Jemena Electricity Networks (Vic) Ltd

Load Demand Forecast Procedure

JEN PR 0507

Internal

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Authorisation

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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 319,000 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 Exceedence (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 derived by NIEIR and adopted by JEN, 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 derived by NIEIR and adopted by JEN, 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
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 Exceedence
TS	Terminal Station
VEDC	Victorian Electricity Distribution Code
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 (VEDC) 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.

For detailed work instructions of the forecasting model, refer to JEN WI 0502 "JEN Load Demand Forecast Work Instruction"[1].

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 (JEN load only) for 10% and 50% probability of exceedence 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 include the procedure used by any independent external forecaster for producing top-down forecasts.

[1] Jemena, *'JEN WI 0502 JEN Load Demand Forecast Work Instruction'*, V1.6, May 2019

1.3 OBJECTIVES

The objectives of this procedure are to:

- Provide an accuracy and unbiasedness to the data management and construction of 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 VEDC; and
- Facilitate continuous improvement of the load demand forecast procedure.

1.4 RESPONSIBILITIES

The Network Capacity Planning & Assessment 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

This section outlines the AER and its consultant's (ACIL Tasman Consulting, now known as ACIL Allen Consulting) view during the Price Review 2011-15, as the key features of best practice distribution load forecasting methodologies2. The presence of such methodological features (as explained for each below) is an important factor in determining whether JEN has, pursuant to clauses 6.5.6(c)(3) and 6.5.7(c)(3) of the NER, produced forecasts that reasonably reflect a realistic expectation of the demand forecast and cost inputs to achieve the operating expenditure objectives and capital expenditure objectives, respectively.

AER's consultant (ACIL Tasman) considered the following features necessary to produce best practice maximum demand, energy and customer number 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.

AER's consultant (ACIL Tasman) also considered the following elements to be relevant to maximum demand forecasting:

- 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 temporary transfers—spatial data must be adjusted for historical spot loads arising from peak load sharing and maintenance, before historical trends are determined.
- 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, 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.

In addition to the features identified above, the AER considers 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

[2] Refer to Section 5.6.2 of the report "Draft decision, Victorian electricity distribution network service providers, distribution determination 2011-2015, June 2010", which is available on the AER website: http://www.aer.gov.au/node/7209 .

out. The AER also considers that the use of the most recent input information is necessary in developing reasonable expectations of future conditions.

Following the AER Final Determination 2011-15, JEN reviewed its load demand forecast methodology and has incorporated the AER and its consultant's view of the features outlined above. JEN considers its current methodology adopted, which is explained in Section 3, is in line with the AER's view of 'best practice methodology'.

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 (up to 5 years) 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 not limited to:

- New connections via Jemena's CIC process, generally involving subdivisions, business projects, etc;
- Load demand changes from mainly large customers via Jemena's Sales & Commercial team, generally involving contract demand changes;
- Local information such as newspaper, media, local councils, Metropolitan Planning Authority, Melbourne 2030, etc;
- Business developments.

Underlying organic growth rate is set up to capture growth rate that are resulted 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 Exceedence) 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 5 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 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 factors such as government policies 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 daily maximum demand for summer period from the specific excel spreadsheet stored in the network planning drive.
   Eg: To determine the 'temperature sensitivity' factors used to normalise the historical maximum demands for feeders, use the excel spreadsheet "2009 Feeder Summer Temperature Sensitivity.xls" located in W:\network planning\feeder forecasts & MDs\2009 Forecasts\Temperature Sensitivity 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. $$\frac{MD \text{ at } 10\% \text{ or } 50\% \text{ } PoE \text{ temperature}}{Actual \text{ demand recorded}} = \frac{f(32.9℃ \text{ or } 29.4℃)}{f(corresponding \text{ temperature for actual demand})}$$

   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.

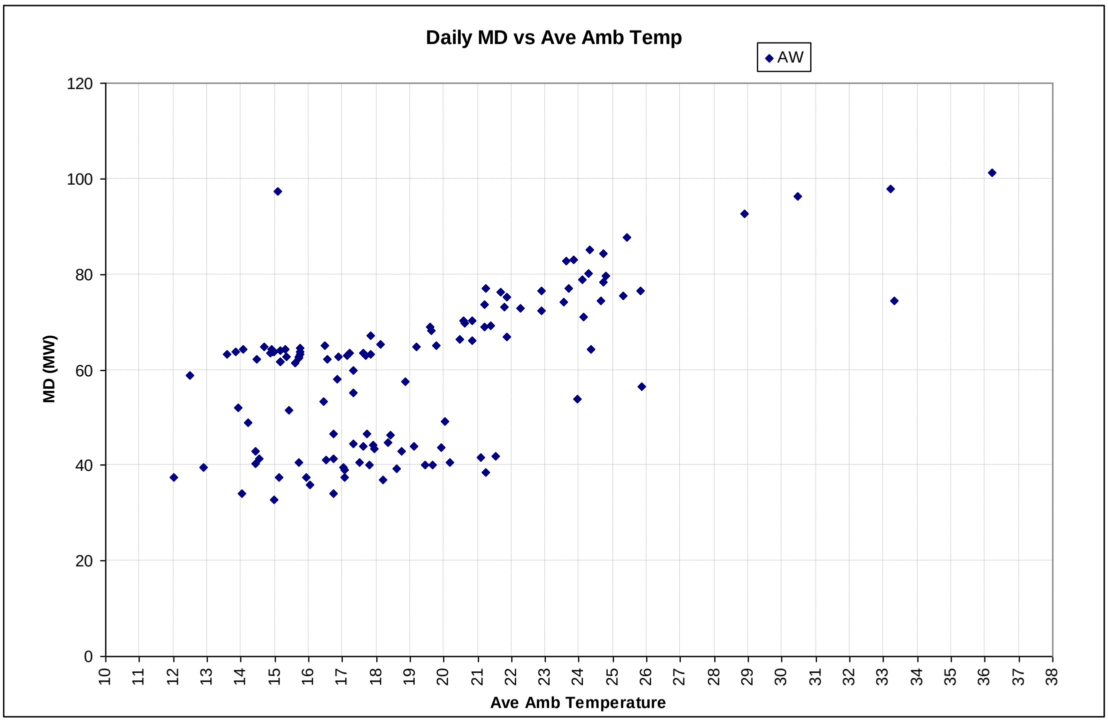
JEN has working notes related to results of regression analysis. The working notes include graphs of 'maximum daily demand versus average daily temperature' sensitivities for each terminal station, zone substation and feeder for summer. The temperature corrections are incorporated in the maximum load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

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

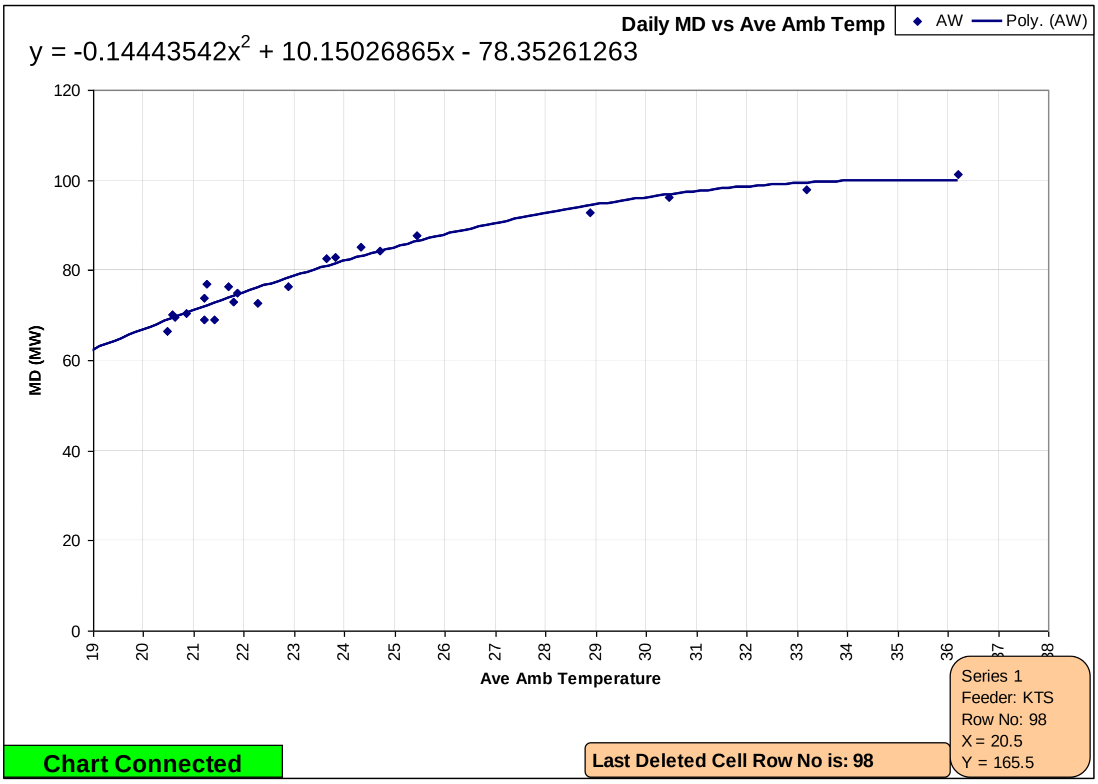
3.7.3 EXAMPLE

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 2008/09 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:

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

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

$$= 100.7\ MW$$

4. 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.

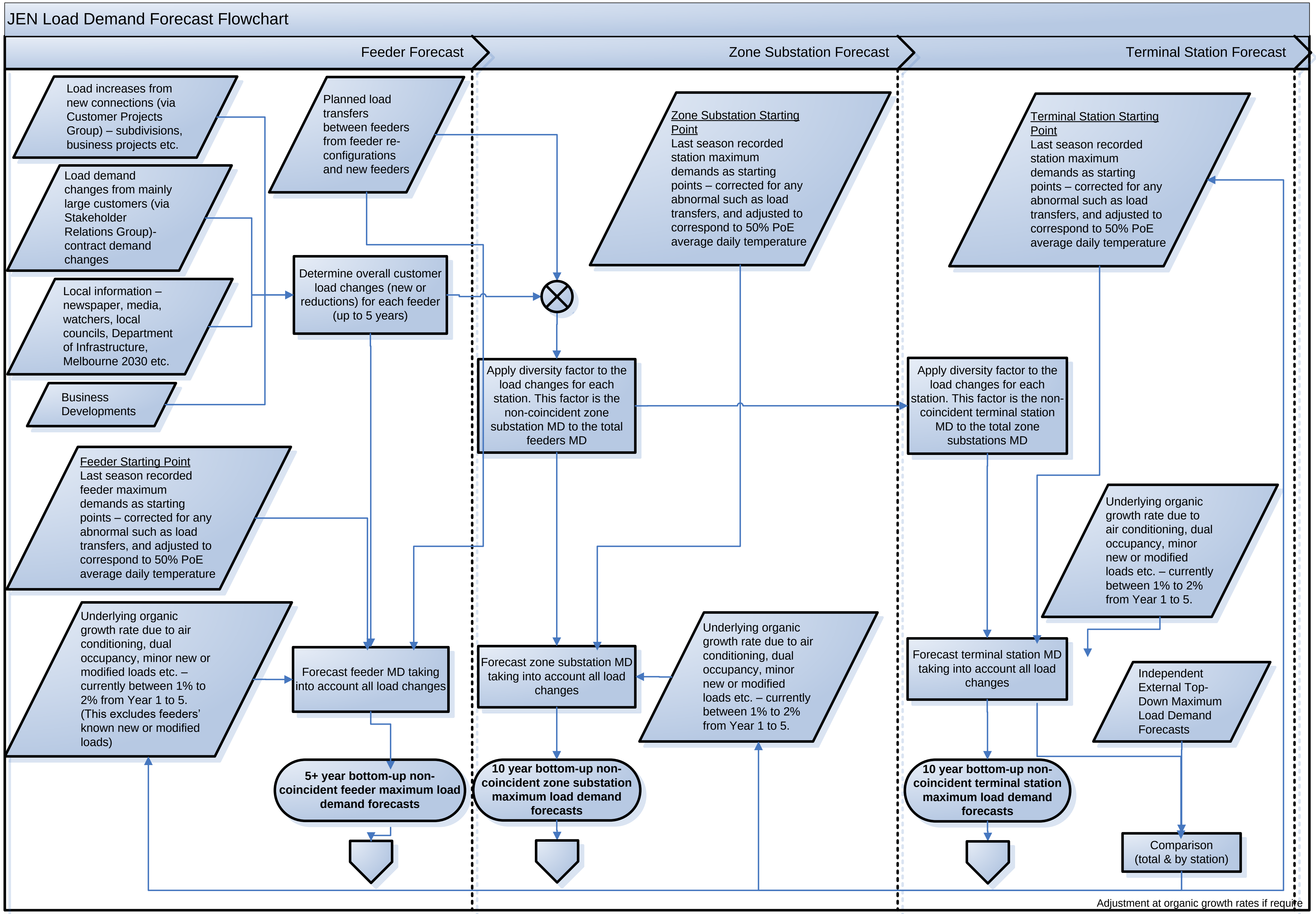
Where significant discrepancies between forecast and actual maximum demand are found, the cause is investigated. In many cases, discrepancies are due to unforseen changes in customer project timelines. Where a cause of the discrepancy cannot be found, the forecast procedure is reviewed.

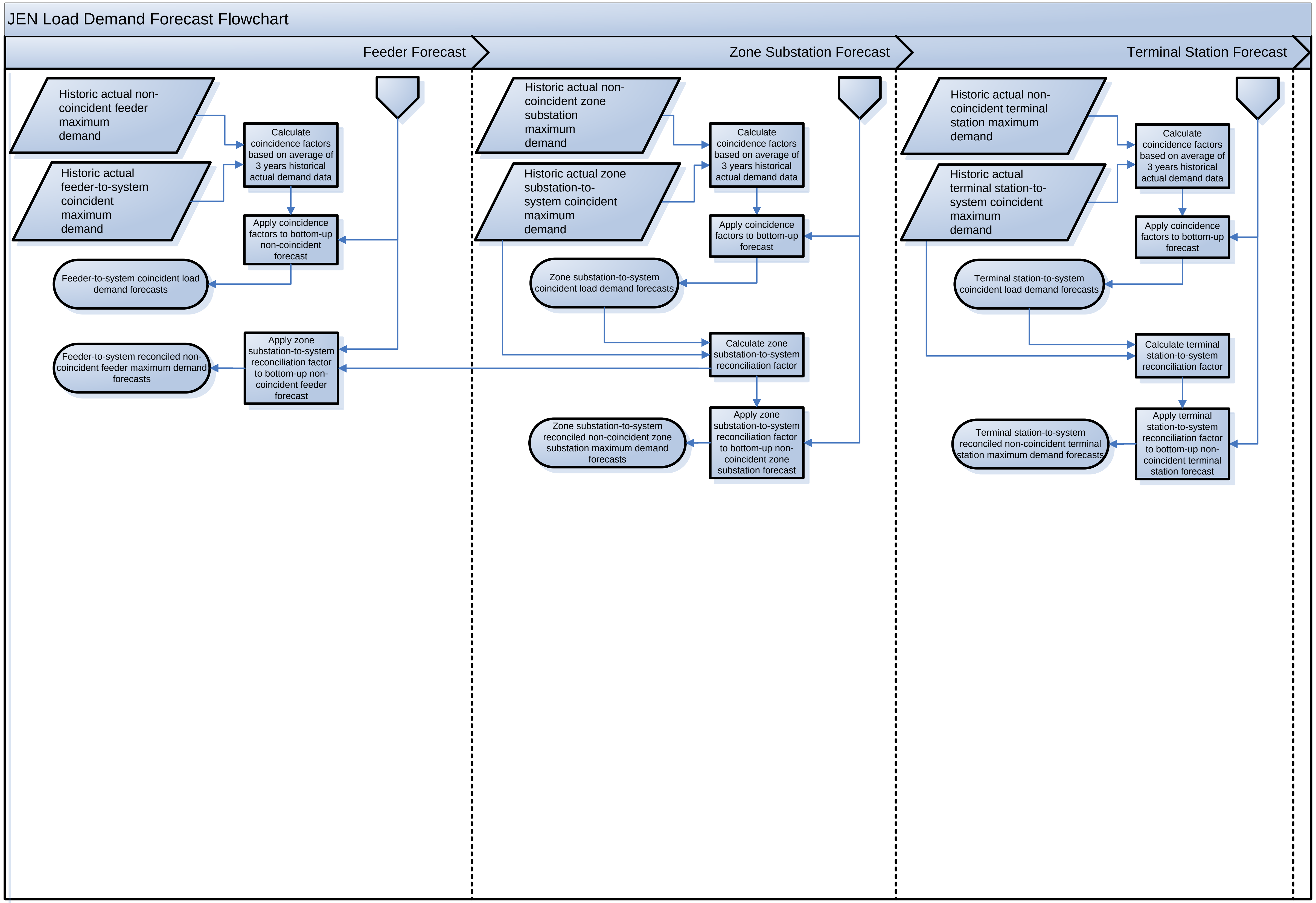
Long-term forecasts are also verified by comparison of several previous years' forecasts to adjusted historical actual maximum demand. This comparison is used to verify underlying growth rates and assumed uptake rates for customer projects.

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

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

