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

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Executive Summary

The integration of Distributed Energy Resources (DERs) is rising in Australia, and according to the Electricity Network Transformation Roadmap, it is estimated that DERs will contribute around 45% of Australia's electricity generation capacity by 2050 [1]. This 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 encouraging Distribution System Operators (DSOs) to take a more proactive approach to managing the unpredictable nature of RESs, in conjunction with the network capacity and prevailing market conditions, to achieve the flexibility required to be able to reduce traditional investments in network infrastructure. To achieve this, it is necessary to improve the cooperation between Transmission System Operators (TSOs) and DSOs. Due to the high complexity and computational burden, an equivalent model for the distribution network needs to be developed for the TSO/DSO interaction and DER services analysis, as well as network and ancillary service planning.

Task WP3.11 TSO-DSO Interface Steady-state Model of Aggregated DER as an Active Entity aims to build an equivalent steady-state model for the TSO/DSO interface for the upstream grid support. To achieve this, the key factors for distribution system equivalent representation need to be determined, and the equivalent representations of distribution systems with electrification, deep integration of renewables, and storage need to be developed. The developed model can equally apply within the distribution network, for a part of the distribution network, or at the boundary of TSO-DSO for the whole distribution network. 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 Report** (https://c4net.com.au/) of WP3.11.

In this **WP3.11 TSO-DSO Interface Steady-state Model of Aggregated DER as an Active Entity,** a new spatial and temporal system reduction methodology has been developed to provide a compact and computationally efficient equivalent model for different system planning and operation studies. Unlike the previous approaches in this domain, the proposed methodology combines time aggregation and network reduction methods to achieve a higher computational efficiency. The proposed methodology including network reduction and time aggregation can be used by Distribution Network Service Providers (DNSPs), for instance to summarise or reduce a part of their detailed network, and, more importantly, by the upper level, such as transmission network operators to incorporate distribution system model into their operation functions, for instance, Security-Constrained Unit Commitment (SCUC) and Security-Constrained Optimal Power Flow (SCOPF). Incorporating the detailed model of the distribution network into transmission operation functions can make the model very complex and even it can make the operation function of transmission networks intractable. Besides the benefit for the operation functions of DSOs and TSOs, the proposed method is more beneficial for planning activities. Its reason is that in the planning we have long term planning horizon. For example, if we consider ten-year planning horizon with our considered time resolution (half-hourly time stamp) it becomes 175,200-time intervals (10 multiplied by 17520). If we want to analyse the whole distribution network for all of these time periods, it can easily make the planning function intractable. For these reasons, the proposed methodology, using both spatial and temporal aggregation, can significantly enhance the computational efficiency of the operation and planning functions of DSOs and TSOs without compromising the accuracy of the network modelling.

The static equivalent representation of the active distribution network is considered in this work. The equivalent model can be used, for instance, for distribution network expansion planning, static security analysis, reactive power optimisation, optimal power flow analysis, load management, and reliability evaluation. In addition, it can be used for different planning and operation functions of the upstream transmission systems.

Both network reduction and time aggregation methods are combined in this work. Since the detailed models of distribution networks in real-time may be challenging to obtain due to insufficient measurement equipment, several network reduction methods have been reviewed in the literature, for instance, Ward, REI, and Regional equivalent method. In this work, Ward methodology has been selected due to its higher accuracy and higher robustness. 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– Case 1: With only load and with no DERs and storage; Case 2: With load and DERs and Case 3: With load, DERs, and storage. Case 2 and Case 3 are further divided two cases. A snapshot-by-snapshot 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 steady-state network reduction 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. The accuracy of the non-linear AC power flow for the reduced network, compared to the original network, is analysed. The developed method provides reduced representative networks with zero or negligible error for all three networks and all three cases.

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.

- Our proposed methodology can reduce a large distribution network to a network in the range of three to five buses which can significantly decrease the computational burden and make the whole transmission-distribution system operation/planning problem tractable.
- AEMO and transmission system operators can better analyse the whole network including the transmission and distribution systems.
- DNSPs will benefit as their representative networks are included in the upstream transmission network analysis instead of replacing their network with just an aggregated load. As a result, the characteristics, conditions, and impacts of the DNSPs' networks are considered in the upstream grid planning and operation and better operating conditions for the whole transmission-distribution system can be planned.
- The proposed method shows zero error or very negligible error at the point of common coupling (PCC) in the reduced network with respect to the original network.

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 doesn't consider dynamic or transient behaviours,
- The network analysis does not include the network maintenance activities and abnormal events like natural phenomena (such as wildfire, flood, and windstorm) because of the lack of available network topology, load profiles, and renewable generations' data as well as natural phenomena data. However, the developed methodology can be applied for the periods of maintenance activities and abnormal phenomena given that the above-mentioned data are available.
- The uncertainties of the renewable generations are not considered due to the lack of their distributional data.

BENEFITS OF THIS PROJECT FOR DIFFERENT STAKEHOLDERS:

Transmission and distribution networks are physically connected (from the circuit theory point of view, they are essentially one circuit). Thus, to run power system operation planning functions, such as SCUC, we need to consider transmission and distribution networks. However, incorporating distribution networks into a transmission system can easily make this operation planning functions intractable due to the large size of distribution networks, which can easily reach hundreds or even thousands of buses. Our proposed methodology can replace a very large distribution network in the range of hundreds or thousands of buses with an equivalent network in the range of 3-5 buses to make power system operation and operation planning functions, considering both transmission and distribution networks, tractable. This is a key advantage for both transmission-level stakeholders, like AEMO, and national network service providers.

For power system planning, the problem of scalability and the problem of tractability become even more critical and complicated. In addition to the operation problems, the developed methodology can be used for power system planning purposes.

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 [2, 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 expensive 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]. In general, regulatory factors pose significant obstacles to the development and execution of market concepts related to TSOs and DSOs [6]. Several technical challenges have yet to be resolved [13-15]. Various network codes are introduced in the European Union to establish the foundations for creating effective coordination between TSO and DSO [15]. Further investigation is required to address data sharing, operational protocols, and market design issues. This will allow TSOs and DSOs to support each other in lowering operation costs while efficiently integrating a large number of RESs. According to the research in [6], the TSO/DSO hybrid-managed model does have more administrative, computational, and technical complexity, even though it improves overall social welfare. Five strategies for TSO and DSO collaboration for planning are reported in [14]. These include regional ancillary service (AS) markets, local AS markets, shared balancing responsibility models, and AS markets for TNs and ADNs. The authors in [14] reported that the business procedures and communication infrastructure must be updated for RES integration, irrespective of the coordination models. The technical viability and obstacles of these conceptual models have been evaluated in a recent review [13]. The work in [16] has focused on the financial aspects of several conceptual market options. Based on a shared AS market, the TSO/DSO hybrid-managed model produced the best economic results [6]. There is a need for equivalent representative modelling of active distribution systems and transmission networks that can be used to analyse the TSO-DSO interaction and perform sensitivity analysis regarding the model generalisation capabilities with electrification scenarios. In general, a transmission network connects multiple distribution networks. The size of the distribution network can be quite large due to the presence of loads, branches, and DERs. Analysing a transmission system with its connected distribution networks with their detailed network models can be computationally challenging and even infeasible due to the convergence and information exchange issues [6, 8]. Adopting compact representative networks offers a promising avenue for substantially reducing computational demands. A common approach to mitigate these computational problems is simplifying the planning models through temporal aggregation [7]. This involves examining models over a chosen subset of representative time periods instead of the entire planning timeframe [9]. To accomplish this, it is crucial to carefully choose a smaller set of representative time periods that accurately reflect the temporal variations in renewable generations and demand data while also accounting for the geographical variety of renewable resources. It is important to highlight that the typical periods identified through the suggested time aggregation technique can be used as input for both deterministic and non-deterministic optimisation methods, such as stochastic programming, chance-constrained optimisation, and robust optimisation [11, 12].

To address these challenges, the following key objectives are identified and addressed in this **WP3.11 TSO-DSO Interface Steady-state Model of Aggregated DER as an Active Entity -**

+ Review existing literature on TSO-DSO interactions.
+ Determine the key factors for distribution system equivalent representation.
+ Develop the DERs and load capability/flexibility aggregation for the distribution system's equivalent representation.
+ Develop a step-by-step method for an equivalent representation of the active distribution network.
+ Develop equivalent representations of distribution systems with electrification, deep integration of renewables, and storage.

An extensive review of the existing literature on TSO-DSO interactions has been performed and presented in **Project Deliverable 1: Literature Review**. In this **WP3.11 TSO-DSO Interface Steady-state Model of Aggregated DER as an Active Entity**, a step-by-step method for an equivalent representation of the active distribution network is developed. The developed method includes both spatial and temporal system reduction methodology to provide a compact and computationally efficient model for different system planning and operational studies. The developed method has been tested on three real MV networks in Victoria for different current and illustrative cases considering Distributed Energy Resources (DERs), Battery Energy Storage Systems (BESSs), and Electricity Vehicles (EVs).

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.

- 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.

The rest of the report is presented as follows – the developed network reduction and time aggregation methods are described in **Section 2**. The description of the selected networks and case studies are given in **Section 3** and **Section 4**. The results of the steady-state analysis of three real Victorian MV networks, are presented in **Section 5**. Finally, the report is concluded by providing final insights and recommendations in **Section 6.** The results of a long-run test for nine months are given in the **Appendix (on Version 2)**.

2. Methodology

Power system planners often extend their planning horizons over long periods, such as ten years or longer, to ensure the cost-effectiveness and reliability of their system plans, considering possible future scenarios. As more wind and solar power resources become available, industry-scale planning models become more challenging over long periods of time [4, 7]. This challenge arises from the necessity to incorporate uncertainties associated with all pertinent data at the operational level (such as uncertainties of loads and renewable generations). To mitigate these computational problems, a common approach is to simplify the planning models through temporal aggregation [4]. This involves examining models over a chosen subset of representative time periods instead of the entire planning timeframe [9]. To accomplish this, it is crucial to carefully choose a smaller set of representative time periods that accurately reflect the temporal variations in renewable generations and demand data while also accounting for the geographical variety of renewable resources. It is important to highlight that the typical periods identified through the suggested time aggregation technique can be used as input for both deterministic and non-deterministic optimisation methods, such as stochastic programming, chance-constrained optimisation, and robust optimisation [11, 12].

Network reduction techniques, commonly involving impedance computations, node/branch reductions, and finding a representative network, are prevalent in power system analysis [10, 13-15], [13], [14], [15]. However, these reductions often yield densely populated impedance matrices, potentially limiting efficiency gains [10], [13]. Equivalent networks have been found in short circuit studies due to their accurate replication of voltages and currents at remaining buses. However, they fail to approximate flows through eliminated branches [10], [13]. Consequently, the applicability of reduced networks in power system analysis is constrained, with significant discrepancies observed between flows computed using reduced networks and those from the original networks [8]. Moreover, conventional equivalent techniques yield reduced networks that are contingent upon specific operations at set points. Only the work in [8] considered the spatial behaviour of renewable generations. Moreover, the resultant models in [10], and [15] could be feasible for multiple operating conditions. This dependency poses challenges for generation expansion planning, which seeks to optimise generation configurations across various load profiles and operating conditions. Given that the network serves as an input for this planning process, it is imperative to have a network interpretation that is independent of set points.

Detailed models of distribution networks in real-time may be challenging to obtain due to insufficient measurement equipment [8]. Hence, the equivalent model of the active distribution network is significant for transmission system operators (TSO) to conduct both operation and planning studies. Conventionally, active distribution networks are represented as ZIP or exponential models with aggregated PV [6], [16]. However, due to the operating point-dependent power consumption, TSO experiences various responses from active distribution networks [16]. Therefore, the equivalent model of the active distribution network should reflect the three key features: (1) active/reactive power feedback to the transmission system, (2) characteristics of DERs, and (3) temporal and spatial behaviours of loads and DERs. However, integrating these into planning frameworks presents another hurdle, given the vast number of operation periods required for modelling and analysis. To address this issue, this **WP3.11 TSO-DSO Interface Steady-state Model of Aggregated DER as an Active Entity** employs time aggregation methods to summarise the network over time, making it more manageable to analyse. The proposed methodology combines time aggregation and network reduction methods to achieve a higher computational efficiency. This **WP3.11 TSO-DSO Interface Steady-state Model of Aggregated DER as an Active Entity** considers the static equivalent representation of the active distribution network which can be used, for instance, for distribution network expansion planning, static security analysis, reactive power optimisation, and optimal power flow analysis. In addition, it can be used for different planning and operation functions of the upstream transmission systems.

This section provides insight into network reduction and time aggregation methods. Afterwards, details of the proposed approach, which combines network reduction and time aggregation methods, will be presented. A brief description of three real Victorian MV distribution networks and cases including DERs, BESSs, and EVs used in this work package is presented at the end of this section.

2.1 Network Reduction Method

Several network reduction methods have been reviewed in the literature, for instance, Ward, REI, and Regional equivalent method. Here, the Ward methodology has been selected due to its higher accuracy and higher robustness [10], [13] as well as tests conducted by this research team. In terms of the Ward reduction method, the injected current at i^{th} bus, denoted as $\mathbf{i}(i)$, can be obtained using (1):

$$\mathbf{i}(i) = \mathbf{s}^*(i)/\mathbf{v}^*(i) \tag{1}$$

In (1), $\mathbf{s}^*(i)$ stands for the complex power and $\mathbf{v}^*(i)$ for the voltage at i^{th} bus.

The network and current vector are reduced utilizing the Gaussian reduction method [13]. Nodal equations of a power system can be described as given in (2):

$$\mathbf{Y}_{bus} \times \mathbf{v} = \mathbf{i} \tag{2}$$

In (2), $\mathbf{Y}_{bus}(n \times n)$ represents the bus admittance matrix for a network with n buses, $\mathbf{v}(n \times 1)$ represents the vector of complex voltages, and $\mathbf{i}(n \times 1)$ represents the vector of complex current injections for the network.

Modified $\mathbf{Y}_{bus}$, after reduction of the k^{th} node, yields as below:

$$\bar{Y'}_{ij} = \bar{Y}_{ij} - \frac{\bar{Y}_{ik}\bar{Y}_{kj}}{\bar{Y}_{kk}} \quad \forall i,j = 1, \dots, n; i,j \neq k \tag{3}$$

In (3), $\bar{Y'}_{ij}$ represents new $\mathbf{Y}_{bus}(n-1) \times (n-1)$ elements from the original $\mathbf{Y}_{bus}(n \times n)$; and $\bar{Y}_{ij}$ represents the original $\mathbf{Y}_{bus}(n \times n)$ elements.

The modified current vector, $\mathbf{i}$ can be presented as:

$$\mathbf{i}'(i) = \mathbf{i}(i) - \frac{\bar{Y}_{ik}}{\bar{Y}_{kk}}\mathbf{i}(k) \quad \forall i = 1, \dots, n; i \neq k \tag{4}$$

In (4), $\mathbf{i}'$ stands for the improved current injection vector.

Upon reduction, the network has r nodes with an updated bus admittance matrix of $r \times r$ dimensions. Subsequently, the revised current injection vector's dimension becomes $r \times 1$. Subsequently, the revised current vector is converted back to complex power for incorporation into load-flow solutions [17], [18], [19]. Importantly, this reduced network encapsulates the complete information of the actual power system under base case conditions.

2.2 Time Aggregation Method

The K-means clustering method has been used to obtain time-aggregated load profiles for the networks with only loads (No DERs and storage devices). However, loads, DERs (PVs and Winds), and storage devices have energy profiles with different magnitudes and frequency of variation. Using the K-means clustering method separately for the energy profiles of loads, DERs, and storage devices does not represent the profiles of representative days. Therefore, a three-step time aggregation method has been developed for cases where DERs and/or storage devices are present with loads.

K-means clustering method

The K-means clustering method originates from signal processing. It is a vector quantisation technique aimed at partitioning observations into clusters based on proximity to cluster means [20]. Each observation is assigned to the cluster with the nearest mean, resulting in the partitioning of the data space into Voronoi cells [21]. K-means clustering optimises within-cluster variances, specifically squared Euclidean distances, rather than regular Euclidean distances, which is known as the Weber problem [21]. The K-means clustering method is adopted to obtain time-aggregated clusters because it is a computationally efficient and effective clustering method widely used in power system studies.

While K-means clustering efficiently minimises squared errors, alternative methods like K-medians and K-medoids may offer better solutions for minimising regular Euclidean distances [21]. The optimal number of clusters in the load data is obtained using the Silhouette criterion. The Silhouette method, established by Belgian statistician Peter Rousseau in 1987, offers a concise means of interpreting and validating the consistency within data clusters [22]. It presents a graphical overview of how effectively each sample has been classified. The Silhouette criterion can be defined as in (5)-(7) [22]:

$$S(u) = \frac{1}{n}\sum_{i=1}^{n}\frac{b(i/u) - a(i/u)}{max\{a(i/u); b(i/u)\}}, s(u) \in [-1,1] \tag{5}$$

$$a(i/u) = \sum_{k \in \{P_i \backslash i\}} \frac{d_{ik}}{n_{P_i} - 1} \tag{6}$$

$$b(i/u) = min_{P_s \neq P_i}\{d_{iP_s}\}, d_{iP_s} = \sum_{k \in P_s} d_{ik}/n_{P_s} \quad (7)$$

where the indices i and u count the samples and clusters, respectively, n indicates the number of samples in the dataset, n_{P_i} and n_{P_s} represent the number of samples in clusters P_i and P_s, respectively, d_{ik} is the Euclidean distance between samples i and k, d_{iP_s} is the Euclidean distance between sample i and cluster P_s, $a(i/u)$ and $b(i/u)$ represent the distance of sample i with its assigned cluster (i.e., P_i) and minimum distance of sample i with other clusters upon the condition that there are u number of clusters, $S(u)$ is the value of the Silhouette criterion for the u number of clusters. More details about the Silhouette criterion can be found in [23].

The Silhouette value, ranging from -1 to +1, serves as a metric to gauge the similarity of a sample to its assigned cluster compared to the neighbouring clusters. A high Silhouette criterion value indicates strong cohesion within the sample's cluster and significant separation from neighbouring clusters, signifying a suitable clustering configuration. Conversely, a low or negative Silhouette value suggests potential issues with the clustering configuration, such as an inadequate number of clusters.

In this work, the Silhouette criterion is used to obtain the optimal number of clusters because this criterion can consider both distances within the clusters and distances between the clusters as given in (5)-(7). In addition, employing representative days yields more precise and resilient outcomes in contrast to utilising representative hours or representative weeks [4], [7], [22]. For this reason, representative days have been selected as representative periods in this work.

Three (3)-step time aggregation method

In the first step, one time series is obtained by calculating the centroid of all data sources. If any of the data sources contain negative values (i.e., energy export value), a shift transformation of that specific data series is performed using the maximum absolute negative value in the dataset. Let the dataset with negative values be $y = f(x)$ and the maximum absolute value of negative values is c. Therefore, the dataset after shift transformation will be $y_{new} = f(x) + c$.

Secondly, the K-means clustering method is used to obtain representative clusters of the centroid time series obtained from the first step. The maximum number of clusters is obtained using the Silhouette criterion.

In the third step, reverse calculations for each data source are performed using the average participation factors of data sources in the centroid time series obtained from the first step. The maximum absolute value of the negative number will be subtracted from the representative profiles of the dataset that had negative values. A step-by-step presentation of the three-step time aggregation method is presented in Figure 1.

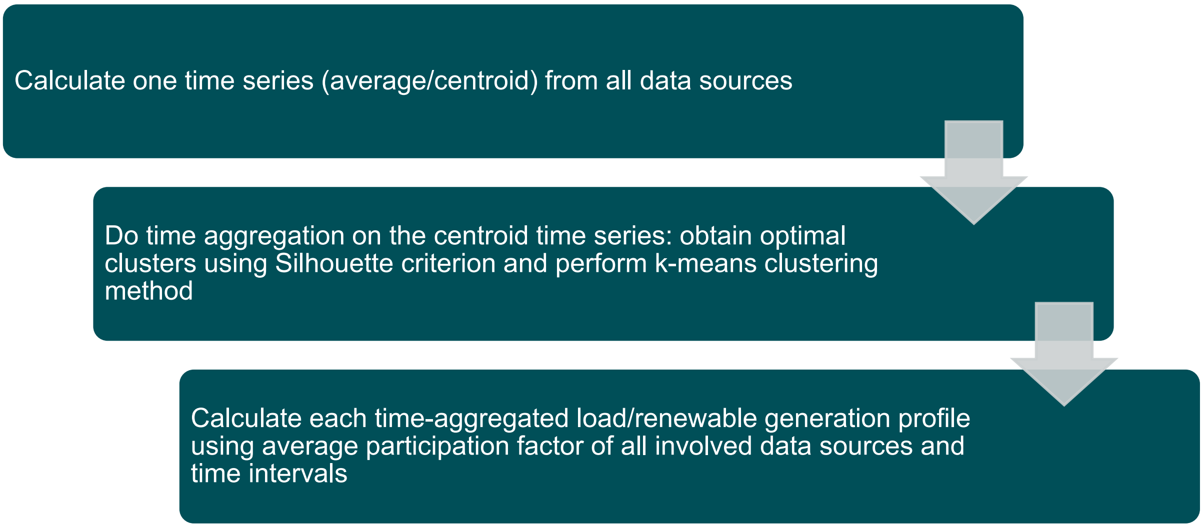

Figure 1 A step-by-step presentation of the three-step time aggregation method.

2.3 Proposed System Reduction Method

A novel system reduction method combining the spatial and temporal reduction approaches under one frame is proposed in this section to obtain a spatially and temporally aggregated representation of the actual power system. A detailed flowchart of the proposed method is given in Figure 2.

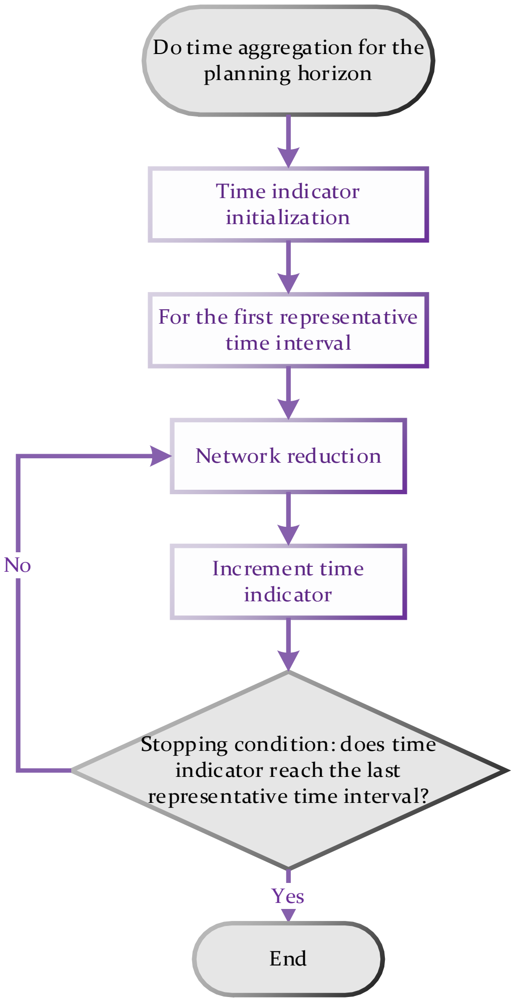

Figure 2 Flowchart of the proposed method.

To implement this proposed combined method, a snapshot-by-snapshot approach is considered. As we have a time aggregated profile, network reduction can be performed for every snapshot within this profile (every representative time interval), which implements an adaptive network reduction. By combining these two approaches, we have developed a new spatial and temporal system reduction methodology to provide a more compact and computationally efficient model compared to previous system reduction methods for different system planning and operation studies. Indeed, the proposed system reduction methodology combines the benefits of time aggregation and network reduction methods.

The networks received from Powercor have been converted into the DIgSILENT PowerFactory environment and a steady-state network power flow analysis has been performed. Then, the network steady-state operating points and network security were analysed for different loading conditions. The K-means clustering method and the three-step time aggregation methods are used to obtain time-aggregated representative days for further analysis. Among the examined network reduction methods, The Ward methodology has been selected due to its higher accuracy and higher robustness. The accuracy of the non-linear AC power flow for the original and reduced network is analysed for different cases, such as cases without DERs, with DERs, and with storage devices. An illustration of the steps to achieve reduced representative network models is presented in Figure 3.

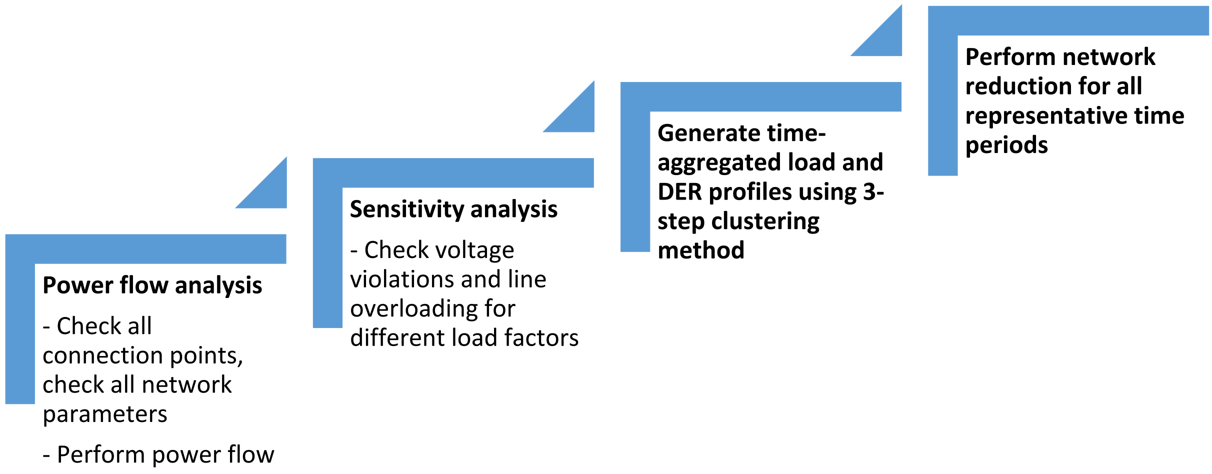

Figure 3 The steps followed to achieve reduced representative network models.

3. Network Description

Three Victorian MV distribution networks with a single operation snapshot are received from Powercor. Two networks are from the Geelong area, while one is from Ballarat. Brief descriptions of these networks are presented below-

Network 1

Network 1 is located in the Geelong area and connected to the Drysdale Zone Substation. There are a total 649 number of 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.

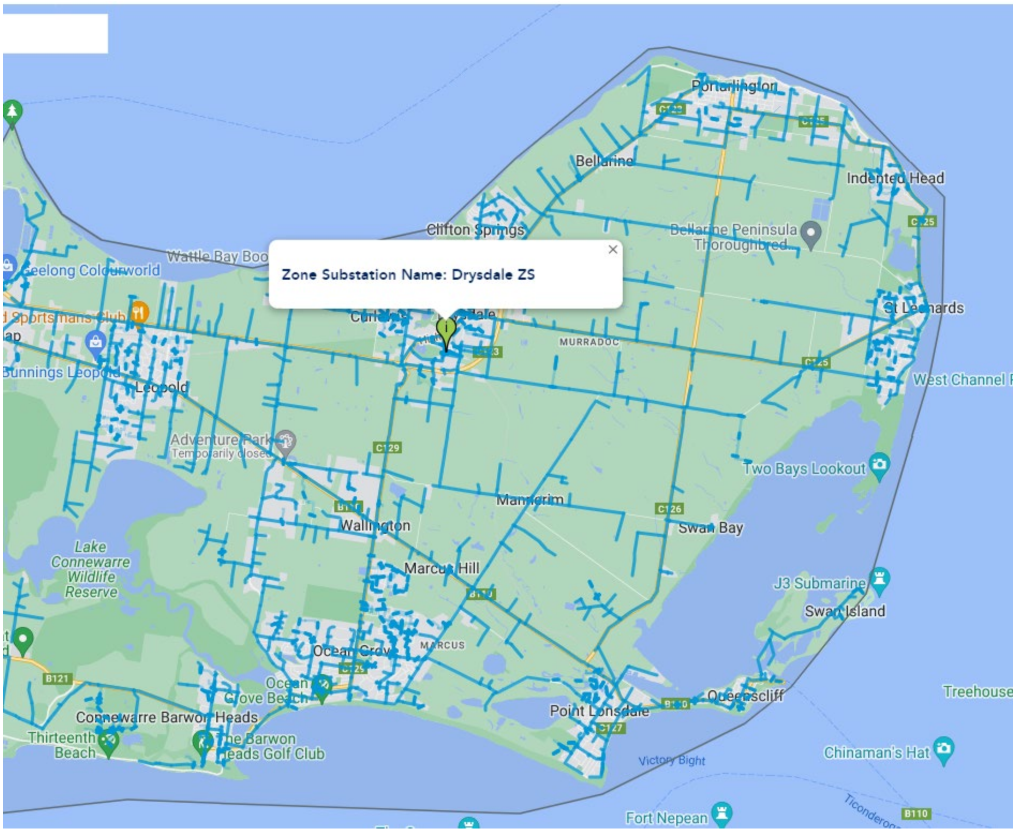

Figure 4 An aerial (Google map) view of Network 1.

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 perform to obtain the representative reduced network. An aerial (Google map) view (https://dapr.powercor.com.au/) of the network is presented in Figure 5.

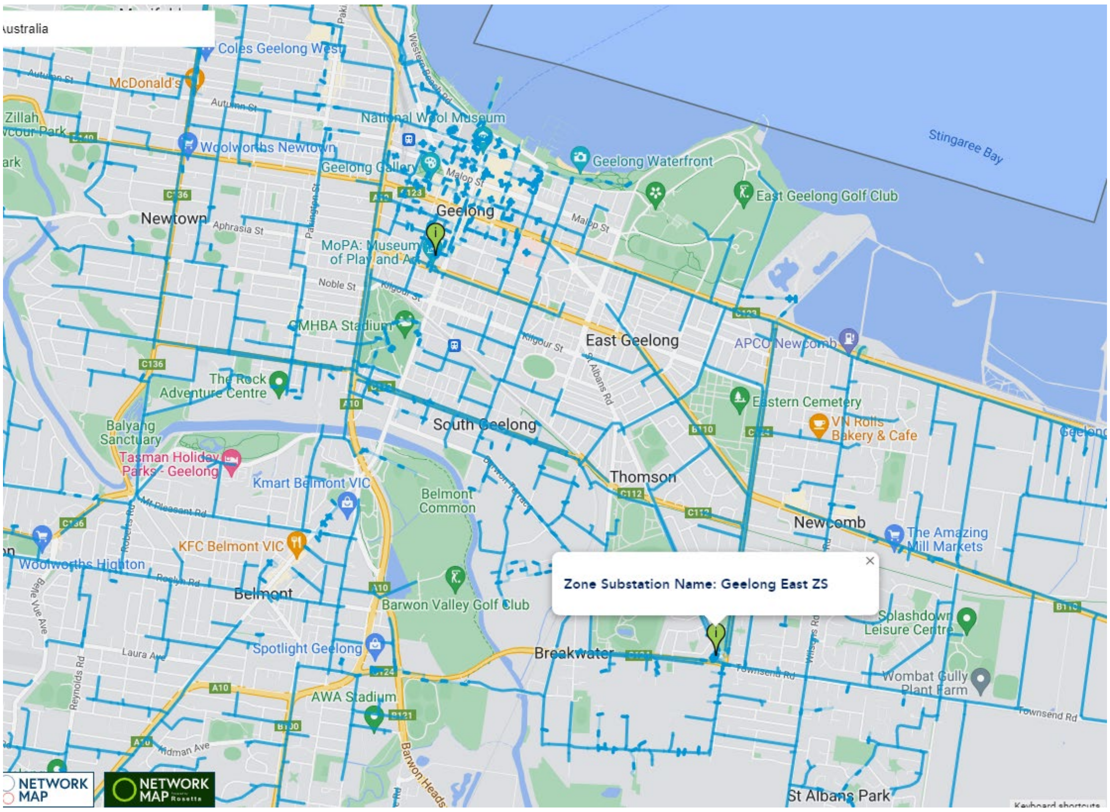

Figure 5 An aerial (Google map) view of Network 2.

Network 3

Network 3 is located in Ballarat. The network is connected to Ballarat South Zone Substation. There are 1759 buses in the network. Total 921 buses among all buses are load buses. A 6.15 MW wind farm is located in this area (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.

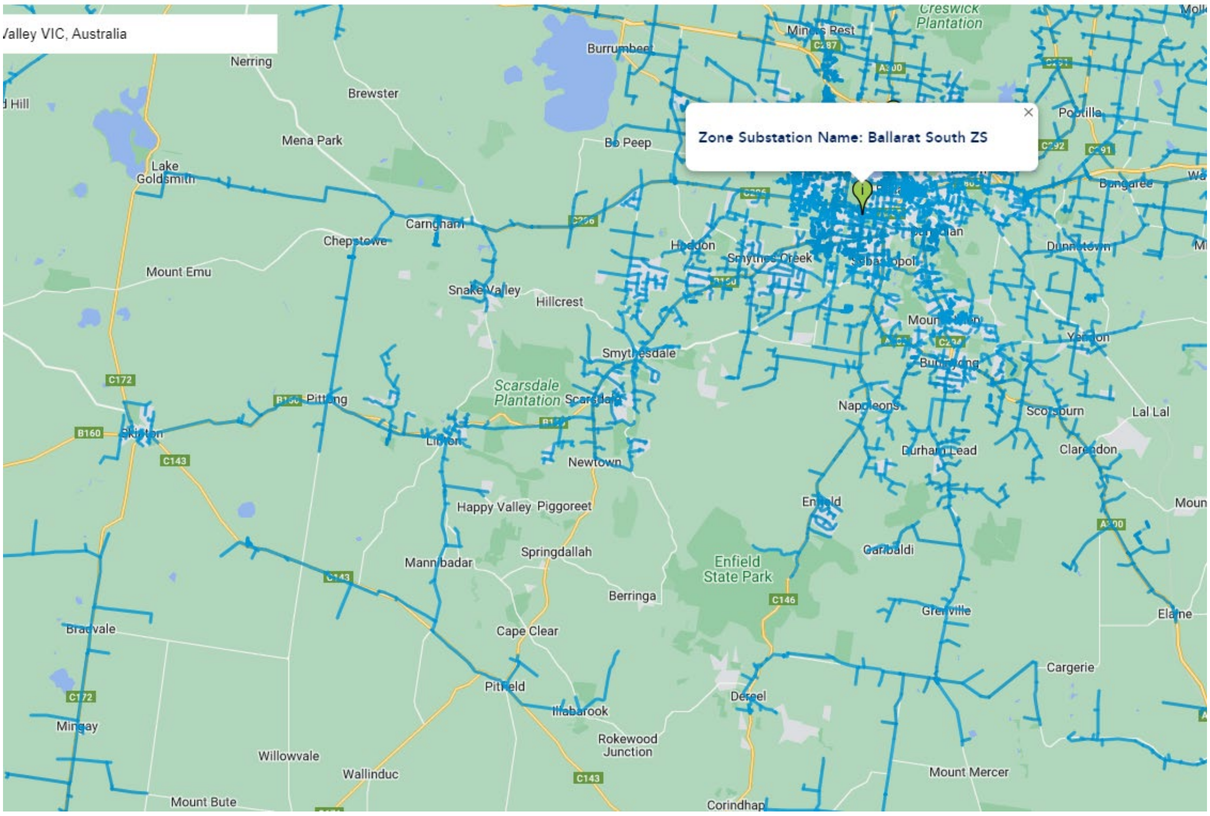

Figure 6 An aerial (Google map) view of Network 3.

4. Case studies

Three cases are considered to validate the proposed methodology. These are –

- **Case 1:** With Loads (No DERs, storage).
- **Case 2A:** With Loads and present DERs (2024).
- **Case 2B:** With Loads and forecasted DERs (2035).
- **Case 3A:** With Loads, present DERs and Storage (2024).
- **Case 3B:** With Loads, forecasted DERs and Storage (2035).

In case 1, time aggregation is performed using the K-means clustering method and the network reduction is performed using the Ward method. The impact of loads is analysed by some sensitivity analysis for several loading conditions.

In case 2A, present and forecasted DERs in the network are considered for time aggregation and model reduction. Since more than one time series data source is involved, the developed three-step time series method has been used for time aggregation. In case 2B, a future illustrative case is considered.

In case 3A, present storage devices such as BESS and EV fleet capacities are considered in the selected networks. In case 3B, we have considered an illustrative future forecast where network 1 and network 2 have PV, BESS, and EV, and network 3 has wind, PV, BESS, and EV fleet connected to the network.

A summary of all cases and resource considered for all three networks are presented in Table 1.

Table 1 Study cases considered for network reduction and time aggregation

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

Demand and DERs considered for present (2024) and future (2035) cases

Network 1 is located in Drysdale, Geelong, and connected to the Drysdale Zone substation. According to the data available in the Powercor database (https://dapr.powercor.com.au/), the maximum demand in 2021 was 57.88 MW. Currently (2024), no operational/proposed Wind, PV, BESS, or EV fleet charging stations are connected to the MV distribution network. In addition, due to the new developments, population growth, and economic expansion in this area, an additional 18.49 MW load (2% load growth every year from 2021) is considered in 2035. (https://www.energy.gov.au/energy-data/australian-energy-statistics/electricity-generation). We have considered a 5 MW PV integration in our forecasted case (2035) in network 1. A 5 MW neighbourhood BESS connected to this network is also considered in the forecasted case. However, the number can vary based on the financial and technical feasibility. Since electric vehicles could account for 6-8% of total electricity demand by 2035, up from 0.5% today, 5 MW EV fleet storage is considered by 2035 (https://www.iea.org/data-and-statistics/charts/electricity-demand-by-mode-2023-2035).

Network 2 is connected to the Geelong East Zone Substation. According to the Powercor database (https://dapr.powercor.com.au/), the maximum demand in 2021 was 50.31 MW. Following the 2% demand increase trend in 2021-22, an additional 16.07 MW demand is considered in 2035 (https://www.energy.gov.au/energy-data/australian-energy-statistics/electricity-generation). Based on several neighbourhood battery initiatives such as '100 Neighbourhood Batteries Program Grants', a 5 MW capacity of BESS is considered to be installed in this network. Similar to Network 1, a 5 MW solar plant is considered to be connected to the network by 2035. Since electric vehicles could account for 6-8% of total electricity demand by 2035, up from 0.5% today, a 5 MW EV fleet storage is considered (https://www.iea.org/data-and-statistics/charts/electricity-demand-by-mode-2023-2035).

Network 3 is located in Ballarat and connected to the Ballarat South Zone Substation. Based on the available Powercor data (https://dapr.powercor.com.au/), the maximum demand was 28.48 MW in 2021. Chepstowe Wind Farm, with a maximum capacity of 6.15 MW, is connected to this network. At present, there are no front-of-the-meter PV, BESS, or EV fleet charging stations connected to the network. For forecast case analysis, we assume that no additional wind farms will be connected to network 3 by 2035. According to the 2021-22 demand increased trend, an additional 9.09 MW demand in network 3 is considered in 2035. With a similar vision of Network 1 and Network 2, a 5 MW solar PV plant is considered to be installed in Network 3. Since this network is a semi-urban network and total demand is almost half of network 1 and network 2, a 2.5 MW BESS is considered in network 3. 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 (https://www.iea.org/data-and-statistics/charts/electricity-demand-by-mode-2023-2035). The demand, DERs and storage values considered for present and future cases in networks 1, 2, and 3 are presented in Table 2.

Table 2 Present (2024) and forecasted (2035) demand and DERs considered for this study

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

5. Results

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 earlier section. The K-means clustering method with the Silhouette criterion has been used for obtaining representative days from half-hour time series data. 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.

5.1 Case 1: With Load (No DERs, and storage)

In Case 1, no front-of-the-meter DERs are considered. 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 for 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. Finally, the reduced networks are obtained by using the representative profiles of the load using the Ward network reduction method. The reduced network for analysis is obtained for each time instance.

a) 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 7 illustrates the single-line diagram of Network 1 connected to the Drysdale Zone Substation.

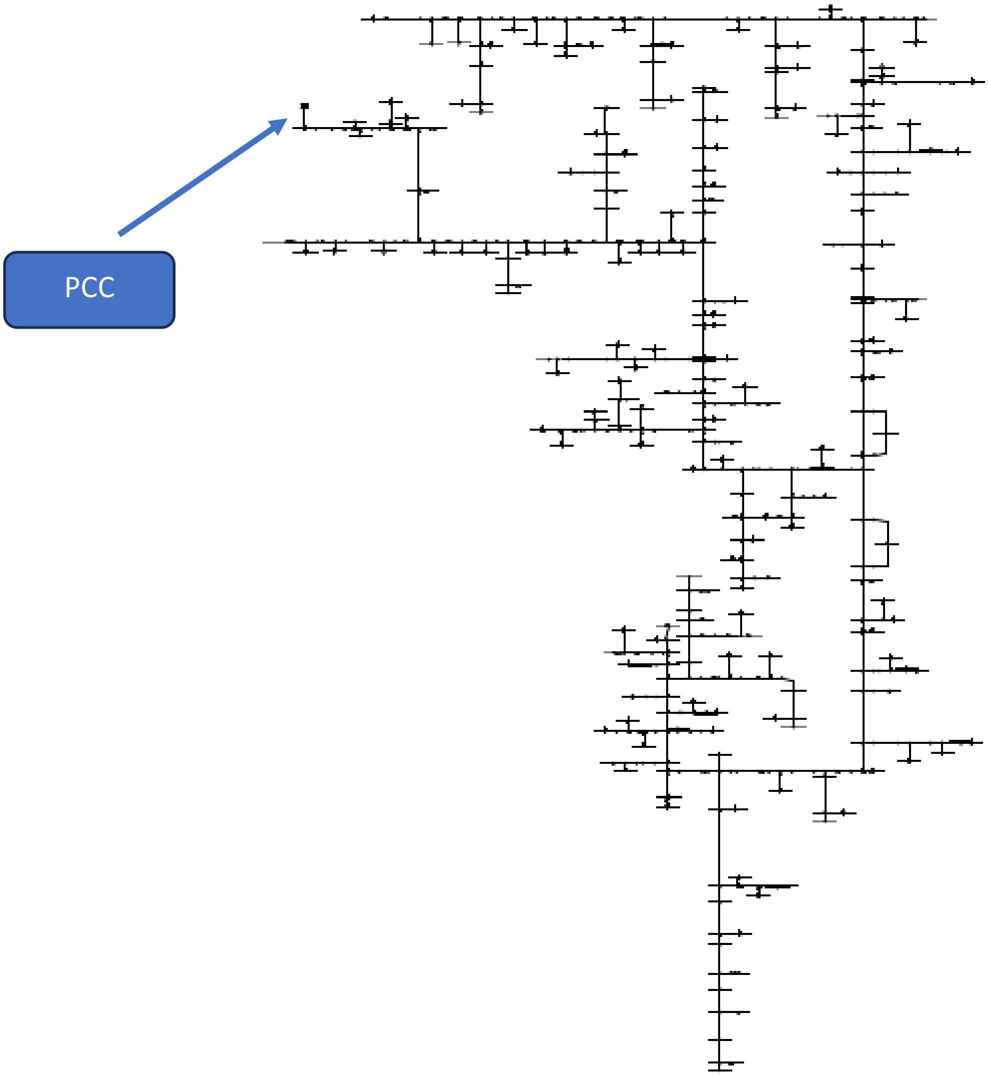

Figure 7 Single-line diagram of Drysdale MV distribution network.

Time aggregated load profiles

The aggregated time-series data of 2021 from Drysdale ZS is presented in Figure 8. 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 9. It is seen that the optimal number of representative days is two (i.e., the highest value of the Silhouette criterion in Figure 9). The representative daily profiles obtained using the K-means clustering method are presented in Figure 10. 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.

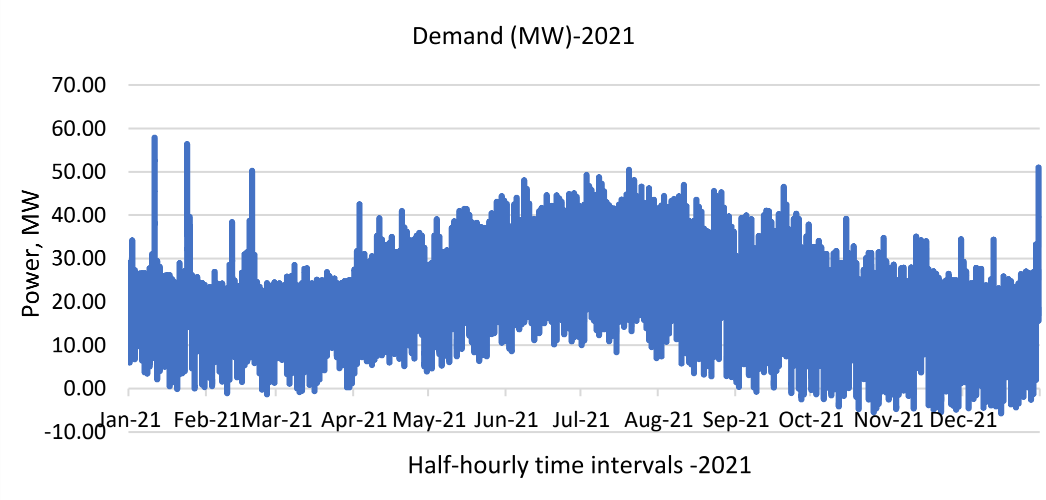

Figure 8 The aggregated time-series data 2021 from Drysdale zone substation.

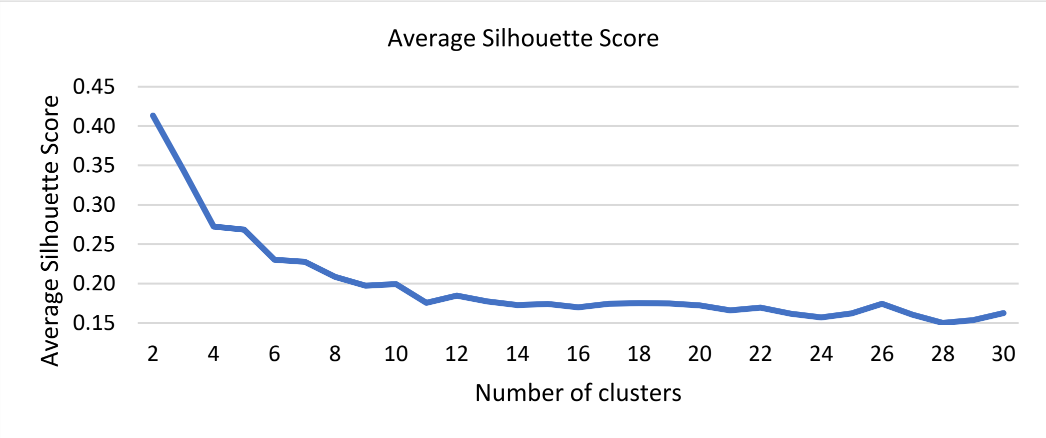

Figure 9 Silhouette criterion results for the time series data 2021.

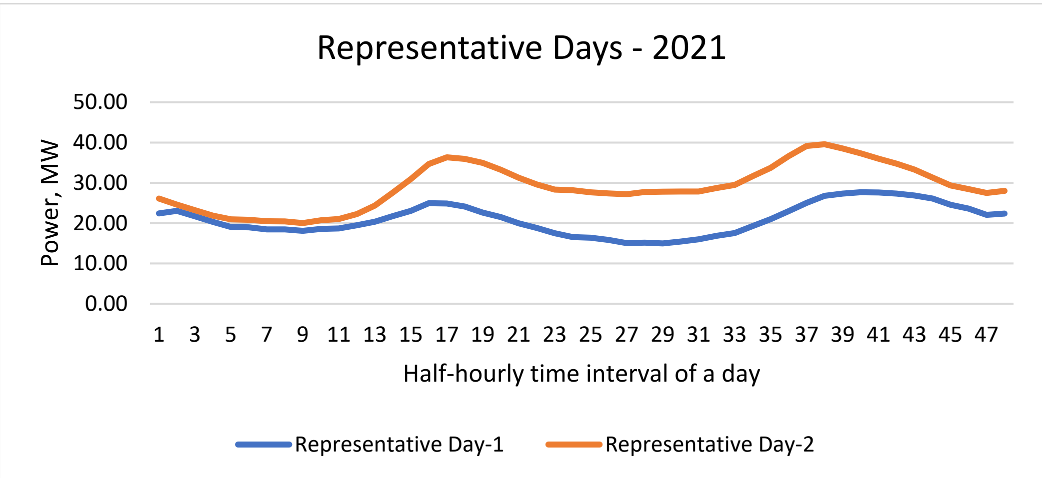

Figure 10 Representative daily profiles obtained by the K-means clustering method.

Spatial load data distribution

The representative daily load profiles of 134 load buses in the network are obtained using the K-means clustering method. The network steady-state operating points and network security conditions 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 a base case loading condition in this analysis. In this base case scenario, the maximum load is approximately 581.65 kW, whereas the minimum load is 0.176 kW. Figure 11 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.

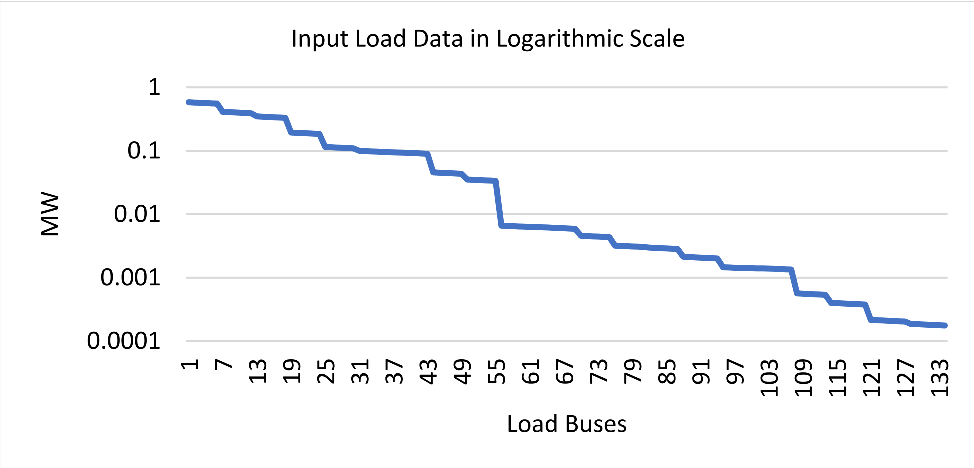

Figure 11 Spatial distribution of load in the network (logarithmic scale).

Steady-state network 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 11. The results of this analysis are shown in Table 3. In this analysis, branch overloads and voltage violations are used as the 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 12. 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 12. These violations are experienced due to daily peak load conditions.

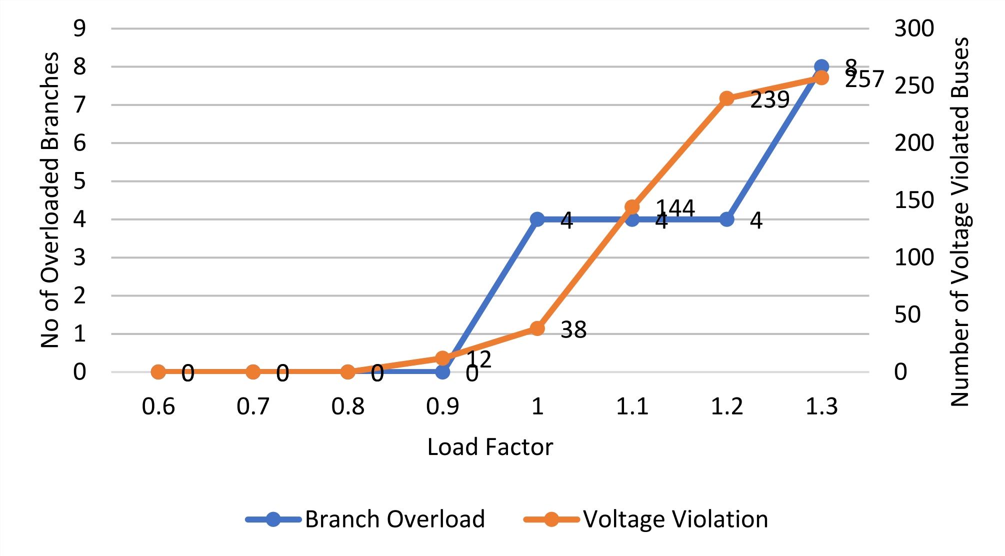

Figure 12 Network security matrices for different loading conditions.

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 up to 1.2, the severity of overloading increases which can be seen from the maximum overloading percentage (the last column in Table 3).

Representative reduced network

In this section, the accuracy of the non-linear AC power flow for the reduced network, compared to the original network, is analysed. The Ward network reduction method has been implemented to reduce the network from 649 buses to a representative 3-bus network. A total of 96 representative networks (for the 96 representative half-hour time intervals) are obtained for the two representative days. The resultant network using the proposed method for the base case loading condition is shown in Figure 13. The comparison among the active power, reactive power, current, and voltage at PCC for the full network and reduced network is presented in Figure 14 and Figure 15, respectively. The representative day with a higher peak value is considered for presenting the results. From the results given in Figure 14 and Figure 15, no differences in the network quantities for the detailed and the reduced networks are observed. The phase angle of zero degrees is reported for both networks.

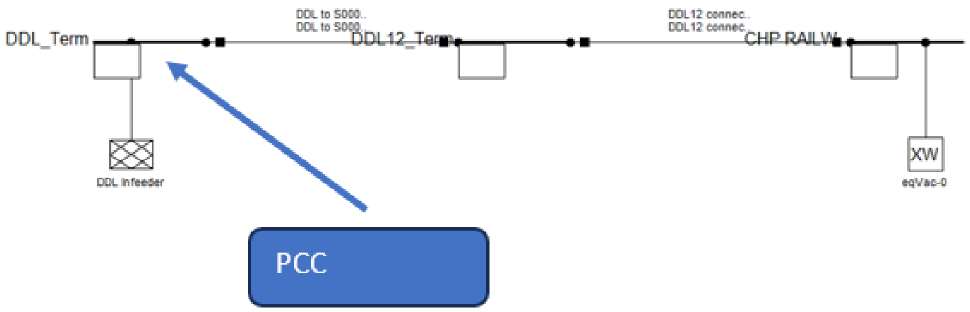

Figure 13 Representative reduced network using the Ward method.

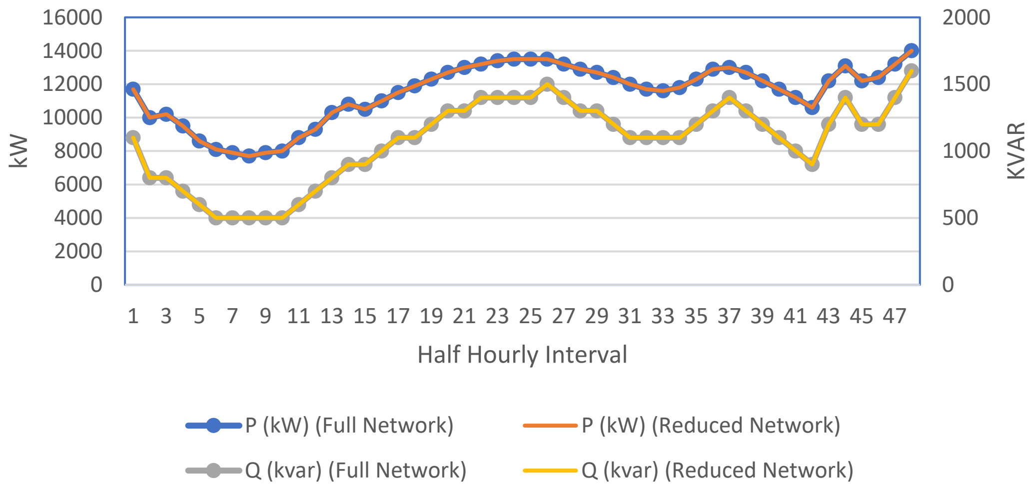

Figure 14 Active and reactive power comparison of full network and reduced network.

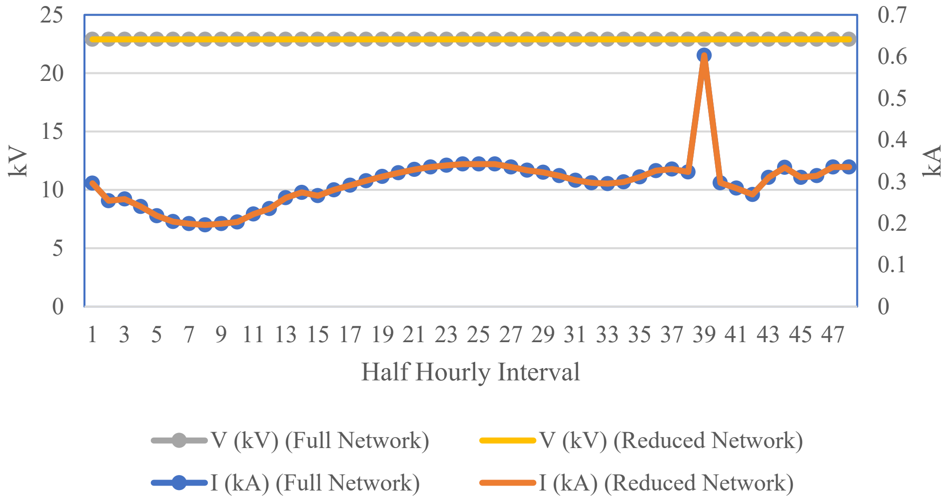

Figure 15 Current and voltage plots of the full network and reduced network.

All key parameters such as active and reactive powers, voltages, and currents at PCC for both the full and reduced network are compared in Table 4. No differences in the network quantities for the detailed and the reduced networks are observed.

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Table 4 Key parameters at PCC of the full and reduced network

Time	P (kW) (Full Network)	P (kW) (Reduced Network)	Q (KVAR) (Full Network)	Q (KVAR) (Reduced Network)	I (kA) (Full Network)	I (kA) (Reduced Network)	V (kV) (Full Network)	V (kV) (Reduced Network)	Phase Angle (Full Network)	Phase Angle (Reduced Network)	Error (%), P	Error (%), Q
12:00 AM	11700	11700	1100	1100	0.296	0.296	22.9	22.9	0	0	0	0
12:30 AM	10000	10000	800	800	0.254	0.254	22.9	22.9	0	0	0	0
1:00 AM	10200	10200	800	800	0.258	0.258	22.9	22.9	0	0	0	0
1:30 AM	9500	9500	700	700	0.24	0.24	22.9	22.9	0	0	0	0
2:00 AM	8600	8600	600	600	0.218	0.218	22.9	22.9	0	0	0	0
2:30 AM	8100	8100	500	500	0.204	0.204	22.9	22.9	0	0	0	0
3:00 AM	7900	7900	500	500	0.199	0.199	22.9	22.9	0	0	0	0
3:30 AM	7700	7700	500	500	0.196	0.196	22.9	22.9	0	0	0	0
4:00 AM	7900	7900	500	500	0.199	0.199	22.9	22.9	0	0	0	0
4:30 AM	8000	8000	500	500	0.203	0.203	22.9	22.9	0	0	0	0
5:00 AM	8800	8800	600	600	0.222	0.222	22.9	22.9	0	0	0	0
5:30 AM	9300	9300	700	700	0.235	0.235	22.9	22.9	0	0	0	0
6:00 AM	10300	10300	800	800	0.261	0.261	22.9	22.9	0	0	0	0
6:30 AM	10800	10800	900	900	0.274	0.274	22.9	22.9	0	0	0	0
7:00 AM	10500	10500	900	900	0.266	0.266	22.9	22.9	0	0	0	0
7:30 AM	11000	11000	1000	1000	0.28	0.28	22.9	22.9	0	0	0	0
8:00 AM	11500	11500	1100	1100	0.291	0.291	22.9	22.9	0	0	0	0
8:30 AM	11900	11900	1100	1100	0.302	0.302	22.9	22.9	0	0	0	0
9:00 AM	12300	12300	1200	1200	0.312	0.312	22.9	22.9	0	0	0	0
9:30 AM	12700	12700	1300	1300	0.321	0.321	22.9	22.9	0	0	0	0
10:00 AM	13000	13000	1300	1300	0.329	0.329	22.9	22.9	0	0	0	0
10:30 AM	13200	13200	1400	1400	0.335	0.335	22.9	22.9	0	0	0	0
11:00 AM	13400	13400	1400	1400	0.339	0.339	22.9	22.9	0	0	0	0
11:30 AM	13500	13500	1400	1400	0.342	0.342	22.9	22.9	0	0	0	0

12:00 PM	13500	13500	1400	1400	0.342	0.342	22.9	22.9	0	0	0	0
12:30 PM	13500	13500	1500	1500	0.342	0.342	22.9	22.9	0	0	0	0
1:00 PM	13200	13200	1400	1400	0.335	0.335	22.9	22.9	0	0	0	0
1:30 PM	12900	12900	1300	1300	0.327	0.327	22.9	22.9	0	0	0	0
2:00 PM	12700	12700	1300	1300	0.322	0.322	22.9	22.9	0	0	0	0
2:30 PM	12400	12400	1200	1200	0.314	0.314	22.9	22.9	0	0	0	0
3:00 PM	12000	12000	1100	1100	0.303	0.303	22.9	22.9	0	0	0	0
3:30 PM	11700	11700	1100	1100	0.297	0.297	22.9	22.9	0	0	0	0
4:00 PM	11600	11600	1100	1100	0.295	0.295	22.9	22.9	0	0	0	0
4:30 PM	11800	11800	1100	1100	0.299	0.299	22.9	22.9	0	0	0	0
5:00 PM	12300	12300	1200	1200	0.311	0.311	22.9	22.9	0	0	0	0
5:30 PM	12900	12900	1300	1300	0.326	0.326	22.9	22.9	0	0	0	0
6:00 PM	13000	13000	1400	1400	0.33	0.33	22.9	22.9	0	0	0	0
6:30 PM	12700	12700	1300	1300	0.323	0.323	22.9	22.9	0	0	0	0
7:00 PM	12200	12200	1200	1200	0.603	0.603	22.9	22.9	0	0	0	0
7:30 PM	11700	11700	1100	1100	0.297	0.297	22.9	22.9	0	0	0	0
8:00 PM	11200	11200	1000	1000	0.284	0.284	22.9	22.9	0	0	0	0
8:30 PM	10600	10600	900	900	0.269	0.269	22.9	22.9	0	0	0	0
9:00 PM	12200	12200	1200	1200	0.31	0.31	22.9	22.9	0	0	0	0
9:30 PM	13100	13100	1400	1400	0.334	0.334	22.9	22.9	0	0	0	0
10:00 PM	12200	12200	1200	1200	0.31	0.31	22.9	22.9	0	0	0	0
10:30 PM	12400	12400	1200	1200	0.314	0.314	22.9	22.9	0	0	0	0
11:00 PM	13200	13200	1400	1400	0.335	0.335	22.9	22.9	0	0	0	0
11:30 PM	14000	14000	1600	1600	0.335	0.335	22.9	22.9	0	0	0	0

b) Network 2

Network 2 is a radial distribution network located in the Geelong East area and 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 16. Two feeders are supplying the network with a tie line normally open.

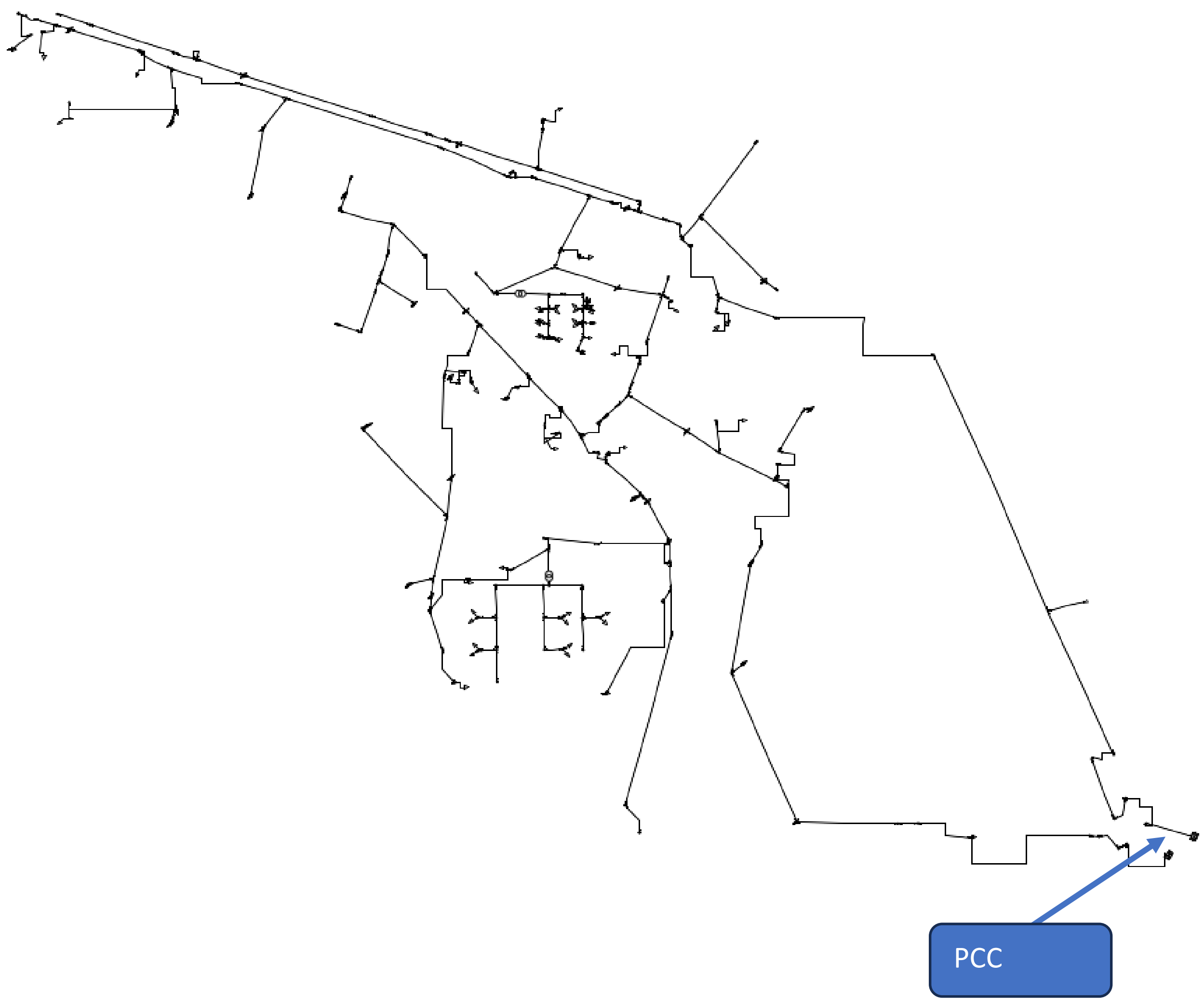

Figure 16 Single-line diagram of Geelong East MV distribution network.

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 17. 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 18. It is seen that the optimal number of representative days is two (i.e., the highest value of the Silhouette criterion in Figure

18). The representative daily profiles obtained using the K-means clustering method are presented in Figure 19.

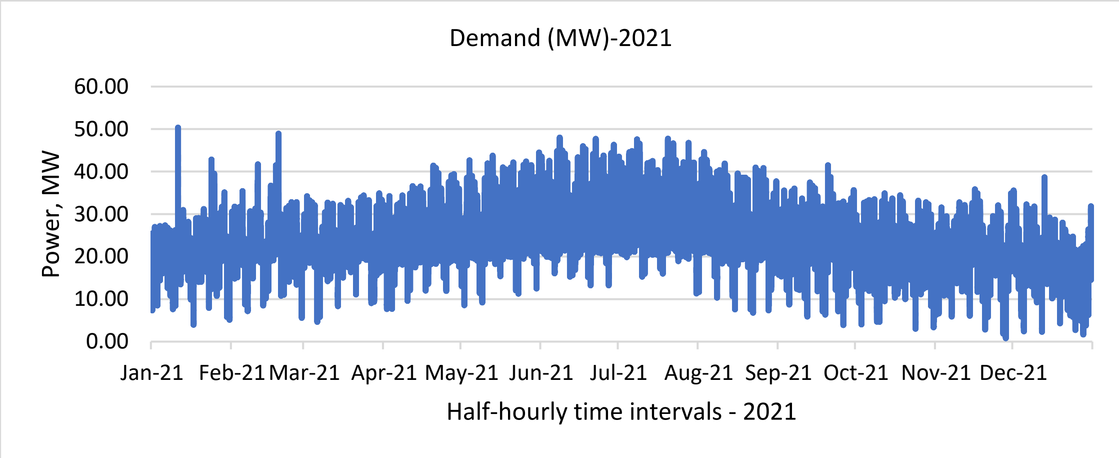

Figure 17 The aggregated time-series data - 2021 from Geelong East zone substation.

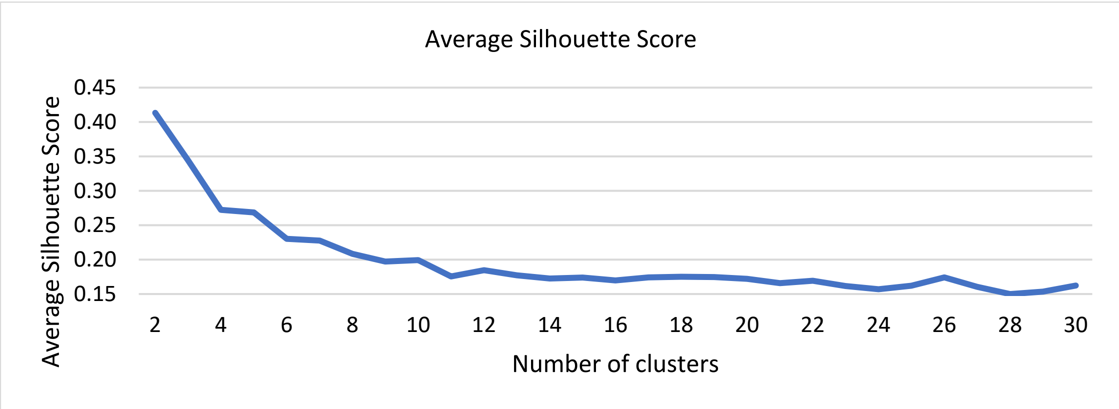

Figure 18 Silhouette criterion results for the time series data 2021.

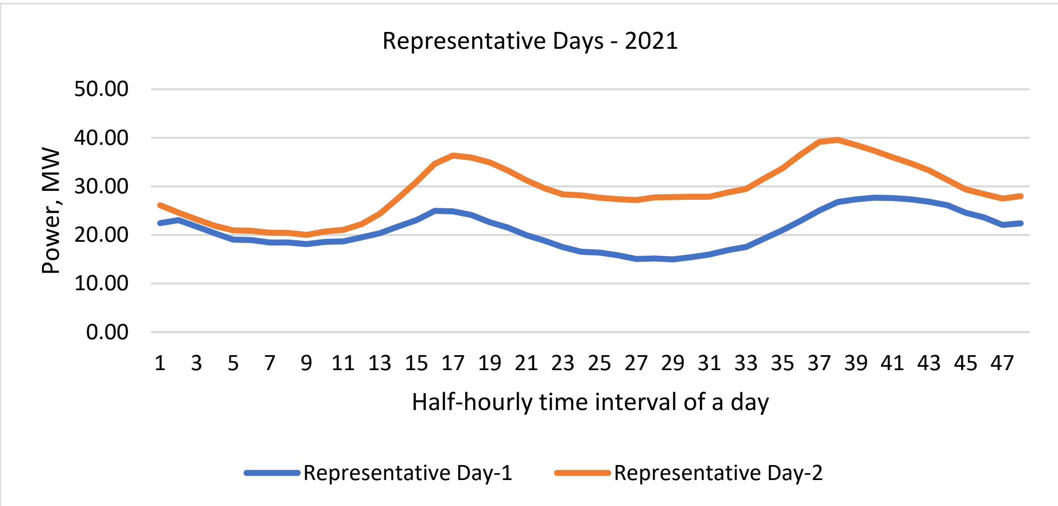

Figure 19 Representative daily profiles obtained by K-means clustering method.

Spatial load data distribution

The network steady-state operating points and network security conditions 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 20 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 315 kW, whereas the minimum load is 5.625 kW.

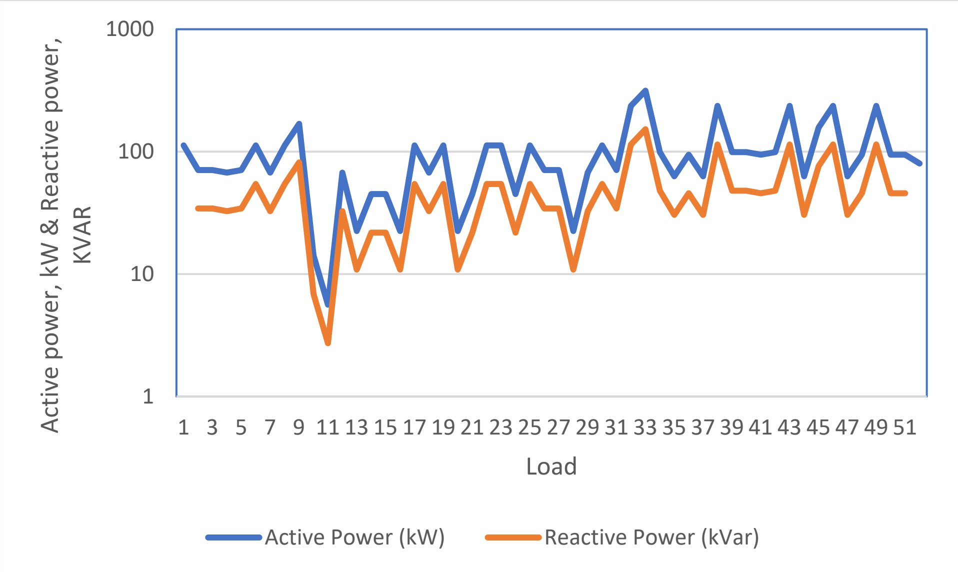

Figure 20 Spatial distribution of load in the network.

Steady-state network 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 20. In this analysis, branch overloads and voltage violations are used as the static security metrics, as given in Table 5. 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 21. It is seen that for the base loading conditions (loading factor = 1), no branches are overloaded and no voltage violations have been observed as illustrated in Table 5 and Figure 21.

Table 5 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%

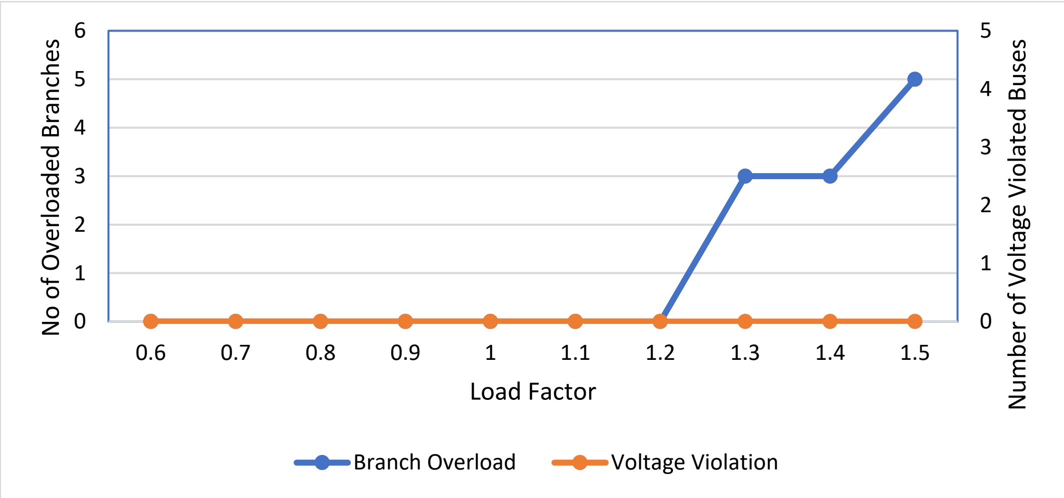

Figure 21 Network security matrices for different loading conditions.

A sensitivity analysis has been performed by changing the loading factor, as given in Table 5. 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 5). These behaviors can be explained considering that increasing/decreasing the loading factor makes the network more/less stressed.

Representative reduced network

In this section, the accuracy of the non-linear AC power flow for the reduced network, compared to the original network, is analysed. The Ward network reduction method has been implemented to reduce the network from 185 buses to a representative network (i.e., feeder 1 and feeder 2). The resultant network using the proposed method for the base case loading condition is shown in Figure 22. The comparison among the active power, and reactive power at PCC of the detailed and reduced networks is presented in Figure 23 and Figure 24. The current, and voltage comparison at PCC for the full network and reduced network is presented in Figure 25 and Figure 26. No differences in the network quantities for the detailed and the reduced networks are observed for feeder 1. However, a 0.2 KVAR difference is observed in the reactive powers of the detailed and reduced networks for feeder 2. The error is 0.015% of the aggregated demand which can be considered negligible for this size of networks. The phase angle of zero degrees is reported for both networks.

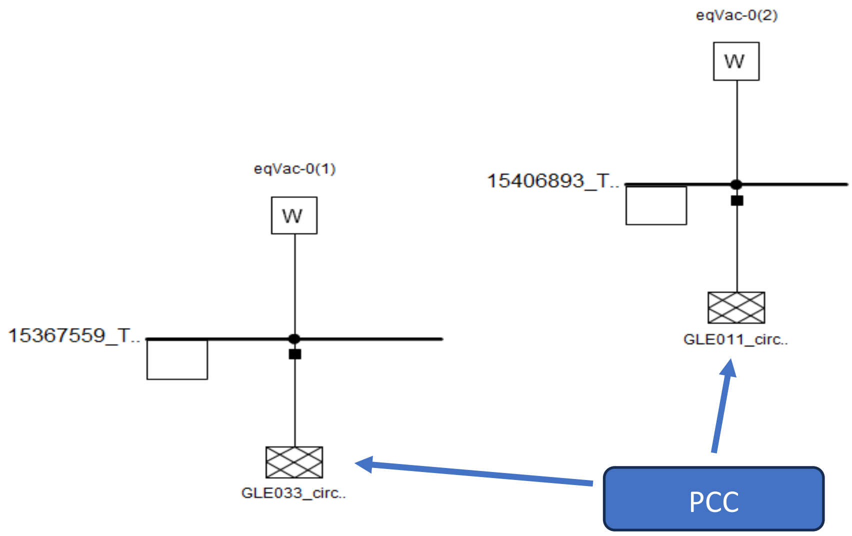

Figure 22 Representative reduced network using the Ward method.

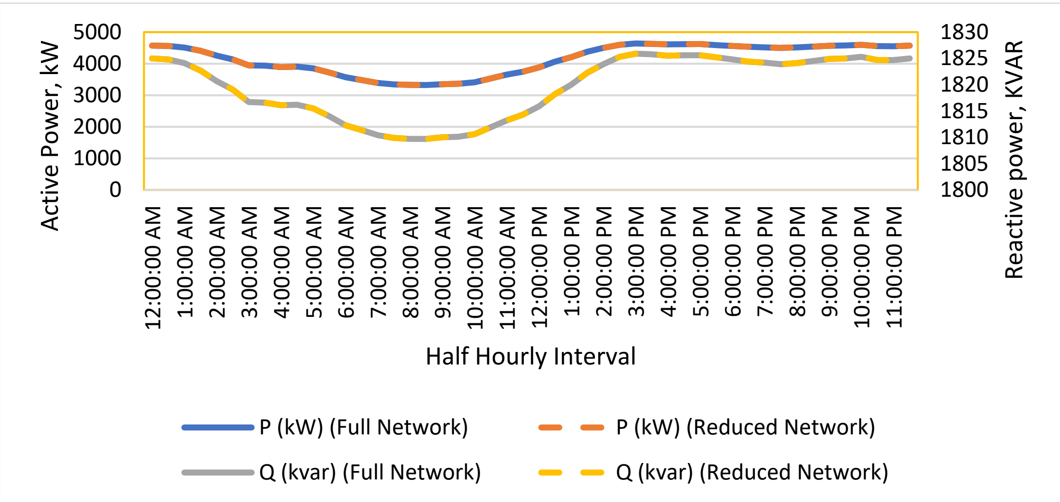

Figure 23 Active and reactive power comparison for full network and reduced network (Feeder 1).

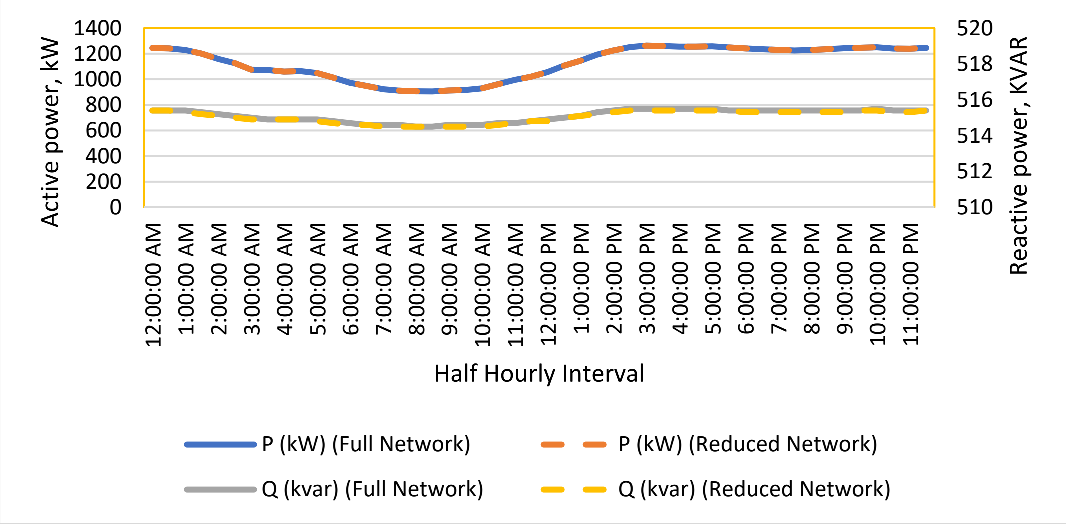

Figure 24 Active and reactive power comparison for full network and reduced network (Feeder 2).

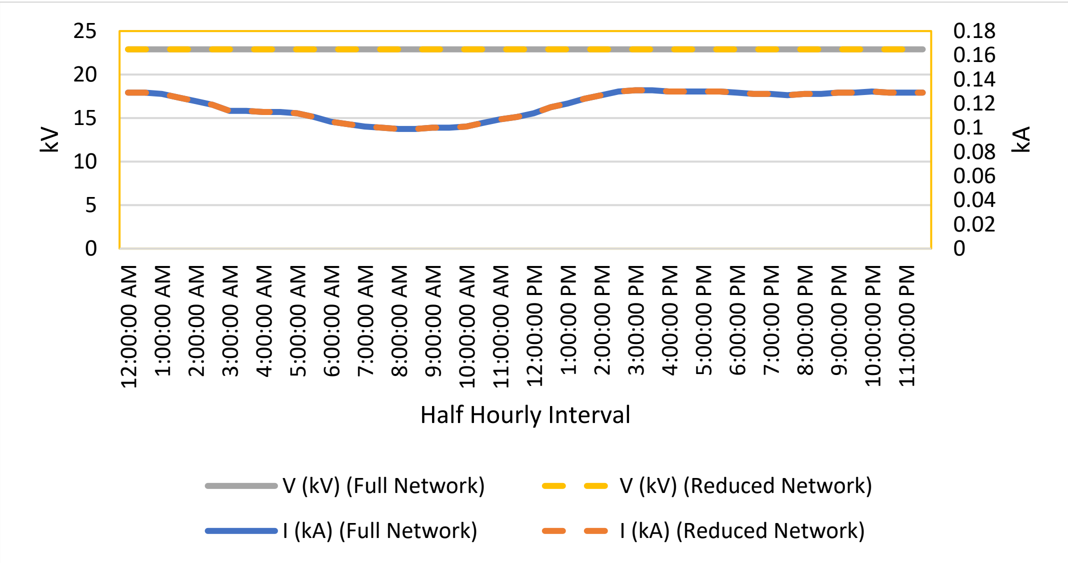

Figure 25 Current and voltage plots for the full network and reduced network (Feeder 1).

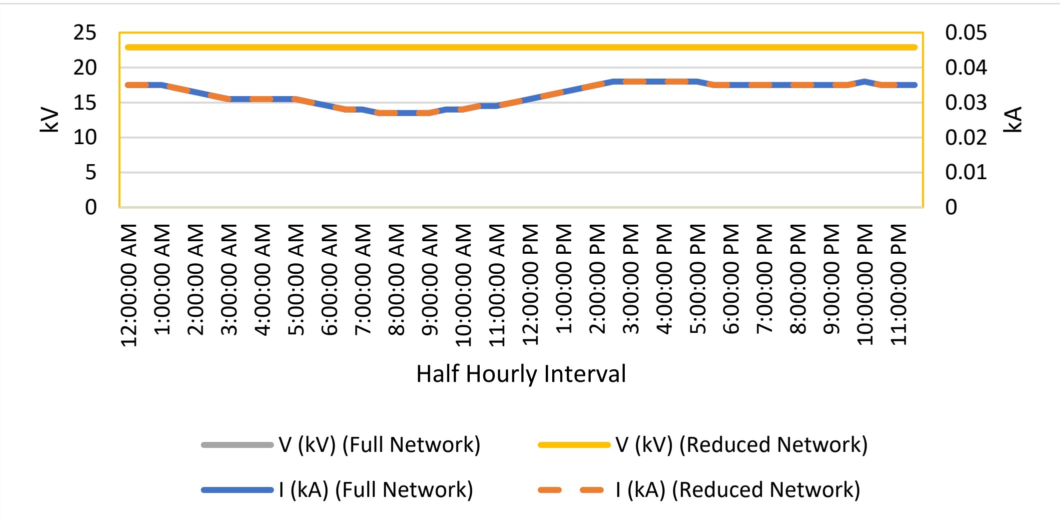

Figure 26 Current and voltage plots for the full network and reduced network (Feeder 2).

All key parameters, such as active and reactive powers, voltages, and currents at PCC for both the full and reduced network, are compared in Table 6 for feeder 1 and in Table 7 for feeder 2. There is no error in active and reactive power in feeder 1. However, in feeder 2, the maximum error of 0.02% for both active and reactive power is observed at PCC between the full network and reduced network.

Table 6 Key parameters at PCC of full and reduced network – feeder 1

Time	P (kW) (Full Network)	P (kW) (Reduced Network)	Q (KVAR) (Full Network)	Q (KVAR) (Reduced Network)	I (kA) (Full Network)	I (kA) (Reduced Network)	V (kV) (Full Network)	V (kV) (Reduced Network)	Phase Angle (Full Network)	Phase Angle (Reduced Network)	Error (%), P	Error (%), Q
12:00 AM	4573.2	4573.2	1825	1825	0.129	0.129	22.9	22.9	0	0	0	0
12:30 AM	4562.1	4562.1	1824.8	1824.8	0.129	0.129	22.9	22.9	0	0	0	0
1:00 AM	4513.4	4513.4	1824.1	1824.1	0.128	0.128	22.9	22.9	0	0	0	0
1:30 AM	4407.9	4407.9	1822.7	1822.7	0.125	0.125	22.9	22.9	0	0	0	0
2:00 AM	4258.1	4258.1	1820.7	1820.7	0.122	0.122	22.9	22.9	0	0	0	0
2:30 AM	4135.7	4135.7	1819.1	1819.1	0.119	0.119	22.9	22.9	0	0	0	0
3:00 AM	3949.3	3949.3	1816.7	1816.7	0.114	0.114	22.9	22.9	0	0	0	0
3:30 AM	3938.7	3938.7	1816.6	1816.6	0.114	0.114	22.9	22.9	0	0	0	0
4:00 AM	3894.2	3894.2	1816.1	1816.1	0.113	0.113	22.9	22.9	0	0	0	0
4:30 AM	3907.8	3907.8	1816.2	1816.2	0.113	0.113	22.9	22.9	0	0	0	0
5:00 AM	3850.9	3850.9	1815.5	1815.5	0.112	0.112	22.9	22.9	0	0	0	0
5:30 AM	3718.6	3718.6	1814	1814	0.109	0.109	22.9	22.9	0	0	0	0
6:00 AM	3570	3570	1812.3	1812.3	0.105	0.105	22.9	22.9	0	0	0	0
6:30 AM	3481.8	3481.8	1811.4	1811.4	0.103	0.103	22.9	22.9	0	0	0	0
7:00 AM	3388.1	3388.1	1810.4	1810.4	0.101	0.101	22.9	22.9	0	0	0	0
7:30 AM	3344.3	3344.3	1809.9	1809.9	0.1	0.1	22.9	22.9	0	0	0	0
8:00 AM	3328.9	3328.9	1809.7	1809.7	0.099	0.099	22.9	22.9	0	0	0	0
8:30 AM	3323.9	3323.9	1809.7	1809.7	0.099	0.099	22.9	22.9	0	0	0	0
9:00 AM	3350.2	3350.2	1810	1810	0.1	0.1	22.9	22.9	0	0	0	0
9:30 AM	3364.7	3364.7	1810.1	1810.1	0.1	0.1	22.9	22.9	0	0	0	0
10:00 AM	3409.9	3409.9	1810.6	1810.6	0.101	0.101	22.9	22.9	0	0	0	0
10:30 AM	3532.5	3532.5	1811.9	1811.9	0.104	0.104	22.9	22.9	0	0	0	0
11:00 AM	3652.1	3652.1	1813.2	1813.2	0.107	0.107	22.9	22.9	0	0	0	0
11:30 AM	3746.2	3746.2	1814.3	1814.3	0.109	0.109	22.9	22.9	0	0	0	0

12:00 PM	3881.3	3881.3	1815.9	1815.9	0.112	0.112	22.9	22.9	0	0	0	0
12:30 PM	4064.9	4064.9	1818.2	1818.2	0.117	0.117	22.9	22.9	0	0	0	0
1:00 PM	4207.4	4207.4	1820	1820	0.12	0.12	22.9	22.9	0	0	0	0
1:30 PM	4380.1	4380.1	1822.3	1822.3	0.124	0.124	22.9	22.9	0	0	0	0
2:00 PM	4500.1	4500.1	1823.9	1823.9	0.127	0.127	22.9	22.9	0	0	0	0
2:30 PM	4595.6	4595.6	1825.3	1825.3	0.13	0.13	22.9	22.9	0	0	0	0
3:00 PM	4641	4641	1825.9	1825.9	0.131	0.131	22.9	22.9	0	0	0	0
3:30 PM	4629.6	4629.6	1825.8	1825.8	0.131	0.131	22.9	22.9	0	0	0	0
4:00 PM	4613.3	4613.3	1825.5	1825.5	0.13	0.13	22.9	22.9	0	0	0	0
4:30 PM	4616.9	4616.9	1825.6	1825.6	0.13	0.13	22.9	22.9	0	0	0	0
5:00 PM	4621.4	4621.4	1825.6	1825.6	0.13	0.13	22.9	22.9	0	0	0	0
5:30 PM	4588.9	4588.9	1825.2	1825.2	0.13	0.13	22.9	22.9	0	0	0	0
6:00 PM	4563.5	4563.5	1824.8	1824.8	0.129	0.129	22.9	22.9	0	0	0	0
6:30 PM	4535.9	4535.9	1824.4	1824.4	0.128	0.128	22.9	22.9	0	0	0	0
7:00 PM	4517.8	4517.8	1824.2	1824.2	0.128	0.128	22.9	22.9	0	0	0	0
7:30 PM	4500	4500	1823.9	1823.9	0.127	0.127	22.9	22.9	0	0	0	0
8:00 PM	4513.8	4513.8	1824.1	1824.1	0.128	0.128	22.9	22.9	0	0	0	0
8:30 PM	4539.2	4539.2	1824.5	1824.5	0.128	0.128	22.9	22.9	0	0	0	0
9:00 PM	4567.4	4567.4	1824.9	1824.9	0.129	0.129	22.9	22.9	0	0	0	0
9:30 PM	4578.4	4578.4	1825	1825	0.129	0.129	22.9	22.9	0	0	0	0
10:00 PM	4595.4	4595.4	1825.3	1825.3	0.13	0.13	22.9	22.9	0	0	0	0
10:30 PM	4555.4	4555.4	1824.7	1824.7	0.129	0.129	22.9	22.9	0	0	0	0
11:00 PM	4553.7	4553.7	1824.7	1824.7	0.129	0.129	22.9	22.9	0	0	0	0
11:30 PM	4574.3	4574.3	1825	1825	0.129	0.129	22.9	22.9	0	0	0	0

Table 7 Key parameters at PCC of full and reduced network – feeder 2

Time	P (kW) (Full Network)	P (kW) (Reduced Network)	Q (KVAR) (Full Network)	Q (KVAR) (Reduced Network)	I (kA) (Full Network)	I (kA) (Reduced Network)	V (kV) (Full Network)	V (kV) (Reduced Network)	Phase Angle (Full Network)	Phase Angle (Reduced Network)	Error (%), P	Error (%), Q
12:00 AM	1244.9	1244.7	515.4	515.4	0.035	0.035	22.9	22.9	0	0	0.02	0.00
12:30 AM	1241.9	1241.7	515.4	515.4	0.035	0.035	22.9	22.9	0	0	0.02	0.00
1:00 AM	1228.6	1228.5	515.4	515.3	0.035	0.035	22.9	22.9	0	0	0.01	0.02
1:30 AM	1200	1199.8	515.3	515.2	0.034	0.034	22.9	22.9	0	0	0.02	0.02
2:00 AM	1159.3	1159.2	515.2	515.1	0.033	0.033	22.9	22.9	0	0	0.01	0.02
2:30 AM	1126	1125.9	515.1	515	0.032	0.032	22.9	22.9	0	0	0.01	0.02
3:00 AM	1075.4	1075.3	515	514.9	0.031	0.031	22.9	22.9	0	0	0.01	0.02
3:30 AM	1072.5	1072.4	514.9	514.9	0.031	0.031	22.9	22.9	0	0	0.01	0.00
4:00 AM	1060.4	1060.3	514.9	514.9	0.031	0.031	22.9	22.9	0	0	0.01	0.00
4:30 AM	1064.1	1064	514.9	514.9	0.031	0.031	22.9	22.9	0	0	0.01	0.00
5:00 AM	1048.6	1048.5	514.9	514.8	0.031	0.031	22.9	22.9	0	0	0.01	0.02
5:30 AM	1012.6	1012.5	514.8	514.7	0.03	0.03	22.9	22.9	0	0	0.01	0.02
6:00 AM	972.3	972.2	514.7	514.6	0.029	0.029	22.9	22.9	0	0	0.01	0.02
6:30 AM	948.3	948.2	514.6	514.6	0.028	0.028	22.9	22.9	0	0	0.01	0.00
7:00 AM	922.8	922.7	514.6	514.5	0.028	0.028	22.9	22.9	0	0	0.01	0.02
7:30 AM	910.9	910.8	514.6	514.5	0.027	0.027	22.9	22.9	0	0	0.01	0.02
8:00 AM	906.7	906.6	514.5	514.5	0.027	0.027	22.9	22.9	0	0	0.01	0.00
8:30 AM	905.3	905.2	514.5	514.5	0.027	0.027	22.9	22.9	0	0	0.01	0.00
9:00 AM	912.5	912.4	514.6	514.5	0.027	0.027	22.9	22.9	0	0	0.01	0.02
9:30 AM	916.4	916.3	514.6	514.5	0.028	0.028	22.9	22.9	0	0	0.01	0.02
10:00 AM	928.7	928.6	514.6	514.5	0.028	0.028	22.9	22.9	0	0	0.01	0.02
10:30 AM	962.1	962	514.7	514.6	0.029	0.029	22.9	22.9	0	0	0.01	0.02
11:00 AM	994.6	994.5	514.7	514.7	0.029	0.029	22.9	22.9	0	0	0.01	0.00
11:30 AM	1020.2	1020	514.8	514.8	0.03	0.03	22.9	22.9	0	0	0.02	0.00

12:00 PM	1056.9	1056.8	514.9	514.8	0.031	0.031	22.9	22.9	0	0	0.01	0.02
12:30 PM	1106.8	1106.6	515	515	0.032	0.032	22.9	22.9	0	0	0.02	0.00
1:00 PM	1145.5	1145.4	515.1	515.1	0.033	0.033	22.9	22.9	0	0	0.01	0.00
1:30 PM	1192.4	1192.3	515.3	515.2	0.034	0.034	22.9	22.9	0	0	0.01	0.02
2:00 PM	1225	1224.9	515.4	515.3	0.035	0.035	22.9	22.9	0	0	0.01	0.02
2:30 PM	1251	1250.8	515.5	515.4	0.036	0.036	22.9	22.9	0	0	0.02	0.02
3:00 PM	1263.3	1263.1	515.5	515.4	0.036	0.036	22.9	22.9	0	0	0.02	0.02
3:30 PM	1260.2	1260	515.5	515.4	0.036	0.036	22.9	22.9	0	0	0.02	0.02
4:00 PM	1255.8	1255.6	515.5	515.4	0.036	0.036	22.9	22.9	0	0	0.02	0.02
4:30 PM	1255.7	1255.6	515.5	515.4	0.036	0.036	22.9	22.9	0	0	0.01	0.02
5:00 PM	1258	1257.8	515.5	515.4	0.036	0.036	22.9	22.9	0	0	0.02	0.02
5:30 PM	1249.1	1249	515.4	515.4	0.035	0.035	22.9	22.9	0	0	0.01	0.00
6:00 PM	1242.2	1242.1	515.4	515.3	0.035	0.035	22.9	22.9	0	0	0.01	0.02
6:30 PM	1234.8	1234.6	515.4	515.3	0.035	0.035	22.9	22.9	0	0	0.02	0.02
7:00 PM	1229.8	1229.7	515.4	515.3	0.035	0.035	22.9	22.9	0	0	0.01	0.02
7:30 PM	1225	1224.8	515.4	515.3	0.035	0.035	22.9	22.9	0	0	0.02	0.02
8:00 PM	1228.7	1228.6	515.4	515.3	0.035	0.035	22.9	22.9	0	0	0.01	0.02
8:30 PM	1235.7	1235.5	515.4	515.3	0.035	0.035	22.9	22.9	0	0	0.02	0.02
9:00 PM	1243.3	1243.1	515.4	515.3	0.035	0.035	22.9	22.9	0	0	0.02	0.02
9:30 PM	1246.3	1246.1	515.4	515.4	0.035	0.035	22.9	22.9	0	0	0.02	0.00
10:00 PM	1250.9	1250.8	515.5	515.4	0.036	0.036	22.9	22.9	0	0	0.01	0.02
10:30 PM	1240.1	1239.9	515.4	515.3	0.035	0.035	22.9	22.9	0	0	0.02	0.02
11:00 PM	1239.6	1239.4	515.4	515.3	0.035	0.035	22.9	22.9	0	0	0.02	0.02
11:30 PM	1245.2	1245	515.4	515.4	0.035	0.035	22.9	22.9	0	0	0.02	0.00

c) 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 27 illustrates the single-line diagram of Network 3 connected to the Ballarat South Zone Substation.

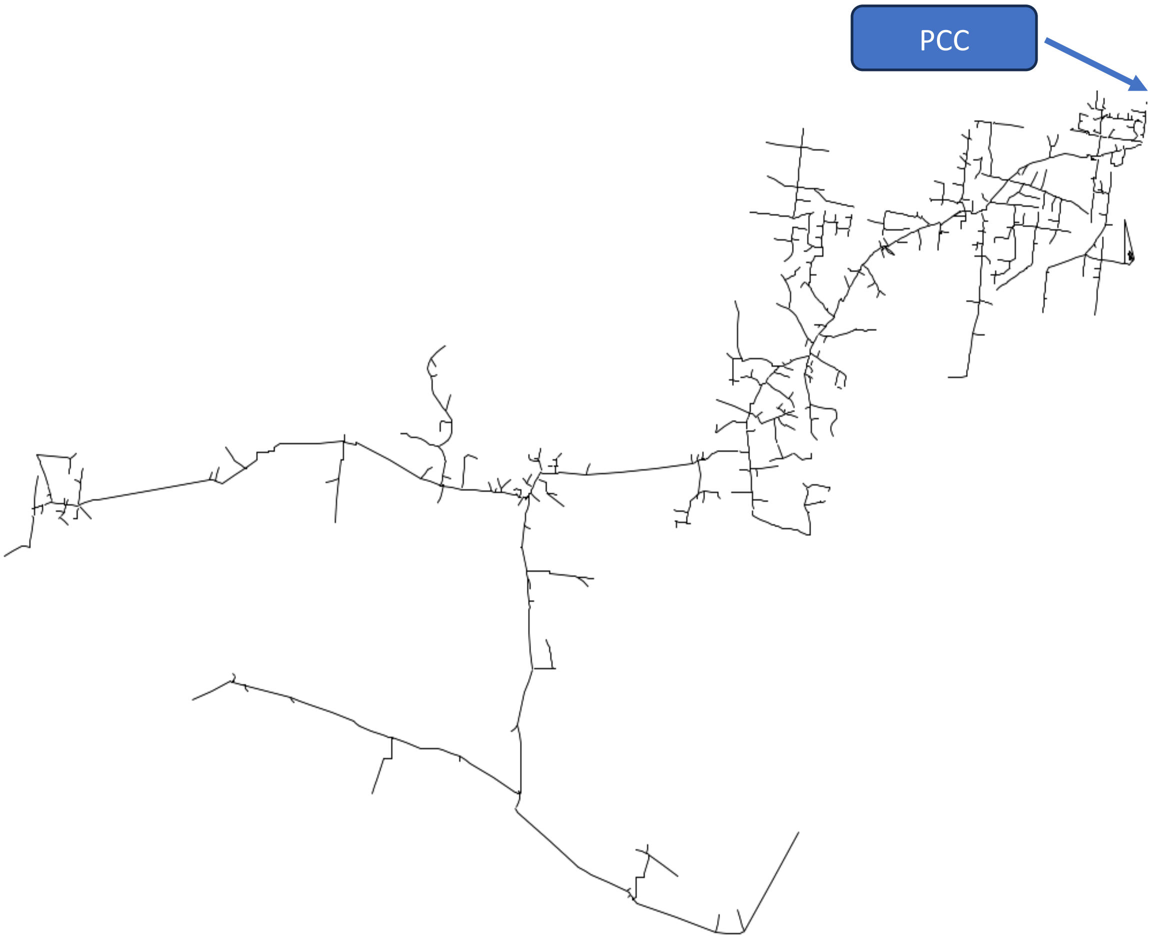

Figure 27 Single-line diagram of Ballarat South MV distribution network.

Time aggregated load profiles

The aggregated time-series data of 2021(30-minute time intervals) from Ballarat South ZS is presented in Figure 28. For 2021, the results of the Silhouette score are plotted against the number of clusters in Figure 29. The highest value of Silhouette criterion is two (as shown in Figure 29). Therefore, two representative days are used. Representative daily profiles are presented in Figure 30. 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.

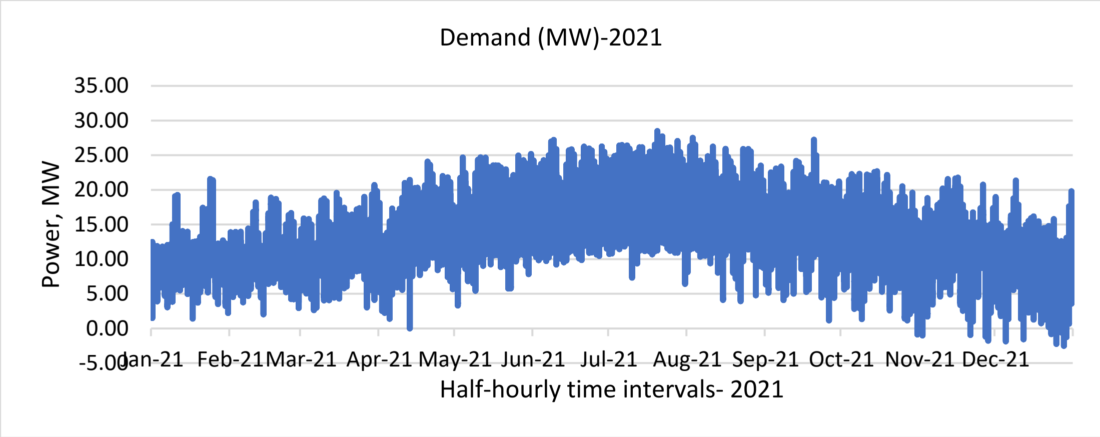

Figure 28 The aggregated time-series data 2021 from Ballarat South zone substation.

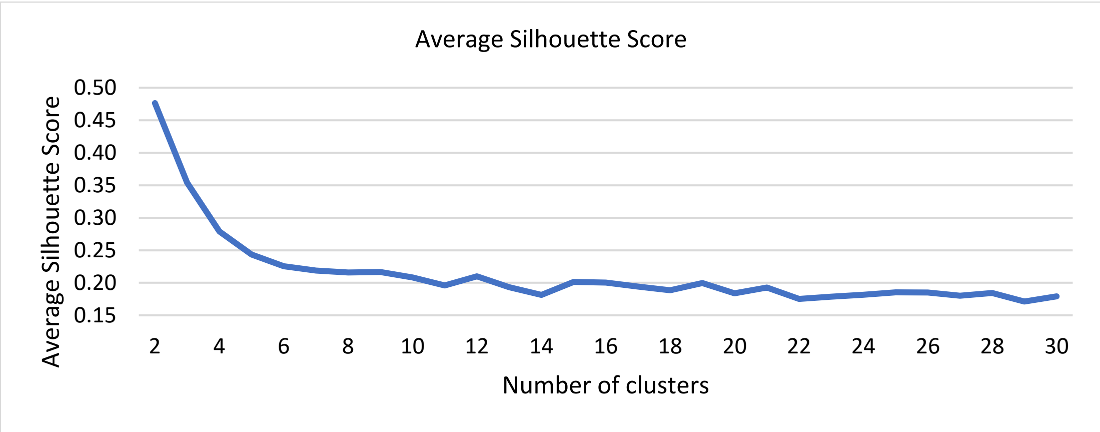

Figure 29 Silhouette criterion results for the time series data 2021.

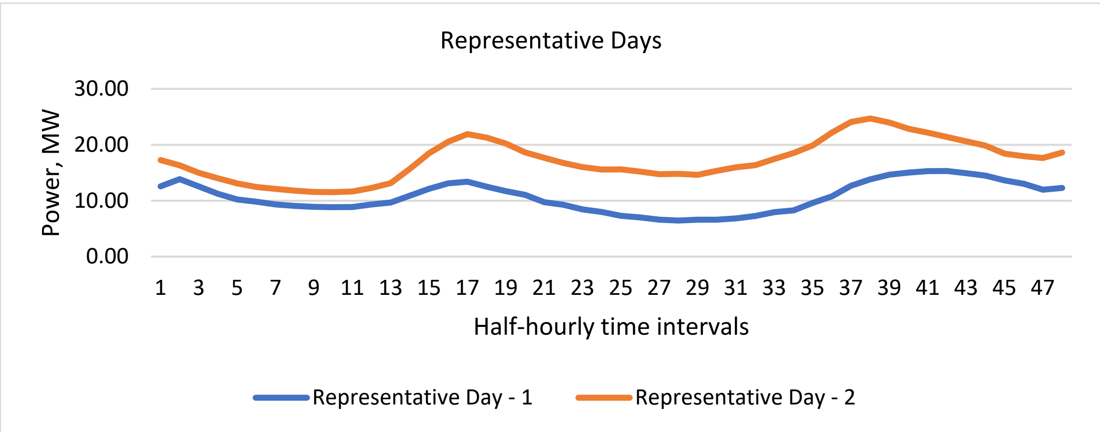

Figure 30 Representative daily profiles obtained by the K-means clustering method.

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 network steady-state operating points and network security conditions 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 386 kW, whereas the minimum load is 0.193 kW. Figure 31 displays the spatial load distribution of the input load data in the network.

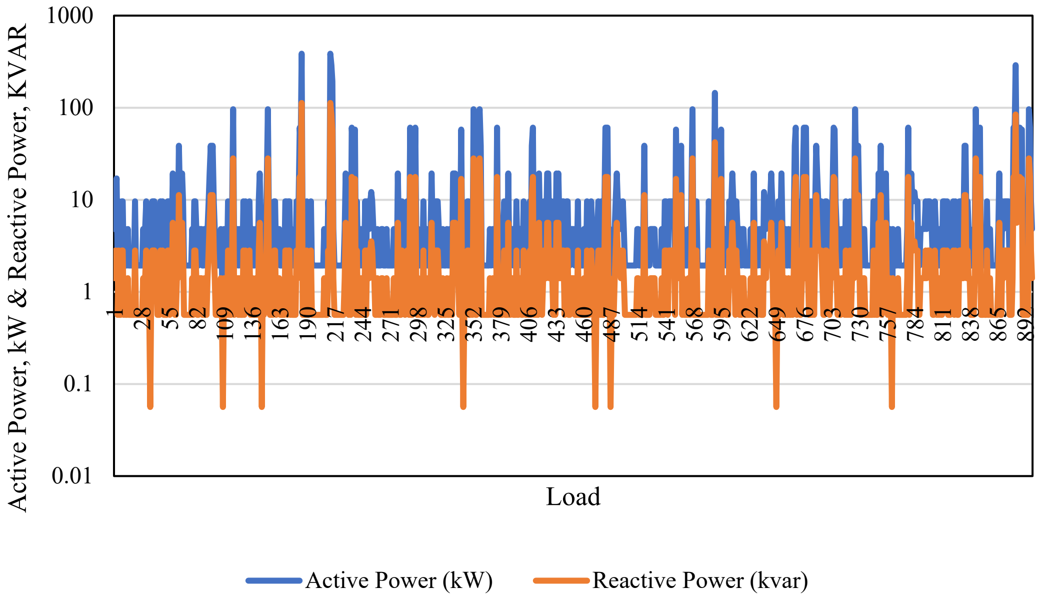

Figure 31 Spatial distribution of load in the network.

Steady-state network 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 31. The results of this analysis are shown in Table 8. In this analysis, branch overloads and voltage violations are used as the static security metrics, as shown in Table 8. The number of branch overloads and the number of bus voltage violations for different loading conditions are given in Figure 32. No overloaded branches are observed in the base case conditions. However, there are 120 bus voltage violations in the base case conditions as illustrated in Table 8 and Figure 32.

Table 8 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%

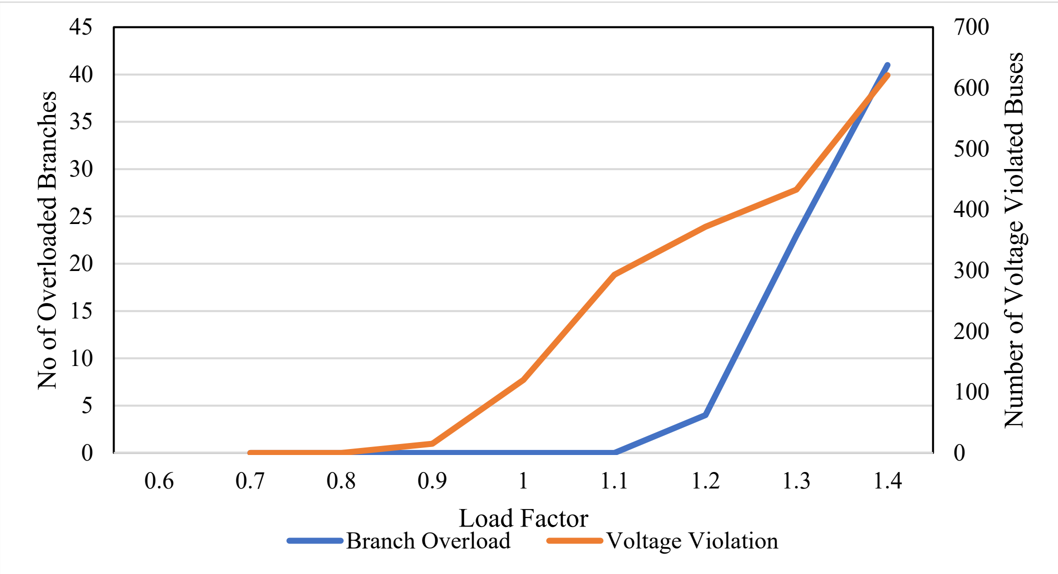

Figure 32 Network security matrices for different loading conditions.

A sensitivity analysis has been performed by changing the loading factor, as illustrated in Table 8. 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 3). These behaviors can be explained considering that increasing/decreasing the loading factor makes the network more/less stressed.

Representative reduced network

In this section, the accuracy of the non-linear AC power flow for the reduced network, compared to the original network, is analysed. The Ward network reduction method has been implemented to reduce the network from 1759 buses to a representative 2-bus network. A total of 96 representative networks (for the 96 representative half-hour time intervals) are obtained for the two representative days. The resultant network for the base case loading condition is shown in Figure 33. The comparison among the active power, reactive power, current, and voltage at PCC for the full network and reduced network is presented in Figure 34 and Figure 35, respectively. From the results given in Figure 34 and Figure 35, a maximum of 5.7 KVAR difference in the reactive power quantities for the detailed and the reduced networks are observed which is 0.044% of the aggregated demand. Thus, even the maximum error is negligible. The phase angle of zero degrees is reported for both networks.

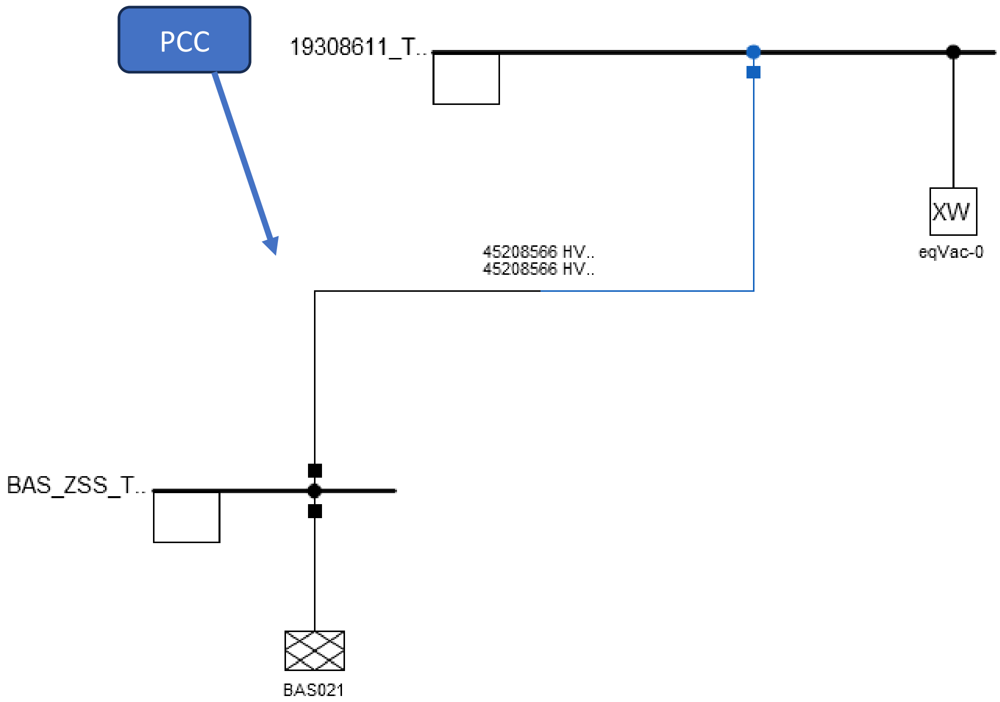

Figure 33 Representative reduced network (Network 3).

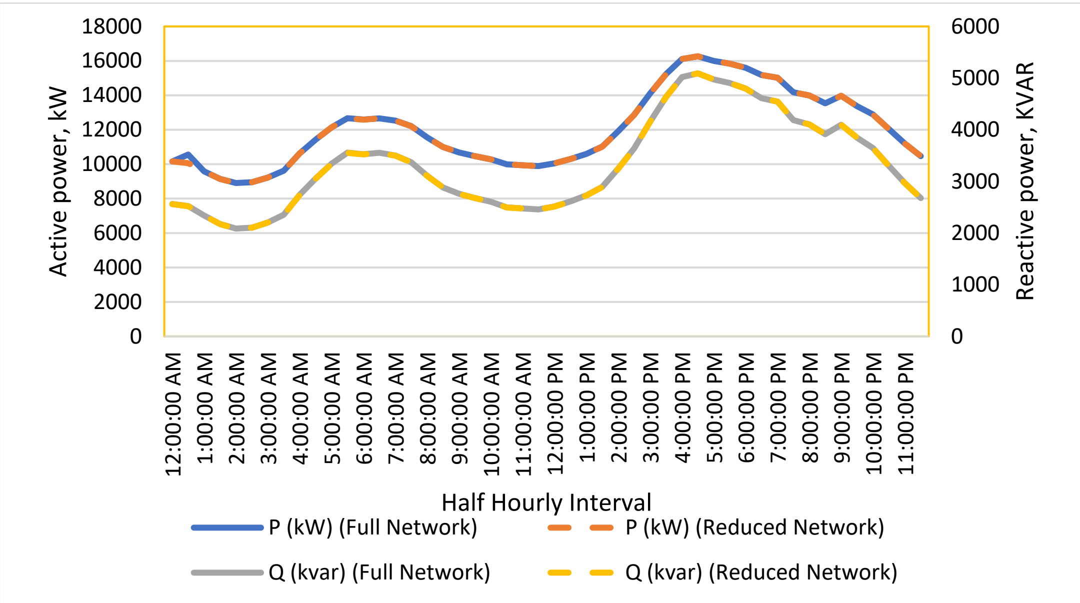

Figure 34 Active and reactive power comparison for full network and reduced network.

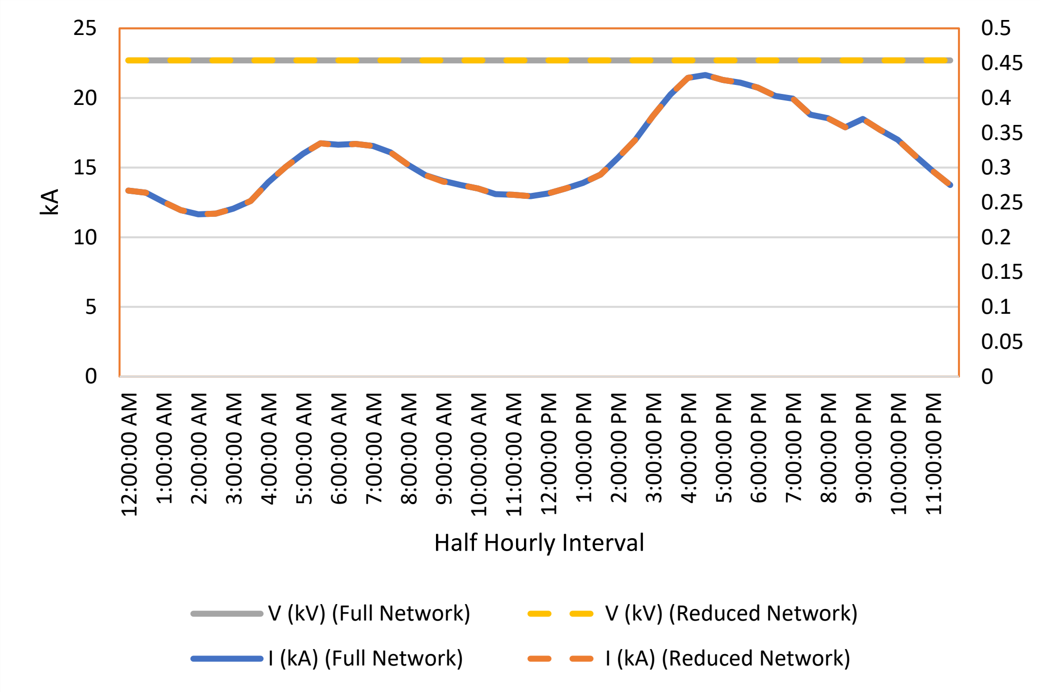

Figure 35 Current and voltage plots for the full network and reduced network.

All key parameters, such as active and reactive powers, voltages, and currents at PCC for both the full and reduced network, are compared in Table 9. A maximum of 4.75% active power error and a maximum of 0.17% reactive power error in the network quantities for the detailed and reduced networks are observed.

Federation University

Table 9 Key parameters at PCC of full and reduced network – Network 3

Time	P (kW) (Full Network)	P (kW) (Reduced Network)	Q (KVAR) (Full Network)	Q (KVAR) (Reduced Network)	I (kA) (Full Network)	I (kA) (Reduced Network)	V (kV) (Full Network)	V (kV) (Reduced Network)	Phase Angle (Full Network)	Phase Angle (Reduced Network)	Error (%), P	Error (%), Q
12:00 AM	10164.5	10162.7	2562.1	2559.9	0.267	0.267	22.7	22.7	0	0	0.02	0.09
12:30 AM	10559.8	10058	2522	2519.9	0.264	0.264	22.7	22.7	0	0	4.75	0.08
1:00 AM	9581.4	9579.9	2340.3	2338.3	0.251	0.251	22.7	22.7	0	0	0.02	0.09
1:30 AM	9143.1	9141.7	2175.5	2173.7	0.239	0.239	22.7	22.7	0	0	0.02	0.08
2:00 AM	8905.3	8904	2086.8	2085.1	0.233	0.233	22.7	22.7	0	0	0.01	0.08
2:30 AM	8952.8	8951.5	2104.5	2102.8	0.234	0.234	22.7	22.7	0	0	0.01	0.08
3:00 AM	9218.2	9216.8	2203.6	2201.8	0.241	0.241	22.7	22.7	0	0	0.02	0.08
3:30 AM	9616.8	9615.2	2353.6	2351.7	0.252	0.252	22.7	22.7	0	0	0.02	0.08
4:00 AM	10626.4	10624.5	2739.9	2737.5	0.279	0.279	22.7	22.7	0	0	0.02	0.09
4:30 AM	11423.7	11421.5	3056.4	3053.6	0.301	0.301	22.7	22.7	0	0	0.02	0.09
5:00 AM	12142.5	12140	3343.5	3340.3	0.32	0.32	22.7	22.7	0	0	0.02	0.10
5:30 AM	12665.8	12663	3555.7	3552.2	0.335	0.335	22.7	22.7	0	0	0.02	0.10
6:00 AM	12590.4	12587.6	3525	3521.5	0.333	0.332	22.7	22.7	0	0	0.02	0.10
6:30 AM	12660.2	12657.5	3553.5	3550	0.334	0.334	22.7	22.7	0	0	0.02	0.10
7:00 AM	12531.8	12529.1	3501.1	3497.7	0.331	0.331	22.7	22.7	0	0	0.02	0.10
7:30 AM	12209.9	12207.3	3370.7	3367.5	0.322	0.322	22.7	22.7	0	0	0.02	0.09
8:00 AM	11550.9	11548.7	3106.9	3104	0.304	0.304	22.7	22.7	0	0	0.02	0.09
8:30 AM	10994.5	10992.5	2882.9	2880.4	0.289	0.289	22.7	22.7	0	0	0.02	0.09
9:00 AM	10678.3	10676.4	2760	2757.5	0.281	0.28	22.7	22.7	0	0	0.02	0.09
9:30 AM	10468.2	10466.4	2678.8	2676.4	0.275	0.275	22.7	22.7	0	0	0.02	0.09
10:00 AM	10280.8	10279	2606.7	2604.4	0.27	0.27	22.7	22.7	0	0	0.02	0.09
10:30 AM	9996.4	9994.7	2497.8	2495.7	0.262	0.262	22.7	22.7	0	0	0.02	0.08
11:00 AM	9941.2	9939.5	2476.8	2474.7	0.261	0.261	22.7	22.7	0	0	0.02	0.08
11:30 AM	9893.2	9891.6	2458.5	2456.4	0.259	0.259	22.7	22.7	0	0	0.02	0.09

12:00 PM	10048.4	10045	2517.7	2513.4	0.263	0.263	22.7	22.7	0	0	0.03	0.17
12:30 PM	10297.9	10296.1	2613.2	2611	0.27	0.27	22.7	22.7	0	0	0.02	0.08
1:00 PM	10599.4	10597.5	2729.5	2727	0.278	0.278	22.7	22.7	0	0	0.02	0.09
1:30 PM	11019.8	11017.7	2892.8	2890.2	0.29	0.29	22.7	22.7	0	0	0.02	0.09
2:00 PM	11913.7	11911.3	3251.6	3248.5	0.314	0.314	22.7	22.7	0	0	0.02	0.10
2:30 PM	12866.2	12860.5	3637.7	3630.5	0.34	0.34	22.7	22.7	0	0	0.04	0.20
3:00 PM	14106.7	14106.7	4154.2	4154.2	0.374	0.374	22.7	22.7	0	0	0.00	0.00
3:30 PM	15221.2	15221.2	4631.9	4631.9	0.405	0.405	22.7	22.7	0	0	0.00	0.00
4:00 PM	16104.5	16104.5	5020	5020	0.429	0.429	22.7	22.7	0	0	0.00	0.00
4:30 PM	16263.7	16263.7	5090.8	5090.8	0.433	0.433	22.7	22.7	0	0	0.00	0.00
5:00 PM	15999.7	15999.7	4973.5	4973.5	0.426	0.426	22.7	22.7	0	0	0.00	0.00
5:30 PM	15840.9	15840.9	4903.2	4903.2	0.422	0.422	22.7	22.7	0	0	0.00	0.00
6:00 PM	15595.6	15595.6	4795.3	4795.3	0.415	0.415	22.7	22.7	0	0	0.00	0.00
6:30 PM	15173.7	15173.7	4611.2	4611.2	0.403	0.403	22.7	22.7	0	0	0.00	0.00
7:00 PM	15019.6	15019.6	4544.5	4544.5	0.399	0.399	22.7	22.7	0	0	0.00	0.00
7:30 PM	14178.6	14178.6	4184.6	4184.6	0.376	0.376	22.7	22.7	0	0	0.00	0.00
8:00 PM	13986.4	13986.4	4103.4	4103.4	0.371	0.371	22.7	22.7	0	0	0.00	0.00
8:30 PM	13535.2	13535.2	3914.3	3914.3	0.358	0.358	22.7	22.7	0	0	0.00	0.00
9:00 PM	13967.8	13967.8	4095.6	4095.6	0.37	0.37	22.7	22.7	0	0	0.00	0.00
9:30 PM	13367.7	13367.7	3844.6	3844.6	0.354	0.354	22.7	22.7	0	0	0.00	0.00
10:00 PM	12878.4	12875.5	3642.7	3639.1	0.34	0.34	22.7	22.7	0	0	0.02	0.10
10:30 PM	12035.9	12033.4	3300.6	3297.5	0.317	0.317	22.7	22.7	0	0	0.02	0.09
11:00 PM	11195.8	11193.7	2966.4	2963.7	0.295	0.295	22.7	22.7	0	0	0.02	0.09
11:30 PM	10466.9	10465.1	2678.3	2675.9	0.275	0.275	22.7	22.7	0	0	0.02	0.09

5.2 Case 2A: With Load 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. There is no front-of-the-meter solar PV connected in all three networks. The network 3 only has a 6.15 MW wind generation in the area. An illustrative estimation of load increase is considered to obtain yearly time series data for 2024 from 2021 by considering the new developments, population growth, and economic expansion in this area (https://www.energy.gov.au/energy-data/australian-energy-statistics/electricity-generation).

a) Network 1

At present, there is no front-of-the-meter DER connected to Network 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 36. 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 37. Two representative days are selected based on the highest value given in Figure 37. It is seen that the optimal number of representative days is two resulting in the highest value of the Silhouette criterion in Figure 37. Figure 38 shows the representative daily profiles.

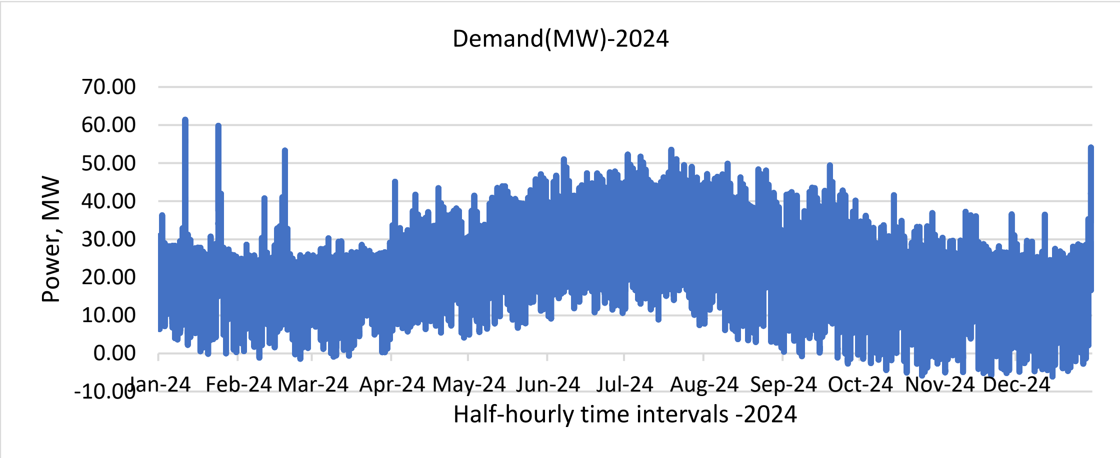

Figure 36 The aggregated time-series data 2024 from Drysdale zone substation.

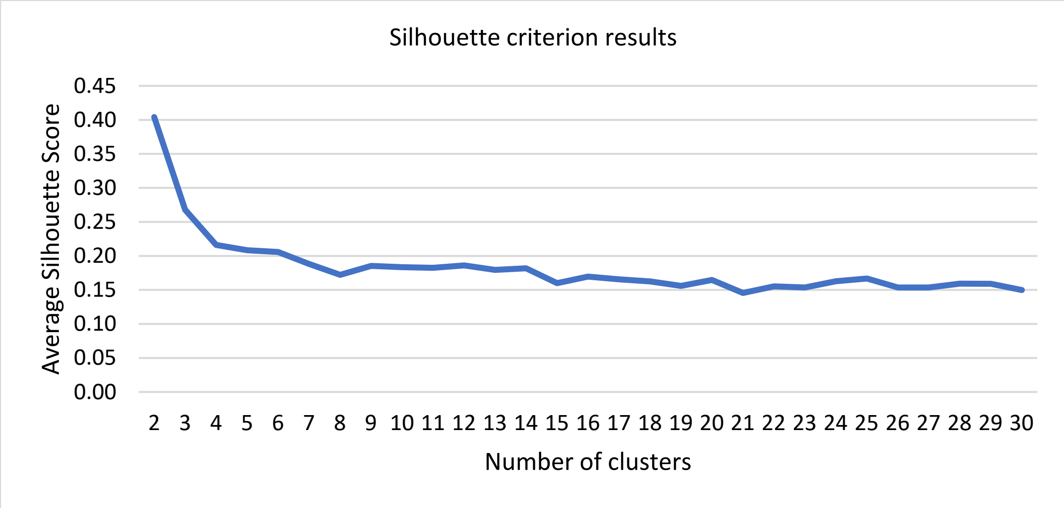

Figure 37 Silhouette criterion results for the time series data 2024.

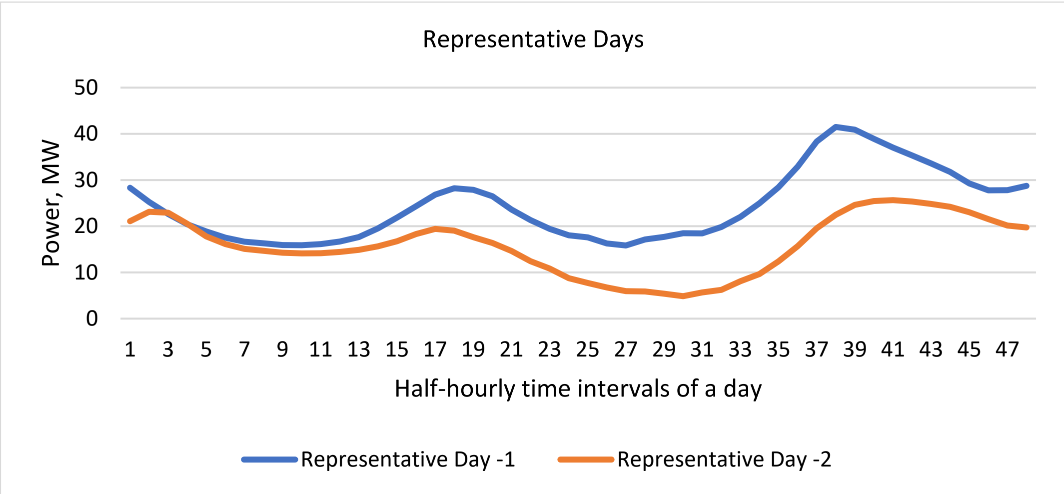

Figure 38 Representative daily profiles obtained by the K-means clustering method.

Representative reduced network

The Ward network reduction method has been implemented to reduce the network. The accuracy of the non-linear AC power flow for the reduced network, compared to the original network, is analysed. A total of 96 representative networks (for the 96 representative half-hour time intervals) are obtained for the two representative days. The comparison among the active power, reactive power, current, and voltage at PCC for the full network and reduced network is presented in Figure 39 and Figure 40. From the results given in Figure 39 and Figure 40, a maximum of 196.3 KVAR difference in the network reactive power quantity for the detailed and the reduced networks are observed, 0.46% of the total load. The phase angle of zero degrees is reported for both networks.

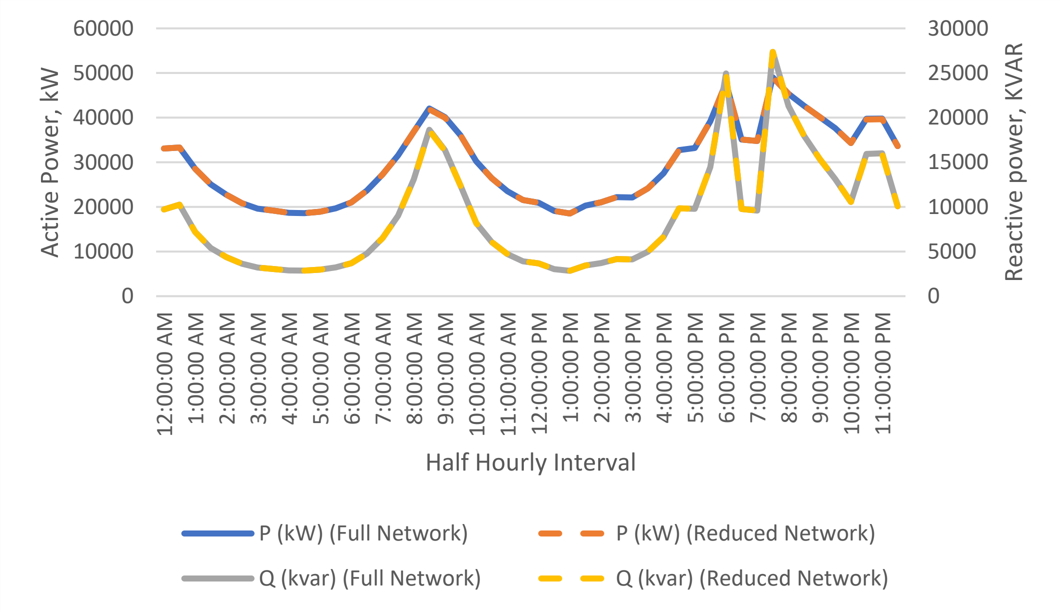

Figure 39 Active and reactive power comparison for full network and reduced network.

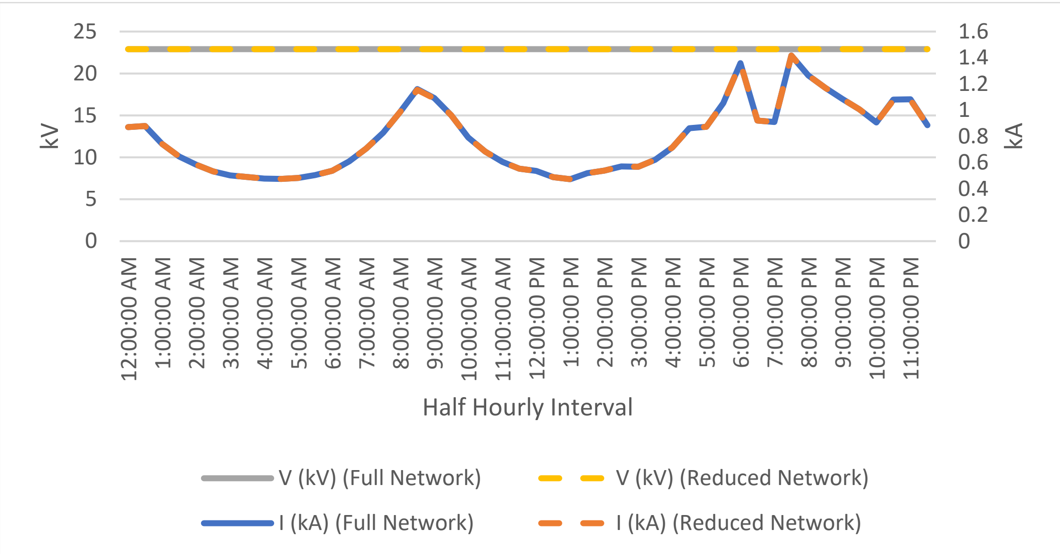

Figure 40 Current and voltage plots for the full network and reduced network.

All key parameters such as active and reactive powers, voltages, and currents at PCC for both the full and reduced network are compared in Table 10. A maximum of 0.47% error in the active power and 0.52% error in reactive power for the detailed and the reduced networks are observed. The maximum error value is very low compared to the size of the network and rating.

Table 10 Key parameters at PCC of full and reduced network

Time	P (kW) (Full Network)	P (kW) (Reduced Network)	Q (KVAR) (Full Network)	Q (KVAR) (Reduced Network)	I (kA) (Full Network)	I (kA) (Reduced Network)	V (kV) (Full Network)	V (kV) (Reduced Network)	Phase Angle (Full Network)	Phase Angle (Reduced Network)	Error (%), P	Error (%), Q
12:00 AM	33086.2	33086.2	9710.2	9710.2	0.87	0.87	22.9	22.9	0	0	0.00	0.00
12:30 AM	33307.5	33307.5	10251.3	10251.3	0.879	0.879	22.9	22.9	0	0	0.00	0.00
1:00 AM	28534.9	28534.9	7192.7	7192.7	0.743	0.743	22.9	22.9	0	0	0.00	0.00
1:30 AM	25041.7	25041.7	5390	5390	0.646	0.646	22.9	22.9	0	0	0.00	0.00
2:00 AM	22710.4	22710.4	4369.4	4369.4	0.584	0.584	22.9	22.9	0	0	0.00	0.00
2:30 AM	20811.1	20811.1	3629.9	3629.9	0.533	0.533	22.9	22.9	0	0	0.00	0.00
3:00 AM	19617.9	19617.9	3205.4	3205.4	0.502	0.502	22.9	22.9	0	0	0.00	0.00
3:30 AM	19158.4	19158.4	3049.9	3049.9	0.49	0.49	22.9	22.9	0	0	0.00	0.00
4:00 AM	18662.5	18662.5	2887	2887	0.477	0.477	22.9	22.9	0	0	0.00	0.00
4:30 AM	18602.5	18602.5	2867.6	2867.6	0.475	0.475	22.9	22.9	0	0	0.00	0.00
5:00 AM	18916.7	18916.7	2969.8	2969.8	0.483	0.483	22.9	22.9	0	0	0.00	0.00
5:30 AM	19692.6	19692.6	3231.1	3231.1	0.504	0.504	22.9	22.9	0	0	0.00	0.00
6:00 AM	20991.6	20991.6	3696.8	3696.8	0.538	0.538	22.9	22.9	0	0	0.00	0.00
6:30 AM	23662.5	23662.5	4770.8	4770.8	0.609	0.609	22.9	22.9	0	0	0.00	0.00
7:00 AM	27272.7	27272.7	6504.8	6504.8	0.707	0.707	22.9	22.9	0	0	0.00	0.00
7:30 AM	31534	31534	9023.1	9023.1	0.828	0.828	22.9	22.9	0	0	0.00	0.00
8:00 AM	36835.5	36835.5	13080.7	13080.7	0.986	0.986	22.9	22.9	0	0	0.00	0.00
8:30 AM	42041.1	41844.8	18644.7	18548.1	1.161	1.155	22.9	22.9	0	0	0.47	0.52
9:00 AM	40127.8	39956.2	16353.7	16268.2	1.093	1.089	22.9	22.9	0	0	0.43	0.52
9:30 AM	36019.7	36019.7	12375.8	12375.8	0.961	0.961	22.9	22.9	0	0	0.00	0.00
10:00 AM	30236.3	30236.3	8195.4	8195.4	0.791	0.791	22.9	22.9	0	0	0.00	0.00
10:30 AM	26411.9	26411.9	6051.5	6051.5	0.684	0.684	22.9	22.9	0	0	0.00	0.00
11:00 AM	23530.6	23530.6	4713.9	4713.9	0.606	0.606	22.9	22.9	0	0	0.00	0.00
11:30 AM	21551.1	21551.1	3908.5	3908.5	0.553	0.553	22.9	22.9	0	0	0.00	0.00

12:00 PM	20929.1	20929.1	3673.5	3673.5	0.536	0.536	22.9	22.9	0	0	0.00	0.00
12:30 PM	19111.3	19111.3	3034.2	3034.2	0.488	0.488	22.9	22.9	0	0	0.00	0.00
1:00 PM	18522.6	18522.6	2841.9	2841.9	0.473	0.473	22.9	22.9	0	0	0.00	0.00
1:30 PM	20293.6	20293.6	3442.1	3442.1	0.519	0.519	22.9	22.9	0	0	0.00	0.00
2:00 PM	21033.4	21033.4	3712.3	3712.3	0.539	0.539	22.9	22.9	0	0	0.00	0.00
2:30 PM	22195	22195	4160.8	4160.8	0.57	0.57	22.9	22.9	0	0	0.00	0.00
3:00 PM	22109.7	22109.7	4126.8	4126.8	0.568	0.568	22.9	22.9	0	0	0.00	0.00
3:30 PM	24157.1	24157.1	4987.6	4987.6	0.622	0.622	22.9	22.9	0	0	0.00	0.00
4:00 PM	27531.2	27531.2	6641.9	6641.9	0.715	0.715	22.9	22.9	0	0	0.00	0.00
4:30 PM	32729.2	32729.2	9837.9	9837.9	0.862	0.862	22.9	22.9	0	0	0.00	0.00
5:00 PM	33202.8	33202.8	9788.2	9788.2	0.873	0.873	22.9	22.9	0	0	0.00	0.00
5:30 PM	39179.1	39179.1	14462.7	14462.7	1.054	1.054	22.9	22.9	0	0	0.00	0.00
6:00 PM	47744.5	47744.5	24945.4	24945.4	1.359	1.359	22.9	22.9	0	0	0.00	0.00
6:30 PM	35110.3	35110.3	9775.5	9775.5	0.92	0.92	22.9	22.9	0	0	0.00	0.00
7:00 PM	34772.9	34772.9	9583	9583	0.91	0.91	22.9	22.9	0	0	0.00	0.00
7:30 PM	49035.5	49035.5	27365.5	27365.5	1.417	1.417	22.9	22.9	0	0	0.00	0.00
8:00 PM	45360	45360	21312.6	21312.6	1.265	1.265	22.9	22.9	0	0	0.00	0.00
8:30 PM	42673.6	42673.6	17983	17983	1.169	1.169	22.9	22.9	0	0	0.00	0.00
9:00 PM	40154.5	40154.5	15374.9	15374.9	1.085	1.085	22.9	22.9	0	0	0.00	0.00
9:30 PM	37638	37638	13116.7	13116.7	1.006	1.006	22.9	22.9	0	0	0.00	0.00
10:00 PM	34310.2	34310.2	10551.6	10551.6	0.906	0.906	22.9	22.9	0	0	0.00	0.00
10:30 PM	39750.4	39583	15941.9	15858.4	1.081	1.076	22.9	22.9	0	0	0.42	0.52
11:00 PM	39808.1	39640	16004.2	15920.3	1.083	1.078	22.9	22.9	0	0	0.42	0.52
11:30 PM	33611.8	33611.8	10065.4	10065.4	0.885	0.885	22.9	22.9	0	0	0.00	0.00

b) Network 2

At present, there is no front-of-the-meter DER connected to Network 2.

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 41. 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 42. Figure 43 shows the representative daily profiles https://www.powercor.com.au/network-planning-and-projects/network-planning/.

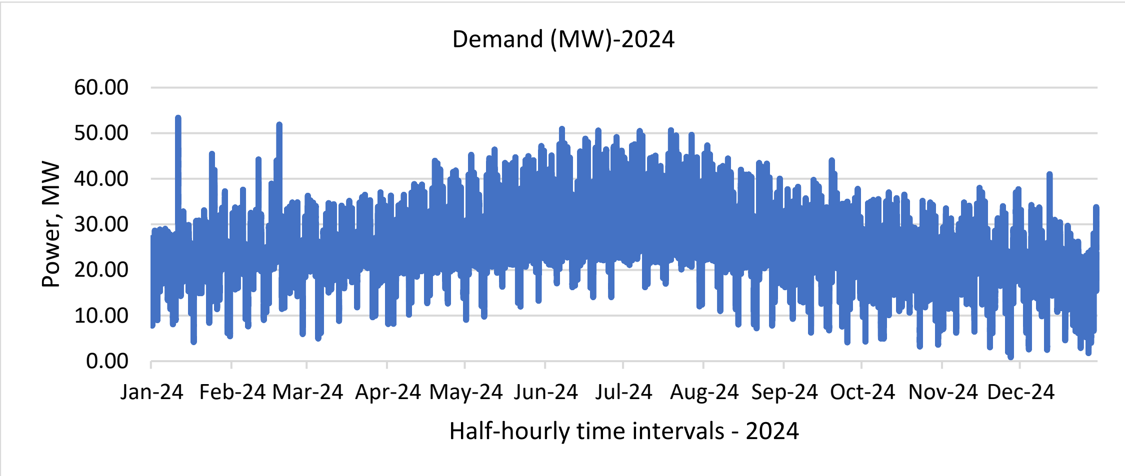

Figure 41 The aggregated time-series data 2024 from Geelong East zone substation.

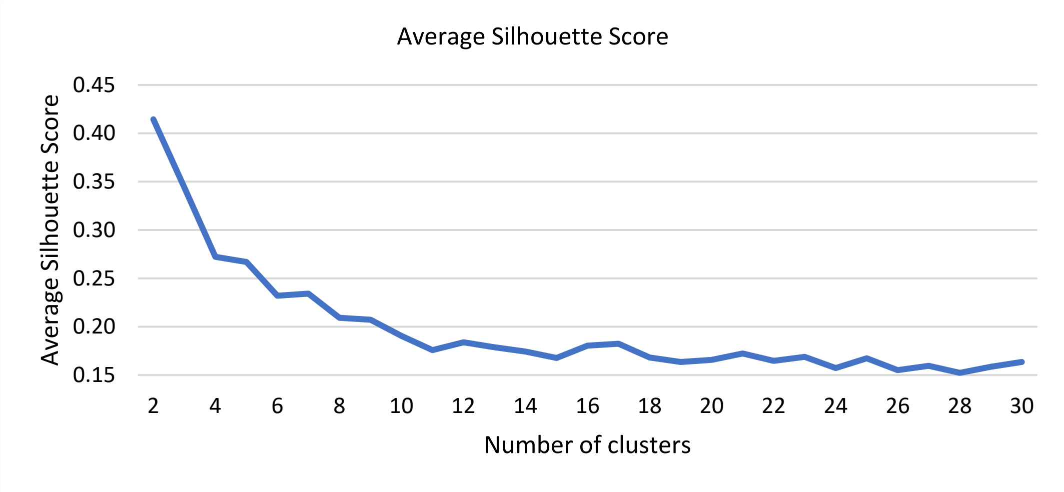

Figure 42 Silhouette criterion results for the time series data 2024.

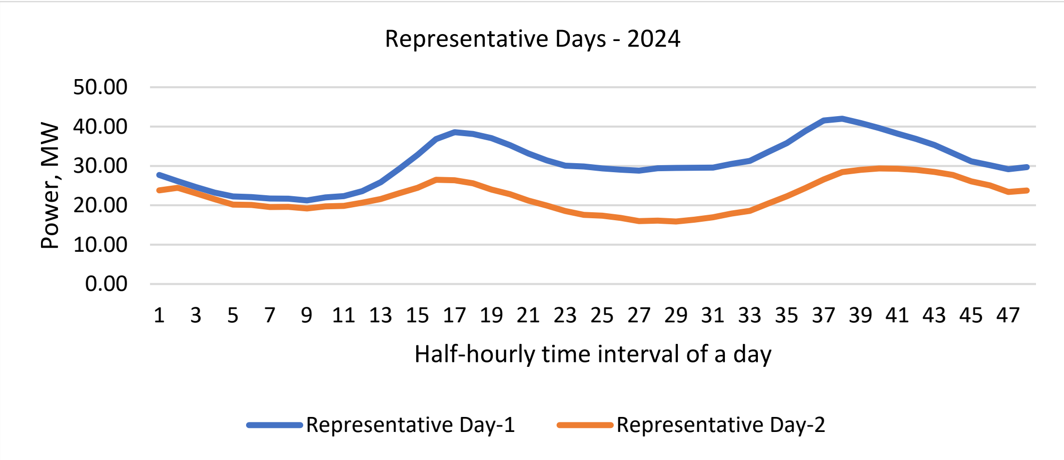

Figure 43 Representative daily profiles obtained by the K-means clustering method.

Representative reduced network

The Ward network reduction method has been implemented to reduce the network. The accuracy of the non-linear AC power flow for the reduced network, compared to the original network, is analysed. A total of 96 representative networks (for the 96 representative half-hour time intervals) are obtained for the two representative days. The comparison among the active power, reactive power, current, and voltage at PCC for the full network and reduced network of both feeders are presented in Figure 44, Figure 45, Figure 46, and Figure 47. From the results given in these figures, no differences in the network quantities for the detailed and the reduced networks are observed. The phase angle of zero degrees is reported for both networks.

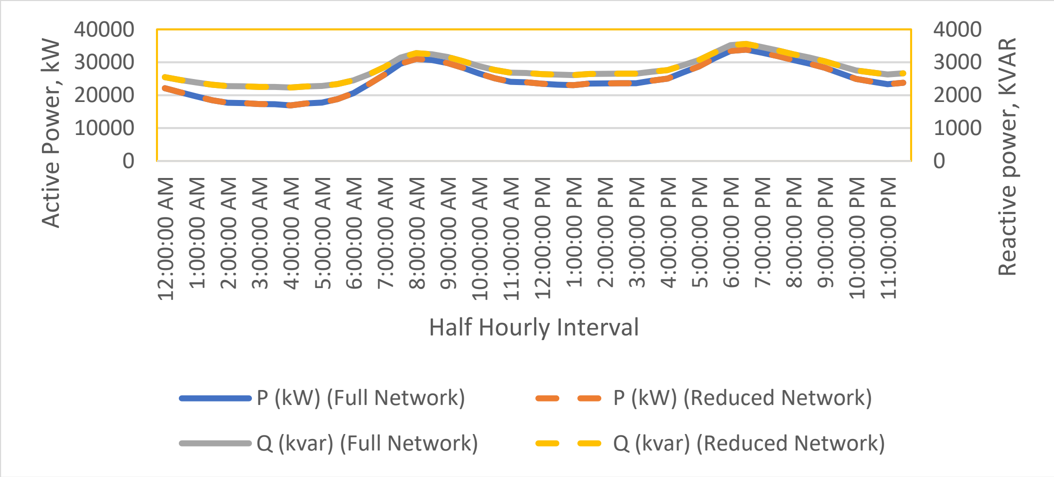

Figure 44 Active and reactive power comparison for full network and reduced network (Feeder 1).

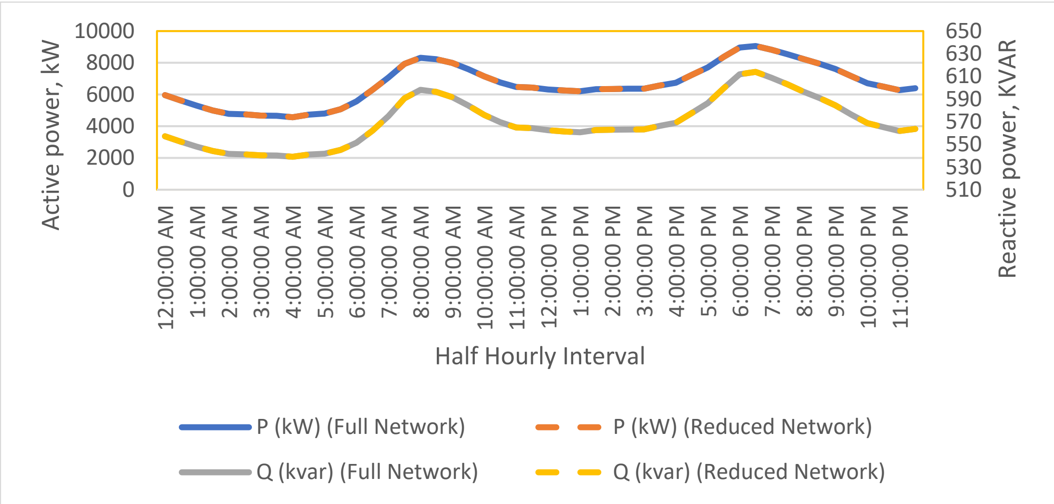

Figure 455 Active and reactive power comparison for full network and reduced network (Feeder 2).

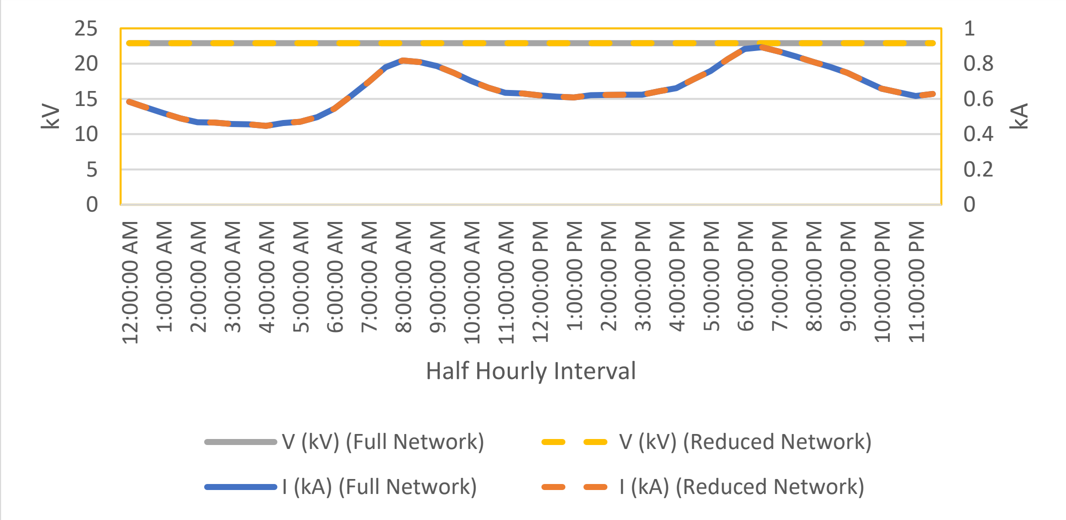

Figure 466 Current and voltage plots for the full network and reduced network (Feeder 1).

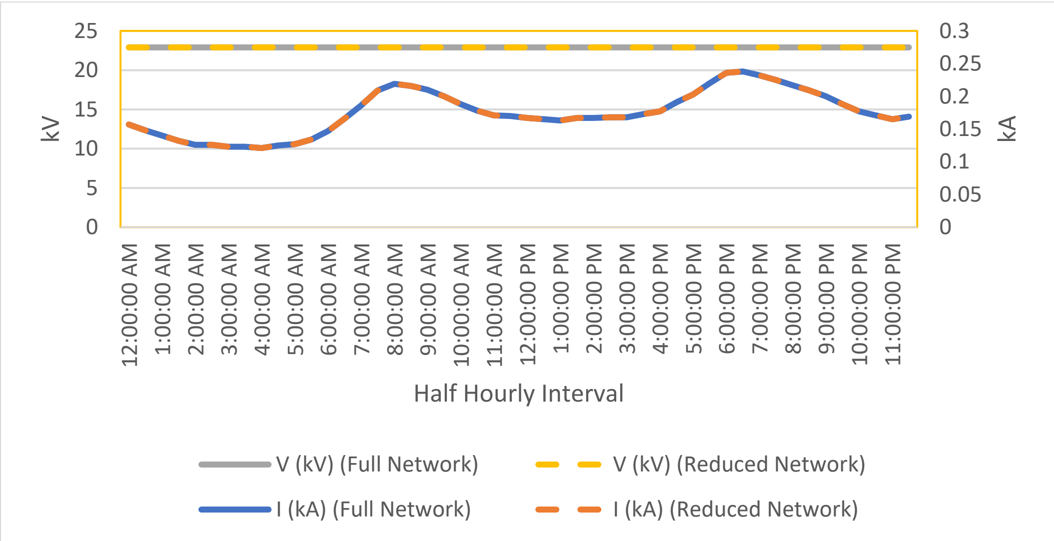

Figure 47 Current and voltage plots for the full network and reduced network (Feeder 2).

All key parameters such as active and reactive powers, voltages, and currents at PCC for both the full and reduced network are compared in Table 11 and Table 12. No differences in the network quantities for the detailed and the reduced networks are observed.

Table 11 Key parameters at PCC of full and reduced networks – feeder 1

Time	P (kW) (Full Network)	P (kW) (Reduced Network)	Q (KVAR) (Full Network)	Q (KVAR) (Reduced Network)	I (kA) (Full Network)	I (kA) (Reduced Network)	V (kV) (Full Network)	V (kV) (Reduced Network)	Phase Angle (Full Network)	Phase Angle (Reduced Network)	Error (%), P	Error (%), Q
12:00 AM	22123.4	22123.4	2547.4	2547.4	0.584	0.584	22.9	22.9	0	0	0.00	0.00
12:30 AM	20844.6	20844.6	2462.7	2462.7	0.551	0.551	22.9	22.9	0	0	0.00	0.00
1:00 AM	19619.9	19619.9	2386.3	2386.3	0.519	0.519	22.9	22.9	0	0	0.00	0.00
1:30 AM	18491.7	18491.7	2320.1	2320.1	0.489	0.489	22.9	22.9	0	0	0.00	0.00
2:00 AM	17703.6	17703.6	2276.1	2276.1	0.468	0.468	22.9	22.9	0	0	0.00	0.00
2:30 AM	17600.9	17600.9	2270.5	2270.5	0.466	0.466	22.9	22.9	0	0	0.00	0.00
3:00 AM	17288.5	17288.5	2253.7	2253.7	0.458	0.458	22.9	22.9	0	0	0.00	0.00
3:30 AM	17245.7	17245.7	2251.4	2251.4	0.456	0.456	22.9	22.9	0	0	0.00	0.00
4:00 AM	16899.3	16899.3	2233.2	2233.2	0.447	0.447	22.9	22.9	0	0	0.00	0.00
4:30 AM	17506.7	17506.7	2265.4	2265.4	0.463	0.463	22.9	22.9	0	0	0.00	0.00
5:00 AM	17767.8	17767.8	2279.6	2279.6	0.47	0.47	22.9	22.9	0	0	0.00	0.00
5:30 AM	18804.7	18804.7	2338.1	2338.1	0.497	0.497	22.9	22.9	0	0	0.00	0.00
6:00 AM	20638.2	20638.2	2449.5	2449.5	0.545	0.545	22.9	22.9	0	0	0.00	0.00
6:30 AM	23387.4	23387.4	2636	2636	0.618	0.618	22.9	22.9	0	0	0.00	0.00
7:00 AM	26321.8	26321.8	2860.7	2860.7	0.695	0.695	22.9	22.9	0	0	0.00	0.00
7:30 AM	29566	29566	3140	3140	0.78	0.78	22.9	22.9	0	0	0.00	0.00
8:00 AM	31015.1	31015.1	3275.3	3275.3	0.818	0.818	22.9	22.9	0	0	0.00	0.00
8:30 AM	30656.9	30656.9	3241.2	3241.2	0.809	0.809	22.9	22.9	0	0	0.00	0.00
9:00 AM	29779.7	29779.7	3159.6	3159.6	0.786	0.786	22.9	22.9	0	0	0.00	0.00
9:30 AM	28307.3	28307.3	3027.8	3027.8	0.747	0.747	22.9	22.9	0	0	0.00	0.00
10:00 AM	26577.8	26577.8	2881.6	2881.6	0.702	0.702	22.9	22.9	0	0	0.00	0.00
10:30 AM	25143	25143	2767.3	2767.3	0.664	0.664	22.9	22.9	0	0	0.00	0.00
11:00 AM	24057.1	24057.1	2685	2685	0.635	0.635	22.9	22.9	0	0	0.00	0.00
11:30 AM	23901.5	23901.5	2673.5	2673.5	0.631	0.631	22.9	22.9	0	0	0.00	0.00

12:00 PM	23473.8	23473.8	2642.2	2642.2	0.62	0.62	22.9	22.9	0	0	0.00	0.00
12:30 PM	23214.7	23214.7	2623.6	2623.6	0.613	0.613	22.9	22.9	0	0	0.00	0.00
1:00 PM	23033.4	23033.4	2610.7	2610.7	0.608	0.608	22.9	22.9	0	0	0.00	0.00
1:30 PM	23525.6	23525.6	2646	2646	0.621	0.621	22.9	22.9	0	0	0.00	0.00
2:00 PM	23581.8	23581.8	2650.1	2650.1	0.623	0.623	22.9	22.9	0	0	0.00	0.00
2:30 PM	23629.3	23629.3	2653.5	2653.5	0.624	0.624	22.9	22.9	0	0	0.00	0.00
3:00 PM	23646.5	23646.5	2654.8	2654.8	0.624	0.624	22.9	22.9	0	0	0.00	0.00
3:30 PM	24403	24403	2710.8	2710.8	0.644	0.644	22.9	22.9	0	0	0.00	0.00
4:00 PM	25043.4	25043.4	2759.6	2759.6	0.661	0.661	22.9	22.9	0	0	0.00	0.00
4:30 PM	26925.1	26925.1	2910.2	2910.2	0.711	0.711	22.9	22.9	0	0	0.00	0.00
5:00 PM	28738.2	28738.2	3065.7	3065.7	0.758	0.758	22.9	22.9	0	0	0.00	0.00
5:30 PM	31259.8	31259.8	3298.7	3298.7	0.825	0.825	22.9	22.9	0	0	0.00	0.00
6:00 PM	33466.7	33466.7	3518.7	3518.7	0.883	0.883	22.9	22.9	0	0	0.00	0.00
6:30 PM	33844.1	33844.1	3557.9	3557.9	0.893	0.893	22.9	22.9	0	0	0.00	0.00
7:00 PM	32927.4	32927.4	3463.6	3463.6	0.869	0.869	22.9	22.9	0	0	0.00	0.00
7:30 PM	31880.8	31880.8	3359.1	3359.1	0.841	0.841	22.9	22.9	0	0	0.00	0.00
8:00 PM	30700.5	30700.5	3245.4	3245.4	0.81	0.81	22.9	22.9	0	0	0.00	0.00
8:30 PM	29614	29614	3144.4	3144.4	0.782	0.782	22.9	22.9	0	0	0.00	0.00
9:00 PM	28350.8	28350.8	3031.6	3031.6	0.748	0.748	22.9	22.9	0	0	0.00	0.00
9:30 PM	26629.9	26629.9	2885.9	2885.9	0.703	0.703	22.9	22.9	0	0	0.00	0.00
10:00 PM	24939.5	24939.5	2751.6	2751.6	0.658	0.658	22.9	22.9	0	0	0.00	0.00
10:30 PM	24134.9	24134.9	2690.7	2690.7	0.637	0.637	22.9	22.9	0	0	0.00	0.00
11:00 PM	23318.3	23318.3	2631	2631	0.616	0.616	22.9	22.9	0	0	0.00	0.00
11:30 PM	23767.5	23767.5	2663.6	2663.6	0.628	0.628	22.9	22.9	0	0	0.00	0.00

Table 12 Key parameters at PCC of full and reduced networks - feeder 2

Time	P (kW) (Full Network)	P (kW) (Reduced Network)	Q (KVAR) (Full Network)	Q (KVAR) (Reduced Network)	I (kA) (Full Network)	I (kA) (Reduced Network)	V (kV) (Full Network)	V (kV) (Reduced Network)	Phase Angle (Full Network)	Phase Angle (Reduced Network)	Error (%), P	Error (%), Q
12:00 AM	5962.7	5962.7	557.1	557.1	0.157	0.157	22.9	22.9	0	0	0.00	0.00
12:30 AM	5622.2	5622.2	552.3	552.3	0.148	0.148	22.9	22.9	0	0	0.00	0.00
1:00 AM	5295.7	5295.7	547.9	547.9	0.14	0.14	22.9	22.9	0	0	0.00	0.00
1:30 AM	4994.5	4994.5	544.1	544.1	0.132	0.132	22.9	22.9	0	0	0.00	0.00
2:00 AM	4783.8	4783.8	541.6	541.6	0.126	0.126	22.9	22.9	0	0	0.00	0.00
2:30 AM	4756.3	4756.3	541.2	541.2	0.126	0.126	22.9	22.9	0	0	0.00	0.00
3:00 AM	4672.7	4672.7	540.3	540.3	0.123	0.123	22.9	22.9	0	0	0.00	0.00
3:30 AM	4661.3	4661.3	540.2	540.2	0.123	0.123	22.9	22.9	0	0	0.00	0.00
4:00 AM	4568.6	4568.6	539.1	539.1	0.121	0.121	22.9	22.9	0	0	0.00	0.00
4:30 AM	4731.1	4731.1	541	541	0.125	0.125	22.9	22.9	0	0	0.00	0.00
5:00 AM	4801	4801	541.8	541.8	0.127	0.127	22.9	22.9	0	0	0.00	0.00
5:30 AM	5078.1	5078.1	545.1	545.1	0.134	0.134	22.9	22.9	0	0	0.00	0.00
6:00 AM	5567.2	5567.2	551.5	551.5	0.147	0.147	22.9	22.9	0	0	0.00	0.00
6:30 AM	6298.7	6298.7	562.1	562.1	0.166	0.166	22.9	22.9	0	0	0.00	0.00
7:00 AM	7076.7	7076.7	574.9	574.9	0.186	0.186	22.9	22.9	0	0	0.00	0.00
7:30 AM	7933.6	7933.6	590.6	590.6	0.209	0.209	22.9	22.9	0	0	0.00	0.00
8:00 AM	8315.3	8315.3	598.2	598.2	0.219	0.219	22.9	22.9	0	0	0.00	0.00
8:30 AM	8221	8221	596.3	596.3	0.216	0.216	22.9	22.9	0	0	0.00	0.00
9:00 AM	7990	7990	591.7	591.7	0.21	0.21	22.9	22.9	0	0	0.00	0.00
9:30 AM	7601.5	7601.5	584.3	584.3	0.2	0.2	22.9	22.9	0	0	0.00	0.00
10:00 AM	7144.4	7144.4	576	576	0.188	0.188	22.9	22.9	0	0	0.00	0.00
10:30 AM	6764.5	6764.5	569.6	569.6	0.178	0.178	22.9	22.9	0	0	0.00	0.00
11:00 AM	6476.5	6476.5	564.9	564.9	0.171	0.171	22.9	22.9	0	0	0.00	0.00
11:30 AM	6435.2	6435.2	564.3	564.3	0.17	0.17	22.9	22.9	0	0	0.00	0.00

12:00 PM	6321.6	6321.6	562.5	562.5	0.167	0.167	22.9	22.9	0	0	0.00	0.00
12:30 PM	6252.8	6252.8	561.4	561.4	0.165	0.165	22.9	22.9	0	0	0.00	0.00
1:00 PM	6204.6	6204.6	560.7	560.7	0.163	0.163	22.9	22.9	0	0	0.00	0.00
1:30 PM	6335.4	6335.4	562.7	562.7	0.167	0.167	22.9	22.9	0	0	0.00	0.00
2:00 PM	6350.3	6350.3	562.9	562.9	0.167	0.167	22.9	22.9	0	0	0.00	0.00
2:30 PM	6362.9	6362.9	563.1	563.1	0.168	0.168	22.9	22.9	0	0	0.00	0.00
3:00 PM	6367.5	6367.5	563.2	563.2	0.168	0.168	22.9	22.9	0	0	0.00	0.00
3:30 PM	6568.2	6568.2	566.4	566.4	0.173	0.173	22.9	22.9	0	0	0.00	0.00
4:00 PM	6738.1	6738.1	569.1	569.1	0.177	0.177	22.9	22.9	0	0	0.00	0.00
4:30 PM	7236.3	7236.3	577.7	577.7	0.191	0.191	22.9	22.9	0	0	0.00	0.00
5:00 PM	7715.3	7715.3	586.4	586.4	0.203	0.203	22.9	22.9	0	0	0.00	0.00
5:30 PM	8379.7	8379.7	599.5	599.5	0.22	0.22	22.9	22.9	0	0	0.00	0.00
6:00 PM	8959.5	8959.5	611.8	611.8	0.236	0.236	22.9	22.9	0	0	0.00	0.00
6:30 PM	9058.5	9058.5	614	614	0.238	0.238	22.9	22.9	0	0	0.00	0.00
7:00 PM	8818	8818	608.7	608.7	0.232	0.232	22.9	22.9	0	0	0.00	0.00
7:30 PM	8543	8543	602.9	602.9	0.225	0.225	22.9	22.9	0	0	0.00	0.00
8:00 PM	8232.5	8232.5	596.5	596.5	0.217	0.217	22.9	22.9	0	0	0.00	0.00
8:30 PM	7946.3	7946.3	590.9	590.9	0.209	0.209	22.9	22.9	0	0	0.00	0.00
9:00 PM	7613	7613	584.5	584.5	0.2	0.2	22.9	22.9	0	0	0.00	0.00
9:30 PM	7158.2	7158.2	576.3	576.3	0.188	0.188	22.9	22.9	0	0	0.00	0.00
10:00 PM	6710.5	6710.5	568.7	568.7	0.177	0.177	22.9	22.9	0	0	0.00	0.00
10:30 PM	6497.1	6497.1	565.2	565.2	0.171	0.171	22.9	22.9	0	0	0.00	0.00
11:00 PM	6280.3	6280.3	561.8	561.8	0.165	0.165	22.9	22.9	0	0	0.00	0.00
11:30 PM	6399.6	6399.6	563.7	563.7	0.169	0.169	22.9	22.9	0	0	0.00	0.00

c) 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.

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 48. The wind profile from 2021 is considered as a general wind power generation profile for this station and used for generating representative daily profiles (as presented in Figure 49). The developed three-step clustering method has been used to obtain representative daily profiles. The combined time series profile is presented in Figure 50. The K-means clustering method is used to identify the representative clusters in the combined time series profile and is presented in Figure 51. 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 52, while the time series profile of representative day-2 is presented in Figure 53.

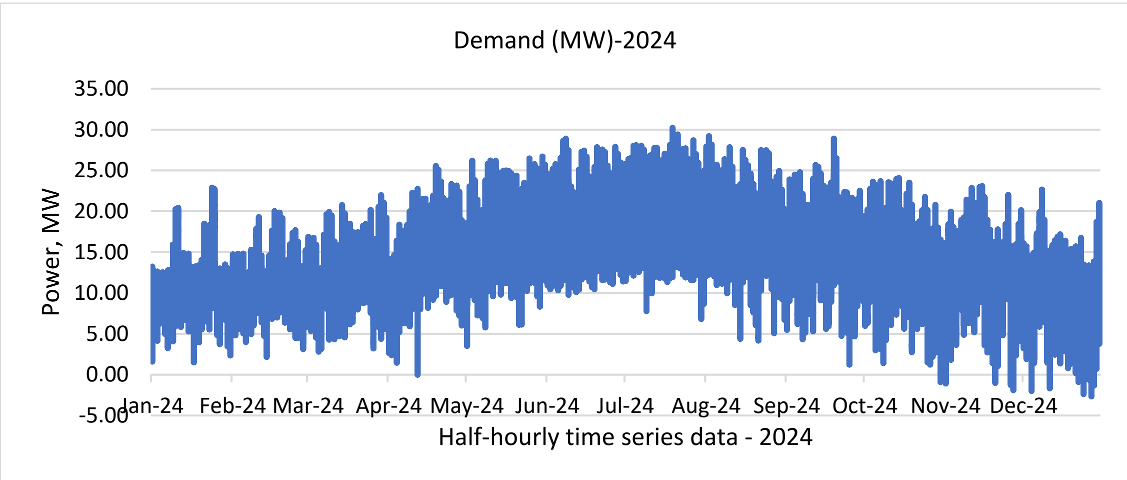

Figure 48 The aggregated time-series data 2024 from Ballarat South zone substation.

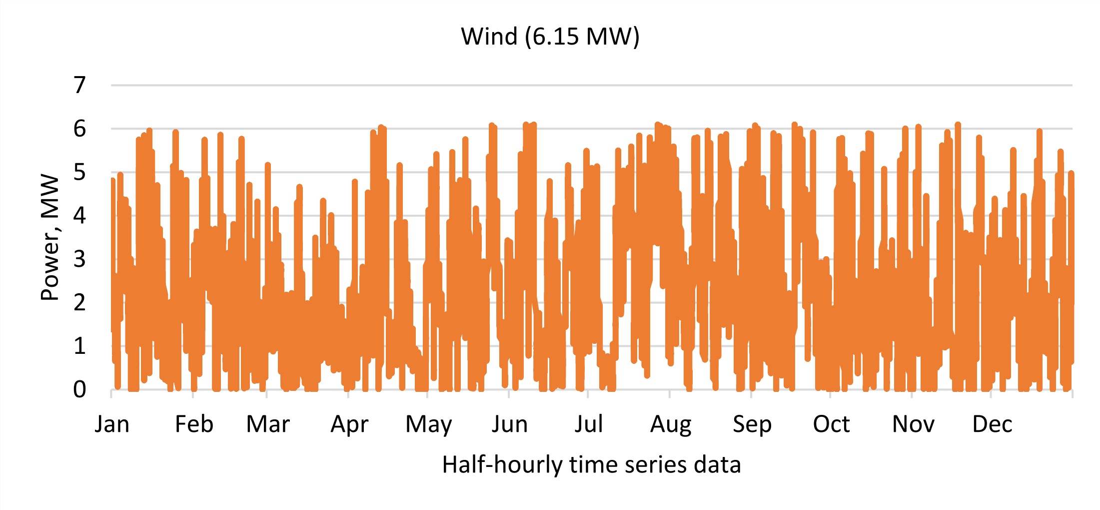

Figure 49 Yearly Wind profile - Chepstowe wind farm.

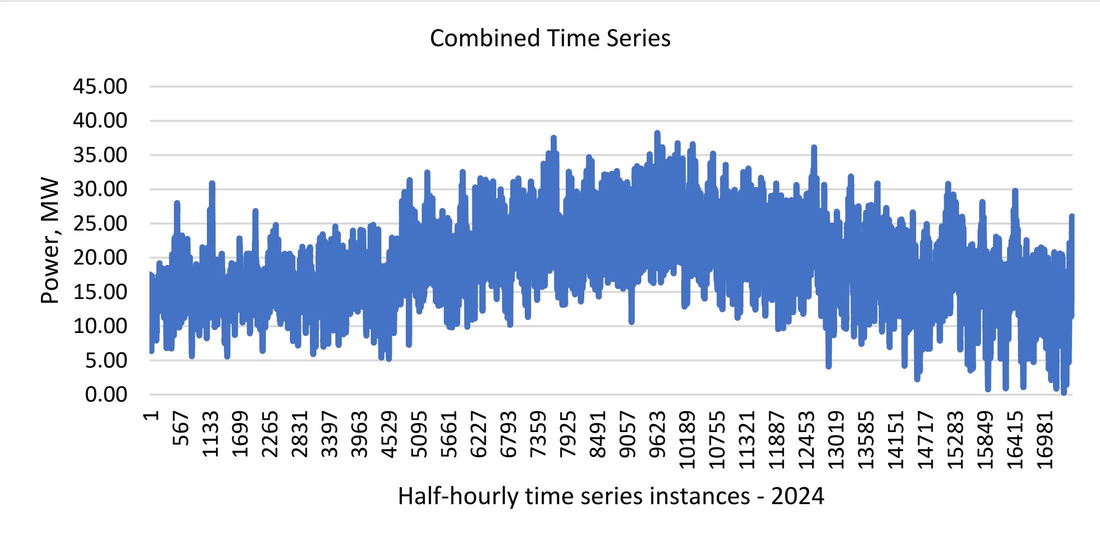

Figure 50 Combined time series data.

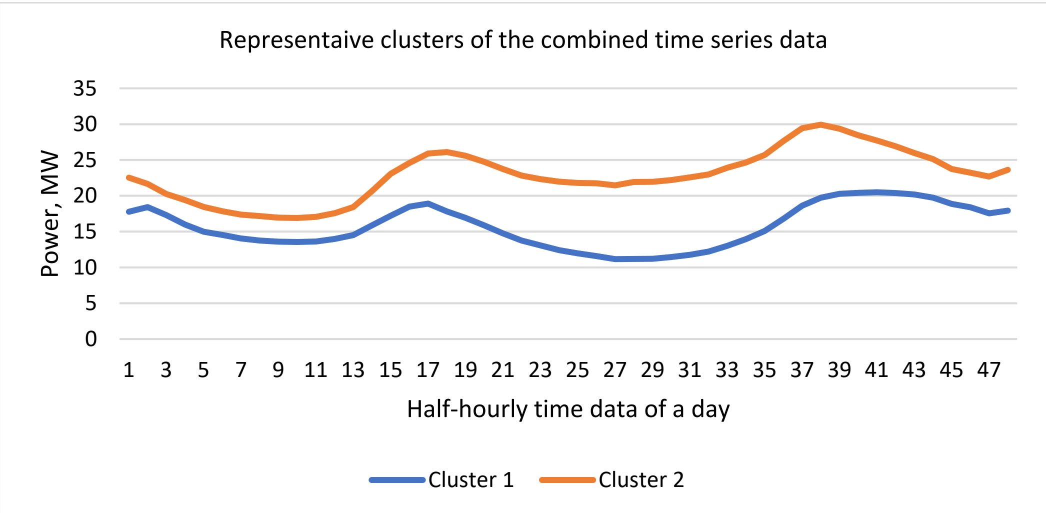

Figure 51 Representative clusters of the combined time series.

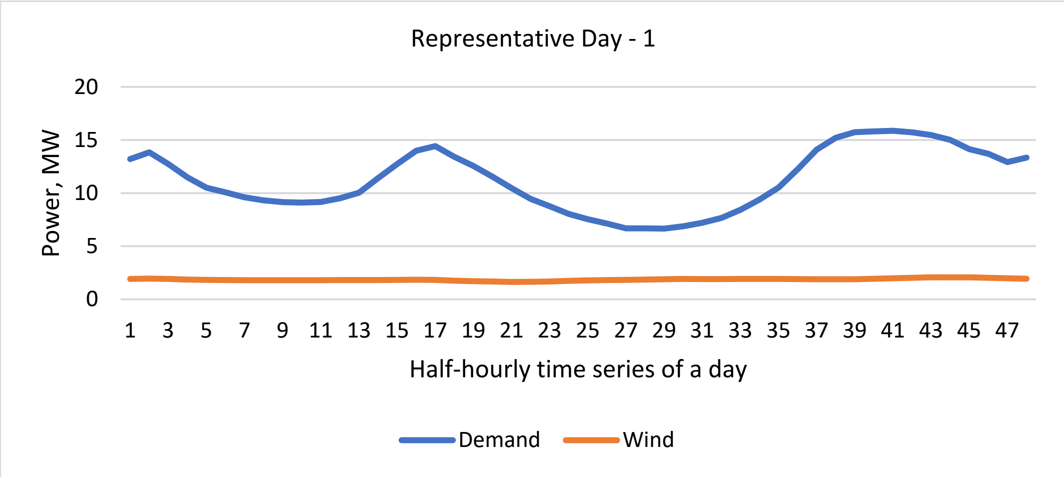

Figure 52 Daily profile - representative day-1 obtained using 3-step time aggregation method.

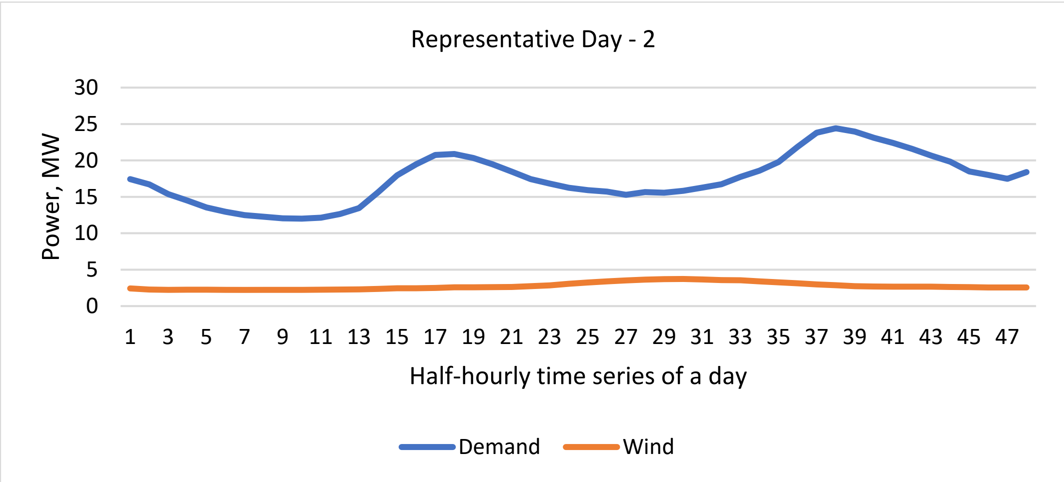

Figure 53 Daily profile - representative day-2 obtained using 3-step time aggregation method.

Representative reduced network

The representative profiles obtained using the 3-step time aggregation method are used to generate a reduced representative network. The accuracy of the non-linear AC power flow for the reduced network, compared to the original network, is analysed. The Ward network reduction method has been implemented to reduce the network. The comparison among the active power, reactive power, current, and voltage at PCC for the full network and reduced network is presented in Figure 54 and Figure 55, respectively. The maximum active power in the detailed network is 23481.3 kW and the maximum reactive power in the detailed network is 4357.7 KVAR. The maximum active power error is 20.7 kW and the maximum reactive power error is 31.5 KVAR while obtaining the reduced network from the detail network. The phase angle of zero degrees is reported for both networks.

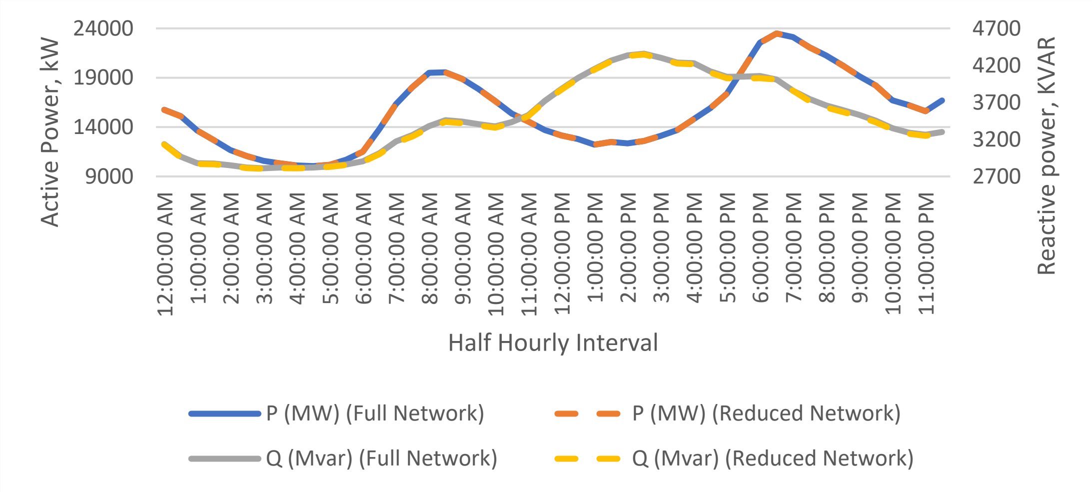

Figure 54 Active and reactive power comparison for full network and reduced network.

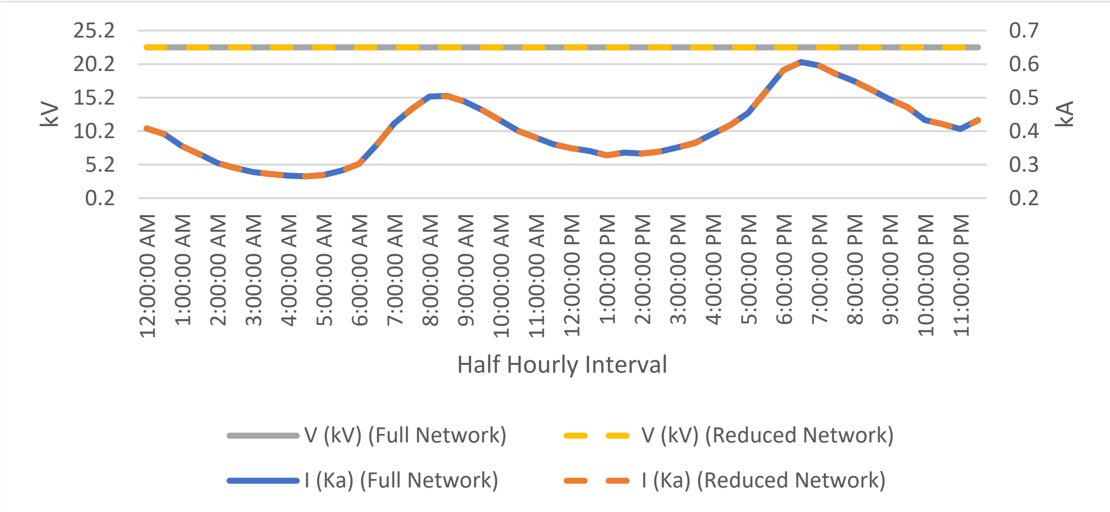

Figure 55 Current and voltage plots for the full network and reduced network.

All key parameters such as active and reactive powers, voltages, and currents at PCC for both the full and reduced network are compared in Table 13. A 0.09% maximum error in active power and a 0.8% maximum error in reactive power for the detailed and the reduced networks are observed.

Table 13 Key parameters at PCC of full and reduced network

Time	P (kW) (Full Network)	P (kW) (Reduced Network)	Q (KVAR) (Full Network)	Q (KVAR) (Reduced Network)	I (kA) (Full Network)	I (kA) (Reduced Network)	V (kV) (Full Network)	V (kV) (Reduced Network)	Phase Angle (Full Network)	Phase Angle (Reduced Network)	Error (%), P	Error (%), Q
12:00 AM	15745	15740.9	3135.3	3130.1	0.408	0.408	22.7	22.7	0	0	0.03	0.17
12:30 AM	15101.2	15091.8	2967.8	2953.6	0.391	0.391	22.7	22.7	0	0	0.06	0.48
1:00 AM	13650.8	13643.1	2879.2	2867.5	0.355	0.355	22.7	22.7	0	0	0.06	0.41
1:30 AM	12673.8	12667.1	2873.9	2863.8	0.331	0.33	22.7	22.7	0	0	0.05	0.35
2:00 AM	11667.6	11661.9	2850.4	2841.7	0.305	0.305	22.7	22.7	0	0	0.05	0.31
2:30 AM	11053.6	11048.5	2819.5	2811.7	0.29	0.29	22.7	22.7	0	0	0.05	0.28
3:00 AM	10578	10573.3	2810.2	2803	0.278	0.278	22.7	22.7	0	0	0.04	0.26
3:30 AM	10328.9	10324.4	2819	2812.1	0.272	0.272	22.7	22.7	0	0	0.04	0.24
4:00 AM	10105.4	10101.1	2814.9	2808.3	0.267	0.267	22.7	22.7	0	0	0.04	0.23
4:30 AM	10044.9	10040.6	2821.1	2814.6	0.265	0.265	22.7	22.7	0	0	0.04	0.23
5:00 AM	10181.2	10176.6	2834.8	2828.1	0.269	0.269	22.7	22.7	0	0	0.05	0.24
5:30 AM	10692	10687.2	2862	2854.7	0.282	0.281	22.7	22.7	0	0	0.04	0.26
6:00 AM	11512.5	11506.9	2903.4	2894.9	0.302	0.302	22.7	22.7	0	0	0.05	0.29
6:30 AM	13793.3	13785.4	3012	3000	0.359	0.359	22.7	22.7	0	0	0.06	0.40
7:00 AM	16326	16315.1	3172.5	3155.9	0.423	0.423	22.7	22.7	0	0	0.07	0.52
7:30 AM	18049.7	18036.4	3259.7	3239.5	0.467	0.466	22.7	22.7	0	0	0.07	0.62
8:00 AM	19501.1	19485.6	3379.9	3356.4	0.503	0.503	22.7	22.7	0	0	0.08	0.70
8:30 AM	19548.2	19532.7	3459.4	3435.7	0.505	0.504	22.7	22.7	0	0	0.08	0.69
9:00 AM	18874.8	18860.3	3441.1	3419	0.488	0.488	22.7	22.7	0	0	0.08	0.64
9:30 AM	17840.6	17827.5	3406.5	3386.7	0.462	0.462	22.7	22.7	0	0	0.07	0.58
10:00 AM	16646.2	16634.8	3376.5	3359.1	0.432	0.432	22.7	22.7	0	0	0.07	0.52
10:30 AM	15368.7	15358.9	3434	3419.1	0.401	0.4	22.7	22.7	0	0	0.06	0.43
11:00 AM	14563.2	14554.3	3527.2	3513.7	0.381	0.381	22.7	22.7	0	0	0.06	0.38
11:30 AM	13696.4	13688.5	3721.7	3709.6	0.361	0.361	22.7	22.7	0	0	0.06	0.33

12:00 PM	13157	13149.6	3882.2	3870.9	0.349	0.349	22.7	22.7	0	0	0.06	0.29
12:30 PM	12792.6	12785.5	4030.1	4019.3	0.341	0.341	22.7	22.7	0	0	0.06	0.27
1:00 PM	12219.2	12212.6	4151.2	4141.2	0.328	0.328	22.7	22.7	0	0	0.05	0.24
1:30 PM	12492.9	12486	4264.1	4253.6	0.336	0.335	22.7	22.7	0	0	0.06	0.25
2:00 PM	12351.7	12344.9	4336.4	4326.1	0.333	0.333	22.7	22.7	0	0	0.06	0.24
2:30 PM	12595.8	12588.8	4357.7	4347	0.339	0.339	22.7	22.7	0	0	0.06	0.25
3:00 PM	13118.4	13110.9	4302.5	4291	0.351	0.351	22.7	22.7	0	0	0.06	0.27
3:30 PM	13694.3	13686.2	4238.4	4226	0.365	0.364	22.7	22.7	0	0	0.06	0.29
4:00 PM	14810.1	14800.8	4229	4214.8	0.392	0.391	22.7	22.7	0	0	0.06	0.34
4:30 PM	15918.3	15907.7	4118.4	4102.1	0.418	0.418	22.7	22.7	0	0	0.07	0.40
5:00 PM	17389.8	17377.2	4045.9	4026.7	0.454	0.454	22.7	22.7	0	0	0.07	0.47
5:30 PM	19952.3	19935.9	4046.9	4022	0.518	0.517	22.7	22.7	0	0	0.08	0.62
6:00 PM	22538.7	22518	4057	4025.5	0.582	0.582	22.7	22.7	0	0	0.09	0.78
6:30 PM	23481.3	23481.3	4009.8	4009.8	0.606	0.606	22.7	22.7	0	0	0.00	0.00
7:00 PM	23106.9	23106.9	3858.5	3858.5	0.596	0.596	22.7	22.7	0	0	0.00	0.00
7:30 PM	22079	22059.2	3745.2	3715.1	0.57	0.569	22.7	22.7	0	0	0.09	0.80
8:00 PM	21253.8	21235.4	3658.1	3630.2	0.549	0.548	22.7	22.7	0	0	0.09	0.76
8:30 PM	20248.1	20231.4	3596	3570.6	0.523	0.523	22.7	22.7	0	0	0.08	0.71
9:00 PM	19152.3	19137.3	3532	3509.2	0.495	0.495	22.7	22.7	0	0	0.08	0.65
9:30 PM	18223.7	18210.1	3453.1	3432.4	0.472	0.471	22.7	22.7	0	0	0.07	0.60
10:00 PM	16703.1	16691.6	3351.2	3333.7	0.433	0.433	22.7	22.7	0	0	0.07	0.52
10:30 PM	16221.7	16210.9	3292.1	3275.7	0.421	0.421	22.7	22.7	0	0	0.07	0.50
11:00 PM	15613.5	15603.4	3264.2	3248.9	0.406	0.405	22.7	22.7	0	0	0.06	0.47
11:30 PM	16687.7	16676.3	3299	3281.6	0.433	0.432	22.7	22.7	0	0	0.07	0.53

5.3 Case 2B: With Loads 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 the network. 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 (https://www.energy.gov.au/energy-data/australian-energy-statistics/electricity-generation).

a) Network 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 56. A 5 MW solar PV farm is considered 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 time series for 2035 (as presented in Figure 57). The developed 3-step time aggregation method has been used to obtain representative daily profiles. The combined time series profile is presented in Figure 58. The K-means clustering method has been used to identify the representative clusters in the combined time series profile and is presented in Figure 59. 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 60, while the time series profile of representative day-2 is presented in Figure 61. 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.

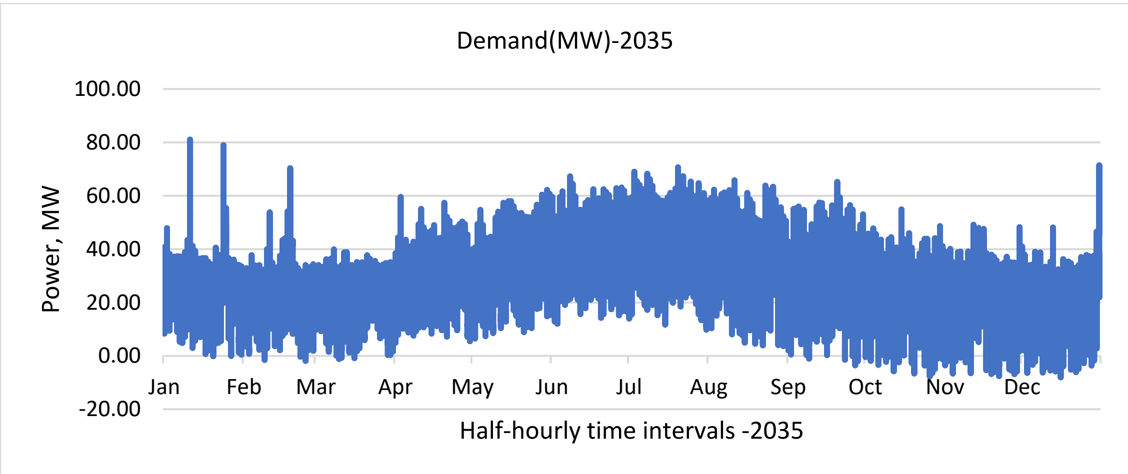

Figure 56 The aggregated time-series data 2035 from Drysdale zone substation.

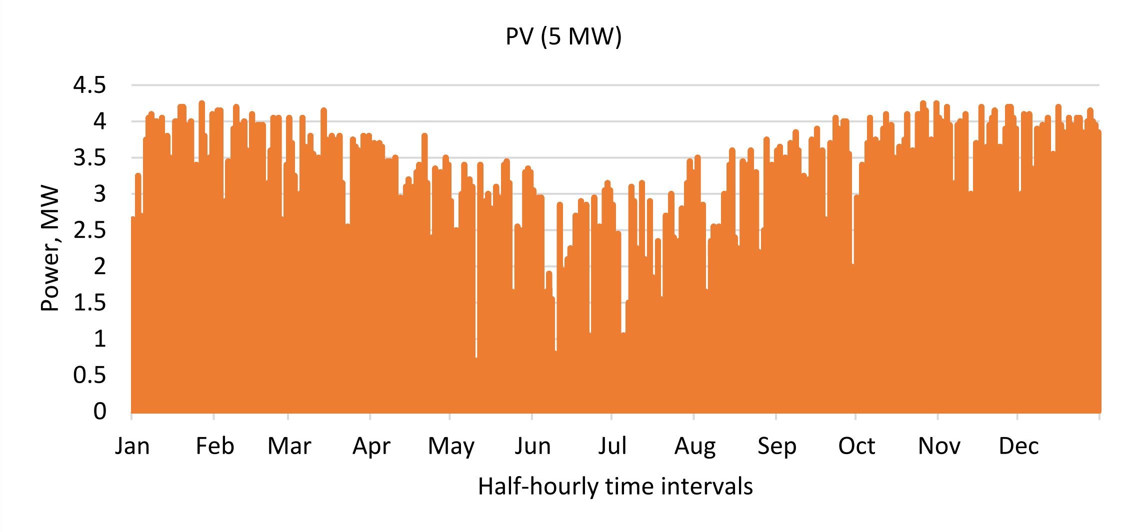

Figure 57 Yearly PV profile - Drysdale area.

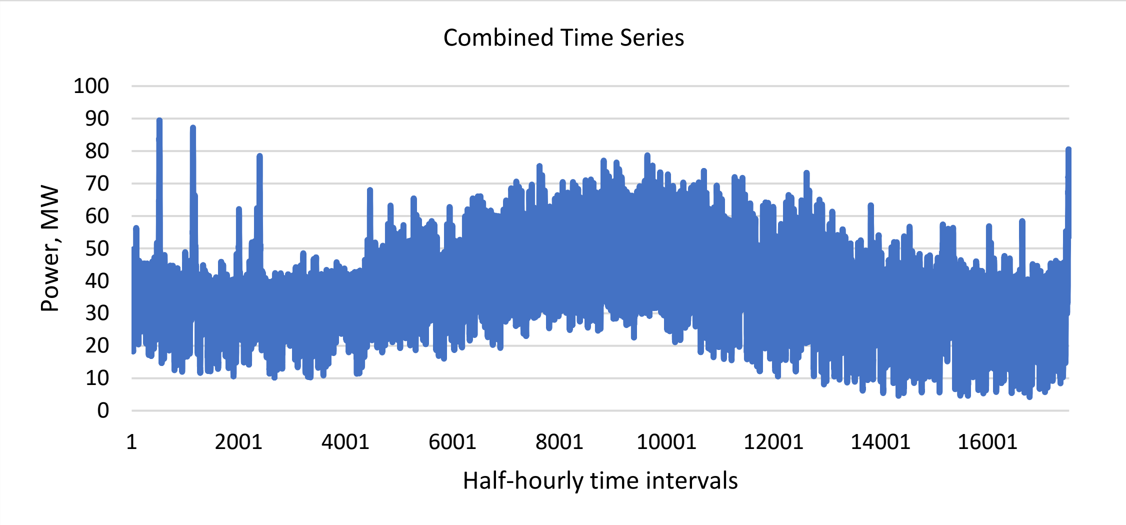

Figure 58 Combined time series data.

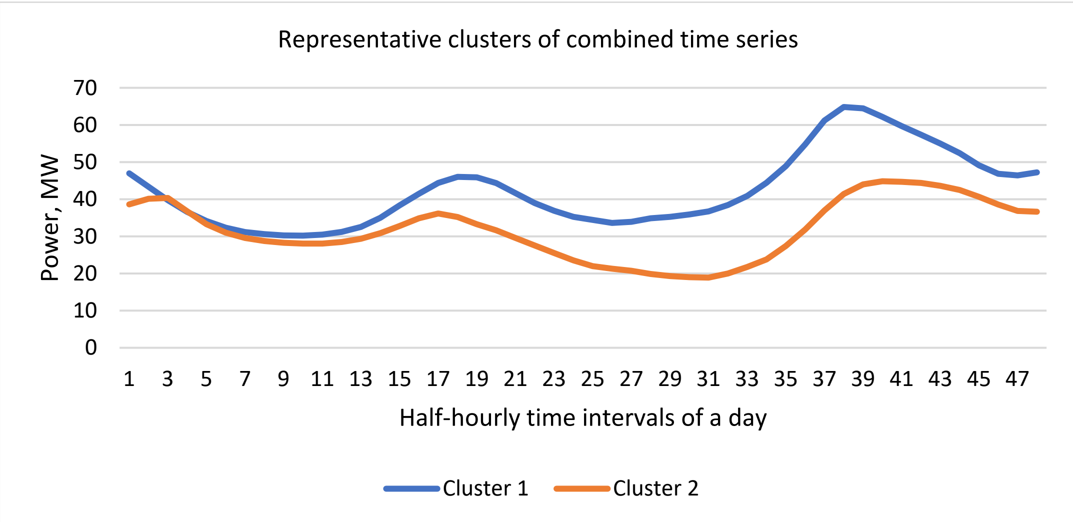

Figure 59 Representative clusters of the combined time series.

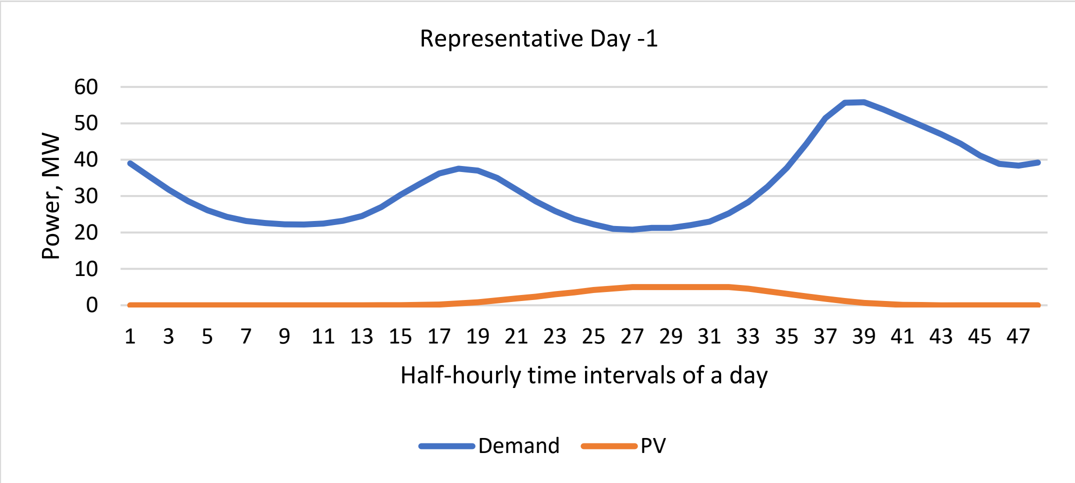

Figure 60 Daily profile - representative day-1 obtained using 3-step time aggregation method.

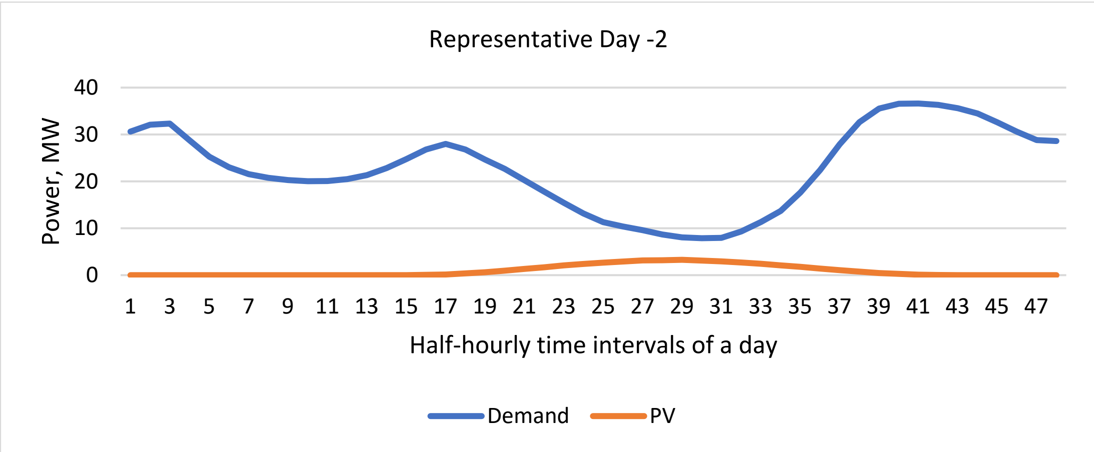

Figure 61 Daily profile - representative day-2 obtained using 3-step time aggregation method.

Representative reduced network

The 3-step time aggregation method is used to obtain representative daily profiles of loads, and PV. The accuracy of the non-linear AC power flow for the reduced network, compared to the original network, has been analysed. The Ward network reduction method has been implemented to reduce the network. The comparison among the active power, reactive power, current, and voltage at PCC for the full network and reduced network is presented in Figure 62 and Figure 63. From the results given in Figure 62 and Figure 63, no differences in the network quantities for the detailed and the reduced networks are observed. The phase angle of zero degree is reported for both networks.

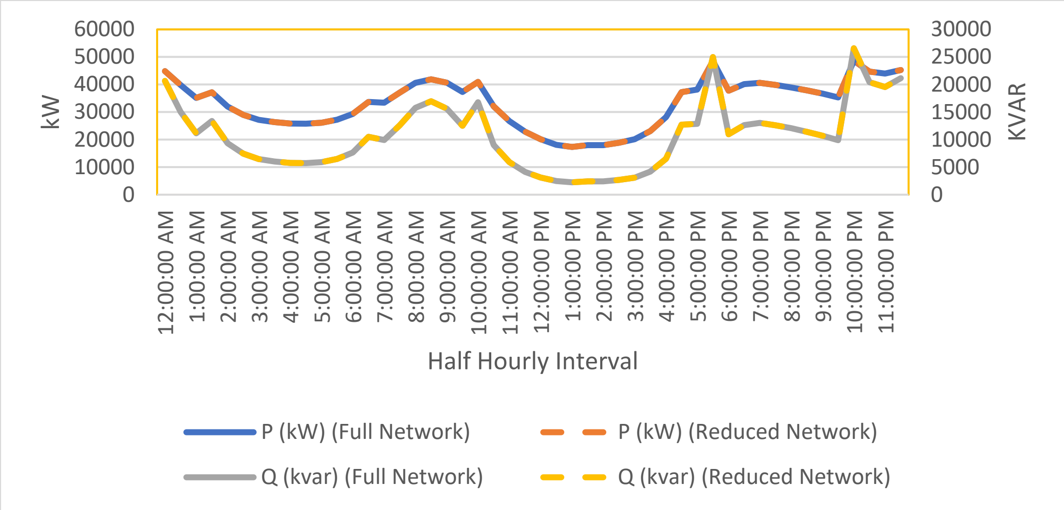

Figure 62 Active and reactive power comparison for full network and reduced network.

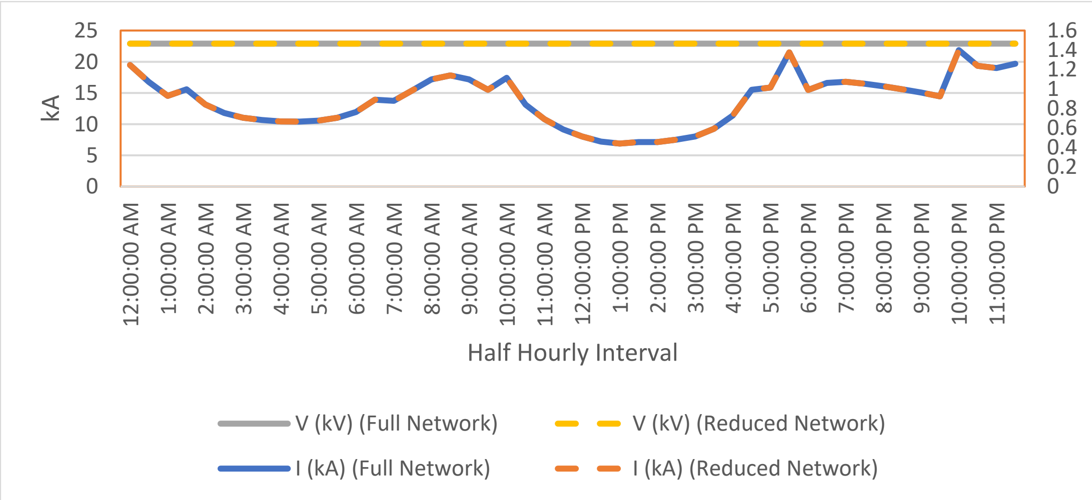

Figure 63 Current and voltage plots for the full network and reduced network.

All key parameters such as active and reactive powers, voltages, and currents at PCC for both the full and reduced network are compared in Table 14. No differences in the network quantities for the detailed and the reduced networks are observed.

Table 14 Key parameters at PCC of full and reduced network

Time	P (kW) (Full Network)	P (kW) (Reduced Network)	Q (KVAR) (Full Network)	Q (KVAR) (Reduced Network)	I (kA) (Full Network)	I (kA) (Reduced Network)	V (kV) (Full Network)	V (kV) (Reduced Network)	Phase Angle (Full Network)	Phase Angle (Reduced Network)	Error (%), P	Error (%), Q
12:00 AM	44868.9	44868.9	20655.3	20655.3	1.246	1.246	22.9	22.9	0	0	0.00	0.00
12:30 AM	39766.7	39766.7	15006.3	15006.3	1.073	1.073	22.9	22.9	0	0	0.00	0.00
1:00 AM	35139.2	35139.2	11151	11151	0.93	0.93	22.9	22.9	0	0	0.00	0.00
1:30 AM	37159.7	37159.7	13381	13381	0.997	0.997	22.9	22.9	0	0	0.00	0.00
2:00 AM	32011.6	32011.6	9342.5	9342.5	0.841	0.841	22.9	22.9	0	0	0.00	0.00
2:30 AM	28995	28995	7455.1	7455.1	0.755	0.755	22.9	22.9	0	0	0.00	0.00
3:00 AM	27180	27180	6456	6456	0.705	0.705	22.9	22.9	0	0	0.00	0.00
3:30 AM	26351.7	26351.7	6021.4	6021.4	0.682	0.682	22.9	22.9	0	0	0.00	0.00
4:00 AM	25838.1	25838.1	5768.8	5768.8	0.668	0.668	22.9	22.9	0	0	0.00	0.00
4:30 AM	25750.2	25750.2	5726.2	5726.2	0.666	0.666	22.9	22.9	0	0	0.00	0.00
5:00 AM	26123.1	26123.1	5908.1	5908.1	0.676	0.676	22.9	22.9	0	0	0.00	0.00
5:30 AM	27235	27235	6484.9	6484.9	0.706	0.706	22.9	22.9	0	0	0.00	0.00
6:00 AM	29337.5	29337.5	7654.5	7654.5	0.765	0.765	22.9	22.9	0	0	0.00	0.00
6:30 AM	33658.9	33658.9	10507.5	10507.5	0.89	0.89	22.9	22.9	0	0	0.00	0.00
7:00 AM	33405.8	33405.8	9922	9922	0.879	0.879	22.9	22.9	0	0	0.00	0.00
7:30 AM	37048.9	37048.9	12607.9	12607.9	0.988	0.988	22.9	22.9	0	0	0.00	0.00
8:00 AM	40606.3	40606.3	15759.2	15759.2	1.099	1.099	22.9	22.9	0	0	0.00	0.00
8:30 AM	41879	41879	16958	16958	1.14	1.14	22.9	22.9	0	0	0.00	0.00
9:00 AM	40642.3	40642.3	15610.6	15610.6	1.099	1.099	22.9	22.9	0	0	0.00	0.00
9:30 AM	37273.1	37273.1	12518.4	12518.4	0.992	0.992	22.9	22.9	0	0	0.00	0.00
10:00 AM	40941.2	40941.2	16778.9	16778.9	1.116	1.116	22.9	22.9	0	0	0.00	0.00
10:30 AM	32032.4	32032.4	9009.8	9009.8	0.84	0.84	22.9	22.9	0	0	0.00	0.00
11:00 AM	26709.3	26709.3	5905	5905	0.69	0.69	22.9	22.9	0	0	0.00	0.00
11:30 AM	22842.7	22842.7	4148.4	4148.4	0.586	0.586	22.9	22.9	0	0	0.00	0.00

12:00 PM	20116.1	20116.1	3123.1	3123.1	0.514	0.514	22.9	22.9	0	0	0.00	0.00
12:30 PM	18118	18118	2482.3	2482.3	0.461	0.461	22.9	22.9	0	0	0.00	0.00
1:00 PM	17340.4	17340.4	2249.6	2249.6	0.441	0.441	22.9	22.9	0	0	0.00	0.00
1:30 PM	17960.9	17960.9	2424.9	2424.9	0.457	0.457	22.9	22.9	0	0	0.00	0.00
2:00 PM	17961.2	17961.2	2425	2425	0.457	0.457	22.9	22.9	0	0	0.00	0.00
2:30 PM	18866.3	18866.3	2694.3	2694.3	0.481	0.481	22.9	22.9	0	0	0.00	0.00
3:00 PM	20140.3	20140.3	3100.9	3100.9	0.514	0.514	22.9	22.9	0	0	0.00	0.00
3:30 PM	23110.6	23110.6	4180.3	4180.3	0.593	0.593	22.9	22.9	0	0	0.00	0.00
4:00 PM	28138.3	28138.3	6509.8	6509.8	0.729	0.729	22.9	22.9	0	0	0.00	0.00
4:30 PM	37207.4	37207.4	12717.1	12717.1	0.992	0.992	22.9	22.9	0	0	0.00	0.00
5:00 PM	38127.6	38127.6	12868.3	12868.3	1.015	1.015	22.9	22.9	0	0	0.00	0.00
5:30 PM	48495.9	48495.9	24966.7	24966.7	1.376	1.376	22.9	22.9	0	0	0.00	0.00
6:00 PM	37719.9	37719.9	10952.3	10952.3	0.991	0.991	22.9	22.9	0	0	0.00	0.00
6:30 PM	40159	40159	12609.8	12609.8	1.062	1.062	22.9	22.9	0	0	0.00	0.00
7:00 PM	40578.3	40578.3	13016.4	13016.4	1.075	1.075	22.9	22.9	0	0	0.00	0.00
7:30 PM	39833.1	39833.1	12596	12596	1.054	1.054	22.9	22.9	0	0	0.00	0.00
8:00 PM	38923.2	38923.2	12066.1	12066.1	1.028	1.028	22.9	22.9	0	0	0.00	0.00
8:30 PM	37843.5	37843.5	11398.1	11398.1	0.997	0.997	22.9	22.9	0	0	0.00	0.00
9:00 PM	36701	36701	10710.2	10710.2	0.965	0.965	22.9	22.9	0	0	0.00	0.00
9:30 PM	35302.4	35302.4	9886	9886	0.925	0.925	22.9	22.9	0	0	0.00	0.00
10:00 PM	48638	48638	26576.5	26576.5	1.399	1.399	22.9	22.9	0	0	0.00	0.00
10:30 PM	44676.4	44676.4	20404.5	20404.5	1.239	1.239	22.9	22.9	0	0	0.00	0.00
11:00 PM	43991.8	43991.8	19541.6	19541.6	1.215	1.215	22.9	22.9	0	0	0.00	0.00
11:30 PM	45237	45237	21145.6	21145.6	1.26	1.26	22.9	22.9	0	0	0.00	0.00

b) Network 2

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

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 64. A 5 MW solar PV farm is considered an illustrative case in 2035. The solar PV generation profile from 2021 is considered a general profile for this area and is used to generate representative daily PV generation profiles for 2035, as presented in Figure 65. The developed 3-step time aggregation method has been used to obtain representative daily profiles. The combined time series profile is presented in Figure 66. The K-means clustering method is used to identify the representative clusters in the combined time series profile, as given in Figure 67. 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– is presented in Figure 68, whereas the time series profile of representative day-2 is presented in Figure 69.

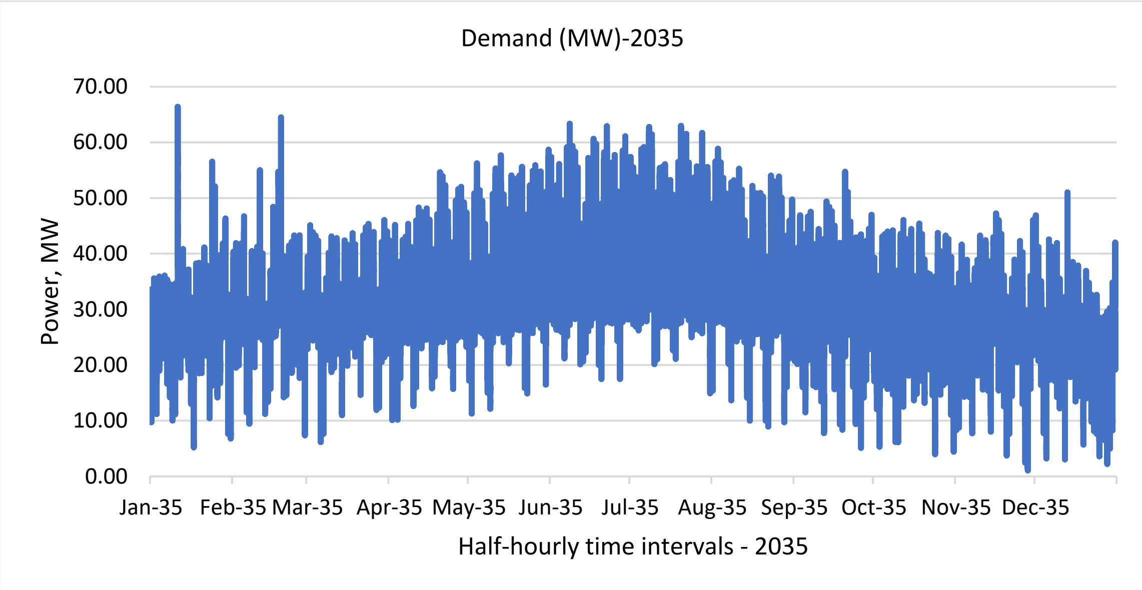

Figure 64 Aggregated time-series data 2035 from Geelong East zone substation.

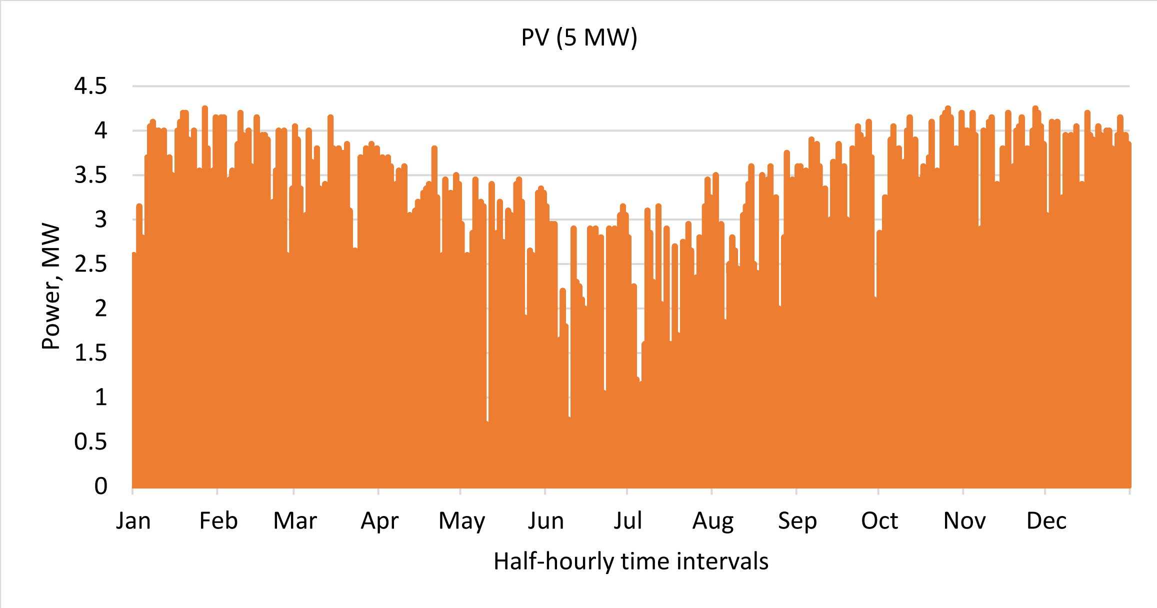

Figure 65 Yearly PV profile - Geelong East area.

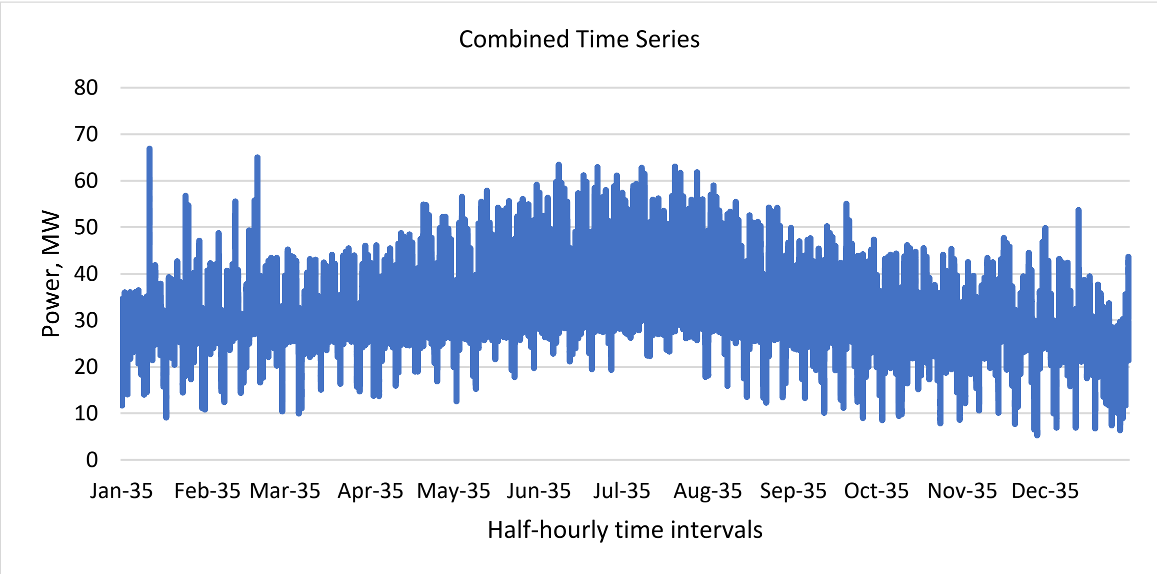

Figure 66 Combined time series data.

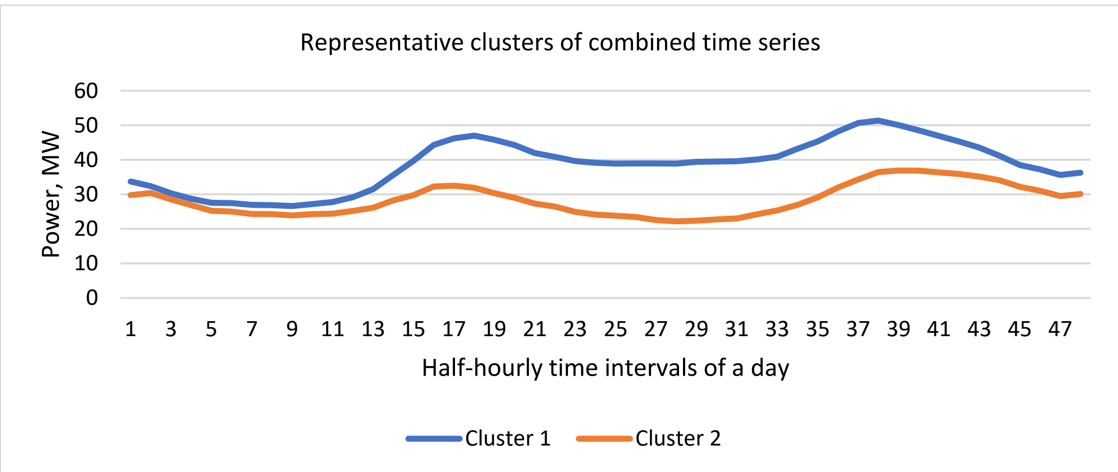

Figure 67 Representative clusters of the combined time series.

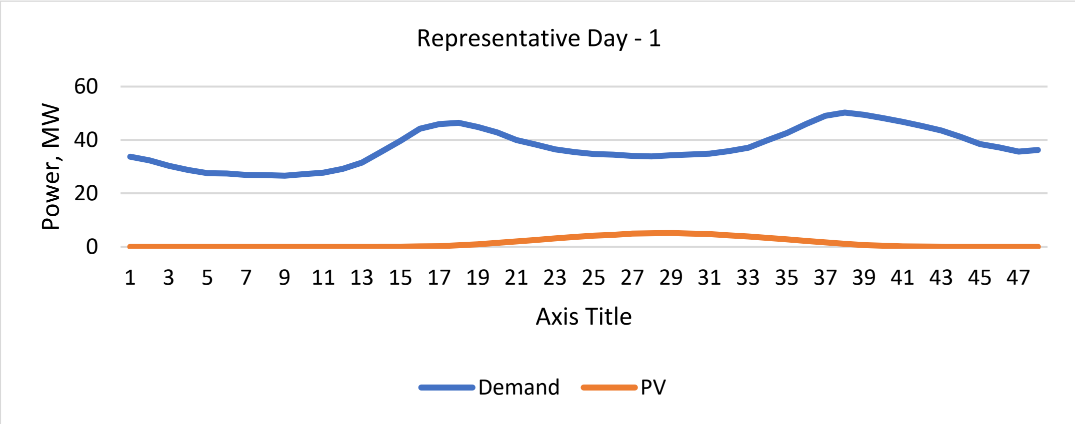

Figure 68 Daily profile - representative day-1 obtained using the 3-step time aggregation method.

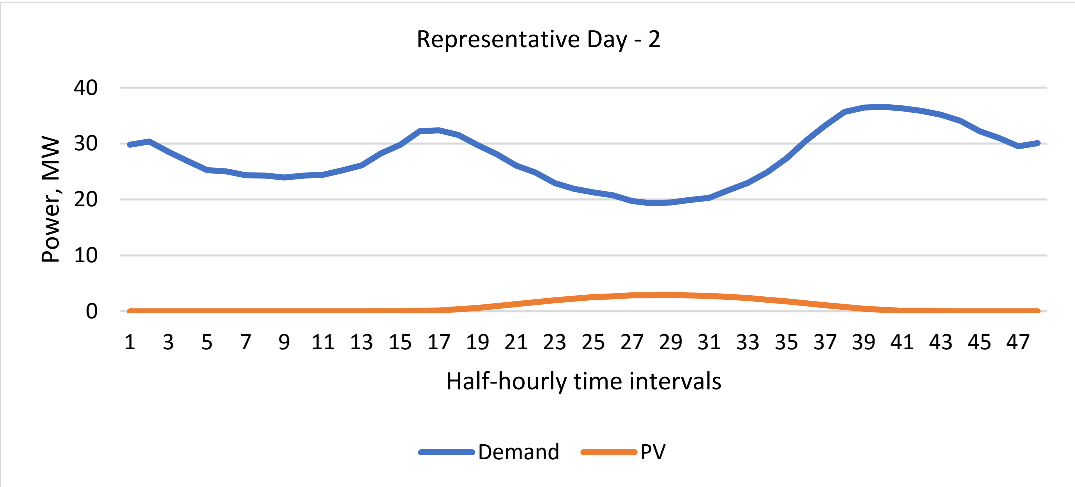

Figure 69 Daily profile - representative day-2 obtained using the 3-step time aggregation method.

Representative reduced network

Two feeders are supplying the demand to the network. The 3-step time aggregation method has been used for obtaining the representative reduced network. The accuracy of the non-linear AC power flow for the reduced network, compared to the original network, is analysed. The Ward network reduction method has been implemented to reduce the network. The comparison among the active power, reactive power, current, and voltage at PCC for the full network and reduced network is presented in Figure 70, Figure 71, Figure 72, and Figure 73. There is no error after obtaining the reduced network from the detailed network of the feeder 1. However, in feeder 2, the maximum active power is 10043.4kW and maximum error is 0.8kW after the reduction of the detailed network. Besides, the maximum reactive power is 637.5 KVAR and the maximum error is 0.08 KVAR after obtaining the reduced network. The phase angle of zero degrees is reported for both networks.

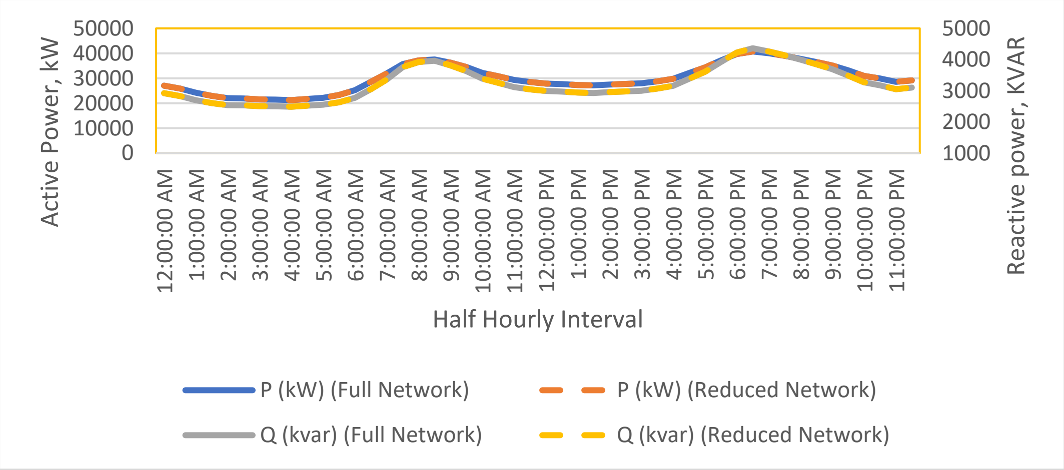

Figure 70 Active and reactive power comparison for full network and reduced network (Feeder 1).

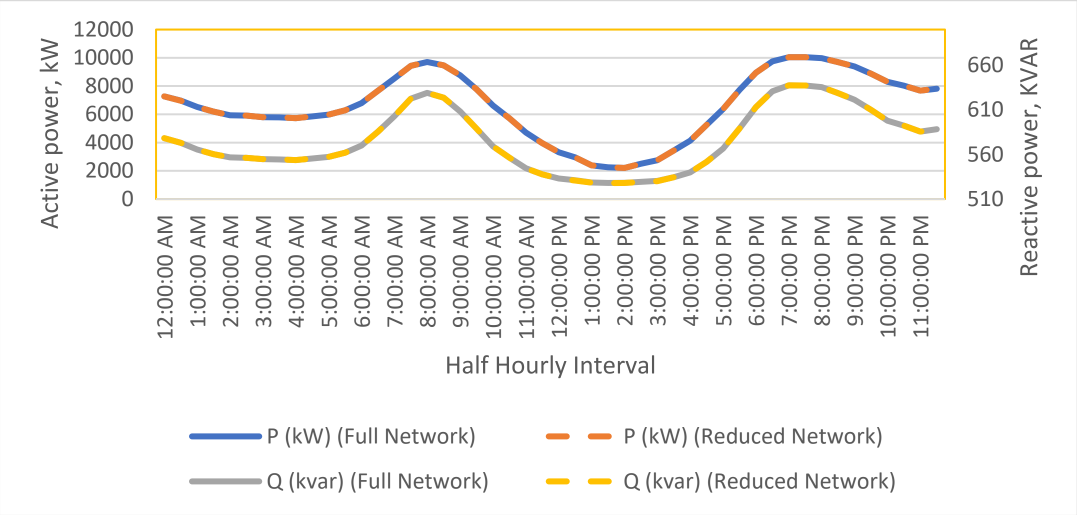

Figure 71 Active and reactive power comparison for full network and reduced network (Feeder 2).

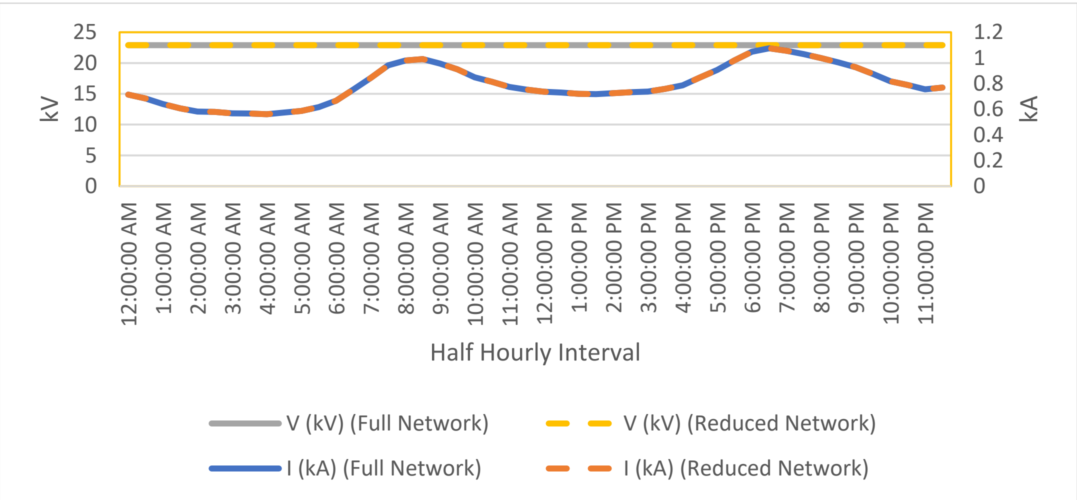

Figure 72 Current and voltage plots for the full network and reduced network (Feeder 1).

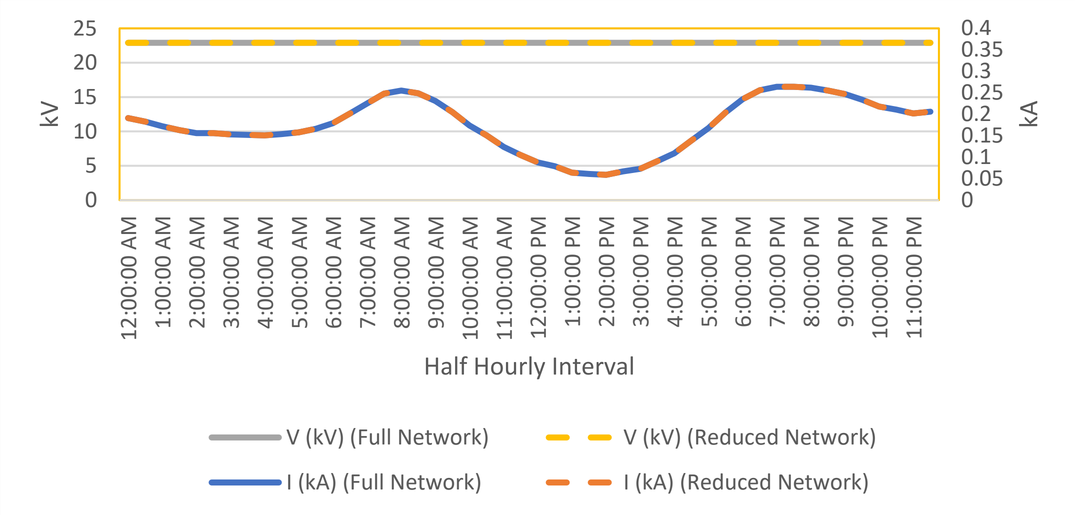

Figure 73 Current and voltage plots for the full network and reduced network (Feeder 2).

All key parameters, such as active and reactive powers, voltages, and currents at PCC for both the full and reduced network, are compared in Table 15 and Table 16. There is no error in feeder 1 reduction. However, maximum error in active power is 0.03% and maximum error in reactive power is 0.08% after the network reduction for feeder 2.

Table 15 Key parameters at PCC of full and reduced network - feeder 1

Time	P (kW) (Full Network)	P (kW) (Reduced Network)	Q (KVAR) (Full Network)	Q (KVAR) (Reduced Network)	I (kA) (Full Network)	I (kA) (Reduced Network)	V (kV) (Full Network)	V (kV) (Reduced Network)	Phase Angle (Full Network)	Phase Angle (Reduced Network)	Error (%), P	Error (%), Q
12:00 AM	27046.1	27046.1	2920.3	2920.3	0.714	0.714	22.9	22.9	0	0	0.00	0.00
12:30 AM	25913	25913	2827.8	2827.8	0.684	0.684	22.9	22.9	0	0	0.00	0.00
1:00 AM	24233.5	24233.5	2698.1	2698.1	0.64	0.64	22.9	22.9	0	0	0.00	0.00
1:30 AM	22968.3	22968.3	2606.1	2606.1	0.607	0.607	22.9	22.9	0	0	0.00	0.00
2:00 AM	22015.3	22015.3	2540	2540	0.582	0.582	22.9	22.9	0	0	0.00	0.00
2:30 AM	21918.9	21918.9	2533.5	2533.5	0.579	0.579	22.9	22.9	0	0	0.00	0.00
3:00 AM	21503.7	21503.7	2505.7	2505.7	0.568	0.568	22.9	22.9	0	0	0.00	0.00
3:30 AM	21445.3	21445.3	2501.8	2501.8	0.567	0.567	22.9	22.9	0	0	0.00	0.00
4:00 AM	21247.5	21247.5	2488.8	2488.8	0.561	0.561	22.9	22.9	0	0	0.00	0.00
4:30 AM	21724.1	21724.1	2520.4	2520.4	0.574	0.574	22.9	22.9	0	0	0.00	0.00
5:00 AM	22186.3	22186.3	2551.7	2551.7	0.586	0.586	22.9	22.9	0	0	0.00	0.00
5:30 AM	23325	23325	2631.5	2631.5	0.616	0.616	22.9	22.9	0	0	0.00	0.00
6:00 AM	25231.9	25231.9	2774.2	2774.2	0.666	0.666	22.9	22.9	0	0	0.00	0.00
6:30 AM	28574.6	28574.6	3051.2	3051.2	0.754	0.754	22.9	22.9	0	0	0.00	0.00
7:00 AM	31942.9	31942.9	3365.2	3365.2	0.843	0.843	22.9	22.9	0	0	0.00	0.00
7:30 AM	35688.9	35688.9	3755.4	3755.4	0.942	0.942	22.9	22.9	0	0	0.00	0.00
8:00 AM	37146.6	37146.6	3918.9	3918.9	0.98	0.98	22.9	22.9	0	0	0.00	0.00
8:30 AM	37540.5	37540.5	3964.2	3964.2	0.991	0.991	22.9	22.9	0	0	0.00	0.00
9:00 AM	36236.3	36236.3	3816	3816	0.956	0.956	22.9	22.9	0	0	0.00	0.00
9:30 AM	34526.7	34526.7	3629.7	3629.7	0.911	0.911	22.9	22.9	0	0	0.00	0.00
10:00 AM	32183.9	32183.9	3389	3389	0.849	0.849	22.9	22.9	0	0	0.00	0.00
10:30 AM	30804	30804	3255.2	3255.2	0.813	0.813	22.9	22.9	0	0	0.00	0.00
11:00 AM	29312.2	29312.2	3117	3117	0.774	0.774	22.9	22.9	0	0	0.00	0.00
11:30 AM	28480.2	28480.2	3042.9	3042.9	0.752	0.752	22.9	22.9	0	0	0.00	0.00

12:00 PM	27892.3	27892.3	2991.9	2991.9	0.736	0.736	22.9	22.9	0	0	0.00	0.00
12:30 PM	27673	27673	2973.1	2973.1	0.73	0.73	22.9	22.9	0	0	0.00	0.00
1:00 PM	27290.1	27290.1	2940.7	2940.7	0.72	0.72	22.9	22.9	0	0	0.00	0.00
1:30 PM	27158.5	27158.5	2929.7	2929.7	0.717	0.717	22.9	22.9	0	0	0.00	0.00
2:00 PM	27481.1	27481.1	2956.8	2956.8	0.725	0.725	22.9	22.9	0	0	0.00	0.00
2:30 PM	27728.4	27728.4	2977.9	2977.9	0.732	0.732	22.9	22.9	0	0	0.00	0.00
3:00 PM	27974.6	27974.6	2999	2999	0.738	0.738	22.9	22.9	0	0	0.00	0.00
3:30 PM	28771.7	28771.7	3068.7	3068.7	0.759	0.759	22.9	22.9	0	0	0.00	0.00
4:00 PM	29771.2	29771.2	3158.8	3158.8	0.786	0.786	22.9	22.9	0	0	0.00	0.00
4:30 PM	32112.7	32112.7	3382	3382	0.847	0.847	22.9	22.9	0	0	0.00	0.00
5:00 PM	34320	34320	3607.8	3607.8	0.906	0.906	22.9	22.9	0	0	0.00	0.00
5:30 PM	37176.4	37176.4	3922.3	3922.3	0.981	0.981	22.9	22.9	0	0	0.00	0.00
6:00 PM	39700.2	39700.2	4221.1	4221.1	1.048	1.048	22.9	22.9	0	0	0.00	0.00
6:30 PM	40729.3	40729.3	4361.8	4361.8	1.075	1.075	22.9	22.9	0	0	0.00	0.00
7:00 PM	40018.1	40018.1	4260.1	4260.1	1.056	1.056	22.9	22.9	0	0	0.00	0.00
7:30 PM	38982.4	38982.4	4134.1	4134.1	1.029	1.029	22.9	22.9	0	0	0.00	0.00
8:00 PM	37816.6	37816.6	3996.3	3996.3	0.998	0.998	22.9	22.9	0	0	0.00	0.00
8:30 PM	36514.9	36514.9	3847.3	3847.3	0.964	0.964	22.9	22.9	0	0	0.00	0.00
9:00 PM	35113.4	35113.4	3692.7	3692.7	0.927	0.927	22.9	22.9	0	0	0.00	0.00
9:30 PM	33170.5	33170.5	3488.3	3488.3	0.875	0.875	22.9	22.9	0	0	0.00	0.00
10:00 PM	30946.6	30946.6	3268.7	3268.7	0.817	0.817	22.9	22.9	0	0	0.00	0.00
10:30 PM	29901.7	29901.7	3170.8	3170.8	0.789	0.789	22.9	22.9	0	0	0.00	0.00
11:00 PM	28592.4	28592.4	3052.8	3052.8	0.755	0.755	22.9	22.9	0	0	0.00	0.00
11:30 PM	29125.4	29125.4	3100.2	3100.2	0.769	0.769	22.9	22.9	0	0	0.00	0.00

Table 16 Key parameters at PCC of full and reduced network - feeder 2

Time	P (kW) (Full Network)	P (kW) (Reduced Network)	Q (KVAR) (Full Network)	Q (KVAR) (Reduced Network)	I (kA) (Full Network)	I (kA) (Reduced Network)	V (kV) (Full Network)	V (kV) (Reduced Network)	Phase Angle (Full Network)	Phase Angle (Reduced Network)	Error (%), P	Error (%), Q
12:00 AM	7268.3	7268.3	578.2	578.2	0.191	0.191	22.9	22.9	0	0	0.00	0.00
12:30 AM	6968.5	6968.4	573	573	0.183	0.183	22.9	22.9	0	0	0.00	0.00
1:00 AM	6523.3	6523.3	565.6	565.6	0.172	0.172	22.9	22.9	0	0	0.00	0.00
1:30 AM	6187.3	6187.3	560.4	560.4	0.163	0.163	22.9	22.9	0	0	0.00	0.00
2:00 AM	5933.9	5933.9	556.7	556.7	0.156	0.156	22.9	22.9	0	0	0.00	0.00
2:30 AM	5908.3	5908.2	556.3	556.3	0.156	0.156	22.9	22.9	0	0	0.00	0.00
3:00 AM	5797.8	5797.8	554.7	554.7	0.153	0.153	22.9	22.9	0	0	0.00	0.00
3:30 AM	5782.2	5782.2	554.5	554.5	0.152	0.152	22.9	22.9	0	0	0.00	0.00
4:00 AM	5729.5	5729.5	553.7	553.7	0.151	0.151	22.9	22.9	0	0	0.00	0.00
4:30 AM	5856.4	5856.4	555.5	555.5	0.154	0.154	22.9	22.9	0	0	0.00	0.00
5:00 AM	5979.4	5979.4	557.3	557.3	0.158	0.158	22.9	22.9	0	0	0.00	0.00
5:30 AM	6282.1	6282.1	561.9	561.9	0.166	0.166	22.9	22.9	0	0	0.00	0.00
6:00 AM	6788	6788	570	570	0.179	0.179	22.9	22.9	0	0	0.00	0.00
6:30 AM	7663.7	7663.7	585.5	585.5	0.202	0.202	22.9	22.9	0	0	0.00	0.00
7:00 AM	8541.1	8541.1	602.9	602.9	0.225	0.225	22.9	22.9	0	0	0.00	0.00
7:30 AM	9430.6	9430.6	622.5	622.5	0.248	0.248	22.9	22.9	0	0	0.00	0.00
8:00 AM	9707.9	9707.9	629.1	629.1	0.255	0.255	22.9	22.9	0	0	0.00	0.00
8:30 AM	9470.4	9470.4	623.7	623.7	0.249	0.249	22.9	22.9	0	0	0.00	0.00
9:00 AM	8764.5	8764.5	608.3	608.3	0.231	0.231	22.9	22.9	0	0	0.00	0.00
9:30 AM	7780.2	7780.2	589	589	0.205	0.205	22.9	22.9	0	0	0.00	0.00
10:00 AM	6621.6	6621.6	569.2	569.2	0.174	0.174	22.9	22.9	0	0	0.00	0.00
10:30 AM	5718.5	5718.5	556.4	556.4	0.151	0.151	22.9	22.9	0	0	0.00	0.00
11:00 AM	4710.5	4710.5	544.6	544.6	0.124	0.124	22.9	22.9	0	0	0.00	0.00

11:30 AM	3960.8	3960.8	537.7	537.7	0.105	0.105	22.9	22.9	0	0	0.00	0.00
12:00 PM	3319.2	3319.2	533.1	533.1	0.088	0.088	22.9	22.9	0	0	0.00	0.00
12:30 PM	2957.2	2956.4	531.1	530.7	0.079	0.079	22.9	22.9	0	0	0.03	0.08
1:00 PM	2384	2383.5	528.6	528.4	0.064	0.064	22.9	22.9	0	0	0.02	0.04
1:30 PM	2250.8	2250.3	528.1	527.9	0.061	0.061	22.9	22.9	0	0	0.02	0.04
2:00 PM	2204.7	2204.2	528.3	528.1	0.059	0.059	22.9	22.9	0	0	0.02	0.04
2:30 PM	2500.3	2499.7	529.4	529.1	0.067	0.067	22.9	22.9	0	0	0.02	0.06
3:00 PM	2746.5	2745.8	530.4	530.1	0.073	0.073	22.9	22.9	0	0	0.03	0.06
3:30 PM	3444.6	3444.6	534.5	534.5	0.091	0.091	22.9	22.9	0	0	0.00	0.00
4:00 PM	4133.5	4133.5	539.9	539.9	0.109	0.109	22.9	22.9	0	0	0.00	0.00
4:30 PM	5252.3	5252.3	551.7	551.7	0.139	0.139	22.9	22.9	0	0	0.00	0.00
5:00 PM	6374.9	6374.9	566.7	566.7	0.168	0.168	22.9	22.9	0	0	0.00	0.00
5:30 PM	7738.4	7738.4	589.3	589.3	0.204	0.204	22.9	22.9	0	0	0.00	0.00
6:00 PM	8943.9	8943.9	613.1	613.1	0.235	0.235	22.9	22.9	0	0	0.00	0.00
6:30 PM	9749	9749	630.9	630.9	0.256	0.256	22.9	22.9	0	0	0.00	0.00
7:00 PM	10043.4	10043.4	637.5	637.5	0.264	0.264	22.9	22.9	0	0	0.00	0.00
7:30 PM	10038.4	10038.4	637.2	637.2	0.264	0.264	22.9	22.9	0	0	0.00	0.00
8:00 PM	9972.8	9972.8	635.4	635.4	0.262	0.262	22.9	22.9	0	0	0.00	0.00
8:30 PM	9697.9	9697.9	628.7	628.7	0.255	0.255	22.9	22.9	0	0	0.00	0.00
9:00 PM	9386.9	9386.9	621.4	621.4	0.247	0.247	22.9	22.9	0	0	0.00	0.00
9:30 PM	8881.8	8881.8	610.1	610.1	0.234	0.234	22.9	22.9	0	0	0.00	0.00
10:00 PM	8297.3	8297.3	597.8	597.8	0.218	0.218	22.9	22.9	0	0	0.00	0.00
10:30 PM	8022.1	8022.1	592.3	592.3	0.211	0.211	22.9	22.9	0	0	0.00	0.00
11:00 PM	7676.8	7676.8	585.7	585.7	0.202	0.202	22.9	22.9	0	0	0.00	0.00
11:30 PM	7817.5	7817.5	588.4	588.4	0.206	0.206	22.9	22.9	0	0	0.00	0.00

c) Network 3

For the future case (2035), a 5 MW solar is considered to be 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.

Time aggregated load profiles

The aggregated time-series data of 2035 from Ballarat South ZS is presented in Figure 74. The load time series data are 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 75. The 6.15 MW wind farm power generation profile is presented in Figure 76. The developed 3-step time aggregation method has been used to obtain representative daily profiles. The combined time series profile is presented in Figure 77. The K-means clustering method is used to identify the representative clusters in the combined time series profile, as presented in Figure 78. 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 79 and the time series profile of representative day-2 is presented in Figure 80.

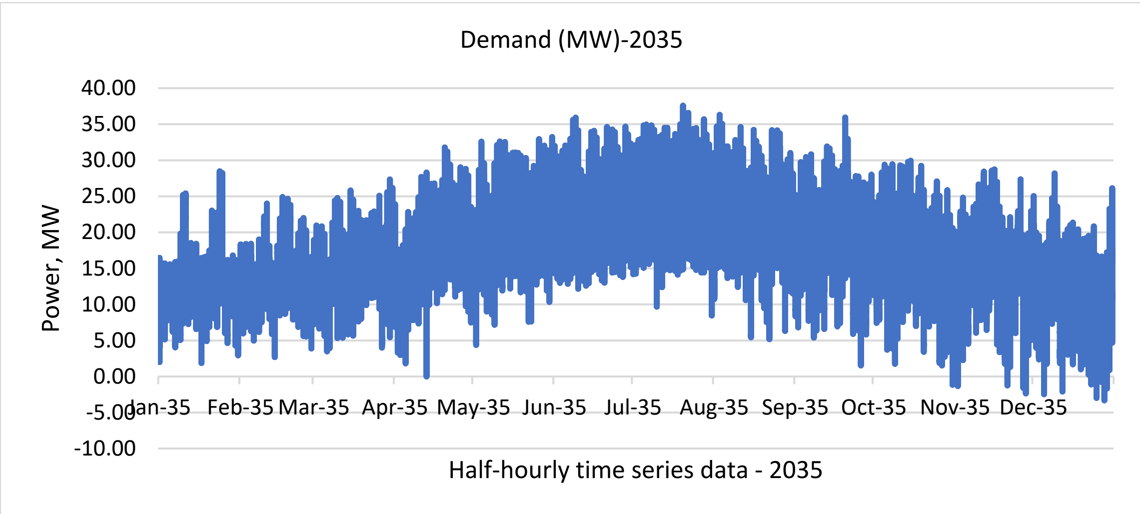

Figure 74 Aggregated time-series data 2035 from Ballarat South zone substation.

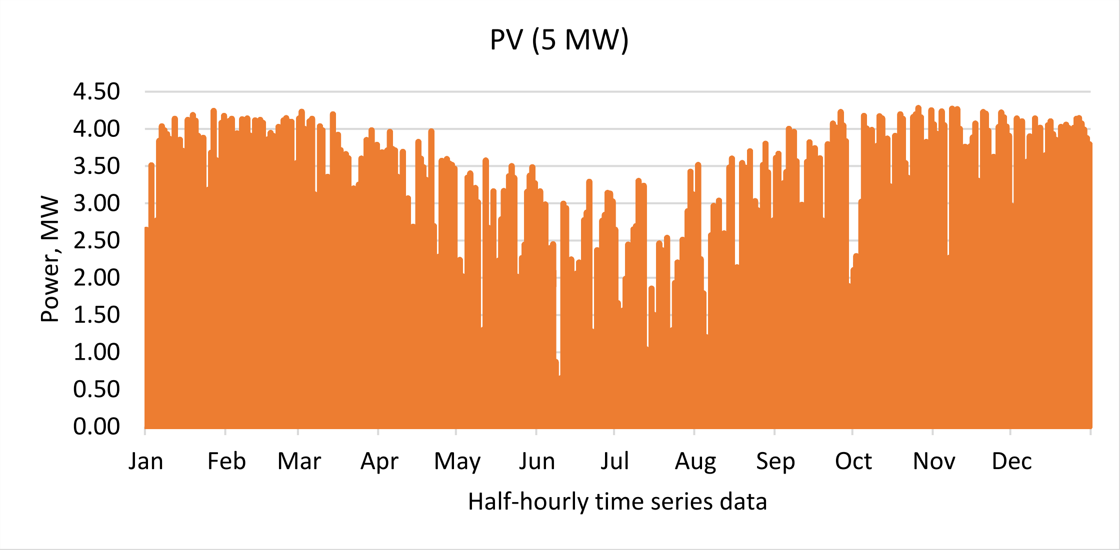

Figure 75 Yearly PV profile - Ballarat South area.

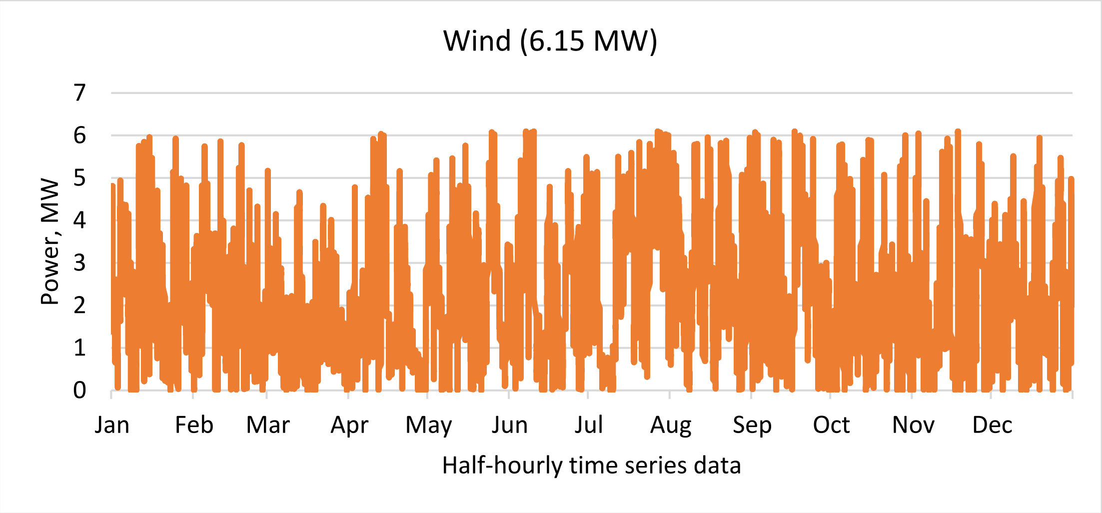

Figure 76 Yearly Wind profile - Chepstowe wind farm.

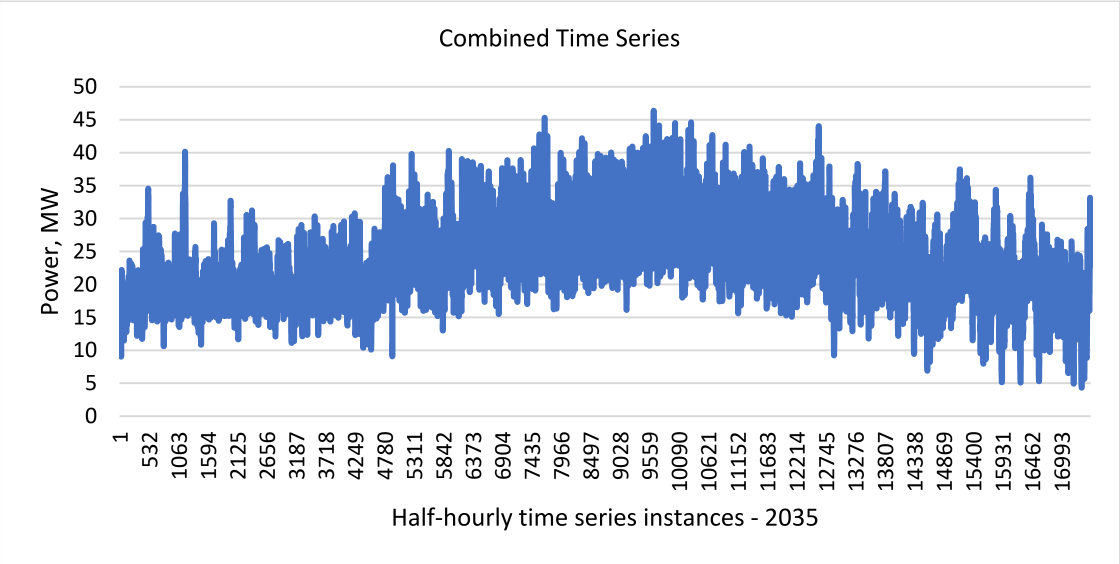

Figure 77 Combined time series data.

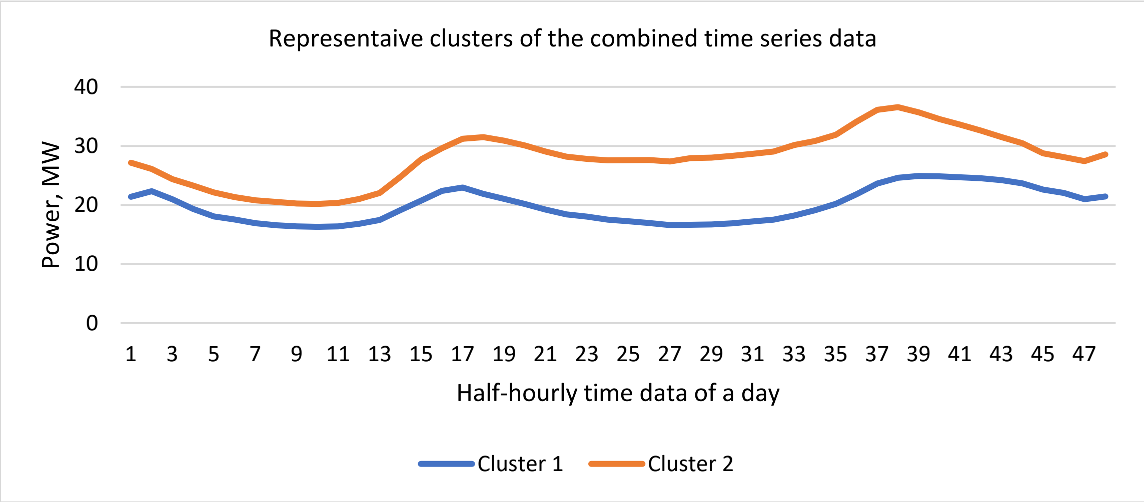

Figure 78 Representative clusters of the combined time series.

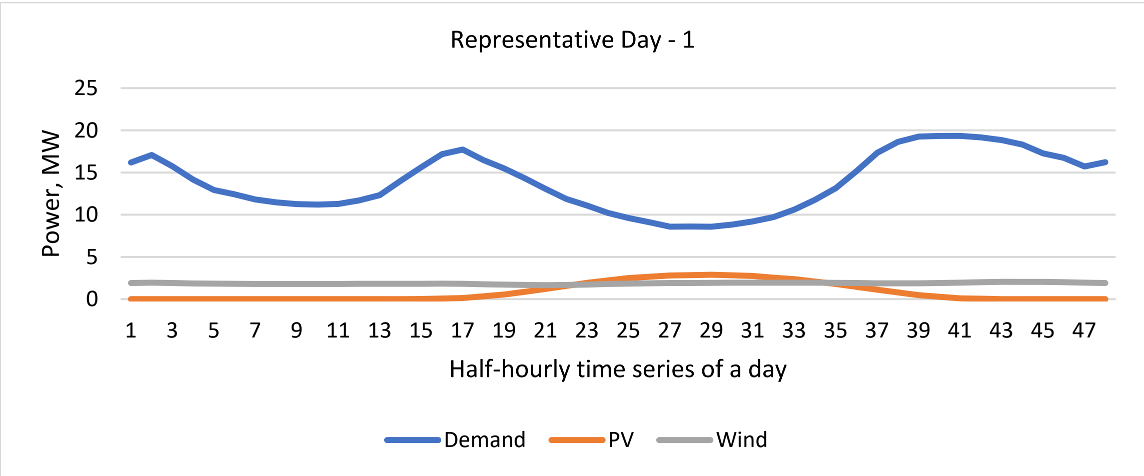

Figure 79 Daily profile - representative day-1 obtained using the 3-step time aggregation method.

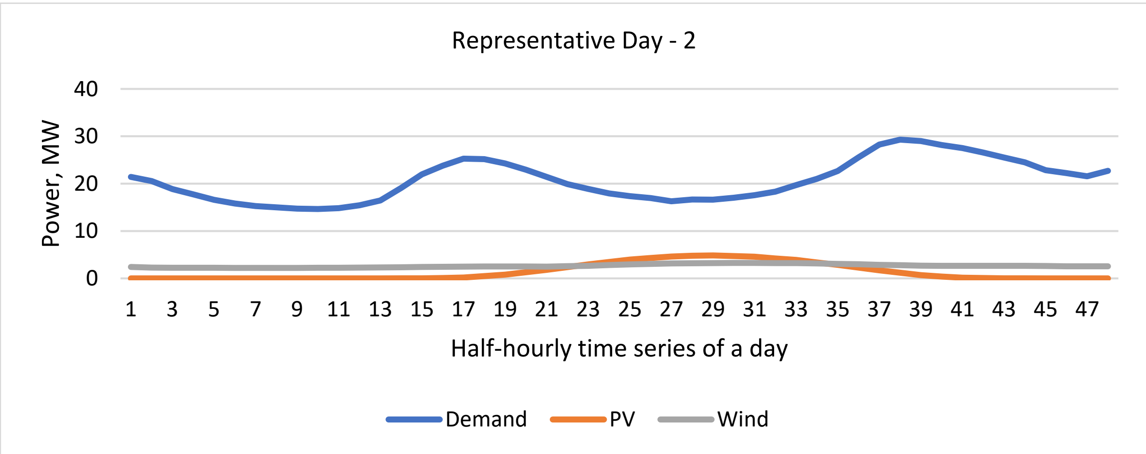

Figure 80 Daily profile - representative day-2 obtained using the 3-step time aggregation method.

Representative reduced network

The representative profiles obtained using the 3-step time aggregation method are used to generate a reduced representative network. The accuracy of the non-linear AC power flow for the reduced network, compared to the original network, is analysed. The Ward network reduction method has been implemented to reduce the network. The comparison among the active power, reactive power, current, and voltage at PCC for the full network and reduced network is presented in Figure 81 and Figure 82. From the results given in Figure 81 and Figure 82, a maximum of 20.8 KVAR difference in the network reactive power quantity for the detailed and the reduced networks is observed. The phase angle of zero degree is reported for both networks.

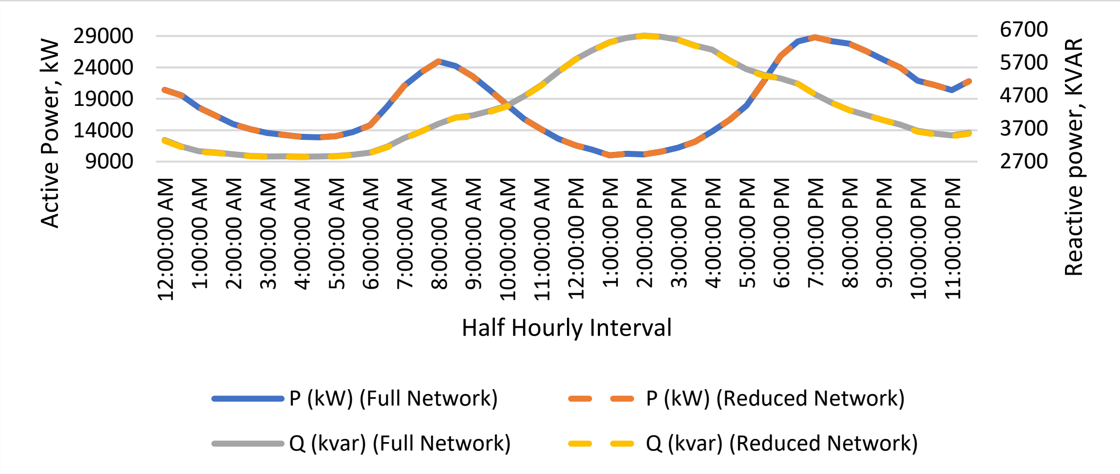

Figure 81 Active and reactive power comparison for full network and reduced network.

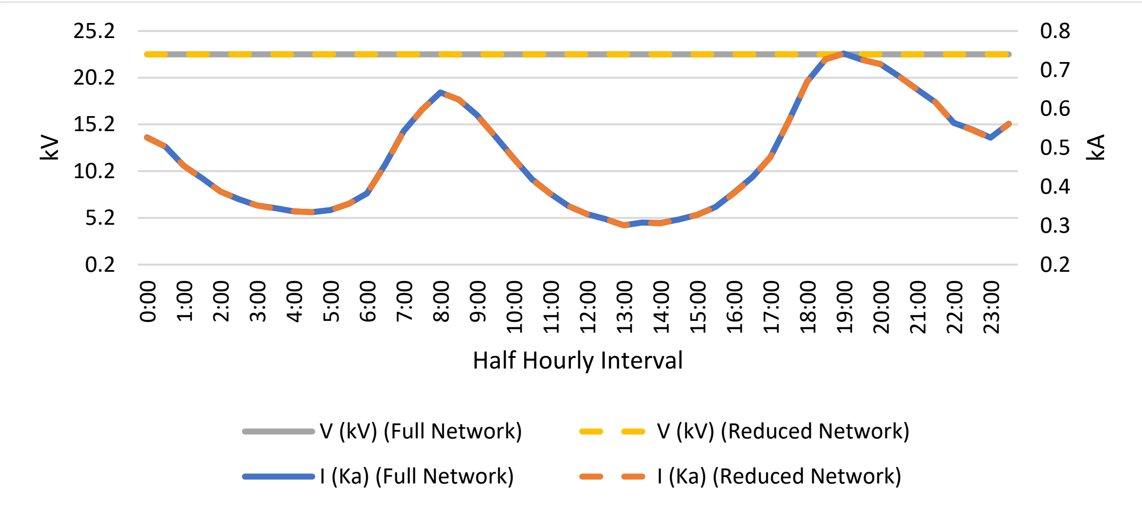

Figure 82 Current and voltage plots for the full network and reduced network.

All key parameters, such as active and reactive powers, voltages, and currents at PCC for both the full and reduced network, are compared in Table 17. A maximum 0.09% error in active power and a maximum 0.82% error in reactive power for the detailed and the reduced networks are observed.

Table 17 Key parameters at PCC of full and reduced network

Time	P (kW) (Full Network)	P (kW) (Reduced Network)	Q (KVAR) (Full Network)	Q (KVAR) (Reduced Network)	I (kA) (Full Network)	I (kA) (Reduced Network)	V (kV) (Full Network)	V (kV) (Reduced Network)	Phase Angle (Full Network)	Phase Angle (Reduced Network)	Error (%), P	Error (%), Q
12:00 AM	20430.9	20413.9	3355.3	3329.5	0.527	0.526	22.7	22.7	0	0	0.08	0.77
12:30 AM	19540.8	19525.3	3158.7	3135.2	0.503	0.503	22.7	22.7	0	0	0.08	0.74
1:00 AM	17596.9	17584.3	3014.8	2995.6	0.454	0.454	22.7	22.7	0	0	0.07	0.64
1:30 AM	16304.1	16293.3	2976.6	2960.1	0.422	0.421	22.7	22.7	0	0	0.07	0.55
2:00 AM	14982	14972.8	2924.4	2910.4	0.388	0.388	22.7	22.7	0	0	0.06	0.48
2:30 AM	14173.6	14165.3	2876.4	2863.8	0.368	0.368	22.7	22.7	0	0	0.06	0.44
3:00 AM	13558.9	13551.3	2856.6	2845.1	0.352	0.352	22.7	22.7	0	0	0.06	0.40
3:30 AM	13241.1	13233.9	2860	2849	0.345	0.344	22.7	22.7	0	0	0.05	0.38
4:00 AM	12948.2	12941.3	2850.8	2840.2	0.337	0.337	22.7	22.7	0	0	0.05	0.37
4:30 AM	12871.8	12864.9	2855.4	2845	0.335	0.335	22.7	22.7	0	0	0.05	0.36
5:00 AM	13045.9	13038.9	2871.9	2861.2	0.34	0.34	22.7	22.7	0	0	0.05	0.37
5:30 AM	13708.2	13700.4	2911	2899.2	0.356	0.356	22.7	22.7	0	0	0.06	0.41
6:00 AM	14771.8	14762.8	2973.8	2960.1	0.383	0.383	22.7	22.7	0	0	0.06	0.46
6:30 AM	17723	17710.2	3151	3131.6	0.458	0.457	22.7	22.7	0	0	0.07	0.62
7:00 AM	21065.5	21047.5	3414.1	3386.7	0.543	0.542	22.7	22.7	0	0	0.09	0.80
7:30 AM	23225	23225	3619.1	3619.1	0.598	0.598	22.7	22.7	0	0	0.00	0.00
8:00 AM	24966.4	24966.4	3846.8	3846.8	0.642	0.642	22.7	22.7	0	0	0.00	0.00
8:30 AM	24216.6	24216.6	4034	4034	0.624	0.624	22.7	22.7	0	0	0.00	0.00
9:00 AM	22589.4	22568.6	4100.7	4069.1	0.584	0.583	22.7	22.7	0	0	0.09	0.77
9:30 AM	20378.6	20361.5	4235.6	4209.6	0.529	0.529	22.7	22.7	0	0	0.08	0.61
10:00 AM	18062.7	18049	4392.3	4371.5	0.473	0.472	22.7	22.7	0	0	0.08	0.47
10:30 AM	15788.2	15777.5	4684.3	4668	0.419	0.418	22.7	22.7	0	0	0.07	0.35
11:00 AM	14160.8	14151.9	5017.6	5004.1	0.382	0.382	22.7	22.7	0	0	0.06	0.27
11:30 AM	12655.3	12647.8	5425.9	5414.5	0.35	0.35	22.7	22.7	0	0	0.06	0.21

12:00 PM	11597	11590.3	5804.2	5794.1	0.33	0.33	22.7	22.7	0	0	0.06	0.17
12:30 PM	10893.6	10887.5	6079.9	6070.6	0.317	0.317	22.7	22.7	0	0	0.06	0.15
1:00 PM	10005.1	9999.6	6321.2	6312.8	0.301	0.301	22.7	22.7	0	0	0.05	0.13
1:30 PM	10241.1	10235.3	6452.6	6443.8	0.308	0.308	22.7	22.7	0	0	0.06	0.14
2:00 PM	10144	10138.3	6522.3	6513.6	0.307	0.306	22.7	22.7	0	0	0.06	0.13
2:30 PM	10591.5	10585.4	6485.8	6476.6	0.316	0.316	22.7	22.7	0	0	0.06	0.14
3:00 PM	11206.3	11199.7	6401.6	6391.6	0.328	0.328	22.7	22.7	0	0	0.06	0.16
3:30 PM	12173.8	12166.4	6219.6	6208.3	0.348	0.347	22.7	22.7	0	0	0.06	0.18
4:00 PM	13803.6	13794.6	6094.3	6080.6	0.384	0.383	22.7	22.7	0	0	0.07	0.22
4:30 PM	15622.2	15611.3	5774.9	5758.3	0.424	0.423	22.7	22.7	0	0	0.07	0.29
5:00 PM	17900.2	17886.4	5502.8	5481.7	0.476	0.476	22.7	22.7	0	0	0.08	0.38
5:30 PM	21745.1	21725.3	5332.2	5302.1	0.569	0.569	22.7	22.7	0	0	0.09	0.56
6:00 PM	25839.4	25839.4	5223.5	5223.5	0.67	0.67	22.7	22.7	0	0	0.00	0.00
6:30 PM	28139.3	28139.3	5062.6	5062.6	0.727	0.727	22.7	22.7	0	0	0.00	0.00
7:00 PM	28797.5	28797.5	4739.4	4739.4	0.742	0.742	22.7	22.7	0	0	0.00	0.00
7:30 PM	28176	28176	4482	4482	0.726	0.726	22.7	22.7	0	0	0.00	0.00
8:00 PM	27781.3	27781.3	4263.8	4263.8	0.715	0.715	22.7	22.7	0	0	0.00	0.00
8:30 PM	26576.9	26576.9	4112.5	4112.5	0.684	0.684	22.7	22.7	0	0	0.00	0.00
9:00 PM	25235.9	25235.9	3958.3	3958.3	0.65	0.65	22.7	22.7	0	0	0.00	0.00
9:30 PM	23959.5	23959.5	3822.1	3822.1	0.617	0.617	22.7	22.7	0	0	0.00	0.00
10:00 PM	21876.4	21857	3636.4	3606.9	0.564	0.563	22.7	22.7	0	0	0.09	0.81
10:30 PM	21199.9	21181.6	3550.2	3522.4	0.547	0.546	22.7	22.7	0	0	0.09	0.78
11:00 PM	20370.7	20353.8	3493.7	3468	0.526	0.525	22.7	22.7	0	0	0.08	0.74
11:30 PM	21801.5	21782.2	3576.3	3547	0.562	0.561	22.7	22.7	0	0	0.09	0.82

5.4 Case 3A: With Loads, 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.

5.5 Case 3B: With Loads, 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 fleet storage are considered to be connected to the network by 2035. 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 (https://www.energy.gov.au/energy-data/australian-energy-statistics/electricity-generation).

a) Network 1

Time aggregated load profiles

The aggregated time-series data of 2035 from Drysdale ZS is presented in Figure 83. 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 a general profile for this area and used for generating representative daily PV generation profiles for 2035 (presented in Figure 84). An aggregated half-hourly time series data of EV charging is presented in Figure 85. Therefore, the representative daily profiles are obtained by using a time series similar to the duration of demand and PV generation. The developed 3-step time aggregation method has been used to obtain representative daily profiles. The combined time series profile is presented in Figure 86. The representative clusters of the combined time series profile are presented in Figure 87. 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 88 and Figure 89. BESS is considered as a dispatchable unit, and thus, no time series modelling is considered for BESS.

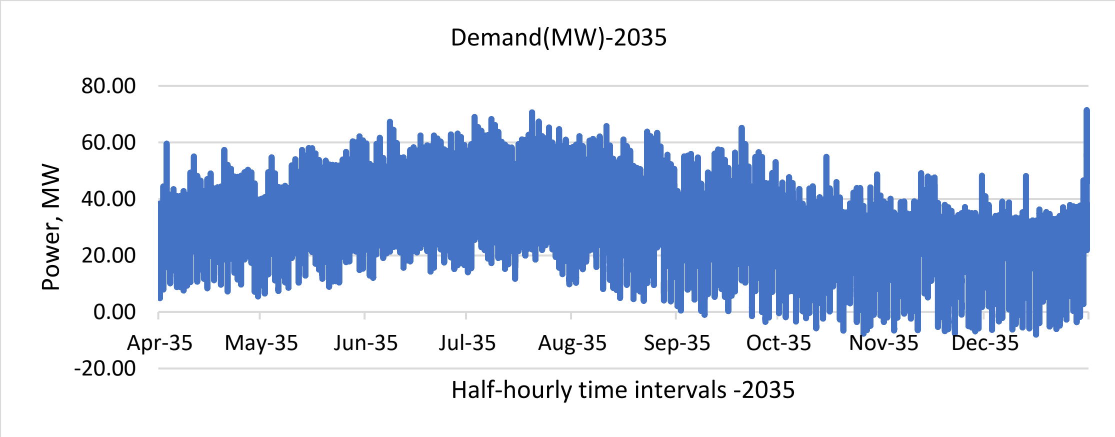

Figure 83 The aggregated time-series data 2035 from Drysdale zone substation.

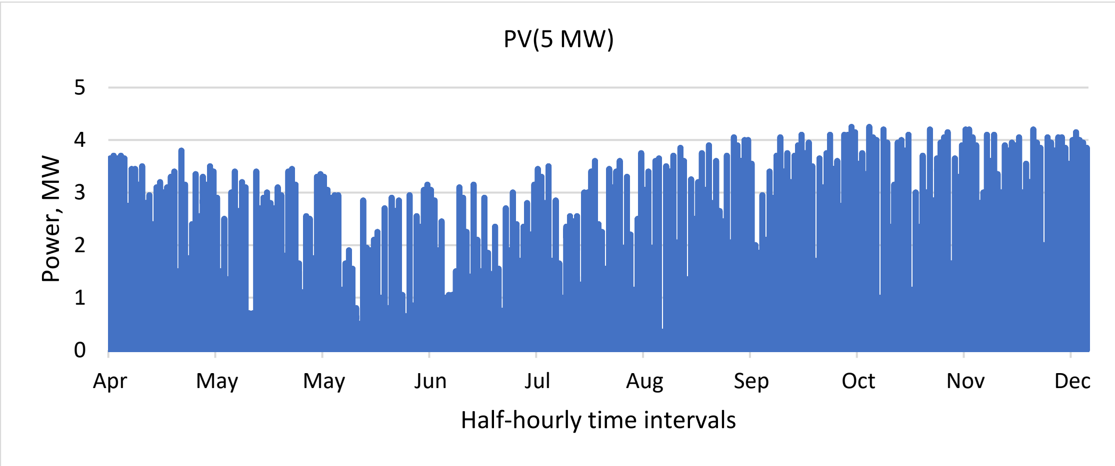

Figure 84 Yearly PV profile - Drysdale area.

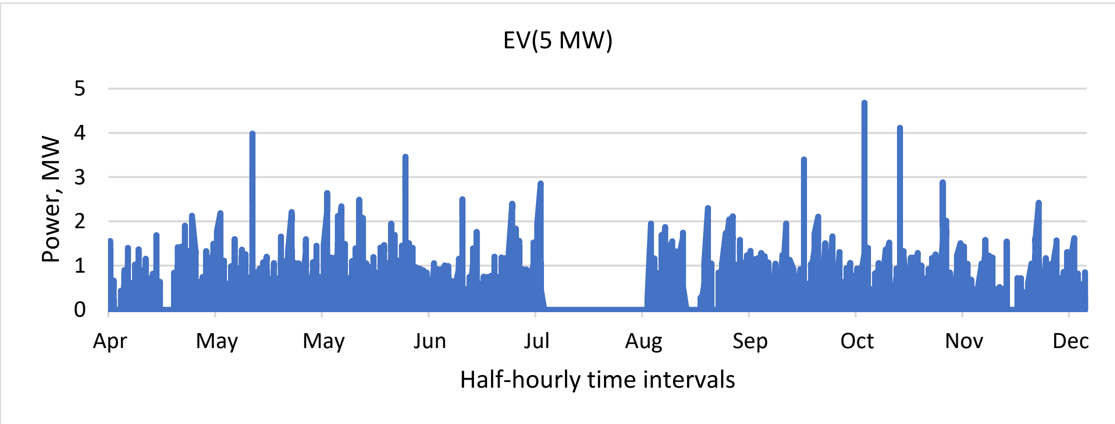

Figure 85 EV time series.

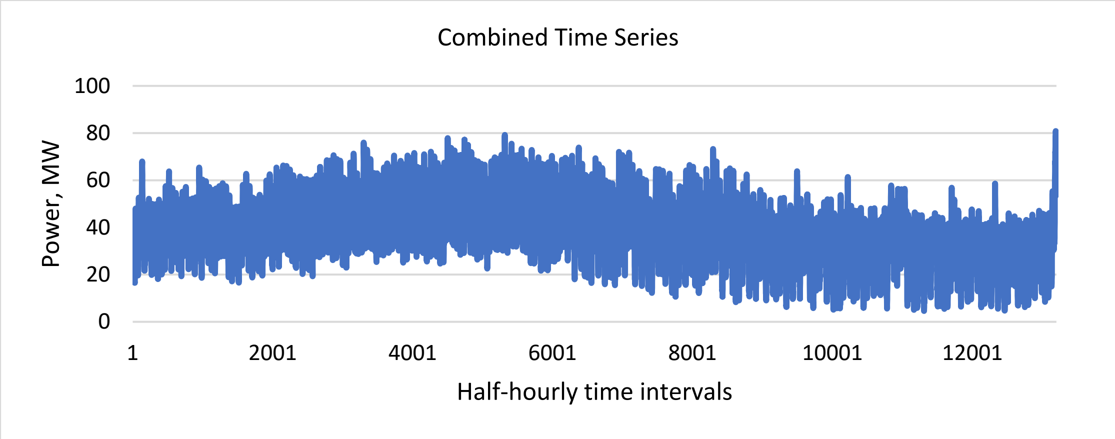

Figure 86 Combined time series data.

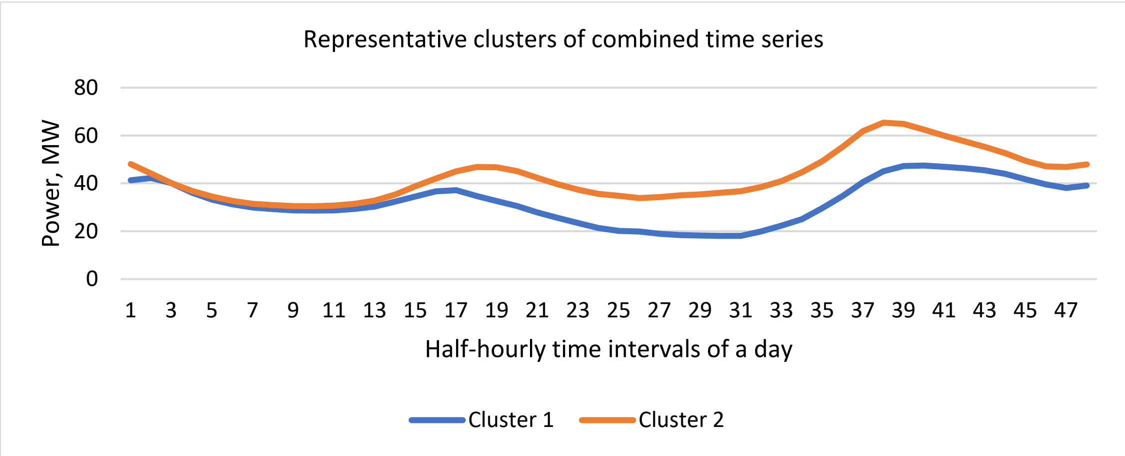

Figure 87 Representative clusters of the combined time series.

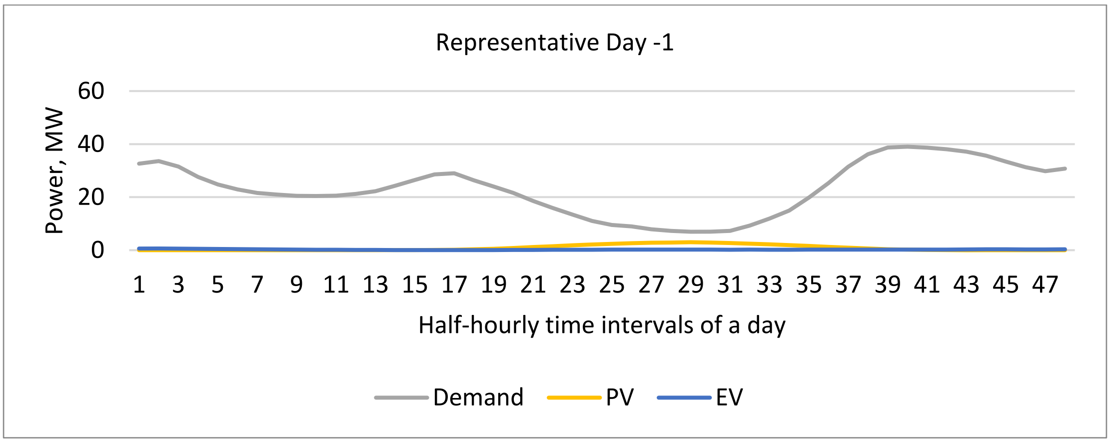

Figure 88 Daily profile - representative day-1 obtained using the 3-step time aggregation method.

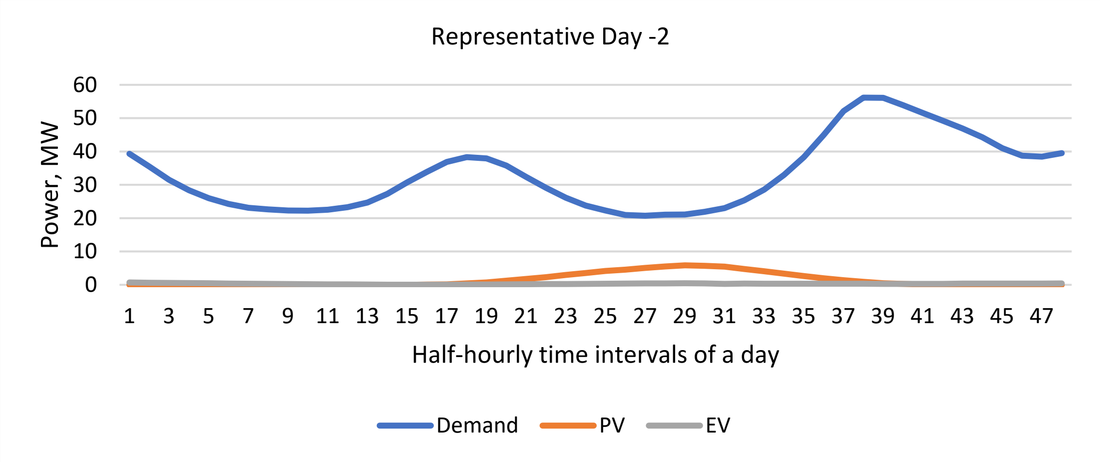

Figure 89 Daily profile - representative day-2 obtained using the 3-step time aggregation method.

Representative reduced network

The representative profiles obtained using the 3-step time aggregation method are used to generate a reduced representative network. The accuracy of the non-linear AC power flow for the reduced network, compared to the original network, is analysed. The Ward network reduction method has been implemented to reduce the network. The comparison among the active power, reactive power, current, and voltage at PCC for the full network and reduced network is presented in Figure 90 and Figure 91. From the results given in Figure 90 and Figure 91, a maximum of 339.7 KVAR difference in the network reactive quantity for the detailed and the reduced networks is observed with a total load demand of 52,530 kW. The phase angle of zero degree is reported for both networks.

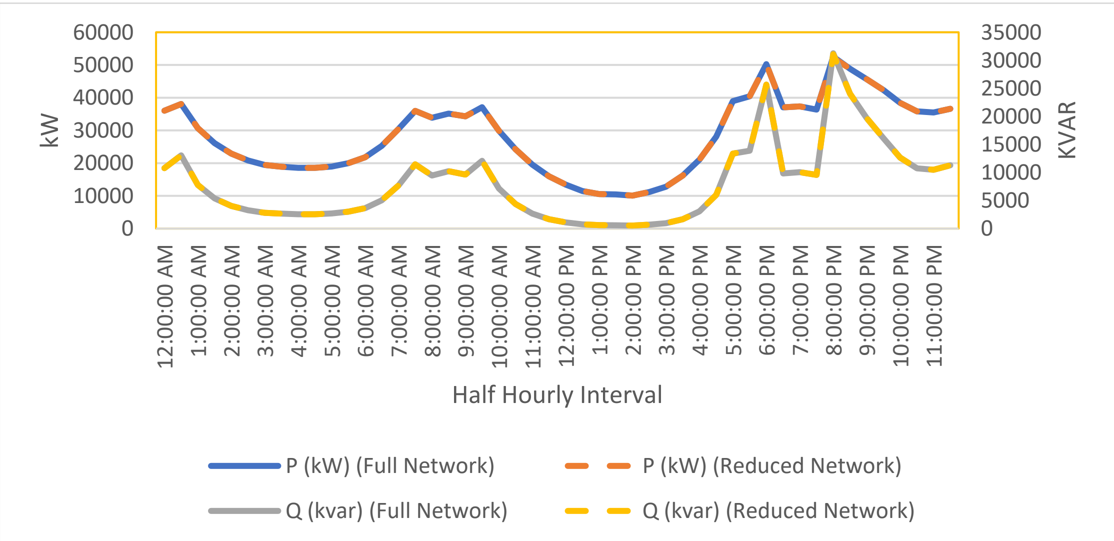

Figure 90 Active and reactive power comparison for full network and reduced network.

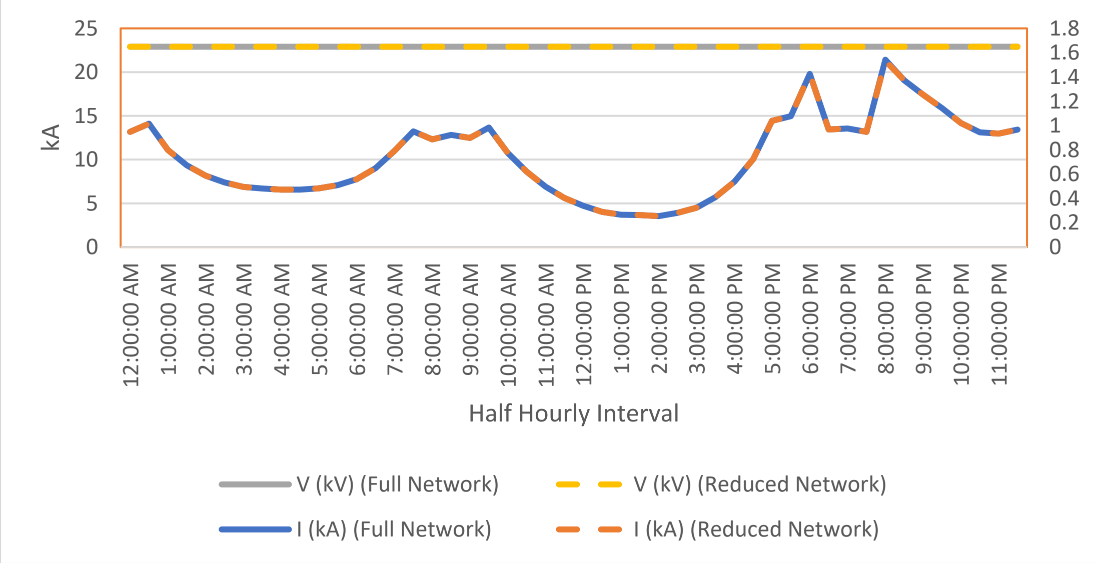

Figure 91 Current and voltage plots for the full network and reduced network.

All key parameters such as active and reactive powers, voltages, and currents at PCC for both the full and reduced network are compared in Table 18. A maximum 0.65% error in active power and a maximum 0.54% error in reactive power for the detailed and the reduced networks are observed.

Table 18 Key parameters at PCC of full and reduced network

Time	P (kW) (Full Network)	P (kW) (Reduced Network)	Q (KVAR) (Full Network)	Q (KVAR) (Reduced Network)	I (kA) (Full Network)	I (kA) (Reduced Network)	V (kV) (Full Network)	V (kV) (Reduced Network)	Phase Angle (Full Network)	Phase Angle (Reduced Network)	Error (%), P	Error (%), Q
12:00 AM	36001.4	36001.4	10768.2	10768.2	0.948	0.948	22.9	22.9	0	0	0.00	0.00
12:30 AM	38097.5	38097.5	13065.1	13065.1	1.016	1.016	22.9	22.9	0	0	0.00	0.00
1:00 AM	30712.6	30712.6	7771.4	7771.4	0.799	0.799	22.9	22.9	0	0	0.00	0.00
1:30 AM	26104	26104	5373.4	5373.4	0.673	0.673	22.9	22.9	0	0	0.00	0.00
2:00 AM	22940.7	22940.7	4038.3	4038.3	0.588	0.588	22.9	22.9	0	0	0.00	0.00
2:30 AM	20810.9	20810.9	3268.4	3268.4	0.532	0.532	22.9	22.9	0	0	0.00	0.00
3:00 AM	19450.3	19450.3	2825.4	2825.4	0.496	0.496	22.9	22.9	0	0	0.00	0.00
3:30 AM	18908	18908	2662.5	2662.5	0.482	0.482	22.9	22.9	0	0	0.00	0.00
4:00 AM	18562.1	18562.1	2562	2562	0.473	0.473	22.9	22.9	0	0	0.00	0.00
4:30 AM	18572.9	18572.9	2568.7	2568.7	0.473	0.473	22.9	22.9	0	0	0.00	0.00
5:00 AM	18956.7	18956.7	2687.2	2687.2	0.483	0.483	22.9	22.9	0	0	0.00	0.00
5:30 AM	19971	19971	3011.8	3011.8	0.51	0.51	22.9	22.9	0	0	0.00	0.00
6:00 AM	21804.8	21804.8	3650.8	3650.8	0.558	0.558	22.9	22.9	0	0	0.00	0.00
6:30 AM	25257.5	25257.5	5047.9	5047.9	0.65	0.65	22.9	22.9	0	0	0.00	0.00
7:00 AM	30434	30434	7701	7701	0.792	0.792	22.9	22.9	0	0	0.00	0.00
7:30 AM	35976.3	35976.3	11446.8	11446.8	0.953	0.953	22.9	22.9	0	0	0.00	0.00
8:00 AM	33872.4	33872.4	9455.3	9455.3	0.887	0.887	22.9	22.9	0	0	0.00	0.00
8:30 AM	35146.8	35146.8	10245	10245	0.924	0.924	22.9	22.9	0	0	0.00	0.00
9:00 AM	34293.9	34293.9	9624.4	9624.4	0.899	0.899	22.9	22.9	0	0	0.00	0.00
9:30 AM	37080.4	37080.4	12095.4	12095.4	0.984	0.984	22.9	22.9	0	0	0.00	0.00
10:00 AM	29906.4	29906.4	7156.8	7156.8	0.776	0.776	22.9	22.9	0	0	0.00	0.00
10:30 AM	24253.2	24253.2	4389.5	4389.5	0.622	0.622	22.9	22.9	0	0	0.00	0.00
11:00 AM	19548	19548	2670	2670	0.498	0.498	22.9	22.9	0	0	0.00	0.00
11:30 AM	15969.9	15969.9	1672.5	1672.5	0.405	0.405	22.9	22.9	0	0	0.00	0.00

12:00 PM	13416.1	13416.1	1105.2	1105.2	0.34	0.34	22.9	22.9	0	0	0.00	0.00
12:30 PM	11475.6	11475.6	763	763	0.29	0.29	22.9	22.9	0	0	0.00	0.00
1:00 PM	10533.9	10533.9	613.2	613.2	0.266	0.266	22.9	22.9	0	0	0.00	0.00
1:30 PM	10427.5	10427.5	591.1	591.1	0.264	0.264	22.9	22.9	0	0	0.00	0.00
2:00 PM	10081.6	10081.6	539.4	539.4	0.255	0.255	22.9	22.9	0	0	0.00	0.00
2:30 PM	11169.3	11169.3	689.6	689.6	0.282	0.282	22.9	22.9	0	0	0.00	0.00
3:00 PM	12797.1	12797.1	957.6	957.6	0.324	0.324	22.9	22.9	0	0	0.00	0.00
3:30 PM	16218.5	16218.5	1672.2	1672.2	0.411	0.411	22.9	22.9	0	0	0.00	0.00
4:00 PM	21070.7	21070.7	3078.4	3078.4	0.537	0.537	22.9	22.9	0	0	0.00	0.00
4:30 PM	28080.5	28080.5	6003.6	6003.6	0.725	0.725	22.9	22.9	0	0	0.00	0.00
5:00 PM	38950.1	38950.1	13370.5	13370.5	1.039	1.039	22.9	22.9	0	0	0.00	0.00
5:30 PM	40405.7	40405.7	13886.4	13886.4	1.078	1.078	22.9	22.9	0	0	0.00	0.00
6:00 PM	50278.9	50278.9	25676.6	25676.6	1.425	1.425	22.9	22.9	0	0	0.00	0.00
6:30 PM	37064.2	37064.2	9830.4	9830.4	0.968	0.968	22.9	22.9	0	0	0.00	0.00
7:00 PM	37345.3	37345.3	10072.4	10072.4	0.976	0.976	22.9	22.9	0	0	0.00	0.00
7:30 PM	36372.5	36372.5	9571.9	9571.9	0.949	0.949	22.9	22.9	0	0	0.00	0.00
8:00 PM	52530.2	52190.5	31257	31086.7	1.542	1.533	22.9	22.9	0	0	0.65	0.54
8:30 PM	48822.9	48822.9	24037.9	24037.9	1.373	1.373	22.9	22.9	0	0	0.00	0.00
9:00 PM	45636.8	45636.8	19702.9	19702.9	1.254	1.254	22.9	22.9	0	0	0.00	0.00
9:30 PM	42318.5	42318.5	16108.8	16108.8	1.143	1.143	22.9	22.9	0	0	0.00	0.00
10:00 PM	38418.1	38418.1	12664.9	12664.9	1.021	1.021	22.9	22.9	0	0	0.00	0.00
10:30 PM	35837.9	35837.9	10736.5	10736.5	0.944	0.944	22.9	22.9	0	0	0.00	0.00
11:00 PM	35491.1	35491.1	10490.9	10490.9	0.934	0.934	22.9	22.9	0	0	0.00	0.00
11:30 PM	36630.5	36630.5	11287	11287	0.967	0.967	22.9	22.9	0	0	0.00	0.00

b) 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 the Network 2 by 2035.

Time aggregated load profiles

The aggregated time-series data of 2035 from Geelong East is presented in Figure 92. 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 93). An aggregated EV charging load data from Jemena and C4NET project is used in this work. The half-hourly time series data of EV charging is presented in Figure 94. Therefore, the representative daily profiles are obtained using the similar duration time series of demand and PV generation. The developed 3-step time aggregation method has been used to obtain representative daily profiles. The combined time series profile is presented in Figure 95. The K-means clustering method is used to identify the representative clusters in the combined time series profile as presented in Figure 96. 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 97 and Figure 98.

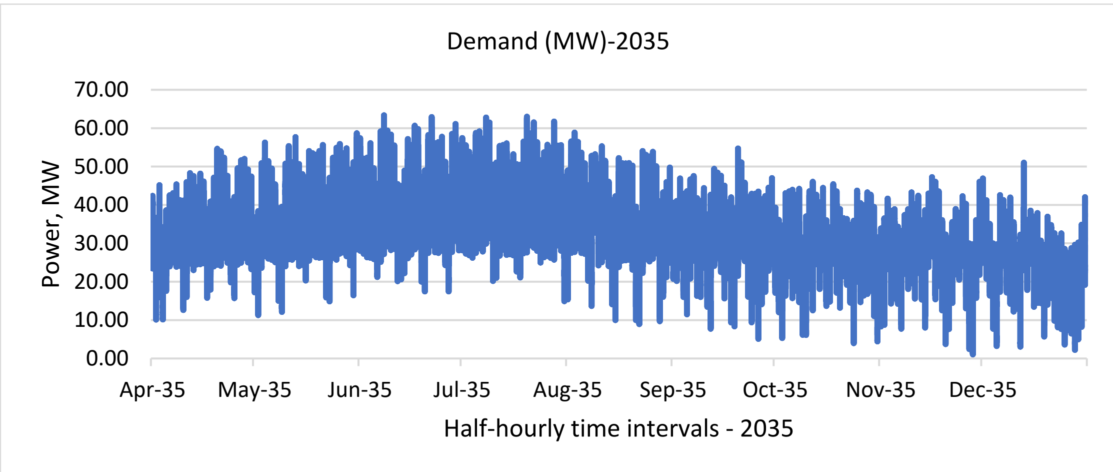

Figure 92 The aggregated time-series data in year 2035 from Geelong East zone substation.

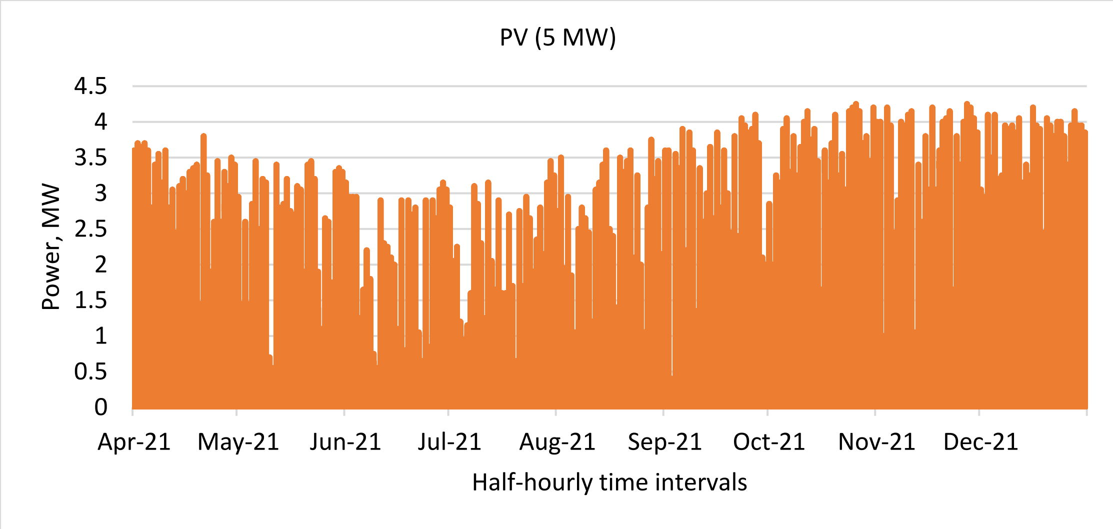

Figure 93 Yearly PV profile - Geelong East area.

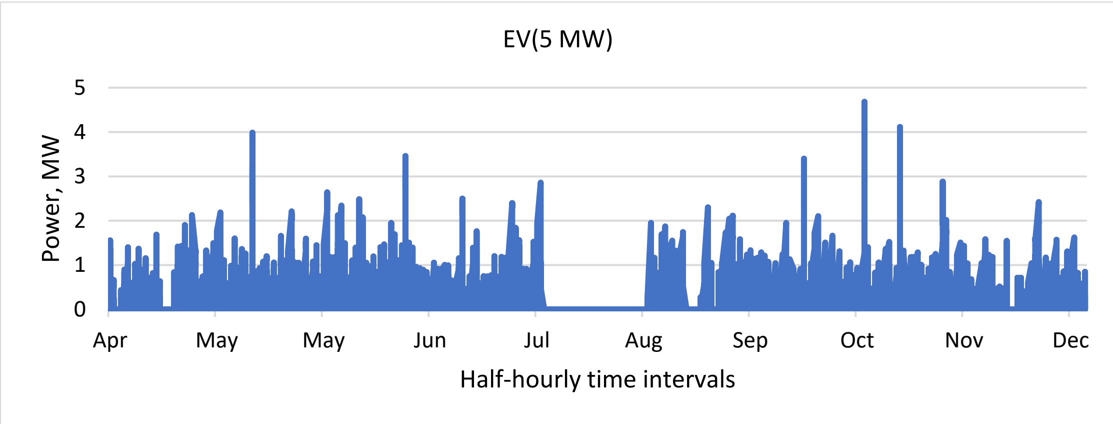

Figure 94 EV time series.

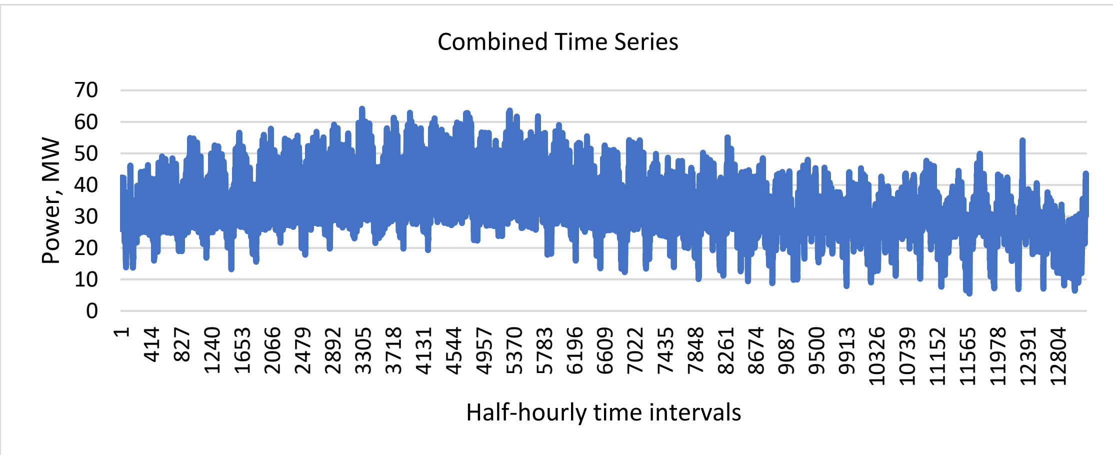

Figure 95 Combined time series data.

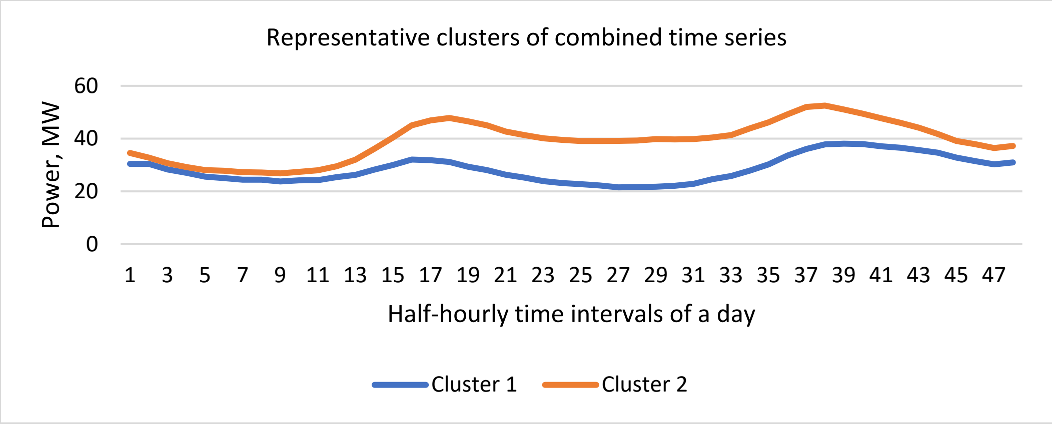

Figure 96 Representative clusters of the combined time series.

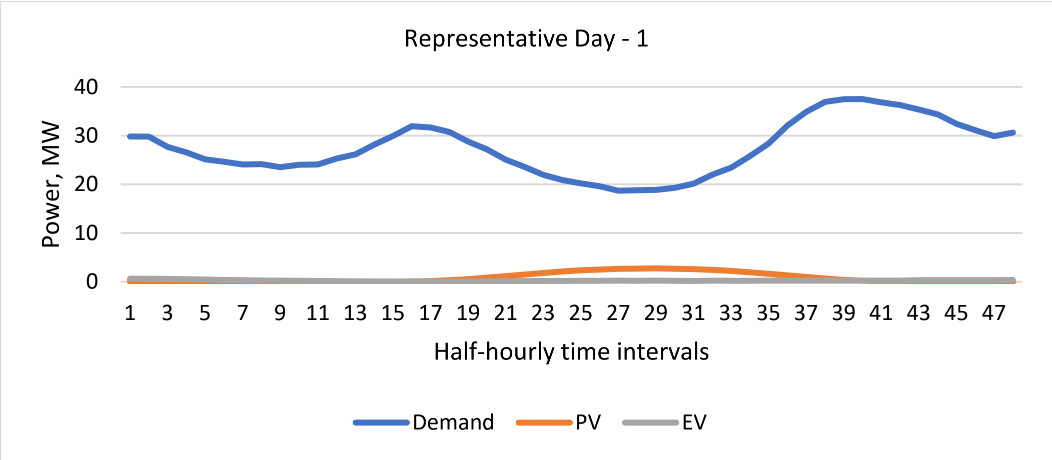

Figure 97 Daily profile - representative day-1 obtained using the 3-step time aggregation method.

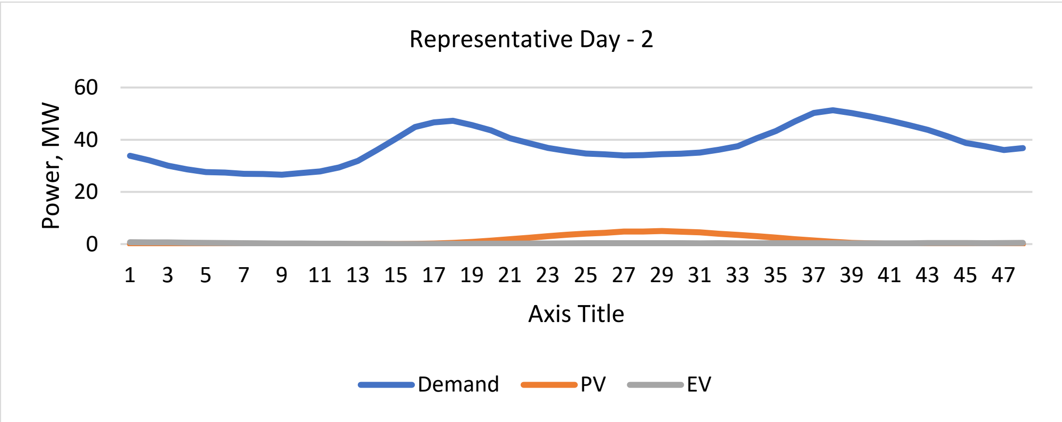

Figure 98 Daily profile - representative day-2 obtained using the 3-step time aggregation method.

Representative reduced network

There are two feeders in the network. The accuracy of the non-linear AC power flow for the reduced network compared to the original network has been assessed. The Ward network reduction method has been implemented to reduce the network. The comparison among the active power, reactive power, current, and voltage at PCC for the full network and reduced network is presented in Figure 99 and Figure 100 for feeder 1 and in Figure 101 and Figure 102 for feeder 2. There is no error in active and reactive power between the reduced network and detail network of feeder 1. For feeder 2, the maximum active power error is 0.9 kW and the maximum error in reactive power is 0.4 KVAR. The maximum active power is 10353.5 kW and maximum reactive power is 645.1 KVAR in the detail network of feeder 2.

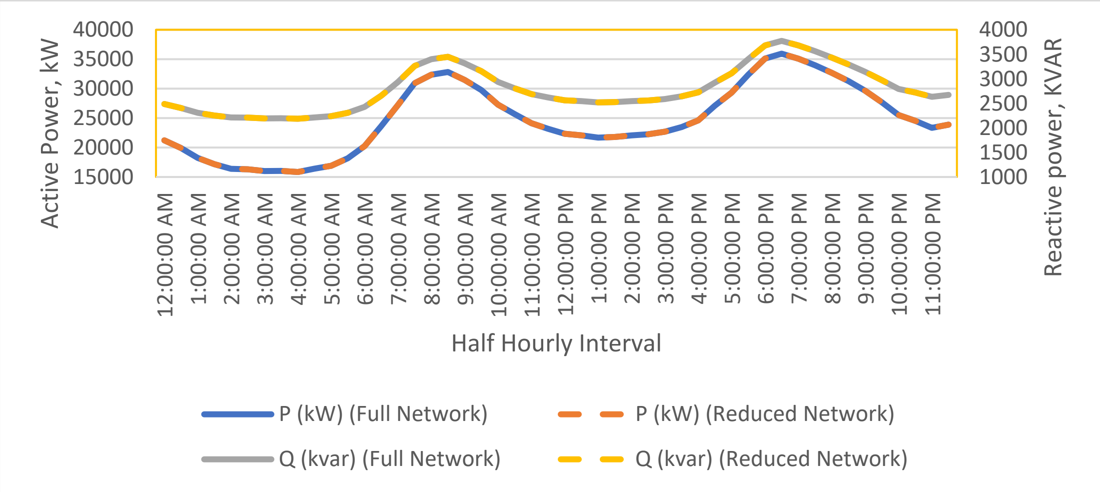

Figure 99 Active and reactive power comparison for full network and reduced network (Feeder 1).

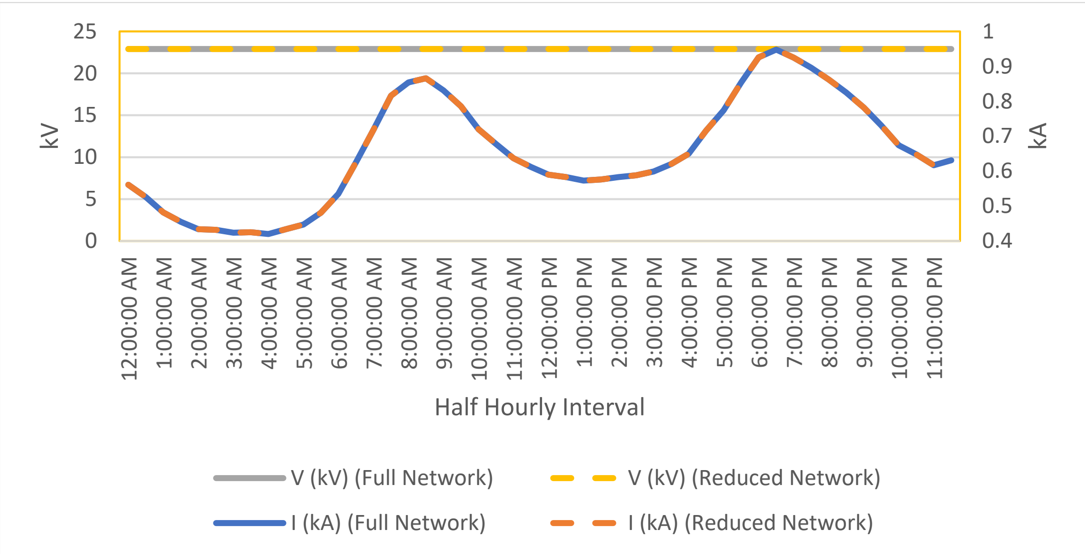

Figure 100 Current and voltage plots for the full network and reduced network (Feeder 1).

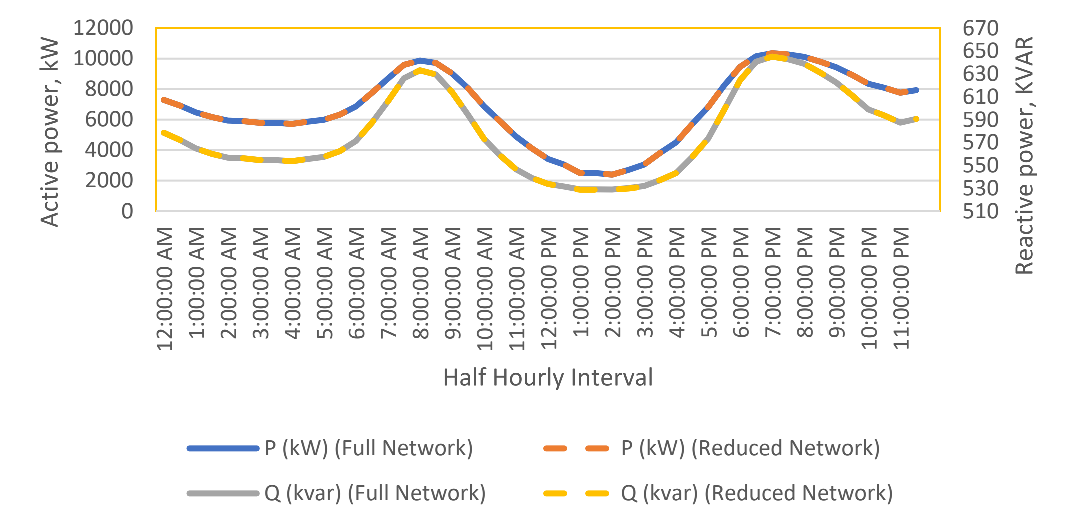

Figure 101 Active and reactive power comparison for full network and reduced network (Feeder 2).

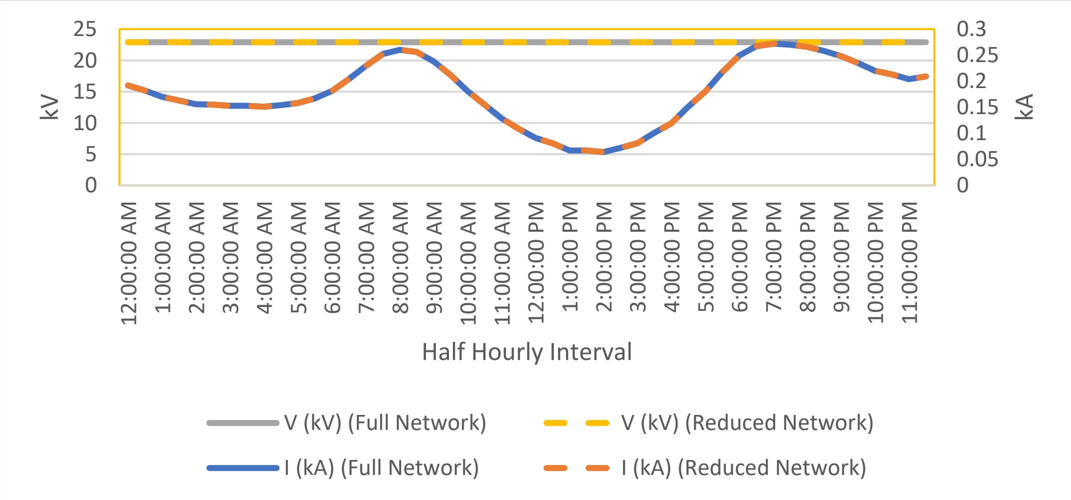

Figure 102 Current and voltage plots for the full network and reduced network (Feeder 2).

All key parameters, such as active and reactive power, voltage and current at PCC for both the full and reduced network, are compared in Table 19 and Table 20. There is no error is the active power at PCC of the reduced network from the detail network. However, a maximum 0.08% in reactive power is observed in the reduced network from the detail network of feeder 2, which is very low and negligible.

Table 19 Key parameters at PCC of full and reduced networks - feeder 1

Time	P (kW) (Full Network)	P (kW) (Reduced Network)	Q (KVAR) (Full Network)	Q (KVAR) (Reduced Network)	I (kA) (Full Network)	I (kA) (Reduced Network)	V (kV) (Full Network)	V (kV) (Reduced Network)	Phase Angle (Full Network)	Phase Angle (Reduced Network)	Error (%), P	Error (%), Q
12:00 AM	21214.3	21214.3	2487.5	2487.5	0.561	0.561	22.9	22.9	0	0	0.00	0.00
12:30 AM	19909.7	19909.7	2406.1	2406.1	0.526	0.526	22.9	22.9	0	0	0.00	0.00
1:00 AM	18237.9	18237.9	2309.4	2309.4	0.482	0.482	22.9	22.9	0	0	0.00	0.00
1:30 AM	17184.2	17184.2	2253	2253	0.455	0.455	22.9	22.9	0	0	0.00	0.00
2:00 AM	16389	16389	2212.8	2212.8	0.434	0.434	22.9	22.9	0	0	0.00	0.00
2:30 AM	16317.8	16317.8	2209.5	2209.5	0.432	0.432	22.9	22.9	0	0	0.00	0.00
3:00 AM	15996.3	15996.3	2193.9	2193.9	0.424	0.424	22.9	22.9	0	0	0.00	0.00
3:30 AM	16042.8	16042.8	2196.4	2196.4	0.425	0.425	22.9	22.9	0	0	0.00	0.00
4:00 AM	15846.8	15846.8	2187.1	2187.1	0.42	0.42	22.9	22.9	0	0	0.00	0.00
4:30 AM	16404.7	16404.7	2214.5	2214.5	0.434	0.434	22.9	22.9	0	0	0.00	0.00
5:00 AM	16901.9	16901.9	2239.7	2239.7	0.447	0.447	22.9	22.9	0	0	0.00	0.00
5:30 AM	18182.8	18182.8	2308.1	2308.1	0.481	0.481	22.9	22.9	0	0	0.00	0.00
6:00 AM	20245.4	20245.4	2428.7	2428.7	0.535	0.535	22.9	22.9	0	0	0.00	0.00
6:30 AM	23649.5	23649.5	2656.3	2656.3	0.625	0.625	22.9	22.9	0	0	0.00	0.00
7:00 AM	27213.4	27213.4	2932.8	2932.8	0.718	0.718	22.9	22.9	0	0	0.00	0.00
7:30 AM	30924.8	30924.8	3262.2	3262.2	0.816	0.816	22.9	22.9	0	0	0.00	0.00
8:00 AM	32364.7	32364.7	3401.4	3401.4	0.854	0.854	22.9	22.9	0	0	0.00	0.00
8:30 AM	32833.6	32833.6	3447.9	3447.9	0.866	0.866	22.9	22.9	0	0	0.00	0.00
9:00 AM	31473.4	31473.4	3314.2	3314.2	0.831	0.831	22.9	22.9	0	0	0.00	0.00
9:30 AM	29765.6	29765.6	3154.4	3154.4	0.786	0.786	22.9	22.9	0	0	0.00	0.00
10:00 AM	27285	27285	2938.2	2938.2	0.72	0.72	22.9	22.9	0	0	0.00	0.00
10:30 AM	25668.6	25668.6	2807.4	2807.4	0.678	0.678	22.9	22.9	0	0	0.00	0.00
11:00 AM	24126.9	24126.9	2690.3	2690.3	0.637	0.637	22.9	22.9	0	0	0.00	0.00
11:30 AM	23171.8	23171.8	2621.4	2621.4	0.612	0.612	22.9	22.9	0	0	0.00	0.00

12:00 PM	22331.2	22331.2	2562.9	2562.9	0.59	0.59	22.9	22.9	0	0	0.00	0.00
12:30 PM	22075.4	22075.4	2545.6	2545.6	0.583	0.583	22.9	22.9	0	0	0.00	0.00
1:00 PM	21681.3	21681.3	2519.2	2519.2	0.573	0.573	22.9	22.9	0	0	0.00	0.00
1:30 PM	21797.2	21797.2	2527	2527	0.576	0.576	22.9	22.9	0	0	0.00	0.00
2:00 PM	22065.6	22065.6	2544.8	2544.8	0.583	0.583	22.9	22.9	0	0	0.00	0.00
2:30 PM	22251.5	22251.5	2557.5	2557.5	0.588	0.588	22.9	22.9	0	0	0.00	0.00
3:00 PM	22685.1	22685.1	2587.5	2587.5	0.599	0.599	22.9	22.9	0	0	0.00	0.00
3:30 PM	23477.2	23477.2	2642.8	2642.8	0.62	0.62	22.9	22.9	0	0	0.00	0.00
4:00 PM	24609.1	24609.1	2725.9	2725.9	0.65	0.65	22.9	22.9	0	0	0.00	0.00
4:30 PM	27118	27118	2923.7	2923.7	0.716	0.716	22.9	22.9	0	0	0.00	0.00
5:00 PM	29329.2	29329.2	3114	3114	0.774	0.774	22.9	22.9	0	0	0.00	0.00
5:30 PM	32382.4	32382.4	3401.7	3401.7	0.854	0.854	22.9	22.9	0	0	0.00	0.00
6:00 PM	35096.1	35096.1	3681.5	3681.5	0.926	0.926	22.9	22.9	0	0	0.00	0.00
6:30 PM	35939.2	35939.2	3773.1	3773.1	0.948	0.948	22.9	22.9	0	0	0.00	0.00
7:00 PM	35073.4	35073.4	3679.2	3679.2	0.925	0.925	22.9	22.9	0	0	0.00	0.00
7:30 PM	33956.5	33956.5	3561.4	3561.4	0.896	0.896	22.9	22.9	0	0	0.00	0.00
8:00 PM	32684.4	32684.4	3432	3432	0.862	0.862	22.9	22.9	0	0	0.00	0.00
8:30 PM	31270.5	31270.5	3293.8	3293.8	0.825	0.825	22.9	22.9	0	0	0.00	0.00
9:00 PM	29646.7	29646.7	3142.4	3142.4	0.782	0.782	22.9	22.9	0	0	0.00	0.00
9:30 PM	27700.9	27700.9	2972.1	2972.1	0.731	0.731	22.9	22.9	0	0	0.00	0.00
10:00 PM	25515	25515	2794.7	2794.7	0.674	0.674	22.9	22.9	0	0	0.00	0.00
10:30 PM	24549.4	24549.4	2721.1	2721.1	0.648	0.648	22.9	22.9	0	0	0.00	0.00
11:00 PM	23348.8	23348.8	2633.5	2633.5	0.617	0.617	22.9	22.9	0	0	0.00	0.00
11:30 PM	23901.2	23901.2	2673	2673	0.631	0.631	22.9	22.9	0	0	0.00	0.00

Table 20 Key parameters at PCC of full and reduced network – feeder 2

Time	P (kW) (Full Network)	P (kW) (Reduced Network)	Q (KVAR) (Full Network)	Q (KVAR) (Reduced Network)	I (kA) (Full Network)	I (kA) (Reduced Network)	V (kV) (Full Network)	V (kV) (Reduced Network)	Phase Angle (Full Network)	Phase Angle (Reduced Network)	Error (%), P	Error (%), Q
12:00 AM	7290.7	7290.7	578.6	578.6	0.192	0.192	22.9	22.9	0	0	0.00	0.00
12:30 AM	6927.1	6927.1	572.3	572.3	0.182	0.182	22.9	22.9	0	0	0.00	0.00
1:00 AM	6468.5	6468.5	564.8	564.8	0.17	0.17	22.9	22.9	0	0	0.00	0.00
1:30 AM	6167.9	6167.9	560.1	560.1	0.163	0.163	22.9	22.9	0	0	0.00	0.00
2:00 AM	5935.3	5935.3	556.7	556.7	0.156	0.156	22.9	22.9	0	0	0.00	0.00
2:30 AM	5895.3	5895.3	556.1	556.1	0.155	0.155	22.9	22.9	0	0	0.00	0.00
3:00 AM	5793.7	5793.7	554.6	554.6	0.153	0.153	22.9	22.9	0	0	0.00	0.00
3:30 AM	5787.7	5787.7	554.6	554.6	0.153	0.153	22.9	22.9	0	0	0.00	0.00
4:00 AM	5722.4	5722.4	553.6	553.6	0.151	0.151	22.9	22.9	0	0	0.00	0.00
4:30 AM	5860.9	5860.9	555.6	555.6	0.154	0.154	22.9	22.9	0	0	0.00	0.00
5:00 AM	5987.7	5987.7	557.4	557.4	0.158	0.158	22.9	22.9	0	0	0.00	0.00
5:30 AM	6322.2	6322.2	562.5	562.5	0.167	0.167	22.9	22.9	0	0	0.00	0.00
6:00 AM	6864.2	6864.2	571.2	571.2	0.181	0.181	22.9	22.9	0	0	0.00	0.00
6:30 AM	7754.6	7754.6	587.2	587.2	0.204	0.204	22.9	22.9	0	0	0.00	0.00
7:00 AM	8688.4	8688.4	606	606	0.229	0.229	22.9	22.9	0	0	0.00	0.00
7:30 AM	9587.8	9587.8	626.1	626.1	0.252	0.252	22.9	22.9	0	0	0.00	0.00
8:00 AM	9878.2	9878.2	633.1	633.1	0.26	0.26	22.9	22.9	0	0	0.00	0.00
8:30 AM	9718.7	9718.7	629.5	629.5	0.256	0.256	22.9	22.9	0	0	0.00	0.00
9:00 AM	9038.2	9038.2	614.2	614.2	0.238	0.238	22.9	22.9	0	0	0.00	0.00
9:30 AM	8065.8	8065.8	594.4	594.4	0.212	0.212	22.9	22.9	0	0	0.00	0.00
10:00 AM	6878	6878	573.3	573.3	0.181	0.181	22.9	22.9	0	0	0.00	0.00
10:30 AM	5896.1	5896.1	558.8	558.8	0.155	0.155	22.9	22.9	0	0	0.00	0.00
11:00 AM	4895.3	4895.3	546.6	546.6	0.129	0.129	22.9	22.9	0	0	0.00	0.00

11:30 AM	4110.7	4110.7	539	539	0.109	0.109	22.9	22.9	0	0	0.00	0.00
12:00 PM	3424.3	3424.3	533.7	533.7	0.091	0.091	22.9	22.9	0	0	0.00	0.00
12:30 PM	3052.9	3052	531.5	531.1	0.081	0.081	22.9	22.9	0	0	0.03	0.08
1:00 PM	2498	2497.4	529	528.7	0.067	0.067	22.9	22.9	0	0	0.02	0.06
1:30 PM	2492.1	2491.5	529	528.7	0.067	0.067	22.9	22.9	0	0	0.02	0.06
2:00 PM	2391.5	2390.9	528.9	528.7	0.064	0.064	22.9	22.9	0	0	0.03	0.04
2:30 PM	2695.8	2695.1	530.1	529.7	0.072	0.072	22.9	22.9	0	0	0.03	0.08
3:00 PM	3049.1	3048.2	531.9	531.5	0.081	0.081	22.9	22.9	0	0	0.03	0.08
3:30 PM	3815.7	3815.7	537.1	537.1	0.101	0.101	22.9	22.9	0	0	0.00	0.00
4:00 PM	4515.1	4515.1	543.3	543.3	0.119	0.119	22.9	22.9	0	0	0.00	0.00
4:30 PM	5711.7	5711.7	557.3	557.3	0.151	0.151	22.9	22.9	0	0	0.00	0.00
5:00 PM	6821.5	6821.5	573.4	573.4	0.18	0.18	22.9	22.9	0	0	0.00	0.00
5:30 PM	8238.4	8238.4	598.6	598.6	0.217	0.217	22.9	22.9	0	0	0.00	0.00
6:00 PM	9466	9466	624.6	624.6	0.249	0.249	22.9	22.9	0	0	0.00	0.00
6:30 PM	10158.7	10158.7	640.7	640.7	0.267	0.267	22.9	22.9	0	0	0.00	0.00
7:00 PM	10353.5	10353.5	645.1	645.1	0.272	0.272	22.9	22.9	0	0	0.00	0.00
7:30 PM	10268.4	10268.4	642.8	642.8	0.27	0.27	22.9	22.9	0	0	0.00	0.00
8:00 PM	10113.2	10113.2	638.8	638.8	0.266	0.266	22.9	22.9	0	0	0.00	0.00
8:30 PM	9797.8	9797.8	631.1	631.1	0.258	0.258	22.9	22.9	0	0	0.00	0.00
9:00 PM	9433.9	9433.9	622.5	622.5	0.248	0.248	22.9	22.9	0	0	0.00	0.00
9:30 PM	8927.6	8927.6	611.1	611.1	0.235	0.235	22.9	22.9	0	0	0.00	0.00
10:00 PM	8348.1	8348.1	598.9	598.9	0.22	0.22	22.9	22.9	0	0	0.00	0.00
10:30 PM	8086.3	8086.3	593.6	593.6	0.213	0.213	22.9	22.9	0	0	0.00	0.00
11:00 PM	7768.1	7768.1	587.4	587.4	0.204	0.204	22.9	22.9	0	0	0.00	0.00
11:30 PM	7930.9	7930.9	590.6	590.6	0.209	0.209	22.9	22.9	0	0	0.00	0.00

c) 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.

Time aggregated load profiles

The aggregated time-series data of 2035 (30-minute time intervals) from Ballarat South ZS is presented in Figure 103. 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 104). The power generation profile of 6.15 MW wind farm is presented in Figure 105. An aggregated EV charging load data used in this section of the analysis is presented in Figure 106. Therefore, the representative daily profiles are obtained using the similar duration time series of demand and PV generation. The developed 3-step time aggregation method has been used to obtain representative daily profiles. The combined time series profile used for the further analysis is presented in Figure 107. The representative clusters of the combined time series profile are presented in Figure 108. 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 109 and Figure 110.

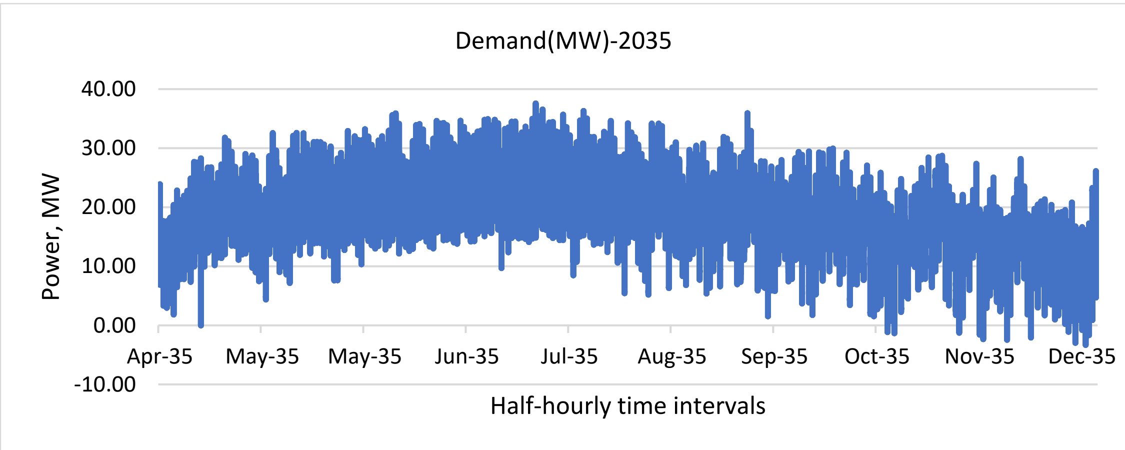

Figure 103 The aggregated time-series data 2035 from Ballarat South zone substation.

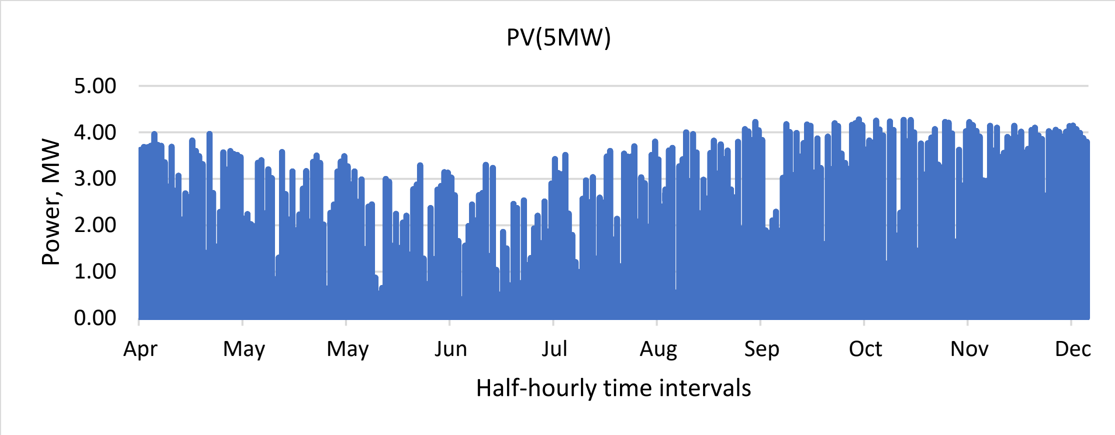

Figure 104 Yearly PV profile - Ballarat South area.

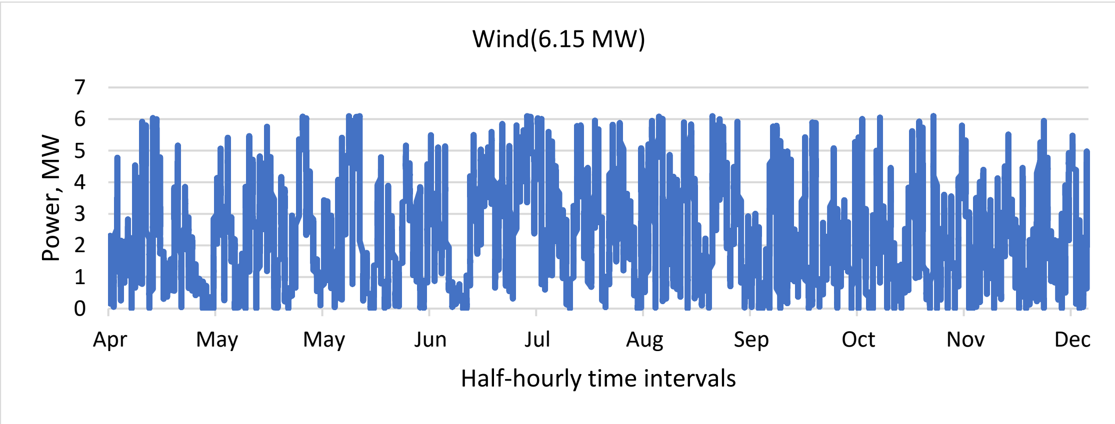

Figure 105 Wind profile - Chepstowe wind farm.

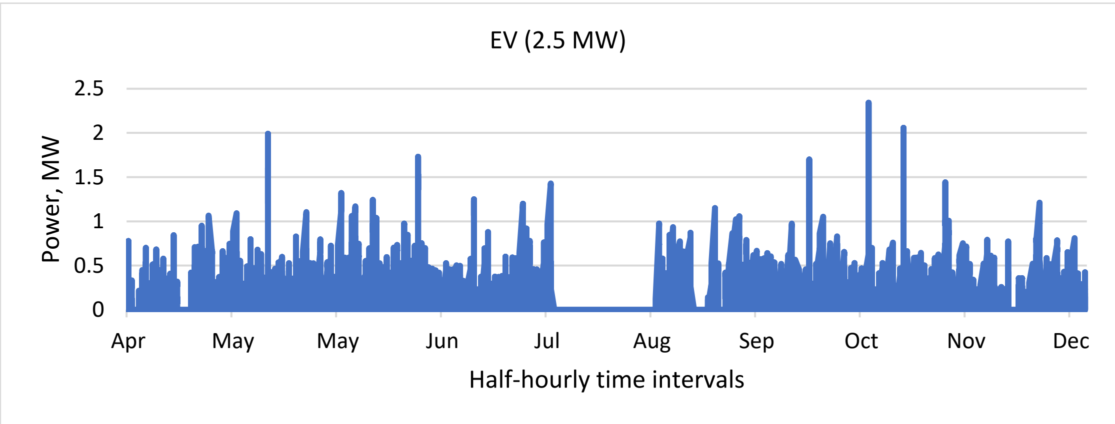

Figure 106 EV time series.

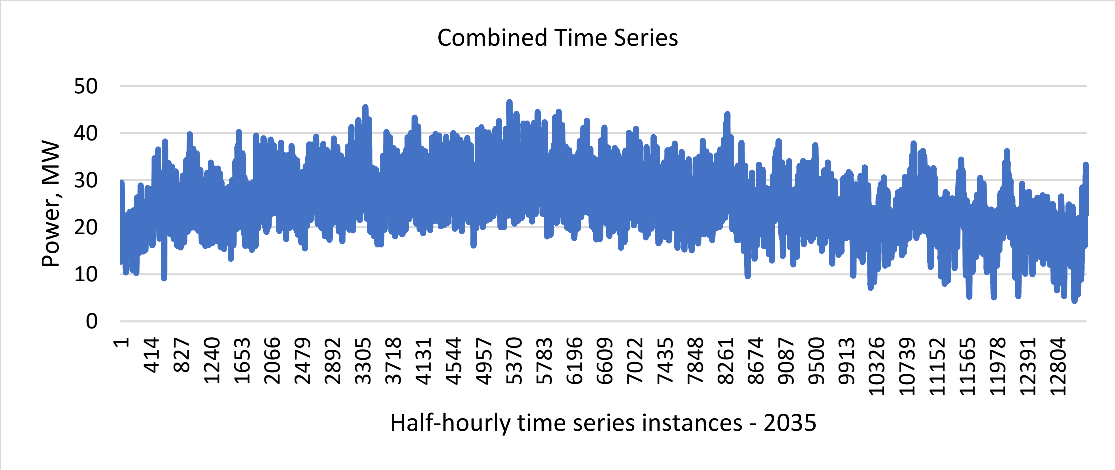

Figure 107 Combined time series data.

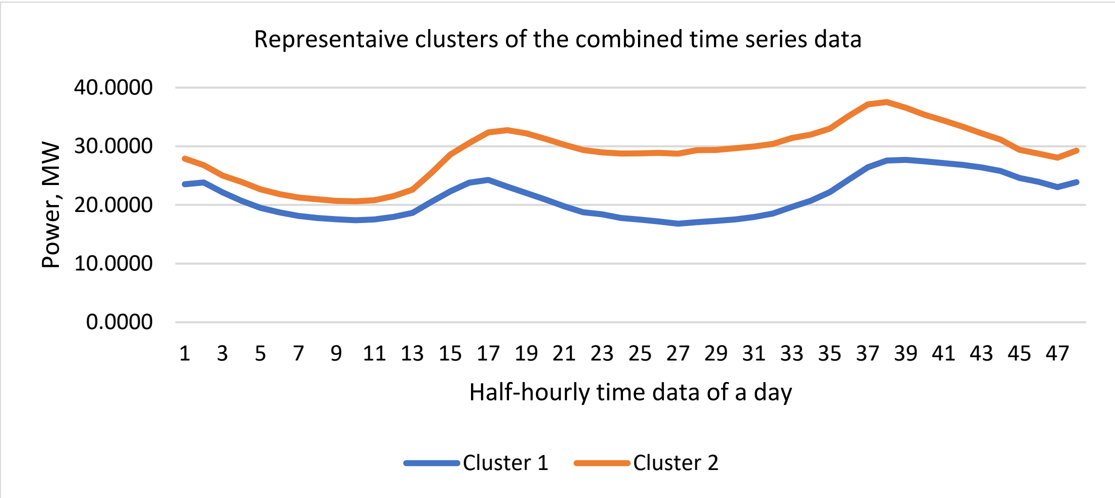

Figure 108 Representative clusters of the combined time series.

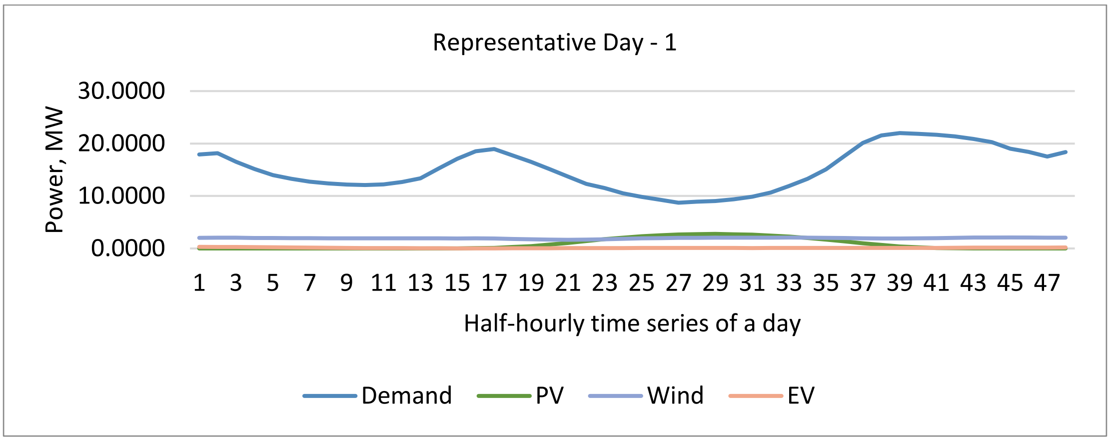

Figure 109 Daily profile - representative day-1 obtained using the 3-step time aggregation method.

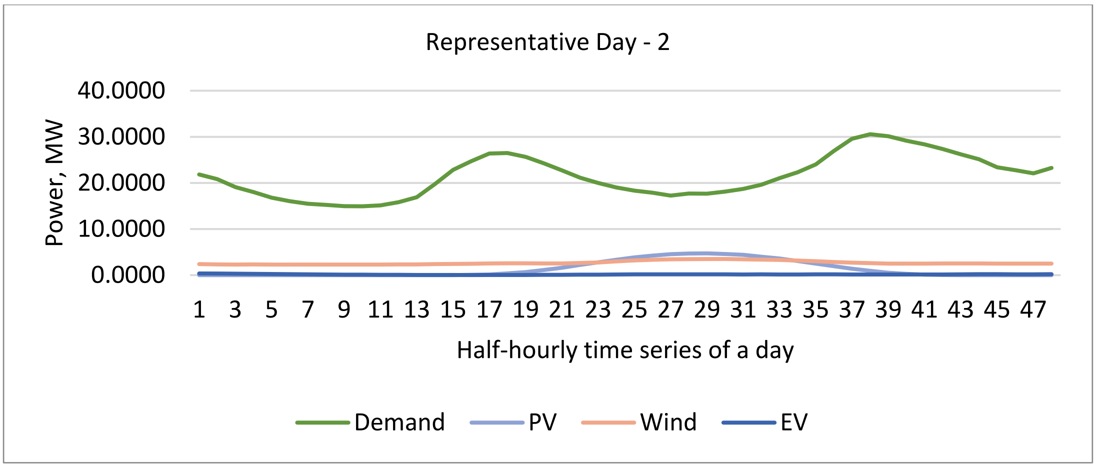

Figure 110 Daily profile - representative day-2 obtained using 3-step time aggregation method.

Representative reduced network

The representative profiles are obtained using the 3-step time aggregation method. The Ward network reduction method has been implemented to reduce the network. The accuracy of the non-linear AC power flow for the reduced network, compared to the original network has been analysed similar to the prior cases. The comparison among the active power, reactive power, current, and voltage at PCC for the full network and reduced network is presented in Figure 111 and Figure 112. The maximum active power is 28356.2 kW and the maximum reactive power is 6931.2 KVAR in the detail network. After network reduction the maximum error in the active power is 20 kW and the maximum error in reactive power is 30.4 KVAR in the reduced network. The phase angle of zero degree is reported for both networks.

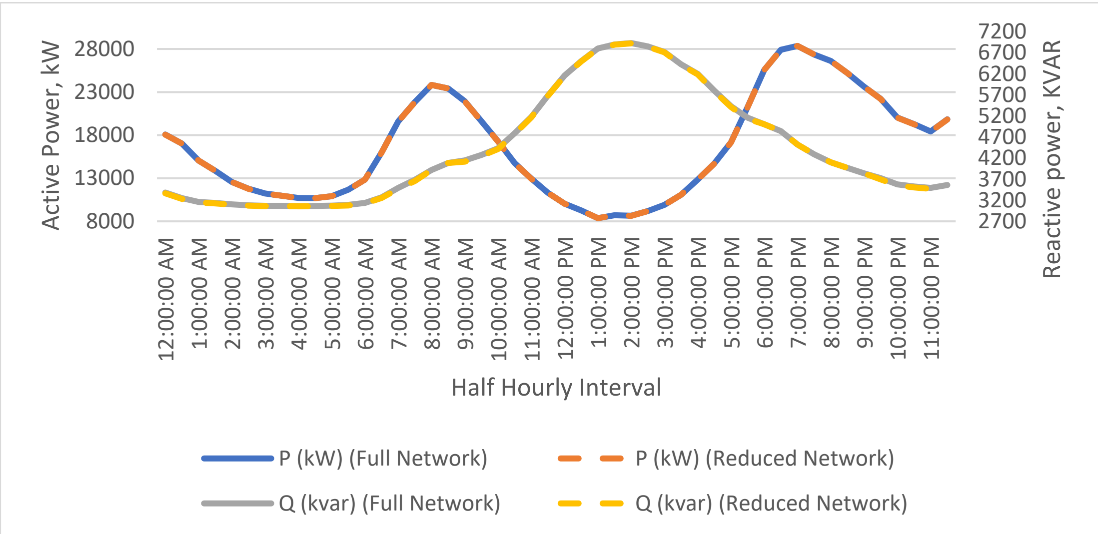

Figure 111 Active and reactive power comparison for full network and reduced network.

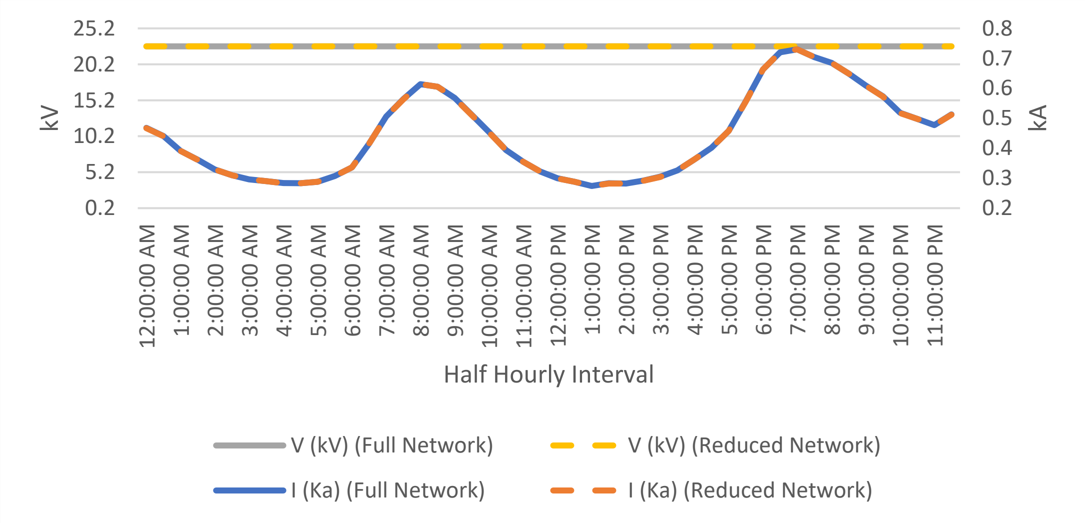

Figure 112 Current and voltage plots for the full network and reduced network.

All key parameters such as active and reactive powers, voltages, and currents at PCC for both the full and reduced network are compared in Table 21. A maximum active power error of 0.10% and a maximum reactive power error of 0.82% are observed between the detailed and reduced networks.

Table 21 Key parameters at PCC of full and reduced network

Time	P (kW) (Full Network)	P (kW) (Reduced Network)	Q (KVAR) (Full Network)	Q (KVAR) (Reduced Network)	I (kA) (Full Network)	I (kA) (Reduced Network)	V (kV) (Full Network)	V (kV) (Reduced Network)	Phase Angle (Full Network)	Phase Angle (Reduced Network)	Error (%), P	Error (%), Q
12:00 AM	18076.6	18063.2	3384.7	3364.4	0.468	0.467	22.7	22.7	0	0	0.07	0.60
12:30 AM	17026.4	17014.5	3250	3232	0.441	0.44	22.7	22.7	0	0	0.07	0.55
1:00 AM	15055.6	15046.2	3161.1	3146.9	0.391	0.391	22.7	22.7	0	0	0.06	0.45
1:30 AM	13866.4	13858.4	3138.3	3126.2	0.362	0.361	22.7	22.7	0	0	0.06	0.39
2:00 AM	12577.2	12570.6	3103.9	3093.9	0.329	0.329	22.7	22.7	0	0	0.05	0.32
2:30 AM	11782.2	11776.3	3081.9	3073	0.31	0.31	22.7	22.7	0	0	0.05	0.29
3:00 AM	11226.1	11220.7	3069.3	3061.2	0.296	0.296	22.7	22.7	0	0	0.05	0.26
3:30 AM	10972.1	10967	3070.9	3063.1	0.29	0.29	22.7	22.7	0	0	0.05	0.25
4:00 AM	10720.1	10715.2	3064	3056.6	0.284	0.283	22.7	22.7	0	0	0.05	0.24
4:30 AM	10701.5	10696.6	3066.1	3058.7	0.283	0.283	22.7	22.7	0	0	0.05	0.24
5:00 AM	10917.1	10912.1	3071.8	3064.1	0.288	0.288	22.7	22.7	0	0	0.05	0.25
5:30 AM	11670.4	11658.9	3093.2	3075.7	0.307	0.307	22.7	22.7	0	0	0.10	0.57
6:00 AM	12852.2	12845.2	3137.2	3126.7	0.336	0.336	22.7	22.7	0	0	0.05	0.33
6:30 AM	15992.6	15982	3271.2	3255.2	0.415	0.415	22.7	22.7	0	0	0.07	0.49
7:00 AM	19596.4	19580.7	3495.1	3471.3	0.506	0.506	22.7	22.7	0	0	0.08	0.68
7:30 AM	21850.7	21831.3	3686.8	3657.3	0.564	0.563	22.7	22.7	0	0	0.09	0.80
8:00 AM	23836.9	23836.9	3918.3	3918.3	0.614	0.614	22.7	22.7	0	0	0.00	0.00
8:30 AM	23429	23429	4087.3	4087.3	0.605	0.605	22.7	22.7	0	0	0.00	0.00
9:00 AM	21928.6	21908.9	4145.9	4116	0.568	0.567	22.7	22.7	0	0	0.09	0.72
9:30 AM	19611.1	19595.1	4275.4	4251.2	0.511	0.51	22.7	22.7	0	0	0.08	0.57
10:00 AM	17275.3	17262.8	4434.6	4415.5	0.454	0.453	22.7	22.7	0	0	0.07	0.43
10:30 AM	14751.4	14741.9	4792.3	4777.9	0.394	0.394	22.7	22.7	0	0	0.06	0.30
11:00 AM	12955.4	12947.7	5177.3	5165.6	0.355	0.355	22.7	22.7	0	0	0.06	0.23
11:30 AM	11309.8	11303.5	5687.9	5678.3	0.322	0.322	22.7	22.7	0	0	0.06	0.17

12:00 PM	10044	10038.5	6163	6154.6	0.3	0.299	22.7	22.7	0	0	0.05	0.14
12:30 PM	9271.6	9266.5	6504.7	6497	0.288	0.288	22.7	22.7	0	0	0.06	0.12
1:00 PM	8371.5	8366.9	6803	6796	0.274	0.274	22.7	22.7	0	0	0.05	0.10
1:30 PM	8713.3	8708.5	6899.2	6891.8	0.283	0.282	22.7	22.7	0	0	0.06	0.11
2:00 PM	8645.8	8641	6931.2	6923.8	0.282	0.282	22.7	22.7	0	0	0.06	0.11
2:30 PM	9188.6	9183.4	6852.7	6844.8	0.292	0.291	22.7	22.7	0	0	0.06	0.12
3:00 PM	9910.9	9905.2	6718.9	6710.3	0.305	0.304	22.7	22.7	0	0	0.06	0.13
3:30 PM	11084.2	11077.7	6425.5	6415.7	0.326	0.326	22.7	22.7	0	0	0.06	0.15
4:00 PM	12849.4	12841.4	6200.1	6187.9	0.363	0.363	22.7	22.7	0	0	0.06	0.20
4:30 PM	14714	14704.1	5799.6	5784.6	0.402	0.402	22.7	22.7	0	0	0.07	0.26
5:00 PM	17169.9	17157.1	5433.7	5414.2	0.458	0.458	22.7	22.7	0	0	0.07	0.36
5:30 PM	21277	21258.1	5161.2	5132.4	0.557	0.556	22.7	22.7	0	0	0.09	0.56
6:00 PM	25567	25567	5005.9	5005.9	0.663	0.663	22.7	22.7	0	0	0.00	0.00
6:30 PM	27908.1	27908.1	4840.8	4840.8	0.72	0.72	22.7	22.7	0	0	0.00	0.00
7:00 PM	28356.2	28356.2	4523.2	4523.2	0.73	0.73	22.7	22.7	0	0	0.00	0.00
7:30 PM	27349	27349	4291.8	4291.8	0.704	0.704	22.7	22.7	0	0	0.00	0.00
8:00 PM	26610.7	26610.7	4101.4	4101.4	0.685	0.685	22.7	22.7	0	0	0.00	0.00
8:30 PM	25194.4	25194.4	3970	3970	0.649	0.649	22.7	22.7	0	0	0.00	0.00
9:00 PM	23617.2	23617.2	3838	3838	0.609	0.609	22.7	22.7	0	0	0.00	0.00
9:30 PM	22214.3	22194.3	3724.2	3693.8	0.573	0.572	22.7	22.7	0	0	0.09	0.82
10:00 PM	20048.7	20032.4	3578.5	3553.6	0.518	0.517	22.7	22.7	0	0	0.08	0.70
10:30 PM	19276.3	19261.2	3527.2	3504.2	0.498	0.498	22.7	22.7	0	0	0.08	0.65
11:00 PM	18426.3	18412.4	3493.6	3472.4	0.477	0.477	22.7	22.7	0	0	0.08	0.61
11:30 PM	19837.1	19821	3562.6	3538.2	0.513	0.512	22.7	22.7	0	0	0.08	0.68

The summary of maximum errors in active and reactive power for different case studies and networks are presented in Table 22 and Table 23. Overall, the maximum error in active power is 0.646% and the maximum power of reactive power is 0.82% after network reduction from the detail network. No error of voltage is found in any of the study cases for all networks.

Table 22 Maximum active power errors for different case studies

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

Table 23 Maximum reactive power errors for different case studies

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

6. Conclusions and Future Research

A novel spatial and temporal system reduction methodology, employing both time aggregation and network reduction techniques, is developed in this **WP3.11 TSO-DSO Interface Steady-state Model of Aggregated DER as an Active Entity**. The synergistic integration of these approaches enhances network analysis and facilitates long-term planning by mitigating complexity and computational overhead, making the combined TSO-DSO studies computationally feasible. Through empirical evaluation of three real-world Victorian systems for three case studies – no DERs, with DERs, and with DERs and storage, the proposed methodology demonstrates a significantly higher computational efficiency than conventional network reduction methods by employing time aggregation capabilities. Notably, the reduced network's independence from operation set points confers an additional advantage, rendering it a concise and accurate representation suitable for the steady-state assessments of power systems, such as large-scale optimal power flow, national corridor planning, and renewable portfolio studies, among others.

The transmission and distribution networks are physically connected, essentially forming one circuit from a circuit theory point of view. In order to carry out power system operation planning functions such as SCUC, it is necessary to take into account both transmission and distribution networks. However, it can be challenging to include distribution networks into a transmission system due to their large size, which can involve hundreds or thousands of buses. Our proposed methodology aims to address this challenge by replacing a large distribution network with an equivalent network comprising 3-5 buses. This approach makes power system operation and planning functions more manageable, providing a significant advantage for transmission-level stakeholders, such as AEMO, and national network service providers.

Key recommendations from this **WP3.11 TSO-DSO Interface Steady-state Model of Aggregated DER as an Active Entity** for future works are as follows –

- Develop the network representation model in considering transient behaviour.
- Consider uncertainties in producing a more comprehensive representative model.
- With the penetration of DERs, the assumption of a single slack bus may need some revision by using multiple or distributed slack buses.

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Appendix

Long run test

The performance of the developed methodology, employing both time aggregation and network reduction approaches has been evaluated with present and future DERs, EV charging stations, and storage uptakes. The synergistic integration of these approaches enhances network analysis and facilitates long-term planning by mitigating complexity and computational overhead, making the combined TSO-DSO studies computationally feasible. However, the representative daily profiles do not cover all network operating conditions. Therefore, a long -run-test has been performed for Ballarat network where all types of DERs (PV and Wind) and storage (BESS and EV fleet storage) are considered. Since the EV storage data is available for nine months, the network reduction has been performed for consecutive nine months in every half-an-hour interval (total 13200 snapshots). A summary of the network reduction performance is presented below:

Table A.1 Errors in the key parameters at PCC after network reduction

Parameters	Median error (%)	Maximum error (%)
Reactive power at PCC	0.019%	7.11%
Active power at PCC	0.060%	1.07%

From Table A.1, the median error in reactive power at PCC is 0.019% and the median error in the active power at PCC is 0.06%.

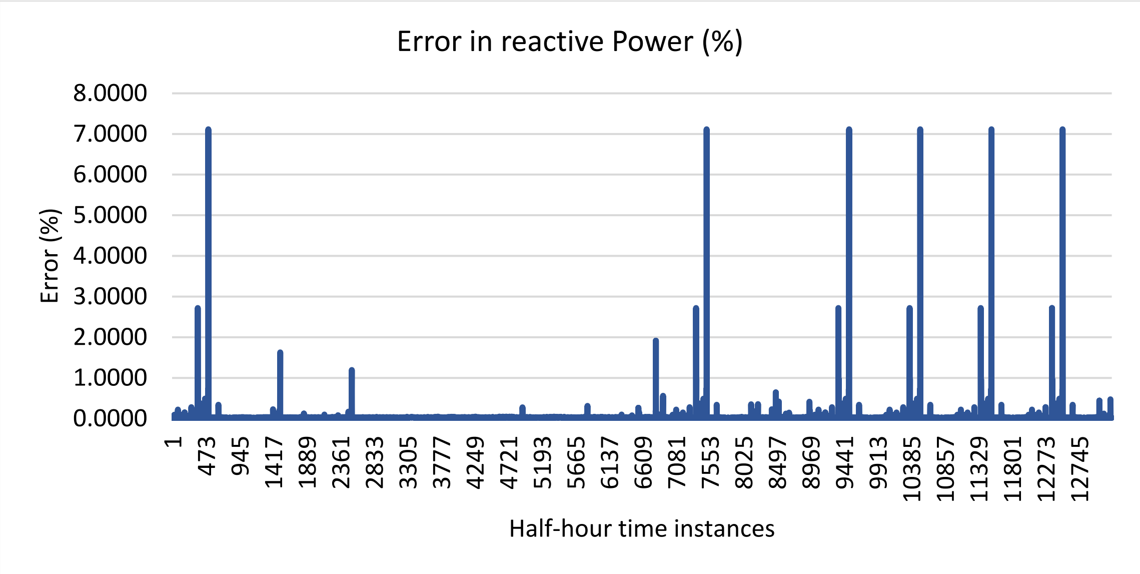

Figure A.1 Errors in reactive power at PCC between the full network and reduced network.

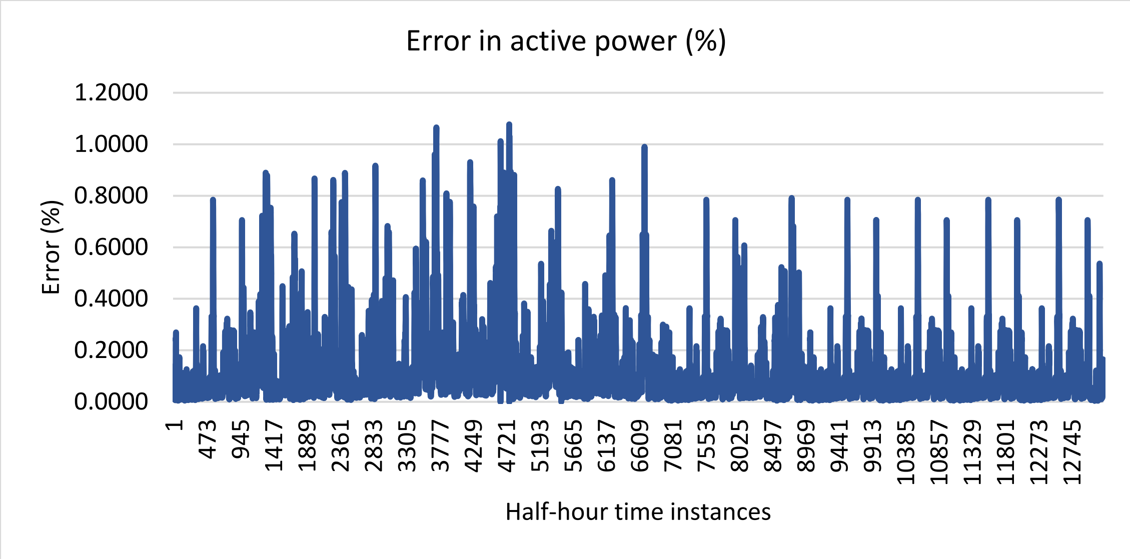

Figure A.2 Errors in active power at PCC between the full network and reduced network.

The errors in reactive power and active power are presented in Figure A.1 and Figure A.2. The maximum error in the reactive power is 7.11%. However, 99.89% of the network reduction errors for reactive power are below 1%. Similarly, the maximum error in the active power is 1.07%. However, 99.96% of the network reduction errors for active power are below 1%.