Jemena Electricity Networks (Vic) Ltd

Response to the Price Reset Regulatory Information Notice

Written Response

Information for the 2021-2026 Regulatory RIN

16. Demands & Connections Forecast

16.1 Provide and describe the methodology and assumptions used to prepare the following forecasts for the *forthcoming regulatory control period*:

(a) *maximum demand*; and

(b) number of new *connections*.

16.1 (a)
The process for preparing maximum demand forecasts involved two independent sets of forecasts prepared annually as described in the table below.

Forecast type	Forecast description
System level (i.e. top-down) forecast	• Prepared by an independent external (macro) economic forecaster ACIL Allen Consulting—refer to Attachment 05-03 • Prepared using econometric techniques • For details regarding the system level forecast methodology and assumptions, see Chapter 5 of Attachment 05-03.
Spatial level (i.e. bottom-up) forecast	• Prepared internally by JEN • JEN reconciles its spatial forecasts to the system forecast at the total network level to produce the final set of maximum demand forecasts, which is used in this submission • For details regarding the spatial forecast and assumptions, see procedure document titled *JEN - RIN - Support - JEN PR0507- Internal Load Demand Forecast Procedure – 20200131 - Public* in JEN's capex supporting documents.

16.1 (b)
The process for preparing new connection forecasts involved two sets of forecasts prepared as described in the table below.

Forecast type	Forecast description
Global level (i.e. top-down) connections capex forecast by JEN's ERP system service codes (**service codes**)	• The methodology and assumptions for the global level (i.e. top-down) connections capex forecast by service codes is documented in the document titled *JEN - RIN - Support - ELE PR 0019 Connection forecast methodology paper – 2020131 – Confidential* in JEN's capex supporting documents
Spatial level (i.e. bottom-up) forecast	• The spatial level (i.e. bottom up) forecast methodology for the volume and descriptor metric expenditure (in Tables 2.5.1, 2.5.2 and 2.5.3 of Workbook 1 – Regulatory determination, regulatory template 2.5) is derived using the connection subcategory forecast expenditure and 2018 actual expenditure ratio, multiplied by the 2018 actual volume or descriptor metric expenditure as the 'base' year. The forecast volumes by connection classification in Table 2.5.3 is further split into New Connections and upgrade to Existing Connections using a sample of projects for each connection subcategory • The connection subcategory expenditure forecast is derived from the global level connections capex forecast output using the JEN ERP system service code mapping method. Essentially, the volume and descriptor metric expenditure forecast in Tables 2.5.1, 2.5.2 and 2.5.3 of Workbook 1 – Regulatory determination, regulatory template 2.5 is growing or declining at the same rate as the connection subcategory expenditure level.

16.2 Provide:

(a) the model(s) *Jemena* used to forecast new *connections* and *maximum demand*;

(b) where *Jemena's* approach to weather correction has changed since demand forecasts were submitted to the AER as part of the previous regulatory determination, provide historically consistent weather corrected maximum demand data, as per the format in *Workbook 1 – Regulatory determination, regulatory templates* 3.4 and 5.4 using *Jemena's* current approach. If any of this data is unavailable, explain why;

(c) for new *connections*, volume and expenditure data requested in *Workbook 1 – Regulatory determination, regulatory template* 2.5; and

(d) any supporting information or calculations that illustrate how information extracted from *Jemena's* forecasting model(s) reconciles to, and explains any differences from, information provided in *Workbook 1 – Regulatory determination, regulatory templates* 2.5, 3.4 and 5.4.

16.2 (a)
The models Jemena used to forecast new connections and maximum demand are outlined in the table below.

Forecast Model	Spreadsheet Name
Connections forecast model	*JEN - RIN - Support – JEN CIC model – 20200131 - Confidential* - global and spatial level connections capex forecast model
System level (top-down) maximum demand forecasts model	ACIL Allen's electricity demand forecast models in JEN – ACIL Allen Att 05-03 Electricity demand forecasts report - 20200131 - Public
Spatial level (bottom-up) maximum demand forecasts model	*JEN – RIN – Support - JEN spatial level maximum demand forecasts model_2019_final_30Oct19 – 20200131 – Confidential* - contains 15 linking Excel spreadsheets

16.2 (b)
Weather corrected maximum demand data has been provided as per the format in regulatory templates 3.4 and 5.4 using JEN's current approach. The methodology has been described in references provided in 16.1 (a) above.

16.2 (c)
For new connections forecast, volume and expenditure data has been provided as per Workbook 1 – Regulatory determination, regulatory template 2.5.

16.2 (d)
All information provided in Workbook 1 – Regulatory determination, regulatory templates 2.5, 3.4 and 5.4 are consistent with JEN's forecasting models. For supporting documents related to methodologies, see 16.1 above and for models, see 16.2 (a) above.

16.3 For each of the methodologies provided and described in response to paragraph 16.1, and, where relevant, data requested under paragraphs 16.2(b) and 16.2(c), explain or provide (as appropriate):

(a) the models used;

(b) a global[1] (top-down) and spatial[2] (bottom-up) demand forecast;

[1] A global level forecast is the demand forecast that applies to the *network* service provider's entire *network*.

[2] A spatial forecast applies to elements of the *network*. For transmission *network* service providers (TNSPs), spatial forecasts could be at the level of *connection points* with distribution network service providers (*DNSPs*) and major *customers*. For *DNSPs*, spatial forecasts could be at the level of *connection point*, *zone substations* and/or HV feeders.

(c) the inputs and assumptions used in the models (including in relation to economic growth, *connections* numbers and policy changes and provide any associated models or data relevant to justifying these inputs and assumptions);

(d) the *weather correction* methodology, how *weather* data has been used, and how *Jemena's* approach to *weather correction* has changed over time;

(e) an outline of the treatment of *block loads*, *transfers* and *switching* within the forecasting process;

(f) each appliance model[3] used, where used, or assumptions relating to *average customer* energy usage (by *customer* type);

(g) how the forecasting methodology used is consistent with, and takes into account, historical observations (where appropriate), including any calibration processes undertaken within the model (specifically whether the load forecast is matched against actual historical load on the system and *substations*);

(h) how the resulting forecast data is consistent across forecasts provided for each *network* element identified in *Workbook 1 – Regulatory determination, regulatory template* 5.4 and system wide forecasts;

(i) how the forecasts resulting from these methods and assumptions have been used in determining the following:

    (i) *capex* forecasts; and

    (ii) *opex* forecasts;

(j) whether *Jemena* used the forecasting model(s) it used in the joint planning process for the purposes of its *regulatory proposal*;

(k) whether *Jemena's* forecasts both *coincident* and *non-coincident maximum demand* at the feeder, *connection point*, *sub-transmission substation* and *zone substation* level, and how these forecasts reconcile with the system level forecasts (including how various assumptions that are allowed for at the system level relate to the *network* level forecasts);

(l) whether *Jemena* records historical *maximum demand* in *MW*, *MVA* or both;

(m) the *probability of exceedance* that *Jemena* uses in *network planning*;

(n) the contingency planning process, in particular the process used to assess high system demand;

(o) how risk is managed across the *network*, particularly in relation to load sharing across *network* elements and *non-network* solutions to peak demand events;

(p) whether and how the *maximum demand* forecasts underlying the *regulatory proposal* reconcile with any demand information or related planning statements published by AEMO, as well as forecasts produced by any *transmission network service providers* connected to *Jemena's network*;

(q) how the normal and emergency ratings are used in determining capacity for individual *zone substations* and *sub-transmission lines*;

(r) where *Jemena* proposes to commence or continue a demand-related *capex project* or *program* during the *forthcoming regulatory control period* on a *HV feeder*:

[3] A *NSP* may incorporate an appliance model in its demand forecasting method to account for the effects of the uptake of appliances (such as air-conditioners) on *maximum demand*.

(i) for each feeder from the *zone substation* that is the connecting *zone substation* for the relevant *HV feeder*, and any other feeders that the relevant *HV feeder* can transfer load to or from:

(A) assumed future load *transfers* between feeders;

(B) assumed feeder underlying load growth rates (exclusive of *transfers* and specific *customer* developments); and

(C) assumed *block loads*, and associated demand assumptions;

(ii) existing *embedded generation* capacity, and associated assumptions on the impact on demand levels;

(iii) assumed future *embedded generation* capacity, and associated assumptions on the impact on demand levels;

(iv) existing *non-network* solutions, and the associated assumptions on the impact on demand levels;

(v) assumed future *non-network* solutions, and associated assumptions on the impact on demand levels; and

(vi) the diversity between feeders;

(s) where *Jemena* proposes to commence or continue a demand-related *capex project* or *program* during the *forthcoming regulatory control period* on a *zone substation* (or relevant *substations* for a *sub-transmission line*):

(i) assumed future load *transfers* between related *substations*;

(ii) assumed underlying load growth rates (exclusive of *transfers* and specific *customer* developments);

(iii) assumed specific *customer* developments, and associated demand assumptions;

(iv) existing *embedded generation* capacity, and associated assumptions on the impact on demand levels;

(v) assumed future *embedded generation* capacity, and associated assumptions on the impact on demand levels;

(vi) existing non-*network* solutions, and the associated assumptions on the impact on demand levels;

(vii) assumed future non-*network* solutions, and associated assumptions on the impact on demand levels; and

(viii) diversity with related *substations*.

16.3 (a) Details of the models used has been provided in 16.2 (a) above, with the associated methodologies reference documents provided in 16.1 above.

16.3 (b) See 16.1 (a) above.

16.3 (c) The inputs and assumptions used in the models are documented in the methodology papers as outlined below.

For system level maximum demand forecast methodology, see Attachment 05-03.

For spatial level maximum demand forecast, see procedure document titled *JEN - RIN - Support - JEN PR0507- Internal Load Demand Forecast Procedure - 20200131 - Public* in JEN's supporting documents.

For connections capex forecast by service codes, see methodology paper titled *JEN - RIN - Support – Customer Connections Forecast Methodology - 20200131 - Confidential* in JEN's supporting documents.

16.3 (d) The probability of exceedance (**POE**) methodology for the system level maximum demand forecast is documented in Attachment 05-03.

At the spatial level maximum demand forecast, the weather correction methodology is documented in supporting document folder. See *JEN - RIN - Support - JEN PR0507- Internal Load Demand Forecast Procedure - 20200131 - Public*.

JEN's approach to weather correction has remained consistent over time.

16.3 (e) For system level maximum demand forecast, block loads are not included at the network level. Transfers and switching are generally not impacted at the network level.

At the spatial level maximum demand forecast, only block loads above 100kVA with high probability of occurrence are generally included in the forecast model. All temporary transfers and switching creating abnormal in the actual maximum demand are corrected to normal network operating conditions. Future load transfers from one part of the network to another part of the network are taken into account in the model for committed projects only. This is done by subtracting and adding of the same amount of load such that it produces a net of zero. For further information, see procedure document titled *JEN - RIN - Support - JEN PR0507- Internal Load Demand Forecast Procedure - 20200131 - Public* in JEN's capex supporting documents.

16.3 (f) JEN's system level and spatial level maximum demand forecast models do not use appliance model or customer energy usage. For further clarifications on system level maximum demand forecast methodology, see ACIL Allen report in Attachment 05-03 and *JEN - RIN - Support - Jemena Internal Demand Forecast Report 2019 – 20200131 – Confidential*.

For its connections forecast, JEN's model does not use an appliance model or customer energy usage.

16.3 (g) For system-level maximum demand forecast methodology, the regression models developed by ACIL Allen used historical data to estimate and quantify the relationship between electricity demand and its drivers. These models were used with projections of the drivers to produce baseline forecasts. In essence, these system-level forecast models take into account the historical observations for both electricity demand and its drivers.

The spatial (ie bottom up) forecast is prepared internally by JEN, and reconcile to the system-level forecast at the total network level to produce the final set of maximum demand forecasts, which is used in this submission. JEN also makes observations of the final forecast numbers at each of its terminal station, zone substation and feeder to ensure they are consistent with historical observations and drivers that underpin the forecasts. For further details, see 16.1 (a) above.

For global-level (ie top-down) connections capex forecast methodology, JEN takes into account the historical observations by using historical capex expenditure (which is essentially the product of unit volume and unit rate) as the 'base' input data as well as the economic growth indices (i.e. ACIL Allen Consulting residential customer number growth forecast and Australian Construction Industry Forum's forecast building and construction expenditure). JEN also makes observations of the final total and each activity capex forecast to ensure they are consistent with historical observations and drivers that underpin the forecasts.

The spatial forecast for the volume and descriptor metric expenditure (in Tables 2.5.1, 2.5.2 and 2.5.3 of Workbook 1 – Regulatory determination, regulatory template 2.5) reconciles to the global level connections capex forecast, to ensure consistency is followed through at the spatial level. For further details, see 16.1 (b) above.

16.3 (h) The process for preparing maximum demand forecasts calls for two independent sets of forecasts to be prepared annually, system level (i.e. top-down) forecast and spatial level (ie bottom-up) forecast. The system level forecast is prepared by an independent external (macro) economic forecaster (ACIL Allen Consulting) and the spatial level forecast is prepared internally by JEN (see *JEN - RIN - Support - JEN PR0507- Internal Load Demand Forecast Procedure - 20200131 - Public*. To ensure the resulting forecast data is consistent across forecasts provided for each network element, JEN reconciles its spatial level forecasts to the system level forecast at the total network level to produce the final set of maximum demand forecasts.

For connections capex forecast, a similar approach was adopted to ensure a consistent forecast is provided for each volume and descriptor metric expenditure, and the total connection capex forecast.

16.3 (i) The maximum demand forecasts are used, as part of the annual planning review process, to:

- Identify network limitations;
- Identify feasible options to manage or mitigate network limitation; and
- Identify and proposing the most feasible option that maximise the net economic (i.e. customer) benefits.

The most feasible solutions for network augmentation will then form part of JEN's capex forecast..

For connections capex forecast, the forecasts resulting from the methods described in 16.1 (b) form the connection capital expenditure forecasts, which forms part of JEN's capex forecast.

16.3 (j) JEN uses the same maximum demand forecast model and connections capex forecast model that it used in the joint planning process where applicable.

16.3 (k) JEN forecasts both coincident and non-coincident maximum demand at the feeder, zone substation and connection point levels. These forecasts reconcile to the system level (at the network level) forecast using historical coincident factors to project forecast coincident factors. For further details, see procedure document titled *JEN - RIN - Support - JEN PR0507- Internal Load Demand Forecast Procedure - 20200131 - Public* in JEN's capex supporting documents.

16.3 (l) JEN records both historic maximum demand in MW and MVA.

16.3 (m) JEN uses both 10% and 50% probability of exceedance in its network planning assessments. For further information relating to JEN network planning criteria, see document titled *JEN - RIN - Support - JEN - Network Augmentation Planning criteria paper - 20200131 - Public* in JEN's supporting documents.

16.3 (n) JEN undertakes extensive network constraint analysis annually, using its annual updated maximum demand forecasts. The extent of a future network constraint is analysed by comparing an asset's forecast maximum demand and its load limit for each year of the planning outlook and a range of contingencies (given loadings and load limits can depend on network conditions). The contingency planning is one of the inputs and assumptions associated with the network constraint analysis, and it incorporates the contingencies that will result in material levels of expected unserved energy, at the least covering system-normal conditions and the most credible single contingency. For further information in relation to the contingency planning process, see document titled *JEN - RIN - Support - JEN - Network Augmentation Planning criteria paper - 20200131 - Public* in JEN's supporting documents.

16.3 (o) See document titled *JEN - RIN - Support - JEN - Network Augmentation Planning criteria paper - 20200131 - Public* in JEN's capex supporting documents, for how the risk is managed across the network.

16.3 (p) JEN's spatial demand forecasts (see *JEN - RIN - Support - JEN PR0507- Internal Load Demand Forecast Procedure - 20200131 - Public*) proposal for the next regulatory control period reconciles to ACIL Allen's independent forecast, see Attachment 05-03.

JEN, however, does not reconcile its spatial demand forecasts to any demand information or related planning statements published by AEMO, or AEMO's transmission connection point forecasts report published on its website. This is because the reasons for the differences between AEMO's connection point forecasts and ACIL Allen Consulting's forecasts are not fully understood. Until these issues are fully understood and resolved through discussions with AEMO, it would not be prudent to adopt AEMO's connection point forecasts for the distribution planning purposes.

16.3 (q) See Schedule 1 of document titled *JEN - RIN - Support - JEN - Network Augmentation Planning criteria paper - 20200131 - Public* in JEN's capex supporting documents, for how the normal and emergency ratings are determined for individual transmission connection points, sub-transmission lines, zone substations, HV feeders and distribution substations.

16.3 (r) (i) Where JEN proposes to commence or continue a demand-related capex project or program during the forthcoming regulatory control period on a HV feeder, the starting point for this assessment is JEN's HV feeders maximum demand forecasts. These forecasts represent the loading on the feeders under network normal state. In assessing whether an augmentation is needed, it considers:
(A) future load transfers between feeders that are available, based on the set of HV feeders forecasts in the relevant years. JEN also takes into account any upstream asset loading (i.e. zone substation and sub-transmission lines) constraints resulted from the transfers;
(B) feeder load growth is determined based on the load forecast methodology documented in the methodology paper titled *JEN - RIN - Support - JEN PR0507- Internal Load Demand Forecast Procedure - 20200131 - Public* in JEN's capex supporting documents;
(C) assumed block loads, and associated demand assumptions are determined based on the load forecast methodology documented in the methodology paper titled *JEN - RIN - Support - JEN PR0507- Internal Load Demand Forecast Procedure - 20200131 - Public* in JEN's capex supporting documents;

16.3 (r) (ii) With respect to existing embedded generators (with a capacity of greater than 1MW), the output of the generators at times of peak demand was recorded for use in the forecast, however the actual observed maximum demand (which includes the generators running) was not altered. The output of photovoltaic (PV) was also included in the actual observed maximum demand, which means the native demand levels would have been higher if the embedded generators and solar PV was not present. The output of solar PV panels are generally not controllable by customers and as such it was incorporated in the observed actual maximum demand and in the forecast.

16.3 (r) (iii) With respect to future embedded generators (with a capacity of greater than 1MW), JEN assumes the generators are not running at times of maximum demand in its forecasts unless network support contracts are in place. JEN assumes the existing embedded generation capacity remains the same for the forecast period. The forecast solar PV capacity and its generation output was however incorporated in the maximum demand forecast, and therefore lowering the maximum demand forecast levels.

16.3 (r) (iv) In the summer of 2017/18 JEN conducted a behavioural demand response (Power Changers program for residential customers), commercial & industrial customer demand response in Flemington area and a proof-of-concept project for the demand response by voltage reduction. A proof of concept for direct load control (DLC) of residential air-conditioners was part of the Power Changers program. These demand management initiatives were commenced in 2018 and some continued into 2019. These initiatives do not have any impact on demand levels provided.

16.3 (r) (v) JEN considers network and non-network solutions in its options analysis to address emerging network constraints, however it does not forecast or assume future non-network solutions will exist unless network support contractual arrangements are in place.

16.3 (r) (vi) The diversity between feeders are considered during the options analysis for a HV feeder augmentation. This would generally involve the option of transferring load from one feeder to another.

16.3 (s) Where JEN proposes to commence or continue a demand-related capex project or program during the forthcoming regulatory control period on a zone substation (or relevant substations for a sub-transmission line), the starting point for this assessment is JEN's zone substations and HV feeders maximum demand forecasts. These forecasts represent the loading on the zone substations and HV feeders under network normal state. In assessing whether an augmentation is needed, JEN considers:

16.3 (s) (i) future load transfer capacity between zone substations (via HV feeders) that are available, based on the set of zone substations and HV feeders forecasts in the relevant years. JEN also takes into account any upstream and downstream asset loading constraints resulted from the transfers;

16.3 (s) (ii) zone substations load growth is determined based on the load forecast methodology documented in the methodology paper titled *JEN - RIN - Support - JEN PR0507- Internal Load Demand Forecast Procedure - 20200131 - Public* in JEN's supporting documents;

16.3 (s) (iii) assumed specific customer developments and associated demand assumptions (i.e. block loads) are determined based on the load forecast methodology documented in the methodology paper titled *JEN - RIN - Support - JEN PR0507- Internal Load Demand Forecast Procedure - 20200131 - Public* in JEN's capex supporting documents;

16.3 (s) (iv) With respect to existing embedded generators (with a capacity of greater than 1MW), the output of the generators at times of peak demand was recorded for use in the forecast, however the actual observed maximum demand (which includes the generators running) was not altered. The output of solar PV was also included in the actual observed maximum demand, which means the native demand levels would have been higher if the embedded generators and solar PV was not present. The output of solar PV panels are generally not controllable by customers and as such it was incorporated in the observed actual maximum demand and in the forecast.

16.3 (s) (v) With respect to future embedded generators (with a capacity of greater than 1MW), JEN assumes the generators are not running at times of maximum demand in its forecasts unless network support contracts are in place. JEN assumes the existing embedded generation capacity remains the same for the forecast period. The forecast solar PV capacity and its generation output was however incorporated in the maximum demand forecast, and therefore lowering the maximum demand forecast levels.

16.3 (s) (vi) In the summer of 2017/18 JEN conducted a behavioural demand response (Power Changers program for residential customers), commercial & industrial customer demand response in Flemington area and a proof-of-concept project for the demand response by voltage reduction. A proof of concept for direct load control of residential air-conditioners was part of the Power Changers program. These demand management initiatives were commenced in 2018 and some continued into 2019. These initiatives do not have any impact on demand levels provided.

16.3 (s) (vii) JEN considers network and non-network solutions in its options analysis to address emerging network constraints, however it does not forecast or assume future non-network solutions will exist unless network support contracts are in place.

16.3 (s) (viii) The diversity between zone substations are considered during the options analysis. This would generally involve the option of transferring load from one zone substation to another.

16.4 Provide:

(a) evidence that any independent verifier engaged by *Jemena* has examined the reasonableness of the method, processes and assumptions in determining the forecasts and has sufficiently capable expertise in undertaking a verification of forecasts; and

(b) all documentation, analysis and models evidencing the results of the independent verification.

16.4 (a) JEN has not engaged an independent verifier to examine the reasonableness of the method, processes and assumptions in determining the forecasts. However JEN has engaged an independent consultant (ACIL Allen Consulting) to prepare the system-level (top-down) maximum demand forecasts. The spatial demand forecast JEN adopted is the same method and processes used in the Electricity Distribution Price Review for the 2016-20 regulatory control period, which reconciles to the system-level maximum demand forecast.

16.4 (b) Not applicable.