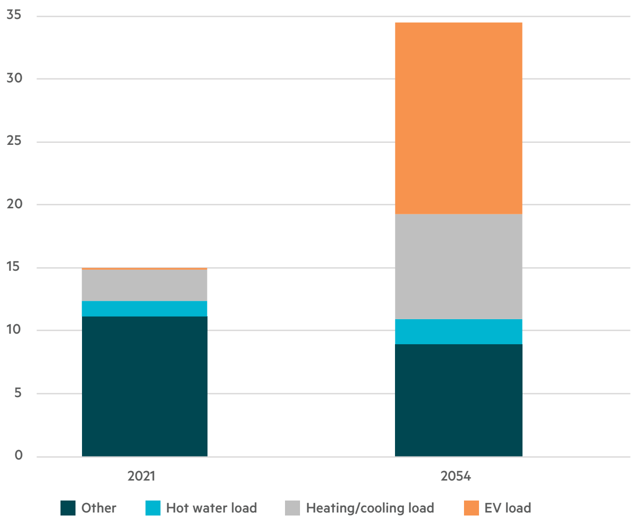
b) Forecast residential consumption

Figure 2: Forecast generation capacity (left) and residential consumption (right) in the NEM according to AEMO's 2024 ISP

3.2 The opportunity

To address a significant industry gap through collaborative research, in 2021, C4NET's Board identified a critical opportunity to further evolve the AEMO's ISP: broadening its scope to consider distribution systems. The ISP plays a central and valuable role in the Australian energy sector—offering harmonised scenarios, rigorous modelling, and incorporating sector-wide consultation— but, by design, it was originally limited to transmission-level infrastructure. Consequently, it did not adequately account for distribution system dynamics amid the broader decarbonisation of the energy grid. Demand flexibility, the impact of consumer energy resources (CER), electrification and evolving consumer behaviour are all expected to have significant impacts on the future electricity system. This has now been broadly recognised and is evolving through recent rule changes and policy settings, such as the actions identified in the ECMC's ISP review that has led to the inclusion of a demand-side factors statement in future ISPs.

THE BREAKDOWN OF ELECTRICITY USAGE OF VICTORIAN HOUSEHOLDS (KWH/D).



The scale of the electrification impact of transport (EVs) and heating & cooling dwarf efficiency improvements across the remaining loads. While hot water is assumed to be predominantly electric, the aggregated load growth is somewhat offset through efficiency improvements of heat pumps compared to existing electric hot water systems

The opportunity

No whole-of-system model exists to plan for mass adoption of DER/CER, electric vehicles and electrification

Fragmented planning and limited distribution-level data visibility to inform policy and decision making

Rising system costs and risks of misalignment between distribution and transmission network investment

Figure 3: Some elements of the future are reasonably predictable based on today's behaviour and technology changes: Electricity use and generation in Victorian households from 2021 (actual) to 2054 (projected) kWh/d, C4NET analysis

The contribution distribution systems could make to addressing system challenges was unclear. The $20 billion *Rewiring the Nation* initiative[10] had little apparent assessment of the potential for distribution systems to support system needs. Orchestration of CER and DER was assumed to reduce distribution network investment growth, but again it was unclear how this would be achieved, or taken into account at system level.

The Integrated System Plan treats distribution systems as unconstrained, not factoring the investment upgrades to manage shifting demand profiles, increasing CER hosting, and the rise in bidirectional energy flows. No integrated modelling framework exists for infrastructure downstream of the transmission level, limiting policymakers' ability to assess and optimise trade-offs between transmission and distribution investments.

This disconnect poses a serious challenge to forecasting future energy scenarios, especially considering rapid changes such as mass uptake of distributed renewables, transport electrification, domestic fuel switching, and emerging energy vectors. These developments are interconnected and must be modelled as such. Without a foundational system framework that encompasses the distribution system, the design of an intelligent, responsive, and efficient decarbonised energy system is constrained.

Given the long lead times for regulatory processes and capital deployment, urgent planning is needed now to explore a range of possible futures and prioritise strategic actions. Decisions made over the next three to five years will set the course for Australia's energy and climate pathways for decades.

A key challenge was how to address the gap. With no global precedent for whole-of-system integration including electricity distribution networks, and no known scalable solutions for the consideration of NEM-wide solutions across 13 different distribution areas, it was unclear whether a feasible approach could be developed.

10 https://www.dcceew.gov.au/energy/renewable/rewiring-the-nation, accessed 23 May 2025

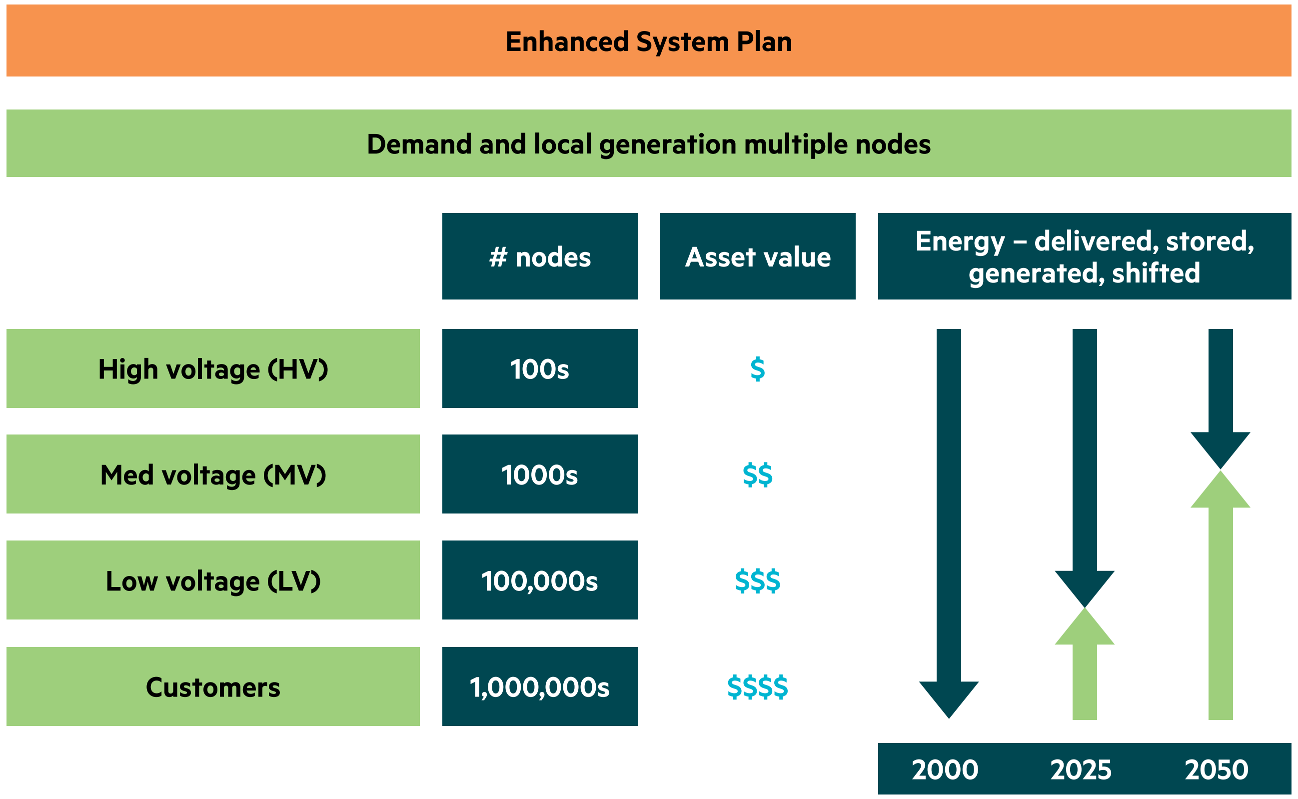


Figure 4: Changes in how energy is delivered, stored and generated is rapidly shifting, impacting the LV assets which collectively make up so much of the network asset value

3.3 Program design

To address the identified opportunity, C4NET leveraged its collaborative role within the energy sector to initiate and deliver the ESP Project. While the distribution system planning gap impacted all sector participants, no single organisation was positioned to lead its resolution. C4NET mobilised a broad coalition of stakeholders with a shared interest in the issue, and who were willing to commit substantial resources to its exploration and resolution.

Fast facts

$3.6M	Total cash investment
11	Partner organisations
5	Universities
15	Research projects
100+	Researcher, industry & government personnel directly contributing

A Project Steering Committee was established to guide the governance, design, and resource commitments of the initiative. This committee included representatives from academia, the Victorian Government, DNSPs, AEMO, and Energy Consumers Australia (ECA).

Given the scale and complexity of the challenge, the project was deliberately scoped to focus on some of these most technically difficult components. The rationale was that demonstrating the feasibility of solutions in these high-complexity areas would provide a foundation for expanding the approach to additional elements—such as commercial and industrial sectors—in future phases (Figure 5).

A comprehensive research program was developed by academics from five universities and structured across work packages comprising groups of projects addressing different three different areas of focus. This program was co-designed over several months in consultation with DNSPs, the Victorian Government, and AEMO. The resulting set of research projects is detailed in the next section of this report.

ESP project scope at-a-glance

Electrification of residential gas

Electrification of light passenger & commercial vehicles

Practicable saturation of residential CER uptake

Applied in Victoria to inform, but all methodologies need to be built for NEM-wide application

The research projects were phased over a two-year timeline and anchored to AEMO's Step Change scenario from the 2024 ISP, which served as the baseline for analysis. C4NET's focus was on the system-wide impact of 100% residential electrification and CER uptake, with a planning horizon of 30 years to align with the ISP's timeframe.

The ESP, while initially developed in Victoria, offers a foundational methodology for national application. It provides a framework to address current modelling gaps, including the role of a more active distribution network and high levels of CER/DER. If scaled, it could support both national energy transition objectives, improve alignment across policy, infrastructure planning, and consumer needs and influence international planning practices.

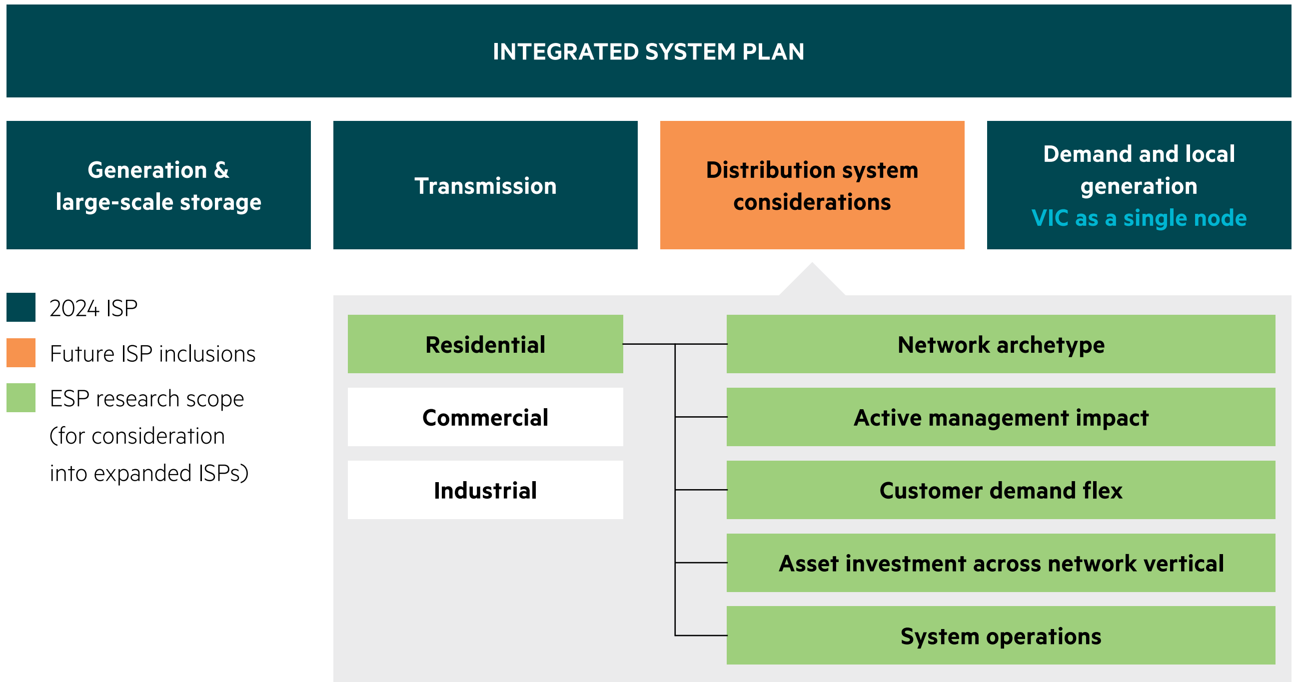


Figure 5: Conceptual design of the areas tackled by the ESP project relative to the ISP and how it may evolve

3.4 Addressing the evolving policy landscape

Alongside the techno-economic program, the project has continuously engaged with key policy and regulatory stakeholders to identify and help pave the way for addressing barriers to meeting the distribution system and planning challenges in a whole of system context.

Energy system planning, once a niche topic, has emerged to become a policy issue that is now attracting significant public attention. The decarbonisation agenda has started to tackle the electrification of gas and transport, and the enablement of CER at a massive scale.

C4NET's research has been a well-timed exploration alongside more recent policy developments such as the ECMC's ISP review response, Federal Government's CER Roadmap and AEMO considering implementation options from ISP 2026 and beyond.

A Policy Advisory Panel (PAP) was established to link researchers to subject matter experts in policy and government relations from DEECA, DNSPs, the Federal Department of Climate Change, Energy and Water (DCCEEW), the Australian Gas Infrastructure Group (AGIG) and Energy Consumers Australia (ECA) as well as a range of guest presenters from participating universities, AEMO, AEMC and other relevant organisations. The PAP forum enabled participants to build understanding of the policy relevant ESP research insights as they emerged from the program and discuss their implications for future energy policy development.

The interactive ESP webinar[11] series also explored policy and regulatory aspects with a range of key stakeholders involved in presentations and expert panel sessions, including Victorian DNSPs, Energy Consumers Australia, the Clean Energy Council, Electric Vehicle Council of Australia, Climate Change Authority, DCCEEW, AEMC and others. The webinars attracted a strong policy-focussed audience from across the Australian energy sector with many questions fielded that further broadened engagement regarding the ESP program.

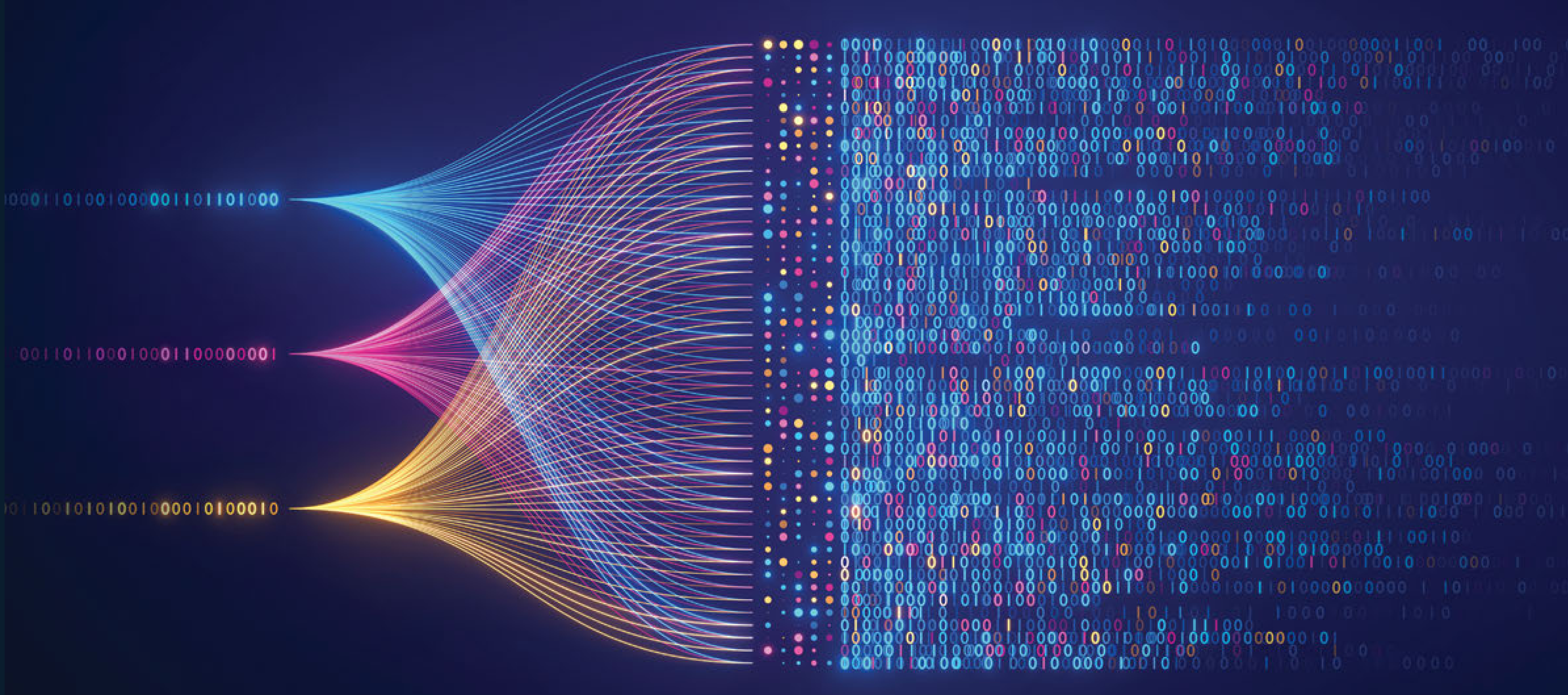
Energy system planning, once a niche topic, has emerged to become a policy issue that is now attracting significant public attention. The decarbonisation agenda has started to tackle the electrification of gas and transport, and the enablement of DER and CER at a massive scale.

11 For webinar highlights, see 'Resources' tab on the ESP Project page on C4NET's website at https://c4net.com.au/projects/enhanced-system-planning-project/

SECTION THREE | Enhanced System Planning project overview

SECTION FOUR

Research design and methodology



4 Research design and methodology

This section outlines the research methodology of the ESP project, detailing its bottom-up modelling approach for integrating distribution networks into whole-of-system planning. It describes the three work packages, the scope of the research and its limitations, and key assumptions. This approach was used by researchers to provide a framework for assessing electrification impacts on the grid, system flexibility, and investment trade-offs in Australia's evolving energy landscape.

4.1 Research program design

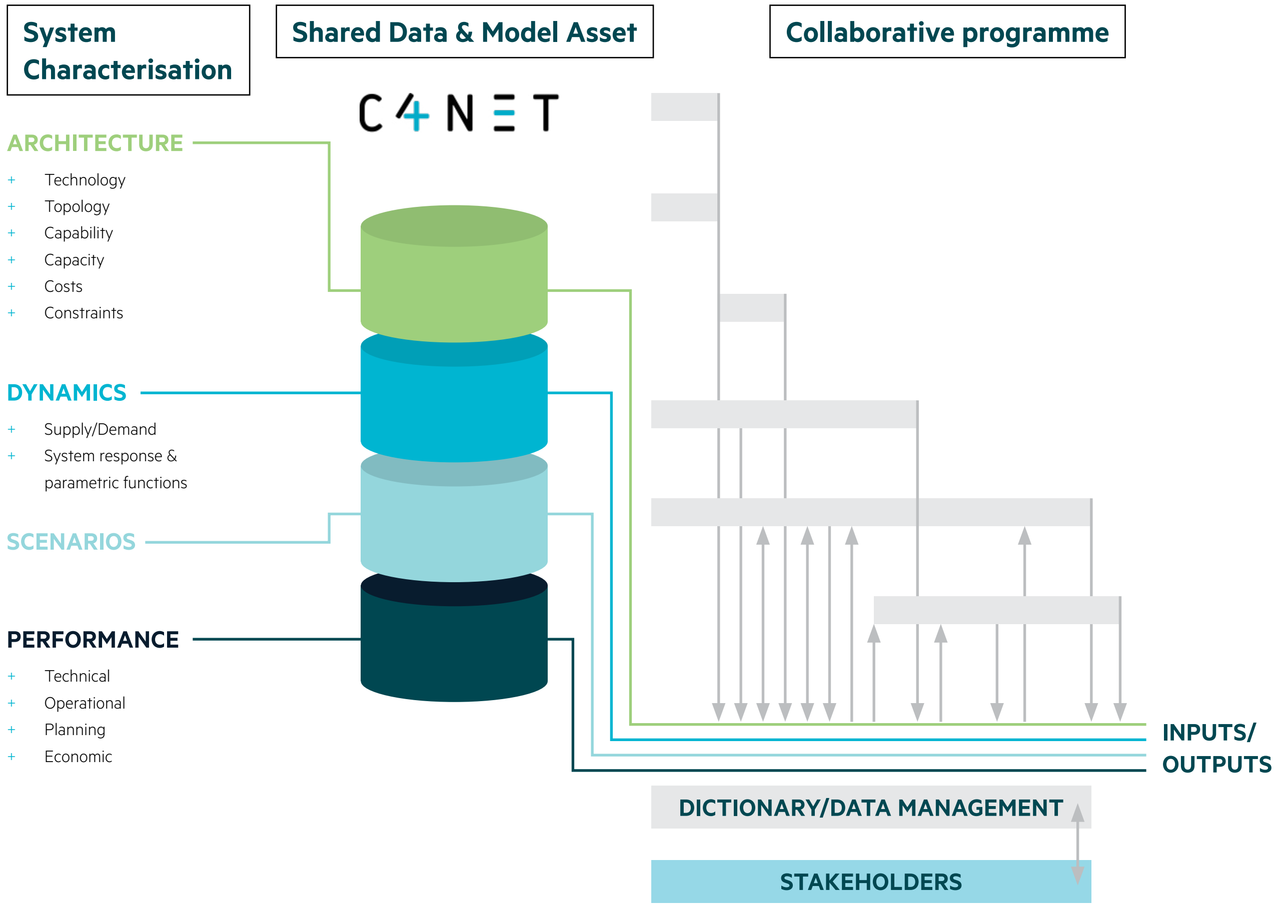


Figure 6: ESP Research program design architecture schematic at outset of the project

The ESP research program was designed to develop a whole-of-system approach, via coordinated modelling frameworks for infrastructure development downstream of the transmission system. Researchers submitted proposals that were reviewed by a subcommittee and recommendations considered by the project's Steering Committee. These were then reshaped and aligned to an overall project architecture conceived by the University of Melbourne's Professor Pierluigi Mancarella through extensive research and industry consultation sessions and grouped and ordered into three thematic work packages.

It became apparent early into this process that no common frameworks existed for how to consider and evaluate multiparametric elements of diverse distribution systems within a whole-of-system approach. The research program architecture factored this in to build a bottom-up, scalable approach that could be adapted NEM-wide. The overall design philosophy was to ensure the bottom-up modelling was physics-based and grounded in existing electricity network structures, included common assumptions, and was adaptable to key variables and techno-economic assessment approaches as described in the following sections.

Projects were staggered according to key interdependencies of individual elements as best they could within the challenging two-year delivery window of the overall project. Industry, AEMO, government and various interest groups were invited to attend monthly updates from researchers to investigate, provide feedback and guidance, and to the broader Technical Advisory Panel monthly forum where needed. These same groups provided feedback to the researchers on their final reports for the researcher's consideration prior to publication, but ultimately these were the independent views and findings of the researchers.

A researcher forum was held twice a year for researchers to share their findings with peers, be updated on overall progress, coordinate between project elements and contemplate research issues.

4.2 Work packages

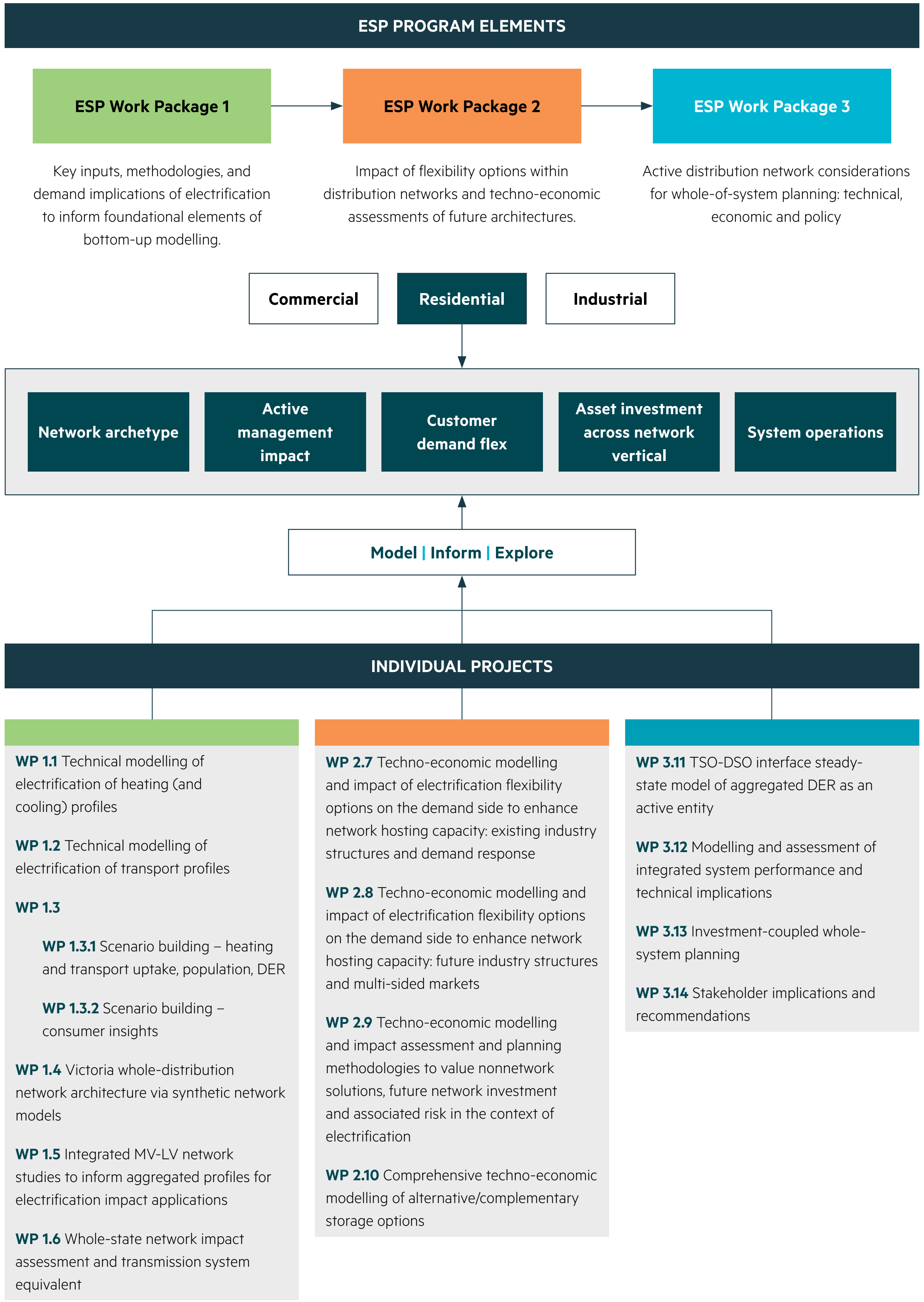


Figure 7: Mapping of individual projects to overall ESP program design through the three Work Packages

The detailed methodology adopted by each project is documented within the researcher's project reports, and summarised in the project summary reports, with the high-level overview provided here.

4.2.1 Work package one: Key inputs, methodologies, and demand network implications of electrification to inform foundational elements of bottom-up modelling

This research work package was scoped and structured to provide "bottom-up" data and a modelling foundation which could be used within the broader ESP research program to assess the residential electrification impact on Victorian electricity distribution networks and connected CER operation.

The research addressed National Metering Identifier (NMI)-level impacts of electrification of:

- Heating, cooling and hot water in Project Work Package WP 1.1, through the development of a physics-based modelling framework using heat pump technologies of various forms and sizes in a granular means to build diversified load for different housing mixes. The outputs fed directly into Projects WP 1.5 and WP 1.6.
- Transport (passenger and light commercial vehicle) in Project WP 1.2, through analytical techniques to extract EV charging profiles from Victorian smart metering data. The methodology showed promise in identifying different charging levels and consumer charging patterns. However, because the empirical data was from a small number of customers it was decided to use CSIRO charging behaviour modelling to feed into Projects WP 1.5 and WP 1.6 in this instance.

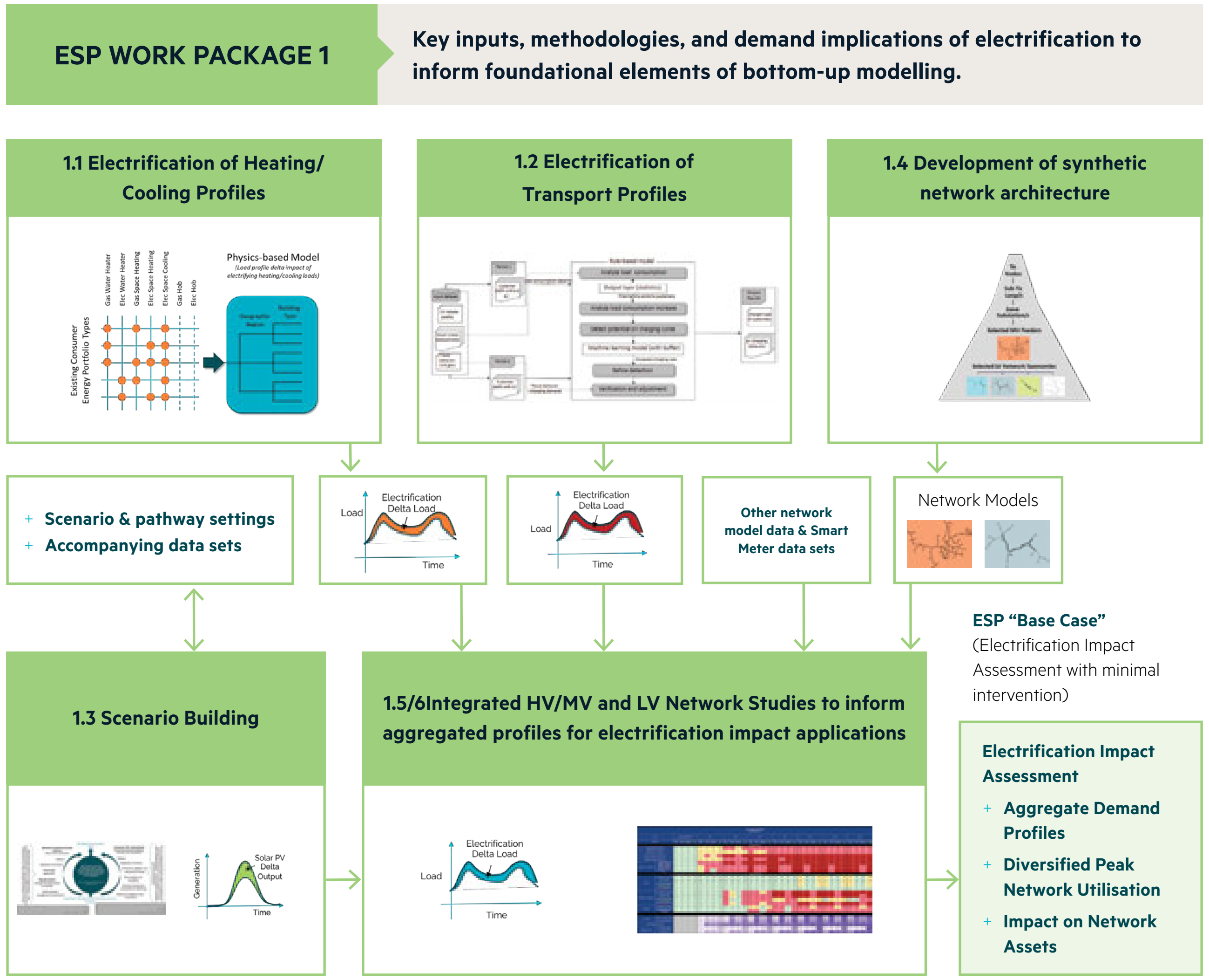


Figure 8: Work package one: how individual research projects were structured to support informing the key inputs, methodologies and demand implications of electrification and residential CER uptake to inform foundational elements of modelling in other Work Packages

Project WP 1.3.1 built the base modelling approach for uptake of various CER devices and electrification at Local Government Area (LGA) level to demonstrate the granularity that could be ultimately used if required for detailed regional forecasting and multi-scenario building. An ESP scenario was then developed for the electrification journey and aligned to the AEMO ISP "Step Change" option, which modelled CER take-up rates and consumer responses, on a five-year incremental basis up to 2054, as discussed further in Assumptions in Section 4.4.

A challenging component was how to sufficiently represent the networks for the electrification impact assessment – different types, topologies, and consumer connection densities. The Victorian distribution networks were modelled on a simplified basis using a representative example of each network "archetype" comprising a combination of real and synthetic components in Project WP 1.4, which would ultimately be aggregated up to the sub-transmission level.

The individual network archetype energy profiles were then aggregated at the individual zone substation level and Victorian sub-transmission level using the electrical network models. Five-yearly power flow analyses were carried out to extend the "base-case" electrification. Different network building blocks were established using a mix of actual electrical network models for the high voltage (HV, 66 kilovolts (kV)) and medium voltage (MV, 22 kV) network components, and pseudo or synthetic models for the low voltage (LV, 400 volts (V)) network components. One illustrative example was chosen to represent each network archetype (central business district (CBD), urban, suburban, short rural and long rural). The CBD was such a different residential component it required a different modelling approach. As the electrification uplift was much smaller in the CBD it was discontinued in this analysis to better allocate scarce modelling resources.

The electrification impact profiles were then added to a representative selection of smart meter energy profiles from selected interest days (Peak Summer, Peak Winter, and Spring Shoulder). These integrated NMI profiles were then randomly applied to the network model "types" in accordance with the ESP scenario, and five-yearly power flow analyses were then carried out to provide a "base-case" electrification impact assessment (with minimal CER management intervention and networks "as is", with and without the application of select dynamic operating envelopes) for each network archetype in Projects WP 1.5. Project WP 1.6 then extended the multi-scenario assessment of electrification impacts through to sub-transmission. The outputs of the electrification impact assessments of Projects WP 1.5 and WP 1.6 were designed to form the base case profiles to inform modelling in work packages two and three.

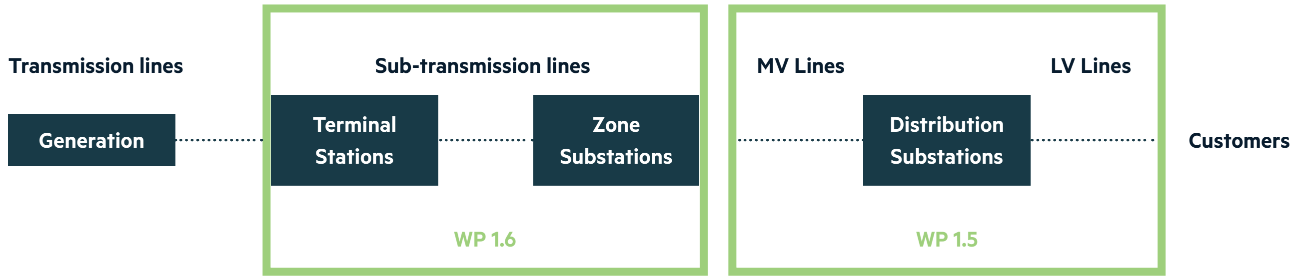


Figure 9: relationship between power flow simulations for WP 1.5 and WP 1.6

Consumer perceptions regarding the adoption and use of CER were included to inform the planned development of multiple scenarios and key considerations for policy makers. Although the project ultimately focussed on a single case due to time and resource constraints, insights from consumer perspectives proved valuable across all components of the project. Project WP1.3.2 conducted two well-structured consumer surveys, the first one focussing on the influence of different policy settings on the adoption of EVs, home EV chargers, home batteries, and the electrification of gas appliances for space heating, water heating, and cooking. The second survey explored attitudes toward third-party control and the management electricity import/export in relation to EV charging, electric space heating, and electric water heating.

Insights from consumer perspectives proved valuable across all components of the project, including surveys exploring attitudes toward third-party control.

4.2.2 Work package two: Impact of flexibility options within distribution networks and techno-economic assessments of future architectures

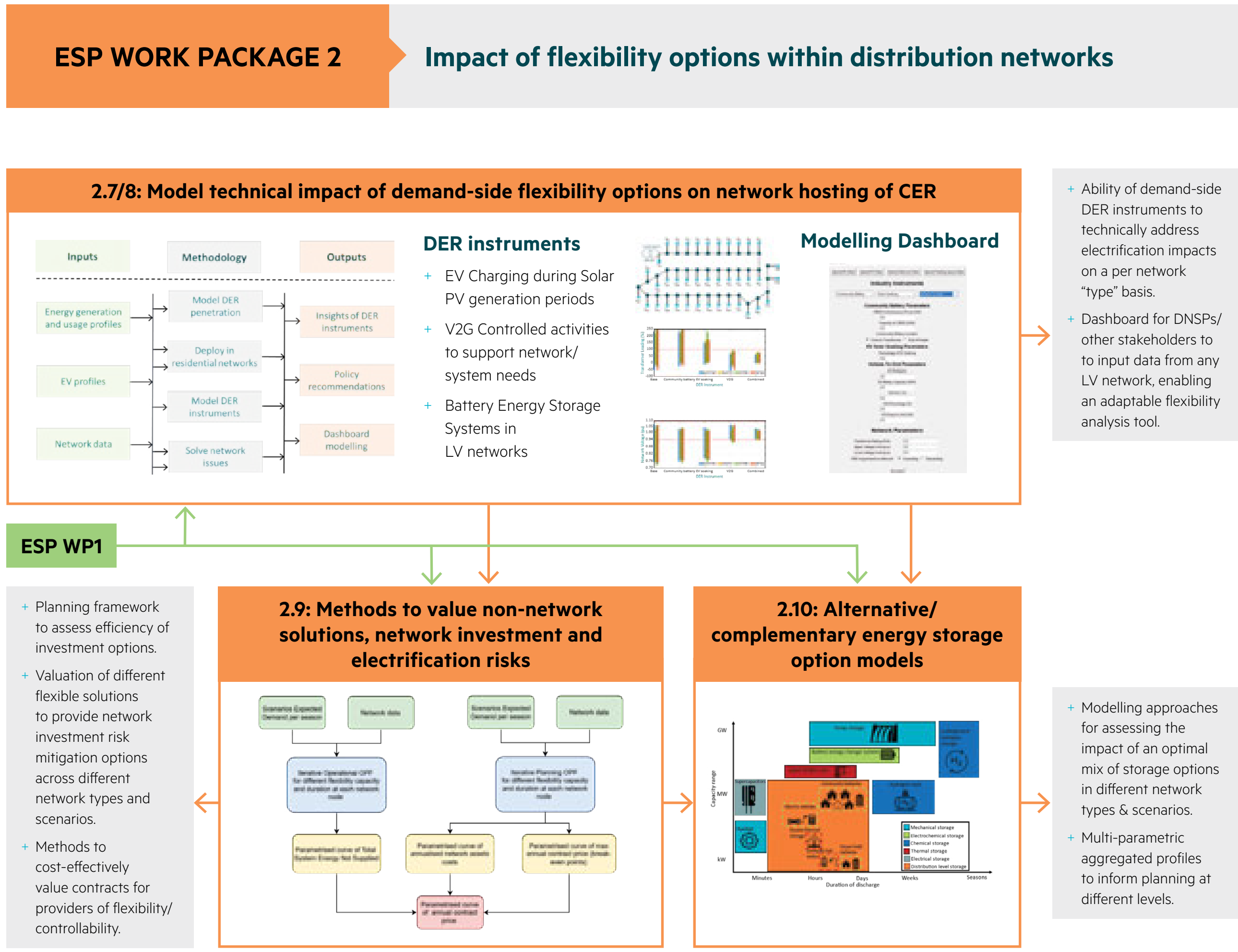


Figure 10: Work Package two looked at the impact of flexibility options within distribution networks and techno-economic assessments of future architectures

Following the modelling of the "base-case" electrification impact in Work Package 1, Work Package 2 focussed on identifying opportunities within the electricity system to manage CER and DER with the objective of reducing the cost and impact of CER/DER integration by enabling more efficient hosting. The work package also examined how CER/DER, when aggregated, could be leveraged to provide flexibility services that support network planning and operation—ultimately mitigating the impacts of electrification and improving the efficiency of future infrastructure investments.

Projects WP2.7 and WP2.8 explored three demand-side DER instruments (solar soaking via EV charging, vehicle-to-grid (V2G) activities to support the electricity network, and LV battery energy storage systems (BESS)), both individually and in concert, and assessed how effective they were in mitigating network issues arising from the electrification journey. The assessment was primarily technical and limited to some of the example LV networks, as it preceded the development of the Project WP1.5 outputs. A model was developed and published so that any electricity network can upload their own data and assess the technical impact of the DER instruments in their own network planning scenarios.

To complement the technical demand-side DER instrument analysis, comprehensive methods of economically valuing non-network solutions, electricity network investment and electrification risks were then developed in Project WP2.9.

The assessment framework approach is founded in techno-economic means of assessing CER and DER coordination options against traditional network asset augmentation, carefully factoring in flexibility, uncertainty and risk elements. This could inform the basis for future planning and regulatory frameworks to assess investment efficiency, introduce risk mitigation options, and to cost-effectively value contracts for providers of flexibility.

With energy storage being a primary enabler of flexibility in distribution networks, Project WP2.10 focussed on approaches to modelling the impact of optimised energy storage options in different electricity network types and scenarios that can inform future planning practices. While these distributed resources are typically deployed at the local network level, the optimal mix of storage options, in aggregate form, enables modelling of impacts across multiple levels within the distribution sector and beyond.

4.2.3 Work package three: Active distribution network considerations for whole-of-system planning implications

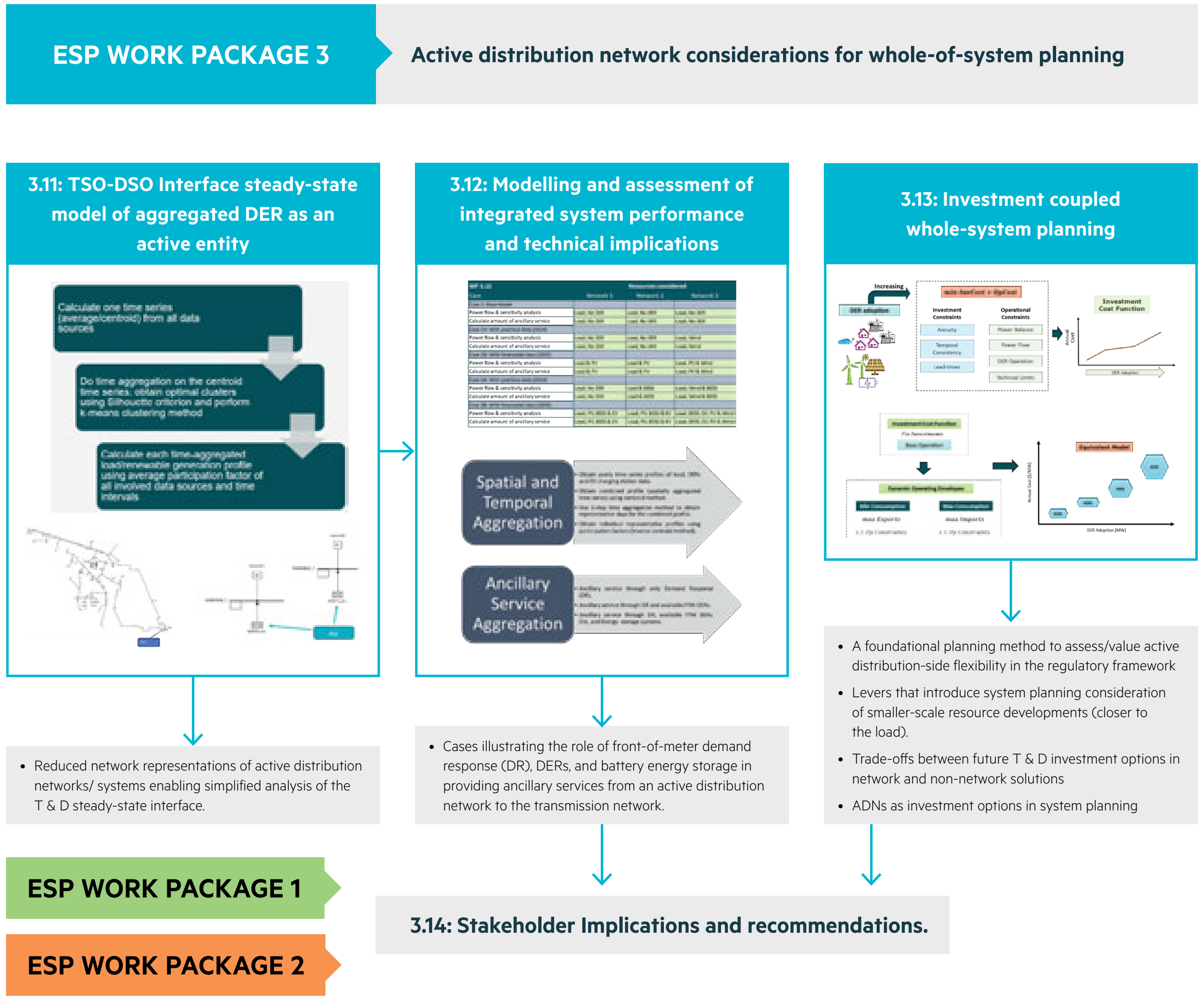


Figure 11: Work Package three, Active Distribution Network considerations for whole-of-system planning

As a logical flow from the first two research work packages, which had a "bottom-up" CER electrification impact focus within the distribution networks, Work Package three focussed on the boundary of electricity transmission and distribution, and potential system flexibility that could be achieved via aggregated DER/CER and electricity distribution network assets operating in a coordinated, active manner, as part of a "whole-of-system" planning environment.

We identified the need to more simply represent the electricity distribution network interfaces at the transmission entry points for integrating distribution networks into overall system planning.

Project WP 3.11 addressed the need to efficiently represent the distribution network interfaces at the transmission entry points in scalable efficient manner. The researchers developed a steady-state reduced distribution network modelling technique at the transmission-distribution (T-D) interface which could incorporate aggregated DER in an active form. This modelling method was then demonstrated on three distribution networks, with the understanding that the same modelling concept could be carried over to the transmission-distribution interface.

Project WP 3.12 assessed the three electricity network models of Project WP 3.11 with varying levels of coordinated DER operation to demonstrate the concept of measuring technical flexibility behaviour and limits, which could be considered for providing system services within an integrated system planning environment.

Project WP 3.13 investigated techno-economic investment aspects of an active distribution network or "system" (ADS) environment – how to assess and value active distribution-side flexibility, consider the trade-offs between future transmission and distribution options, and represent active distribution networks (ADNs) as investment options in overall integrated system planning. The research developed a common framework approach for representing the ADS in a way that is compatible with other generators in the ISP. Case studies run on select assets indicated the scope of savings between assets connected at the sub-transmission level compared to the transmission network, and the potential value of further harnessing flexibility from the lower voltage parts of distribution networks.

The outputs/outcomes and key information/insights/messages and consequences from the broader ESP research work across all three Work Packages were then gathered and synthesised for incorporation in the final stakeholder briefings and ESP Project reporting in WP 3.14, Stakeholder implications and recommendations.

4.3 Scope and limitations

The ESP program's purpose is to demonstrate that bottom-up electricity distribution system modelling is feasible and yields tangible benefits to support the evolution of AEMO's ISP.

The ESP project aimed at informing the impact of full electrification of transport (passenger and light commercial vehicles), residential CER uptake, residential reticulated gas use (space heating/cooling and hot water) and DER on electricity network assets within the NEM. The application of models utilised Victorian data with the methodologies adaptable to inputs and assumptions from any region for NEM-wide application.

AEMO's Step Change scenario from the 2024 ISP served as the baseline for analysis. It was adapted as detailed in Section 4.4 to inform C4NET's focus on the system-wide impact of 100% residential electrification and CER uptake, with a planning horizon of 30 years to align with the ISP's timeframe. Outside of scope were consideration of alternative net zero scenarios, electrification of commercial and electrical loads, forecasting of consumer participation rates or CER uptake rates, direct modelling of network archetypes or structures from non-Victorian distribution networks.

The modelling illustrates the impact of participation rates and the potential value created of select actions, it doesn't inform the optimal allocation of that value to the various actors involved to drive the participation sought.

The modelling is naturally limited to the data that was accessible to the researchers and has not been verified.

4.4 Assumptions

Through development of the ESP, projects under each work package made assumptions that reflect baseline observations of how best to build upon the work undertaken. These are detailed in the individual researcher project reports and summarised in an ESP assumptions book published on C4NET's website. Broader base assumptions are discussed here.

ESP Step Change Scenario-aligned assumptions

As a design principle, the project sought to minimise the difference in base assumptions from those in the Step-Change Scenario of AEMO's ISP 2024. The fewer the differences the easier it will be for stakeholders familiar with the ISP to digest the findings. C4NET did not seek to forecast when various electrification elements were adopted; instead the analysis focussed on the impact of 100% adoption. Where elements weren't fully electrified by 2053, they were accelerated to inform the full uptake implications, whenever they occur.

The key high-level aspects were:

+ Study period – as for ISP 2024 (i.e. 30 years to 2053)
+ Population growth – as for ISP 2024
+ House number, size, type and efficiency – AEMO 2023 IASR (Inputs Assumptions and Scenarios Report)[12] for base dwelling numbers, with split of other parameters informed by Project WP 1.3.1
+ EV uptake – as for ISP 2024 (largely saturation of electrification by 2053 with 6.5 million vehicles)
+ Rooftop solar PV – as for ISP 2024 (largely practicable saturation by 2053 with ~8 kW average per viable site. It is worth noting that the ISP has residential areas being net-generators from about 2040)
+ Household battery – as for ISP 2024 noting this is well short of saturation but not an ESP base case target parameter
+ Electrification of heating/cooling and domestic hot water – accelerated from ISP 2024. The modelling assumptions took 2023 approximate market shares and converted all gas space heating to heat pump devices, gas and electric hot water storage to heat pump storage and assumed instant gas hot water is converted to instant electric by 2053, all with a straight-line conversion rate.
+ Electrification of gas cooking – not modelled.

At various times, researchers have modelled orchestrated CER/DER to help inform the potential value of various forms of flexibility. Any participation of CER in such mechanisms will only be achievable if the owners of those devices participate. From a research design perspective, beyond understanding current perceptions and preferences under WP 1.3.2, the project did not seek to inform how that participation would be achieved, noting there are many possible pathways including through market mechanisms, standards, default settings with consumer override, network controls, aggregators, virtual power plants (VPPs) and so on. A proportion of devices are likely to never be available for any orchestration.

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SECTION FIVE

Findings, observations and key outputs

5 Findings, observations and key outputs

This section presents key findings from the ESP research program, highlighting electrification impacts, CER and DER flexibility, and co-optimisation strategies between transmission and all levels of the distribution network (high, medium and low voltage). It introduces methodologies for integrating active distribution networks (ADNs) into system planning, demonstrating cost-saving potential while addressing regulatory and market changes for a more efficient energy transition. Finally, it introduces a 5-step roadmap to an expanded, whole of system planning approach that includes deeper integration of electricity distribution network elements, outlining a clear end point and pathway to deliver it so that integration benefits can be achieved as designed.

5.1 Foundational building blocks to inform bottom-up modelling approaches

5.1.1 Electrification of heating/cooling and domestic hot water

A widely consulted, physics-based modelling framework was developed to assess the bottom-up impact of electrifying space heating, cooling, and domestic hot water (DHW) systems. The model incorporates key building characteristics—such as type, size (e.g., number of occupants), thermal properties, and energy efficiency—allowing it to be scaled across different regions and electricity network types. It also accounts for variations in consumer behaviour, including temperature setpoints, usage patterns, and responses to tariffs or incentives.

The model operates at the level of individual buildings and generates 30-minute interval demand profiles over 24-hour periods for key representative days: Winter Peak, Winter Average, Summer Peak, Summer Average, and Shoulder Season.

A specific tool was developed, coded in Python, which allows combining the different average customer level demand profiles for each energy service, i.e., space heating/cooling and DHW, given the total number of buildings in the area under analysis and the proportion of building with specific attributes.

The tool is operated via a user-friendly Excel-based interface, allowing users to input combinations of building models and assess the resulting impact of diversified energy demand profiles on electricity infrastructure. Simulations for electrification impact assessments in WP1.5 and WP1.6 used after-diversity demand profiles based on a sample of 300 buildings.

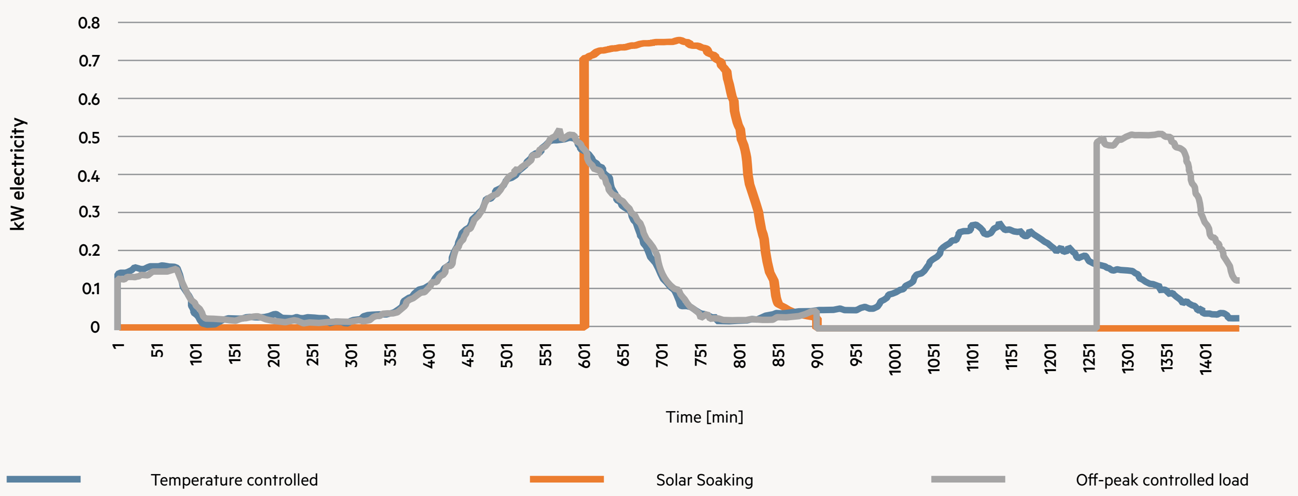


Figure 12: An example profile developed under WP1.1, Average building-level DHW demand profile for a three person household in Ballarat on a Winter Peak day supplied by an electrohydraulic heat pump (EHP) water heater under different operating strategies

Household energy use for heating, cooling, and hot water is largely predictable and stable, which together with the bottom-up physics-based modelling to convert from gas to electricity, supports a confident projection of such appliances' demand profiles into the future. This of course needs to be considered in the context of consumer adoption rate (of the technologies), and the effects of time shifting controllable loads on the energy profile.

5.1.2 Electrification of transport

In contrast to the predictability and stability of forecasts for electrification of heating, cooling and DHW, there is considerable uncertainty about the future charging profiles of EVs. The total monthly or annual energy consumption is reasonably predictable, assuming little change to current statistics:

+ The average vehicles per household of about 1.6,
+ the average km driven per vehicle of ~14,000 km/year, or <40 km/day,
+ reasonably flat kilometers per month across the year.

The uncertainty in charging profiles arises due to limited data availability, the disproportionate influence of early adopters in existing datasets, and the early-stage development of incentives, charging management systems, and retail tariff structures. In the absence of strong empirical evidence, scenario modelling will need to be relied upon such as the CSIRO modelling used in the ISP 2024.[13] The diversified profiles for modelling in WP 1.5 and WP 1.6 were built from the CSIRO modelling. Algorithmic modelling developed under the ESP offers potential early insights into customer charging behaviour. It showed promising capability in its ability to disaggregate three different charge levels from smart meter data but needed a broader customer data base to provide sufficient confidence to build representative after-diversity demand profiles for broader electrification impact assessments.

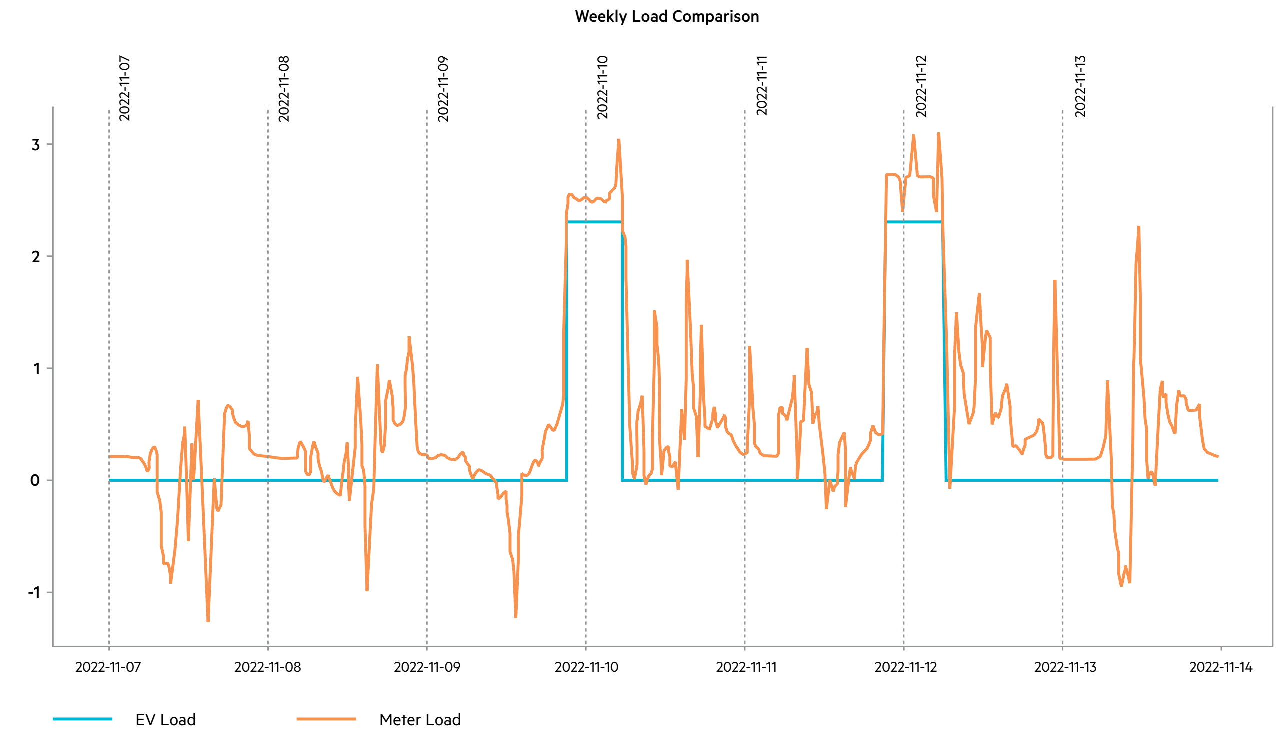


Figure 13: Example of a weekly meter load profile with charging evident for a customer with a 2.3 kW charger

13 It is noted that the CSIRO modelling is constantly updated as further empirical data becomes available, such as from trials underway around Australia.

5.1.3 Base consumer demand profiles

Victoria's widespread deployment of smart meters made it an ideal location to trial the methodologies developed under the ESP project. Randomised and anonymised datasets comprising thousands of sites were available, enabling the development of robust demand profiles and assessments of load diversity.

C4NET has undertaken extensive analysis of the impact of various CER devices for Solar Victoria, which provided a rich foundation to extrapolate future scenarios from. Given the current national directives for smart-meter deployment across the NEM, data availability is unlikely to be an impediment to broader adoption of ESP methodologies in expanded whole-of-system planning.

5.1.4 Demographic data

The outputs of WP 1.3.1 demonstrate that data is largely available to support geographically granular modelling. NMI-level data is easily matchable to postcode and generally recorded against local government areas to support emergency responses, although these are sometimes in separate databases. Establishing a consistent approach to link NMI-level data with electricity network asset information and demographic datasets would significantly enhance future planning capabilities. While the ESP project did not identify a clear need for this level of granularity, such detail may become increasingly important in the context of regional population growth patterns and its implications for electricity network design.

5.1.5 Building scalable network models

From a long-term planning perspective, it is highly desirable that representative electricity network models are available that can be used in algorithmic approaches (such as power flow studies) to provide reasonable scaled-up understanding of power system performance and are manageable for informing different iterations or scenarios. At the outset of the ESP project, it was intended to adopt network typologies developed by CSIRO through the Australian Renewable Energy Agency's (ARENA) *National Low-Voltage Feeder Taxonomy Study* and the 2013 *National Feeder Taxonomy for medium-voltage (MV) networks*. However, both researchers and the DNSPs raised concerns regarding the applicability of these typologies to the Victorian context and their suitability for the project's subsequent phases.

As a result, the project used actual Victorian MV feeder data supplied by DNSPs to represent MV network models. When scaled to a zone substation in latter parts of the project, each MV feeder connected to the zone substation was classified into one of the four feeder types, with the MV feeder scaled to match the peak loading of the zone substation MV feeder head. Simplified pseudo–low-voltage (LV) network models were also constructed to enable automation and improve modelling efficiency.

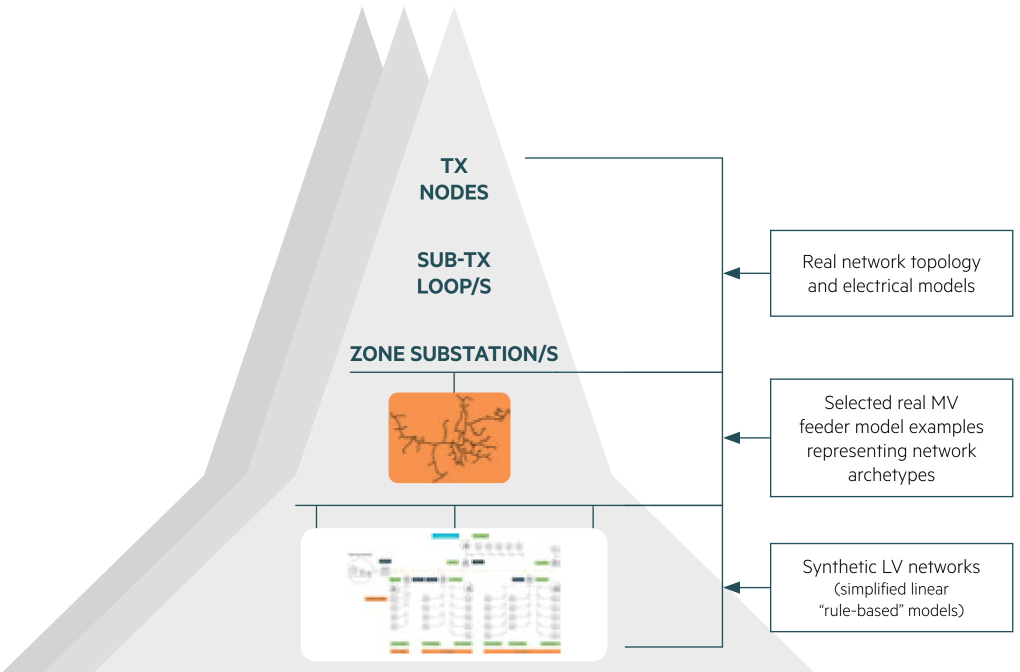


Figure 14: Network representation approach developed in WP 1.4

An ongoing consideration is the extent to which MV and LV models should be integrated, and whether full integration is necessary for bottom-up modelling in future stages. DNSPs noted that full power flow analysis from sub-transmission through to LV customers is rarely undertaken due to its complexity. Where partial models are used, results depend on assumptions made at the interface between different network levels—specifically, voltage and power flow conditions at the MV feeder head and the MV-to-LV connection point.

The project developed five archetypal MV-LV network models based on actual Victorian data from WP 1.4. These models represent distinct network types—CBD, urban, suburban, rural-short, and rural-long. Each MV feeder model was paired with simplified pseudo-LV networks for connected distribution substations. Snapshot power flow analysis from DNSPs helped define operational parameters such as transformer tap settings and voltage regulator configurations. However, the approach has limitations, including insufficient representation of SWER (Single Wire Earth Return) lines.

Looking ahead to broader application across the NEM, C4NET has identified the potential to develop a manageable set of representative electricity network models, given that many network characteristics are consistent across DNSP regions. Achieving this will require strong collaboration with DNSPs to build scalable, adaptable models suitable for scenario planning. Incorporating real-world data — including NMI-level datasets — will improve model accuracy. Privacy concerns are expected to be manageable, as anonymisation or aggregation of a small subset of data would likely be sufficient for long-term planning purposes.

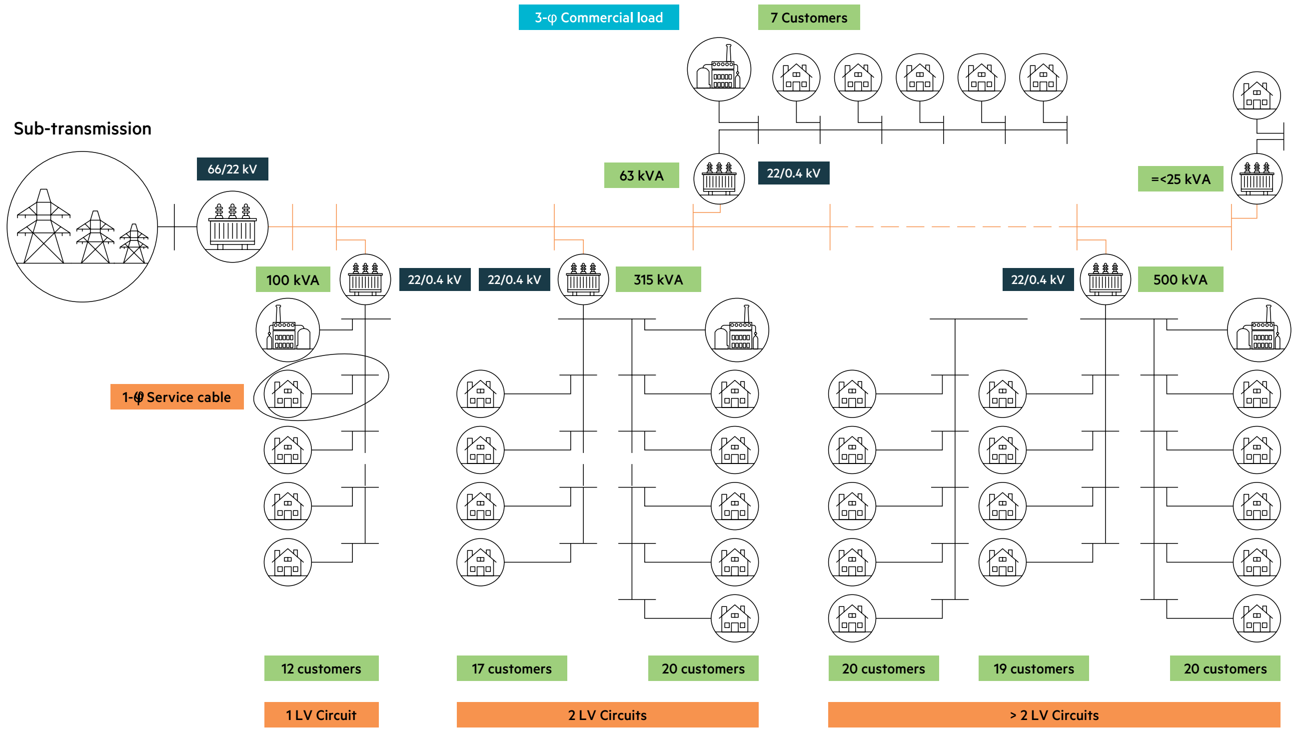


Figure 15: An illustrative example of a portion of MV-LV network model developed

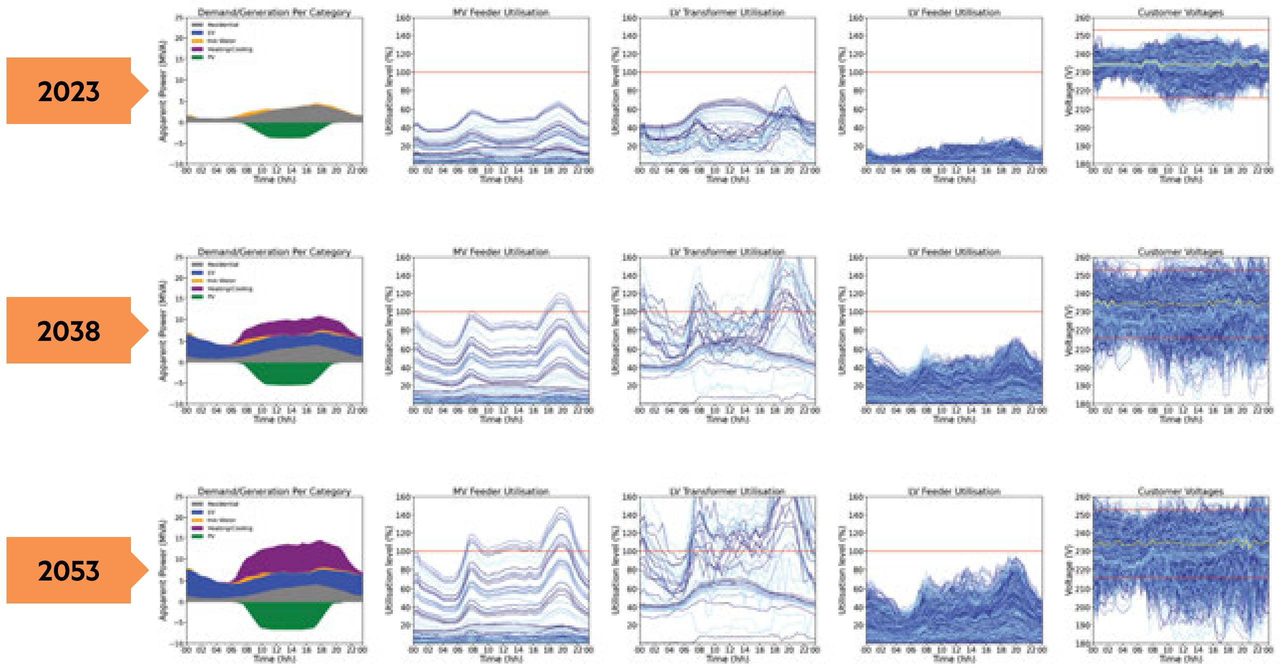
5.2 Electrification and solar uptake impact on network assets

Time-series, three-phase power flow analysis was conducted at 30-minute intervals for three representative days across seven analysis years. This analysis was performed under two scenarios: with and without Dynamic Operating Envelopes (DOEs). It covered seven five-year periods, assessing multiple electrical parameters across various levels of electricity distribution network assets.

The results highlighted the importance of incorporating detailed electrical complexities, such as voltage and thermal constraints, into network impact assessments. These complexities arise from the forecast introduction of new device types and loads associated with electrification and DER.

FORECASTING THE NETWORK IMPACTS OF ELECTRIFICATION

Deep dive analyses used actual industry data eg Electrification Impact Assessment - Urban Network Performance



FORECASTING THE NETWORK IMPACTS OF ELECTRIFICATION

Detailed maps show network asset impacts across low and medium voltage networks

Urban Network SBY32 (Without DOEs)

Year		Base Demand (No DER)				2023				2028				2033			
Day Type		Winter Peak	Summer Peak	Spring Shoulder	Year Long	Winter Peak	Summer Peak	Spring Shoulder	Year Long	Winter Peak	Summer Peak	Spring Shoulder	Year Long	Winter Peak	Summer Peak	Spring Shoulder	Year Long
Voltage Assessment																	
Voltage Drop Non-Compliance		0%	0%	0%	0%	1%	2%	0%	2%	8%	6%	3%	8%	22%	16%	13%	22%
Voltage Rise Non-Compliance		0%	0%	0%	0%	0%	0%	0%	0%	3%	1%	1%	3%	10%	3%	4%	10%
Minimum Voltage at Customers (V)		218	216	221	216	213	208	214	208	196	199	206	196	179	179	189	179
Maximum Voltage at Customers (V)		252	252	248	252	256	254	255	256	266	260	262	266	274	269	265	274
Voltages at LV Networks	% of LV Networks w/ Voltage Drop Issues	0%	0%	0%	0%	19%	27%	8%	27%	54%	54%	35%	54%	60%	60%	60%	60%
	% of LV Networks w/ Voltage Rise Issues	0%	0%	0%	0%	4%	6%	6%	6%	31%	27%	19%	31%	54%	44%	42%	54%
	% of LV Networks w/ Voltage Drop & Rise Issues	0%	0%	0%	0%	2%	6%	0%	6%	31%	27%	17%	31%	54%	44%	42%	54%
Thermal Assessment																	
LV Circuit	Overall Maximum Utilisation	27%	32%	20%	32%	39%	30%	30%	39%	65%	44%	41%	65%	72%	67%	55%	72%
	% of HoF w/ Util. Always below 100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	% of HoF Achieving Util. from 100% to 110%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	% of HoF Achieving Util. above 110%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Distribution Transformer	Overall Maximum Utilisation	75%	89%	71%	89%	89%	84%	71%	89%	121%	111%	82%	121%	179%	163%	119%	179%
	% of Tranf. w/ Util. Always below 100%	100%	100%	100%	100%	100%	100%	100%	100%	85%	98%	100%	85%	58%	69%	90%	58%
	% of Transf. Achieving Util. from 100% to 110%	0%	0%	0%	0%	0%	0%	0%	0%	6%	0%	0%	6%	8%	6%	6%	8%
	% of Transf. Achieving Util. above 110%	0%	0%	0%	0%	0%	0%	0%	0%	8%	2%	0%	8%	33%	25%	4%	33%
MV Feeder	Overall Maximum Utilisation	65%	75%	61%	75%	72%	70%	62%	72%	84%	81%	66%	84%	105%	100%	82%	105%
	Overloaded Conductor Length (kM)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.1	0.0	0.3
PV Curtailemt Assessment																	
Per Customer	Max. PV Curtailment (kWh)	/	/	/	/	0.9	12.7	8.6	12.7	3.8	38.0	16.3	38.0	6.9	56.9%	23.1%	56.9
	Max. PV Curtailment (%)	/	/	/	/	2%	13%	10%	13%	6%	38%	18%	38%	11%	53%	23%	53%
% of PV Customers Curtailed		/	/	/	/	0%	27%	23%	27%	28%	33%	28%	33%	31%	36%	31%	36%
Aggregate Export	PV Curtailment (MWh)	/	/	/	/	0.0	5.1	4.2	1446.1	0.2	9.7	8.3	2813.6	1.4	14.6	12.6	4319.8
	PV Curtailment (%)	/	/	/	/	0%	7%	7%	6%	0%	11%	10%	9%	2%	14%	13%	12%

Year		2038				2043				2048				2053			
Day Type		Winter Peak	Summer Peak	Spring Shoulder	Year Long	Winter Peak	Summer Peak	Spring Shoulder	Year Long	Winter Peak	Summer Peak	Spring Shoulder	Year Long	Winter Peak	Summer Peak	Spring Shoulder	Year Long
Voltage Assessment																	
Voltage Drop Non-Compliance		34%	26%	24%	34%	39%	31%	29%	39%	43%	32%	29%	43%	45%	34%	30%	45%
Voltage Rise Non-Compliance		14%	8%	6%	14%	19%	10%	11%	19%	19%	12%	10%	19%	23%	10%	11%	23%
Minimum Voltage at Customers (V)		173	178	185	173	169	172	180	169	170	173	180	170	171	179	180	171
Maximum Voltage at Customers (V)		278	270	278	278	282	271	274	282	279	271	276	279	279	270	272	279
Voltages at LV Networks	% of LV Networks w/ Voltage Drop Issues	65%	63%	63%	65%	60%	63%	60%	63%	63%	63%	60%	63%	65%	63%	60%	65%
	% of LV Networks w/ Voltage Rise Issues	58%	46%	50%	58%	56%	46%	54%	56%	58%	50%	52%	58%	56%	54%	50%	56%
	% of LV Networks w/ Voltage Drop & Rise Issues	58%	46%	50%	58%	56%	46%	54%	56%	58%	50%	52%	58%	56%	54%	50%	56%
Thermal Assessment																	
LV Circuit	Overall Maximum Utilisation	90%	80%	74%	90%	101%	89%	84%	101%	105%	94%	77%	105%	105%	99%	85%	105%
	% of HoF w/ Util. Always below 100%	100%	100%	100%	100%	99%	100%	100%	99%	98%	100%	100%	98%	96%	100%	100%	96%
	% of HoF Achieving Util. from 100% to 110%	0%	0%	0%	0%	1%	0%	0%	1%	2%	0%	0%	2%	4%	0%	0%	4%
	% of HoF Achieving Util. above 110%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Distribution Transformer	Overall Maximum Utilisation	234%	216%	171%	234%	281%	243%	184%	281%	306%	261%	191%	306%	330%	281%	202%	330%
	% of Tranf. w/ Util. Always below 100%	46%	46%	63%	46%	44%	44%	56%	44%	42%	42%	58%	42%	42%	42%	54%	42%
	% of Transf. Achieving Util. from 100% to 110%	4%	4%	8%	8%	2%	2%	4%	4%	0%	4%	4%	4%	0%	0%	6%	6%
	% of Transf. Achieving Util. above 110%	50%	50%	29%	50%	54%	54%	40%	54%	58%	54%	38%	58%	58%	58%	40%	58%
MV Feeder	Overall Maximum Utilisation	127%	123%	97%	127%	140%	134%	110%	140%	148%	142%	106%	148%	154%	149%	115%	154%
	Overloaded Conductor Length (kM)	0.8	0.7	0.0	0.8	1.7	1.1	0.5	1.7	2.0	1.7	0.3	2.0	2.0	2.0	0.7	2.0
PV Curtailemt Assessment																	
Per Customer	Max. PV Curtailment (kWh)	10.6	61.7%	23.1	61.7	17.4	69.5	37.9	69.5	22.9	79.1	30.4	79.1	25.4	63.2	42.4	63.2
	Max. PV Curtailment (%)	15%	54%	22%	54%	24%	57%	32%	57%	29%	61%	27%	61%	31%	47%	34%	47%
% of PV Customers Curtailed		33%	39%	33%	39%	35%	41%	44%	44%	37%	44%	41%	44%	38%	47%	47%	47%
Aggregate Export	PV Curtailment (MWh)	3.4	20.3	17.5	6060.4	6.2	27.3	31.4	10594.5	9.9	35.6	23.8	8612.1	13.4	43.8	39.0	13606.6
	PV Curtailment (%)	5%	17%	16%	15%	7%	20%	22%	20%	10%	23%	19%	18%	13%	25%	25%	24%

Figure 16: Illustration of the multiple dimensions assessed under the power flow studies of WP1.5

As electrification and distributed solar generation increases, electricity distribution network assets increasingly reach network limitations. This is particularly so within the low voltage part of the network, because this is where the CER are connected and their operational profiles have coincident patterns that reduce natural load or generation diversity. Network export hosting capacity limits will mean solar exports also become increasingly curtailed.

To mitigate these impacts, the adoption of export DOEs and reliance on mandated solar inverter power quality response modes enables electricity networks to accommodate higher levels of solar connections while maintaining system integrity. However, where solar generation is not self-consumed, curtailment may be substantial. Consumer tolerance for import DOEs remains uncertain; therefore, in this analysis, import DOEs were conservatively applied only to Level 2 EV charging. The import DOE impact increased additional charge time by no more than six hours, representing what C4NET considered a manageable trade-off for improved network stability. The modelling indicates that as electrification further progresses and drives up electricity peak demand, import DOEs applied to Level 2 EV charging only are no longer sufficient to manage thermal and voltage constraints.

The analysis is subject to the forecast rates of solar uptake and electrification with only a single base case modelled. Solar adoption was modelled to grow more rapidly during the first ten years, with electrification impacts becoming more prominent thereafter. By 2033, approximately 14% of distribution transformers across Victoria are expected to experience overloading, increasing to 24% by 2038—significantly limiting further CER and DER integration unless addressed.

The impacts of electrification of gas and transport will push most low voltage electricity network assets beyond their present limits and solar curtailment will become material within the next decade. The project found:

+ Significant electricity network augmentation will be required to accommodate electrification and broader CER connections. Augmentation will push up costs of electrification and the energy transition increasing the importance of more efficient proactive works, in place of inefficient and higher cost reactive works.
+ Diversity in network characteristics, consumer behaviour, and policy settings will materially affect outcomes, highlighting the need for adaptable planning approaches.
+ Impacts vary by network type, requiring tailored responses to achieve cost-effective outcomes from a system-wide perspective. This highlights the considerations needed by policy makers as they develop jurisdiction-wide solutions.
+ Voltage and thermal constraints will increase without active CER management, leading to more frequent curtailment of renewable generation and asset overloading.
+ The broad application of DOE moderates network impacts and facilitates more solar capacity being connected into the network, but with consumer impact of increased curtailment from the underlying network hosting capacity for exports.
+ As electrification further drives up electricity demand, the application of import DOEs, such as for level 2 EV charging or beyond to other flexible loads may be a valuable lever to further moderate network impacts.
+ Uncertainty in DER adoption and demand growth presents risks of both under- and over-investment in long-life network assets, reinforcing the importance of scenario-based planning.

5.3 Active distribution networks - harnessing flexibility to mitigate distribution network asset impact

5.3.1 Assessing CER impact and potential flexibility to mitigate network issues

With the rapid forecast growth in bidirectional energy flows from electrification and solar uptake, it is unsurprising that electricity network assets will need expanded capacity. As peak demand is the key driver of network asset investment, without careful planning the scale of network capacity increases could exceed the increase in required energy capacity, resulting in higher network costs ultimately borne by consumers.

Because the operational behaviour of CER (such as solar, electric vehicles (EVs), batteries, and smart appliances) can be managed, electricity distribution networks are no longer passive systems or represented simply as a net load only. CER technologies offer inherent flexibility, which, when harnessed to deliver benefit to the distribution network or broader system, can reduce the need for traditional electricity network augmentation. When asset and operating cost growth are kept below energy growth, network costs per unit of energy fall, benefiting all consumers.

What is an active distribution network?

In an active distribution network, the network and user side of the load, as well as the status of distributed power operation, is monitored in near real-time. The applied control strategy is to optimise the access and management of distributed generation (effectively addressing distribution network congestion and constraints) and to optimise its operation in coordination with the transmission network and the overall power system.

This control is proactive, pre-emptive and responsive. This contrasts with traditional "passive" distribution networks where control is restricted to the benefit of the distribution network , and is reactive, responding to specific distribution network conditions or abnormalities, only acting to benefit the overall system under specific operational contingencies.

The ISP 2024 represents the demand of various regions, but not at a granularity that provides necessary insights for incorporation of active systems. To illustrate, Victoria was represented as a single region with one demand curve (increasing to three for ISP 2026). The ESP is beginning to reflect active distribution network dynamics by incorporating assumptions about some DER coordination.

That said, operating an active system introduces complexity and new cost considerations, as well as requiring communications and systems investment alongside the need for regulatory change. Managing large numbers of small, independently operated devices entails uncertainty and risk. The availability and responsiveness of assets will depend on the alignment of incentives, operational rules, technical standards, and the impact on consumers' preferred use of their devices.

The closer localised demand matches localised generation at peak times the less infrastructure is needed. There are some aligned benefits of consumers with CER optimising their own demand to their retail tariff and solar generation to optimising at each node of the distribution network, and even through to system level as discussed in the next section. The better matched the aggregate profile at each of the lower nodes, the less infrastructure is required further up the network.

C4NET analysis for Solar Victoria has found Victorian households with solar installed self-consume just under 30% of the electricity they generate. This rises to nearly 60% when a household battery is used. Where other CER devices such as DHW storage and EVs are added there is a potential to significantly lift the self-consumption and local consumption rates, decreasing the export hosting challenge.

At LV network level, the beneficial effects of the three flexibility instruments applied to selected LV network models illustrated key insights of:

+ Community batteries - The location of the community batteries relative to the transformer in the LV network is important to assist with voltage compliance. Placement closer to the end of the feeder is better able to address voltage drop across the network and improve voltage profiles. It was also critical that networks had control when at peak congestion times (but not other times).
+ EV charging through solar soaking – Delivers a combined benefit of reduced reverse power flow during PV generation period, and reduced peak consumption as EVs are charged less during peak consumption period.
+ V2G – Create an ability to further reduce the peak consumption by discharging energy back into the grid during peak consumption period.
+ A combination of the three flexibility instruments above was needed in the modelled cases to materially reduce adverse network impacts in cases of high CER and solar deployment.

A dashboard was developed to allows DNSPs to investigate the impact of the three flexibility instruments on specific electricity networks with parameters of their choice.

When CER instrument behaviours are applied more holistically to look across electricity network structures such as the work done under WP2.10 on the storage options, the merits of the detailed bottom-up approach to inform the impact of the various levers available become particularly clear. When considering the impact of BESS EVs and semi-controllable thermal loads of DHW and heating and cooling (referred to as Building Fabric Related Storage, or BFRS), each loads impact on peak and how this varies over time is apparent (Figure 17).

Three case studies were run:

1. Single-bus model that assesses the full potential of CER coordination in an unconstrained environment
2. Adding in sub-transmission constraints to give a more realistic assessment
3. Integrating market price signals.

All of the following is highly dependent on the variable assumptions and the network models they are applied to. Only single cases are illustrated. However, the value of the methodological approach to informing future scenarios, and the relative impact of the options and levers within, is a key take away.

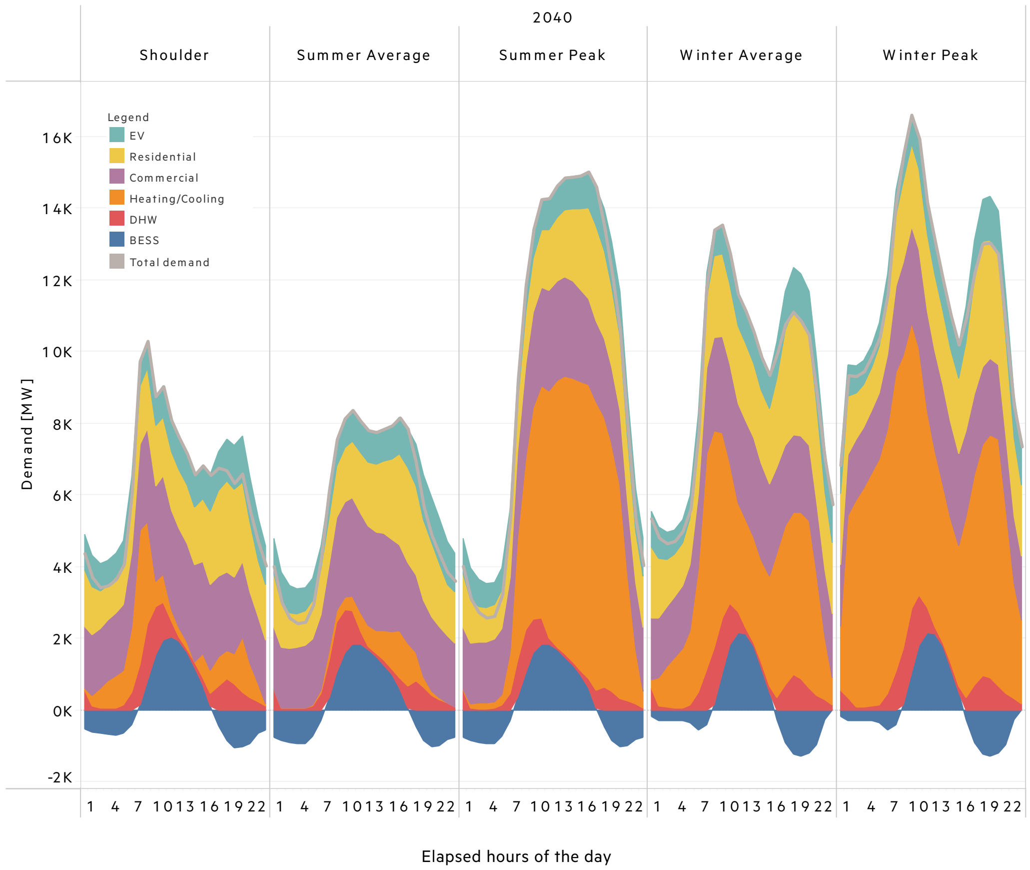


Figure 17: Sample of aggregated profiles 2040 (WP2.10)

In the first case, BESS played the most significant role in flattening the load profile. BFRS and DHW was of notable contribution to the shaving of the peak on crucial winter peak days. Unsurprisingly, coordinated deployment of all CER options delivered the greatest benefits by enabling higher self-consumption of solar generation and flattening peak demand. As unconstrained, the CER-impact can be overstated, but is informative when considering options for reduce constraints for potential value.

The second case where sub-transmission constraints are applied is considered somewhat more realistic and factor in complexities such as line congestion and solar curtailment.

Under this case as modelled on a rural sub-transmission network (Figure 18), the CER coordination reduced peak demand by a significant 13% during dominant winter peak days in 2050 which, if representative of more electricity networks, translates to significant reductions in network investment needs.

The third case explored the integration of market price signals into CER coordination on the same rural network to inform the trade-off between leveraging market benefits and increased line overloading. The modelled result illustrating that when CER is optimised for maximum energy arbitrage it exacerbated line congestion. While pricing structures can't be forecast accurately for the future, this highlights that current market pricing does not align the incentives of all actors to deliver lower cost solutions, and the risk of non-optimised price signals.

The CER coordination reduced peak demand by a significant 13% during dominant winter peak days in 2050 which, if representative of more electricity networks, translates to significant reductions in network investment needs.

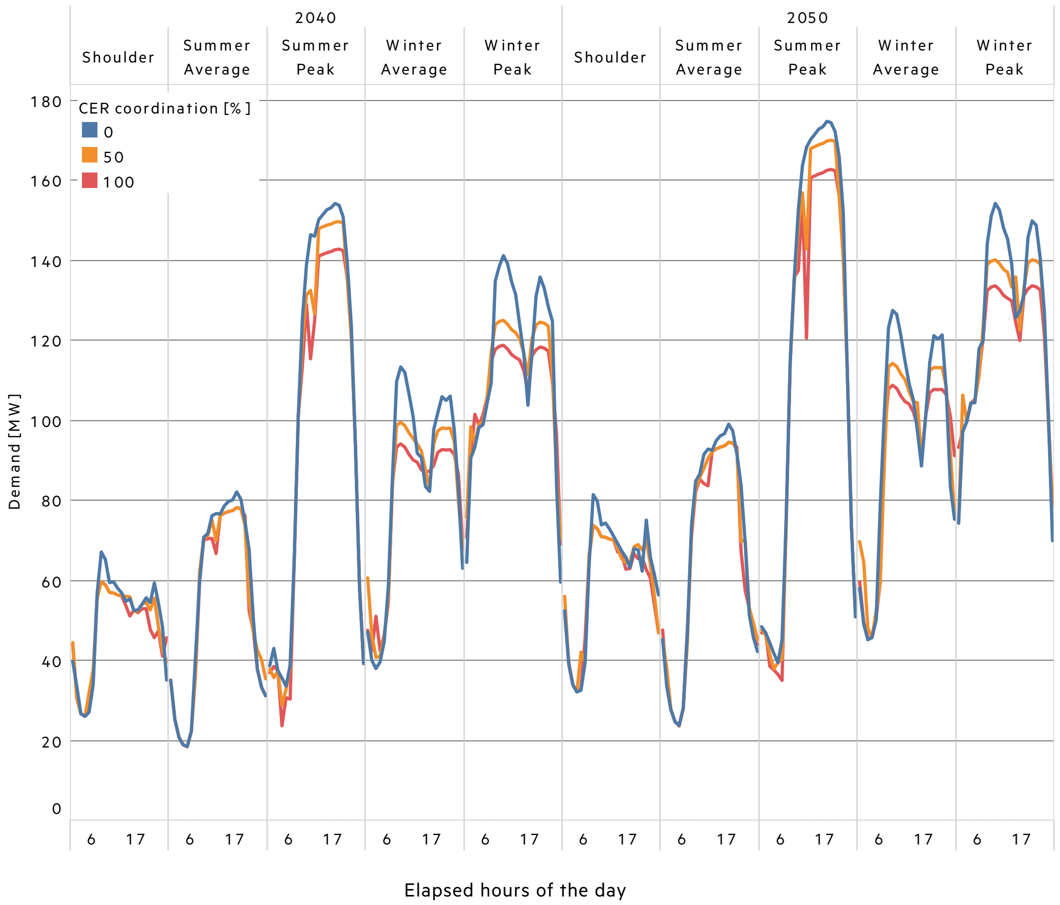


Figure 18: Illustrative impact of CER coordination impact on a single sub-transmission network

The findings highlighted the critical role of advanced models that account for electricity network constraints while maintaining computational tractability. It was only when sub-transmission network constraints were included that limitations to optimisation of CER coordination could be observed, and illustrates the risk of relying on today's unconstrained representation in system planning. The granularity shown in the cases illustrated could be further increased to include the MV and LV networks following a similar methodology.

5.3.2 Decision making framework for the assessment of non-network solutions

Historically, the primary revenue stream for regulated electricity network businesses has been returns on the Regulated Asset Base (RAB). In recent years, regulatory mechanisms have sought to encourage networks to adopt efficient alternatives to traditional network asset augmentation—commonly referred to as non-network solutions (NNS).

Techno-economic modelling of NNS enhances existing DNSP planning frameworks by incorporating scenario-based uncertainty into the decision-making process. This approach explicitly values the flexibility that NNS, enabled by CER and DER, can provide.

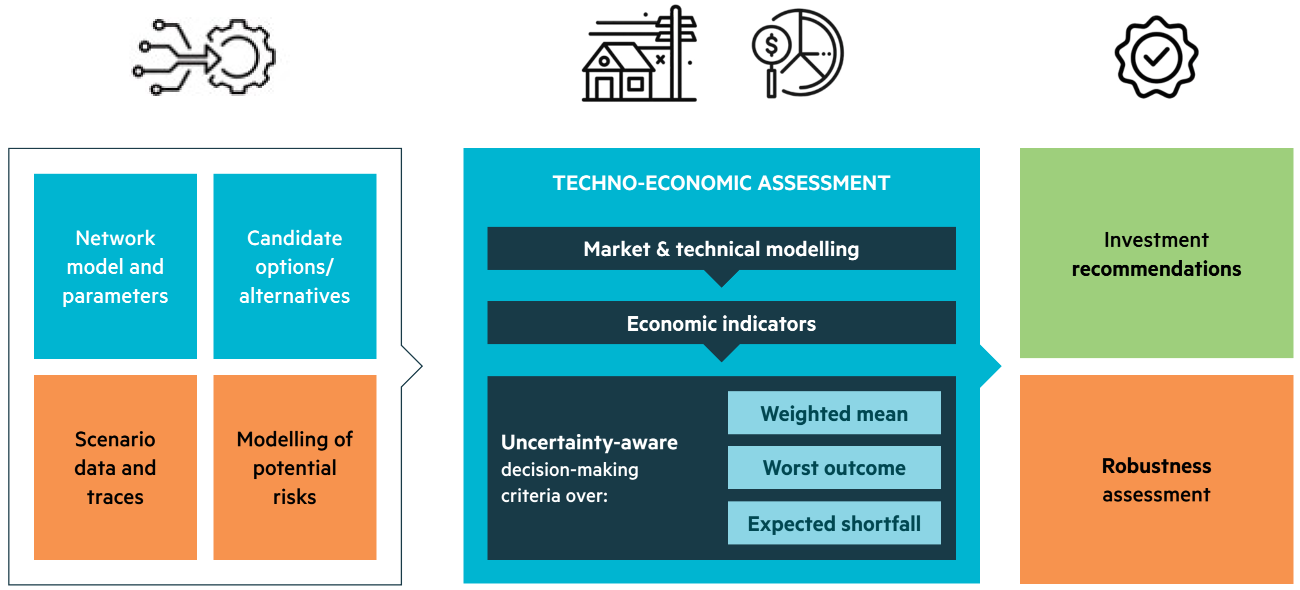
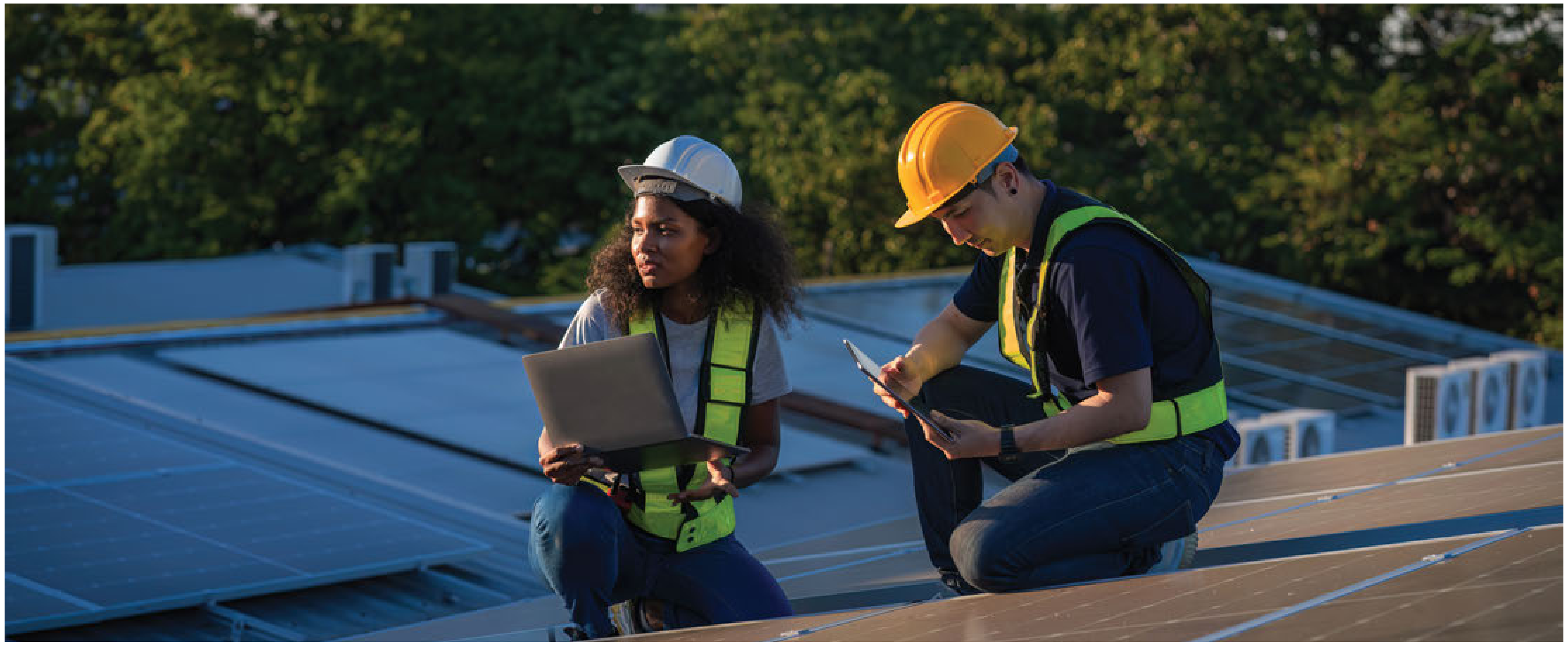


Figure 19: General structure of the decision-making framework for the assessment of asset augmentation solutions versus alternatives (NNS)

A structured, theory-based, transparent, and implementable framework was developed under the ESP to evaluate the risks, costs, and benefits of deploying NNS as an alternative to traditional augmentation at any level of the distribution network (low voltage, medium voltage, or sub-transmission). This decision-making tool is designed for universal application and specifically to support internal DNSP planning processes. It could also serve as a methodological foundation for use by the Australian Energy Regulator (AER) in future regulatory assessments.



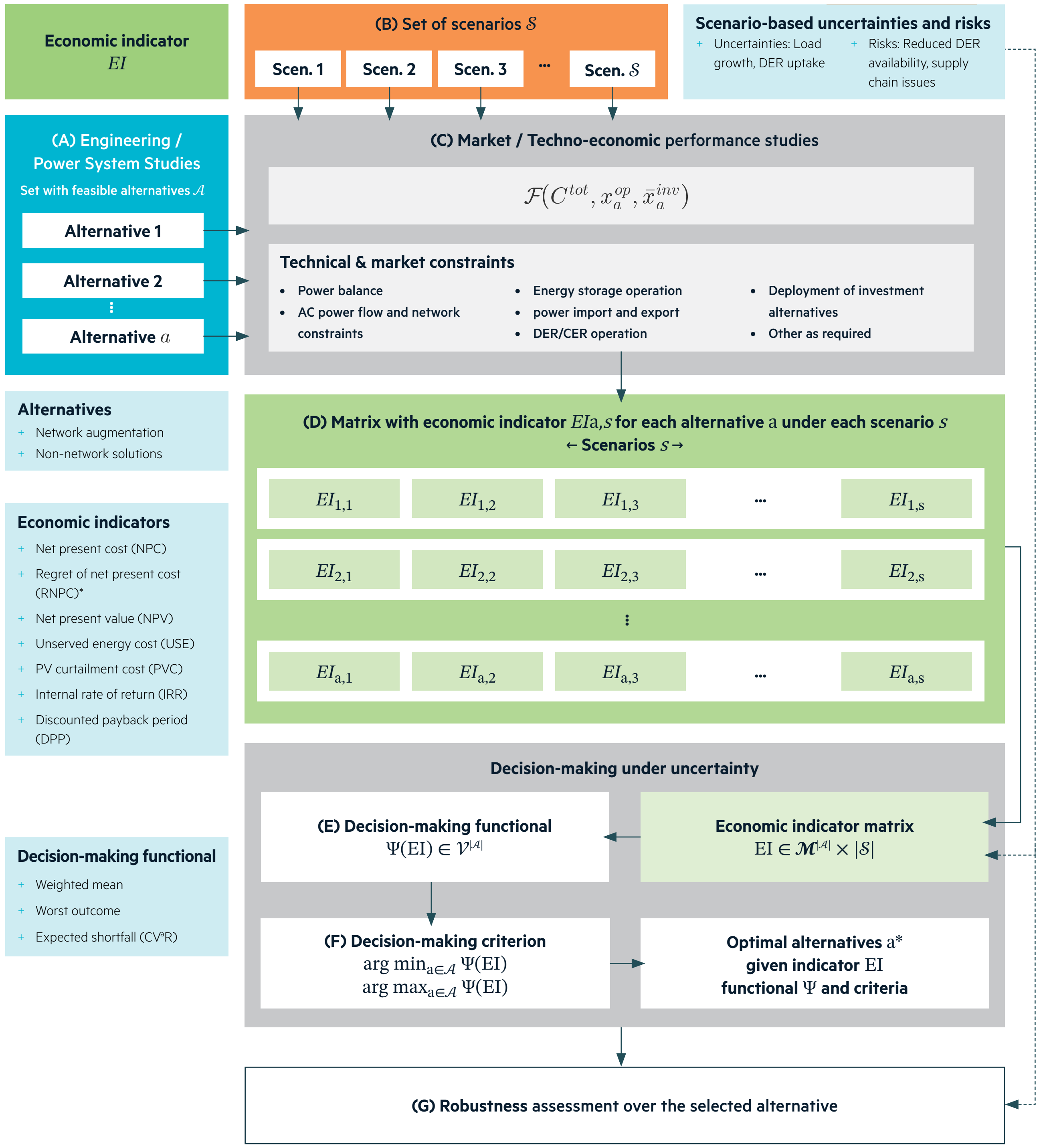


Figure 20: Technical overview of the decision-making framework model developed in WP 2.9

The framework model has multiple modules as illustrated in Figure 20:

A. Engineering assessments for systemic generation of alternatives (credible options) to address an identified system need (specific objective targeted to be addressed). These may include asset augmentation such as substation extensions, line upgrades or transformer replacements, with NNS such as demand response, BESS and distributed generation at various levels of control.

B. Weighted scenario design with uncertainty and risk considerations to user defined parameters. While the uncertain parameters may vary depending on the specific case, general considerations at the distribution system planning level could include peak growth and underlying demand profile, CER/DER uptake levels and operational behaviour, supply costs, impact of policy changes and capital expenditure forecasts.

C. Techno-economic assessment incorporating market modelling that simulates operational behaviour of the distribution system over the analysis timeframe, assessing the technical viability and economic implications of each alternative. The outputs cover capital costs, operating costs and technical system performance indicators.

D. User defined economic indicators for quantitative assessment of each option.

E. Selection and calculation of decision-making functionals, the mathematical operator that aggregates the outcomes of economic indicators across multiple scenarios to facilitate a comparative assessment for the user's specified risk tolerance and objective functions. Different decision-making functionals embody distinct approaches to handling uncertainty and risk: the model allows for the minimising losses to be prioritised or, alternately, expected benefits to be maximised, and so on.

F. Selection and ranking of investment alternatives for any given decision-making criterion.

G. Robustness assessment incorporating a sensitivity analysis for underlying assumptions to ensure the optimal decision remains consistent under variations in scenario likelihoods. This enhances the credibility and reliability of investment decisions in the face of real-world uncertainty, contributing to more informed distribution system planning.

In the limited illustrative case studies conducted, the modelling framework often identified NNS as more favourable than traditional network asset augmentation. Application of the framework also helped quantify the value of CER in meeting system needs, supporting the development of consumer-facing incentives that reward behaviours aligned with system benefits.

The flexibility enabled by CER and DER, when coupled with enhanced operational practices, has the potential to improve system outcomes and support progress toward zero-emissions targets.

A combination of a co-optimised electricity network and CER/DER orchestration solutions and control strategies can significantly reduce overall cost impacts across the active distribution network. Network utilisation can be optimised through a combined application of levers, such as DOEs, to protect network integrity together with mechanisms to align incentives of various actors, such as consumer tariffs and new aligned market functions (or proxies).

However, it is unlikely that such optimisation can be achieved under the current regulatory and planning frameworks. Realising these benefits will require:

- Better alignment of incentives across all market actors to encourage participation and investment that supports system-wide co-optimisation.
- Recognition of strategic, long-term asset planning, moving beyond a focus solely on near-term constraints.
- Development of appropriate valuation frameworks to reward CER-based solutions and flexibility.
- Updated asset utilisation metrics: current measures, which assess asset use based only on peak demand, fail to capture the full value of energy storage and flexible resources. A more comprehensive approach, one that considers energy throughput over time and differentiates between import and export capability, is needed.

The storage adjacent to the grid from passenger vehicles alone should well exceed 300 gigawatts (GW) in Victoria by 2050, indicating the enormous potential to harness such complementary assets for the system if the incentives are sufficient for car owners to connect and participate.

CER orchestration has clear value to all system users. The degree to which it exists is not only a function of technology uptake rates, but the consumer's willingness to have their assets participate. Understanding consumer perception and how it changes overtime can be important, even though it is very hard to predict where it may be over 30 years. If consumers close off to participation due to bad experiences or feelings of inequity or unfairness it may be significantly more difficult to entice them back.

Consumer policy perceptions on how to fairly integrate CER/DER into the national electricity market was assessed through two separate surveys, the first which drew on policy scenarios including purchase cost, operating cost, infrastructure and mandates, and the second of which explored the consumer's willingness to allow third party control. Respondents showed a strong preference for retaining control of their CERs but were prepared to trade off control for energy bill savings and preferred the incentive offered by market-based mechanisms rather than mandates. In general, consumer perceptions were that the energy system was unfair to them which remains a barrier and may influence adoption of, and participation in, technologies and orchestration solutions.

A lot can be done within the system to keep complexity at a minimum, with systems, processes and standards, market design and regulatory frameworks all working to ensure the consumer role within the transition is easy to navigate and to ensure their CERs provides electricity network and market opportunities that recognises the value of the consumer's own investment. Fairness, trust, complexity and impact all play into how various decision points may benefit or influence participation either actively or passively. Ultimately, consumer sentiment and behavioural preferences should be treated as material uncertainties in planning and scenario development.

5.4 Active distribution networks – harnessing flexibility to optimise at broader system level

The ISP process to date inherently assumes electricity distribution networks will be augmented to address the uptake in CER and, beyond some initial orchestration concepts and recent rule changes to better consider distribution considerations, does not consider co-optimisation opportunities outside assets connected to the transmission grid.. Until addressed, distribution networks and transmission networks will be planned largely independently. This misses any co-optimisation opportunity and will lead to levels of redundancy and over-investment. Expanding planning and operation beyond the transmission system brings significant complexity to what is already a massive planning challenge, not only from having 13 independent distribution networks connected, but also because of the inherent complexity within the multiple layers within distribution networks. The case for change is therefore dependent on finding efficient means to co-optimise the opportunities and ensure the potential value created outweighs the cost.

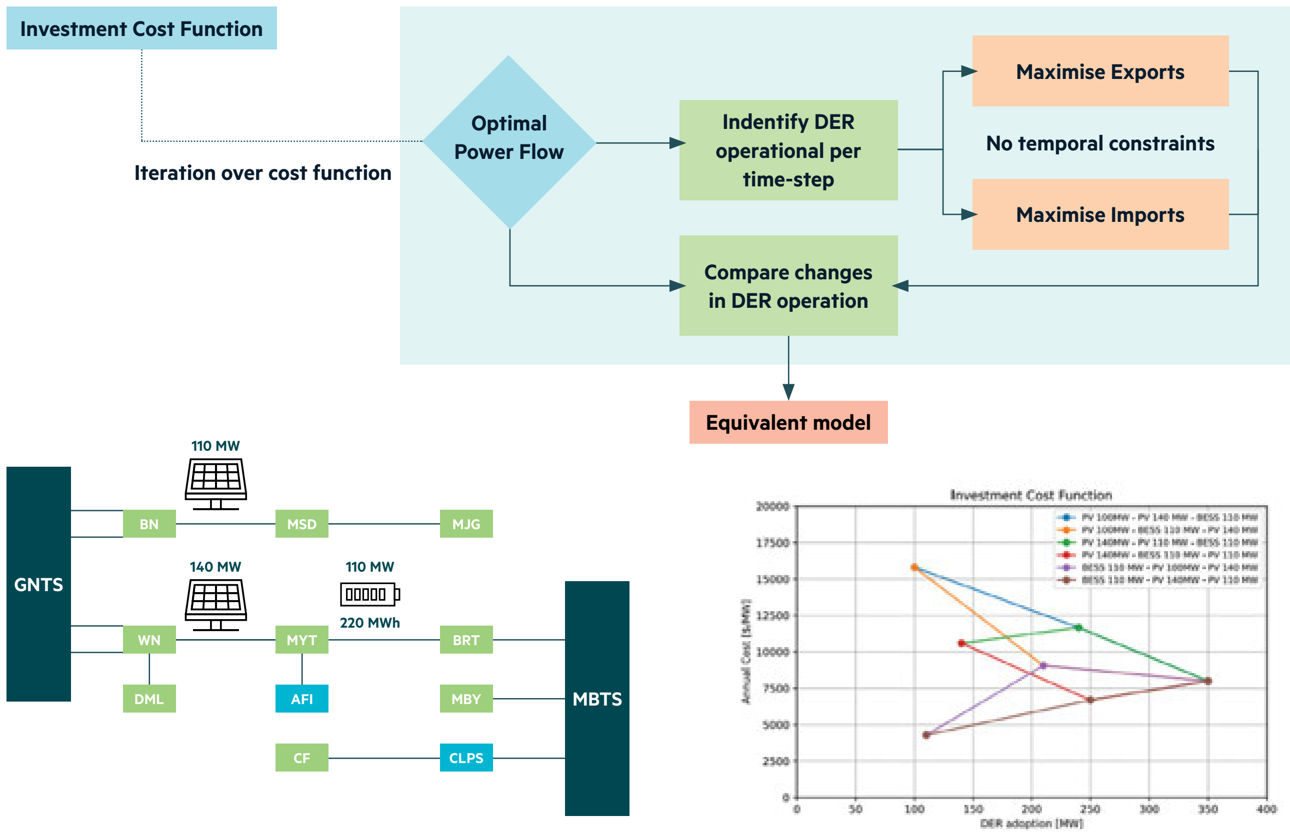


Figure 21: Illustrative example using AusNet's GNTS-MBTS sub-transmission network to produce multiple investment cost functions for different sequences of DER investments. The DER options considered are two distributed photovoltaic (PV) systems with 110 MW and 140 MW, and a 2-hour BESS with 110 MW

The project tackled the methodological means to represent distribution systems in a manner that can be incorporated into ISP planning. The approach characterised the network at a reference node as a flexible generator, a controlled load, and managed storage, all with operational limits, as illustrated in Figure 22.

The development of co-design frameworks can easily become prohibitively complex. WP 3.13 has delivered a bottom-up methodology to represent the planning of active distribution systems management within the transmission planning framework, characterising flexibility in a manner that can be incorporated and evaluated by AEMO to best identify the lowest cost, secure and reliable energy system at an acceptable level of risk. The framework was designed to minimise the iterative processes between distribution and transmission planning. Uniquely, it parameterises distribution network infrastructure, DER and their coordination infrastructure as a function of increasing DER adoption levels. The resultant investment cost curve and operating envelopes can be computed independently by each DNSP with their unique knowledge of their own electricity network and provided to AEMO. AEMO can then consider the trade-offs between investments in distribution and transmission networks.

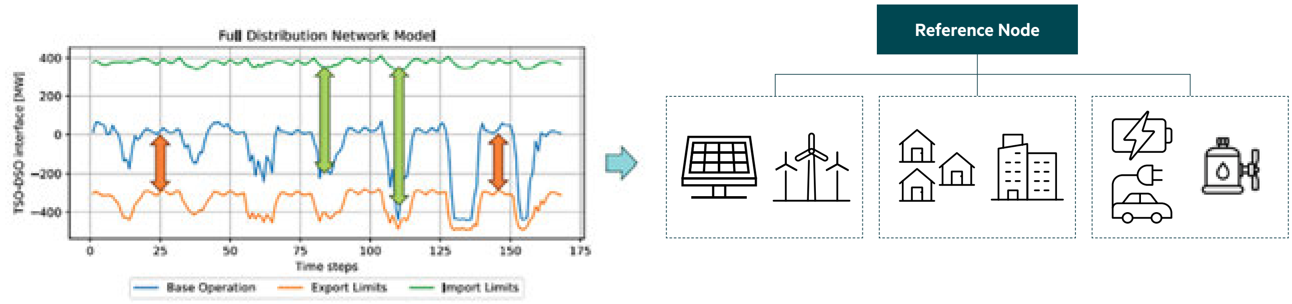


Figure 22: Illustration of the nodal operating envelope concept developed for WP 3.13

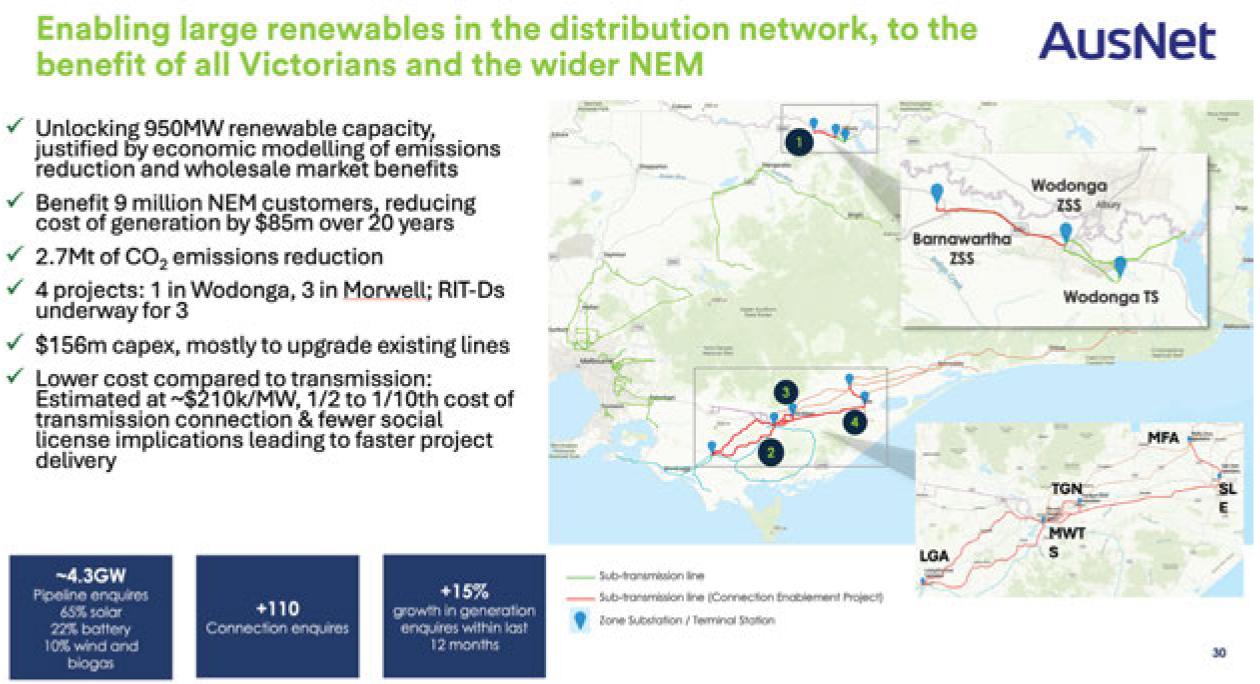


Figure 23: A current example of benefits of connecting large DER directly to the sub-transmission compared to transmission in a case study provided by AusNet Services. Note, the assessment benefits are based on synergies with existing assets only: full capture of the flexibility from operating as an integrated active distribution would be additional upside

For DNSPs to develop the inputs for AEMO, a methodology has been developed that addresses the optimisation problem for varying levels of DER adoption that factors sequencing of DER investments. To achieve a scalable whole-system planning framework it is crucial to understand how and what is the best method to represent the operational capabilities of distribution systems (within thermal and voltage limitations) that are unlocked by additional DER and the investments required to support them. In this context, the project developed an operational framework that employs the concept of nodal operating envelopes (NOEs) to characterise the flexibility limits of distribution systems, that is, maximum exports and imports for which the system can securely operate under network constraints, so that distributed resources can be aggregated and efficiently managed from a whole-of-system perspective.

Application of the methodology to large-scale assets connected at the sub-transmission level demonstrated that the sequence of asset connection significantly impacts the cost function. A deterministic case study using multiple nodes from ISP 2024 found that coordinated DER enabled active distribution networks to be connected at least 25% less cost than equivalent transmission infrastructure, with a 5% reduction in curtailment. Other case studies also demonstrated substantial cost savings.

While further development is required to transition the model from research to implementation, if these savings are validated and shown to be broadly representative, the potential system-wide savings across the NEM could amount to several billion dollars from optimised DER connections at sub-transmission level compared to investment in the transmission system alone. Additionally, distribution network assets are generally more incremental, enhance overall reliability and face fewer development challenges than transmission infrastructure. These benefits - lower cost, reduced delays, and improved emissions outcomes – make co-optimisation a strong candidate for further investment and development.

The modelling frameworks developed under WP3.13 are broadly applicable at any level of the energy system. Beyond the sub-transmission connection opportunity, initial case application appears to indicate DER assets connected in the electricity distribution networks can further lower system costs if the flexibility and capacity of the MV-LV networks are included. While this brings added complexity and would therefore need further investigation of net value, on the assumption that the net value is positive, a roadmap can be developed for the evolution of system planning to best position identification of whole-of-system opportunities and the co-optimisation of asset planning and operation.

The integrated operation of the system is an underlying critical element in unlocking the flexibility value at system level. There can be multiple operators, but systems, data exchanges and protocols need to be developed for efficient co-optimisation at the TSO/DSO interface. This would be a new capability to be developed by both the TSO and the various DSOs.

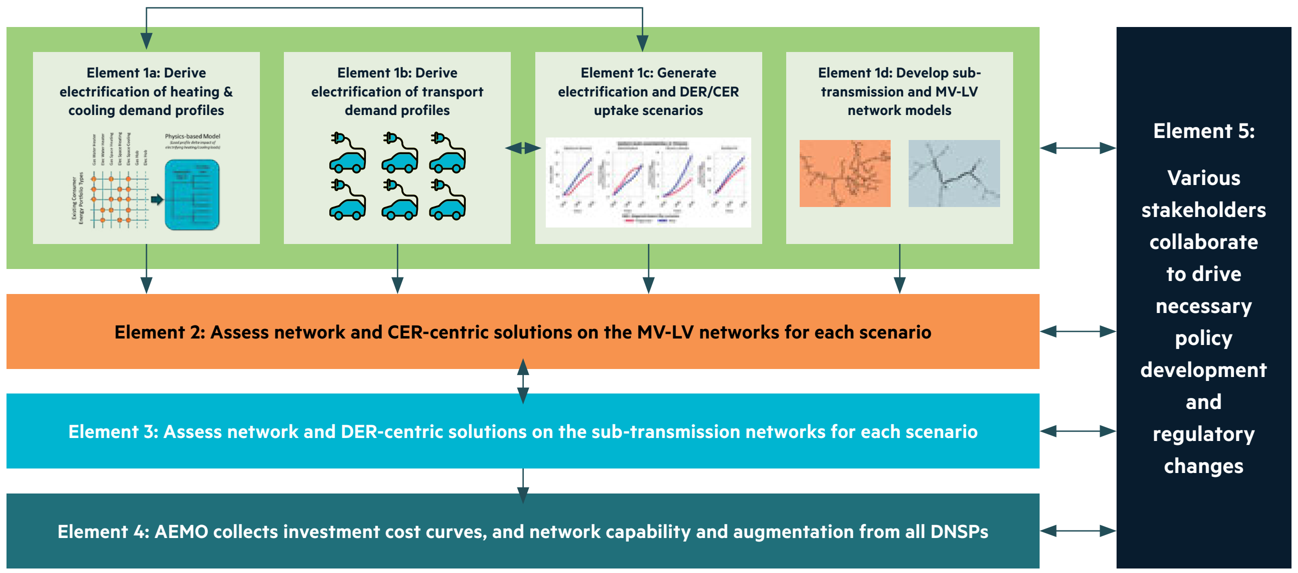


Figure 24: Overview of ESP roadmap

5.5 Roadmap to an expanded, whole-of-system integrated system planning

The ISP review commissioned by the ECMC identified the need for the ISP to shift to a more whole-of-system approach, including deeper integration of electricity distribution network elements. From the ESP project findings above, C4NET similarly concludes that distribution system considerations are critical for whole-of-system planning and suggests they should be integrated as a priority. Developments across the NEM mean distribution systems can no longer be represented as just a net load. Without proper integration of distribution systems into integrated planning and operation, there is a significant risk of overinvestment and inefficiency.

C4NET considers having an agreed roadmap in place is paramount. Having a clear end point and pathway to deliver it assists with identifying all the elements necessary to achieve the integration benefits as designed, particularly important when the changes can only be achieved by having policy makers and regulators, AEMO. DNSPs and the broader system groups working in concert to deliver a coordinated outcome.

To address this, a roadmap has been developed as part of the ESP project for integrating distribution networks and DERs/CERs into whole-of-system planning. Developed through insights from the ESP work packages and associated stakeholder consultation, the roadmap focuses initially on the low-voltage networks and residential loads. While commercial and industrial aspects require further development, many of the same principles, frameworks and methodologies are as applicable across the whole system. There is also a need for parallel efforts to develop operational and regulatory reforms to make the model effective. These reforms should aim to remove current barriers, better align incentives across actors, and support the effective integration of active distribution networks into broader system planning.

The proposed roadmap consists of five main elements. The first four follow a bottom-up, physics-based, techno-economic approach, and the fifth revolves around policy development and regulatory changes, as described below. Figure 24 illustrates an overview of elements underlying the proposed roadmap, including a suite of models and assessments. The overall roadmap is an iterative approach, where the outputs of each of the different models or analytical processes are used to determine or refine inputs into the other models and processes. Figure 24 also shows that Elements 1a, 1b, 1c, and 1d can be performed in parallel, and that Element 5 spans the entirety of the whole process. It is important to note that the uptake of rooftop PV, BESS, electric heat pumps, and EVs in Elements 1a, 1b, and 1c is largely driven by the degree of consumer participation and by key policy and regulatory changes, such as support or incentives for these technologies that the scenarios would be designed to represent.

The implementation of such a roadmap would be aligned with the ECMC actions from the ISP review already underway but remain a significant change from where the ISP is today. Considerations for implementation actions are further discussed in Section 5.6.

5.5.1 Element 1a: Derive electrification of heating/cooling demand profiles

This element consists of employing physics-based bottom-up approaches to derive and forecast demand profiles that reflect electrification of heating, cooling, and domestic hot water (DHW) for different archetypes of residential and commercial consumers on a given MV-LV network. This process, which is summarised in Figure 25,[14] starts by classifying buildings into different types depending on several characteristic, including space use (e.g., residential or commercial), geometry, construction material, thermal properties and thermal inertia, household size, and occupancy behaviour. This information is then combined with location-specific weather conditions (e.g., outdoor temperature and solar irradiance) to determine the operating performance of electric heat pumps and heat gains from solar irradiance to generate heating/cooling profiles. This element may be performed by research bodies such as universities or CSIRO, in consultation with DNSPs and AEMO.

The use of a physics-based bottom-up approach is critical in the absence of sufficient historical granular demand data for gas heating and DHW. As more granular historical data and cognitive analytics become accessible over time, this element may progressively shift towards a hybrid approach, leveraging both data-driven and physics-based techniques.

Coordinated DER enabled active distribution networks to be connected at least 25% less cost than equivalent transmission infrastructure, with a 5% reduction in curtailment.

14 More details on how to develop such approaches can be found in WP 1.1., noting that commercial building profiles would need to be added.

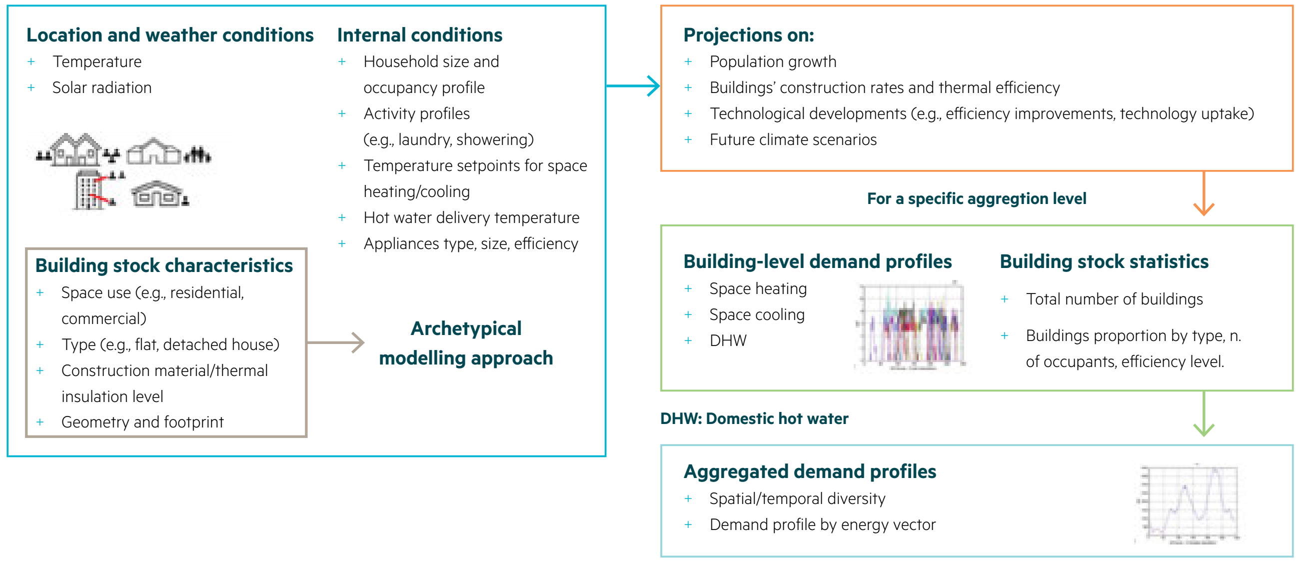


Figure 25: Bottom-up process for deriving individual and aggregated demand profiles on a given MV-LV network

5.5.2 Element 1b: Derive electrification of transport demand profiles

This element consists of deriving charging and discharging profiles of EVs by either extracting them from smart meter data or directly from known charger types.[15]

This element, which is also expected to be undertaken by research bodies such as universities or CSIRO, in consultation with DNSPs and AEMO, could also provide information on latent storage capacity, i.e., degree of flexibility EVs could potentially provide when coordinated. This undertaking is underpinned by several key steps, including but not limited to:

- Estimating EV model diversity and travel distance,
- Identifying and classifying EV charger sizes,
- Extracting the exact time and duration of charging/discharging, and
- Extracting probability distributions and coincidence factors.

An illustration of typical EV capacity (kW) and storage profiles (kWh) for MV- and LV-connected EVs are shown in Figure 26.

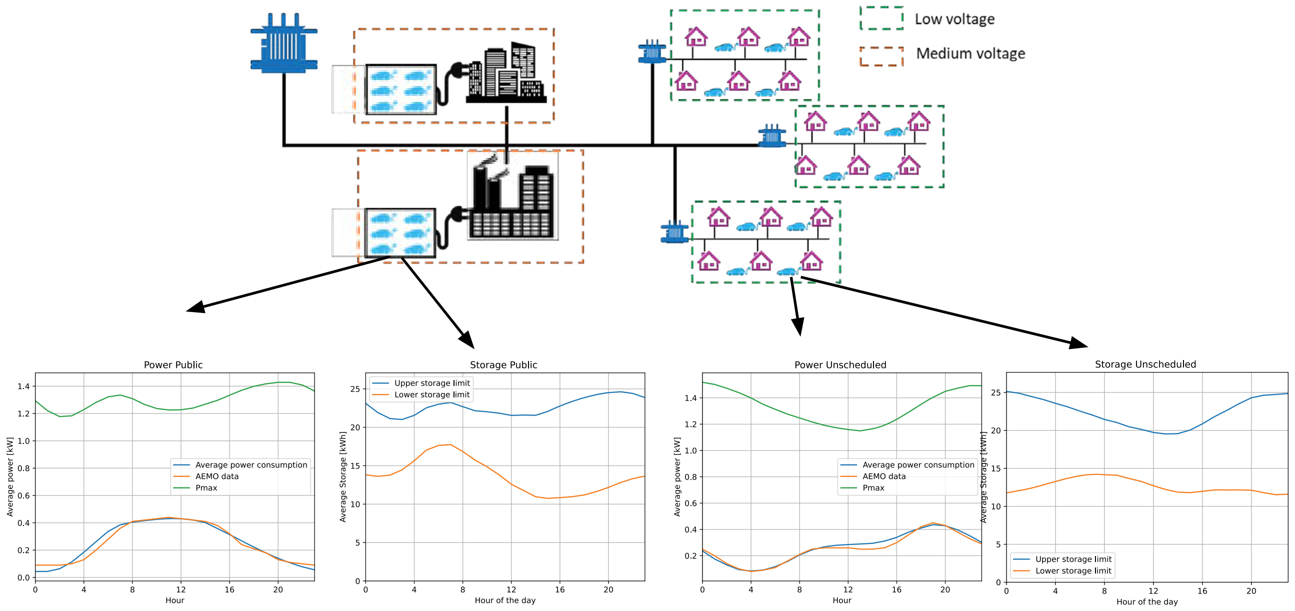


Figure 26: Illustration of what a typical storage profile (kWh) looks like for an MV-connected EV (left) and an LV-connected EV (right)

15 More details on how to derive EV charging/discharging profiles and latent storage capacity can be found in WP 1.2 and WP 2.10.

5.5.3 Element 1c: Generate electrification and DER/CER uptake scenarios

Uncertainty in the projections of both electrification of heating/cooling and transport in Elements 1a and 1b above and CER and DER uptakes calls for generating different scenarios of their evolution in the future. This element therefore consists of generating different scenarios with different probabilities that depend on how likely a certain scenario will unfold.

This element may be performed by research bodies such as universities or CSIRO, in consultation with DNSPs and AEMO.[16] Harmonising these scenarios among DNSPs (e.g., low, medium, and high CER/DER uptake and coordination levels) may be necessary to facilitate their seamless integration with AEMO's scenarios.

An example of different uptake scenarios is shown in Figure 27.

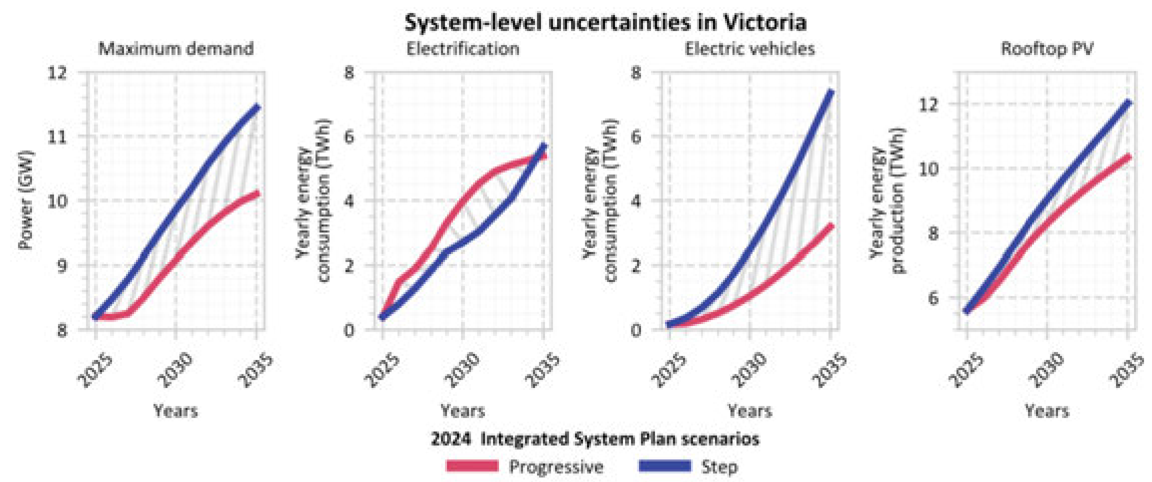


Figure 27: Example of system level differences between modelled ISP scenarios (ISP 2024)

16 More details on how to develop such scenarios can be found in WP 1.3 and WP 2.9.

5.5.4 Element 1d: Develop sub-transmission and MV-LV network models

A crucial element in the roadmap is to develop representative models for each DNSP's sub-transmission and MV-LV networks based on a predetermined taxonomy. This element may be performed by research bodies such as universities or CSIRO, in consultation with DNSPs and, possibly, AEMO as well. Representative MV-LV network models can, for example, be divided into various types such as urban, CBD, suburban, short-rural, and long-rural.[17] Such network models can be built with the help of SCADA/ADMS systems, smart meter data, and data-driven physics-based state-estimation techniques. Building network models is not expected to be a bottleneck in the near future thanks to increasing uptake in advanced control and communication infrastructure increasing the visibility of the state of network assets (e.g., electrical parameters of transformers and overhead lines and cables, on-load tap changer (OLTC) and off-load tap changer (OFTC) tap positions, etc.) and demand alike.

An illustration of an archetypical distribution network is shown in Figure 28.

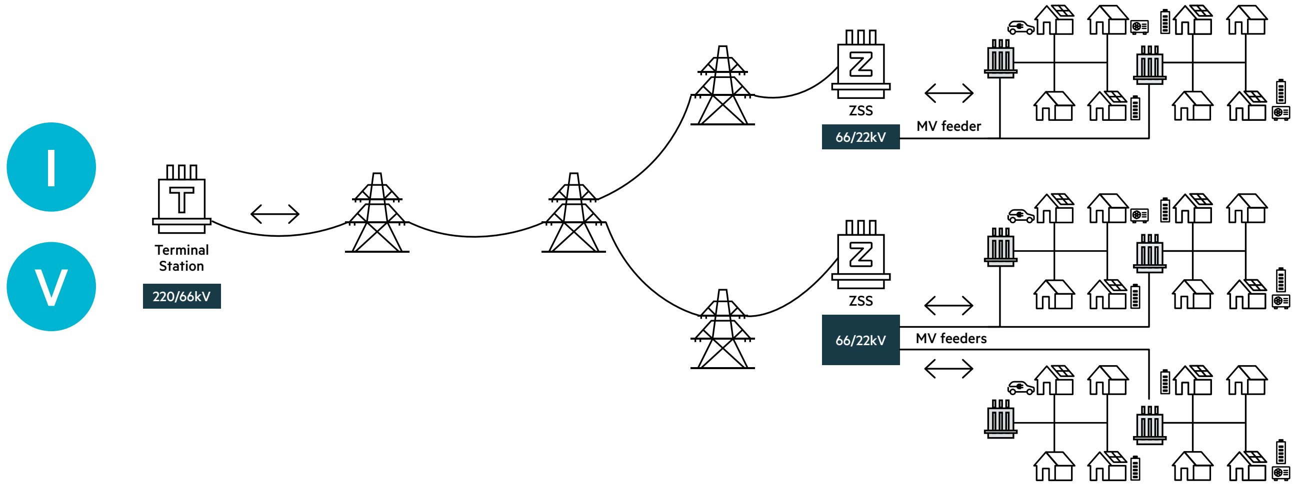


Figure 28: Illustration of an archetypical distribution network with voltage levels of 66 kV for the sub-transmission part all the way down to the 22 kV on the MV side and 400 V on the LV side

17 More details on how to develop such approaches can be found in WP 1.4.

5.5.5 Element 2: Assess network and CER-centric solutions on the MV-LV networks

The outputs from Element 1 can be used as inputs for an expansive set of MV-LV three-phase unbalanced power flow or optimal power flow studies, as illustrated in Figure 29 These studies can be performed by each DNSP, with potential consultation with research bodies (e.g., universities or CSIRO), using their representative MV-LV network models (developed in Element 1d) to assess a set of network and CER-centric (i.e., non-traditional-network-asset) alternatives or options. The goal is to derive key metrics such as the capability of the existing distribution network, augmentation potential, investment cost curves, degree of CER flexibility (in MWh), and relevant economic indicators such as:

- Net present cost (NPC),
- Regret of net present cost (RNPC),
- Net present value (NPV),
- Unserved energy cost (USE),
- PV curtailment cost (PVC),
- Internal rate of return (IRR), and
- Discounted payback period (DPP).

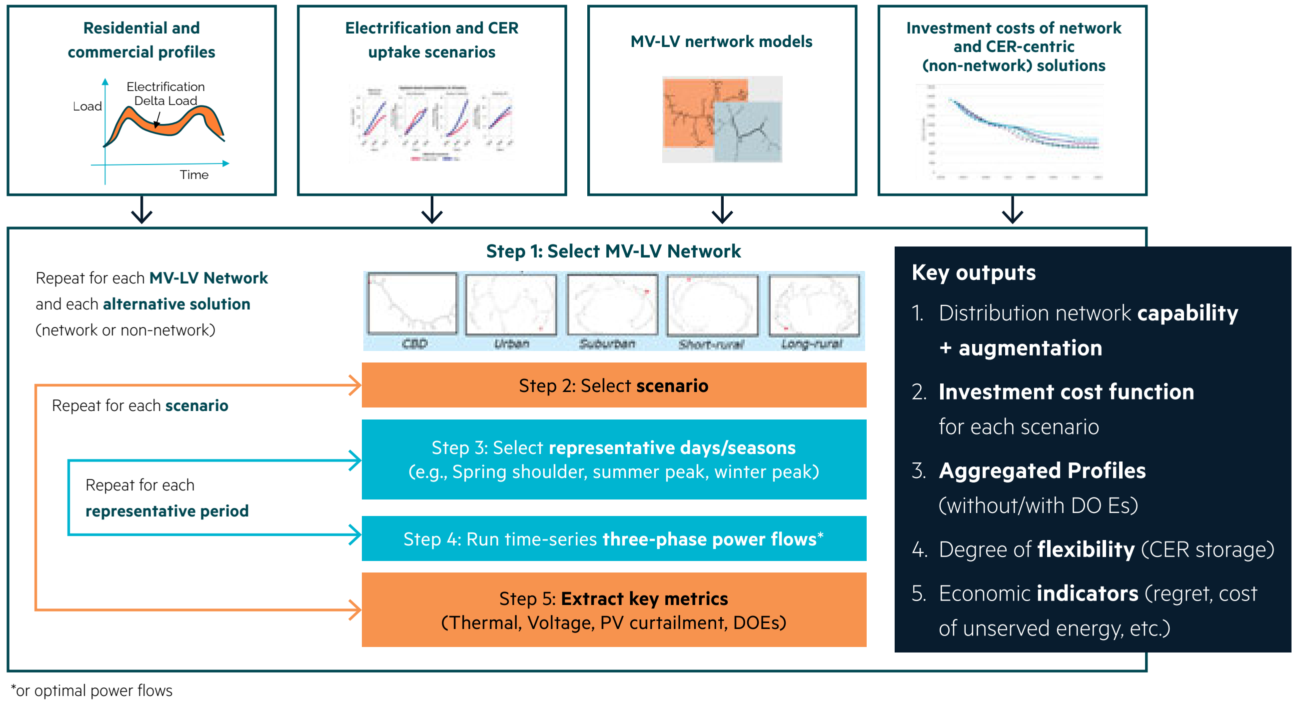


Figure 29: Flow chart describing the inputs and outputs of the power flow (or optimal power flow) studies performed under Element 2

The process outlined in Figure 29 starts by selecting a specific MV-LV network model and uptake scenario, followed by the selection of representative days for each year to 2050, for example. Next, the DNSP selects an augmentation option and its associated cost from the set of network and CER-centric (i.e., non-traditional-network-asset) solutions and then runs a three-phase unbalanced[18] power flow (or optimal power flow) to assess impact on voltages, thermal limits, and PV curtailment with and without DOEs and smart inverter capabilities such as Volt-Var/Watt control (VVWC).[19] The process is repeated for each type of representative network model and each network and CER-centric solution to obtain a comprehensive lookup table[20] that maps all the inputs into key outputs for each scenario, which include, but are not limited to:

- Distribution network capability,
- Distribution network augmentation capability (including CER),
- Investment cost curves,
- Aggregated demand profiles (without DOEs and VVWC),
- Degree of flexibility (i.e., CER storage), and
- Economic indicators.

The set of network- and CER-centric solutions also includes a "no action required" option, which allows the DNSP to perform power flow (or optimal power flow) analyses to quantify the location and magnitude of voltage and thermal issues

18 A four-wire unbalanced power flow could also be considered if the neutral wire has a non-negligible current.

19 More details on how such on such power flow and optimal power flow studies can be found in WP 1.5 and WP 2.10, respectively.

20 More details on how such a lookup table could look like can be found in WP 2.9.

prior to considering mitigation measures such as DOEs and VVWC. The DNSP then evaluates the extent to which these mitigation measures can alleviate the identified issues. If issues persist, the DNSP can proceed to assess a range of network and CER-centric (non-traditional-network-asset) solutions to determine their value—namely, the extent of mitigation and the associated cost—and ultimately identify the optimal mix of solutions based on a chosen hierarchy of metrics or objectives for each scenario and level of CER uptake and/or coordination.

5.5.6 Element 3: Assess network and DER-centric solutions on the sub-transmission networks

This element performs a similar assessment to the one in Element 2 but now on the representative sub-transmission network models of each DNSP by taking the outputs from Element 2 as inputs, namely:

+ Aggregated demand profiles,
+ Aggregate CER flexibility (in MW and MWh),
+ Investment cost curves, and
+ Distribution network capability and augmentation for each scenario and for each MV-LV network connected to the sub-transmission network at hand.

Additionally, the DNSP at this stage can once again identify a set of network and DER-centric (i.e., non-traditional-network-asset) options to evaluate. In this case the non-traditional-network-asset options may be MW-scale batteries and PV systems.

The process delineated in Figure 30 begins with the DNSP selecting a specific sub-transmission network and uptake scenario, followed by the selection of representative days for each year from now out to 2050, for example. Next, the DNSP selects an augmentation option and its associated cost from the set of network and DER-centric (i.e., non-traditional-network-asset) solutions and then invokes a power flow or optimal power flow routines to assess, among many others, impact on voltages, thermal limits, and (MW-scale) PV curtailment.[21] The process is repeated for each sub-transmission network model and each network and DER-centric alternative to once again obtain a comprehensive lookup table[22] that maps all the inputs into key outputs for each scenario, which include, but are not limited to:

+ Distribution network capability and augmentation,
+ Investment cost curves,
+ Aggregated demand profiles,
+ Degree of flexibility (i.e., CER and DER storage), and
+ Economic indicators.

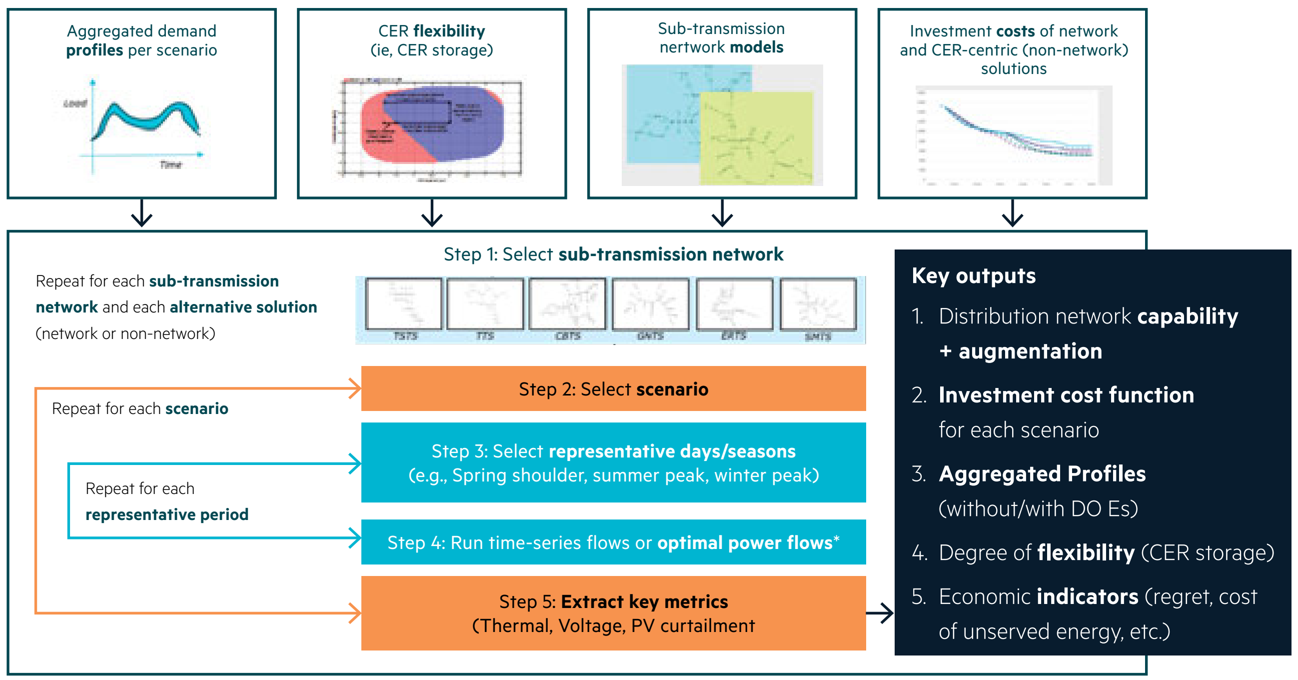


Figure 30: Flow chart describing the inputs and outputs of the optimal power flow studies performed under Element 3

21 More details on how such on such power flow and optimal power flow studies can be found in WP1.6 and WP 3.13, respectively.

22 More details on how such a lookup table could look like can be found in WP 2.9.

At this stage the DNSP will have collected distribution network capability and required augmentation, investment cost curves, and aggregated demand profiles for each DZS on the sub-transmission network. Similar to Element 2, the set of network- and DER-centric solutions also includes a "no action required" option. This allows the DNSP to perform optimal power flow studies that optimise the capability, augmentation, and associated investment cost functions of each MV-LV network (as computed in Element 2), with the aim of mitigating the location and magnitude of voltage and thermal issues on the sub-transmission network—if they exist—prior to considering network and non-traditional network asset solutions. This eventually allows the DNSP to find the trade-offs between investments on the MV-LV network (downstream from each Zone Substation (ZSS)) and on the sub-transmission network. The DNSP is then able to identify the optimal mix of solutions based on a chosen hierarchy of metrics or objectives for each scenario and level of DER/CER uptake and/or coordination.

A feedback iteration between Elements 2 and 3 may be needed to achieve increased accuracy in the impact assessment and optimised solution mix. Such a feedback iteration may be particularly relevant in the context of system security and how a voltage disturbance on the sub-transmission network can impact transformers and inverter-based resources downstream.

5.5.7 Element 4: AEMO collects investment cost curves, and network capability and augmentation capability from all DNSPs

At this stage, the DNSPs hand over to AEMO the electricity distribution network capability and augmentation, and the investment cost curves computed in Element 3 for each scenario, which can now be seamlessly integrated into AEMO's ISP, as illustrated in Figure 31. The overarching aim is to allow each DNSP, using their own tools, to derive distribution network capability envelopes and cost curves as functions of DER and CER uptake/adoption, which when considered in the ISP enables AEMO to find trade-offs between distribution network investments and investments in transmission or utility-scale generation and storage technologies.

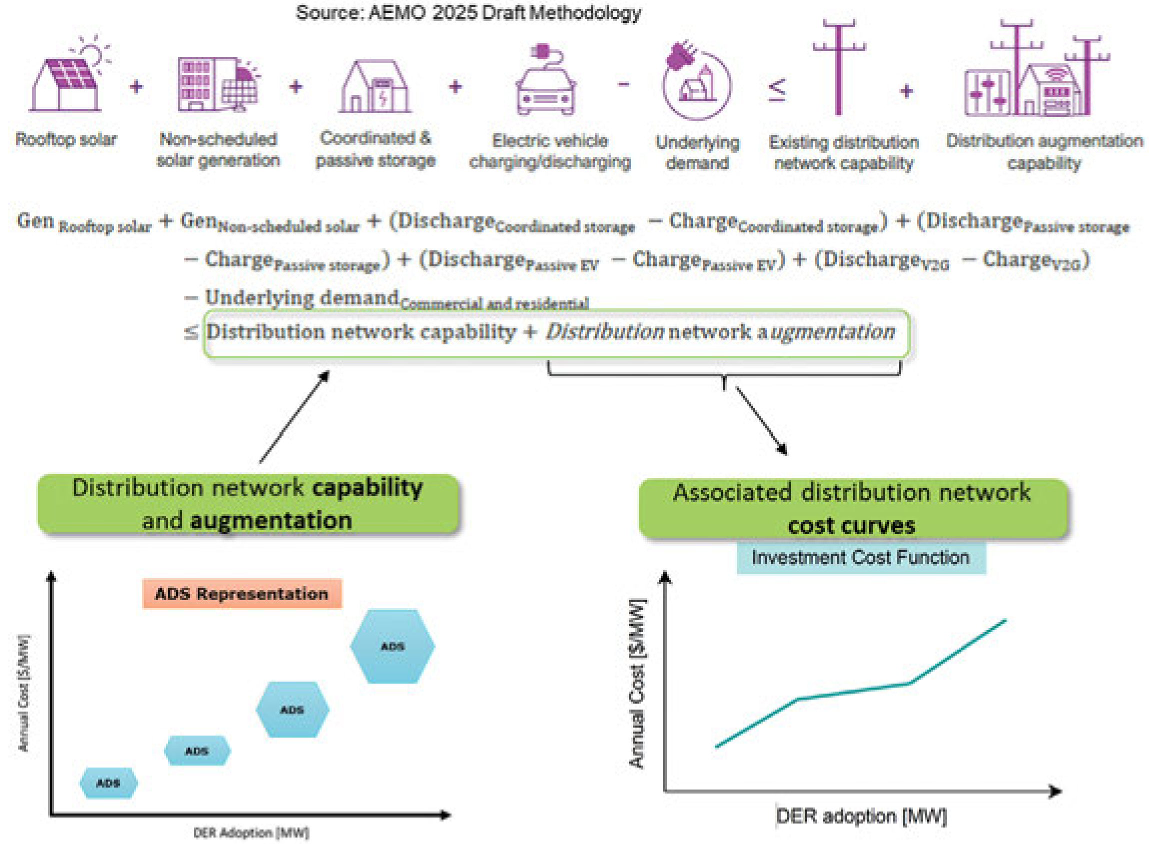


Figure 31: Integration of distribution network capability and augmentation, along with the associate investment cost curves into AEMO's ISP

SECTION FIVE Findings, observations and key outputs

5.5.8 Element 5: Various stakeholders collaborate to drive regulatory changes

This final element consists of engaging industry, government, and consumer groups to align research findings with policy development. This can be in the form of a roadmap for regulatory changes that support integrating active distribution networks and CER/DER in whole-of-system planning. This element may be performed in parallel with the other elements and can therefore either inform, or be informed by, each of the first four elements in the roadmap.

There are multiple levels of regulatory changes that would be required. At the most basic level, it is likely that rule changes would be required to ensure AEMO and DNSP roles and obligations are consistent with the delivery of the roadmap and how costs of doing so are addressed. At the more complex level, market design and regulatory changes will be required to support integrated operations and align incentives of all actors within the system to achieve the goals being solved for.

The merits of having a roadmap in place will assist alignment of parties and regulatory changes in having an agreed and common goal. For example, Energy Consumers Australia's recent proposal to the AEMC to change the National Electricity Rules[23] focussed on integrated distribution system planning and proposes a range of distribution level data to be made available. As drafted it is somewhat unclear how the data will be used. No doubt this will be addressed through the consultation phase, but this would be a promising avenue to apply data needed to be consistent with ESP methodologies in practice for the benefit of all consumers.

The merits of having a roadmap in place will assist alignment of parties and regulatory changes in having an agreed and common goal.

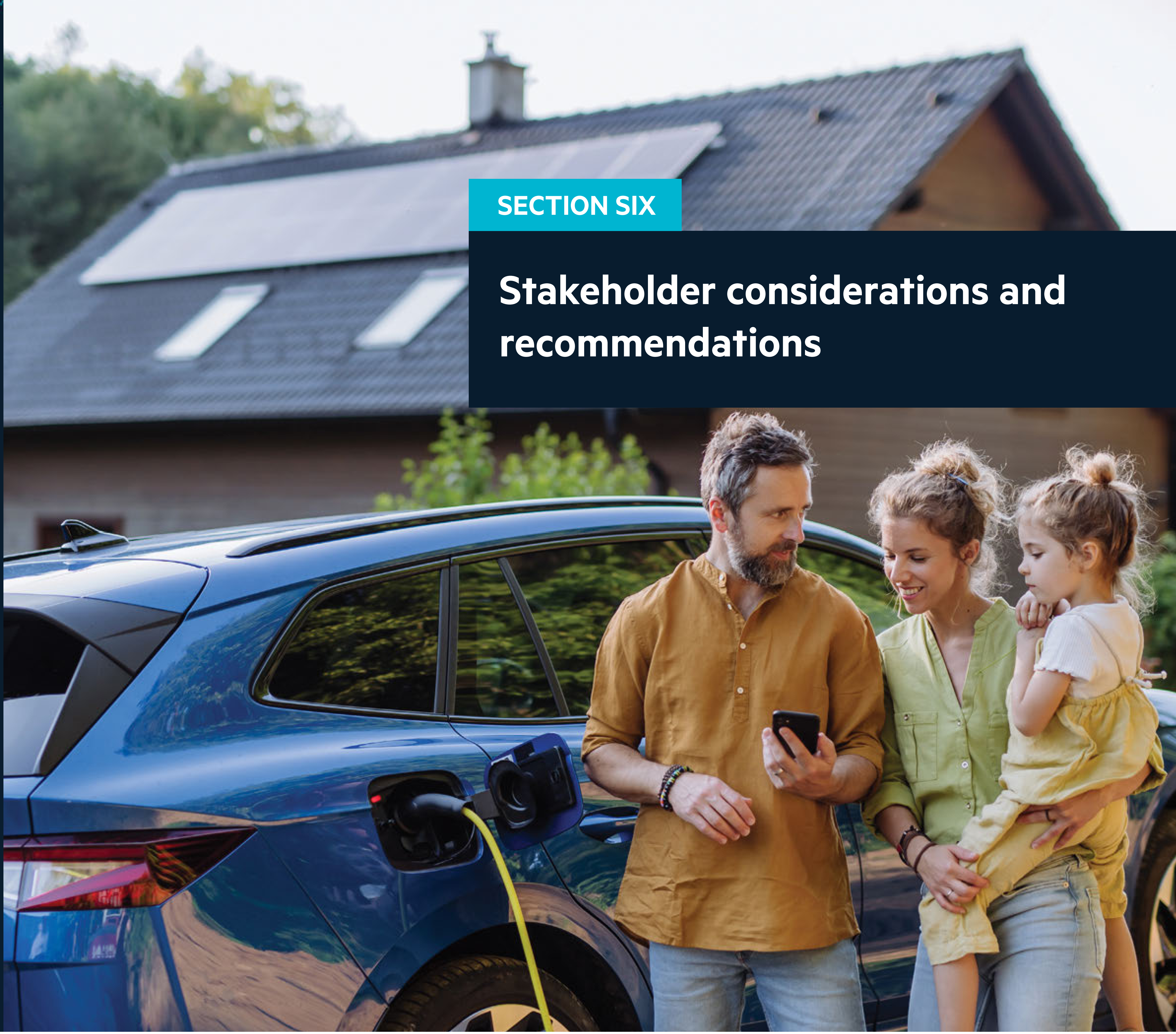
5.6 Considerations for implementation in future ISPs

The implementation of any such roadmap as described above is challenging. The path to implementation would need to have been broadly consulted, supported with necessary rule changes and would likely require change to current roles and responsibilities of actors within the NEM, among others. These issues are discussed further under the recommendations in Section 6.

The roadmap outlined in Elements 1 to 5 in Section 5.5 forms a complete and self-contained methodology that fully enables the integrated planning of transmission and distribution systems from the bottom up. However, developing such a methodology within a short timeframe may be a challenging undertaking. Therefore, a potential first step could involve adopting a simplified version of this roadmap that focuses solely on the electricity sub-transmission networks.

More specifically, this simplified version — potentially implementable in AEMO's 2028 ISP — may preclude the development of representative MV-LV network models and instead focus only on sub-transmission network models under Element 1d. This implies that the capability of the existing distribution network, augmentation potential, and investment cost curves described in Element 2 would no longer be derived using unbalanced power flow or optimal power flow analyses. Although they no longer capture electricity network constraints, and therefore the true cost of MV-LV network augmentation, the decision-theory-based economic indicators described in Element 2 can now be developed in a more time-efficient manner. Similar to the complete roadmap outlined above, both DER and CER uptakes can be treated as *variables* — rather than exogenous (fixed) input — that can be optimised to find trade-offs between investments in the distribution network (including both network and DER- and CER-centric solutions) and investments in transmission or utility-scale generation and storage technologies. Potential savings from treating DER and CER uptake as endogenous (i.e., variables) can help quantify potential subsidies needed to drive this uptake in alignment with the outcomes of the optimisation.

23 https://www.aemc.gov.au/rule-changes/integrated-distribution-system-planning, accessed 23 May 2025



SECTION SIX

Stakeholder considerations and recommendations

6 Stakeholder considerations and recommendations

The integration of outputs such as data models and collaboration across the ESP has enabled key insights and outcomes to be leveraged to inform the messaging included in this report for stakeholders. In conducting the project, C4NET and the researchers had the privileged opportunity to think across the sector without the constraints experienced by any individual stakeholder. C4NET was uniquely positioned to bring relevant parties together to address the challenge.

While the recommendations have been grouped by stakeholder group of primary relevance, the strategic nature of the central recommendations mean that they involve all stakeholders contributing to them to a degree. Each stakeholder will have recommendations within their remit or ability to execute, of which they can best advise, but if there is agreement on the end point it's believed they will collaborate with others as necessary to deliver on the recommendations and address any constraints.

The next iteration of the ISP's evolution and subsequent direction has been decided by the ECMC as discussed further throughout this section. The ESP research findings and recommendations contribute to better detail what this could achieve and how to get there.

The recommendations centre around the key findings of:

- That distribution system considerations need be integrated into the ISP to enable co-optimisation of asset planning and operation across the entire electricity system
- The recommended way to do this is for them to be modelled as active distribution systems incorporating systemised representation of their constraints and flexibility at each level (high, medium and low voltage networks)
- How to achieve this – foundational methodologies and a proposed implementation roadmap for the planning aspects.

While broadly consulted with the subject matter experts from the project partners, the work done to date is primarily from the research environment. Outputs will need further evolution or verification, plus broader consultation before adoption into practice by the sector.

Detailed findings of each individual work package, and the considerations for each of the stakeholders above as well as consumers and further research directions are included in the work package summary documents. The raw research findings are in the individual work package research reports.

6.1 Key considerations and recommendations for AEMO

As noted by the Minister for Climate Change and Energy (Cwth),[24] effective planning of the energy system has never been more important. The ISP is the NEM's preeminent long-term planning document. The recent ECMC ISP review identified opportunities to supercharge the ISP, expanding its scope to ensure the ISP sets a direction for the transformation across the entire energy system, including broader integration of gas and better integration of demand-side opportunities.

The ESP project has demonstrated the importance and value of integrating electricity distribution network considerations to inform demand-side opportunities. It has provided foundational methodologies to support this integration and highlighted how active distribution systems can enable the incorporation of flexibility and demand-side resources into what has historically been a supply-focussed planning process.

The ECMC has tasked AEMO with enhancing demand forecasting and optimisation of the demand-side. The ISP evolution roadmap developed through the ESP outlines how this can be achieved systematically across successive ISP iterations. Central to this evolution is the adoption of harmonised methods to characterise distribution networks as active systems. This approach enables DNSPs to produce the inputs required by AEMO and provides AEMO with the confidence to integrate these inputs into optimised, whole-of-system development pathways, from transmission planning through to consumer participation.

Importantly, evolving the ISP to integrate active distribution systems remains consistent with DNSPs retaining responsibility for planning their own electricity networks. What changes is the nature of the planning process — it becomes co-optimised with system-level planning via a standardised set of inputs. AEMO can play a central role in driving this standardisation, facilitating like-for-like comparisons and supporting selection of the most efficient development pathway.

An action from the ECMC recommendations from the ISP review is:

The System Planning Working Group and AEMO will work with the relevant stakeholders, including DNSPs, to develop a suitable approach to trade off the cost of unlocking increasing tranches of orchestrated CER and distributed resources against other investment options for use in the earliest ISP practicable.

This proposed integration of distribution system considerations aligns with the ECMC's directions for the 2026 ISP and contributes to further co-optimisation ambitions by further by proposing a nationally consistent framework based on active distribution system concepts developed in the ESP. This approach supports a truly integrated planning process — encompassing the entire distribution system and unlocking the full value of DER and consumer participation in the energy transition.

The roadmap for incorporating active distribution systems into integrated system planning primarily addresses the planning dimension of the energy transition. The ESP project has made a substantial contribution in this regard for consideration and offers a strong foundation that can be expanded to include commercial and industrial energy users across the NEM. The frameworks developed and included in the roadmap include those to systematically inform the trade-offs listed above, and importantly for application at multiple points across network verticals.

To maximise its impact, the planning approach advocated would need to be complemented by the development of corresponding operational planning frameworks and progression strategies for regulatory reform, to both of which the ESP findings offer insights.

AEMO is governed by strict regulatory and operational boundaries to deliver the ISP that may limit their ability to adequately consider or implement the recommendations identified in this report. AEMO is best placed to identify what needs to be addressed for them to enact the recommendations that the ECMC could then consider supporting.

24 ECMC 2024, Review of the Integrated System Plan: ECMC Response, Energy and Climate Change Ministerial Council, Canberra. CC BY 4.0.

The ESP has highlighted the criticality of incorporating distribution system considerations in whole of system planning to deliver the lowest cost system. It is recommended:

1. The System Planning Working Group and AEMO to:
   a. consider the ESP findings to address optimisation for the demand side, and the roadmap as a key means for implementation of the ECMC ISP action for co-optimisation through incorporation of active distribution systems into future ISPs as a suitable approach to assess cost trade-offs of unlocking increasing tranches of orchestrated CER and DER against other investment options; and in parallel
   b. identify priority issues and actions needed to permit AEMO and DNSPs to implement, including roles and responsibilities, regulatory requirements, consultation and rule changes to permit and allocate costs.
2. Should the adoption of the roadmap be supported, the System Planning Working Group and AEMO to:
   a. Commission the development of frameworks for integrated system operation which recognises the future "active" nature of distribution network operations, as well as regulatory and market development to align incentives, and
   b. propose the implementation into the next appropriate ISP review framework, such as any post-2026 ISP review or the AEMC's scheduled ISP review to be published in 2027.

Implementing the roadmap would also contribute to other ISP review actions such as:

+ Better data on industrial and consumer electrification (including by sub-regions), and
+ Enhanced demand forecasting, in:
  - Building on the momentum developed between DNSPs and AEMO on data provision for the 2026 ISP, and
  - Developing a framework and methodology to support DNSPs and jurisdictions develop projections and undertake analysis in a consistent manner to support the ISP's development.

Building on the data validation and update processes for key ISP inputs from their work with the likes of CSIRO, AEMO can further facilitate the capture and curation of operational data to help understand customer behavioural insights of CER use and electrification impacts. C4NET's groundbreaking longitudinal study for Solar Victoria and AEMO's recent gas-electricity meter data linking projects demonstrate the type of insights to be gained. By way of another example, the AEMO CER Data Exchange[25] may provide a useful validation source for CER market trends in the future.

The ESP has highlighted the importance of sound, physics-based modelling of electrification impacts and CER adoption.

3. AEMO to coordinate common methodologies for characterisation of the electrification of space heating/cooling, domestic hot water, EV charging in active distribution systems for planning purposes, including evaluation of the frameworks developed under the ESP. This work could be conducted by consultants or researchers under guidance of AEMO rather than having to be done by AEMO or the DNSPs.

Given that distribution systems are generally operated separately to the transmission system to which they connect, a coordinated framework for TSO-DSO engagement will need to be developed. Such a framework should be developed collaboratively, likely involving AEMO, DNSPs, AEMC and the AER so that the financial impacts of any co-optimisation planning and operation are clearly understood, appropriately allocated and able to influence investment decisions.

In the near term, the most significant gains appear to lie in enabling large-scale DER connections at the sub-transmission level and harvesting the flexibility that they introduce to the system. There is urgency in addressing this opportunity to ensure the system remains on track to achieve net zero targets. Transmission planning and development face well-known challenges, including rising costs and community resistance. In contrast, several distribution businesses across the NEM have highlighted opportunities to leverage existing network capacity and infrastructure, such as pre-existing easements, to reduce costs, accelerate delivery, and mitigate planning and development risks.

While full integration of assets into coordinated transmission–distribution planning and operation will yield the greatest long-term value, some benefits can be realised sooner through strategic sub-transmission connections and supporting upgrades. Where a lower cost and community support can be demonstrated, regulatory or operational barriers to these near-term opportunities should be addressed, even as the broader planning and operational frameworks continue to evolve.

The ESP has identified means to assess opportunities to directly connect large scale storage, solar and wind directly into the sub-transmission networks. It appears this can be at significantly lower cost than transmission connections in some cases.

4. AEMO and transmission planners such as VicGrid to ensure large scale assets are evaluated against comparative opportunities that utilise the capacity, complementary assets and flexibility available in respective distribution networks.
5. AEMO, TNSPs and DNSPs to develop common frameworks for the integrated operation of assets connected to sub-transmission networks along with the necessary rule change requests.

While there was not sufficient time to explore and assess the potential ESP-related opportunities from VicGrid's recently released draft Victorian Transmission Plan (VTP),[26] C4NET does note and encourage VicGrid to consider distribution network planning integration options from the proposed 2027 VTP update onwards in close collaboration with AEMO and their ISP development process.

Once active distribution systems are represented in the ISP, it will be possible to undertake more detailed economic analysis of the relative merits of various levels and forms of CER and DER orchestration, compared to alternate solutions. To date only top-down analyses have been performed and they indicate substantial savings from a more orchestrated grid.[27] Significant consideration was given to informative orchestration scenarios in the ESP project. The first, referred to as the "evolutionary" pathway assumed the grid would continue development largely as it does now and consumers retaining maximum agency. While the approach prioritises consumer autonomy it results in higher electricity network investment to accommodate unmanaged or poorly coordinated energy flows. The second, "revolutionary" pathway, assumes more proactive policy settings, underpinned by the deployment of enabling infrastructure for communications and coordination. This pathway supports a high level of DER orchestration, enabling significant reductions in electricity network costs while still aiming to preserve consumer choice. The ESP project ended up needing to consolidate on just the base case, but future work could expand to apply ESP frameworks to inform the relative merits of these two pathways. The DER and CER orchestration opportunities are further discussed in Appendix 4.

25 https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/markets-and-framework/CER-Data-Exchange-Industry-CoDesign, accessed 23 May 2025

26 https://www.energy.vic.gov.au/renewable-energy/vicgrid/the-victorian-transmission-plan, accessed 23 May 2025

27 An example is the Clean Energy Council's "Modelling the Value of CER to Energy Consumers" report, May 2024

6.2 Key considerations and recommendations for DNSPs

The transformation facing electricity distribution networks over the next 30 years is without precedent. It is rare for a single generational fuel swap to occur, let alone two at the same time as transitioning distribution systems to host the single largest source of generation at the same time. The connection of data centres over through the next decade themselves could be transformational. This shift will necessitate the development of new coordination systems, the emergence of new market structures, and significant changes to the regulatory environment to ensure reliability, affordability, and equity throughout the transition.

DNSPs have planned and operated largely independently of each other and separate to the rest of the system, relying on it to meet their supply needs through sound integrated planning systems. However, as distribution systems are becoming more active, it is an imperative that they are factored into whole-of-system integrated long-term planning to reduce cost, improve reliability and resilience and serve their customer's needs. A critical element of whole of system planning is to raise visibility of the role distribution systems can play in actively minimising the reliance on transmissions system expansion. This will lead to a significant change in long-term planning and operation, and growing interdependence on other parts of the sector. With the planned increase in data centre connections (higher voltage parts of the network) and the impact of electrification and CER over the next few years, when considering the timeframes to implement major reforms it is an imperative that implementation of an appropriate plan to integrate active distribution systems into NEM-wide planning and operation be actioned as soon as possible.

It is an imperative that implementation of an appropriate plan to integrate active distribution systems into NEM-wide planning and operation be actioned as soon as possible.

The ESP has highlighted the criticality of incorporating distribution system considerations in whole of system planning to deliver the lowest cost system, but AEMO can't deliver this by themselves. DNSPs have unique knowledge and insights into their own distribution networks and are well placed to contribute to this integrated planning approach, consistent with their obligations under the AEMC's rule change of improving consideration of demand-side factors in the ISP.
To support implementation of the ESP roadmap if adopted, it is recommended that:

6. DNSPs should work collaboratively to address areas where AEMO will benefit from harmonisation. This is likely to include:

  a. Consistent representation of distribution networks across an expanded set of regional nodes or transmission system connection points

  b. Development of a manageable number of scalable network archetypes for modelling long-term planning outcomes

  c. Provision of standardised data to inform modelling

  d. Common approaches to the characterisation of flexibility.

7. DNSPs should develop the capability to produce accurate parametric representations of their networks suitable for the proposed whole-system planning approach.

8. DNSPs work with AEMO for the development of a co-optimised DSO-TSO framework, incorporating both data exchange and value sharing.

DNSPs have the most detailed knowledge and understanding of their individual networks. This expertise can be combined with AEMO's integrated system planning expertise to support the incorporation of active distribution networks into the ISP. It will be challenging for AEMO to efficiently integrate thirteen diverse distribution systems into an integrated NEM-wide plan. Harmonised common approaches that allow for critical localised differences will assist. Building on their engagement with AEMO in the development of the 2026 ISP, there are clear opportunities for DNSPs to collaborate further in developing consistent, well-considered methodologies to support whole-of-system planning.

To enable accurate parametric representation of active distribution networks in this planning process, DNSPs will require a deeper understanding of their network limitations, and the investment required to unlock distributed energy resources and operational flexibility. This includes technologies and mechanisms such as dynamic operating envelopes, equivalent network models, and active distribution network (ADN) capabilities.

It is recommended that DNSPs continue to build the capability to generate accurate parametric models that align with whole-of-system planning requirements. This may involve improving access to accurate electricity network data, as well as undertaking targeted trials of ADN technologies to assess their technical feasibility and cost-effectiveness.

The electrification of hot water, heating and cooling, and transport is significantly reshaping residential electricity demand profiles. This shift is further influenced by changes in population, demographics, housing stock, appliance efficiency, and evolving consumer behaviours and purchasing preferences. These variables introduce uncertainty and complexity that will evolve over time. The planning frameworks developed under the ESP are designed to assess such factors, incorporating uncertainty and risk to support more robust decision-making.

Beyond long-term system planning, these frameworks offer potential value to DNSPs in their engagement with regulators—especially in identifying opportunities for change and systematically assessing business cases. Notably, the framework developed under ESP WP2.9 offers a structured methodology for evaluating non-network solutions against traditional electricity network augmentation, factoring in the uncertainty and variability introduced by CER and DER adoption.

The ESP has developed a number of methodologies, tools and frameworks to assist with planning, many of which have use beyond just from an integrated system planning viewpoint.

9. DNSPs should evaluate the tools developed under the ESP for use in their own planning.

10. DNSPs should work with AEMC and AER to foster the development of the ESP framework for non-network solution assessment – navigating uncertainties, planning risks and facilitating investment decisions.

While recognising that additional work is necessary, the ESP's bottom-up approach can have a fundamental role in shaping the DSO-TSO narrative, identifying that within all levels of the distribution networks there are opportunities to support the energy transition that could share or reshape the cost burden on consumers and industry more widely.

To achieve this, a harmonised approach to DNSP forecasting and planning is needed. Such an approach must be underpinned by a shift in policy and regulatory frameworks to reflect the active role of CER and DER, and the emergence of bi-directional energy flows. Central to this evolution will be mechanisms that appropriately value consumer assets, behaviours, and choices for all actors, while aiming to deliver consistent and simplified outcomes across network boundaries.

Consumer research undertaken as part of the project highlighted perception of a lack of fairness in their engagement with the energy system. Helping consumers understand the shared value of electricity network participation, particularly when tied to the connection and use of CER, may improve engagement and build trust. Variability in outcomes across adjacent distribution areas presents a challenge, especially for consumers, technology providers, and policy makers. However, long-standing programs such as controlled hot water demonstrate that where third-party coordination can occur without noticeable impacts on service or comfort, consumer acceptance can be high.

CER orchestration offers significant system-wide value, however consumer willingness to participate will depend on the extent to which engagement aligns with their preferences, is perceived as beneficial, and is easy to navigate. Building consumer trust and understanding will be essential to realise this potential.

11. DNSPs to consider working collaboratively within jurisdictions to harmonise communication to customers and minimise difference in CER connection policies and opportunities to participate in network service opportunities.

12. DNSPs to work with policy makers to help communicate the role of DOEs and their advantage for all system users.

13. DNSPs to work with policy makers to build trust with consumers for better engagement of their CER, understanding the benefits of doing so and convey with them how they benefit, ideally with aligned incentives.

6.3 Key considerations and recommendations for policy makers and regulatory bodies

The policy decisions of the next few years will fundamentally impact the energy system investment that will likely shape the sector for decades. Through delivering the ESP research program and extensive engagement activities, C4NET has identified key policy and regulatory gaps and provided insights to guide a fast-tracked strategic approach to addressing them. The project's findings are of broad relevance to existing initiatives and policy formation in all states. Given the direct engagement with the Victorian Government, through DEECA, and the Commonwealth Government, through DCCEEW, the mapping of direct relevance and recommendations have been written in the context of those jurisdictions, but in most cases will be just as relevant elsewhere. A mapping of the ESP program against select initiatives underway in Victoria and Federally are listed in Appendix 6 and the recommendations detailed here are not seeking to replace or replicate actions already underway, instead they are either additional or enhancing.

The ISP review initiated by the ECMC resulted in a number of actions that were published in March 2024. The review recognised the preeminent role of the ISP, and the actions relating to more effective consideration of demand-side opportunities and shift towards a more whole-of-system consideration effectively call for means to address the unlocking of orchestrated CER and DER against other investment options. The ESP's findings strongly contribute to this, laying out a detailed roadmap for the addition of distribution system considerations through a methodological framework for representation of active distribution systems in an evolved ISP.

The ESP has highlighted the criticality of incorporating distribution system considerations in whole of system planning to ensure the lowest cost system. As noted in Section 6.1,

The System Planning Working Group and AEMO to:

a. consider the ESP findings to address optimisation for the demand side, and the roadmap as a key means for implementation of the ECMC ISP action for co-optimisation through incorporation of active distribution systems into future ISPs as a suitable approach to assess cost trade-offs of unlocking increasing tranches of orchestrated CER and DER against other investment options, and priority issues to be addressed; and in parallel

b. commission the development of frameworks for integrated system operation which recognises the future "active" nature of distribution network operations, as well as regulatory and market development to align incentives.

Given the scale of this challenge, AEMO will need time and resources from DNSPs to reasonably consult, adapt and integrate the roadmap. The AEMO ISP team is already challenged with an enormous delivery and continuous improvement schedule which naturally limits their ability to codevelop bigger evolutions in parallel, and the legislative and regulatory requirements they must operate within.

14. AEMC to consider, as part of its upcoming ISP review, whether the current regulations are adequate to allow for this work to progress in accordance with ECMC's expectations for the co-optimisation ISP recommendation.

There is an opportunity to evolve current regulatory assessment frameworks for valuing non-network solutions, as discussed in more detail in Section 5.3. The frameworks should be consistent with the parametric approach in the ESP roadmap for the representation of active distribution systems in integrated system planning and adopt a common and transparent approach to the inclusion of uncertainty and risk as outlined in WP 2.9.

As highlighted in DNSP action 10, AEMC and AER to work with DNSPs foster the development of the ESP framework for non-network solution assessment from WP2.9 – navigating uncertainties, planning risks and facilitating investment decisions.

While the roadmap proposed under the ESP project focuses on the planning elements, there are a number of regulatory and integrated system operational aspects that are current gaps. Other energy jurisdictions around the world are facing similar challenges and there are some informative elements of these that may assist development in Australia.

For the integrated plan to be enacted it needs the accompanying integrated operations of the system. Large assets and aggregated smaller ones will need to be operated in concert with electricity network management to co-optimise to meet the needs of the distribution network and the broader system, and roles and accountabilities of each actor need to be clarified. The evolution of the DSO function and its relationships with the TSO and markets will be critical.

The DSO will have relevance, and different challenges, for each level of distribution networks depending on the degree of interdependency. There may be some learnings from how the DSO incentive governance approach being pursued in the UK.[28]

The DSO function needs to be developed for fuller value capture from integrated system planning incorporating active distribution networks. The DSO function has applicability across the electricity distribution network and should accommodate all aspects from TSO-DSO interface through to coordination of CER in LV networks.

15. AEMC to accelerate the development of comprehensive DSO frameworks in anticipation of broader inclusion of active distribution systems in integrated system planning and operation including associated market development for flexibility, consistent with the CER Roadmap.

And as noted in the previous section, AEMC and AER to work with DNSPs to foster the development of the ESP framework for non-network solution assessment – navigating uncertainties, planning risks and facilitating investment decisions.

28 https://www.ofgem.gov.uk/sites/default/files/2025-03/DSO-Incentive-Governance-Document_v1.2.pdf, accessed 23 May 2025

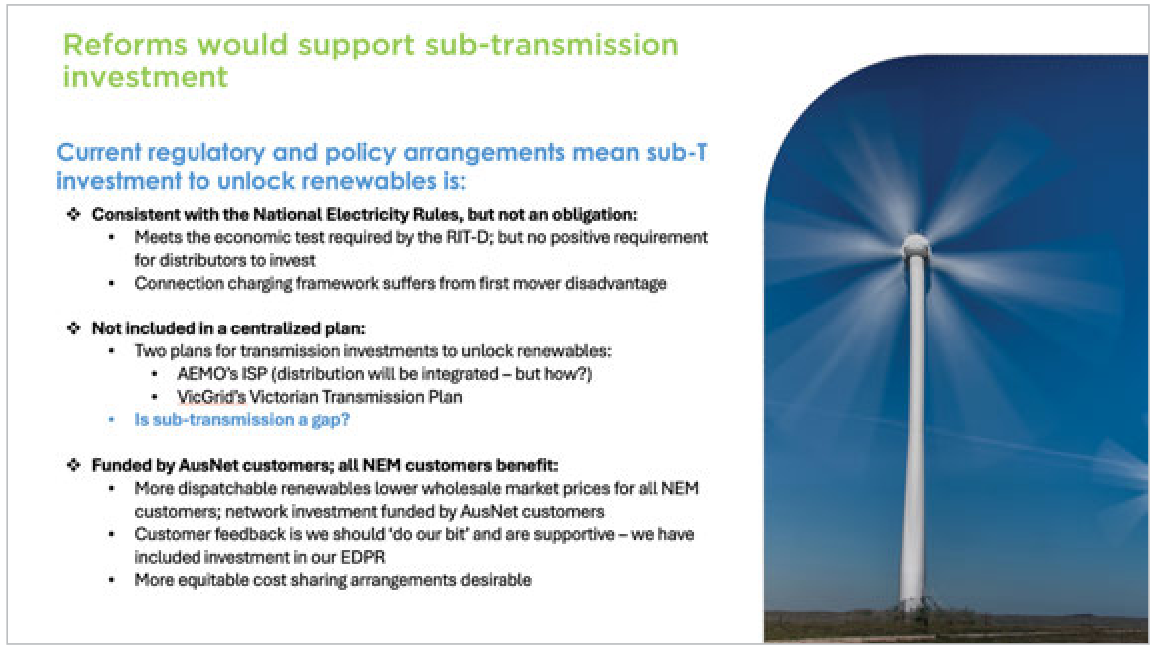


Figure 32: A current case example of impediments to the connection of large-scale generation and storage assets to the sub transmission networks shared by AusNet Services during an ESP webinar

From a regulatory reform viewpoint, there are a number of aspects to address, which is unsurprising given the pace and scale of change within the system already. Examples of the points identified through the conduct of the ESP include:

+ The need for **better alignment of incentives** – orchestration seeks actors to behave in ways that address system issues to lower costs for all. However, there are many cases where the regulatory or consumer pricing landscape either doesn't sufficiently contemplate CER and DER mechanisms or the incentives are just not aligned. For example:
  - The EV Council advise EV owners "*it's better for everyone if you set your EV to start charging later, rather than at 5pm-6pm*"[29] – however for the bulk of retail tariffs there's no incentive for consumers to do this, so why would they?[30]
  - There is an oversupply of solar during the day yet Victorian DNSPs still predominantly have resistive hot water heaters charging at night – where is the incentive for them to move it? There are different approaches for other DNSPs.
  - DNSPs could undertake strategic investments to enable more rooftop solar generation to be connected – but there is no compelling investment case to do so as this isn't sufficiently valued in current assessments
  - DNSPs could unlock system-wide capacity and flexibility to facilitate connection of large-scale generation and storage assets to the sub-transmission networks but have no positive obligation to invest for this purpose.
+ **Market development for flexibility** – the use of flexibility, particularly from storage, can significantly reduce electricity network asset augmentation needs. The what degree this is best addressed by a market-based solution, regulation or some form of hybrid with sharing of value to customers will take time to develop. A stop-gap measure may assist accelerate the connection of storage, and could utilise a mechanism such as a class waiver to kick start DNSP investment in storage. Implementation of aspects of the ESP investment-coupled whole system planning and decision making framework to guide storage investment decisions could address limitations of the current RIT-D test/framework to address first mover disadvantage, broader customer benefits and cost recovery risk.

  In addition, there is little common understanding of the potential for storage to redefine the electricity networks of the future. At present, network capacity is only factored in terms of peak loads, but storage use enables utilisation of assets across a time period to be optimised. Better visibility of the opportunity will come from adding utilisation over time, such as is recommended in the ECA's recent "Integrated Distribution System Planning (electricity) rule change request" submission to the AEMC.[31]
+ **DOE implementation** – the application of DOEs can push up CER connection volumes as electricity networks have greater confidence of network integrity being preserved, and can defer network augmentation (shown in the ESP for both solar export and type-2 EV charging import DOEs). How the available network capacity is allocated as DOEs to consumers in the local area needs to balance fairness and equity with best benefit for all consumers. Whichever way it is decided, it needs to be carefully communicated to consumers as it can be complex, and misunderstanding can lead to unintended erosion of trust and heighten perception of unfairness.
+ **Removal of impediments for the connection of large-scale assets to sub transmission networks** – it appears there are cases where these connections are cheaper, faster and simpler than connection to the transmission system. Incorporation of active distribution networks into integrated system planning and the better alignment of incentives should address the current challenges in the longer term but will take time to implement. Given the urgency of the challenge to connect these assets, where a lower cost and community support are demonstrated regulators are encouraged to implement measures to address existing impediments and the asset recovery test issue, as highlighted in a recent case-study shared by AusNet Services (see Figure 32).

While consumers often express legitimate concerns about external control of their devices, research shows that these concerns tend to diminish when the benefits of coordinated control, such as cost savings, grid reliability, and decarbonisation, are clearly communicated.

The greater the level of interdependency within and across electricity networks, the more important it is to have well-aligned structures to incentivise the preferred behaviour of each actor to lower the costs for all.

16. AEMC could build a program to pro-actively develop better holistic approaches to incentive alignment needs of the future. DNSPs, the ECA and transmission planners could all assist in identifying current and emerging gaps to be addressed. Include both market and non-market means to address.

17. Regulators and governments to adopt stop-gap measures to address the immediate opportunity for preferential connection of large-scale assets to the sub-transmission system where there is a strong economic case to do so.

18. Ensure all transmission expansion cases are compared to viable alternatives in the sub-transmission networks in case a lower cost alternate can be identified.

19. Adopt the recommended additional asset utilisation reporting for all major electricity network assets in transmission and distribution networks, as proposed by the ECA in their rule change proposal.

Policymakers have a critical role to play in shaping consumer understanding of the electricity grid such as its limitations, capabilities, and the impacts of CER. Addressing current perceptions of unfairness and mistrust requires clear, consistent engagement that highlights both individual and community-level benefits of CER integration. While consumers often express legitimate concerns about external control of their devices, research shows that these concerns tend to diminish when the benefits of coordinated control, such as cost savings, grid reliability, and decarbonisation, are clearly communicated.

More complex tools, such as DOEs, are likely to be less intuitive for the average consumer. This presents a clear opportunity for government involvement in public education and engagement, rather than relying solely on DNSPs, retailers, and technology vendors to bridge the knowledge gap. Policymaker intervention can also promote a broader understanding of the communal benefits that come from being connected to the grid. Many consumers remain unaware of how their CER

29 "Guide to charging your EV at home" EV Council - https://electricvehiclecouncil.com.au/a-z-charging/, accessed 23 May 2025

30 Behind-the-meter policy, including Vehicle to Grid and Vehicle to Home, is being addressed through the CER Roadmap

31 https://www.aemc.gov.au/sites/default/files/2025-02/New%20rule%20change%20proposal%20-%20Energy%20Consumers%20Australia%20-%2020250122.pdf, accessed 23 May 2025

systems (e.g., rooftop solar, home batteries, EVs) may impact other users on the network. There is a strong case for ongoing research into consumer behaviour, attitudes, and usage of CER. Programs such as the UK's Energy Systems Catapult "Living Labs", now being piloted in Australia by CSIRO, offer a promising model for advancing this research and informing policy development.

The exchange of data can be facilitated by policy makers through rule changes. DNSPs are tasked with maintaining reliability and resilience in the system yet are blind to network impacting aspects of many industrial sites and CER/DER connected devices, including EV chargers. Better protocols for the free exchange of data reasonably required to operate the system are encouraged as market mechanisms are inefficient and not ubiquitous. The value of the smart meter data in enabling much of this study has further demonstrated the data's value.

As interoperability, system coordination and interdependency increases, so too does complexity. Technology solutions can simplify the consumer facing aspects of that but is much simpler if done so in an environment of trust and faith that the system is delivering fairness and equity. Policy makers, DNSPs and providers of the services, such as retailers and aggregators, have a joint responsibility to build offerings that share value and communicate transparently with consumers.

20. Consider longitudinal consumer sentiment studies relating to CER and develop a better understanding of their adoption of CER services. Policy makers to consider longitudinal consumer sentiment studies relating to CER and develop a better understanding of their adoption of CER services.

21. Policy makers to facilitate the adoption of DOEs in conjunction with DNSP's increasing the inverter size to 10kW that can be connected without further engineering studies. Together with this policy makers should help communicate the value of DOEs to customers and consider differentiated offerings where storage is paired with the solar installation (such as DHW, home battery or EV with degrees of control).

22. Facilitate data access – both to DNSPs for the information they need to best manage the system and from DNSPs to help planners and investors identify opportunities once mechanisms are in place to realise those values.

The breadth and timeliness of this research naturally contributes to many existing government policies and initiatives at both state and federal level. In Appendix 6 we have provided further insights of how the ESP relates to key federal policies, as well as for Victoria which we expect may be relevant to other jurisdictions. The third table in Appendix 6, Strategic gaps for policy-makers, provides some additional recommendations to those outlined in this chapter.

23. Policymakers and regulatory bodies should consider the additional insights and recommendations contained in Appendix 6.

SECTION SEVEN

Conclusions and next steps

7 Conclusions and next steps

The incorporation of electricity distribution system considerations into integrated system planning is becoming increasingly important as we electrify and mass adopt CER. Representing networks as *active distribution systems* has been shown to be valuable and feasible, with the project having demonstrated key foundational methodologies for further development and application NEM-wide. The ESP project has proposed a detailed roadmap for evolution of AEMO's ISP and steps for implementation that contributes actions set out by the ECMC from their ISP review. Implementation is a complex task, but there is no impediment to starting now.

Implementation of the roadmap will evolve integrated system planning and operation to best identify the optimal development pathway considering the whole-of-system assets and capabilities, lowering costs for the energy transition for all users. Having a strategic target agreed will assist current and future rule changes, while policy settings and data exchange frameworks work to a common end-goal and drive efficiency.

Given that implementation will take time, implementing the roadmap as outlined may risk failing to address near-term issues such as how to best connect large-scale solar, wind and storage to meet emission goals. To account for this, the recommendations of the project additionally include nearer-term actions to capture cost savings and speed to implement by connecting such assets to the sub-transmission network while the fuller roadmap is being implemented.

By its very nature, the integrated approach will involve close working relationships between AEMO, DNSPs, policy makers and regulatory bodies to implement. Given the savings potential from CER coordination, consumers will need to be at the heart of any planning. The current regulatory and market structures will need to evolve to better align incentives of all actors, capture the value created and fairly allocate it.

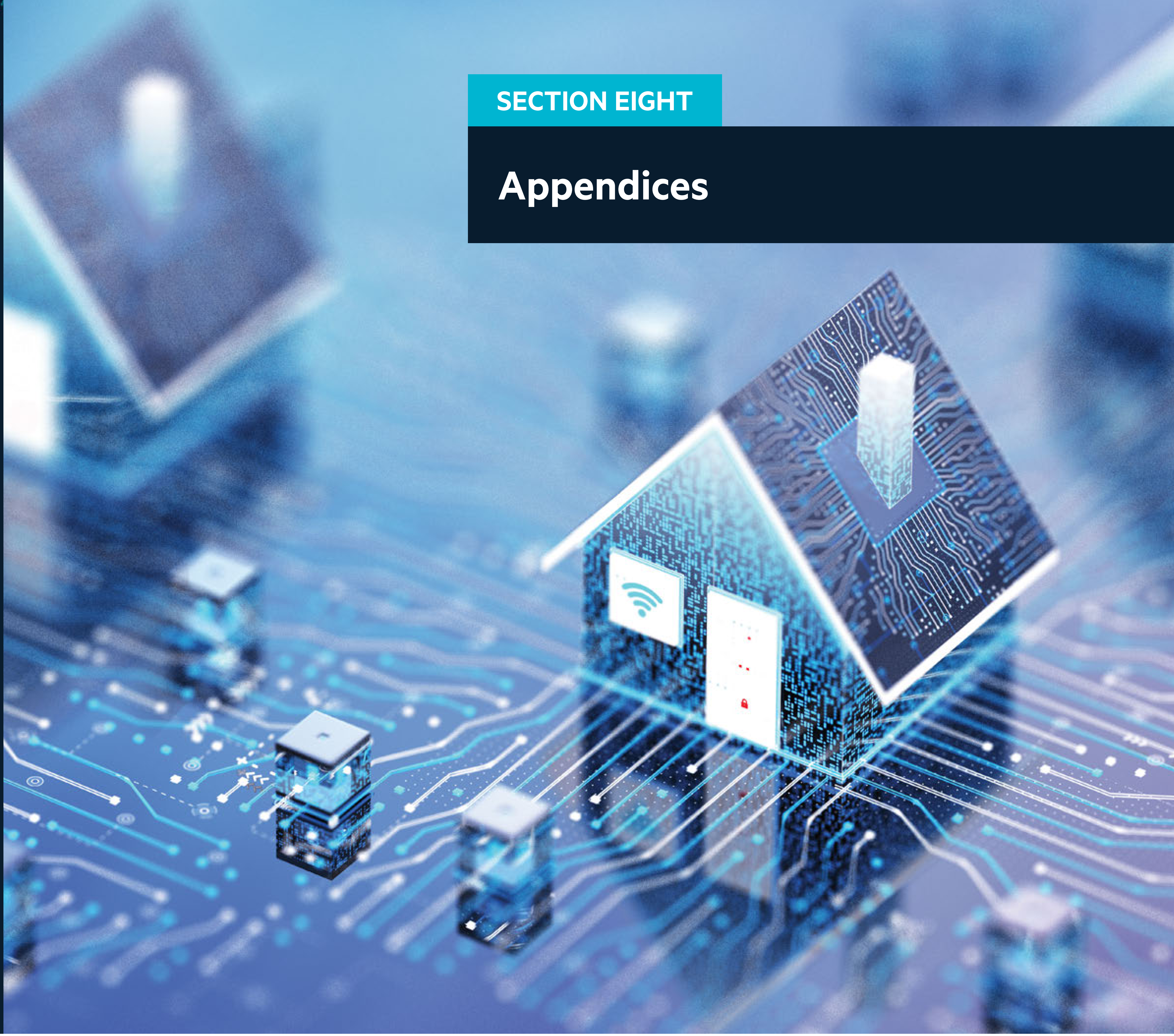
The recommendations have been directed to where C4NET best believes they can be championed across AEMO, DNSPs and policy makers. There are no preconditions or impediments for them to be fully evaluated now and adjusted as needed for implementation. It's a wonderful opportunity to really set the course for the future of our energy system.

Let's get on with it.

SECTION SEVEN Conclusions and next steps

SECTION EIGHT

Appendices



Appendix 1 – C4NET

In 2018 the Victorian Government seed-funded and established C4NET with the goal of building capability through data, modelling and research to address emerging issues across Australia.

C4NET is an industry-led, not-for-profit member-based company. Its members are committed to employing collaborative approaches to solving complex sector-wide challenges from the sector's transition.

The Centre aspires to the vision that the Australian energy sector will efficiently transition to a sustainable, low emission and vibrant industry underpinned by data driven information and new energy deployment – the energy market and grid of the future.

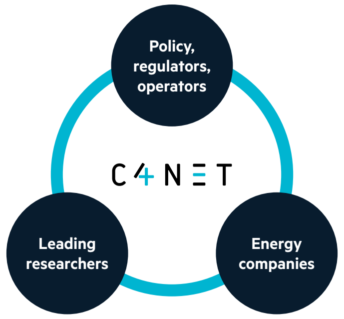
In working towards that vision, C4NET provides solutions for complex sector-based challenges through collaborative works, focussed on:

+ Provision of sound, evidence-based policy support.
+ Advocacy for the use of electricity data to support an efficient energy transition.
+ Enabling the integration of new technologies that lower cost, improve sustainability and deliver value for consumers.

Focussing on the electricity distribution network through to consumer areas of the energy supply and delivery chain, C4NET takes a broad role and has developed the unique function and capability to bring research, government and industry together for collaborative studies, and also as data broker across the energy system to inform a large variety of policy arenas. The value of the energy data available, particularly in Victoria through its ubiquitous advanced metering infrastructure (AMI) smart meter deployment has enabled policy makers to consider a range of factors such as the role C4NET has sought to play to deliver data-driven research, in collaboration with government, industry and academia to address:

+ Data access and utilisation;
+ New energy adoption; and
+ Evidence-based policy & program support.

More information can be found on the C4NET website, www.c4net.com.au.



C4NET Members

Appendix 2 – Governance, collaboration and co-ordination

Governance arrangements for the ESP were established to ensure the program was underpinned by oversight, policy and technical guidance. This was achieved through the following groups and mechanisms.

Steering committee

The steering committee was established to include membership with executive representation from the five electricity distribution networks, the Victorian Government, academia, AEMO and ECA. The Steering committee provided strong guidance on the formation and structure of the project, and ongoing strategic advice through its implementation.

Research Council

Research leads across Melbourne, RMIT and Monash Universities guided the broader approach to research across the ESP, with knowledge of methodological approaches and gaps that could help shape the program.

Technical advisory panel (TAP)

The TAP was appointed to provide technical guidance across projects, to discuss aspects of research approaches that needed more analysis or guidance from a technical perspective through monthly meetings. Membership included senior technical leaders, lead researchers and government representatives.

Policy Advisory Panel (PAP)

The PAP met every 6-8 weeks, to engage and provide insights into the relevance of policy initiatives emerging throughout the life of the project and to understand the possible policy implications of the research as it unfolded. Membership included representatives from DEECA, DCCEEW, AGIG, and others.

Work Package Progress meetings

Each project research teams met with C4NET and industry and government subject matter experts to discuss progress, share insights and outcomes and key concerns, issues etc.

Research Forums

Four all-day researcher forums were held for researchers to share ideas, calibrate between project elements, collaborate and provide peer review.

C4NET

Provided dedicates project roles of Technical Director and Program Manager as well as overall project direction, oversight, management, communications and administration.

SECTION EIGHT Appendices

Appendix 3 – Research and industry collaboration learnings

Research and industry collaboration underpinned the success of the ESP with a combined approach to identifying the most suitable approach to addressing the goals of the ESP. We have shown through the program that there is willingness where there is confidence (learnings across electricity networks, with confidence with data etc.).

A key insight gained through the work program has been the essentiality of:

- clear objectives;
- awareness of the intersection between work packages and the program as a whole;
- regular orientation of status; and
- clear records of meeting outcomes and dissemination of updates.

Of significance, however, was the gap in knowledge and understanding that has become apparent between researchers and industry and across research organisations. This was evident through:

- Lack of appreciation or understanding of knowledge and capability, between researchers and industry
- An inability of some researchers to absorb or be responsive to industry guidance and feedback
- An unwillingness of some researchers to change approach
- Limited knowledge of the broader context of the research work being undertaken by industry and across research institutions
- Change of personnel within organisations leaving gaps in ownership and knowledge or work agreed and underway
- Organisational leadership and dissemination of information leading to minimal engagement across organisations
- Limited foresight by industry.

Appendix 4 – Orchestration opportunities

The growth in intelligent CER across large cross-sections of the residential population provides a wide variety of electricity cost-reduction opportunities for consumers. These opportunities arise principally from being able to align the operation of these distributed resources with the individual premises' energy portfolio, the status of the local electricity network, the needs of the power supply system and the energy market.

Operationalising these opportunities requires a supporting ecosystem which includes proven electricity network and commodity-based technology sets, viable economic business models with agency, regulatory oversight, and consumer acceptance/buy-in.

Network impact assessments and solution research in the ESP program show that a combination and co-optimisation of network-side DER and consumer CER coordination/orchestration solutions could be cheaper than asset investment alone.

This appendix describes various potential avenues for DER/CER to be coordinated or orchestrated to achieve a value-based outcome, some of which have been considered in the ESP research work packages, and noting that there will be consumers with CER who do not want to participate in these schemes, or their involvement will vary depending on their personal preferences or risk-reward appetite.

Asset/Site-based operational boundaries

Asset/site-based establishment of operational boundary conditions via regulation and electricity network service providers is seen a key mechanism to reduce network expenditure. This can also be a catalyst for consumer agents to manage CER assets at an individual site within the set operational boundaries to align with market pricing to reduce consumer costs.

The identified ways to achieve this is currently via:

- Application of technical standards
- Incorporating flexible export limits into Connection Agreements
- Mandating allowable operating ranges via DOEs
- Asset operation coordination (e.g. distributed resource management (DRM) load control of air conditioners, hot water heaters).

Site-based orchestration

In addition to the operational boundary conditions provided by electricity networks, there is an opportunity for site-based orchestration via aggregators or agents with the goal of increasing customer value (while also benefiting themselves). The approach taken could include discretionary load shifting to increase self-consumption of energy generated behind the meter, or to arbitrage the applied tariffs to reduce consumer costs.

The following can also be achieved:

- Use of CER/DER to participate in the energy market
- Use of CER/DER *(particularly stored energy assets)* to provide network services *(includes in front of the meter (FTM) DER assets)*
- Use of CER/DER *(particularly stored energy assets)* to provide system services *(includes FTM DER assets)*

While benefits may be shared through participation in these additional service activities, complex contractual relationships and arrangements may be necessary for consumers to engage with these agents, as in the current market through virtual power plants. Ensuring that there is a simplified market structure with a focus on consumer protections and regulatory frameworks to value consumer empowerment and mitigate detriment will be necessary here.

CER fleet type orchestration

Another opportunity to achieve benefits through service provision is to manage network connected CER "types" (e.g. DHW, EV chargers etc.) as a fleet. This would typically be provided by aggregators or agents, with benefits shared between the agent and customers. It would likely require multiple trading arrangements to be in place, with the added complexity that there may be conflicting value propositions between site and fleet orchestration.

The following could be achieved:

- Use of CER/DER fleet to participate in the energy market *(e.g. V2G)*
- Use of CER/DER fleet to provide network services *(includes FTM DER assets)*
- Use of CER/DER fleet to provide system services *(includes FTM DER assets)*

Multiple trading arrangements translates to multiple contextual points for customers. In reflecting on the consumer preferences and perceptions, ensuring an element of consumer control is maintained and cost is reduced is necessary. Further, principles of simplicity need to underpin an approach such as this.

The following tables explore the above types of potential orchestration opportunities in more detail, noting that most of these are future-facing and not currently fully developed or operationalised.

Network-led 'Orchestration' coupled with CER Site Manager/Consumer Agent applications

APPLICATION	GOVERNANCE REGIME	WHAT'S BEING ORCHESTRATED?	HOW ACHIEVED TECHNICALLY?	WHO IS MANAGING?	HOW IS THE VALUE REWARDED?	COMMENTS
Technical Standards applied to CER inverters	Introduced & managed via AS processes	Connected CER behaviour *(e.g. Volt/VAR and Volt/Watt characteristics)*	Built into Smart Inverter functionality - autonomous operation. No intervention required.	Does not require an active manager. Compliance managed vis AS processes.	No specific value balancing. Results in decreased DNSP expenditure.	Configuration of inverter functionality by installers varies and compliance management is challenging
Direct asset load control via DNSP signal	Managed via National Energy Rules (NER) and Regulatory Framework	Connected CER behaviour *(e.g. A/C control, DHW charge periods)*	DNSP signalling to domestic A/C units (DR Modes) Ripple Control or Smart Meter second element control (DHW)	DNSP manages in accordance with the Regulation	Cash/Tariff/Fee incentive to consumers to participate. Electric DHW Control is "Opt-Out" in Victoria. Results in decreased DNSP expenditure.	Not specifically an orchestration as currently implemented, however is likely to be, in the ESP "Revolution" pathway.
Flexible Exports (FE)	Managed via NER and Regulatory Framework	Connected CER generation behaviour *(e.g. Dynamic ceiling limit for exports of energy to the grid)*	DNSP signalling to Smart Inverters *(coupled to PV and Batteries)* with power measurement at the network point of connection. Site response could be coupled with controllable loads and market pricing by the CER Site Manager/ Consumer Agent.	DNSP manages the FE signalling. CER Site Manager/Consumer Agent manages implementation and operation at the site, including any value-adding. Compliance managed by CER technical standards regulator? (CER Roadmap).	Attractive option for consumers -increased export energy benefits compared to fixed limits. Decreased DNSP expenditure. CER Site Manager/Consumer Agent can align exports with market pricing and share benefits.	Not specifically orchestration. Future related DNSP/DSO "active" network/ system functions could be reflective of orchestrative behaviour *(e.g. enlarge export capacity by active network voltage regulation).*
Dynamic Operating Envelopes (DOE)	Managed via NER and Regulatory Framework	Connected site load/generation behaviour *(e.g. Dynamic limits for exports/imports of energy to/from the grid)*	DNSP signalling to the site management device (e.g. HEMS unit). Site responses include local control of Smart Inverters *(coupled to PV and Batteries),* controllable loads, and alignment with market pricing by the CER Site Manager/ Consumer Agent.	DNSP manages the DOE signalling. CER Site Manager/Consumer Agent manages implementation and operation at the site, including any value-adding. Compliance managed by CER technical standards regulator? (CER Roadmap).	As per Flexible Exports, but expanded to include the Demand side of the envelope. Dynamic operational boundary conditions should enable consumers to connect larger capacities of managed CER.	Not specifically orchestration. Future related DNSP/DSO "active" network/ system functions could be reflective of orchestrative behaviour *(e.g. enlarge export/import capacity by active network voltage regulation).*

Aggregator/Agent led Site CER/DER Orchestration

APPLICATION	GOVERNANCE REGIME	WHAT'S BEING ORCHESTRATED?	HOW ACHIEVED TECHNICALLY?	WHO IS MANAGING?	HOW IS THE VALUE REWARDED?	COMMENTS
Discretionary behind the meter (BTM) load shifting to increase self consumption of generated energy *(or to arbitrage applied Tariffs)*	Contracted arrangement between Customer and Aggregator/Agent.	Connected site load/generation behaviour *(e.g. shift water-heating/EV charging/Battery charging activity to coincide with BTM generation)*	Via Aggregator/Agent home energy management system (HEMS)	Aggregator/Agent *(to align with Customer requirements and preferences).*	Via contractual conditions between the Aggregator/Agent and the Customer	This orchestration focuses purely on individual Customer value and can result in capacity constraints relating to multi-site orchestration activities.
Use of CER/DER to participate in the energy market	NEM rules and processes. Assume future relaxation of requirements for distributed energy participation.	Connected site load/generation behaviour *(e.g. use available site stored energy facilities to provide/absorb energy to/from the grid within a market context)*	Via NEM (or derivative) mechanisms and processes - requires data exchange, signalling etc. between the Aggregator/Agent HEMS and the Market Operator. *(e.g. as per Project EDGE)*	The Market Operator manages the market related activities and processes, and the Aggregator/Agent manages the CER/DER activities.	Via contract between the Aggregator/Agent and the Customer. Note that there would need to be a contractual arrangement between the site retailer and the Aggregator/Agent	Participation in the NEM is onerous and costly, hence it is likely that market participation will only occur when there is a high value opportunity *(e.g. when the spot price is abnormally high)*
Use of CER/DER *(particularly stored energy assets)* to provide network services *(includes FTM DER assets)*	Distributed Services Market (DSM) rules and processes *(future).* Alternatively by Network CER Management Agreement.	Connected site load/generation behaviour *(e.g. Smart Inverter functionality to provide real/reactive power support using available site generation/stored energy/controlled load facilities)*	Via exchange of CER/DER data and control/management signals between DNSP and Aggregator/Agent HEMS. For the DSM, this is achieved via market processes. Under Network CER Management Agreement, communication can be more direct.	DNSP/DSO manages network processes, Market Operator manages DSM processes, Aggregator/Agent manages CER/DER activities. Compliance managed by DSM or by DNSP/DSO	Via DSM or a network "fee for service" arrangement, and as per contractual conditions between the Aggregator/Agent and the Customer.	Use of this application on a day-to-day basis is likely to impact other CER/DER management activities which primarily focus on individual customer benefits rather than communal customer benefits.
Use of CER/DER *(particularly stored energy assets)* to provide system services *(includes FTM DER assets)*	Ancillary Services Market rules and processes.	Connected site load/generation behaviour *(e.g. CER/DER control provides frequency control ancillary services (FCAS)/ other services using available site generation/stored energy/ controlled load facilities)*	Via Ancillary Services (or derivative) mechanisms and processes - requires data exchange, signalling etc. between the Aggregator/Agent HEMS and the Market Operator.	The Market Operator manages the market related activities and processes, and the Aggregator/Agent manages the CER/DER activities.	Via contract between the Aggregator/Agent and the Customer. Note that there may need to be a contractual arrangement between the site retailer and the Aggregator/Agent	Use of this application is likely to impact other CER/DER management activities because of the "reserved" CER/DER capacity for the system service delivery.

Aggregator/Agent led CER/DER Fleet Orchestration

APPLICATION	GOVERNANCE REGIME	WHAT'S BEING ORCHESTRATED?	HOW ACHIEVED TECHNICALLY?	WHO IS MANAGING?	HOW IS THE VALUE REWARDED?	COMMENTS
Use of CER/DER fleet to participate in the energy market *(e.g. V2G)*	NEM rules and processes. Assume future relaxation of requirements for distributed energy participation.	BTM asset type load/generation behaviour *(e.g. use available site stored energy facilities to provide/absorb energy to/from the grid within a market context)*	Via NEM (or derivative) mechanisms and processes - requires data exchange, signalling etc. between the Aggregator/Agent HEMS and the Market Operator. *(e.g. as per Project EDGE)*	Market Operator manages market related activities and processes. Fleet Aggregator/Agent manages the specific CER/DER asset activities. CER Site Manager ensures compliance at network PoC.	Via contract between the aggregator/agent and the customer. Note that there would need to be a contractual arrangement between the site retailer and the aggregator/agent.	Participation in the NEM is onerous and costly, hence it is likely that market participation will only occur when there is a high value opportunity *(e.g. when the spot price is abnormally high)*
Use of CER/DER Fleet *(particularly stored energy assets)* to provide network services *(includes FTM DER assets)*	Distributed Services Market (DSM) rules and processes *(future).* Alternatively by Network CER Management Agreement.	Connected asset type load/ generation behaviour *(e.g. Hot Water Heating control at a fleet level to provide voltage management support)*	Via exchange of CER/DER data and control/management signals between DNSP and Aggregator/Agent systems. For the DSM, this is achieved via market processes. Under Network CER Management Agreement, communication can be more direct.	DNSP/DSO manages network processes, Market Operator manages DSM processes, Aggregator/Agent manages CER/DER activities. CER Site Manager ensures compliance at network PoC.	Via DSM or a network "fee for service" arrangement, and as per contractual conditions between the aggregator/agent and the Customer.	Use of this application on a day-to-day basis is likely to be complex in that the specific CER/DER asset behaviour has to align with other CER/DER activities at the site so as not to infringe PoC compliance.
Use of CER/DER Fleet *(particularly stored energy assets)* to provide system services *(includes FTM DER assets)*	Ancillary Services Market rules and processes.	Connected asset type load/ generation behaviour *(e.g. CER/DER control provides FCAS/other services using available asset generation/ stored energy)*	Via Ancillary Services (or derivative) mechanisms and processes - requires data exchange, signalling etc. between the Aggregator/ Agent systems and the Market Operator.	The Market Operator manages market related activities/processes, the Aggregator/Agent manages the specific CER/DER asset activities, CER Site Manager ensures compliance at network PoC.	Via contract between the aggregator/ agent and the customer. Note that there may need to be a contractual arrangement between the site retailer and the aggregator/agent.	Use of this application is likely to impact other CER/DER management activities because of the "reserved" CER/DER capacity for the system service delivery.

SECTION EIGHT
Appendices

Appendix 5 – Flexibility

A common theme emerging from the ESP research is the potential role that coordinated or orchestrated DER and CER can play in an integrated system planning context (and in actual operations) to reduce whole-of-system costs and increase investment efficiency by introducing "flexibility" into the distribution system at multiple levels.

In the context of this document, "flexibility" is the time-varying ability of participants and users within the electricity supply system to adjust electrical load, generation, or to affect the transfer of power, in positive response to a system or network stimulus. This ability can be loosely grouped into two categories:

1. where adjustment can be accommodated within a normal operating envelope, and
2. where adjustment requires operation outside normal operational boundaries.

Examples of (1) are charging/discharging energy storage assets within an acceptable state of charge (SoC), provision of reactive support by inverter coupled DER/CER, dynamic network voltage control using transformer OLTC facilities and other reactive plant.

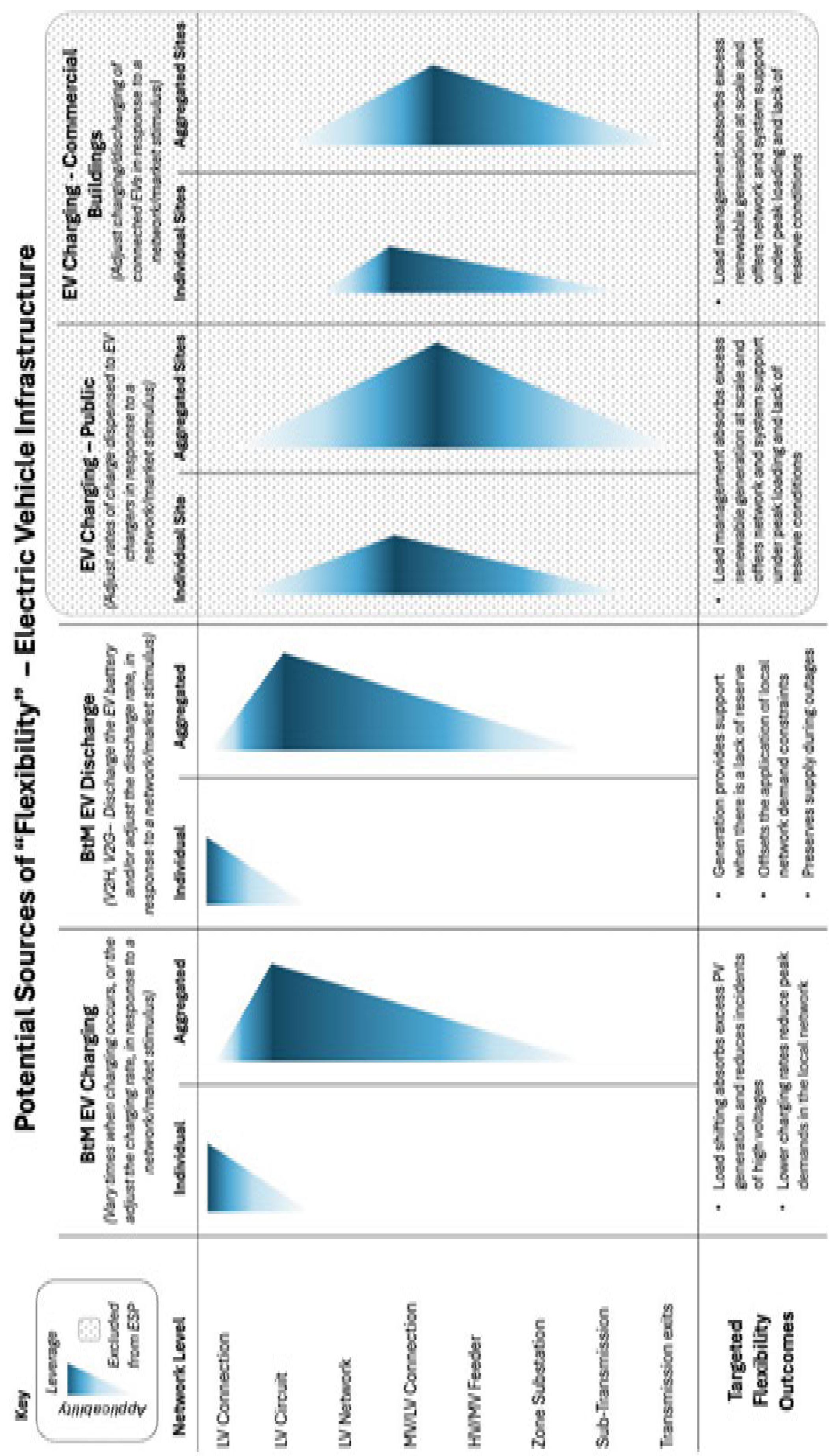
Examples of (2) are forced load shedding, load shifting resulting in unacceptable outcomes (e.g. EV not ready to drive when needed, lack of hot water when needed), generation curtailment beyond acceptable levels (e.g. preventing behind the meter generation from servicing local behind the meter loads).

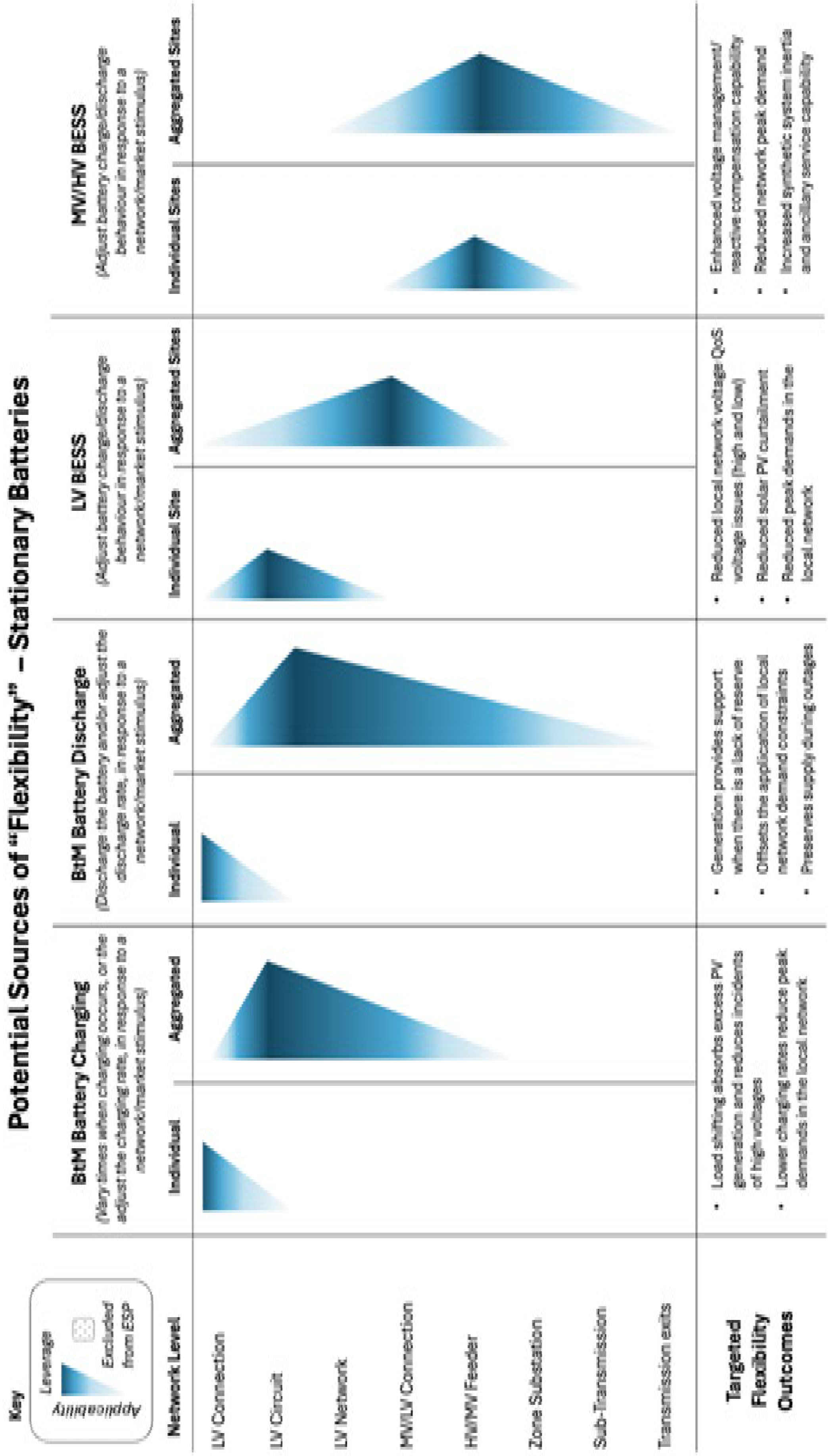
A further consideration of this ability is the temporal nature of the response – the capacity to deliver levels of response for specified time durations, as well as whether flexibility response actions affect subsequent operating profiles (e.g. load shifting of EV charging affects later network demand profiles).

The ESP research has considered category (1) flexibility with various assumed temporal response characteristics.

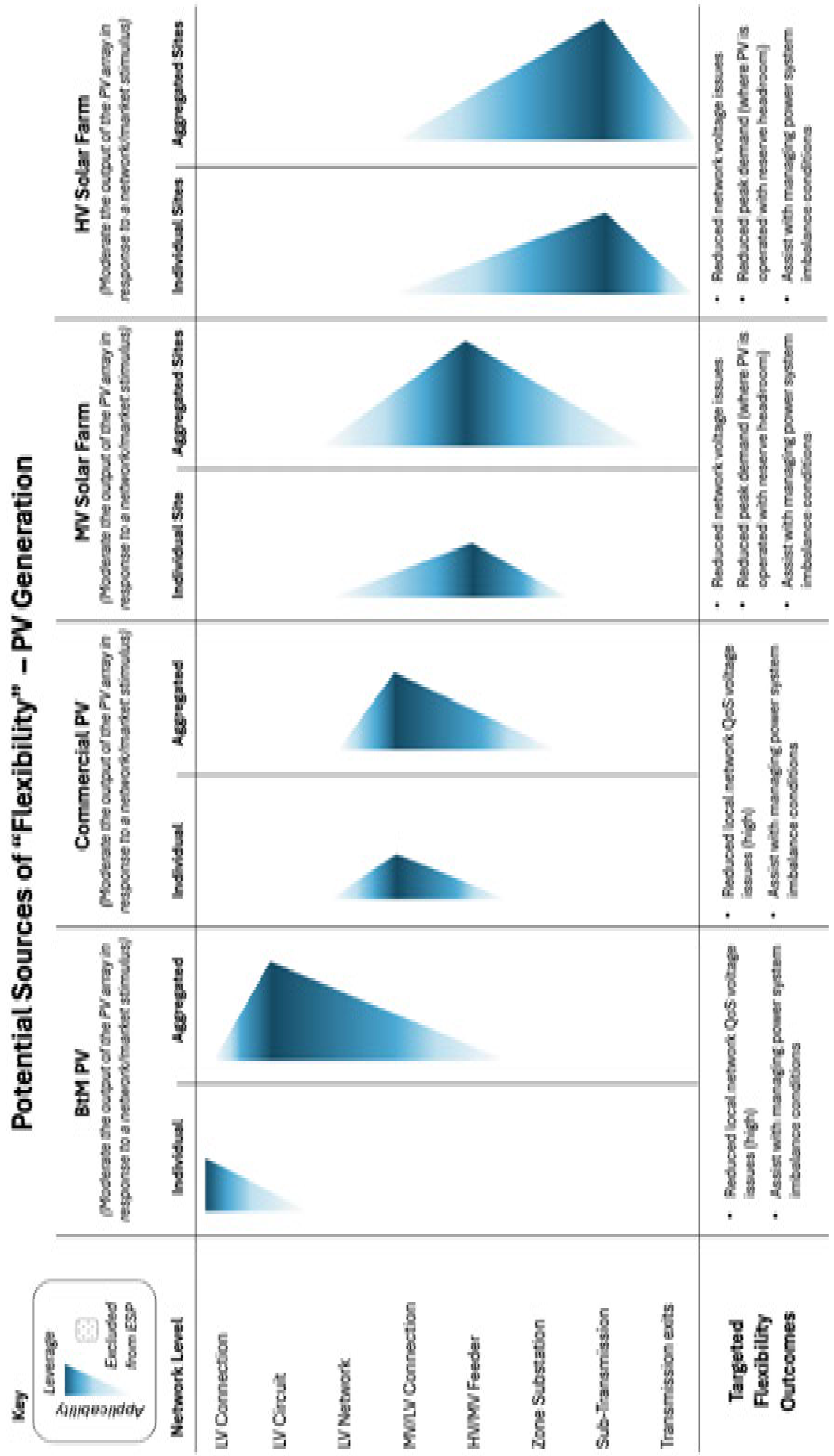
The purpose of this document is to add further colour to aggregation opportunities and various flexibility related outcomes from the ESP research, by briefly illustrating the variety of ways that flexibility can be created, what outcomes are targeted, and how it could play out across the distribution network.

Managed or coordinated DER/CER energy storage is a prime potential source of flexibility in the electricity supply system. The following two tables illustrate the various ways that this might apply in future.





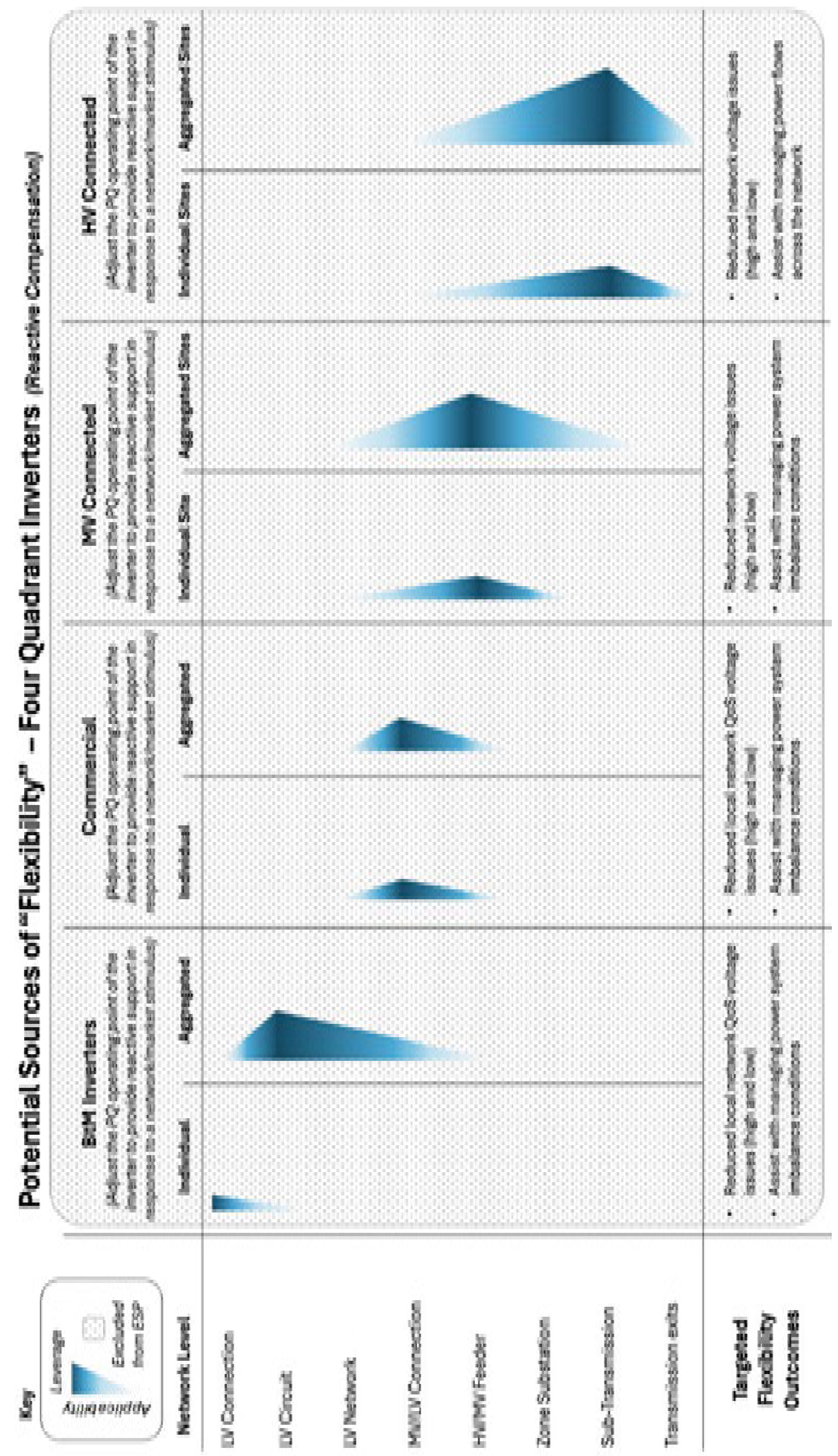
Renewable generation in the form of solar PV and wind, although exhibiting a high degree of uncontrolled variability and subject to intermittency, can also be a potential source of flexibility if coordinated with network, system and market conditions. The following table illustrates the various ways that this might apply in future for PV systems.



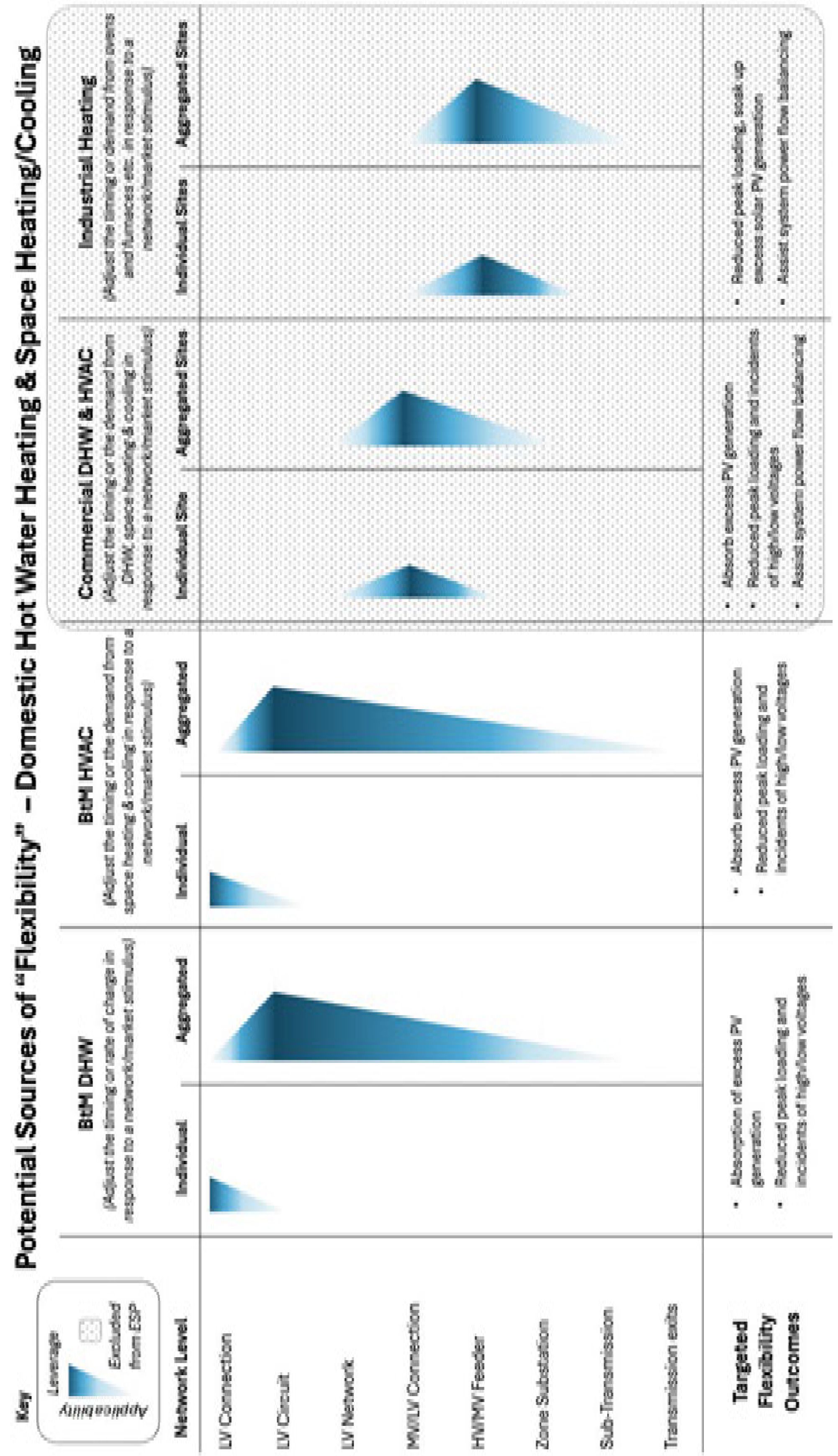
The vast majority of generation-centric DER and CER connected into distribution networks are inverter coupled. Increasingly, these inverters offer four quadrant power capability, which means they can adjust the real and reactive power composition of the output to offer the attributes of a full circular power characteristic (subject to the capability limits of the device) to suit a particular purpose. This naturally creates a source of flexibility which can be very efficient.

An example of this is where solar PV inverters can be configured to supply/absorb reactive power at night. This reactive power can be produced or absorbed at near zero real power production, ignoring the small amount of real power required by the inverter electronics (i.e. having an operating point approaching +/- 90 degrees in the circular power characteristic).

Although not considered in the ESP research, the following table illustrates the various ways that this might apply in future across the population of inverters.

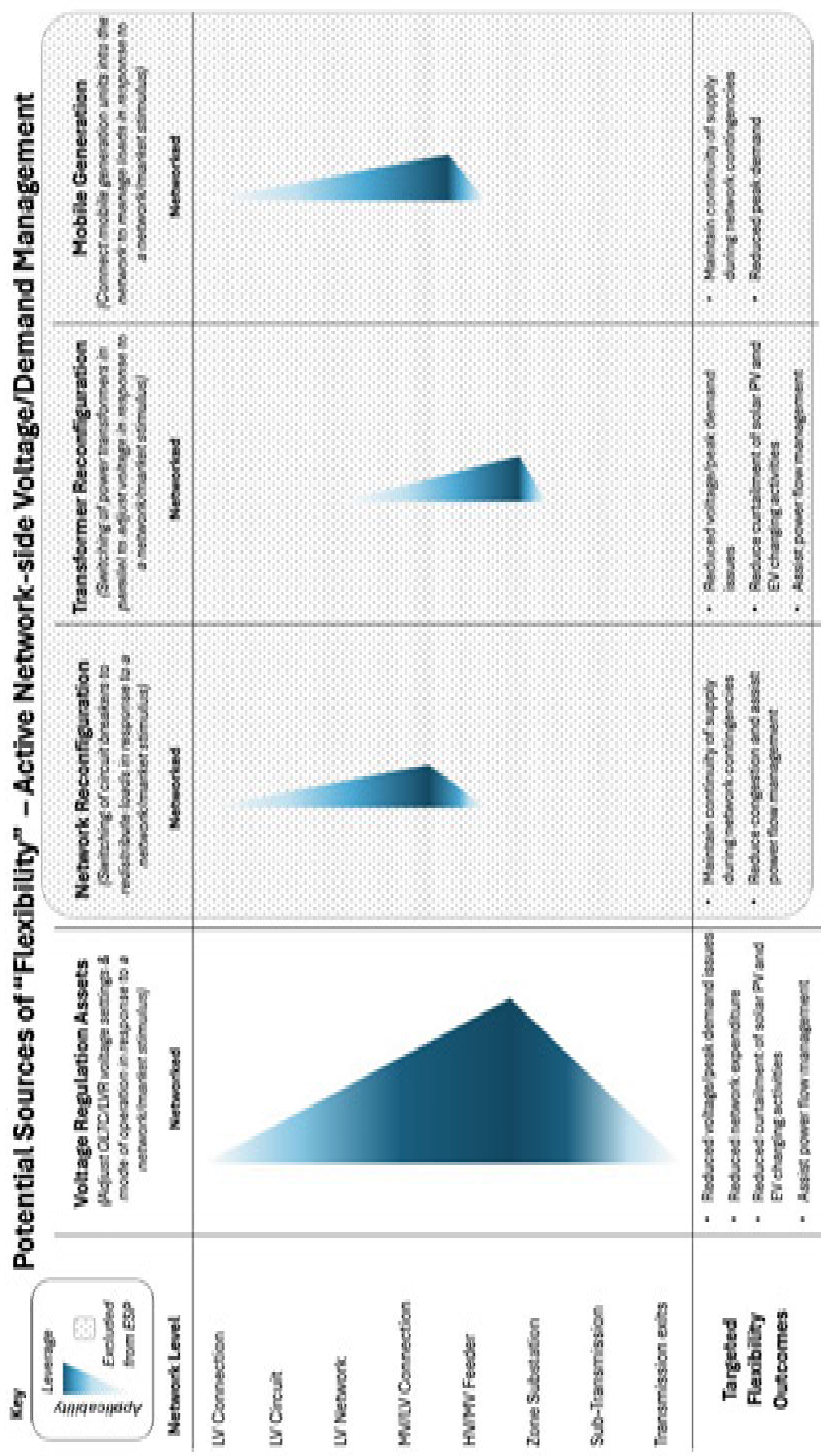


Another potential source of flexibility comes from the transition from gas to heat-pump technologies for domestic hot water heating and space heating/cooling. This is an area which can be significantly influenced by personal preferences and consumer override activities, however at scale it can have material benefits. The following table illustrates the various ways that this might apply in future across the different applications.



Lastly, the distribution networks themselves have inherent sources of flexibility that can be utilised for specific purposes. Much of these capabilities are already applied by DNSPs as part of their normal regulatory obligations, however these applications are typically limited to managing distribution network voltages, power flows and congestion, and they do not directly consider the wider “system” or market conditions. Although there is often a strong positive correlation between the distribution network management activities and the system/market needs, the opportunity exists to broaden the application of these assets to consider whole-of-system benefits and efficiency.

The following table illustrates several ways that this might apply in future across the different assets.



Appendix 6 – Policy mapping

ESP Alignment to national objectives | ECMC response to ISP review actions

ALIGNED ACTIONS FROM ECMC RESPONSE	ESP ALIGNMENT
1. **Enhanced demand forecasting** AEMO should enhance demand forecasting in the 2026 ISP by: + Developing a framework, methodology and guidance material to support DNSPs and jurisdictions to develop projections and undertake analysis in a consistent manner to support the ISP’s development + Undertaking targeted stakeholder engagement to enhance assumptions underpinning consumer energy resources (CER) and distributed resources projections in the ISP. The assumptions should reflect a comprehensive view of initiatives affecting CER and distributed resources uptake and evaluate the implications for operational demand. + Analysing how electrification and CER / distributed resources development sensitivities affect operational demand projections and consider these directly in the ISP modelling where relevant. + Subject to available information, analysing how distribution network service provider (DNSP) investments, programs and annual plans, may impact CER and distributed resources development, and thereby the Optimal Development Path (ODP) for transmission, and include these findings in the ISP in order to send clearer signals to inform DNSP planning.	Framework, methodology and harmonised assumption development: + For residential and light commercial network demand forecasting, including the operational demand implications of the transition to - 100% EV uptake - Electrification of domestic gas usage - Incorporates impacts of full CER/DER adoption + That is physics based, highly granular and co-designed with multiple DNSPs + Complements ISP in anticipation of whole-of-system design needs + Informs critical upcoming policy choices, market and regulatory design challenges and asset planning options + That is of modular design for scalability to all Australian regions + **Opportunity to develop multi-ISP roadmap for incorporation of full distribution considerations (demand, hosting and flexibility) codeveloped by AEMO and distribution businesses**
2. **Better data on industrial and consumer electrification** Jurisdictions and AEMO will work together to ensure the provision of key inputs for the 2026 ISP that includes information about relevant jurisdictional policy developments and scenarios and projections about industrial and consumer electrification demand in NEM sub regions	ESP focuses on the impact of consumer electrification having considered jurisdictional policy developments and models impact at sub-regions in a highly granular method (down to representative feeder-type).
3. **Optimising for the demand side** The System Planning Working Group and AEMO will work with the relevant stakeholders, including DNSPs, to develop a suitable approach to trade off the cost of unlocking increasing tranches of orchestrated CER and distributed resources against other investment options for use in the earliest ISP practicable.	+ **Framework for valuing both asset augmentation and non-augmentation solutions factoring in uncertainty for NEM-wide application developed** + **Investment coupled scalable methodology for informing orchestrated CER, plus DER (including connections through to sub-transmission level)** + **multi-ISP roadmap as outlined above**

SECTION EIGHT Appendices

SECTION EIGHT Appendices

ESP relevance to national energy policy strategies and frameworks

NATIONAL ENERGY STRATEGIES / FRAMEWORKS	ESP RELEVANCE
Powering Australia: DCCEEW	Planning to optimise sub-transmission storage on the distribution network is critical to meeting emissions reduction targets: the ESP explores and assesses the viability while the Climate Change Authority's 2024 Annual Progress Report32 has also flagged the importance. ESP also demonstrated how burden of future electricity transmission development and costs can be reduced.
Rewiring the Nation - DCCEEW	Adopting the ESP approach can provide new planning and techno-economic information to support the selection of optimal distribution network-related projects from the $20 billion Rewiring the Nation fund to modernise the electricity grid and deliver new and upgraded grid infrastructure across Australia.
Grid Enhancing Technologies for Electricity Networks (GETS) - DCCEEW	Innovations and techno-economic insights from projects that emerge from the $30 million GETS competitive grants funding program (commencing from 2025) would serve as valuable input data for optimising non-network solutions across the transmission and distribution interface, as enabled through an ESP approach.
National Energy Performance Strategy (NEPS): DCCEEW	Demand flexibility is a key aspect of energy performance and ESP research outlines why planning is required and what is needed to optimise flexibility in the distribution network. ESP is aligned with addressing most of NEPS supporting actions.
Trajectory for Low Energy Buildings: DCCEEW	National Construction Code (NCC): 'Grid impact and optimisation' is noted as a key consideration for NCC 2028 modelling where the primary focus is on residential buildings. ESP specifically addresses this area.
Future fuels and vehicles strategy (FFVS): DCCEEW	ESP demonstrates planning needed and provides insights to support the FFVS objectives of ensuring the electricity system is EV-ready.
Future Gas Strategy (FGS): DCCEEW	ESP provides insights to the extent, and a planning approach to optimise, electrification options to provide greater choice. Given this in turn impacts household gas demand it is a relevant consideration for the FGS updates and implementation.

32 https://www.climatechangeauthority.gov.au/sites/default/files/documents/2024-11/2024AnnualProgressReport.pdf, accessed 23 May 2025

Strategic gaps for policy-makers

WHAT	WHY	WAY FORWARD
Clarify/implement DSO role, governance and incentives as a matter of urgency then refine as needed	Without clear governance, accountabilities and incentives, 'active' distribution system capability is unlikely to emerge in a responsive cohesive way across Australia to meet CER/customer needs	+ UK's DSO approach provides learning by doing insights – particularly the latest guidance regarding DNO/DSO obligations. + Also Appx 1 DSO Baseline Expectations (pp 28-35) & recent changes + ESP insights useful to shape Australian requirements along with CER Roadmap initiatives
Clear the way for cost effective sub-transmission storage	Storage needed to meet net zero and provide flexibility will not be delivered and optimised in time without removing the barriers to distribution network investment in flexible storage solutions. Climate Change Authority has noted via recommendation 4 in their 2024 annual progress report as critical for achieving net zero targets on time (CCA also via C4NET ESP webinar).	+ Class waiver for distribution network battery storage ownership to get market started and evolve over time + Implementation/refinement of ESP decision making framework to guide storage investment decisions (including addressing limitations of RIT-D test/framework to address first mover disadvantage, broader customer benefits and cost recovery risk). + Eg AusNet Services case study from 30 Apr 2025 C4NET webinar
Provide additional research insights to foster innovative tariffs/pricing and consumer acceptance	Continue to explore, refine and feed additional data into demand forecasting methodologies, DOE integration considerations and other market facing insights which influence industry to pursue electricity network and retail tariff design/innovation and aggregation opportunities and test consumer acceptance. eg. Living Labs, UK Energy Systems Catapult.	+ Sharing ESP reports with energy sector stakeholders, including the AEMC to inform their tariff reform consultations. + DCCEEW funding further research via universities and/or CSIRO (currently exploring Living Labs in Aus)
ISP integration of distribution system considerations	This has been recognised as a gap by ECMC's ISP review and is in the early stages of being raised for consultation by AEMO in ISP 2026. C4NET identified this gap prior to this and our work in partnership with Vic DNSPs, AEMO and universities provides a useful base to inform and fast-track design and implementation.	+ Anticipating ISP 2026 & upcoming electricity network options consultation + Needs some sort of partnership that drives innovation and accountability to evolve distribution system planning/integration – perhaps a joint research initiative between AEMO-CSIRO and distribution business representatives, with accountability to ECMC
Future resourcing of integrated planning	C4NET has filled a necessary gap to start things, however without obligations and incentives on the relevant parties the skills/capabilities won't be able to be provided for in a timely way (often too many competing near term priorities).	+ Obligations and incentives (as above) should assist in providing the signals to DNSPs to dedicate appropriate resources, however policy-maker attention will likely be required to ensure the new capability/resourcing is available at AEMO to enable effective integration.

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ESP mapping to the CER Roadmap

CER WORKSTREAM	OUTCOME	ESP RELEVANCE
Consumers		
C.2 More equitable access to the benefits of CER (2024: 2027)	1. *Development of options (2025) and implementation of selected options to deliver more equitable access to the benefits of CER for all consumers.*	+ ESP demonstrates that when coupled with an "active" distribution system, the connection and coordination of solar, wind and storage at the sub-transmission level will ease the investment challenge in the transmission network and reduce overall system costs. Modelled savings of over 25% are illustrated in WP3.12 case studies which would represent multi-billion-dollar savings if valid more broadly across the NEM. It has also been demonstrated that coordination of CER at the fringe of the grid can also have a material benefit upstream and also contribute to reducing overall system costs.
C.3 CER information to empower consumers	1. *Communication framework and strategy to ensure CER participation is compelling and easily understood by all consumers.* 2. *Consumer support to empower consumers in a high CER future.*	+ ESP highlights a viable pathway to enable greater CER participation via an active distribution system. While consumers don't need to understand the detail, it will be helpful from a trust building and communications perspective for them to know that every reasonable effort is being made to provide a CER-ready grid. Conversely, if ESP-like measures are not taken proactively, consumer trust can erode. + ESP WP1.3.2 also investigated consumer perceptions of policies designed to encourage the adoption and management of CER in Australia and underscored the importance of policies that both encourage CER adoption and ensure consumer willingness to allow some external management of their CER.
Technology		
Other	1. *Jurisdictions review their own technical or regulatory frameworks and remove barriers for consumer adoption of vehicle to-grid opportunities.*	+ ESP highlights that the impacts of electrification of gas and transport will push most low voltage electricity network assets beyond their current limits and solar curtailment will be material within the next decade (WP1.5/6). Consideration should be given to expanding class waivers or other forms of exemption to enable DNSPs to scale distribution system storage through ownership and leasing to third parties to realise network and market benefits for consumers. + AER/AEMC and DNSPs are urged to develop common model frameworks in line with the illustrative prototypes developed under the ESP project in WP3.13 for asset and solution assessment efficiently capturing uncertainty, while allowing total system benefits to be assessed in the RIT-D test. + Lack of adequate planning is a barrier: distribution system considerations are critical for whole of system planning and must be integrated as a priority (WP3.14).
Markets		
M.1 Enable new market offers and tariff structures to extract greater benefits from CER		+ With more data and validation, ESP methodologies developed in WP1.1 & 1.2 to assess the impacts of electrification of heating/cooling demand and transport have the potential to be used to inform future electricity network tariff design and structures.
M.2 Data sharing arrangements to inform planning and enable future markets	1. *Establish data access rights, metrics and processes for collection and sharing of CER and relevant network data to be used for effective investment decisions and compliance with CER standards and utilisation in the market.*	+ ESP has collected a wide range of useful datasets to demonstrate what network data is needed (across all WPs), as well as developing methodological frameworks to consider investment decisions.
M.3 Redefine roles for market operations	1. *Define the roles and responsibilities of distribution level market operation and drive alignment of incentives between market participants for CER integration.*	+ ESP demonstrates the need to clearly define the functions and capabilities required for effective distribution system operation, defining key capabilities and data requirements without specifying which organisation should assume specific responsibilities (WP3.14). Key capabilities must be identified to ensure efficient system operation, focusing more on what needs to be done rather than on assigning roles to particular entities. + There is a need for increased consideration, analysis, and valuation of non-network solutions and the management of CERs by DNSPs as part of their planning and operational frameworks. DNSPs may need to consider the development and application of active distribution network/system functionalities that align with and integrate into broader system needs to leverage the increased flexibility within the distribution network. + WP2.10 has developed a techno-economic model that has the capability to quantify the incentives that may be needed to offer consumers to compensate for use of their storage assets.

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CER WORKSTREAM	OUTCOME	ESP RELEVANCE
M.3 ct'd	1. *Define the role of DNSPs to achieve equitable two-way market operations, including in owning/operating community batteries and kerbside EV chargers, and other distributed resources.*	+ While ESP doesn't look specifically at the role of DNSPs, WP 2.7 and 2.8 analysed the effectiveness of three different CER instruments for CER flexibility management in mitigating distribution network congestion and voltage issues: community batteries, EV charging through solar soaking, and vehicle to grid technology. The findings of this work showed that, in the longer-term, all of these CER instruments would be required to mitigate the electricity network issues arising from the increased electrification. + In parallel, WP 2.10 focuses on conducting a comprehensive techno-economic analysis to evaluate the benefits of integrating different storage solutions within distribution networks — including EV, thermal storage, and household- and community-owned batteries — across multiple future scenarios. By doing so, WP 2.10 seeks to identify synergies among storage technologies and other distributed energy resources, enhancing system flexibility and resilience.
Power systems operations		
P.1 Enable consumers to export and import more power to and from the grid	1. *Fast track implementation of flexible exports component of dynamic operating envelopes (DOEs) by network operators to enable increased CER flexibility, third party participation and maximise benefits to the system and customers.* 2. *Future work: Full implementation of dynamic operating envelopes that addresses dynamic imports.*	+ WP 1.5 used electrified heating/cooling and EV charging profiles from other ESP work packages to assess the impact of electrification on medium-voltage and low-voltage parts of different types of distribution networks under various scenarios with different distributed energy resources technology mixes and management strategies. The developed multi-scenario power flow analysis was then used to demonstrate the effectiveness of both import and export DOEs in improving DER operation and mitigating electricity network issues. Combined application of levers/measures that protect network integrity, such as DOEs, together with tariffs and market function (or proxies), were shown to optimise network utilisation and lower the network cost impact of electrification.
P.3 Improve voltage management across distribution networks	1. *Examine costs and benefits of improving voltage management across distribution networks to lower costs for consumers.* 2. *Future work: Consideration of costs and benefits to determine best approach for consumers, to improve network voltage management.*	+ WP 1.5 demonstrated the effectiveness of both import and export DOE in improving DER operation and mitigating voltage issues. + WP 2.7 and 2.8 analysed the effectiveness of three different CER instruments for CER flexibility management in mitigating distribution network congestion and voltage issues.
P.4 Incentivising distribution network investment in CER	1. *Pathways identified to further incentivise distribution network investment frameworks to efficiently utilise CER and optimise network assets.*	+ The degree of CER coordination can substantially influence the extent to which transmission and distribution infrastructure, as well as utility-scale storage investments, can be displaced or deferred. In essence, an integrated transmission and distribution planning framework that considers the flexibility of CERs can identify optimal trade-offs between electricity network infrastructure investments, on the one hand, and the degree of coordination and its associated costs, on the other. The cost of CER coordination includes the cost of communication and control infrastructure needed to enable this coordination, and possibly economic incentives to increase CER adoption.
P.5 Redefine roles for power system operations	1. *Define the roles and responsibilities of power system operation with high CER and drive alignment of incentives between industry actors for CER integration for agreement by Energy Ministers.*	+ See M.3 for related content.

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ESP alignment with Victorian Government policies

- ESP supports the plan to reach 95% renewable energy by 2035 and beyond, and the Victorian Minister for Energy's commitment that: "Victoria's electricity transition will deliver **clean, affordable, reliable and secure** electricity for all Victorians"
- ESP supports and enhances up to 15 out of 23 actions under the four pillars of the **Cheaper, Cleaner, Renewable Plan**

1 Enabling the renewables big build

- A1.1 Building energy storage to support more renewables
- A1.3 Coordinated transmission planning
- A1.4 Expanding and modernising the transmission network
- A1.5 Improving planning and approval processes to provide better and more timely outcomes

ESP VALUE ADD

Planning and optimising cost-effective DER/CER and flexibility in distribution (D) and reducing the burden of future transmission (T) needs

2 Empowering households and businesses to lower energery bills

- A2.1 Helping households, communities and businesses access distributed energy resources
- A2.2 Driving the uptake of zero emissions vehicles.
- A2.3 Protecting consumers and supporting grid stability through regulatory reform
- A2.4 Improving the functioning of distributed energy resource markets
- A2.5 Decarbonising homes and businesses
- A2.6 Supporting households and businesses to electrify

ESP VALUE ADD

Integrated system planning (D + T) and active distribution network systems provides the flexibility to host greater DER and CER at a lower overall system cost

3 Managing the transition away from fossil fuels

- A3.2 Maintaining targeted gas use during the transition
- A3.3 Working with AEMO and industry to ensure reliability
- A3.4 Enhancing energy safety and network resilience

ESP VALUE ADD

Enhanced integrated planning capability, tools and systems to collaboratively deliver energy transition outcomes (eg Victorian Gas Substitution and Zero Emissions Vehicle Roadmaps)

4 Creating jobs, skills and supply chains

- A4.1 Strengthening local renewable electricity supply chains
- A4.2 Developing the Victorian Energy Jobs Plan and the Women in Energy Strategy

ESP VALUE ADD

Supports an evolution to more localised energy planning and improves confidence for renewable energy investment and jobs

Key Victorian Government policies: ESP relevance & next steps

Gas Substitution & Zero Emission Vehicle Roadmaps

ESP INSIGHTS

- Electrification of gas and transport will push most low voltage network assets beyond their current limits within the next decade.
- Solar curtailment will be material

NEXT STEPS

Encourage investment in active distribution network systems to unlock DER/CER flexibility to cost effectively mitigate impacts

Victorian Transmission Plan (VTP)

ESP INSIGHTS

- Cost burden of future transmission needs could be significantly eased; modelled case shows 25% savings
- Supports social license outcomes

NEXT STEPS

Consider how ESP methodologies could be used to broaden future VTP option considerations to incorporate integrated distribution planning, taking learnings from ESP and ISP 2026

Victorian renewable energy and storage targets

ESP INSIGHTS

- Potential for 2035 targets to be met more cost effectively lowering total system and hence consumer costs

NEXT STEPS

- Policy measures to encourage investment in sub-transmission level storage include:
- Requesting class waiver from the AER to enable DNSPs to own and lease batteries to 3rd parties to enable network and market benefits
- Reforming relevant regulations (eg RIT-D) to incorporate system level benefits

ESP = Vic leadership for key national reforms

ESP INSIGHTS

- Provides key methodological and supporting evidence base for implementing ECMC ISP action
- Demonstrates how CER Roadmap and National Electric Vehicle Strategy outcomes can be further supported by integrated planning
- Quantifying the value of distribution system flexibility also important to inform NEM market design and efficient operation

NEXT STEPS

Continue advocacy of, and changes to support detailed whole-of-system planning being adopted at national level.

Appendix 7 – Glossary of terms

ADMD	After Diversity Maximum Demand – This is a measure of the highest demand averaged across all customers at peak time and informs network design and capacity available for connections.
AEMC	The Australian Energy Market Commission
AEMO	The Australian Energy Market Operator
AER	The Australian Energy Regulator
AMI	Advanced Metering Infrastructure
BESS	Battery Energy Storage System (battery with integrated PCE/inverter)
C4NET	Centre for New Energy Technologies Ltd
CER	Consumer Energy Resources – DER that is located on the consumer side of the meter
DCCEEW	The Commonwealth Department of Climate Change, Energy, the Environment and Water
DEECA	The Victorian Government's Department of Energy, Environment and Climate Action
DER	Distributed Energy Resource, such as renewable generation assets like solar and wind, and energy storage
DER Register	A register of DER devices as collated by AEMO across Australia
DHW	Domestic Hot Water – the water heaters used at residential sites.
Distributor	As in a respective distribution network business, in the ESP context an DNSP
DNSP	Distribution Network Service Provider, or electricity distribution network business. There are 13 DNSPs in the NEM, of which Victoria has five. Their operational areas are often referred to as their respective "zones" or "patches".
DOE	Dynamic Operating Envelopes- externally applied dynamic safe operating energy import and/or export limits to maintain electricity network system integrity. They can be updated dynamically to enable a greater and more flexible use of the electricity network while maintaining system stability and safe operation.
DSO	Distribution System Operator
ECMC	Energy and Climate Change Ministerial Council, a forum for the Commonwealth, Australian States and territories, and New Zealand to work together on priority issues of national significance and key reforms in the energy and climate change sectors.
EMS	Energy Management System, the controls of the DER electrical components. This may be a collection of stand-alone controls, or individual elements such as the inverter data
EV	Electric Vehicle
Export	Solar generated electricity (kWh) surplus to the instantaneous site electricity demand returned to the grid
FCAS	Frequency Control and Ancillary Services

HV	High voltage, used in context of electricity Distribution Networks in reference to the 66kV assets
HVAC	Heating, Ventilation and Air Conditioning, typically generically used for the totality of major heating and cooling on the site for residential site
Import	Electricity (kWh) drawn from the grid by a site
ISP	The Australian Energy Market Operator's Integrated System Plan. Note that this can be used generically or with reference to a specific year of the biannual publication.
kW	Kilowatt, a measure of power (1000 watts)
kWh	Kilowatt hour, the measure of electricity consumed/generated/exported per hour
LV	Low voltage, used in context of electricity Distribution Networks in reference to the 400V assets
MV	Medium voltage, used in context of electricity Distribution Networks in reference to the 24kV assets
NMI	National Metering Identifier, a unique numerical identifier for each electricity meter
OLTC	On-load tap changer, device used in transformers to regulate output voltage without interrupting the power supply
pu	Ratio of the voltage to the related voltage in voltage assessments. E.g. one pu on a 66kV voltage level means a voltage of 66kV, one pu on a 220kV voltage level means a voltage of 220kV and so on.
PV	Photovoltaic, the form of solar panels that convert light (photons) to electricity
RAB	Regulated Asset Base, in this report's context for regulated electricity network businesses, the asset base from which a regulated economic return is calculated.
Self-consumption	The amount (kWh) or proportion (%) of solar generated onsite that is consumed on site (i.e. not exported back to the grid)
Solar	Photovoltaic solar system unless otherwise specified (e.g. Solar Hot Water)
SWER	Single wire earth return, a low-density electricity network type common in rural areas
TSO	Transmission System Operator
V2B	Vehicle to building
V2G	Vehicle to grid
V2H	Vehicle to home
VPP	Virtual Power Plant – in this study being a residential solar and battery system that is in whole or part controlled by a 3rd party operator with the home's occupant's consent.
Whole-of-system	A comprehensive view of the entire energy system, and within the electricity system this encompasses generation, transmission, distribution, storage and distributed energy resources, including consumer energy resources.

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