Stakeholder Implications and Recommendations

C4NET Project Overview and roadmap

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Project Consortium

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Table of Contents

Figures

Glossary

ADMS	Advanced Distribution Management System
AEMO	Australian Energy Market Operator
BESS	Battery energy storage system
CER	Consumer energy resources
CFG	Coal-fired generation/generator
DER	Distributed energy resource
DHW	Domestic hot water
DN	Distribution network
DNSP	Distribution network service provider
DOE	Dynamic operating envelope
DSO	Distribution system operator
DZS	Distribution zone substation
ESP	Enhanced System Plan
EV	Electric vehicle
GFG	Gas-fired generation/generator
LV	Low voltage
MV	Medium voltage
OE	Operating envelope
OFTC	Off-load tap changer
OLTC	On-load tap changer

SCADA	Supervisory Control and Data Acquisition
TNSP	Transmission network service provider
TSO	Transmission system operator
V2B	Vehicle-to-building
V2H	Vehicle-to-home
V2G	Vehicle-to-grid
VRE	Variable renewable energy
VVWC	Volt-Var/Watt control
WP	Work package

Executive Summary

Brief overview of the ESP

The Enhanced System Planning (ESP) project is a significant and collaborative research project aimed at informing sub-transmission level electricity planning in Australia beyond 2030. Its focus is on building methodologies and approaches for bottom-up modelling and to highlight the opportunities presented through the distribution system and by integrating Distributed Energy Resources (DER) and Consumer Energy Resources (CER), with the goal of informing whole-of-system planning. The ESP seeks to inform gaps that would emerge in the Australian Energy Market Operator's (AEMO) current Integrated System Plan (ISP)[1] is expanded beyond its current scope to take a more whole-of-system approach in alignment with the Energy and Climate Change Ministerial Council's (ECMC) recommendations.[2] The ESP project is targeted at addressing the distribution system considerations aspect of this expanded scope, with a particular focus on bottom-up modelling approaches from the low voltage distribution system upwards, as outlined in Figure 1.

[1] 2024 Integrated System Plan (ISP), Australian Energy Market Operator, June 2024

[2] Review of the Integrated System Plan: ECMC Response, ECMC, April 2024

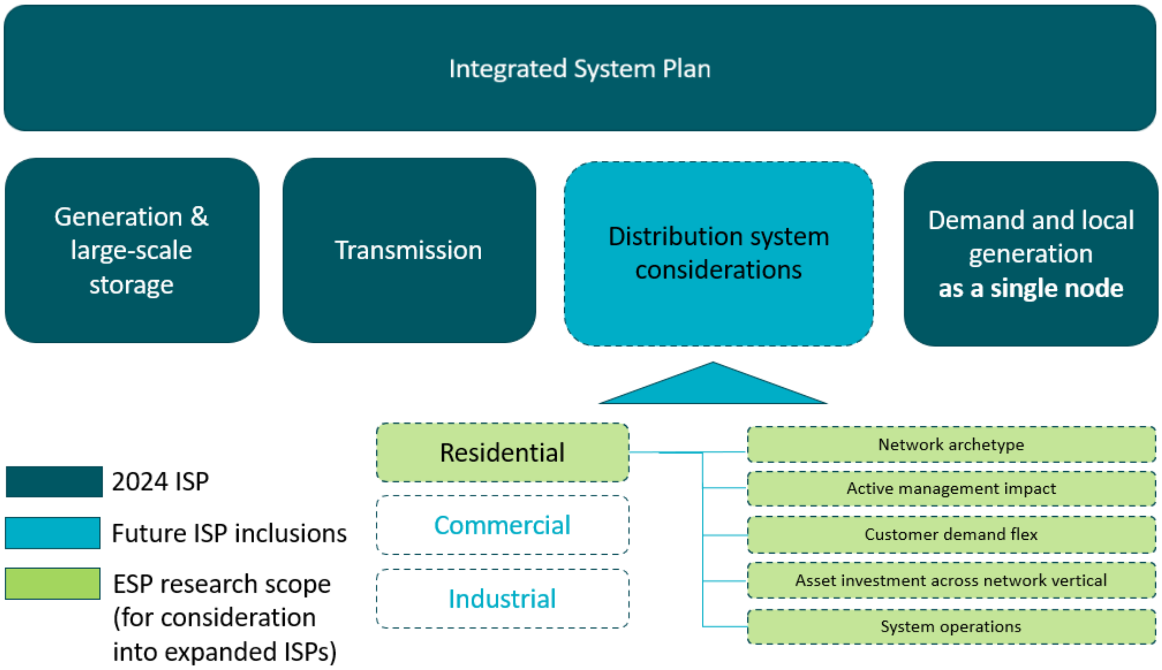


Figure 1: Distribution system components of whole-of-system planning.

This has been addressed through fifteen projects across three distinct 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 techno-economic assessments of future architectures.
- **Work package three:** Active distribution network considerations for whole-of-system planning implications: technical, economic and policy.

The alignment of the ESP program elements above with distribution system components of whole-of-system planning is illustrated in Figure 29 in Appendix 3.

Project vision and goals

WP 3.14's vision is to delineate a general methodological approach to inform the challenges and opportunities of incorporating distribution network planning into whole-of-system planning for the benefits of the consumers in the energy transition journey. By bridging existing gaps in the evolution of planning methodologies, the project aims to create a more coordinated and effective framework to ensure that future asset investments and integrated operation signals are assessed from a whole-of-system viewpoint. The overarching objective is to inform investment choices while ensuring that the broader energy ecosystem, including market design, regulatory frameworks, and supporting infrastructure is designed to support this transition.

A key goal is to establish a unifying framework, given the absence of a global playbook or rule book for addressing distribution network challenges and the unique characteristics of Australia. Whole-of-system planning must incorporate distribution system considerations, as any approach that overlooks these factors is likely to result in sub-optimal outcomes for the consumers.

The ESP project is built on the foundation of developing a unified methodological approach, with contributions from various researchers to integrate critical components and create a potential roadmap to integrated system planning starting from engagement with distribution businesses, government, and policy makers, providing an opportunity to discuss the project's value and key insights. Additionally, long-term planning decisions made in the next five years will have long-term consequences for 2040 and 2050, underscoring the need for evidence-based policy and active stakeholder engagement to drive effective outcomes.

The ESP and the energy transition

As power systems evolve, traditional approaches to transmission network (TN) planning are being challenged by the increasing uptake of consumer energy resources (CERs)[3] and distributed energy resources (DERs)[4] embedded in distribution networks, in conjunction with a substantial increase in demand due to electrification. These challenges are further exacerbated by the shift from conventional generation, which is flexible, to renewable energy generation, which is largely inflexible. This section outlines the main outcomes across the different ESP work packages (WP) and their envisaged role in the shift from conventional supply-centric planning to a more dynamic, consumer-centric approach—integrating transmission, generation, and distribution planning while accounting for bilateral flexibility and the bidirectional nature of modern power systems.

Traditional planning of power systems: The supply-centric paradigm

Traditionally, distribution networks (DNs), which are predominantly *radial* in topology, were designed based on after-diversity maximum demand (ADMD), 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 transmission networks (TNs), combined with a higher degree of demand diversity, translates to a much higher asset utilisation. As a result, TNs commonly witness congestion. However, due to the potentially widespread consequences of failure, reliability in the design of TNs is ensured by incorporating redundancy (i.e., N-1 security) and robust designs to withstand potential failures.[5]

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 the demand therefore meant that flexibility had to be

[3] CER refers to small-scale, behind-the-meter energy resources owned by consumers, such as rooftop solar less than 100 kW, battery systems less than 5 MW, and electric vehicles (EVs) that may be capable of sending electricity back to the grid. In this report, CER are assumed to be connected predominantly on the LV side of the distribution network, except for a subset of EVs connected to the MV network.

[4] DER is a broader term that encompasses larger assets, such as community batteries and larger PV systems between 100 kW and 30 MW, connected on the MV side or sub-transmission side of the distribution network. In this report, CERs are not considered a subset of DERs to make the distinction clearer.

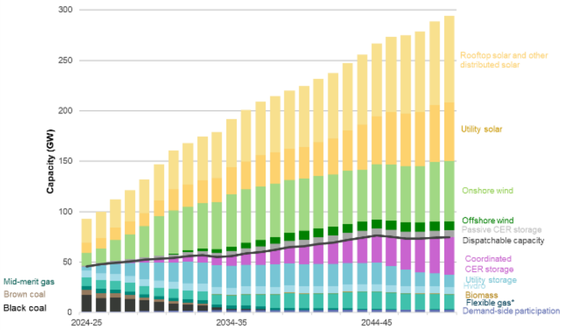
[5] Congestion on the TNs gives rise to price arbitrage opportunities between different regions.

appropriately considered in the *joint planning* of transmission and generation under a *centralised* paradigm.

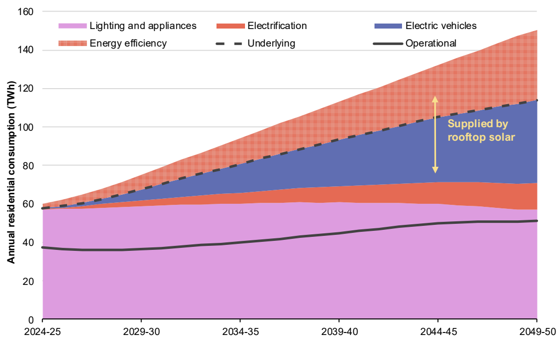
In summary, traditional network design was largely centred around servicing the (after-diversity) peak demand with little consideration to demand management options except in extreme circumstances (e.g., brownouts, industrial level etc), and in doing so ignored the potential flexibility within the system beyond the control of power flows on the transmission level. 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.

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. The first is the shift from coal-fired generation (CFG) to renewable generation. The second is a significant increase in electricity demand mainly due to electrification of transport, heating, cooling, and cooking.[6] These drivers are recognised by the Australian Energy Market Operator (AEMO) in their 2024 Integrated System Plan (ISP) [1], which envisions a three-fold increase in utility-scale wind and solar capacity by 2030, with a national target of 82%, increasing to six-fold by 2050, from 21 GW in 2024 to 127 GW, as shown in Figure 2 a). AEMO also forecasts a two-fold increase in residential electricity consumption by 2050 as households charge electric vehicles (EVs) and use more electricity for heating, cooling, and cooking, as shown in Figure 2 b).



a) Forecast capacity in the NEM



b) Forecast residential consumption

[6] Data centres are also envisaged to contribute to a significant increase in demand.

Figure 2: Forecast generation capacity (left) and residential consumption (right) in the NEM according to AEMO's 2024 ISP [1].

In the absence of data that characterises the electrification of residential space heating and cooling and domestic hot water (DHW), WP 1.1 developed a physics-based modelling framework and tool to assess the impact of this electrification on DNs. By leveraging bottom-up modelling methodologies, WP 1.1 provided a baseline understanding of the impact of the electrification of residential gas demand on electricity network planning. In parallel, WP 1.2 also developed bottom-up modelling methodologies to extract EV charging profiles from Victorian smart metering data and assess the impact of vehicle-to-grid (V2G) technology on these profiles. The project sought to establish a foundational understanding of how transport electrification influences energy demand patterns, and the insights gained could also help inform electricity network planning.

This transition, accompanied by an increasing uptake of behind-the-meter distributed energy resources (DERs) such as rooftop PV systems, small-scale battery energy storage systems (BESSs), and EVs, presents new opportunities for a paradigm shift in how DNs are planned and designed. As shown in Figure 2 a), this shift is also recognised by AEMO's 2024 ISP [1] which forecasts a four-fold increase in rooftop PV capacity reaching 72 GW by 2050, underscoring the central role of DER in the energy transition. Despite their unequivocal role in accelerating the energy transition, this DER uptake introduces unprecedented operational challenges for DNs due to exacerbated voltage unbalance and dynamic range and accelerated degradation of overhead lines and transformers due to frequent overloading (i.e., violated thermal limits). For example, surplus generation from rooftop PV, especially in the middle of the day when consumption is low and solar output is high, can reverse the direction of power flow and potentially cause voltage problems and congestion in DNs.

To alleviate these issues, dynamic operating envelopes (DOEs), illustrated in Figure 3, were recently proposed in Australia to maximise DER operation while safeguarding network integrity by limiting power exports (generation) from DERs at different times of the day [2]. WP 1.5 used the electrified heating/cooling profiles from WP 1.1 and the EV charging profiles from WP 1.2 to assess the impact of electrification on medium-voltage (MV, e.g., 22 kV line-to-line) and low-voltage (LV, 400 V line-to-line) parts of different types of DNs under various scenarios with different DER technology mixes and DER management strategies. The developed multi-scenario power flow analysis was then used to demonstrate the effectiveness of both import and export DOE in improving DER operation and mitigating voltage issues. AEMO's "Step Change" scenario of the 2024 ISP was the foundation for the base scenario. Harmonising with these established approaches makes it easier to align ESP findings with broader system elements. EV uptake and charging profiles were adopted from AEMO's ISP. Solar PV uptake and generation were the derived residential component of the distributed solar, and electrification of heating and cooling and DHW was amended to reflect full adoption by the end of the ISP period (2054). WP 1.3.1 considered a more granular means of building up the demographic and

DER aspects of the key assumptions within the ISP to inform whether such an approach may be feasible in the future, however the findings were not used to inform any scenario within the ESP study. The integrated MV-LV DN models used in WP 1.5 were developed earlier under WP 1.4 which categorised the networks into 5 different types and used a mix of actual electrical network models for the HV and MV network components, and pseudo or synthetic models for the LV network components.

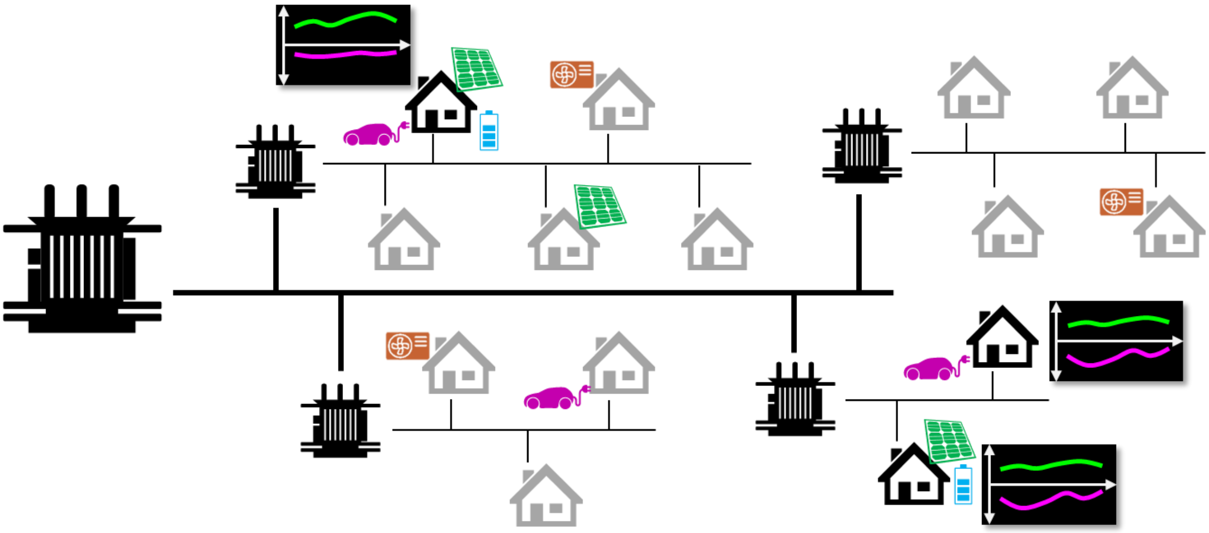
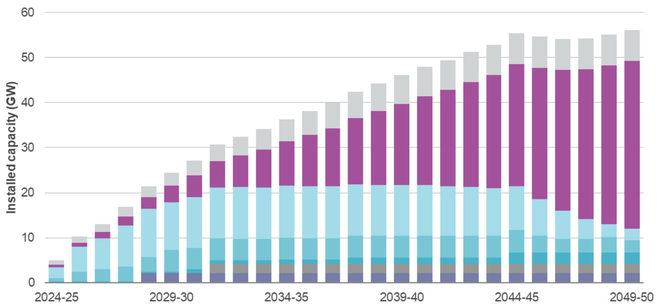


Figure 3: An illustration of dynamic operating envelopes (DOEs).

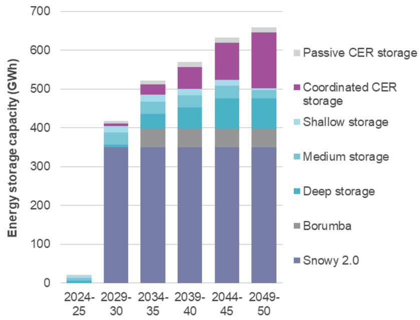
WP 1.6 then extended this multi-scenario assessment of the impacts of electrification to Victorian sub-transmission (i.e., 66kV line-to-line) networks based on the modelling and results from WP 1.1 to 1.5. Both WP 1.5 and 1.6 demonstrated that, despite the benefits from non-network solutions such as DOE network reinforcements will still be required over the next 30 years to accommodate the increasing generation and demand from residential customers. The sub-transmission network used in WP 1.6 was also developed in WP 1.4.

Unfortunately, DOE export limits lead to *curtailing* rooftop PV generation at certain times of the day. However, increased adoption of CERs, such as behind-the-meter household, business, or industrial battery energy storage systems (BESSs)—including EVs capable of exporting electricity to the grid—not only significantly reduces PV curtailment but also presents new opportunities for leveraging their flexibility in the operation and planning of power systems. On the other hand, widespread adoption of utility-scale variable renewable energy (VRE), which is inherently non-dispatchable, is *decreasing* the flexibility from the TNs side. Nevertheless, in a system that is dominated by VRE, electrification of heating and transport is arguably the best pathway for decarbonisation. Therefore, the role of storage, and demand flexibility in general, becomes of paramount importance in VRE-dominated power systems.

Compounded by a substantial increase in rooftop PV and other distributed solar, the monumental scale of VRE development identified in AEMO's 2024 ISP [1] (see Figure 2 a)) will require a commensurate increase in *firming* technology in the form of dispatchable storage reaching 36 GW/522 GWh in 2034-35 and increasing to 56 GW/660 GWh of storage capacity in 2049-50, as shown in Figure 4. According to AEMO, coordinated CER storage in 2049-50 will take centre stage with around 38 GW, or 47% of dispatchable capacity.



a) Installed storage capacity



b) Installed storage energy capacity

Figure 4: Installed storage capacity (left) and storage energy capacity (right) in the NEM according to the *Step Change* scenario in AEMO's 2024 ISP [1].

In light of these projections, WP 2.7 and 2.8 analysed the effectiveness of three different CER instruments for CER flexibility management in mitigating DN congestion and voltage issues. These three instruments, assessed both individually and in concert, are community batteries, EV charging through solar soaking, and V2G technology. At the same time, WP 1.3.2 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 over their CER.

WP 2.9 focused on the techno-economic modelling and impact assessment of integrating DER into distribution system planning (DSP), highlighting the importance of flexibility, uncertainty considerations, and economic and physical risk analysis. It evaluates the benefits, methodologies, and applications of leveraging DER flexibility as an alternative to traditional network asset investments in the context of electrification and the energy transition. WP 2.0 also aims to provide a potential future framework for industry and regulatory consideration to value network and DER-centric option investments.

In practice, in addition to behind-the-meter BESSs and V2G EVs, there could be a lot more distributed storage than anticipated. WP 2.10 explored additional types of CERs on the DN that could potentially be coordinated, beyond what AEMO is predicting in the 2024 ISP. In this context, the term "coordination" refers to an intelligent management (e.g., charging and discharging of BESSs and EVs) and aggregation of these resources to, among other objectives, reshape the demand profile of the power system—reducing the magnitude of peak demand and alleviating challenges associated with operating under minimum load conditions. These additional CER, illustrated in Figure 5, which are in the form of thermal storage of buildings and DHW, could potentially displace DN augmentation if less expensive communication and control infrastructure is deployed to enable their coordination. WP 2.10 is also exploring scenarios where the level of EV coordination could potentially be higher than the one modelled in AEMO's 2024 ISP [1]. AEMO expects that by 2050 up to 40% of EV will still be uncoordinated, as shown in Figure 6. Influencing an increase in this level of EV coordination may require the right economic incentives, which will likely be far outweighed by the system benefits that higher levels of EV coordination could bring.

This emergence of these CERs, which are accompanied by real-time monitoring and management capabilities, transforms traditional DNs into *active distribution systems* (ADSs), paving the way for an increased network utilisation and energy efficiency in general by actively managing their flexibility (e.g., through demand response). The flexibility in ADSs gives rise to the concept of virtual power plants (VPPs), in which a party aggregates a collection of CER devices and *coordinates* their control to deliver services for power system operations and electricity markets. Since the degree of coordination reflects the degree of underlying flexibility in the ADS, VPPs will play an important role in the interactions with both the transmission network service providers (TNSPs) and the distribution network service providers (DNSPs), particularly in the context of planning. Recognising the value of this flexibility opens new avenues for *integrating* CERs into both DN and TN operation and planning, mirroring how traditional integrated generation and transmission planning catered for the inflexibility of traditional demand.

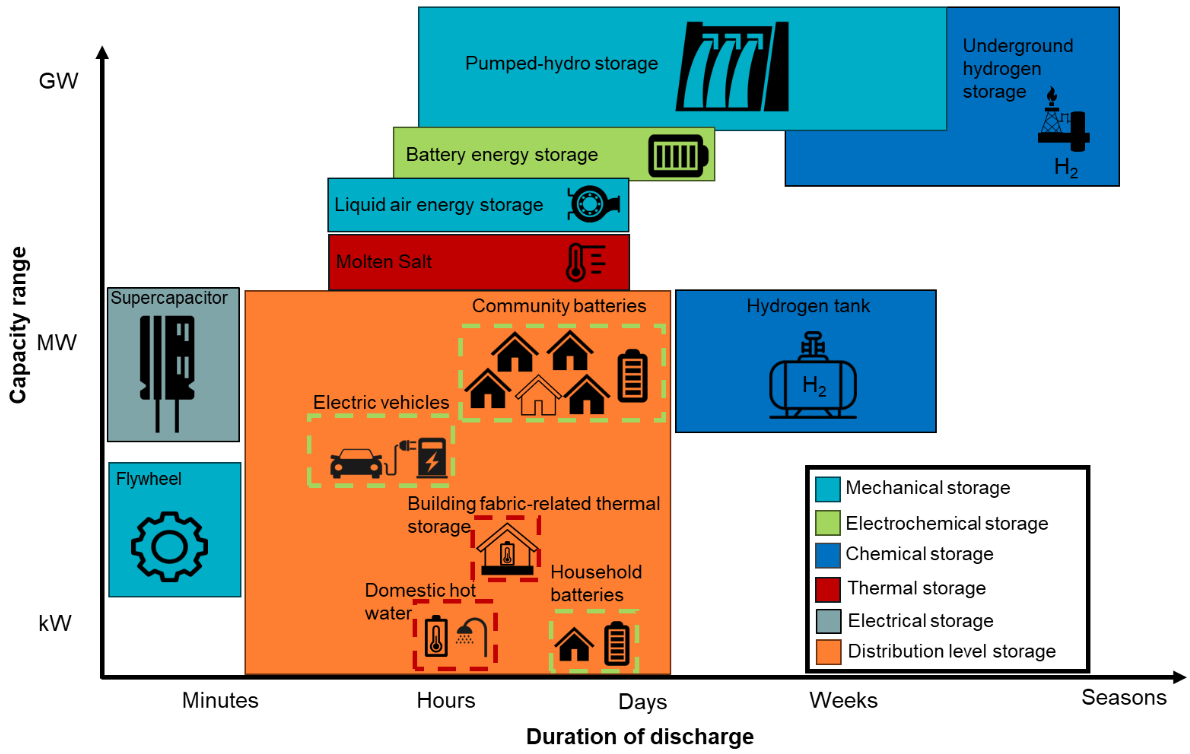


Figure 5: Suitability of various energy storage technologies against duration of discharge and energy storage capacity.

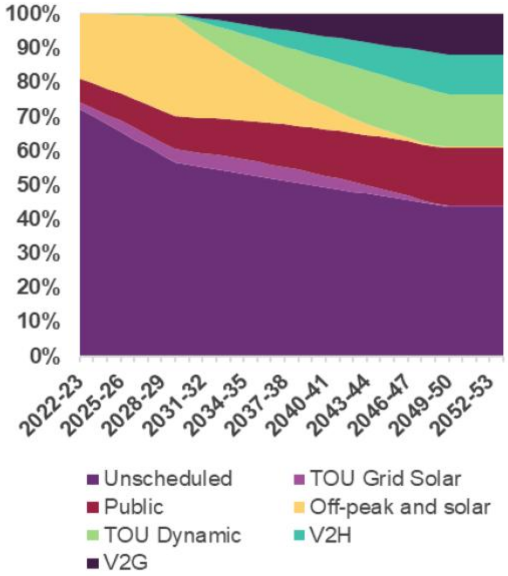
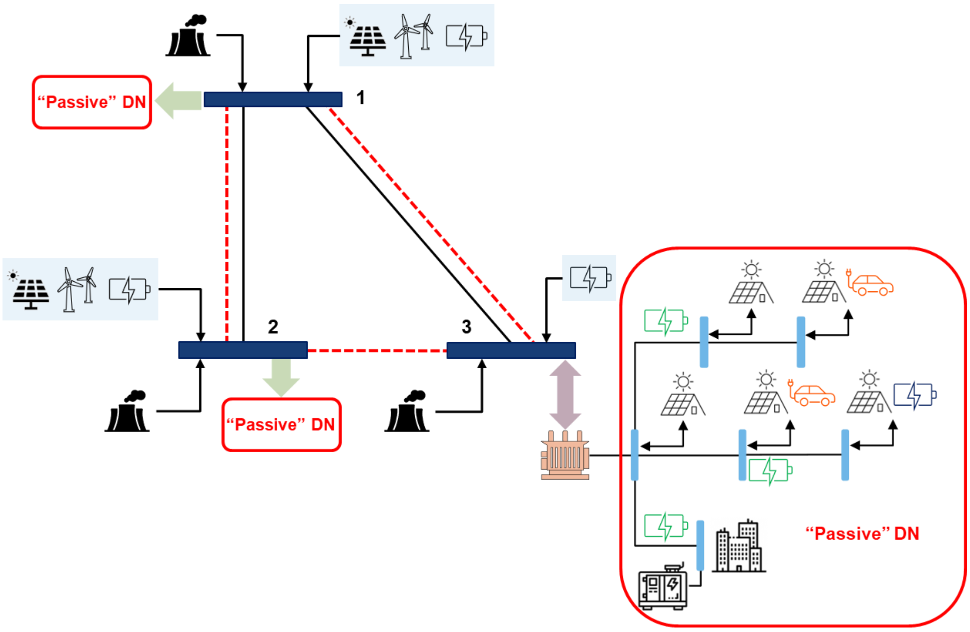


Figure 6: Split of charging types for medium residential vehicles [1].

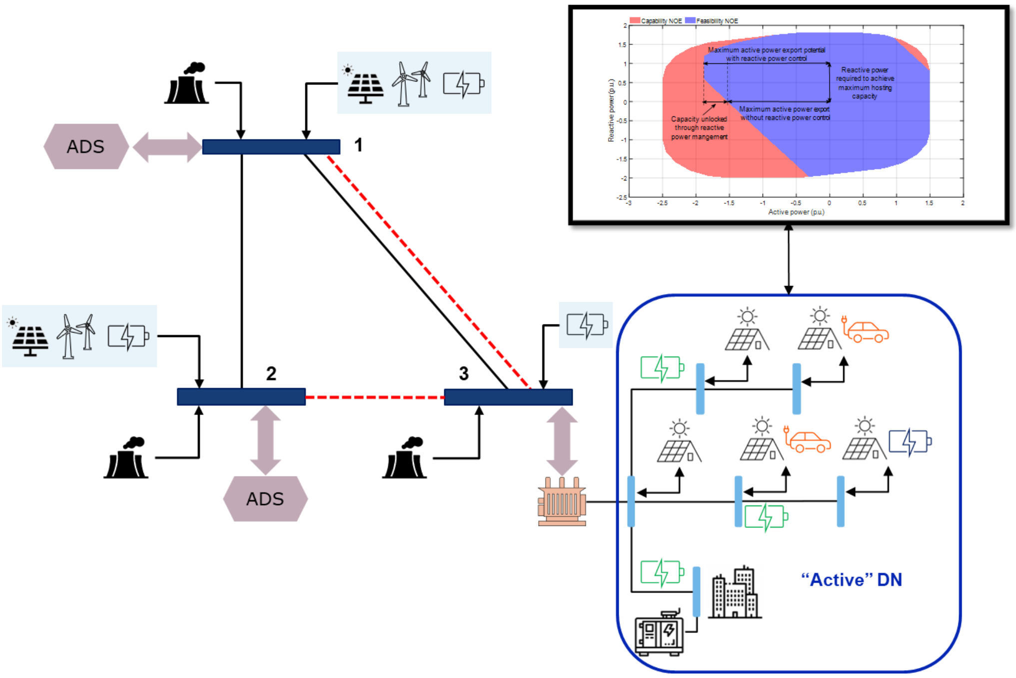
In doing so, the degree of CER coordination can substantially influence the extent to which transmission and distribution infrastructure, as well as utility-scale storage investments, can be *displaced* or *deferred*. In essence, an integrated TN and DN planning framework that caters for the flexibility of CERs can identify optimal trade-offs between 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.

Figure 7 illustrates an example that shows the impact of two different assumptions on the degree of flexibility—in other words, DER and CER coordination—on TN planning. Figure 7 a) is a case that assumes the DN is passive and Figure 7 b) assumes that the DN is active (i.e., ADS). The assumption of passive DN entails that the demand seen from the TN side is a single *input* profile that reduces to a single point at a certain snapshot in time. In contrast, in the ADS case, the demand seen from the TN side is no longer a unidimensional profile but rather an *operating envelope* (OE) in the P-Q space (i.e., active and reactive power space), as shown in Figure 8. This OE, which characterises the aggregate network limits as seen from the side of TNs, capture voltage constraints, congestion, and the degree of flexibility of the ADS at a certain point in time in both directions—export and import. A closer look at the OE in Figure 8 reveals a striking resemblance to the P-Q capability of a conventional generator like a gas-fired generator (GFG) or a CFG, which represents how much active and reactive power can be produced at any point in time. This means that each DN connected to a TN node can be represented as an equivalent to a large-scale generator, whose flexibility can now influence the planning solution. The main difference however is that due to the presence of distributed storage in the DNs like CERs, the OE in Figure 7 is bidirectional in the P-Q space whereas for conventional generator it is not.

The example shows that the case with ADS displaces more costly transmission infrastructure (transmission line between buses 1 and 2 in Figure 7 b)) installed in the case where the DNs was assumed to be passive. More specifically, in the integrated solution in Figure 7 b), the sum of the cost of DN augmentation, the cost of DER and CER, and the cost of communication and control infrastructure, is smaller than the cost of installing the transmission line between buses 1 and 2 on the TN side. These costs could also potentially include economic incentives, possibly in the form of price signals. This example is also suggesting that the flexibility of ADS alone is enough to integrate utility-scale VRE, avoiding the need for building more transmission infrastructure.



a) Planning under the assumption of *passive* distribution network



b) Planning under the assumption of *active* distribution system

Figure 7: Example of repercussions of two different assumptions on the degree of flexibility (DER and CER coordination).

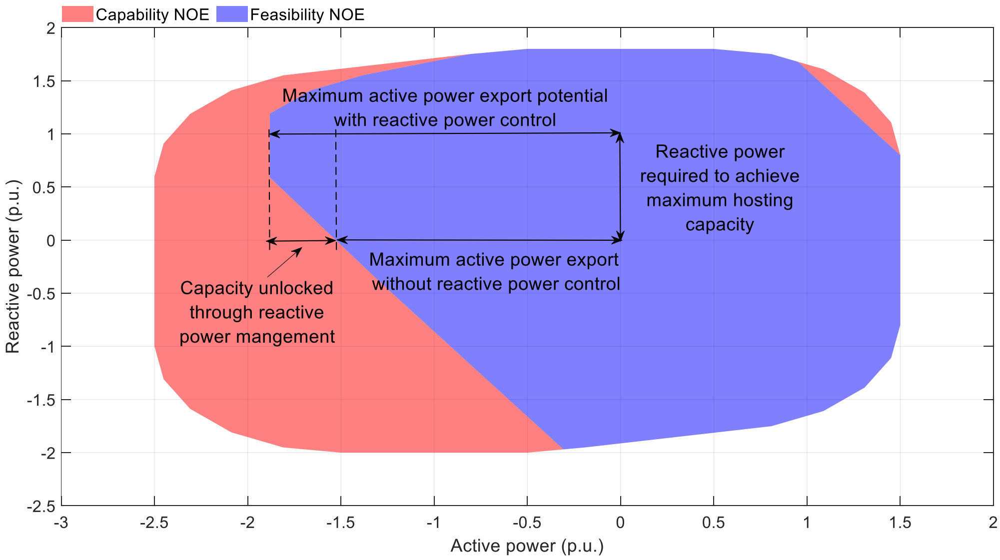


Figure 8: Illustration of an operating envelope (OE) of an ADS with DER and CER.

Planning of future power systems: The consumer-centric paradigm

TNSP-DNSP interactions

At present, TNs and DNs are largely planned and operated independently**,** which overlooks the potential value of DER and CER coordination. Although AEMO recognises the role and accordingly forecasts a massive uptake of coordinated CER, it assumes that DNs will be appropriately and independently augmented to facilitate this adoption. In other words, the cost of DN augmentation is not considered in the planning in the ISP. This lack of coordination between the TNSP (i.e., AEMO in this case) and the DNSPs may lead to redundancy in investments and a possible overestimation of DER, CER, and demand flexibility, thereby completely overlooking the trade-offs between investing in DNs and investing in TNs. This potential redundancy in investments could translates to higher costs, which ultimately trickles down to the consumers.

As a first step towards representing DNs in TN planning and improving the coordination between TNSPs and DNSPs, WP 3.11 developed a methodology for reducing the size of large DNs to more compact models with only three to five buses, significantly decreasing computational complexity while preserving network accuracy. This is expected to provide a tool that assists TNSPs in including DNs in their scenario planning, allowing more effective grid operation and planning.

WP 3.12 focuses on modelling and evaluating provision of ancillary services (AS), particularly frequency and reactive power support, from ADS to TNs. Specifically, WP 3.12 assessed three network models with varying levels of coordinated DER operation to demonstrate the concept of measuring technical flexibility behaviour and limits, which could potentially be considered for providing system services within an integrated system planning environment.

TNs and DNs planning methodology

In the absence of co-design frameworks that enable necessary collaboration between TNSPs and DNSPs, an ideal methodology for integrating TNs and DNs planning is one that requires *minimal* iterative processes between them. If investments in DN infrastructure, DER, CER, and their coordination infrastructure can be parameterised as a function of increasing levels of DER and CER adoption, the resulting *investment cost curve* could be computed independently by the DNSP and then handed over to the TNSP, which can then optimise over it to find trade-offs between investments in DNs and TNs.

Such a methodology, illustrated in Figure 9, could be completely *distributed*, allowing the DNSP to independently perform DN planning and provide *investment cost curves* and associated *OEs* that can be used directly by AEMO. This eliminates lengthy back-and-forth interactions between the two, while enabling the DNSP to leverage their own capabilities, tools, and practices, to produce these *investment cost curves* and associated *OEs*, reflecting their best understanding of how DER and CER coordination should be represented.

These *investment cost curves* and associated *OEs* can be viewed by AEMO as equivalent investments that could be optimised over in conjunction with transmission, generation, and utility storage. If the cost of augmentation on the DNs is lower than that of the TNs then the system planner deems it more cost effective to invest in the DNs instead of in the TNs, as illustrated in Figure 7.

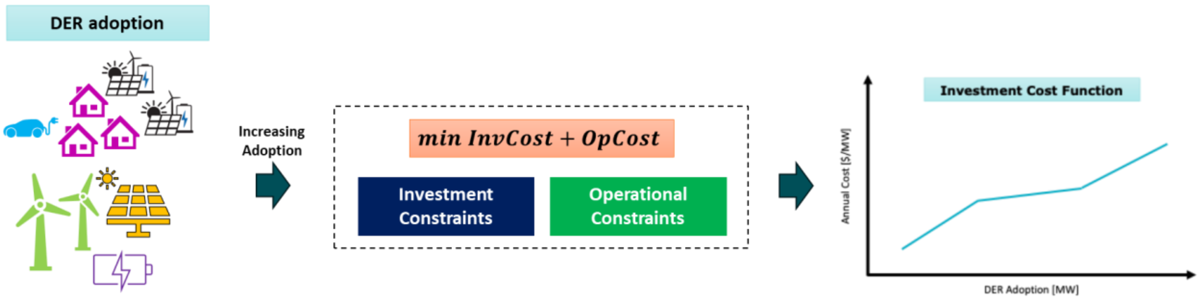


Figure 9: Deterministic approach to parametrise the investments required (costs) for ADS to support multiple levels of DER adoption. It includes the infrastructure cost to support DER coordination.

The next step is to develop a methodology for deriving these investment cost curves. The DNSP can build these cost functions (in MW) by solving an optimisation problem for each level of DER and CER adoption. This step is illustrated in Figure 10, which is an example that considers AusNet's GNTS-MBTS sub-transmission network to produce multiple investment cost functions for different sequences of DER investments. Three DER options on the sub-transmission network are considered: two distributed PV systems with 110 MW and 140 MW, and a 2-hour BESS with 110 MW.

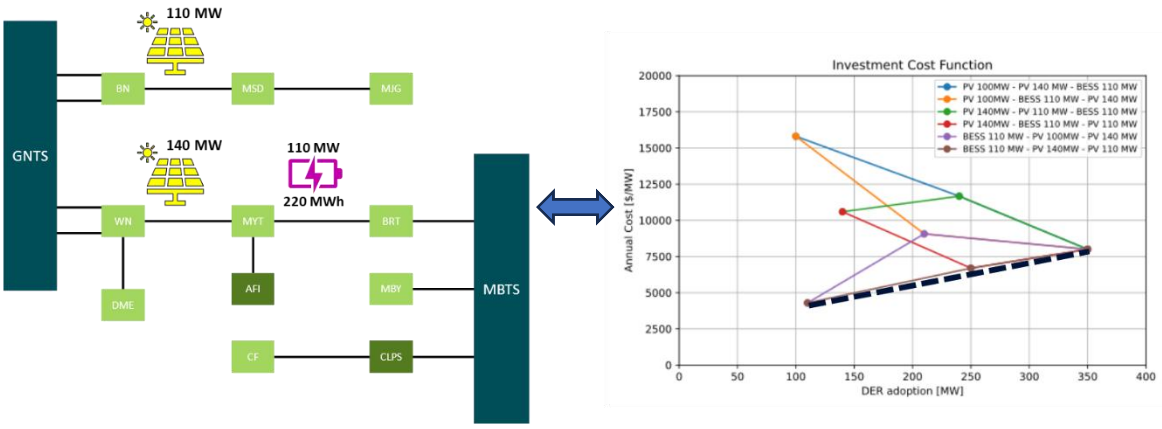


Figure 10: Example using AusNet's GNTS-MBTS sub-transmission network to produce multiple investment cost functions for different sequences of DER investments. The DER

options considered are two distributed PV systems with 110 MW and 140 MW, and a 2-hour BESS with 110 MW.

Findings under WP 3.13 suggested the following. Firstly, as shown in Figure 10, the *order* of installing the assets changes the cost functions. Luckily, optimisation techniques can guarantee the optimal portfolio of investments for each level of DER adoption. Secondly, as shown in Figure 11, when the coordination of (expected) CER on the MV-LV is viewed as an option, infrastructure investment costs are reduced, making the development of DER on the sub-transmission network more competitive from a whole-of-system point of view.

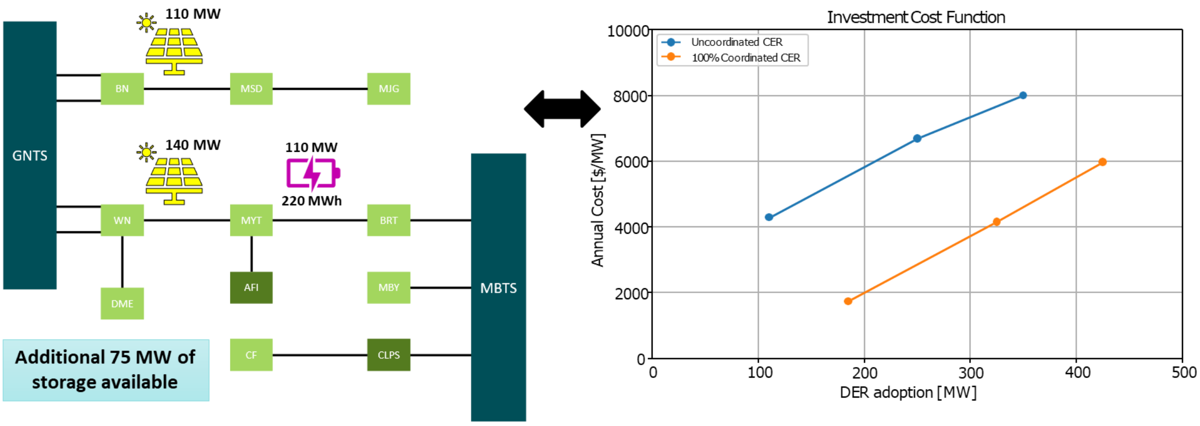


Figure 11: Impact of the level of DER adoption.

Once a suitable representation of the distribution side (investment and operation) is constructed, DNs can be *integrated into whole-of-system planning frameworks* such as an enhanced ISP. This process is illustrated in Figure 12. Nonetheless, implementing this in practice may require changes in policy, regulation, and incentives, especially since many states—like Victoria—have multiple DNSPs.

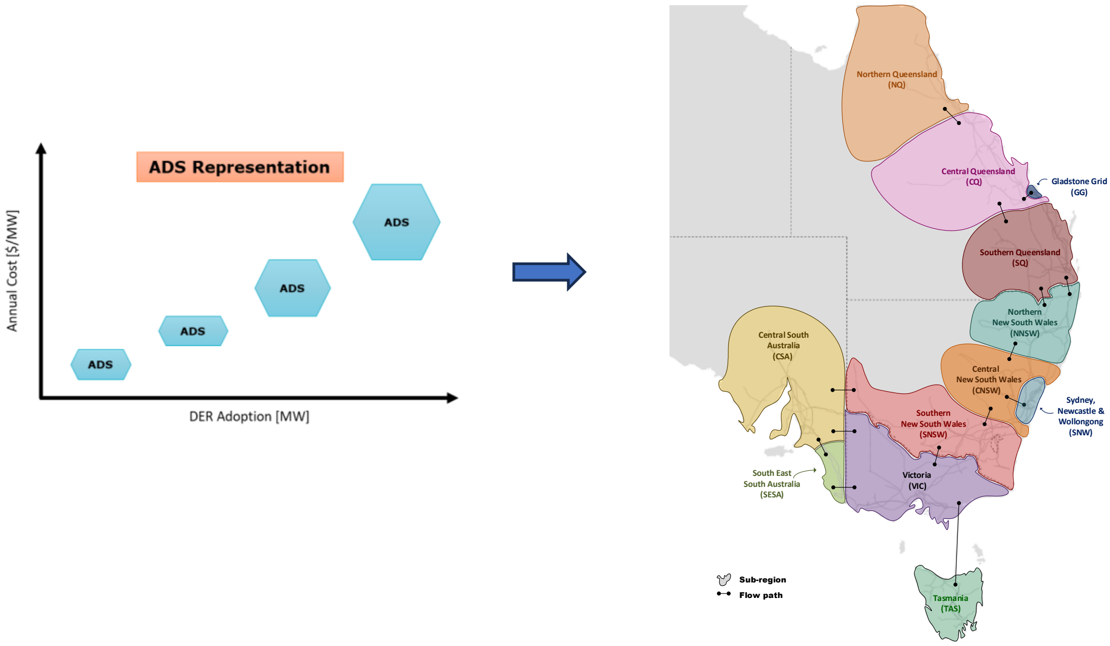
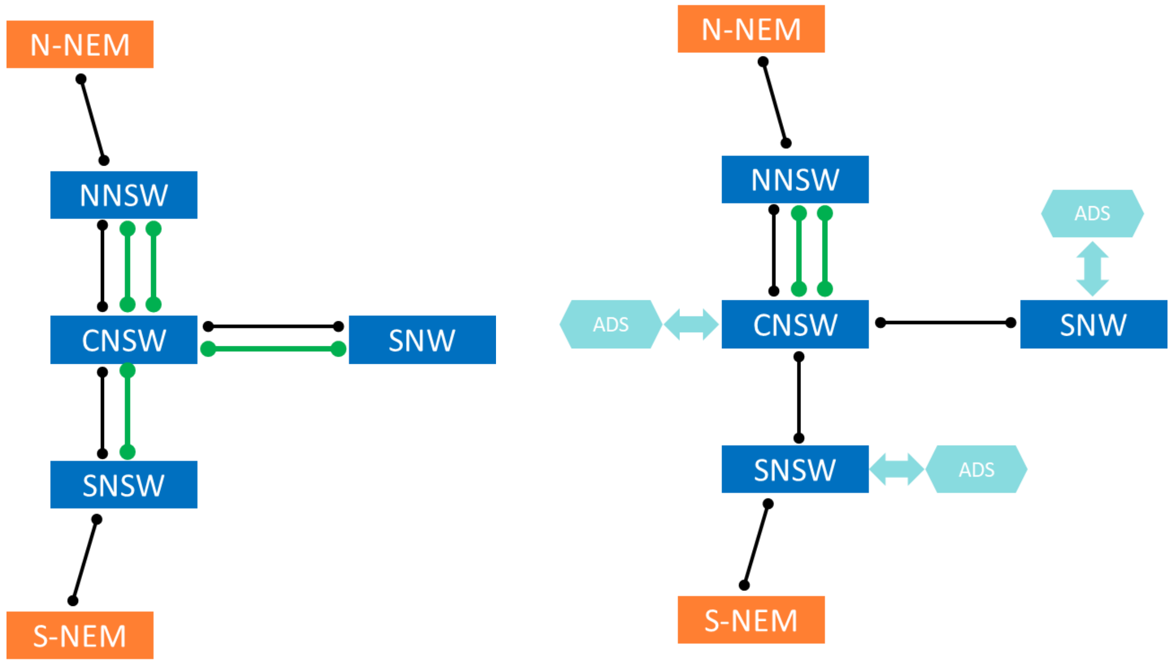


Figure 12: Integration of an ADS representation into a whole-of-system plan.

To test the integration and scalability of this methodology, a deterministic case study based on the 2024 ISP [1] was carried out using 2035 as reference year in the Step Change scenario. Focused on New South Wales (4 nodes represented in the ISP), cost functions are computed for each one of these nodes while aggregating the north and south side of the NEM, as shown in Figure 13. The same sub-transmission networks shown in Figure 10 are plugged into AEMO's ISP, followed by running a cost-benefit analysis. To do this, the representative sub-transmission networks in Figure 10 are then proportionally allocated demand traces, and DER adoption scenarios obtained from AEMO's 2024 IASR workbook [3].

In the absence of DER coordination, the integrated planning solution deems it optimal to invest in transmission infrastructure between CNSW-NNSW, CNSW-SNSW, and CNSW-SNW, as shown in Figure 13 a). On the other hand, increasing the level of DER coordination to 100% results in deferring transmission lines CNSW-SNSW and CNSW-SNW. In fact, in this specific example, this deferral results in 26% savings in total costs (mainly interconnector and network costs, but also some operational costs) for the period analysed, and a reduction of 5% in overall VRE curtailment.

It should be noted that, although suggesting potentially significant benefits, these numbers are specific to this particular example and should not be generalised. The key takeaway here is the underlying *methodology* itself, which will be explored in more detail in Section: Roadmap to an expanded, whole-of-system integrated system planning below.



a) Case *without* DER coordination

b) Case *with* DER coordination

Figure 13: Whole-of-system planning example.

TNs and DNs planning under uncertainty

The rapidly changing energy system landscape introduces short-term and long-term uncertainties around energy policy, technology uptake and costs, evolving business models, and environmental and sociopolitical factors, all of which should be appropriately considered in planning studies. Electrification trends and the uptake of DER are exacerbating the *uncertainty* in power system planning, not to mention uncertainty around DER coordination options and potential service (see Figure 14).

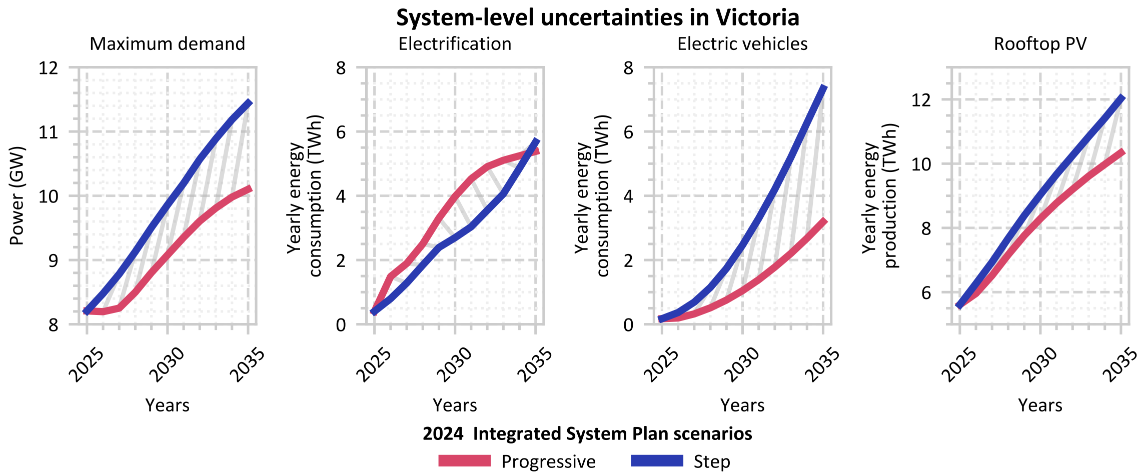


Figure 14: System-level uncertainties in Victoria.

AEMO's 2024 ISP [1] captures these uncertainties by proposing three different scenarios, *Progressive Change* at 42% likelihood, *Step Change* at 43% likelihood, and *Green Energy Exports* at 15% likelihood, each reflecting a different pathway of how the future could unfold. The ISP then reflects these scenario probabilities in a *deterministic* methodology that determines the development path that produces the least-worst weighted regret (LWWR). Recognising the importance of uncertainty, WP 2.9 demonstrated that a representation of uncertainty is key to value the benefits that non-network alternatives could provide by developing uncertainty-aware methodological frameworks to assess non-network alternatives against conventional augmentations in the context of distribution system planning. The methodology in WP 2.9, which is anchored in decision theory, is designed with practicality in mind to enable decision-makers to define and test multiple scenarios and to manage potential risks when examining different DN investment options under uncertainty and quantifying the value of non-network alternatives.

In general, such a framework can assist system planners in pre-emptively minimising the risk of investing in a suboptimal power system architecture today or being locked out of a more cost-effective one in the future. Using a single scenario often results in solutions that underestimate the *option value* of non-traditional-network assets when they are considered as options in system planning expansion. This is especially true if an investment is made today assuming a certain scenario will unfold, but then halfway through construction the trajectory of the system evolution jumps from one scenario to another. When this happens, the risk of *stranded assets* increases significantly.

Capturing such these risks cannot be achieved with deterministic planning approaches; instead, stochastic planning is more suitable. Interestingly, previous work in [4], [5] demonstrated that a stochastic TN planning approach often finds compromise solutions that strongly favour flexible non-network solutions, such as utility-scale BESS or CER coordination. In other words, DER and CER coordination under stochastic integrated planning approaches can potentially systematically reduce transmission-level and distribution-level investments and provide a risk-hedging value. Due to significant uncertainty around the development pathway of the TN, leveraging the uptake of DERs and CERs—which can be deployed and coordinated relatively quickly[7]—creates value as a risk hedge against stranded assets.

[7] Quick deployment can only occur when the required technical infrastructure, market structure, and customer readiness are established in advance.

Stakeholder implications

Impacts of electrification on the distribution network

- The impacts of electrification of gas and transport will push low voltage network assets beyond their current limits and solar curtailment will be material within the next decade.
- If left unmitigated, network impacts will increase the cost of electrification and the broader energy transition.
- Impacts of electrification and CER adoption vary by network type and across the energy system, potentially requiring tailored solutions, levels of investment, and regulatory treatment, to achieve best value outcomes for consumers.
- Network impact assessments should consider the complexities of the flow of electricity (e.g., voltage drops and thermal limits etc.) within distribution networks that arise from each new type of connected device and load.
- As electrification and CER adoption grow, voltage and thermal impacts will increase, leading to greater renewable energy curtailment in the absence of CER management strategies.
- The broad application of dynamic operating envelopes (DOEs), with an efficient objective function, will enable higher hosting capacity using existing assets, and allow consumers to connect larger solar systems where desirable.
- Diversity in network characteristics, consumer adoption of CER, their use, participation in network/system activities, and future policy and incentive frameworks will significantly influence how distribution network assets are impacted.
- Although they are expected to have a far-reaching and detrimental impact on distribution networks if uncoordinated, CER/DER storage and distributed generation in general present valuable operational and whole-of-system planning opportunities by harnessing their local and aggregated flexibility when their operation is coordinated.
- The emergence of DERs/CERs, which are accompanied by real-time monitoring and management capabilities, transforms traditional (passive) distribution networks into *active distribution systems* (ADSs), paving the way for an increased network utilisation and energy efficiency in general by actively managing their flexibility.

Strategic planning for network and CER/DER management solutions

- A combination of network and CER/DER management solutions can lower overall cost impacts across the distribution network but will not be optimised through a business-as-usual approach.

- A mix of network-side DER and CER coordination/orchestration solutions could be cheaper than asset investment alone (e.g., through deferment or avoidance).
- Combined application of levers/measures that protect network integrity, such as DOEs, together with tariffs and market function (or proxies) to help align behavioural incentives, can optimise network utilisation, and lower the network cost impact of electrification.
- Adopting a proactive and strategic approach to policy, regulation, and incentives for CER management and participation enables greater long-term investment efficiency in both transmission and distribution networks.
- Appropriate valuation and reward structures for CER management solutions are essential to increase consumer acceptance and implementation amid rising uncertainty and risk.
- Common frameworks are required in the regulatory process to efficiently measure the value of assets with uncertainty and risk, in comparison with traditional solutions.
- Balancing consumer investments and preferences with system needs is vital for effective CER integration.
- Aligning consumer outcomes across distribution and transmission networks will support a smoother energy transition.
- Enhancing system "flexibility" through CER/DER and improved distribution network operations contributes positively to system outcomes and net zero commitments.
- Introducing flexibility at the grid-consumer interface through CER coordination benefits upstream parts of the network (i.e., parts of the network with higher voltage levels), ultimately supporting system security and balancing consumer and transmission investments.
- The cost of network augmentation alone to meet increased demand will be significantly higher than one that considers managing demand through ADS and CER/DER coordination.

Unlocking distribution network capacity to support transmission investment

- When coupled with an "active" distribution system (ADS), the connection of solar, wind and storage at the sub-transmission will ease the investment challenge in the transmission network and reduce overall system costs.
- Implementing and sequencing flexibility in ADS, alongside regulatory incentives, can help moderate upstream system investment needs. While noting investment costs would need to be verified with industry, modelled savings of over 25% are illustrated in case studies in WP 3.13 (using AEMO REZ data) which would represent multi-billion-dollar savings if valid more broadly across the NEM.
- Increased and strategically sequenced flexibility can reduce the need for additional transmission infrastructure by easing the impact of electrification, aligning with both public sentiment and a timely

response to reach net zero. This supports the pathway to lowest overall system costs, at the highest value for consumers.

- Expanded capability of ADS functions will need to be developed, and evolve to consider whole system impacts and benefits, on top of local system needs, by managing distribution congestion and ensuring these actions are aligned with needs of the whole system.

The importance of distribution system considerations in whole-of-system planning

- Long-term, bottom-up planning within the distribution network supports better management of system uncertainty by incorporating flexibility through active distribution sub-systems and coordinated CER/DER.
- Future planning approaches should leverage bottom-up modelling to highlight opportunities for enhanced network utilisation and improved supply quality at the grid-consumer interface.
- Insights into uptake rates and behavioural trends in low-voltage networks enable a better understanding of network impacts and asset limitations, allowing for the consideration of both network and non-network solutions and their effect on the broader network/system.
- Energy profiles provide insights into how power flows change within the distribution network and their implications for networks.
- Whole-of-system planning enables actionable investments to create an ecosystem for the future, including for markets, that are more closely aligned across the electricity supply system and ensures long-term interests of consumers are served by a whole-of-system approach to planning.
- As a gap currently exists in this area, there is a need for AEMO, DNSPs, and other stakeholders to collaborate on a process that incorporates granular distribution sector considerations into overall long-term system planning in an efficient and harmonised manner across NEM participants.
- The ESP project has not only demonstrated the potential value of including active distribution networks (which include CER/DER coordination) in an expanded ISP process but has also developed new methodologies and modelling techniques to enable this inclusion and demonstrate its feasibility.
- The "*Roadmap to an expanded, whole-of-system integrated system planning*" delineated in this report presents a comprehensive, self-contained methodology that establishes the foundation for whole-of-system planning from the bottom up. However, given the scale and complexity of this approach, developing it within a short timeframe may be challenging. Therefore, stakeholders should acknowledge its scope and pursue its implementation iteratively across multiple ISP cycles.

Managing uncertainty in long-term whole-of-system planning

- Managing uncertainty in long-term whole-system planning requires a coordinated approach between transmission and distribution system planning, particularly with the increasing integration of CER. Given the dynamic nature of energy markets, evolving technologies, and shifting consumer behaviours, planning frameworks should evolve towards becoming adaptive, flexible, and possibly data driven.
- Scenario-based planning consists of multiple scenarios to account for a range of possible futures can help manage uncertainty related to CER adoption rates, technological advancements, policy changes, and market developments to build robust strategies that can adapt to different conditions.
- While it is a promising approach to incorporating uncertainty, computationally tractable approaches may need to be developed to address the large-scale nature of the ensuing optimisation models.

Role of the consumer

- From the consumer perspective, it is essential to consider customer impacts and experiences throughout the project. A strong focus on consumer advocacy ensures that consumer needs and concerns are effectively represented.
- Understanding the consumer journey is crucial, with insights from other initiatives that highlighted market gaps and consumer challenges. These insights reinforce the importance of incorporating consumer experiences into the project's development.
- Additionally, as consumers increasingly invest in their own energy resources, culminating in a larger, now shared infrastructure, it is important to ensure that they understand this responsibility and the role they play within the broader energy system by being key contributors to the enablement of CER coordination solutions.
- The development of an ecosystem centred around consumer participation, encouragement, acceptance, adoption, behaviour, and rewards must be undertaken in tandem with long-term system planning activities.

Role of DNSP

- There is a need to clearly define the functions and capabilities required for fully capturing the benefits of effective distribution system operations as they become more valuable to, and integrated with, whole-of-system considerations, without specifying which organisation should assume specific responsibilities.
- To ensure efficient system operation, it is essential to establish consensus on the gaps that may emerge in the transition to a more integrated planning approach, and to develop a systematic

strategy for addressing these gaps across the NEM—focusing on what actions are required rather than on assigning responsibilities to specific entities.

- It is crucial to determine the operational requirements, including the necessary capabilities and data, to ensure that all essential distribution system functions are performed effectively.
- To support a longer-term planning outlook, DNSPs—whose current modelling and forecasting practices typically focus on 5–10 year horizons (aligned with two EDPR cycles)—may need to evolve these approaches to more effectively balance medium-term priorities with longer-term system needs. This could involve incorporating longer-term considerations into planning frameworks and using back-casting methods to chart viable transition pathways from the present state.
- Developing simplified yet sufficiently representative models of distribution networks is essential to balance the accuracy of network representation with the computational efficiency required for power flow or optimal power flow analyses. In parallel, it is important to advance and apply analytical techniques to estimate future consumer demand profiles, particularly in cases where comprehensive historical data is unavailable.
- 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.
- Distribution network planning must evolve from its current largely independent approach to one that incorporates broader system roles and aligns with whole-of-system objectives.
- To realise the full benefits of integrated planning, DNSPs will need to collaborate with AEMO to ensure distribution network flexibility, constraints, and opportunities are accurately represented, and also coordinate with each other and AEMO to harmonise planning approaches for feasible NEM-wide implementation.

Stakeholder engagement

- Engaging with key stakeholders, including distribution businesses, government, and policy makers, is essential to ensuring the project’s insights are effectively communicated and adopted.
- Effective communication is crucial, with a focus on framing the project’s results in a way that allows stakeholders to understand the broader implications. To support this, a roadmap will be developed as a platform for engaging with distribution businesses, government, and policy makers, providing an opportunity to discuss the project’s value and key insights.

- Throughout the ESP project, C4NET engaged policy makers, including the Australian Energy Market Commission (AEMC), the Federal department, and the Victorian government, to ensure the project's findings contribute to policy development.
- Additionally, consumer engagement is a key consideration, particularly through advocacy groups such as Energy Consumers Australia (ECA). Involving these groups aims to integrate consumer perspectives and address key consumer questions within the project's outputs.

Recommendations

- AEMO and DNSPs continue to build on their recent collaborations to:
    - Take ESP methodologies from research to production, where appropriate, and expand to all DNSP areas.
    - Include bottom-up approach sufficient to inform to at least MV transformer level for a discreet range of network archetypes.
    - Ensure harmonisation of a scalable and efficient integrated whole-of-system planning approach.
- Policymakers and regulators must ensure alignment of investment case assessment frameworks to encourage operational behaviour to deliver lower network service costs and lower whole system costs for a NEM that is forecast to be increasingly reliant on distribution connected resources:
    - Align incentives and remove existing disincentives and impediments, for DNSPs to invest in infrastructure and operational practices which would enable not just higher CER uptake and reduced export curtailment for its customers but also deliver greater economic value for all NEM customers through improved coordination of CER/DER across the system. At present there is insufficient meaningful regulatory and commercial incentives which allow DNSPs to undertake such investments where the benefit for customers may result from systemwide access to lower cost renewable energy rather than lower local network costs.
    - Consider other international regulatory examples where use of distribution network assets (or a combination of network and coordinated CER assets) are enabled to align with (or participate in) activities where benefits are shared with the consumer. (e.g. UK Regulation allows DNSPs to participate in FCAS markets with a mandated % sharing of any benefits with the consumers).
    - While broader regulatory reform may ultimately be required to enable DNSPs to scale distribution system storage through ownership and leasing to third parties, there is a nearer-term opportunity to utilise mechanisms such as class waivers or other forms of exemption to begin unlocking network and market benefits in parallel.

- AER/AEMC and DNSPs to develop common model frameworks in line with the illustrative prototypes developed under the ESP project for asset and solution assessment efficiently capturing uncertainty, while allowing total system benefits to be assessed in the RIT-D test.
- Support reporting of asset utilisation at both peak and energy levels for infrastructure assets at all levels of transmission and distribution network infrastructure.

- Remove investment barriers, develop integrated planning-operating roles, and evaluate all generation and large-scale storage connection options against sub-transmission alternatives.
- Support the introduction of DOEs (or similar measures) in conjunction with increasing household export capacity.

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

This section proposes a potential roadmap for integrating DNs and DERs/CERs into whole-of-system planning by distilling all the insights generated across all the work packages within the ESP and combining them with the recommendations (delineated in the previous section) as well as feedback from DNSPs, AEMO, AEMC, AER, and ECA.

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 and regulatory changes, as described below. Figure 15 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 15 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.

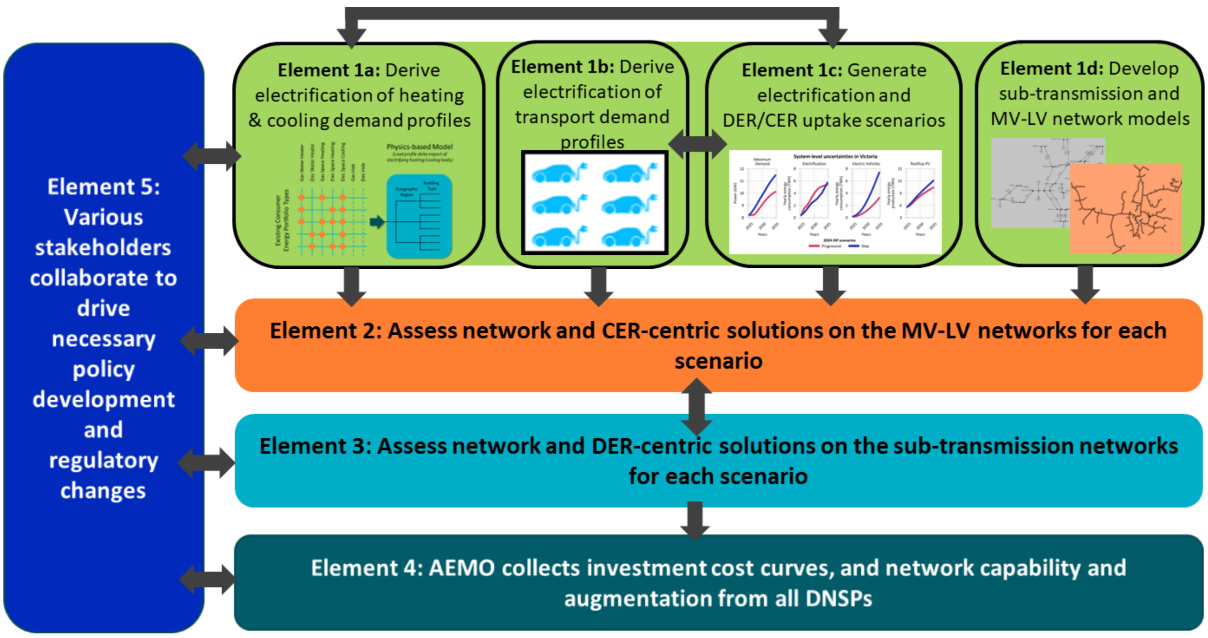


Figure 15: Overview of ESP roadmap.

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 16,[8] 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 particularly critical in the absence of sufficient historical 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.

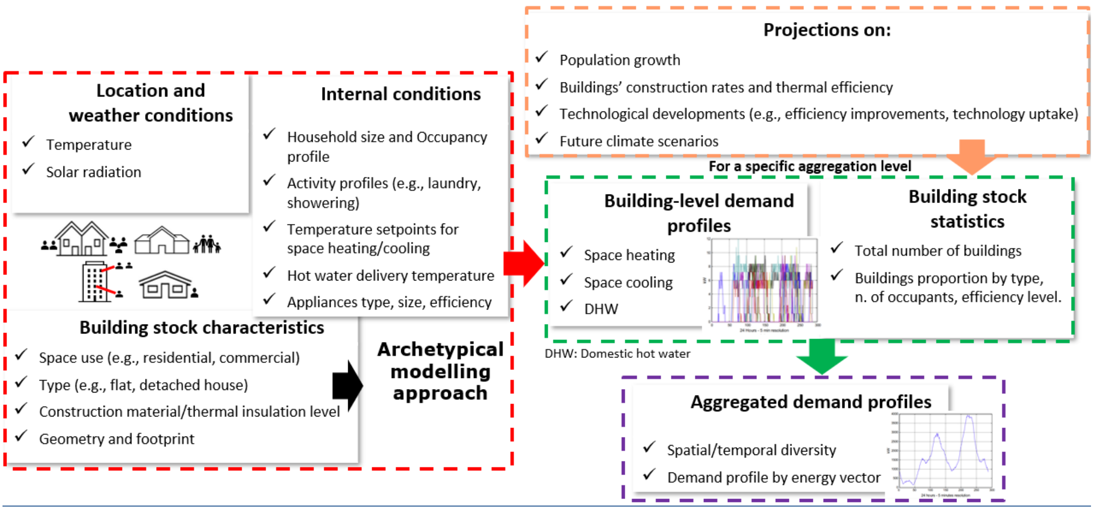


Figure 16: Bottom-up process for deriving individual and aggregated demand profiles on a given MV-LV network.

[8] More details on how to develop such approaches can be found in WP 1.1.

Element 1b: Derive electrification of transport demand profiles

This element consists of deriving charging and discharging profiles of electric vehicles (EVs) by either extracting them from smart meter data or directly from known charger types.[9] 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 inform on latent storage capacity, i.e., degree of flexibility they 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 17.

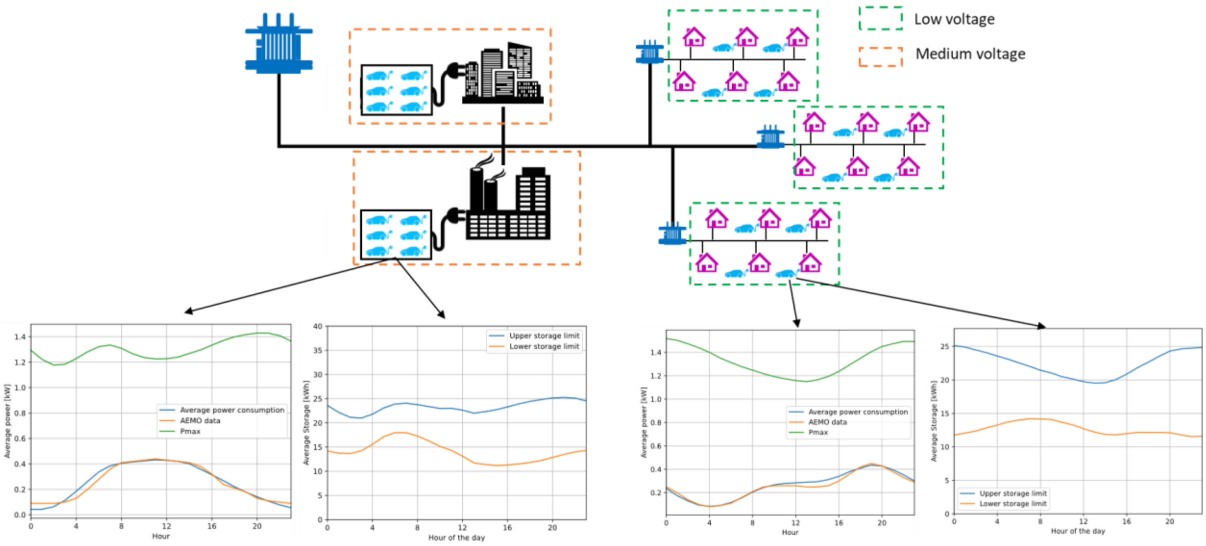


Figure 17: Illustration of what a typical storage profile (kWh) looks like for an MV-connected EV (left) and an LV-connected EV (right).

[9] 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.

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 in the future. This element may be performed by research bodies such as universities or CSIRO, in consultation with DNSPs and AEMO.[10] 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 18.

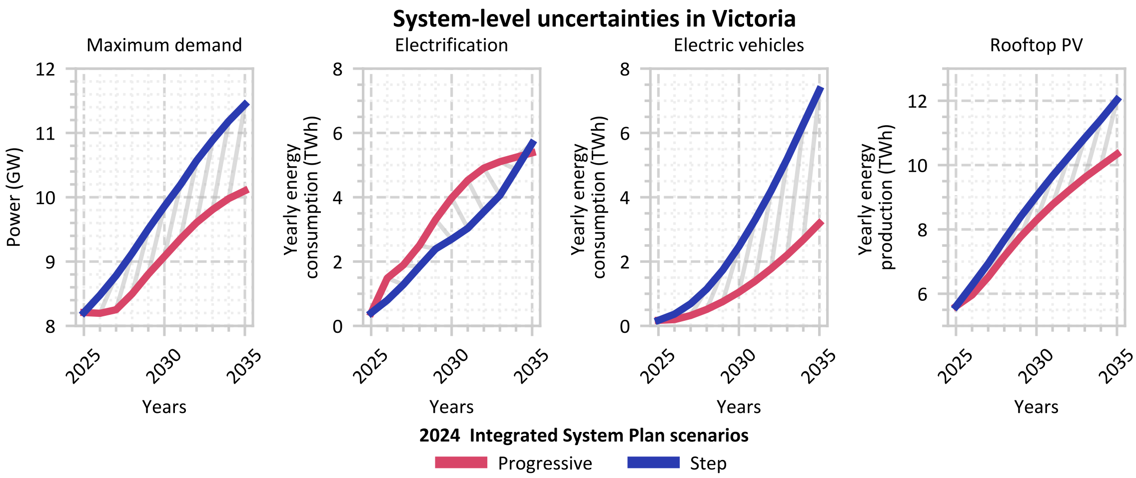


Figure 18: Example of a different evolution trajectories under two different scenarios.

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 instance be divided into various types such as urban, CBD, suburban, short-rural, and long-rural.[11] Such network models can be built with the help of SCADA/ADMS systems, smart meter data, and data-driven physics-based state-estimation

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

[11] More details on how to develop such approaches can be found in WP 1.4.

techniques. This feat is expected to no longer be a bottleneck in the near future thanks to increasing uptake in advanced communication and control infrastructure which is increasing the visibility of the state of network assets (e.g., electrical parameters of transformers and overhead lines and cables, OLTC and OFTC tap positions, etc.) and demand alike.

An illustration of an archetypical distribution network is shown in Figure 19.

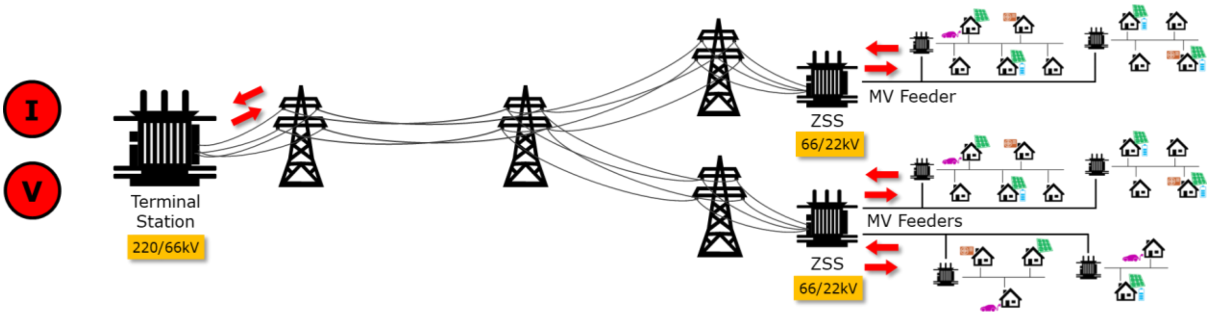


Figure 19: Illustration of an archetypical distribution network with voltage levels of 66 kV for the sub-transmission part all the way down to the 22 kV on the MV side and 400 V on the LV side.

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

The outputs from Element 1 can now 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 20. 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 1c) to assess a set of network and CER-centric (i.e., non-network) 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).

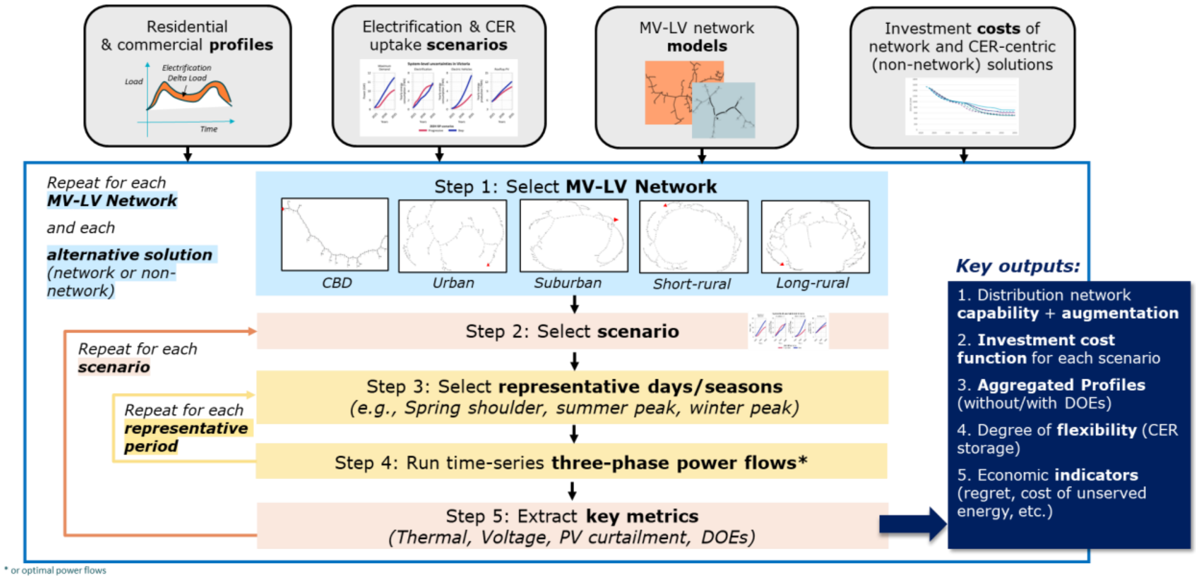


Figure 20: Flow chart describing the inputs and outputs of the power flow (or optimal power flow) studies performed under Element 2.

In more detail, the process outlined in Figure 20 starts by selecting a specific MV-LV network model 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 CER-centric (i.e., non-network) solutions and then runs a three-phase unbalanced[12] power flow (or optimal power flow) to assess, among many others, impact on voltages, thermal limits, and PV curtailment both with and without DOEs and smart inverter capabilities such as Volt-Var/Watt control (VVWC).[13] The process is repeated for each type of representative network model and each network and CER-centric solution to obtain a comprehensive *lookup table*[14] 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.

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

[13] 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.

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

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 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-network) 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.

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-network) options to evaluate. In this case the non-network options may be MW-scale batteries and PV systems.

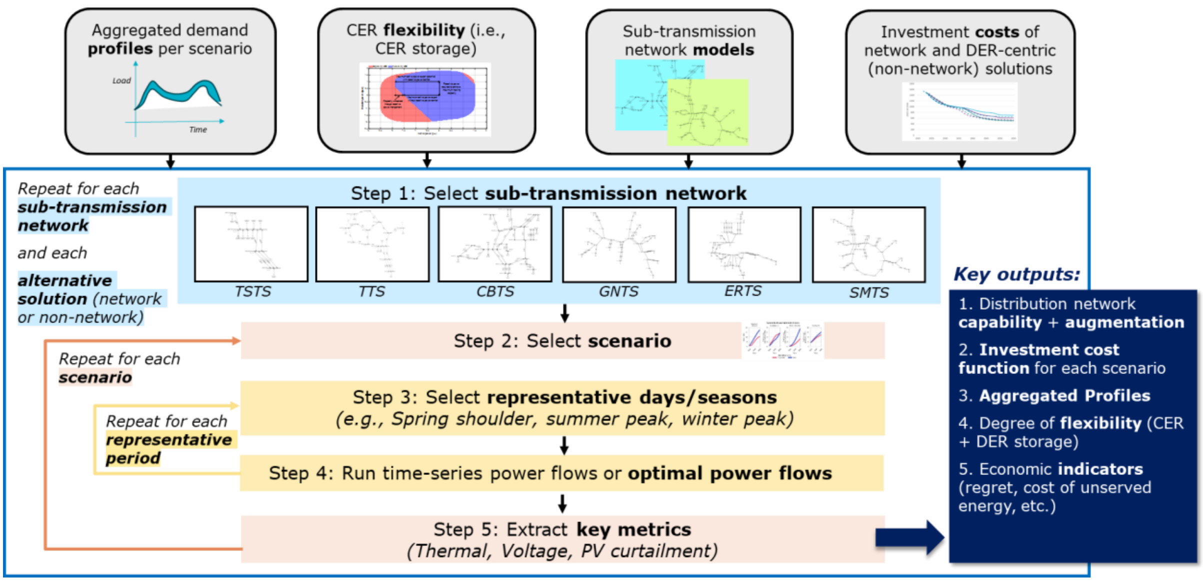


Figure 21: Flow chart describing the inputs and outputs of the optimal power flow studies performed under Element 3.

The process delineated in Figure 21 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-network) 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.[15] 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*[16] 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.

At this stage, the DNSP will have collected distribution network capability and 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-network solutions. This eventually allows the DNSP to find the trade-offs between investments on the MV-LV network (downstream from each DZS) and on the sub-transmission network and ultimately 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.

[15] 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.

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

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

At this stage, the DNSPs hand over to AEMO the 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 22. 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.

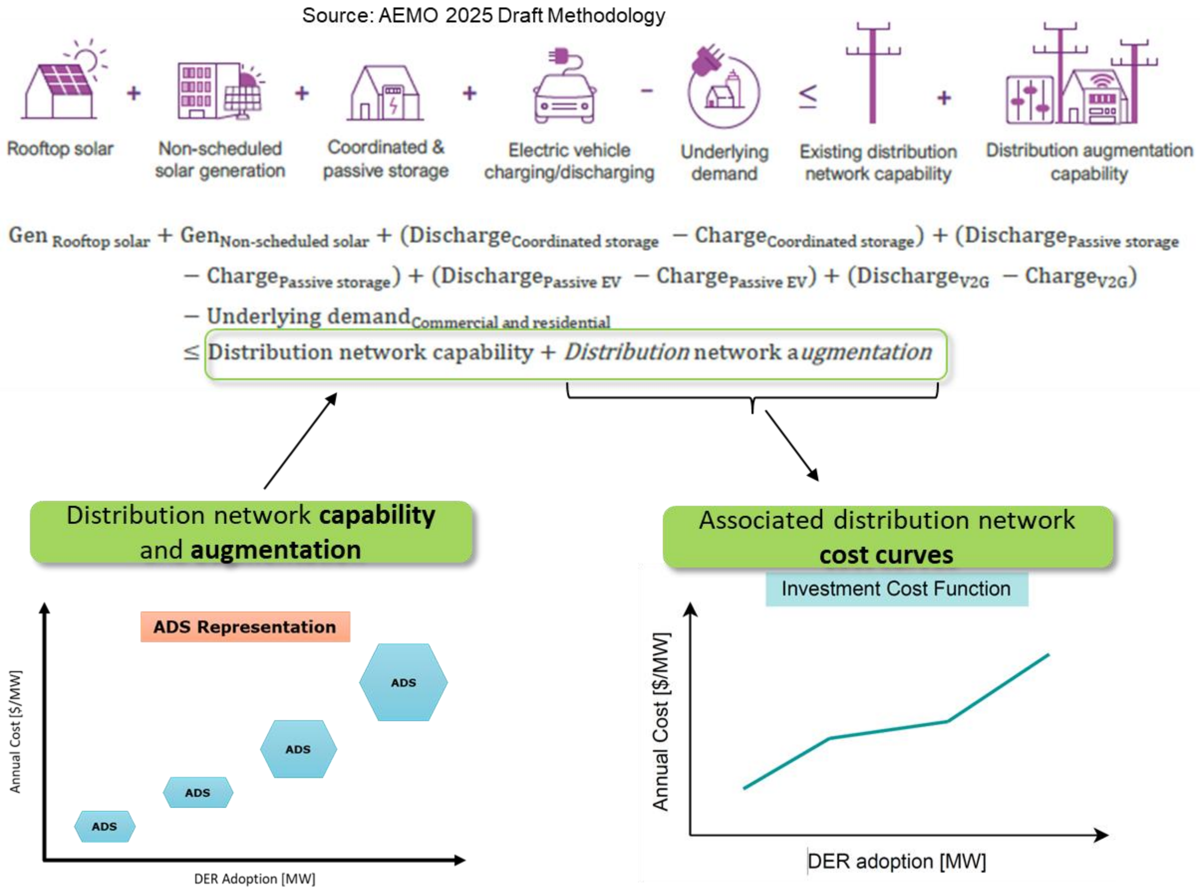


Figure 22: Integration of distribution network capability and augmentation, along with the associate investment cost curves into AEMO's ISP.

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.

Recommendations for implementation in AEMO's 2028 ISP

The roadmap outlined in Elements 1 to 5 above forms a complete and self-contained methodology that lays the groundwork the integrated planning of transmission and distribution systems from the bottom up. However, because developing such an expansive methodology within a short timeframe may be a challenging undertaking, all involved stakeholders should recognise its scale and instead aim to implement it iteratively over multiple ISP cycles. Therefore, a potential first step could involve adopting a simplified version of this roadmap that focuses solely on the 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 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 over 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.

Conclusion

The Enhanced System Planning (ESP) project has provided a comprehensive framework for integrating distribution network considerations into whole-of-system planning. By developing and refining bottom-up modelling methodologies, the project has highlighted the critical role of Distributed Energy Resources (DERs) and Consumer Energy Resources (CERs) in the energy transition. Through extensive research across multiple work packages, the findings reinforce the need for coordinated planning between transmission and distribution networks to ensure a cost-effective, reliable, and resilient power system.

The ESP builds on the strong foundation established by AEMO's Integrated System Plan (ISP), which has already provided a robust framework for system-wide planning. The ISP's thorough approach offers an excellent starting point, and the ESP now takes this further by incorporating active distribution systems, capturing emerging savings opportunities inherent in DER/CER integration. These opportunities can drive substantial cost reductions and enhance system flexibility as the energy transition progresses.

Key outcomes of the ESP include the development of investment cost functions for active distribution systems, distribution network capability maps (which also consider dynamic operating envelopes), and strategies for incorporating CER flexibility into system planning while considering uncertainty and risks. The project has also demonstrated that leveraging DER coordination can defer or replace costly transmission investments, ultimately reducing total system costs and supporting Australia's decarbonisation goals.

The findings underscore the appeal for a paradigm shift in electricity system planning—one that fully integrates distribution-level considerations, consumer participation, and innovative flexibility mechanisms. Implementing and sequencing flexibility in active distribution systems (ADS), alongside regulatory incentives, can help moderate upstream system investment needs and avoid double-investment in infrastructure. Additionally, harnessing flexibility from lower voltage area CERs presents the potential for even greater savings, further reducing the need for costly investments in transmission and distribution infrastructure. While investment costs would need to be verified with industry, modelled savings of over 25% are illustrated in case studies in WP 3.13 (using AEMO REZ data), which would represent multi-billion-dollar savings if applicable more broadly across the NEM. Future work should focus on refining these methodologies, strengthening policy and regulatory frameworks, and enhancing stakeholder collaboration to facilitate the transition towards an optimised, consumer-centric energy system.

An important consideration is the critical role of long-term integrated system planning in translating strategic "plans" into operational realities. Realising the full potential of future system flexibility—enabled by coordinated DERs and CERs, and active network management—hinges on proactive, forward-looking planning. Such planning should drive ecosystem-wide investments necessary to operationalise these strategies. Without this foundational planning, the latent flexibility embedded in DER/CER is unlikely to be effectively realised. This is particularly pertinent given the challenges associated with DER and CER adoption, as well as the need for third-party stakeholders to accept and enable the integration of their assets into power system operations.

The ESP’s insights serve as a foundation for future energy planning efforts, providing actionable strategies for policymakers, industry stakeholders, and network operators to navigate the challenges and opportunities of a rapidly evolving energy landscape.

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Appendix 1—Overview of ESP outcomes

Work package 1: Foundation for bottom-up modelling

WP 1 established the fundamental framework for bottom-up modelling, employing a systematic approach to determine energy profiles for each electrification element. The development and application of various modelling techniques were necessary, primarily due to data availability constraints and the need to reduce uncertainty across different elements. The key inputs, methodologies, and demand implications of electrification underpinning WP 1 are illustrated in Figure 23.

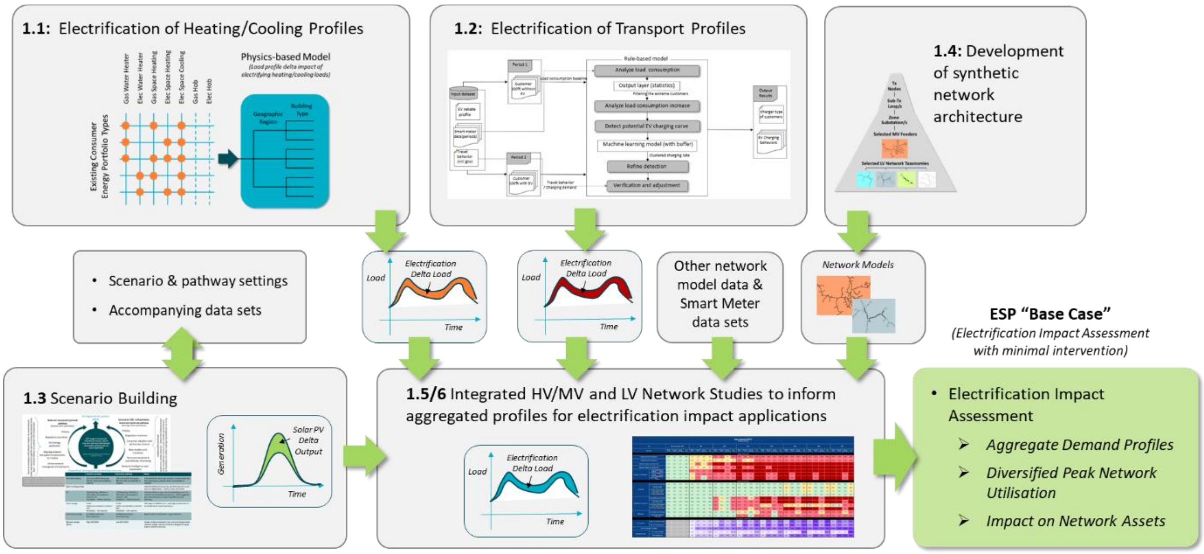

Figure 23: WP 1: Key inputs, methodologies, and demand implications of electrification to inform foundational elements of bottom-up modelling.

Electrification of heating and cooling

This theme falls under WP 1.1.

Key focus

WP 1.1 aimed at developing a technical modelling framework and tool to assess the impact of electrifying heating and cooling profiles on the DNs. By leveraging bottom-up modelling methodologies, the project provides a baseline understanding of electrification's demand implications and its role in electricity network planning. The framework is designed to evaluate different scenarios of domestic gas substitution with electricity, helping to inform decision-making for infrastructure upgrades and system flexibility. A highly accessible tool, built using a granular bottom-up approach, was developed to model the impacts based on a customisable set of user-defined inputs.

Background

Electrifying domestic gas demand is a crucial step toward achieving decarbonisation of end use. Given the significant scale of domestic gas consumption, particularly in Victoria, this transition plays a key role in DNs planning.

Outcomes

WP 1.1 has delivered a detailed modelling framework incorporating building-level energy demand models based on climate zones, appliance types, and occupant behaviours. A user-friendly tool was developed, enabling aggregated demand analysis for greenfield developments and existing homes. The model estimates After Diversified Maximum Demand (ADMD) increases, assisting in determining substation infrastructure requirements and upgrade costs. Additionally, a key insight from the research highlights how network tariffs with “off-peak” and “solar soaking” provisions could mitigate peak demand increases. The outputs of this model will be further utilised in Integrated MV-LV network studies to refine electrification impact assessments.

Electrification of transport

This theme falls under WP 1.2.

Key Focus

WP 1.2 aimed to model the electricity demand profiles for residential EV charging and assess the impact of vehicle-to-building (V2B) and vehicle-to-home (V2H) technologies on these profiles. By leveraging bottom-up modelling methodologies, the project sought to establish a foundational understanding of how transport electrification influences energy demand patterns. The insights gained will help inform electricity network planning and strategies for integrating EV effectively into the grid.

Background

The transport sector is a major and growing contributor to greenhouse gas emissions in Australia. Achieving the nation’s net zero emissions target by 2050 requires a transition to zero-emission transport, with battery electric vehicles playing a crucial role. However, this shift presents both challenges and opportunities for the electricity grid. A key challenge is ensuring sufficient network capacity to support the additional demand from EV charging. On the other hand, strategic charging management can enhance grid utilisation and maximise the use of renewable energy sources, particularly rooftop solar PV. Additionally, emerging V2B and V2H technologies could allow EV to act as distributed energy resources (DER), feeding energy back into buildings and the grid to improve system resilience.

Outcomes

WP 1.2 has provided critical insights into how residential EV charging impacts electricity demand profiles and the potential benefits of V2B and V2H technologies. The findings highlight the importance of smart charging strategies that align EV charging with off-peak periods and surplus renewable generation, reducing strain on the grid while enhancing energy efficiency. The modelling outcomes will inform future network planning efforts, ensuring that electricity infrastructure can accommodate the growing uptake of EVs while unlocking opportunities for grid-supporting technologies.

Scenario building

This theme falls under WP 1.3.1.

Key Focus

WP 1.3.1 aims to develop regional and suburban-level energy scenarios for Victoria, addressing gaps in current national and state-level forecasts. By disaggregating AEMO’s ISP and IASR forecast data, the study will create more granular scenarios for urban, semi-urban, and rural areas, such as Horsham, Ballarat, Melbourne CBD, Dandenong, and Epping. These scenarios will incorporate demographic trends, socioeconomic shifts, EV uptake transformation, and climate change impacts, allowing for a more detailed understanding of energy consumption, EV adoption, and renewable energy integration at a regional level.

Background

AEMO’s 2023 IASR scenarios consider broad-scale demographic and technological trends but do not provide insights at a granular regional or suburban level. This lack of detailed regional data limits the ability to assess local energy needs and infrastructure planning effectively. To bridge this gap, the study will develop region-specific energy scenarios using assumptions and levers consistent with the IASR, while also introducing additional parameters tailored to local conditions. Sensitivity analyses will be conducted to explore how factors such as population growth and socioeconomic changes influence EV uptake and renewable energy adoption in different regions.

Outcomes

The project will produce granular regional energy scenarios by leveraging IASR forecast data and disaggregating it based on demographic, socioeconomic, and technological trends. Key outcomes include:

- A scenario-building framework that accounts for regional variations in energy consumption, EV adoption, and heating and cooling demand.
- A methodology for disaggregating national-level data into regional insights using correlations between population growth, income levels, energy demand, and technology adoption.

- An open-architecture model capable of integrating with AEMO's ISP forecasts, ensuring adaptability to future updates.
- Stakeholder engagement with C4NET researchers and practitioners to refine assumptions and methodologies.

By providing regional and suburban energy insights, this study will enable more effective energy planning and policy decisions for Victoria.

Fairly integrating CER into the NEM: Consumers' policy perceptions

This theme falls under WP 1.3.2.

Key focus

The research project investigates consumer perceptions of policies designed to encourage the adoption and management of CER in Australia. It explores how much control consumers want over their CER and their views on policies regulating electricity import and export between CER and the electricity network.

Background

CER adoption is crucial for achieving Australia's decarbonisation goals. As more consumers integrate CER, electricity flow between their premises and the network changes. If not managed properly, this can lead to network capacity issues, such as supply transformer overloads from peak-time electric vehicle (EV) charging or voltage imbalances from excess solar PV exports. However, strategic CER usage, such as charging EVs during peak solar PV generation, can help mitigate these issues.

Outcomes

The study highlights the importance of policies that both encourage CER adoption and ensure consumer willingness to allow some external management over their CERs. Proper coordination, known as CER coordination, can help optimise energy flow and reduce the overall costs of decarbonisation in Australia.

Whole of distribution network architecture

This theme falls under WP 1.4.

Key Focus

WP 1.4 focuses on developing synthetic electricity DNs models to represent the Victorian grid for research and industry applications. It details the methodology, data acquisition, modelling approach, and validation techniques used to create pseudo-low-voltage (LV) network models that support various power system studies, including load flow analysis, voltage constraints, and hosting capacity assessments.

Background

Initially, the study planned to use CSIRO taxonomy models but found them biased toward networks outside Victoria. Instead, researchers shifted to a pseudo-LV network method that better reflects Victorian network characteristics. The models incorporate data from distribution network service providers (DNSP) and account for different network types, including urban, suburban, rural, and CBD feeders. The study also converted ten actual LV network models into a unified software platform for further validation.

Outcomes

The report presents five representative network models and their power flow simulation results. While the models are scalable and automate network development, they have limitations in capturing network parameter diversity and accurately modelling commercial and industrial customers. Despite these challenges, the developed models will serve as a foundation for future ESP work packages to assess power system impacts and improve network planning.

Integrated MV-LV network studies

This theme falls under WP 1.5.

Key focus

WP 1.5 focuses on assessing the impacts of electrification on Victoria's medium-voltage (MV) and low-voltage (LV) DNs. It includes a literature review on global electrification impact studies, identifies research gaps, and outlines methodologies to analyse the interaction between MV and LV networks in the presence of DER.

Background

Victoria is experiencing a rapid increase in DER adoption, including rooftop solar photovoltaics (PVs), EV, residential batteries, and gas electrification (e.g., heat pumps). While this supports the state's renewable energy goals, it also creates technical challenges such as voltage instability and asset congestion in DNs not originally designed for high DER penetration. Existing studies often fail to fully assess these challenges due to their limited scope—focusing on either MV or LV networks separately and analysing only specific DER technologies rather than their aggregated impact.

Outcomes

So far, WP 1.5 recommends an advanced model-based approach for electrification impact assessment using integrated MV-LV network models. This method aims at incorporating detailed power flow simulations, time-series analysis, and realistic DER management strategies such as flexible export limits and smart EV charging. By comparing these strategies with conventional network upgrades, the study aims to provide Victorian distribution companies with data-driven recommendations for future network planning beyond 2030.

Victorian whole-of-state network impact assessment

This theme falls under WP 1.6.

Key focus

The report focuses on assessing the impact of DER on Victoria's sub-transmission network (66kV). It includes a literature review of DER adoption, current sub-transmission planning practices in Victoria, and a comparison with the UK's Distribution Network Operators (DNOs). The goal is to provide recommendations for Victorian DNSP regarding sub-transmission network planning beyond 2030.

Background

Victoria is experiencing a rapid increase in DER adoption, including rooftop solar PV, EV, residential batteries, and gas electrification. While these technologies support renewable energy goals, they introduce technical challenges such as voltage instability and asset congestion. Although DER primarily impact lower voltage levels (22kV and below), their aggregated demand profile can significantly affect sub-transmission networks, potentially causing thermal and voltage constraints. Currently, DNSP in Australia conduct annual five-year network plans, compartmentalising assessments by voltage level, with sub-transmission networks typically analysed individually.

Outcomes

The project will assess DER impacts on sub-transmission networks using data from previous ESP work packages, including aggregated demand profiles from WP 1.5. It will evaluate thermal and voltage issues at Distribution Zone Substations (DZSs), sub-transmission lines, and terminal stations, considering both network and non-network solutions. The findings will help DNSP understand potential future challenges and develop strategies for effective network planning. Additionally, the project will provide maximum and minimum demand profiles and a methodology to facilitate broader impact assessments beyond 2030.

Work package 2: Impact of flexibility options within distribution networks

The primary objective of WP 2 was to investigate opportunities for managing DER and CER in coordination with the local network. This approach aimed to minimise the impact and cost associated with their integration while exploring their potential to provide flexibility in network planning and operation when aggregated. Figure 24 illustrates the scope of WP 2.

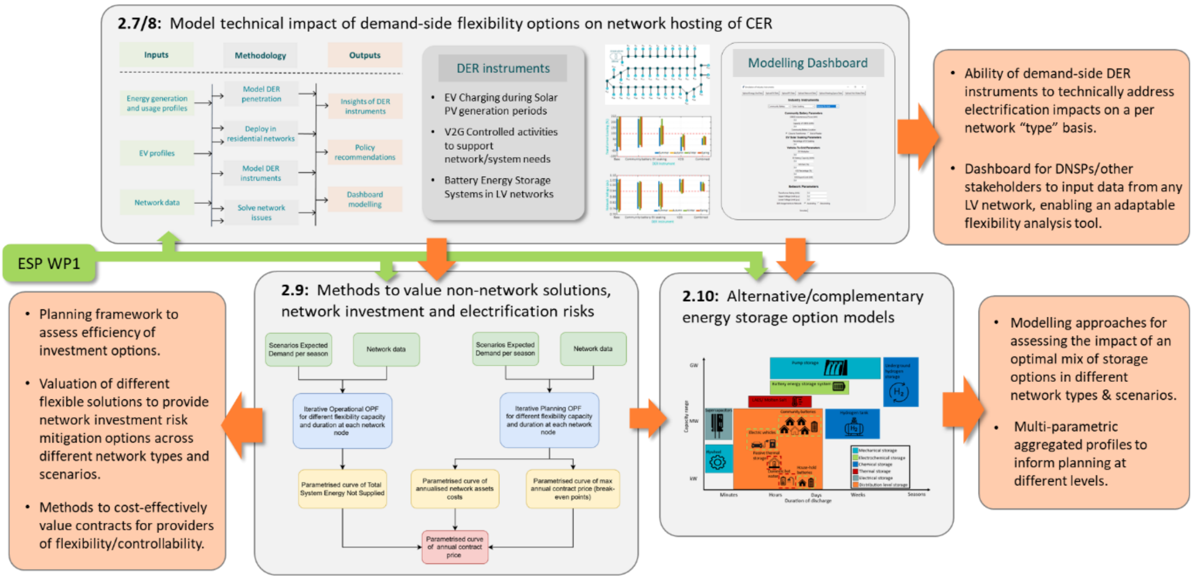

Figure 24: WP 2: Impact of flexibility options within distribution networks.

Techno-economic modelling

This theme falls under WP 2.7 and WP 2.8.

Key focus

WP 2.7 and 2.8 analysed DER instruments as solutions for addressing demand-side management challenges within LV DNs. It examines transformer overloading, voltage limit breaches, and hosting capacity constraints due to high DER penetration, including solar PV systems and EV. The study focuses solely on LV network issues, providing targeted insights for DNSP while excluding broader system-level or market-related functions.

Background

Victoria's LV networks are facing increasing technical challenges due to high DER adoption, leading to transformer overloading and voltage stability issues. A modelling tool was developed for DNSP to simulate DER management strategies using real-world network data. This tool evaluates the effectiveness of community batteries, EV charging through solar soaking, and vehicle-to-grid (V2G) technology in mitigating these network constraints. The study emphasises that the success of DER instruments depends on strategic deployment and management, such as battery placement and EV charging coordination.

Outcomes

The study found that community batteries are most beneficial in urban areas with high solar penetration, while V2G technology is more effective in rural networks. EV charging through solar soaking helps reduce network strain by aligning charging times with solar generation. The report recommends prioritising community batteries in high-PV areas, incentivising daytime EV charging, and carefully managing V2G systems. While economic factors were not fully assessed, the findings provide a basis for further techno-economic evaluations. WP 2.7 and 2.8 recommend that future research should consider market interactions and broader network variations to enhance the applicability of these insights.

Techno-economic modelling—non-network solutions

This theme falls under WP 2.9.

Key focus

WP 2.9 focuses on the techno-economic modelling and impact assessment of integrating DER into distribution system planning (DSP). It evaluates the benefits, methodologies, and applications of leveraging DER flexibility as an alternative to traditional network asset investments in the context of electrification and the energy transition.

Background

Australia is experiencing increased DER uptake, posing operational and planning challenges for DNs. The report reviews global and Australian studies on DER integration in DSP, highlighting the importance of flexibility, uncertainty considerations, and economic and physical risk analysis. It also examines real-world frameworks from the UK, California, and Australia to assess how DER can be valued as an alternative to network reinforcement.

Outcomes

The literature review confirms that incorporating DER flexibility in DSP can reduce operational and investment costs under coordinated schemes. However, current methodologies often fail to address all necessary complexities, such as uncertainty and pricing mechanisms. To bridge this gap, the project aims to develop a comprehensive methodology to assist Distribution System Operators (DSO) and regulators in effectively integrating DER into network planning.

Alternative/complementary storage options

This theme falls under WP 2.10.

Key focus

WP 2.10 focuses on conducting a comprehensive techno-economic analysis of various storage options within DNs to support the high penetration of renewables and increasing electrification. It aims to evaluate the benefits of integrating different storage solutions—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.

Background

Increase integration of CER into DNs presents new opportunities for coordinating them for system benefits. WP 2.10 aims to assess the extent to which various storage solutions at the distribution level can be utilised to enhance system flexibility, thereby supporting optimal dispatch and planning within distribution networks.

Outcomes

WP 2.10 aims to enhance understanding of the role and flexibility of various storage options in DNs. It seeks to provide the Victorian and Australian governments with valuable insights into potential cost savings achievable through the efficient utilisation of storage resources.

Work package 3: Active distribution system considerations for whole-of-system planning

Building upon the first two research work packages, which primarily focused on a bottom-up assessment of electrification impacts and CER flexibility within distribution networks, this research explored the interface between transmission and distribution. It aimed to evaluate the potential for system flexibility through the coordinated operation of aggregated DER and CER alongside distribution network assets within a whole-of-system planning framework. Figure 25 illustrates the scope of WP 3.

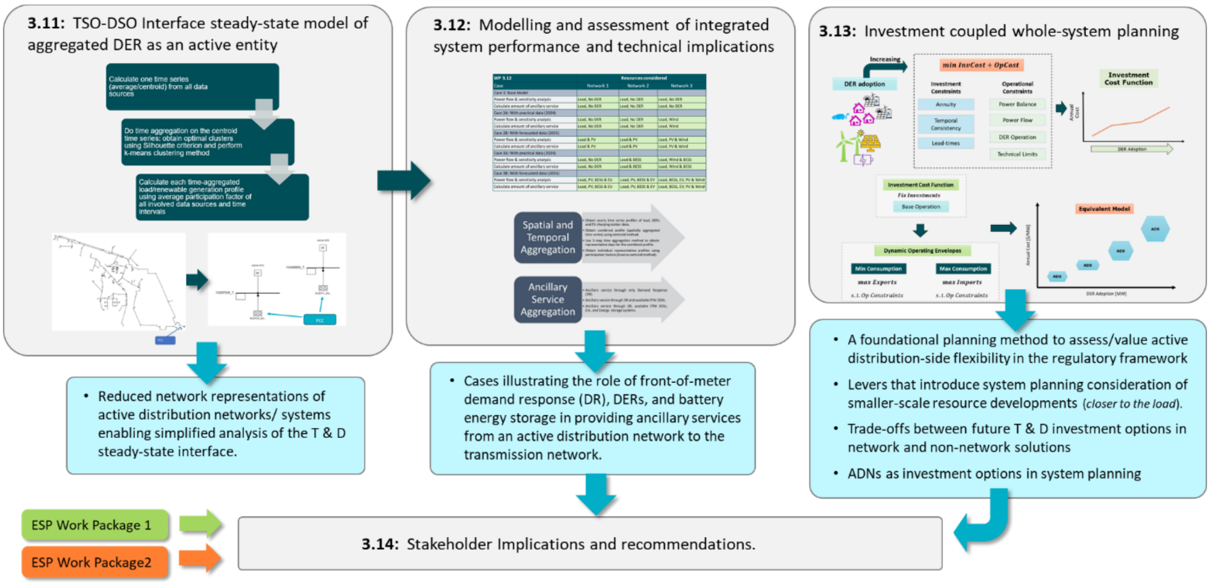

Figure 25: WP 3: Active distribution system (ADS) considerations for whole-of-system planning.

TSO-DSO Interface

This theme falls under WP 3.11.

Key focus

The report focuses on developing an equivalent steady-state model for the TSO-DSO interface to enhance the integration of DER into the electricity network. It aims to address computational complexity challenges in power system operation and planning by reducing large DNs into compact models while maintaining accuracy. The methodology combines network reduction and time aggregation techniques to improve efficiency in network analysis and planning.

Background

Australia is experiencing increasing DER penetration, projected to reach 45% of total electricity generation capacity by 2050. This growth presents challenges such as network congestion and voltage fluctuations. To manage these issues, collaboration between transmission system operators (TSO) and DSO is essential. Existing modelling approaches struggle with computational burdens, making it difficult to incorporate detailed distribution network data into transmission-level planning. WP 3.11 seeks to develop a more efficient modelling approach to address these challenges.

Outcomes

The developed methodology enables the reduction of large DNs to compact models with only three to five buses, significantly decreasing computational complexity while preserving network accuracy. It facilitates improved coordination between TSO and DSO, allowing more effective grid operation and planning. The methodology benefits AEMO, network service providers, and DNSP by integrating detailed DNs characteristics into upstream transmission system analyses. The model achieves near-zero error at the point of common coupling (PCC), ensuring reliability in planning and operational decisions. Key applications include security-constrained unit commitment (SCUC), optimal power flow analysis, network expansion planning, and market clearing functions. However, the study is limited to steady-state analysis and does not consider dynamic events or renewable generation uncertainties due to data constraints.

Modelling and assessment of integrated system performance

This theme falls under WP 3.12.

Key focus

WP 3.12 focuses on evaluating the coordination mechanisms between TSO and DSO for providing ancillary services (AS), particularly frequency and reactive power support, from active distributed networks (ADN) to transmission networks (TNs). It also aims to develop a tool for estimating these support services and analysing network and market interactions to enhance system reliability and efficiency.

Background

As the penetration of DER in Australia increases—projected to contribute 45% of total electricity generation by 2050—future DNs will need to operate both in islanded mode and in grid-connected mode while offering ancillary services to the upstream network. While DER provide potential benefits, they also present challenges such as network congestion and voltage excursions. Avoiding large infrastructure investments requires improved TSO-DSO coordination to manage the variability of renewable energy sources (RES) and integrate services provided by DER without compromising power system integrity.

Outcomes

WP 3.12 aims to develop an equivalent model of the DNs connected to the transmission system under various operating conditions. Key outcomes include assessing the feasibility of reactive and frequency support from DNs to TNs, identifying potential system benefits, and creating a tool to estimate support services. Preliminary findings of the study provide insights into the effectiveness of these ancillary services, with future work focusing on refining methodologies for steady-state modelling, network reduction, and time aggregation techniques to improve grid coordination and stability.

Investment-coupled whole-of-system planning

This theme falls under WP 3.13.

Key focus

WP 3.13 focuses on improving coordination between transmission and distribution system planning to better integrate CER and DER. It evaluates different methodologies for integrated planning and proposes a distributed approach to enhancing decision-making, reducing inefficient investments, and accurately capturing the value of CER in the Australian power system.

Background

The increasing deployment of small-scale energy assets such as EV, distributed storage, and distributed generation is transforming passive DNs into active ones, increasing complexity in power system planning. AEMO estimates that up to AU$4.1 B in large-scale investments could be avoided if CER is effectively coordinated. However, current system planning processes treat DER and CER as static components rather than actively considering their limitations and investment needs. Transmission and distribution planning remain largely independent processes, leading to inefficiencies and conflicting investments.

Outcomes

WP 3.13 identifies four main integrated planning methodologies—centralised, duality-based, iterative, and distributed approaches—assessing their feasibility for real-world applications. Given the challenges of data exchange and computational burden in other methods, the distributed approach is advocated as the most suitable solution. This methodology provides a parametric representation of required investments in ADS, optimising costs while supporting DER adoption. By enabling DSOs to generate cost functions and inform system planners like AEMO, the proposed approach has the potential to enhance coordination, improve investment decisions, and eliminate the need for detailed distribution network modelling in transmission planning.

Integrated planning could bring benefits regarding investment and operational costs, as well as improved resource allocation if compared to independent planning approaches. System planners and regulatory entities around the world have identified the need for new methodologies and improve coordination to better address the challenges of future power systems. Therefore, WP 3.13 provides the methodological steps to represent the planning of active distribution systems within whole-of-system planning, such that any DNSP can produce information to coordinate this framework.

By producing an investment cost function to support levels of DERs, it has been shown that the connection schedule of expected DERs can represent a huge difference in the infrastructure investments that need to be in place, as depicted in Figure 26. In this sense, taking advantage of the synergies between different technologies and location, such as solar and BESS, can help reduce total investment costs and make DER more cost-effective from a whole system perspective. Thus, this methodology can enhance the understanding for DNSPs on the most economical way to connect DERs.

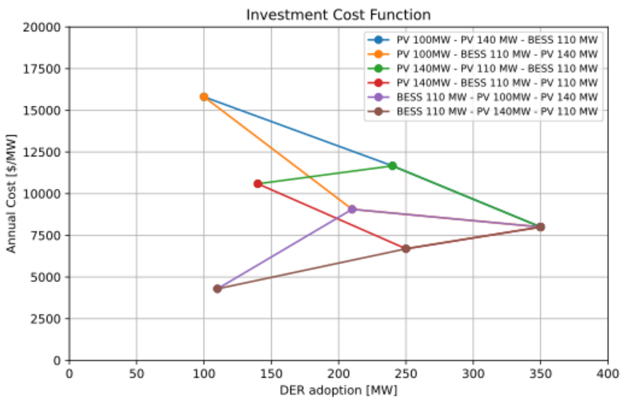

Figure 26: Impact of DER connection schedule.

Moreover, the value of active network management and CER coordination can impact this cost function as well, serving as a crucial conclusion for DNSP to look at these alternatives when planning their networks, and take a more active role in the operation of distribution system. Doing so could open the door for additional DER to connect, which could be more attractive from a whole-of-system perspective.

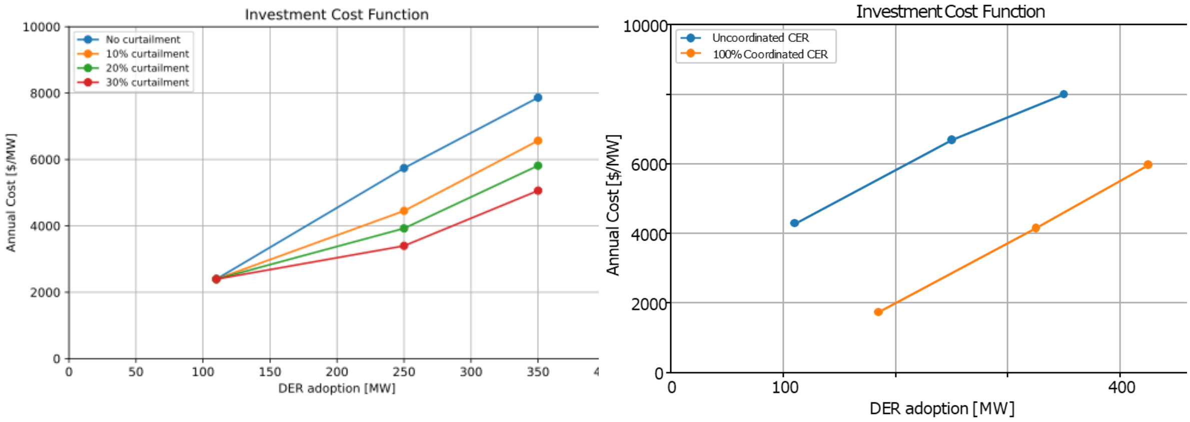

Figure 27: Impact of DER curtailment and CER coordination.

Finally, this information can be included in any transmission planning problem, allowing to decide over large- and small-scale resources within this whole-of-system perspective. This was shown for the state of Victoria by comparing the development of DER against renewable energy zones (REZ) within the state (information from the ISP 2024). To do this, three sub-transmission networks from AusNet were analysed, CBTS, GNTS-MBTS, and SMTS**.** The parametrisation of DER was associated with the connection enquiries according to AusNet information as seen in Figure 28, where the investment cost includes infrastructure to support DER and the capital cost of these assets to truly compare investments across the whole system. Moreover, AEMO identifies 15 REZ options for the state of Victoria with an average capital cost of 0.75 $M/MW**,** with the highest being REZ 6 with 2.8 $M/MW, and the lowest 0.15 $M/MW for REZ 5.

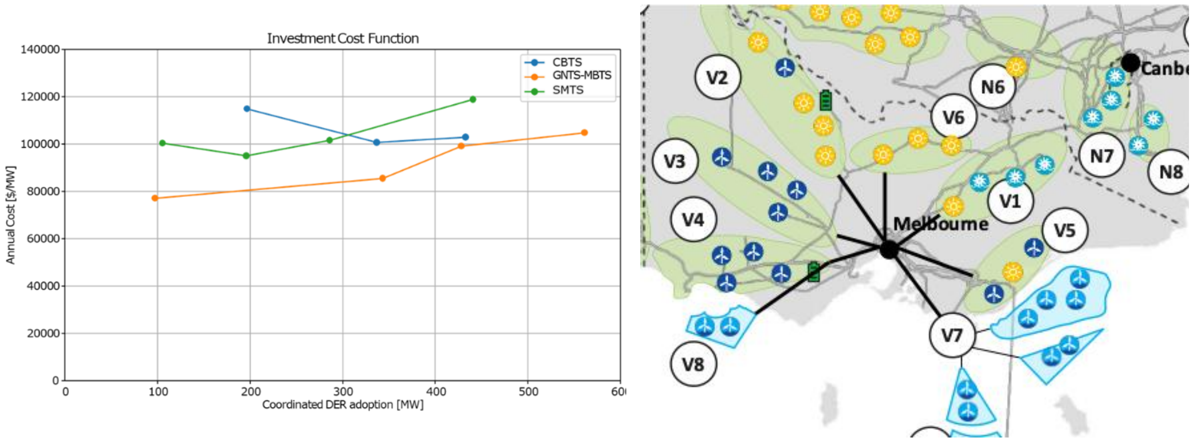

Figure 28: Cost functions for sub-transmission networks and renewable energy zones in Victoria.

Results show that, if decision-making over DER is neglected, a total of 13.4 GW of transmission augmentations for REZ 4, REZ 5, REZ 6, and REZ 7 are needed. This is to support the development of 100 MW of solar in REZ 6, and 5.8 GW of wind in REZ 4, REZ 5, REZ 6 and REZ 7, plus 4.1 GW of large-scale storage (4 hours) are built in REZ 4. On the contrary, once we unlock the possibility of investing in DER, the total transmission needed is 8 GW, reduction of 5.4 GW, while developing 800 MW of solar, and 5.4 GW of wind, with only 3.5 GW of large-scale storage, representing a reduction of 600 MW. Therefore, just by taking a whole-of-system decision-making perspective, it is possible to develop resources across the system in a more efficient way, which could be even greater if we properly assess CER coordination within these networks.

Appendix 2—Bigger picture integration with the ISP

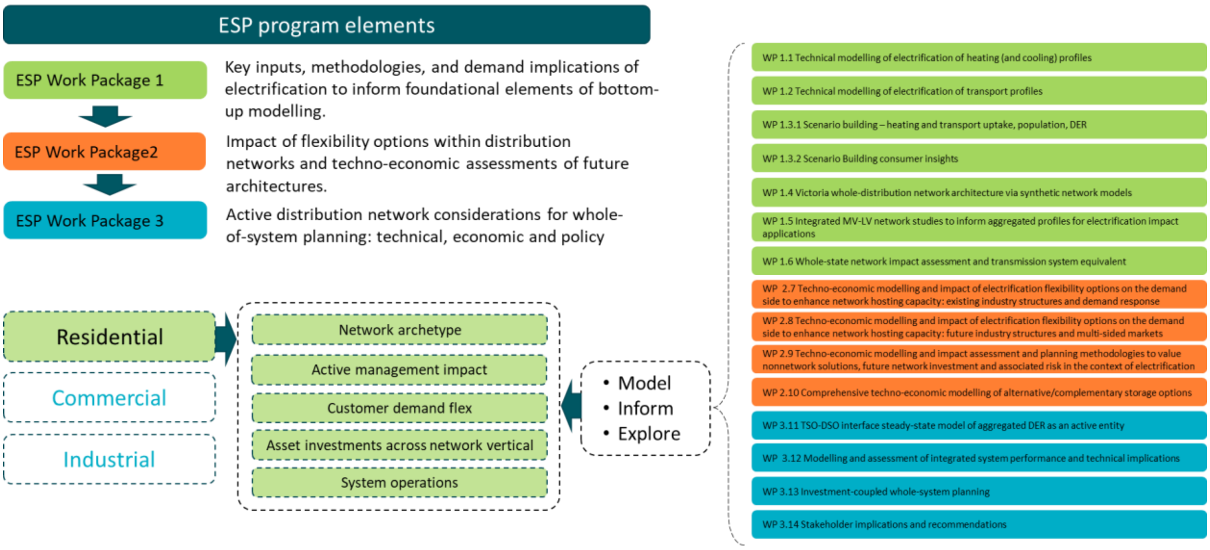

Figure 29: ESP alignment with distribution system components of whole-of-system planning.

Appendix 3—ESP project and research partners