TIME OF USE CHARGING PERIODS

ANALYSIS OF PEAK AND MINIMUM DEMANDS

FINAL REPORT

Energy Queensland

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Endgame Economics
24.01, 9 Castlereagh St
Sydney, NSW 2000
Australia

Executive Summary

Endgame Economics has been engaged by Energy Queensland Limited (EQL) to undertake an analysis of the timing of historical and forecast peak and minimum demands in the Energex and Ergon Energy network areas. This work was completed to advise EQL on the timing of the charging windows for off-peak and peak network tariffs for residential and small business customers for the 2025-2030 regulatory period.

The timing of the windows determines when different network rates apply. The time-of-use (TOU) periods should be selected so that network pricing can signal the distributor's efficient costs of providing services to customers.

To advise EQL on the appropriate setting of time-of-use windows, we assessed various metrics of maximum and minimum demands on a half-hourly zone substation basis for both historical and forecast data.

Our main findings can be summarised as:

- Historical peak demands across substations have become more concentrated over the past 10 years, typically occurring around 6 pm in Energex and 7 pm in Ergon.
- Future peak demands are projected to occur slightly later, typically occurring around 7 pm in Energex and 7:30 pm in Ergon over the period 2025-2030.
- Historical minimum demands at most substations have shifted from overnight to being heavily concentrated in the middle of the day, mostly occurring in the period 11 am – 1 pm.
- Forecast minimum demands are expected to continue to occur in the middle of the day in 2025-30 but may occur slightly earlier with the uptake of electric vehicles.
- Given the increasing concentration of peak demands in the evening and minimum demands in the middle of the day, there may be scope for 'narrowing' the width of the current peak and off-peak windows.

Taking into consideration the totality of the analysis, our findings are that the current time intervals are likely to capture most peak and minimum demands across Energex and Ergon Energy for the upcoming 2025-2030 regulatory period.

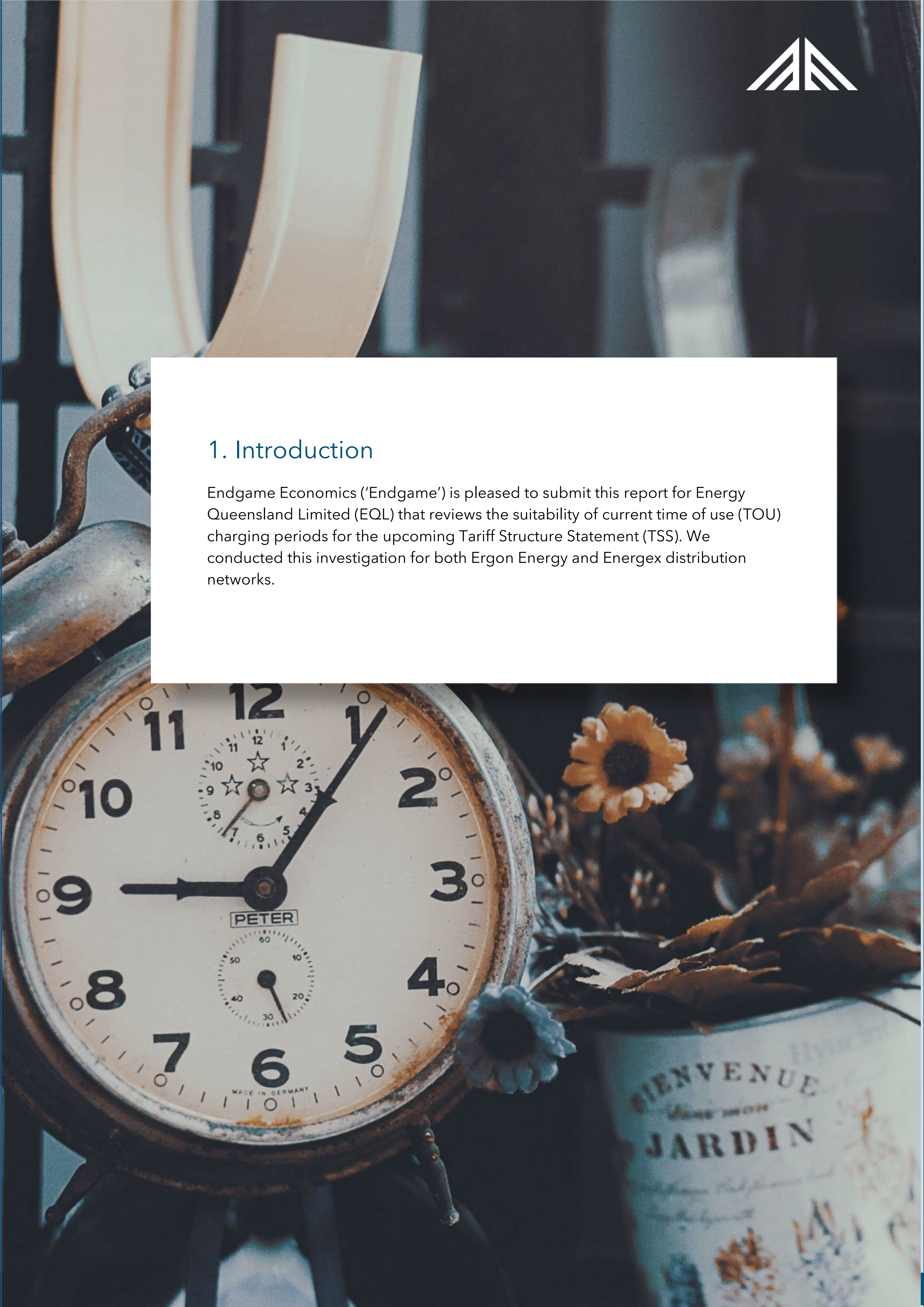
Given the increasing concentration of peak and minimum demands over time, our analysis suggests that the current windows could be narrowed to the following periods:

- Peak window at 5:00 pm – 8:00 pm
- Off-peak window at 10:00 am – 3:00 pm

This would allow a sharper LRMC price signal to be sent to customers and should increase economic efficiency by reducing the period in the evening that customers are 'over-signalled' network costs.

However, the benefits of narrowing the time-of-use windows in terms of sending a sharper price signal should be weighed against the costs of change.

Table of contents



1. Introduction

Endgame Economics ('Endgame') is pleased to submit this report for Energy Queensland Limited (EQL) that reviews the suitability of current time of use (TOU) charging periods for the upcoming Tariff Structure Statement (TSS). We conducted this investigation for both Ergon Energy and Energex distribution networks.

1. Introduction

1.1. Context

In preparation for the 2025-2030 regulatory reset, Energy Queensland Limited is required to prepare a Tariff Structure Statement for Energex and Ergon Energy ('Ergon') which outlines the proposed network tariffs for the upcoming period. As part of this process, EQL must propose time of use charging windows which will define the time of day that different tariff rates will apply. These windows should be set to promote cost reflectivity, in accordance with the network pricing principles set out in clause 6.18.5 of the National Electricity Rules (NER).

Endgame Economics ('Endgame' or 'we') have been engaged by EQL to undertake an analysis of the timing of historical and forecast peak and minimum demands in the Energex and Ergon Energy network areas to advise EQL on the timing of the charging windows for off-peak and peak network tariffs for residential and small business customers. This refers to the specific hours of the day (and potentially also the seasons) during which different network tariffs apply. The time-of-use periods should be selected so that network pricing can signal the distributor's efficient costs of providing services to customers.

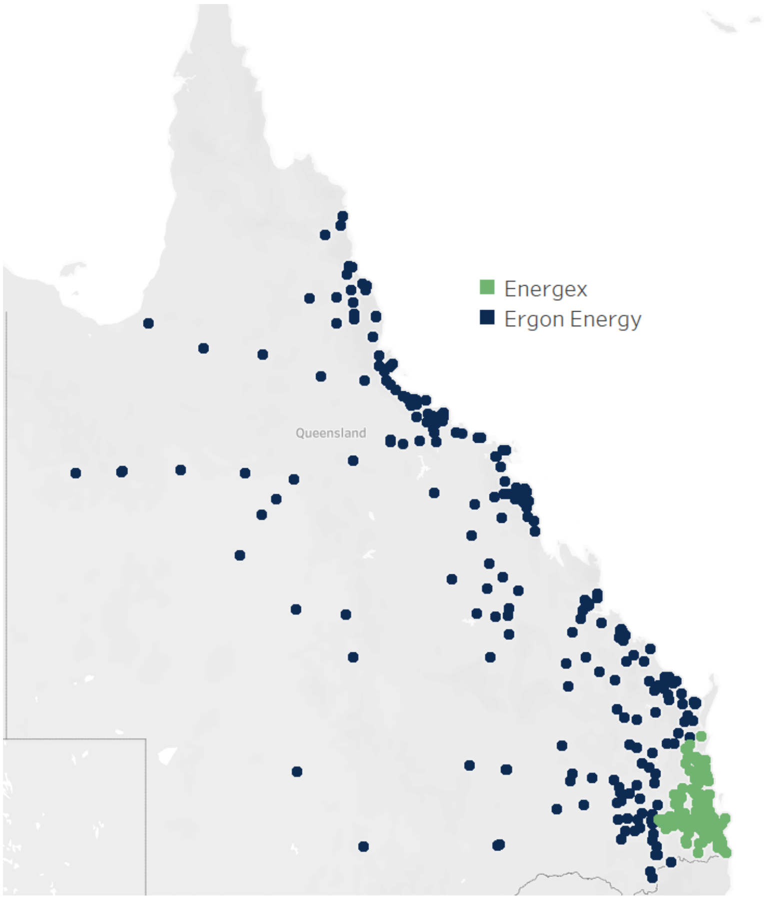
Increased network costs arise when demand approaches the capacity of the network and augmentation is needed to allow for increased flows, i.e. during times of peak demand. Outside of peak demand periods the marginal cost of transporting electricity is typically very low. However, in recent years the rapid uptake of rooftop solar PV has led to very low minimum demands in many parts of the distribution networks, leading to increasing costs of accommodating additional export.

Setting time of use windows that signal the efficient costs of the network involves accurately reflecting the long-run marginal cost (LRMC) of network services in the network prices faced by end customers. At a high level, this typically involves setting the 'peak' window during periods of peak demand and 'off-peak' windows during periods of minimum demand. The current low voltage peak demand TOU window for both networks occurs between 4 pm – 9 pm while the off-peak or solar trough window occurs between 9 am – 4 pm, see Figure 1.

Figure 1 – Current time of use charging windows

In defining TOU windows we have analysed the timing of peak and minimum demands at all 533 zone substations across the Energex and Ergon Energy distribution areas. There are currently 240 substations in Energex's supply area in the south-east corner of the state (roughly covering Brisbane, the Gold Coast and Sunshine Coast); and 293 are in Ergon Energy's supply area, which cover much of the rest of the state. Figure 2, maps out each of the zone substations in the state, the Energex distribution area is represented in green and Ergon's distribution area is in blue.

Figure 2 – Queensland zone substations



1.2. Relevant pricing principles

As set out in the National Electricity Rules (NER), a DNSP's tariff structure should be aligned with pricing principles to signal the efficient costs of using the network at a particular point in time, while ensuring that tariffs are reasonably understandable by consumers and are able to be reflected by retailers in their retail offers. Specific to this piece of work, two relevant sections of the rules are:

- Section 6.18.5 (a) Network pricing objective
- Section 6.18.5 (g) (3) Pricing principles

Section 6.18.5 (a) Network pricing objective states,

*'The network pricing objective is that the tariffs that a Distribution Network Service Provider charges in respect of its provision of direct control services to a retail customer should **reflect** the Distribution Network Service Provider's **efficient costs of providing those services** to the retail customer.'*

For consumers to make efficient decisions about whether to consume one more unit of the network service, they must face a price that signals the long-run marginal cost of an incremental unit of demand to the network.

Some obligations are of little consequence. For example, the obligation to ensure that sufficient capacity is available at 4 am in the morning on a Sunday has almost no incremental effect on network costs.

There is typically a single binding obligation that dominates all others – the obligation to provide power when demand on the network is at its greatest. This might be during the system-wide peak, or it might be during a localised peak (e.g. at a zone substation).

Because maximum demand is the primary driver of network costs, the marginal cost of the network service is therefore typically expressed in terms of the cost per kVA of the system or maximum local demand. For emphasis, the 'additional unit' of the network service is one more kVA of system-wide or local maximum demand. Hence, it is essential that we examine where and when this peak occurs.

Additionally, the existence of a maximum demand TOU is supported in the pricing principles section of the NER 6.18.5 (g) (3) and states,

*'The revenue expected to be recovered from each tariff must: comply with sub-paragraphs (1) and (2) in a way that **minimises distortions to the price signals for efficient usage** of the relevant service that would result from tariffs that comply with the pricing principle set out in paragraph (f).'*

To summarise, TOU charging windows should be set to allow network tariffs to accurately signal the efficient costs of using the network at different times.

1.3. Overview of our approach

To advise EQL on the appropriate setting of time-of-use windows for the 2025-30 regulatory period, we assessed various metrics of maximum and minimum demands on a half-hourly zone substation basis for both historical and forecast data. Our primary focus was on the evolution of historical intra-day demand profiles to inform the likely timing of peak and minimum network demands for the 2025-2030 financial years. This involved historical and forward-looking analysis:

- Historical analysis – we analysed the timing of peak and minimum demands at each substation in the Ergon Energy and Energex network over the 2012 – 2022 financial years.
- Forward-looking analysis – we analysed the timing of peak and minimum demand using:
    - EQL's forecast maximum and minimum demand profiles at each substation out to FY 2030; and,
    - AEMO 2022 Integrated System Plan (ISP) forecasts for Queensland operational demand out to FY 2030.

The combination of historical and forward-looking analysis allowed us to develop a better understanding of the changes in the demand profile over time. The analysis of historical data enabled us to understand how demand profiles have changed in different parts of the distribution networks using actual data. While the forecast analysis allowed us to incorporate future developments including the projected uptake of electric vehicles and the continued uptake of rooftop PV.

1.4. Summary of our findings

Our main findings can be summarised as:

- Historical peak demands across substations have become more concentrated over the past 10 years, typically occurring around 6 pm in Energex and 7 pm in Ergon.
- Future peak demands are projected to occur slightly later, typically occurring around 7 pm in Energex and 7:30 pm in Ergon over the period 2025-30.
- Historical minimum demands at most substations have shifted from overnight to being heavily concentrated in the middle of the day, mostly occurring in the period 11 am – 1 pm.
- Forecast minimum demands are expected to continue to occur in the middle of the day in 2025-30 but may occur slightly earlier with the uptake of electric vehicles.
- Given the increasing concentration of peak demands in the evening and minimum demands in the middle of the day, there may be scope for 'narrowing' the width of the current peak and off-peak windows.

Taking into consideration the totality of the analysis, our findings are that the current time intervals are broadly appropriate for the upcoming 2025-2030 regulatory period.

There should also be consideration of the significant projected uptake of electric vehicles (EVs) for the 2025-30 regulatory period. While projected EV uptake in included in the EQL and AEMO demand forecasts, the charging behaviour of electric vehicles is a new source of uncertainty that may lead to changes in the demand profile in the future.

Upon analysing peak demand patterns, we found a greater concentration of peaks in recent years to the early evening, particularly around 6 pm in Energex and slightly later, around 7 pm in Ergon. Our forward-looking analysis suggests that peak demands may shift slightly later in the future, around 7 pm in Energex and 7:30 pm in Ergon, possibly due to the increasing use of electric vehicles (EVs). These maximums are well within the current peak demand window.

The distribution network has undergone a fundamental shift, largely driven by the uptake of solar PV. This has changed the shape of the demand profile, shifting minimum demands from overnight to the middle of the day when solar output is at its highest.

For Energex, minimum demand occurs between 11 am and 12 pm, while for Ergon, this window is slightly later, between 11:30 am and 1 pm. Our forward-looking analysis suggests that the timing of minimum demand is unlikely to change significantly in the future.

Overall, the evidence suggests the current timing of the peak and off-peak windows are broadly appropriate for 2025-2030. Projected peak demands are likely to be concentrated in the peak window and projected minimum demands are likely to be concentrated in the off-peak window.

Given the increasing concentration of peak demands in the evening and minimum demands in the middle of the day, there may be some benefit in narrowing the current time of use windows. This could be achieved by delaying the start of the current peak window and/or bringing the end of the peak window earlier whilst ensuring that the new window captures the period where most peak demands are likely to occur. This would allow a sharper LRMC price signal to be sent to customers and should increase economic efficiency by reducing the period in the evening that customers are 'over-signalled' LRMC.

Likewise, the off-peak window could be narrowed to reflect the increasing concentration of minimum demands in the middle of the day.

Taking into consideration the likely timing of peak demand and minimum demands, the peak and off-peak charging windows could be narrowed for the 2025-2030 period to the following:

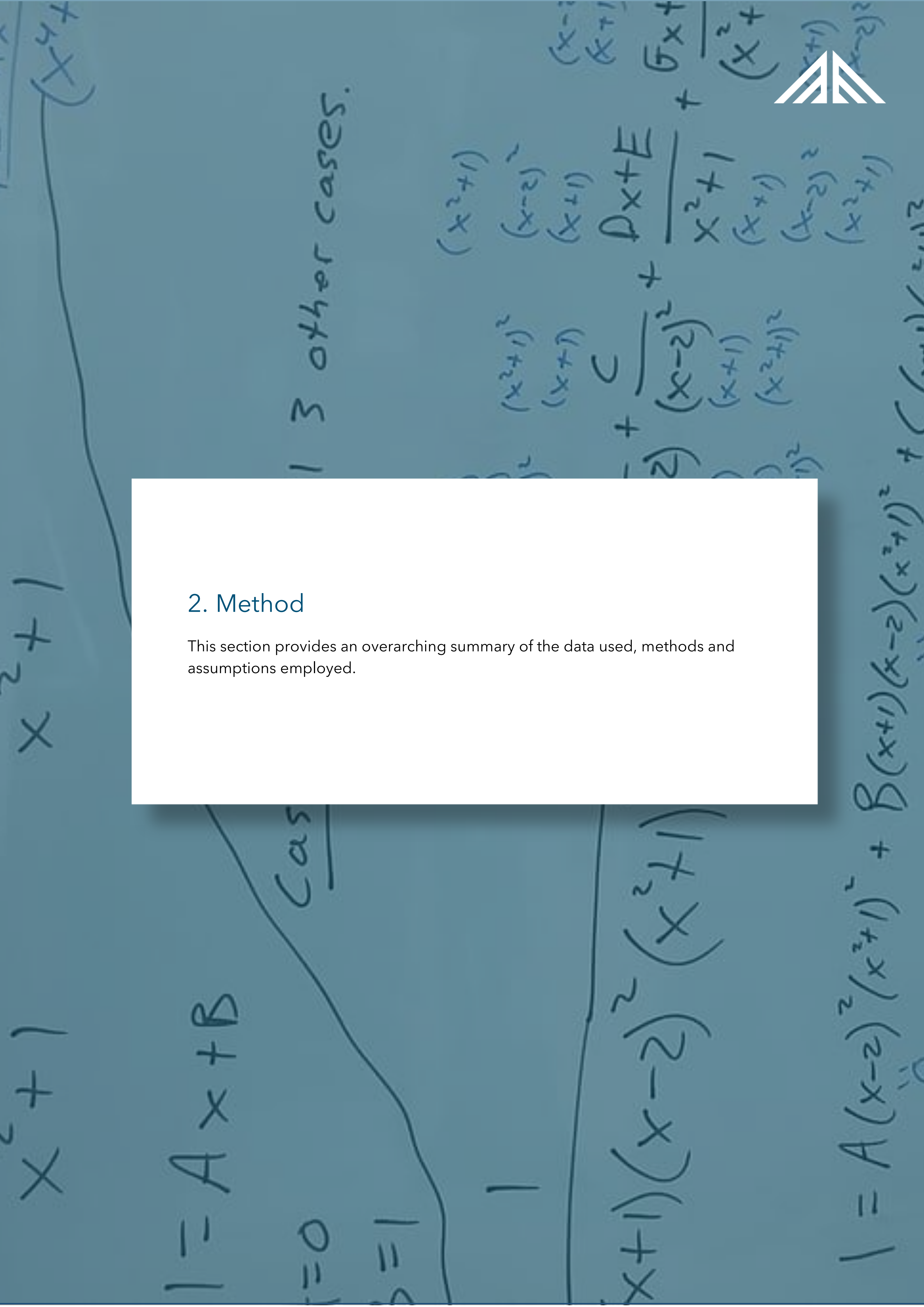
- Peak window at 5:00 pm – 8:00 pm
- Off-peak window at 10:00 am – 3:00 pm

However, the benefits of narrowing the time of use windows in terms of sending a sharper price signal should be weighed against the costs of change. There should also be consideration of possible changes in the demand profile introduced by the uptake of EVs. While the EQL and AEMO forecasts underlying our forward-looking analysis incorporate EVs, the charging behaviour of EVs represents a new source of uncertainty.

1.5. Structure of the report

The remainder of this report is structured as follows:

- **Section 2** provides a summary of our methodology including assumptions and our approach for addressing errors in the historical substation data.
- **Section 3** analyses the results for maximum demand
- **Section 4** explores the results for minimum demand.
- **Section 5** concludes with our recommendations.



2. Method

This section provides an overarching summary of the data used, methods and assumptions employed.

2. Method

This section provides an overarching summary of the data used, methods and assumptions employed in our time of use window analysis.

2.1. Assumptions and limitations of our analysis

There are significant challenges associated with setting time of use windows for a distribution network. Network costs are driven by investment in individual assets in different parts of the network, and at different voltage levels. Demand peaks in different parts of the network are not necessarily coincident. The timing of peak demand at a particular substation in the Brisbane CBD may be very different from another substation in a suburban part of the network. Setting a single time of use window for an entire distribution network area necessitates trade-offs, for e.g. setting a peak window to signal LRMC at a time period where the majority of substations experience peak demand may 'over-signal' costs in a different part of the network where there is excess capacity at that time.

There are also uncertainties regarding future demand forecasts. The profile of electricity demand can change over time due to a number of factors. For example, as the analysis in this report shows, the uptake of rooftop PV has significantly changed the demand profile, pushing peak demand later in the day and concentrating minimum demands in the middle of the day.

Taking into consideration these challenges and the availability of data, our analysis has focused on how peak and minimum demands have changed, and are projected to change, at the substation level across both Energex and Ergon Energy networks. Our objective has been to find the time periods where peak and minimum demands are likely to occur for the majority of substations across the two networks.

The analysis in this report necessarily relies on some key assumptions. As will be seen in the report, our historical analysis focuses on the substation level, using publicly available substation demand data. This analysis involved some data cleaning and processing assumptions which are laid out in Section 2.1.1. Our forward-looking analysis uses demand forecasts from EQL's internal forecasting team and AEMO's 2022 Integrated System Plan. Demand forecasting relies on a number of assumptions.

Overall, the different sources and methods we have adopted have led to similar conclusions for the likely timing of peak and minimum demands. However, our findings and recommendations should be interpreted with these assumptions and limitations in mind.

2.1.1. Data cleaning

The historical substation datasets included missing values and other errors including extreme positive and negative outliers. To address this, we have replaced missing values and values with an absolute difference of a given threshold within a window with the mean for that hour by zone substation, year and day of the week.

More specifically, for Ergon, if values were missing or are greater than 100 MW or less than -10 MW and have an absolute difference of 20 MW between two observations. They were replaced with the mean for that hour by zone substation, year and day of the week.

For Energex, if values are missing or are greater than 200 MW or less than -120 MW and have an absolute difference of 20 MW between two observations or an absolute difference of 50 MW between four observations. They were replaced with the mean for that hour by zone substation, year and day of the week.

We see this as a pragmatic approach that minimises the probability of incorrectly identifying real data as "errors". As our focus is on peak and minimum demand periods, this substitution is unlikely to significantly affect results. By replacing values with the mean we reduce the risk of our findings being skewed by errors in the raw data.

It should also be noted that financial year 2022 substation data for Ergon Energy ends on March 31 2022. While this is unlikely to significantly change the peak demand results, it may impact the minimum demand results which increasingly are occurring in the shoulder seasons. To account for this, many of the results presenting the most recent year actually focus on FY 2021 for Ergon Energy substations.

2.2. Historical analysis

For the historical analysis, we used publicly available data published by Energex and Ergon to assess when peak and minimum demands occur throughout the year by each zone substation. For Energex data was available for the 2012-2022[1] financial years, whilst similarly for Ergon data was available from March 2011 – March 2022[2]. Hence, due to not having complete data for Ergon in FY 2022, we have focused on both FY 2021 and 2022 in our analysis.

After considering the availability of data and the approaches of other distributors, we have decided to undertake this analysis on a substation basis. We believe that identifying peak and minimum demands at this level across the networks is a suitable proxy for the main drivers of costs in the network.

2.2.1. Analysis

For our analysis, we investigated several metrics related to minimum and maximum demand.

It is important to note that peak (and increasingly minimum) demands are the major drivers of costs in distribution networks. Therefore, maximum and minimum demand analysis based on average, or typical, demand profiles do not necessarily provide a good indication of the times of day when incremental demand (or export) drive network augmentation costs. For example, if we plot average demands by year and by substation we get a misleading picture of when the extremes may occur (particularly for the timing of minimum demand). In Figure 3 and Figure 4, we can see that minimum average demand occurs overnight for both networks. In the following section, minimum demands by substation show a different picture, with annual minimum demands in the year occurring in the middle of the day when the weather is mild and rooftop PV is generating near its maximum.

[1] Energex. Zone substation load data reports. https://www.energex.com.au/about-us/company-information/our-network/data-to-share/zone-substation-load-data-reports
[2] Ergon. Zone substation data reports. https://www.ergon.com.au/network/help-and-support/about-us/who-we-are/data-to-share/zone-substation-data-reports

Figure 3 – Energex average network demand across zone substations and year

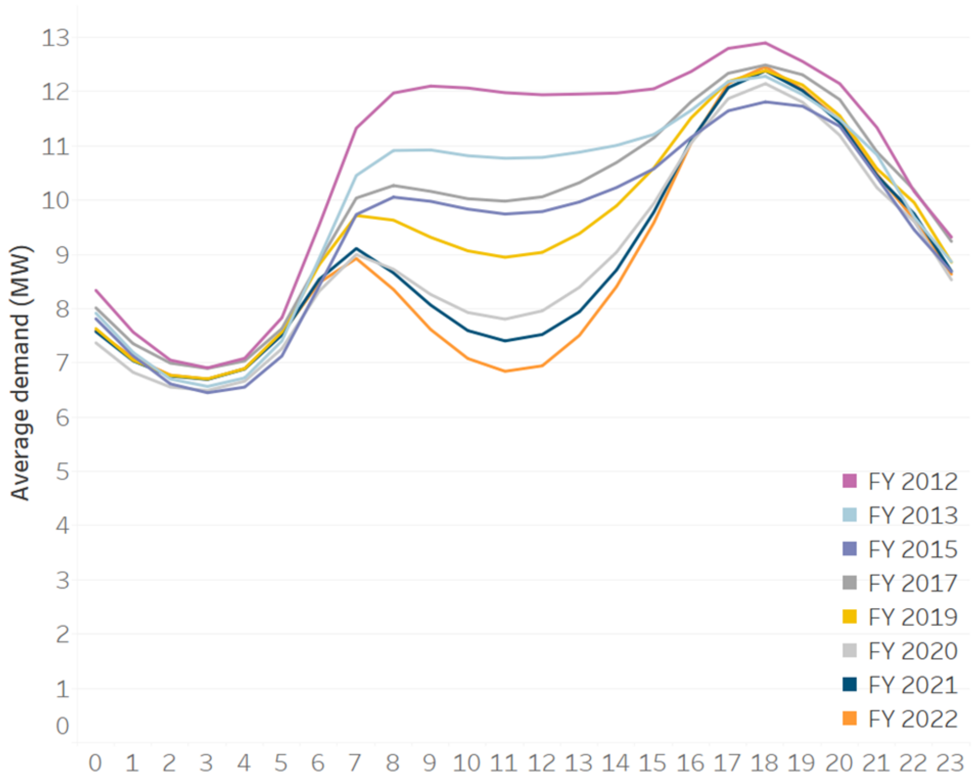
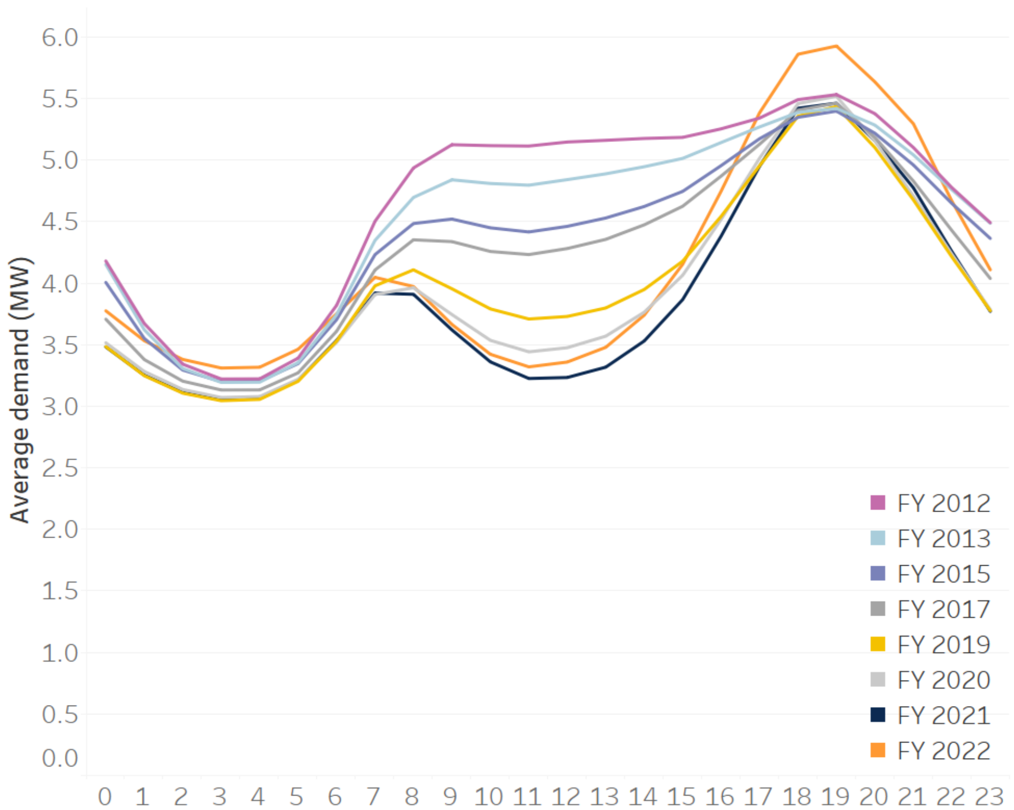


Figure 4 – Ergon average network demand across zone substations and year



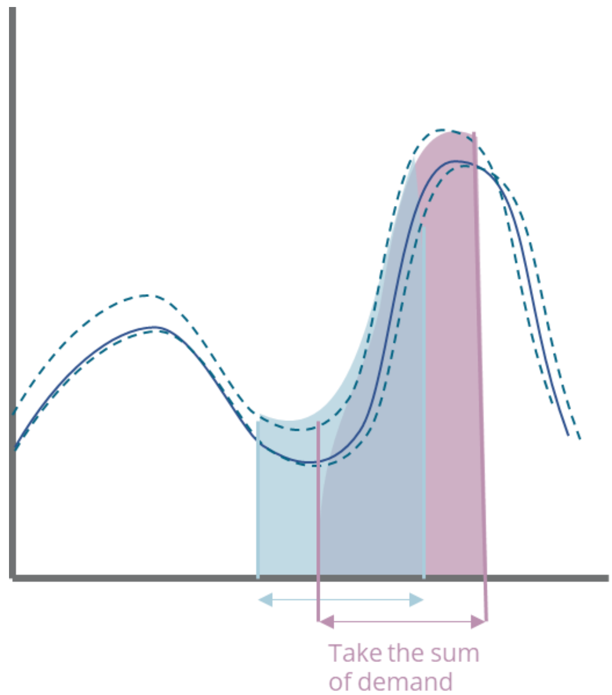
The purpose of time-of-use windows is to signal to customers when costs are incurred. As previously stated, this occurs when demand exceeds the capacity of the network, typically during peak demand periods when demand is approaching capacity limits which may occur only a few times in a year (or even not at all in a given year).

Another consideration we have factored into our analysis is that some actual peak-demand events can be driven by a combination of rare factors, as is the case for Energex in FY 2022 when extensive cloud cover and hot weather caused a peak in demand during the off-peak period in the afternoon. To account for this, our main historical analysis investigates when extreme demand events occur by investigating observations greater than the 90th percentile and less than the 10th percentile for each zone substation and year to account for this.

2.2.2. Rolling sum investigation

To assess whether the current window is appropriate for peak demand we computed a rolling sum of demand across different window lengths of three and five hours. The greatest sum or area will demonstrate when peak demand occurs for that window. For example, given the three-hour window, we took the sum of demand from 3 pm – 6 pm. Then moved the window over an hour, taking the sum for 4 pm – 7 pm, so on and henceforth, Figure 5.

Figure 5 – Rolling sum method



2.3. Forecast Analysis

Our forward-looking analysis looks at half-hourly demands for the 2025-30 period using substation demand forecasts from both EQL and operational demand forecasts from the AEMO 2022 Integrated System Plan.

AEMO's operational demand forecasts incorporate the continued uptake of consumer energy resources (CER) including rooftop PV and EVs. We found when maximum (minimum) demand occurs for each day. Then for each financial year took the top (lowest) five demand occurrences and investigated when (ie, time of day) they occur. If we were to only choose the top (lowest) five demand occurrences for the financial year these could fall on the same day and not provide a true picture of their distribution.

Additionally, EQL provided us with their 2022 forecasts of their typical peak demand day (POE50) and a minimum demand day using a medium scenario for each zone substation across both networks. We also found when maximum and minimum demand is predicted to occur for these days employing a similar method to the historical analysis.

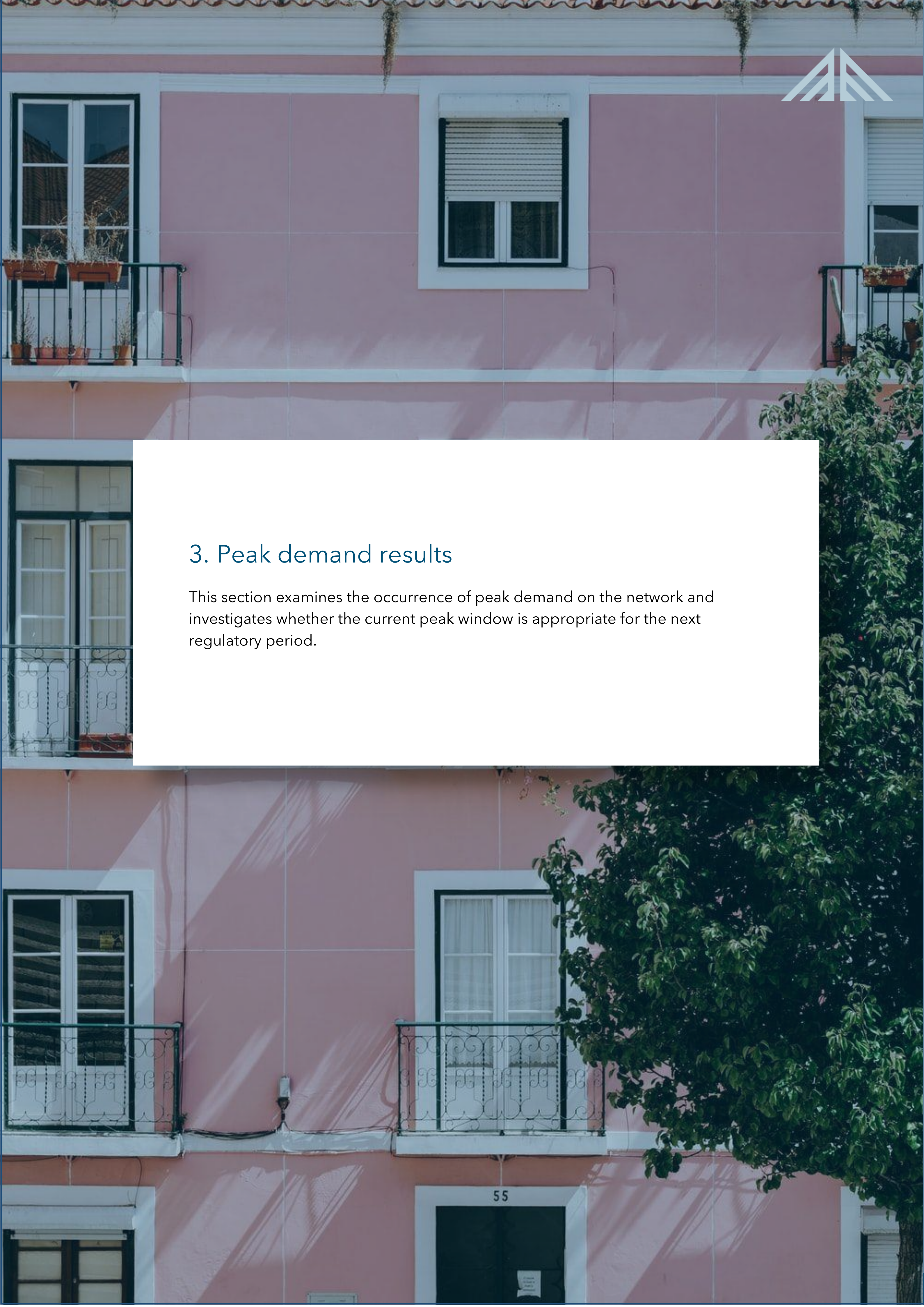
2.4. Desktop review of the method from other DNSPs

To ensure our method is consistent with industry practice we conducted a secondary review into how other DNSPs identify their time-of-use windows. The below table summarises the method by five other distributors across the National Electricity Market (NEM) with hyperlinks referencing their documents. Overall, most DNSPs investigate historical data identifying the hour in which peak demand occurs, season and type of day. Accordingly, our analysis follows a similar structure.

Table 1 – DNSP TOU window methods

Network	Summary	Reference	Pages
TasNetworks	Investigates the system load profile and identifies the peak demand period. Chooses the same windows for residential and small business consumers.	Tariff Structure Explanatory Statement Regulatory Control Period 1 July 2019 to 30 June 2024	146-148
SAPN	Used historical data to investigate at what time of the day peak demand occurs, what season and what day (ie, weekend or weekday). Investigated historical maximum demand by subregion with emphasis on the CBD. Took historical demand but adjusted for future PV.	Attachment 17 Tariff Structure Statement Part B - Explanatory Statement 2020-25 Revised Regulatory Proposal	32-43

Ausgrid	Finds historical top 100 peak demand periods and plots their occurrence by month. Takes a forecast for 2029 and plots the time of day that each zone substation will experience its peak demand. Investigates peaks by day of the week.	Ausgrid 2024-2029 TSS explanatory statement.	34-36
Evoenergy	Identifies when peak demand occurs and the months it occurs in. Not much information is provided on their analysis.	Attachment 7: Proposed Tariff Structure Statement. Regulatory proposal for the ACT electricity distribution network 2024–29	12-14
Jemena	Used historical data to investigate at what time of the day peak demand occurs, what season, and what day (ie, weekend or weekday).	2021 - 26 Electricity Distribution Price Review Revised Proposal	24-29



3. Peak demand results

This section examines the occurrence of peak demand on the network and investigates whether the current peak window is appropriate for the next regulatory period.

3. Peak demand results

This section examines the timing of peak and high demands for each of the Energex and Ergon Energy network areas. We begin by presenting our historical analysis of how the timing of the peaks have changed over time, then we present how they are projected to change for the 2025-30 regulatory period.

3.1. Historical maximum demand

3.1.1. Maximum demand periods

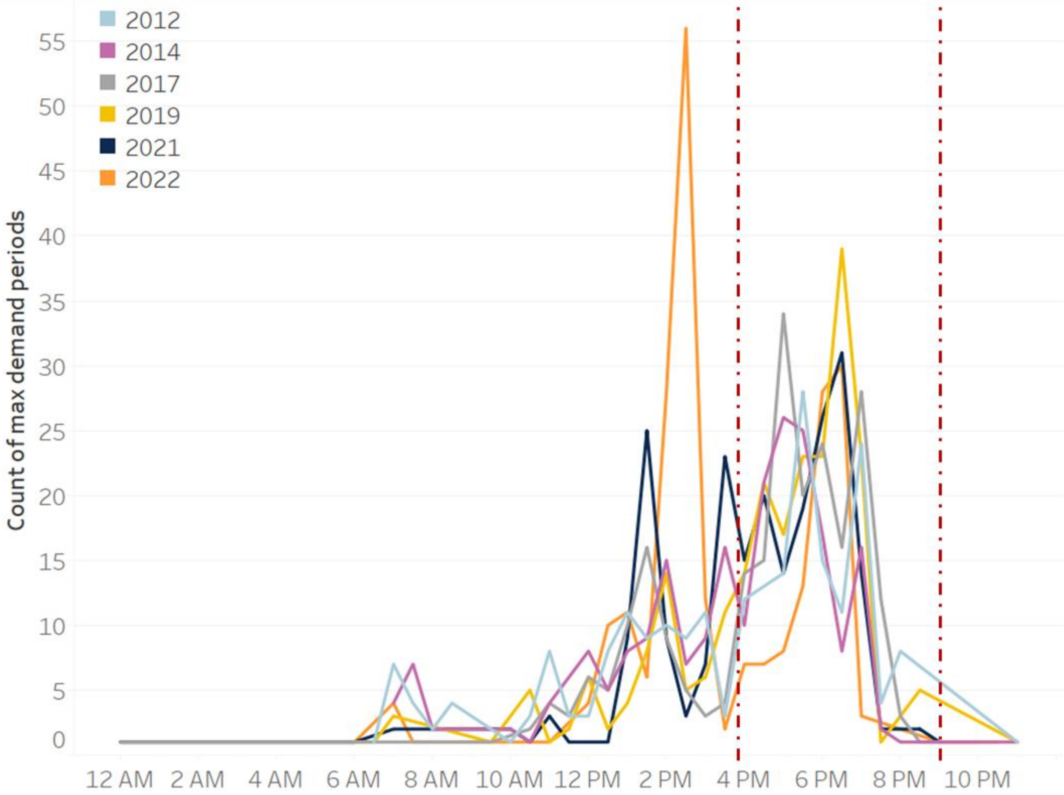
To initiate this section, we explored when historic peak demand occurred for each substation and year in both the Energex and Ergon Energy networks. Throughout this report we present the same analysis for each network, first Energex then Ergon Energy. This allows for an easy comparison between the two businesses. For Energex demand generally reaches its maximum between 5 pm – 7 pm which lies within the current 4 pm – 9 pm window, Figure 6.

However, it can immediately be seen that in 2022 peak demand at many substations occurred outside of this window at around 2:30pm, February 2. On this day temperatures in Brisbane reached 35.5 degrees Celsius contributing to high electricity demand[3]. Further, heavy cloud cover prevented solar PV generation and limited its ability to counteract midday loads.

This unusual peak demand event in 2022 demonstrates the limitations of focusing solely on the absolute peak demands which can in a given year occur due to a combination of factors. To overcome this, we have also analysed the timing of actual demands above the 90th percentile of demand for each substation in each year.

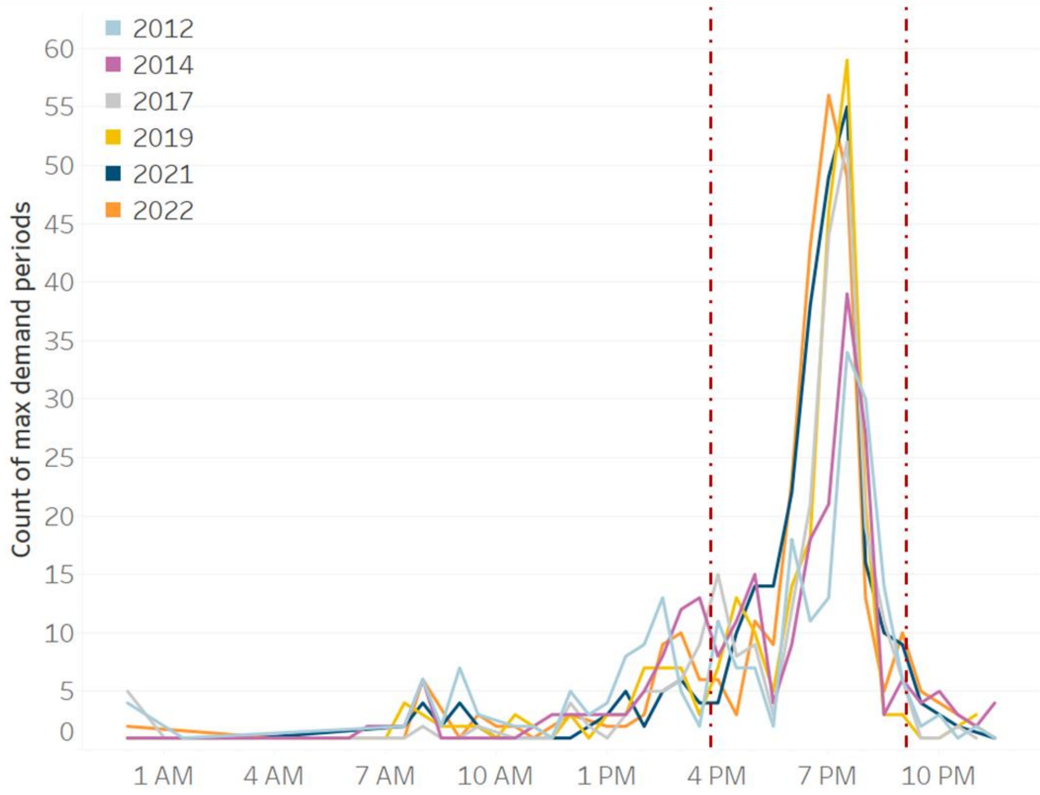
[3] BOM. Brisbane, Queensland February 2022 Daily Weather Observations http://www.bom.gov.au/climate/dwo/202202/html/IDCJDW4019.202202.shtml

Figure 6 – Energex count of maximum demand periods for each FY and substation



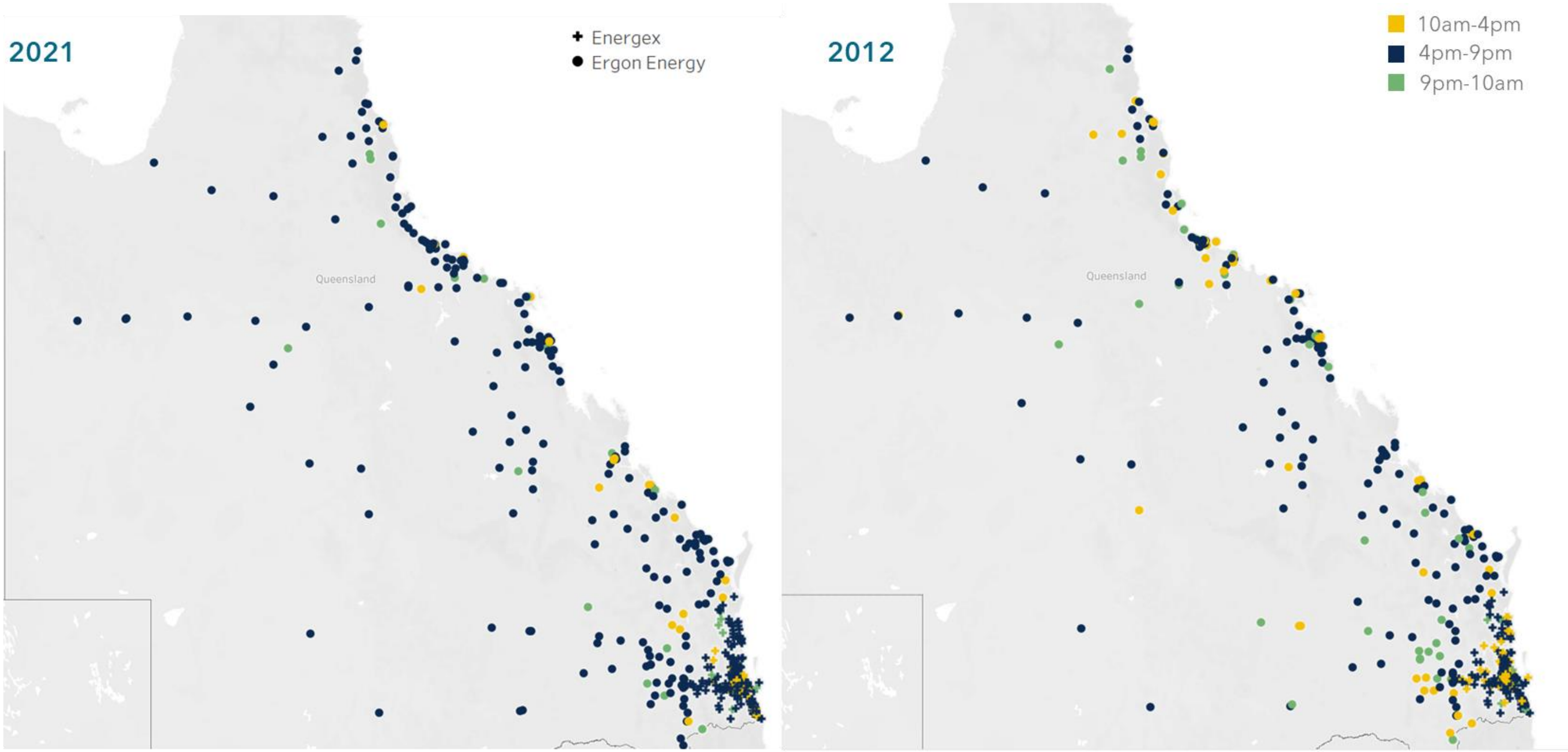
Ergon's peak demand events are concentrated between 5 pm – 8 pm, as shown in Figure 7. This graph also demonstrates the increasing frequency of peak demand occurring around 7 pm over time.

Figure 7 - Ergon count of maximum demand periods for each FY and substation



In addition, we conducted a geographical exploration, investigating where and when in Queensland maximum demand occurs overtime. Comparing 2021 with 2012, peak demand is increasingly becoming more concentrated within the 4 pm – 9 pm window, Figure 8. We chose the year FY 2021 due to data completeness for Ergon and due to the outlier 2022 event for Energex.

Figure 8 - Time of day peak demand occurs for each zone substation by year and location



However, delving further in Energex's CBD substations peak demand typically occurs during the day which is expected for commercial areas, as seen in Figure 9 and Figure 10. Whilst for Ergon the picture is different with only certain CBD areas such as Rockhampton and Gladstone experiencing midday demand peaks, as shown in Figure 11.

Figure 9 - Time of day peak demand occurs for Brisbane CBD FY 2021

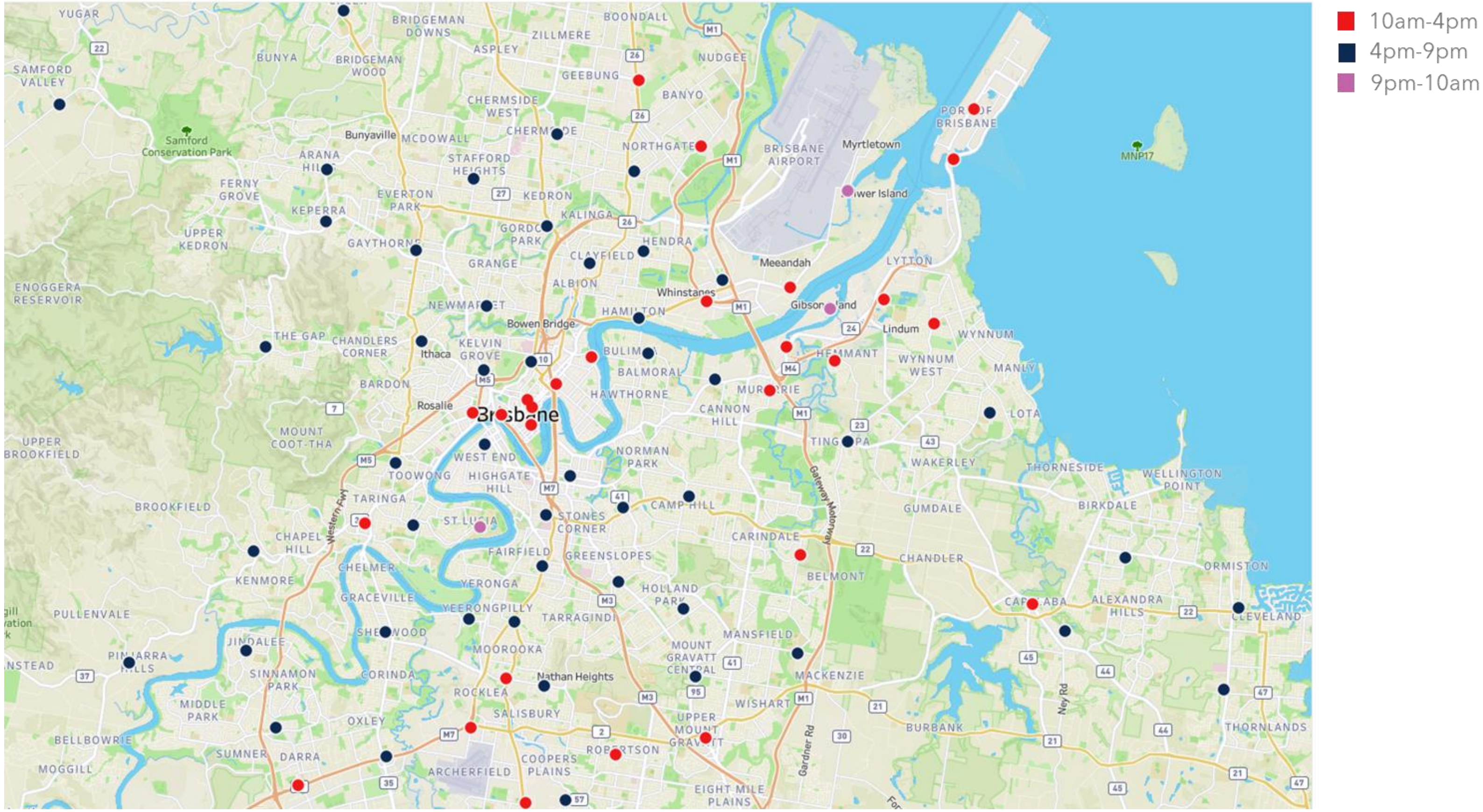


Figure 10 - Time of day peak demand occurs for Gold Coast FY 2021

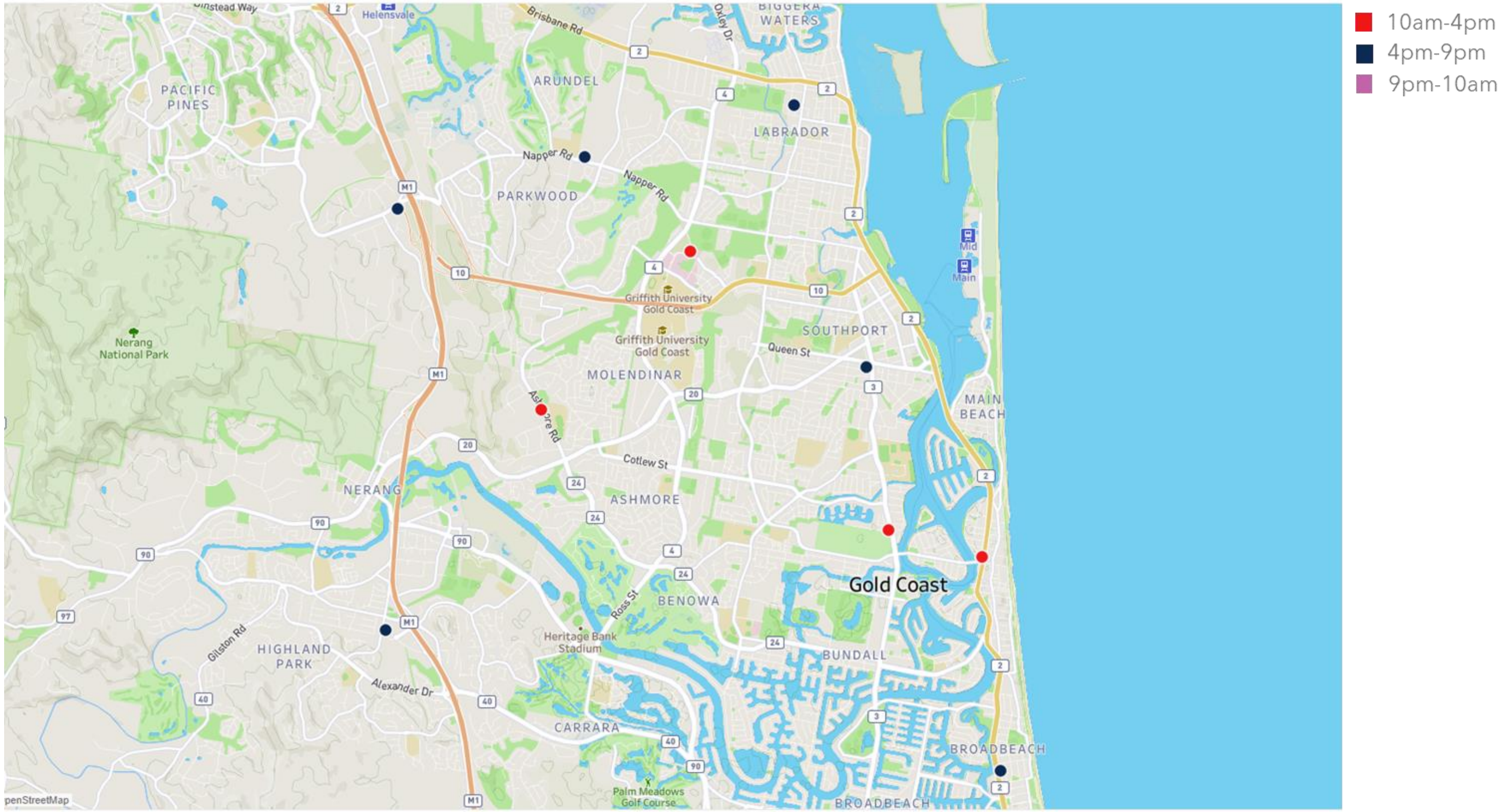
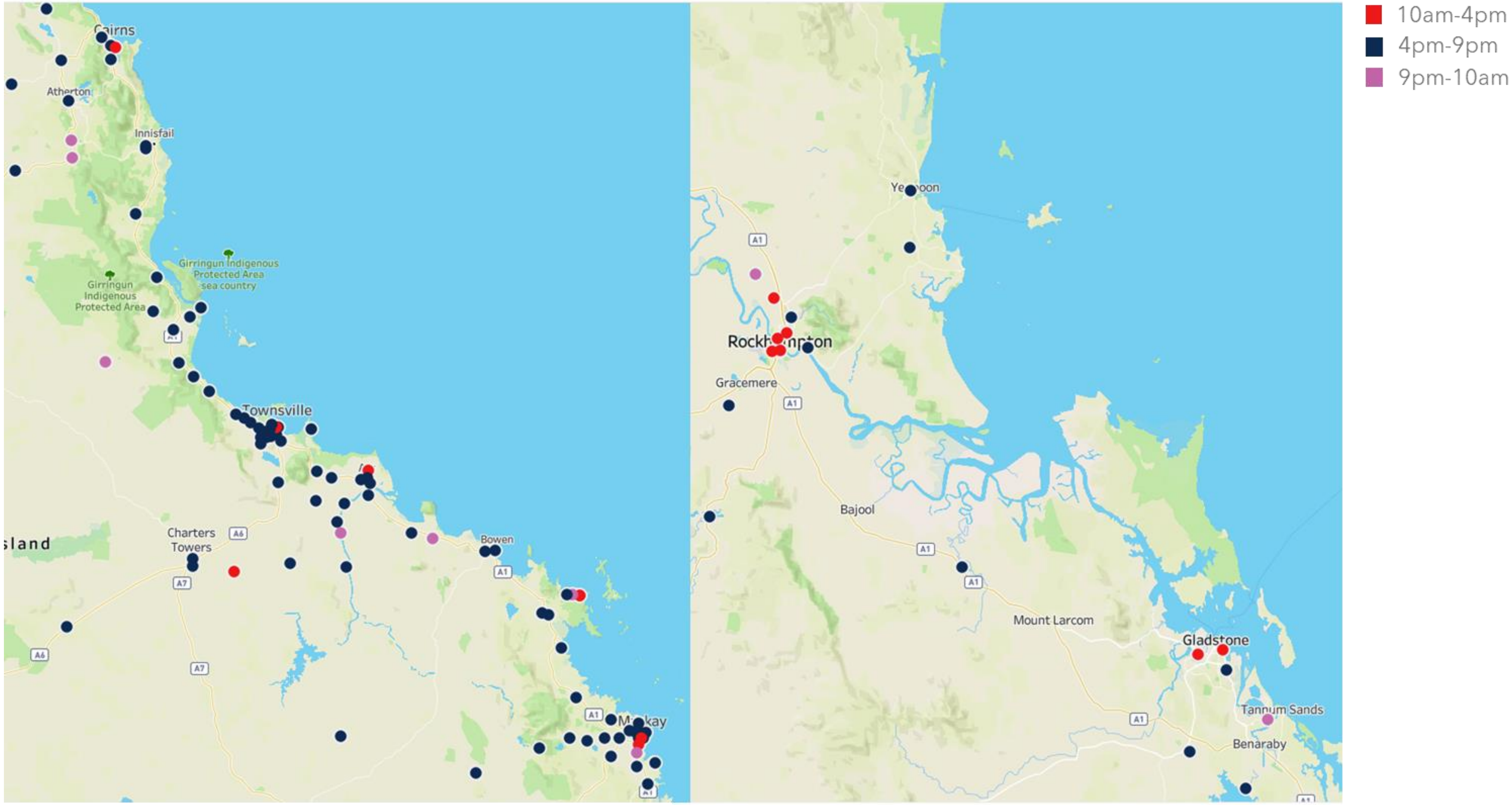


Figure 11 - Time of day peak demand occurs for Ergon FY 2021

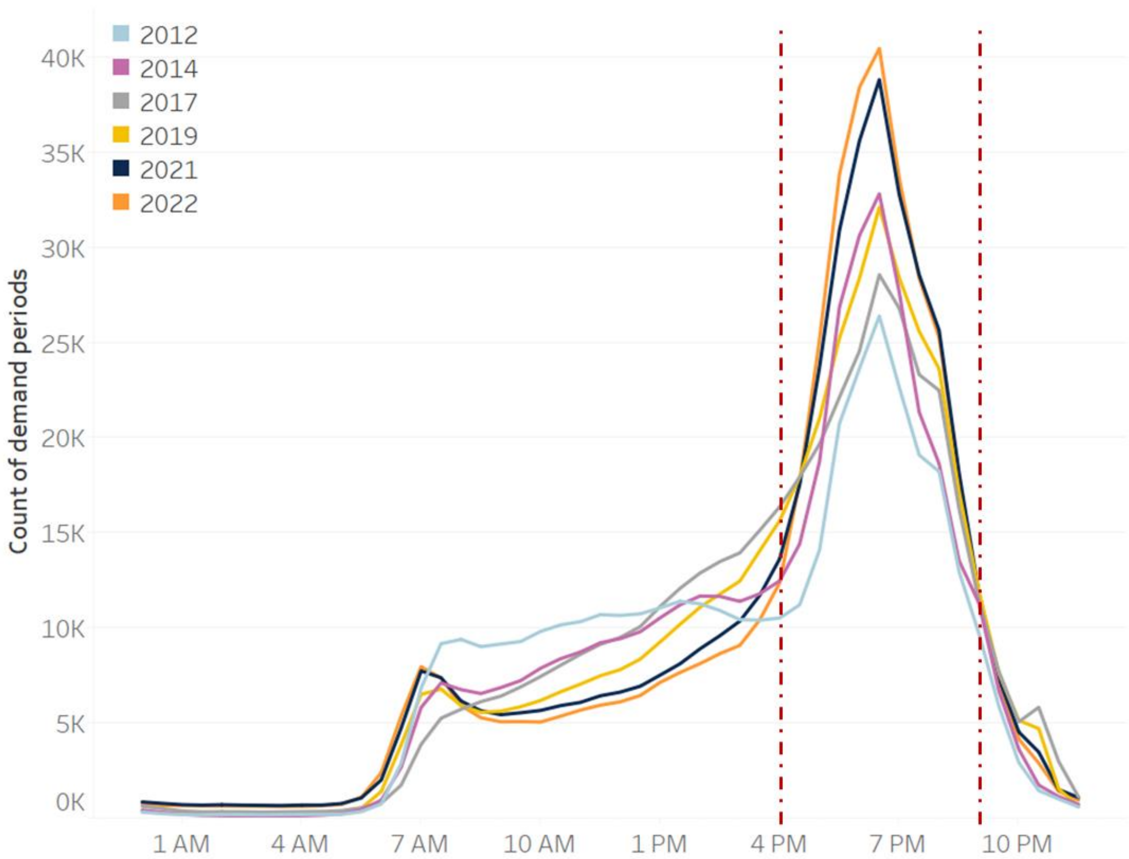


3.1.2. High demand periods

We now focus our analysis on the top demand periods defined by being greater than the 90th percentile for each zone substation and financial year. For Energex, demands above the 90th percentile typically occur between 5 pm – 8 pm, Figure 12.

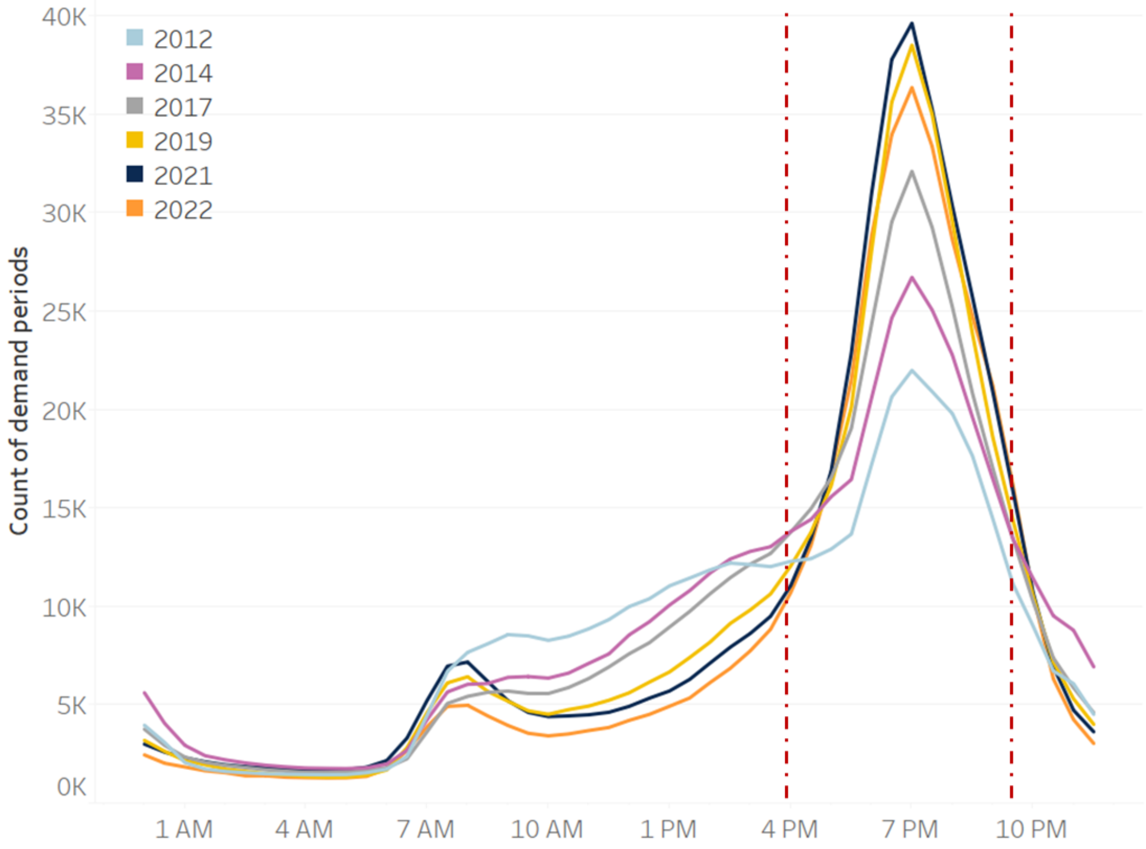
This implies that high demand periods are more likely to occur in the evening with the image also conveying how the peak is becoming more concentrated around 6pm in the evening over time.

Figure 12 – Energex count of demand periods greater than the 90th percentile for zone substation and FY



Conversely, for Ergon peak demands occur later during the evening at approximately between 5:30 pm and 9 pm, Figure 13.

Figure 13 - Ergon count of demand periods greater than the 90th percentile for zone substation and FY



For both networks, peak demand events typically occur in summer, Figure 14 and Figure 15. In recent years, this has become more frequent.

Substations in the Energex area are more likely to experience peak demand in winter months relative to substations in the Ergon area where there are some substations experiencing high demands in the shoulder seasons (spring and autumn). For both networks in winter there are a small number of substations experiencing above 90th percentile demands between 7 am – 8:30 am.

Figure 14 – Energex count of demand periods greater than the 90th percentile plotted by season

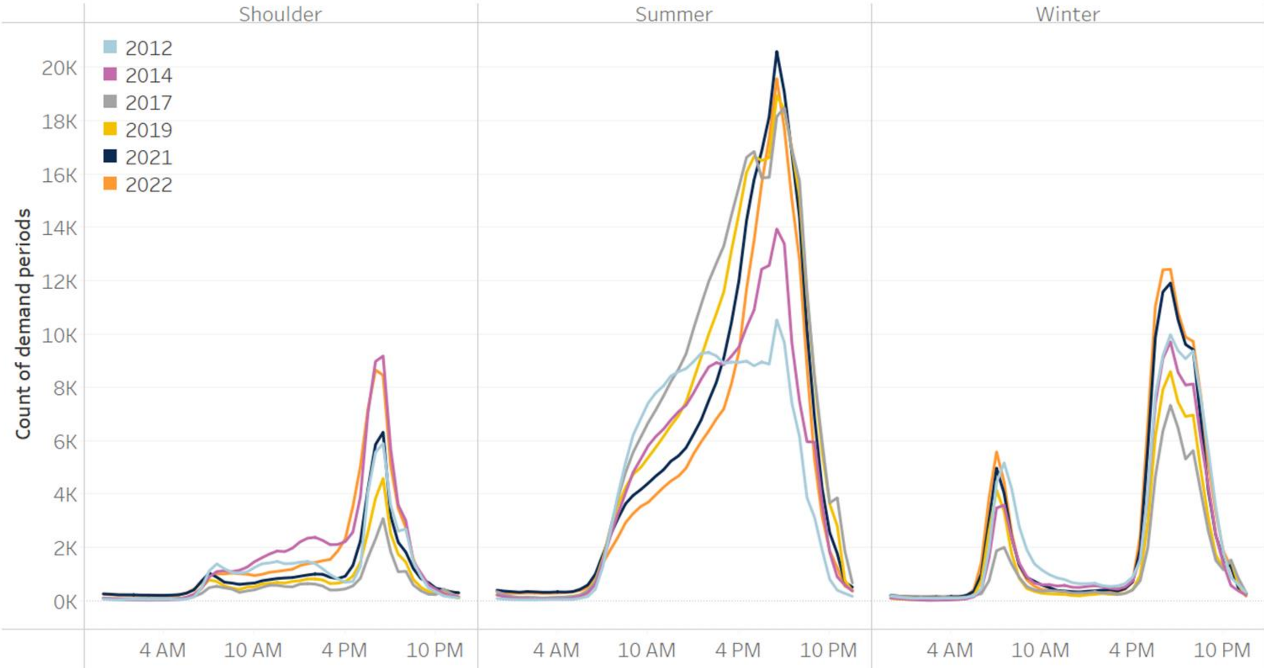
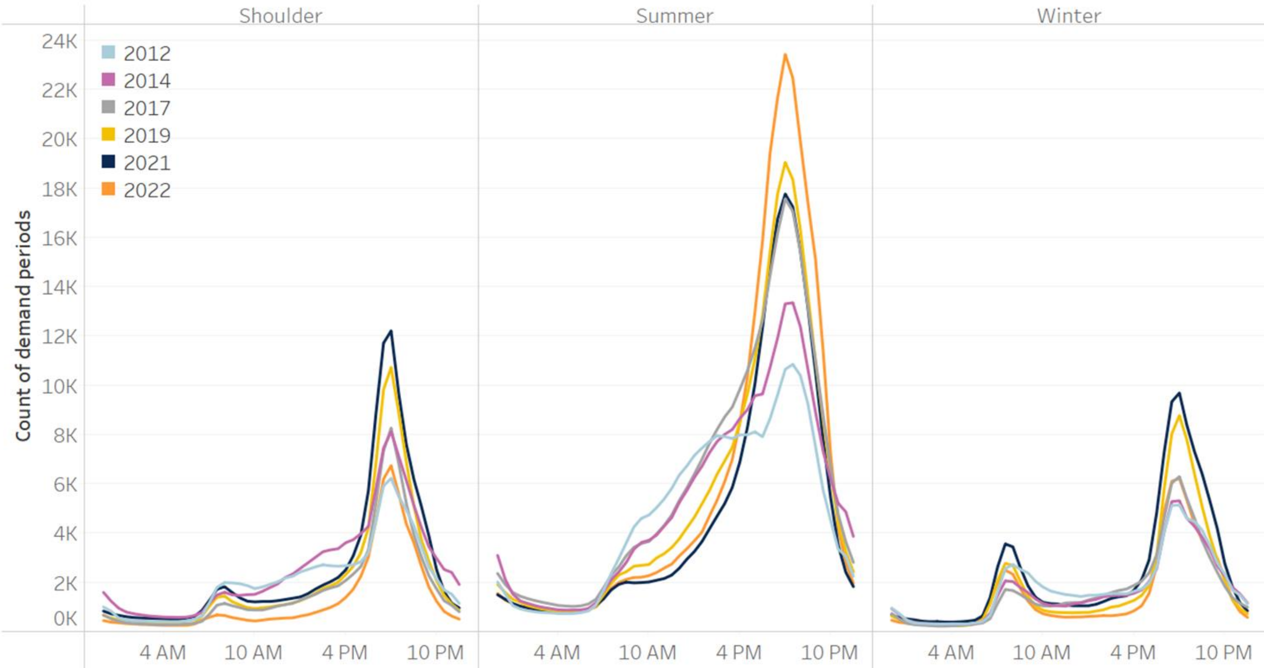


Figure 15 - Ergon count of demand periods greater than the 90th percentile plotted by season



Some other analysis we completed identified that high demands for both networks occur primarily on weekdays, Figure 16 and Figure 17. Although, there are a small number of substations experiencing high demands on weekends.

Figure 16 - Energex count of demand periods greater than the 90th percentile plotted by type of day

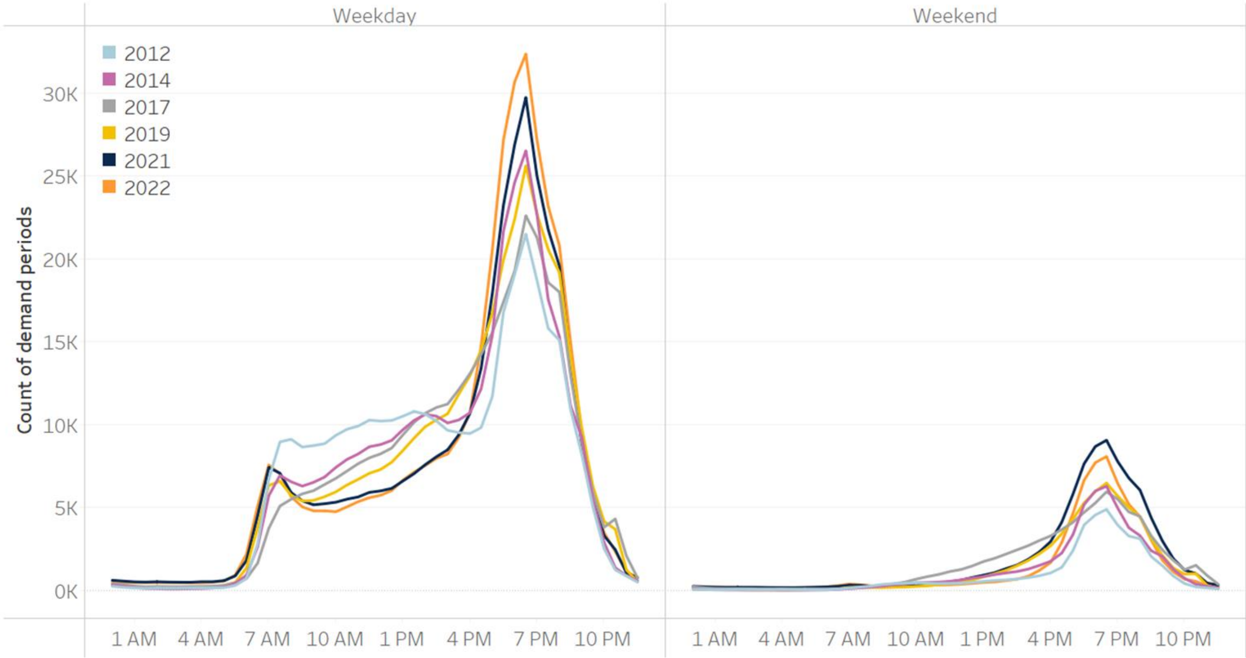
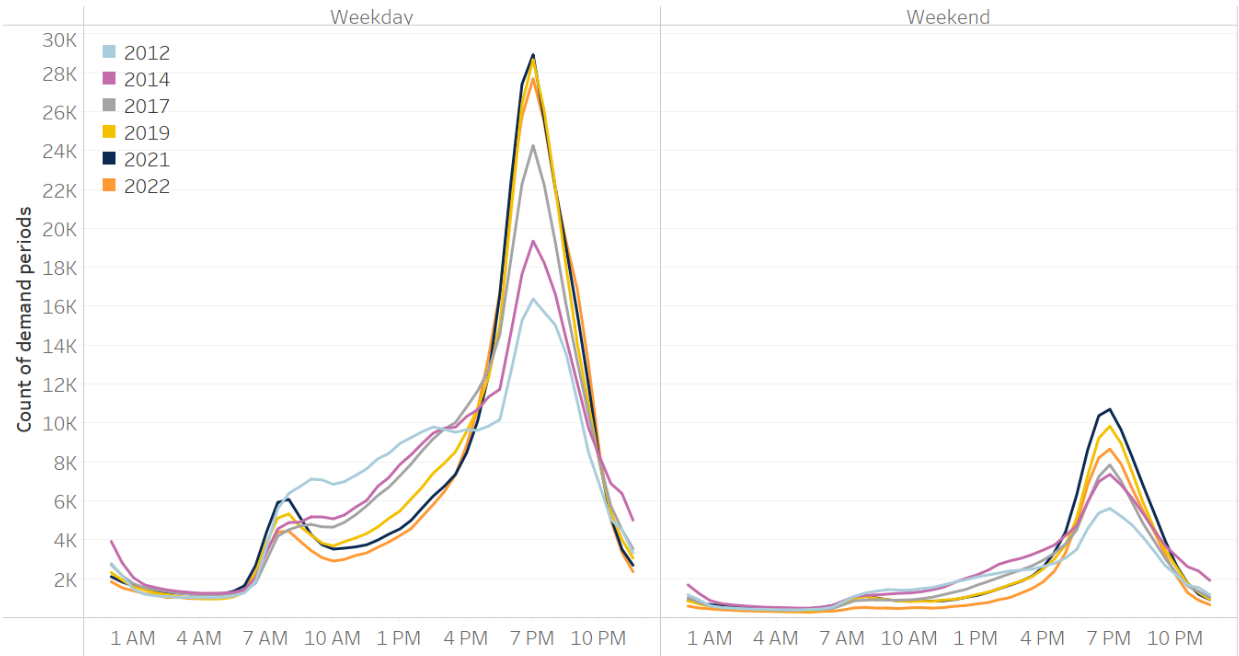


Figure 17 - Ergon count of demand periods greater than the 90th percentile plotted by type of day



We also investigated when high demand periods occur for different "size" substations, defined by their maximum demand. Figure 18 and Figure 19. For substations with larger peak demand, of greater than 30MW for Energex and greater than 20MW for Ergon, the demand profile is a constant shape and does not peak during the evening window.

The substations with larger peak demands typically have a larger proportion of "flatter" loads, or loads that peak during the day. However, the vast majority of substations have peak demands occurring in the evening, around 6pm in Energex and 7pm in Ergon.

Figure 18 – Energex count of 90th percentile demands by MW bin

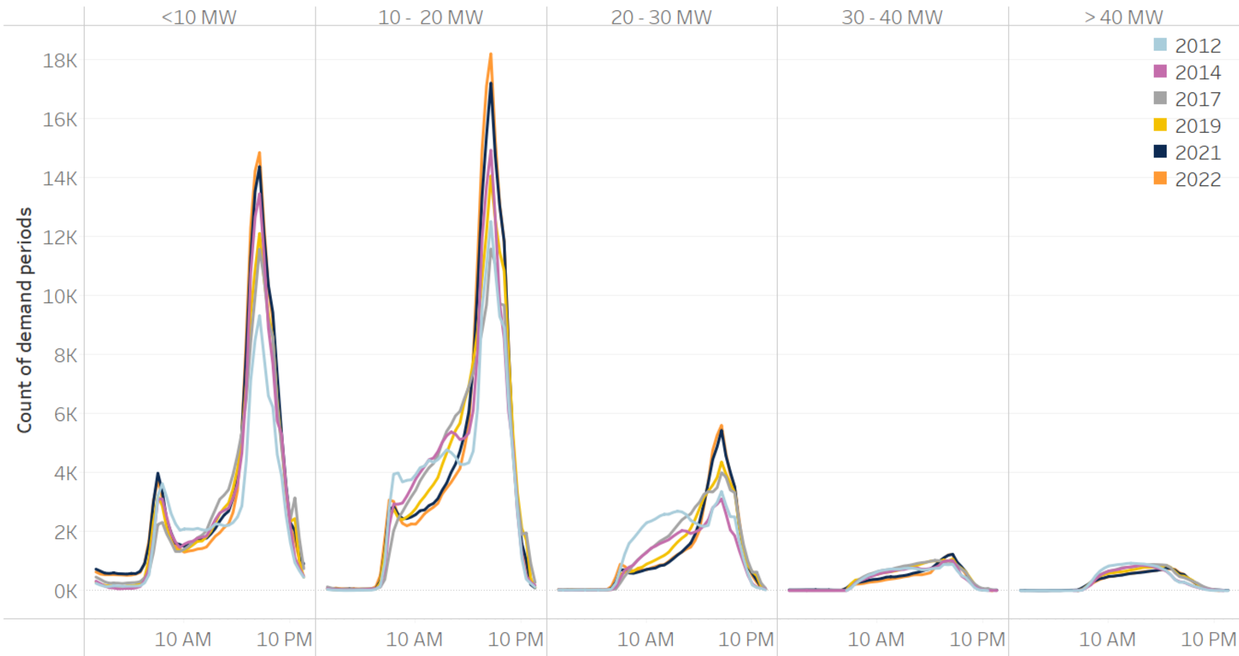
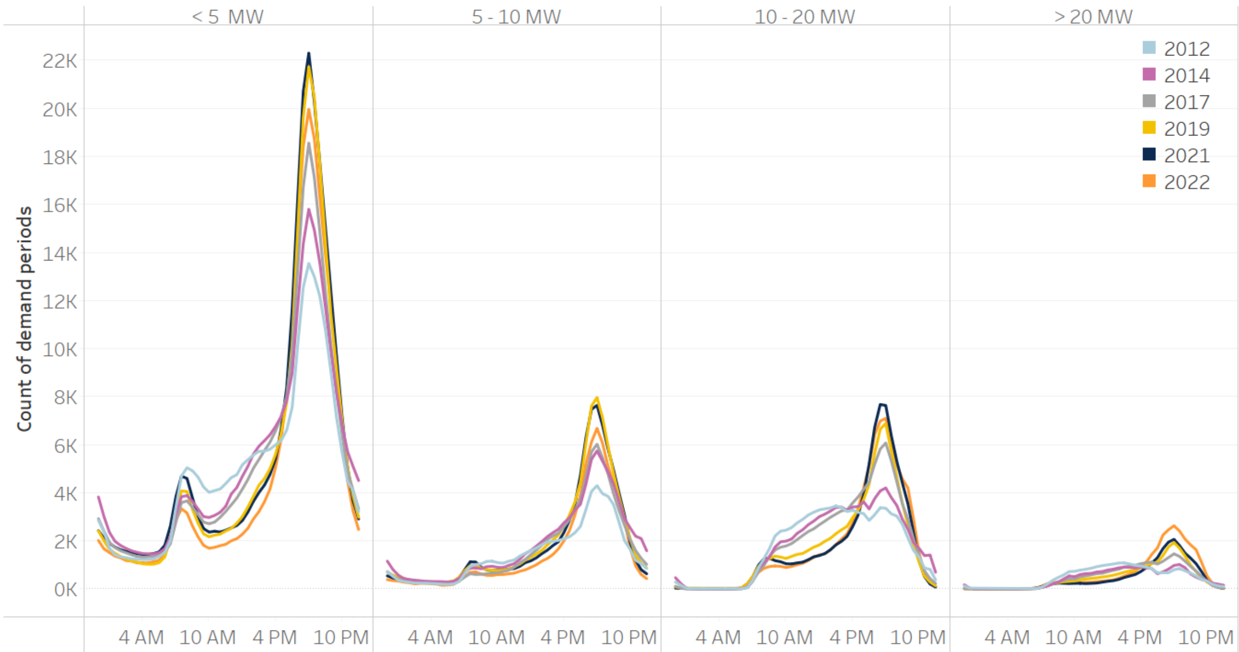


Figure 19 - Ergon count of 90th percentile demands by MW bin



Overall, more than half of high demand periods greater than the 90th percentile occur during the current peak window and this likelihood has increased overtime. For Energex in FY 2012 this was 46 per cent, Figure 20, while for Ergon this was 41 per cent, Figure 21. This increased to 62 per cent for Energex in FY 2022 and 59 percent for Ergon.

Figure 20 – Energex percentage of zone substations experiencing 90th percentile demand by current tariff window

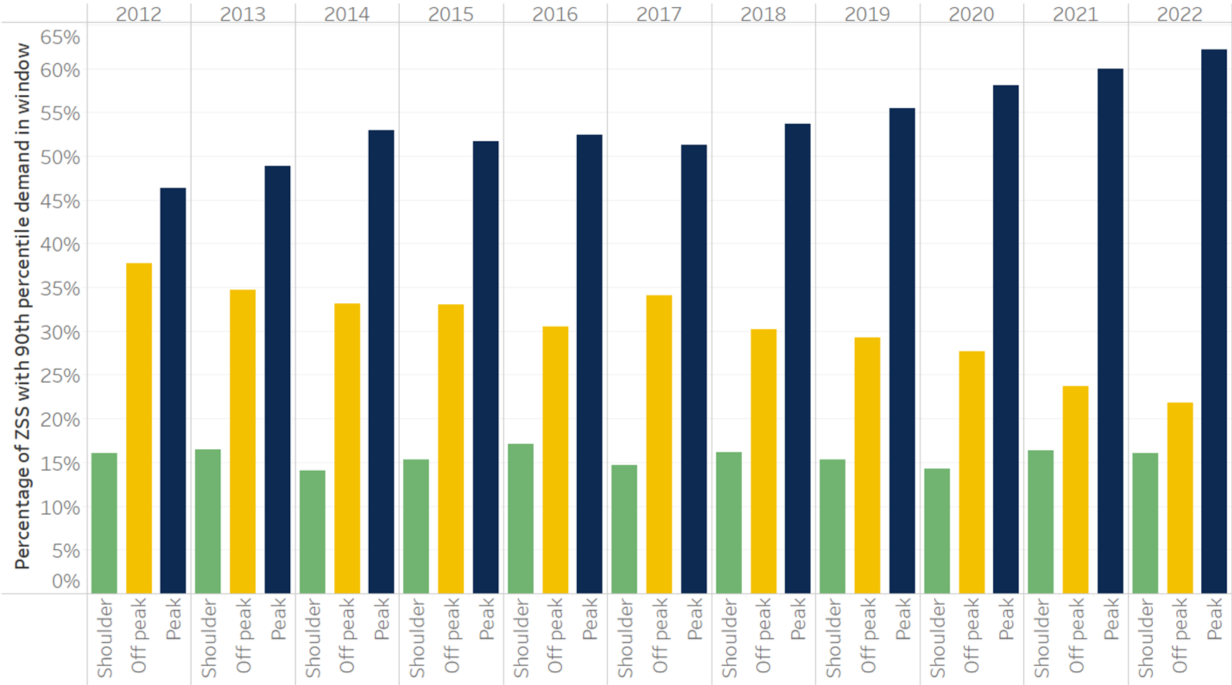
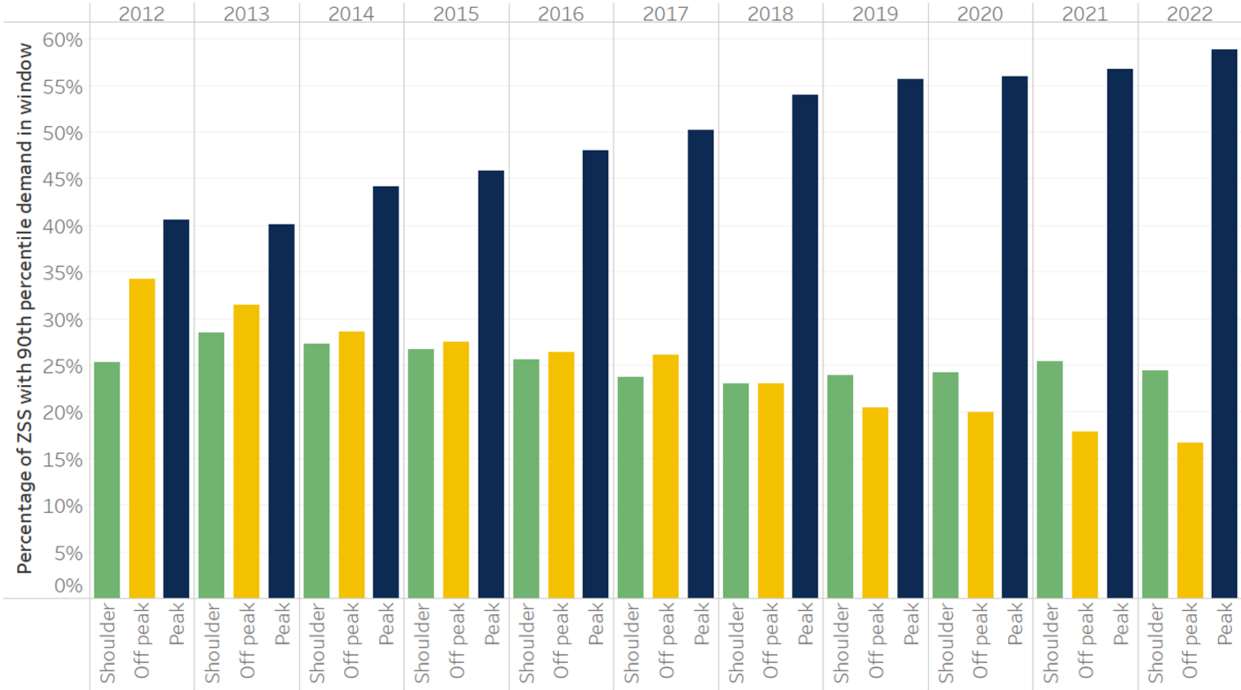


Figure 21 - Ergon percentage of zone substations experiencing 90th percentile demand by current tariff window

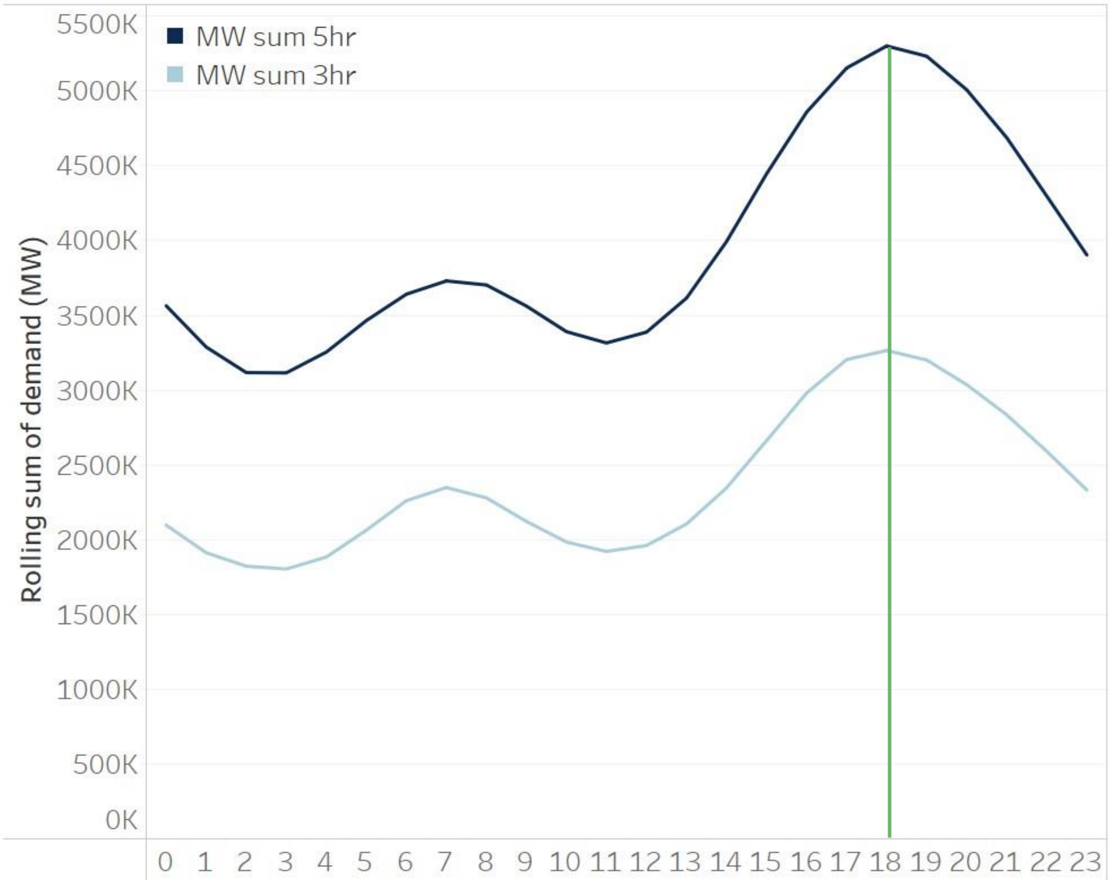


3.1.3. Rolling sum analysis

As previously mentioned in our methodology, part of this analysis involved computing a rolling sum of demand across different window lengths of three and five hours with the greatest sum or area demonstrating when peak demand occurs for that window.

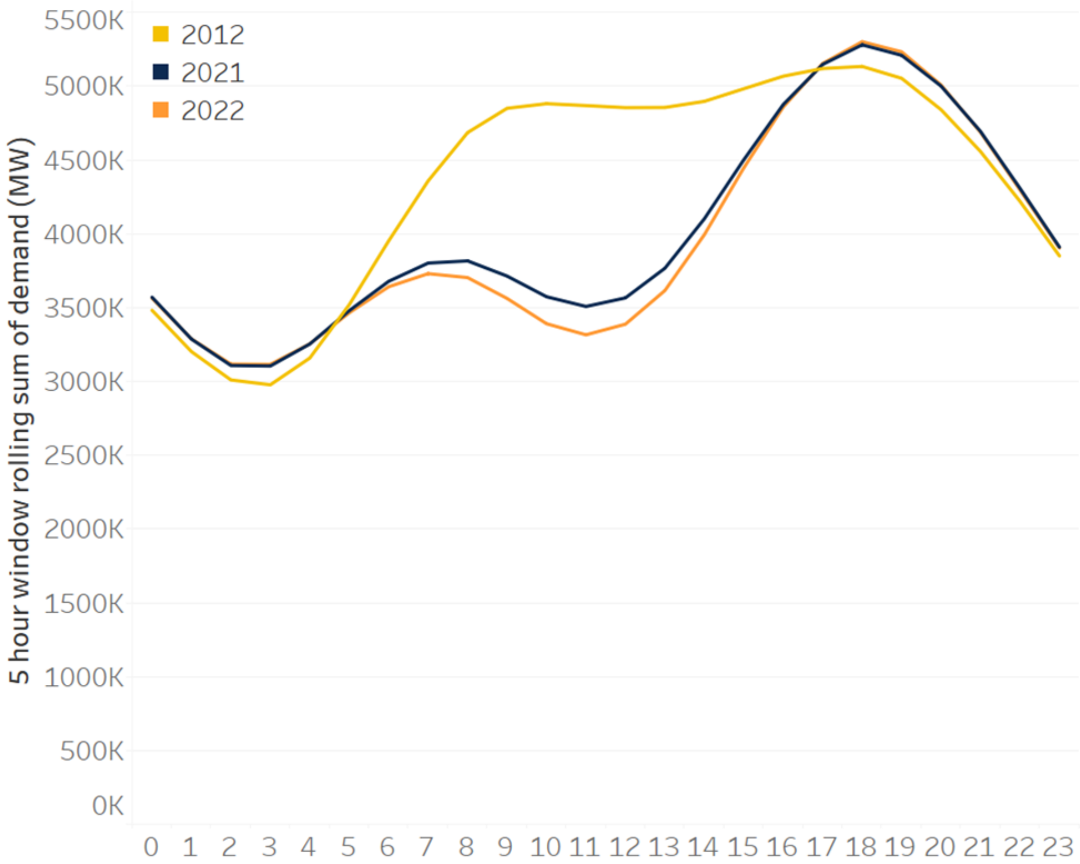
For Energex, the centre of both three and five hour windows occur at 6 pm, Figure 22. This implies that for the five hour window the sum of hourly demands is the greatest between 4 pm – 9 pm which is the current window set out in the TSS. For the three-hour window the sum of demand is the greatest between 5 pm – 8 pm.

Figure 22 - Energex rolling sums of demand for different windows, where the observation marks the centre of the specified window FY 2022



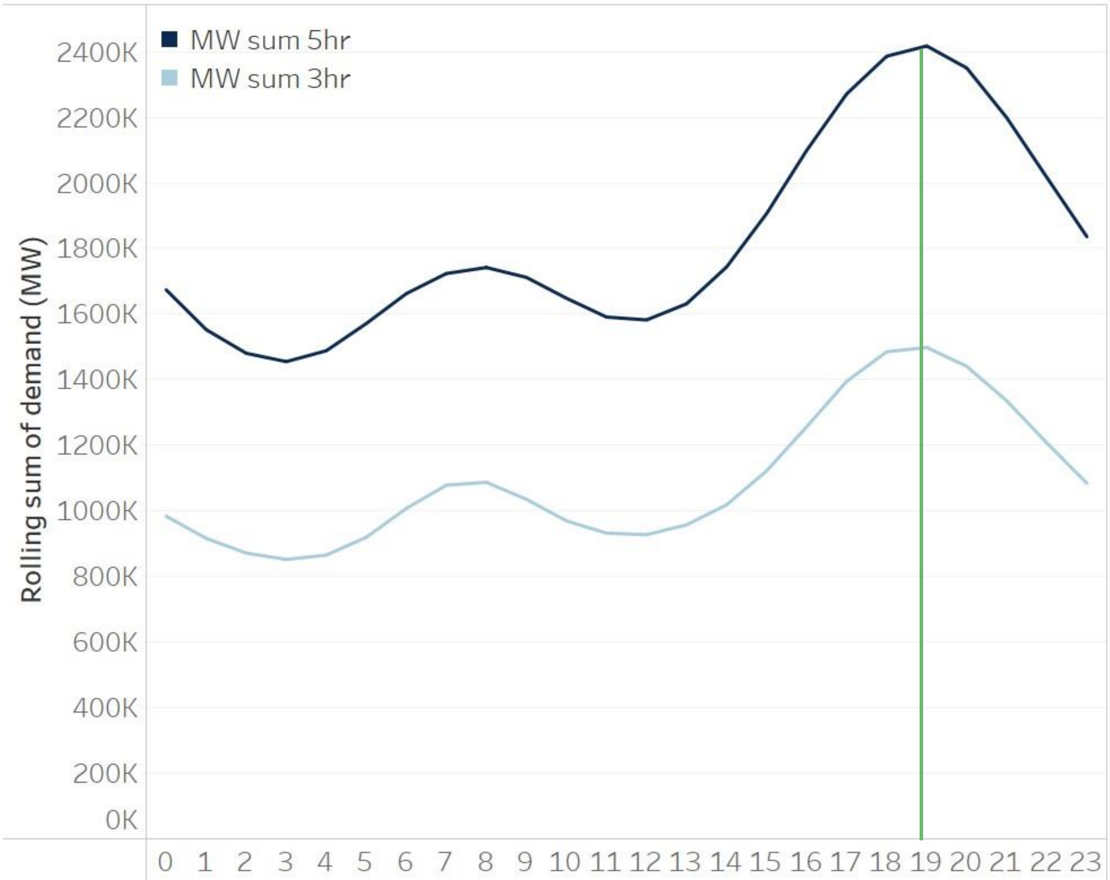
This pattern has dramatically changed overtime, Figure 23. In 2012 the five hour window sum of demand was relatively close to the peak for from 9 am onwards to 8 pm. Whereas in 2022 there is a clear distinction of the largest demands only occurring between 4 pm – 9 pm.

Figure 23 - Energex rolling sums of demand for a five hour window, where the observation marks the centre of the specified window for different years



On the other hand, for Ergon, the centre of the maximum sum of demand for both windows occurs one hour later at 7 pm, Figure 24. For example, given the 5-hour window, the sum of demand is the highest between 5 pm - 10 pm. Whilst for the three-hour window the sum of demand reaches its maximum between 6 pm - 9 pm. These results suggest that peak demands occur marginally later than the time of use window currently employed.

Figure 24 - Ergon rolling sums of demand for different windows, where the observation marks the centre of the specified window FY 2022



3.2. Forecast maximum demand

Our analysis of the projected timing of peak demand over the 2025-30 period uses forecast data from the AEMO 2022 ISP and EQL's internal maximum and minimum demand forecasts by substation from 2022.

We start by using AEMO's 2022 ISP operational demand traces to analyse when future peaks are expected to occur. Using a probability of exceedance (POE) 50 trace for Queensland we identified when the top five demands take place on different days for each forecasted year.

The operational demand traces are Queensland-wide, and do not provide the granularity of the historical analysis of substation data. However, we include these forecasts as another source of information about how the demand profile of Queensland is likely to change over time. An advantage of the ISP demand traces is that they incorporate projections of CER uptake, including EVs and rooftop PV, which are likely to have an impact on the demand profile over the 2025-30 period.

Maximum demand is expected to occur solely between 6:30 pm – 7 pm for the next five years, Figure 25. While using a POE-10 trace maximum demand is expected to occur between 5 pm – 7 pm, Figure 26. These results are consistent with our historical investigation.

Figure 25 - Top five occurrences of maximum demand (POE-50) for QLD

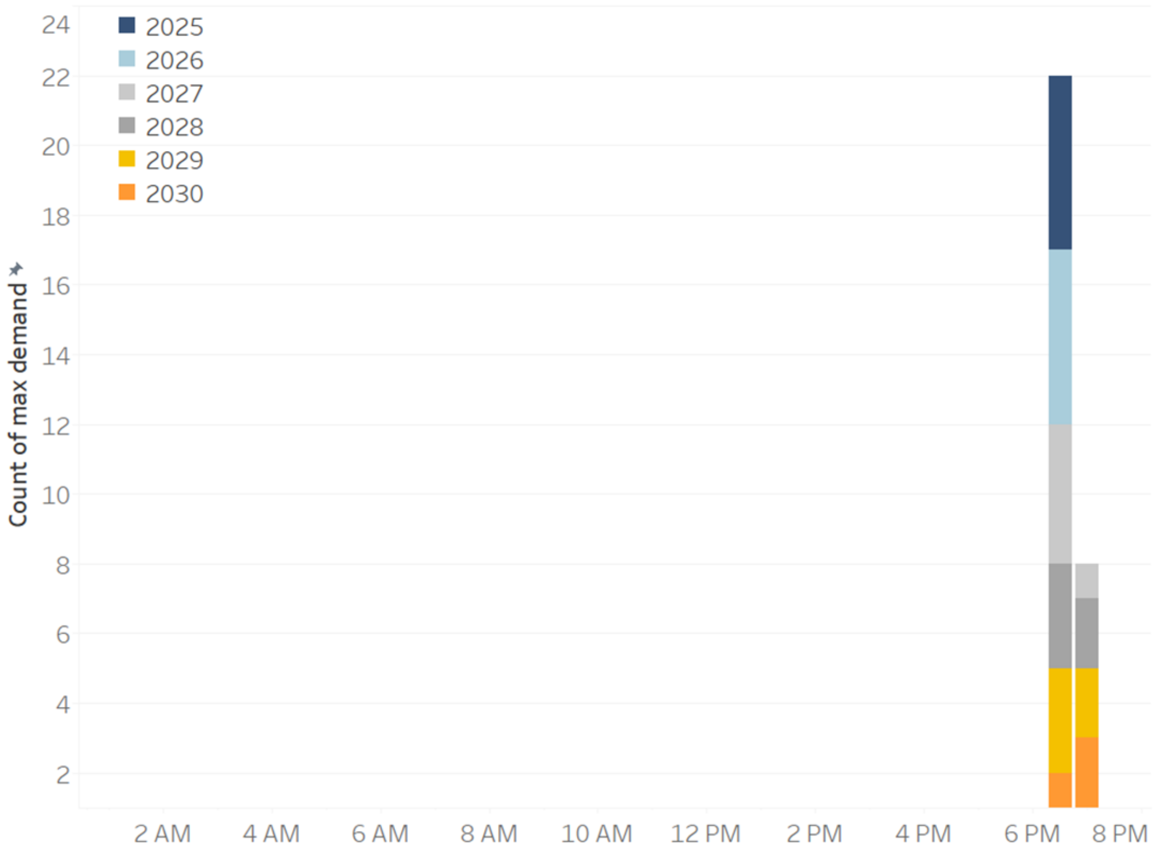
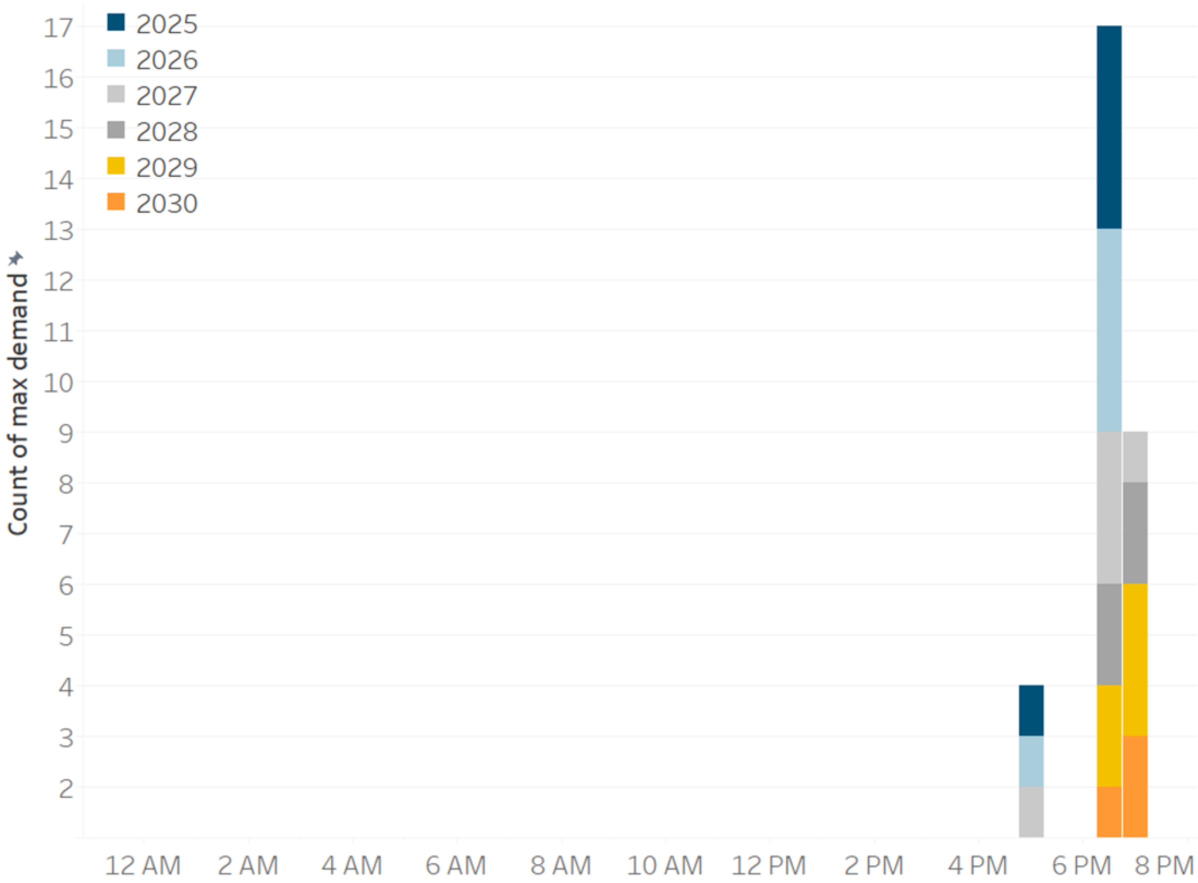
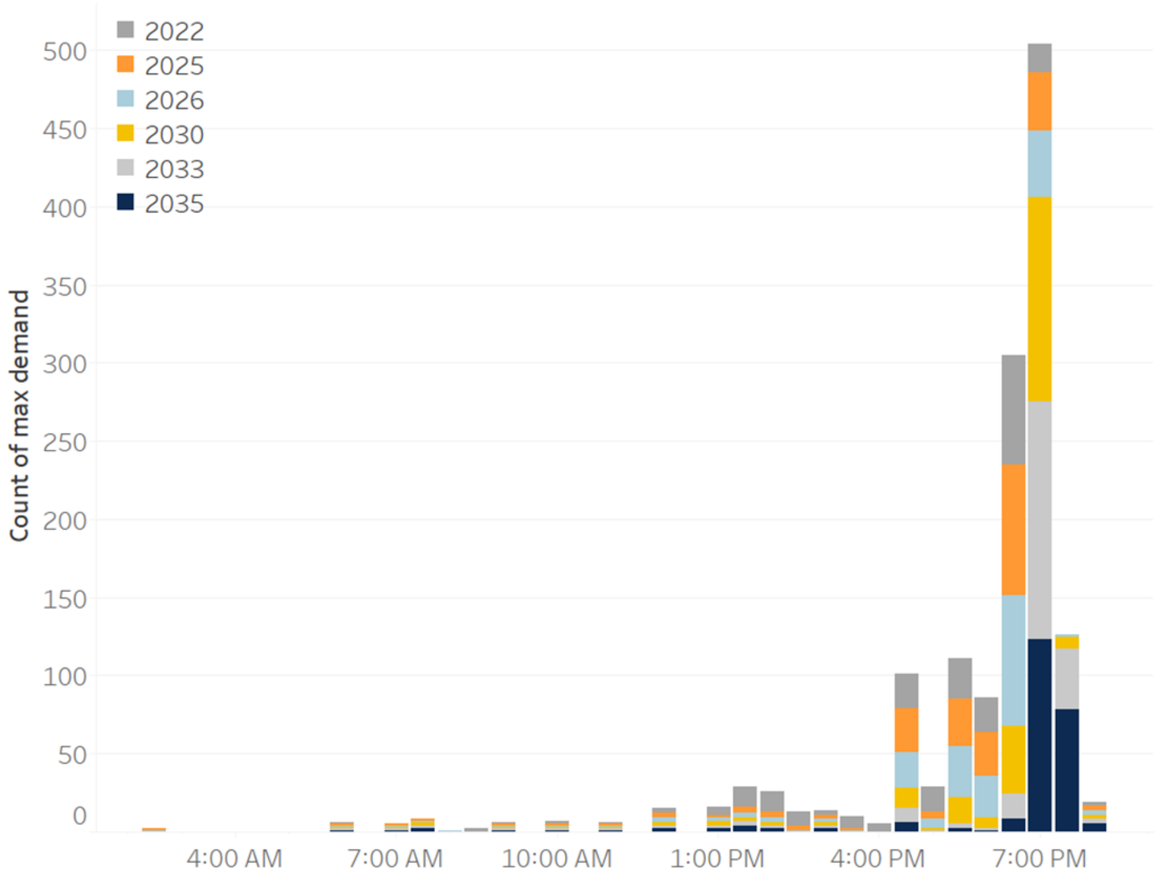


Figure 26 - Top five occurrences of maximum demand (POE-10) for QLD



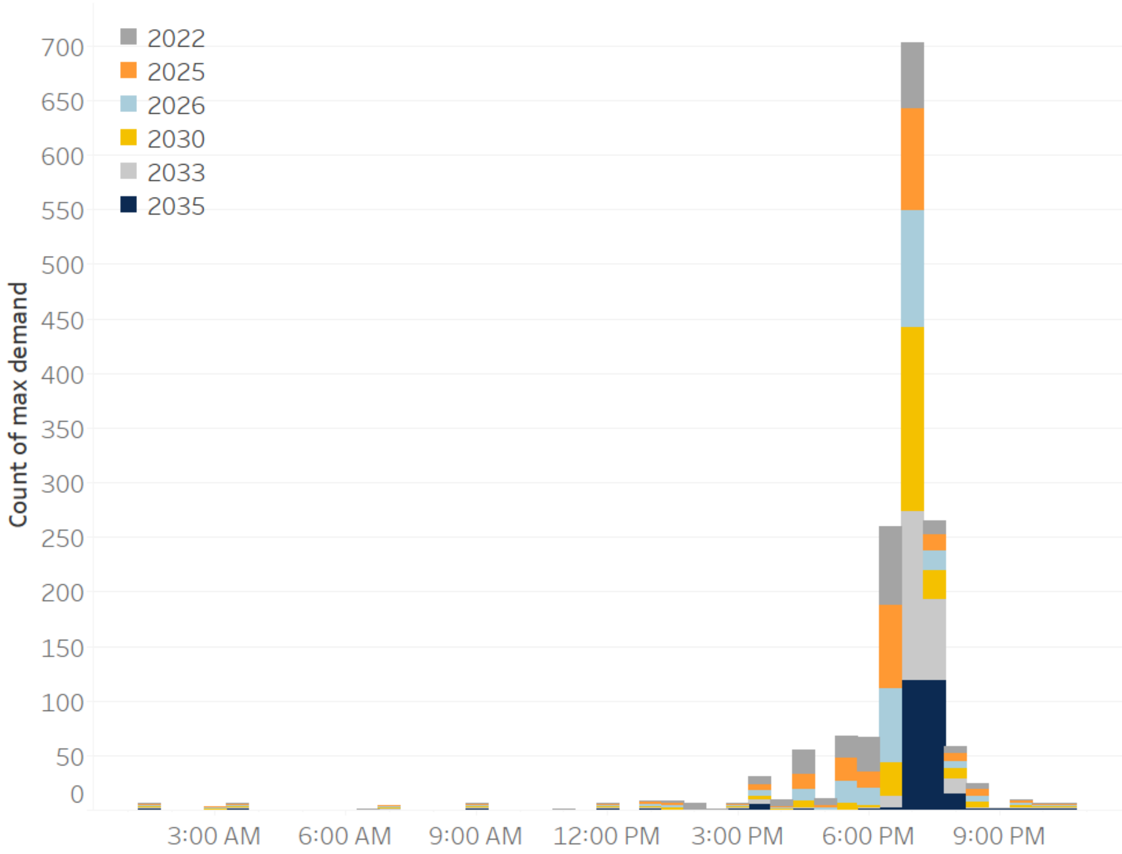
Additionally, EQL provided Endgame with their 2022 POE-50 peak demand day forecasts for each network, substation and year. For Energex, maximum demand in 2025 is expected to occur between 4:30 pm – 7 pm, with a majority of substations peaking at 6:30 pm, Figure 27. While in 2030 this shifts later to 6:30 pm and 7 pm. This is also slightly delayed than current peak demands for the network but still remains within the current defined window.

Figure 27 - Energex forecasted maximum demands by substation and year



For Ergon, in 2025 predicted maximum demand is expected to occur between 5:30 pm – 7 pm which is consistent with current peak observations, Figure 28. In 2030, this window is expected to narrow with maximum demands occurring between 6:30 pm and 7 pm. Again, this is consistent within the current window.

Figure 28 - Ergon forecasted maximum demands by substation and year



4. Minimum demand results

In this section, we focus on analysing minimum demand events on the network and assess if the current off-peak timeframe is suitable for the upcoming regulatory period.

4. Minimum demand results

In this section, we focus on analysing minimum demand events on the network and assess if the current off-peak timeframe is suitable for the upcoming regulatory period.

Our historical and forward-looking analysis of minimum demands indicates that they are becoming increasingly concentrated in the middle of the day in both networks. This is driven by the continued uptake of rooftop PV and is likely to continue throughout 2025-30.

The uptake of electric vehicles over the 2025-30 period introduces a new source of uncertainty. This could lead to some small changes in the timing of minimum demand, but is unlikely in our view, to significantly offset the impact of continued rooftop PV uptake.

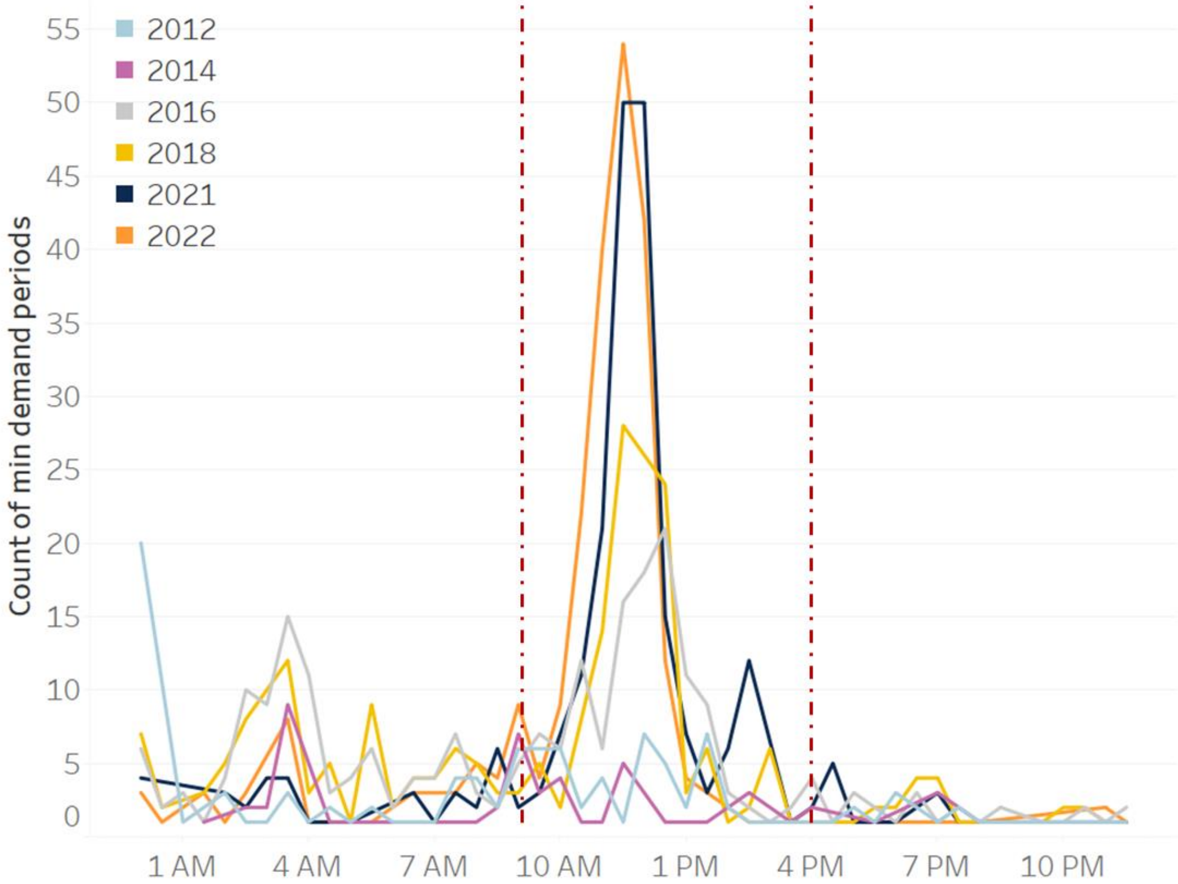
4.1. Historical minimum demand

4.1.1. Minimum demand periods

Our initial exploration starts with identifying when minimum demand occurs for each substation and year across both networks.

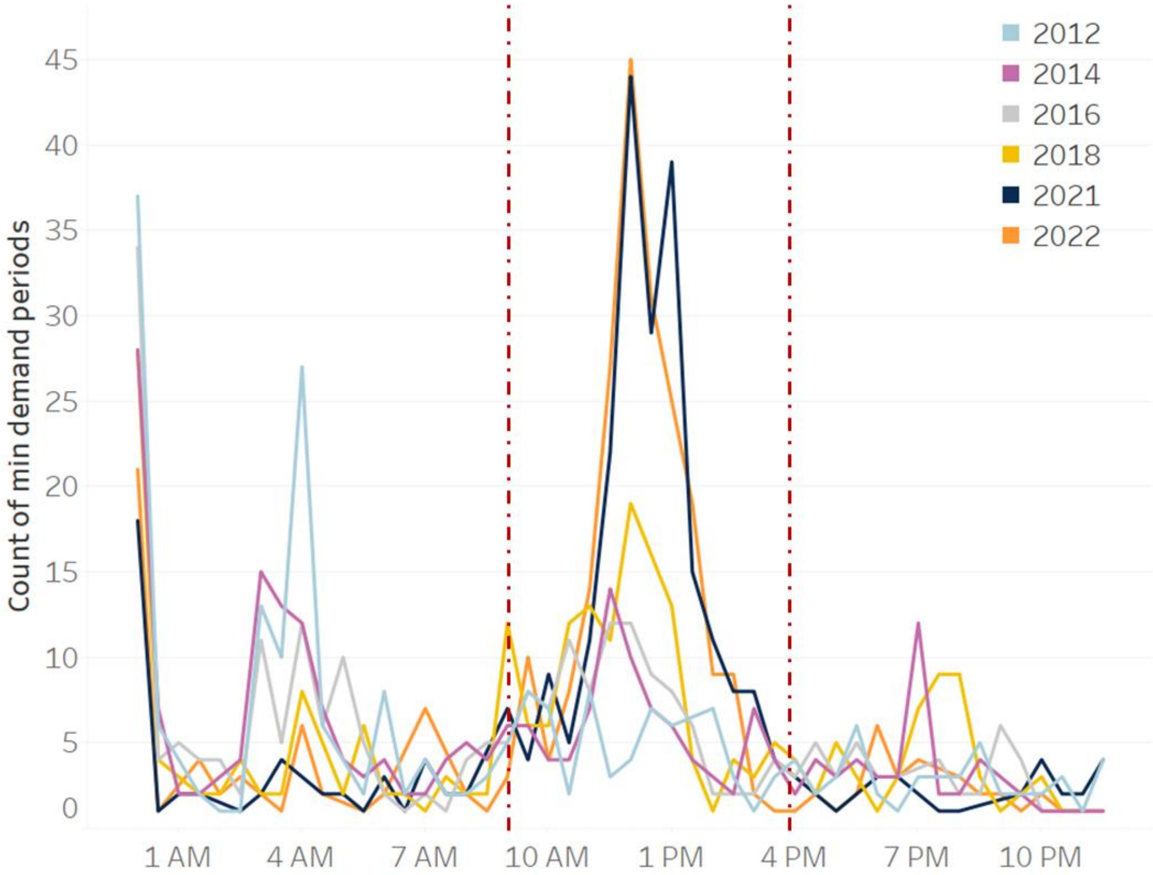
In the Energex network, demand typically reaches its yearly minimum between 10 am and 1 pm at most substations, as shown in Figure 29. The frequency of these events occurring during this window has increased in recent years due to the uptake of solar PV shifting minimum demand to the middle of the day. In FY 2022, the majority of events occurred in the hour between 11am and 12pm.

Figure 29 - Energex count of minimum demand periods for each FY and substation



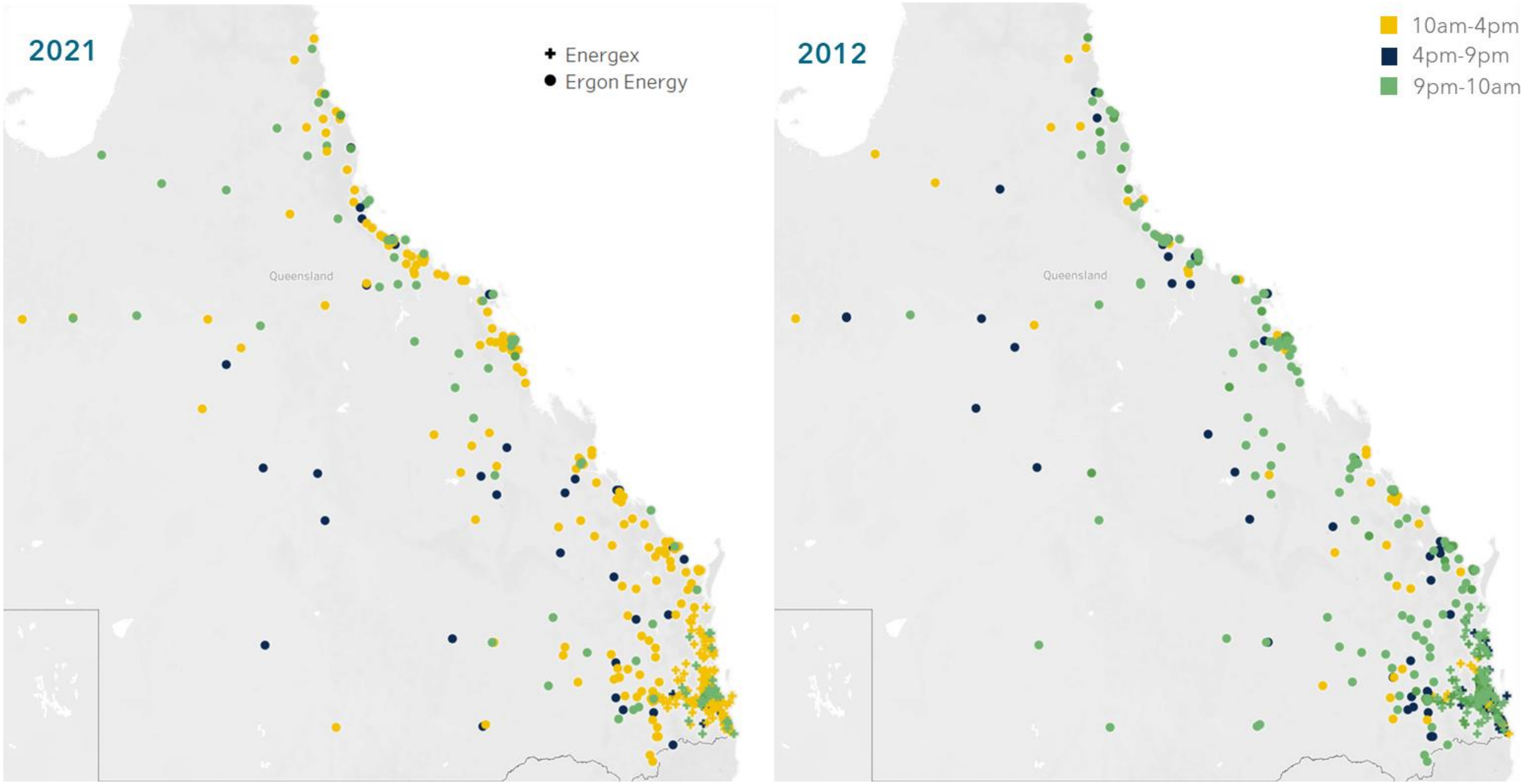
The narrative concerning Ergon more accurately illustrates this transition, whereby the minimum demand in earlier years is observed post-midnight, Figure 30. Similar to Energex this window has now shifted to the middle of the day, albeit later between 11 am – 2 pm. In FY 2021 and the earlier part of FY 2022, minimum demand primarily occurred between 11:30 am and 1 pm.

Figure 30 - Ergon count of minimum demand periods for each FY and substation



The aforementioned shift is more clearly discernible in the following image whereby minimum demand across the state in FY 2012 occurred overnight (right hand side), represented in green, to the middle of the day in FY 2021 (left hand side), represented in yellow, Figure 31. We chose the year FY 2021 due to data completeness for Ergon.

Figure 31 - Time of day minimum demand occurs for each zone substation by year and location

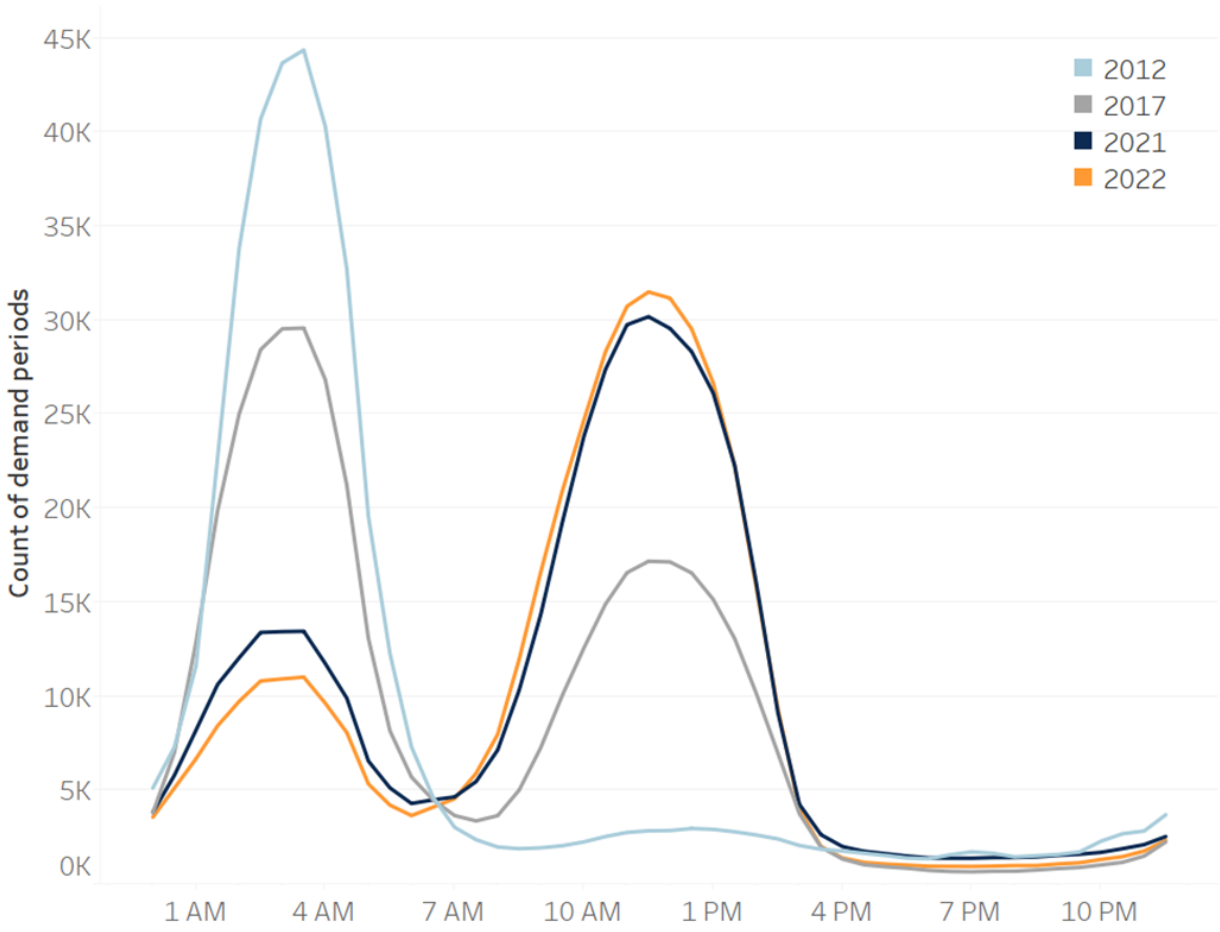


4.1.2. Minimum demand periods

The remainder of this analysis focuses on identifying minimum demand periods by classifying events that are less than the 10th percentile for each zone substation and financial year. The results are largely consistent with the results from the minimum demand analysis discussed above. Periods of low demand at most substations is increasingly shifting from early in the morning to the middle of the day, reflecting the uptake of rooftop PV.

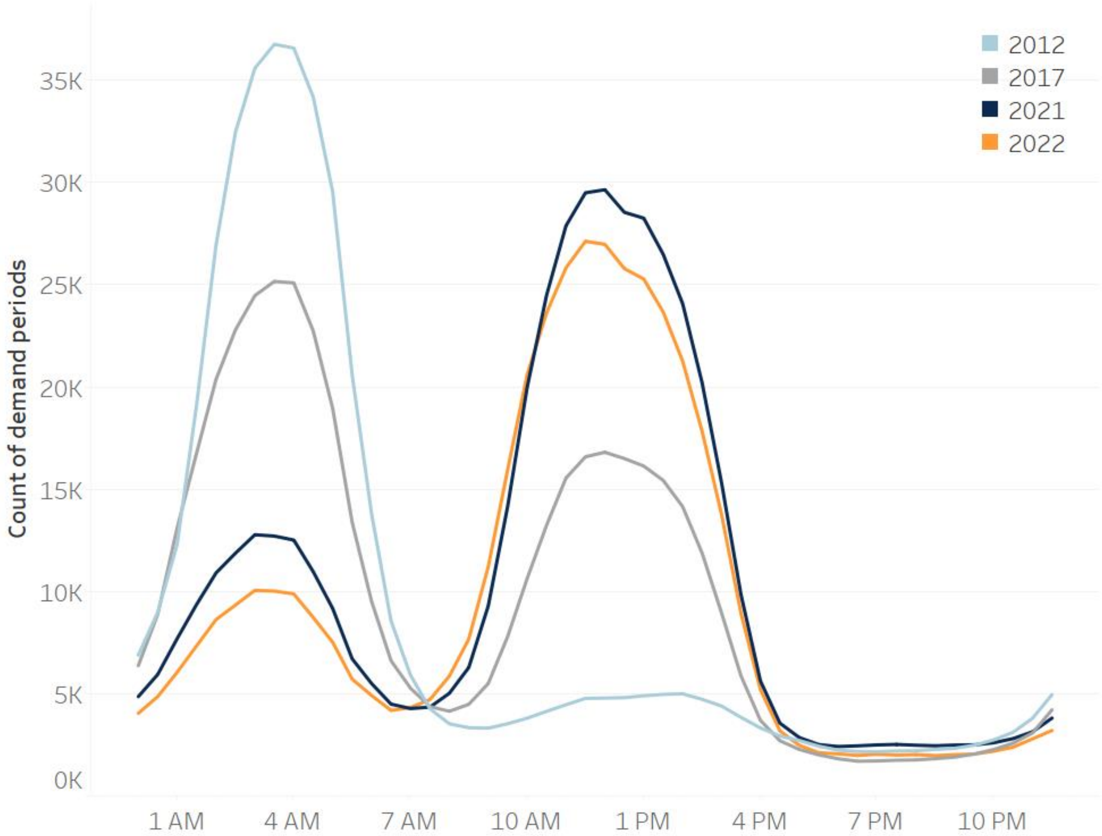
For Energex, minimum demand events have historically occurred between 2 am – 4 am, Figure 32. Again, the continued uptake of rooftop PV is driving low demand periods towards the middle of the day, typically occurring between 11am - 1 pm.

Figure 32 – Energex count of demand periods less than the 10th percentile for each zone substation and year



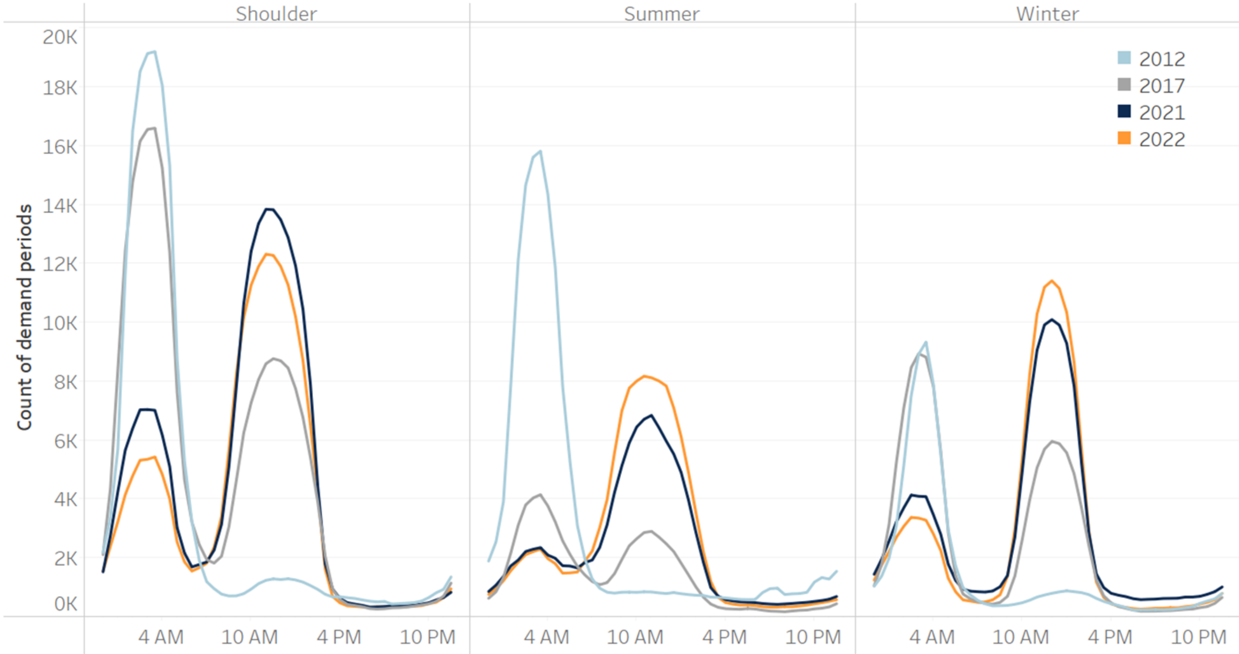
With Ergon, all minimum demand events prevail one hour later compared to Energex. Figure 33 shows that historically lull periods were between 3 am and 4 am. However, this has shifted to 10:30 am to 1:30 pm in 2022. It should be noted that the occurrence of these events span a wider window.

Figure 33 - Ergon count of demand periods less than the 10th percentile for each zone substation and year



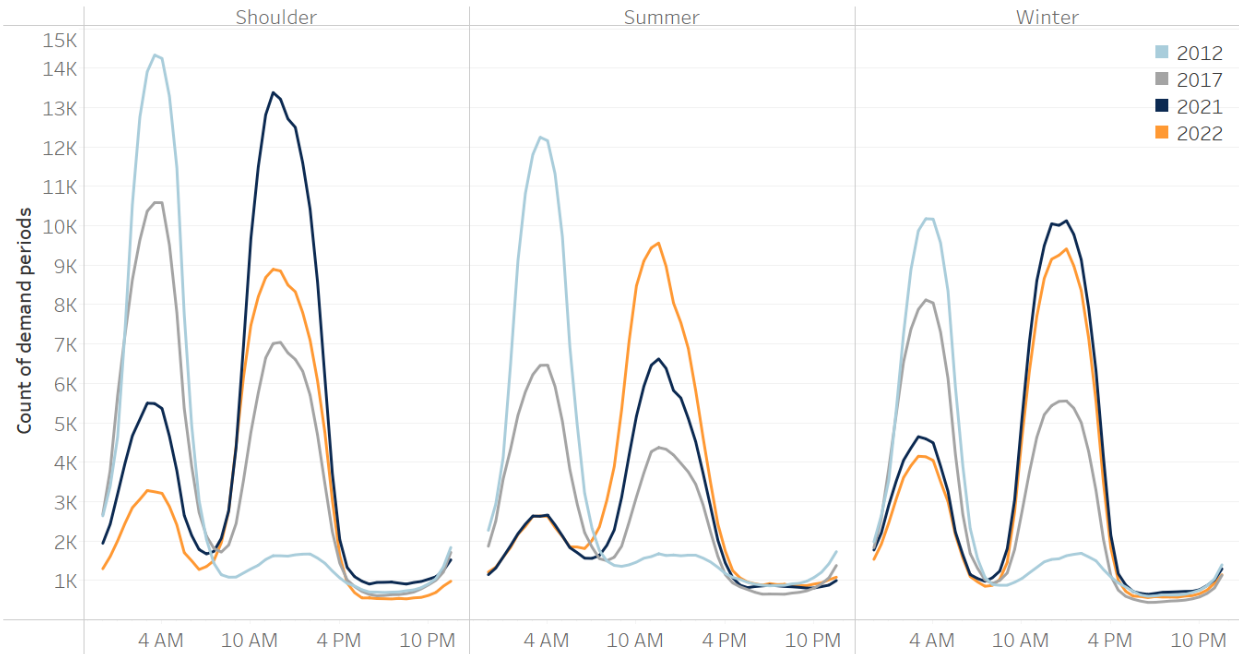
The seasonality distinction of when minimum demand events occur is not as prevalent relative to maximum demand. Generally low demand periods are witnessed throughout all seasons. For Energex, minimum demand occurs more frequently during the shoulder seasons, and this has been constant over time, although, the frequency is slightly decreasing, Figure 34.

Figure 34 - Energex count of demand periods less than the 10th percentile plotted by season



Ergon exhibits a similar pattern. From FY 2012 to FY 2021 minimum demand events primarily occur during the shoulder season, Figure 35. For 2022 low demand events are spread evenly throughout the year.

Figure 35 - Ergon count of demand periods less than the 10th percentile plotted by season



Minimum demand events are increasingly occurring on all days of the week, Figure 36 and Figure 37. Traditionally, periods of very low demand occur on weekdays but the distinction has shifted overtime. Additionally, on weekends, the window of minimum demand events is larger compared to weekdays. For instance, Energex FY 2022 weekday minimum demands occur between 10 am – 1:30 pm whilst 8:30 am – 2 pm for a weekend. For Ergon FY 2021, minimum demands on a weekday occur between 10 am – 2 pm and for a weekend between 9:30am – 3 pm.

Figure 36 - Energex count of demand periods less than the 10th percentile plotted by type of day

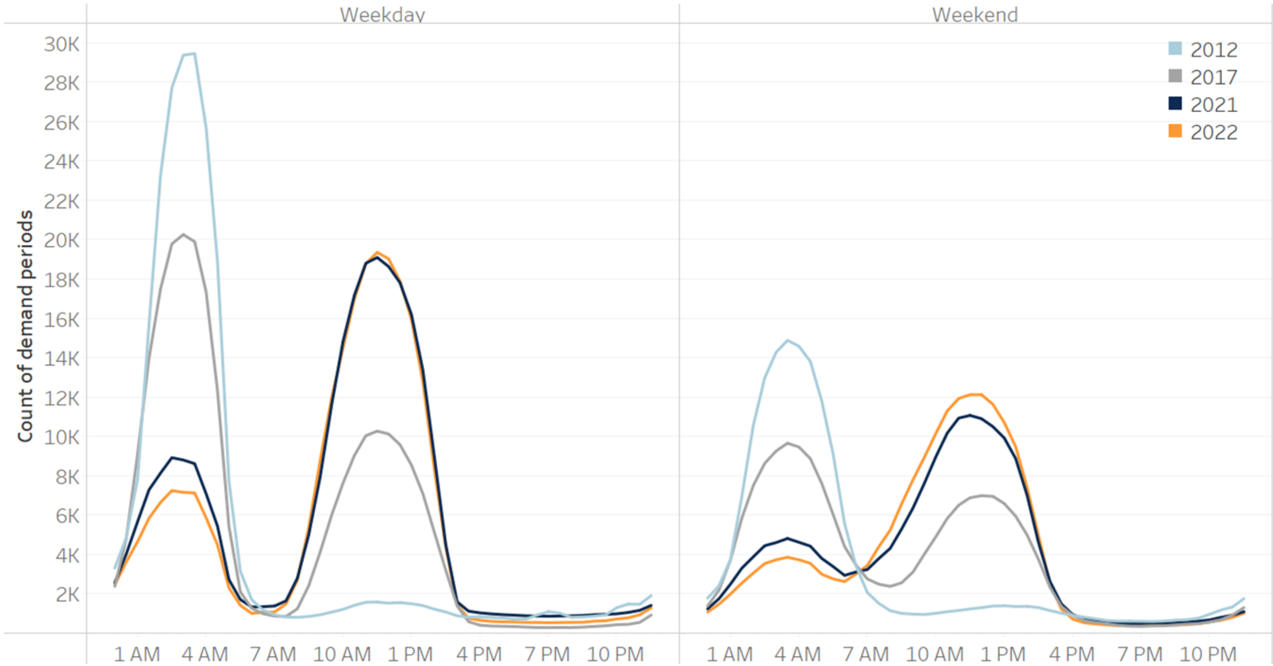
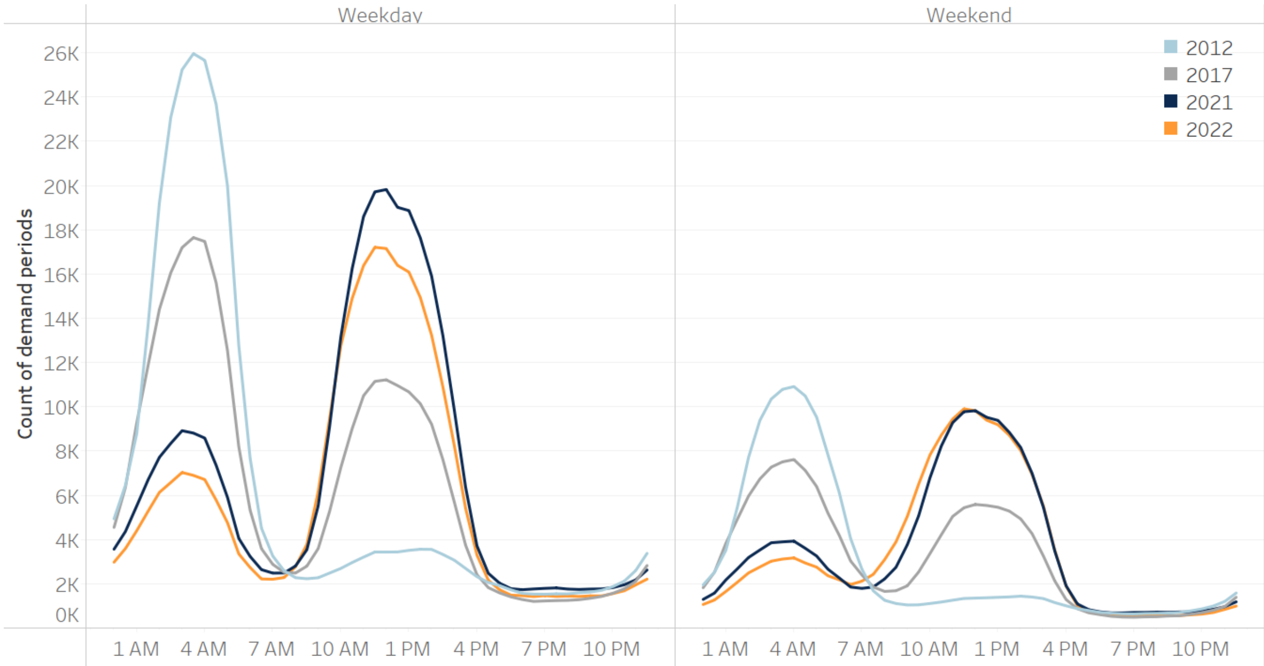


Figure 37 - Ergon count of demand periods less than the 10th percentile plotted by type of day



To conclude this section, we additionally found the percentage of low demand periods (i.e. less than the 10th percentile by substation and financial year) that fit into the current defined time of use windows. There has been a large shift in when these events occur overtime, Figure 38 and Figure 39. In FY 2012, 85 per cent of minimum demands occurred during the shoulder period for Energex and 80 per cent for Ergon. While for Energex in FY 2022, this percentage decreased to 31 per cent with 65 per cent of minimum demands occurring during the midday off-peak period. Similarly, for Ergon in FY 2021, 30 per cent of low demands occurred during the shoulder period with the majority, 61 per cent occurring during the defined off-peak.

Figure 38 - Energex percentage of zone substations experiencing 10th percentile demand by current tariff window

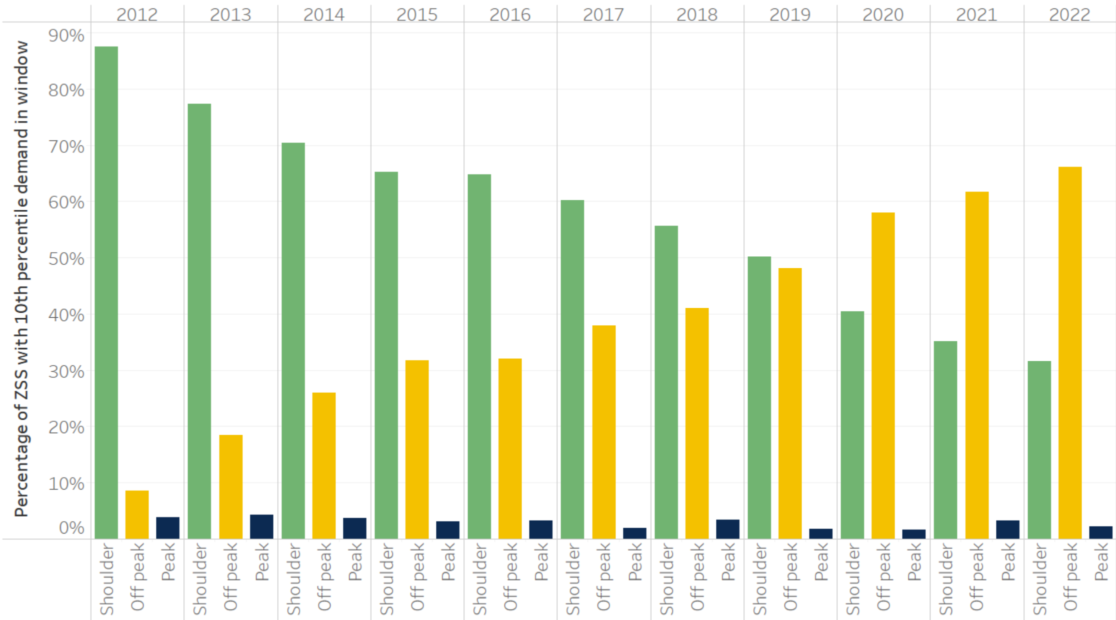
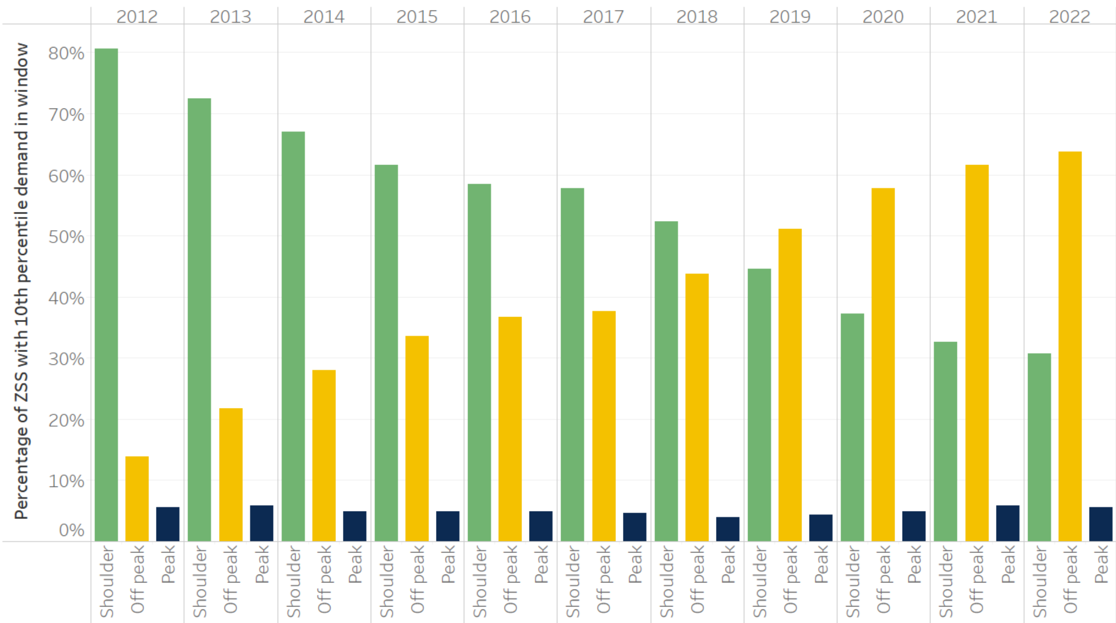


Figure 39 - Ergon percentage of zone substations experiencing 10th percentile demand by current tariff window



4.2. Forecast minimum demand

Like previously, we initialise this analysis by using AEMO's 2022 ISP operational demand traces to investigate when future minimums are expected to occur. We used both POE-50 and POE-10 traces for Queensland, identifying when the lowest five demands transpire for each forecasted year.

Using AEMO's POE-50 traces, minimum demands are solely expected to occur between 11:30 am and 12 pm, Figure 40. For 2030, this is expected to solely occur at 11:30 am. However, for POE-10 traces minimum demands are projected to occur between 11 am and 12:30 pm, Figure 41. Although, there is a wider window, this is still consistent with troughs largely occurring around midday.

Figure 40 – AEMO's predicted occurances of minimum demand using POE-50

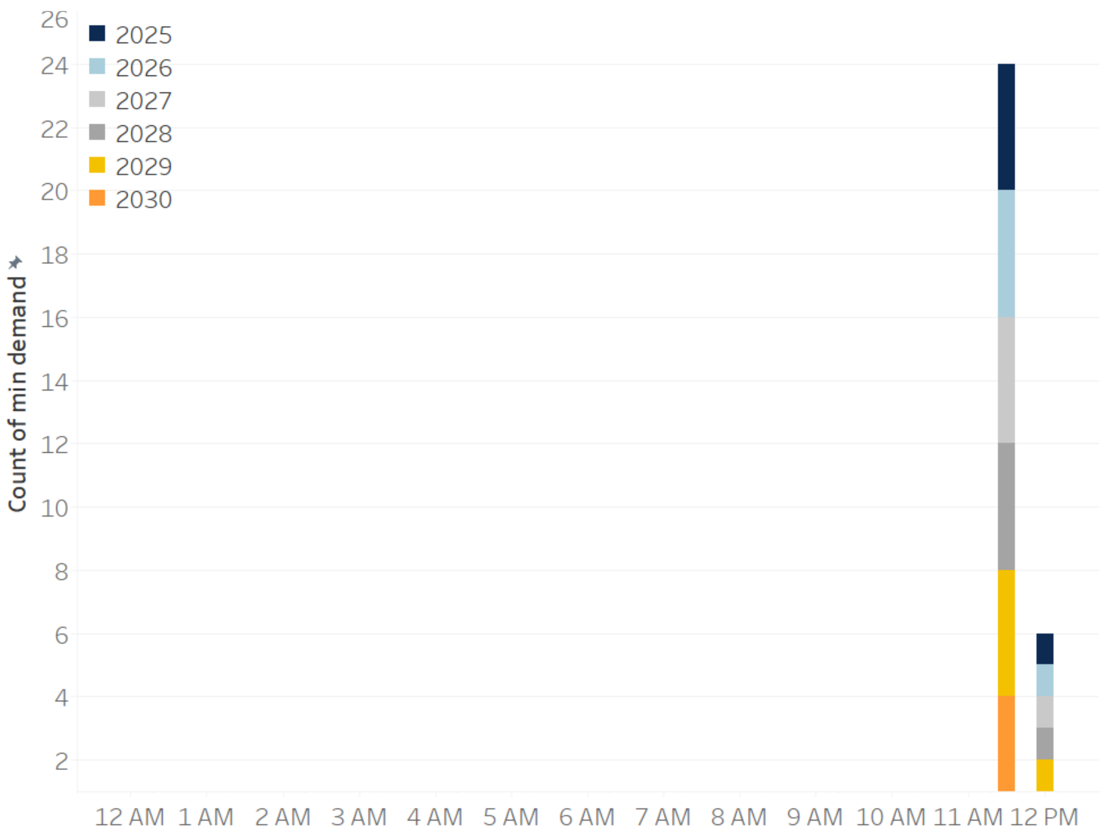
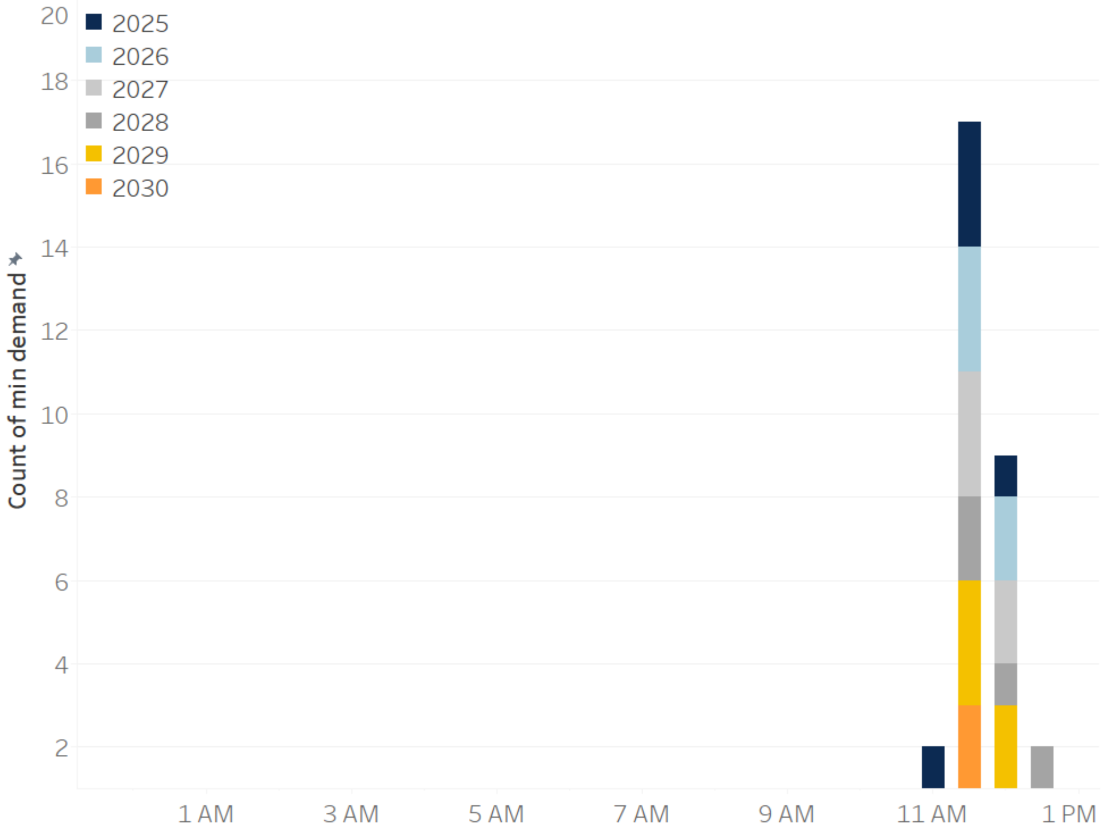
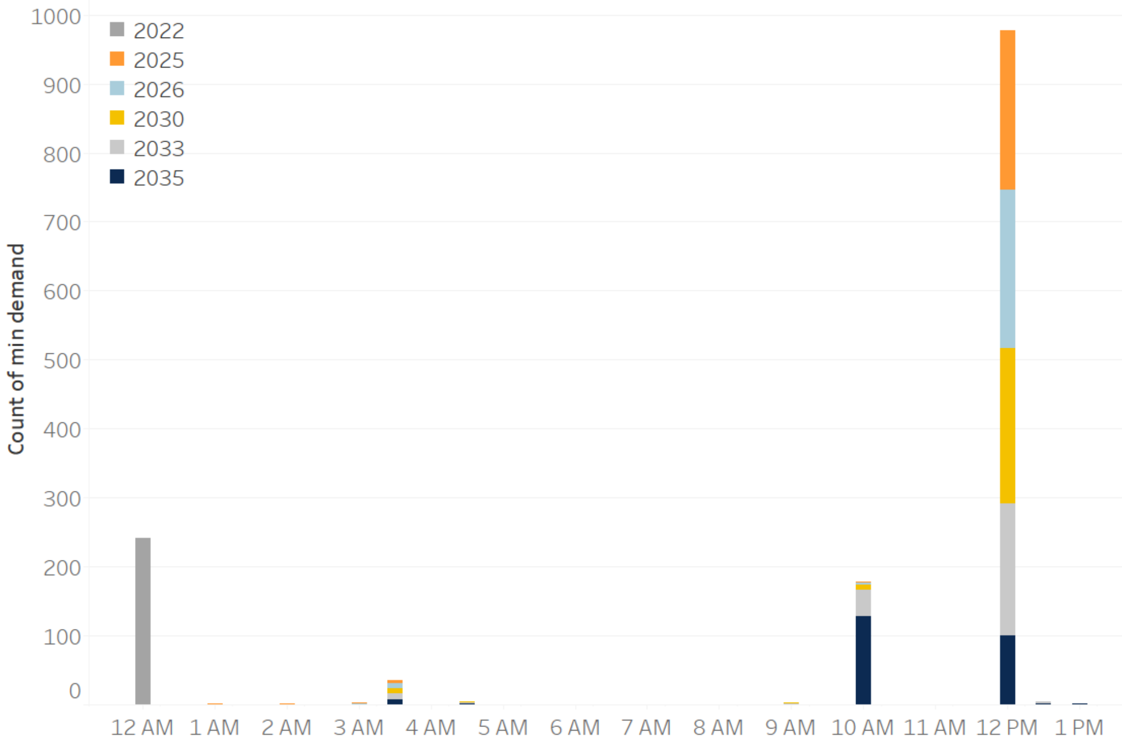


Figure 41 - AEMO's predicted occurances of minimum demand using POE-10



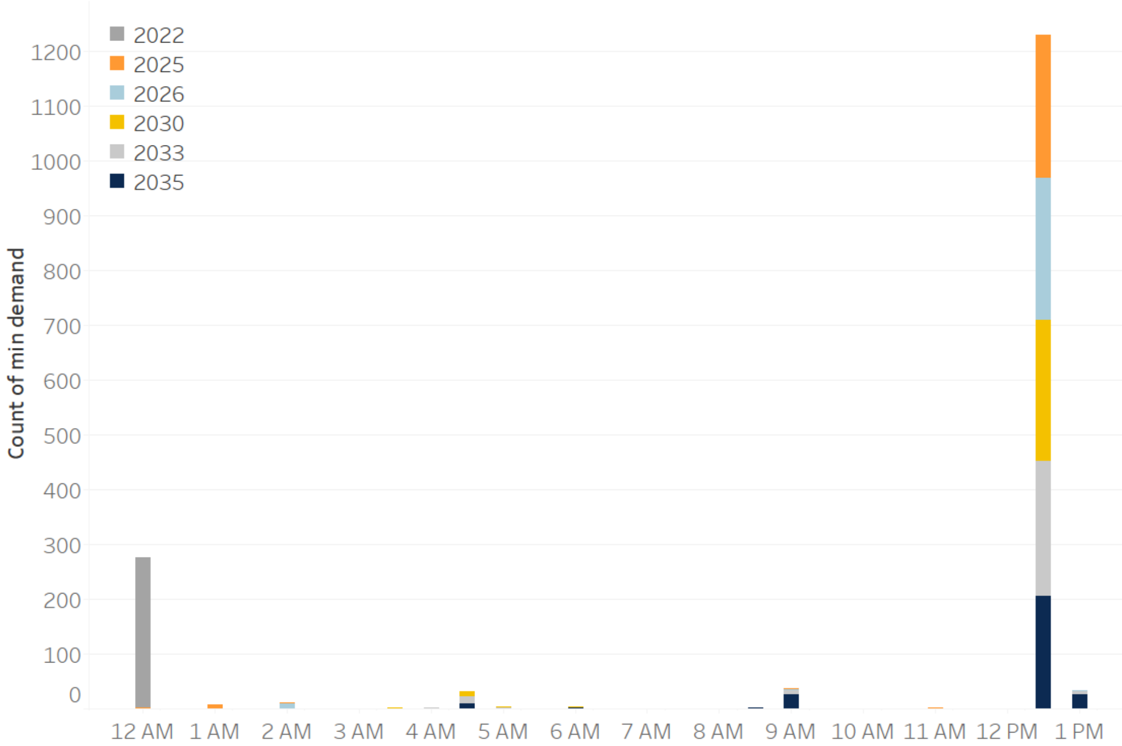
Furthermore, we used EQL's 2022 forecasts of a typical minimum demand profile for each zone substation and financial year to assess when these events are expected to occur for each network separately. For Energex, the forecast of minimum demand varies overtime, Figure 42. For instance, this data suggests that between 2025-2030 Queensland wide minimum demand will likely occur around12 pm. While then on, in the next decade 2033-2035, is expected to slowly widen eventuating between 10 am – 12 pm. However, this is outside of the relevant regulatory period but could provide evidence towards not moving the current off-peak window. It should also be noted that for some substations minimum demand is expected to take place at 3:30 am nonetheless this is a very small portion of the network.

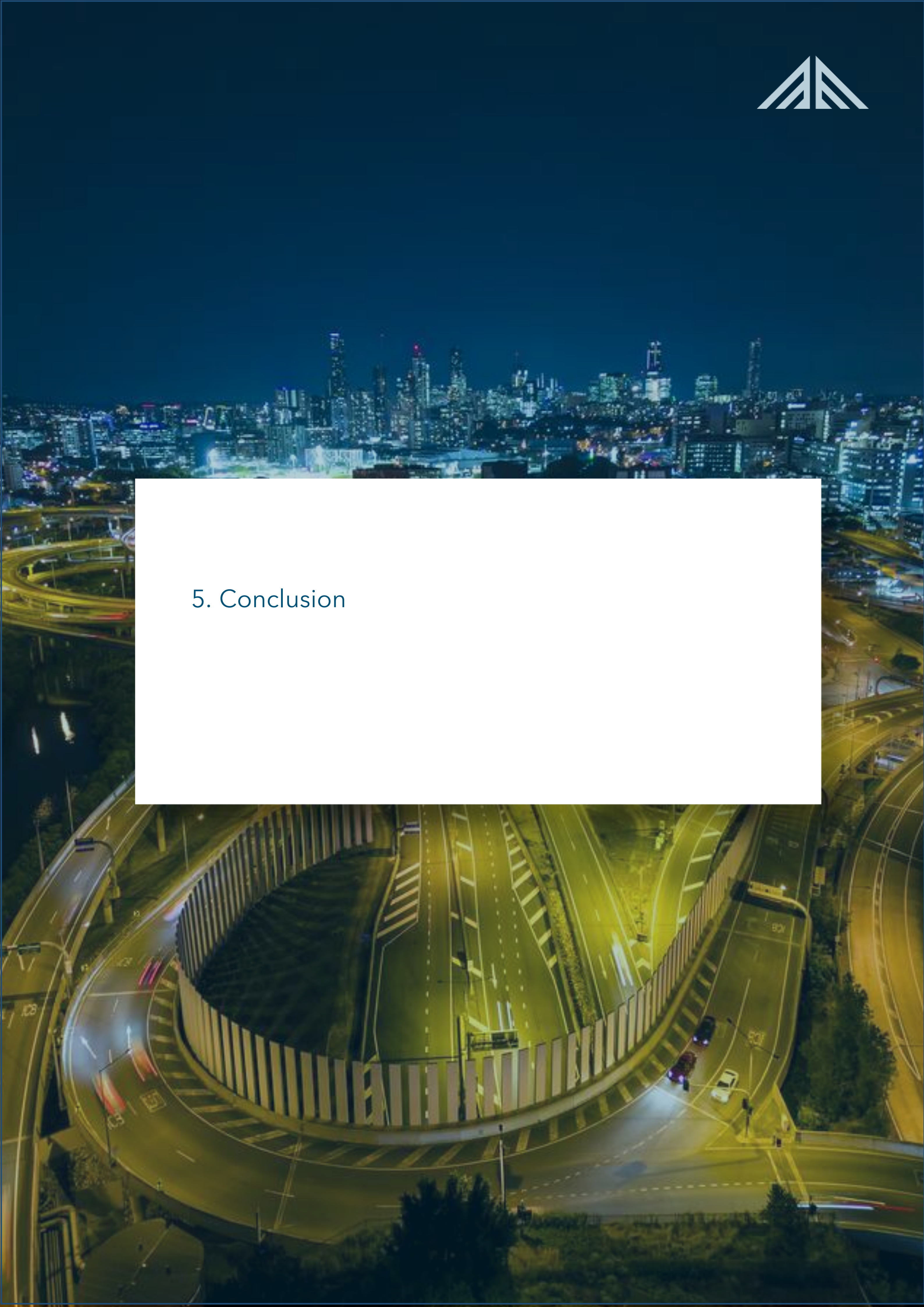
Figure 42 – Energex forecasted minimum demands by substation and year



On the other hand, for Ergon minimum demand is forecasted to occur marginally later at 12:30 pm and this is consistent over time, as shown in Figure 43. After 2025 there are some observations of events occurring in the very early hours of the morning between 2 am – 5 am and 9 am. Overall, the majority of estimates are consistent with AEMO's forecasts and occur between the current off-peak window.

Figure 43 – Ergon forecasted minimum demands by substation and year





5. Conclusion

5. Conclusion

We undertook analysis of peak and minimum demands to ascertain appropriate time of use charging windows.

Our main findings can be summarised as:

- Historical peak demands across substations have become more concentrated over the past 10 years, typically occuring around 6pm in Energex and 7pm in Ergon
- Future peak demands are projected to occur slightly later, typically occuring around 7pm in Energex and 7:30pm in Ergon over the period 2025-30.
- Historical minimum demands at most substations have shifted from overnight to be heavily concentrated in the middle of the day, mostly occuring in the period 11am – 1pm.
- Forecast minimum demands are expected to continue to occur in the middle of the day in 2025-30 but may occur slightly earlier with the uptake of electric vehicles.
- Given the increasing concentration of peak demands in the evening and minimum demands in the middle of the day, there may be scope for 'narrowing' the width of the current peak and off-peak windows.

Taking into consideration the totality of analysis, our findings are that the current time intervals are broadly appropriate for the upcoming 2025-30 regulatory period.

Our examination started with investigating historical data, determining the timing of actual peak and minimum demands, and the distribution of 'high' demands above the 90th percentile and 'low' demands below the 10th percentile by financial year.

Our analysis finds that there has been a greater concentration of peaks, particularly at around 6pm in Energex, and marginally later, approximately at 7 pm in Ergon. Our rolling sum investigation for Energex implies that cumulative five-hour peak demand occurs between 4 pm - 9 pm which is the current window. While for Ergon, cumulative five-hour peak demand occurs between 5 pm - 10 pm. Furthermore, forward looking analysis suggests that peak demands may shift slightly later in 2025-2030 to around 7 pm in Energex and 7:30 pm in Ergon.

The distribution network has undergone a significant change and this pattern is expected to continue into the future. The uptake of solar PV has dramatically transformed the shape of intraday load. This is especially prevalent for minimum demand which has shifted from overnight to midday. Based on our evaluation of minimum demand it has been determined that the uptake of rooftop PV systems have had a substantial influence, concentrating minimums to midday. For Energex, minimum demand occurs between 11 am – 12 pm whilst for Ergon this window is insignificantly later between 11:30 am – 1 pm. Our forward-looking analysis suggests the timing of minimum demand is unlikely to significantly change.

Given the increasing concentration of peak demands in the evening and minimum demands in the middle of the day, there may be some benefit in narrowing the current time of use windows. This could be achieved by delaying the start of the current peak window and/or bringing the end of the peak window earlier whilst ensuring that the new window captures the period where most peak demands are likely to occur. This would allow a sharper LRMC price signal to be sent to customers and should increase economic efficiency by reducing the period in the evening that customers are 'over-signalled' LRMC.

Likewise, the off-peak window could be narrowed to reflect the increasing concentration of minimum demands in the middle of the day.

Taking into consideration the likely timing of peak demand and minimum demands, the peak and off-peak charging windows could be narrowed for 2025-2030 period to the following:

- Peak window at 5:00 pm – 8:00 pm
- Off-peak window at 10:00 am – 3:00 pm

However, the benefits of narrowing the time of use windows in terms of sending a sharper price signal should be weighed against the costs of change. There should also be consideration of possible changes in the demand profile introduced by greater electrification, and the uptake of CER including EVs and rooftop PV. These factors introduce uncertainty into forecasts and may lead to changes in the demand profile over time.

Endgame Economics
24.01, 9 Castlereagh St
Sydney, NSW 2000
Australia
M: +61 425 204 793
T: +61 2 9037 0370
E: info@endgame-economics.com