Jemena Electricity Networks (Vic) Ltd

Load Demand Forecast Procedure

JEN PR 0507

Internal

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Authorisation

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History

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1	04/02/2010	Initial Document	Tan Bui
1.1	15/02/2013	Document number added and change of title	Tan Bui
2	02/04/2015	Added reconciliation methodology	Nicole Walker
3	15/05/2019	Reviewed and updated references	Tan Bui
4	21/10/2024	Updated to include top down forecast and major customer forecast overview	Budi Soetantijo

Owning Functional Area

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GLOSSARY

Average daily temperature	The average of maximum daytime and minimum overnight temperatures.
Jemena Electricity Networks (JEN)	One of five licensed electricity distribution networks in Victoria, the JEN is 100% owned by Jemena and services over 375,000 customers via an 11,000 kilometre distribution system covering north-west greater Melbourne.
maximum demand (MD)	The highest amount of electrical power delivered, or forecast to be delivered, over a defined period (day, week, month, season or year) either at a connection point, or simultaneously at a defined set of connection points.
megavolt ampere (MVA)	Refers to a unit of measurement for the apparent power in an electrical circuit. Also million volt-amperes.
network	The apparatus, equipment, plant and buildings used to convey, and control the conveyance of, electricity to customers (whether wholesale or retail) excluding any connection assets. In relation to a Network Service Provider, a network owned, operated or controlled by that Network Service Provider.
Probability of Exceedance (POE)	The likelihood that a given level of maximum demand forecast will be met or exceeded in any given year: • 50% POE maximum demand is the level of annual demand that is expected to be exceeded one year in two. • 10% POE maximum demand is the level of annual demand that is expected to be exceeded one year in ten.
10POE condition (summer)	Refers to an average daily ambient temperature of 32.9ºC, with a typical maximum ambient temperature of 42ºC and an overnight ambient temperature of 23.8ºC.
50POE condition (summer)	Refers to an average daily ambient temperature of 29.4ºC, with a typical maximum ambient temperature of 38.0ºC and an overnight ambient temperature of 20.8ºC.
50POE and 10POE condition (winter)	50POE and 10POE condition (winter) are treated the same, referring to an average daily ambient temperature of 7ºC, with a typical maximum ambient temperature of 10ºC and an overnight ambient temperature of 4ºC.

ABBREVIATIONS

AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
DAPR	Distribution Annual Planning Report
DNSP	Distribution Network Service Provider
Fdr	Feeder
JEN	Jemena Electricity Network
HV	High Voltage
LV	Low Voltage
MD	Maximum Demand
MW	Mega-Watt
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NIEIR	National Institute of Economic and Industry Research
POE	Probability of Exceedance
TS	Terminal Station
VEDCoP	Victorian Electricity Distribution Code of Practice
ZSS	Zone Substation

1. INTRODUCTION

Load demand forecasting is a critical component of the distribution annual planning process as it is instrumental in identifying network capacity constraints and driving capital expenditure to ensure the standard of service to customers is maintained. As such, Jemena is required by the Victorian Electricity Distribution Code of Practice (VEDCoP) and National Electricity Rules to prepare load demand forecasts.

National Electricity Rules (NER) clause 5.13.1(d) states that:

> *"Each Distribution Network Service Provider must, in respect of its network:*
>
> *(1) prepare forecasts covering the forward planning period of maximum demands for:*
>
> *(i) sub-transmission lines;*
>
> *(ii) zone substations; and*
>
> *(iii) to the extent practicable, primary distribution feeders,*
>
> *having regard to:*
>
> *(iv) the number of customer connections;*
>
> *(v) energy consumption; and*
>
> *(vi) estimated total output of known embedded generating units"*

1.1 PURPOSE

The purpose of this document is to provide a high-level description of the procedure Jemena uses to produce its annual maximum load demand forecasts.

1.2 SCOPE

The scope of this document includes the high-level procedure for development of JEN internal load demand forecasts. These forecasts include the summer and winter maximum demand forecasts at the feeder, zone substation and terminal station levels (for the JEN load only) for 10% and 50% probability of exceedance scenarios. These forecasts are developed using a bottom-up methodology and are then reconciled to the top-down maximum demand forecasts produced by an independent external forecaster.

This document does not cover the procedure for spatial-level minimum demand forecasts, as it is prepared by our independent consultant.

This document also provides an overview of the independent top-down forecasts covered in Section 3.8. The objectives of this procedure are to:

- Provide accuracy and unbiasedness to the data management and construction of the forecasting model;
- Provide transparency to the process;

- Ensure a consistent and repeatable approach to the development of the JEN internal forecast from year to year;
- Align with AER's view as key features of best practice distribution load forecasting methodologies;
- Align with JEN PR 0007 "JEN Network Augmentation Planning Criteria";
- Meet regulatory obligations relating to load demand forecasting as defined in the NER and VEDCoP; and
- Facilitate continuous improvement of the load demand forecast procedure.

1.3 RESPONSIBILITIES

The Network Planning team is responsible for the development of the annual load demand forecasts for the Jemena Electricity Network and for the development and ongoing improvement of this procedure.

2. BEST PRACTICE DISTRIBUTION LOAD FORECASTING

Given the criticality of our distribution load forecasting approach, we continually review our methodology to ensure that it represents best-practice forecasting and, in turn, reflects a realistic expectation of demand load forecasting.[1]

2.1 AER'S VIEWS ON LOAD FORECASTING

One aspect of our continual review is consideration of AER feedback. As part of the 2011-15 Victorian Electricity Distribution Determination process, the AER set out what it considers to be best practice load forecasting[2] and noted advice from its consultant at the time ACIL Tasman. ACIL Tasman considered the following features are necessary to produce best practice forecasts:

- **Accuracy and unbiasedness** – careful management of data (removal of outliers, data normalisation) and forecasting model construction (choosing a parsimonious model based on sound theoretical grounds that closely fits the sample data).
- **Transparency and repeatability** – as evidenced by good documentation, including documentation of the use of judgment, which ensures consistency and minimises subjectivity in forecasts.
- **Incorporation of key drivers** – including economic growth, population growth, growth in the number of households, temperature and weather-related data (where appropriate), and growth in the numbers of air conditioning and heating systems.
- **Model validation and testing** – including assessment of statistical significance of explanatory variables, goodness of fit, in-sample forecasting performance of the model against actual data, diagnostic checking of the old models, out of sample forecast performance.

ACIL Tasman also considered the following elements to be relevant:

- **Spatial (bottom up) forecasts validated by independent system level (top down) forecasts** – best practice forecasting requires these forecasts to be prepared independently of each other. The impact of macroeconomic, demographic and weather trends are better able to be identified and forecast in system level data, whereas spatial forecasts are needed to capture underlying characteristics of areas on the network. Generally, the spatial forecasts should be constrained (or reconciled) to system level forecasts.
- **Weather normalisation** – correcting historical loads for abnormal weather conditions is an important aspect of demand forecasting. Long time-series weather and demand data are required to establish a relationship between the two and conduct weather correction. Weather correction is relevant to both system and spatial level forecasts, and the system level weather correction processes are more sophisticated and robust.
- **Adjusting for discrete block loads** – large new developments (for example, shopping centres, housing developments) should be incorporated into the forecasts, taking into account of the probability that each development might not proceed. Only block loads exceeding a certain size threshold should be included in the forecasts, forecasts; to avoid potential double counting, as historical demands incorporate block loads.
- **Incorporation of maturity profile of service area in spatial time series** – recognising the phase of growth of each zone substation, taking into account of the typical lifecycle of a zone substation, depending on its age, helps to inform likely future growth rates.

[1] As per Rule 6.5.6 (c)(3) and Rule 6.5.8(c)(3).

[2] See section 5.6.2 of AER's Victorian Electricity Distribution Determination 2011-2015 Draft Decision .

In addition to the features identified above, the AER considered that accuracy and consistency of forecasts at different levels of aggregation also affects the overall reasonableness of the forecasts, as accuracy at the total level may mask errors at lower levels (for example, at each zone substation or tariff class) that cancel each other out. The AER also considered that the use of the most recent input information is necessary in developing reasonable expectations of future conditions.

Since receiving this feedback, we reviewed and amended our demand forecasting approach to ensure that it included the features and elements (outlined above) and accordingly is consistent with what the AER considered to be best practice forecasting.

In preparing our maximum and minimum demand forecasts, JEN engages an independent consultant for the system-level (top-down) forecasts. JEN prepares the spatial level (bottom-up) maximum demand forecasts internally, and our independent consultant prepares the spatial level minimum demand forecasts.

In the more recent 2021-26 Victorian Electricity Distribution process, the AER made no specific suggestions to improve our forecasting methodology, but was concerned that our forecast differed to AEMO's forecast over the same period, Despite this, the AER accepted our augmentation forecast in full. Given this feedback, our forecasting process now also includes a cross-check and comparison against AEMO's forecast as part of our verification processes.

2.2 JEMENA'S VIEW ON BEST PRACTICE DISTRIBUTION LOAD FORECASTING AS PRESENTED IN OUR DISTRIBUTION ANNUAL PLANNING REPORT

Jemena considers the following features necessary to produce best practice maximum demand, minimum demand, energy and customer number forecasts:

- **Accuracy and unbiasedness** – careful management of data (removal of outliers, data normalisation) and forecasting model construction (choosing a prudent model based on sound theoretical grounds that closely fits the sample data);
- **Transparency and repeatability** – as evidenced by good documentation, including documentation of the use of judgment, which ensures consistency and minimises subjectivity in forecasts;
- **Incorporation of key drivers** – including economic growth, population growth, growth in the number of households, temperature and weather-related data (where appropriate), growth in the number of solar PV systems, and growth in the numbers of electric vehicles, gas electrification, air conditioning and heating systems; and
- **Model validation and testing** – including the assessment of statistical significance of explanatory variables, goodness of fit, in-sample forecasting performance of the model against actual data, diagnostic checking of old models, out-of-sample forecast performance.

JEN also considers the following elements to be relevant to maximum demand and minimum demand forecasting:

- **Independent forecasts** – spatial (bottom-up) forecasts should be validated by independent system-level (top-down) forecasts, and both spatial and system-level forecasts should be prepared independently of each other. The impact of macroeconomic, demographic and weather trends can better be identified and forecasted in system-level data, whereas spatial forecasts are needed to capture underlying characteristics of specific areas within the network. Generally, the spatial forecasts should be constrained (or reconciled) to system-level forecasts;
- **Weather normalisation** – correcting historical loads for abnormal weather conditions is an important aspect of demand forecasting. Long time-series weather and demand data are required to establish a relationship between the two and conduct weather correction;
- **Adjusting for temporary transfers** – spatial data must be adjusted for historical spot loads arising from peak load sharing and maintenance before historical trends are determined;

- **Accounting for distributed embedded generation** – noting that the network sees the net load, understanding the contribution that embedded generation has in reducing the underlying customer load;
- **Adjusting for discrete block loads** – large new developments, such as shopping centres and housing developments, should be incorporated into the forecasts, taking into account the probability that each development might not proceed. Only block loads exceeding a certain size threshold should be included in the forecasts to avoid potential double counting, as historical demands incorporate block loads; and
- **Incorporation of the maturity profile of service area in spatial time series** – recognising the phase of growth of each zone substation depending on its age, and taking into account the typical lifecycle of a zone substation, helps to inform likely future growth rates.

In preparing our maximum and minimum demand forecasts, JEN engages an independent consultant for the system-level (top-down) forecasts. JEN prepares the spatial level (bottom-up) maximum demand forecasts internally, and our independent consultant prepares the spatial level minimum demand forecasts.

3. FORECAST PROCEDURE

The procedure used for maximum load demand forecast is an integrated bottom-up and top-down forecast. The bottom-up forecast is built up at the feeder level which is prepared by JEN, and the top-down forecast is prepared by an independent consultant using an econometric model. The procedure described in this section is a bottom-up forecast, which is then reconciled to the top-down forecast, and is divided into five phases, as follows:

- Phase 1: Feeder forecast
- Phase 2: Zone substation forecast
- Phase 3: Terminal station forecast
- Phase 4: Forecast coincident demand
- Phase 5: Reconcile forecasts

Each of these phases is explained below.

3.1 PHASE 1: FEEDER FORECAST

Under the Feeder Forecast phase, the overall customer load changes (new or reductions) for each feeder are determined. These generally exclude new air conditioning installations in existing dwellings, dual occupancy and minor new or modified loads. Customer load changes come from many sources, and these include, but are not limited to:

- New connections via Jemena's CIC process, generally involving subdivisions, business projects, etc;
- Load demand changes from mainly small to medium commercial and industrial type customers, generally involving contract demand changes; and
- Business developments.

Noting this excludes major customer load connections such as large data centres, which are forecast separately in the JEN's Major Customer Forecast.

We also consider the underlying organic growth rate set up to capture growth rate resulting from new air conditioning installations in existing dwellings, dual occupancy and minor new or modified loads that have not been allowed for in the overall customer load changes. Organic growth rates are determined based on historic trends, local area knowledge (e.g. city council planning), and economic data provided by the independent external forecaster. Adjustments to organic growth rates are also made towards the end of the forecast period to take into account that known load information is limited in the later years.

Planned load transfers between feeders from committed projects involving feeder re-configurations and new feeder works are also determined and incorporated in the feeder forecast.

One of the key inputs into the Feeder Forecast module is the feeder starting point which is based on previous year's recorded maximum demands. These feeder starting points are corrected for any abnormality such as temporary load transfers, and adjusted to correspond to 50% POE (Probability of Exceedance) average daily temperature. Refer to Section 3.7 for weather normalisation of historical maximum demand methodology.

The feeder maximum load demand forecasts for forward years are then determined using feeder starting points and taking into account all load changes including overall customer load changes (new or reductions), planned load transfers and estimated organic growth rate.

Feeder forecasts are produced for a minimum of 10 years.

3.2 PHASE 2: ZONE SUBSTATION FORECAST

Similar to the Feeder Forecast module, zone substation maximum load demand forecasts start with determination of zone substation starting points followed by accounting for all load changes including overall customer load changes (new or reductions), planned load transfers and organic growth rate.

Note that the overall customer load changes (new or reductions) and planned load transfers come from feeders information and are diversified prior to being included into the zone substation forecasts. These diversity factors are the non-coincident zone substation maximum demands to the corresponding total maximum demand of feeders connected to that zone substation.

The underlying organic growth rate is used to capture organic growth from new air conditioning installations in existing dwellings, dual occupancy and minor new or modified loads that have not been allowed for in the overall customer load changes. Organic growth rates are determined based on historic trends, local area knowledge (e.g. city council planning), and economic data provided by the independent external forecaster. Adjustments to organic growth rates are also made towards the end of the forecast period to take into account that known load information is limited in the later years.

One of the key inputs into the Zone Substation Forecast module is the zone substation starting point which is based on the previous year’s recorded maximum demands. These zone substation starting points are corrected for any abnormality such as temporary load transfers, and adjusted to correspond to 50% POE (Probability of Exceedance) average daily temperature. Refer to Section 3.7 for weather normalisation of historical maximum demand methodology.

Zone substation forecasts are produced for a minimum of 10 years.

3.3 PHASE 3: TERMINAL STATION FORECAST

Similar to the Zone Substation Forecast module, terminal station maximum load demand forecasts are determined based on terminal station starting points and all load changes including overall customer load changes (new or reductions), planned load transfers and organic growth rate.

The overall customer load changes (new or reductions) and planned load transfers from zone substation information are diversified prior to being included in terminal station forecasts. These diversity factors are the non-coincident terminal station maximum demand to the corresponding total maximum demand of the zone substations connected to that terminal station.

The underlying organic growth rate is used to capture organic growth from new air conditioning installations in existing dwellings, dual occupancy and minor new or modified loads that have not been allowed for in the overall customer load changes. Organic growth rates are determined based on historic trends, local area knowledge (e.g. city council planning), and economic data provided by the independent external forecaster. Adjustments to organic growth rates are also made towards the end of the forecast period to take into account that known load information is limited in the later years.

One of the key inputs into the Terminal Station Forecast module is the terminal station starting point which is the previous year's recorded station maximum demands. These terminal station starting points are corrected for any abnormality such as temporary load transfers, and adjusted to correspond to 50% POE (Probability of Exceedance) average daily temperature. Refer to Section 3.7 for weather normalisation of historical maximum demand methodology.

Terminal station forecasts are produced for a minimum of 10 years.

3.4 PHASE 4: FORECAST COINCIDENT DEMAND

Forecasts of demand coincident to the forecast system level maximum demand are required to meet regulatory information notice (RIN) reporting requirements and as an input to the process for reconciliation to the top-down forecast. Coincident demand is determined by applying coincidence factors based on historical data to the non-coincident forecast developed above.

Formulae for the calculation of forecast demand coincident to system level maximum demand are as follows:

1. Coincidence factors

$$Fdr\ to\ system\ coincidence\ factor = \left[\frac{Historical\ fdr\ to\ system\ coincident\ MD}{Historical\ fdr\ noncoincident\ MD}\right]_{3\ year\ average}$$

$$ZSS\ to\ system\ coincidence\ factor = \left[\frac{Historical\ ZSS\ to\ system\ coincident\ MD}{Historical\ ZSS\ noncoincident\ MD}\right]_{3\ year\ average}$$

$$TS\ to\ system\ coincidence\ factor = \left[\frac{Historical\ TS\ to\ system\ coincident\ MD}{Historical\ TS\ noncoincident\ MD}\right]_{3\ year\ average}$$

2. Coincident demand

$$Fdr\ to\ system\ coincident\ demand = Fdr\ to\ system\ coincidence\ factor \times feeder\ MD\ forecast_{bottom-up}$$

$$ZSS\ to\ system\ coincident\ demand = ZSS\ to\ system\ coincidence\ factor \times ZSS\ MD\ forecast_{bottom-up}$$

$$TS\ to\ system\ coincident\ demand = TS\ to\ system\ coincidence\ factor \times TS\ MD\ forecast_{bottom-up}$$

3.5 PHASE 5: FORECAST RECONCILIATION

JEN internal bottom-up forecasts are reconciled with the independent external top-down forecasts at the system level to account for longer term forecast factors such as government policies, uptake of Consumer Energy Resources (CER) and economic conditions that are not captured by the bottom-up forecasts.

The process for reconciling the forecasts to the system level involves determining the reconciliation factors at each network level and applying them to the non-coincident bottom up forecasts.

Formulae for calculation of coincident demand and system level reconciliation factors are as follows. The calculation should be repeated for summer and winter for both 50% and 10% POE forecasts.

1. System level reconciliation factors[3]:

$$Fdr\ to\ system\ reconciliation\ factor_{year} = \frac{\left[\frac{\sum Historical\ fdr\ to\ system\ coincident\ demand}{Historical\ system\ level\ MD}\right]_{3\ year\ average}}{\left[\frac{\sum feeder\ to\ system\ coincident\ demand\ forecast}{Independent\ system\ level\ MD\ forecast}\right]_{year}}$$

$$ZSS\ to\ system\ reconciliation\ factor_{year} = \frac{\left[\frac{\sum Historical\ ZSS\ to\ system\ coincident\ demand}{Historical\ system\ level\ MD}\right]_{3\ year\ average}}{\left[\frac{\sum ZSS\ to\ system\ coincident\ demand\ forecast}{Independent\ system\ level\ MD\ forecast}\right]_{year}}$$

$$TS\ to\ system\ reconciliation\ factor_{year} = \frac{\left[\frac{\sum Historical\ TS\ to\ system\ coincident\ demand}{Historical\ system\ level\ MD}\right]_{3\ year\ average}}{\left[\frac{\sum TS\ to\ system\ coincident\ demand\ forecast}{Independent\ system\ level\ MD\ forecast}\right]_{year}}$$

2. Bottom-up forecast maximum demand reconciled to the system level forecast

$$Fdr\ MD\ forecast_{reconciled} = Fdr\ to\ system\ reconciliation\ factor \times feeder\ MD\ forecast_{bottom-up}$$

$$ZSS\ MD\ forecast_{reconciled} = ZSS\ to\ system\ reconciliation\ factor \times ZSS\ MD\ forecast_{bottom-up}$$

$$TS\ MD\ forecast_{reconciled} = TS\ to\ system\ reconciliation\ factor \times TS\ MD\ forecast_{bottom-up}$$

3.6 FORECASTING PROCESS FLOWCHART

The flowchart of the JEN Load Demand Forecast procedure is outlined in Appendix A.

3.7 METHODOLOGY TO NORMALISE ACTUAL MAXIMUM DEMAND TO 10TH & 50TH PERCENTILE AVERAGE DAILY TEMPERATURES

This section provides a summary of the methodology used to normalise actual maximum demand to 10% and 50% percentile average daily temperatures.

3.7.1 10TH & 50TH PERCENTILE AVERAGE TEMPERATURES

The average daily temperatures correspond to 10% and 50% POE are provided in Table 3.1 below. It is no longer necessary to adjust winter MD's as the sensitivity is negligible during winter.

Table 3–1: Summer and winter MD temperature standards

Probability of Exceedance	10%	50%
Summer average daily temperature	32.9°C	29.4°C
Winter average daily temperature	5.4°C	7.1°C

[3] Exclude MB demand from calculations. This station has constant load and therefore a reconciliation factor of 1.

3.7.2 NORMALISATION OF HISTORICAL MAXIMUM DEMAND

The methodology used to determine the 'temperature sensitivity' factors used to normalise the historical maximum demands to the 10% and 50% POE are described below.

1. Determine the daily historical maximum demand from the metering data.
2. Calculate the corresponding average daily temperatures from daily maximum daytime and minimum overnight temperatures. The temperature data are obtained from a weather station located at Keilor terminal station.
3. For each terminal station, zone substation, or feeder, plot the daily maximum demand against the average daily temperature for summer.
4. Draw a second order (Parabola) line of best fit for each graph that represents the daily peaks at different temperatures. Note that representation of average daily temperatures above 20ºC would provide a better parabolic line of best fit.
5. Determine the Parabolic formulae for each terminal station, zone substation and feeder from the lines of best fit.
6. These 'temperature sensitivity' parabolic formulae are then used to normalise historical maximum demand to the 10% and 50% POE temperatures by applying the following equation:
7. $$\frac{MD\ at\ 10\%\ or\ 50\%\ PoE\ temperature}{Actual\ demand\ recorded} = \frac{f(32.9℃\ or\ 29.4℃)}{f(corresponding\ temperature\ for\ actual\ demand)}$$

   Note that this application is effectively in Per Unit terms rather than actual magnitude. These formulae are generally restricted to a maximum average daily temperature limit of 36ºC. Beyond this level is treated as a constant 36ºC, which represents a saturation point.

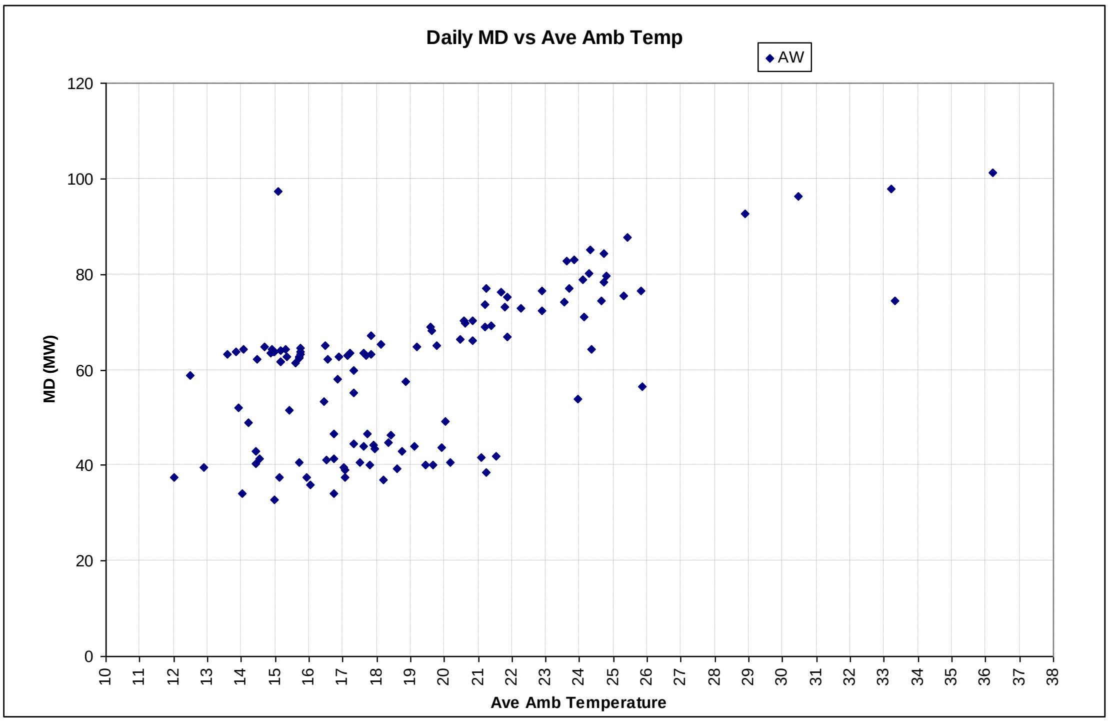
JEN has working notes related to results of regression analysis. The working notes include graphs of 'maximum daily demand versus average daily temperature' sensitivities for each terminal station, zone substation and feeder for summer. The temperature corrections are incorporated in the maximum load demand forecast model.

JEN does not analyse trends in weather patterns and hence does not incorporate these in the spatial-level forecasts.

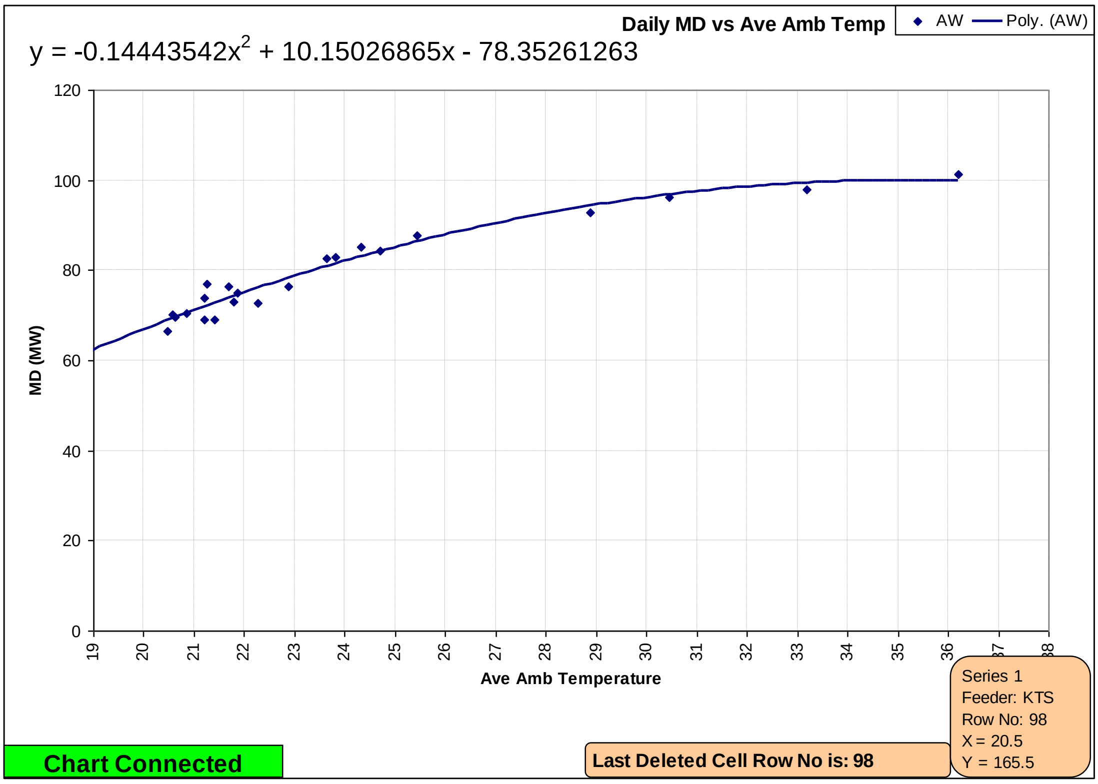
3.7.3 EXAMPLE

An example of zone substation AW is provided below on how the maximum demand is normalised to the 10% and 50% POE temperatures.

A graph of the raw data of daily maximum demand versus average daily temperature is produced below for the summer period.



Draw a second order (Parabola) line of best fit for each graph that represents the daily peaks at different temperatures. (This is done by deleting unwanted points on the graph to achieve the line of best fit formulae). Note that representation of average daily temperatures above 20ºC would provide a better parabolic line of best fit.



Record equation for line of best fit which will be used to determine the ratio for the normalisation. The summer maximum demand and its corresponding average daily ambient temperature is also required.

In this case, zone substation AW has a recorded summer maximum demand of 101.2MW with the corresponding average daily ambient temperature of 36.2ºC.

The summer maximum demand at 50% POE temperature would be:

$$\frac{MD\ at\ 50\%\ PoE\ temperature}{Actual\ demand\ recorded} = \frac{f(29.4℃)}{f(36.2℃)}$$

$$MD\ at\ 50\%\ PoE\ temp = 101.2 \times \frac{-0.14443542 \times (29.4)^2 + 10.15026865 \times (29.4) - 78.35261263}{-0.14443542 \times (36.2)^2 + 10.15026865 \times (36.2) - 78.35261263}$$

$$= 96.6\ MW$$

The summer maximum demand at 10% POE temperature would be:

$$\frac{MD\ at\ 10\%\ PoE\ temperature}{Actual\ demand\ recorded} = \frac{f(32.9℃)}{f(36.2℃)}$$

$$MD\ at\ 10\%\ PoE\ temp = 101.2 \times \frac{-0.14443542 \times (32.9)^2 + 10.15026865 \times (32.9) - 78.35261263}{-0.14443542 \times (36.2)^2 + 10.15026865 \times (36.2) - 78.35261263}$$

$$= 100.7\ MW$$

3.8 TOP-DOWN FORECAST

The independent external top-down forecasts at system level considers drivers like weather conditions, new technologies (solar PV, batteries, EVs, and electrification), and macro-economic trends in Jemena electricity network.

The top-down forecasts includes detailed models for native demand, CER forecasts, electrification impacts, and large generators to create a timeseries forecast (instead of only forecast the peak demand) to allow structural changes in load consumption and the impact of the new technologies on maximum and minimum demand.

The top-down forecasts model utilises various historical and forecast data sources, including:

- An economic outlook for Victoria and JEN's supply area, as measured by the Victorian Gross State Product (**GSP**) growth projections;
- Growth in customer numbers in local government areas and for Jemena's supply area, as measured by the number of inhabitants;
- Solar PV generation capacity and battery storage based on analysis of historical installation rates and AEMO's 2024 Forecasting Assumptions Update and Scenarios Report – Inputs and Assumptions Workbook[4];
- Electricity prices, comprising network use of system (**NUoS**) charges, wholesale electricity costs and other costs such as retail margin applied to electricity sales;
- Projections of uptake of electric vehicles based on AEMO's Integrated System Plan (**ISP**) inputs and assumptions;

[4] Refer to AEMO | 2024 Forecasting Assumptions Update Consultation

- Projections of uptake of gas electrification based on Victoria's Gas Substitution Roadmap[5], including a new policy made in July 2023 to phase out new residential gas connections from 1 January 2024; and
- Variation in temperature patterns (weather).

For a detailed methodology of the top-down forecasts, refer to Blunomy's Vision Modelling Guide.

3.9 MAJOR CUSTOMER DEMAND FORECAST

Over the past two years, JEN has received an unprecedented number of data centre and major load connection enquiries, many of which require feasibility assessments across multiple locations within the service area. Many of these enquiries are now advancing to formal connection applications, offers, and delivery.

Due to the uncertainty surrounding the commitment, timing, and load uptake of these uncommitted connections, their aggregated maximum demand has yet to be included in JEN's underlying demand forecasts. Instead, moderated block load forecasts for each affected network asset are created.

This approach allows us to identify which network limitations are specifically due to a major customer connection. The method for forecasting major customer block loads is based on the customers' own demand forecasts which we moderate based on our assessment of each connection's likelihood and uptake.

Likelihoods are assigned to each connection based on the project's status and progression through the connection process, ranging from "In Flight" to "Unlikely." These likelihoods help create moderated maximum demand uptake profiles that adjust the timing and magnitude of the customers' load uptake. To establish a range of maximum demand forecasts scenarios., we developed three load scenarios: Base, Low, and High.

The network assets for each of these maximum demand forecasts are identified, and the likelihood of the connection going ahead is assessed. Using these moderated forecasts, the network asset demand forecast is calculated for each asset and in turn the affected upstream assets. For customers with recently completed connection projects, the load uptake forecasts are not moderated. For a detailed methodology of JEN's major customers, refer to ELE-999-PA-EL-007 Major Customer Forecast Methodology.

3.10 PROCEDURE VERIFICATION

Maximum demand is reviewed on an annual basis following the end of the summer period (31 March).

Actual summer maximum demand values are extracted, adjusted for abnormals (e.g. transfers), and temperature corrected using the methodology described in section 3.7. This data is then compared to the most recent maximum demand forecast for that year.

Where significant discrepancies between forecast and actual maximum demand are found, the cause is investigated. In many cases, discrepancies are due to unforseen changes in customer project timelines. Where a cause of the discrepancy cannot be found, the forecast procedure is reviewed.

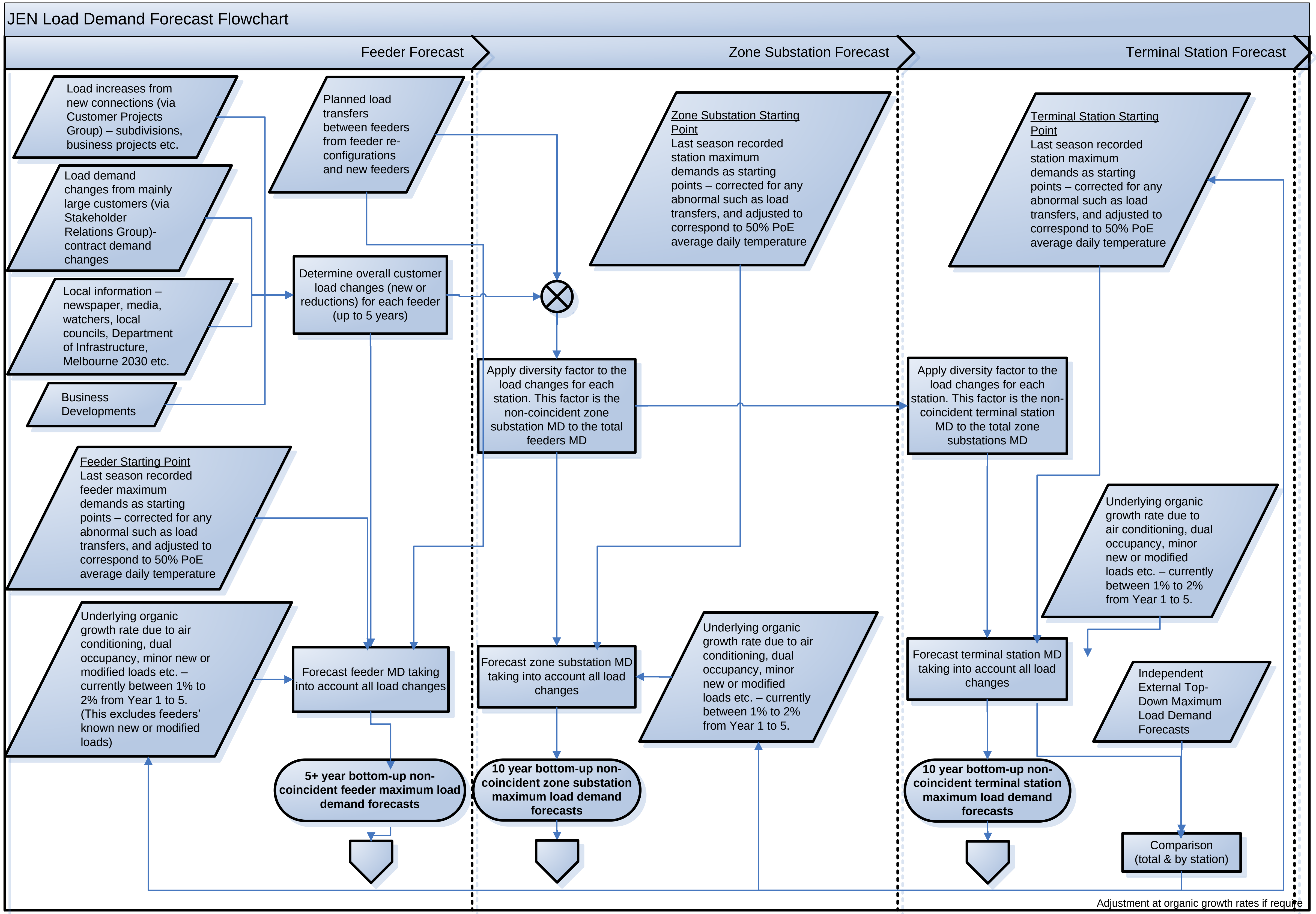
Information gathered from the forecast verification process is incorporated into the next forecast.

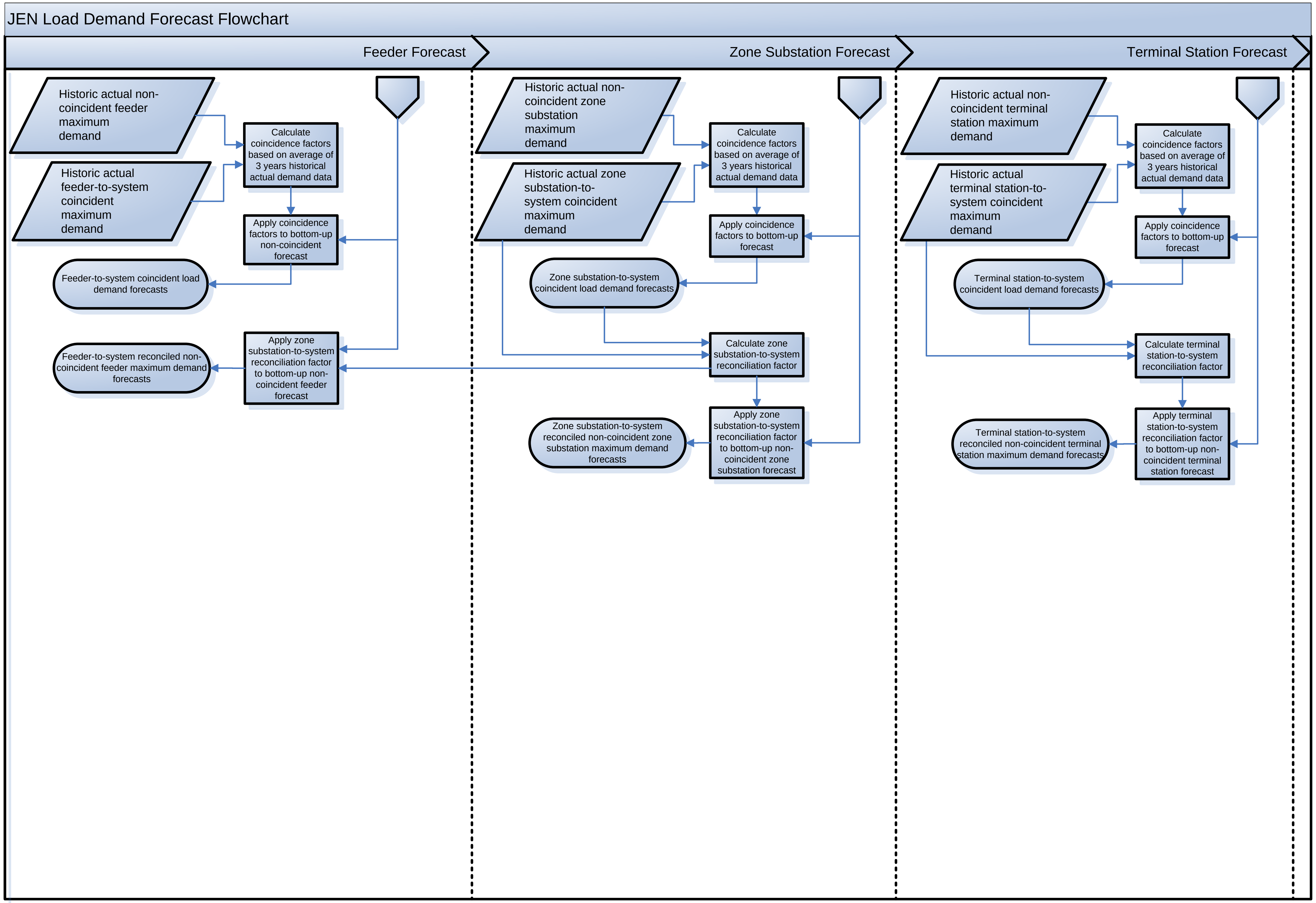
Maximum demand forecasts are also compared against those produced by AEMO.

[5] Refer to Victoria's Gas Substitution Roadmap (planning.vic.gov.au)

Appendix A
Load Demand Forecast Flowchart

A1. LOAD DEMAND FORECAST FLOWCHART




JEN Load Demand Forecast Flowchart
Feeder Forecast
Zone Substation Forecast
Terminal Station Forecast
Historic actual non-coincident feeder maximum demand
Historic actual feeder-to-system coincident maximum demand
Calculate coincidence factors based on average of 3 years historical actual demand data
Apply coincidence factors to bottom-up non-coincident forecast
Feeder-to-system coincident load demand forecasts
Apply zone substation-to-system reconciliation factor to bottom-up non-coincident feeder forecast
Feeder-to-system reconciled non-coincident feeder maximum demand forecasts
Historic actual non-coincident zone substation maximum demand
Historic actual zone substation-to-system coincident maximum demand
Calculate coincidence factors based on average of 3 years historical actual demand data
Apply coincidence factors to bottom-up forecast
Zone substation-to-system coincident load demand forecasts
Calculate zone substation-to-system reconciliation factor
Apply zone substation-to-system reconciliation factor to bottom-up non-coincident zone substation forecast
Zone substation-to-system reconciled non-coincident zone substation maximum demand forecasts
Historic actual non-coincident terminal station maximum demand
Historic actual terminal station-to-system coincident maximum demand
Calculate coincidence factors based on average of 3 years historical actual demand data
Apply coincidence factors to bottom-up forecast
Terminal station-to-system coincident load demand forecasts
Calculate terminal station-to-system reconciliation factor
Apply terminal station-to-system reconciliation factor to bottom-up non-coincident terminal station forecast
Terminal station-to-system reconciled non-coincident terminal station maximum demand forecasts

