Enhanced System Planning Project

C4NET | ESP Enhanced System Planning

C4NET Project Overview

TSO-DSO Interface Steady-state Model of Aggregated DER as an Active Entity

Work package 3.11

and

Modelling and Assessment of Integrated System Performance and Technical Implications

Work package 3.12

March 2025

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1. Purpose of the report

The Enhanced System Planning (ESP) project is a significant and collaborative research project aimed at informing sub transmission level electricity planning 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 Consumer Energy Resources (CER) and Distributed Energy Resources (DER), with the goal of informing whole of system planning. The ESP seeks to inform gaps that would emerge if 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 for enhancing energy demand forecasting in the ISP[2]. The ESP Project is targeted at addressing the distribution system considerations aspect of this expanded scope, with particular focus on bottom-up modelling approaches from the low voltage distribution system upwards, as outlined in *Figure 1*. For the bigger picture of integration with the ISP see *Appendix Two.*

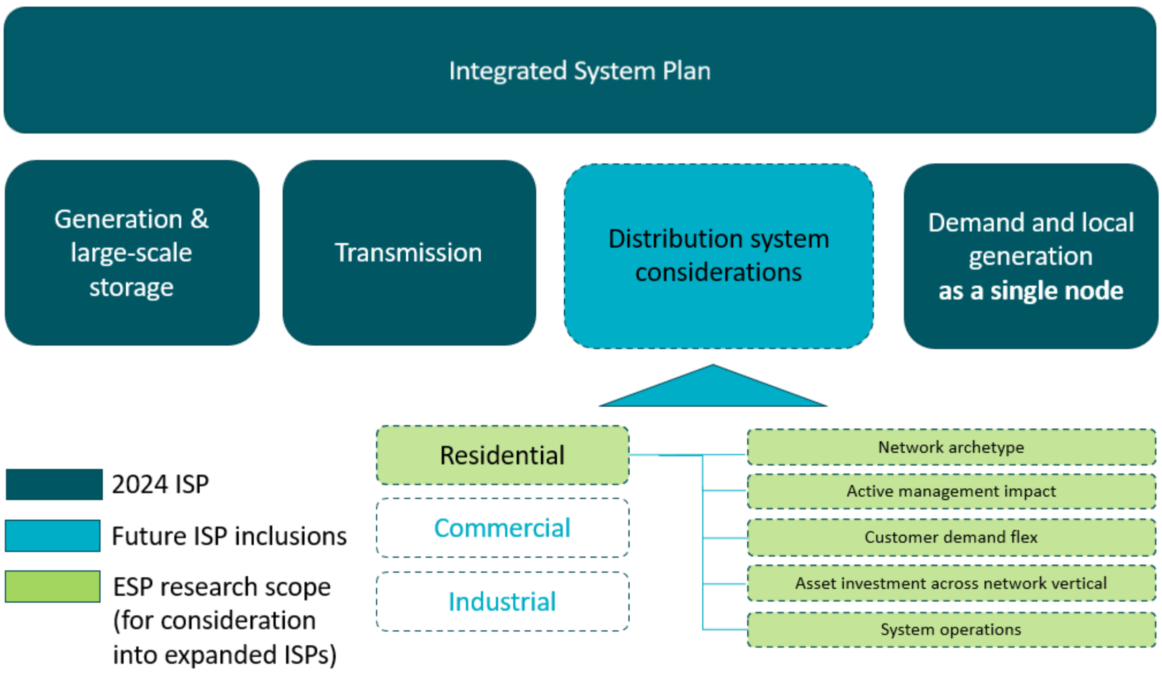


Figure 1 – Relationship between ISP and ESP

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.

[1] 2024 Integrated System Plan (ISP), Australian Energy Market Operator, June 2024
[2] Review of the Integrated System Plan: ECMC Response, ECMC, April 2024

- **Work package two**: Impact of flexibility options within distribution networks Techno-economic implications of future architectures.
- **Work package three:** Active distribution network considerations for whole-of-system planning implications: technical, economic and policy

A key project of work package three, Federation University undertook two related research projects: **TSO-DSO Interface Steady-state Model of Aggregated DER as an Active Entity** (WP3.11) and **Modelling and Assessment of Integrated System Performance and Technical Implications** (WP3.12). CERs are consumer-owned technologies that allow households to generate energy (e.g., rooftop photovoltaics), store energy (e.g., electric vehicles, household batteries), and/or shift how they use energy (e.g., smart electric hot water systems). Distributed Energy Resources (DERs) are like CERs except they are normally connected in front of the customer meters whereas CER are connected behind the customer meters. Significant number of CERs/DERs can cause challenges, such as network congestion and voltage excursions, when their operations conflict with network conditions. To support Renewable Energy Sources (RESs) integration, large investments in new network infrastructure in transmission and distribution networks can be avoided by exploring the flexibility that can be leveraged from these CERs/DERs. As CERs/DERs are embedded in the distribution networks, the transmission system operator requires better ability to model at the transmission and distribution network interface to consider the integrated effect of the CER/DER operations within the context of the distribution networks.

The current electricity supply structure in Australia has the Australian Energy Market Operator (AEMO) operating the transmission network as the Transmission System Operator (TSO). Historically there hasn't been a need for a companion Distribution System Operator (DSO) role. With the increasing active nature of the distribution network brought about by increased levels and diversity of embedded CER/DER, however, it is likely that this new role will evolve to operate the distribution network to provide flexibility services to both the Distribution Network Service Provider (DNSP) and the TSO. To improve the efficiency of this market arrangement so ultimately the consumers benefit, it is important that the TSO, in its operational and long-term planning, considers the behaviour and operation status of CERs/DERs embedded in the distribution networks, as well as inherent flexibility that can be introduced by distribution network management activities in concert with connected DER/CER.

The Operational Technology (OT) systems used for the purpose of remote monitoring and control are called Supervisory Control & Data Acquisition (SCADA) systems. SCADA interfaces to Energy Management System (EMS) for advanced transmission applications. For advanced distribution applications SCADA interfaces with Advanced Distribution Management System (ADMS). For the TSO to carry out integrated system studies covering both transmission and distribution networks, there are a number of possible technical options, of which these three are prominent:

1. Extending TSO's SCADA/EMS into the distribution networks by capturing network data, real-time operation data as well as forecast data (for scenario assessment). This will, in effect, allows the TSO to run supply and security studies for the complete transmission and distribution network as an integrated entity. This option, however, requires significant investment and likely incurs long study runtime. It also potentially foregoes the opportunity to synthesize active distribution network operations relating to CER/DER that benefit the local networks and the overall system.
2. An alternative to (1) is to interface TSO's SCADA/EMS with the DSO's SCADA/ADMS, to allow data and commands to be passed between the two systems. When the TSO wishes to conduct a system study on the integrated network, it will ask the relevant DSO system to conduct the study on the distribution network and returns the results. The DSO results are then taken into account by the TSO system in running the transmission study. This option may incur lesser investment (compared with Option 1) but will require significant coordination between the TSO & DSO to ensure compatibility of their systems. Study runtime could be faster than Option 1.
3. Another alternative to (1) is to represent the distribution network as an equivalent model at the transmission/distribution network interface. The TSO will run system studies based on the simplified representation of the distribution network. This option is likely to require the least investment, has faster study runtime but may be less accurate. The option also maximises the application of expertise within the TSO/DSO domains in the short to medium term.

The Federation University Australia research project aims to build an equivalent steady-state model for the TSO/DSO interface for the upstream grid support, in line with Option (3) above (WP3.11), and then apply the model to demonstrate a number of flexibility services that can be provided to meet the energy market ancillary service requirements using CER/DER from the active distribution networks (WP3.12). The CER/DER assessed include demand response, Front-of-the-meter (FOTM) solar systems and wind systems, and FOTM energy storage systems (including battery energy storage systems and electric vehicle charging stations). The ancillary services covered are Frequency Control Ancillary Services (FCAS) and Reactive Power Services (part of Network Support & Control Ancillary Services, NSCAS).

This report is designed to inform stakeholders in their understanding of the equivalent steady-state model developed and its potential applications for informing ancillary services from DSO to TSO.

In addition, C4NET has sought through this report to summarise and evaluate the research, identify any opportunities or limitations with the approach taken, and highlight any observations or insights for AEMO, DNSPs, regulators and policy makers and market operators and for future research. This has also been done taking into consideration broader consultation and a range of stakeholder views and seeks to maintain a focus on consumers as the beneficiaries of an integrated energy system.

2. Project Summary

The **TSO-DSO Interface Steady-state Model of Aggregated DER as an Active Entity** aims to build an equivalent steady-state network model to represent a portion of the distribution system at an interface (called the Point of Common Coupling, PCC) with the upstream network. The equivalent representation incorporates essential elements of active distribution networks such as distributed renewable generation (CER/DER), electric vehicles and storage systems. The model developed can be applied within the distribution network to represent a part of the distribution network, or at the boundary of TSO-DSO for the whole distribution network. In addition, the project delivers a time aggregation methodology to reduce one-year dataset into two representative day profiles. The purpose of the equivalent network model and time aggregation is to reduce the computational effort required to conduct planning studies while preserving the accuracy of the study results.

The equivalent steady-state network model and time aggregation approach is then used in **Modelling and Assessment of Integrated System Performance and Technical Implications** to demonstrate the provision of ancillary services from the active distribution networks to the transmission network covering frequency regulation and reactive power support.

Both projects use three Victorian Medium Voltage (MV) networks as case studies to demonstrate the methodology.

The project's relationship with other research projects in Work Packages 1, 2 & 3 is illustrated in *Figure 2* below.

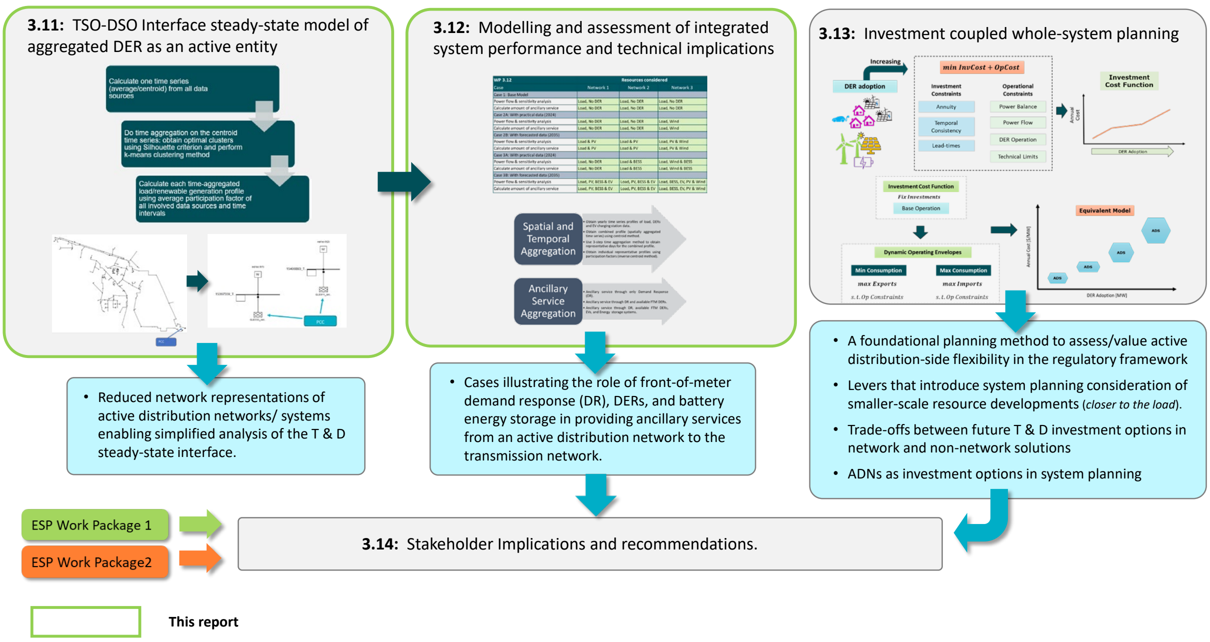


Figure 2 – Relationship between this research project and other projects in Work Packages 1, 2 & 3

The project has delivered an ancillary service calculator which allows users to input their own load, DER and storage profiles (time series data up to half-hourly resolution for the duration of 1 year) for building up the equivalent steady-state model, vary the parameters relating to ancillary service participation from the various resources, and outputs the estimated quantum of ancillary services (FCAS and reactive power).

3. Research methodology and approach

Distribution networks are extensive incorporating many consumers and network assets. Connection point to each network asset and customer off-take are modelled as “buses” in network topology terminology. Typical distribution network topologies include many buses. In addition, long-term planning studies span a long time horizon. A time resolution of half-hourly over 10-year planning horizon means 175,200 time periods to be considered in the planning studies. If there are 1,000 buses in the network topology, there will be 175 million results to be calculated in each planning study!

Detailed modelling of distribution networks in network studies are therefore computationally intensive hence it could be desirable that spatial reduction technique can be applied to reduce portions of the network to their simplified equivalent representations. In addition, time aggregation technique can be used to reduce the number of time periods to be studied.

3.1 Approach

The project proposes a new methodology that combines network reduction methods and time aggregation to achieve a higher computational efficiency. For network reduction the project adopts the Ward methodology. K-means clustering method in association with the Silhouette criterion is used to obtain the optimal number of representative periods to reduce the number of time period required for the studies.

The Ward methodology can replace a very large distribution network in the range of hundreds or thousands of buses with an equivalent network in the range of 3-5 buses, while preserving the characteristics and conditions at the boundary (PCC) between the equivalent network and the upstream network.

A three-step time aggregation method is developed utilising K-means clustering technique and the Silhouette criterion to obtain representative days with representative daily profiles of loads, PV, wind, and EV from half-hourly energy data. Instead of running studies using half-hourly data over the whole study period, the time aggregation approach allows the studies to be run for the representative days.

A flowchart for the combined network reduction and time aggregation is shown in Figure 3:

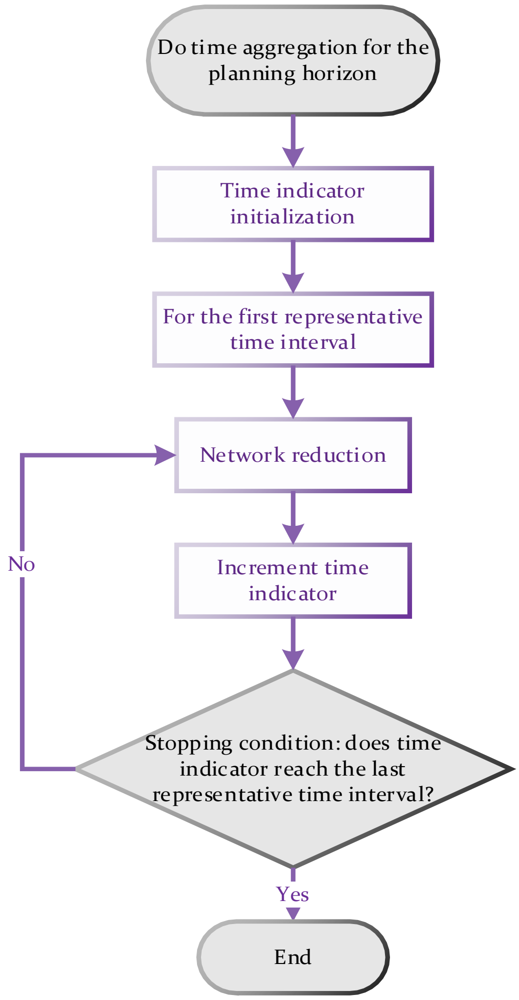


Figure 3 - Flowchart of the proposed method[3]

3.2 Inclusions, exemptions and limitations

Following limitations are noted for model development and analysis because of the limited scope of the project and the unavailability of appropriate network information[4]:

- It is a steady-state model and doesn't consider dynamic or transient behaviours;
- The network analysis does not include abnormal network conditions caused by network maintenance activities and unplanned outages triggered by natural phenomena (such as wildfire, flood, and windstorm) because of the lack of available network topology, load profiles, and renewable generations' data as well as natural phenomena data. However, the developed methodology can be applied for the periods of maintenance activities and abnormal phenomena if the above-mentioned data are available;
- The uncertainties of the renewable generations are not considered due to the lack of their distributional data. In other words, nominal outputs of renewable generations are assumed;

[3] WP3.11 TSO-DSO Interface Steady-state Model of Aggregated DER as an Active Entity, Section 2.3, Page 14
[4] WP3.12 TSO-DSO Interface Steady-state Model of Aggregated DER as an Active Entity, Executive Summary, Page 6

- While projection of load for the future includes estimated native load growth, other growth factors such as increased adoption of solar PV and electrification and their effect on net load profile have not been included.

3.3 Base assumptions

Nil.

3.4 Model Accuracy Validation

The proposed methodology is tested on three real-world Victorian MV distribution networks connected to Drysdale Zone Substation (Network 1), Geelong East Zone Substation (Network 2), and Ballarat South Zone Substation (Network 3).

Three case studies are considered – Case 1: With only load and with no DERs and storage; Case 2: With load and DERs and Case 3: With load, DERs, and storage. Case 2 and Case 3 are further divided into cases A and B. A snapshot-by-snapshot approach is used to implement the proposed combined method.

Table 1 - Study cases considered for network reduction and time aggregation

WP 3.11	Resources considered		
Case	Network 1	Network 2	Network 3
Case 1: Base Model			
Power flow & sensitivity analysis	Load, No DER	Load, No DER	Load, No DER
Representative network analysis	Load, No DER	Load, No DER	Load, No DER
Case 2A: With practical data (2024)			
Power flow & sensitivity analysis	Load, No DER	Load, No DER	Load, Wind
Representative network analysis	Load, No DER	Load, No DER	Load, Wind
Case 2B: With forecasted data (2035)			
Power flow & sensitivity analysis	Load & PV	Load & PV	Load, PV & Wind
Representative network analysis	Load & PV	Load & PV	Load, PV & Wind
Case 3A: With practical data (2024)			
Power flow & sensitivity analysis	Load, No DER	Load & BESS	Load, Wind & BESS
Representative network analysis	Load, No DER	Load & BESS	Load, Wind & BESS
Case 3B: With forecasted data (2035)			
Power flow & sensitivity analysis	Load, PV, BESS & EV	Load, PV, BESS & EV	Load, BESS, EV, PV & Wind
Representative network analysis	Load, PV, BESS & EV	Load, PV, BESS & EV	Load, BESS, EV, PV & Wind

3.4.1 Accuracy of network reduction

The networks received from the DNSP were converted into the DIgSILENT PowerFactory environment and a steady-state network power flow analysis was performed. Then the network steady-state operating points and network security were analysed for different loading conditions representing the present (2024) and future (2035). The K-means clustering method and the three-step time aggregation methods are used to obtain time-aggregated representative days for further analysis. For each representative half-hour time interval, a reduced network is obtained using Ward network reduction methodology. Example of time aggregation and network reduction results for Network 3 (Ballarat South Zone Substation) are shown in Figures 4 & 5:

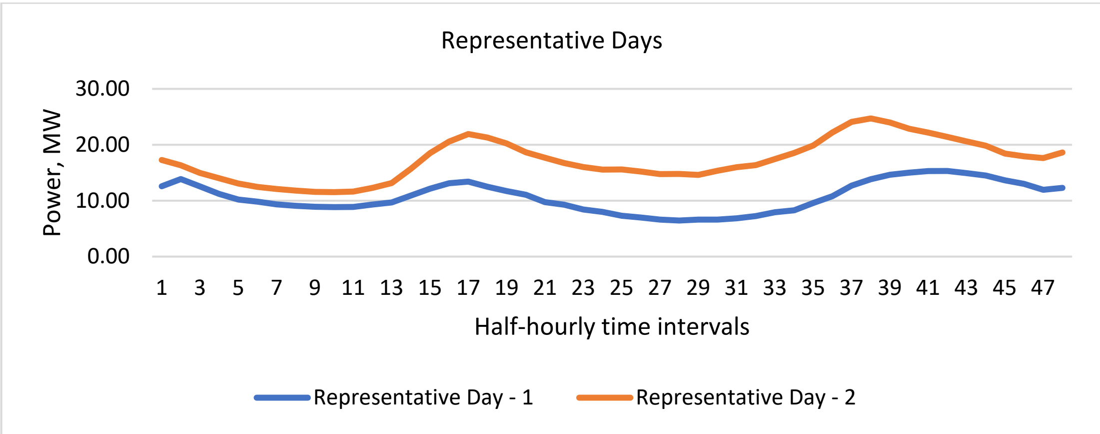


Figure 4 - Representative daily profiles obtained from time aggregation for Network 3

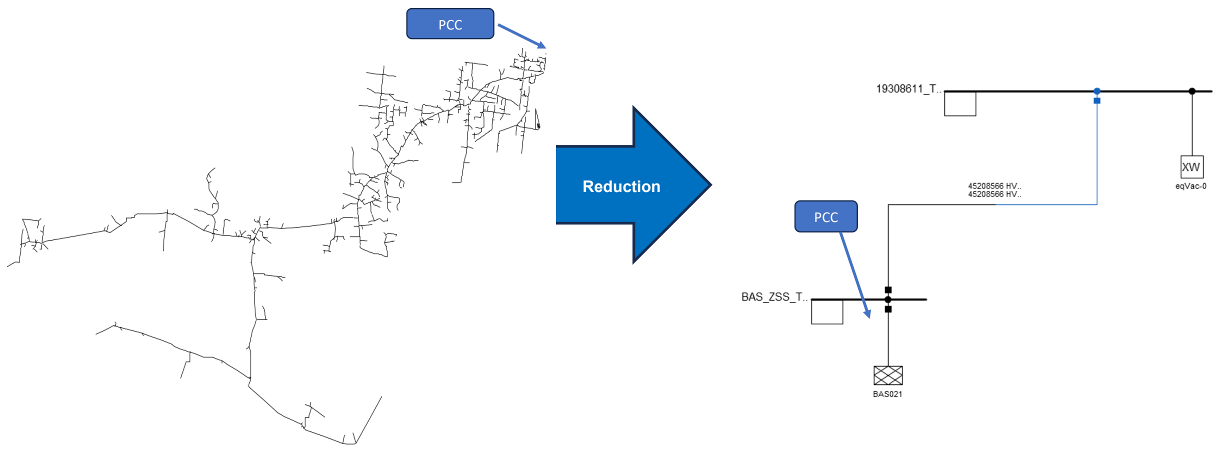


Figure 5 - Example output from network reduction for Network 3

The accuracy of the non-linear AC power flow results (active and reactive powers, voltages, and currents) for the original and reduced network is analysed for the three cases, namely without DERs, with DERs, and with storage devices, at the Point of Common Coupling (PCC) between the reduced network and the upstream network.

The summary of maximum errors in active and reactive power for different case studies and networks are presented in Table 2 and Table 3. Overall, the maximum error in active power is 0.646% and the maximum power of reactive power is 0.82% after network reduction. No error of voltage is found in any of the study cases for all networks.

Table 2 - Maximum active power errors for different case studies[5]

Cases	Network 1			Network 2			Network 3		
	Max, P	Max error, P (kW)	Max error, P (%)	Max, P	Max error, P (kW)	Max error, P (%)	Max, P	Max error, P (kW)	Max error, P (%)
Case 1	14000	0	0	1263.3	0.2	0.02	16263.7	501.8	0.02
Case 2A	49035.5	196.3	0.47	9058.5	0	0	23481.3	20.7	0.09
Case 2B	48638	0	0	10043.4	0.8	0.03	23481.3	20.7	0.09
Case 3A	49035.5	196.3	0.47	9058.5	0	0	23481.3	20.7	0.09
Case 3B	52530.2	339.7	0.65	10353.5	0.9	0.03	28356.2	20	0.10

Table 3 - Maximum reactive power errors for different case studies[6]

Cases	Network 1			Network 2			Network 3		
	Max, Q	Max error, Q (KVAR)	Max error, Q (%)	Max, Q	Max error, Q (KVAR)	Max error, Q (%)	Max, Q	Max error, Q (KVAR)	Max error, Q (%)
Case 1	1600	0	0	515.5	0.1	0.02	5090.8	7.2	0.20
Case 2A	27365.5	96.6	0.52	614	0	0	4357.7	31.5	0.80
Case 2B	26576	0	0	637.5	0.4	0.08	4357.7	31.5	0.80
Case 3A	27365.5	96.6	0.52	614	0	0	4357.7	31.5	0.80
Case 3B	31257	170.3	0.54	645.1	0.4	0.08	6931.2	30.4	0.82

3.4.2 Accuracy of time aggregation

As the representative daily profiles do not cover all network operating conditions, a long-run test has been performed for the Ballarat South network where all types of DERs (PV and Wind) and storage (BESS and EV fleet storage) were considered and run for every half-hour over a 9-month period. A summary of the network reduction performance in the long-run test, compared with the use of representative daily profiles, is presented in Table 4:

Table 4 - Maximum active and reactive power errors compared with long-run test[7]

Parameters	Median error (%)	Maximum error (%)

[5] WP3.11 TSO-DSO Interface Steady-state Model of Aggregated DER as an Active Entity, Section 5.5, Table 22, Page 113
[6] WP3.11 TSO-DSO Interface Steady-state Model of Aggregated DER as an Active Entity, Section 5.5, Table 23, Page 113
[7] WP3.11 TSO-DSO Interface Steady-state Model of Aggregated DER as an Active Entity, Appendix, Table A.1, Page 117

Reactive power at PCC	0.019%	7.11%
Active power at PCC	0.060%	1.07%

3.5 Modelling of Integrated System Performance

After verifying the accuracy of the network reduction and time aggregation methodology, WP3.12 uses the methodology developed in WP3.11 to illustrate the potential of ancillary services from the DERs in the distribution network to the transmission network, for different system planning and operation studies. The CER/DER assessed include demand response, Front-of-the-meter (FOTM) solar generation and wind generation, and FOTM energy storage systems (including battery energy storage systems and electric vehicle charging stations). The ancillary services covered are Frequency Control Ancillary Services (FCAS) and Reactive Power Services (part of Network Support & Control Ancillary Services, NSCAS). The three Victorian MV networks used in WP3.11 are used for the illustrative case studies in WP3.12.

3.5.1 Case studies for ancillary services

The DER resources considered for ancillary services include load demand response (DR), solar PV, wind, energy storage systems (ESS) and electric vehicle (EV) charging stations. Except DR, all the other DER resources are assumed to be connected directly to the MV network in front of the customer meters. While reasonable assumptions are used to forecast the load and DER data for 2035, the focus of the project is not on forecasting methodology. The forecast data should be treated as illustrative.

The study cases are shown in Table 5 while the maximum load demand and DER resources are shown in Figure 6:

Table 5 – Study cases considered for ancillary services[8]

WP 3.12	Resources for ancillary service		
Case	**Network 1**	**Network 2**	**Network 3**
Case 1: Base Model	DR	DR	DR
Case 2A: With practical data (2024)	DR	DR	DR and Wind
Case 2B: With forecasted data (2035)	DR and PV	DR and PV	DR, PV, and Wind
Case 3A: With practical data (2024)	DR	DR	DR and Wind

[8] WP3.12 Modelling and Assessment of Integrated System Performance and Technical Implications, Section 2.2.3, Table 1, Page 18

Case 3B: With forecasted data (2035)	DR, PV, ESS, and EV station	DR, PV, ESS, and EV station	DR, PV, Wind, ESS, and EV station

Table 6 - Present (2024) and forecasted (2035) demand and DERs for analysis[9]

Demand and DERs	Network 1		Network 2		Network 3	
	Present 2024	Forecast 2035	Present 2024	Forecast 2035	Present 2024	Forecast 2035
Max Demand	61.42 MW	76.37 MW	53.39 MW	66.38 MW	30.22 MW	37.57 MW
PV	-	5 MW	-	5 MW	-	5 MW
Wind	-	-	-	-	6.15 MW	6.15 MW
BESS	-	5 MW	-	5 MW	-	2.5 MW
EV	-	5 MW	-	5 MW	-	2.5 MW

3.5.2 Settings of DR

DR can affect active power consumption and hence can provide FCAS service. Four parameters are used to define DR:

- Location of DR providing loads (% of customers participating in DR) – Customers providing DR may be spread at different locations of the network. However, as this information is not known, the DR resources are randomly distributed in the whole network;
- Amount of DR participation (% of participating load from each customer);
- Type of DR (% of up and % down reserve from the total DR reserve) – load increase represents a down reserve while load decrease represents an up reserve.

3.5.3 Settings of PV Generation

As modern-day PV inverters can change their active and reactive power outputs by operating below their Maximum Power Point (MPP), PV generation can provide both up and down FCAS and reactive power ancillary services. Three parameters are used to define PV for the two ancillary services:

- Amount of PV participation (% of participating PV owners)
- Type of response (% of up and % down reserve from the total PV reserve)

3.5.4 Settings of Wind Generation

As modern-day inverter-connected wind turbines can change their active and reactive power output by adjusting their position with respect to the wind direction and utilising the power electronics inside the inverter, wind generation can provide both up and down FCAS and reactive power ancillary services. Three parameters are used to define wind for the two ancillary services:

[9] WP3.12 Modelling and Assessment of Integrated System Performance and Technical Implications, Section 2.2.4, Table 2, Page 19

- Amount of wind participation (% of participating wind owners)
- Type of response (% of up and % down reserve from the total wind reserve)

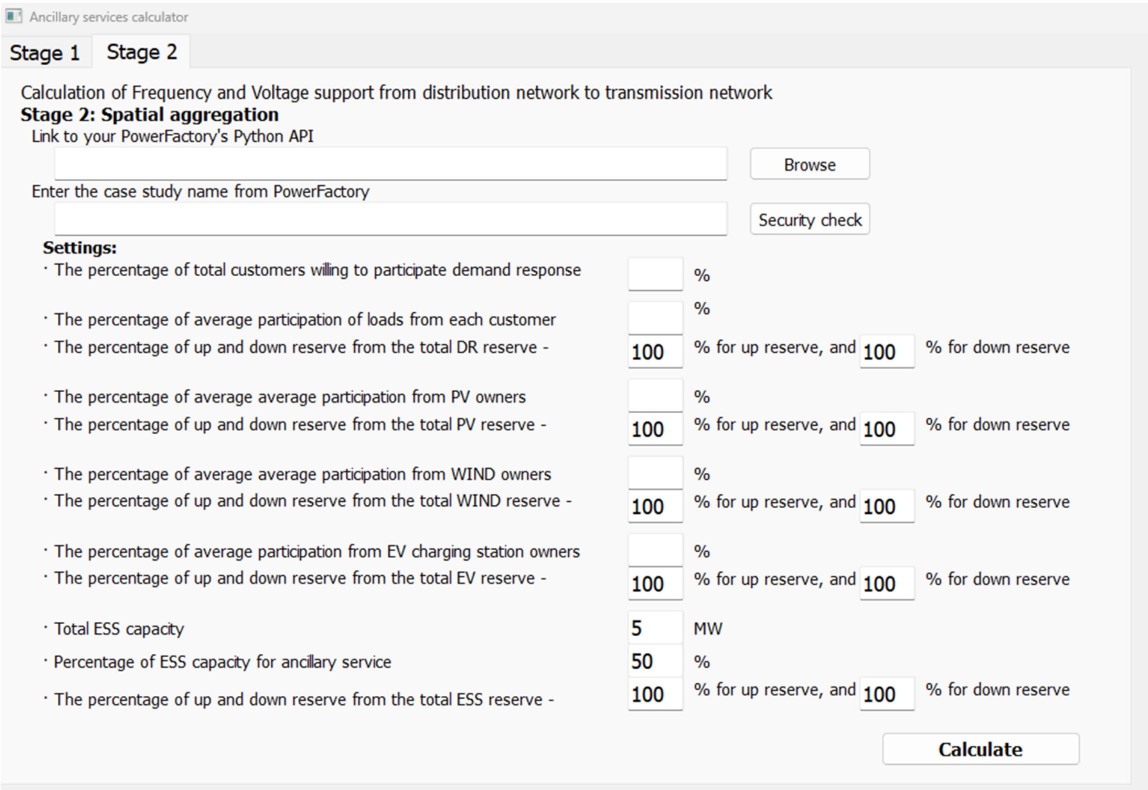
3.5.5 Settings of Energy Storage Systems

Energy storage systems (ESS), comparing battery energy storage systems (BESS) and EV charging stations with V2G capability, can either consume or generate active and reactive power from/to the distribution network by charging or discharging. They can therefore provide both up and down FCAS and reactive power services. Three parameters are used to define ESS for the two ancillary services:

- Amount of ESS participation (% of ESS capacity offered for service)
- Type of response (% of up and % down reserve from the total ESS reserve)

Table 7 shows the user defined parameters in the ancillary service calculator tool.

Table 7 - User defined parameters to calculate FCAS and reactive power services[10]



3.5.6 Ancillary service modelling results

Modelling results indicate that all three networks can provide significant DER resources for market ancillary service when owners of these resources are incentivised to participate. This is particularly true when considering the possible future of higher DER penetration. Example of the modelling

[10] WP3.12 Modelling and Assessment of Integrated System Performance and Technical Implications, Appendix A, Page 78

outputs for Network 3 Case 3B are shown in Figures 6 to 9 below[11]. Note the modelling results are illustrative rather than definitive:

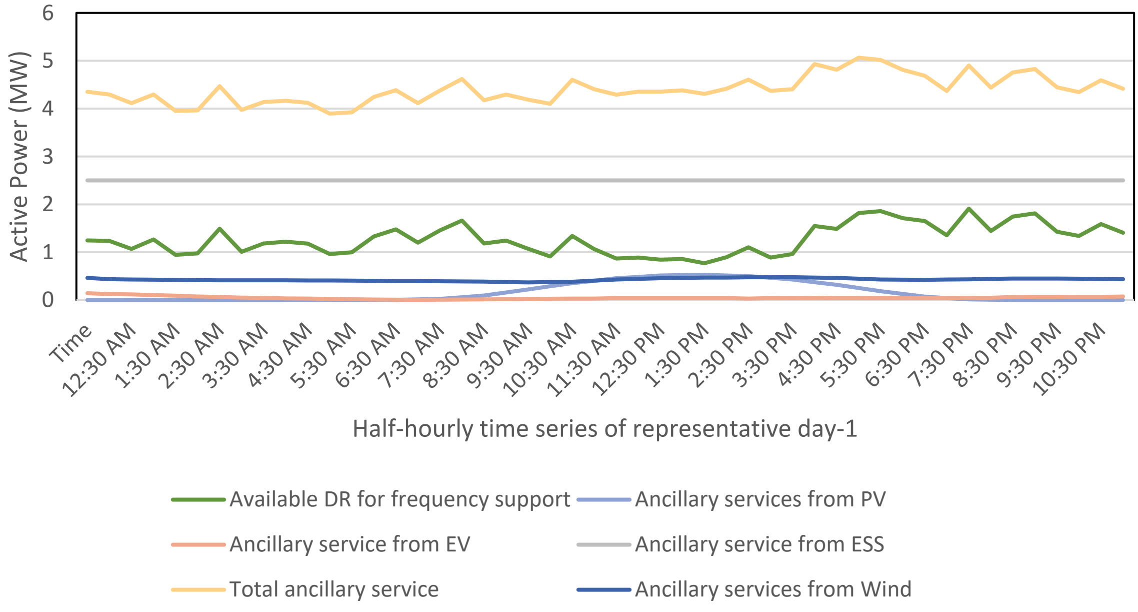


Figure 6 - Available FCAS from Network 3 with DR, DER (PV, Wind) and storage (ESS, EV) participation in representative day-1

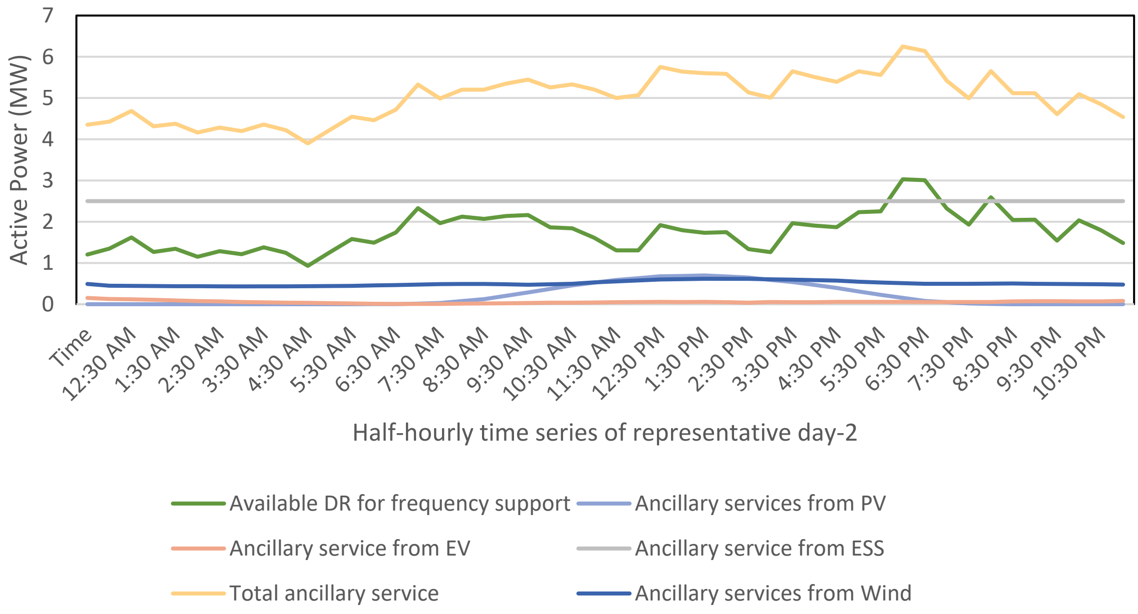


Figure 7 - Available FCAS from Network 3 with DR, DER (PV, Wind) and storage (ESS, EV) participation in representative day-2

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[11] WP3.12 Modelling and Assessment of Integrated System Performance and Technical Implications, Section 3.5.3.2, Pages 71-72

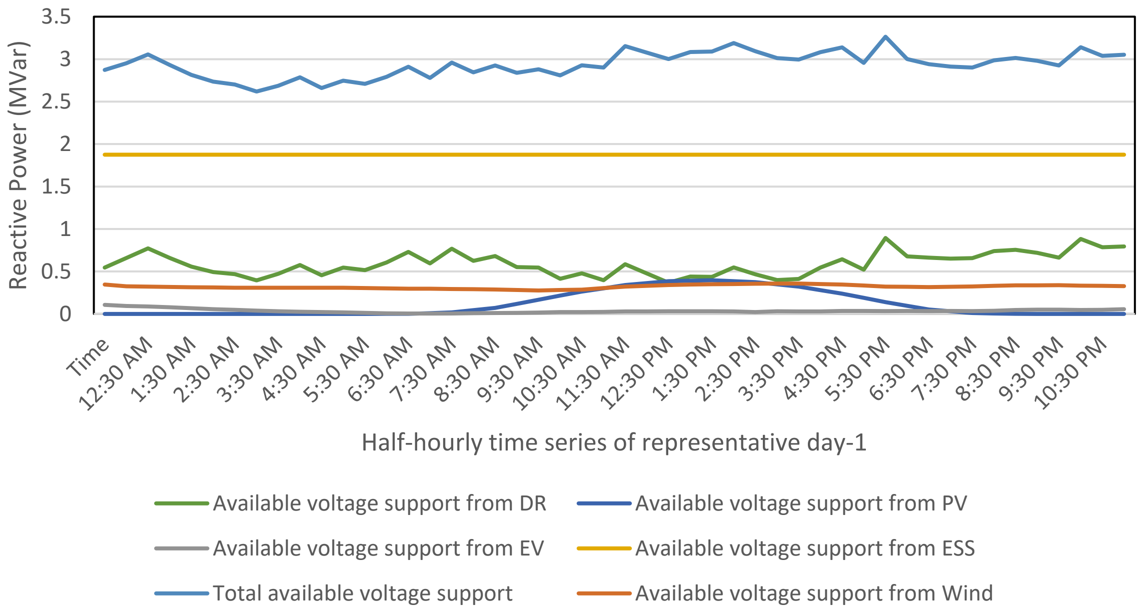

Figure 8 - Available reactive power support from Network 3 with DR, DER (PV, Wind) and storage (ESS, EV) participation in representative day-1

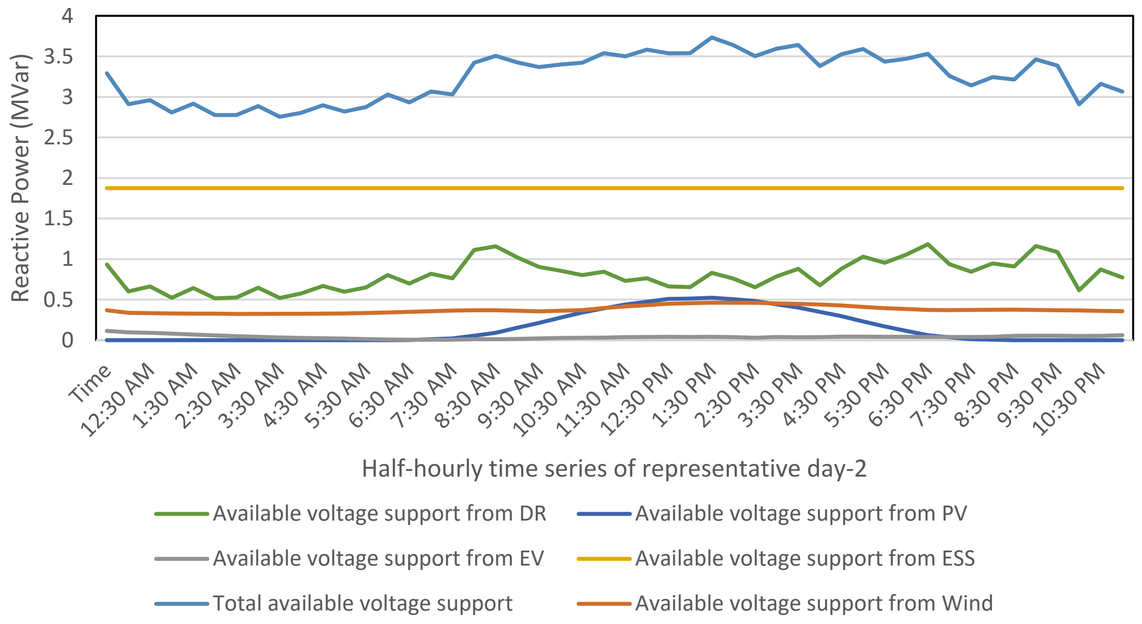

Figure 9 - Available reactive power support from Network 3 with DR, DER (PV, Wind) and storage (ESS, EV) participation in representative day-2

4. Observations, insights and key reflections for stakeholders

4.1 DNSPs

The proposed methodology is demonstrated to produce very accurate planning study results (power flow analysis), at the interface, for the three networks used as case studies. For DNSPs a few questions remain for this approach to work practically:

1. While the significant reduction in the size of the equivalent network (hundreds of buses to 5 buses) and study time period reduction (to two representative days) is expected to reduce the computational effort, the reduction in study run-time has not been quantified and reported. Question remains to be answered: the runtime is faster, but how much faster when take into account the processing capability of modern-day computers?
2. In terms of computational efficiency, how does the proposed methodology compared with features that have either been implemented or considered by vendors of Advanced Distribution Management Systems (ADMS)?
3. For DNSP planning, they would need to consider both maximum and minimum demand periods due to the significant penetration of residential solar PV systems. The representative daily profiles will need to cover, as a minimum, (a) Maximum load with minimum solar generation, and (b) minimum load with maximum solar generation. With energy transition maximum load could occur on hot summer days or cold winter days, maximum solar generation normally occur in summer, minimum load during midday, minimum solar generation during cloudy/rainy days and winter. It is not clear if the various permutations are covered by two representative daily profiles.
4. The network reduction technique has been demonstrated for three MV networks. For DNSP applications, there are at least three network levels that will benefit from the proposed methodology: (a) Low Voltage network, with the PCC at the LV bus of the MV/LV distribution substation, (b) MV network, with the PCC at the MV bus of the HV/MV zone substation, and (c) Sub-transmission network, with the PCC at the HV bus of the transmission terminal station. Could the proposed methodology support a bottom-up iterative approach that can result in an equivalent network at the interface between the DNSP and AEMO?
5. It is encouraging to see the modelling approach of network reduction and time aggregation can efficiently compute the amount of flexibility services available at the PCC. The flexibility considered, with the exception of load DR, are primarily provided by DER connected to the MV network level. It will be important to be able to model CERs (such as residential roof-top PV, BESS and EV) that are embedded in the LV distribution network.
6. The research has made simple assumptions about CER/DER participation and response capability. It has not explored the market mechanism as well as the technologies that will be

required to achieve the said outcome. The modelling would need to be re-run when DNSPs have the actual data of CER/DER participation and response capability.

4.2 AEMO

For AEMO, the main interest is an accurate equivalent network model at each interface with DNSPs (the physical interface is at the transmission terminal station) that captures the loads and generation originating from the DNSP networks. While the proposed methodology looks interesting, it would need to be further tested if it can produce accurate equivalent network model at the interface (refer question 3 in Section 4.1 above) that covers all the scenarios (combination of loads and generation) of interest (refer question 2 in Section 4.1 above). In addition, more real-life networks would need to be tested to confirm the robustness of the approach.

Furthermore, AEMO would need models that can be used to study network transient behaviours. The steady-state model is not adequate for this purpose.

4.3 Policy makers

Policy makers will be interested in the standardisation of the equivalent network models that represent all the different DNSP networks across the NEM, as standardisation will ultimately lower the cost of implementation should this approach be adopted. As discussed in 4.2, the robustness of the approach needs to be tested on more DNSP networks with different topologies and load/generation patterns.

This project has confirmed that CER/DER in the distribution networks can technically provide FCAS and reactive power services to the TSO via the TNSP/DNSP network interface. Policy settings are instrumental in incentivising customer behaviours, or overcome barriers to participation, and encourage market developments which will bring benefits to both the distribution and the transmission networks. Policy makers may contemplate what sort of services may be best provided within the DNSPs to support greatest efficiency for the whole network and the market or rule changes needed to ensure or incentivise DER/CER provides this.

It should be further noted that technology infrastructure will need to be in place to coordinate/orchestrate CER/DER if they are to be used to provide flexibility services. Ideally the technology platform should be established first to support the development of a market for such services.

4.4 Consumer

It is generally recognised that DSO functions will be required for consumers to participate and support the energy transition. One key function of the emerging DSO role is to interface with the TSO (AEMO) from a technical and market perspective. The equivalent electrical model representing the distribution network at the TSO/DSO interface could provide an efficient approach for defining the technical parameters of interest to the TSO/AEMO.

4.5 Research

Key recommendations for future works are as follows[12]:

- Develop the network representation model in considering transient behaviour;
- Consider uncertainties in producing a more comprehensive representative model;
- With the penetration of DERs, the assumption of a single slack bus may need some revision by using multiple or distributed slack buses;
- Extend the modelling to cover CERs, such as residential roof-top PV, residential BESS and EV, that are embedded in the LV distribution network;
- Refine the assumptions relating to DR and DER (PV, wind, ESS etc.) participation, to more accurately forecast available flexibility in distribution networks for service provision to the transmission network.

[12] WP1.3.2 TSO-DSO Interface Steady-state Model of Aggregated DER as an Active Entity, Section 6, Page 114

Appendix One

Researcher profile

Conducted by: Federation University, Melbourne

Lead Researcher: Dr BM Ruhul Amin

Research Team: Tan Nhat Pham, Md Sazal Miah, A/Professor Rakibuzzaman Shah, Professor Nima Amjady

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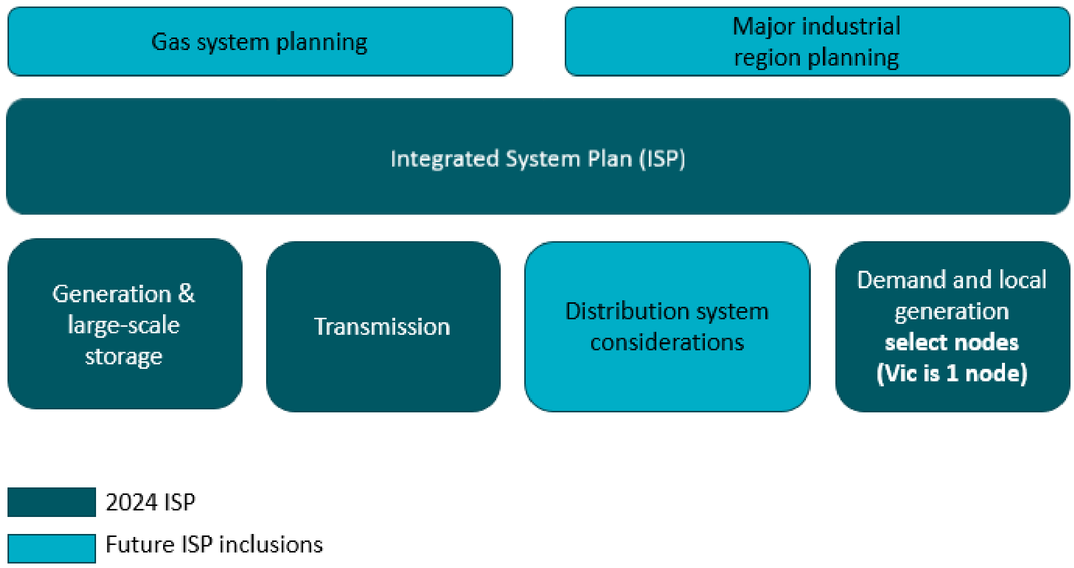
About C4NET

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

Central to C4NET's program of work is the Enhanced System Planning (ESP) project, a significant and collaborative research project aimed at informing sub transmission level electricity planning beyond 2030, with a focus on building methodologies and approaches for bottom-up modelling and to highlight the opportunities presented through the distribution system and integrating Consumer Energy Resources (CER), to inform whole of system planning.

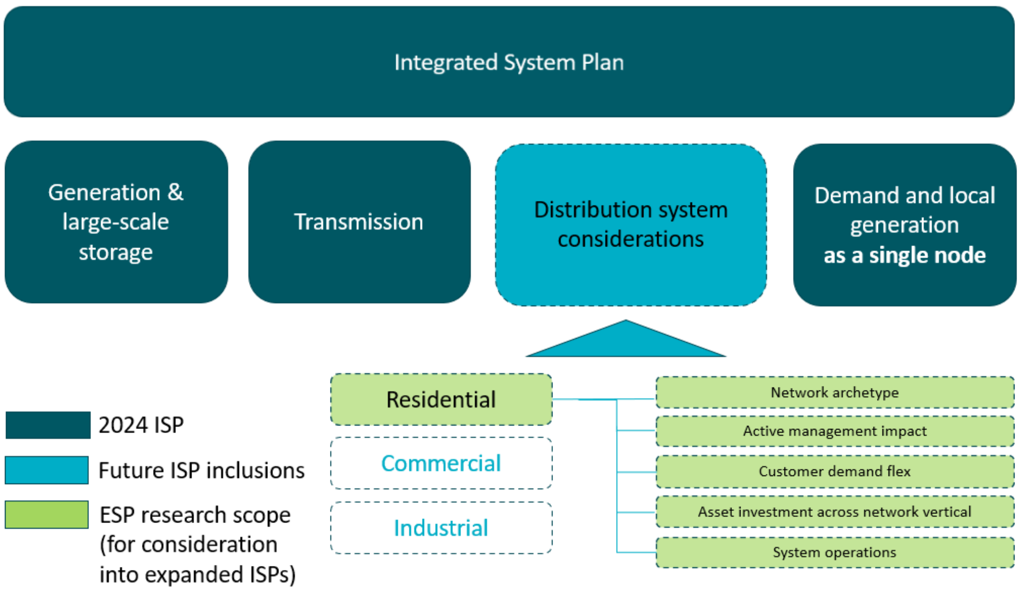
Appendix Two – Bigger picture integration with the ISP

Shift towards whole of system planning



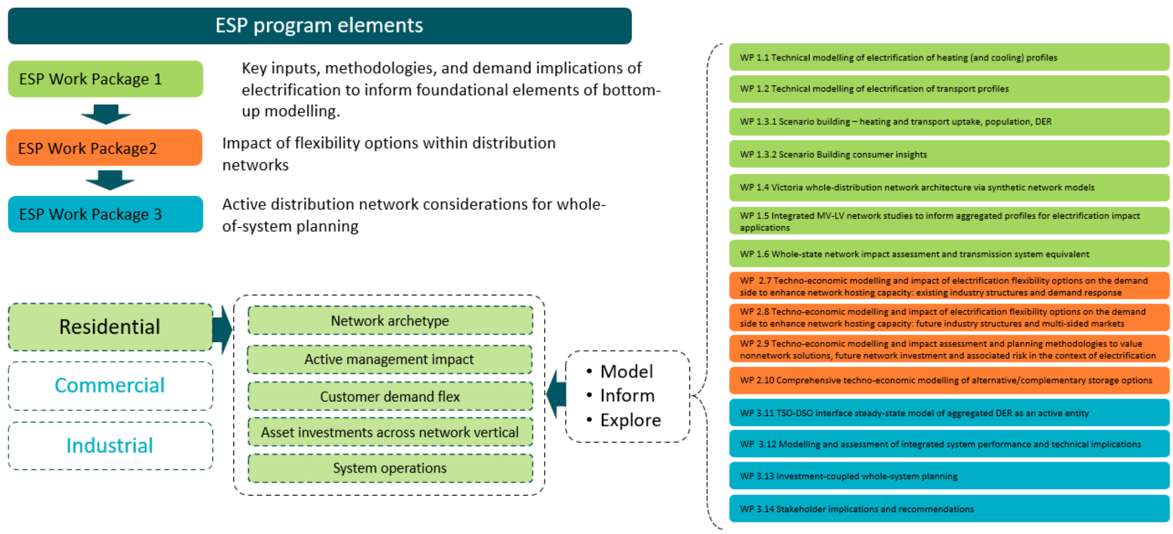
The Energy and Climate Change Ministerial Council (ECMC) accepted the recommendations of the review of the ISP which target transformation of the energy system as a whole, with particular reference to gas system planning, major industrial region planning and distribution systems.

Distribution system components of whole of system planning

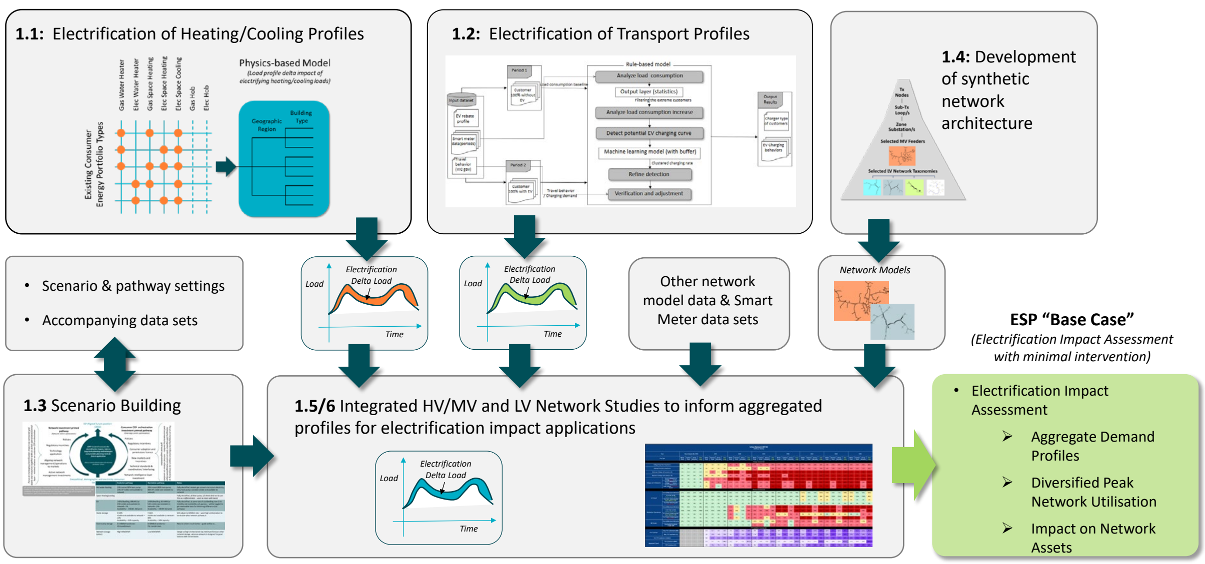


The ESP was scoped to be deliverable with the resources and time at hand to inform feasibility of broader application. It focussed on the more complex areas around residential and low voltage assets of the distribution system, with an application across Victorian networks with methodologies applicable to any region in the NEM.

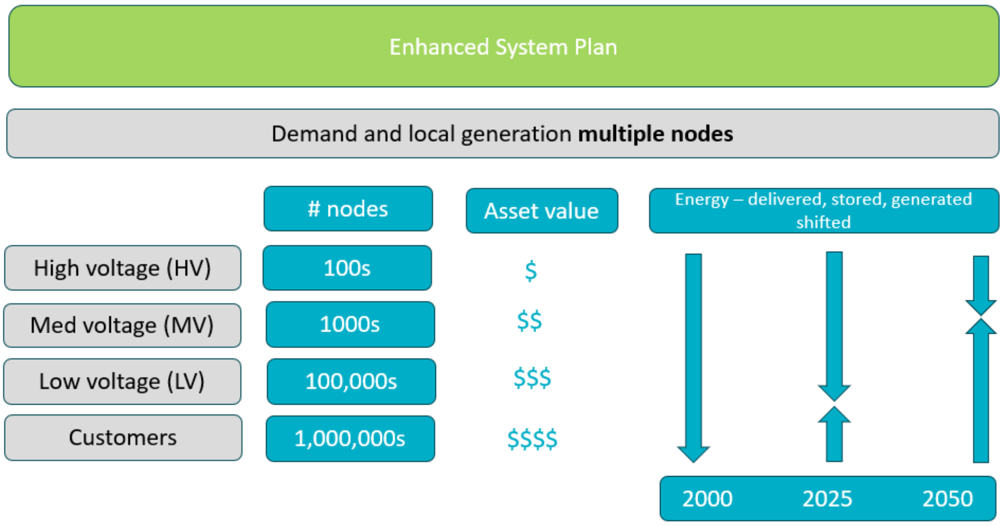
ESP alignment with distribution system components of whole of system planning



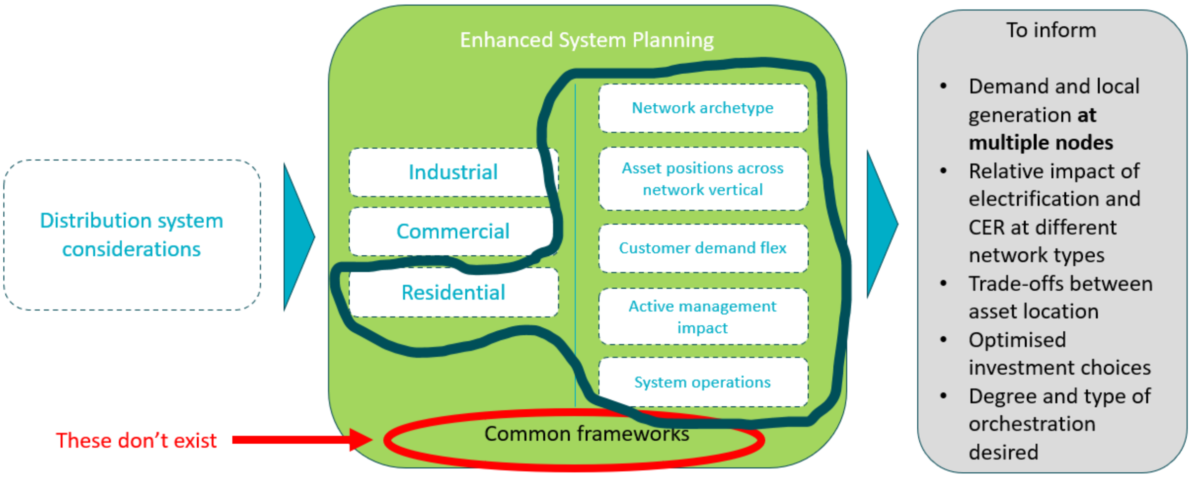
The 'base case' for residential electrification impact assessment, the flex options and relativity to other investment options



Elements needed to meaningfully inform distribution system aspects in whole of system planning



Methodological gaps in whole of system planning



Appendix Three – ESP project and research partners