ENDGAME ECONOMICS

DEMAND FORECAST REVIEW

SA Power Networks

This report/document can be made public and published on the Australian Energy Regulator's website as part of SA Power Networks' Revised Regulatory Proposal.

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1. Introduction

Endgame Economics ('Endgame') is pleased to submit this report for SA Power Networks that assesses their demand forecasting method which will assist their revised regulatory proposal to the Australian Energy Regulator.

1. Executive Summary

SA Power Networks (SAPN) has asked Endgame Economics (Endgame) to investigate its maximum demand forecasting methodology for its revised regulatory proposal. This document addresses the concerns posed by the Australian Energy Regulator (AER) in its draft determination for the upcoming reset period. Endgame concludes that the overall methodology is sound and provides a robust forecast for network planning purposes.

SAPN should update their system-level forecast to the 2024 ISP

SAPN should move away from using the 2022 ESOO since it is now outdated. However, we recommend that SAPN uses the 2024 ISP as opposed to the ESOO 2024 because there is a marked difference in maximum demand between other AEMO publications which has not been explained by AEMO. The processes involved in developing the forecasts in the ISP are also more robust than those involved in the ESOO. We suggest that SAPN continues to use the ISP in the future as the system-level forecast due to its nature for system and transmission network planning.

Block loads are not overestimated or duplicated

The AER is concerned that block loads are overestimated or duplicated. We believe that this is not the case due to the following reasons:

- AEMO has not requested information on new block loads from SAPN since early 2023 which included 2022 block load forecasts. SAPN now has additional block loads that are forecasted to enter and be considered for network planning purposes. Hence, the system-wide forecasts from AEMO do not include these.
- Economic growth is a component in the system-level forecast and appears to be driven by residential connections and increases in household income. SAPN's block load forecasts include industrial, agricultural, utility and commercial loads which are contrary to the bleak forecasted outlook in the business sector.
- SAPN uses diversified block loads where the diversity factor is a percentage applied indicating the contribution of the block load to the system peak. Typically, SAPN applies diversity factors in the range of 70%-100% depending on the industry in which the block load operates in. This would reduce the risk of overestimating demand.

We recommend that SAPN obtains daily consumption profiles to determine diversity factors where appropriate

We understand that SAPN typically assigns a diversity factor of 70%-100% to connecting block loads, depending on the customer segment. We recommend that SAPN test these assumptions by considering the daily consumption profiles of these or similar loads.

The threshold of block loads is appropriate but the choice to accumulate is not recommended

SAPN uses 5% of a transmission connection point as a threshold to determine if diversified block loads should be included in the system forecast. They then compare this to the aggregate number of diversified block loads connecting to a particular transmission connection point. 5% is a significant amount and, in some cases, greater than 10MW which is AEMO's threshold and in almost all cases greater than 1MW which is Ausgrid's threshold.

However, we recommend that SAPN does not accumulate block loads before assessing against the materiality threshold.

SAPN should conduct sensitivities to investigate the probability of block loads entering and the impact of delays.

SAPN does not currently investigate the probability of block loads entering and the impact of delays. We asked SAPN to analyse the probability of block loads entering and determined that in most cases they enter but sometimes with a delay. We suggest that SAPN conducts a sensitivity on the impact of delays and consider implementing this in their forecasts, for example by adding a 2-year delay.

2. Introduction

2.1. Context

SA Power Networks (SAPN) is currently undergoing its regulatory determination reset for the period 2025-2030. After submitting their proposal in January, the Australian Energy Regulator (AER) has provided feedback on their demand forecasts. This report investigates SAPN's forecasting method for their updated regulatory proposal and addresses the AER's concerns.

Investments in infrastructure by energy distributors occur in blocks when peak demand exceeds the capacity of the network. Therefore, forecasting electricity peak demand is important for electricity distribution networks to identify areas where network investment is needed ahead of demand growth. Otherwise, network infrastructure can be damaged and consumers can experience poor reliability outcomes. With the transition well underway, electricity demand is expected to grow at a rapid rate due to electrification and the uptake of electric vehicles (EVs).

2.2. AER's concerns

We understand that the AER is concerned about two issues:

- Relevance of assumptions
- Treatment of block loads

2.2.1. Relevance of assumptions

In their proposal, SAPN used system forecasts from the Australian Energy Market Operator's (AEMO) Electricity Statement of Opportunities (ESOO) which was published in 2022. However, the industry is rapidly evolving, and the AER has asked SAPN to update these to 2024 forecasts.

2.2.2. Block loads

With relation to block loads, the AER is concerned that block loads are over-estimated or duplicated. The AER in their draft decision mentions SAPN did not provide sufficient evidence on their rationale for including these in the system-level forecast. The AER has a specific concern related to the classification of block loads,

"Another concern we have is SA Power Networks' application of its threshold for block loads. SA Power Networks applies a 5% materiality threshold for making block load adjustments at the relevant local levels, which we consider appropriate as it prevents potential duplications with trend projections. However, SA Power Networks appears to have applied a block load adjustment at the system level when the 5% capacity threshold is met at a transmission connection point level, which does not necessarily mean the 5% system capacity threshold is met. This would result in overestimation."

-AER draft decision SAPN 2023-2030 overview

Furthermore, the AER is also concerned about SAPN's approach to the eventuality of block loads being connected to the network,

"Additionally, to avoid overstating the forecast, SA Power Networks needs to carefully evaluate potential overestimations in customer-requested loads, the likelihood of projects not proceeding, and the impact of project loads on seasonal and system peak time. In the revised proposal, SA Power Networks should detail the measures it has in place to mitigate the risk of overestimation in the forecast. "

-AER draft decision SAPN 2023-2030 overview

2.3. Our assessment

We conducted this assessment by reviewing documents provided to us by SAPN, this includes information they provided to the AER throughout the proposal consultation process. Furthermore, we conducted multiple meetings and discussions with SAPN including a demonstration of the forecasting tool.

We have also reviewed key AEMO publications where they are relevant to SAPN's demand forecast, for e.g., the forecasting update from the ESOO 2024, demand forecasting methodology etc. We have also met with AEMO together with SAPN to get further details on the updates and methodologies used by AEMO in their demand forecasts.

2.4. Structure of the report

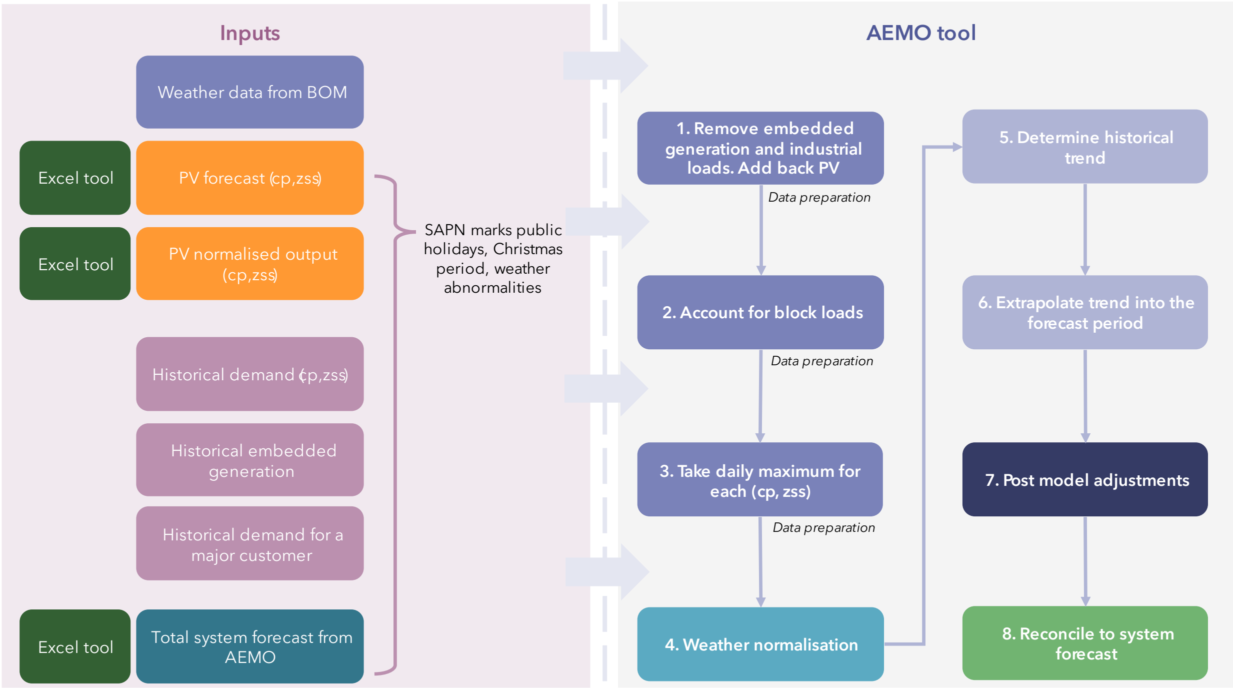
This report is structured as follows:

- **Section 3,** provides a summary of SAPN's demand forecasting methodology.
- **Section 4,** explores the updated system forecast inputs.
- **Section 5,** discusses the treatment of block loads.
- **Section 6,** concludes with our recommendations.

3. Demand forecasting method

3.1. Overview

Figure 1 – SAPN's forecasting method



SAPN produces demand forecasts using a custom R-studio tool built by AEMO that follows the 2016 connection point forecasting methodology[1]. This tool produces Probability of Exceedance (POE) 10 and 50 forecast demands for each zone substation and transmission connection point.

Various inputs are fed into the tool including historical data, solar PV and system forecasts, historical weather data and forecast block loads, Figure 1. The tool accounts for weather patterns (temperature) when it normalises demand to extract POE distributions, the tool then forecasts the trend and conducts post-modelling adjustments. The post-model adjustments also include the reconciliation of each zone substation and transmission connection point to the system-level forecast.

3.2. Inputs

3.2.1. Solar PV

Various solar PV inputs are required in the model including:

- Historical solar PV capacity for each zone substation.

[1] AEMO. Connection point forecasting methodology. 2016. https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/tcpf/2016/aemo-transmission-connection-point-forecasting-methodology.pdf

- Solar PV uptake: To create solar PV forecasts SAPN has an Excel model that takes AEMO's forecast for the state and disaggregates it according to current PV uptake.
- Solar traces: SAPN has a set of normalised solar PV traces that are fed into the tool which is then multiplied with forecast capacity.

3.2.2. Total system forecast from AEMO

This input can be found in SAPN's *NEFR Forecast File Generator* spreadsheet.

SAPN uses residential/business, electrification and electric vehicle central POE 10 and 50 forecasts from AEMO's ESOO or ISP for the total system forecast. The proposed demands which Endgame has reviewed uses ISP 2024 system forecasts. SAPN calculates the gradient or trend from AEMO's system forecast over the full horizon (20 years) and applies it to a baseline or starting point which is the trend of historical POE 10 corrected actuals. Major block loads that to SAPN's knowledge were not incorporated into AEMO's forecasts have also been added.

3.2.3. Other inputs

Other inputs that are fed into the model include historical demand data for each zone substation and historical weather outcomes sourced from the Bureau of Meteorology.

3.3. Modelling method

3.3.1. Data preparation

Before data gets processed by the tool produced by AEMO, SAPN indicates the following for each zone substation:

- If public holidays, weekends and the Christmas period should be excluded.
- If the zone substation should be excluded from reconciling to the system forecast.
- If industrial loads should be removed from the zone substation demand trace.
- If there are other exclusions from the regression eg, temperature or outliers.
- Historic long-term block loads or transfers that have occurred.
- Manual adjustments to diversity factors.

From our conversations with SAPN, they remove public holidays, weekends, Christmas periods and industrial loads from the data for most zone substations. Furthermore, they also exclude temperatures below 28 °C. The tool then removes block loads and industrial sites whilst adding solar PV back by using historical capacity and the normalised solar trace to derive underlying demand.

3.3.2. Weather normalisation

Model fit

The AEMO tool corrects for weather to account for the intrinsic relationship between temperature and demand. It does this by running a regression for each year, season, zone substation or transmission connection point, see the equation below. The AEMO 2016 forecasting methodology states that the tool uses data from the previous three years however it is our understanding that SAPN uses 13 years. The residuals are also collected for the simulation process.

$$MaxDemand_{cp,d} = B_0 + B_1 MaxTemp_{cp,d} + B_2 MinTemp_{cp,d} + B_3 Yr1 + B_4 Yr2 + e$$

Where:

d is day

cp is the transmission connection point

Max demand is the maximum demand on a day

MaxTemp is the maximum temperature for a day

MinTemp is the minimum temperature for a day

Yr1 and Yr2 are fixed effects to account for the year

The model also conducts a check to ensure the zone substation is weather-sensitive. If the R-squared is under 0.3 then a different equation is used and demonstrated below:

$$MaxDemand_{cp,d} = B_0 + e$$

Simulation

The regression models are run for each year of historical weather data in summer where the tool uses 30 years. The distribution of residuals from the model fitting process is sampled 500 times and applied to the historical estimate to produce a new distribution of weather-corrected demands. Using this distribution the tool extracts POE 90, 50 and 10 levels.

3.3.3. Trend calculation and extraction

For each zone substation, a trend is created using the historical weather-corrected POE 10 and 50 estimates. The model chooses between a linear and cubic trend based on two tests:

- The Davidson-Mackinnon J-test: tests whether the fitted values of the cubic model add a statistically significant amount of explanatory power to the linear model.
- Outlier test: assesses if the last historical data point adds explanatory power when included as a dummy variable.

This trend is then extrapolated throughout the forecast horizon.

3.3.4. Post model adjustments

Block loads

Block loads and transfers are put back in by an increase or decrease in load at the zone substation or transmission connection point.

Solar PV

The baseline POE forecasts do not include solar PV and the model incorporates it through several steps. For each zone substation:

1. A rooftop PV trace is taken and normalised for a historically high-demand day.
2. The trace is then multiplied by the forecasted PV capacity.
3. An underlying normalised demand trace is also taken for a historically high-demand day. This is done by taking 5 years of half-hourly demand data and choosing the 99th percentile.
4. The underlying demand trace is scaled to the block load adjusted extrapolated forecast.
5. The forecast PV trace is subtracted from the above underlying demand trace.
6. The new daily maximum demand is identified for each forecast year.

3.3.5. Reconciliation to system forecast

The reconciliation process ensures that other factors such as EVs, electrification and energy efficiency are accounted for by using AEMO's system forecast which includes these elements. There are three steps to reconciling each transmission connection point forecast to the system (See section 3.3.5).

Step 1: Calculate and apply diversity factors

Diversity factors are computed for each transmission connection point to understand its demand at the time of the regional peak. This is done using historical data and taking an average of the previous five years.

They are calculated using the following equation:

$$Diversity\ factor_{cp} = \frac{Demand\ at\ time\ of\ regional\ peak_{cp}}{Peak\ demand_{cp}}$$

Where cp is the transmission connection point and peak demand is the transmission connection point's maximum demand forecast which is non-coincident and unreconciled.

For example, in 2022 a transmission connection point has a peak demand of 100MW but during a regional peak demand event, it is measured to be 80MW. Therefore, the diversity factor is 0.8.

Then the diversity factor is multiplied by the transmission connection point forecast to obtain the co-incident unreconciled transmission connection point forecast.

Example - Taken from AEMO's connection point methodology documentation

Year	Maximum demand forecast non-coincident and unreconciled	Diversity factor	Maximum demand forecast coincident but unreconciled
2023	100	0.8	80
2024	102	0.8	81.6

Step 2: Calculate the co-incident scaling factor

Scaling factors are calculated to ensure each zone substation forecast reconciles to the system forecast. For each year the tool sums the coincident unreconciled demand forecasts and compares it to AEMO's system peak demand. It computes a scaling factor defined by the following equation.

$$Scalling\ factor = \frac{System\ forecast}{\sum coincident\ forecasts}$$

The maximum coincident but unreconciled demand forecast for each transmission connection point is scaled using this factor.

Example - Taken from AEMO's connection point methodology documentation

Year	Maximum demand forecast non-coincident and unreconciled	Diversity factor	Maximum demand forecast coincident but unreconciled	Co-incident scaling factor	Coincident connection point forecast reconciled
2023	100	0.8	80	0.971	77.7
2024	102	0.8	81.6	0.982	80.1

Step 3: Calculate the non-coincident transmission connection point forecasts

Non-coincident transmission connection point forecasts are reconciled to the growth rate of the regional forecast using an indexing approach.

Firstly, the sum of non-coincident peaks is calculated. Then the growth rate of the regional forecast and the sum of non-coincident peaks are determined. An indexing ratio is computed by dividing the two.

$$Inital\ index\ ratio = \frac{Regional\ forecast\ growth\ index}{Aggregate\ connection\ point\ forecast\ growth\ index}$$

Example - Taken from AEMO's connection point methodology documentation

Year	Regional forecast (MW)	Regional forecast growth index	The sum of non-coincident connection point forecasts	Aggregate connection point forecast growth index	Initial index ratio
2023	8,798	1	10,069	1	1
2024	8,868	1.008	10,031	0.996	1.012

In their methodology, AEMO applies a blending factor to ensure that in the earlier periods, more weight is placed on the non-coincident forecast. While, in the longer term, the forecast would be based on the system forecast. According to the 2016 methodology paper, the second forecast year has a blending factor of 0.25, followed by 0.5, 0.75 and then 1 for the remaining horizon.

The final index ratio is calculated by the equation.

$$Final\ index\ ratio = (Inital\ index\ ratio - 1) * blending\ factor + 1$$

Example - Taken from AEMO's connection point methodology documentation

Year	Regional forecast (MW)	Regional forecast growth index	The sum of non-coincident connection point forecasts	Aggregate connection point forecast growth index	Initial index ratio	Blending factor	Final index ratio
2023	8,798	1	10,069	1	1	1	1
2024	8,868	1.008	10,031	0.996	1.012	0.25	1.003

The last step is to take the final index ratio and multiply it by the unreconciled non-coincident transmission connection point forecast.

3.4. Outputs

The model produces co-incident and non-coincident forecasts for each zone substation or transmission connection point, year and POE 50 and 10 levels.

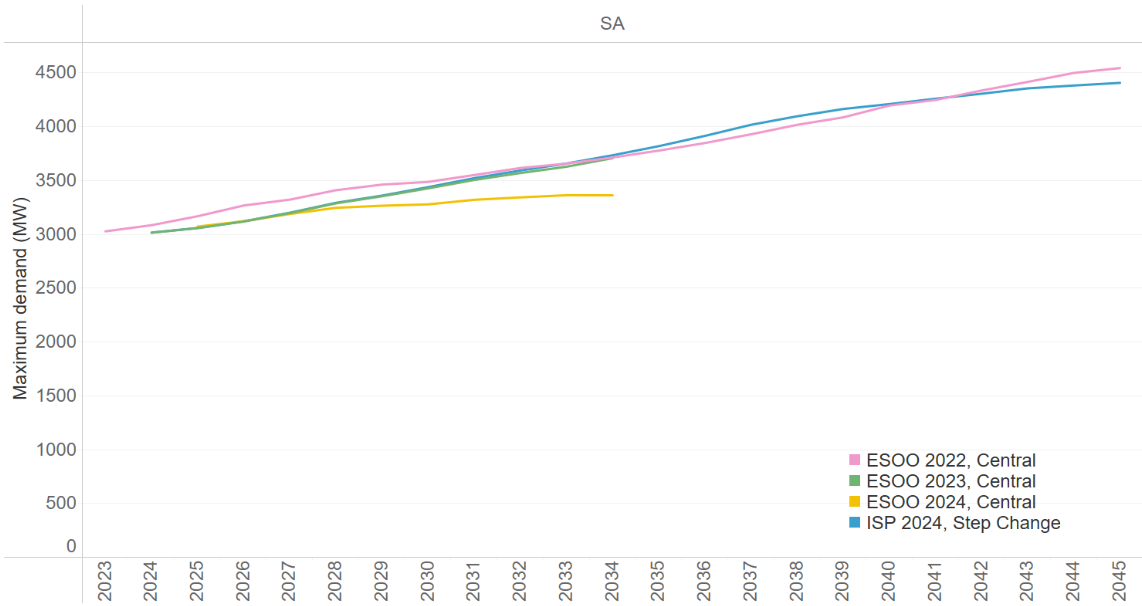
4. Updating the system forecast

We agree with the AER that SAPN should update their forecasts to use more recent assumptions and system-wide forecasts from AEMO. Part of good practice forecasting is using accurate and up-to-date inputs where available.

SAPN has decided to update their forecasts using the 2024 ISP. Their primary reason for using this data is due to timing, that it was released early enough to develop estimates in time for the revised proposal. The ISP is also a robust document and is used for system planning. Two years of extensive planning and input development is conducted to produce this forecast. On the other hand, the ESOO is published every year and not all assumptions are updated in the non-ISP year. For example, the multi-sector modelling that underpins overall societal growth is only run for each ISP and not updated for the ESOO. The ISP can also trigger Regulatory Investment Tests for Transmission (RIT-T). Projects that are actionable in the ISP (not the ESOO) require a RIT-T within two years of the ISP. For these reasons, the ISP should be preferred over the ESOO as an input for distribution network planning.

Furthermore, using the ISP 2024 is a good decision as opposed to the 2024 ESOO because of the material change in forecasts between the two documents and consistency with previous AEMO forecasts. Figure 2 below demonstrates AEMO's forecasted South Australian maximum demand between various publications. This includes residential, business, electric vehicles and electrification components which are relevant for SAPN.

Figure 2 – South Australia forecasted maximum demands between AEMO publications



(Endgame analysis using AEMO data)

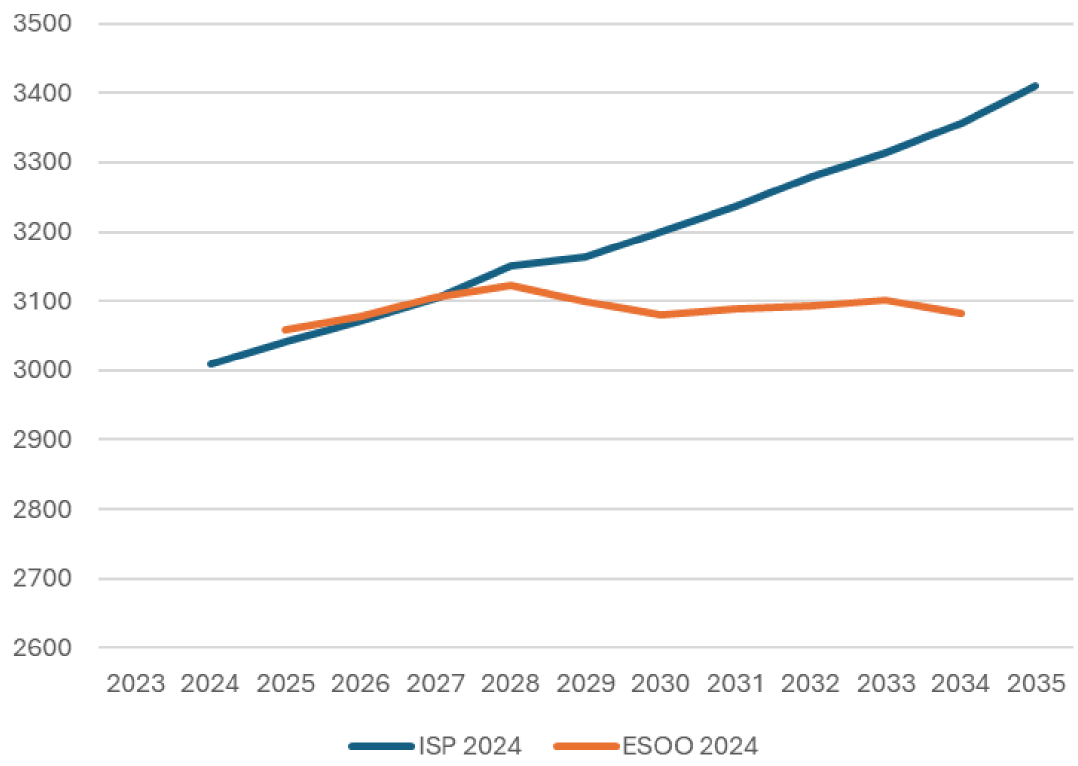
It is evident that the 2024 ESOO does not align with previous forecasts and demonstrates flat growth, unfortunately, there is no clear evidence on why this change occurred. SAPN and

Endgame have met with AEMO twice[2]. However, at the time of writing, AEMO was not able to provide a definitive reason for the large deviation in the updated forecasts. Due to the complexity and scale of the forecasting process, they have identified several "possible" factors which could drive this result. However, they were not able to confidently identify the critical driver or drivers of this change.

This significant deviation in maximum demand suggests that there will be no growth in South Australia which is inconsistent with the expected transition. This is also inconsistent with other documents, including the economic forecasts that were prepared for the ISP. This difference is of particular concern if AEMO's forecasts remain uncertain and or re-align with previous years, making it difficult for the network to determine planning needs.

Investigating further, most of this difference is occurring due to stagnation in the residential and business sectors (refer to Figure 3). We don't believe this is driven by changes in economic growth since there is a small difference between assumptions used in each publication (refer to Figure 4). SAPN has speculated that this change in the 2024 ESOO is due to recent weather patterns, the recent three La Nina years (2020-2023) could place considerable weight in the forecast. South Australia hasn't experienced a hot year since 2019. We agree that this could be the cause due to how the weather normalisation process occurs which is similar to the connection point methodology described earlier. However, it is not definite that this is causing the point of difference between the publications.

Figure 3 – Residential + Business forecast maximum demand comparison



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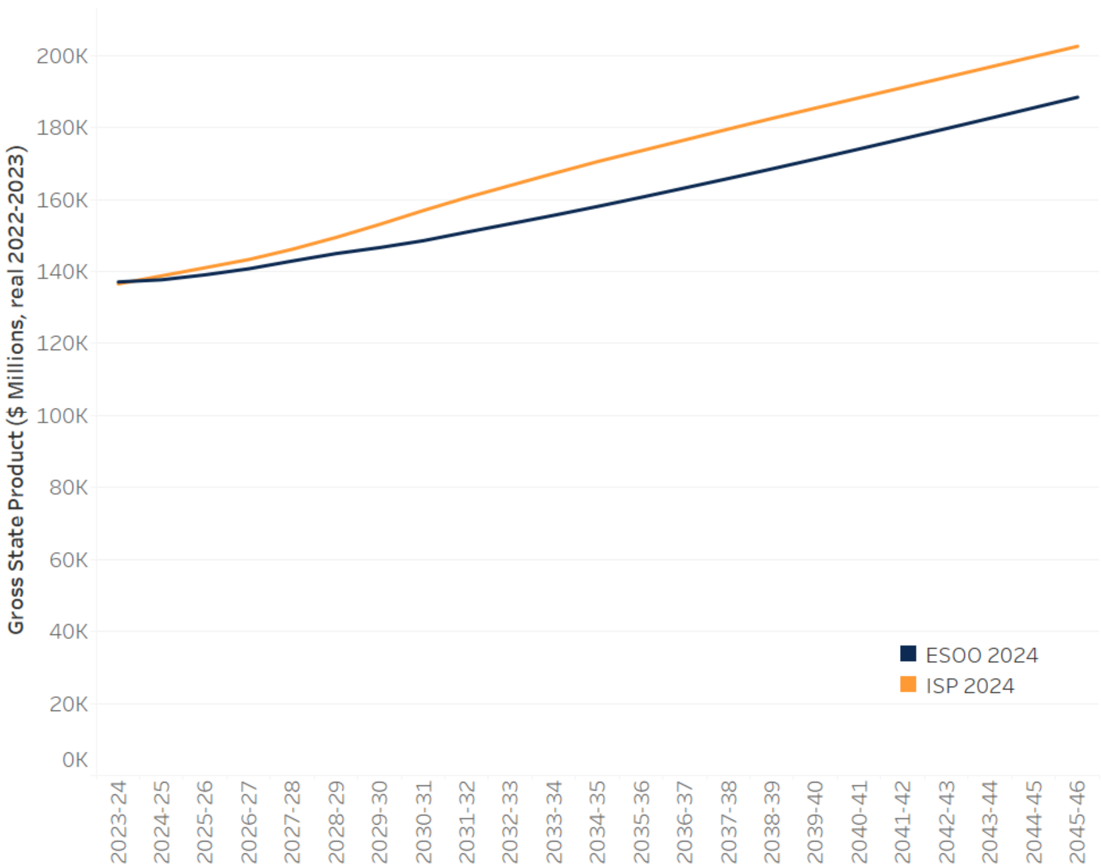
[2] Endgame and SAPN met with AEMO's energy forecasting and demand forecasting teams on 18 Oct 2024, and on 8 Nov 2024.

(SAPN analysis using AEMO data)

Figure 4 – Gross state product forecasts used by AEMO for South Australia[3]



(Endgame analysis using AEMO data)

There is however a decrease in the ESOO 2024 short-term uptake of EVs relative to the ISP 2024, Figure 5. Although, the high growth rates seen in later years are contrary to stagnating maximum demand growth unless AEMO assumes all EV customers are charging during the day which is an optimistic assumption due to the current uncertainty surrounding time of use tariffs, retailer pass-throughs and the response of consumer behaviour.

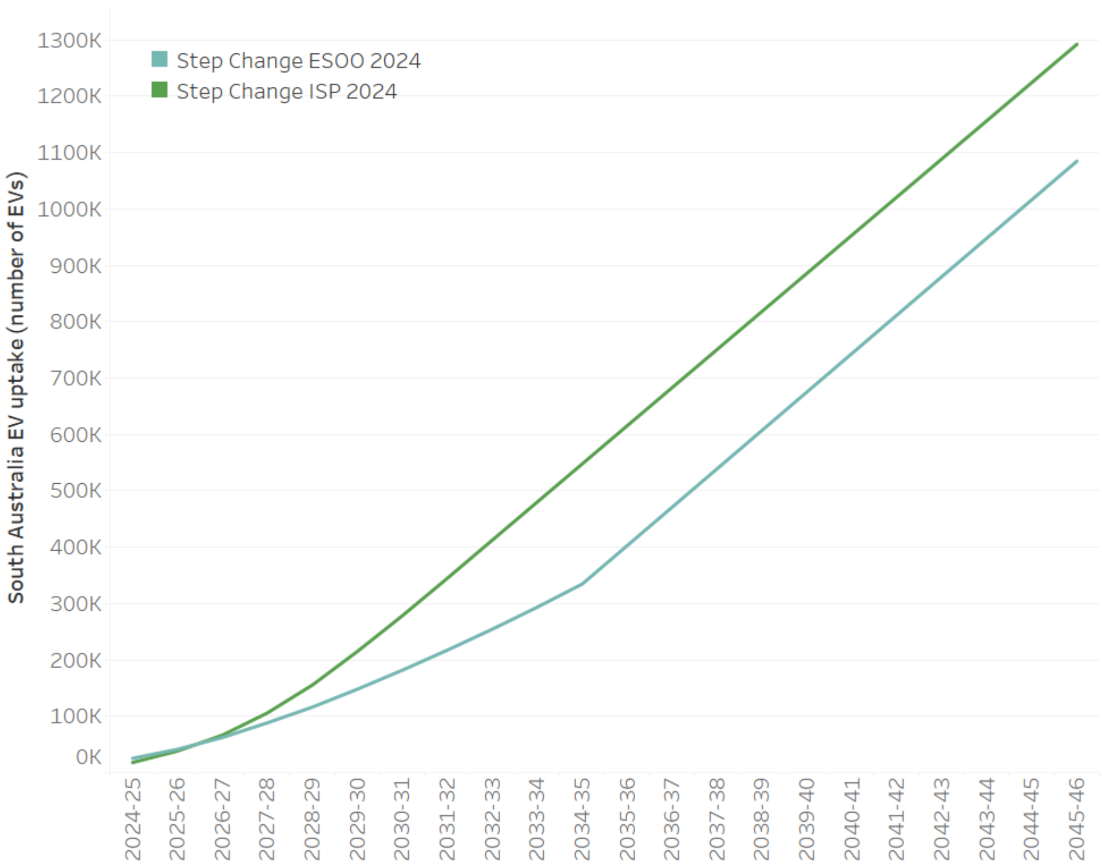
There is also a risk that the updated EV and electrification numbers no longer align with the multi-sector modelling[4] undertaken for the 2024 ISP. This modelling is critical to electricity demand as it incorporates state targets for electrification and decarbonisation in other

[3] AEMO. 2024 forecasting assumptions update (for ESOO). https://aemo.com.au/consultations/current-and-closed-consultations/2024-forecasting-assumptions-update-consultation and AEMO. 2024 ISP. https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp

[4] Climateworks and CSIRO 2022 multi-sector energy modelling https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/csiro-climateworks-centre-2022-multisector-modelling-report.pdf

sectors of the economy. In discussions with AEMO, they have also confirmed the above and hence may not align with the ambitions of state governments to decarbonise and electrify. This again reveals the fact that the ESOO demand forecast development process is more consultative as opposed to the ISP process which is more dependent on sector forecasts and surveys developed by AEMO and their consultants.

Figure 5 – South Australia EV uptake assumptions used by AEMO



(Endgame analysis using AEMO data)

We deem that due to the material change in forecasts in the ESOO 2024, the ISP 2024 should be used because it is consistent with previous assumptions and released in the same year and its processes are likely to be more robust. In future demand forecasting exercises, SAPN should consider using the ISP as the basis for system-level forecasts as it plays a key role in system planning, a process SAPN is currently engaging in through this regulatory proposal. For more information on how this consolidates with consumption forecasts please see the appendix.

5. Treatment of block loads

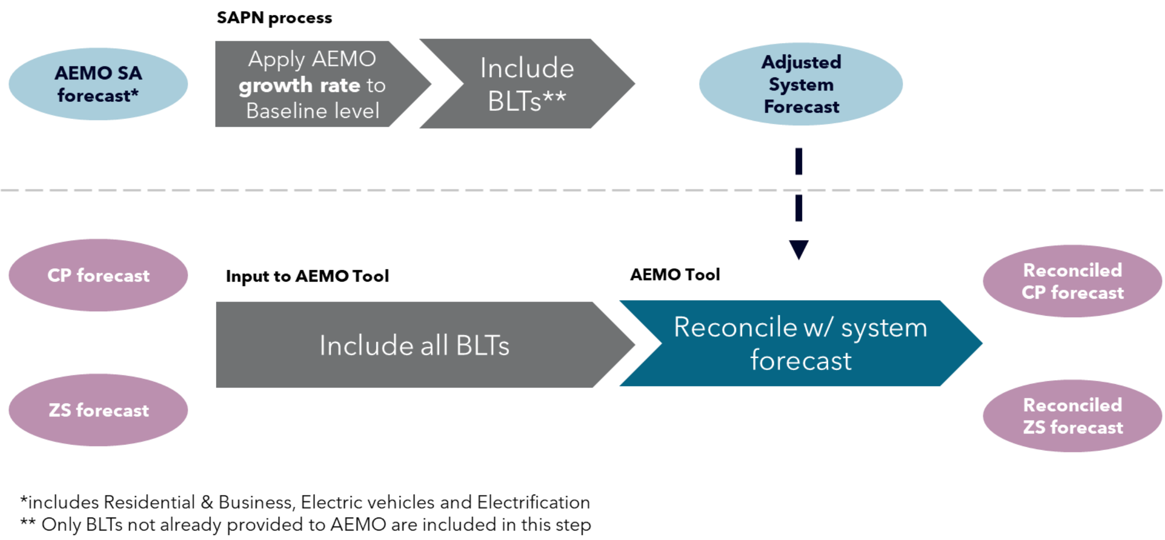
A block load can be defined as a large, discrete, and usually consistent demand caused by large customers connecting to the network or changing consumption patterns. SAPN is informed of these future block loads once large customers submit a connection request. SAPN then investigates the load as part of a connections assessment, including the potential impact on forecast demand. These loads will significantly impact the maximum demand trend of a zone substation and should be accounted for if they are highly likely to come online during the forecast period. SAPN considers the connection to be highly likely to connect once the customer becomes committed.

SAPN classifies a block load as greater than 5% of a transmission connection point or zone substation capacity or if the accumulation of proposed block loads exceeds this threshold (Response to AER information request 012). Other networks such as Ausgrid refer to them being new connections that are greater than 1MW (Ausgrid Maximum demand forecast attachment 5.6a[5]). We will return to this definition in section 5.3.

5.1. Reconciliation process

Being the only DNSP in South Australia, SAPN uses AEMO's state system forecast to reconcile demands from their baseline individual zone substation forecasts. This process is highlighted in the diagram, Figure 6 below.

Figure 6 – Reconciliation process



To create the adjusted system forecast, SAPN takes residential/business, electrification and electric vehicle central POE 10 and 50 forecasts from AEMO's ESOO or ISP. From that data, SAPN applies AEMO's 20-year trend to the most recent historical maximum demand. SAPN then adds block loads.

[5] Ausgrid. Maximum demand forecast. https://www.aer.gov.au/system/files/Ausgrid%20-%20Att.%205.6.a%20-%20Maximum%20demand%20forecast%20-%2031%20Jan%202023%20-%20Public.pdf

We understand that these block loads are additional and have not been provided to AEMO. Usually, this is because of differences in the timing of publication between various documents (SAPN response to AER information request 005). Furthermore, SAPN informed us that AEMO did not request a list of future block loads in the 2024 Standing information request (SIR). Therefore, they are unaccounted for in the system-wide business demand forecast. SAPN also considers them to be not accounted for in the native or economic growth rate (SAPN follow up to forecasting meeting documentation 12/06/24). We agree with SAPN and explore this further in the following sections.

In the bottom-up forecasting approach, block loads are first removed to conduct the weather normalisation process and then added back during the post-model adjustment process before the reconciliation procedure.

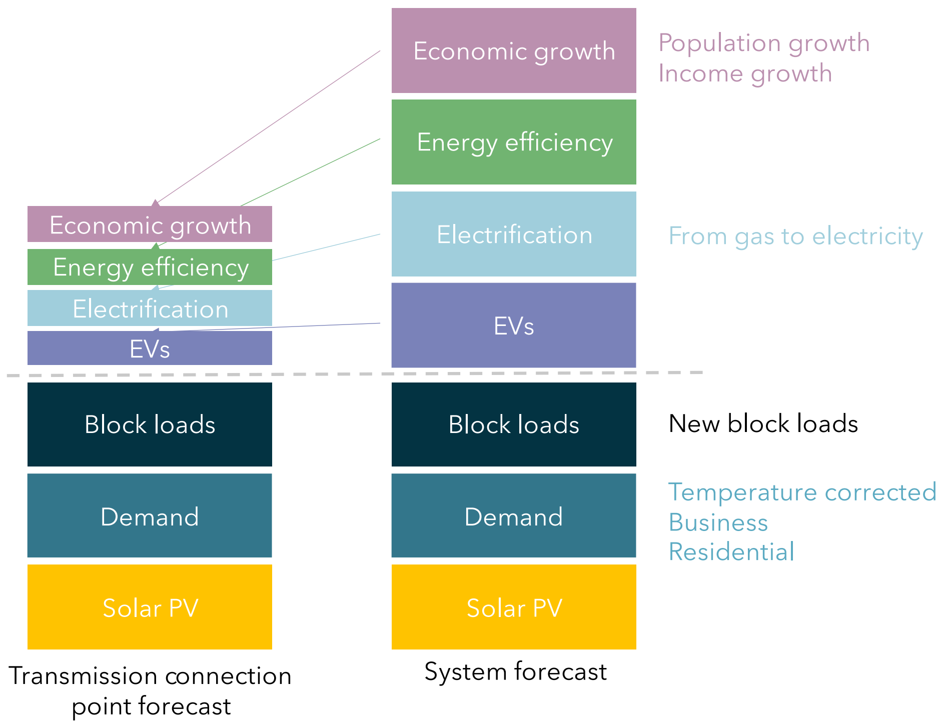
The resulting output of these two processes are:

- System forecast accounting for large block loads
- Zone substation forecast accounting for block loads

5.2. Purpose of reconciliation process and components

The tool's connection point forecasts are simplistic in that they only account for temperature-corrected demands, solar PV and block loads. The system forecast is responsible for scaling and distributing other post-model adjustments (from the system level) such as EVs and economic growth to each transmission connection point or zone substation to build the final forecast which is highlighted in Figure 7 below.

Figure 7 – Reconciliation components



From the scaling factor equation in section 3.3.5, the denominator will likely be lower than AEMO's system forecast due to not accounting for electrification, EVs etc. in the connection point forecast. This means that the connection point forecasts will need to be scaled upwards.

5.2.1. AEMO has not requested for information

It is our understanding, that the AER is concerned about duplication with these additional block loads being included separately under the system demand forecast. We believe this is not the case as AEMO has not requested any block load information from SAPN since the Standing Information Request issued in early 2023. Where SAPN provided block loads based on their 2022 forecast, their latest available at the time. Hence, AEMO has not considered new loads to be connected in their forecasts. SAPN does not think the block loads are incorporated into AEMO's system-level forecasts (through the LILs component).

5.2.2. AEMO considers large loads greater than 10MW

Furthermore, AEMO considers large loads in the system forecast that are greater than or equal to 10MW for more than 10% of the financial year. Typically, SAPN's block loads are lower and therefore not accounted for by AEMO (see appendix for a list of block loads). Even though these block loads are smaller than 10MW some transmission connection points have very low capacity e.g., Mount Gunson 33kV with 10MVA. Even if a small load joined in absolute terms it would take up a large proportion of its capacity and should be considered for network augmentation purposes.

5.2.3. Economic growth is small and driven by consumers, not business investment

In AEMO's forecasting process, the business mass-market component is forecasted in two stages with the first being driven by temperature variability and the second by electrification, economic trends, prices, climate change and energy efficiency variables[6].

There is only a small likelihood that SAPN's block loads are incorporated into the economic growth component because economic growth is expected to be very low in the next few years having little impact on electricity demand growth. BIS Oxford Economics who produced economic forecasts for the 2024 ISP expects the Gross State Product (GSP) for South Australia to be 1.53% between FY22-27[7].

Moreover, Deloitte Access Economics predicts that economic growth will be driven by new dwellings and increases in disposable income by residential consumers, Figure 8[8]. In

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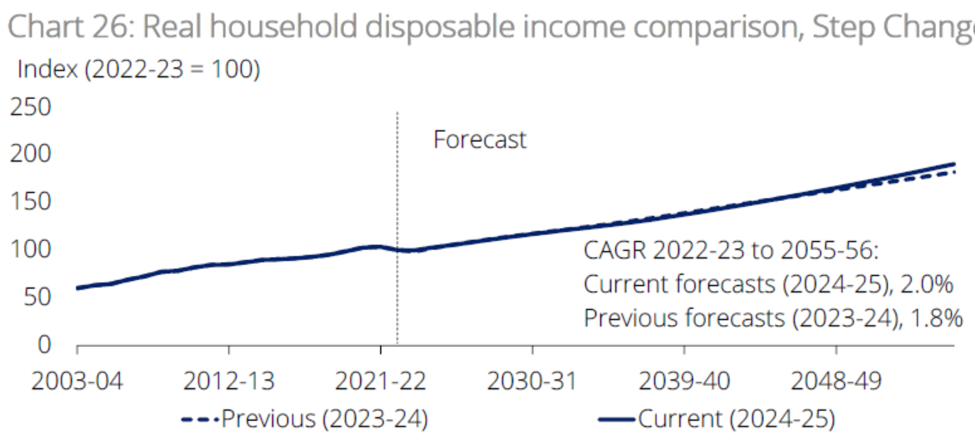
[6] AEMO. Forecasting approach – Electricity demand forecasting method. 2023. https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2024-electricity-demand-forecasting-methodology-consultation/electricity-demand-forecasting-methodology.pdf?la=en

[7] BIS Oxford Economics. Macroeconomic projections report. 2022. https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/bis-oxford-economics-2022-macroeconomic-outlook-report.pdf?la=en

[8]Deloitte Access Economics. FRG meeting 6 – meeting pack. 2024 https://aemo.com.au/consultations/industry-forums-and-working-groups/list-of-industry-forums-and-working-groups/forecasting-reference-group-frg

contrast, manufacturing and utilities are expected to decline in the short term and flatten, Figure 9. SAPN's forecasts incorporate expected block load increases from utilities, manufacturing, infrastructure projects, agriculture and mining, Section 7.1. These loads are not transfers and are associated with new major infrastructure projects and data centres, upgrades to industrial sites, defence and farming land which are contrary to the forecasted short-term business economic growth figures. These block loads are specific to a transmission connection point and not smoothed across the network. Thus, the step change in demand should properly be accounted for at the zone substation and transmission connection point.

Figure 8 – Deloitte Access Economics residential economic forecast used in AEMO's forecast



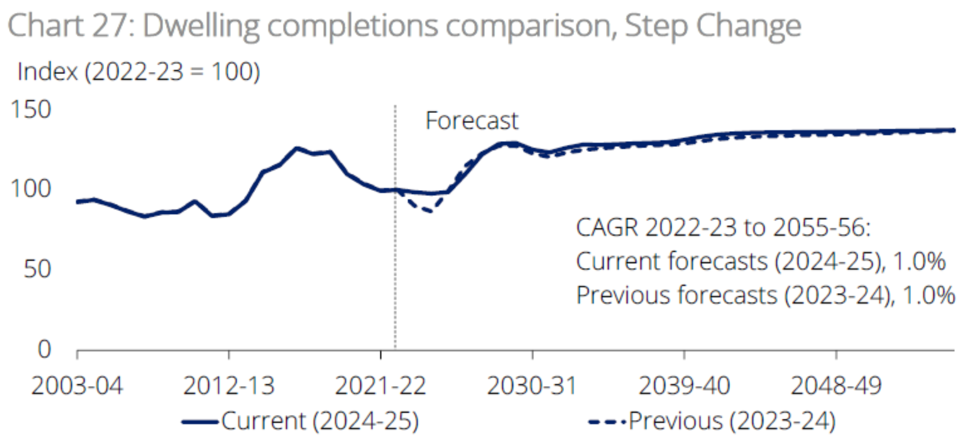
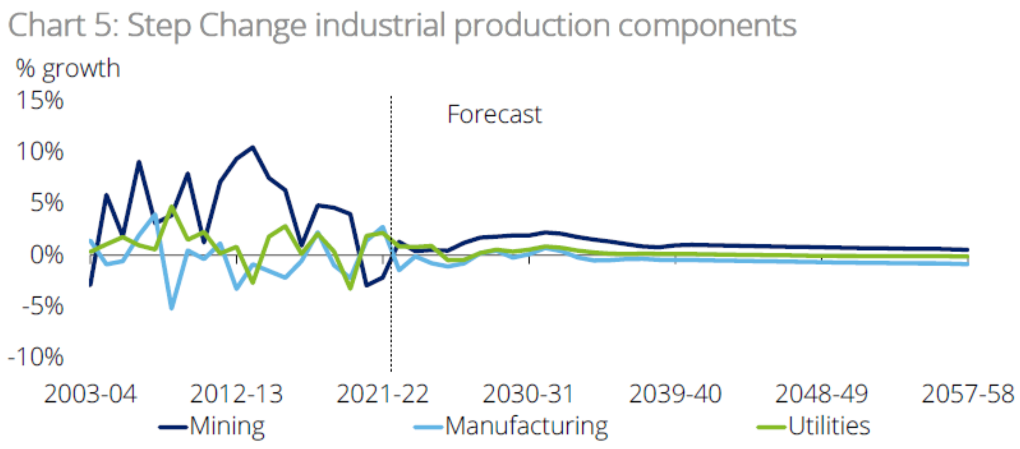


Figure 9 - Deloitte Access Economics business economic forecast used in AEMO's forecast



(AEMO and Deloitte data)

5.3. Classification of block loads

5.3.1. SAPN's classification method

SAPN considers future block loads for large customers only after receiving customer commitment as part of a connection request. Under their agreement, SAPN is obliged to provide energy to cover the customer's anytime agreed maximum demand including during network peaks. After obtaining this value they assign a diversity factor (method section 3.3.5) and calculate the diversified load.

SAPN classifies a block load at the zone substation level if the accumulation of diversified block loads is equal to or exceeds the 5% capacity threshold of the substation. These will be included in the zone substation forecast.

On the other hand, SAPN classifies a block load at the transmission connection point level if the sum of all diversified block loads from the substations under a transmission connection point is equal to or exceeds the 5% capacity threshold of the connection point. These are added to the system-level forecast as SAPN deems them significant.

5.3.2. The AER's concerns

In their draft decision, the AER had a specific concern related to the classification of block loads, *"Another concern we have is SA Power Networks' application of its threshold for block loads. … However, SA Power Networks appears to have applied a block load adjustment at the system level when the 5% capacity threshold is met at a transmission connection point level, which does not necessarily mean the 5% system capacity threshold is met. This would result in overestimation."*

-AER draft decision SAPN 2023-2030 overview

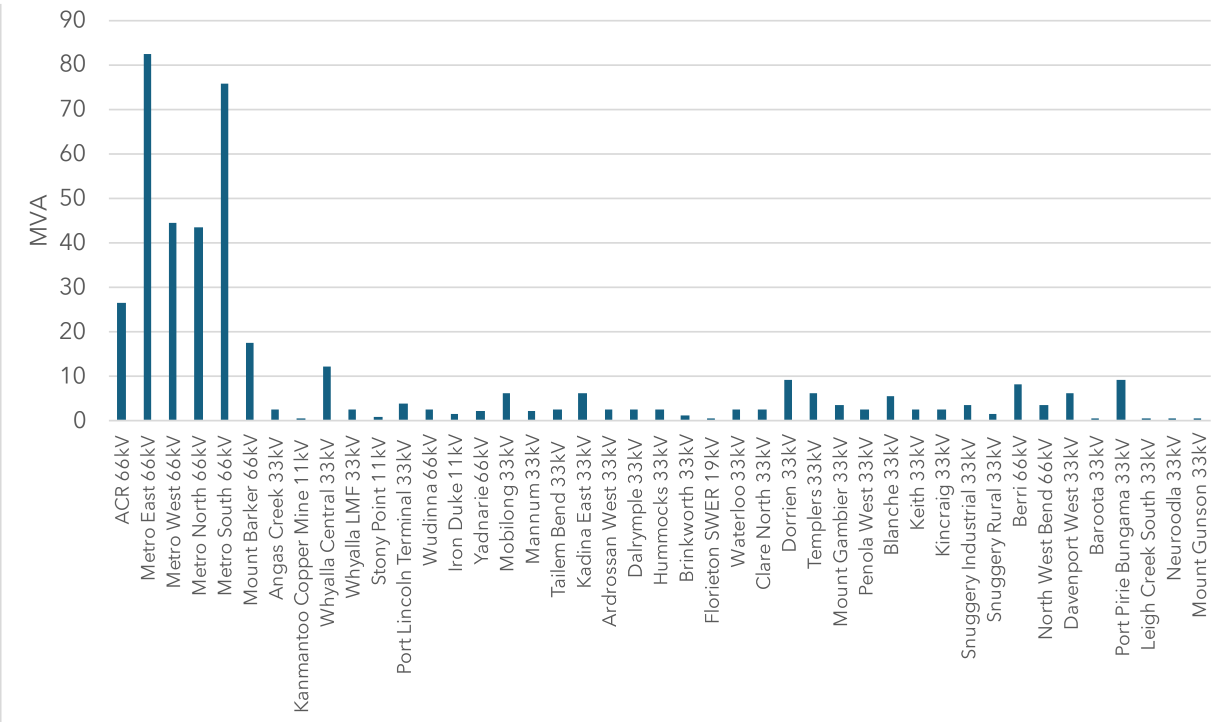
We understand that the AER is concerned about SAPN including block loads in the system forecast that are 5% of the transmission connection point threshold and not 5% of total South Australian demand. The historically highest maximum demand recorded in South Australia was 3023 MW in 2019 with 152 MW being 5% of that load. We believe that it is very unlikely for a customer to be connecting to SAPN's distribution network with that amount of load and is quite unreasonable for the AER to suggest such a threshold. AEMO considers block loads that are greater than or equal to 10MW at a system level for more than 10% of the financial year and therefore the AER's value is too restrictive[9].

What is a reasonable threshold?

SAPN deems 5% of substation capacity as fair and reasonable because they believe this threshold is not too risk-averse, allowing sensible project identification timings. They are concerned about substations already close to capacity and think 5% is appropriate to address this.

Figure 10 below shows 5% of transmission connection point capacities across SAPN's network. For commercial and CBD areas 5% is a substantial amount and in many cases is greater than AEMO's threshold. Alternatively, for rural areas, transmission connection points are small and rated between 3MVA - 10MVA. If a block load was to enter, which is typically greater than 1 MW (see appendix for a list of block loads and sizes), it would take up a significant portion of this capacity and should be considered. Based on this analysis and since the AER approves block loads greater than 1MW for Ausgrid's network we consider SAPN's 5% threshold as appropriate.

Figure 10 – Five per cent of Transmission Connection Point capacities



[9] AEMO. Forecasting approach – Electricity demand forecasting method. 2023. https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2024-electricity-demand-forecasting-methodology-consultation/electricity-demand-forecasting-methodology.pdf?la=en

(Endgame analysis using SAPN data)

5.3.3. We suggest that SAPN removes residential new loads from the system forecast and accumulating block loads before assessing materiality

After discussions with SAPN, we understand that they also include new large residential loads that are greater than 200kW into the system-level forecast and meet the 5% accumulation threshold. Based on the economic growth analysis presented previously in section 5.2.3 we don't believe that they are additional to AEMO's forecasts and are inherently included at the system level. This is because future growth in electricity is predicted to be driven by households and new dwelling connections. These new residential developments should be considered and added to the bottom-up zone substation and transmission connection point forecast.

However, SAPN has informed us that this comment only applies to one transmission connection point, Mt Barker, and the materiality of including this would be small. There are two projects to be considered, one of which will be deferred and the other has strong justification to succeed regardless of the system forecast decreasing. SAPN is concerned that making this change will impact other transmission connection point forecasts in an adverse manner due to how the AEMO tool conducts the reconciliation process. Therefore, we believe it is appropriate for SAPN to continue with their current forecasting process since the removal of residential block loads only impacts one transmission connection point.

We also recommend not accumulating block loads before assessing the 5% materiality threshold as this may count as excess block loads. From our assessment, most transmission connection points with block loads are largely driven by a single block load and the choice to accumulate is not expected to significantly change the results.

5.4. Probability of block loads entering

The AER is also concerned that block loads will not connect as expected, *"Additionally, to avoid overstating the forecast, SA Power Networks needs to carefully evaluate potential overestimations in customer-requested loads, the likelihood of projects not proceeding, and the impact of project loads on seasonal and system peak time. In the revised proposal, SA Power Networks should detail the measures it has in place to mitigate the risk of overestimation in the forecast."*

-AER draft decision SAPN 2023-2030 overview

In their assessment of block loads, SAPN does not investigate the likelihood of connections but rather considers the probability of these loads contributing to the timing of the system peak through the diversity factor.

5.4.1. Diversity factor

Block loads that have reached the committed stage in the SAPN connections process get assigned a diversity factor. We understand that SAPN assigns industrial organisations and public infrastructure a diversity factor of between 70% - 100% (AER information request 012).

We asked SAPN to investigate the time-of-day profile for different block loads which can help determine appropriate diversity factors. Assuming peak demand occurs between 7pm – 8pm[10], some patterns exist across groups. Typically processing plants contribute during peak demand and should be given a high diversity factor, for example between 70% - 100%. Industrial, commercial and agricultural block loads are less likely to contribute to the peak and their diversity factors should be lower to reflect this such as 30% - 60%. However, the profiles do vary within categories and SAPN should consult with the proposed load entering to understand their daily consumption profiles.

We are not aware of other DNSP's using diversity factors when considering the contribution of block loads to peak demand and consider this a conservative and responsible approach by SAPN.

5.4.2. Probability of load connecting

SAPN deems that once block loads reach the committed stage, they are very likely to go ahead. Endgame asked SAPN to provide information on block loads that were forecasted to enter and their outcomes, Table 1. From those that were forecasted to enter in 2022, 14 block loads connected with only 1 being cancelled. However, 4 have been delayed and 5 are awaiting confirmation. Therefore, SAPN has predicted with 60% accuracy[11]. Sensitivity analysis, such as applying a two-year delay or decreasing a small proportion of block loads, may be beneficial to understand how changes in probability impact the expenditure forecast.

Table 1 – SAPN's 2022 block load forecast

	Count	MW
Connected	14	27.58
Delayed	4	14.35
Cancelled	1	2.5
TBC	5	5.86

(Endgame analysis using SAPN data)

After conducting desktop research, it seems as though other DNSPs also use their planning and connections teams to identify probable block loads. For example, Energex uses its planning team to provide local insights. Essential Energy uses estimates of likely future large industrial loads and Special Activation Precincts whilst also conducting a sensitivity test on the impact of larger loads connecting in the future. Ausgrid uses proposed connections but applies a scaling factor of 0.5 for late-stage block loads. Except for Endeavour Energy, we believe that the other DNSPs do not conduct a detailed investigation into the probability of block loads connecting and that the diversity factor method is sufficient provided that SAPN can provide more evidence for choosing those percentages.

5.5. Sensitivity analysis

We asked SAPN to further investigate the impacts of block loads on final expenditure by conducting a sensitivity analysis. From SAPN's analysis, a complete exclusion of block-loads

[10] SAPN. DAPR. 2024. https://www.sapowernetworks.com.au/public/download.jsp?id=9716
[11] 14/24 = 0.6 (rounded)

from demand-driven project results in approximately $30mil reduction (or 15% reduction) in total expenditure.

As previously mentioned, block loads should be included but the amount should be based on their timing to peak demand and the probability of these loads entering. We recommend that SAPN conduct sensitivities to test both connection delays as well as reduced loads. We suggest that SAPN consider sensitivities that reduce the total contribution of the diversified block load by a further 10% – 50%. This will provide reassurance that the probability of these loads connecting is addressed.

6. Conclusion

This document reviewed SAPN's maximum demand forecast methodology for their revised regulatory proposal. We conclude that the methodology is sound and provides a robust forecast for network planning purposes.

6.1. Updated inputs

Furthermore, SAPN should use updated assumptions since the 2022 ESOO is now outdated. However, we recommend that SAPN uses the 2024 ISP as opposed to the ESOO 2024 because there is a marked difference in maximum demand between other AEMO publications which has not been explained by AEMO. The processes involved in the development of the forecasts in the ISP are also more robust compared to the ones involved in the ESOO.

6.2. Block loads

In particular, we don't believe that business block loads should be removed from the system-level forecast because:

- AEMO has not requested block load information from SAPN since early 2023 which included 2022 block load forecasts. SAPN now has additional block loads that are forecasted to enter and be considered for network planning purposes.
- AEMO only considers block loads greater than 10MW in their forecasts which excludes most loads that would be connecting to a distribution network.
- Economic growth in the business sector is forecasted to be very low or negative in the immediate term. This is especially true for industrial and commercial loads which are typically block loads for SAPN's purposes. We don't believe that general increases in economic growth by businesses sufficiently capture SAPN's predicted increase in block loads.

SAPN's methodology for determining diversity factors is appropriate, However, to increase condifence in the foreacsts we recommend that SAPN conduct sensitivity analysis (on top of diversity factors) to test the contribution of block loads to the demand-driven expenditures. We recommend that SAPN consider sensitivities that reduce the total contribution of the diversified block load by a further 10% – 50%.

7. Appendix

7.1. SAPN's block loads for their revised proposal forecast

Transmission Connection Point	Summer Year	Load with diversity factor applied
Ardrossan-West-33kV	2025	2
Ardrossan-West-33kV	2025	2
Ardrossan-West-33kV	2025	0.2
Berri-66kV	2025	2.3
Berri-66kV	2025	4.05
Davenport-West-33kV	2026	18
Kadina-East-33kV	2025	0.6
Kanmantoo-11kV	2025	0.3
Metro-East-66kV	2027	7
Metro-East-66kV	2025	7.6
Metro-North-66kV	2025	1.7
Metro-North-66kV	2025	8
Metro-North-66kV	2025	1.2
Metro-North-66kV	2025	1.2
Metro-North-66kV	2025	1
Metro-North-66kV	2026	1.9
Metro-North-66kV	2026	1.3
Metro-North-66kV	2026	1.8
Metro-North-66kV	2027	3.6
Metro-South-66kV	2026	4.5
Metro-South-66kV	2026	2.3

Metro-South-66kV	2025	1.1
Metro-South-66kV	2027	18.3
Metro-South-66kV	2029	-18.3
Metro-South-66kV	2029	6.5
Metro-South-66kV	2028	16
Metro-South-66kV	2030	-16
Metro-South-66kV	2030	4.38
Mobilong-33kV	2025	1
Mount-Barker-66kV	2025	8
Mount-Barker-66kV	2026	4
Mount-Gunson-33kV	2030	6.4
Port-Lincoln-Terminal-33kV	2026	4.5
Port-Lincoln-Terminal-33kV	2026	5.5
Yadnarie-66kV	2025	4.82
Yadnarie-66kV	2030	7.8

7.2. Comparison of annual consumption and max demand forecasts

We have conducted a thorough analysis of AEMO's maximum demand forecast and cannot reconcile the large change in maximum demand, especially for business and residential components, between the 2024 ISP and ESOO, Figure 11 and Figure 12.

Figure 11 - AEMO's 2024 South Australian residential and business maximum demand forecasts

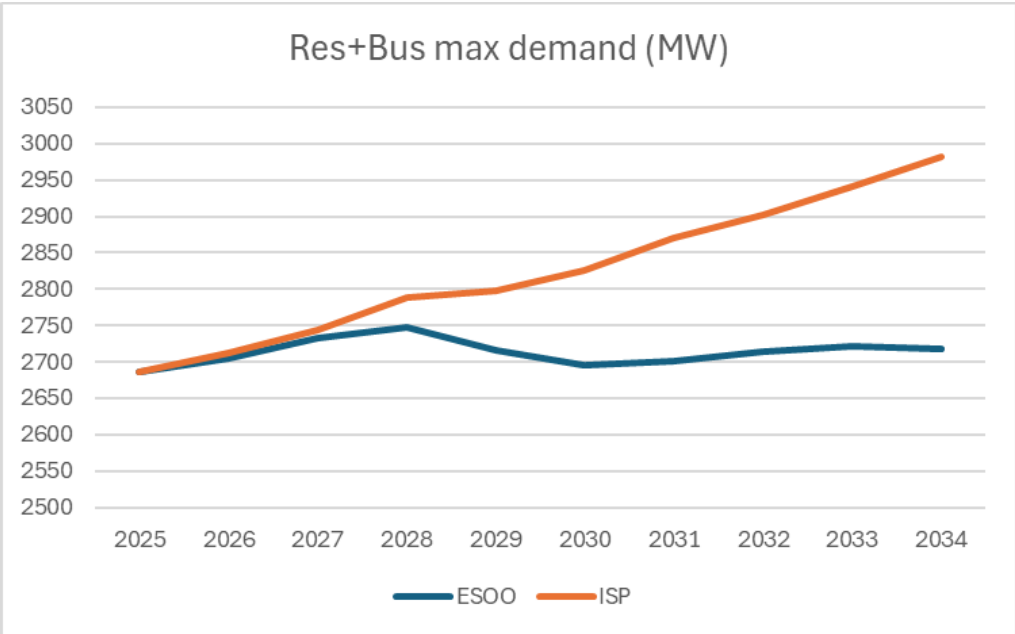
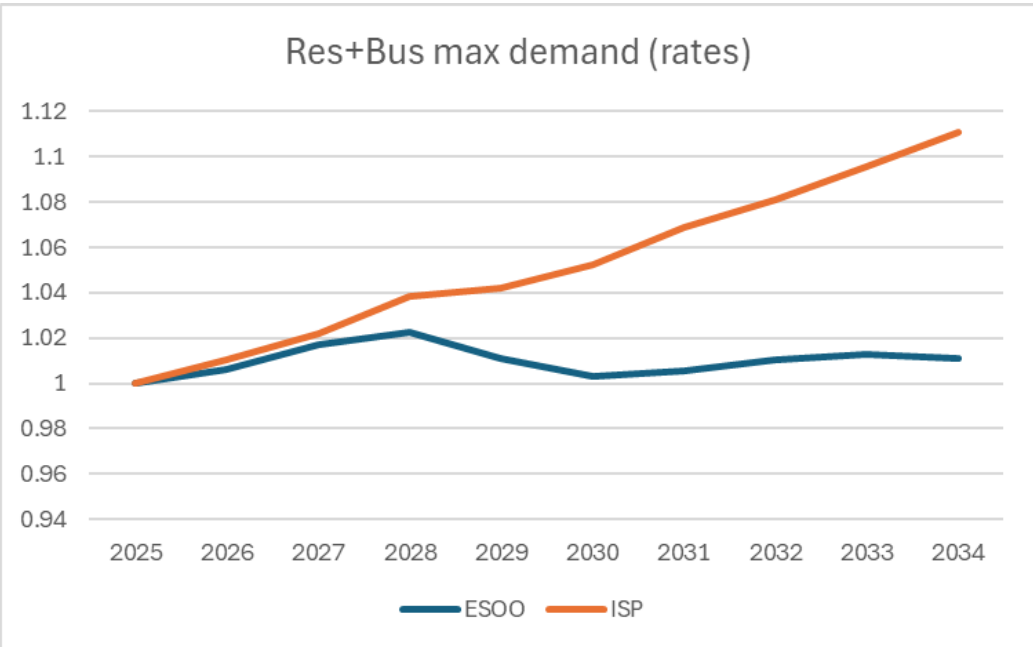


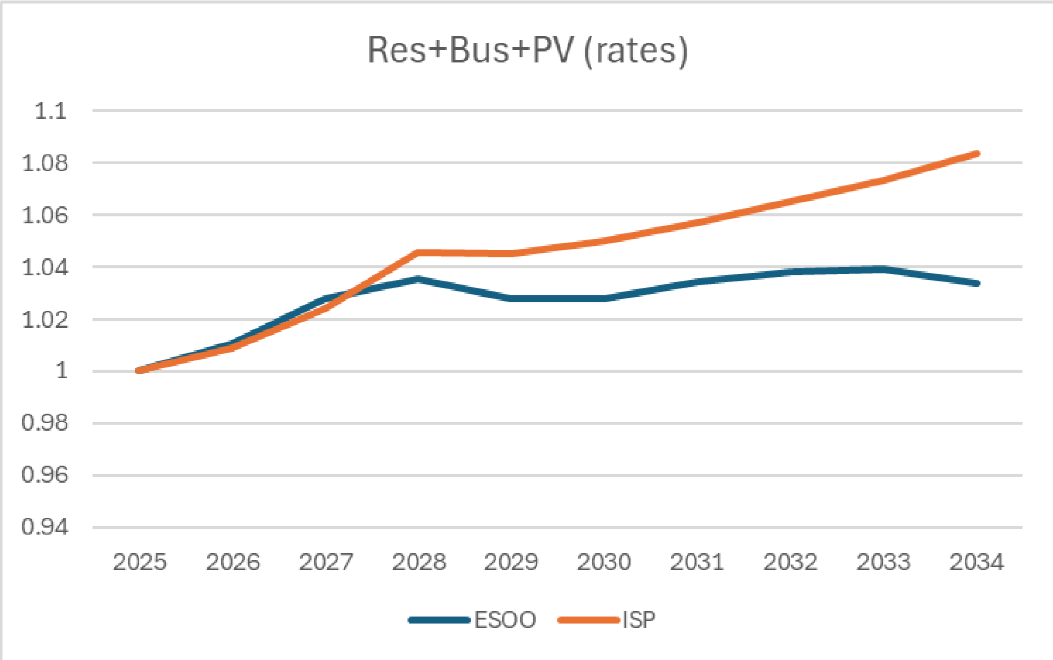
Figure 12 - AEMO's 2024 South Australian residential and business maximum demand forecast growth rates



AEMO has told us that annual consumption is an important input into the maximum demand forecasts, and we have decided to explore this further. Unfortunately, we have struggled to consolidate the two.

For annual consumption growth, the ESOO 2024 is slightly higher than the 2024 ISP in the immediate term, Figure 13. Note that we are comparing underlying demand and have included solar PV in the growth rates.

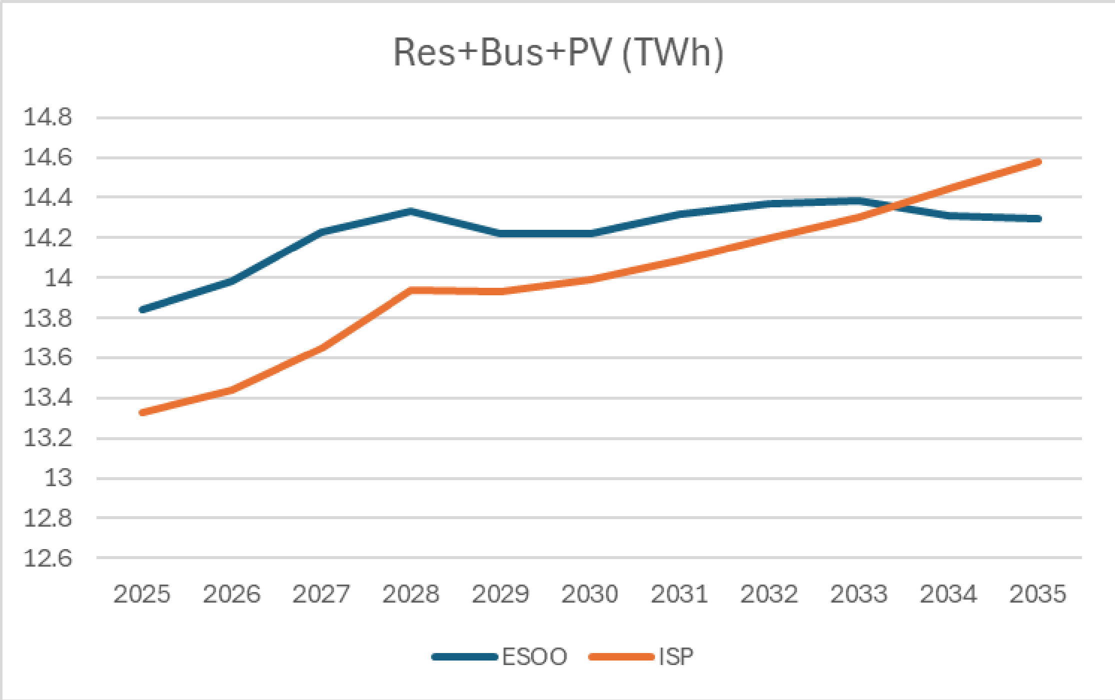
Figure 13 – AEMO's 2024 South Australian underlying annual consumption growth rates



We noticed that maximum demand growth is slower than annual consumption growth for the 2024 ESOO. Where the year-on-year (YoY) maximum demand grows at 0.11% whereas for annual consumption it is 0.3% (YoY). In the 2024 ISP, maximum demand grows faster at 1.05% (YoY) than annual consumption at 0.96% (YoY). Typically, we would expect that maximum demand grows faster than annual consumption unless AEMO assumes that residential and business connection points get less 'peaky'. If so, this is a critical assumption, and not enough discussion has been made about this issue. AEMO has not explained this during our consultations and we can only speculate that they have used milder weather years or higher price elasticity assumptions to result in this outcome.

Furthermore, the actual levels of annual consumption and maximum demand portray differing stories. Figure 11 shows stagnating or declining maximum demand whilst Figure 14 demonstrates increasing consumption. Annual consumption can increase without maximum demand increasing if consumers shift their usage to other periods of the day. We don't believe that improvements in energy efficiency can offset the growth in electrification due to the transition. Hence, we should expect that maximum demand would increase with consumption.

Figure 14 – AEMO's 2024 South Australian underlying annual consumption forecast



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