Modelling and Assessment of Integrated System Performance and Technical Implications

Final Report: April 22, 2025

Report for Centre for New Energy Technologies (C4NET)

Project Consortium

LEAD AND AUTHOR

OF THIS REPORT

Dr B M Ruhul Amin, Dr Tan Nhat Pham, Md Sazal Miah, A/Professor Rakibuzzaman Shah, and Professor Nima Amjady

Federation University Australia, Centre for New Energy Transition Research (CfNETR), Mt Helen, VIC 3353, Australia

The research team would like to thank AEMO for the inputs and suggestions provided in this work.

Disclaimer

Acknowledgement

This research is part of a program of fourteen projects, which have variously been funded and supported under C4NET's Enhanced System Planning collaborative research project. While conducted independently, the authors acknowledge the funding and in-kind support of C4NET, its members and supporters, and its ESP project partners.

Executive Summary

The Electricity Network Transformation Roadmap estimates the Distributed Energy Resources (DERs) contribution to Australia's electricity generation capacity will reach around 45% by 2050. Alongside many potential benefits, the significant number of DERs can cause several challenges and technical problems, such as network congestion and voltage excursions. To support Renewable Energy Sources (RESs) integration, large investments in new network infrastructure can be avoided by leveraging the flexibility offered by managing connected (front of meter) DERs in the distribution network. To achieve this, it is necessary to improve the cooperation between Transmission System Operators (TSOs) and DSOs. In addition, the provision of energy and ancillary services from DERs to the transmission network without compromising the power system integrity needs to be explored.

Task WP3.12 Modelling and Assessment of Integrated System Performance and Technical Implications aims to assess the coordination mechanism between TSO and DSO for the ancillary services, in particular frequency regulation and reactive power supports that can be provided from the Active Distributed Networks (ADNs) to the Transmission Networks (TNs). It also aims to develop tools to estimate support services for upstream grids and downstream grids and perform the network and market interaction analysis. To achieve this, the equivalent network of the distribution network connected to the transmission network needs to be evaluated considering several loading conditions of the network, such as - demand response, DERs, and energy storage with present and forecast future data. There are several barriers and challenges in providing Ancillary Services (ASs) to TNs, such as adequate regulation, market design, technical and operational issues, and communication and coordination between TSO and DSO.

A literature review of the existing literature on modelling TNs/ADNs coordination approaches, ancillary services provided by the Active Distribution Networks (ADNs) to Transmission Networks (TNs), physical modelling of transmission and active distribution networks, equivalent representative network modelling approaches, control mechanisms, test cases, market analysis, optimisation methods, and the software and tools used for modelling and analysis has been conducted in Literature Review phase (https://c4net.com.au/) of WP3.12. The literature review report also reviews the existing literature on ancillary services provided by the ADNs to TNs, the existing AS structure, resources in ADNs to provide ASs, deterministic and non-deterministic optimisation problem formulation, solution approaches, validations, test systems, simulation software, and hardware system.

In this WP3.12 Modelling and Assessment of Integrated System Performance and Technical Implications, a step-by-step spatial and temporal system reduction methodology has been developed to provide a compact and computationally efficient equivalent model for calculating the potential ancillary services – both frequency and voltage support from the distribution network to transmission network for different system planning and operation studies. Unlike the previous approaches in this domain, the proposed methodology combines spatial and temporal aggregation of the network to achieve a higher computational efficiency. The proposed method also calculates the aggregated ancillary services from the distribution network to the transmission network for a time series of representative snapshots of the network using historical time series data. However, the proposed model is also capable of calculating the amount of ancillary service in any present or forecasted scenarios. Besides the operational functions of DSOs and TSOs, the proposed method is more beneficial for planning activities of the long-term planning horizon. For example, if a 10-year planning horizon is considered with a half-hour time resolution, it becomes a total of 175,200-time intervals (10 multiplied by 17520, the number of half-hour intervals in a year). Analysing these huge number of time intervals can easily make the operational function intractable. For this reason, the developed method uses a spatial and temporal representation of the network for the whole-time horizon using both spatial and temporal aggregation that significantly enhances the computational efficiency of the operation and planning functions of DSOs and TSOs.

At first, the K-means clustering method is used to obtain time-aggregated load profiles. Loads, PV, Wind, and EV profiles are distinctive in their frequency of magnitude variations. Therefore, a three-step time aggregation method is developed to obtain representative days with representative daily profiles of loads, PV, wind, and EV. Three case studies are considered for calculating ancillary services from the active distribution network– Case 1: AS from only demand response (DR); Case 2: AS from DR and DERs, such as PV and Wind; and Case 3: AS from DR, DERs and energy storage such as energy storage system (ESS) and EV fleet station. Case 2 and Case 3 are further divided into two cases (including current scenario and forecasted scenario). A snapshot-by-snapshot time series approach is used to implement the proposed combined method. Three real-world Victorian MV distribution networks - Drysdale, Geelong East, and Ballarat South are used as test systems to validate the developed ancillary service calculation method.

The network steady-state operating point analysis and network security analysis for different loading conditions are performed for all networks. These loading conditions are obtained from the base case condition by changing the loading factor with the selected spatial load distribution. Ancillary services, including both frequency and voltage support, have been calculated for all three networks, considering different cases of representative network conditions using present and future data. The network and market interaction has been analysed and discussed in the report.

Key achievements of this project are as follows -

This work addresses the computational complexity problems of the detailed model of the distribution network for the operation and planning functions of the upstream transmission systems, such as Security Constrained Unit Commitment (SCUC) and market clearing functions. The provided spatial and temporal aggregation tools can make the complex planning and operation functions of the practical TN/ADNs tractable.

The proposed methodology can calculate the aggregated ancillary services, provided by an ADN for the TN, for a representative time series of snapshots of the network. Both frequency regulation and voltage support ancillary services are considered. The developed methodology and tool are capable of estimating AS for any level of DR, DERs and ESS in the network. However, simplistic assumptions are considered for result generation due to the lack of real-world data.

AEMO and transmission system operators can better analyse the whole network, including the transmission and distribution systems. Furthermore, AEMO can benefit from additional ancillary service resources provided by ADNs to more effectively run the market.

The following assumptions are made for model development and analysis because of the limited scope of the project and the unavailability of appropriate network information:

It is a steady-state model and does not consider dynamic or transient behaviours. However, the developed methodology considers the time series snapshots of the network for AS calculation and analysis. This means that the trajectory of statis operating points will be considered and analysed.

The network analysis does not include network maintenance activities and abnormal events like natural phenomena (such as, wildfires, floods, and windstorms) because of the lack of available network topology, load profiles, and renewable generation data as well as natural phenomena data. However, the developed methodology can be applied to periods of maintenance activities and abnormal phenomena, given that the above-mentioned data are available.

The uncertainties of the load demand and renewable generations are not considered due to the lack of their distributional data and the lack of specific resource availability within that distribution for the representative time series snapshots.

1 Project Overview

The energy market has shifted towards sustainable electricity generation in recent years, with a growing emphasis on integrating renewable energy sources (RESs) into the distribution grids [1-3]. Installation of control modules to regulate the asynchronous power of RESs in the distribution systems is quite costly. As an alternative, planning policies that revolve around the collaboration between transmission networks (TNs) and active distribution networks (ADNs) have emerged for RES power management [4, 5]. This approach eliminates the need for installation of additional devices and reduces operational costs for distribution systems [6, 7]. Transmission system operators (TSOs) provide voltage and frequency regulation services along with congestion management for transmission systems. In contrast, distribution system operators (DSOs) focus on managing congestion and voltage within the distribution grid [8]. With proper coordination between TSO and DSO, both entities can accomplish individual goals while maintaining the stability, reliability, and security of the integrated TN/ADN system. The role of "DSOs" is nascent and evolving in many areas. In the current arrangement, DNSPs (as a DNO) manage congestion and network voltages but they don't manage it from a "system" position - i.e. they don't moderate the inputs and outputs to the network, and the network configuration, to service the broader system/market needs.

Future distribution networks will be integrated with numerous active DERs. This enables the islanded mode operation and provides ancillary services for the upstream network in the grid-connected mode, thereby improving the reliability and resiliency of the whole system in many folds [9]. In recent years, the concept of ADNs providing ancillary support to a higher voltage level has gained momentum, and several proof-of-concept large-scale projects have achieved promising results [10-12]. The UK Power Networks (UKPN) and the National Grid Electricity System Operator (NG ESO) are jointly running the world's first trial to dispatch active and reactive power services to the transmission network utilising different types of DERs, including storage assets. The effective operation requires at least 90% of the response to be provided within 2s [12]. Test cases that developed in the SmartNet (http://smartnet-project.eu/) are being used for the coordination of transmission and distribution system operations [10].

The Electricity Network Transformation Roadmap estimates the DERs' contribution to Australia's electricity generation capacity will reach around 45% by 2050 [1]. To support Renewable Energy Sources (RESs) integration, large investments in new network infrastructure can be avoided by encouraging Distribution System Operators (DSOs) to take a more proactive approach to managing the unpredictable nature of RESs. The future distribution networks integrated with numerous active Distributed Energy Resources (DERs) will be able to operate in islanded mode and provide ASs for the upstream network in the grid-connected mode, thereby, improving the reliability and resiliency of the whole system in many folds. To achieve this, it is necessary to improve the cooperation between Transmission System Operators (TSOs) and DSOs. In addition, the provision of energy and ancillary services from DERs to the transmission network without compromising the power system integrity needs to be explored.

There are several technical and non-technical challenges that need to be solved for a closer interaction between TSO, and DSOs. The technical challenges are congestion of transmission and distribution interface, congestion of transmission lines, balancing challenge, voltage support, (Anti-)Islanding, re-synchronization and black start. The non-technical interactions are – balancing between infrastructure investment and use of flexibility, role of markets, setting a level playing field for flexibility and the role of regulation [13]. Power systems with a high penetration of distributed energy resources (DER) at the distribution voltage levels, create a need for a new level of interaction between transmission system operators (TSOs) and distribution system operators (DSOs).

Task WP3.12 Modelling and Assessment of Integrated System Performance and Technical Implications aims to assess the coordination mechanism between TSO and DSO for the ancillary services, in particular frequency regulation and reactive power supports that can be provided from the Active Distributed Networks (ADNs) to the Transmission Networks (TNs). It also aims to develop a tool to estimate support services to the upstream grid from downstream and perform the network and market interaction analysis. To achieve this, the equivalent network of the distribution network connected to the transmission network needs to be evaluated considering several loading conditions of the network such as with demand response (DR), DERs, and storage systems with present and forecasted future data. In order to accomplish these aims, the objectives of **Task WP3.12** are as follows:

+ Coordination mechanism for reactive support from the distribution network to the transmission network.
+ Assess the frequency support from the distribution network to the transmission system.
+ Assessment of the potential system benefits.
+ Develop a tool for estimating support services upstream from downstream.
+ Network and Market Interaction Analysis

An extensive review of the existing literature related to the energy and ancillary services (AS) provided by ADNs to TNs to maintain the adequacy and security of the network has been performed and presented in **Project Deliverable 1: Literature Review (**https://c4net.com.au/**)**. DSOs can provide AS to TSOs in several ways depending on the cooperation and interaction between them. These ancillary services include energy arbitrage, congestion management, voltage support, frequency regulation, black-start capability, and other functions. There are some barriers and challenges in providing AS to TNs such as the need for enough regulation, market design, technical and operational issues, and communication and coordination between TSO and DSO. This report reviews the existing literature on modelling TNs/ADNs coordination approaches, ancillary services provided by the ADNs to TNs, control mechanisms, test cases, market analysis, physical models and their detailed/reduced representations, optimisation methods, and the software and tools used for modelling and analysis.

A coordinated process is proposed in [14] that minimises the network loss while also maintaining the technical limits of the TNs. The network assets in TNs and ADNs need to communicate with each other for better TSO-DSO coordination and maintaining the system security. The coordination can be done in a centralised, decentralised, and distributed manner. In the centralised approach, a single operator is considered responsible for controlling the whole system. A centralised control with existing infrastructure is a valid assumption for a system not covering a large geographical area. The TNs' and ADNs' resources are dispatched in this centralised system, considering the integrated optimisation of the entire system [15]. The centralised system suffers from a single-point failure and highly depends on generation and consumption forecasts to determine operating set points for DGs. The centralised approach relies highly on an expensive communication network and computationally prohibits increasing the network size. Several works in the literature [16-23] have used the centralised method because of its simple structure, depicting the best possible scenario.

In the decentralised approach, DERs perform their control actions using local measurements [15, 24, 25] without relying on a central command. Although the decentralised approach improves security by preventing single-point failure, it can face the challenges of network active/reactive balance and data privacy in ADNs with high DER penetration. In many literatures, distributed approaches are proposed to overcome the shortcomings of centralised and decentralised methods [14, 26-31]. The distributed approach uses local measurements and exchanges limited information to ensure the data privacy of consumers. This approach is computationally light and can be used as a solution to emergencies.

The increasing installation of DERs poses several operational and planning complexities in TS and DS. However, the interaction between TSO-DSO also has the potential to provide flexibility and ancillary services to the network. The development of smart meters, sensors, communication networks and data platforms provide more visibility and control of the grid and resources. The technologies can facilitate the coordination and optimisation of TSO-DSO interaction. However, it also requires new standards, protocols, and regulatory measures.

A summary of the research gaps in this area, identified from the reviewed literature, is presented in Figure 1.

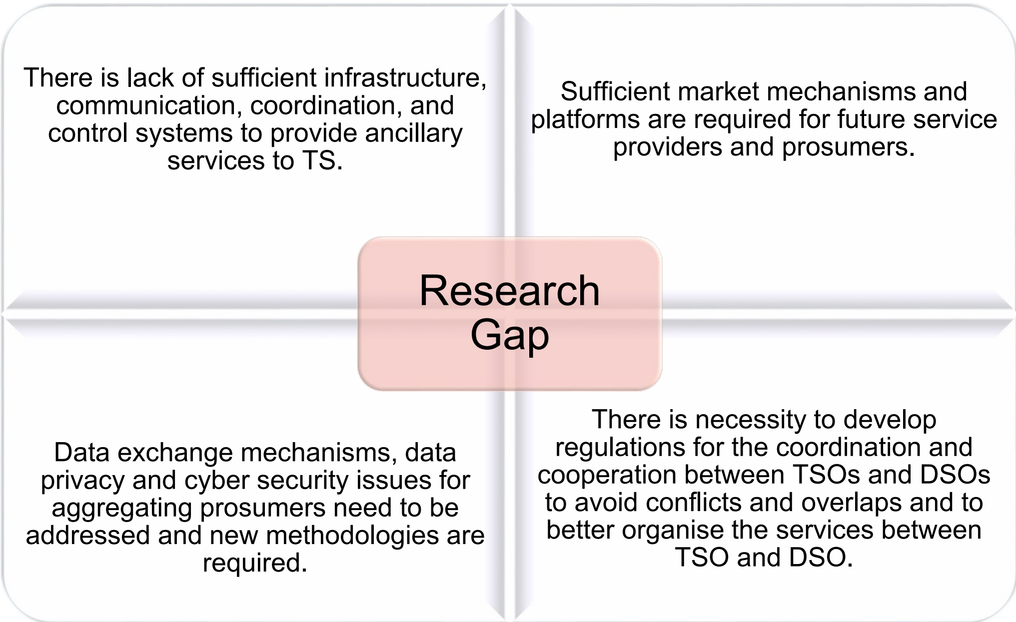


Figure 1 Summary of research gaps (energy and ancillary services provided by ADNs to TNs).

In this **WP3.12 Modelling and Assessment of Integrated System Performance and Technical Implications**, a step-by-step method by leveraging the temporal and spatial aggregation of the distribution network resource profiles is developed. The developed model is tested with historical and future demand and DERs time series data. However, further works are needed in forecasting demand and distributed resources profile which may be governed by other market-related activities or business model preferences. The developed method provides a compact and computationally efficient model for calculating the potential ancillary services – both frequency and voltage support from the distribution network for different system planning and operational studies. The developed method has been tested on three real MV networks in Victoria for different current and forecast cases considering Distributed Energy Resources (DERs), ESSs, and Electricity Vehicle (EV) stations.

The following assumptions are considered in this study -

+ Dynamic analysis of the network and uncertainties are out of the scope of this project.
+ Maintenance manoeuvres in the network are not considered in this work. A time series of snapshots of the network is considered.
+ High-level forecasts for the load growth and DER integration in the network for 2035 along with the current conditions in 2024 are considered for future illustrative cases. Developing the forecast method is out of the scope of this project. Further development is required in forecasting distributed resource availability across the time domain.
+ The developed tool calculates the available potential ancillary services from the network for different time periods. It only analyses network supply/demand balance and security status before participation in ancillary services.
+ Specific levels of DR, DER, and Storage availability is considered to estimate the ancillary services available from distribution network to the upstream network.

The background and objectives of **Task WP3.12** are discussed in **Section 1**. **Section 2** discusses the methodology for the coordination mechanism between TSO and DSO for ancillary services alongside the description of the networks and case studies for ancillary service calculation and analysis. The results of frequency and reactive power ancillary supports for different case studies are presented in **Section 3.** Finally, the work is concluded by providing final insights and recommendations in **Section 4**. The user manual of the developed ancillary service calculation tool and the network and market interaction analysis of ancillary services from the distribution network to the transmission network is presented in the **Appendix**.

2 Methodology

The active distribution network has the potential to provide ancillary services to the transmission network using demand response (DR), DERs, ESSs, and EV charging stations. A step-by-step methodology has been developed in this work package to estimate the support services in particular frequency and reactive supports to the upstream grid from downstream. The topology and load profiles of a network change with time due to varying consumer demands as well as variations in the generation/network configuration. A steady-state analysis of the network has been performed in this work. Dynamic analysis of the network and uncertainties are out of the scope of this project. Besides, maintenance manoeuvres in the network are not considered in this work. The developed method considers both spatial and temporal aggregation of the network. The time series data of a specific time frame (i.e., one year) is used to obtain representative profiles on the network. A step-by-step representation of the proposed method is illustrated in Figure 2.

In the first step, load flow and sensitivity analysis are performed to evaluate the distribution network. The security measures such as under/over voltage violations and overloading of the network are performed. Second, time aggregated profiles of load, DERs and EV stations are obtained using clustering method. A novel 3-step time aggregation method is developed considering the distinct nature of the time series profiles of demand, PV, Wind, and EV charging station. Finally, the amount of frequency and reactive power ancillary supports are estimated from the distribution network to the upstream network using time aggregated profiles of the demand, DERs, ESSs and EV charging stations.

The unique characteristic of the developed method is that it is based on spatial and temporal representation. If a single representative network is considered, that will be valid for that particular time. However, the operating point of the power system changes with time. Therefore, time series data are considered to obtain representative days of the year/given time frame. The reduced models are obtained for every representative time period. To validate our methodology, representative days with 30-minute intervals are considered. However, the representative equivalent network can be obtained for 5-minute or lower intervals.

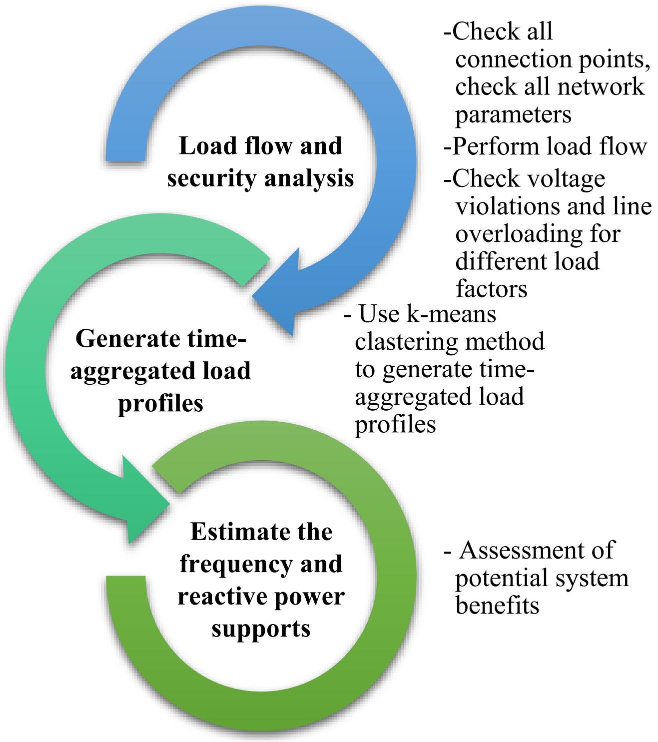


Figure 2 Methodology for the calculation of ancillary services from DR, DERs, and ESSs.

Following inputs are required for the developed model –the total number of DR-providing loads and their spatial distribution in the network, up and down participation rates in DR program and their time of participation per day in DR program. Based on these input parameters, the frequency control ancillary services (denoted as $FCAS$) can be calculated using the following equations:

$$S_{DR} \in S_L \tag{1}$$

$$FCAS = \sum_{i=1}^{|S_{DR}|} L_i \times P_i^{FCAS} \tag{2}$$

where, S_L represents the set of loads; S_{DR} is the DR-participating loads; $|S_{DR}|$ is the cardinality of the set S_{DR}; L_i presents the consumption amount of individual load i; and the participation rate of i^{th} DR-providing load in the DR FCAS program is represented by P_i^{FCAS}.

Similarly, following equations can be used to estimate the voltage control AS (VCAS):

$$VCAS = \sum_{i=1}^{|S_{DR}|} L_i \times P_i^{VCAS} \times PF_i \tag{3}$$

Where, the participation rate of i^{th} DR-providing load in the DR VCAS program is represented by P_i^{VCAS}; and PF_i is the power factor of the i^{th} DR-providing load.

Usually, DR is used as a regulation reserve which is faster than spinning reserve [32]. A customer typically provides up and down reserves for frequency control. Therefore, DR FCAS is formulated as (1) - (2). The direction of up and down reserves from the load set point is presented in Figure 3. The load increase identifies as down reserve and load decrease identifies as up reserve. The formula for up and down reserves can be presented as -

$$P_i^{FCAS,Dn} = L_i^{Up} - L_i^{n} \tag{4}$$

$$P_i^{FCAS,Up} = L_i^{n} - L_i^{Dn} \tag{5}$$

Where $P_i^{FCAS,Dn}$ refers to down FCAS reserve and $P_i^{FCAS,Up}$ refers to up FCAS reserve of i^{th} load; L_i^n represents the base load of i^{th} consumer; and L_i^{Up} and L_i^{Dn} are the maximum limits of load increase and decrease of i^{th} consumer respectively. A graphical representation of (4) and (5) is presented in Figure 3.

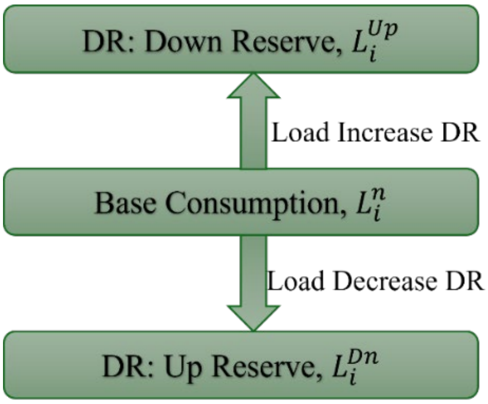


Figure 3 Up and down reserve from demand response.

The proposed method calculates representative profiles from time series demand, DERs and Storage data. The available AS can be calculated by considering different levels of % participation DR customers, their location, participation rates, duration of DR, different participation rate of PV, WIND, BESS and EVs. The developed tool first performs the security analysis of the network for AS. If there is a violation of voltage or line loading it will notify the operator. If there is no security violation, the tool will produce AS estimation for that set up. The security measures can be checked after providing ancillary services for changing conditions of the network. The developed model is not a dynamic model. It works for a given set of settings at a time. To calculate AS for other conditions of the network, the setting need to be changed to perform AS estimation.

The developed methodology can be used for power system planning purposes. For power system planning, the problem of scalability and the problem of tractability become more critical and complicated. The use representative profiles for AS calculation will reduce the computational time and complexity in the planning operations.

2.1 Network Description

The developed methods have been tested and validated in three Victorian distribution networks. Two networks are from the Geelong area, while one is from Ballarat. The SINCAL files with a single operation snapshot of these MV distribution networks are received from Powercor. Publicly available network data (https://dapr.powercor.com.au/) from Powercor are used to model the network into the DIgSILENT PowerFactory software simulation environment to calculate ancillary services for different cases. Brief overviews of these networks are as follows:

2.1.1 Network 1

Network 1 is located in the Geelong area and connected to the Drysdale Zone Substation. There is a total of 649 buses in network 1, where 134 of them are load buses. A 1.067 MW Drysdale Biogas plant in this area uses renewable Biomass or Waste - Landfill Gas as its fuel. At present, there are no front-of-the-meter DERs, BESSs, and EV stations in the networks. However, as illustrative future cases, PV, BESSs, and EV stations are considered in the network to obtain the representative reduced network. An aerial (Google map) view (https://dapr.powercor.com.au/) of the network is presented in Figure 4.

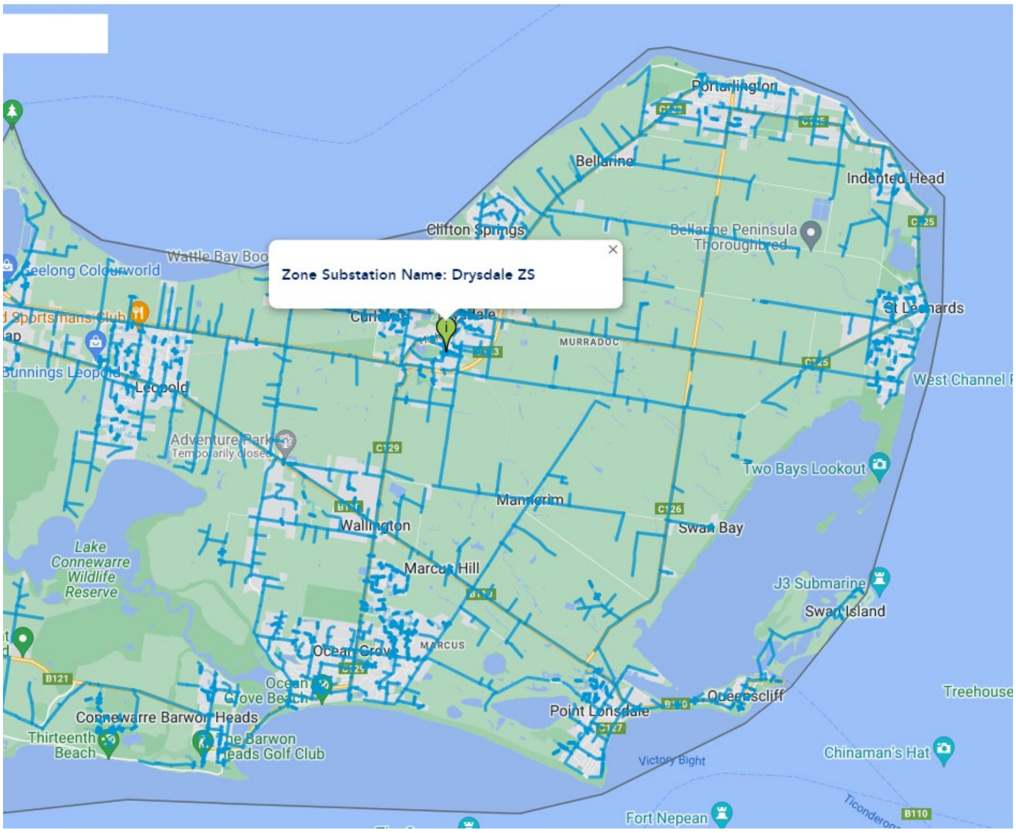


Figure 4 An aerial (Google map) view of Network 1.

2.1.2 Network 2

Network 2 is located in Geelong East and connected to the Geelong East Zone Substation. Among the 185 buses in network 2, 52 are load buses. At present, no front-of-the-meter DERs, BESSs, and EV stations are found in this network. However, as illustrative future cases, PV, BESS, and EV stations are considered in Network 2 to obtain the representative reduced network. An aerial (Google map) view (https://dapr.powercor.com.au/) of the network is presented in Figure 5.

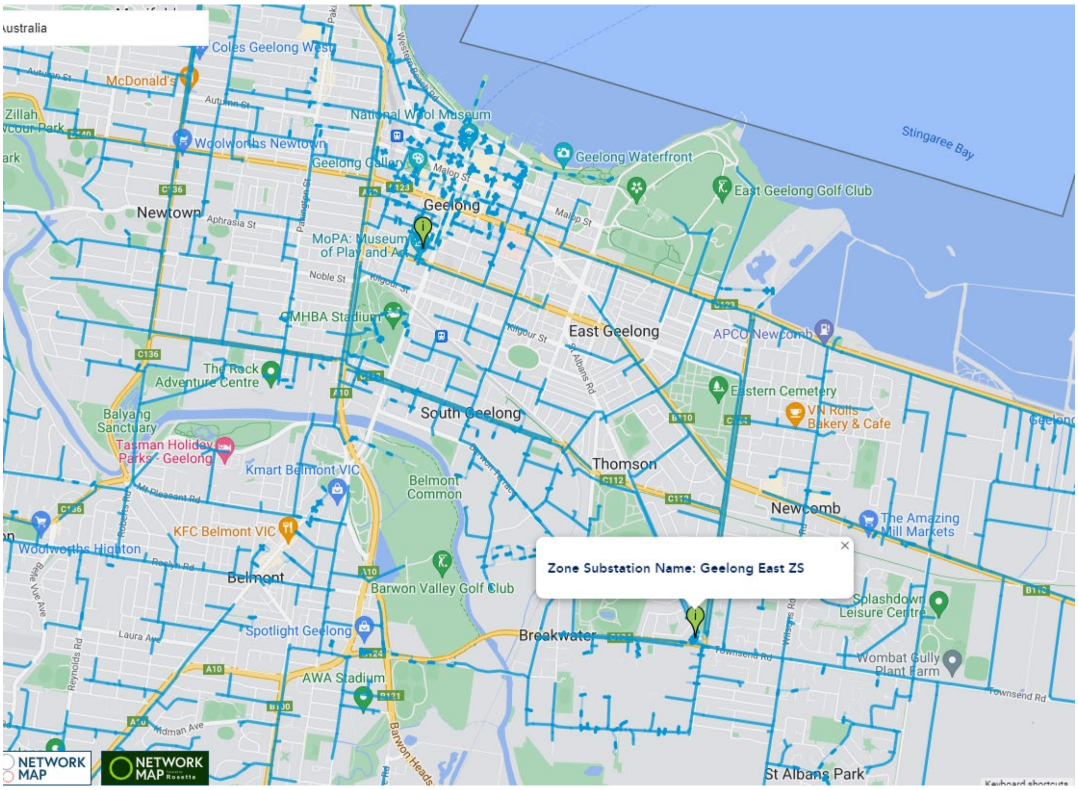


Figure 5 An aerial (Google map) view of Network 2.

2.1.3 Network 3

Network 3 is located in Ballarat. The network is connected to the Ballarat South Zone Substation. There are 1759 buses in the network. A total of 921 buses among all buses are load buses. A 6.15 MW wind farm commissioned in 2015 (https://renewables.networkmap.energy/). Similar to the prior two network models, no front-of-the-meter DERs, BESSs, or EV charging stations are currently found. Future cases will consider all of these to obtain the reduced network model. An aerial (Google map) view (https://dapr.powercor.com.au/) of the network is presented in Figure 6.

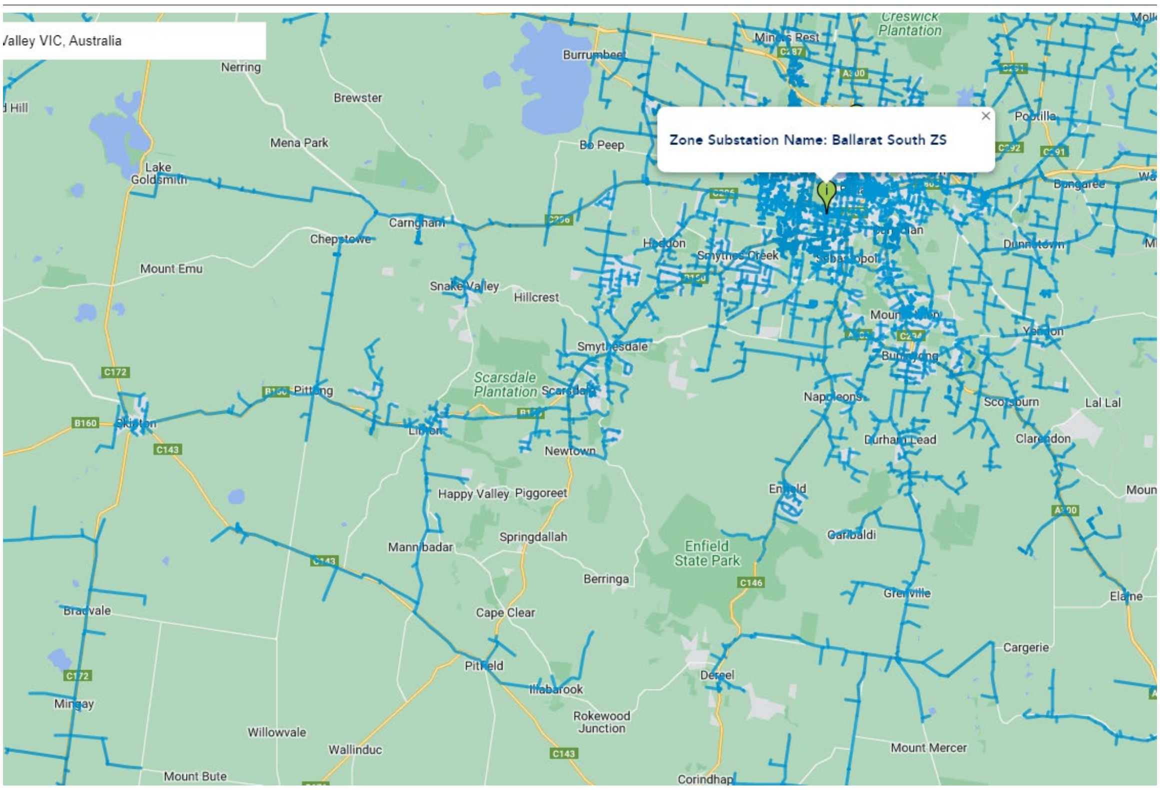


Figure 6 An aerial (Google map) view of Network 3.

2.2 Case Studies

Three illustrative cases are considered to depict the role of DR, DERs, and storage in providing ancillary services from ADNs to the TN. These cases are as follows:

- **Case 1:** With DR
- **Case 2A:** With DR and DERs (2024)
- **Case 2B:** With DR and DERs (2035)
- **Case 3A:** With DR, DERs (2024) and Storage (2024)
- **Case 3B:** With DR, DERs (2024) and Storage (2035)

2.2.1 Case 1

Case 1 is referred to as a **base case** of the network and only demand response of the load is considered to provide ancillary services. In practice, estimating AS availability from DR is a complex process due to the interrelation of the % participation, diversity of customer loads, their location in the network, variation of participation duration across the time domain, up/down characteristics and replacement of shifted loads in different time segments. Therefore, following key assumptions are considered in our study to calculate AS using DR -

- Location of providing loads
- Amount of DR participation

- Timing of DR
- Type of the demand response

Location of DR providing loads. It is assumed that a percent of total customers will provide demand response at a time. These customers may be spread in different locations in the network. Sensitivity analysis has been performed to estimate ancillary services from demand response for a range of customer participation for ancillary service support. As no spatial distribution is given to us, these resources are randomly distributed in the whole network.

Amount of DR participation. It is also highly unlikely that the DR participant customers will agree to share their full loads for demand response. Thus, it is necessary to assume a percentage of demand as DR.

Timing of DR. The amount of DR will also depend on the time of DR participation and the duration of DR participation in a day. The duration of providing DR can be, for example, one to six hours. DR provision can be partly in peak time, and partly in medium load time.

Type of the demand response. For instance, some DR providers are interested in just shifting their energy consumption (e.g., from peak time to off-peak time). However, some other DR providers may accept to decrease their energy consumption. For instance, we may consider 50% of DR as a shift of time and 50% as a demand reduction. In this work, the increase or decrease of demand during the DR period is considered for calculation and analysis [33-35].

When a consumer participates in DR, it typically provides up reserve and down reserve. However, DR is not in the spinning reserve category. Usually, demand response is faster than spinning reserve. The spinning reserve requirement is 10 minutes of reaction time. The DR is much faster in the range of seconds. Actually, the DR is usually categorised as a regulation reserve, which is typically used for frequency control [35]. The direction of the reserve from the load set point is presented in Figure 3.

2.2.2 Case 2

In case 2, the ancillary services from DERs, such as PV and Wind, are considered alongside the demand response. Present net load profile is used for ancillary service calculation covering the impacts of behind the meter DERs. For future illustrative cases, we made an assumption of 2% net demand rise in each year. This assumption will be impacted by the future integration of behind-the-meter DERs. The aggregation of behind the meter resources for AS will also impact the net demand profile in future. However, developing advanced forecasting method that considers the DERs uptake in the future was beyond the scope of our project. The front of the meter PVs and Winds are explicitly modelled as active entities to provide frequency and voltage support. The case 2 is divided into two categories – case 2A and case 2B. Case 2A considers present load profiles and DERs (2024) of the network and case 2B is analysed using illustrative forecast load and DER (2035).

In cases 2 and 3, present and forecasted DERs in the network are considered for time aggregation and ancillary service calculation. Since more than one time series data source is involved, the developed three-step time series method has been used for time aggregation.

The participation mechanism of wind and PV generation in up-reserve and down-reserve is presented below:

(a) Wind

For a downward reserve of wind, spillage can be used for providing ancillary services. For upward reserve, the wind power plant may have some wind turbines that do not generate power. For instance, these wind turbines may be positioned against the wind. When it is needed to generate power from a wind turbine, it is positioned in front of the wind so that when the wind flows, it hits the blades, and the wind turbine rotates to generate electric power.

A wind turbine has two types of control mechanisms: pitch control which controls the angle of the blade and yaw control which controls the surface of the wind turbine. Yaw control can rotate the wind turbine and position it against the wind. In this case, the wind cannot typically rotate the blades of the wind turbine. Wind exists, but wind turbines do not generate any power because their blades do not rotate.

The wind generators or wind power plants that want to participate in the reserve market, usually keep some of their wind turbines in this no-generation state. When it is needed (for instance, when the reserve is called by the system operator), they can rotate their wind turbines using Yaw control and generate power [36]. It is very fast and can be as fast as a hydrogenator because hydro generators usually should change their outflow, such as their turbine outflow. Also, it is a mechanical control that changes the turbine outflow and changes the generated power by the hydro generator. There is a similar situation for the wind generator. It may not be as fast as DR as DR is as fast as turning on/off a switch. However, it may be as fast as to be used for the Frequency Control Ancillary Service (FCAS) [37]. So, today, wind generators can participate in the power system by providing both down and up reserves.

By using appropriate control mechanisms, a wind power plant can participate in the reserve market even in the regulation reserve market and can provide frequency regulation reserve in both up and down sides.

The inverters used for integrating smaller DER plants are typically designed for active power transfer. However, they are also capable of providing reactive power during idle periods. Utilization of reactive power capabilities of BTM resources requires aggregation of the resources due to their smaller sizes and larger numbers. Both large-scale and distributed IBRs are crucial to provide reactive power in future grid. An illustration of future grid with IBRs is presented in Figure 7.

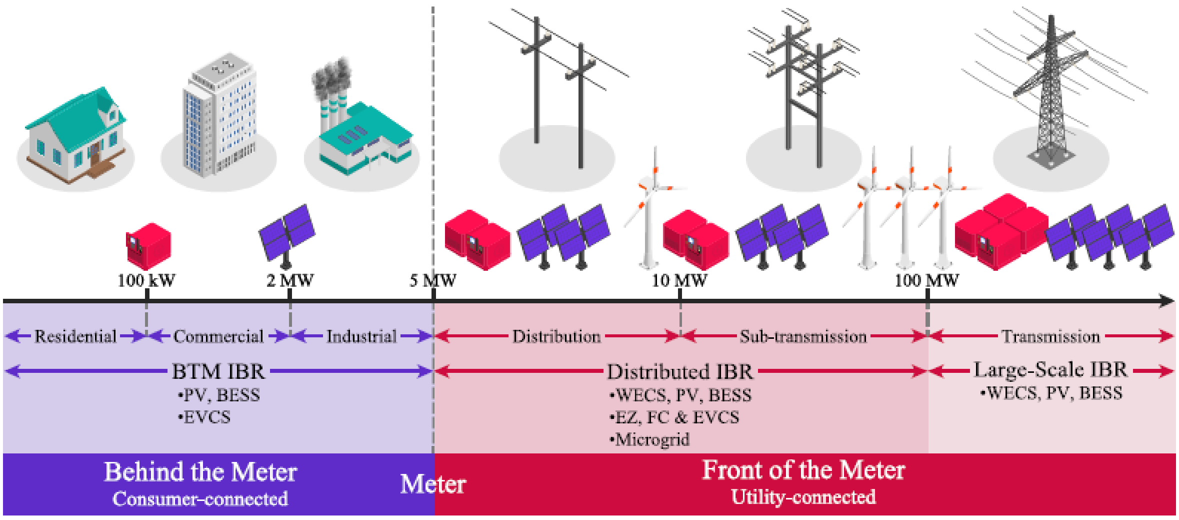


Figure 7 Various IBRs integrated into the grid [38].

Although supporting reactive power by IBRs will increase the converter cost, they require less installation cost and time compared to their conventional counterpart. The significant integration of IBRs based wind, PV and batteries will change the structure of reactive power support in future grid. An illustration of reactive power flow in the future grid is presented in Figure 8.

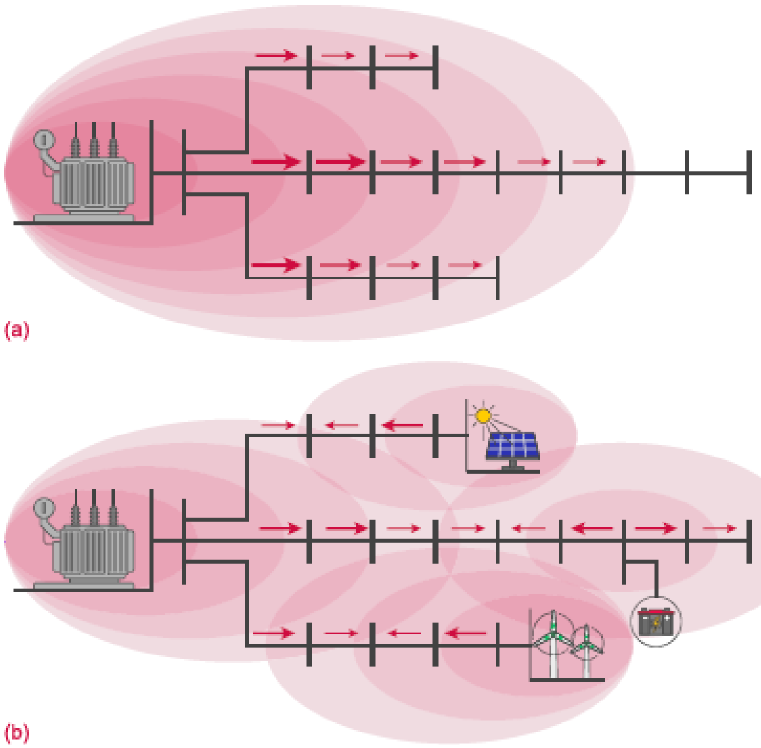


Figure 8 Reactive power flow: (a) passive network (b) active network [38].

However, in this study we have assumed that DERs are reactive power compensator and estimated the reactive power. The modelling of reactive power capability curve for estimating reactive power support was not considered due to the lack of real-world data.

(b) PV

PV can also participate in the FCAS market with a mechanism similar to wind. Even it may be simpler. Spillage can be used to provide down reserve and they can cover some PV cells so that these PV cells do not generate power and retain them for generating power as upward reserve.

The IBRs of PV can be used to provide reactive power support from the distribution network to the upstream network. In this study we have considered PV as reactive power compensator. The modelling of reactive power capability curve for estimating reactive power support was not considered due to the lack of real-world data.

2.2.3 Case 3

In case 3, storage devices, such as EV and BESS, are considered alongside DR and DERs as active entities to provide frequency and voltage support. The case 3 is divided into two categories – case 3A and case 3B. Case 3A considers present load profiles, DERs, and storages (2024) of the network and case 3B uses illustrative forecast load, DER, and storages (2035).

Participating in regulation markets is growing trend among battery storage systems. The excess energy with the high share of PVs in the network can result in reverse flows and over voltages in the network. BESS and EVs can significantly increase self-consumption and self-sufficiency of the prosumers and introduce more flexibility which can be further exploited in peak shaving, load leveling, demand response, voltage regulation, and other ancillary services. The use of BESS can be varied based on its use case such as residential BESS and utility-scale BESS. An effective utilisation model of utility scale BESS deployed at TSO-DSO interface is presented in [39]. The participation of battery storage systems in multiple markets such as reserve and regulation markets in a power pool is described in [40].

ESS may have different participation rates in different hours of representative days or in general in different hours of operation day. However, in the lack of real-world data, for simplicity we assumed in the test case same participation rate in ancillary services for whole hour. The participation mechanism of battery storage in up-reserve and down-reserve assumed in this work is presented below.

ESS should have some free capacity on both sides. Suppose that its state of charge (SoC) is 50%. This means that 50% of its energy capacity has been already filled and the remaining 50% is empty. In this case, ESS can discharge by about 50 per cent (not to zero, maybe 10% remaining SoC is needed for the battery safety) and can charge by about 50% (again maybe not to 100% SoC, maybe up to 95% SoC for the battery safety). In this case, BESS has the capacity to charge and discharge. Since a BESS can quickly charge and discharge, it can participate in the reserve market and also in the regulation market. For futuristic cases, the EV charging stations are considered as ancillary service providers and analysed in case 3B [41, 42]. A summary of all cases and resources considered for all three networks is presented in Table 1.

Table 1 Study cases considered for network reduction and time aggregation

Cases	Resources for ancillary service		
	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
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

2.2.4 Demand, DERs and Storage for Present (2024) and Future (2035) Cases

To validate the methodology and the ancillary service estimation tool, future cases of 2035 are considered in Case 2B and Case 3B. Developing more accurate forecast method is required to estimate the future capacity of PV, Wind, BESS, and EV in future. Since developing forecasting method is not the focus of this work, simplistic assumptions based existing literature and practices are considered.

The net demand profile of 2021 is obtained from Powercor database which is a combined profile of gross demand and BTM DERs in the network. A yearly 2% net demand growth is considered for future years from 2021 to 2035 [43]. Necessary assumptions on PV, WIND, BESS and EV are considered based on the geographical locations and future growth of DERs [41]. But this not a limitation of the developed model and developed software tool. The proposed model can work with accurate forecast DER values and provide real world data.

These are not actual values, but rather an estimation based on the network size and national and global trend of DER and storage participation in the network. The capacity of DERs and storage systems is presented in Table 2.

Table 2 Present (2024) and forecasted (2035) demand and DERs for analysis

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

The following assumptions are considered to obtain an illustrative forecast of DERs and storage in the networks:

- Due to the new developments, population growth, and economic expansion in this area, an additional 2% load growth every year from 2021 to 2035 for Network 1 and 2 is considered. According to the 2021-22 demand increase trend, an additional 2% load growth every year from 2021 to 2035 in network 3 is considered [43, 44].
- We have considered a 5 MW PV integration in our forecasted cases (2035).
- Since electric vehicles could account for 6-8% of total electricity demand by 2035, up from 0.5% today, 2.5 MW EV fleet storage is considered for network 3 and 5 MW for other two network by 2035 [41].
- There is a 6.15 MW wind firm in the Network 3. We have considered 5 MW BESS integration for the forecasted Network 1 and 2, and 2.5 MW for the forecasted Network 3.

3 Results and Discussions

In an active distribution network (ADN), various DERs are connected to provide ASs. These resources include solar PV systems, ESSs, wind turbines, micro-turbines, EVs, and controllable loads. Each of these resources can contribute uniquely to the provision of ASs, enhancing the stability and reliability of the grid.

The proposed spatial and temporal system reduction method developed for the TSO-DSO interface steady-state model has been tested in this section for cases described in the prior section. The K-means clustering method with the Silhouette criterion has been used to obtain representative days from half-hour time series data (i.e., one-year profile). The PV and Wind profiles for relevant networks are obtained from publicly available sources. The EV charging profile is obtained from case studies conducted by C4NET and Jemena. The results obtained from all cases are described in the subsequent sections.

3.1 Case 1: With DR

In this case 1, only DR is considered to provide ancillary services from the distribution network to the upstream network. In practice, estimation of available DR from a network is a complex process and interrelated with several factors such as location of DR loads, percent participation of them, time of DR, duration of DR etc. The AS service estimation is performed under different assumptions of these factors. ASs have been calculated for randomly distributed DR loads with different % participation for various time instances.

The base model of the network provided by Powercor is used for power flow study and network reduction analysis. At first, the network is tested using power flow analysis in the DIgSILENT PowerFactory environment. Then, a sensitivity analysis is performed to check voltage violations and overloading conditions for different loading factors. Historical time series load data is used to generate the representative time aggregation profiles using the K-means clustering method with the Silhouette criterion. Finally, the ancillary services – frequency and voltage support – have been calculated using the developed ancillary service calculation tool.

3.1.1 Network 1

Network 1 is a radial distribution network located in the Geelong area and connected to the Drysdale Zone Substation. The network data of this test system is obtained from the DNSP and modelled in the DIgSILENT PowerFactory. Figure 9 illustrates the single-line diagram of Network 1 connected to the Drysdale Zone Substation.

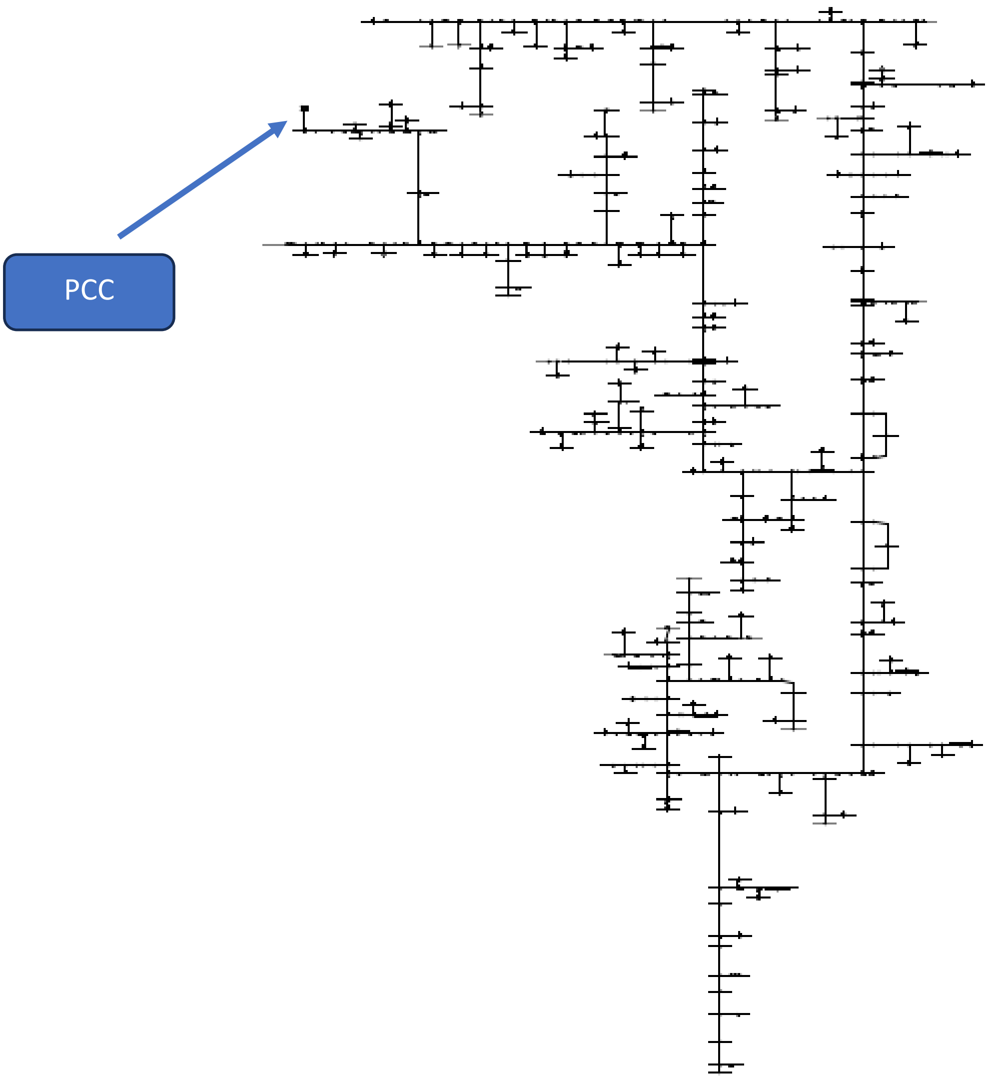


Figure 9 Single-line diagram of Drysdale MV distribution network.

3.1.1.1 Time Aggregated Load Profiles

The aggregated time-series data of 2021 from Drysdale ZS is presented in Figure 10. The load time series data are in 30-minute time intervals. The aggregated load data is distributed among the load buses using the participation factor of loads in the base network model. A conventional network reduction method without time aggregation, i.e., complete data with 30-minute time resolution, requires performing power flow and network reduction for 17,520 half-hour time intervals (the number of half-hour time intervals within a year) multiplied by the number of years in the planning horizon. This can significantly increase the computation burden. Thus, the time aggregation method is implemented to reduce the time series data of every year into a reasonable number of representative periods (representative days). The optimal number of representative periods is identified using the Silhouette criterion. For 2021, the results of the Silhouette score are plotted against the number of clusters in Figure 11. It is seen that the optimal number of representative days is two (i.e., the highest value of the Silhouette criterion in Figure 11). The representative daily profiles obtained using the K-means clustering method are presented in Figure 12. With the advent of time aggregation, the number of required power flow analysis and network reduction processes is reduced from 17,520 in a conventional network reduction method to 96 in the proposed method.

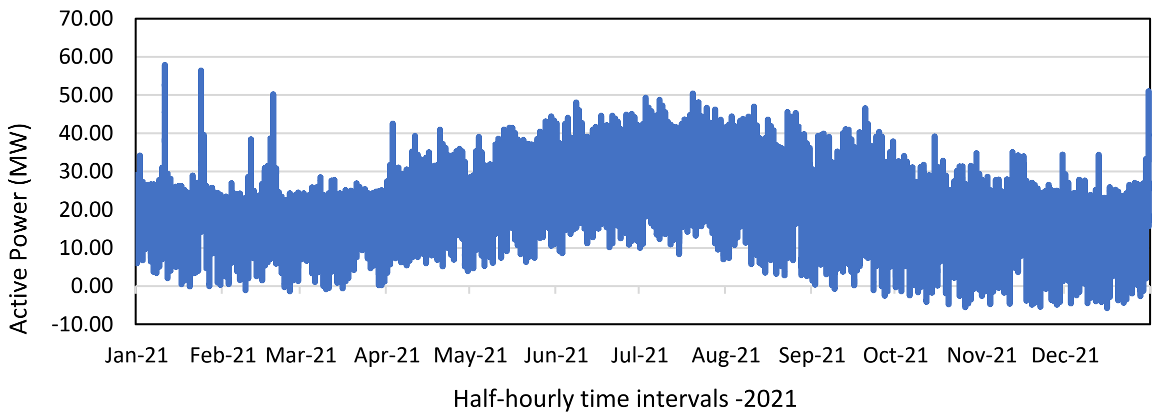


Figure 10 Aggregated time-series data 2021 from the Drysdale zone substation.

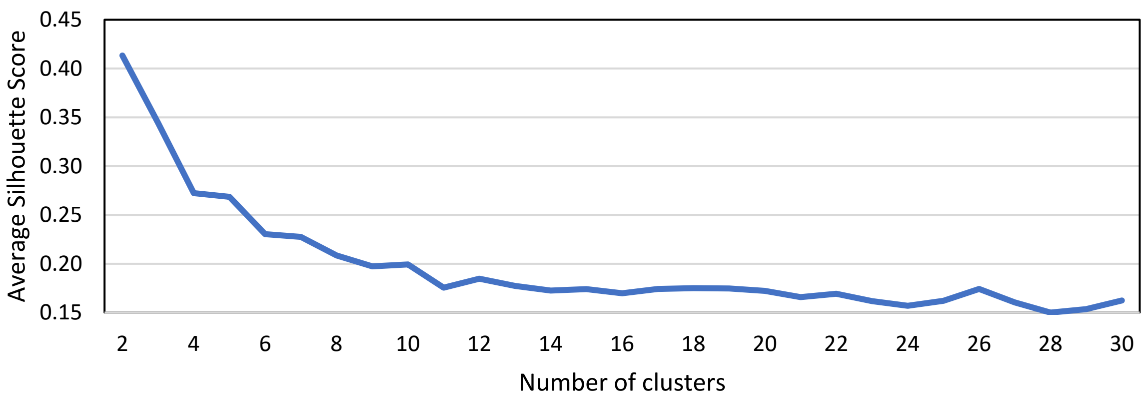


Figure 11 Silhouette criterion results for the time series data 2021.

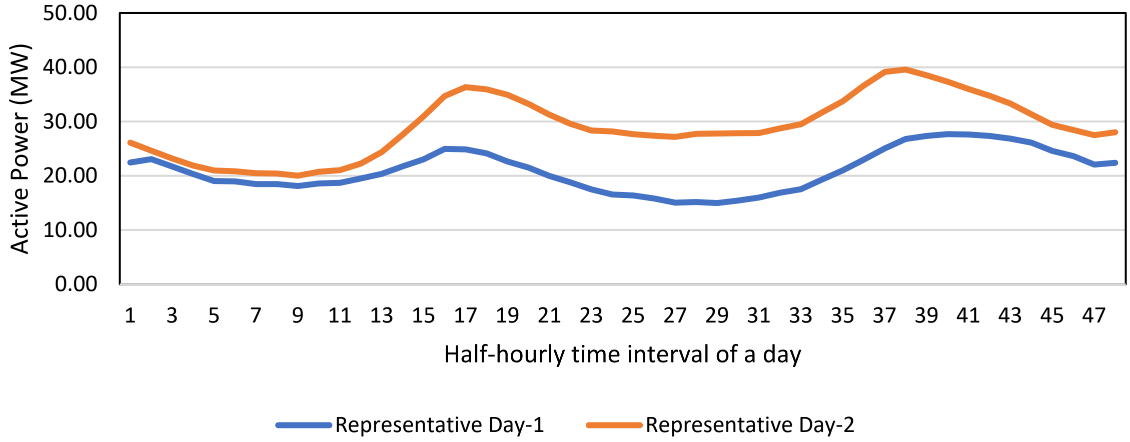


Figure 12 Representative daily profiles obtained by the K-means clustering method.

3.1.1.2 Spatial Load Data Distribution

The representative daily load profiles of 134 load buses in the network are obtained using the K-means clustering method and spatial load distribution factors. The ancillary services have been analysed for 96 loading conditions of two representative days. The number of loading conditions varies based on the optimal number of representative periods identified by the Silhouette criterion. The spatial load distribution of a single snapshot is presented here to illustrate the results and validate the proposed methodology. Since the daily peak loading condition captures one of the extreme conditions of the network, it is considered as a base case loading condition in this analysis. In this base case scenario, the maximum load is approximately 0.58165 MW, whereas the minimum load is 0.000176 MW. Figure 13 displays the spatial load distribution of the input load data in the network. It has been presented on a logarithmic scale for a better presentation.

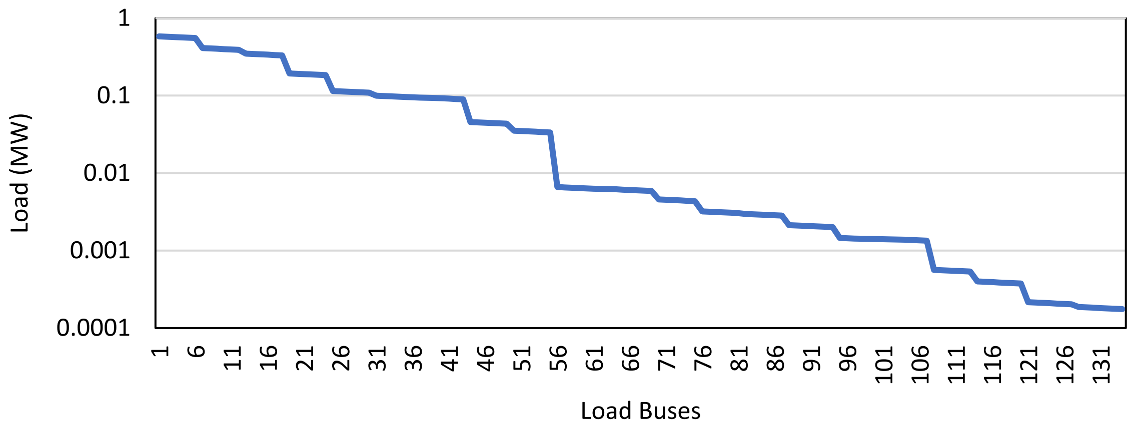


Figure 13 Spatial distribution of load in the network (logarithmic scale).

3.1.1.3 Network Security Analysis

In this section, the network steady-state operating point analysis and network security analysis for different loading conditions are performed and presented. These loading conditions are obtained from the base case condition by changing the loading factor and using the selected spatial load distribution given in Figure 13. The results of this analysis are shown in Table 3. In this analysis, branch overloads and voltage violations are used as static security metrics, as illustrated in Table 3. The allowable range for bus voltages is considered as (0.94 - 1.06). To also have a graphical insight into the results, the number of branch overloads and the number of bus voltage violations for different loading conditions are given in Figure 14. It is seen that for the base loading conditions (loading factor = 1), four buses are slightly overloaded (with a maximum overload of 8.9%). Also, there are 38 bus voltage violations in the base case conditions, as illustrated in Table 3 and Figure 14. These violations are experienced due to daily peak load conditions.

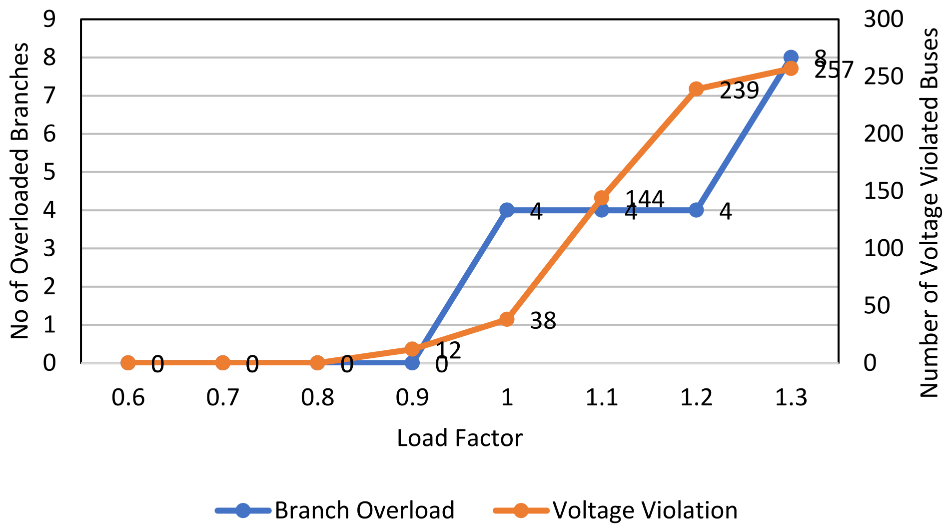


Figure 14 Network security matrices for different loading conditions.

Table 3 Steady-state network analysis for different loading conditions

Load Factor	Branch Overload	Voltage Violation	Type of Voltage Violation	Percent Over Loading (max)
0.6	0	0	-	-
0.7	0	0	-	-
0.8	0	0	-	-
0.9	0	12	Under voltage	-
1.0	4	38	Under voltage	8.9%
1.1	4	144	Under voltage	20.8%
1.2	4	239	Under voltage	33.1%
1.3	8	257	Under voltage	45.6%

A sensitivity analysis has been performed by changing the loading factor, as given in Table 3. By decreasing the loading factor below 1, the number of overloaded branches and the number of bus voltage violations decrease, while for the loading factor values below 0.9, there is no overloaded branch and bus voltage violation. On the other hand, the number of under-voltage buses increases by increasing the loading factor above 1. Although the number of overloaded branches does not increase by increasing the loading factor, the severity of overloading increases which can be seen from the maximum overloading percentage (the last column in Table 3).

3.1.1.4 Ancillary Services from Network 1

In case 1, only DR is considered for providing ancillary services (i.e., frequency and voltage support). The estimated ancillary services from Network 1 are presented in Figure 15 (for representative day-1) and (Figure 16 for representative day-2), respectively. It is assumed that 20% of total customers will provide 20% of their total load for DR services. Total demand response is 1 MW or more in several instances which would meet the FCAS criteria by AEMO [42].

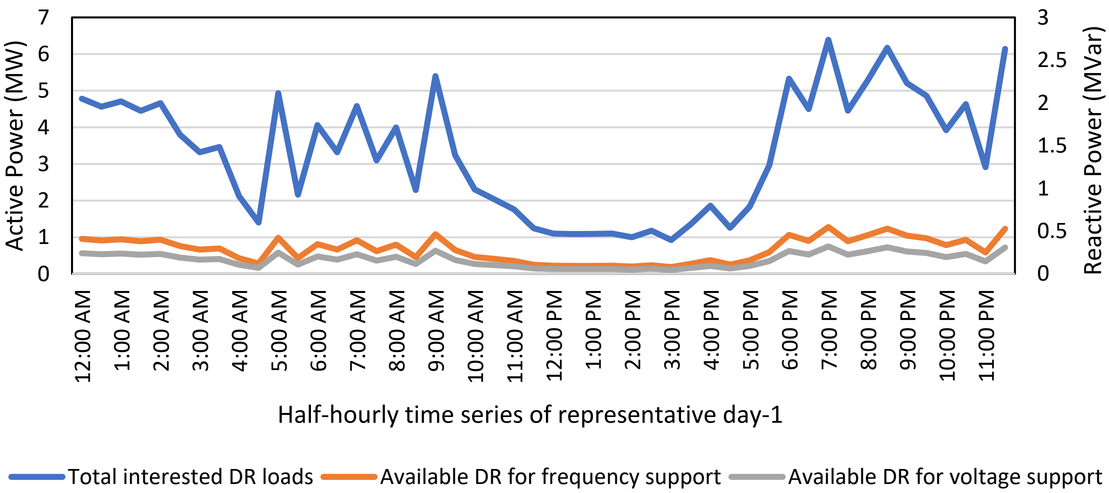


Figure 15 Available AS from Network 1 with DR participation in representative day-1.

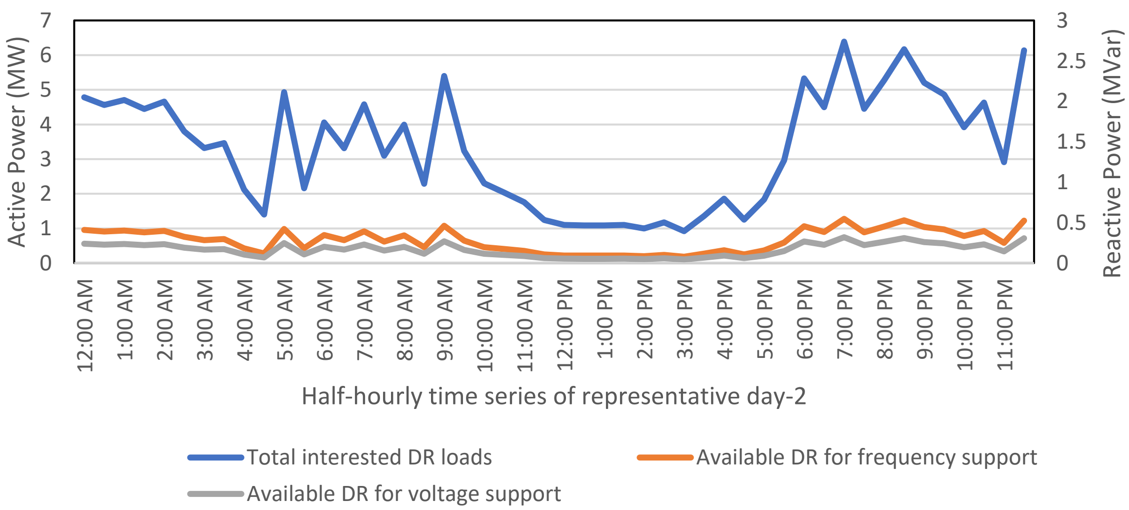


Figure 16 Available AS from Network 1 with DR participation in representative day-2.

3.1.1.5 Sensitivity Analysis

Ancillary services with 15 % DR providing loads

It is unlikely that all loads of a network participate in DR. For this reason, we have performed analyses considering different percentages of DR-providing loads. In this case, it is assumed that just 15% of total network loads are interested in providing DR. Also, DR participating loads will be willing to sacrifice a percentage of their total load for DR. The frequency and reactive power support with 40% participation of DR providing loads are presented in Table 4 and with 30% participation of DR providing loads are presented in Table 5. At 5:00 PM – 9:00 PM, the available amount of frequency support is over 1 MW which fulfil one of the requirements defined by AEMO to participate in FCAS market while all demand providing loads (i.e., 15% of total network loads) agree to participate in DR by allocating 40% of their consumptions to DR.

Table 4 Ancillary services with 40% participation of DR providing loads (15% DR providing loads)

DR participation time	Interested DR loads (kW)	Available DR (Frequency Support) (kW)	Up reserve (P) (kW)	Down reserve (P) (kW)	Available DR (Reactive power support) (kVar)
5:00 PM - 5:30 PM	0.014	0.006	0.003	0.002	0.001
5:30 PM - 6:00 PM	0.162	0.065	0.039	0.026	0.018
6:00 PM - 6:30 PM	2.588	1.035	0.621	0.414	0.316
6:30 PM - 7:00 PM	2.515	1.006	0.604	0.402	0.307
7:00 PM - 7:30 PM	2.429	0.972	0.583	0.389	0.296
7:30 PM - 8:00 PM	2.316	0.926	0.556	0.371	0.282
8:00 PM - 8:30 PM	2.204	0.882	0.529	0.353	0.269
8:30 PM - 9:00 PM	1.972	0.789	0.473	0.315	0.241

Table 5 Ancillary services with 30% participation of DR providing loads (15% DR providing loads)

DR participation time	Interested DR loads (kW)	Available DR (Frequency Support) (kW)	Up reserve (P) (kW)	Down reserve (P) (kW)	Available DR (Reactive power support) (kVar)
5:00 PM - 5:30 PM	0.014	0.004	0.003	0.002	0.001

5:30 PM - 6:00 PM	0.162	0.048	0.029	0.019	0.015
6:00 PM - 6:30 PM	2.588	0.777	0.466	0.311	0.220
6:30 PM - 7:00 PM	2.515	0.754	0.453	0.302	0.214
7:00 PM - 7:30 PM	2.429	0.729	0.437	0.292	0.207
7:30 PM - 8:00 PM	2.316	0.695	0.417	0.278	0.197
8:00 PM - 8:30 PM	2.204	0.661	0.397	0.265	0.188
8:30 PM - 9:00 PM	1.972	0.591	0.355	0.237	0.167

Ancillary services with 20 % DR providing loads

The amount of ancillary support from the distribution network is calculated for 20% DR providing loads. The results for 40% load participation of 20% DR providing loads are presented in Table 6 and for 30% participation of 20% DR providing loads are presented in Table 7. From Table 6 and Table 7, it is seen that the number of hours with more than 1 MW frequency support have been increased compared to Table 4 and Table 5.

Table 6 Ancillary services with 40% participation of DR providing loads (20% DR providing loads)

DR participation time	Interested DR loads (kW)	Available DR (Frequency Support) (kW)	Up reserve (P) (kW)	Down reserve (P) (kW)	Available DR (Reactive power support) (kVar)
5:00 PM – 5:30 PM	0.458	0.183	0.110	0.073	0.052
5:30 PM – 6:00 PM	0.645	0.258	0.155	0.103	0.073
6:00 PM – 6:30 PM	3.689	1.476	0.885	0.590	0.405
6:30 PM – 7:00 PM	3.587	1.435	0.861	0.574	0.394
7:00 PM – 7:30 PM	3.463	1.385	0.831	0.554	0.380
7:30 PM – 8:00 PM	3.306	1.323	0.794	0.529	0.363
8:00 PM – 8:30 PM	2.769	1.108	0.665	0.443	0.303
8:30 PM – 9:00 PM	2.478	0.991	0.595	0.397	0.270

Table 7 Ancillary services with 30% participation of DR providing loads (20% DR providing loads)

DR participation time	Interested DR loads (kW)	Available DR (Frequency Support) (kW)	Up reserve (P) (kW)	Down reserve (P) (kW)	Available DR (Reactive power support) (kVar)
5:00 PM – 5:30 PM	0.458	0.137	0.082	0.055	0.034
5:30 PM – 6:00 PM	0.645	0.193	0.116	0.077	0.049
6:00 PM – 6:30 PM	3.689	1.107	0.664	0.443	0.287
6:30 PM – 7:00 PM	3.587	1.076	0.646	0.430	0.279
7:00 PM - 7:30 PM	3.463	1.039	0.623	0.416	0.269
7:30 PM - 8:00 PM	3.306	0.992	0.595	0.397	0.257
8:00 PM - 8:30 PM	2.769	0.831	0.498	0.332	0.217
8:30 PM - 9:00 PM	2.478	0.743	0.446	0.297	0.194

Ancillary services with 25 % DR providing loads

The DR providing loads are increased to 25% in this case and frequency and reactive power ancillary services are estimated for 40% and 30% participation of DR loads. The results are presented Table 8 and Table 9, respectively. More than 1 MW available DR (frequency support) is from 5:00 PM to 9:00 PM.

Table 8 Ancillary services with 40% participation of DR providing loads (25% DR providing loads)

DR participation time	Interested DR loads (kW)	Available DR (Frequency Support) (kW)	Up reserve (P) (kW)	Down reserve (P) (kW)	Available DR (Reactive power support) (kVar)
5:00 PM - 5:30 PM	0.468	0.187	0.112	0.074	0.055
5:30 PM - 6:00 PM	0.691	0.276	0.165	0.111	0.079
6:00 PM - 6:30 PM	4.328	1.731	1.039	0.693	0.479
6:30 PM - 7:00 PM	4.208	1.683	1.009	0.673	0.466
7:00 PM - 7:30 PM	4.063	1.625	0.975	0.65	0.45

7:30 PM - 8:00 PM	3.879	1.551	0.931	0.621	0.429
8:00 PM - 8:30 PM	3.308	1.32	0.794	0.529	0.364
8:30 PM - 9:00 PM	2.96	1.18	0.71	0.473	0.326

Table 9 Ancillary services with 30% participation of DR providing loads (25% DR providing loads)

DR participation time	Interested DR loads (kW)	Available DR (Frequency Support) (kW)	Up reserve (P) (kW)	Down reserve (P) (kW)	Available DR (Reactive power support) (kVar)
5:00 PM - 5:30 PM	0.468	0.14	0.084	0.056	0.044
5:30 PM - 6:00 PM	0.691	0.207	0.124	0.083	0.063
6:00 PM - 6:30 PM	4.328	1.298	0.78	0.519	0.367
6:30 PM - 7:00 PM	4.208	1.262	0.757	0.505	0.357
7:00 PM - 7:30 PM	4.063	1.219	0.731	0.488	0.345
7:30 PM - 8:00 PM	3.879	1.164	0.698	0.465	0.329
8:00 PM - 8:30 PM	3.308	0.993	0.595	0.397	0.277
8:30 PM - 9:00 PM	2.96	0.888	0.533	0.355	0.248

3.1.2 Network 2

Network 2 is a radial distribution network located in Geelong East. This network is connected to the Geelong East Zone Substation. The network data of this test system is obtained from the DNSP and modelled in the DIgSILENT PowerFactory. The single-line diagram of Network 2 connected to the Geelong East Zone Substation is illustrated in Figure 17. Two feeders are supplying the network with a tie line normally open.

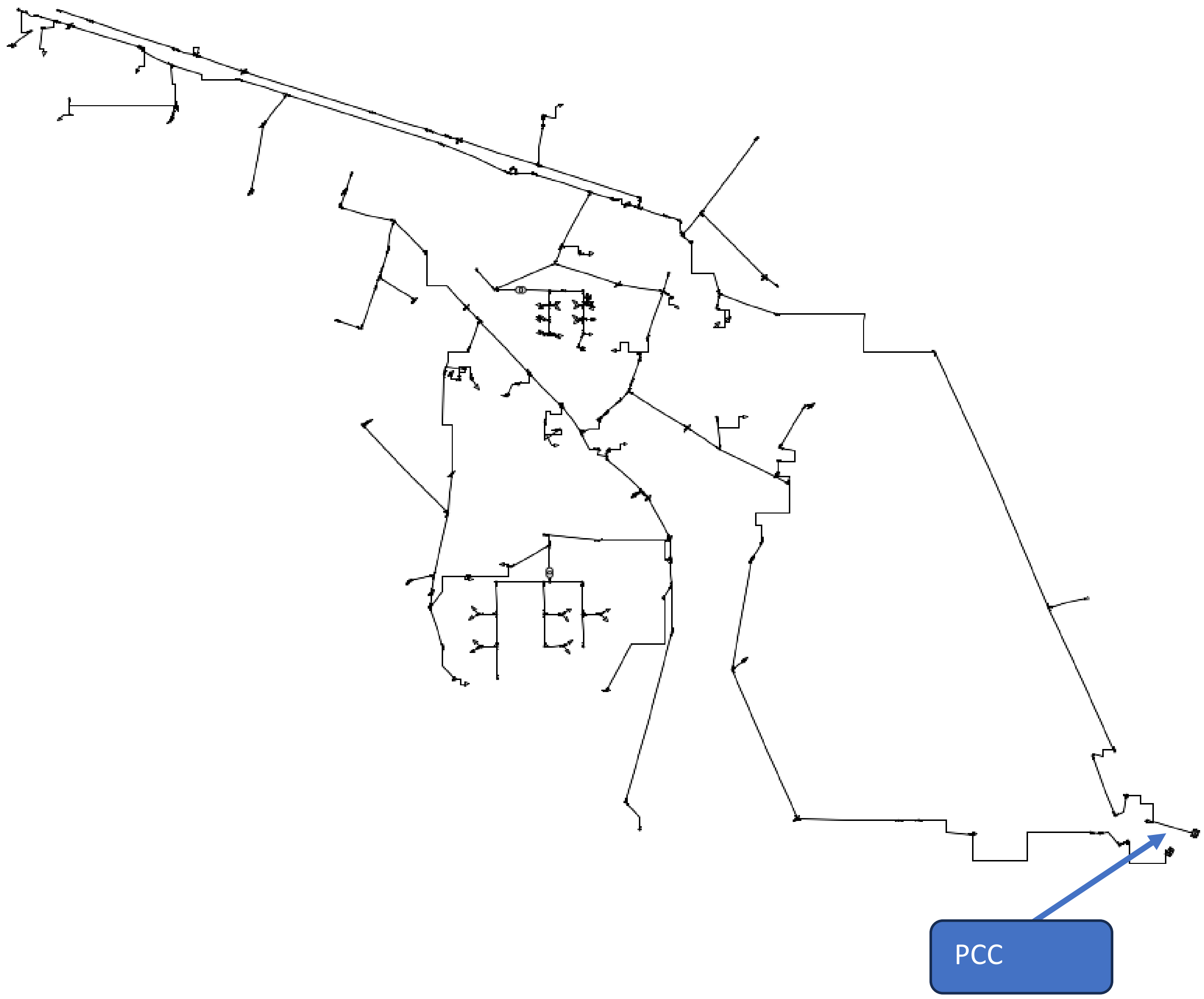


Figure 17 Single-line diagram of Geelong East MV distribution network.

3.1.2.1 Time Aggregated Load Profiles

The time-aggregated load profiles are obtained using historical load time series data provided by the DNSP. The aggregated time-series data of 2021 from Geelong East ZS is presented in Figure 18. The optimal number of representative periods is identified using the Silhouette criterion. The results of the Silhouette score (for 2021) are plotted against the number of clusters in Figure 19. It is seen that the optimal number of representative days is two (i.e., the highest value of the Silhouette criterion in Figure 19). The representative daily profiles obtained using the K-means clustering method are presented in Figure 20.

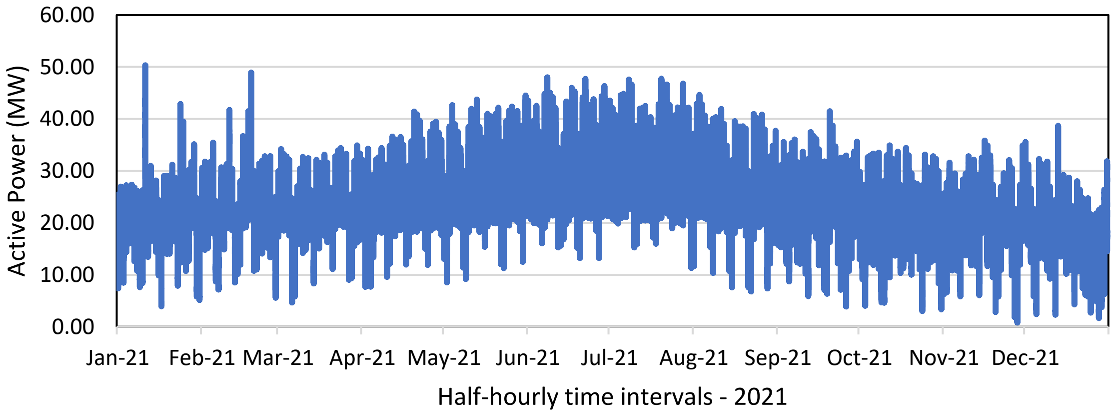


Figure 18 Aggregated time-series data - 2021 from Geelong East zone substation.

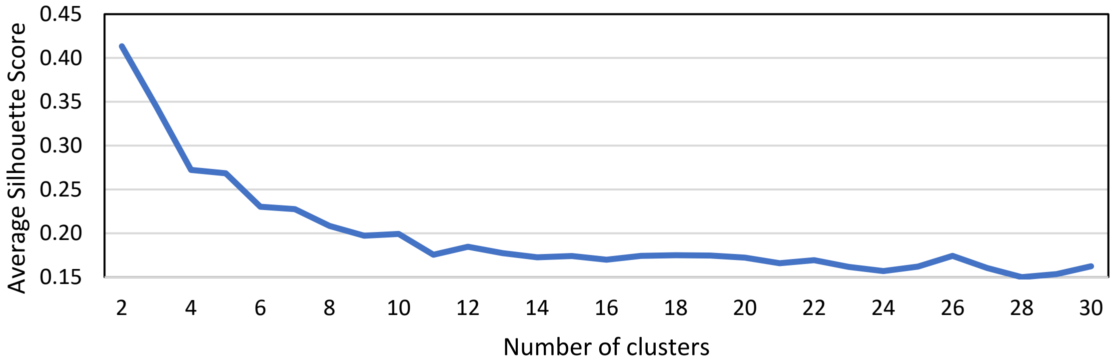


Figure 19 Silhouette criterion results for the time series data 2021.

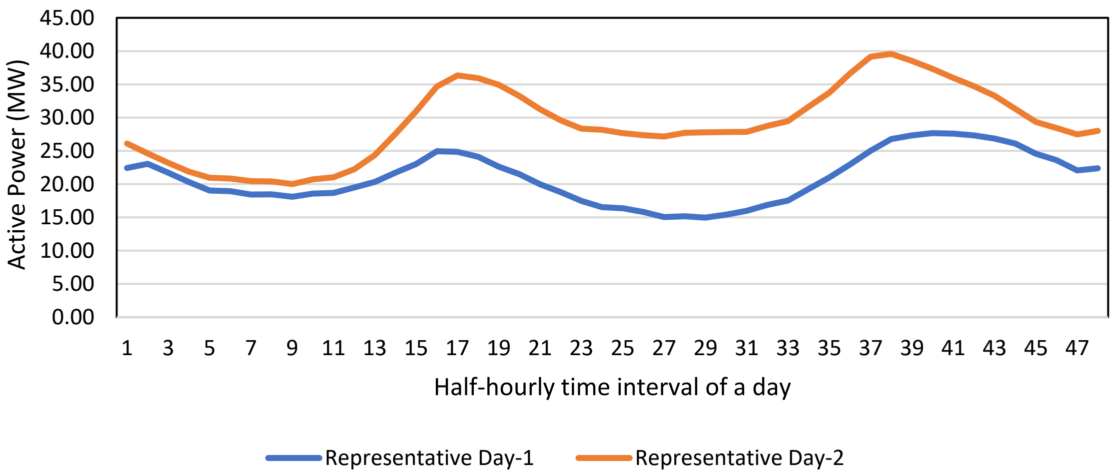


Figure 20 Representative daily profiles obtained by K-means clustering method.

3.1.2.2 Spatial Load Data Distribution

The ancillary services have been analysed for 96 loading conditions of two representative days. The number of loading conditions varies based on the optimal number of representative periods identified by the Silhouette criterion. The spatial load distribution of a single snapshot is presented in Figure 21 for the illustration of the results and validation of the proposed methodology. Since the daily peak loading condition captures one of the extreme conditions of the network, it is considered as a base case loading condition in this analysis. In this base case scenario, the maximum load is approximately 0.315 MW, whereas the minimum load is 0.005625 MW.

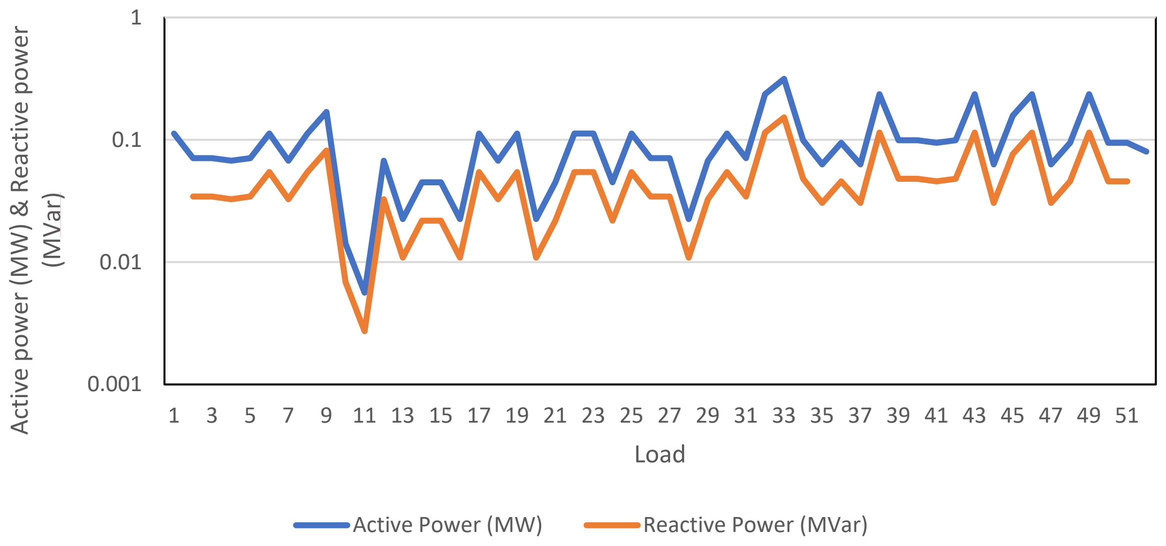


Figure 21 Spatial distribution of load in the network.

3.1.2.3 Network Security Analysis

The network steady-state operating point analysis and network security analysis for different loading conditions in Network 2 are performed and presented in this section. The loading conditions are obtained from the base case loading factor by using the selected spatial load distribution shown in Figure 21. In this analysis, branch overloads and voltage violations are used as the static security metrics, as given in Table 10. The allowable range for bus voltages is considered as (0.94 - 1.06). To provide a graphical insight into the results, the number of branch overloads and the number of bus voltage violations for different loading conditions are given in Figure 22. It is seen that for the base loading conditions (loading factor = 1), no buses are overloaded and no voltage violations have been observed as illustrated in Table 10 and Figure 22.

Table 10 Steady-state network analysis for different loading conditions

Load Factor	Branch Overload	Voltage Violation	Type of Voltage Violation	Percent Over Loading (max)
0.8	0	0	-	-
0.9	0	0	-	-
1	0	0	-	-
1.1	0	0	-	-
1.2	0	0	-	-
1.3	3	0	-	Max 3.2%
1.4	3	0	-	Max 11.2%
1.5	5	0	-	Max 19.2%

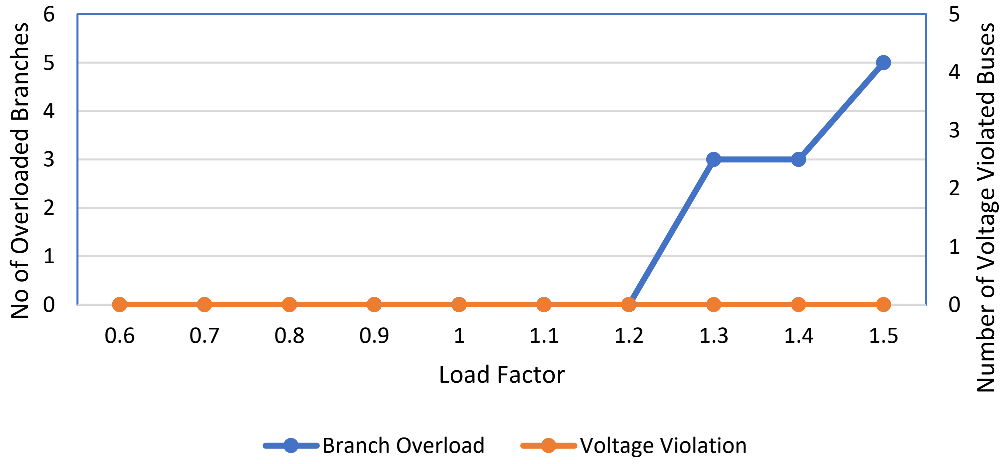


Figure 22 Network security matrices for different loading conditions.

A sensitivity analysis has been performed by changing the loading factor, as given in Table 10. By decreasing the loading factor below 1, no line overloading and voltage violations have been observed. On the other hand, the number of overloaded brunches increases by increasing the loading factor above 1. The severity of branch overloading increases with the increase in load factor (the last column in Table 10). These behaviors can be explained considering that increasing/decreasing the loading factor makes the network more/less stressed.

3.1.2.4 Ancillary Services from Network 2

The estimated ancillary services from Network 2 are presented in Figure 23 for representative day-1 and Figure 24 for representative day-2. It is assumed that 20% of total customers provide 20% of their total load for DR services. Total demand response is 1 MW or more in several instances which may meet the FCAS criteria by AEMO. The network can also provide reactive power support to the transmission network.

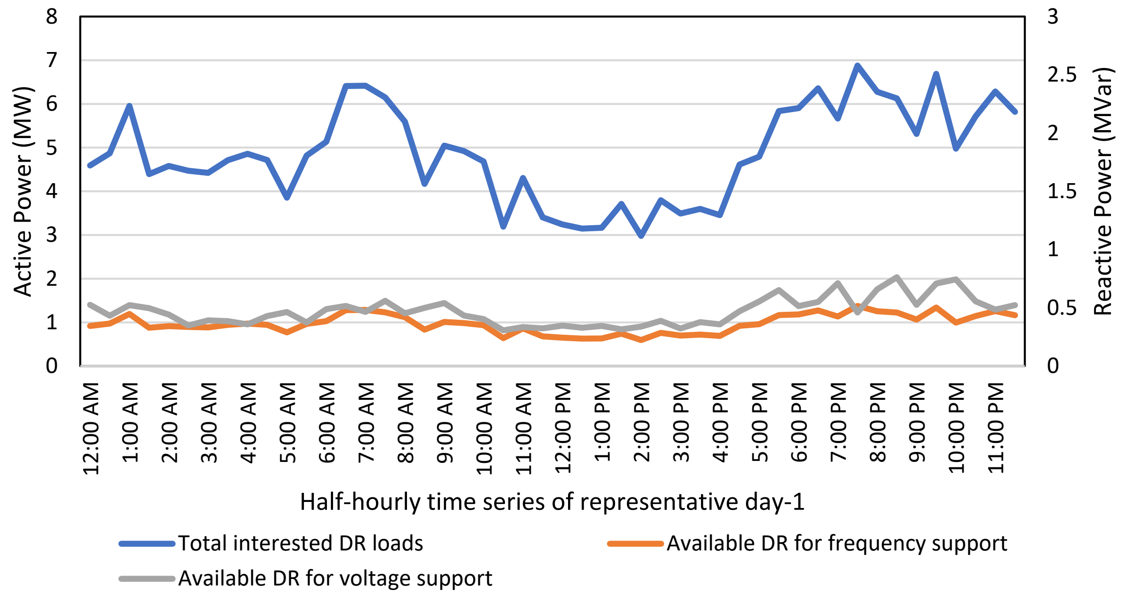


Figure 23 Available AS from Network 2 with DR participation in representative Day-1.

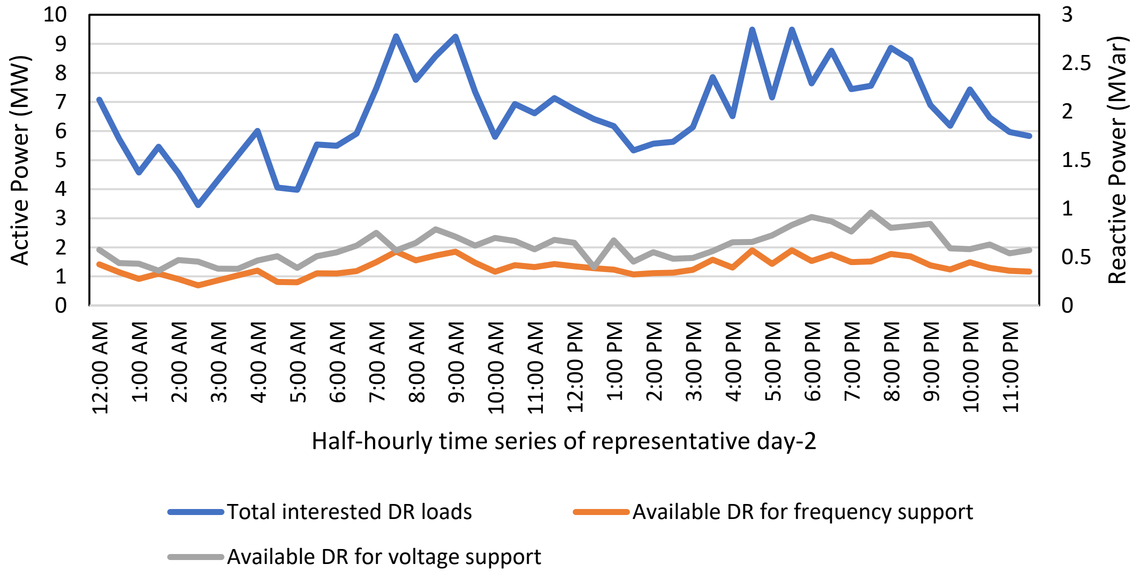


Figure 24 Available AS from Network 2 with DR participation in representative day-2.

3.1.2.5 Sensitivity Analysis

Ancillary services with 30 % DR providing loads

The ancillary service provided by network 2 has been estimated considering that 30% of total loads are participating in DR. The results for 40% participation of DR providing loads are presented in Table 11 and the results for 30% participation of DR providing loads are shown in Table 12. Network 2 is relatively small, and the frequency support is below 1 MW all the time of the representative load profile.

Table 11 Ancillary services with 40% participation of DR providing loads (30% DR providing loads)

DR participation time	Interested DR loads (kW)	Available DR (Frequency Support) (kW)	Up reserve (P) (kW)	Down reserve (P) (kW)	Available DR (Reactive power support) (kVar)
5:00 PM - 5:30 PM	882.30	352.91	211.75	141.16	91.13
5:30 PM - 6:00 PM	1507.70	559.86	335.91	223.94	148.31
6:00 PM - 6:30 PM	2002.11	757.86	454.71	303.14	196.05
6:30 PM - 7:00 PM	1990.06	753.29	451.97	301.31	194.87
7:00 PM - 7:30 PM	1982.15	750.30	450.18	300.12	194.10
7:30 PM - 8:00 PM	1868.38	747.35	448.41	298.94	193.33
8:00 PM - 8:30 PM	1118.56	404.91	242.94	161.96	104.90
8:30 PM - 9:00 PM	500.07	200.03	120.01	80.012	48.30

Table 12 Ancillary services with 30% participation of DR providing loads (30% DR providing loads)

DR participation time	Interested DR loads (kW)	Available DR (Frequency Support) (kW)	Up reserve (P) (kW)	Down reserve (P) (kW)	Available DR (Reactive power support) (kVar)
5:00 PM - 5:30 PM	882.30	264.68	158.81	105.87	67.22
5:30 PM - 6:00 PM	1507.70	419.89	251.93	167.95	113.36
6:00 PM - 6:30 PM	2002.11	568.39	341.03	227.35	154.62
6:30 PM - 7:00 PM	1990.06	564.97	338.98	225.98	153.69
7:00 PM - 7:30 PM	1982.15	562.73	337.63	225.09	153.08
7:30 PM - 8:00 PM	1868.38	560.51	336.30	224.20	152.48
8:00 PM - 8:30 PM	1118.56	303.68	182.20	121.47	87.28
8:30 PM - 9:00 PM	500.07	150.02	90.01	60.00	41.66

Ancillary services with 40 % DR providing loads

The analysis of network 2 has been extended by considering 40% DR providing loads. The results of 40% participation of DR providing loads are presented in Table 13. The results with 30% participation of DR providing loads are presented in Table 14. Again, none of the time periods has more than 1 MW frequency support.

Table 13 Ancillary services with 40% participation of DR providing loads (40% DR providing loads)

DR participation time	Interested DR loads (kW)	Available DR (Frequency Support) (kW)	Up reserve (P) (kW)	Down reserve (P) (kW)	Available DR (Reactive power support) (kVar)
5:00 PM - 5:30 PM	908.20	363.28	217.96	145.31	88.92
5:30 PM - 6:00 PM	1686.50	631.38	378.82	252.55	163.93
6:00 PM - 6:30 PM	2538.10	972.25	583.35	388.90	246.16
6:30 PM - 7:00 PM	2522.82	966.40	579.84	386.56	244.68
7:00 PM - 7:30 PM	2512.80	962.57	577.54	385.02	243.71
7:30 PM - 8:00 PM	2396.94	958.77	575.26	383.51	242.75
8:00 PM - 8:30 PM	1623.43	606.85	364.11	242.74	156.63
8:30 PM - 9:00 PM	856.367	342.54	205.52	137.01	82.69

Table 14 Ancillary services with 30% participation of DR providing loads (40% DR providing loads)

DR participation time	Interested DR loads (kW)	Available DR (Frequency Support) (kW)	Up reserve (P) (kW)	Down reserve (P) (kW)	Available DR (Reactive power support) (kVar)
5:00 PM - 5:30 PM	908.20	272.46	163.47	108.98	68.93
5:30 PM - 6:00 PM	1686.50	473.53	284.12	189.41	123.13
6:00 PM - 6:30 PM	2538.10	729.19	437.51	291.67	194.88
6:30 PM - 7:00 PM	2522.82	724.80	434.88	289.92	193.70
7:00 PM - 7:30 PM	2512.80	721.92	433.15	288.77	192.94
7:30 PM - 8:00 PM	2396.94	719.08	431.45	287.63	192.18
8:00 PM - 8:30 PM	1623.43	455.14	273.08	182.05	125.43
8:30 PM - 9:00 PM	856.367	256.91	154.14	102.76	72.04

3.1.3 Network 3

Network 3 is a radial distribution network located in the Ballarat area and connected to the Ballarat South Zone Substation. The network data of this test system is obtained from the DNSP and modelled in the DIgSILENT PowerFactory. Figure 25 illustrates the single-line diagram of Network 3 connected to the Ballarat South Zone Substation.

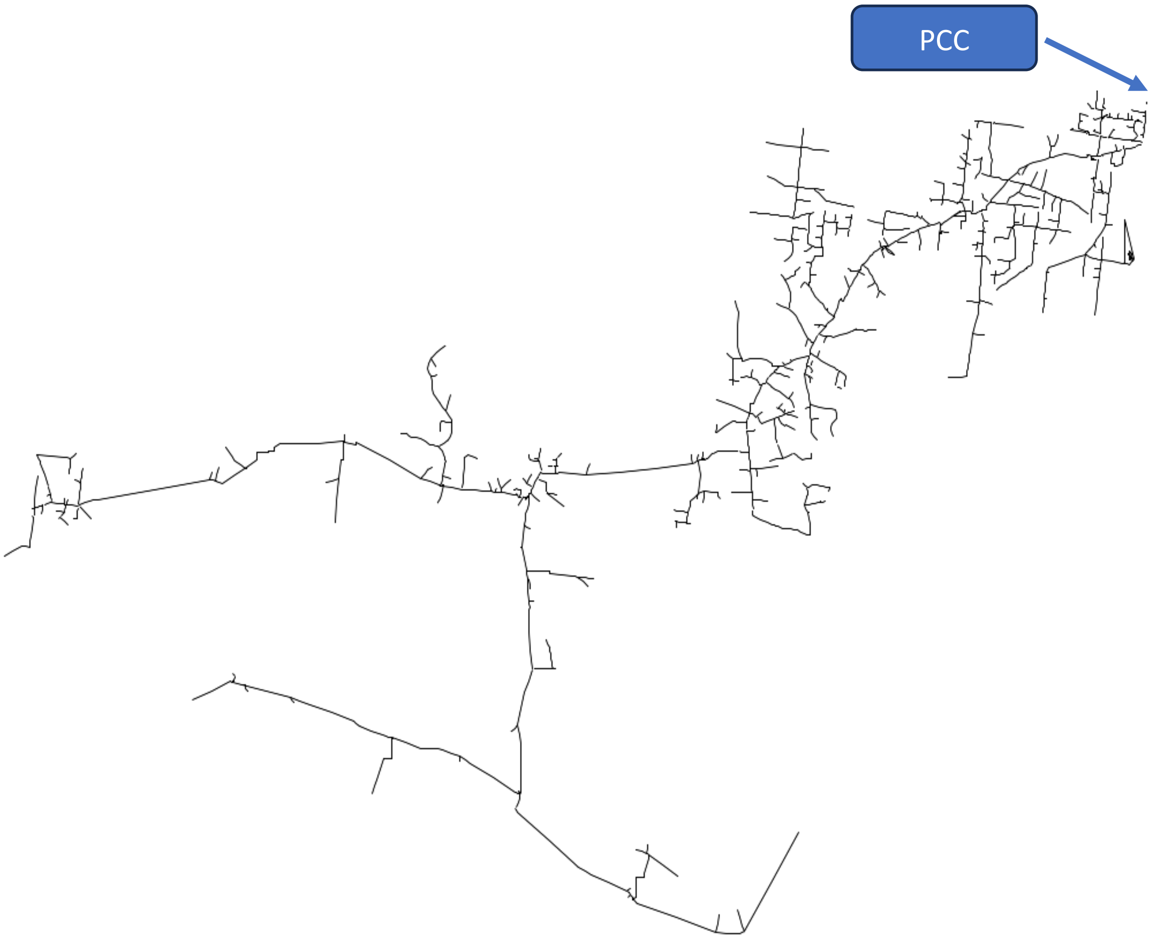


Figure 25 Single-line diagram of Ballarat South MV distribution network.

3.1.3.1 Time Aggregated Load Profiles

The aggregated time-series data of 2021(30-minute time intervals) from Ballarat South ZS is presented in Figure 26. For 2021, the results of the Silhouette score are plotted against the number of clusters in Figure 27. The highest value of the Silhouette criterion is two (as shown in Figure 27). Therefore, two representative days are used. Representative daily profiles are presented in Figure 28. With the advent of time aggregation, the number of required power flow analysis and network reduction processes is reduced from 17,520 in a conventional network reduction method to 96 in the proposed method.

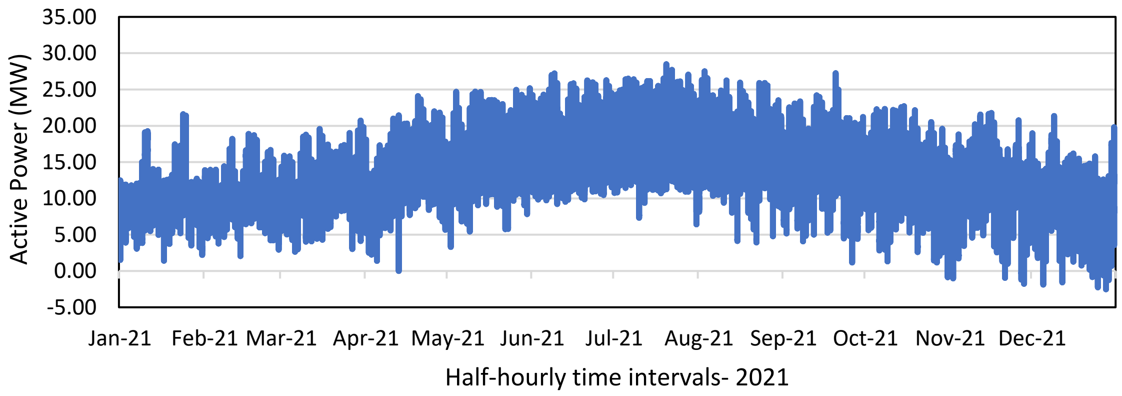


Figure 26 Aggregated time-series data 2021 from Ballarat South zone substation.

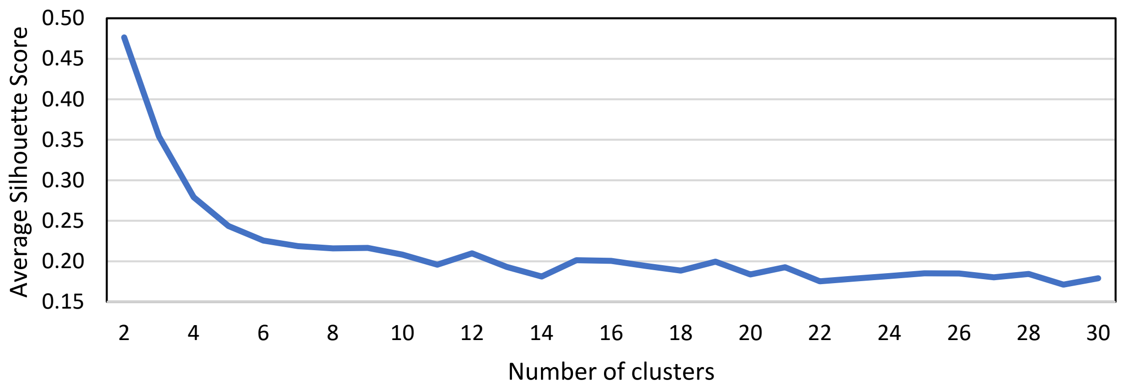


Figure 27 Silhouette criterion results for the time series data 2021.

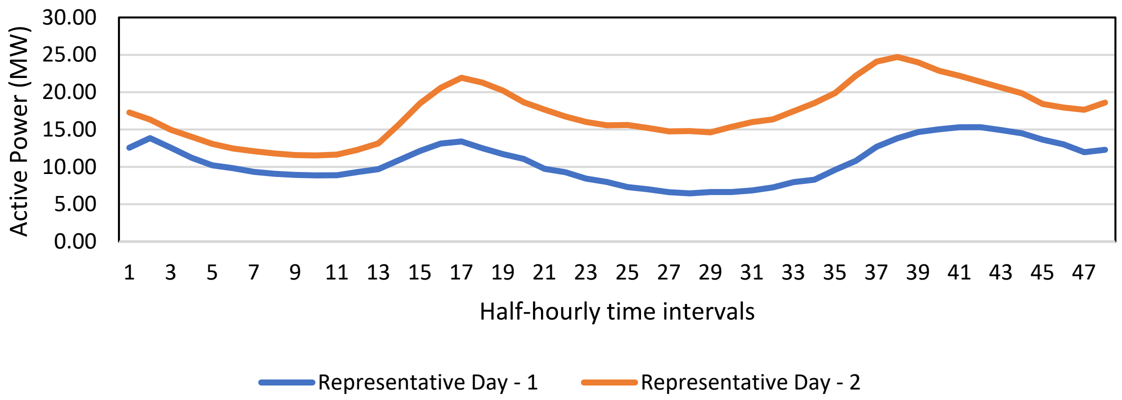


Figure 28 Representative daily profiles obtained by the K-means clustering method.

3.1.3.2 Spatial Load Data Distribution

The representative daily load profiles of 921 load buses in the network are obtained here using the K-means clustering method. The ancillary services have been analysed for 96 loading conditions of two representative days. The number of loading conditions varies based on the optimal number of representative periods identified by the Silhouette criterion. Similar to the prior cases, the spatial load distribution of a single snapshot is presented here to illustrate the results and validate the proposed methodology. Since the daily peak loading condition captures one of the extreme conditions of the network, it is considered as a base case loading condition for this analysis. In this base case scenario, the maximum load is approximately 0.386 MW, whereas the minimum load is 0.000193MW. Figure 29 displays the spatial load distribution of the input load data in the network.

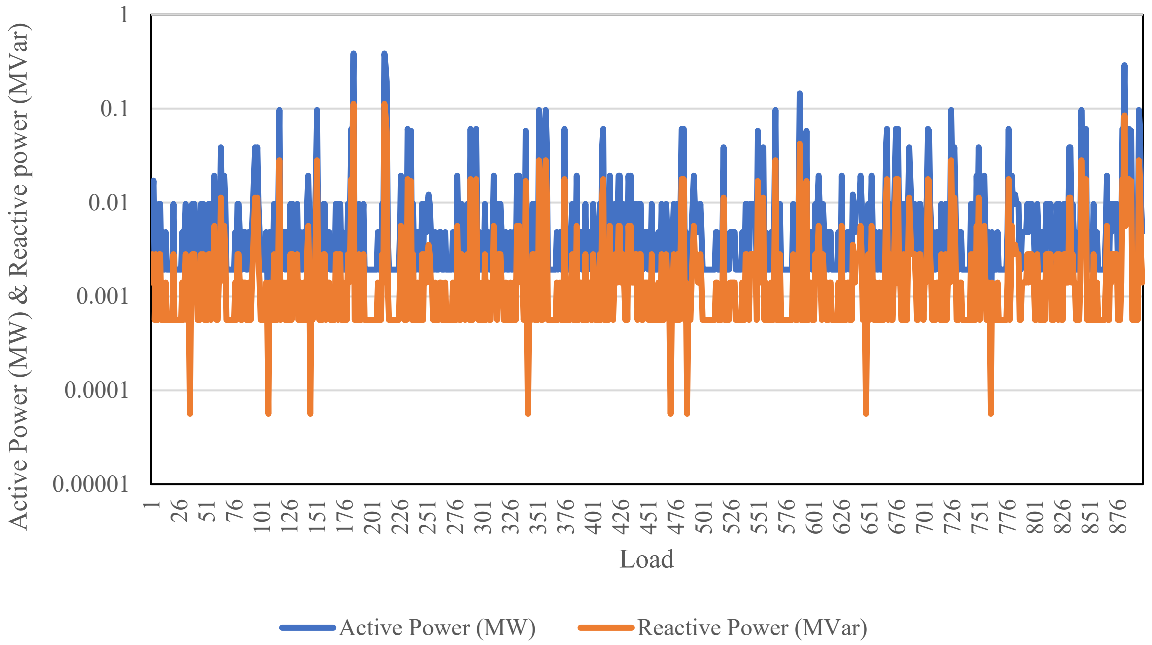


Figure 29 Spatial distribution of load in the network.

3.1.3.3 Network Security Analysis

In this section, the network steady-state operating point analysis and network security analysis for different loading conditions for network 3 are performed and presented. These loading conditions are obtained from the base case condition by changing the loading factor of the selected spatial load distribution shown in Figure 29. The results of this analysis are shown in Table 15. In this analysis, branch overloads and voltage violations are used as static security metrics, as shown in Table 15. The number of branch overloads and the number of bus voltage violations for different loading conditions are given in Figure 30. No overloaded buses are observed in Figure 30. Also, there are 120 bus voltage violations in the base case conditions as illustrated in Table 15 and Figure 30.

Table 15 Steady-state network analysis for different loading conditions

Load Factor	Branch Overload	Voltage Violation	Type of Voltage Violation	Percent Over Loading (max)
0.8	0	0	Under voltage	-
0.9	0	15	Under voltage	-
1	0	120	Under voltage	-
1.1	0	293	Under voltage	-
1.2	4	372	Under voltage	Max 4.2%
1.3	23	433	Under voltage	Max 13.8%
1.4	41	621	Under voltage	Max 23.5%

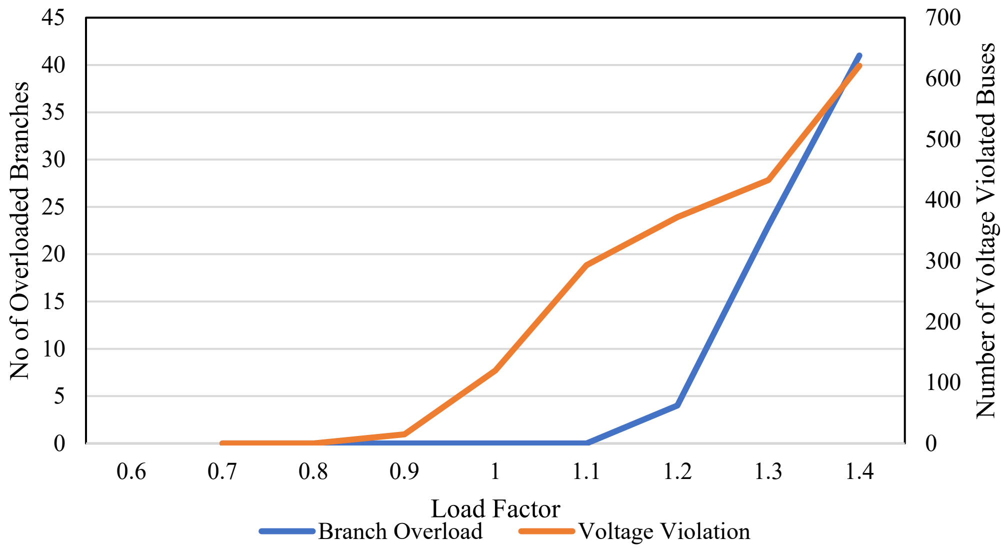


Figure 30 Network security matrices for different loading conditions.

A sensitivity analysis has been performed by changing the loading factor, as illustrated in Table 15. The number of bus voltage violations decreases for the loading factor below 1. No overloaded branch and bus voltage violations are observed for the loading factor below 0.9. On the other hand, the number of under-voltage buses increases by increasing the loading factor above 1. The severity of overloading increases with the increase of the loading factor, which can be seen in the maximum overloading percentage (the last column in Table 15). These behaviors can be explained considering that increasing/decreasing the loading factor makes the network more/less stressed.

3.1.3.4 Ancillary Services from Network 3

Only DR is considered for FCAS and Voltage control ancillary service (VCAS) support to the upstream of the network from the active distribution network. The calculated ancillary services from Network 3 are presented in Figure 23 for representative day-1 and Figure 32 for representative day-2. It is assumed that 20% of total customers provide 20% of their total load for DR services. Total demand response is 1 MW in some instances which may meet the demand response and frequency ancillary service criteria by AEMO. The network can also provide some reactive power support to the transmission network.

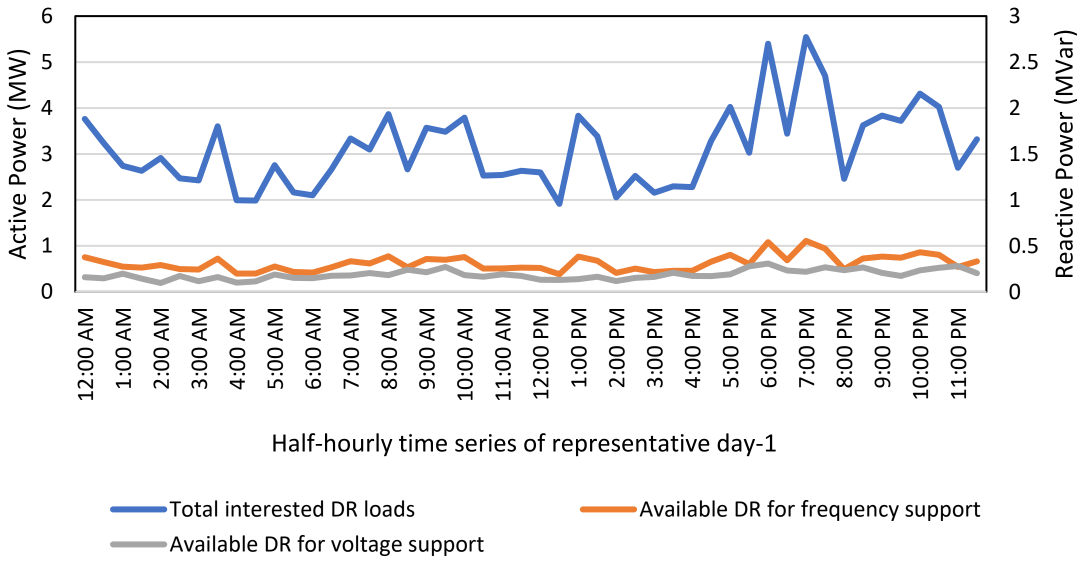


Figure 31 Available AS from Network 3 with DR participation in representative day-1.

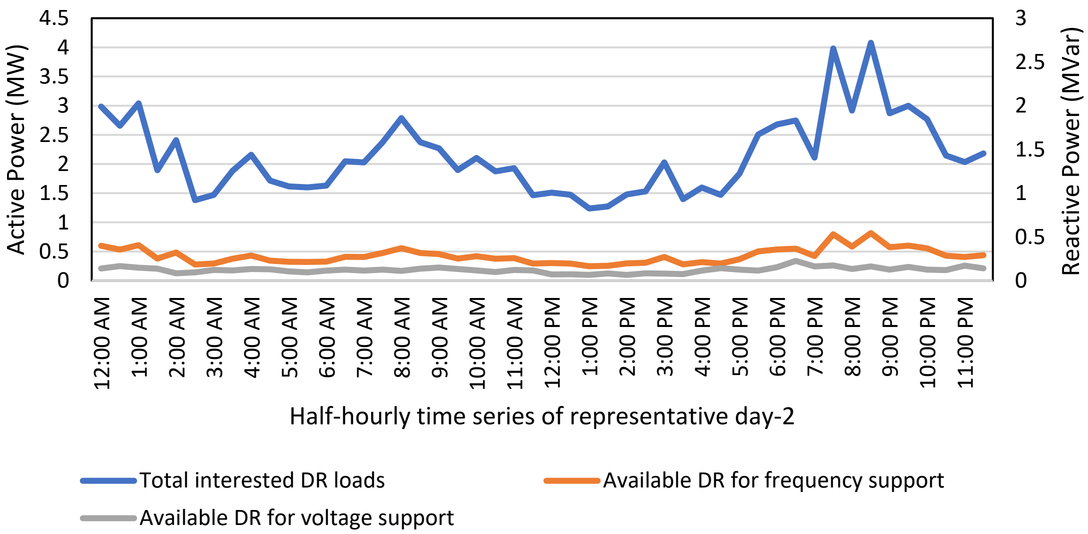


Figure 32 Available AS from Network 3 with DR participation in representative day-2.

Sensitivity Analysis

Ancillary services with 25 % DR providing loads

Network 3 is larger compared to networks 1 and 2. The ancillary support calculation is performed considering 25% DR providing loads. The results considering 40% and 30% participation of DR providing loads are shown in Table 16 and Table 17, respectively. More than 1 MW frequency support is available from 5:30 PM to 8:30 PM as presented in Table 16.

Table 16 Ancillary services with 40% participation of DR providing loads (25% DR providing loads)

DR participation time	Interested DR loads (kW)	Available DR (Frequency Support) (kW)	Up reserve (P) (kW)	Down reserve (P) (kW)	Available DR (Reactive power support) (kVar)
5:00 PM - 5:30 PM	290.28	116.11	69.66	46.44	31.55
5:30 PM - 6:00 PM	2793.55	1117.42	670.45	446.96	300.05
6:00 PM - 6:30 PM	3369.38	1347.75	808.65	539.10	362.34
6:30 PM - 7:00 PM	3284.69	1313.87	788.32	525.55	353.23
7:00 PM - 7:30 PM	3253.64	1301.45	780.87	520.58	349.90
7:30 PM - 8:00 PM	3083.22	1233.28	739.97	493.31	331.57
8:00 PM - 8:30 PM	2787.93	1115.17	669.10	446.06	299.51
8:30 PM - 9:00 PM	539.57	215.82	129.49	86.33	58.34

Table 17 Ancillary services with 30% participation of DR providing loads (25% DR providing loads)

DR participation time	Interested DR loads (kW)	Available DR (Frequency Support) (kW)	Up reserve (P) (kW)	Down reserve (P) (kW)	Available DR (Reactive power support) (kVar)
5:00 PM - 5:30 PM	290.28	87.08	52.25	34.83	23.66
5:30 PM - 6:00 PM	2793.55	838.06	502.84	335.22	225.03
6:00 PM - 6:30 PM	3369.38	1010.81	606.48	404.32	271.76
6:30 PM - 7:00 PM	3284.69	985.40	591.24	394.16	264.92
7:00 PM - 7:30 PM	3253.64	976.09	585.65	390.43	262.42
7:30 PM - 8:00 PM	3083.22	924.96	554.98	369.98	248.68
8:00 PM - 8:30 PM	2787.93	836.38	501.82	334.55	224.63
8:30 PM - 9:00 PM	539.57	161.87	97.12	64.74	43.75

3.2 Case 2A: With DR and Present DERs (2024)

The installation of front-of-the-meter DERs, such as solar PV and wind, in the network is considered alongside the loads in case 2A. However, there is no front-of-the-meter solar PV connected in all three networks in this case. Network 3 only has 6.15 MW wind generation in the area. Yearly 2% growth on net demand is considered to obtain net demand profile of 2024 by considering the new developments, population growth, and economic expansion in this area [43]. The amount of DR participation will vary based on the percentage participation of customers, their locations, time and duration of DR operation.

3.2.1 Network 1

At present, there is no front-of-the-meter DER connected to Network 1. Therefore, only DR is considered for calculating ancillary services in this network for case 2A.

3.2.1.1 Time Aggregated Load Profiles

The time-aggregated load profiles of 2024 are generated using the time series load data of 2021. The aggregated time-series data of 2024 (30-minute time intervals) from Drysdale ZS is presented in Figure 33. At present, there is no DER (PV and Wind) connected to network 1. Thus, we have implemented the K-means clustering method to reduce the time series data of every year into a reasonable number of representative periods (representative days). For 2024, the results of the Silhouette score are plotted against the number of clusters in Figure 34. Two representative days are selected based on the highest value given in Figure 34. Figure 35 shows the representative daily profiles.

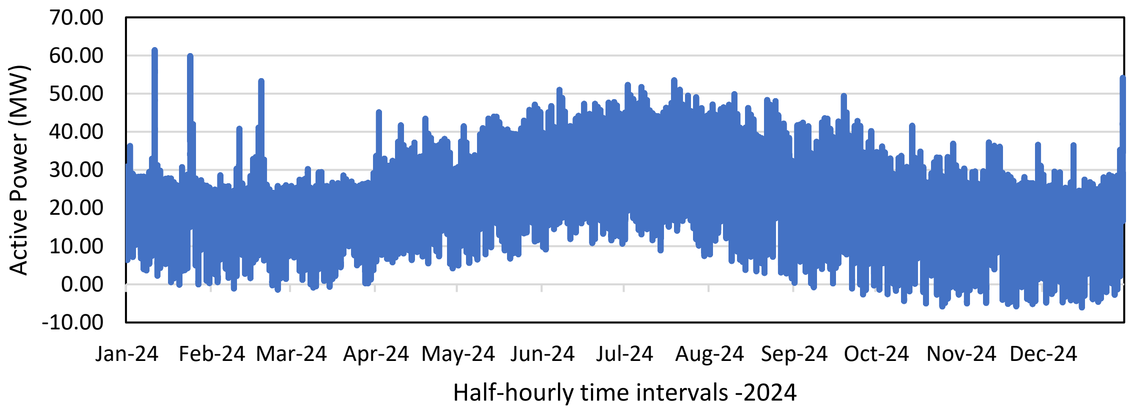


Figure 33 Aggregated time-series data 2024 from the Drysdale zone substation.

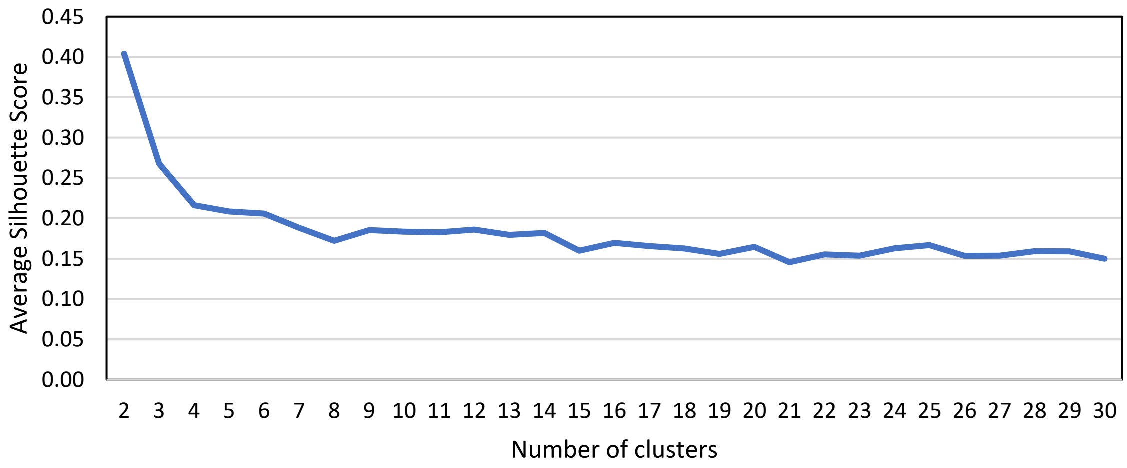


Figure 34 Silhouette criterion results for the time series data 2024.

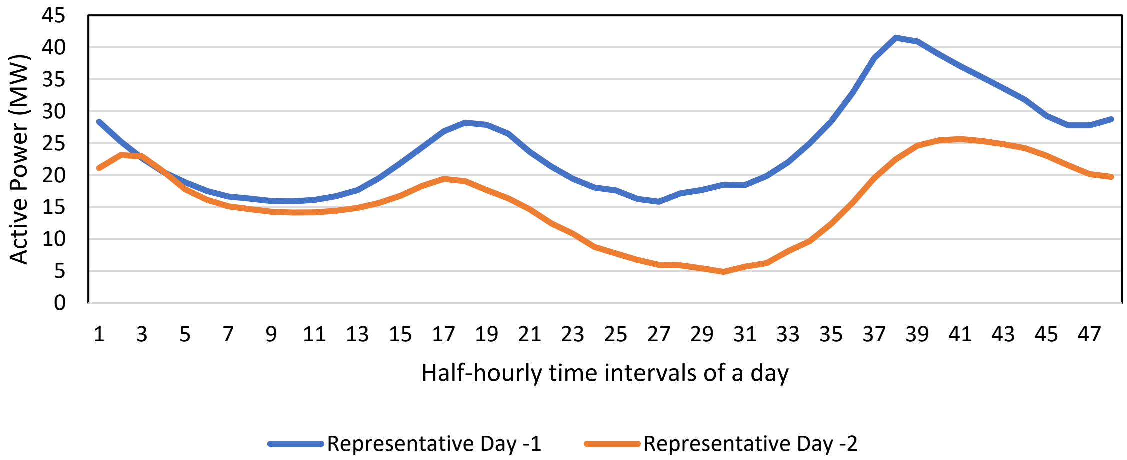


Figure 35 Representative daily profiles obtained by the K-means clustering method.

3.2.1.2 Ancillary Services from Network 1

In case 2A, the present (2024) demand profile and available DERs are considered for providing ancillary services. Since there is no available front-of-the-meter DER in Network 1, only DR is considered for providing frequency and voltage support in this case. The calculated ancillary services from Network 1 are presented in Figure 36 for representative day-1 and Figure 37 for representative day-2. Total demand response is 1 MW or more in some instances which may meet the demand response and FCAS criteria by AEMO for market participation [42]

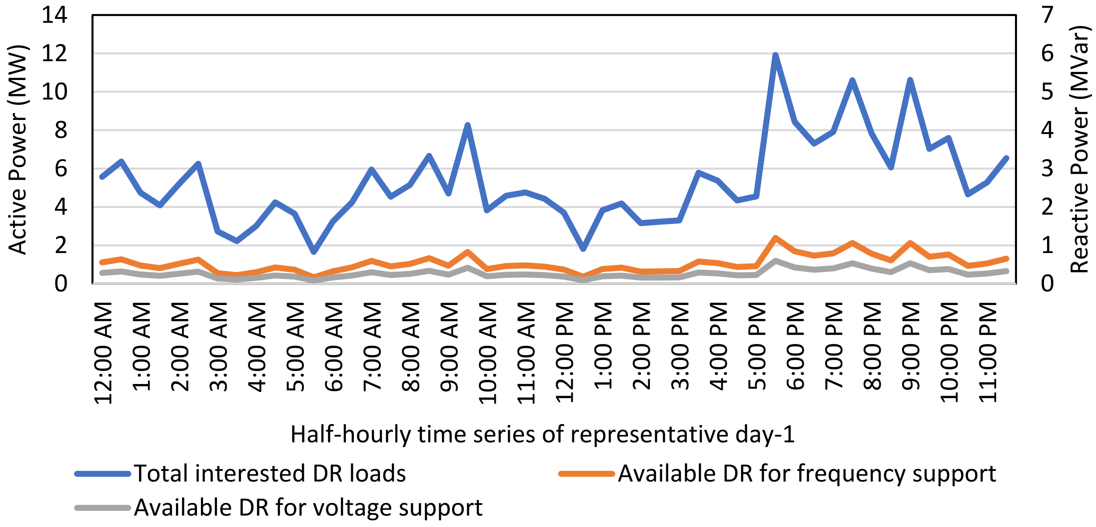


Figure 36 Available AS from Network 1 with DR participation in representative day-1.

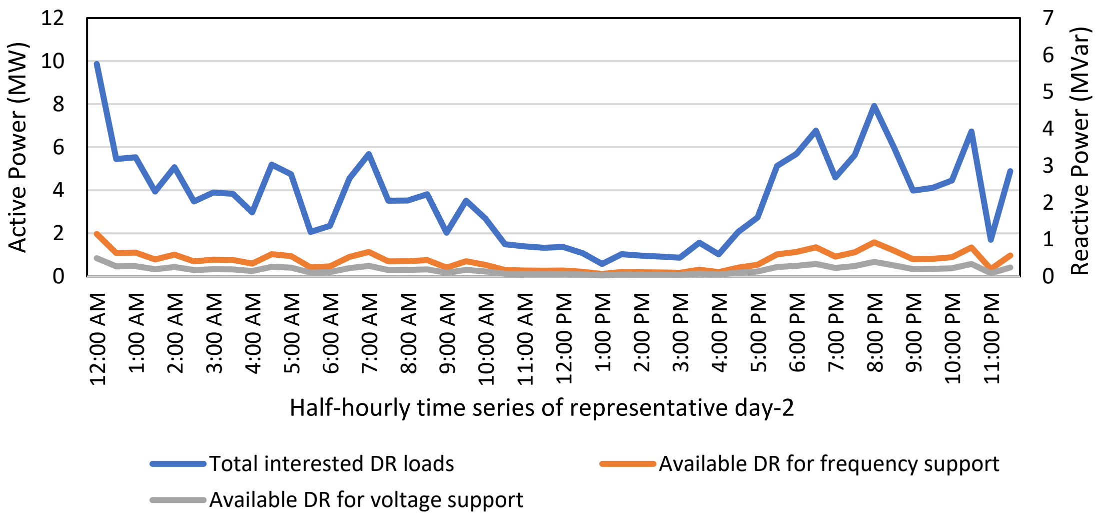


Figure 37 Available AS from Network 1 with DR participation in representative day-2.

3.2.2 Network 2

At present, there is no front-of-the-meter DER connected to Network 2. Therefore, only DR is considered for calculating ancillary services in this network for case 2A.

3.2.2.1 Time Aggregated Load Profiles

Similar to network 1, The time series aggregated load data of 2024 is obtained using the load data of 2021. The time series data is available on the Powercor website. The aggregated time-series data of 2024 from Geelong East ZS is presented in Figure 38. There is no DER (PV and Wind) connected to this network at present (2024). The K-means clustering method has been implemented to reduce the time series data of every year into a reasonable number of representative periods (representative days). The optimal number of representative periods is identified using the Silhouette criterion. For 2024, the results of the Silhouette score are plotted against the number of clusters in Figure 39. Figure 40 shows the representative daily profiles.

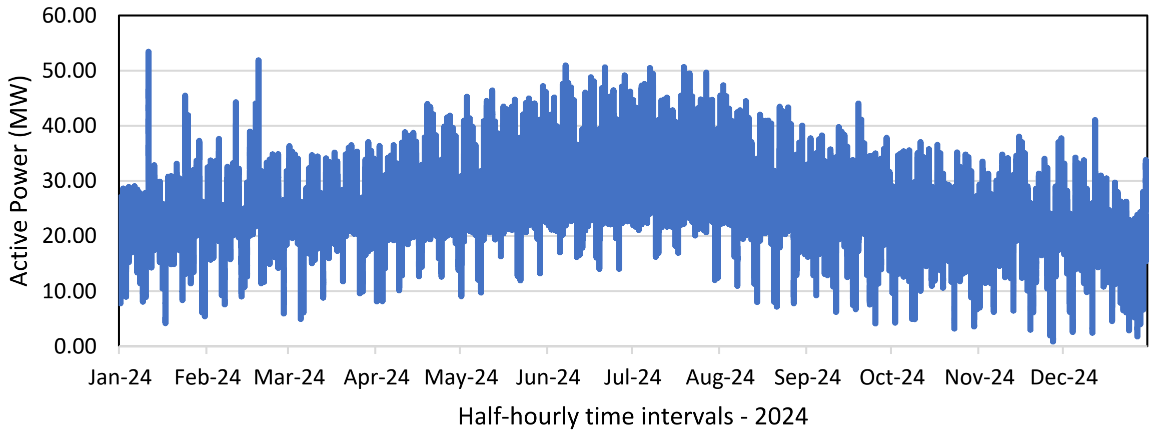


Figure 38 Aggregated time-series data 2024 from Geelong East zone substation.

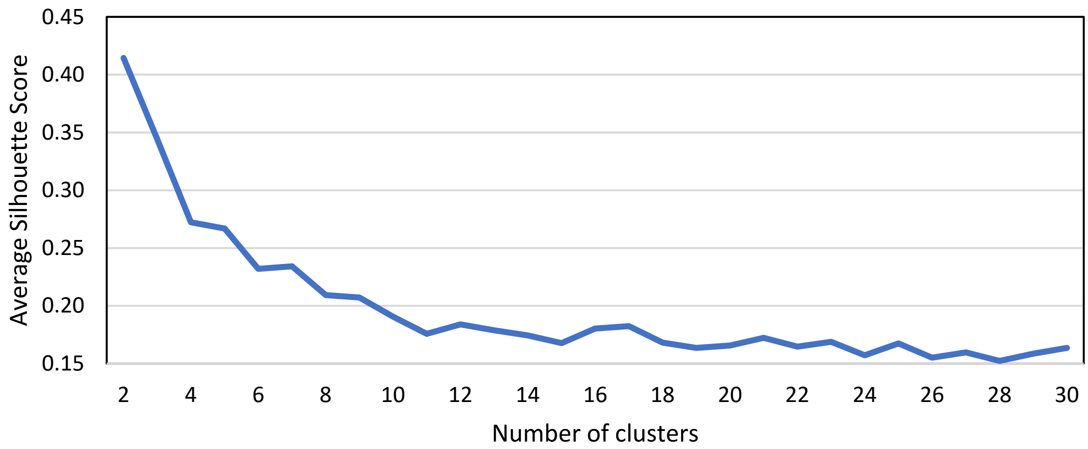


Figure 39 Silhouette criterion results for the time series data 2024.

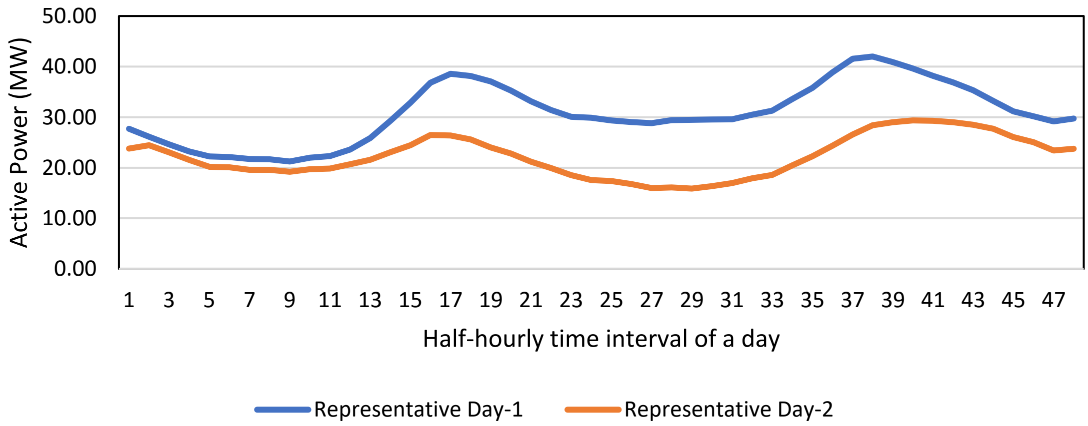


Figure 40 Representative daily profiles obtained by the K-means clustering method.

3.2.2.2 Ancillary Services from Network 2

In case 2A, the present (2024) demand profile and available DERs are considered for providing ancillary services. Since there is no available front-of-the-meter DER in Network 2, only DR is considered for providing frequency and voltage support. The calculated ancillary services are presented in Figure 41 for representative day-1 and Figure 42 for representative day-2. Total demand response is 1 MW or more in several instances of representative days. These results show the capability of this network to participate in the DR and FCAS market operated by AEMO [42]. The network also has the capability to participate in voltage support, which is a non-marketed ancillary service at present managed by AEMO.

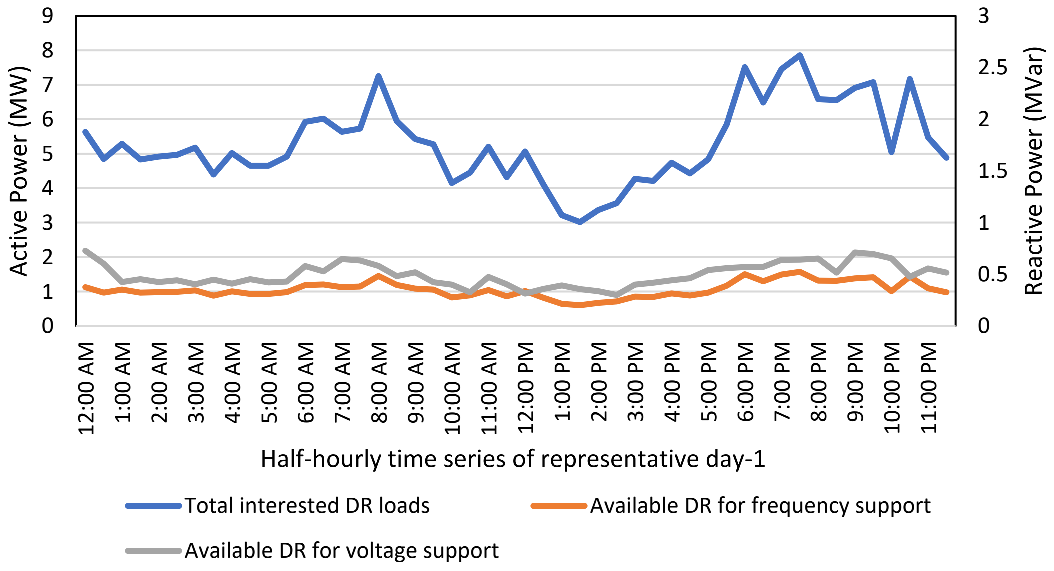


Figure 41 Available AS from Network 2 with DR participation in representative day-1.

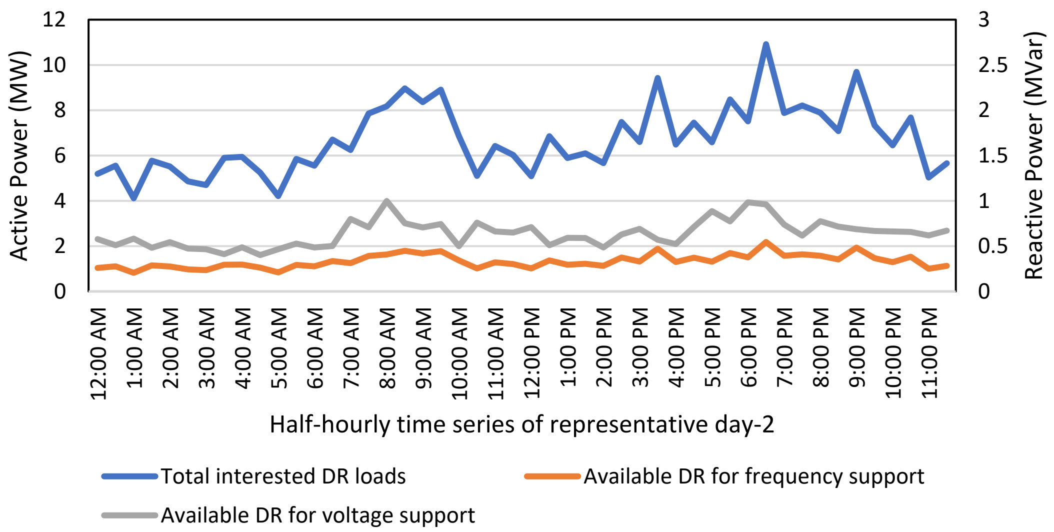


Figure 42 Available AS from Network 2 with DR participation in representative day-2.

3.2.3 Network 3

At present, there is no front-of-the-meter Solar PV connected to Network 2. A 6.15 MW wind farm in the Chepstowe area has been operational since 2015. Therefore, a representative model of this wind farm has been used.

3.2.3.1 Time Aggregated Load Profiles

The time series aggregated load data of 2024 is obtained using the load data of 2021 from Powercor. The aggregated time-series data of 2024 (30-minute time intervals) from Ballarat South ZS is presented in Figure 43. The wind profile from 2021 is considered as a general wind power generation profile for this station and is used for generating representative daily profiles (as presented in Figure 44). The developed three-step clustering method has been used to obtain representative daily profiles. The combined time series profile is presented in Figure 45. The K-means clustering method is used to identify the representative clusters in the combined time series profile and is presented in Figure 46. The representative daily profiles of loads and wind generation are obtained by using the average participation factors in the combined time series profiles. The time series profile of representative day – 1 is presented in Figure 47, while the time series profile of representative day-2 is presented in Figure 48.

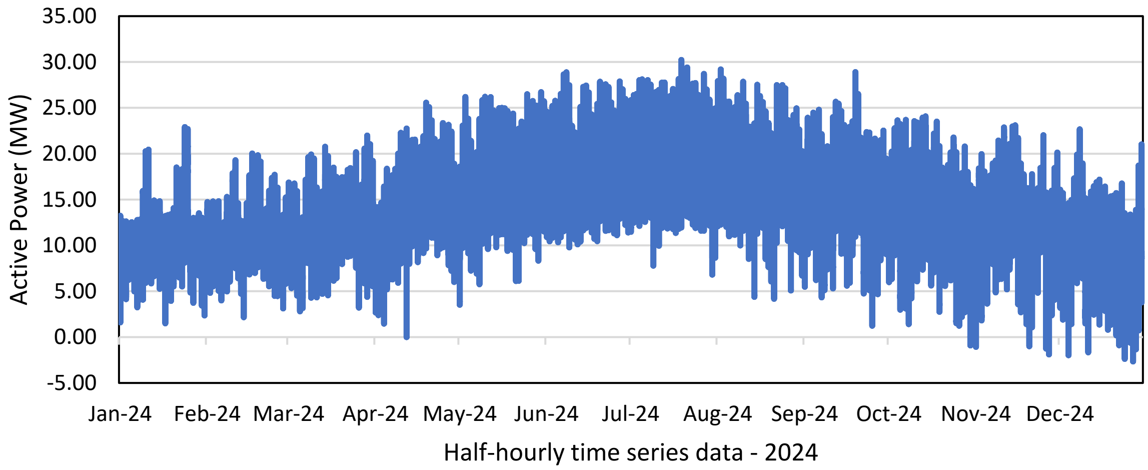


Figure 43 Aggregated time-series data 2024 from Ballarat South zone substation.

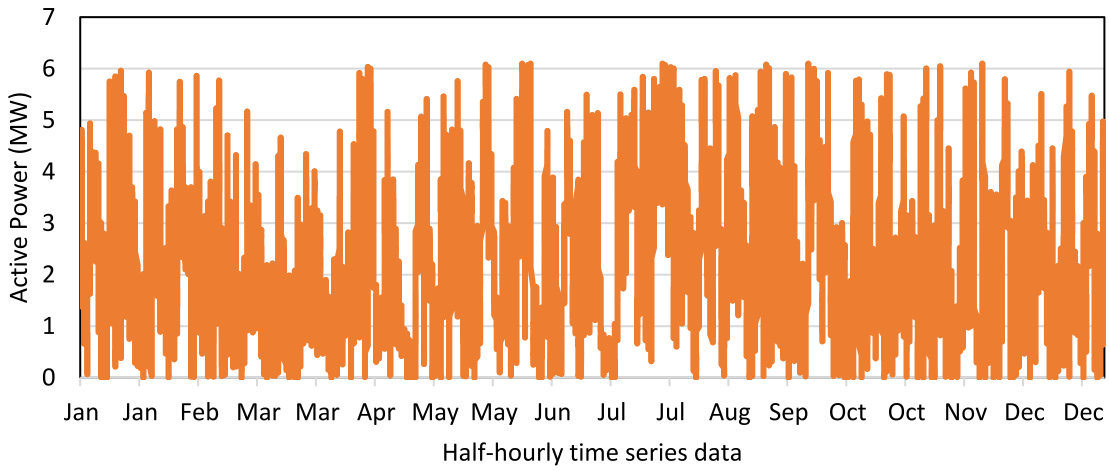


Figure 44 Yearly Wind profile - Chepstowe wind farm.

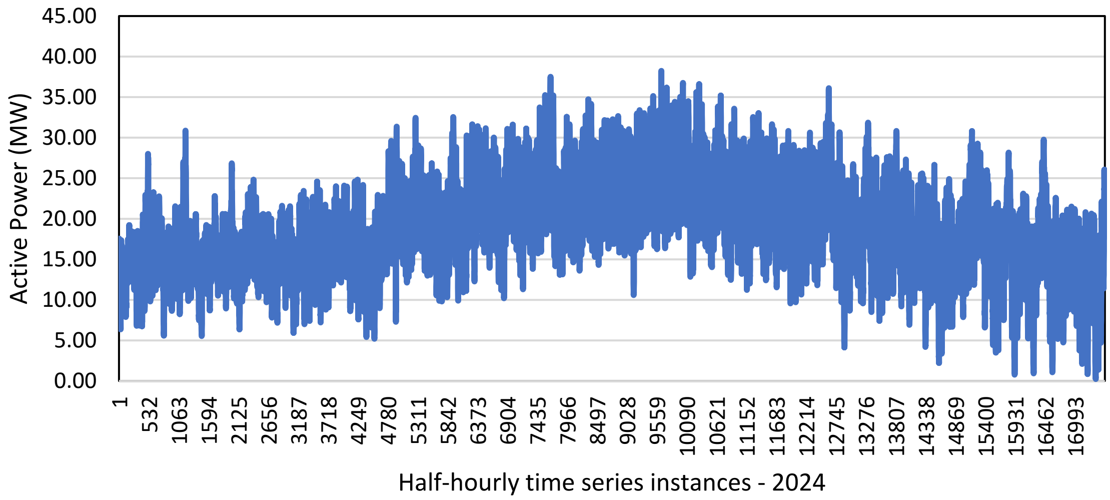


Figure 45 Combined time series data.

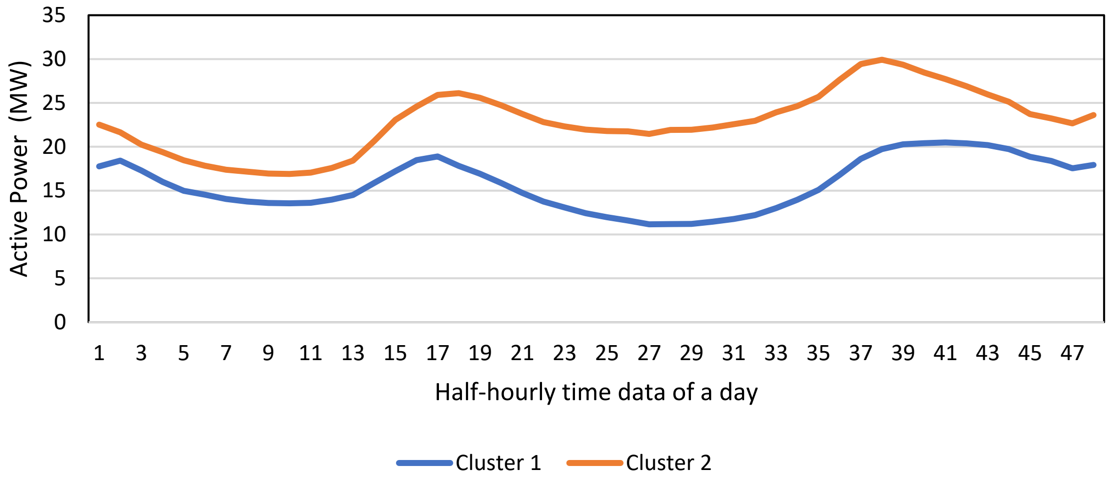


Figure 46 Representative clusters of the combined time series.

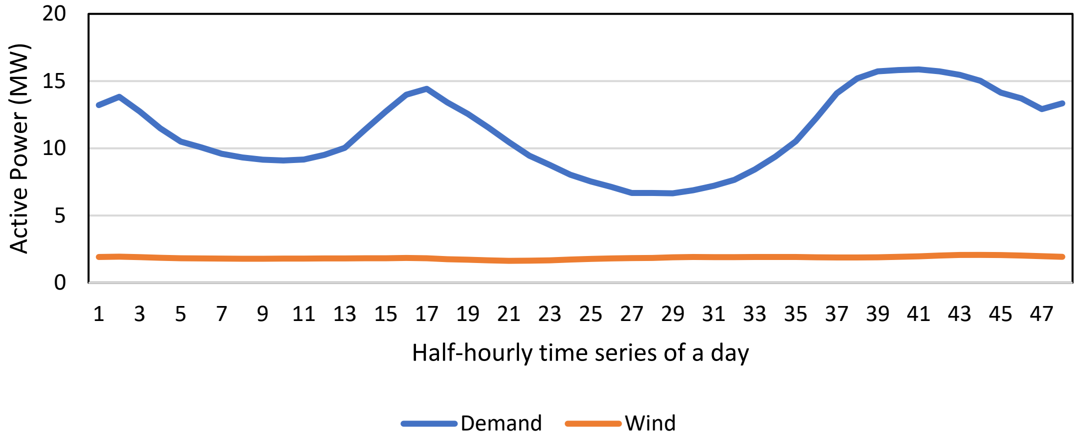


Figure 47 Daily profile - representative day-1 obtained using 3-step time aggregation method.

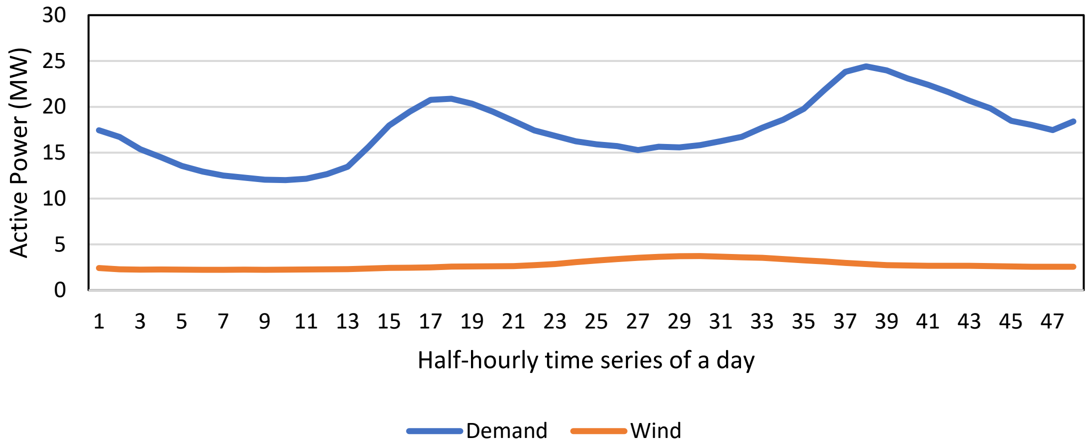


Figure 48 Daily profile - representative day-2 obtained using 3-step time aggregation method.

3.2.3.2 Ancillary Services from Network 3

In case 2A, the present (2024) demand profile and available DERs are considered for providing ancillary services. Since there is a 6.15 MW Wind farm in Network 3, the ancillary services can be provided from both Wind and DR. The calculated frequency ancillary services are presented in Figure 49 for representative day-1 and Figure 50 for representative day-2. The voltage ancillary services are calculated and presented in Figure 51 and Figure 52 for representative day-1 and representative day-2, respectively. A total of 20% of the total customers are considered to provide 20% of the loads as DR loads. Total FCAS is close to 1 MW in many instances within the representative days.

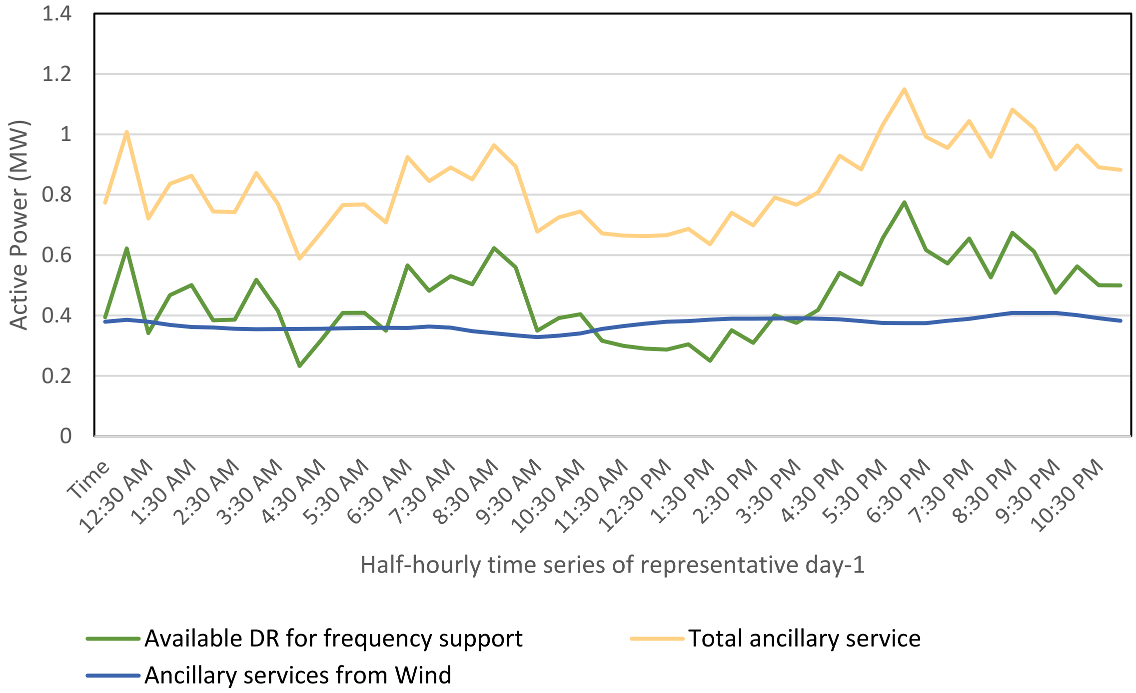


Figure 49 Available FCAS from Network 3 with DR and DER (Wind) participation in representative day-1.

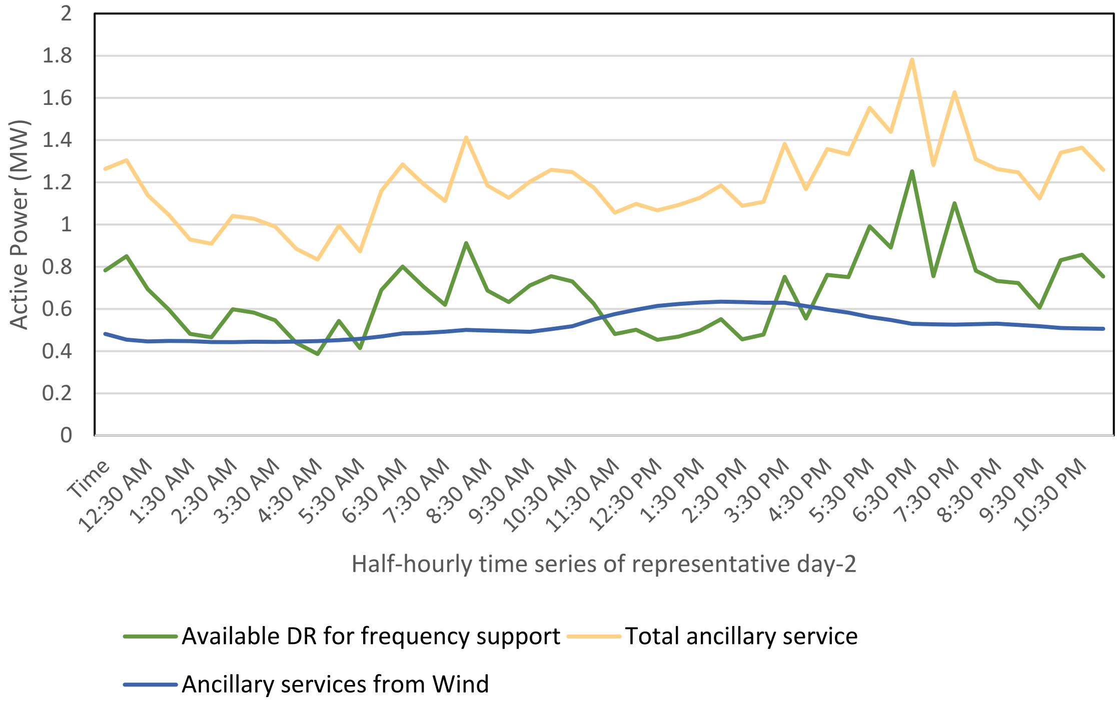


Figure 50 Available FCAS from Network 3 with DR and DER (Wind) participation in representative day-2.

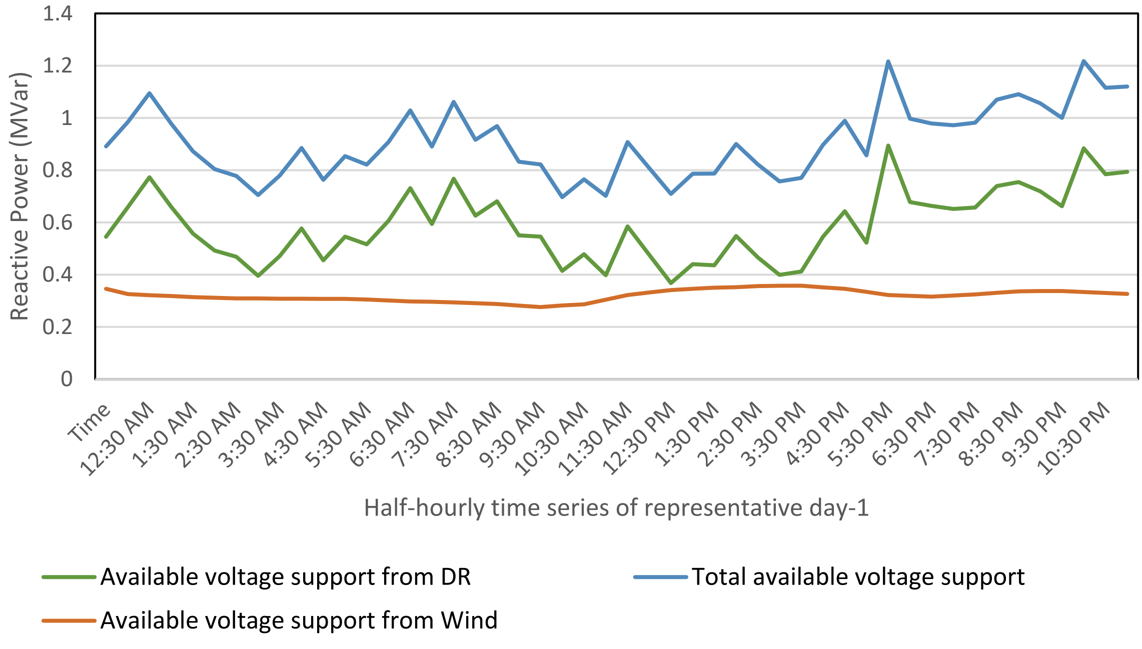


Figure 51 Available VCAS from Network 3 with DR and DER (Wind) participation in representative day-1.

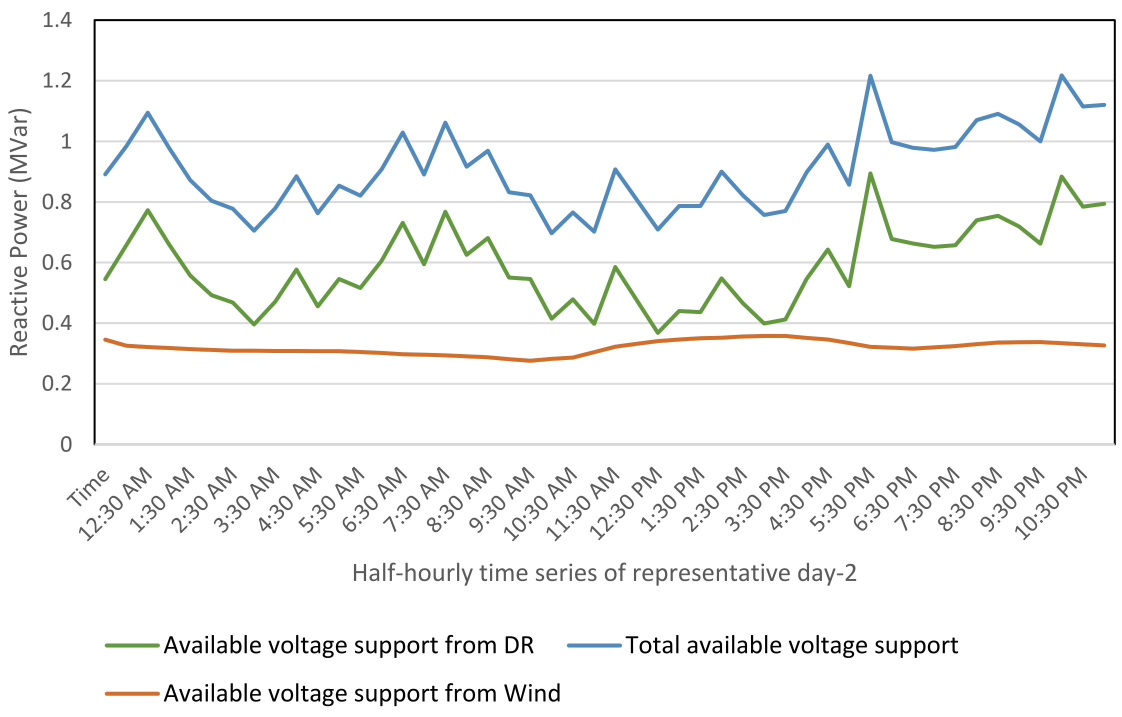


Figure 52 Available VCAS from Network 3 with DR and DER (Wind) participation in representative day-2.

3.3 Case 2B: With DR and Forecasted DERs (2035)

Case 2B is an illustrative case study where future (2035) installation of DERs in the network is considered. For this case, a 5 MW solar PV is considered to be connected to all networks. An illustrative estimation of load increase is considered to obtain yearly time series data for 2035 from 2021 data by considering the new developments, population growth, and economic expansion in this area. Yearly 2% growth on net demand is considered to obtain net demand profile of 2024 by considering the new developments, population growth, and economic expansion in this area [43]. The amount of DR participation will vary based on the percentage participation of customers, their locations, time and duration of DR operation. The future uptake of DERs depends on the technology developments, government policies and many other factors. Necessary assumptions on PV, WIND, BESS and EV are considered based on the geographical locations and future growth of DERs [41] and presented in Table 2.

3.3.1 Network 1

3.3.1.1 Time Aggregated Load Profiles

The time-aggregated load profiles of 2035 are generated using the time series load data (30-minute time intervals) of 2021. The aggregated time-series data of 2035 from Drysdale ZS is presented in Figure 53. A 5 MW solar PV farm is considered as an illustrative case in 2035. The solar power from 2021 is considered as a general profile for this area and used for generating PV generation series for 2035 (as presented in Figure 54). The developed 3-step time aggregation method has been used to obtain representative daily profiles. The combined time series profile is presented in Figure 55. The K-means clustering method has been used to identify the representative clusters in the combined time series profile and its results are presented in Figure 56. The representative daily profiles of loads and PV generation are obtained by using the average participation factors in the combined time series profiles. The time series profile of representative day–1 is presented in Figure 57, while the time series profile of representative day-2 is presented in Figure 58. With the advent of time aggregation, the number of required power flow analysis and network reduction processes is reduced from 17,520 in a conventional network reduction method to 96 in the proposed method.

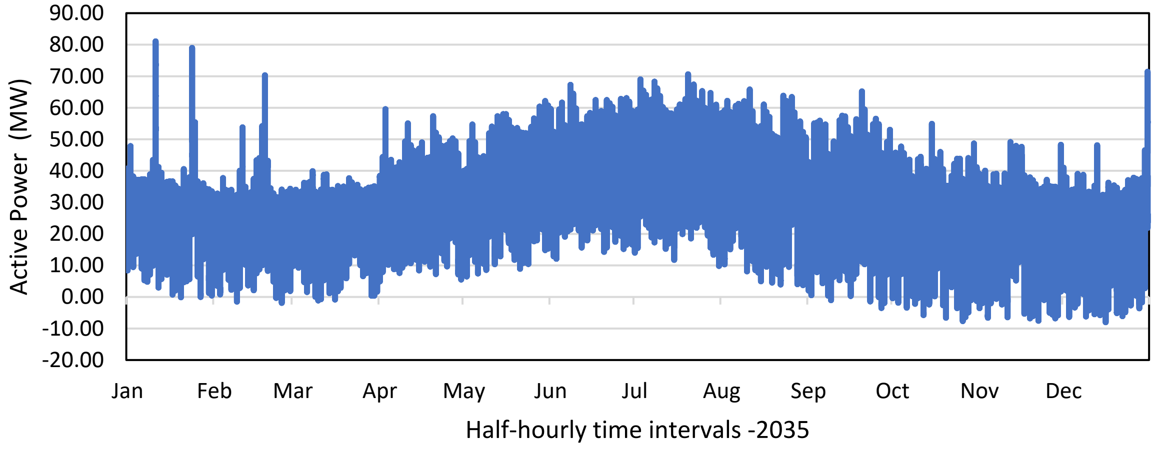


Figure 53 Aggregated time-series data 2035 from the Drysdale zone substation.

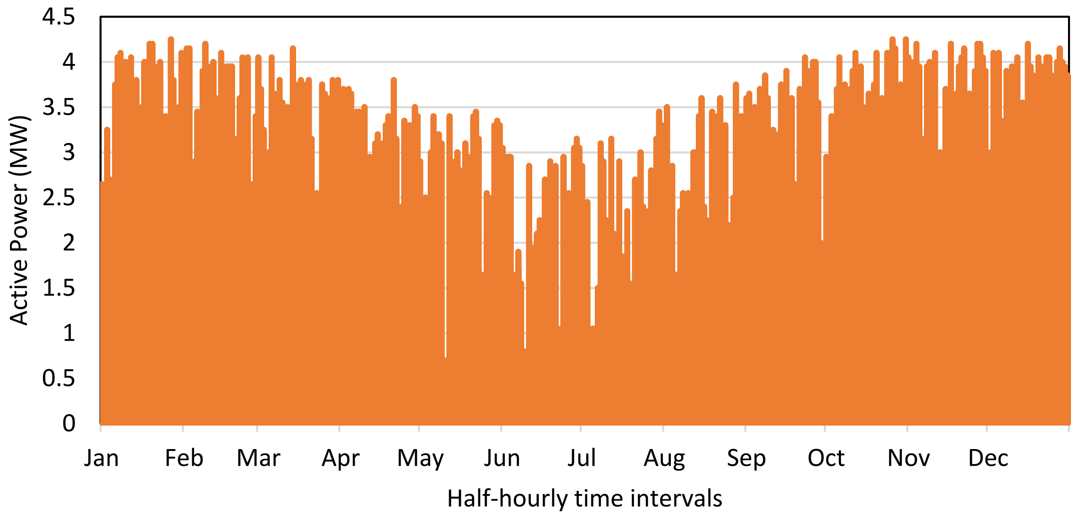


Figure 54 Yearly PV profile - Drysdale area.

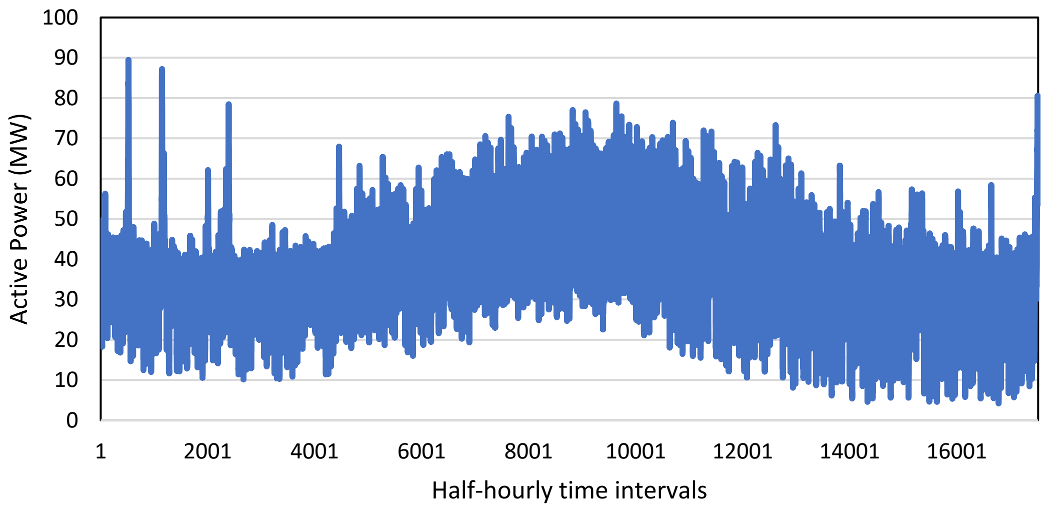


Figure 55 Combined time series data.

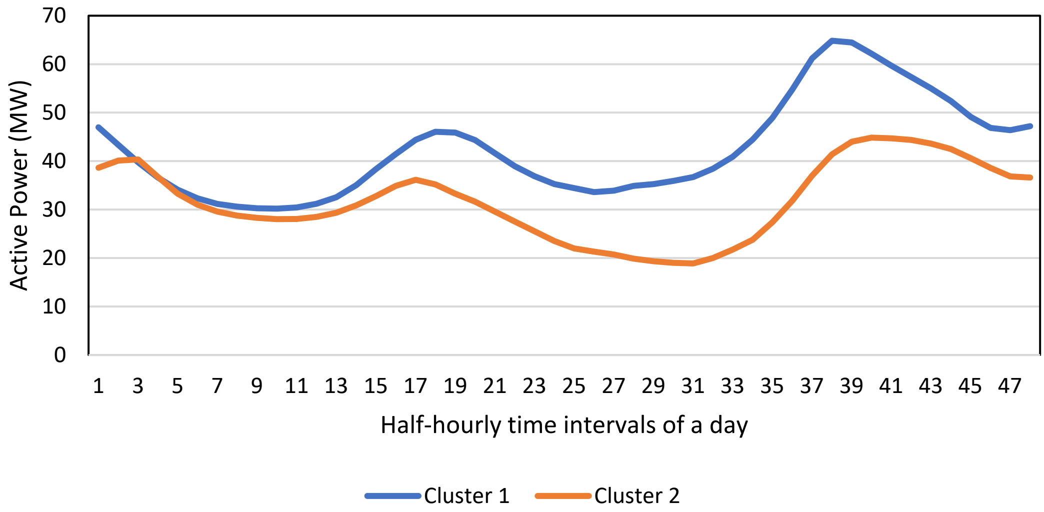


Figure 56 Representative clusters of the combined time series.

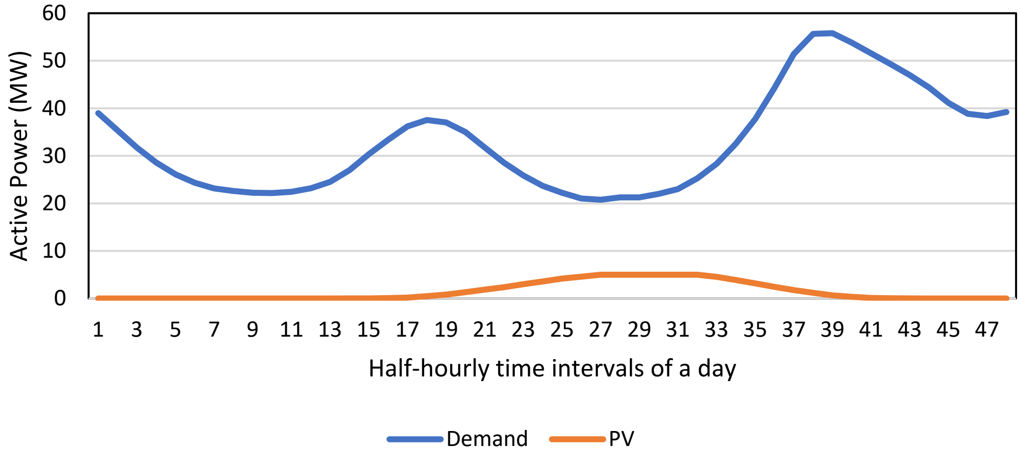


Figure 57 Daily profile - representative day-1 obtained using 3-step time aggregation method.

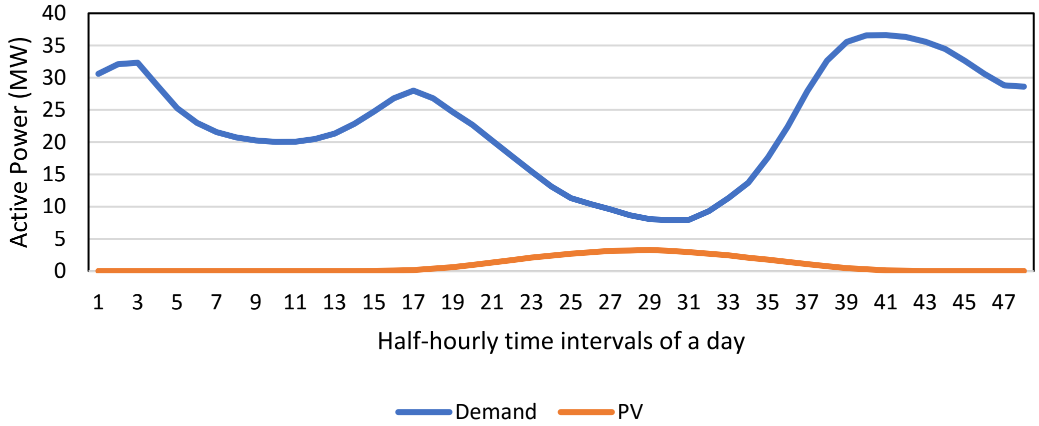


Figure 58 Daily profile - representative day-2 obtained using 3-step time aggregation method.

3.3.1.2 Ancillary Services from Network 1

In case 2B, ancillary services are calculated for an illustrative future DER integration (2035) in network 1. In network 1, PV is considered as a future DER in the network and illustrative growth in demand is considered for DR. The calculated frequency ancillary services are presented in Figure 59 and Figure 60 for representative day-1 and day-2 respectively. Similarly, the calculated voltage ancillary services are presented in Figure 61 and Figure 62 for representative day-1 and representative day-2, respectively.

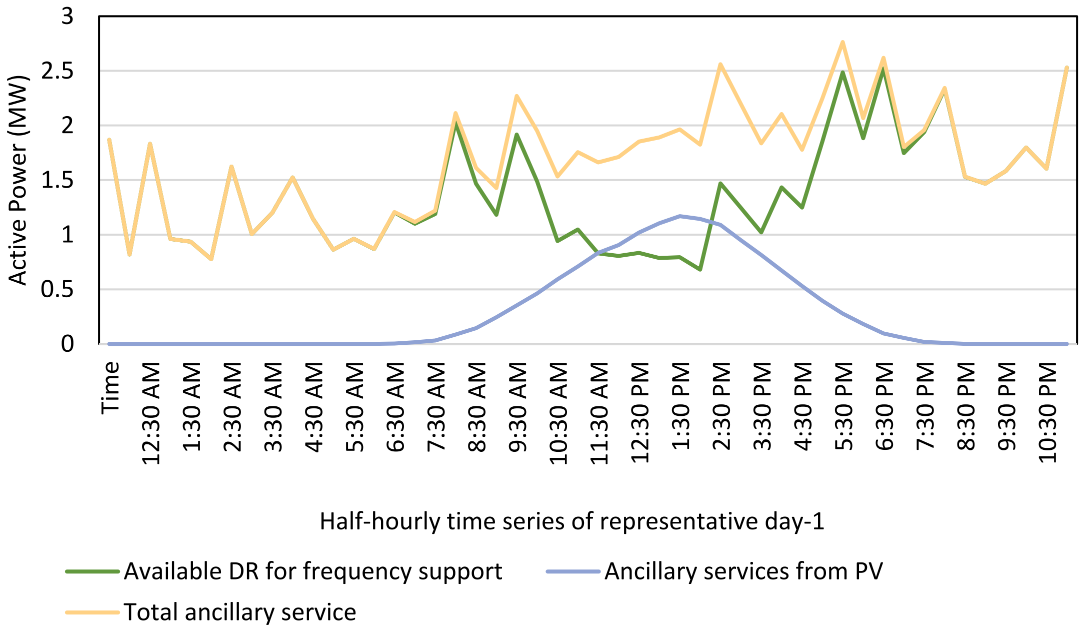


Figure 59 Available FCAS from Network 1 with DR and DER (PV) participation in Representative Day-1.

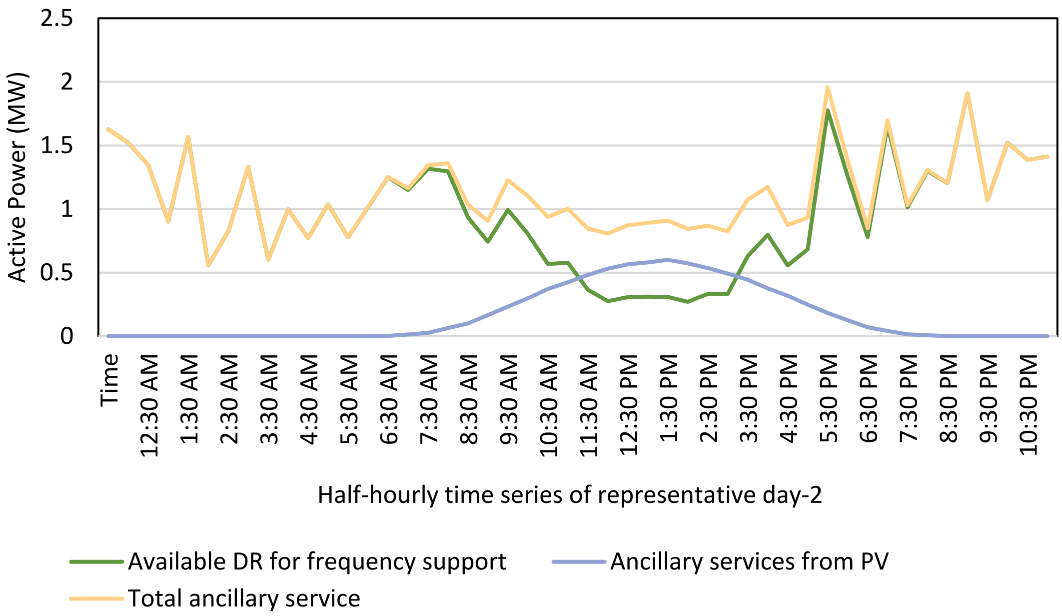


Figure 60 Available FCAS from Network 1 with DR and DER (PV) participation in representative day-2.

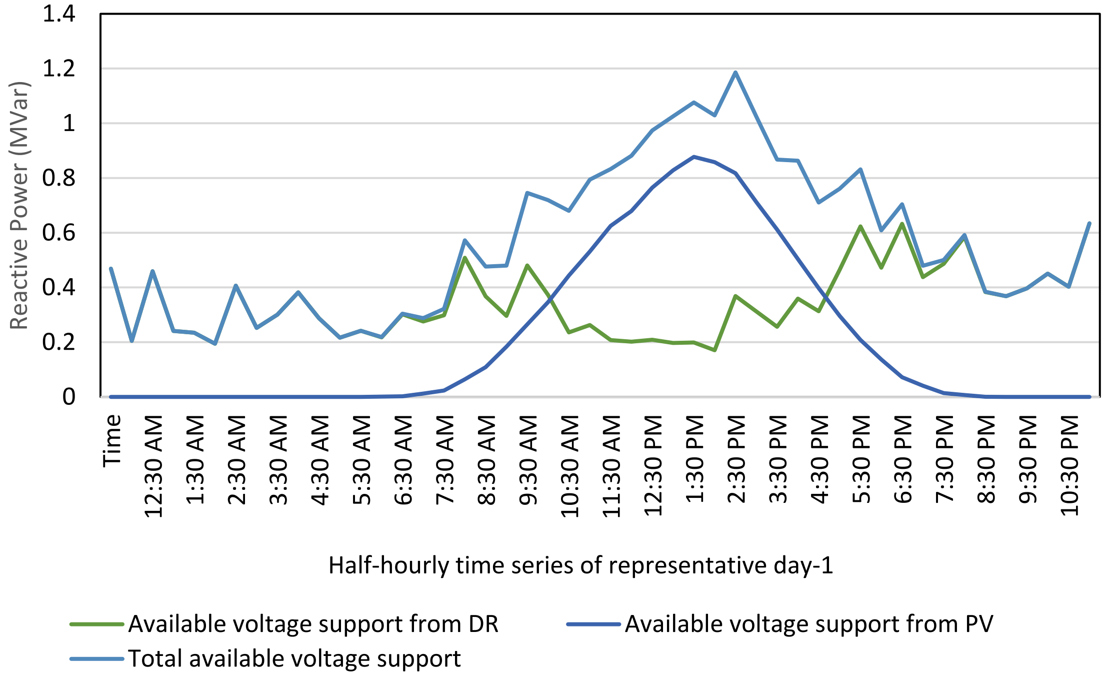


Figure 61 Available VCAS from Network 1 with DR and DER (PV) participation in representative day-1.

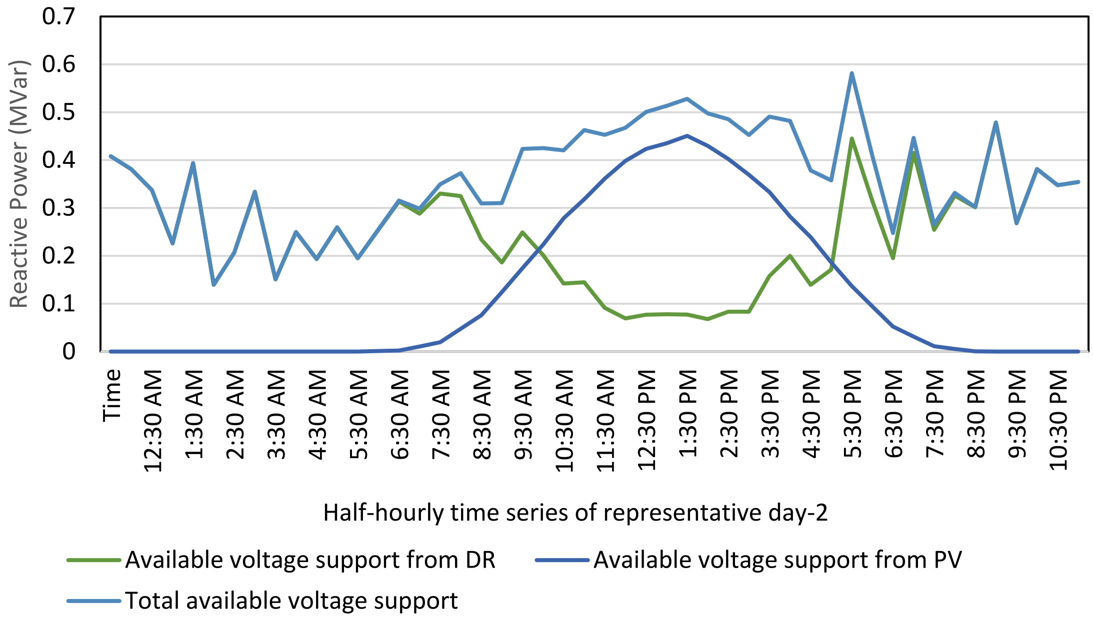


Figure 62 Available VCAS from Network 1 with DR and DER (PV) participation in representative day-2.

3.3.2 Network 2

For Case 2B, a 5 MW front-of-the-meter solar is considered to be connected to Network 2 by 2035.

3.3.2.1 Time Aggregated Load Profiles

The time series aggregated load data of 2035 is obtained using the load data (30-minute time intervals) of 2021 from Powercor. The aggregated time-series data of 2035 from Geelong East ZS is presented in Figure 63. A 5 MW solar PV farm is considered an illustrative case in 2035. The solar PV generation profile from 2021 is considered as a general profile for this area and is used to generate representative daily PV generation profiles for 2035, as presented in Figure 64. The developed 3-step time aggregation method has been used to obtain representative daily profiles. The combined time series profile is presented in Figure 65. The K-means clustering method is used to identify the representative clusters in the combined time series profile, as given in Figure 66. The representative daily profiles of loads and PV generation are obtained by using the average participation factors in the combined time series profiles. The time series profile of representative day-1 is presented in Figure 67, whereas the time series profile of representative day-2 is presented in Figure 68.

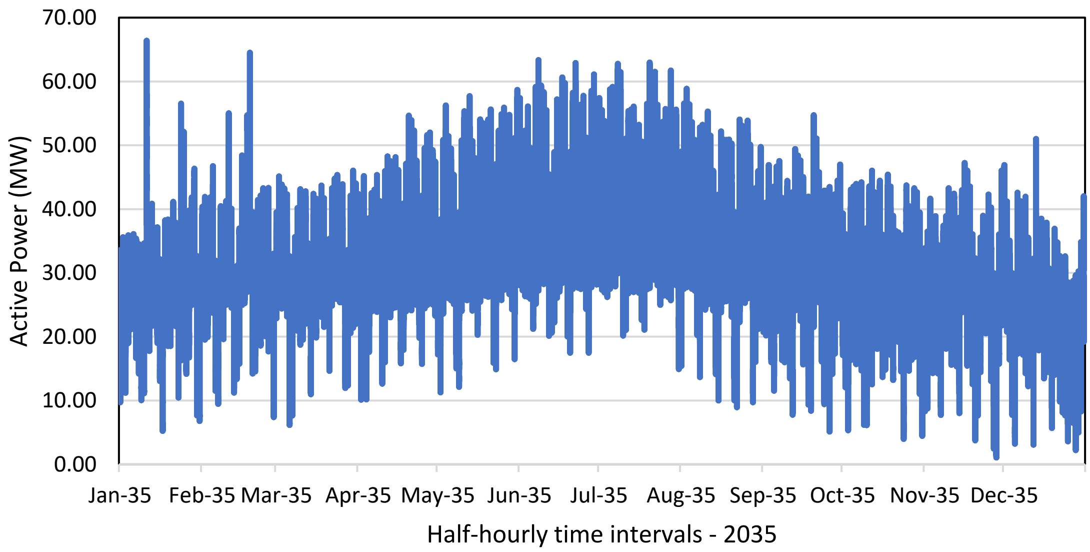


Figure 63 Aggregated time-series data 2035 from Geelong East zone substation.

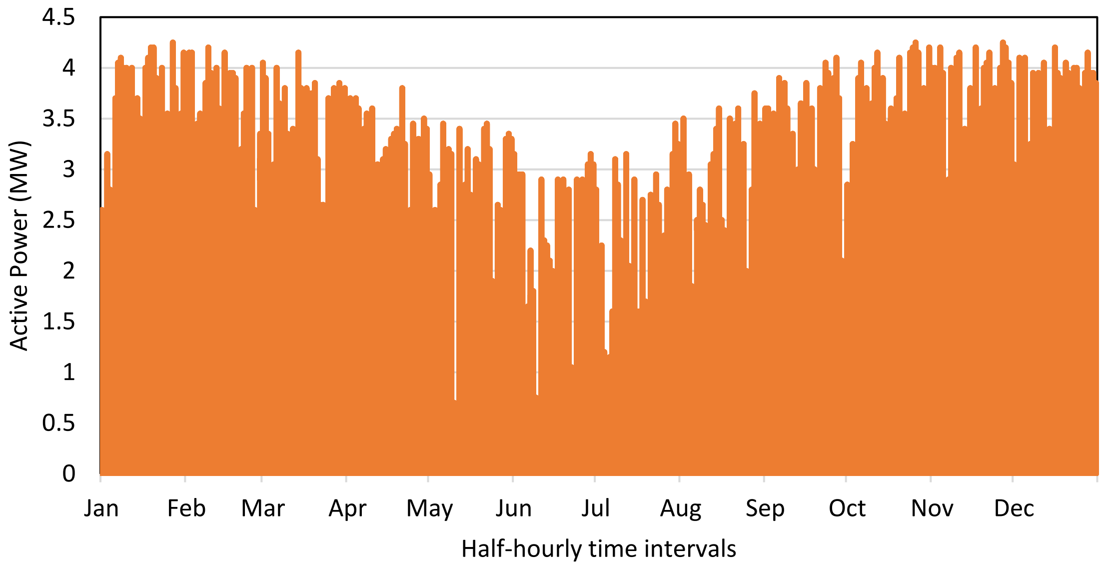


Figure 64 Yearly PV profile - Geelong East.

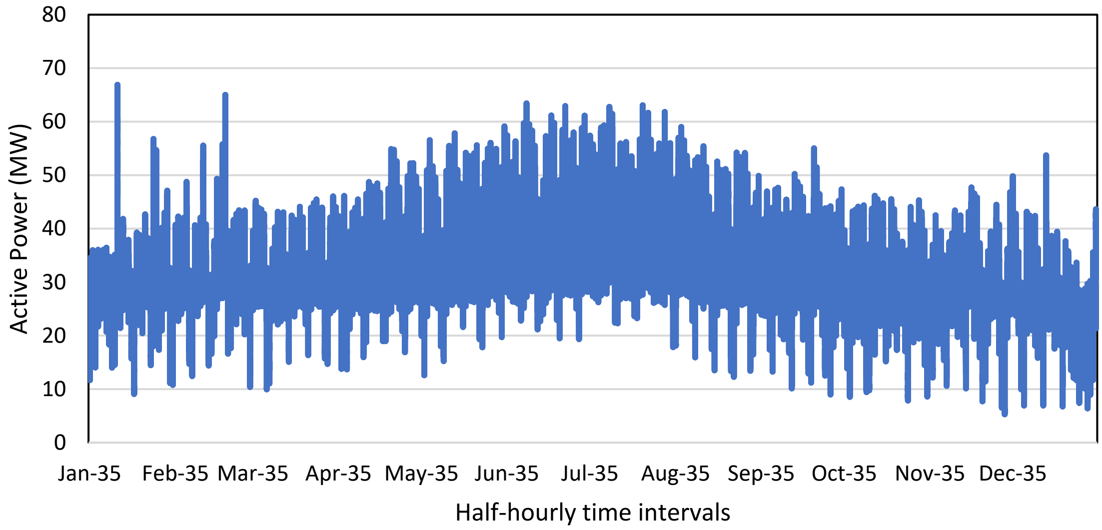


Figure 65 Combined time series data.

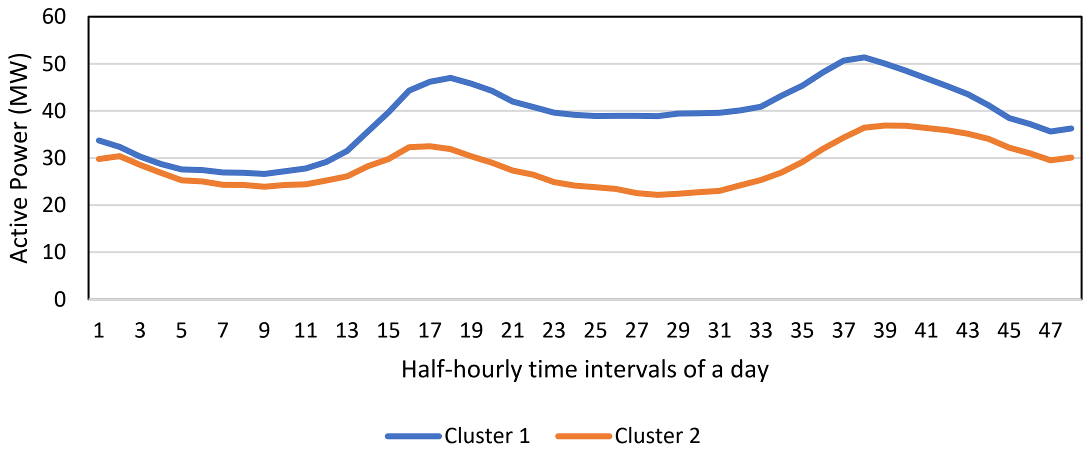


Figure 66 Representative clusters of the combined time series.

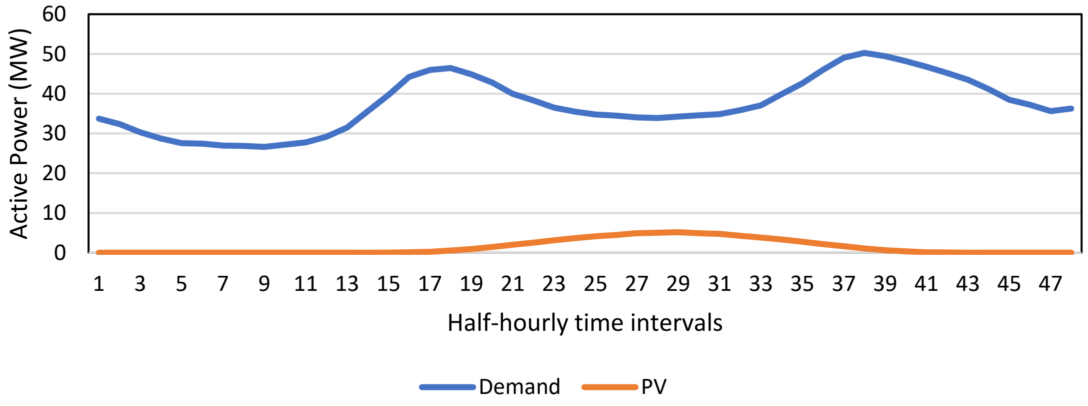


Figure 67 Daily profile - representative day-1 obtained using the 3-step time aggregation method.

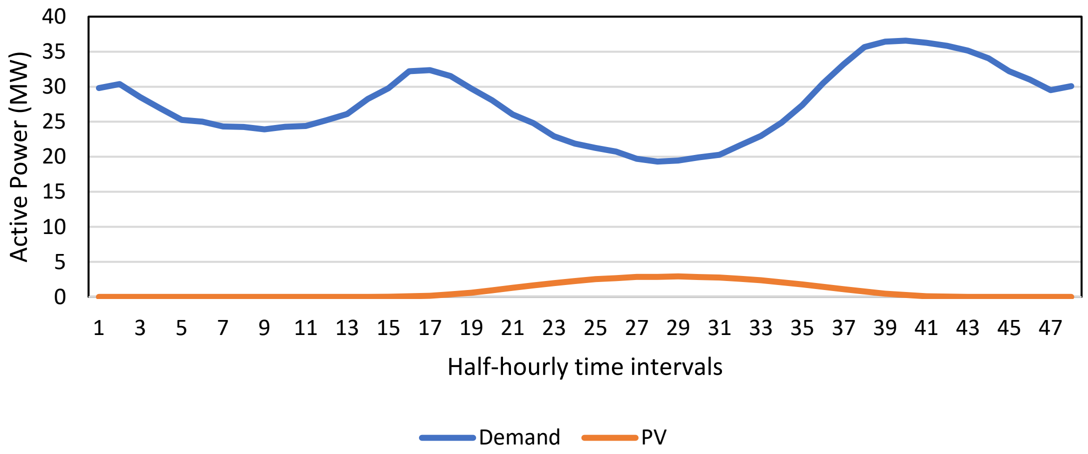


Figure 68 Daily profile - representative day-2 obtained using the 3-step time aggregation method.

3.3.2.2 Ancillary Services from Network 2

In case 2B, ancillary services are calculated for an illustrative future DER integration (2035) in network 2. In network 2, PV is considered as a future DER in the network and illustrative growth in demand is considered for DR. The estimated frequency ancillary services are presented in Figure 69 and Figure 70 for representative day-1 and day-2, respectively. Similarly, the calculated voltage ancillary services are presented in Figure 71 and Figure 72 for representative day-1 and day-2, respectively.

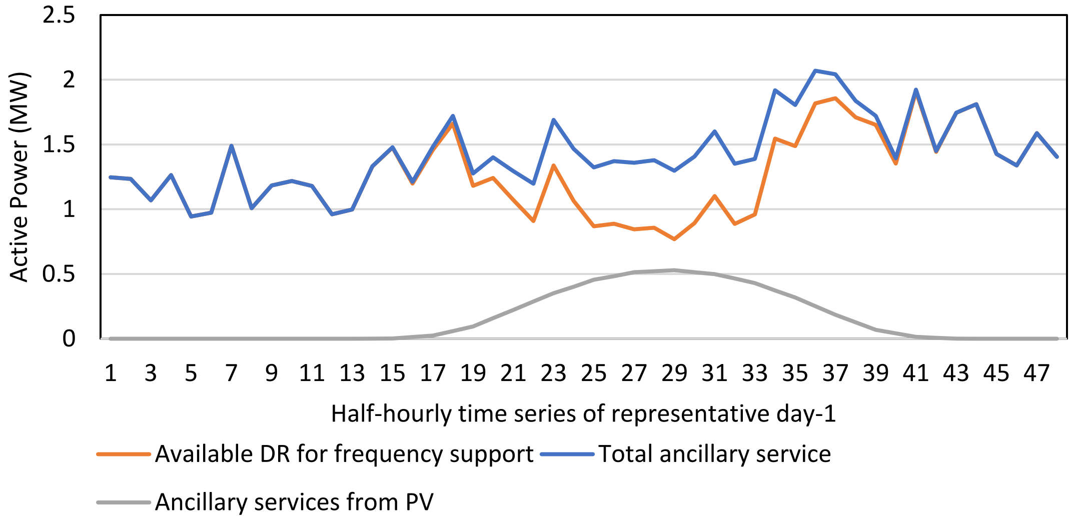


Figure 69 Available FCAS from Network 2 with DR and DER (PV) participation in representative day-1.

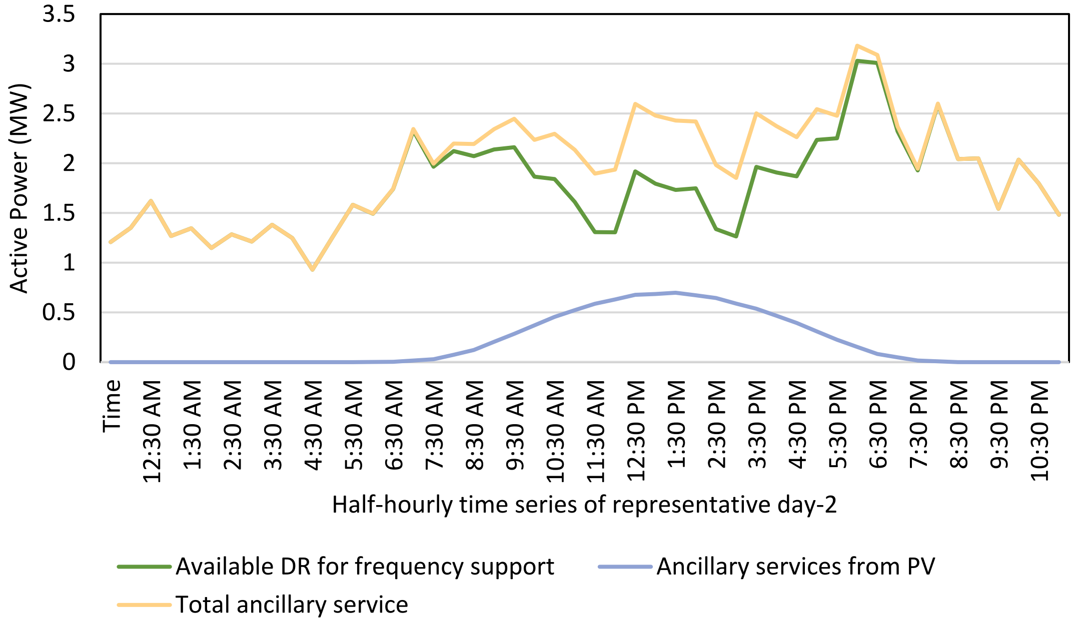


Figure 70 Available FCAS from Network 2 with DR and DER (PV) participation in representative day-2.

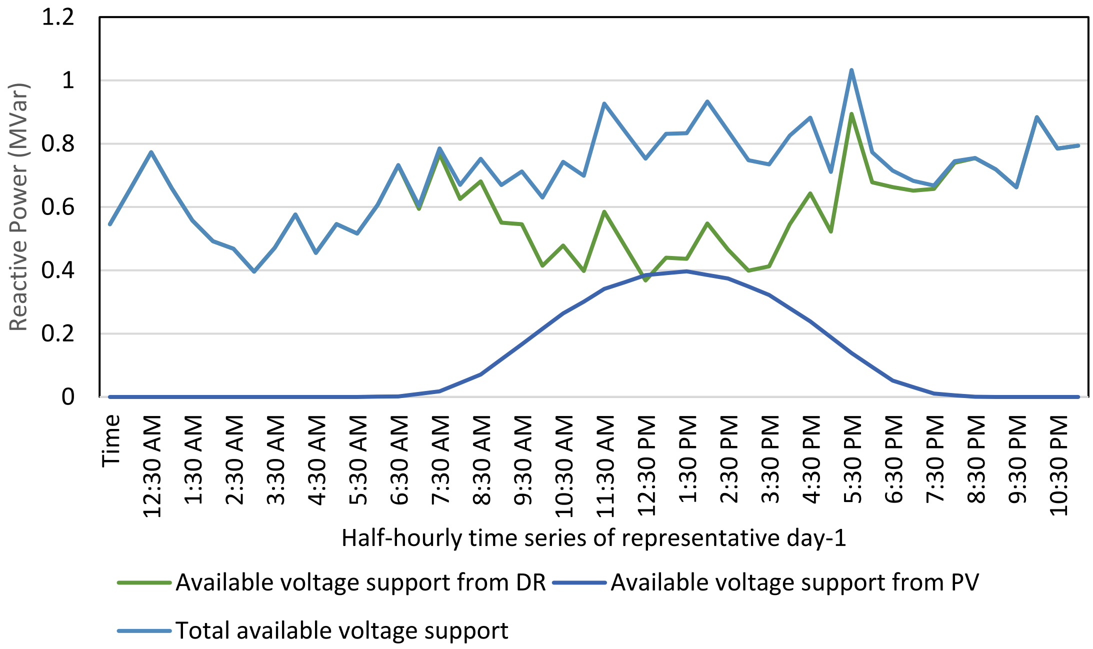


Figure 71 Available VCAS from Network 1 with DR and DER (PV) participation in representative day-1.

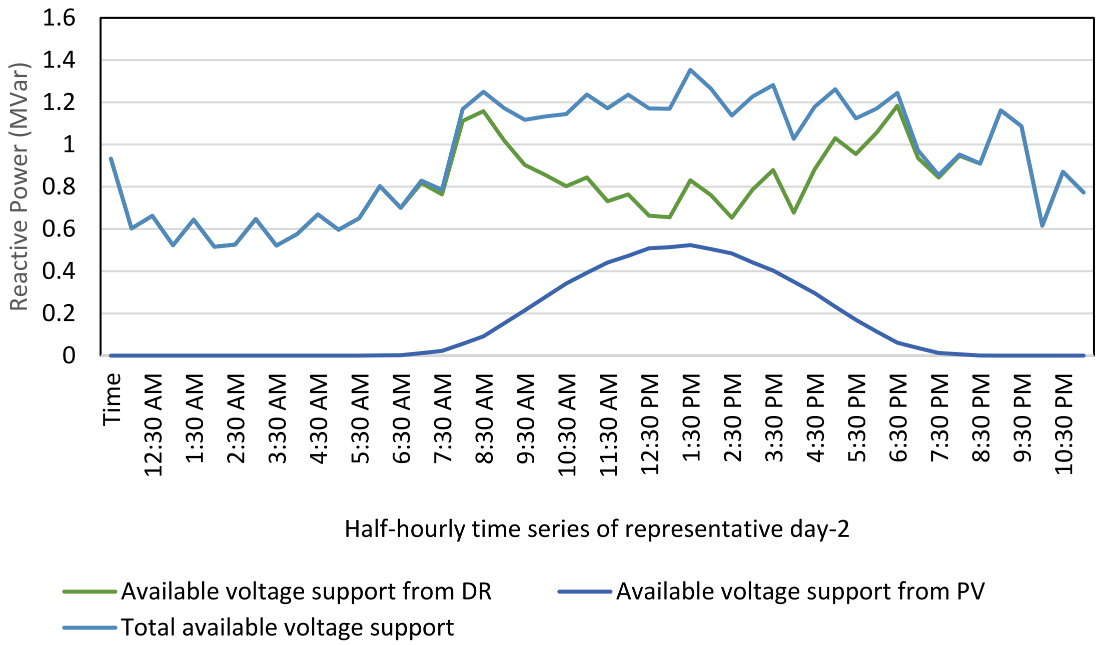


Figure 72 Available FCAS from Network 2 with DR and DER (PV) participation in representative day-2.

3.3.3 Network 3

For the future case (2035), a 5 MW solar is connected to the network alongside the existing 6.15 MW wind farm. An illustrative estimation of load increase is considered to obtain yearly time series data for 2035 from 2021 data by considering the new developments, population growth, and economic expansion in this area.

3.3.3.1 Time Aggregated Load Profiles

The aggregated time-series data of 2035 from Ballarat South ZS is presented in Figure 73. The load time series data is in 30-minute time intervals. A 5 MW solar PV farm is considered as an illustrative case in 2035, and the PV generation profile is presented in Figure 74. The 6.15 MW wind farm power generation profile is presented in Figure 75. The developed 3-step time aggregation method has been used to obtain representative daily profiles. The combined time series profile is presented in Figure 76. The K-means clustering method is used to identify the representative clusters in the combined time series profile, as presented in Figure 77. The representative daily profiles of loads and PV generation are obtained by using the average participation factors in the combined time series profiles. The time series profile of representative day-1 is presented in Figure 78 and the time series profile of representative day-2 is presented in Figure 79.

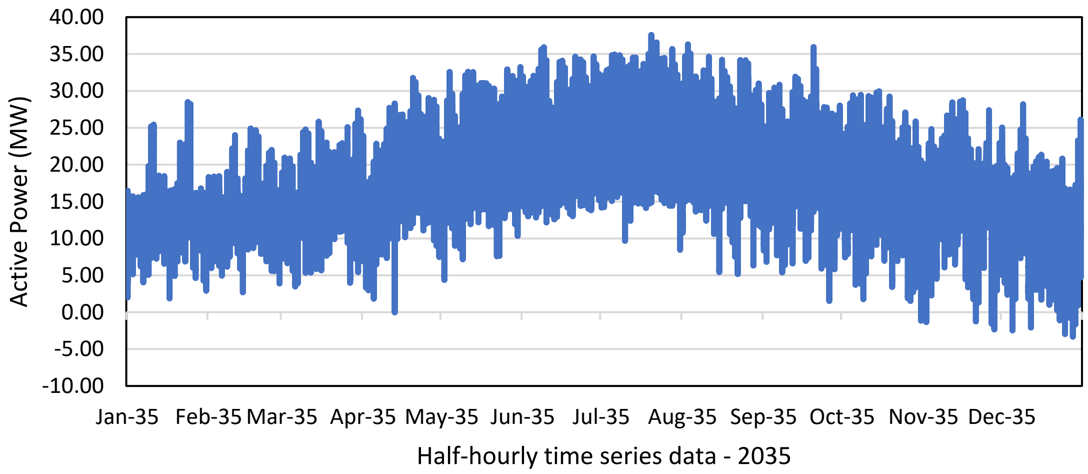


Figure 73 Aggregated time-series data 2035 from Ballarat South zone substation.

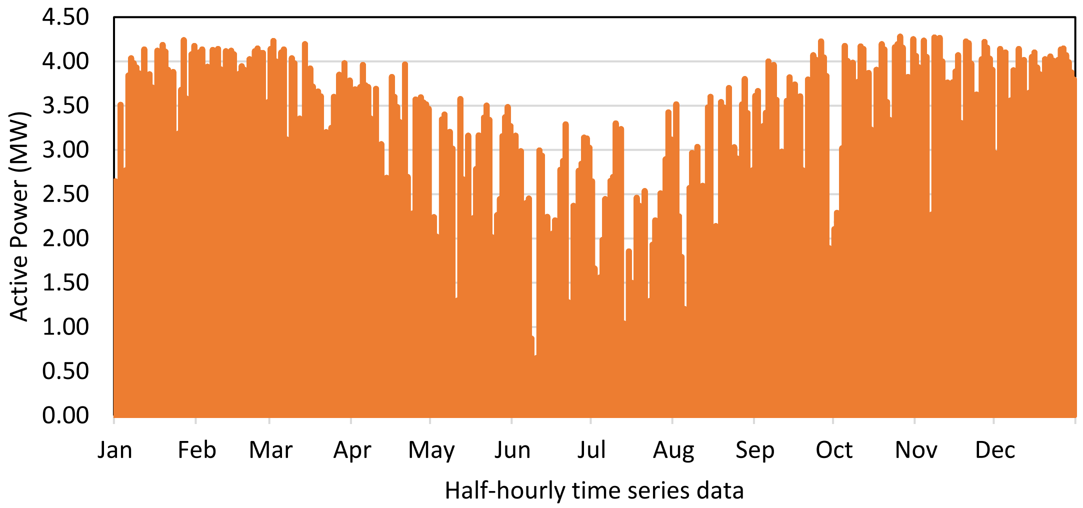


Figure 74 Yearly PV profile - Ballarat South.

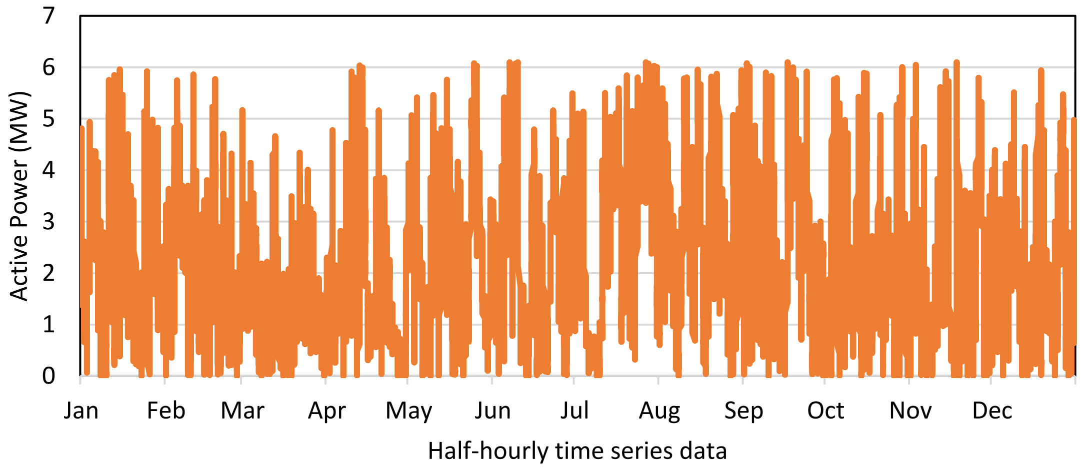


Figure 75 Yearly Wind profile - Chepstowe wind farm.

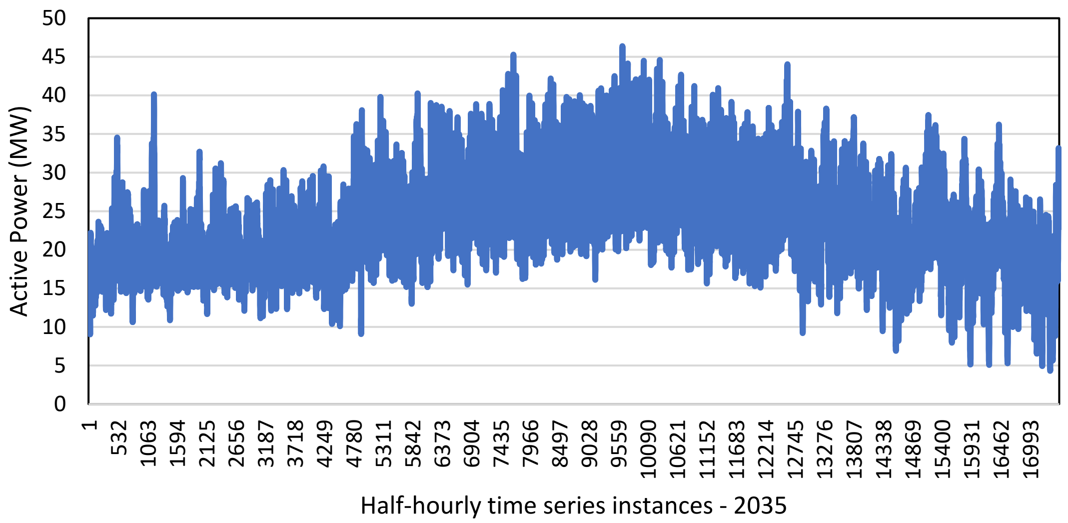


Figure 76 Combined time series data.

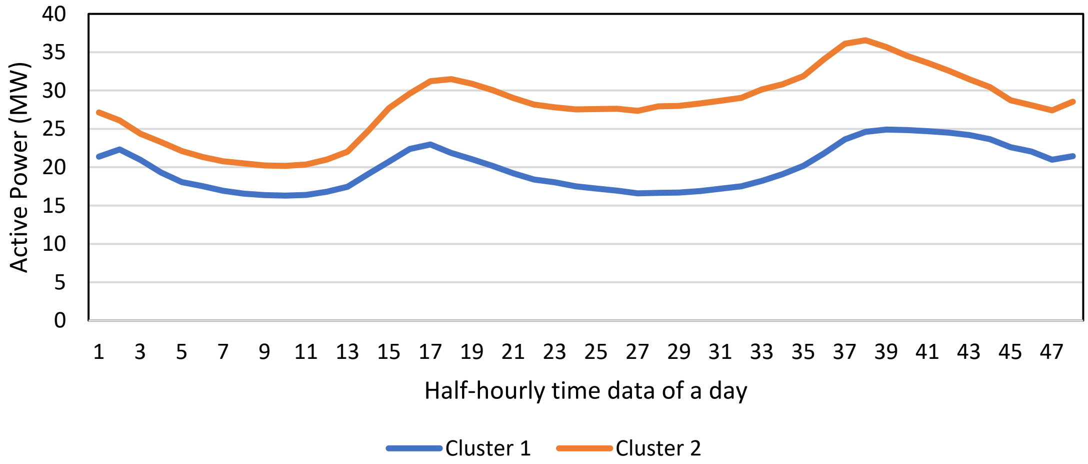


Figure 77 Representative clusters of the combined time series.

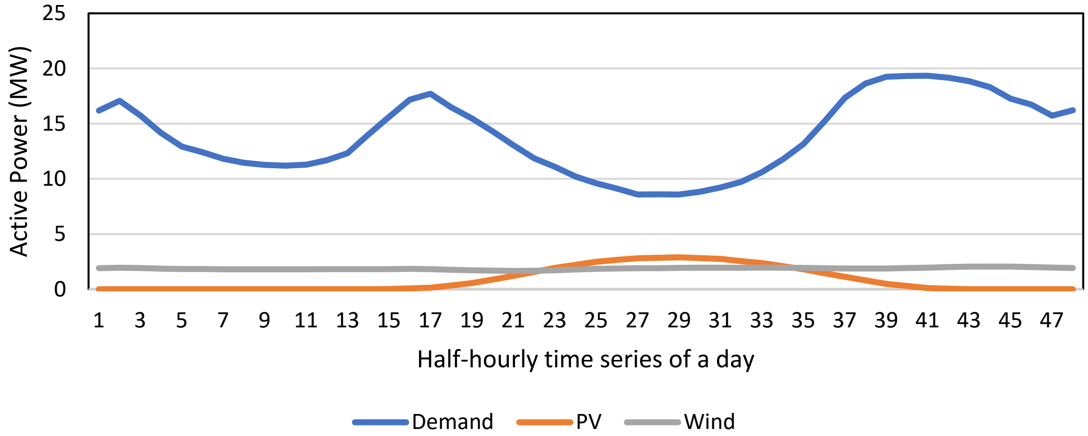


Figure 78 Daily profile - representative day-1 obtained using the 3-step time aggregation method.

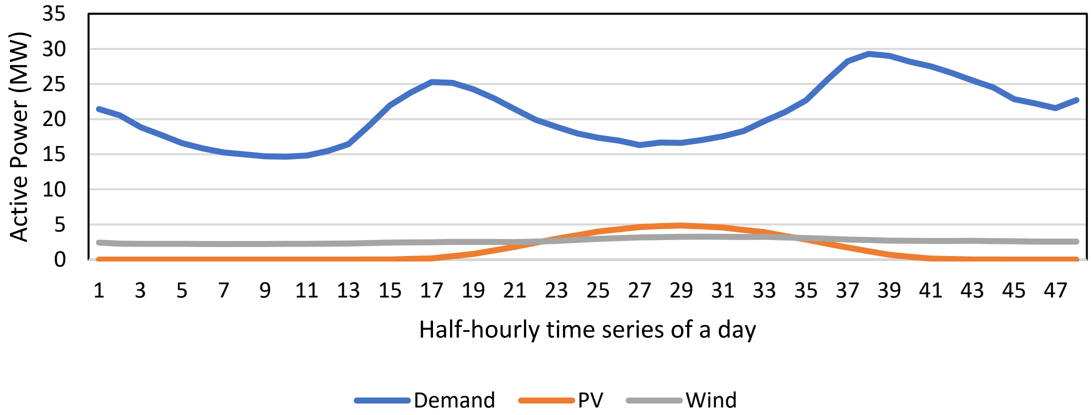


Figure 79 Daily profile - representative day-2 obtained using the 3-step time aggregation method.

3.3.3.2 Ancillary Service from Network 3

In case 2B, ancillary services are calculated for an illustrative future DER integration (2035) in network 3. In network 3, PV and Wind are considered as future DERs in the network and an illustrative growth in demand is considered for DR. The calculated frequency ancillary services are presented in Figure 80 and Figure 81 for representative day-1 and day-2, respectively. Similarly, the calculated voltage ancillary services are presented in Figure 82 and Figure 83 for representative day-1 and day-2, respectively.

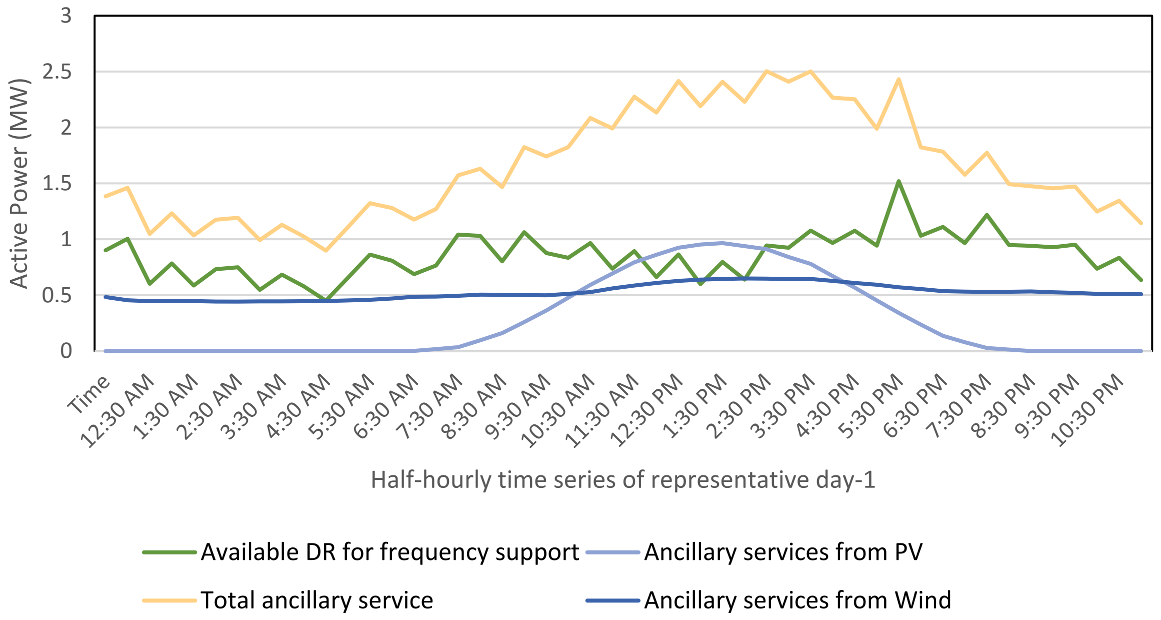


Figure 80 Available FCAS from Network 3 with DR and DER (PV, Wind) participation in representative day-1.

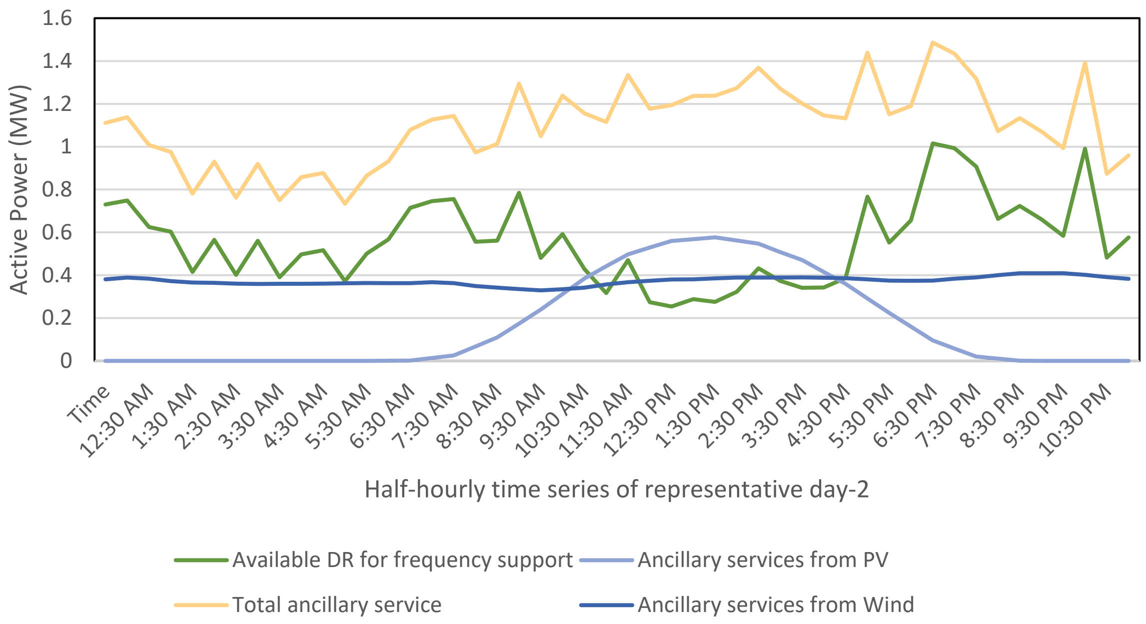


Figure 81 Available FCAS from Network 3 with DR and DER (PV, Wind) participation in representative day-2.

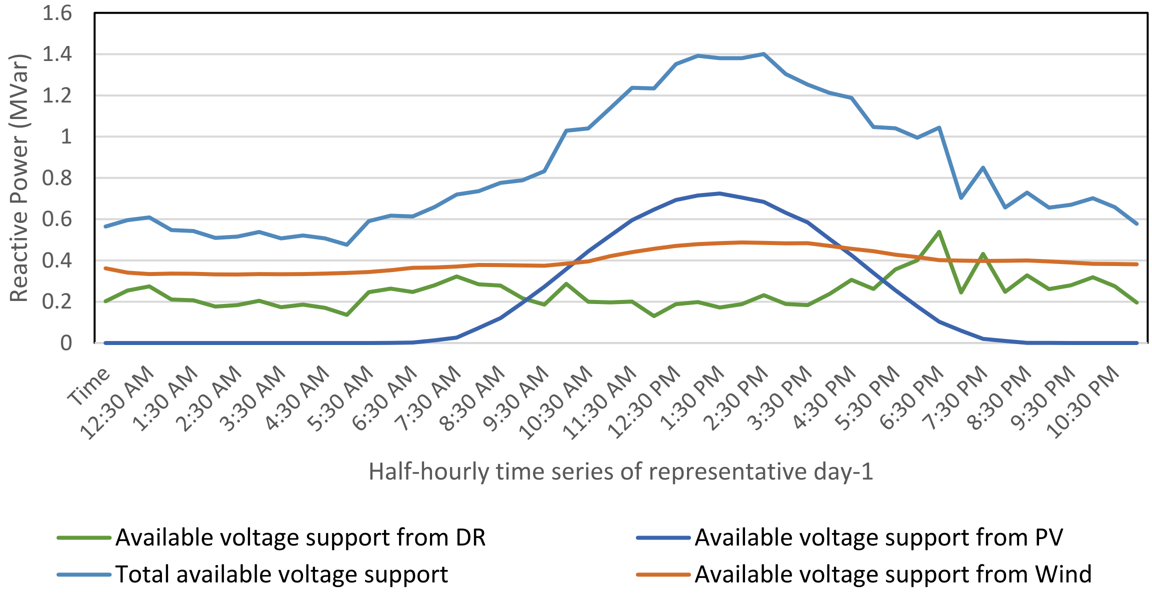


Figure 82 Available VCAS from Network 3 with DR and DER (PV, Wind) participation in representative day-1.

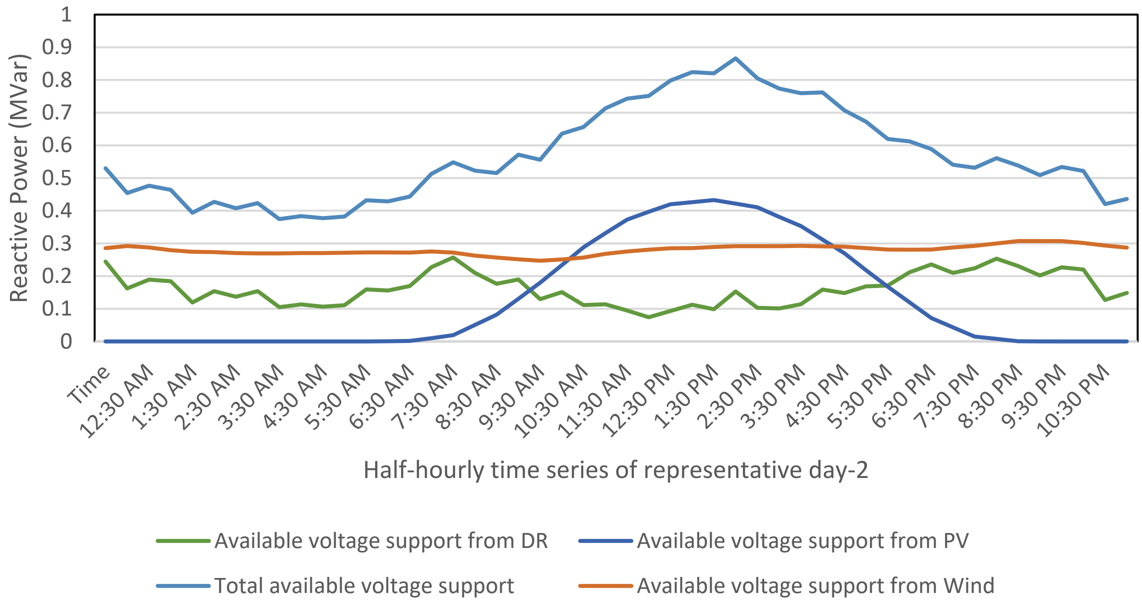


Figure 83 Available VCAS from Network 3 with DR and DER (PV, Wind) participation in representative day-2.

3.4 Case 3A: With DR, Present DERs, and Storage (2024)

In case 3A, the present installation of DERs and storage in the networks are considered. However, there is no front-of-the-meter storage connected to any of the considered networks. Therefore, the detailed and reduced networks of Case 2A and Case 3A are identical with similar outcomes.

3.5 Case 3B: With DR, Forecasted DERs, and Storage (2035)

Case 3B is an illustrative case study with future (2035) installation of DERs and storage in the network. For this case, front-of-the-meter solar PV, BESS, and EV charging stations are considered to be connected to the network by 2035. Yearly 2% growth on net demand is considered to obtain net demand profile of 2024 by considering the new developments, population growth, and economic expansion in this area [43]. The amount of DR participation will vary based on the percentage participation of customers, their locations, time and duration of DR operation. The future uptake of DERs depends on the technology developments, government policies and many other factors. Necessary assumptions on PV, WIND, BESS and EV are considered based on the geographical locations and future growth of DERs [41] and presented in Table 2.

3.5.1 Network 1

3.5.1.1 Time Aggregated Load Profiles

The aggregated time-series data of 2035 from Drysdale ZS is presented in Figure 84. The load time series data are in 30-minute time intervals. A 5 MW solar PV farm is considered an illustrative case in 2035. The solar PV generation profile from 2021 is considered as a general profile for this area and used for generating representative daily PV generation profiles for 2035 (presented in Figure 85). An aggregated half-hourly time series data of EV charging is presented in Figure 86. Therefore, the representative daily profiles are obtained by using a combined time series with the same duration of demand and PV generation time series. The developed 3-step time aggregation method has been used to obtain representative daily profiles. The combined time series profile is presented in Figure 87. The representative clusters of the combined time series profile are presented in Figure 88. The representative daily profiles of loads, PV generation, and EV are obtained by using the average participation factors in the combined time series profiles. The time series profiles of representative day-1 and -2 are presented in Figure 89 and Figure 90. BESS is considered as a dispatchable unit, and thus, no time series modelling is used for BESS.

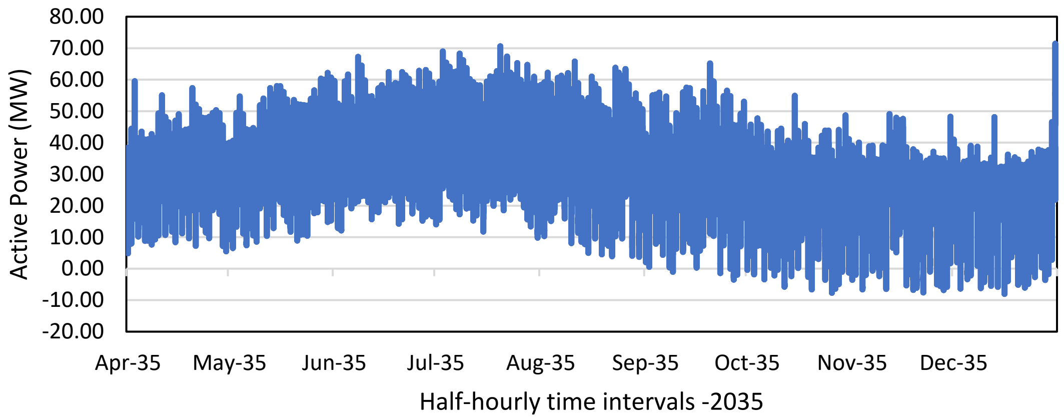


Figure 84 The aggregated time-series data 2035 from the Drysdale zone substation.

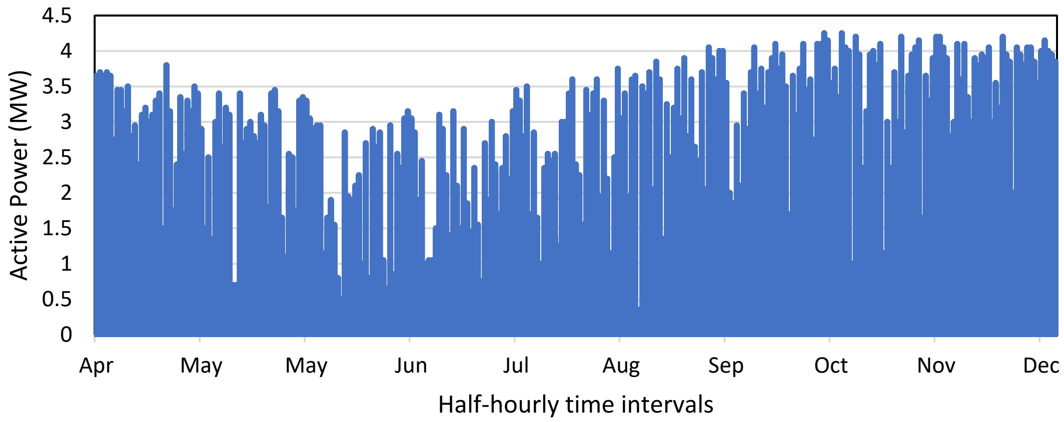


Figure 85 Yearly PV profile - Drysdale area.

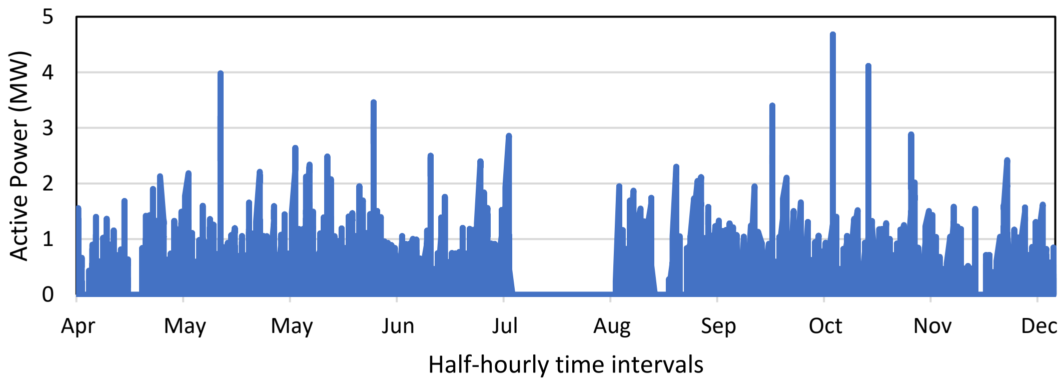


Figure 86 EV time series data.

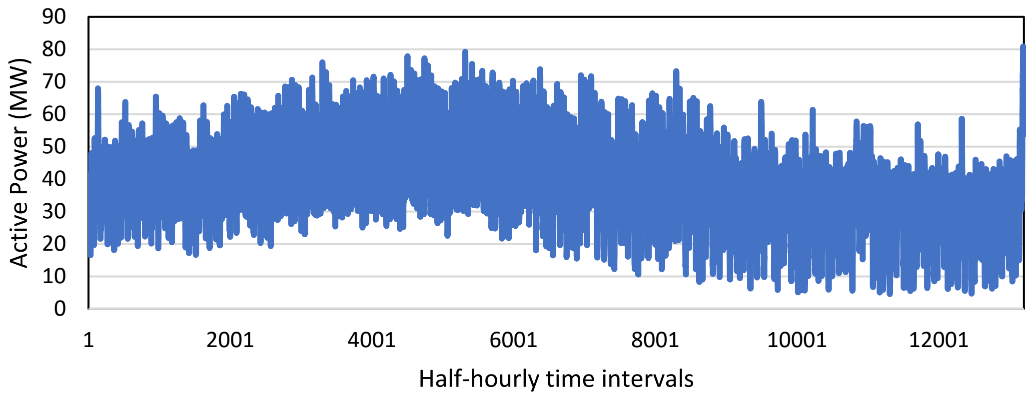


Figure 87 Combined time series data.

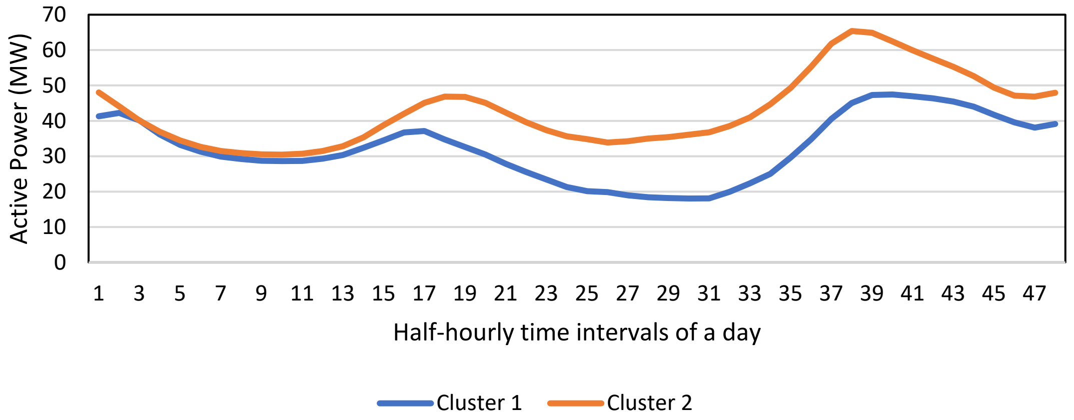


Figure 88 Representative clusters of the combined time series.

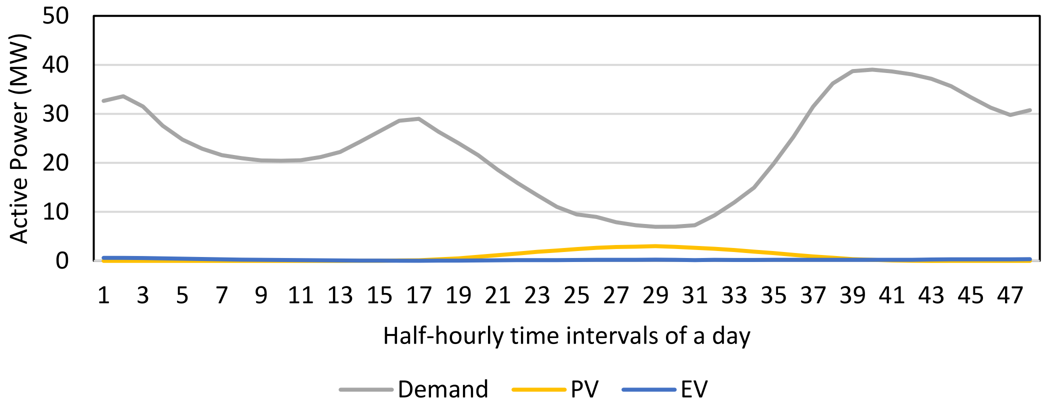


Figure 89 Daily profile - representative day-1 obtained using the 3-step time aggregation method.

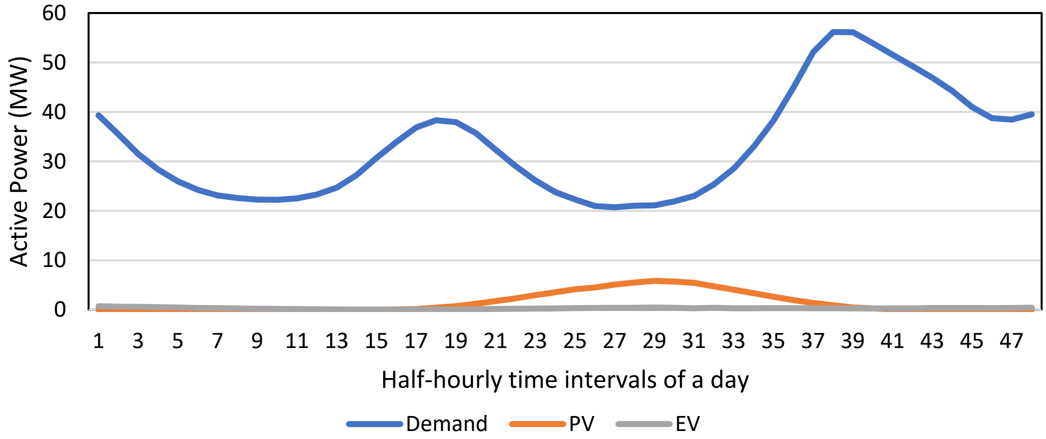


Figure 90 Daily profile - representative day-2 obtained using the 3-step time aggregation method.

3.5.1.2 Ancillary Services from Network 1

In case 3B, ancillary services are calculated for an illustrative future DER and storage integration (2035) in the network. The integration of storage refers to the integration of both ESS and EV charging stations. In network 1, PV, EV, and ESS are considered as future DERs and storage in the network and an illustrative growth in demand is considered for DR. The calculated frequency ancillary services are presented in Figure 91 and Figure 92 for representative day-1 and day-2 respectively. Similarly, the calculated voltage ancillary services are presented in Figure 93 and Figure 94 for representative day-1 and day-2, respectively. The amount of ancillary services increased significantly after considering DERs and ESSs in the network.

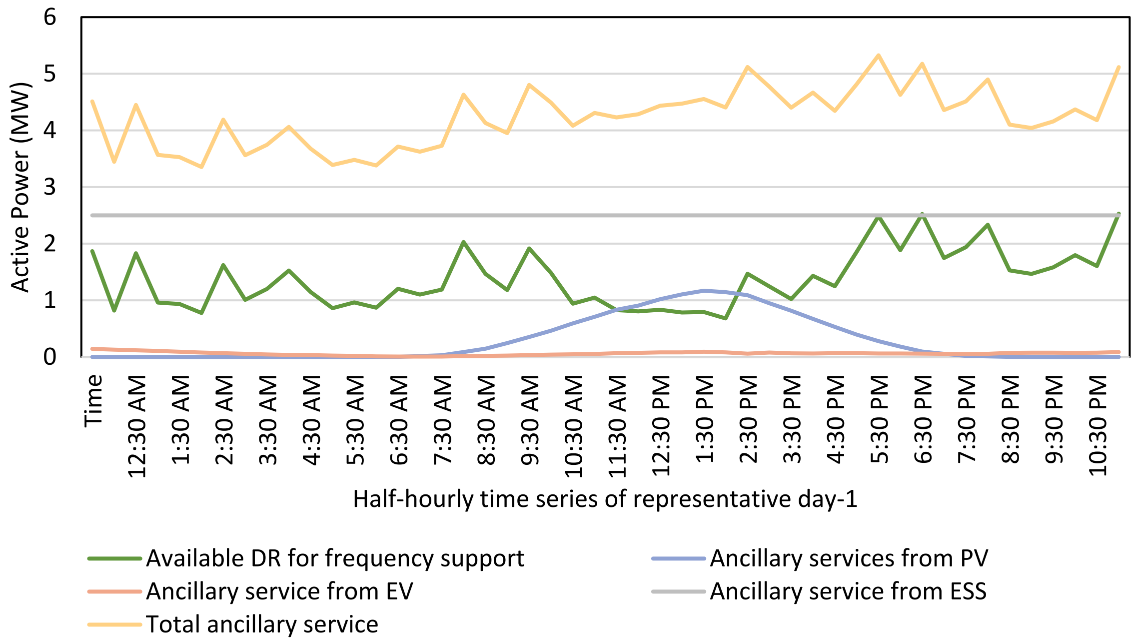


Figure 91 Available FCAS from Network 1 with DR, DER (PV) and storage (ESS, EV) participation in representative day-1.

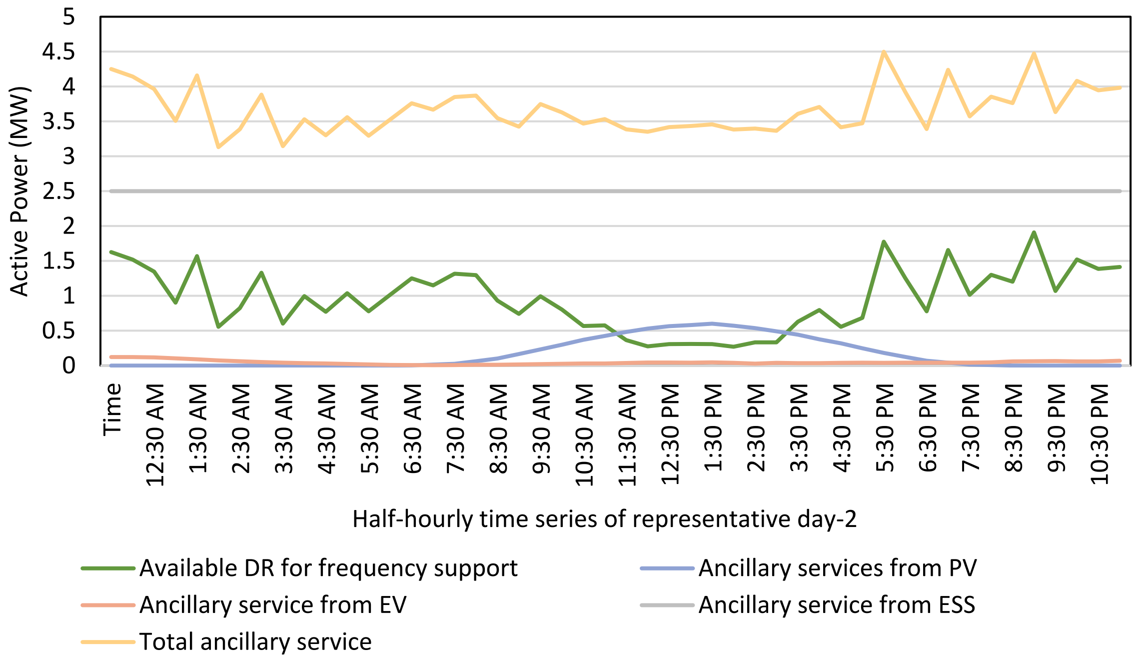


Figure 92 Available FCAS from Network 1 with DR, DER (PV) and storage (ESS, EV) participation in representative day-2.

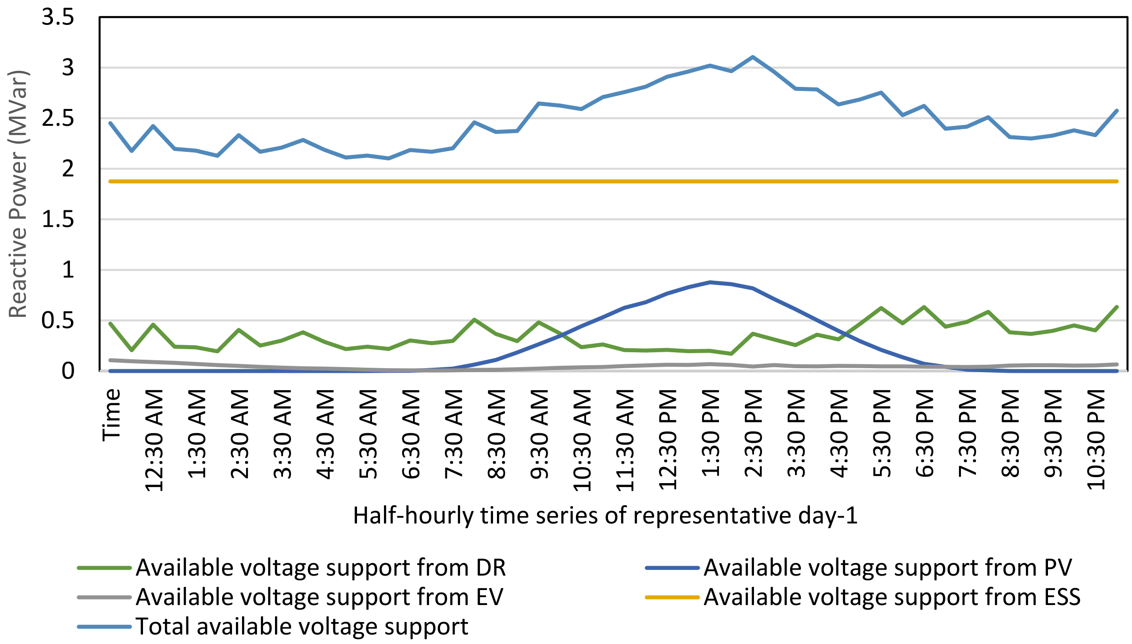


Figure 93 Available VCAS from Network 1 with DR, DER (PV) and storage (ESS, EV) participation in representative day-1.

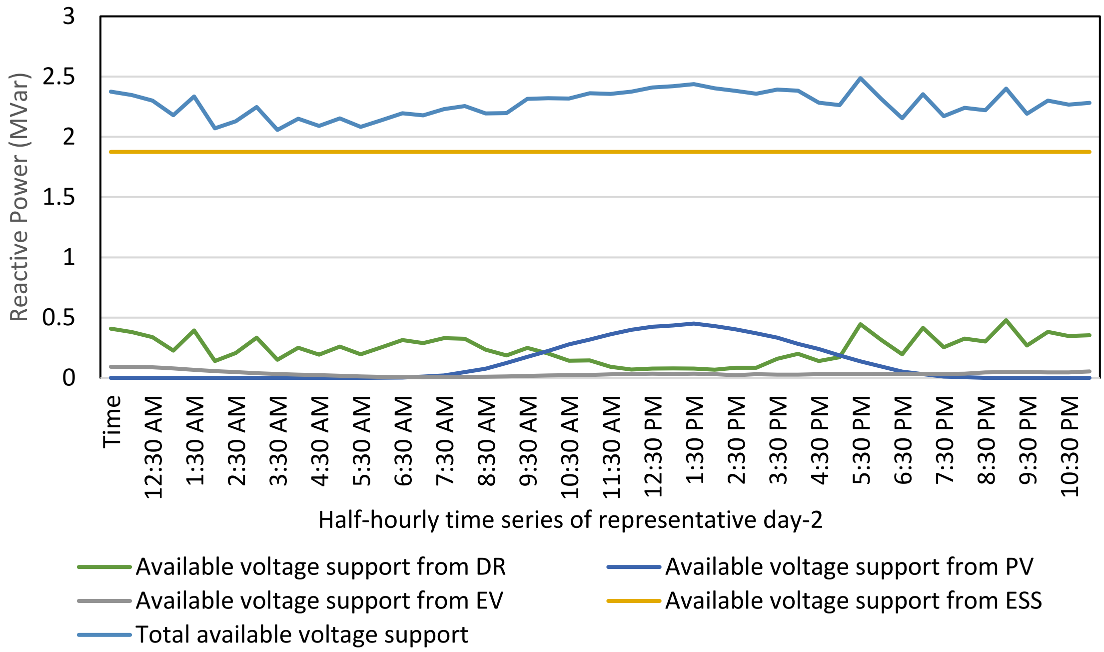


Figure 94 Available VCAS from Network 1 with DR, DER (PV) and storage (ESS, EV) participation in representative day-2.

3.5.2 Network 2

For Case 3B, a 5 MW front-of-the-meter solar and 5 MW EV fleet storage are considered to be connected to Network 2 by 2035.

3.5.2.1 Time Aggregated Load Profiles

The aggregated time-series data of 2035 from Geelong East is presented in Figure 95. The load time series data is in 30-minute time intervals. A 5 MW solar PV farm is considered as an illustrative case in 2035. The solar PV generation profile from 2021 is considered as a general profile for this area and used for generating representative daily PV generation profiles for 2035 (presented in Figure 96). An aggregated EV charging load data from the Jemena and C4NET project is used in this work. The half-hour-time series data of EV charging is presented in Figure 97. Therefore, the representative daily profiles are obtained using a combined time series with the same duration of demand and PV generation time series. The developed 3-step time aggregation method has been used to obtain representative daily profiles. The combined time series profile is presented in Figure 98. The K-means clustering method is used to identify the representative clusters in the combined time series profile as presented in Figure 99. The representative daily profiles of loads, PV generation, and EV are obtained by using the average participation factors in the combined time series profiles. The time series profiles of representative day–1 and -2 are presented in Figure 100 and Figure 101.

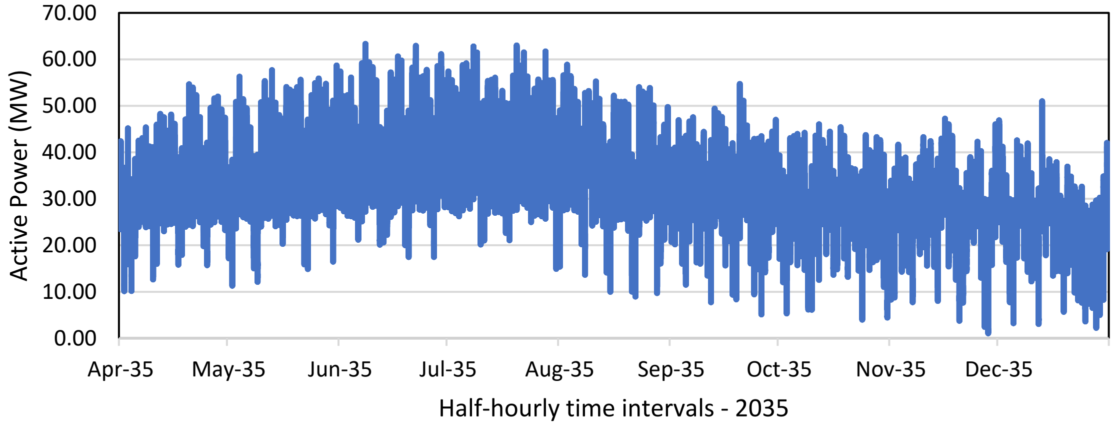


Figure 95 Aggregated time-series data in year 2035 from Geelong East zone substation.

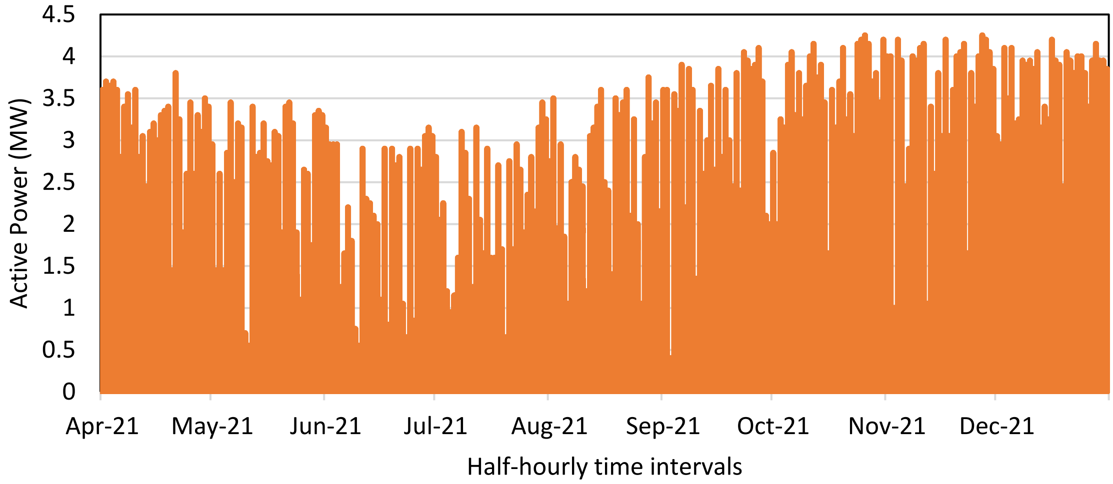


Figure 96 Yearly PV profile - Geelong East area.

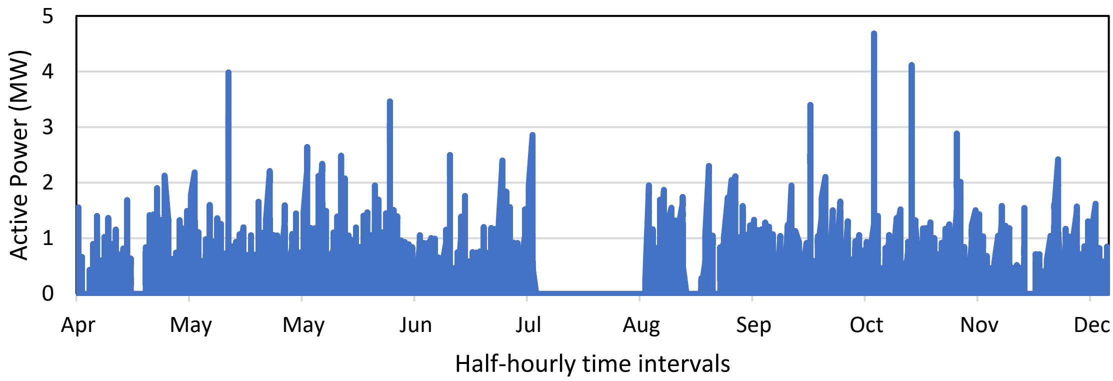


Figure 97 EV time series data.

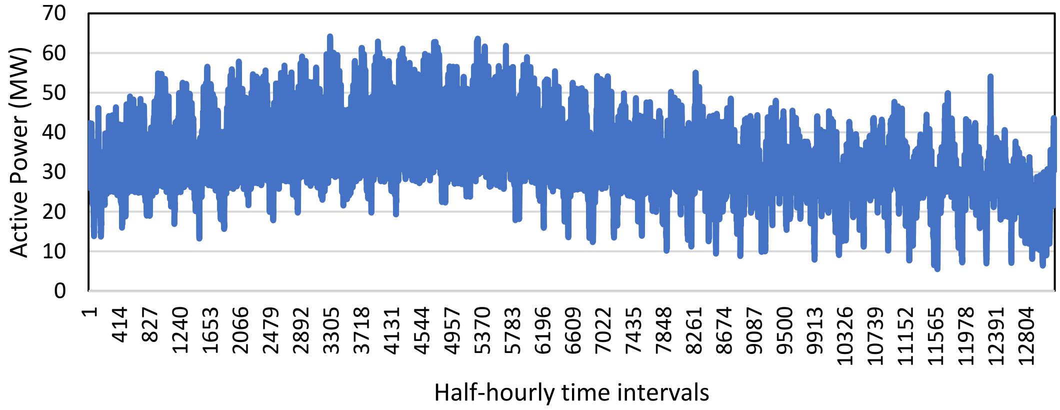


Figure 98 Combined time series data.

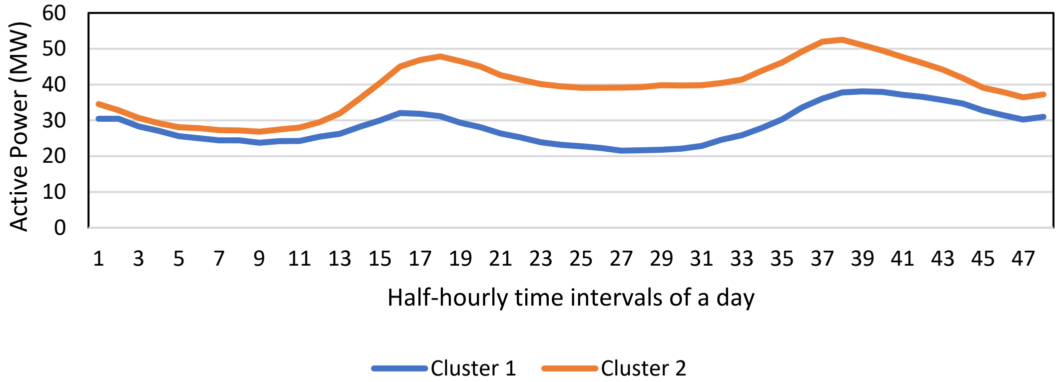


Figure 99 Representative clusters of the combined time series.

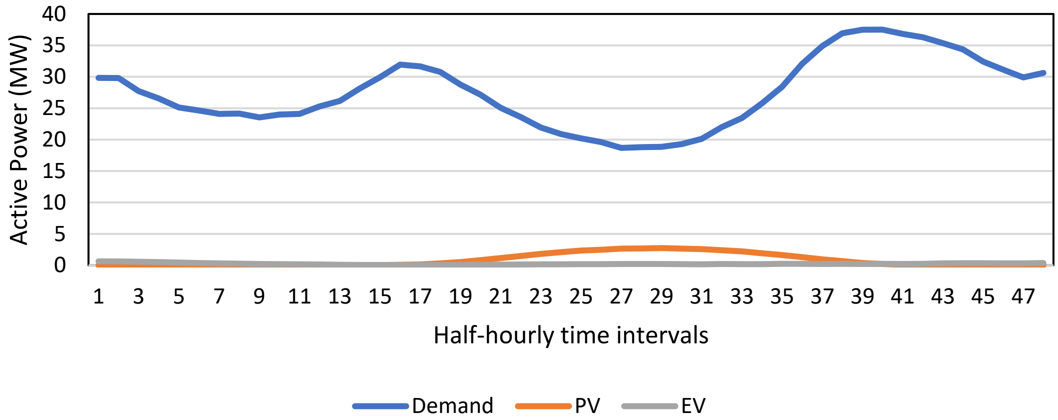


Figure 100 Daily profile - representative day-1 obtained using the 3-step time aggregation method.

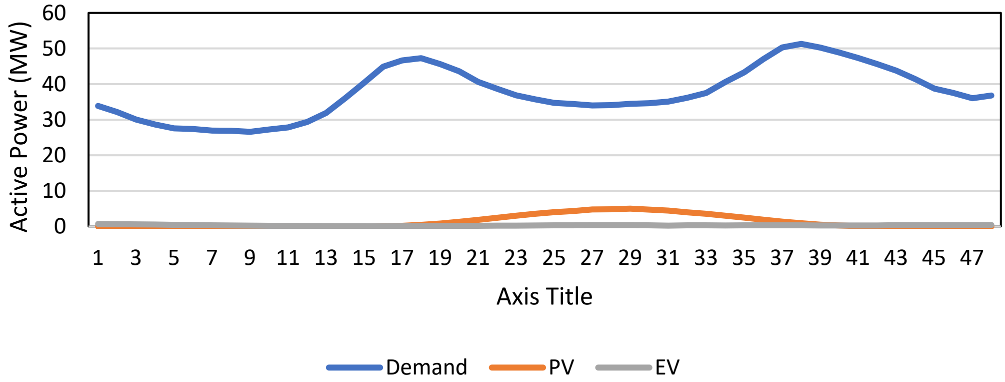


Figure 101 Daily profile - representative day-2 obtained using the 3-step time aggregation method.

3.5.2.2 Ancillary Services from Network 2

In case 3B, ancillary services are calculated for an illustrative future DER and storage integration (2035) in the network. The integration of storage refers to the integration of both ESS and EV charging stations. In network 2, PV, EV, and ESS are considered as future DERs and storage in the network and an illustrative growth in demand is considered for DR. The calculated frequency ancillary services are presented in Figure 102 and Figure 103 for representative day-1 and day-2, respectively. Similarly, the calculated voltage ancillary services are presented in Figure 104 and Figure 105 for representative day-1 and day-2, respectively. The amount of ancillary services increased significantly after considering DERs and ESSs in the network.

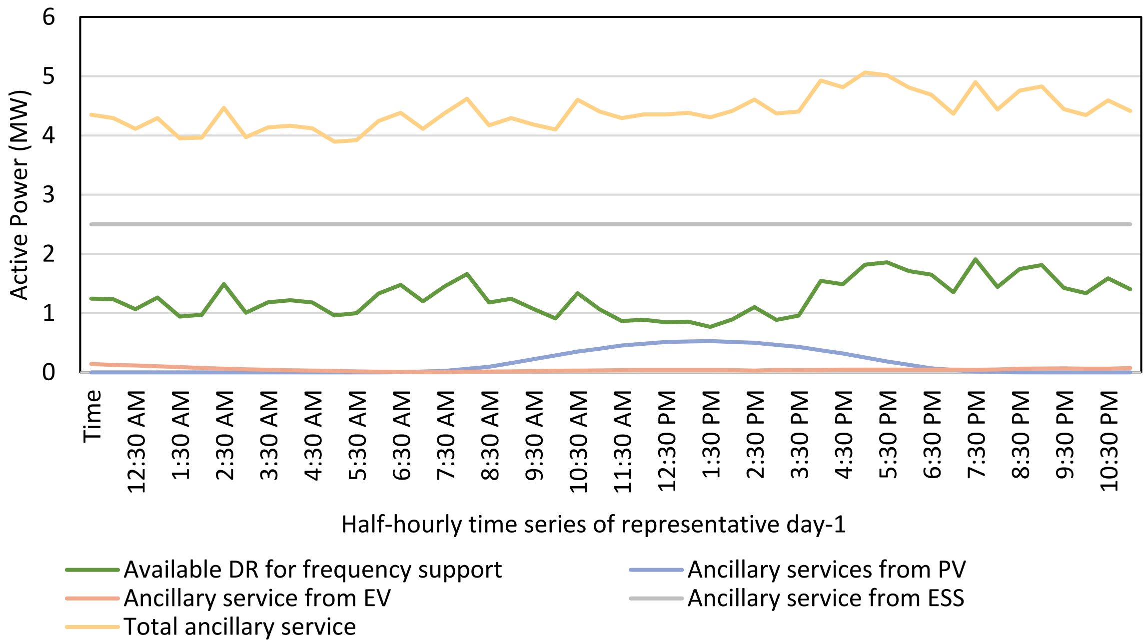


Figure 102 Available FCAS from Network 2 with DR, DER (PV) and storage (ESS, EV) participation in representative day-1.

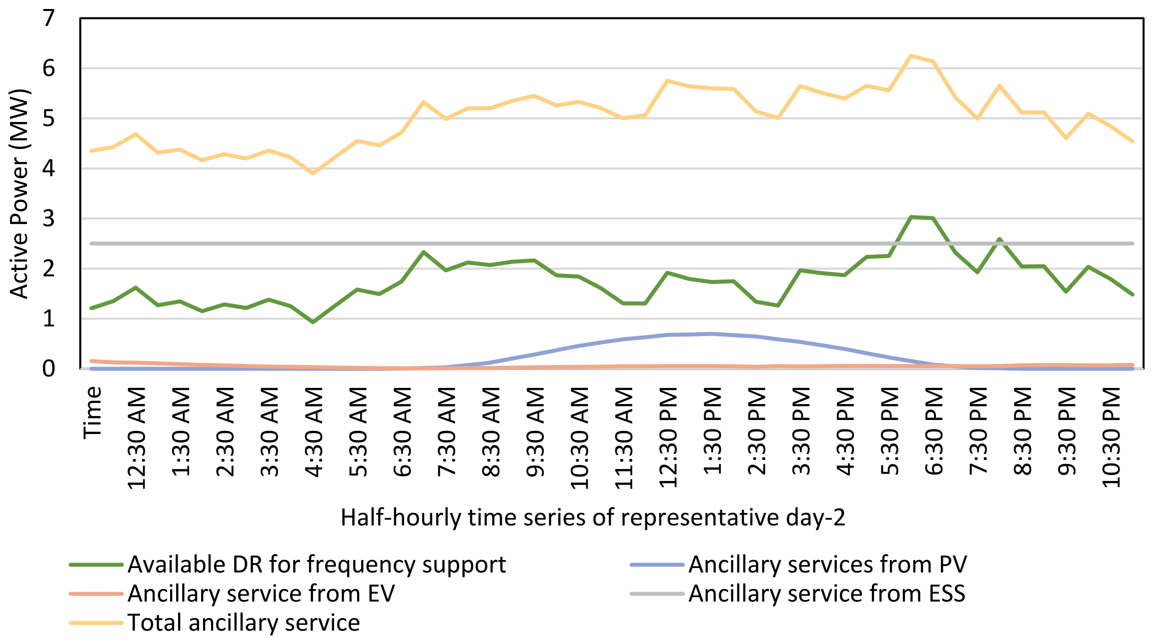


Figure 103 Available FCAS from Network 2 with DR, DER (PV) and storage (ESS, EV) participation in representative day-2.

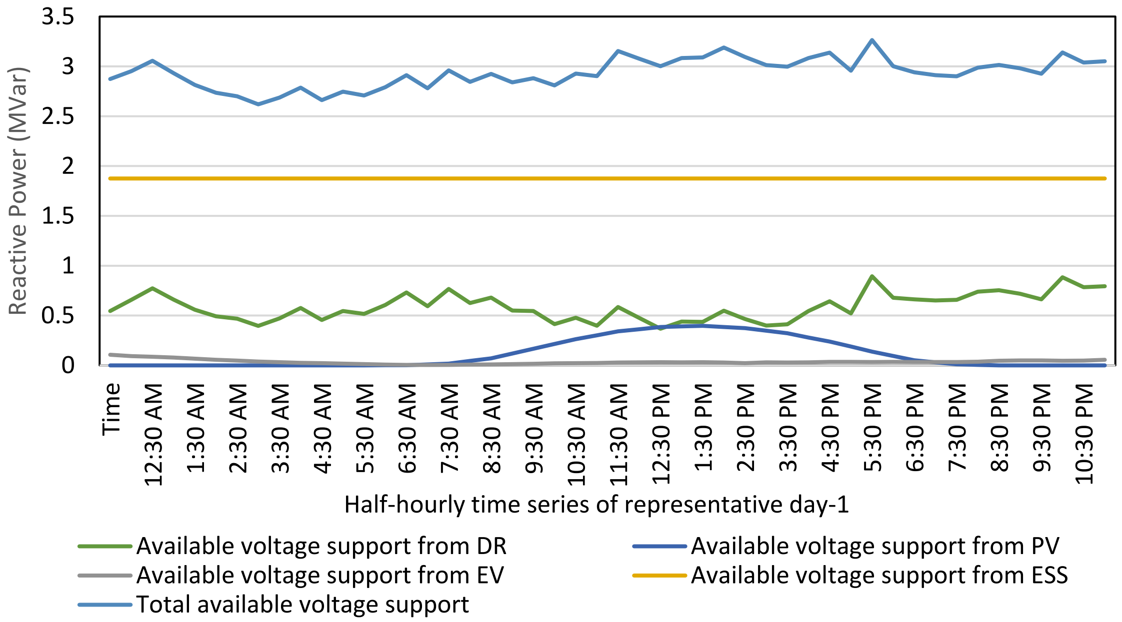


Figure 104 Available VCAS from Network 2 with DR, DER (PV) and storage (ESS, EV) participation in representative day-1.

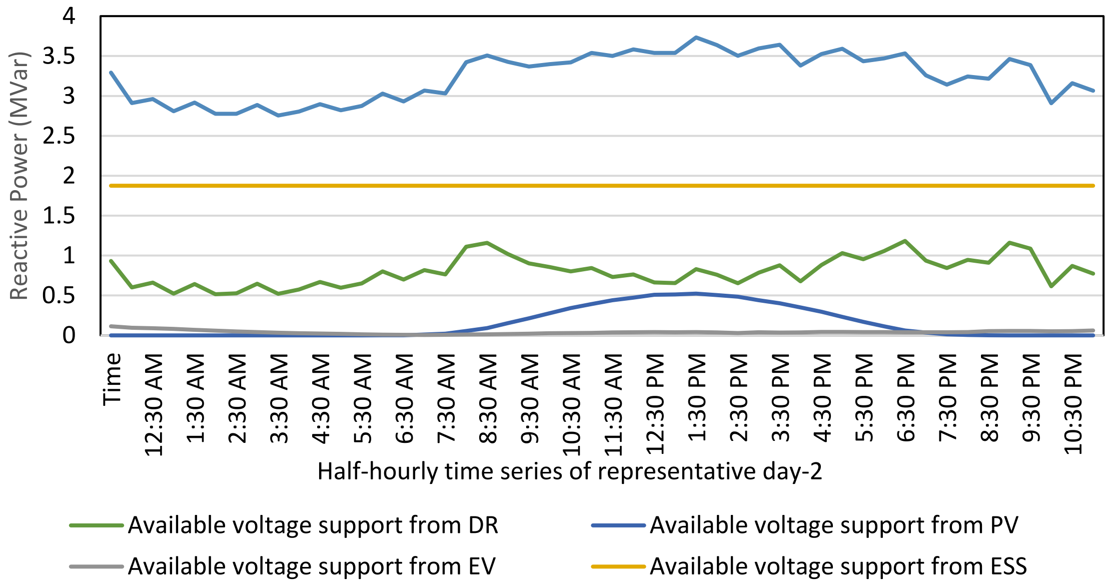


Figure 105 Available VCAS from Network 2 with DR, DER (PV) and storage (ESS, EV) participation in representative day-2.

3.5.3 Network 3

For the future case (2035), a 5 MW solar and 2.5 MW EV fleet storage are considered to be connected to the network with the existing 6.15 MW wind farm. A 2.5 MW BESS is also considered in this work. An illustrative estimation of load increase is considered to obtain yearly time series data for 2035 from 2021 data by considering the new developments, population growth, and economic expansion in this area.

3.5.3.1 Time Aggregated Load Profiles

The aggregated time-series data of 2035 (30-minute time intervals) from Ballarat South ZS is presented in Figure 106. A 5 MW solar PV farm is considered as an illustrative case in 2035. The solar PV generation profile from 2021 is considered as a general profile for this area and used for generating representative daily PV generation profiles for 2035 (presented in Figure 107). The power generation profile of the 6.15 MW wind farm is presented in Figure 108. An aggregated EV charging load data used in this analysis is presented in Figure 109. Therefore, the representative daily profiles are obtained using a combined time series with the same duration of demand and PV generation time series. The developed 3-step time aggregation method has been used to obtain representative daily profiles. The combined time series profile used for further analysis is presented in Figure 110. The representative clusters of the combined time series profile are presented in Figure 111. The representative daily profiles of loads, PV generation, and EV are obtained by using the average participation factors in the combined time series profiles. The time series profiles of representative day-1 and -2 are presented in Figure 112 and Figure 113, respectively.

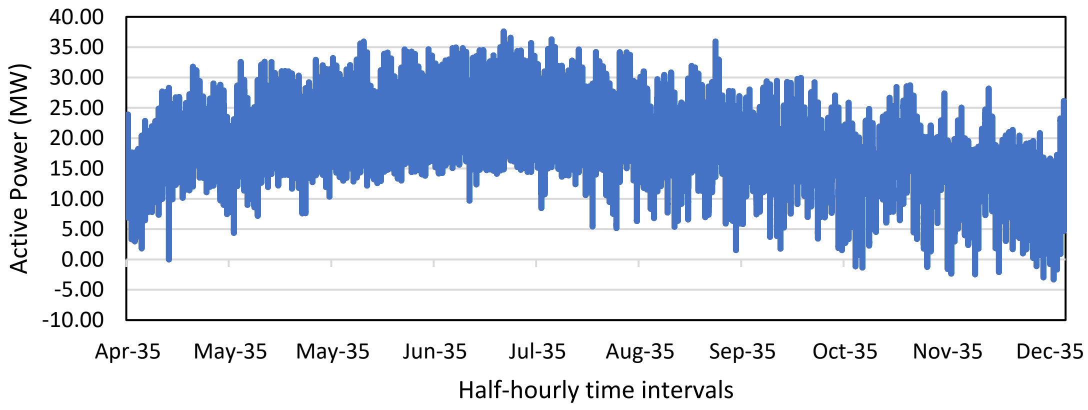


Figure 106 Aggregated time-series data 2035 from the Ballarat South zone substation.

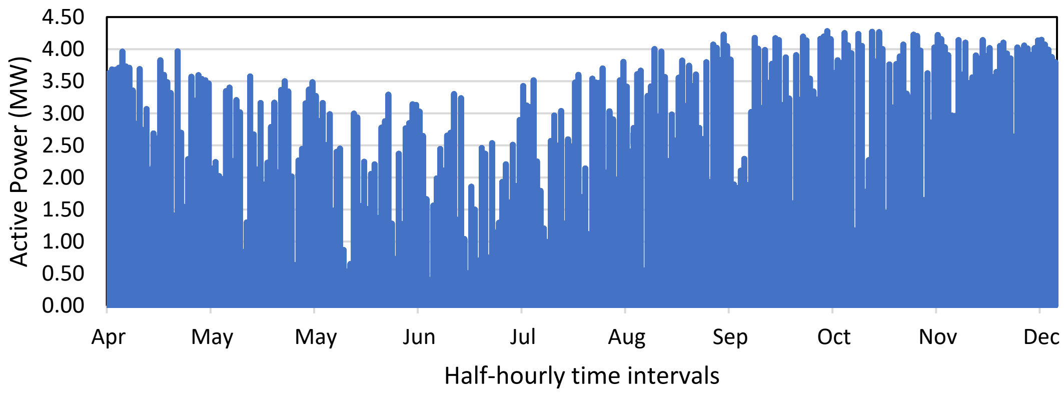


Figure 107 Yearly PV profile - Ballarat South area.

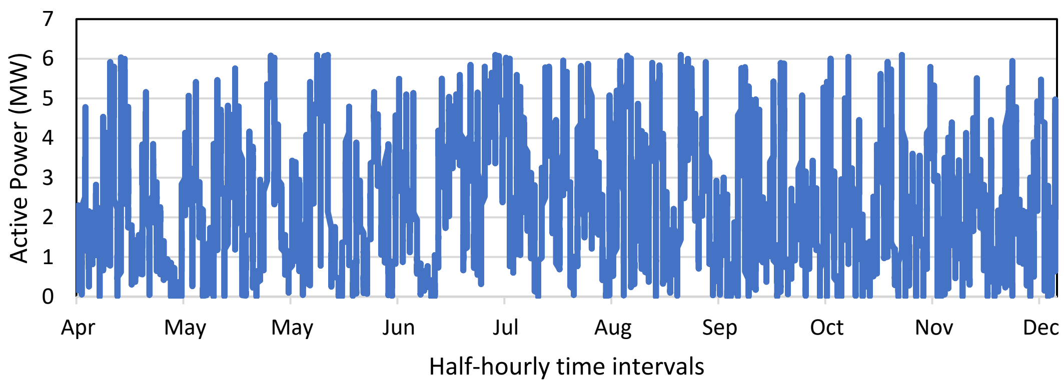


Figure 108 Wind profile - Chepstowe wind farm.

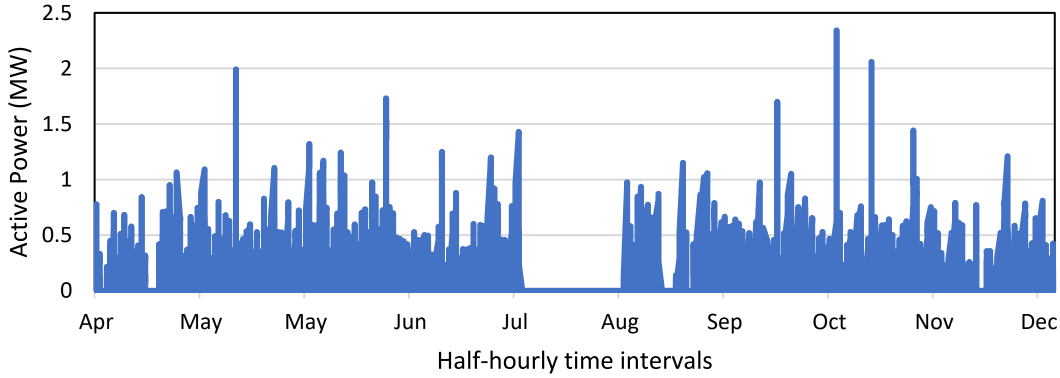


Figure 109 EV time series data.

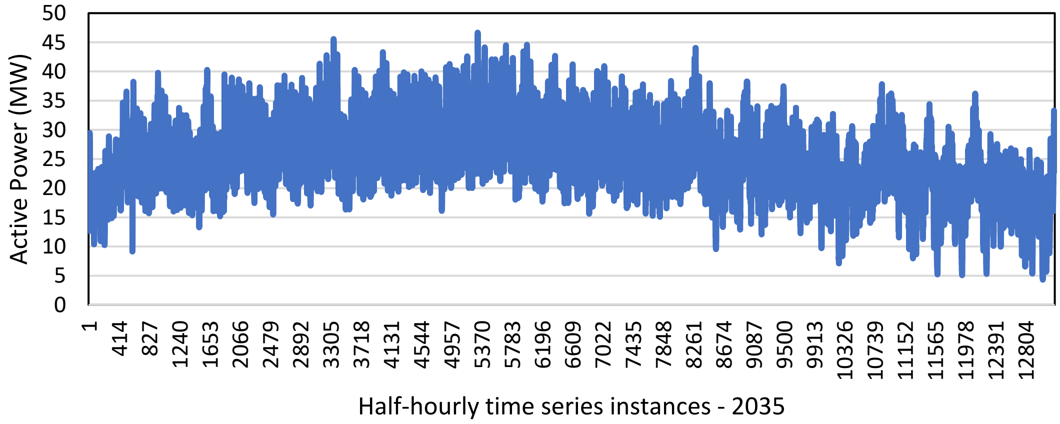


Figure 110 Combined time series data.

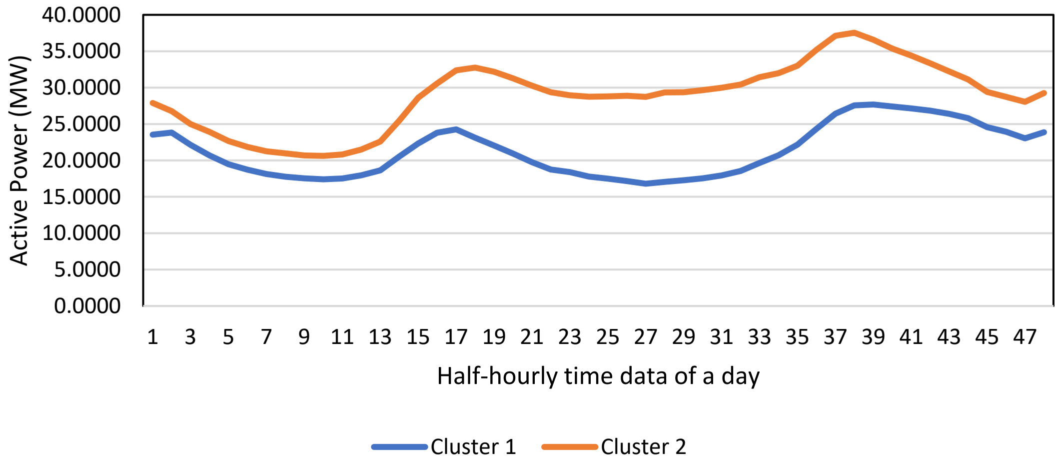


Figure 111 Representative clusters of the combined time series.

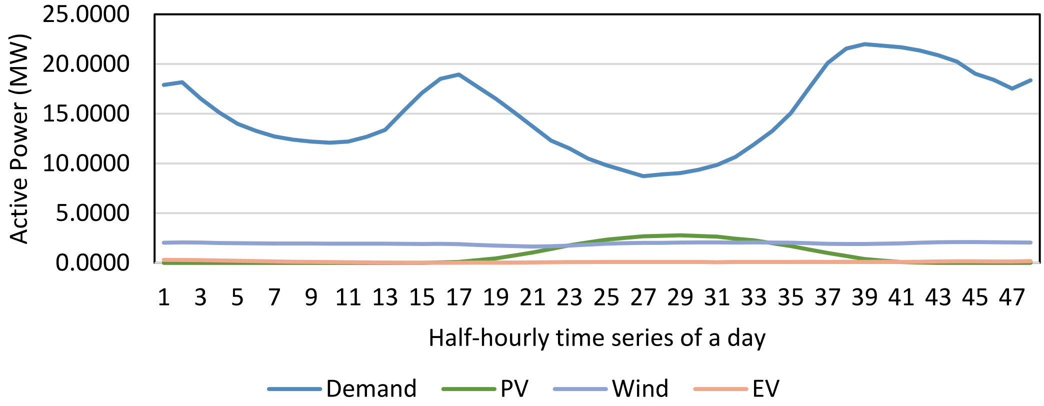


Figure 112 Daily profile - representative day-1 obtained using the 3-step time aggregation method.

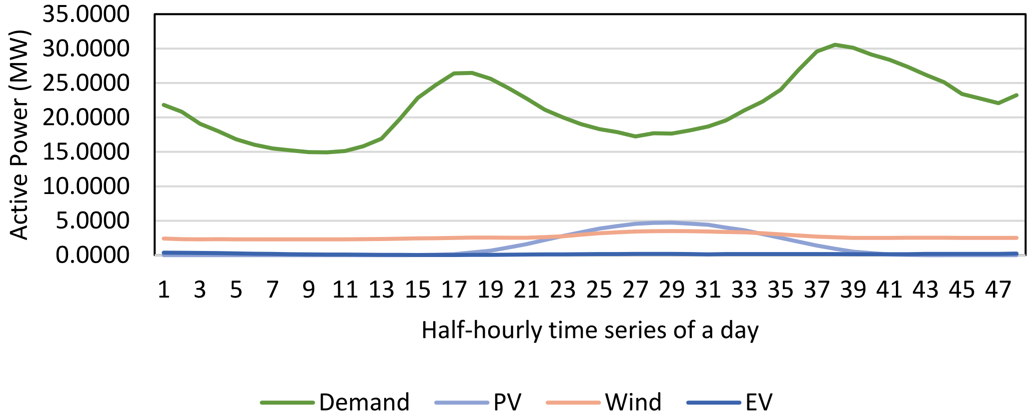


Figure 113 Daily profile - representative day-2 obtained using 3-step time aggregation method.

3.5.3.2 Ancillary Services from Network 3

In case 3B, ancillary services are calculated for an illustrative future DER and storage integration (2035) in the network. The integration of storage refers to the integration of both ESS and EV charging stations. In network 3, PV, Wind, EV, and ESS are considered as future DERs and storage in the network and an illustrative growth in demand is considered for DR. The calculated frequency ancillary services are presented in Figure 114 and Figure 115 for representative day-1 and day-2, respectively. Similarly, the calculated voltage ancillary services are presented in Figure 116 and Figure 117 for representative day-1 and day-2, respectively. The amount of ancillary services increased significantly after considering DERs and ESSs in the network.

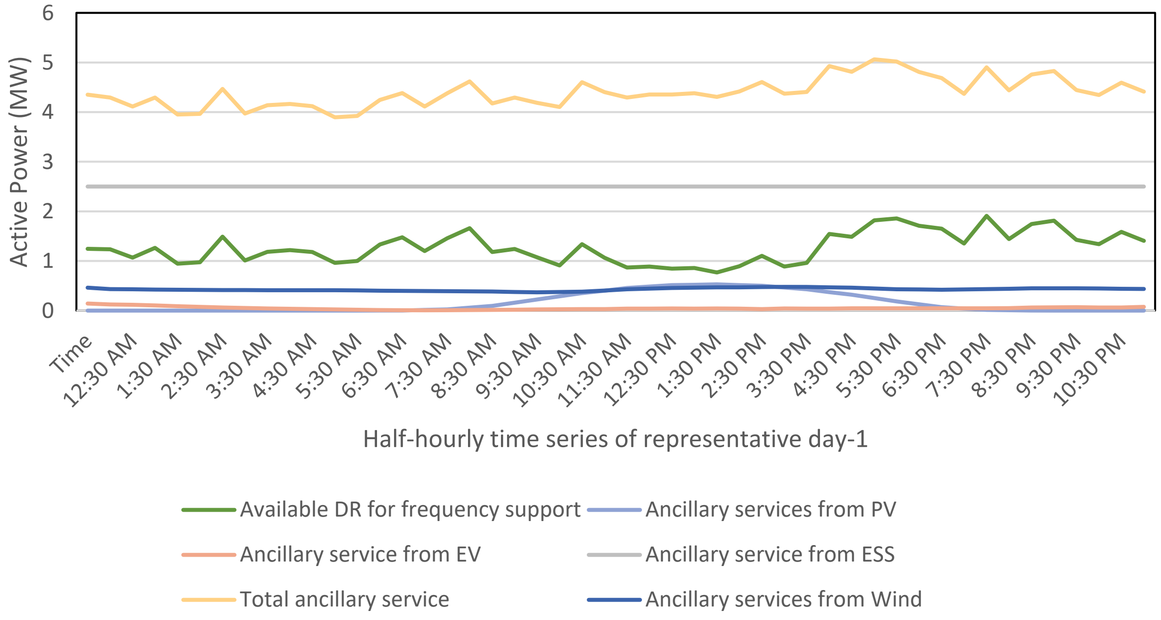


Figure 114 Available FCAS from Network 3 with DR, DER (PV, Wind) and storage (ESS, EV) participation in representative day-1.

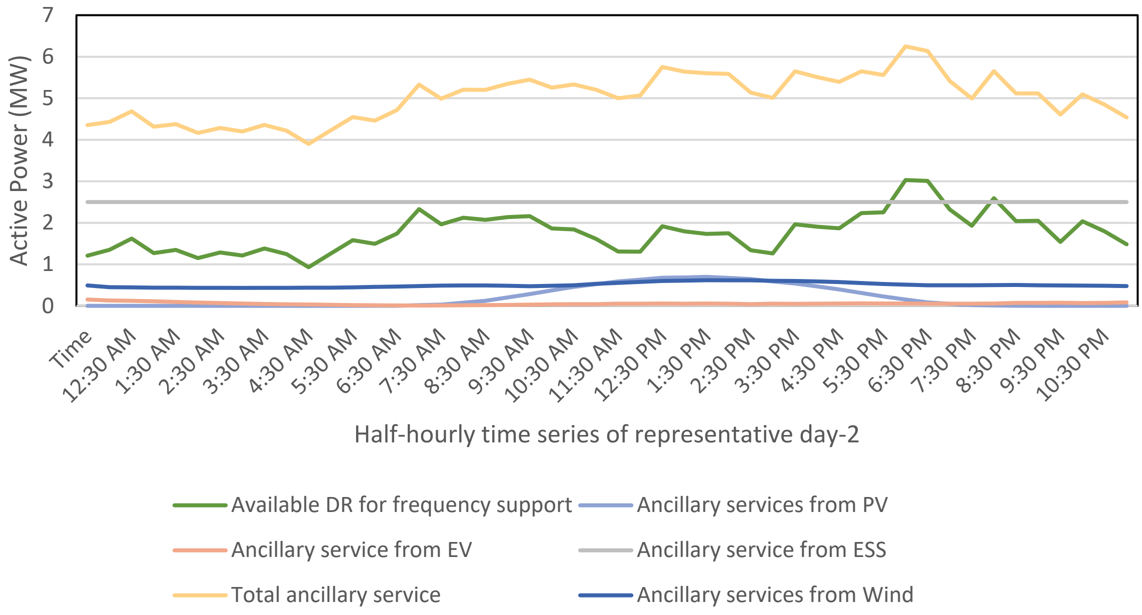


Figure 115 Available FCAS from Network 3 with DR, DER (PV, Wind) and storage (ESS, EV) participation in representative day-2.

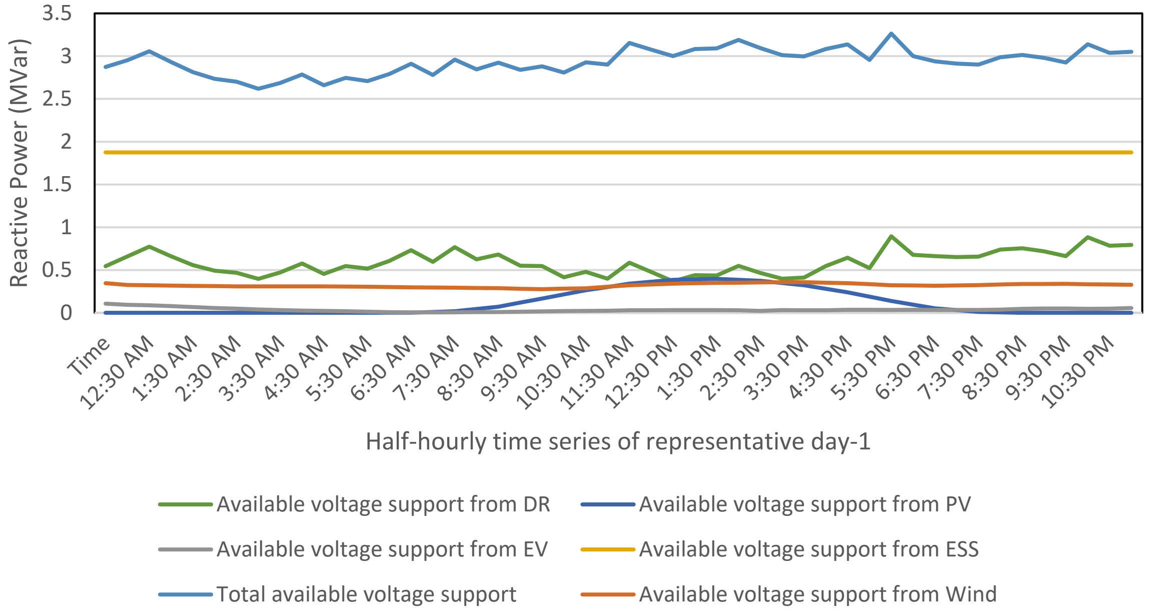


Figure 116 Available VCAS from Network 3 with DR, DER (PV, Wind) and storage (ESS, EV) participation in representative day-1.

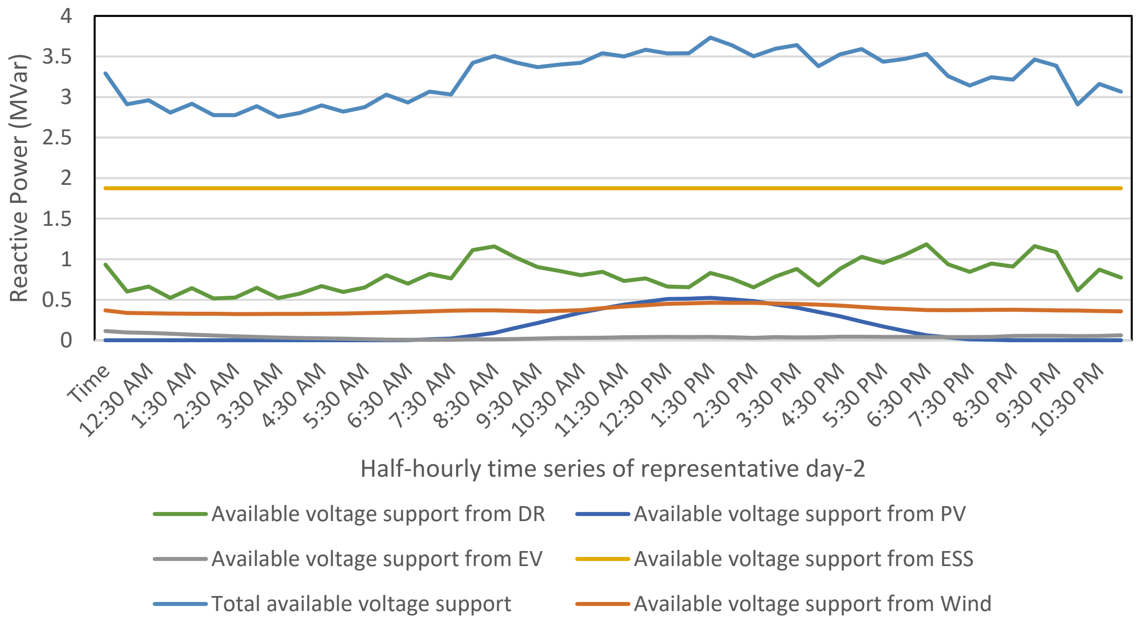


Figure 117 Available VCAS from Network 3 with DR, DER (PV, Wind) and storage (ESS, EV) participation in representative day-2.

4 Network and Market Interaction Analysis

Decommissioning of traditional synchronous generator and integration of RESs elevates the necessity of ancillary provision in the transmission network to maintain its stability and reliability. The requirement of additional ancillary services can be costly for the transmission network because they need to allocate more and more reserve to compensate the variability of these new DERs, especially renewable DERs. Since the penetration of residential and utility-scale DERs are increasing, the extra capabilities of DERs in the distribution network can used to compensate ancillary service requirement by the transmission network. By aggregating these DERs can significantly decrease the planning and operation cost of future renewable integrated power systems and also improves system reliability and security. If these services are not provided by the downstream grid the upstream grid should invest on them, provide, plan or operate more reserve, voltage supports services, frequency regulation reserve. And these will add operation and investment cost of the upstream grid.

In the TSO-DSO interacted market, resources located in distribution networks such as DR, DERs, ESS and EVs will participate in providing the ancillary service support to local network and TNs. The local need for ancillary services will co-exist with the system need for balancing and congestion management. In this work, FCAS and VCAS services from the distribution network to TNs are analysed. The architecture of the real time markets needs to be revisited to accommodate the market interaction in the TSO-DSO coordinated system. The flexible demand and storage, observability of the network, co-ordination on the TSO-DSO border and the information to be exchanged need to be identified for appropriate coordination and market participation [45].

In this work, the security of the network is analysed before aggregating the ancillary services. If the network is secure to provide ancillary service, then the estimation of AS is calculated. After providing AS from the safe operating point the configuration of the network may change. The system status, security status, operating point will be checked again to determine whether the system can provide further service or not.

In their System Operation 2020 report titled Future Role of Distribution System Operators – Innovation Landscape Brief, IRENA explores and strategically analyzes the following models:

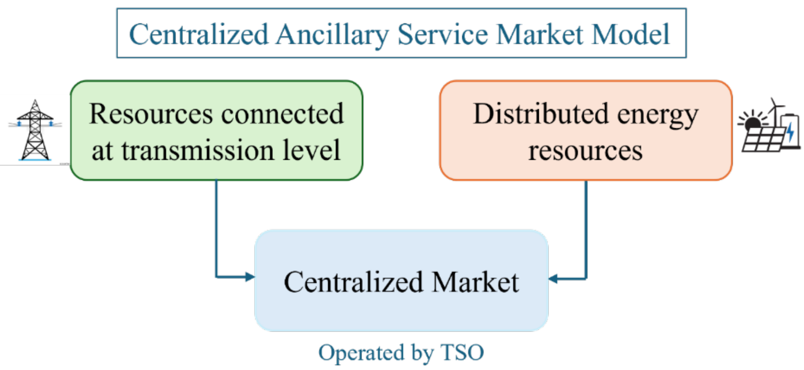


Figure 118 Schematic diagram of centralized ancillary service market model.

The Figure 118 illustrates the Centralized Ancillary Service Market Model, where the TSO plays a dominant role in acquiring ancillary services from both transmission-connected resources and DERs. In this model, a single, centralized market is operated by the TSO, ensuring standardized processes and lower operational costs. While DERs participate in the market, they require technical validation from the DSO to ensure their operations do not create grid constraints.

The market organization follows a TSO-centric approach, where the TSO has priority in allocating DER flexibility. The DSO's role is limited, as it only checks for distribution grid constraints and provides technical validation but does not actively participate in the procurement of services. On the other hand, the TSO directly acquires ancillary services from DERs, aggregates resources at the distribution level, and ensures they compete with larger, transmission-level resources in the centralized market.

This model offers several benefits, particularly in scenarios where distribution networks do not experience significant congestion. A single, centralized market leads to lower operational costs, easier regulatory implementation, and reduced computational complexity, as only the transmission grid is considered. However, a key challenge of this approach is that distribution grid constraints may not always be fully respected, potentially leading to inefficiencies or network congestion.

Overall, this centralized model simplifies market operations and reduces costs but requires careful management to ensure that DER participation does not negatively impact local distribution networks.

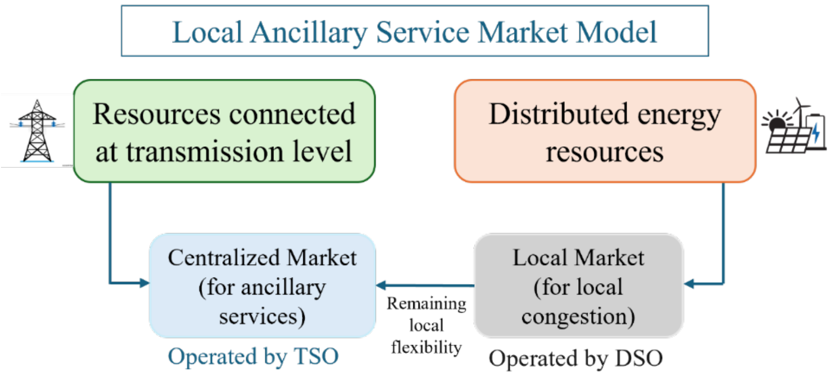


Figure 119 Schematic diagram of local ancillary service market model.

The Figure 119 illustrates the Local Ancillary Service Market Model, which introduces a separate local flexibility market operated by the DSO alongside the centralized ancillary service market managed by the TSO. In this model, DERs first participate in the local market, where the DSO prioritizes the use of local flexibility to manage congestion and other distribution-level constraints. After addressing local needs, the DSO aggregates and transfers the remaining flexibility to the centralized market, allowing the TSO to acquire additional ancillary services while ensuring that grid constraints at the distribution level are respected.

The market organization follows a dual structure, where the TSO oversees the centralized market, while the DSO operates the local market for DERs. The allocation principle prioritizes DSO's needs first, ensuring that local flexibility is utilized before any remaining capacity is made available to the TSO-led central market. In this setup, the DSO is responsible for local congestion management, has priority in using flexible resources at the distribution level, and ensures that only bids complying with local grid constraints are forwarded to the TSO's ancillary service market. Meanwhile, TSO's role is limited to acquiring the remaining flexibility after receiving technical validation from the DSO, ensuring the feasibility of the orders.

This model offers several benefits, including giving DSOs priority in using local flexibility, actively supporting the procurement of ancillary services, and lowering entry barriers for small-scale DERs by allowing participation in local markets. However, there are also challenges, such as the need for sequential coordination between the centralized and local markets, requiring extensive communication between the TSO and DSO. Additionally, for the local market to function effectively, it must have a sufficiently large size and an adequate number of participants to ensure competition and prevent liquidity issues.

Overall, the Local Ancillary Service Market Model balances TSO and DSO roles by ensuring local flexibility is prioritized before allowing DERs to participate in the centralized market. While this approach enhances grid stability and enables small-scale DERs to contribute, it also requires close coordination and a well-structured local market to prevent inefficiencies.

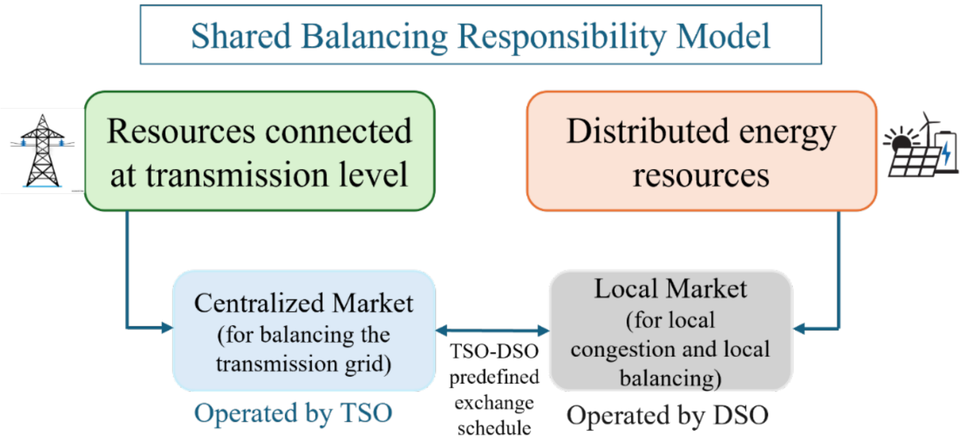


Figure 120: Schematic diagram of shared balancing responsibility model.

The Figure 120 illustrates the Shared Balancing Responsibility Model, which builds upon the Local Ancillary Service Market Model but introduces a key difference: remaining local flexibility is not offered to the Transmission System Operator (TSO). Instead, Distributed System Operators (DSOs) retain full control over the flexibility within their networks, using it exclusively for local balancing and congestion management. This results in a clear separation of roles between TSOs and DSOs, with predefined exchange schedules governing their interactions.

In terms of market organization, this model consists of both a central market operated by the TSO and a local market managed by the DSO. However, unlike previous models, the allocation principle gives DSOs exclusive control over distributed energy resources (DERs) flexibility, meaning that the TSO cannot acquire any remaining local flexibility after the DSO has addressed local needs. The DSO's role is significantly expanded in this model, as it is solely responsible for local grid balancing, congestion management, and ensuring stability within the distribution network. The TSO, on the other hand, focuses solely on resources connected at the transmission level, maintaining separate responsibilities from the DSO at individual TSO-DSO interconnection points.

This model presents several benefits, including reducing the TSO's need to procure ancillary services, lowering entry barriers for small-scale DERs, and establishing clear role boundaries between TSOs and

DSOs. However, there are also challenges, such as the complexity of defining a mutually agreed-upon exchange schedule between the TSO and DSO. Additionally, local markets must be large enough and competitive to prevent liquidity issues, and the total volume of ancillary services procured by both the TSO and DSO could be higher compared to other models.

Overall, the Shared Balancing Responsibility Model enhances DSO autonomy by ensuring that local flexibility is fully utilized for distribution grid needs, while the TSO focuses exclusively on balancing the transmission network. This approach creates clear functional boundaries between the two entities but requires careful coordination and structured local markets to operate effectively.

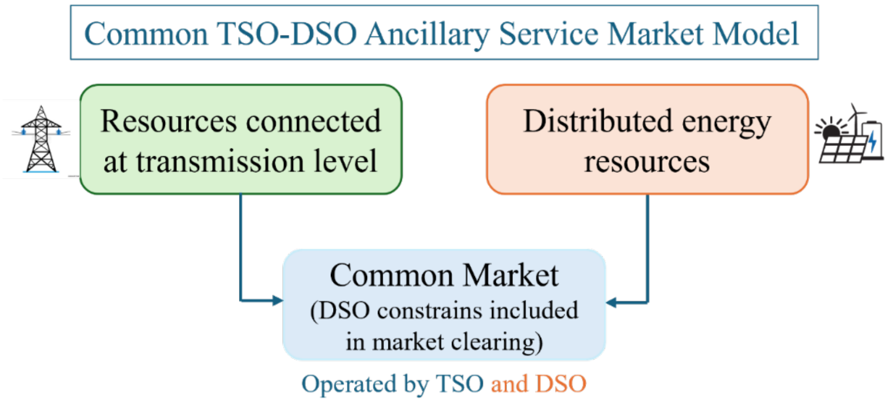


Figure 121: Schematic diagram of common TSO-DSO ancillary service market model.

The Figure 121 illustrates the Common TSO-DSO Ancillary Service Market Model, where TSOs and DSOs jointly manage a common market for ancillary services and flexibility resources. Unlike previous models, which maintained separate markets or allocated flexibility to a specific operator, this model integrates both transmission and distribution-level resources into a single market, ensuring that flexibility is allocated to the system operator with the highest need. This approach optimizes cost efficiency by considering both TSO and DSO constraints in the market-clearing process.

In terms of market organization, the model operates under a shared framework, with TSOs and DSOs collaborating closely to ensure effective resource allocation. The allocation principle prioritizes cost minimization, meaning flexibility resources are acquired in a way that reduces total system costs for both operators. The role of the TSO and DSO is fully integrated, as they jointly procure and utilize flexibility, ensuring that system-wide needs are met efficiently while preventing unnecessary competition or redundancy in procurement.

This model offers significant benefits, including minimized total system costs for ancillary services and optimal use of flexible resources through enhanced coordination. However, there are also challenges associated with its implementation. Allocating costs between the TSO and DSO can be complex, as determining the fair share of expenses requires detailed coordination. Additionally, managing the market is computationally intensive, given that both transmission and distribution grid constraints need to be resolved within a single optimization mechanism.

Overall, the Common TSO-DSO Ancillary Service Market Model represents a highly integrated and cooperative approach to managing flexibility resources. While it offers economic and operational efficiency, its success depends on sophisticated market-clearing algorithms and effective cost-sharing agreements between TSOs and DSOs.

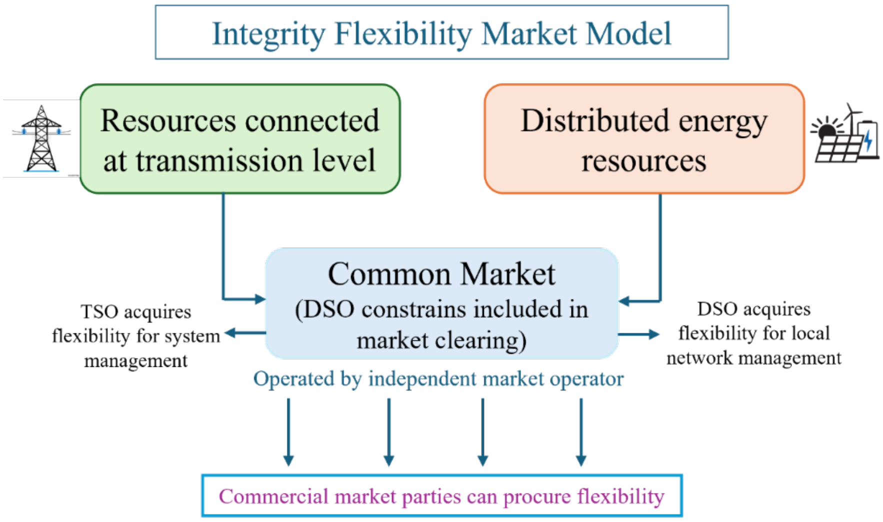


Figure 122: Schematic diagram of integrity flexibility market model.

The Figure 122 illustrates the Integrated Flexibility Market Model, which represents the most complex approach to managing flexibility resources. In this model, a common market for flexibility is established, incorporating resources connected at both the transmission and distribution levels. Unlike previous models where TSOs and DSOs operated separately or in coordination, this model introduces an independent market operator responsible for managing the flexibility market. Additionally, commercial market parties can participate, further increasing competition and liquidity.

The market organization is structured around this independent market operator, ensuring that flexibility resources are provided and allocated based on market forces. The allocation principle follows the highest willingness-to-pay approach, meaning flexibility is allocated to the bidder offering the highest price, whether a TSO, DSO, or a commercial market participant. This makes the model more dynamic and competitive, fostering efficient price discovery and enhancing system-wide flexibility procurement.

In terms of roles, the DSO acquires flexibility for local network management, ensuring grid stability at the distribution level. DSOs also provide technical validation to ensure that procured flexibility resources support efficient power flows. This approach is similar to the Common TSO-DSO Ancillary Service Market Model, with the added feature that commercial entities can actively regulate their market position in real-time. Meanwhile, the TSO acquires flexibility for system management from the independent market operator, ensuring that network constraints and grid balancing needs at the transmission level are met. The market operator allocates flexibility resources to the highest bidder, optimizing system-wide efficiency.

The benefits of this model include high liquidity and competitive pricing due to a large number of market participants, as well as increased balancing options for responsible parties to manage grid imbalances. However, significant challenges exist, such as the need to establish an independent market operator, ensuring seamless data sharing between TSOs, DSOs, and market participants, and managing high computational complexity to resolve transmission and distribution constraints within a unified framework.

Overall, the Integrated Flexibility Market Model offers a highly competitive and market-driven approach to flexibility procurement. While it promises efficient resource allocation and price competitiveness, its successful implementation relies on sophisticated market mechanisms, strong regulatory frameworks, and advanced computational capabilities to manage system constraints effectively.

5 Conclusions and Future Research

This task, WP3.12 Modelling and Assessment of Integrated System Performance and Technical Implications, assesses the coordination mechanism between Transmission System Operators (TSOs) and Distribution System Operators (DSOs) regarding ancillary services, specifically frequency regulation and reactive power support. These services can be provided by Active Distribution Networks (ADNs) to Transmission Networks (TNs).

A step-by-step methodology has been developed for both spatial and temporal aggregation of the network to create representative active distribution networks for ancillary service calculations. Although the study focuses on steady-state analysis, it generates a time series of representative snapshots for calculating ancillary services. This integrated approach enhances network analysis and facilitates long-term planning by reducing complexity and computational demands, making the combined TSO-DSO studies more computationally feasible.

Three scenarios are analysed: ancillary services from demand response, ancillary services from both demand response and distributed energy resources, and ancillary services from demand response, distributed energy resources, and energy storage systems. The study estimates the present and future ancillary services available from the downstream grid to the upstream network. A thorough analysis of network and market interactions clearly shows the potential benefits of ancillary services provided by the active distribution network to the transmission network.

Key recommendations from this **Task WP3.12 Modelling and Assessment of Integrated System Performance and Technical Implications** for future works are as follows –

- Develop the network representation model by considering transient behaviours.
- Consider uncertainties in producing a more comprehensive representative model.
- Consider natural phenomena (such as wildfire, flood, and windstorm) and the associated resiliency models to produce resiliency-oriented representative frameworks.
- Refining 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.

Appendix

Appendix A:

User Manual: Ancillary Service Calculation

1. Run the Ancillary service calculator using the main_new.exe file. Wait until the graphical user interface opens.

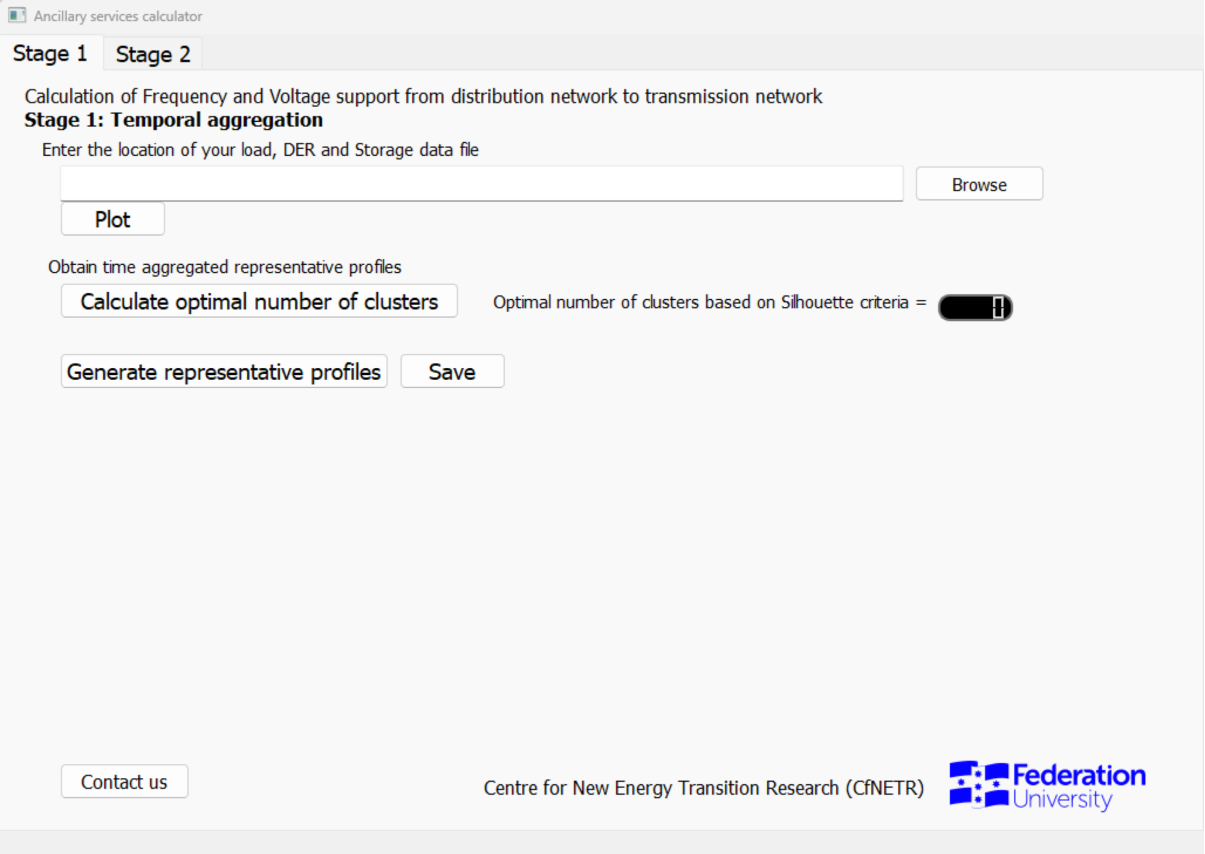
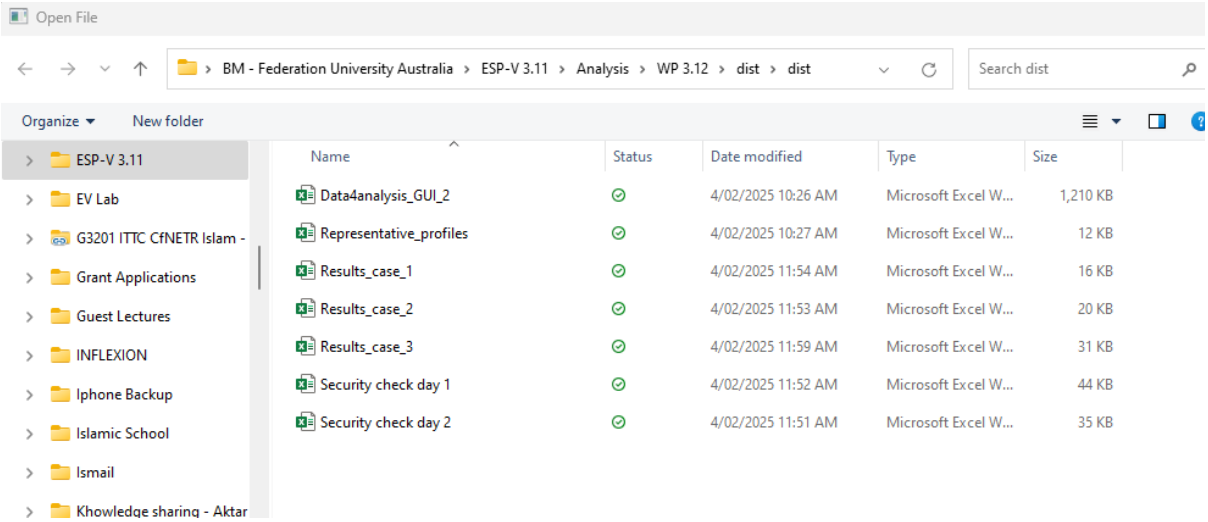


Figure: User interface – stage one

Stage 1:

1. Now in the stage 1 GUI, click “Browse” to select the excel file for the time series data file.



2. The tool is capable to work with any time resolution data. However, in our study, the resolution of time series is half-hour. Thus, we have used complete 48 instances of selected days. All time series profiles should have the same number of instances.

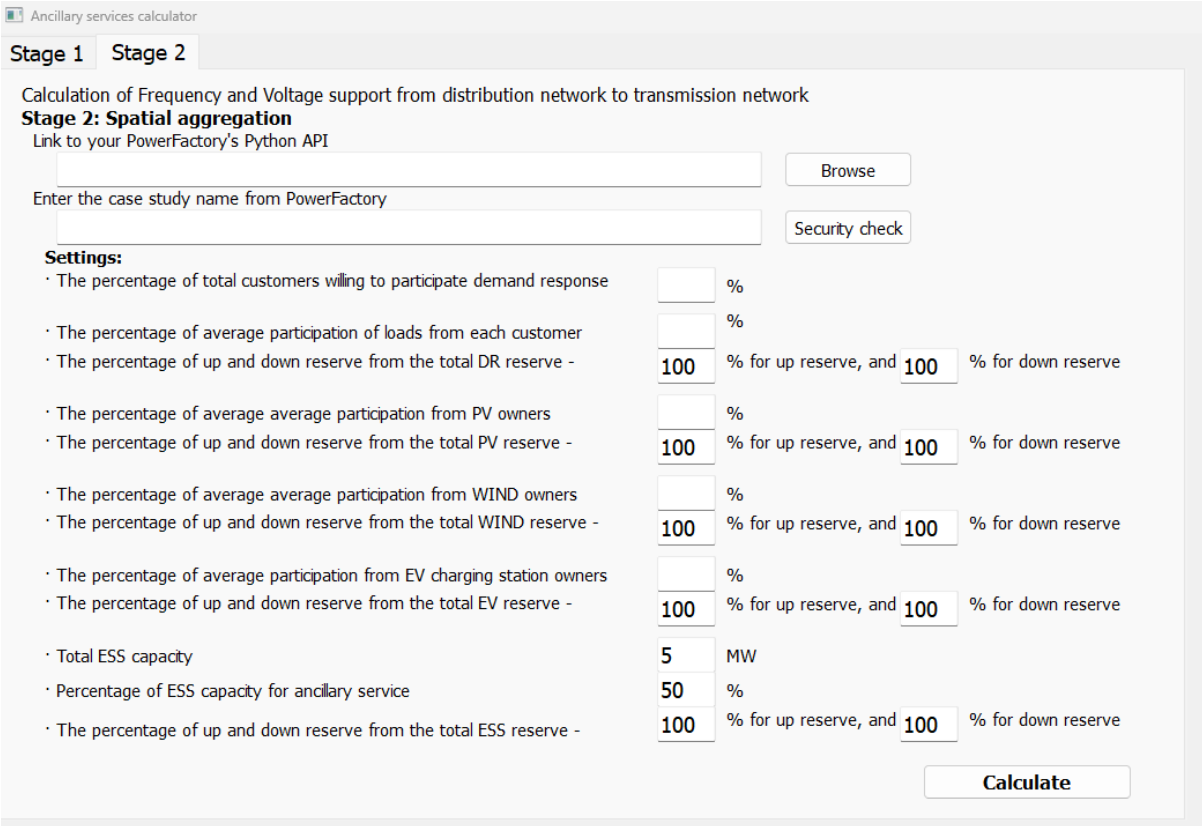
Demand - 2035	PV	Wind	EV
15.11	0.00	2.50	0.684552996
15.11	0.00	2.73	0.529624352
14.66	0.00	3.11	0.530403106
13.09	0.00	3.49	0.646004707
11.76	0.00	3.82	0.528787914
11.55	0.00	4.15	0.379714342
10.83	0.00	4.38	0.271626268
10.08	0.00	4.62	0.233222193
9.70	0.00	4.71	0.232602074
9.61	0.00	4.81	0.232270383
9.80	0.00	4.80	0.214272529

Figure: excel file format

3. Now click the ‘plot’ button to plot all the time series – Demand, PV, Wind and EV.
4. Click the ‘calculate optimal number of clusters’ button to identify the optimal cluster number using Silhouette criteria.
5. Click ‘Generate Representative Profiles’ to generate representative profiles.
6. Click ‘Save’ to save representative profiles in Excel file format. The files will be saved in the same folder where the main_new.exe file is.

Stage 2:

1. Click ‘Stage 2’ to open the GUI for stage 2.

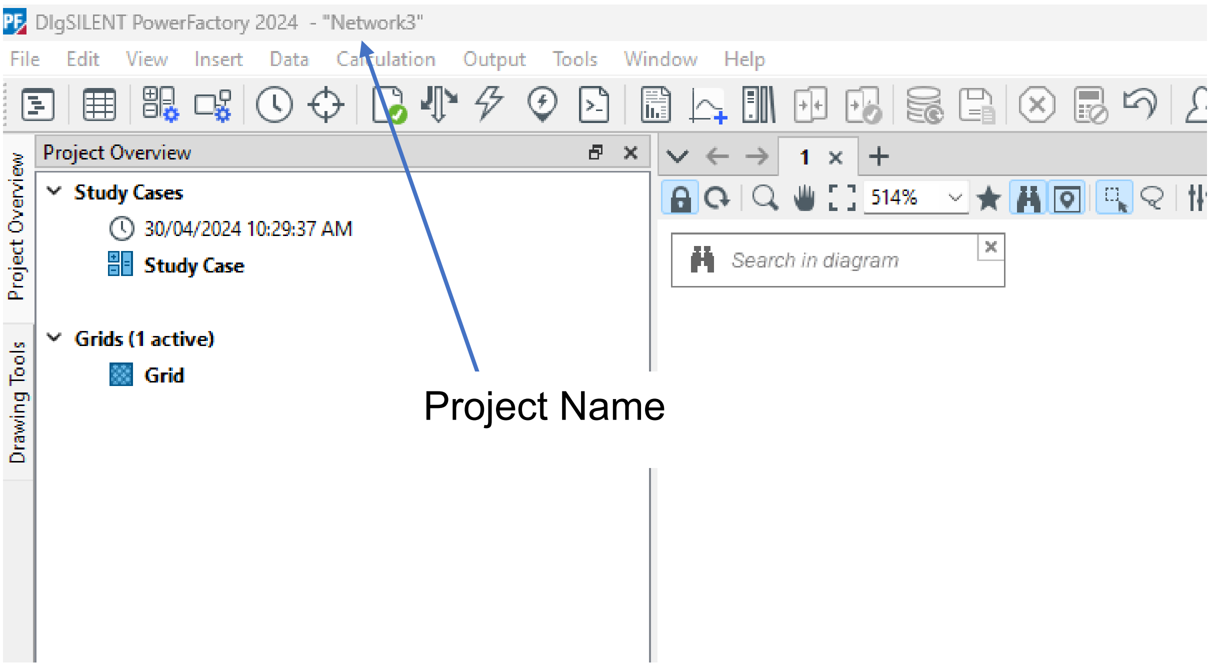


2. Click ‘Browse’ to select the PowerFactory’s API.

An example path is provided below. The actual path may vary from user to user.

C:\Program Files\DIgSILENT\PowerFactory 2024 SP5A\Python\3.9

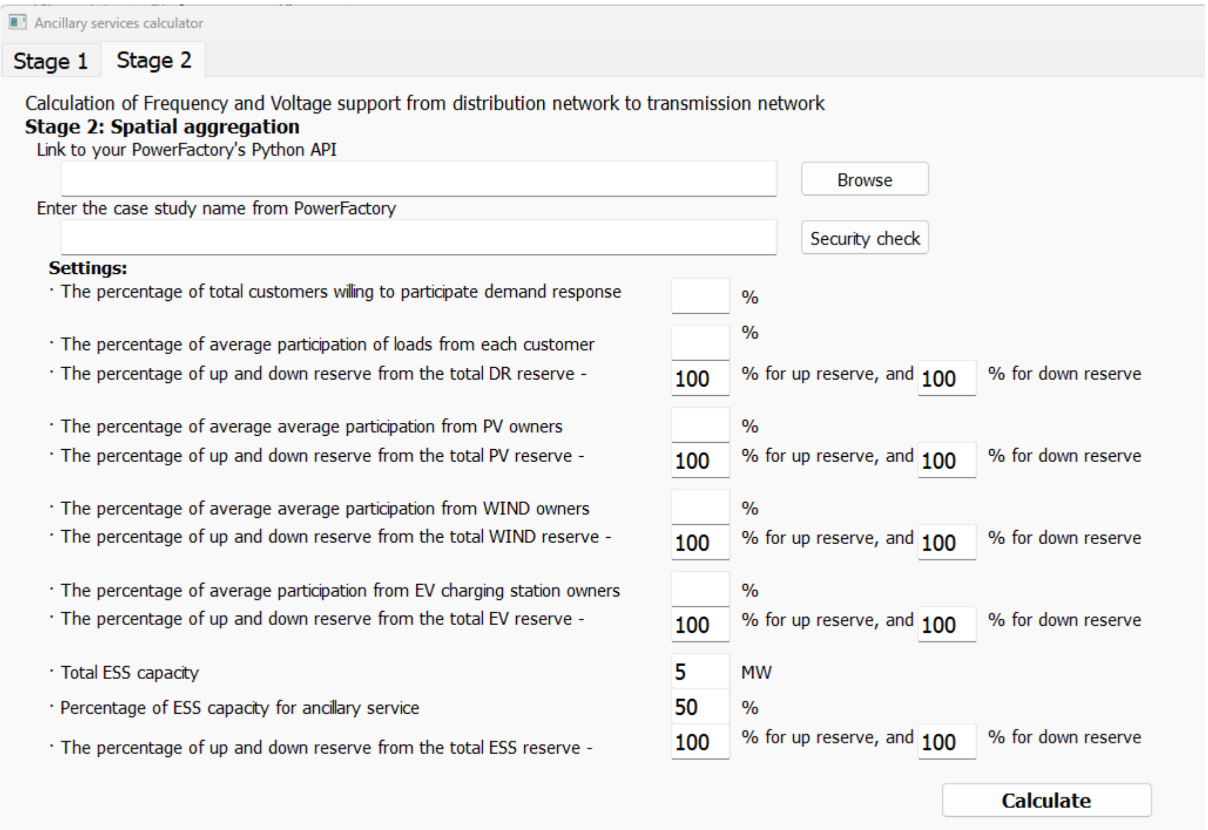
3. Before the security check write the project name of the PowerFactory network file.



4. Click the 'Security Check' button. The network security for all representative snapshots will be performed and the results will be saved in Excel files to the same directory. If there is any security violation i.e., bus over/under voltage, and/or line overloading, the number of violations will be counted in the Excel file. If the user still wants to proceed with the ancillary service estimation, he/she should complete the settings and click the 'calculate' button.
5. Settings:
    - The percentage of total customers willing to participate in demand response
        - Mention the percentage of the total customers willing to participate in demand response, i.e., 40% of the total customers.
    - The percentage of average participation of loads from each customer
        - This value is the average load participation from each customer to demand response, i.e., 30% of the load from each DR participant customer.
    - The percentage of up and down reserve from the total DR reserve
        - 100% up and down reserve means that 100% of DR loads will be used for AS. The user can vary this amount to retain the network security.
    - The average participation from PV owners
        - This value is the amount of AS committed to DNSP from the PV owner, i.e., 30%.
    - The percentage of up and down reserve from the total PV reserve
        - 100% up and down reserve means that 100% of the PV reserve will be used for AS. The owner/regulator can vary this amount to retain the network security.
    - The average participation from Wind owners
        - This value is the amount of AS committed to DNSP from the Wind owner, i.e., 30%.
    - The percentage of up and down reserve from the total Wind reserve
        - 100% up and down reserve means that 100% of Wind reserve will be used for AS. The owner/regulator can vary this amount to retain the network security.
    - The average participation from EV stations
        - This value is the amount of AS committed to DNSP from the EV stations, i.e., 10%.
    - The percentage of up and down reserve from the total EV stations reserve
        - 100% up and down reserve means that 100% of EV station storage will be used for AS. The owner/regulator can vary this amount to retain the network security.
    - Percentage of ESS capacity for ancillary service
        - This is the amount of energy storage reserve for ancillary service. The other amount can be dedicated to reliability or other commitments, i.e., 50%.

- The owner/regulator can vary this amount to retain the network security or save the battery life cycle.

6. Click ‘calculate’ to calculate the estimated ancillary services for the provided settings. The user may vary the settings to observe the AS available from the network.



Appendix B:

Network and Market Interaction Analysis

Ancillary services are essential to maintain system security, reliability and supplies of electricity at acceptable quality. The focus on ancillary services is increasing due to high penetrations of renewables connecting to the national grid which has natural output fluctuations.

The National Electricity Market (NEM) ancillary services can broadly categorise as –

- Frequency Control Ancillary Services (FCAS).
- Network Support & Control Ancillary Services (NSCAS). or
- System Restart Ancillary Services (SRAS)

Appendix B.1:

Frequency Control Ancillary Services (FCAS)

FCAS are used by AEMO to maintain the frequency of the electrical system, NSCAS are primarily used to control the voltage at different points of the electrical network, control the power flow of the network element and maintain transient and oscillatory stability following major power system events. SRAS is reserved for contingency situations in which there has been a complete or partial system blackout, and the electrical system must be restarted. Some of the ancillary services are managed through the open market such as FCAS and others are maintained through contracts between AEMO and service providers.

Like the electricity spot market, there is a market for ancillary services. Similar to the spot market for energy, generators (and loads) can offer ancillary services and AEMO dispatches them. The cost of this ancillary service is then distributed among the customers based on the 'causer pay' principle. The integration of DERs and storage devices brought the opportunity for distribution network operators to aggregate these resources and provide ancillary services to the transmission network. The total payment made for ancillary services in 2024 is $135m. The ancillary service payments in Victoria from the last few years are presented in Figure 123. A customer or aggregated customers can register as a demand response service provider (DRSP) in the National Electricity Market. A DRSP can classify plants at market connection points as ancillary service units (ASU) or qualifying load as wholesale demand response units (WDRU) (https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/participate-in-the-market/registration/register-as-a-drsp).

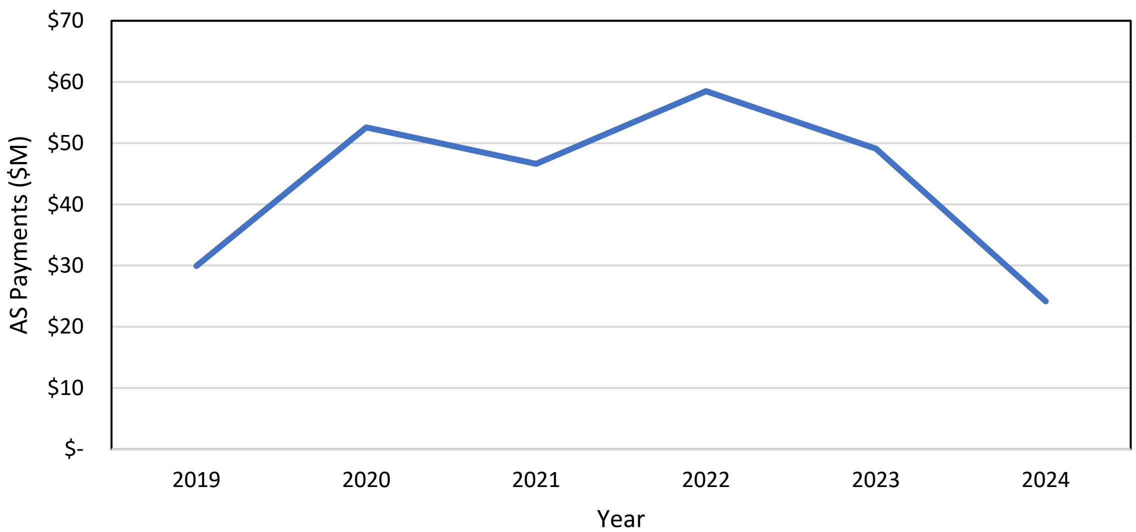


Figure 123 Ancillary services payments [46].

The average quarterly average prices for each global FCAS service across the NEM for the past five years are presented in **Error! Reference source not found.**. These include average prices for both raise and lower regulation services and raise and lower contingency services (fast - 6 seconds, slow - 60 seconds, delayed - 5 minutes) (https://www.aer.gov.au/industry/registers/charts/quarterly-global-fcas-prices-services). The volume-weighted FCAS prices of a single day in NEM are presented in Figure 125.

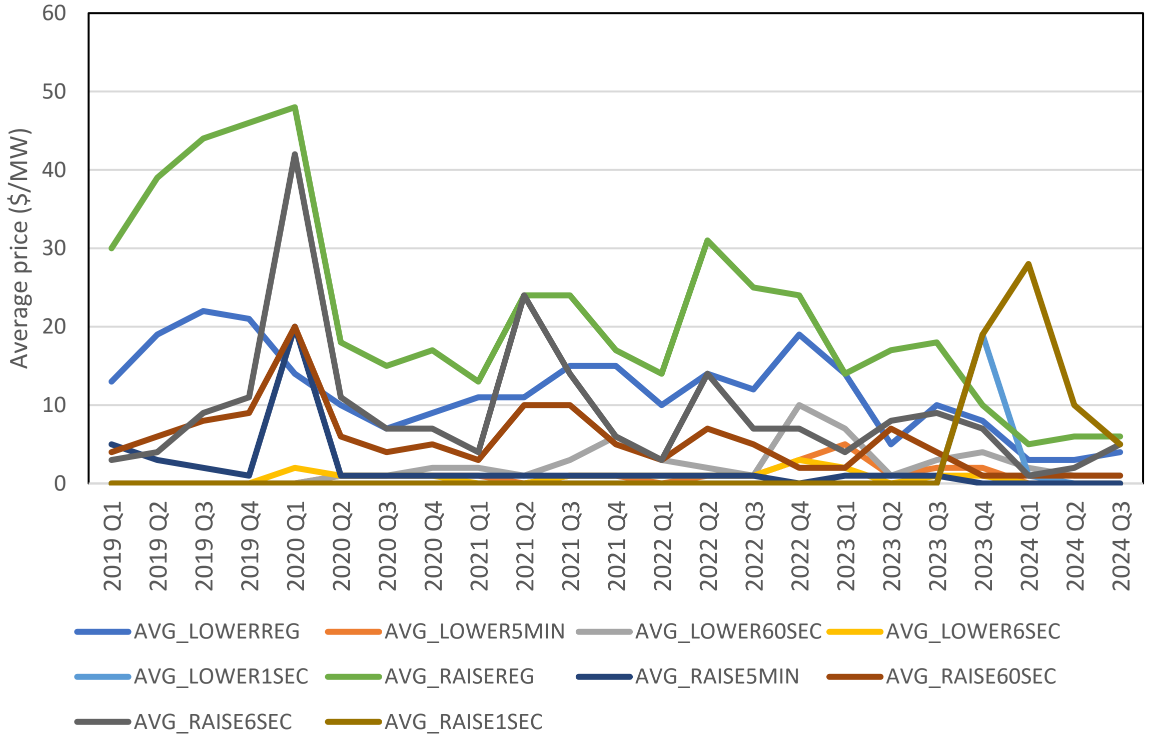


Figure 124 Quarterly average prices for each global FCAS service across the NEM for the past five years..

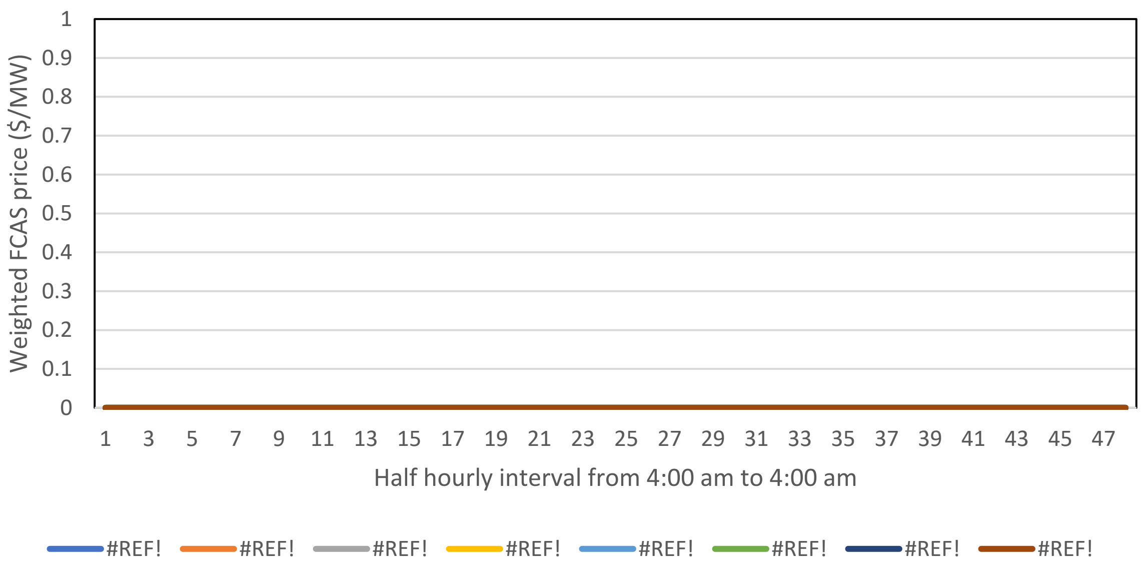


Figure 125 Volume Weighted FCAS Prices for 8 December 2024 [44].

Regulation FCAS

Regulation FCAS is provided by generators on Automatic Generation Control (AGC) [42]. The AGC system allows AEMO to monitor System Frequency, time error and FCAS Facility output at all times.

The AEMO sends control signals to AGC through SCADA (on a regular cycle, such as every 4 s) to deliver Regulation FCAS to alter the controlled MW output of generating units or electricity consumption of loads to assist with correcting the demand/supply imbalance. There are eight markets in the NEM for procuring sufficient FCAS at any given time. The regulation of FCAS markets are:

- Regulation Raise: Regulation service used to correct a minor drop in frequency.
- Regulation Lower: Regulation service used to correct a minor rise in frequency.

Contingency FCAS

Under the NEM frequency standards AEMO must ensure that, following a credible contingency event, the frequency deviation remains within the contingency band and is returned to the normal operating band within five minutes. The contingency markets are -

- Fast Raise (6-Second Raise): 6-second response to arrest a major drop in frequency following a contingency event.
- Fast Lower (6-Second Lower): 6-second response to arrest a major rise in frequency following a contingency event.
- Slow Raise (60-Second Raise): 60-second response to stabilise frequency following a major drop in frequency.
- Slow Lower (60 Second Lower): 60-second response to stabilise frequency following a major rise in frequency.
- Delayed Raise (5-Minute Raise): 5-minute response to recover frequency to the normal operating band following a major drop in frequency.
- Delayed Lower (5 Minute Lower): 5-minute response to recover frequency to the normal operating band following a major rise in frequency.

A summary of the requirements to participate in the FCAS market is presented below –

- The MW quantity in each price band in each trading interval must be specified in whole MW;
- the market ancillary service offer must include the following values:
    - the response breakpoint.
    - the upper and lower enablement limits; and
    - the response capability.
- FCAS Providers must ensure they have sufficient headroom or footroom and operate their equipment in accordance with NER 4.9.3A(c) so that their FCAS Facilities can deliver FCAS in response to a dispatch instruction immediately following enablement by AEMO.
- Where an Aggregated FCAS Facility is used, the reservation of headroom or footroom applies to the Aggregated FCAS Facility only.
- The Generation Amount or Load Amount must be measured at, or close to, each relevant connection point and summed to calculate the Aggregated Generation Amount or Aggregated Load Amount.

Appendix B.2:

Network Support and Control Ancillary Service (NSCAS)

VCAS is provided to control voltages on the system. Generators absorb or generate reactive from or onto the electricity grid and control the local voltage accordingly. The VCAS can categorised as follows -

- Synchronous Condenser: A generating unit that can generate or absorb reactive power while not generating energy in the market.
- Static Reactive Plant: Equipment such as capacitors or reactors that can supply or absorb reactive power.

According to NER 3.11.1(c), VCAS is considered as one of the non-market ancillary services.

Appendix C:
Network and Market Interaction Analysis

NER 3.11.2(a) specifies that there are ten different types of FCAS. They are -

<table>
<tr><th>Type</th><th>NER Term</th><th>Commonly Referred to as…</th><th>Group</th><th>Description</th><th>Key Purpose</th><th>Usually Facilitated by…</th></tr>
<tr><td rowspan="6">Contingency FCAS</td><td>Fast raise service</td><td>6-Second Raise FCAS</td><td rowspan="2">Fast FCAS</td><td>A rapid increase in generation or a decrease in load in response to decreases in Local Frequency.</td><td rowspan="2">To arrest a change in System Frequency following a contingency event that takes it outside the NOFB within the first 6 s of a Frequency Disturbance and then provide an orderly transition to a Slow FCAS.</td><td>• Governor or governor-like control systems
• Frequency relay detecting a frequency deviation and starting a fast generating unit or disconnecting load.
• Rapid change in charging or discharging from batteries.</td></tr>
<tr><td>Fast lower service</td><td>6-Second Lower FCAS</td><td>A rapid decrease in generation or an increase in load in response to increases in Local Frequency.</td><td>• Governor or governor-like control systems.
• Frequency relay detecting a frequency deviation and reducing a generating unit's output or increasing load.</td></tr>
<tr><td>Slow raise service</td><td>60-Second Raise FCAS</td><td rowspan="2">Slow FCAS</td><td>An increase in generation or a decrease in load in response to decreases in Local Frequency.</td><td rowspan="2">To stabilise System Frequency following a contingency event within the first 60 s of a Frequency Disturbance, and then provide an orderly transition to a Delayed FCAS.</td><td>• Governor or governor-like control systems
• Frequency relay detecting a frequency deviation and reducing load.</td></tr>
<tr><td>Slow lower service</td><td>60-Second Lower FCAS</td><td>A decrease in generation or an increase load in response to increases in Local Frequency.</td><td>Governor systems on generating units.</td></tr>
<tr><td>Delayed raise service</td><td>5-Minute Raise FCAS</td><td rowspan="2">Delayed FCAS</td><td>An increase in generation or a decrease in load in response to decreases in Local Frequency.</td><td rowspan="2">To return System Frequency to 50 Hz within the first 5 min of a Frequency Disturbance, and to sustain that response until central dispatch can re-schedule generation and load to balance the power system.</td><td>Frequency relay detecting a frequency deviation starting up generating units or reducing load.</td></tr>
<tr><td>Delayed lower service</td><td>5-Minute Lower FCAS</td><td>A decrease in generation or an increase in load in response to increases in Local Frequency.</td><td>Frequency relay detecting a frequency deviation and reducing generating unit output or increasing loads.</td></tr>
<tr><td rowspan="2">Regulation FCAS</td><td>Regulating raise service</td><td>Raise Regulation FCAS</td><td rowspan="2">Regulation FCAS</td><td>Increasing generation or decreasing load relative to the Ancillary Service Facility's Reference Trajectory in response to Raise Signals to increase System Frequency.</td><td rowspan="2">To support control of System Frequency and time error in tandem with PFR in response to variations of demand and generation within a dispatch interval.</td><td rowspan="2">Setpoint controllers on generating units.</td></tr>
<tr><td>Regulating lower service</td><td>Lower Regulation FCAS</td><td>Decreasing generation or increasing load relative to the Ancillary Service Facility's Reference Trajectory in response to Lower Signals to reduce System Frequency.</td></tr>
</table>

Source: AEMO Market ancillary service specification (https://aemo.com.au/consultations/current-and-closed-consultations/mass-consultation)

REFERENCES

[1] "Electricity Network Transformation Roadmap: Final Report," CSIRO and Energy Networks Australia, April 2017. [Online]. Available: https://www.energynetworks.com.au/projects/electricity-network-transformation-roadmap/

[2] N. G. Ude, H. Yskandar, and R. C. Graham, "A Comprehensive State-of-the-Art Survey on the Transmission Network Expansion Planning Optimization Algorithms," *IEEE Access,* vol. 7, pp. 123158-123181, 2019.

[3] A. Moreira, D. Pozo, A. Street, and E. Sauma, "Reliable Renewable Generation and Transmission Expansion Planning: Co-Optimizing System's Resources for Meeting Renewable Targets," *IEEE Transactions on Power Systems,* vol. 32, no. 4, pp. 3246-3257, Jul 2017.

[4] N. Sarajpoor, L. Rakai, J. Arteaga, N. Amjady, and H. Zareipour, "Time Aggregation in Presence of Multiple Variable Energy Resources," *IEEE Transactions on Power Systems,* vol. 39, no. 1, pp. 587-601, Jan 2024.

[5] V. Vahidinasab, M. Tabarzadi, H. Arasteh, M. I. Alizadeh, M. M. Beigi, H. R. Sheikhzadeh, K. Mehran, and M. S. Sepasian, "Overview of Electric Energy Distribution Networks Expansion Planning," *IEEE Access,* vol. 8, pp. 34750-34769, 2020.

[6] N. Sarajpoor, L. Rakai, N. Amjady, and H. Zareipour, "Generalizing Time Aggregation to Out-of-Sample Data Using Minimum Bipartite Graph Matching for Power Systems Studies," *IEEE Transactions on Power Systems,* vol. 39, no. 3, pp. 5352-5365, May 2024.

[7] W. Dai, J. Yu, X. Liu, and W. Y. Li, "Two-Tier Static Equivalent Method Of Active Distribution Networks Considering Sensitivity, Power Loss And Static Load Characteristics," *International Journal of Electrical Power & Energy Systems,* vol. 100, pp. 193-200, Sep 2018.

[8] X. Y. Shang, Z. G. Li, J. H. Zheng, and Q. H. Wu, "Equivalent Modeling Of Active Distribution Network Considering The Spatial Uncertainty Of Renewable Energy Resources," *International Journal of Electrical Power & Energy Systems,* vol. 112, pp. 83-91, Nov 2019.

[9] Y. X. Liu, R. Sioshansi, and A. J. Conejo, "Hierarchical Clustering to Find Representative Operating Periods for Capacity-Expansion Modeling," *IEEE Transactions on Power Systems,* vol. 33, no. 3, pp. 3029-3039, May 2018.

[10] L. Aththanayake, N. Hosseinzadeh, A. Gargoom, and H. H. Alhelou, "Power System Reduction Techniques For Planning And Stability Studies: A Review," *Electric Power Systems Research,* vol. 227, Feb 2024.

[11] S. Dehghan, N. Amjady, and P. Aristidou, "A Robust Coordinated Expansion Planning Model For Wind Farm-Integrated Power Systems With Flexibility Sources Using Affine Policies," *IEEE Systems Journal,* vol. 14, no. 3, pp. 4110-4118, Sept 2020.

[12] S. Dehghan, N. Amjady, and A. J. Conejo, "A Multistage Robust Transmission Expansion Planning Model Based on Mixed Binary Linear Decision Rules-Part I," *IEEE Transactions on Power Systems,* vol. 33, no. 5, pp. 5341-5350, Sep 2018.

[13] H. B. Antony Zegers, "TSO-DSO Interaction: An Overview of Current Interaction between Transmission and Distribution System Operators and An Assessment of Their Cooperation in Smart Grids," ISGAN: International Smart Grid Action Network, 2014.

[14] G. C. Kryonidis, M. E. Tsampouri, K. N. D. Malamaki, and C. S. Demoulias, "Distributed methodology for reactive power support of transmission system," *Sustainable Energy Grids & Networks,* vol. 31, Sep 2022.

[15] N. Savvopoulos, T. Konstantinou, and N. Hatziargyriou, "TSO-DSO Coordination in Decentralized Ancillary Services Markets," *2019 2nd International Conference on Smart Energy Systems and Technologies (Sest 2019),* 2019.

[16] S. Karagiannopoulos, J. Gallmann, M. G. Vayá, P. Aristidou, and G. Hug, "Active Distribution Grids Offering Ancillary Services in Islanded and Grid-Connected Mode," *IEEE Transactions on Smart Grid,* vol. 11, no. 1, pp. 623-633, Jan 2020.

[17] D. Xie, M. B. Liu, L. X. Xu, and W. T. Lu, "Generalized Nash Equilibrium Analysis Of Transmission And Distribution Coordination In Coexistence Of Centralized And Local Markets," *International Journal of Electrical Power & Energy Systems,* vol. 137, May 2022.

[18] S. Karagiannopoulos, C. Mylonas, P. Aristidou, and G. Hug, "Active Distribution Grids Providing Voltage Support: The Swiss Case," *IEEE Transactions on Smart Grid,* vol. 12, no. 1, pp. 268-278, Jan 2021.

[19] I. I. Avramidis, F. Capitanescu, V. A. Evangelopoulos, P. S. Georgilakis, and G. Deconinck, "In Pursuit of New Real-Time Ancillary Services Providers: Hidden Opportunities in Low Voltage Networks and Sustainable Buildings," *IEEE Transactions on Smart Grid,* vol. 13, no. 1, pp. 429-442, Jan 2022.

[20] F. Capitanescu, "TSO-DSO interaction: Active Distribution Network Power Chart For TSO Ancillary Services Provision," *Electric Power Systems Research,* vol. 163, pp. 226-230, Oct 2018.
[21] I. G. Marneris, A. V. Ntomaris, P. N. Biskas, C. G. Baslis, D. I. Chatzigiannis, C. S. Demoulias, K. O. Oureilidis, and A. G. Bakirtzis, "Optimal Participation of RES Aggregators in Energy and Ancillary Services Markets," *IEEE Transactions on Industry Applications,* vol. 59, no. 1, pp. 232-243, Jan 2023.
[22] G. Coletta, A. Laso, G. M. Jónsdóttir, M. Manana, D. Villacci, A. Vaccaro, and F. Milano, "On-Line Control of DERs to Enhance the Dynamic Thermal Rating of Transmission Lines," *IEEE Transactions on Sustainable Energy,* vol. 11, no. 4, pp. 2836-2844, Oct 2020.
[23] T. Jiang, Z. W. Shen, X. L. Jin, R. F. Zhang, A. Parisio, X. Li, and X. Kou, "Solution to Coordination of Transmission and Distribution for Renewable Energy Integration into Power Grids: An Integrated Flexibility Market," *Csee Journal of Power and Energy Systems,* vol. 9, no. 2, pp. 444-458, Mar 2023.
[24] E. O. Kontis, A. R. del Nozal, J. M. Mauricio, and C. S. Demoulias, "Provision of Primary Frequency Response as Ancillary Service From Active Distribution Networks to the Transmission System," *IEEE Transactions on Smart Grid,* vol. 12, no. 6, pp. 4971-4982, Nov 2021.
[25] F. Escobar, J. M. Víquez, J. García, P. Aristidou, and G. Valverde, "Coordination of DERs and Flexible Loads to Support Transmission Voltages in Emergency Conditions," *IEEE Transactions on Sustainable Energy,* vol. 13, no. 3, pp. 1344-1355, Jul 2022.
[26] A. Majzoobi and A. Khodaei, "Application of microgrids in providing ancillary services to the utility grid," *Energy,* vol. 123, pp. 555-563, Mar 15 2017.
[27] T. Q. Zhao, A. Parisio, and J. V. Milanovic, "Distributed Control Of Battery Energy Storage Systems In Distribution Networks For Voltage Regulation At Transmission-Distribution Network Interconnection Points," *Control Engineering Practice,* vol. 119, Feb 2022.
[28] G. Valverde, D. Shchetinin, and G. Hug-Glanzmann, "Coordination of Distributed Reactive Power Sources for Voltage Support of Transmission Networks," *IEEE Transactions on Sustainable Energy,* vol. 10, no. 3, pp. 1544-1553, Jul 2019.
[29] A. Singhal and V. Ajjarapu, "A Framework to Utilize DERs' VAR Resources to Support the Grid in an Integrated T-D System," *2018 IEEE Power & Energy Society General Meeting (Pesgm),* 2018.
[30] H. H. Chen, H. Y. Li, C. Q. Lin, X. L. Jin, R. F. Zhang, and X. Li, "An Integrated Market Solution To Enable Active Distribution Network To Provide Reactive Power Ancillary Service Using Transmission-Distribution Coordination," *Iet Energy Systems Integration,* vol. 4, no. 1, pp. 98-115, Mar 2022.
[31] Y. L. Ji, Q. S. Xu, and L. Sun, "Distributed Robust Dispatch For The Coordination Of Transmission And Distribution Systems Considering Air Conditioning Loads," *International Journal of Electrical Power & Energy Systems,* vol. 148, Jun 2023.
[32] J. H. Eto, J. Nelson-Hoffman, E. Parker, C. Bernier, P. Young, D. Sheehan, J. Kueck, and B. Kirby, "The Demand Response Spinning Reserve Demonstration--Measuring the Speed and Magnitude of Aggregated Demand Response," in *2012 45th Hawaii International Conference on System Sciences*, 4-7 Jan. 2012 2012, pp. 2012-2019.
[33] A. H. Nebey, "Recent Advancement In Demand Side Energy Management System For Optimal Energy Utilization," *Energy Reports,* vol. 11, pp. 5422-5435, Jun 2024.
[34] "Demand response - Australian Renewable Energy Agency (ARENA)." https://arena.gov.au/renewable-energy/demand-response/.
[35] G. Morales-España, R. Martínez-Gordón, and J. Sijm, "Classifying And Modelling Demand Response In Power Systems," *Energy,* vol. 242, Mar 1 2022.
[36] G. M. Starke, C. Meneveau, J. King, and D. F. Gayme, "Yaw-Augmented Control for Wind Farm Power Tracking," *2023 American Control Conference, Acc,* pp. 184-191, 2023.
[37] J. Aho, A. Buckspan, J. Laks, P. Fleming, Y. Jeong, F. Dunne, M. Churchfield, L. Pao, and K. Johnson, "A Tutorial of Wind Turbine Control for Supporting Grid Frequency through Active Power Control," *2012 American Control Conference (Acc),* pp. 3120-3131, 2012.
[38] H. P. H. Saboori, S. Dehghan, G. Strbac, N. Amjady, D. Novosel, V. Terzija, "Reactive Power Implications of Penetrating Inverter-based Renewable and Storage Resources in Future Grids Towards Energy Transition – A Review," *Proceedings of the IEEE,* 2025.
[39] N. Savvopoulos, C. Y. Evrenosoglu, T. Konstantinou, T. Demiray, and N. Hatziargyriou, "Contribution of Residential PV and BESS to the Operational Flexibility at the TSO-DSO

Interface," *2021 International Conference on Smart Energy Systems and Technologies (Sest),* 2021.
[40] M. Kazemi, H. Zareipour, N. Amjady, W. D. Rosehart, and M. Ehsan, "Operation Scheduling of Battery Storage Systems in Joint Energy and Ancillary Services Markets," *IEEE Transactions on Sustainable Energy,* vol. 8, no. 4, pp. 1726-1735, Oct 2017.
[41] "Electricity demand by mode, 2023-2035 – Charts – Data & Statistics - IEA." https://www.iea.org/data-and-statistics/charts/electricity-demand-by-mode-2023-2035.
[42] "AEMO. Market Ancillary Services Specification And FCAS Verification Tool." https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/ancillary-services/market-ancillary-services-specification-and-fcas-verification-tool.
[43] "Electricity generation | energy.gov.au." https://www.energy.gov.au/energy-data/australian-energy-statistics/electricity-generation.
[44] "AEMO. Volume Weighted FCAS Prices." https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/data-nem/market-management-system-mms-data/volume-weighted-fcas-prices.
[45] "Smart TSO-DSO interaction schemes, market architectures and ICT Solutions for the integration of ancillary services from demand side management and distributed generation." https://cordis.europa.eu/project/id/691405.
[46] AEMO. "Ancillary Services Payments and Recovery." https://wa.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/data-nem/ancillary-services-data/ancillary-services-payments-and-recovery.