evoenergy

Attachment 1: Augmentation expenditure

Revised regulatory proposal for the Evoenergy electricity distribution determination 2024 to 2029

November 2023

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1. Revised augmentation forecast

Augmentation underpins the delivery of net zero in the ACT

The Australian Capital Territory (ACT) remains at the forefront of Australia's energy transition. The ACT Government's ambitious 2045 net zero target requires a rapid and extensive reduction in emissions. Natural gas is gradually being phased out while transport is being decarbonised through the adoption of electric vehicles (EVs).

These factors are driving material change in terms of the scale, function and criticality of our network. We are transitioning from our traditional role of providing one-way energy flows to becoming the single crucial platform that underpins nearly all energy use in the ACT. The importance and value to consumers of a reliable and resilient electricity network has never been greater.

The electrification of gas and transport will increase peak demand and place enormous pressure on our network, especially at the 11kV feeder and low voltage levels. While the ongoing roll-out of cost-reflective tariffs and future technologies to facilitate dynamic control of EVs will assist, extensive network reinforcement remains necessary.

Delayed network augmentation will result in capacity constraints with detrimental outcomes for consumers. This risk isn't hypothetical. Capacity constraints are preventing new customers from connecting to the West London electricity network.[1] In our case, insufficient capacity will pause the ACT's decarbonisation journey (and wider economic development) while the network catches up to consumer demand. This would lead to higher network prices (through lower network throughput), higher consumer whole of system costs, higher emissions and delays in the achievement of emission reduction targets, all contrary to the updated National Electricity Objective.

The augmentation forecasting challenge

Traditionally, augmentation has primarily been driven by new connections and gradual changes in demand over time (due to population growth, electrification, improving energy efficiency, etc.). Our established forecasting tools and techniques, such as peak demand forecasting, consistent with good industry practice, have focussed on historical data and observable relationships.

However, the future is going to be unlike the past. We are confronting unprecedented levels of urban infill, above-average connection growth, and the highest levels of inflation seen in 30 years, all during an energy transition that is reshaping our role. The transition, in particular, presents a unique challenge.

Forecasting the impact of the electrification of gas and transport is challenging due to the limited (or absence of) directly applicable historical data to rely on. This is compounded by the consumer-led nature of the transition. Investment needs will be driven by location specific consumer decisions on when gas appliances are replaced or EVs are purchased and charged. Our approach to navigate these complexities is to continue to keep an open mind and adopt a flexible approach.

Initial proposal and Australian Energy Regulator feedback

Our initial proposal augmentation forecast included a series of projects to reinforce the network in response to ongoing demand growth from new development, particularly from new and renewed precincts, and peak demand growth from the uptake of EVs. This forecast was prepared in late 2022.

[1] Latest updated from the Mayor of London available here.

Since developing our initial proposal, we have refined our approach and integrated new data on expected demand and costs. This led to an updated (lower) EV peak demand forecast, which we provided to the Australian Energy Regulator (AER) in April 2023.

The AER considered our EV peak demand forecasting approach reasonable. It indicated that it is comfortable with the overarching approach to forecasting EV loads[2] but raised other concerns with elements of our forecasting approach.

The AER produced a placeholder demand forecast (which it noted should not be regarded as a realistic expectation of demand).[3] Energy Market Consulting associates (EMCa) used this indicative forecast to identify which augmentation projects could be deferred but noted that the appropriateness of these deferrals needs to be considered through network engineering assessments.[4]

On the basis of its placeholder forecast, the AER accepted almost all of our non-EV demand driven expenditure (aside from the second transformer at Molonglo and a proposed community battery). It rejected all but one of the sixteen EV-demand driven projects proposed.

Evolution of our forecasting approach and the conservative bias embedded throughout

We have continued to refine our forecasting approach to reflect the most recent and robust data available to us, both in terms of our peak demand forecast and the costs of delivering the augmentation required.

We appreciate the AER's recognition of the forecasting challenges we face[5] and the ongoing engagement over the past year. We have updated our forecasting approach to address the AER's concerns and implement the suggestions made (see Appendix D).

Like all forecasts, ours is limited by data constraints. Where these have arisen, we have made a conscious choice to adopt the more conservative approach. For instance:

- Our forecast does not fully account for the electrification of gas. While we have a high-level view of the impact (based on the Australian Energy Market Operator's forecasts), we do not yet have the geographic specifics to prepare a peak demand forecast for the electrification of gas at the feeder level.
- A conservative approach at both the zone substation and feeder levels to ensure no duplication between the baseline trend and connection adjustments.
- Assuming no load from EVs on controlled charging profiles at peak times (even though studies show that a small amount of charging still occurs).
- Not considering differences between ACT consumers and assumed Commonwealth Scientific and Industrial Research Organisation (CSIRO) charging patterns (e.g. from a higher uptake of wall charging, which increases charging capacity).
- The use of charging profiles from Australian Energy Market Operator (AEMO)'s central Step Change scenario. This approach does not take into account that Progressive Change scenario (which results in a higher EV peak demand in the long-term) is estimated to occur with a probability of 42% (one percentage point lower than the likelihood of the central Step Change scenario).[6]

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[2] AER 2023, *Draft Decision Evoenergy Electricity Distribution Determination 2024 to 2029, Attachment 5 Capital Expenditure,* p.17. Available here

[3] AER 2023, *Draft Decision Evoenergy Electricity Distribution Determination 2024 to 2029, Attachment 5 Capital Expenditure,* p.13. Available here

[4] EMCa 2023, *Review of proposed expenditure on DER and Augex,* p.34. Available here

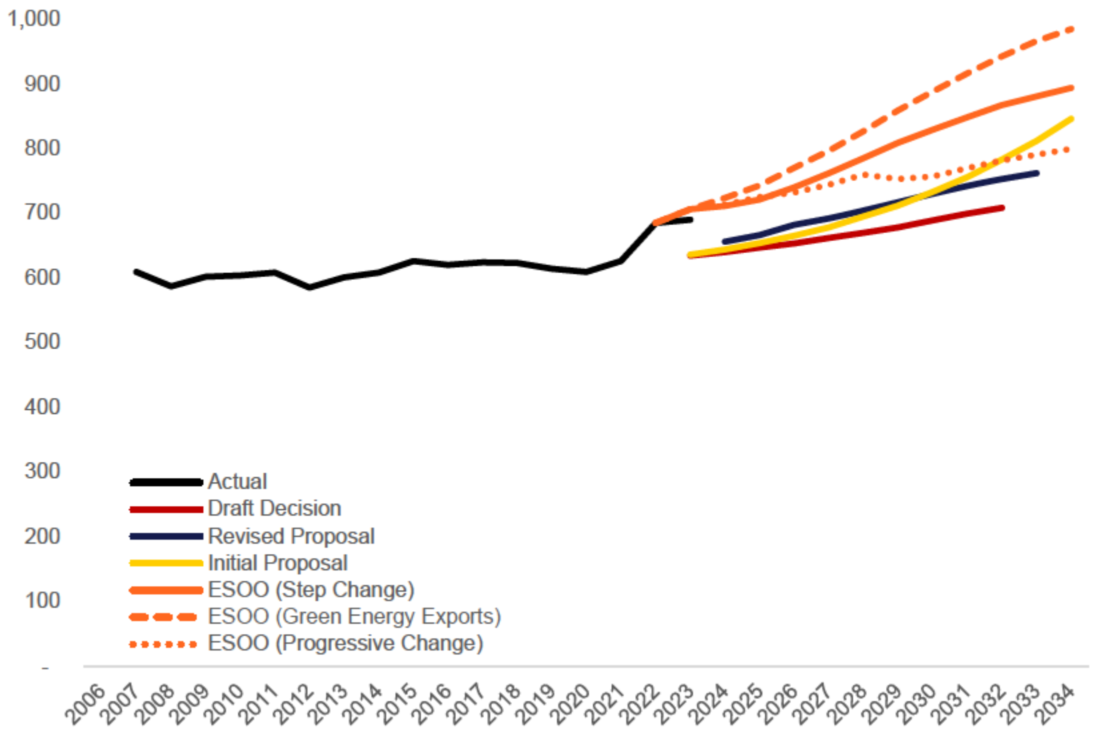
[5] AER 2023, *Draft Decision Evoenergy Electricity Distribution Determination 2024 to 2029, Attachment 5 Capital Expenditure,* p.15. Available here

[6] AEMO 2023, *2023 ISP Delphi Panel*, Available here

- We have smoothed (and largely delayed) the delivery of our augmentation program to improve deliverability and reduce the risk of further cost increases.

The consequences of these decisions can be seen in our updated peak demand forecast at the system level in winter (Figure 1). Overall, our forecast is slightly higher than our prior forecast in the earlier years but has a slower growth over time.

Figure 1 Winter System Peak demand actual and forecasts (POE 50) MVA



The implied AEMO forecast for the ACT is 13 per cent higher than our demand forecast by 2028/29.[7] Top-down checks across a range of forecasts (shown in Appendix C) show similar patterns. This is likely because our forecast does not fully account for the electrification of gas.[8]

We also asked the Centre for International Economics (the CIE) to assess our updated methodology (see Attachment 1.1). The CIE confirmed that our forecasts have improved from our Initial Proposal and have addressed the AER's suggestions. However, the CIE also identified a conservative bias (where our forecasts are likely to understate peak demand) as electrification of gas is not included.

Overall, despite this inherent conservatism, we consider that our forecast represents a realistic expectation of demand (consistent with the capital expenditure criteria), given that it is the best estimate of demand we can produce in the circumstances.[9]

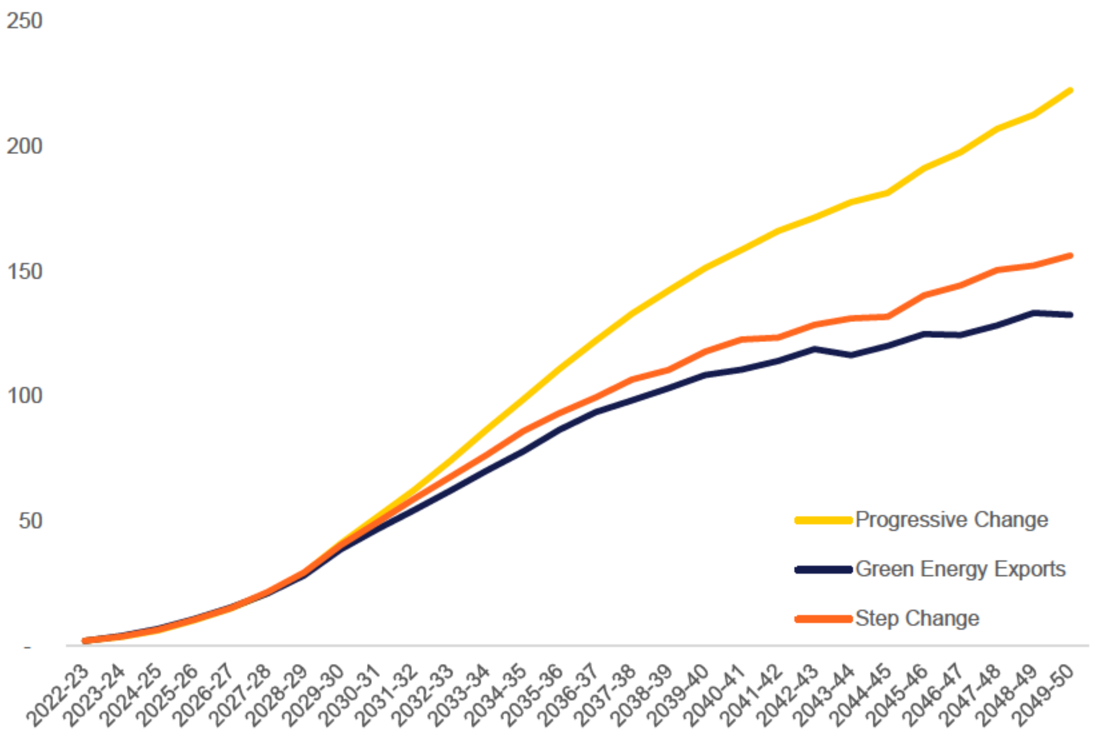
[7] As AEMO does not produce an ACT specific forecast, we have prepared implied forecasts based on the percentage change in peak demand forecast in NSW and Victoria. This forecast, relative to our forecast, along with AEMO's forecasts of other jurisdictions are presented in Appendix C.
[8] As discussed in section 2.1 the electrification of gas which has occurred in the last two years is partially included in the forecast, although the impact is largely averaged out by the preceding data.
[9] Rule 6.5.7(c)(1)(iii).

The next step on a long journey

It is important to recognise that our augmentation plans for the 2024–29 regulatory period represents the next step on our path towards achieving the ACT's ambitious 2045 net zero target.

The anticipated increase in peak demand, as evidenced by our forecasts and corroborated by other independent third-party forecasts (see appendix C), necessary to achieve net zero by 2045 will be substantial. This is shown in Figure 2, which provides the long-term view of peak EV demand by AEMO scenario.[10] We can expect to see a similar sustained increase in peak demand due to the electrification of gas.

Figure 2 Forecast Peak EV Demand by AEMO Scenario (MW)



The main implication from the expected sustained, significant and ongoing increase to peak demand – as observed in all of AEMO's scenarios – is the asymmetric risk from under and over investment.

In this context, the risk of over-investment is that an investment is made earlier than required – incurring additional costs related to the time value of money. This cost is an order of magnitude lower than the risk of making an investment which will ultimately not be required.

In contrast under investment will mean that the network will not have sufficient capacity to meet consumer demand. This will lead to reduced system reliability and system security and prevent consumers from unlocking the benefits of electrification. In turn this will lead to higher network prices (resulting from lower network throughput) and inhibit the achievement of net zero emissions in the ACT.

This context has been considered but not integrated into our forecasting approach. We have justified each project on its merits using the peak demand forecast available to us. However, with the

[10] AEMO's 2023 ESOO Projections only go out to 2034 so a similar chart for the electrification of gas cannot be produced. However, AEMO's 2022 ESOO projections shows that winter demand in NSW and Victoria is expected to continue to rise over the period to 2051, see here.

expected persistent increase in maximum demand, we are confident that our approach to network planning is a no-regrets strategy.

However, the substantial rise in peak demand required to achieve net zero by 2045, together with the conservative bias embedded in our forecast, means there is a real risk that our capex forecast will not be sufficient. It is possible that we will need to reopen our forecasts mid-period. This is discussed further in Attachment B.

Updated zone substation costs

In addition to demand uncertainty, national and global supply chain constraints, together with workforce and skill shortages, are driving above-inflation cost increases to infrastructure projects across Australia.

AEMO, for instance, has found that these factors have resulted in a 30 per cent real increase – that is on top of the record high levels of recent inflation – between the 2022 and 2024 Integrated System Plans.

We are not immune to these external forces. Since submitting our initial proposal, we have completed the tender process for the design and construction of our new 132/11kV Molonglo zone substation. We found that costs were materially higher than our previous cost estimates based on an earlier tender for our Harman zone substation.

Given the quantum of the cost increase, we asked Advisian to review our tender process and provide an analysis of the cost movement (Attachment 1.2). Advisian found that the tender process aligned with good industry practice, and the observed cost increases are consistent with current market conditions.

The cost increases, set out below, are stark but unsurprising, given the external cost headwinds we are experiencing, which are particularly pronounced in the ACT. These are further discussed in Appendix F.

We have updated our cost estimates for our zone substation augmentation projects (to align with the latest market data). This ensures that our capex forecast reflects the cost inputs required to achieve the capital expenditure objectives, as set out in the capital expenditure criteria.[11]

Revised proposal augmentation forecast

Based on our revised peak demand forecast, we have reviewed and updated our augmentation forecast and refreshed our engineering assessments of each constraint. This review ensures that our revised proposal forecast reasonably reflects the capital expenditure criteria (including a realistic expectation of demand and cost inputs) and the achievement of the capital expenditure objectives (such as meeting or managing expected demand to maintain the reliability and security of our network).

In respect of our non-EV driven program, we found that relative to the AER's draft decision:

- all projects accepted are still required;
- the second transformer at Molonglo is required and cannot be deferred ($9.5 million);
- an additional feeder will be required to meet expected non-EV demand in Barton ($3.2 million); and

[11] Rule 6.5.7(c)(1)(iii).

- the competitive market price to build and connect the new 132/11kV zone substations at Molonglo and Strathnairn has increased. The costs of these projects has increased from $35.2 million to $78.7 million.

While for EV-demand driven augmentation:

- we will require six new feeders to meet the growth in peak demand driven by EVs ($25. million), rather than the one included in the AER's draft decision and the 10 included in our initial proposal[12]; and
- while not required to be completed this period based on our revised demand forecasts, we will need to commence early works and land purchases for the new Mitchell and Curtin zone substations towards the end of the period ($2.8 million).

Our revised proposal reflects these updates, as shown in Table 1.The change in individual EV feeder costs between initial and revised proposals reflects the change in the timing profile of the feeder investments consistent with the revised demand forecasts. Further detail is provided in Appendix G.

Business cases supporting each of these projects setting out the constraint, options and preferred option are provided in Appendix 1.4. The remainder of this attachment provides details on our updated peak demand forecasting and approach to developing our capex forecast.

Table 1 Non-EV-Driven Augmentation projects

Project	Draft Decision	Revised Proposal
Molonglo zone substation	Required	✓ Accept – but have updated cost based on recent competitive tender
Molonglo zone substation 2nd transformer	Defer	Do not accept. Still required.
Strathnairn zone substation	Required	✓ Accept – but have updated cost based on recent competitive tender
Supply to Barton	N/A	New project – required by 2025
All other projects	Required	✓ Accept acceptance

[12] Our initial proposal also included other works for instance to upgrade low voltage circuits.

Table 2 EV-Driven Augmentation projects

Project	Draft Decision	Revised Proposal
Supply to Braddon	Defer	Do not accept. Still required.
Supply to Watson	Defer	Do not accept. Still required.
Supply to Ainslie	Defer	Do not accept. Still required.
Supply to Campbell	Defer	Do not accept. Still required.
Supply to Franklin	Defer	Do not accept. Still required.
Supply to Philip	Defer	✓ Accept deferral
Supply to Canberra CBD Feeder 1	Required	✓ Accept acceptance
Supply to Canberra CBD Feeder 2	Defer	✓ Accept deferral
Supply to Canberra CBD Feeder 3	Defer	✓ Accept deferral
Mitchell zone substation	Defer	Do not accept. Still require land purchase and project initiation in 2024–29
Curtin zone substation stage 1	Defer	– Partly accept. Still require land purchase and project initiation in 2024–29
Zone substation QoS reactive plant	Defer	✓ Accept deferral
EN24 Distribution substation upgrade	Defer	✓ Accept deferral
EN24 low voltage circuit overhead program	Defer	✓ Accept deferral
EN29-34 Woden to Curtin 132kV underground cable	Defer	✓ Accept deferral

2. Peak demand forecast

Since our initial regulatory proposal and 2022 Annual Planning Report, we have continued to refine our forecast over time to incorporate new data and improve our approach. In early 2023, this led to an update to the forecast impact of EVs, which was provided to the AER and formed the basis of the AER's draft decision.

More recently, we have sought to identify and integrate new sources of data and take into account observations from winter 2023. We have also carefully considered and, where possible and appropriate, adopted and integrated the AER's helpful feedback and suggestions (see Appendix D for a detailed summary).

Key changes include:

- **Adopting the CSIRO's electric vehicle load profile assumptions from AEMO's 2024 Integrated System Plan,** reflecting changes in charging behaviour due to the roll-out of cost-reflective tariffs and adoption of managed charging (where retailers or aggregators control and optimise EV charging). More details are provided in Appendix B.
- **Addressing the potential for duplications between the baseline trend and connection adjustments**, as raised by the AER. Lacking robust data to alter the baseline trend, we have adopted a more conservative approach. This includes, for our zone substation peak demand forecasting approach, alignment with the AER's draft decision approach.

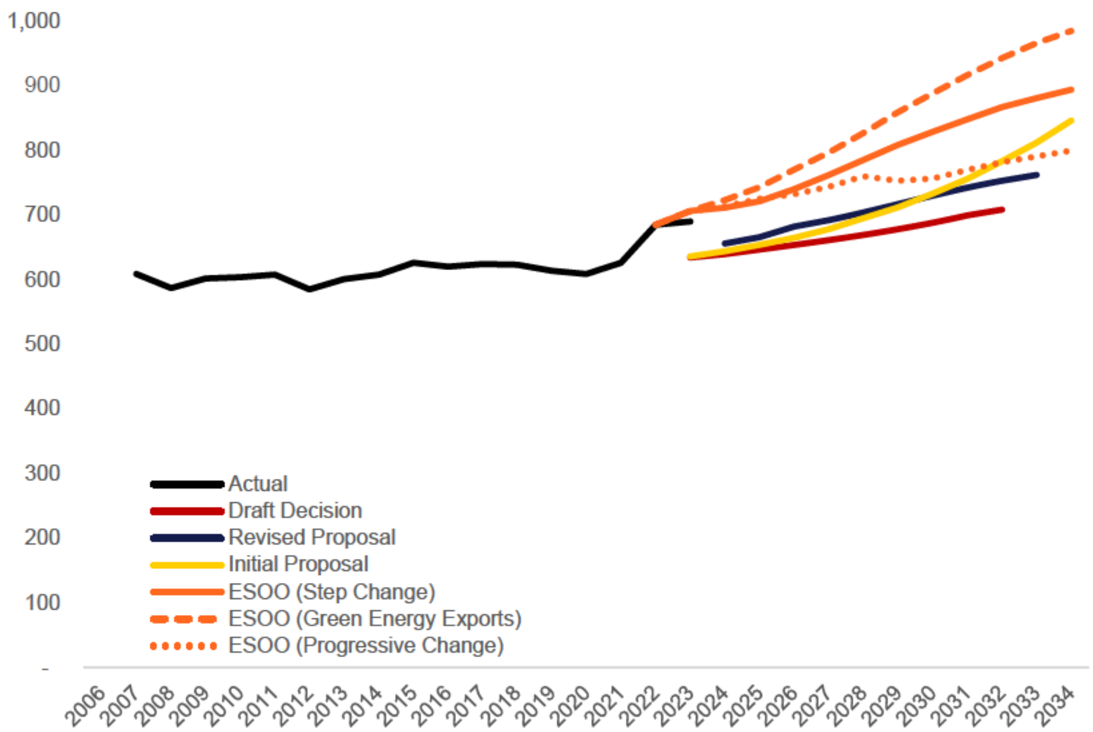
Despite updates in various areas, accounting for the electrification of gas has been challenging due to limited time and data.[13] As a result, at this stage, we couldn't develop a robust post-modelling adjustment that could be applied at the feeder level. We will continue to monitor gas demand data over the period better to understand the extent of the structural shift in demand.

To validate our updated methodology, we sought the Centre for International Economics (CIE)'s assessment (see Attachment 1.1). While they noted improvements, they also identified a conservative bias in our forecasts.

Figure 1 (provided again as Figure 3 on page 15) presents our revised winter system peak demand forecast (Probability of Exceedance 50 per cent), indicating a continual increase in winter peak demand over the 2024–29 regulatory period. It starts slightly higher than our initial proposal but shows a more gradual increase, reflecting the flatter CSIRO EV charging load profile.

[13] A structural shift was only confirmed in the most recent winter.

Figure 3 Winter System Peak demand actual and forecasts (POE 50) MVA



Despite the structural shift in winter peak demand over the past two years, its overall impact on our forecast is minimal due to the averaging effect of the preceding 14 years of data. This issue was identified and explained further in CIE's report (Attachment 1.1).

Figure 3 also incorporates a high-level cross-check against AEMO's 2023 Electricity Statement of Opportunities (ESOO) forecasts. Since AEMO doesn't provide an ACT-specific forecast, we derived an estimate using an index of average peak demand growth across Victoria and NSW. The forecast aligns with Acil Allen and GHD's forecast for the ACT Government, which predicts peak demand between 750 - 1100 MW by 2034, depending on the scenario.[14]

Our cross checks indicate that our revised forecast understates the expected increase in peak demand.

Electrification of gas

The AER, in its draft decision, requested that we better address the gas transition and explain how this has been considered in its revised proposal.[15]

The initial proposal forecast (developed in late 2022) assumed there would be no material impact from the electrification of gas over the 2024–29 regulatory period. While we recognised that the electrification of gas will have long-term impacts on demand, at the time, we considered that the electrification of transport would have a larger impact in the medium term due to the nature of an ad hoc consumer led transition from gas.

Since submitting our proposal, we have conducted additional analysis of peak demand in 2022 and 2023 and considered AEMO's forecasts in the ESOO. This analysis indicates that the electrification of

[14] See figures 51, 72, 110 and 145 here
[15] AER 2023, *Draft Decision Evoenergy Electricity Distribution Determination 2024 to 2029, Attachment 5 Capital Expenditure*, p.13. Available here

gas has caused a structural shift in peak winter demand and is likely to continue to materially increase peak demand over the 2024–29 regulatory period.

Although we have prepared an 'electrification reference case' forecast at the system level, the lack of time and data has prevented us from making a robust adjustment at the feeder level.

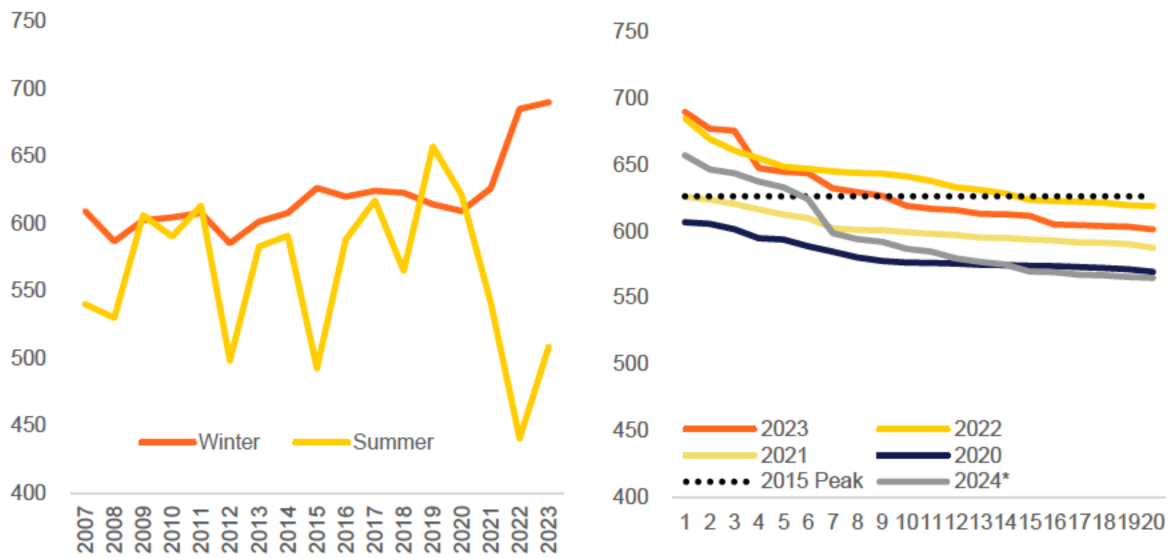
As a result, given cost-of-living pressures and heightened forecasting risks, we have made a conscious decision to adopt a conservative approach and to make no adjustment for the electrification of gas. This means that our revised proposal forecast will likely understate peak demand over the 2024–29 regulatory period. We bear the associated risk that our proposed capital expenditure program may reflect less investment than required. However, as discussed further in Attachment B, we may need reopen our forecasts mid-period.

Electrification has led to a structural change in winter peak demand

Over the last two years, we have experienced record levels of winter peak demand on our electricity network and declining usage of our gas network over winter. This change in usage across both of our networks is likely driven by the introduction of policy initiatives, such as financial incentives to substitute gas heating with electric heating commencing in 2021[16], as well as consumer sentiment.

As shown in Figure 4, winter peak demand over the past two years has surpassed the previous system record set in summer 2018/19.[17] Also shown in Figure 4 is a comparison of historic peak demand compared to the top 20 winter demand days seen over the 2019/20 to 2023/24 period. It illustrates how peak demand in recent years is now regularly – on average once a week in June and July – exceeding the winter record set in 2015. These peak demand events are occurring in the morning (the current system record was set at 8am) and on the weekend.

Figure 4 Actual Peak Demand compared to Top 20 winter peak days from 2020–2024 (MVA)[18]



Note 2024 financial year is not complete.

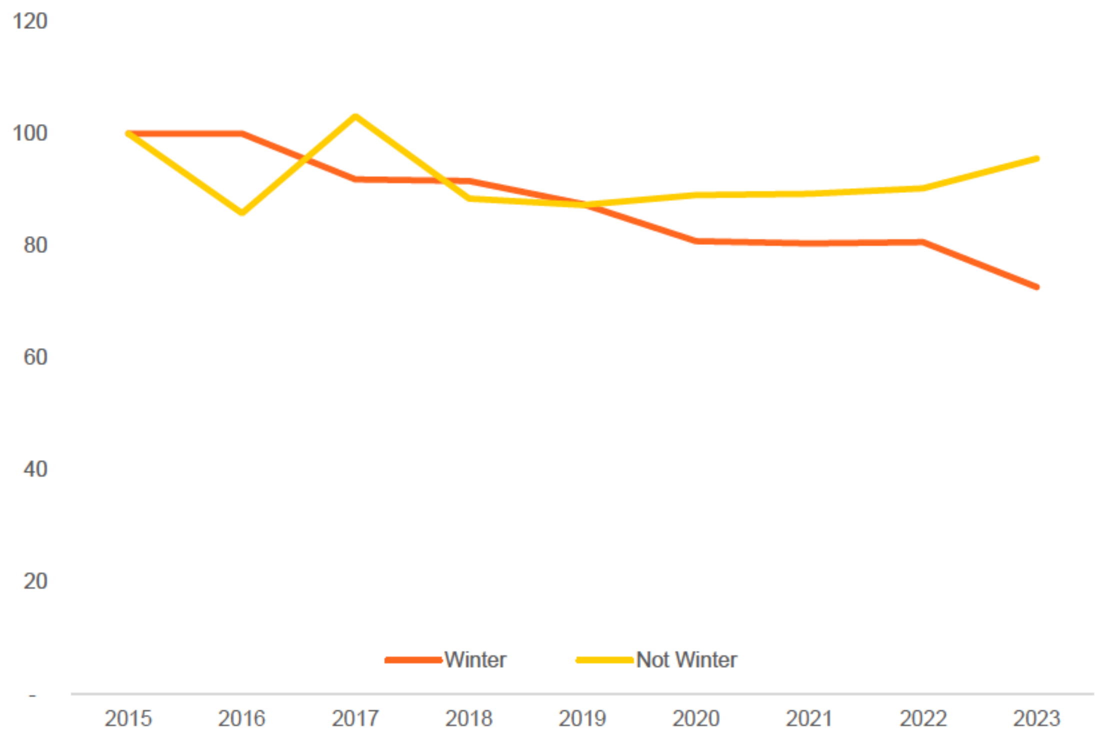
[16] These incentives are provided by ActewAGL (see here) as part of the Energy Efficiency Improvement Scheme (see here).

[17] The 2018/19 summer was the warmest on record while the more recent summers over 2021, 2022 and 2023 have been the coolest years since 2012. Maximum temperatures at Canberra airport were 38.0°C, 32.7°C and 36.1°C in 2021, 2022 and 2023 much lower than the summers in in 2019 and 2020 which had maximum temperatures of 41.6°C and 44.0°C.

[18]

Although we haven't observed significant disconnections on our gas network, a steady decline in winter volumes is evident. Figure 5 shows that the reduction in winter throughput has been larger than the reduction outside of winter.[19] This pattern is consistent with appliance shifting heating loads from our gas network to our electricity network, driving a broad-based increase in peak demand. It also explains why we are now seeing peak demand events occurring in the morning and on the weekend.

Figure 5 Evoenergy gas network TJs/Customer/day (2015=100)

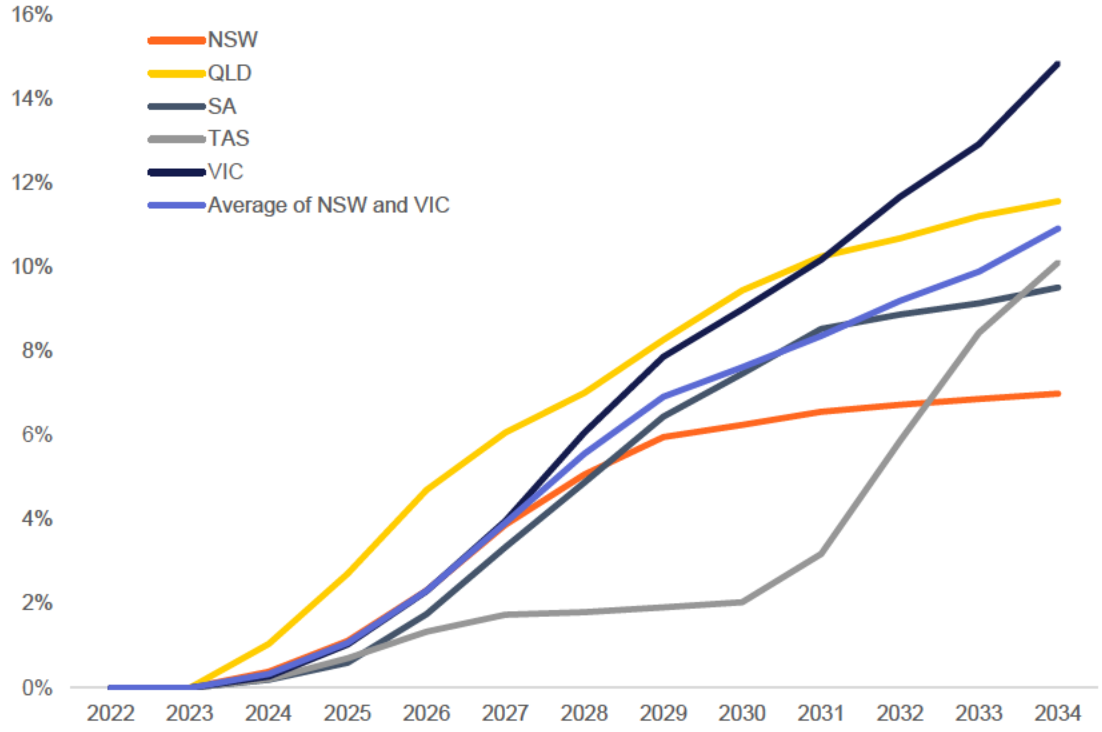


[19] The chart presents throughput represented by an index where throughput in 2015 has been set to 100 rather than the average winter and non-winter consumption per customer.

Ongoing electrification: expected to grow over time

AEMO's peak demand forecasts, prepared as part of the Electricity Statement of Opportunities (ESOO), account for the increase in peak demand driven by gas electrification. This is shown by jurisdiction in Figure 6 for the central step change scenario.

Figure 6 2023 ESOO projected increase in peak demand due to electrification (POE 50, Step change scenario) MW



Although AEMO does not prepare ACT specific forecasts, we consider that the best comparator for the ACT is the average of AEMO's forecast for NSW and Victoria.

Two key factors are driving an increase in peak demand from the electrification of gas. The first is the overall size of the gas load. The second is the size of the gas load relative to the size of the electricity network. In both cases, as shown in Table 3, the ACT is about the average of NSW and Victoria. These metrics indicate that using the average increase in peak demand across NSW and Victoria is a reasonable estimate of the increase in peak demand on our network.

Electrification over the average of NSW and Victoria results in an increase to peak demand of about 6.9 per cent by 2029 in AEMO's central step change scenario.

Table 3 Average residential gas loads per gas and electricity customers

	Average residential gas load per gas customer (GJ)	Average of residential gas load per electricity customer (GJ)
NSW	20.0	8.9
Victoria	47.6	37.8
Average of NSW and Victoria	33.8	23.3
Evoenergy	33.6	26.4

Electrification reference case

We have developed an alternative system peak demand forecast considering gas electrification. Though not used for identifying network constraints or underpinning augmentation projects, it serves as a high-level cross-check and informs our forecast's reasonableness.

Creating this electrification reference case requires two adjustments at the system and zone substation level:

1. to the starting point – to account for electrification which has already occurred; and
2. to the ongoing trend – to incorporate electrification which will occur.

Our baseline trend forecasting approach, which is projected from the average of observations from 2007 to 2023, necessitates the first adjustment. While the recent increases in peak demand are included in the data used by the baseline trend model, these observations are largely averaged out by data from the preceding years. The forecasting model does not consider any data other than the peak in each year and does not recognise the broad-based increase in peak demand we have experienced.

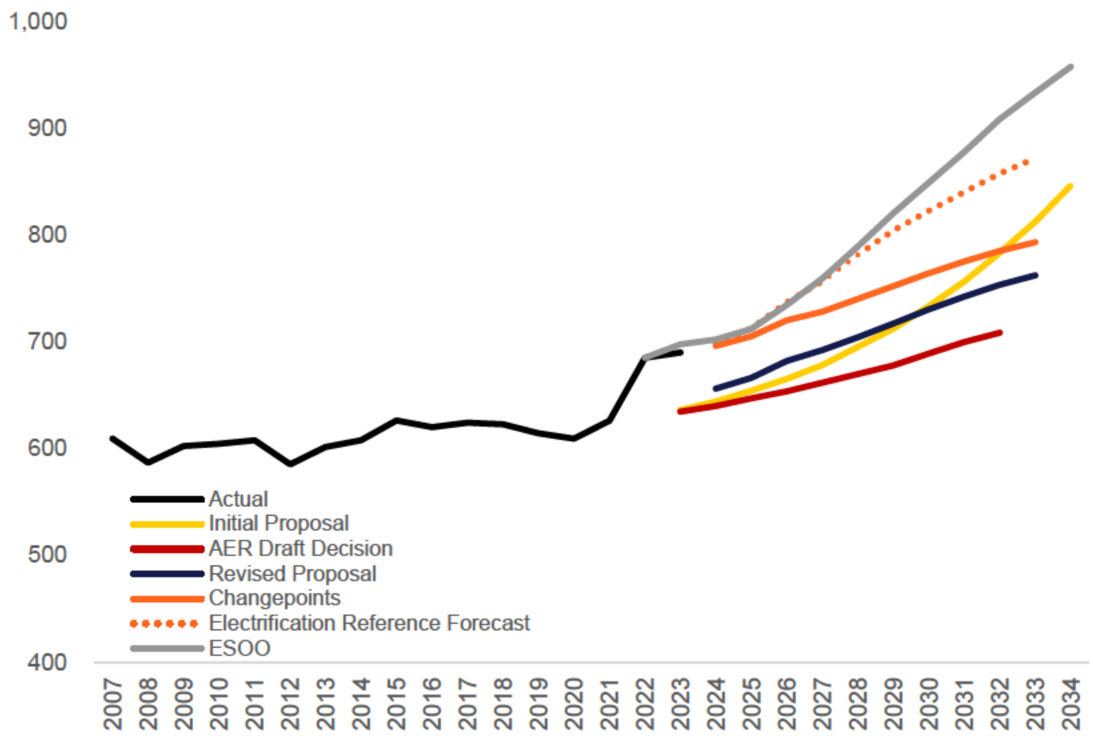
To change the start point, we used functionality built into our forecasting model where we set a 'change point' in 2022. This results in a forecast commencing from the most recent demand observations. This approach is consistent with AEMO's approach for transmission connection point forecasts.[20]

To account for ongoing electrification, we make an adjustment using ESOO data. Specifically, we use the electrification component of the peak demand forecast prepared by AEMO for NSW and Victoria. We identify the proportion of peak demand due to electrification each year and make a corresponding adjustment to our peak demand forecast.

Figure 7 presents the changepoint forecast and its combination with the ESOO electrification adjustment. The result closely aligns with AEMO's step-change scenario forecast, being approximately 87 MW (13 per cent) higher than our revised proposal forecast in 2028/29.

[20] See Attachment 1.1, page 23

Figure 7 System winter peak demand forecast (POE50) with electrification reference case (MW)



Although our electrification reference case aligns with AEMO's approach and independent forecasts (see Appendix C), its high-level nature lacks the specificity needed for feeder and low voltage network loads. Hence, we retain it solely as a high-level cross-check.

Peak demand forecasting methodology

The purpose of peak demand forecasts is to identify future network constraints. These arise across the four levels of our network:

1. **Transmission level** (including the Bulk Supply Points, which connect our grid to the National Electricity Market) facilitates large-scale energy transmission across and through the ACT. There are 4 bulk supply points across our network and 181 km of transmission lines.
2. **Zone substations**, crucial nodes in our network, which link the 132kV transmission network to the predominantly 11kV high voltage feeder network. We have 13 zone substations (and one mobile zone substation) in our network.
3. **High voltage network** consisting of feeders distributing power from our zone substations to large customers and our street level low voltage network. We have 271 feeders.
4. **Low voltage network** is the largely meshed grid of distribution lines running through backyards (and along streets), delivering electricity to most end-users.

Peak demand forecasts at the higher levels (transmission and zone substation) are predominately produced using trends with post-modelling adjustments to capture factors not considered. Trends are used as the specific details of smaller individual customer requirements can be averaged out over a larger number of customers. Connection data, while accurate in the near term, typically fades out beyond a timeframe of about three years due to the typical lead time of a customer enquiry or connection application.

Peak demand forecasts at lower levels need a higher degree of accuracy and granularity to identify constraints. We need details on the location, size and timing of forecast loads (i.e., where specifically do we need additional capacity) to determine how the individual feeders will be affected and what feasible solutions are available.

These details reveal patterns and trends which can be hidden when looking at aggregates. For example, there is a considerable difference between 300 new EVs being purchased uniformly across a zone substation area and 300 EVs all being purchased in a particular suburb. While loads at a zone substation would be equivalent, there are significant differences at the feeder level.

Using specific details also ensures that the forecast load profiles reflect loads of actual connections, which can differ from averages derived from historical trends.

Given these differences, we prepare two sets of forecasts. One at the zone substation (and system) level is largely driven by trends. At the feeder level, we focus on more data that has the specifics required.

System and zone substation forecasts

Forecasting peak demand at the system and zone substation levels is primarily based on historical trends, which account for temperature variations and gradual changes in demand over time. Two adjustments are made – first, for connections not captured in the historical trend and second, for electric vehicle charging loads.

The AER, in its draft decision, indicated it was largely satisfied with our methodology (aside from adjustments to reflect historical connections – see below).[21]

Baseline trend forecast

Peak demand is projected using a Bayesian statistical model with two demand drivers:

- Temperature which captures the relationship between the weather and peak demand.
- Time which captures the aggregate change in demand over time due to factors such as development, climate change, historical population growth, electrification, energy efficiency, etc.

The model produces these estimates using data over the 2007/08 to 2022/23 period.

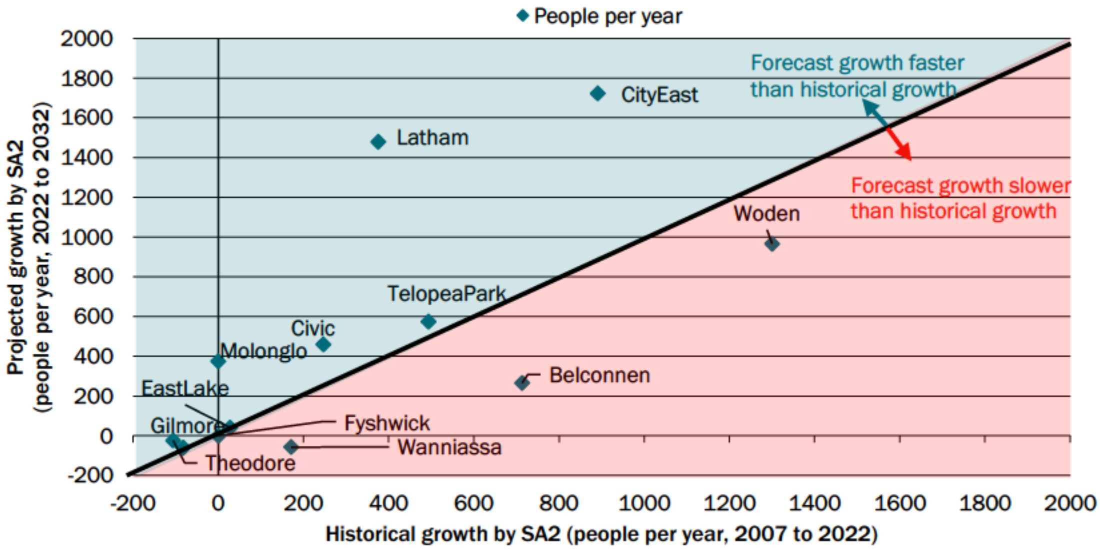
As the model only has two demand drivers, it does not produce individual estimates on the impact of population, electrification, energy efficiency, etc. – these are all bundled together within the time trend and calculated over the whole data period. This has two drawbacks:

1. Shifts within the period are not identified – such as the recent increase in peak demand due to the electrification of gas.
2. The forecast cannot be adjusted to reflect different circumstances, for instance, if population growth or development is expected to be higher than experienced in the past.

These drawbacks can be material. For instance, the CIE identified that there is a substantial difference between historic and forecast population growth, as shown in Figure 8. This indicates that a peak demand forecast in the City East zone substation solely based on historical trends will underestimate peak demand requirements.

[21] AER 2023, *Draft Decision Evoenergy Electricity Distribution Determination 2024 to 2029, Attachment 5 Capital Expenditure,* p.15. Available here

Figure 8 CIE's comparison of actual and forecast population growth by zone substation



Despite shortcomings in our baseline trend forecast (which will lead to demand being understated), we have made no changes to this component of our forecast other than to add the additional year of data now available.

Connection adjustments

We adjust the baseline trend to capture large new connections not included in the historical trend (such as industrial loads or data centres). This is through the addition of connection 'block loads.'

To determine whether an adjustment is required, we review the data obtained through connection enquiries, connection applications and government land release programs and apply a five-step process. This process validates, moderates, allocates, adjusts and filters these loads before they are added. This process is outlined in Appendix A.

In its draft decision, the AER was concerned about the possible duplication of loads included in the baseline trend as well as the connection adjustments.[22] The AER suggested that we remove connections from historic load data to prevent double counting.

While we agree that this is conceptually logical, practical data limitations have prevented the adoption of this approach. It would require extracting, analysing, cleaning, and aligning data from different systems (for instance, our zone substation and billing system data). This approach would be expensive and would have been unlikely to result in sufficiently robust data in time for this revised proposal.

Instead, we have adjusted our approach to the connection adjustment. We have applied new load inclusion criteria to only include loads not likely to be captured in the historical trend (data centres, off-peak connections, industrial connections) as outlined in Table 4. This approach errs on the side of caution to avoid double counting any loads and is consistent with the approach applied by the AER in its draft decision.[23]

[22] AER 2023, *Draft Decision Evoenergy Electricity Distribution Determination 2024 to 2029, Attachment 5 Capital Expenditure*, p.19. Available here

[23] AER 2023, *Draft Decision Evoenergy Electricity Distribution Determination 2024 to 2029, Attachment 5 Capital Expenditure*, p.15. Available here

Table 4 System and zone substation load inclusion by forecast level

Load element	System Forecast	Zone forecast
Residential connection	×	×
Mixed/commercial connection	◉	×
Industrial connection	◉	✓
Off-peak connection	◉	✓
Data centre connection	◉	✓
EV model	✓	✓
Electrification of gas	×	×
Statistical trend	✓	✓

Key: ✓ Included, × Excluded, ◉ Inclusion by exception

This approach is conservative as it only adjusts for a small subset of loads. There is no adjustment for where connections are above the historical trend, for instance, where development will be higher than has historically been observed.

Electric vehicle adjustments

A second adjustment is required to include peak demand from EV charging as there is minimal EV charging captured in historical data on which baseline forecast is derived. The AER considered this approach reasonable and is comfortable with the overarching approach to forecasting EV loads.[24]

The EV adjustments are calculated by our EV peak load models. A detailed outline of the methodology (including how we have incorporated the AER's feedback) and data sources is set out in Appendix B.

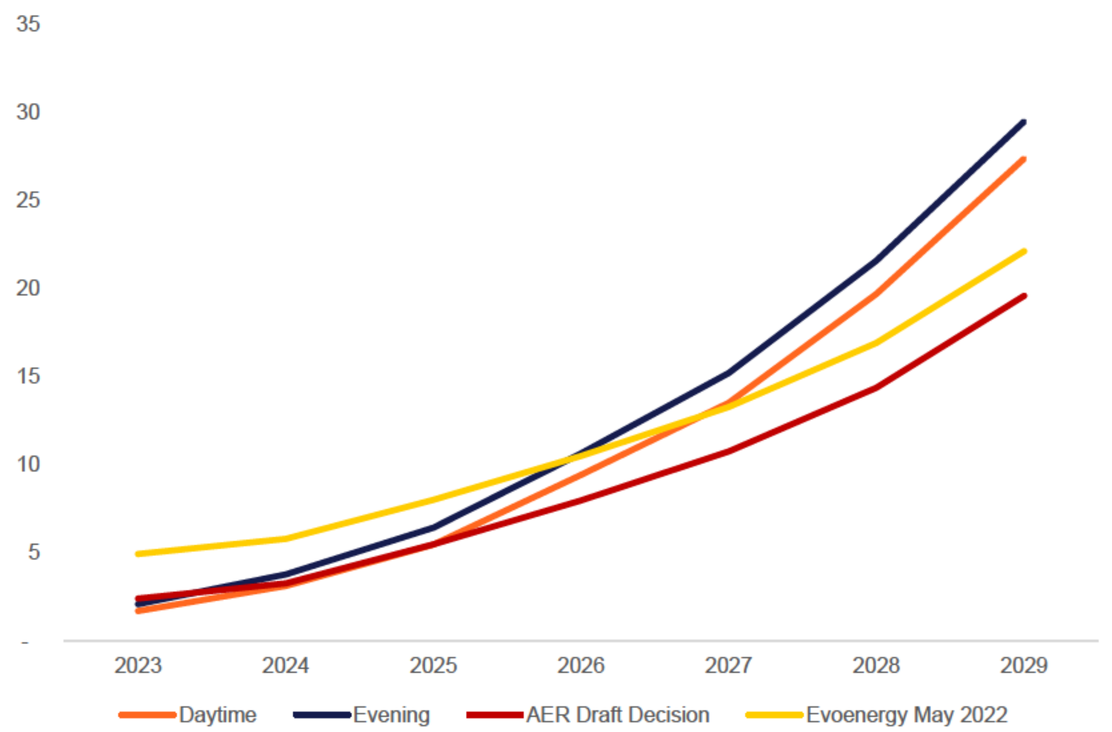
Broadly, the models forecast, by zone substation, an EV peak day load profile. This is then used to identify the overall evening and daytime peak by year. Depending on the zone substation the daytime or evening peak[25] is added to the zone substation forecast.[26]

[24] AER 2023, *Draft Decision Evoenergy Electricity Distribution Determination 2024 to 2029, Attachment 5 Capital Expenditure*, p.17. Available here
[25] A daytime peak is used for Angle Crossing, Belconnen, City East, Civic, East Lake, Fyshwick, Tennent and Telopea Park. All other zone substations use an evening peak.
[26] This is consistent with a suggestion from the AER to properly account zone substations which peak at different times.

A comparison of the total electric vehicle load adjustment is provided in Figure 9. Overall, there has been an increase in the size of the adjustment since our last forecast in May 2022 (on which the AER's draft decision is based). The increase is largely because we are now forecasting 52,000 residential EVs[27] in 2028/29, up from 32,000 in our earlier forecast. The updated forecast reflects recent uptake, the highest in Australia as a proportion of new car sales. EV uptake has been driven by ACT Government policy which includes setting a clear direction (with the phase-out of the sale of internal combustion engines by 2035), making EVs more affordable (stamp duty exemptions and interest free loans) as well as providing information supporting and informing uptake.

The AER's draft decision included an adjustment to remove loads from EVs connected in 2022. This would be an appropriate adjustment if our baseline trend was forecast from load in 2022 (a 'from the point' forecast), as electric vehicle load in that year would be implicitly included. However, the baseline trend forecast is a 'from the line' forecast, which is effectively an average load over the 2007 to 2022 (and now 2023) period. This means most of the EV load in 2022 has not been included, and no adjustment is required at the zone substation level to our EV block forecast before it can be applied.

Figure 9 EV Zone Substation Peak Demand Adjustment (MVA)



The zone substation peak demand forecast is conservative

Overall, we consider that our zone substation peak demand forecast is likely to understate peak demand given the extent of conservatism built into the forecast, including:

1. The electrification of gas has not been accounted for, resulting in a lower starting point and a smaller increase in peak demand over time.
2. Conservative approach to connection adjustments to avoid any risk of duplication with the trend.
3. No adjustment for demand drivers outside of time and temperature – including for higher levels of development, land releases, population growth, etc.

[27] This includes trucks as well residential (including motorcycles), commercial vehicles.

This is confirmed by the top-down checks relative to other 3rd party independent forecasts, as presented in Appendix C.

Feeder forecasts

A conservative approach to ensuring no duplication between the trend and connection data

Identifying peak demand constraints at the feeder level requires a higher degree of accuracy and granularity, which can only be obtained by integrating our connection data (enquiries, requests, land release forecasts, etc.) into our forecasts.

The alternative, relying on higher-level trends, would result in a forecast that does not identify connections that we know will be required. It would also not identify constraints on individual feeders.

Given the need for a high degree of granularity, our feeder forecasts are based on a year of actual hourly load, rather than a normalised, average, or typical load profile. This approach ensures that we capture the seasonal and daily variations that occur at each specific feeder.

Our forecasts are based on data extracted in September 2022, which include the calendar year 2022 winter and 2021/22 financial year summer. Obtaining feeder level load data requires a large degree of manual processing to extract and clean data from our Advanced Distribution Management System (ADMS). This differs from data for our zone substations, which can be obtained from system reports. We did not update the data set for our revised forecast as it would have required extracting data in July (to be ready in August – when we started our revised demand forecast) and would have only provided one additional month of winter load data. Instead, we prioritised internal resources to address feedback from the AER on our connection and EV adjustments.

As a result:

- Our winter feeder loads (unlike our zone substation forecasts) include the electrification of gas which had occurred in calendar year 2022.
- Our summer feeder loads are based on an extremely low year of summer peak demand due to cool weather (as shown earlier in Figure 4). As the data is not weather normalised, it will result in a conservative bias in all forecast summer peaks.

As identified by the AER, including connection data risks duplication with the baseline trend.[28] As with our zone substation level peak demand forecasts, we have adopted a conservative approach. However, given the need to rely on connection data, the methodology differs.

To ensure there is no duplication at the feeder level, we apply no baseline trend to the year-long hourly load data. This is a conservative approach for several reasons:

1. Ongoing increases in winter peak demand from our existing connections is expected, due to the continued electrification of gas.
2. Winter peak demand has been largely flat in areas of low connection growth. This indicates that factors driving peak demand reductions in summer (specifically the increasing penetration of solar) do not apply in winter.

As discussed above, we cannot decompose the baseline trend calculated at the zone substation level into components to isolate and remove the impact of historical connections. However, we can analyse the historical trends together with population growth and other network data to identify the likely sign, magnitude and size of the trend if connections were excluded.

[28] Another drawback from relying on connection data is that connection visibility is reduces the further out the forecasting horizon (as connection applications, particularly for smaller developments, are not lodged seven years in advance).

Firstly, as discussed earlier, we are seeing record levels of winter peak demand on our network due to the electrification of gas. The 2021/22 and 2022/23 winter peaks were 9 per cent and 10 per cent above the previous winter record, respectively. This indicates that change in winter peak demand represented by the baseline trend, even once historic connections are accounted for, is likely to be positive and materially so.

The second piece of data considered is the historic change in zone substation peak demand set out in Table 5. While these trends do not include any material amount of electrification of gas due to the longer data horizon, the data does indicate that:

- Overall, winter peak demand is growing while summer peak demand is falling, highlighting that different factors are at play in summer and winter.
- At individual zone substation level, winter peak demand is generally flat in areas with low population (and likely low connection) growth. This indicates it is unlikely that winter peak demand growth would be negative even once accounting for historic connections.[29]

Table 5 Average change in peak demand from 2007 to 2022

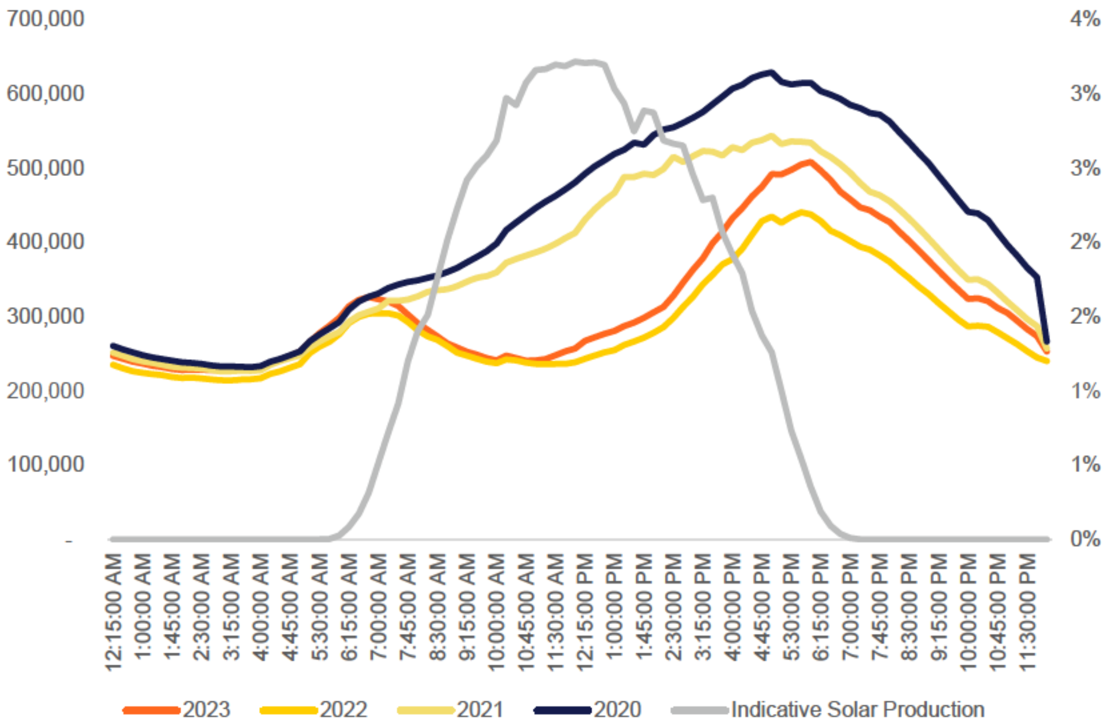
Zone substation	Summer	Winter	Population growth (people per year)
Belconnen	-0.6%	0.4%	714
City East	-2.3%	0.2%	891
Civic	-1.0%	0.3%	247
East Lake	-4.5%	-2.5%	891
Fyshwick	5.0%	8.0%	1
Gilmore	5.0%	3.9%	-82
Gold Creek	6.6%	6.6%	3,567
Latham	-0.1%	0.5%	375
Telopea Park	-2.3%	-1.0%	494
Theodore	0.9%	-0.2%	-106
Wanniassa	-1.5%	-0.5%	171
Woden	-1.7%	0.8%	1,300
Total (System)	**-0.5%**	**0.8%**	**8,463**

Note: change is based on 2007 or later consistent with the demand forecasting model inputs.

[29] Also illustrated by the graphs of peak demand over time presented in Appendix E.

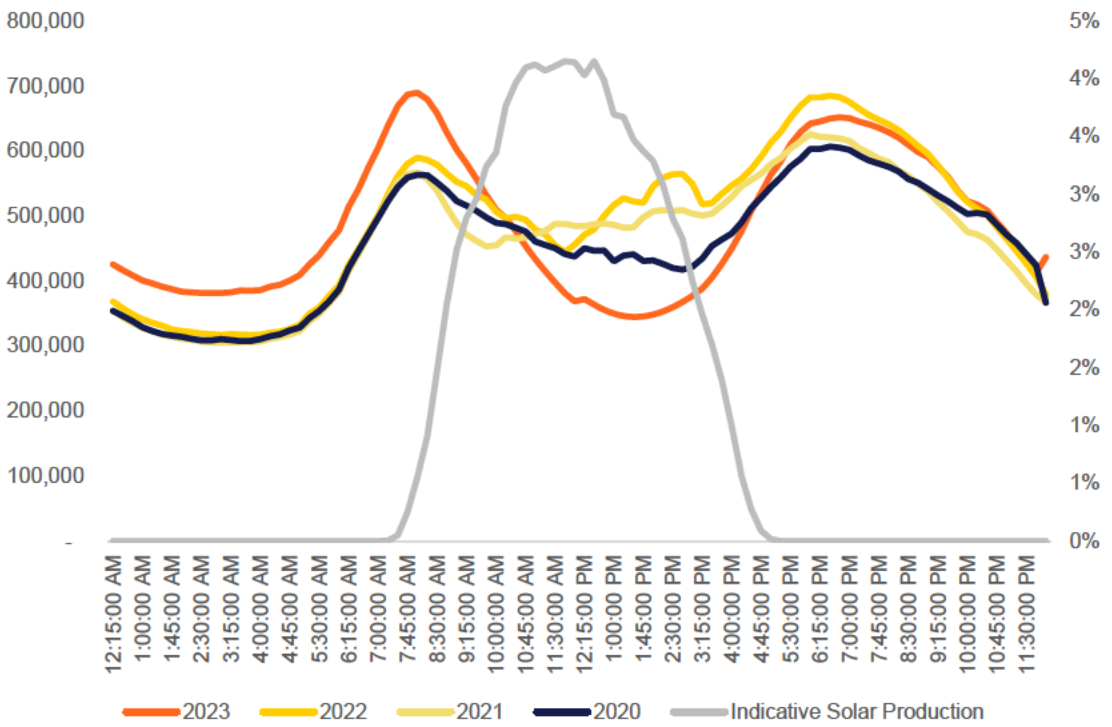
The third factor to consider is the impact of solar generation, which is driving changes in the load shape. As shown in Figure 10, in summer there is an overlap between the peak, which occurs between 4pm and 6pm, and the tail end of solar generation, which can still occur up to about 7pm. It is this overlap that is driving the small reductions in peak summer demand over time.

Figure 10 Summer peak demand days over the last four years MW and indicative summer solar production (%)



In contrast, as winter peaks occur in the morning and later in the evening, solar production cannot reduce winter demand, as shown in Figure 11 . This explains why we generally do not observe reductions in winter peak demand.

Figure 11 Winter peak demand days over the last four years (MW) and indicative winter solar production (%)



Overall, these factors indicate that if historic connections could be accounted for, the residual trend in winter peak demand would likely be no larger than one per cent and likely flat if not positive. However, if the recent impact of the electrification of gas were accounted for, it would likely be materially positive. As outlined in earlier, this would likely be in the order of 3.4 per cent a year over the period to 2028/29.[30]

Feeder forecasting method

The purpose of peak demand forecasts at this level is to produce a set of year-long annual load profiles for each feeder.

We apply a two-stage process where we produce load profiles derived only from forecast connections (these forecasts drive our non-EV demand program). The second stage is preparing an additional set of forecasts, which include EV demand (which in turn drives our EV demand program).

The first step is to extract the actual year-long load profile for each relevant feeder. The connection loads are derived from the validation, moderation, allocation, adjustment and process outlined in Appendix A and are then added to each feeder's load profile.

A second forecast is then produced to incorporate the impact of EVs. EV loads are derived from two outputs of our EV peak demand forecasting model:

1. The overall peak demand from EVs in each suburb is allocated to feeders based on the number of customers served in that suburb.
2. The EV load profile normalised to a 1 MW peak.

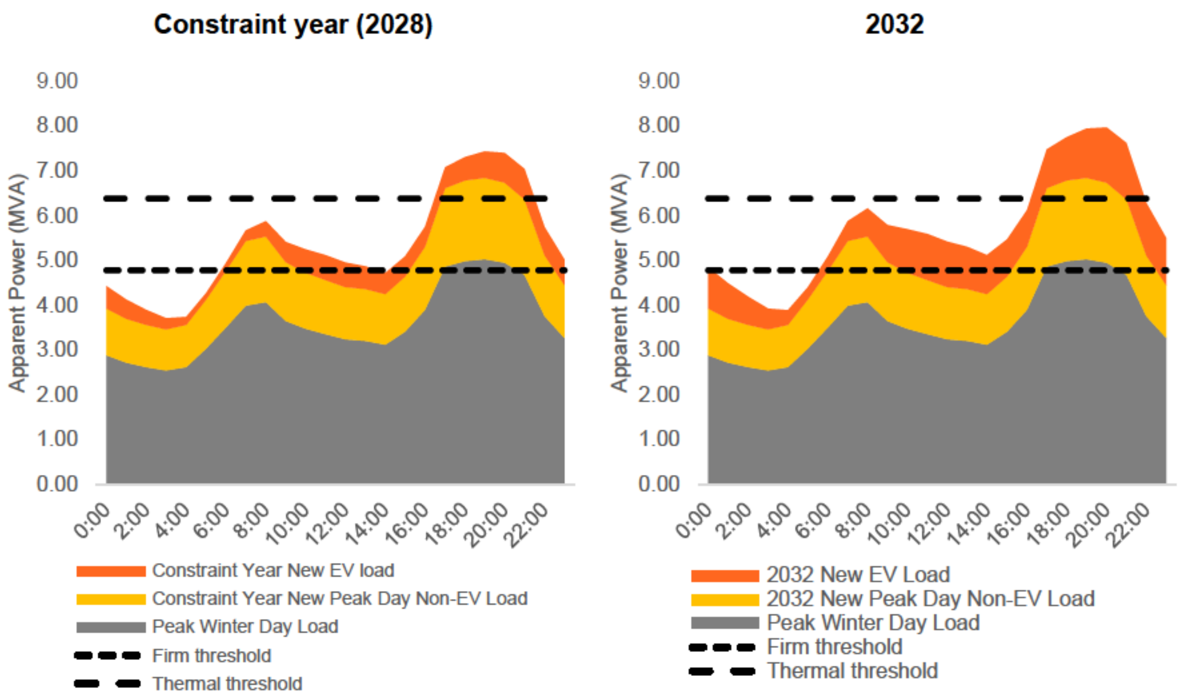
[30] Calculated based on the electrification component included in AEMO's peak demand forecast for NSW and Victoria which ramps up from 0.3% in 2024 to 6.9% in 2029.

Together, these two inputs are combined to produce a set of annual year-long EV peak demand profiles for each feeder.

An example is shown in Figure 12 for our Ijong feeder. The figure shows how the load from existing new connections and EVs are stacked. In this case, most of the shape is derived from the existing load profile, while the EV loads add load mostly in the day and the late evening (the overlap between the convenience and nighttime charging profiles).

The figure also shows how EV loads tip load over the edge of requiring investment and that EV loads will continue to grow into the future. What starts off relatively small grows quickly (largely due to the large numbers of EVs, which outweigh the reduction in peak demand per EV).

Figure 12 Ijong feeder load profile



A summary of the block load inclusion criteria at the feed level is captured in Table 6.

Table 6 Block load inclusion by forecast level

Load element	BAU feeder forecast	EV feeder forecast
Residential connection	✓	✓
Mixed/commercial connection	✓	✓
Industrial connection	✓	✓
Off-peak connection	✓	✓
Data centre connection	✓	✓
EV model	×	✓
Electrification of gas	×	×
Statistical trend	×	×

Key: ✓ Included, × Excluded, ◉ Inclusion by exception

3. Investment program development

Once the peak demand forecasts are prepared, a series of engineering analyses are undertaken to determine whether any investment is required, the timing of that investment, and how the program should be best delivered. This section sets out our overall approach.

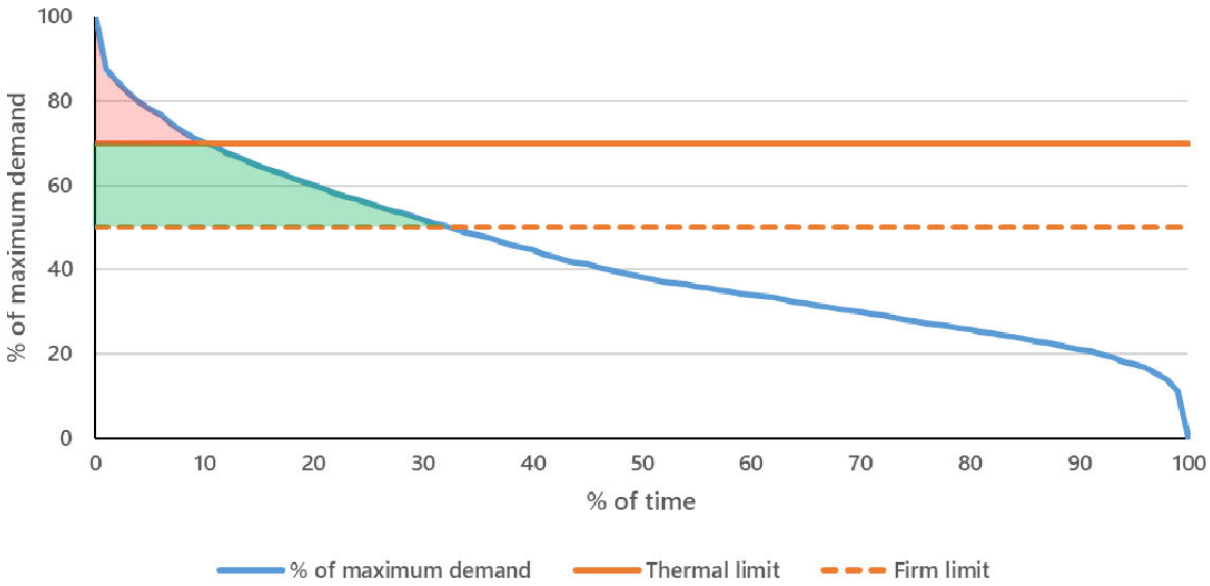
Project identification, timing and sensitivity analysis

Engineering analysis is undertaken on a constraint-by-constraint basis to identify all feasible options. This includes changing the network configuration (e.g. shifting load between feeders or between zone substations), non-network solutions (such as the use of batteries) and network solutions.

While a constraint-by-constraint approach is taken, a broader view of the network as a whole is maintained. This ensures that the feasible options take into account other projects which are planned to go ahead.

A probabilistic risk-based approach is applied to identify the preferred solution, including timing. This assessment is based on the probability and consequence of lost load. At the feeder level, load duration curves (as illustrated in Figure 13) are derived based on the forecast annual hourly load profiles together with the firm and thermal ratings of the relevant assets. These load duration curves are combined with the duration and consequence of a load event (which differs depending on the asset, its overall configuration in the network, redundancy, etc.) to determine a risk-adjusted based cost from the constraint.

Figure 13 Example load duration curves



The optimal timing is determined when the risk-based cost of the constraint exceeds the annualised investment cost. Sensitivity analysis is then conducted by altering key assessment inputs, as outlined in Figure 13, to identify the impact on the project timing.

Table 7 Feeder level sensitivity analysis

Scenario	Probability of failure	CAPEX	Value of customer reliability	Demand
Base Case	0%	0%	0%	0%
Minimise benefits relative to costs	-10%	10%	-10%	-5%
Maximise the benefits relative to costs	10%	-10%	10%	5%
Cost and benefits low	-10%	-10%	-10%	-5%
Cost and benefits high	10%	10%	10%	5%

Program review and deliverability

As discussed in Appendix F, there is increasing pressure on skilled workforces capable of delivering electricity infrastructure projects. There is also only a limited pool of capable suppliers who can deliver feeder projects in the ACT.

To manage price and deliverability risk we have adjusted the timing of projects to smooth the overall profile. This re-profiling has led to many projects being deferred. While we have aimed to ensure that projects are delivered within the timing range of the sensitivity analysis, in some cases, this has not been possible.

Table 8 shows the results of our program level adjustments. White rows are projects delivered consistent with the optimal timing identified by the probabilistic risk-based approach. Yellow cells indicate projects deferred but still anticipated to be delivered within the sensitivity range of the optimal timing. Orange cells represent projects that have been deferred beyond the sensitivity range.

Factoring in deliverability into our program results in another layer of conservatism in our overall augmentation forecast.

Table 8 Feeder timing optimal versus program

Feeder Projects	Optimal timing	Sensitivity Range	Program timing
Non-EV demand driven			
Feeder from Latham ZS to Strathnairn	2024	2024–2025	2026
Feeder from Civic ZS to City East	2025	2025–2026	2025
Feeder from East Lake ZS to Kingston	2027	2027–2028	2028

Feeder Projects	Optimal timing	Sensitivity Range	Program timing
Feeder from Civic ZS to CBD	2026	2026	2027
Feeder from East Lake ZS to Fyshwick	2025	2025	2026
Feeder from Civic ZS to Lyneham	2027	2026–2029	2027
Feeder from Woden ZS to Curtin	2028	2028	2029
Feeder from Wanniassa ZS to Woden Town Centre	2029	2028–2032*	2029
Feeder from East Lake ZS to Fairbairn	2025	2024–2025	2026
Feeder from Gilmore ZS to Hume West	2027	2027	2027
Feeder from Wanniassa ZS to Greenway	2028	2024–2032*	2029
Feeder from Civic ZS to Canberra	2026	2026	2029
Feeder from Gold Creek ZS to Gungahlin	2025	2025–2027	2027
Feeder from Telopea Park ZS to Barton	2025	2025	2026
EV Demand driven			
Feeder from City East ZS to Canberra CBD	2026	2026–2027	2026
Feeder from Gold Creek ZS to Franklin	2025	2025–2029	2027
Feeder from City East ZS to Braddon	2028	2027–2030	2029
Feeder from City East ZS to Watson	2029	2028–2029	2029
Feeder from City East ZS to Ainslie	2029	2028–2031	2029
Feeder from City East ZS to Campbell	2029	2027–2032*	2030

Note analysis window ends in 2032.

Mitchell and Curtain zone substations

Based on our current peak demand forecast, we will require new zone substations in Mitchell and Curtin by around the middle of the 2029-34 period. While we anticipate that we will incur the bulk of these costs in 2029-34, given the 3–5-year time frame to build a zone-substation, we will need to purchase land and begin project initiation (to prepare and submit a development approval, community engagement, environmental assessments etc.) These costs are required in the EN24 period to ensure that delays related to site acquisition and development approval do not in turn delay the construction of the zone-substations.

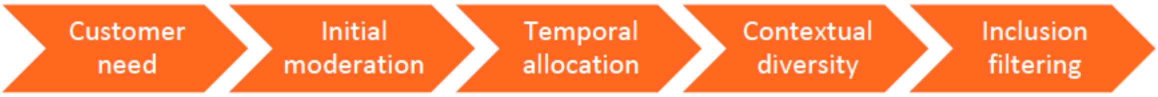
APPENDIX A – CONNECTION ADJUSTMENTS

Connections data is built from a combination of specific connection enquiries, applications, and government land release programs. Load elements are categorised according to their source and their expected demand profile. For non-EV demand adjustments, categories include:

- Residential;
- Mixed/commercial;
- Industrial;
- Off-peak; and
- Data centre.

The data collected then goes through a five stage transformation process, as outlined in the diagram below.

High-level block load transformation steps



Customer need

The first indicator that block loads may be required comes from some form of customer need statement. This can be directly from proponents in the form of enquiries or applications to Evoenergy or indirectly in the form of government land release program publications.

Statements of customer need typically provide a proponent's assessment of their power requirements in a particular location (inclusive of load components), required energisation timing, and, in some cases, indicators of project staging.

Initial moderation

Three key factors are considered in the initial moderation process:

1. Load component filtering. Where electric vehicle provisions are included within a customer's power requirement estimate, these are removed to avoid any double-counting against the EV model block load.
2. Internal demand validation. Proponents often overestimate their power requirements when submitting applications to Evoenergy. As a result, Evoenergy calculates an internal view of after diversity maximum demand (ADMD) for the provided load components. This tends to be lower than the value provided by proponents.
3. Probabilistic reduction. Projected demand from a project is multiplied by its probability of proceeding within the current regulatory period, determined using probability factors.

Probability factors

Probability factors are derived from measurable and objective project milestones that are representative of the level of commitment by a project developer and/or how certain it is that a load will connect during the regulatory period in question.

The probabilistic benchmarks are used as a proxy for the adjustment factors used in load forecasting. For example, if a load is associated with a 50 per cent probability, only 50 per cent of the forecast load will be applied in forecasting. For loads considered >80 per cent, the full load is applied in forecasting.

In instances where there are multiple loads or sources of loads in the regulatory period, the probabilities are averaged and rounded down to the nearest category.

Table 9 Probabilistic Determination Criteria

Probability of Proceeding (during 2024–29)		Project milestones					
		Initial Network Inquiry	Preliminary Network Advice	DA Approval	Application for network connection	Connection Agreement/ payment?	Commenced construction
Almost certain	~99%	✓	✓	✓	✓	✓	✓
Very high	>90%	✓	✓	✓	✓	✓	×
High	>75%	✓	✓	✓	×	×	×
Medium	>50%	✓	✓	×	×	×	×
Low	>25%	✓	×	×	×	×	×

Of course, it is not possible to obtain 100 per cent certainty that a development will proceed, or a load will connect during the regulatory period. Therefore, we have set the highest probability category at ~99 per cent.

Temporal allocation

Loads are often energised at a lower level of demand than their eventual need (particularly in the case of large developments). To account for this, where relevant, loads are assigned a ramp profile that distributes peak demand impacts of this eventual load over multiple years. This helps to avoid over-estimation of peak demand impacts in the initial energisation year.

Contextual diversity application

Each of the loads retains a generic ADMD value from the initial moderation step. Depending on the characteristics of the load and the characteristics of the network element (feeder or zone substation), further diversity may be appropriate.

Summer and winter additional diversity factors, corresponding to a block load of a given category being added to a feeder or a zone substation of a given category, are captured in Table 10. Note that the photovoltaic zone / feeder profile is rare in practice.

Table 10 Summer and winter diversity factors

Block profile	Zone / feeder profile				
	Data Centre (DAT), ☀,❄	Residential (DOM) ☀,❄	Industrial (IND) ☀,❄	Mixed / commercial (MIXCOM) ☀,❄	Photovoltaic (PV) ☀,❄
Data Centre	1.0,1.0	1.0,1.0	1.0,1.0	1.0,1.0	1.0,1.0
Residential	1.0,1.0	1.0,1.0	0.5,0.8	1.0,1.0	1.0,1.0
Industrial	1.0,1.0	0.5,0.8	1.0,1.0	1.0,0.9	1.0,1.0
Mixed / Commercial	1.0,1.0	0.8,1.0	1.0,0.9	1.0,1.0	1.0,1.0
Off Peak	1.0,1.0	0.6,0.8	0.5,0.4	0.6,0.6	1.0,1.0
EV	1.0,1.0	1.0,1.0	1.0,1.0	1.0,1.0	1.0,1.0

Key: ☀ Summer diversity, ❄ Winter diversity

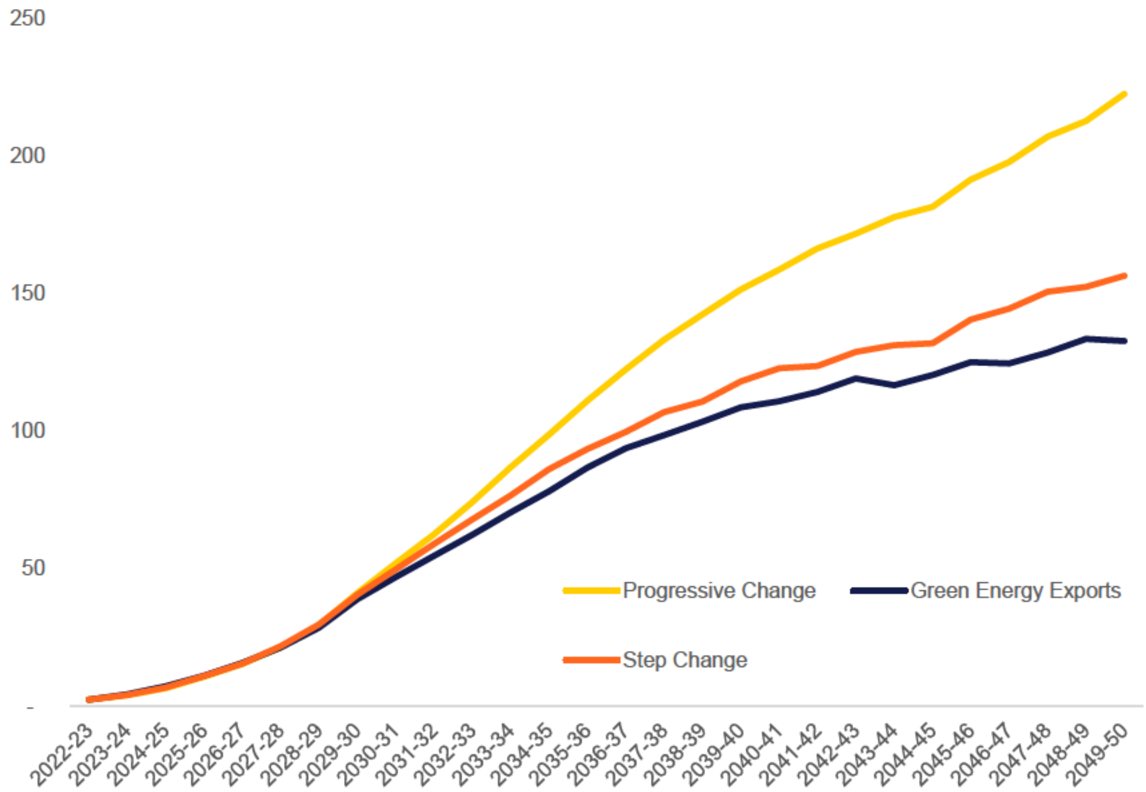
APPENDIX B – ELECTRIC VEHICLE PEAK DEMAND FORECASTING MODEL

As forecasting the impact of EVs on peak demand is challenging,[31] we have aimed to adopt a simple and flexible methodology where we rely on independent third-party data and update our forecasts as new information comes to light. Consistent with this approach, we provided the AER with an update in April 2023. It was this forecast the AER relied on in forming its draft decision.

The AER indicated that it is generally comfortable with the forecasting methodology[32] and identified several potential improvements. These include increasing the level of sophistication to account for various hourly load profiles, updating the forecast to reflect the latest inputs (including the latest data from AEMO / CSIRO), and to provide greater transparency around underlying assumptions. We appreciate the AER's feedback and adopted each of the suggestions made. This document, along with the redeveloped models, aims to provide the requested transparency.

Figure 14 sets out the high-level results of peak EV demand across all zone substations by AEMO scenario.[33] The results show that in all scenarios, EVs will drive a material increase in peak demand over the next 25 years.

Figure 14 Forecast Peak EV Demand by AEMO Scenario



[31] Due to the need to rely on economic projections and trial data (rather than actual observations), the high-level of uncertainty around almost all aspects of EV charging and the sheer scale of the additional load.
[32] AER 2023, *Draft Decision Evoenergy Electricity Distribution Determination 2024 to 2029, Attachment 5 Capital Expenditure*, p.15. Available here
[33] In practice the results are calculated and applied at both the zone substation and suburb level rather than the total level to reflect nuances such as location differences around the timing of each peak.

Differences between scenarios are driven by CSIRO assumptions on EV charging behaviours. Specifically, assumptions around the extent to which customers access cost-reflect tariffs and the take up of dynamic system-controlled charging post 2030.

We have based our revised proposal on the Step Change scenario (AEMO's central scenario). We note that AEMO convened a Delphi Panel of expert stakeholders to collect and test their view of the relative likelihood of each scenario.[34] These likelihoods inform the 2024 Integrated System Plan's Draft Optimal Development Path.

The outcome of the Dephi process was that Step Change, Progressive Change and Green Energy Export scenarios were given probabilities of 43 per cent, 42 per cent and 15 per cent, respectively. Together, the results presented in Figure 14 indicates that in the long term, there is a 42 per cent chance EV peak demand is significantly higher than we are forecast and only a 15 per cent chance that EV peak demand is slightly below our forecast.

Available data sources

Our EV block load forecasting approach is designed to take advantage of the most recent and robust data available. Ahead of preparing our revised forecasting approach, we reviewed the available forecasts, trial data and EV trial reports. The most relevant and appropriate data sources are summarised in Table 11.

Table 11 Assessment of relevant data sources

Data source	Findings
[redacted]	[redacted]
Deloitte Access Economics' (DAE) Zero Emission Vehicle Charge Rollout Report[35] October 2021 Commissioned by the ACT Government	• Best available geographic split of residential EV update split by Statistical Area 2 (SA2). • Forecast provided on an annual basis. • Does not include motorcycles, commercial vehicles or trucks. • Forecast out of date (actual EV take up now higher than forecast).
ACT Government registration data	• Current numbers of EVs registered in the ACT. • Does not include the ~15,000 commonwealth vehicles[36] , of which 75% will either be either battery EV, hydrogen fuel cell vehicle (FCEV) or plug-in hybrid by 2025.[37]
CSIRO EV forecasts	• Provides a forecast of EVs by type (small, large, medium, residential, motorcycles, commercials, trucks, buses, etc.)

[34] AEMO 2023, *2023 ISP Delphi Panel*, Available here
[35] Available here
[36] See here
[37] Australian Government 2023, *National Electric Vehicle Strategy, Improving the update of EVs to reduce emissions and improve the wellbeing of Australians*, p.vi. Available here

Data source	Findings
Developed as part of AEMO's 2023 Input, Assumptions and Scenario process	• Presents average January 2040 charging profiles (not peak day charging profiles). • A series of profiles presented for each vehicle type (convenience, daytime, highway, night-time). • Provides an annual split of charging profiles over time. • Incorporates the ongoing roll-out of cost-reflective tariffs and take up of dynamic charging profiles (coordinated charging, etc.). • Profiles splits vary by AEMO scenario. • Forecast not ACT specific.
Evoenergy billing data	• Identifies the location of customers by suburb.
Ergon/Energex's SmartCharge tariff trial	• Identifies EV charging on peak and non-peak days.

The results of other trials and studies were reviewed and evaluated but not included due to data limitations, availability, sample size or better alternative data sources. This is typical as each trial or study has a specific objective that differs from our goal of forecasting EV loads in the ACT.

An example is Origin Energy's recent trial[38] to collect insights on the effectiveness of smart charging to optimise EV charging. This study was made up of a highly engaged cohort,[39] with a smart charger and access to a smart charging platform. These factors increase the responsiveness of these trial participants. The use of a smart charge also increases peak energy usage (which has a higher capacity than a wall socket).

The trial also provided participants with significant incentives: 10 cents/kWh for charging outside of peak times or a 25 cents/day reward for allowing Origin to curtail charging. These incentives are large. The distribution component of our residential basic tariff, for instance, is 4.1333 cents/kWh and 27.81 cents/day.[40]

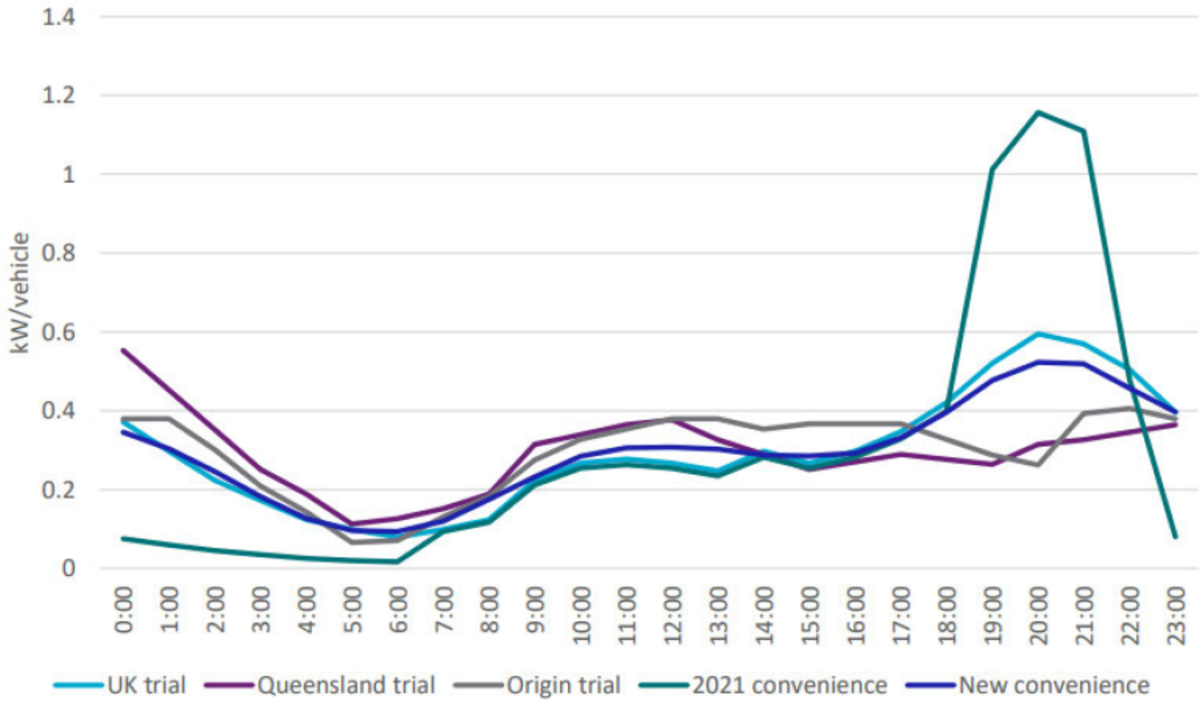
As a result, the study outcomes are not directly applicable to our customers. However, we do use this data indirectly, as the insights and learnings from this trial (along with the results of others) were integrated into the CSIRO's updated charging profiles.

Assumptions on the use of wall chargers

One of the most important insights from the Origin trial was not around the charging profiles or customer responsiveness to price signals but the finding that prior to joining the trial, most participants were using a standard power socket (with peak energy usage of up to 2.4kW) rather than a wall charger (typical capacity of 7.2kW). This insight is what drove the significant reduction in CSIRO charging profiles between its 2021 profiles (on which we based our initial forecast) and its most recent 2022 profiles,[41] as can be seen in Figure 15.

[38] See here
[39] See page 8 here
[40] Our time of use network tariff distribution charges are 27.81 cents/day plus 8.282, 2.819 and 1.381 cents/kWh for energy in peak, shoulder and off-peak times.
[41] CSIRO 2022, *Electric vehicle projections 2022,* Commissioned for AEMO's draft 2023 Input, Assumptions and Scenarios Report, p. 46 See here

Figure 15 Change in the CSIRO convenience charging profile



However, as shown in Table 12, our recent survey of our customers indicates that twice as many people in the ACT are using wall charges relative to the Origin Energy trial participants. Further, one-third of customers with a wall charger report using a three-phase charger with capacity up to 22kW (rather than the standard 7kW). This data indicates that the CSIRO profiles are likely to understate the peak power usage of an EV user in the ACT. We do not make any adjustments to account for this.

Table 12 Proportion of customers using a wall charger

	Origin Energy Smart Charging Trial (150 participants)	Evoenergy Customer Survey (65 customers)
Public / work charger	5%	15%
Wall charger	23%	42%
Standard power socket / 15A socket	71%	43%

Approach

The EV peak demand forecast is comprised of three elements:

- annual weighted average load profiles for residential vehicles, commercial vehicles and trucks;
- forecast of residential vehicles, commercial vehicles and trucks by location; and
- a winter peak adjustment factor.

This data is combined to produce an hourly EV peak load profile – for each zone substation and each suburb (for use in the feeder peak demand forecast).

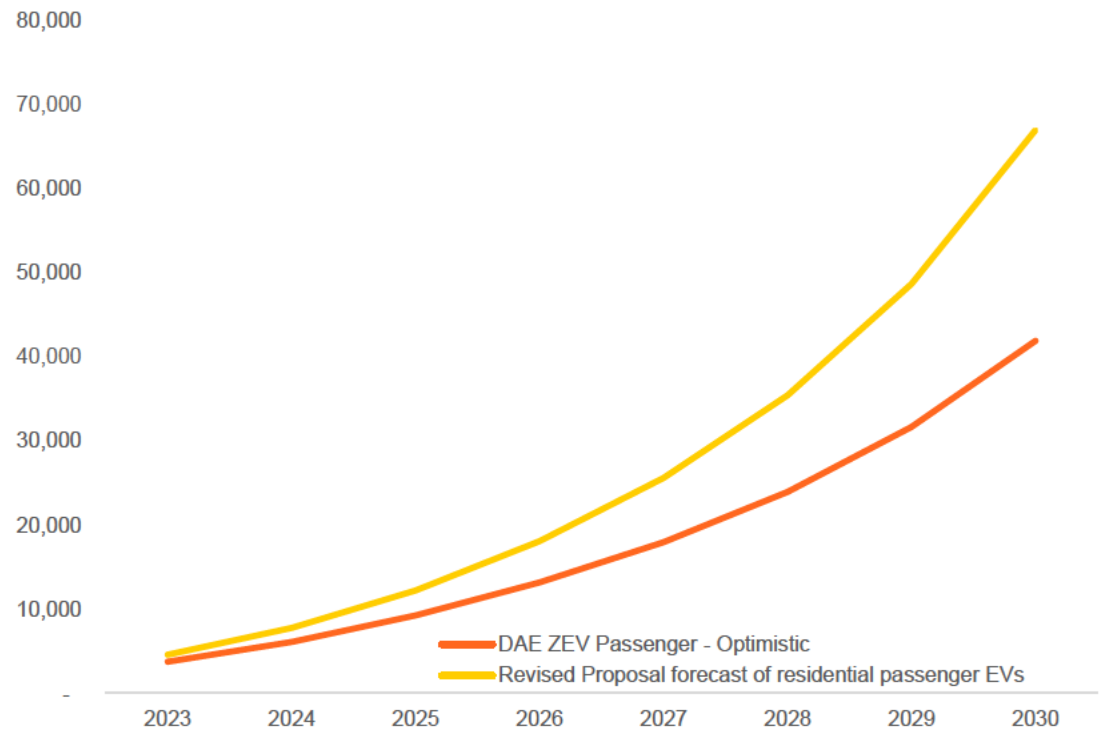
Forecasting EVs

We use the [redacted], only includes passenger EVs and has no geographic granularity, we make the following adjustments:

- We use the EV uptake profile generated by DAE to produce an annual forecast of EVs.
- We allocate residential EVs to SA2 regions using data from the DAE report.
- We estimate the number of motorcycles, trucks and commercial vehicles using the ratio of residential passenger vehicles from the CSIRO forecast. This approach ensures consistency with the weighted average load profiles.[42]
- We allocate commercial vehicles and trucks to suburbs based on the split of commercial and industrial customers in our billing system.

The result of these adjustments is a forecast of residential vehicles, commercial vehicles and trucks by geographic location.

Figure 16 Initial and revised residential passenger EV forecast



[42] This means that if changes are made to these ratios, changes would also be required to the weighted average load profiles. For instance, if the number of motorcycles were reduced, then the number of motorcycles used to create the weighted average load profile would similarly need to be reduced otherwise the weighted average load profiles would not be consistent with the forecast mix of vehicles.

Annual weighted average load profiles

Weighted average load profiles are produced by combining CSIRO projections of the 2040 weekday load profiles together with the proportion of vehicles on each profile. The data used for medium residential vehicles is shown in Figure 17. Note the falling proportion of vehicles on a convenience profile (due to the impact of cost-reflective tariffs) as well as the relatively small uptake of controlled charging until the 2030s.

Figure 17 CSIRO projections for a medium residential vehicle (Step Change Scenario)

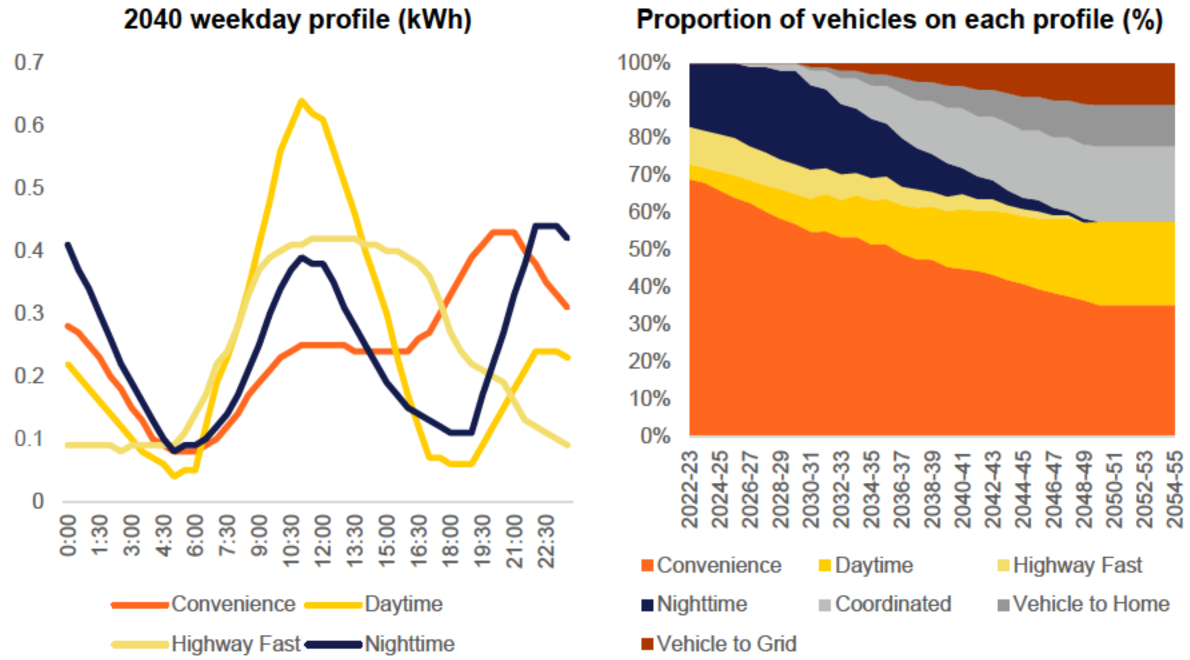
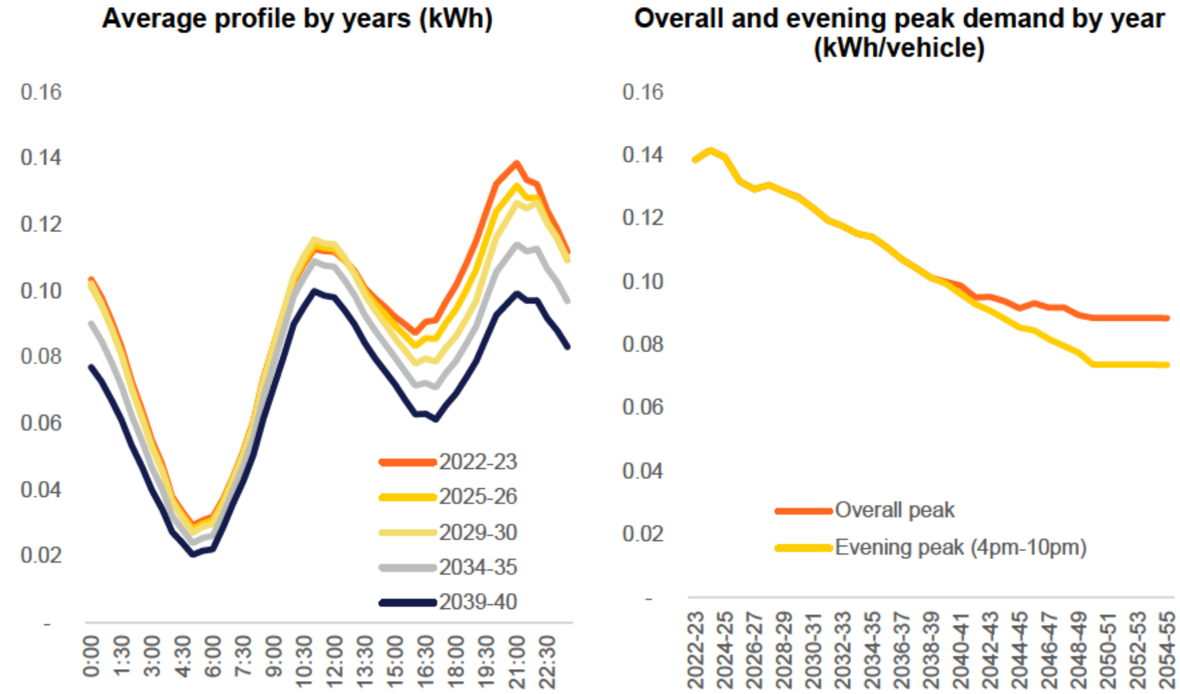


Figure 18 shows the average load profile by year produced for a medium residential vehicle when the 2040 profile along with the proportions of vehicles on each profile is combined. The graphs show the evening peak reducing over time such that by 2040, the daytime peak is higher than the evening peak. Over time, the peak load also falls. This is because the load from dynamic profiles (where a retailer or aggregative controls charging) is assumed to be zero at peak times.[43]

[43] This is a conservative assumption given that studies from AGL and Origin have both found that even with controlled charging EV charging is non-zero at peak times. See page 20 here and page 19 here

Figure 18 Average profile and peak demand for a medium residential vehicle (Step Change Scenario)

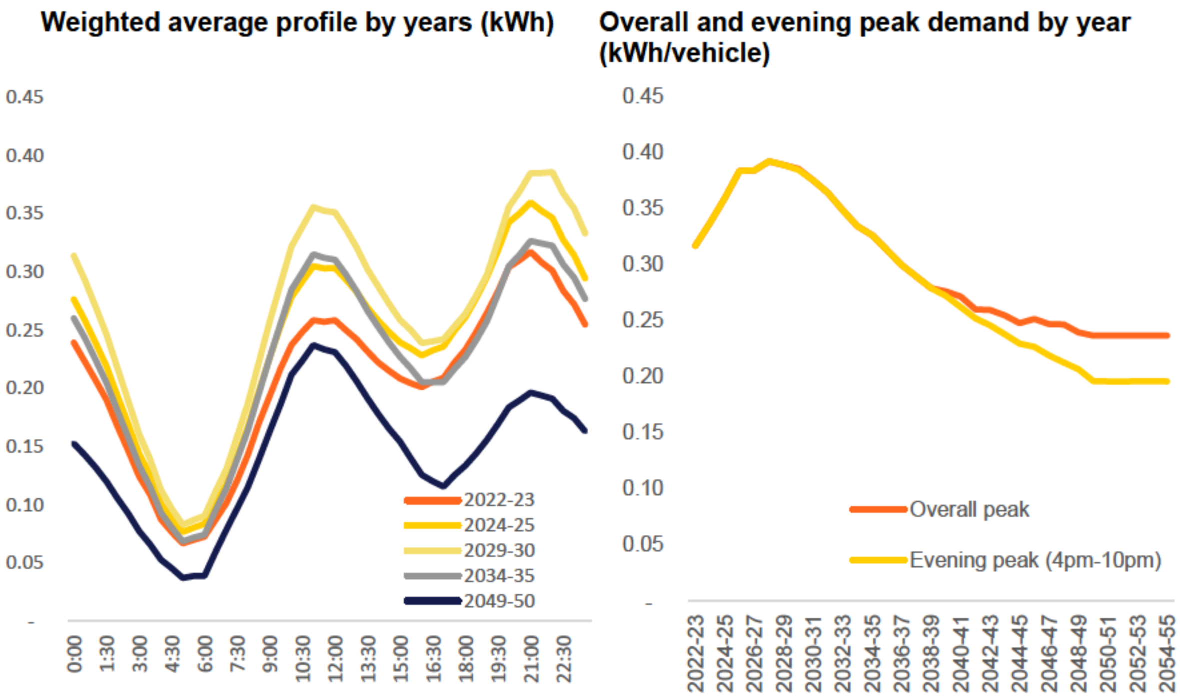


Average load profiles for each vehicle type are then combined to produce three profiles for:

- residential vehicles – made up of a weighted average of Large Residential, Medium Residential, Motorcycle and Small Residential vehicles.
- commercial vehicles – made up of a weighted average of Large Light Commercial, Medium Light Commercial and Small Light Commercial vehicles.
- Trucks – made up of a weighted average of articulated trucks and rigid trucks.

The weighted average load profile for residential vehicles is shown in Figure 19.

Figure 19 Residential weighted average load profile and peak demand (Step Change Scenario)



Peak demand on a per vehicle basis increases over the 2022/23 to 2029/30 period due to the projected take up of larger vehicles (shown below in Figure 20). This is because the impact of cost-reflective tariffs in reducing EV peak demand is more than offset by the increase in peak demand from larger EVs.

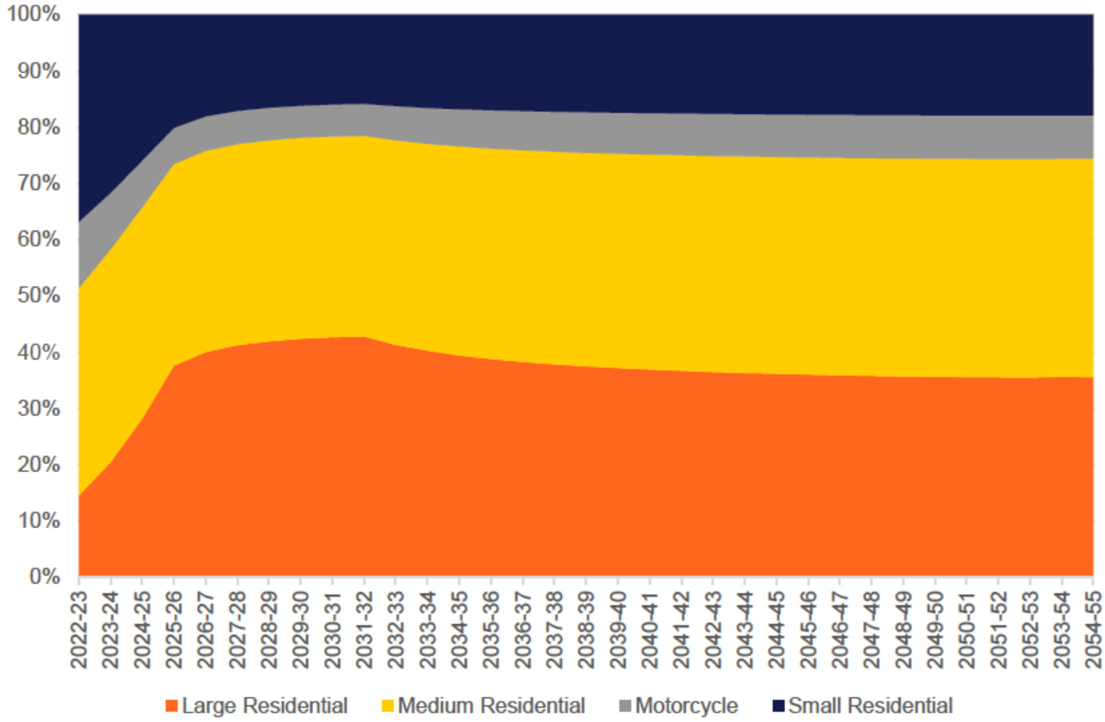
Notably, the peak demand per EV forecast of around 0.34kWh/vehicle is much lower than what was observed in recent trials. For instance, while the diversified average evening peak in the Energex/Ergon trial was just below 0.4 kWh/vehicle, it reached almost 0.6kWh during the day and after midnight.[44]

As the CSIRO produces data for each of AEMO's forecast scenarios (progressive change, step change and green energy exports) weighted average profiles are produced for each scenario.

The CSIRO also prepares different load profile assumptions for different jurisdictions. However, as there are no material differences, profiles are based on data for NSW.

[44] Ergon & Energex 2023, *EV SmartCharge Queensland Insights Report*, Figure 1. Available here

Figure 20 Make up of residential EVs over time



Winter peak adjustment factor

The CSIRO charging profiles represent the average profile on a weekday in January 2040. However, we are forecasting peak demand (rather than average monthly demand) on a winter peaking network.

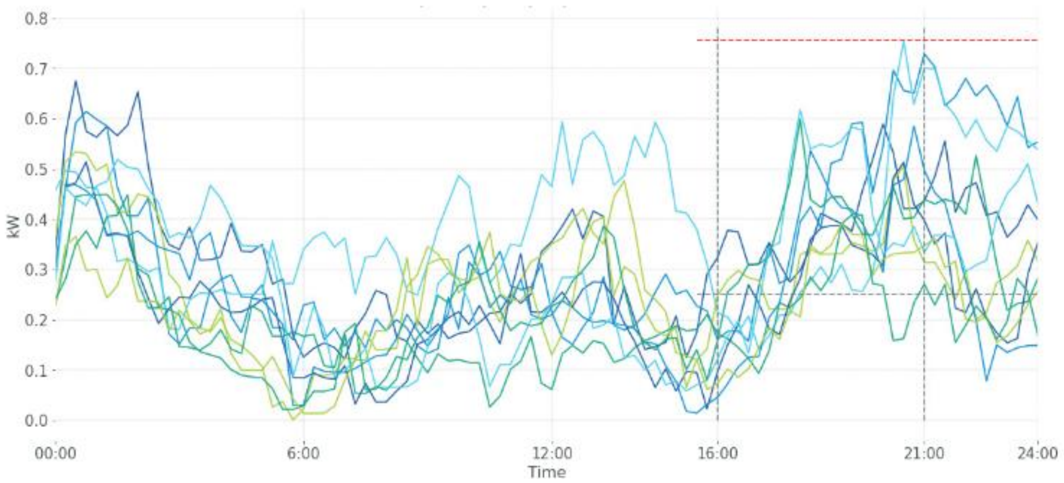
The Electric Nation trial in the United Kingdom found that winter has a triple effect on EVs with the use of heating, cold weather reducing the efficiency of batteries, and greater use of demisters and headlights.[45] This resulted in higher charging frequencies in winter. Given the increasingly broad nature of our peak demand (with weekly peak demand events in June and July) and that weather is likely to drive both increased EV charging together with home heating usage, it is highly likely that a peak demand event will coincide with a peak EV charging day.

The Energex/Ergon EV SmartCharge trial found that on the top 10 charging days, the diversified load reached 0.75kW per vehicle in the evening[46] – which is 25 per cent higher than the daytime diversified peak of 0.6kW per vehicle and 87.5 per cent higher than the evening diversified peak of load of 0.4 kW per vehicle.[47]

We have made an adjustment of 25 per cent to convert CSIRO's January average profile to a peak winter profile, based on difference between the peak demand on a peak day and the daytime peak, observed in the Energex/Ergon trial. We made no adjustments to commercial vehicles or truck profiles. We consider this adjustment conservative as the diversified load that we are forecasting is significantly lower than observed by Ergon and Energex (0.35kW/vehicle relative to 0.6kW).

[45] Electric Nation 2019, *Powered Up, Charging EVs without stressing the electricity* network, p.18. See here
[46] Ergon & Energex 2023, *EV SmartCharge Queensland Insights Report,* Figure 20. Available here
[47] Ergon & Energex 2023, *EV SmartCharge Queensland Insights Report,* Figure 1. Available here

Figure 21 Diversified average and peak demand profiles in the top 10 demand days from the Energex/Ergon EV SmartCharge trial



APPENDIX C – TOP DOWN TESTING OF SYSTEM PEAK DEMAND FORECAST

Figure 22 Comparison against AEMO's Electricity Statement of Opportunities (POE 50, System, Winter)

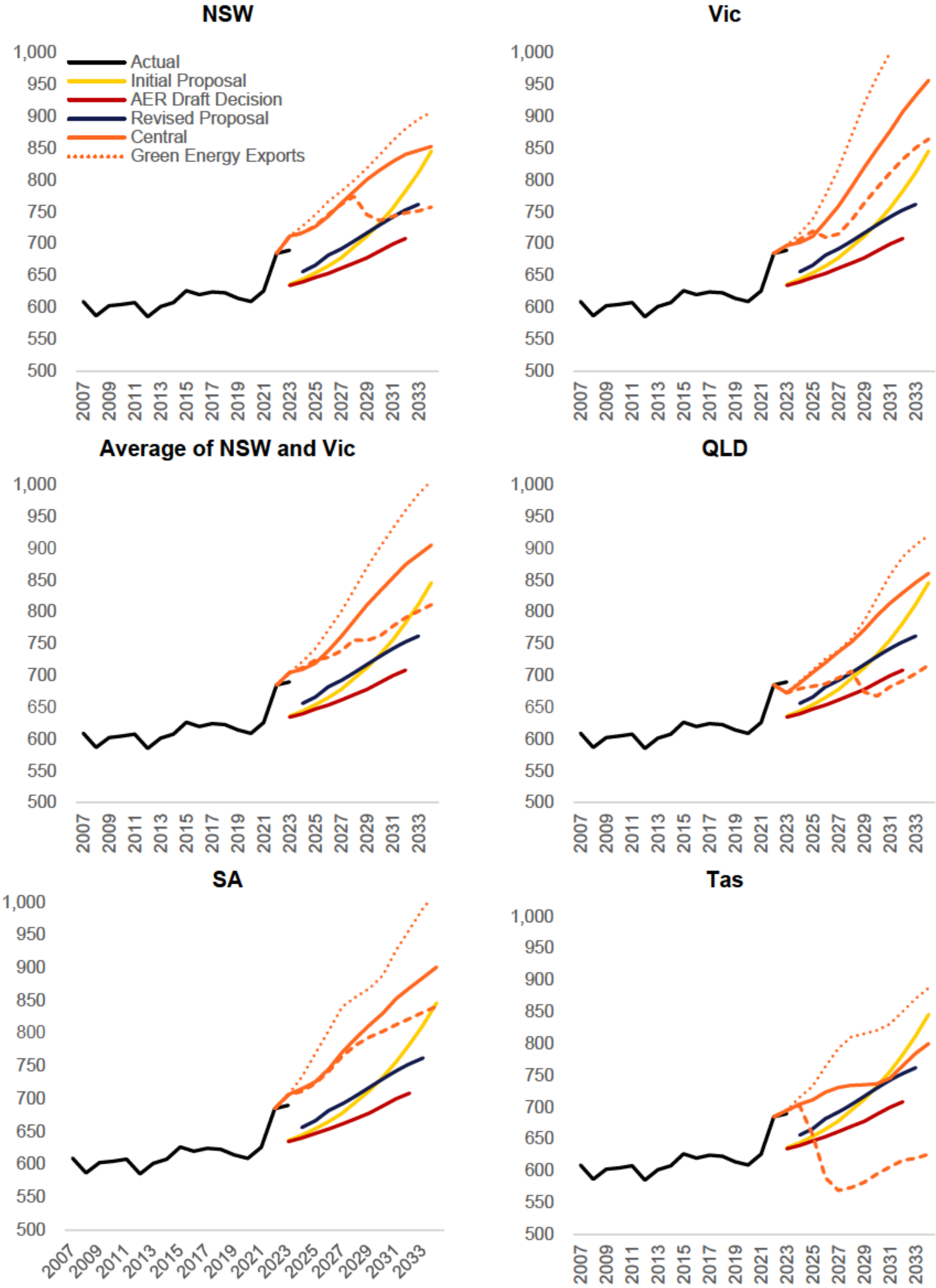


Figure 23 Comparison against [redacted] (POE 50, System, Winter)

[redacted]

APPENDIX D – ADOPTION OF AER DRAFT DECISION FEEDBACK

Table 13 How the AER's feedback has been addressed

AER Request	Addressed
We require Evoenergy to refine the forecasting approach and the modelling inputs to address our concerns in its revised proposal.	✓ Accepted, further detail on each suggestion outlined below.
Additionally, Evoenergy should better address the gas transition as part of its move to electrification and explain how this has been considered in its revised proposal.	✓ Accepted, see Section 2
Since the regulatory proposal was submitted on 31 January 2023, new information has become available that impacts on the demand forecast and will need to be taken into consideration. This includes the CSIRO's 2022 electric vehicle projections on the EV charging profile and the ACT Government's updated EV forecast. As the information continues to develop, we require Evoenergy to update its forecast to reflect the latest available data where appropriate and refine its model input and forecasting approach for the revised proposal.	✓ Accepted, see Appendix B.
Historical Trend	
..we require Evoenergy in its revised proposal to either make the appropriate historical block loads adjustments, or adequately explain why the adjustment is not necessary.	– As we do not have the data to make adjustments for historic block loads, we have instead adjusted our forecasting methodology to ensure no duplication, see section 2.
EV related demand forecast	
..we expect the EV block load forecasts would be updated based on more up to date EV charging profile assumptions.	✓ Accepted, see Appendix B.
.. we consider there are still a number of improvements Evoenergy should address in its revised proposal: • for the zone substation peak demand, Evoenergy should take a more sophisticated assumption than winter evening peak for EV block loads to	✓ Accepted, see Appendix B.

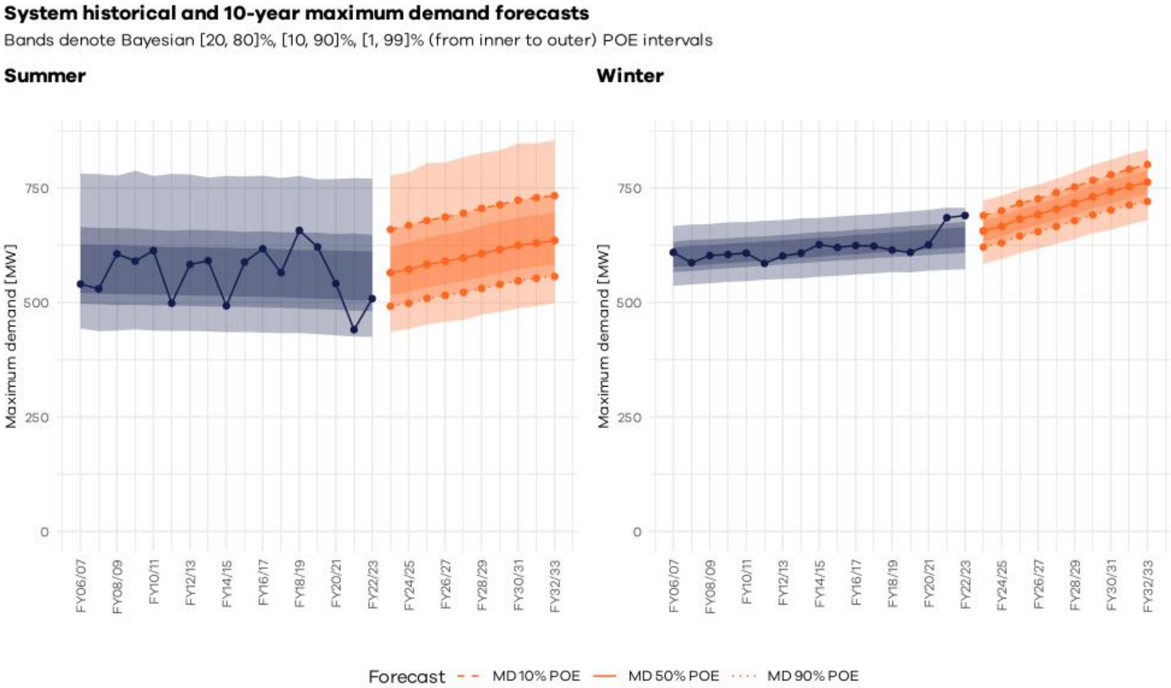
AER Request	Addressed
properly account for the various hourly load profiles for EV charging across zone substations, which may have different peak times • Evoenergy should continue to update its forecasts to reflect the latest inputs from AEMO • provide greater transparency around the underlying assumptions applied for EV demand forecasts to inform the demand forecasting and augmentation capital expenditure assessment • further revise the assumption on EV uptake (based on the updated ACT Government forecast) and charging profile on an energy per vehicle basis and zone substation peaking time.	
Non-EV demand	
Evoenergy should refine its approach with the following considerations: • block loads above the trend should be removed from the historical period and added to the forecast period to prevent duplications that have been captured within the trend component of the demand forecasts. This is to ensure only the demand impact driven by factors such as population, economic growth, energy prices, demand management, CER and energy efficiencies is carried to the forecast period as part of the trend projection	– As we do not have the data to make adjustments for historic block loads, we have instead adjusted our forecasting methodology to ensure no duplication. See section 2 for more detail.
• Adjustments for block loads above the long trend should be observed for any trend estimated, regardless of whether the trend is estimated to be positive or negative. This is because the trend can result from an offset between the increasing demand from population and economic growth and the decline in the historical period due to other long-term demand drivers (for example, rising electricity prices, demand management,	✓ Accepted, see consideration in section 2.

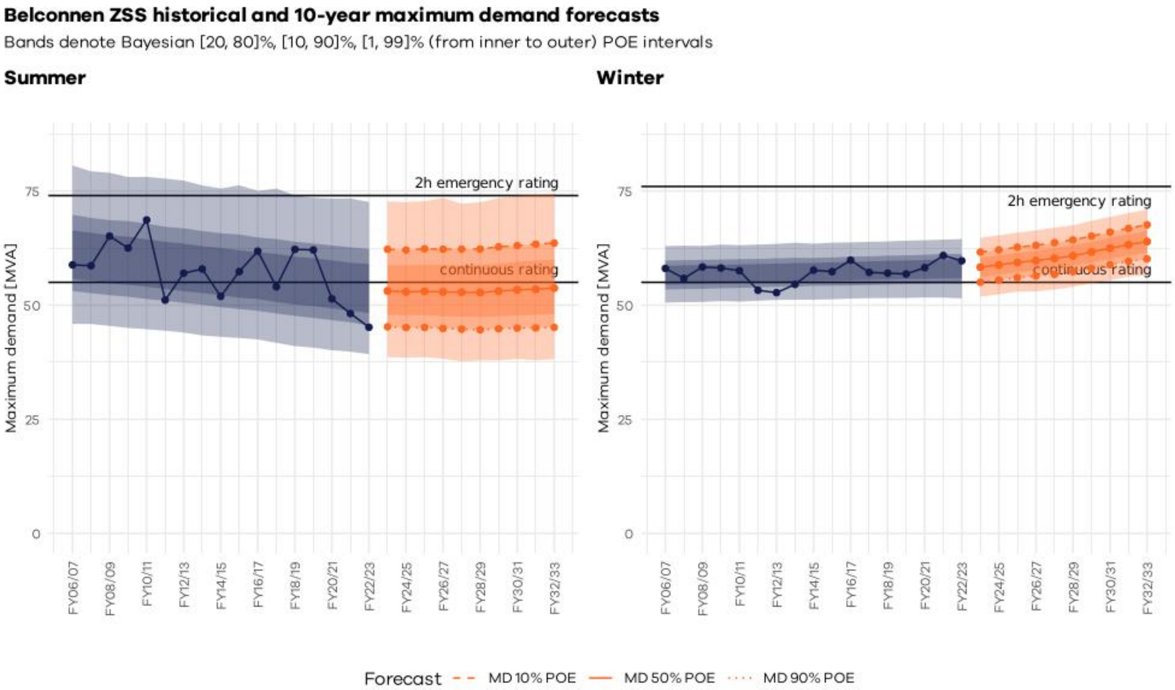
AER Request	Addressed
photovoltaic systems, battery storage and greater energy efficiencies).	
• Fundamentally, it is population and economic growth that drives up electricity consumption and demand in the longer term. Evoenergy should take into account its historical understanding of the drivers affecting electricity demand to ensure the residential and commercial block loads only reflect the forecast above the trend	✓ Accepted, see consideration in section 2.2.
• Evoenergy included a threshold of 0.5 MVA to identify large residential, commercial, or mixed developments so that these large projects can be added to the block load forecast. However, this threshold is not consistently applied to prevent double counting in the baseline trend. Further, we require Evoenergy to provide its rationale for selecting 0.5 MVA as the threshold.	✓ Accepted, we removed this threshold in favour of a new load inclusion methodology as outlined in section 2.2.
Conclusion	
.. Evoenergy should address the following matters in its revised proposal: • further consideration of individual demand drivers such as population and economic growth, price changes, demand management including time-of-use tariffs, and technological changes like energy efficiency, consumer energy resources, and their demand impact.	✓ Accepted, explored in section 2.
• the methodology for forecasting non-EV peak load needs to be more comprehensive, with a clear and detailed outline of the method used. Deviations from this methodology should be thoroughly explained and justified. This extends not only to individual projects but also for different load types, the project probability used, and the application of seasonal factors	✓ Accepted, see section 2 and Appendix A.
• the consideration of a consistent time period for its historical data to model the demand at the system wide level and	The time periods for most zone substations commenced in 2007. Data for the East Lake Zone substation started when it was

AER Request	Addressed
zone substations, and an explanation of the rationale for the chosen periods	commissioned in 2013. Data for other zone substations commenced in 2008 (City East, Civic, Gilmore), while data for Fyshwick and Telopea Park commenced in 2015 and 2013, respectively. These adjustments were made historically and would likely have been the result of data checks to remove or repair erroneous data at the zone substation level. We have made no changes to this data or the selection of years used other than to add additional years of observations. We now have 10 years of data for Telopea Park, we are decommissioning Fyshwick, and have 15/16 years of data for most other zone substations. Given the materiality of the other adjustments and the limited time to refine our demand forecast, we have not prioritised a review of our historical data to see if it can or should be included. We consider that the inclusion of this data is unlikely to have a material impact on our forecast, particularly as the system level forecast does not drive any specific augmentation project. We also note that consumer use of electricity has changed fundamentally over the last 16 years (uptake of air-conditioners, roll-out of solar, batteries, energy efficiency, etc) and is likely to continue to change. In reviewing our forecasting approach for the future, we will consider whether to start dropping data out, whether to use older data available, or whether to introduce additional demand drivers to account for these changes.
• provide further explanations on assumptions applied to take account of the impact from gas to electricity conversions and time-of-use tariffs	✓ Accepted. The impact of the electrification of gas has not been fully integrated into the forecast, see section 2. The impact of time-of-use tariffs (together with all other factors) on the baseline trend is set out in section 2. The forecast impact of cost-reflective tariffs on EV peak demand is implicitly included through the application of the CSIRO's load profiles, see Appendix B for more detail.

AER Request	Addressed
• provide further clarification on how the method is applied using the sample data and supporting evidence, along with summary information to estimating the maximum demand for projects as well as for different types of load	✓ Accepted, see Appendix A.
• provide a clearer rationale for the selection of specific input parameters, especially in cases where discrepancies or variations in inputs have been introduced.	✓ Accepted, we have provided an outline of our forecasting approach and the key parameters used in section 2 and Appendix A.

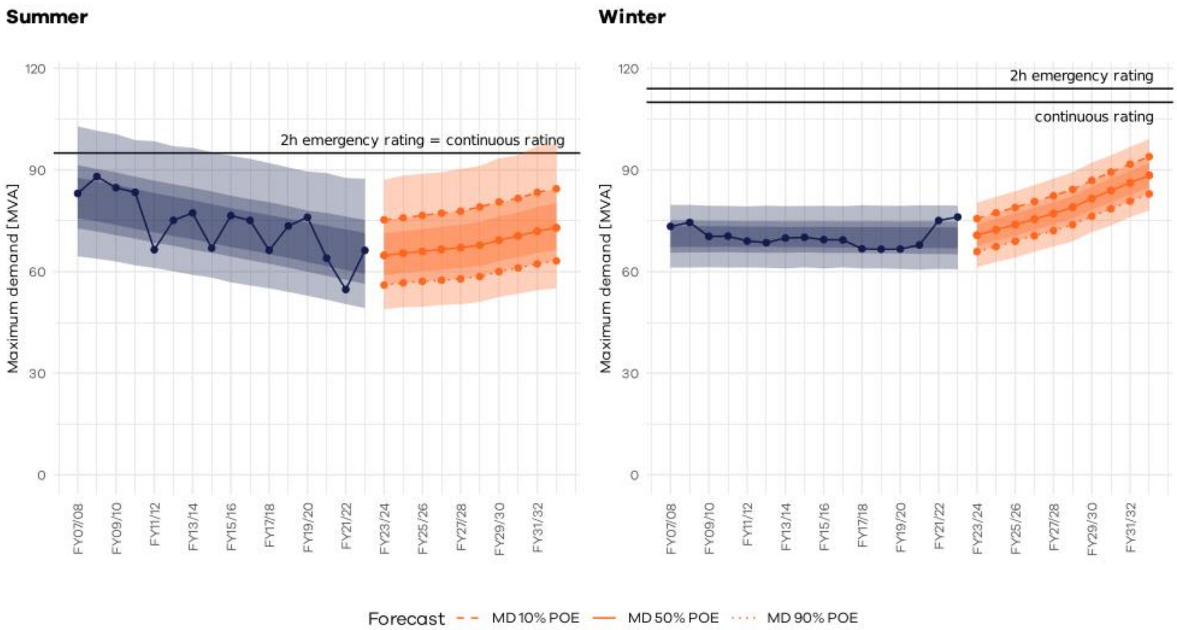
APPENDIX E – ZONE SUBSTATION PEAK DEMAND FORECASTS





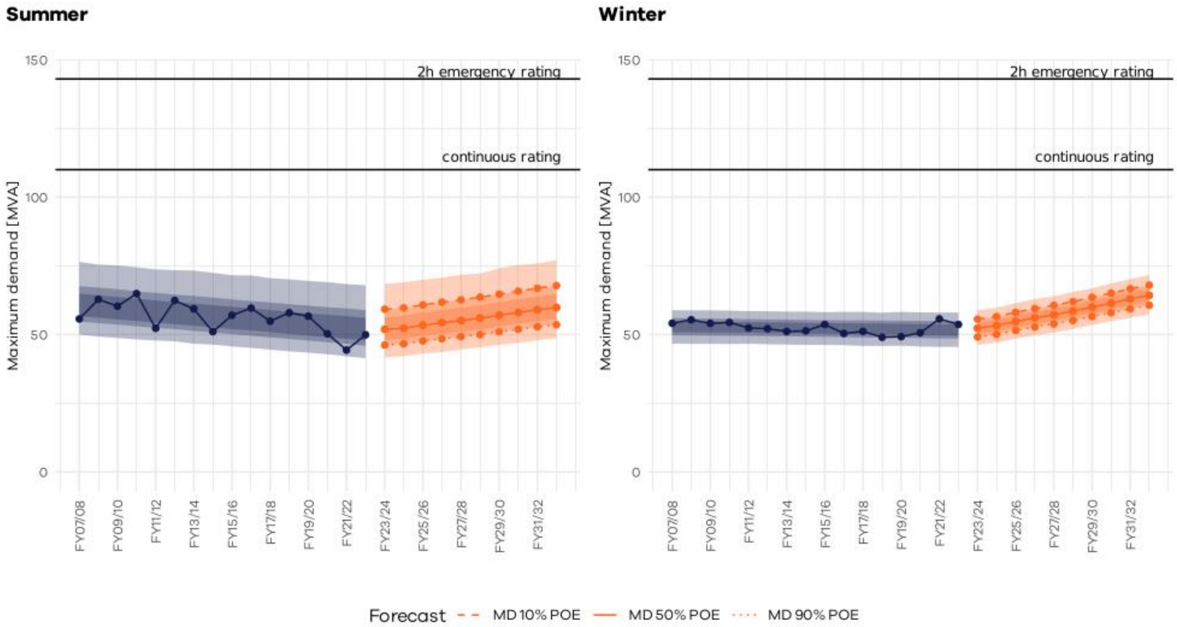
City East ZSS historical and 10-year maximum demand forecasts

Bands denote Bayesian [20, 80]%, [10, 90]%, [1, 99]% (from inner to outer) POE intervals



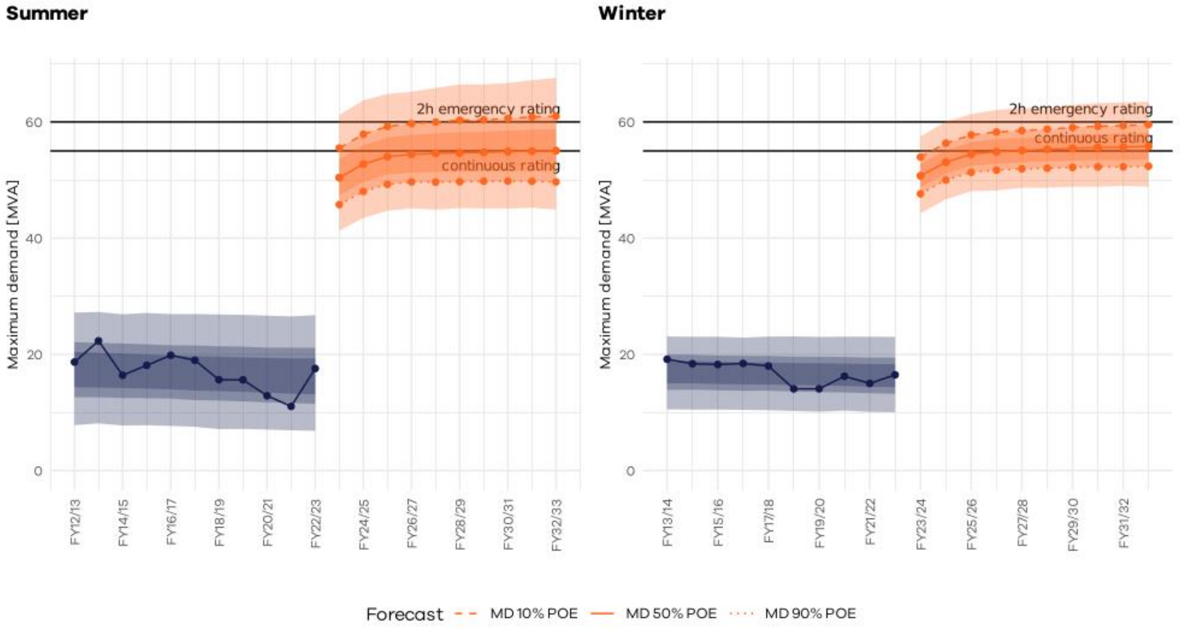
Civic ZSS historical and 10-year maximum demand forecasts

Bands denote Bayesian [20, 80]%, [10, 90]%, [1, 99]% (from inner to outer) POE intervals



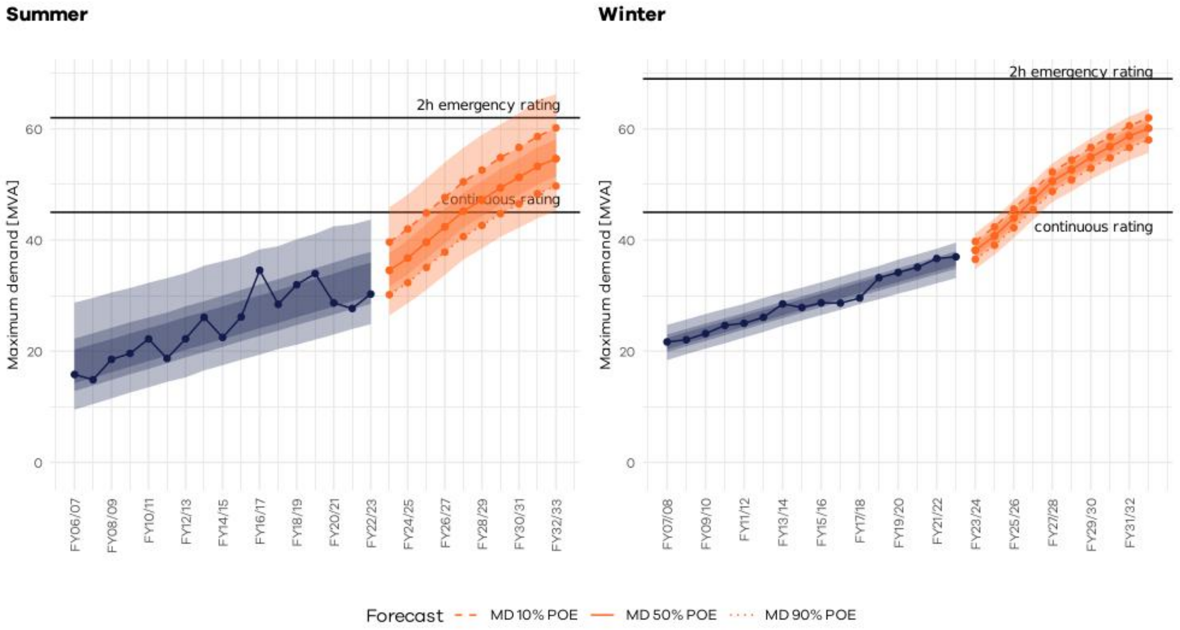
East Lake ZSS historical and 10-year maximum demand forecasts

Bands denote Bayesian [20, 80]%, [10, 90]%, [1, 99]% (from inner to outer) POE intervals



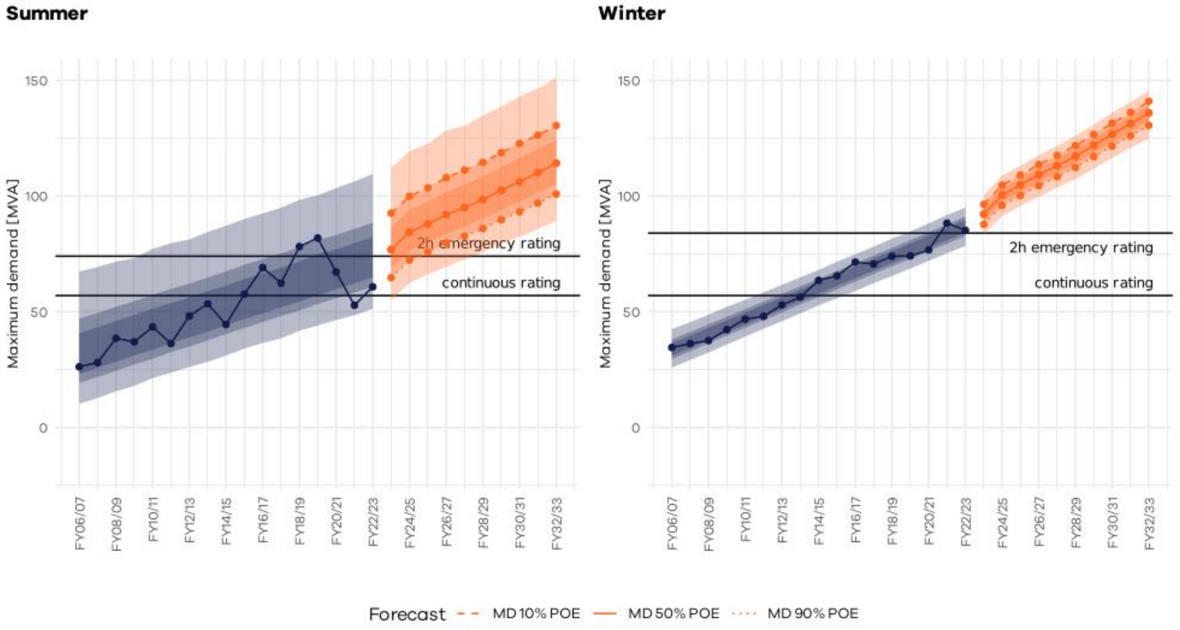
Gilmore ZSS historical and 10-year maximum demand forecasts

Bands denote Bayesian [20, 80]%, [10, 90]%, [1, 99]% (from inner to outer) POE intervals



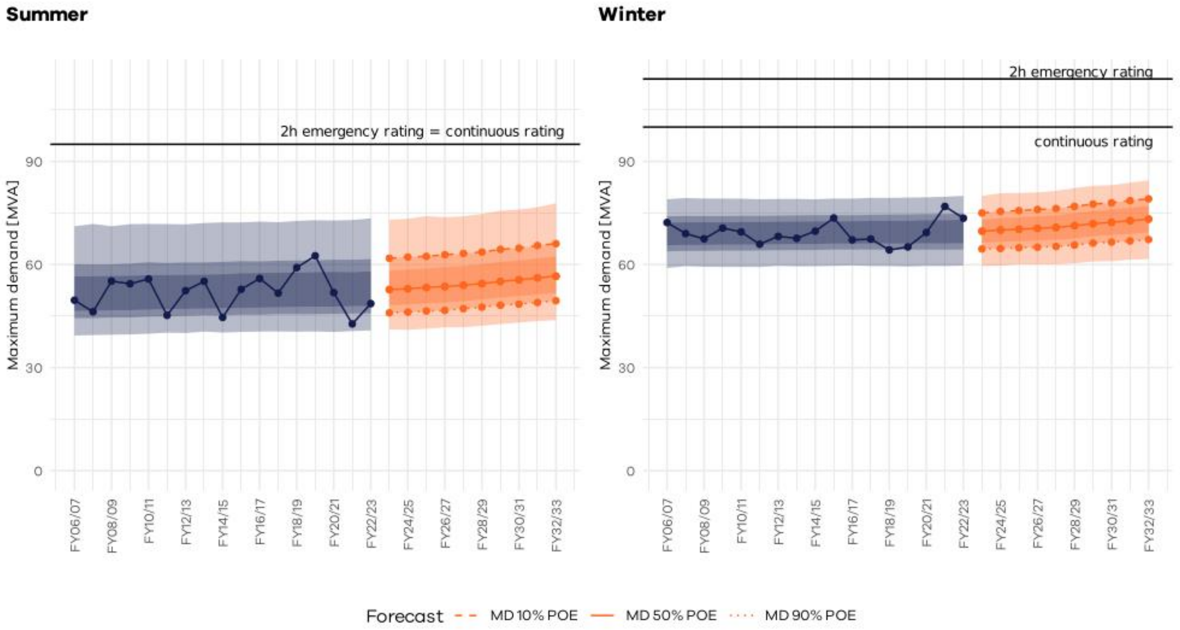
Gold Creek ZSS historical and 10-year maximum demand forecasts

Bands denote Bayesian [20, 80]%, [10, 90]%, [1, 99]% (from inner to outer) POE intervals



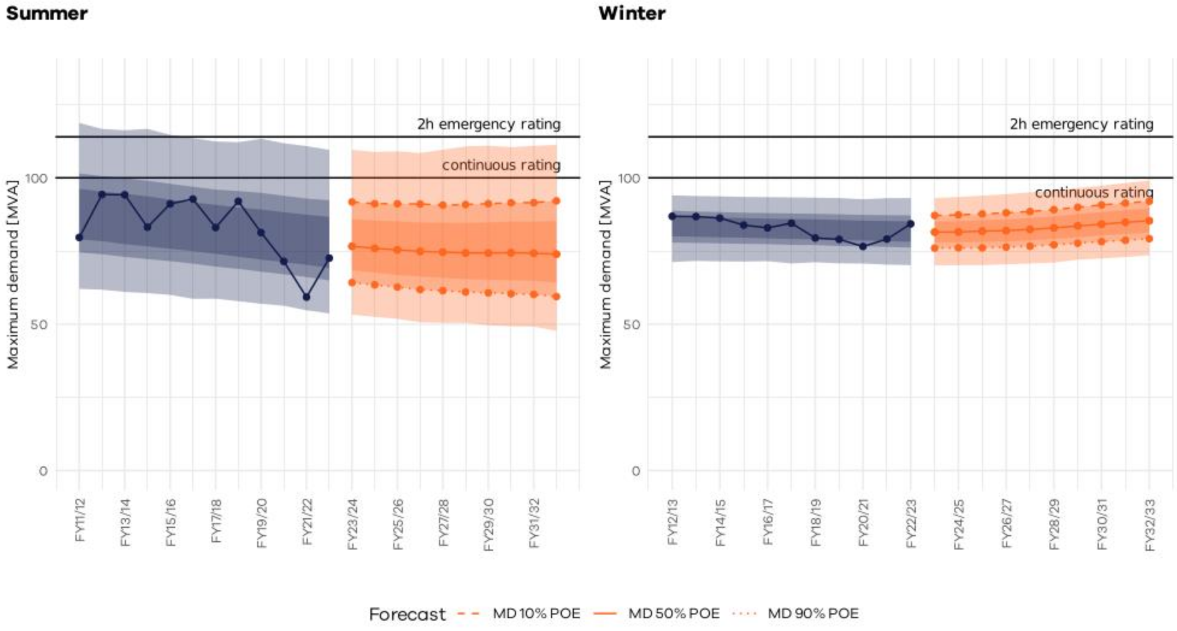
Latham ZSS historical and 10-year maximum demand forecasts

Bands denote Bayesian [20, 80]%, [10, 90]%, [1, 99]% (from inner to outer) POE intervals



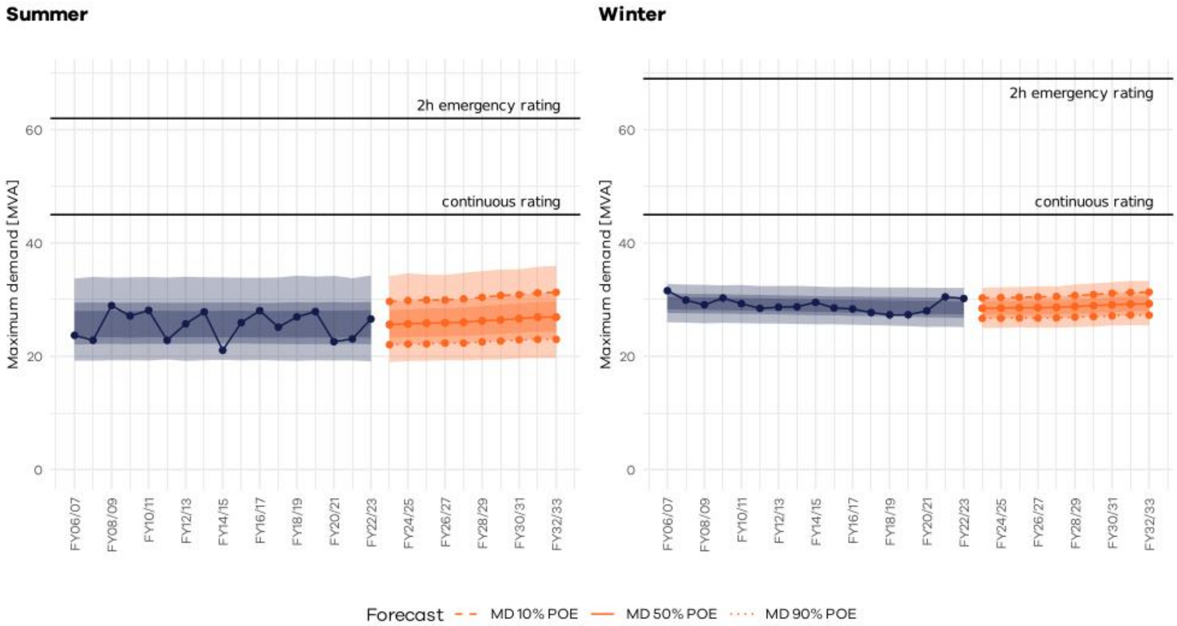
Telopea Park ZSS historical and 10-year maximum demand forecasts

Bands denote Bayesian [20, 80]%, [10, 90]%, [1, 99]% (from inner to outer) POE intervals



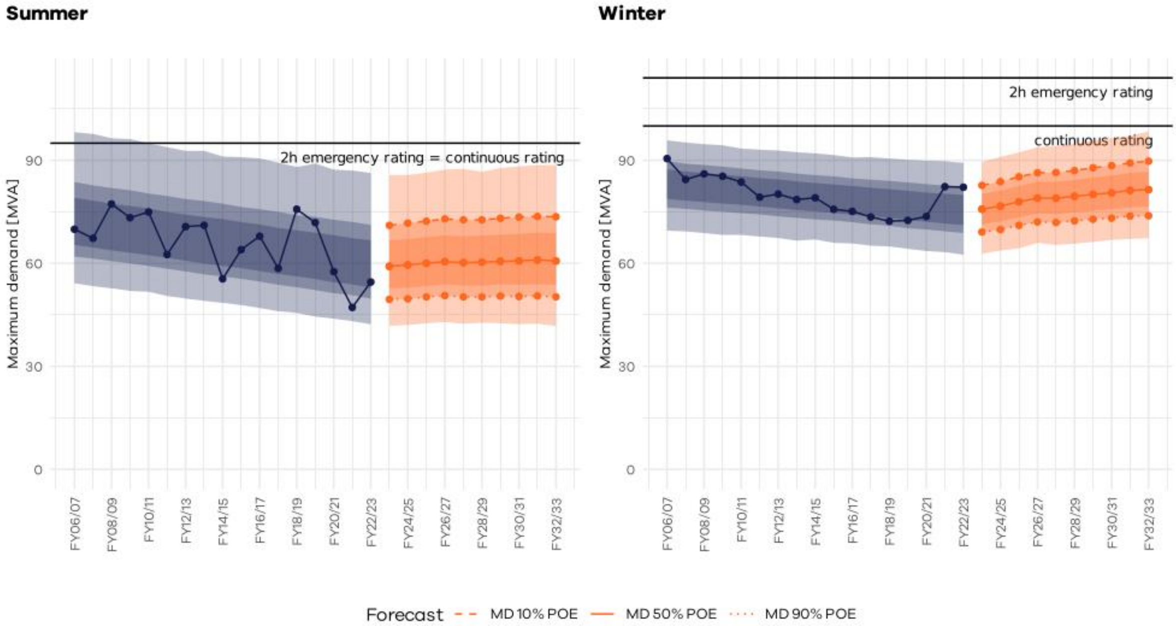
Theodore ZSS historical and 10-year maximum demand forecasts

Bands denote Bayesian [20, 80]%, [10, 90]%, [1, 99]% (from inner to outer) POE intervals



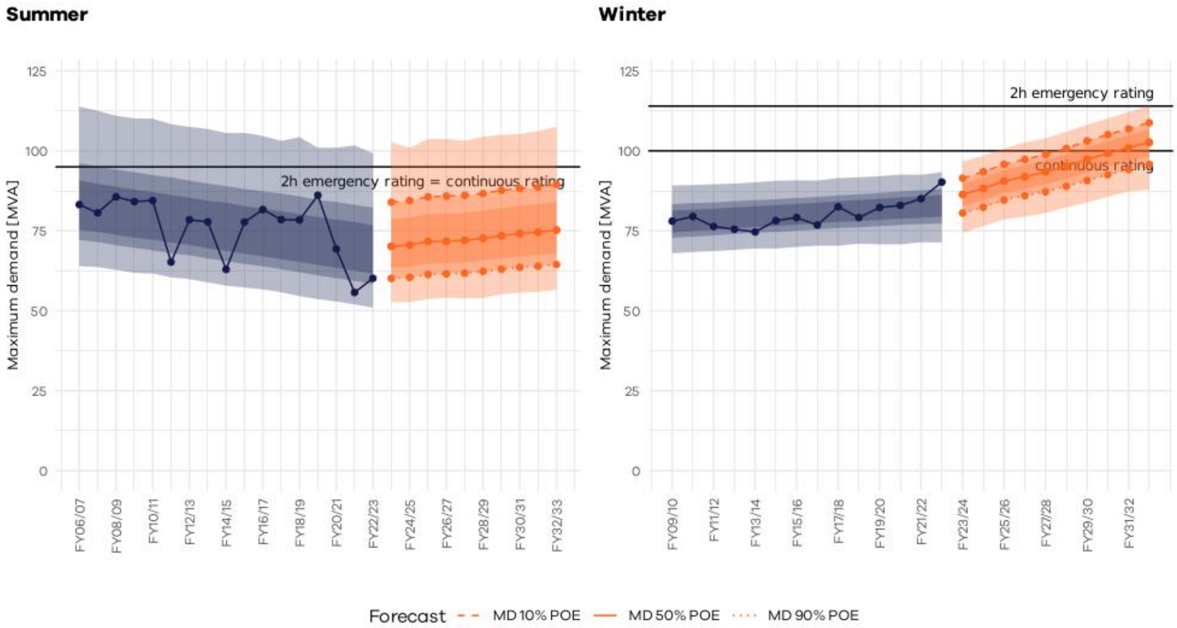
Wanniassa ZSS historical and 10-year maximum demand forecasts

Bands denote Bayesian [20, 80]%, [10, 90]%, [1, 99]% (from inner to outer) POE intervals



Woden ZSS historical and 10-year maximum demand forecasts

Bands denote Bayesian [20, 80]%, [10, 90]%, [1, 99]% (from inner to outer) POE intervals



APPENDIX F – EXTERNAL MARKET FORCES INCREASING COSTS

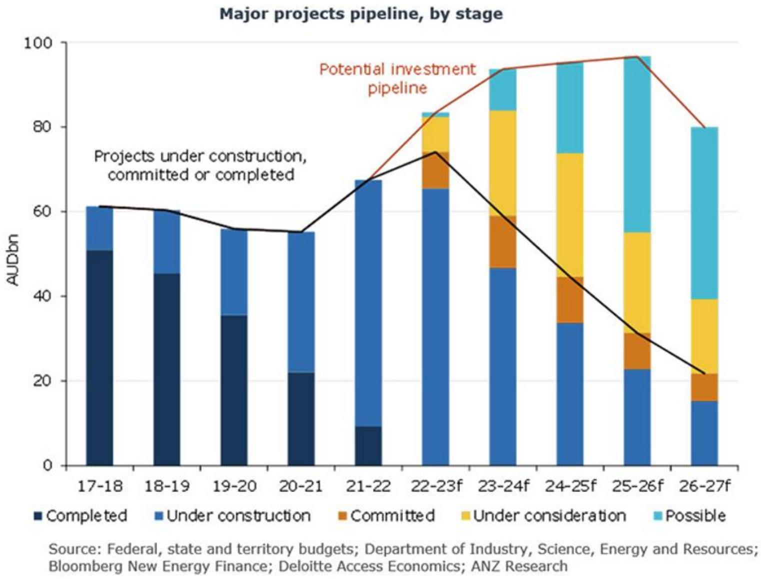
Global supply chain constraints, together with skilled workforce shortages, are driving economy wide above inflation cost increases in infrastructure, particularly in specialised niche areas such as high-voltage transmission projects.

These cost increases have been widely felt. AEMO, for instance, has identified that its cost estimates have increased by about 30 per cent in real terms between its 2022 and 2024 Integrated System Plans.[48] These cost increases are directly comparable to the cost increases we have observed given the similar technologies and skill sets required to build transmission infrastructure and our zone substations, which connect to our 132kv transmission network.

While some global supply chain pressures have eased (such as with microchips – although long lead times remain), shortages and price increases of other essential components (e.g. with switchgear and transformers[49]) have emerged. We have also seen growth in the cost of materials such as concrete and structural steel, which is reported to have increased by 50 per cent and 40 per cent, respectively, since 2022.[50]

These factors coincide with a step change in the major projects in 2022-23, which is expected to continue to place additional pressure on the skilled workforce. This can be seen in ANZ's major project pipeline in Figure 24.

Figure 24 ANZ's Major Projects Pipeline[51]

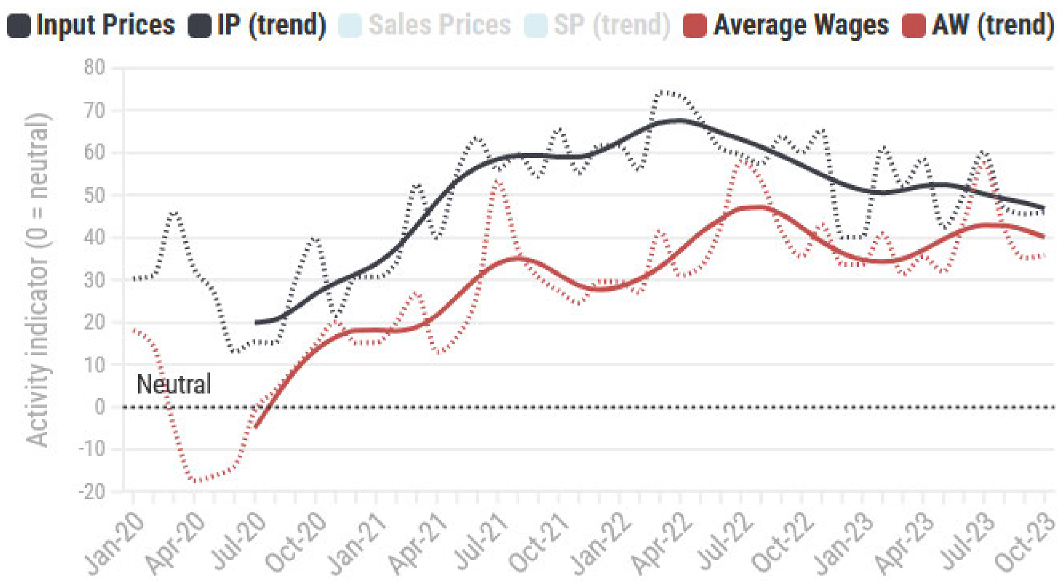


Infrastructure Partnerships Australia is similarly forecasting an increase in the project pipeline and identified a 412 per cent increase in energy sector labour demand between financial quarter three in 2021 and financial quarter two in 2023.[52]

[48] AEMO 2032, *2023 Transmission Expansion Options Report,* September, p.3. Available here
[49] See here and here
[50] See here
[51] ANZ 2023, *Australia's infrastructure opportunity still to peak*, August 22. Available here
[52] Infrastructure Partnerships Australia. Available here.

The impact of the growing infrastructure pipeline can be seen in the Ai Group's price and wages indicators, which shows that input prices remain elevated (Figure 25). Lines above neutral indicates that activity is expanding (below zero indicates contraction).

Figure 25 AI Group Australian Industry Index: Price and wages[53]

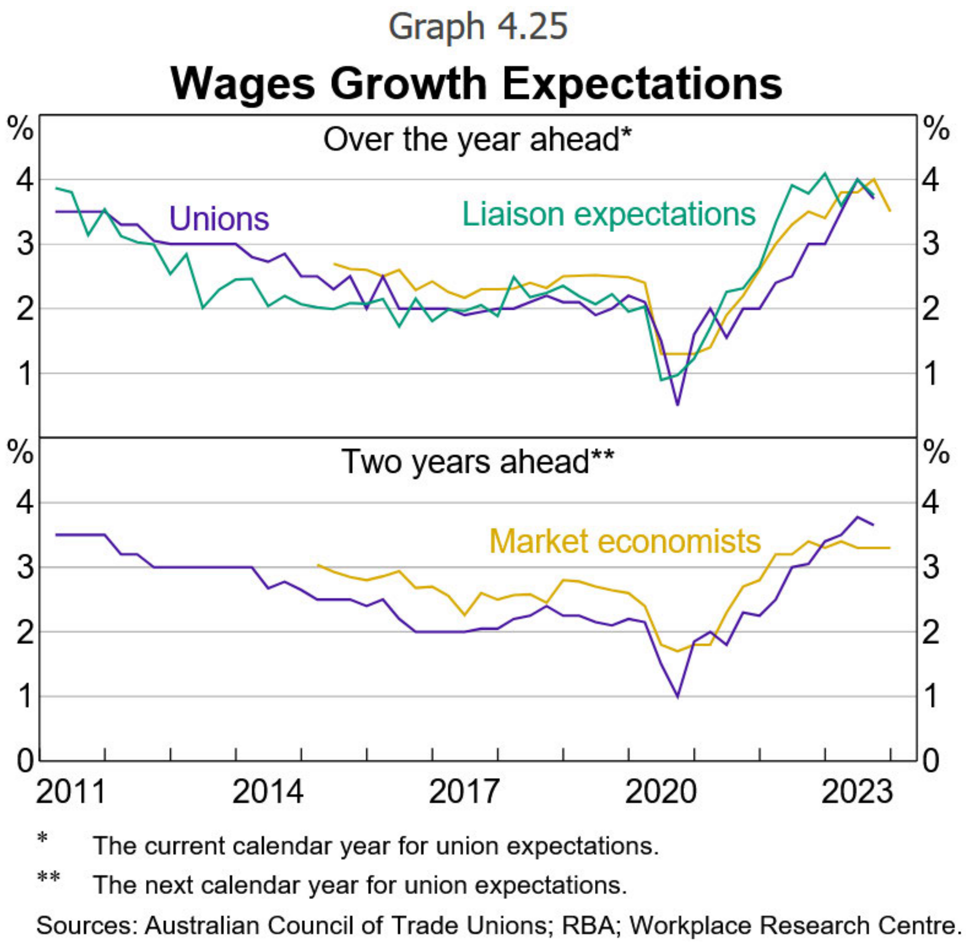


The link between the pipeline of projects and inflation has resulted in the International Monetary Fund recommending that Australian governments implement "..public investment projects at a more measured and coordinated pace, given supply constraints, to alleviate inflationary pressures and support the RBA's disinflation efforts."[54]

This has led to increases in wage expectations (which are implicitly embedded in supplier tenders). Data from the RBA indicates that wage expectations grew over 2021 and 2022, explaining a key difference between prices between the Harman and Molonglo tenders.

[53] AI Group Australian Industry Index. Available here
[54] IMG 2023, *Australia: staff Concluding Statement of the 2023 Article IV Mission, October 31.* Available here

Figure 26 Reserve Bank of Australia Statement on Monetary Policy (November 2023) Wage Growth Expectations



APPENDIX G – DIFFERENCE BETWEEN AER DRAFT DECISION AND OUR REVISED PROPOSAL

Table 14 Initial, draft decision and revised proposal augmentation expenditure ($2023/24)

	Initial Proposal	Draft Decision	Revised Proposal
Non-EV Demand driven	**86.77**	**83.09**	**135.98**
Molonglo Zone Substation	10.46	10.51	25.47
Molonglo Zone Substation 2nd transformer	4.03	-	9.48
Strathnairn Zone Substation	20.75	20.83	43.76
Supply to Barton	-	-	3.16
All other projects	51.53	51.75	54.10
EV-Driven	**74.06**	**3.17**	**27.88**
Supply to Braddon	3.82	-	3.98
Supply to Watson	2.93	-	5.58
Supply to Ainslie	4.76	-	5.58
Supply to Campbell	4.99	-	1.23
Supply to Franklin	4.94	-	5.39
Supply to Canberra CBD Feeder 1	3.15	3.17	3.28
Mitchell zone substation	2.17	-	1.69
Curtin zone substation stage 1	19.11	-	1.15
All other projects	28.19	-	-
Other (secondary systems, reliability and quality)	**20.06**	**18.12**	**21.10**
Community battery	2.01	-	-
Other	18.05	18.12	21.10
Total	**180.88**	**104.38**	**184.96**

Cost differences are generally due to updated inflation estimates.

Feeder cost differences are due to timing changes based on our updated peak demand forecast and program level optimisation. This results in costs falling in and out of the 2025-29 regulatory period. For instance, the Feeder from City East zone Substation to Campbell has been moved back one year (so that half the costs now fall into EN29), while the feeder from the City East zone substation to Watson has been brought forward one year, bringing costs from 2029/30 (EN29) into 2028/29 (EN24).

Our revised proposal also combines zone-substation and related feeder works as both are required to address the identified constraint and are considered together. As a result:

- Project *20009665 - 11kV Feeder from Strathnairn ZS* ($1.7m) has been removed with costs included in Project '*20001760 - Strathnairn Zone Substation'* in the revised proposal.

- Project *20001374 - 11 kV Feeder from Molonglo Zone - Supply to Molonglo Valley District* ($3.3m) has been removed and with costs included in Project *17519206 - Molonglo Zone Substation.*

Lastly, we have identified that while our proposal included the CER integrated step change (which the AER accepted in its draft decision) an oversight was made which meant that not all associated capex was included in the capex model. Accordingly, in our revised proposal we have included an additional line item *20011838 - DER Integration (Dynamic Control and STATCOMs* to include these costs. This ensures that our capex program aligns with the DER Integration business case. Our revised proposal also accepts the AER's decision to remove expenditure relating to community batteries and does not include the line item *20009872 Grid scale community battery.*