Jemena Electricity Networks (Vic) Ltd

Response to the Economic Benchmarking Regulatory Information Notice

Basis of Preparation

Information for the 2020-21 regulatory year

Public

31 October 2021

For the purposes of this document, *regulatory year* means the period covering 1 July 2020 to 30 June 2021.

3.1 REVENUE

3.1.1 REVENUE GROUPING BY CHARGEABLE QUANTITY

Actual information

Variable	Source and why actual	Methodology	Assumptions
DREV0101 – DREV0109	The data is sourced from JEN's two billing systems. JEN therefore considers the information to be actual information. The data is then captured in the Excel Line Charge file on a monthly basis and is summated in worksheet "Year to date".	**DREV0101 TO DREV0109** is categorised as Standard Control Services (**SCS**). Data provided relates to DUoS revenue + F-factor. This is in line with section 3.2 of the Explanatory Statement - Economic Benchmarking RIN that requires revenue to be reported inclusive of the effect of incentive schemes. The data is obtained from JEN's billing systems where a monthly report is produced from each billing system to record quantities and revenue by tariff component. The data is then captured in the line charge file on a monthly basis and is summated in worksheet "Year to date". The tariff codes listed below are incorporated in JEN's approved annual tariffs which are published by the AER. **DREV0101**: Comprises of Standing charge revenue for all tariff codes. **DREV0102:** Comprises of Peak revenue for A100 and A200 tariff codes. **DREV0103:** Comprises of Peak revenue except for A100, A200 and A290 tariff codes.	N/A

Variable	Source and why actual	Methodology	Assumptions
		DREV0104: Comprises of Shoulder revenue for all tariff codes **DREV0105**: Comprises of All Off-Peak revenue except for A180 and A290 tariff codes. **DREV0106:** Comprises of Peak and Off Peak revenue for A180 tariff code. **DREV0107**: Comprises of Peak and Off Peak revenue for A290 tariff code. **DREV0108:** Demand charge captured under variable code DREV0109. **DREV0109:** Comprises of Billed Maximum demand revenue for all tariff codes.	
DREV0110	The data is sourced from JEN's two billing systems. JEN therefore considers the information to be actual information. The data is then captured in an Excel file on a monthly basis and is summated in worksheet "Year to date".	**DREV0110** is categorised as Alternative Control Services. The data is obtained from JEN's billing systems where a monthly report is produced from each billing system to record quantities and revenue by tariff component. The data is then captured in an Excel file on a monthly basis and is summated in worksheet "Year to date".	AMI metering revenue is reported in this table.
DREV0111	Volume data and revenue for jobs completed in the month was sourced directly from JEN systems (OneSAP and SAP ISU) and so this information is reported as 'actual information'.	**DREV0111** is categorised as Alternative Control Services. JEN's revenue collection process uses a combination of projects (Work Breakdown Structure (**WBS**) elements) and General Ledger (**GL**) accounts to collect revenues at the macro level. Product codes are set up to collect revenues at a micro level.	Routine connections are the sum of the Routine connections - customers below 100 amps and Routine connections, for customers > 100amps; supply abolishment, temporary disconnects, energisation and de-energisation of existing premises.

Variable	Source and why actual	Methodology	Assumptions
		These Product codes are designed to collect revenues based on the activity type on which an individual works are billed. The ACS revenue is derived from extracting all of JEN's financial transactions from SAP that is charged to ACS accounts. Each of these transactions is then classified to the regulatory categories of this template by referring to the produce code of the project or the general ledger account it is charged to. Only product codes relating to connections are summated.	
DREV0112	The data is sourced from JEN's Annual RIN table 4.1 "Public Lighting ". The information obtained in the reports is consistent with the AER's definition of actual information as per section 2.2.2 of Better Regulation Explanatory Statement: regulatory information notices to collect information for Economic Benchmarking November 2013.	**DREV0112** is categorised as Alternative Control Services. The data is sourced from JEN's Annual RIN tables 4.1.	
DREV0113	Volume data for jobs completed in the month was sourced directly from JEN systems (SAP ISU) and so this information is reported as 'actual information'.	Methodology as per the DREV0111 **DREV0113** is categorised as Alternative Control services. The total of the fee based and quoted based charges are summated, once summated the routine new connections charge (DREV0111) is subtracted for each calendar year to derive DREV0113.	

Variable	Source and why actual	Methodology	Assumptions

Estimated information

No estimated information is provided.

3.1.2 REVENUE GROUPING BY CUSTOMER TYPE OR CLASS

Actual information

Variable	Source and why actual	Methodology	Assumptions
DREV0201 – DREV0205	The data is sourced from JEN's two billing systems. JEN therefore considers the information to be actual information. The data is then captured in the Excel Line Charge file on a monthly basis and is summated in worksheet Year to date.	The data is obtained from JEN's billing systems where a monthly report is produced from each billing system to record quantities and revenue by tariff component. The data is then captured in the line charge file on a monthly basis and is summated in worksheet Year to date.	**DREV0201 TO DREV0205** is categorised as Standard Control Services, only relates to DUoS revenue. The tariff codes listed below are incorporated in JEN's approved annual tariffs which are published by the AER. **DREV0201:** Comprises of DUoS revenue for A100 to A180 tariff codes. **DREV0202:** Comprises of DUoS revenue for A200, A210 and A250 tariff codes. **DREV0203:** Comprises of DUoS revenue for A230, A270, and A300 to A37R tariff codes. **DREV0204:** Comprises of DUoS revenue for A400 to A50E tariff codes. **DREV0205:** Comprises of DUoS revenue for A290 tariff code.

Variable	Source and why actual	Methodology	Assumptions
DREV0206 Alternative Control Service	The data is sourced from JEN's Economic Benchmarking RIN (**RIN B**) Tables DREV0111, DREV0112 & DREV0113. The information obtained in the reports is consistent with the AER's definition of actual information as per section 2.2.2 of Better Regulation Explanatory Statement: regulatory information notices to collect information for Economic Benchmarking November 2013.	Summation of DREV0111, DREV0112 & DREV0113 The data is classified as "revenue from other customers" as there is no report to capture this information by customer type or class.	N/A

Estimated information

No estimated information is provided.

3.1.3 REVENUE (PENALTIES) ALLOWED (DEDUCTED) THROUGH INCENTIVE SCHEMES

Actual information

Variable	Source and why actual	Methodology	Assumptions
DREV0301	The EBSS forms part of the building block revenue determined at the beginning of each regulatory period. This particular variable is derived from other records used in the ordinary course of business, and so is categorised as actual information on the basis that it is materially dependent on information recorded in JEN's business records and its presentation for the	The EBSS for regulatory year 2021 is based on the EBSS for the last 6 months of 2020 (2nd half of 2020) and the first six months of 2021. That is: *EBSS (RY2021) = EBSS (2nd half of 2020) + EBSS (1st half of 2021)* The methodology for calculating the EBSS for the second half of 2020 is to multiply the calendar year 2020 EBSS dollar value (calculated from steps 1 to 5	

Variable	Source and why actual	Methodology	Assumptions
	purposes of the Notice are not contingent on judgement and assumptions for which there are valid alternatives, which could lead to a materially different presentation in the response to the Notice. The 2020 calendar year EBSS dollar value is obtained from the 2020 Economic Benchmarking RIN template table 3.1.3.	below) with the proportion of actual revenue net of incentive schemes (STPIS and F-factor) in the second half to 2020 to the total 2020 revenue: *EBSS (2nd half of 2020) = EBSS (2020)* (actual revenue earned in 2nd half of 2020/ actual revenue earned in 2020)* Where: actual revenue earned = actual revenue reported net of any incentive mechanism schemes, and EBSS relative share is an average for each regulatory period. As per the AER decision for the interim period (1 Jan 21 to 30 Jun 21), there is no EBSS for the first half of 2021, hence the value is zero. Step 1: Replicate the ESC and AER's calculations to calculate the NPV of the building block revenues and the smoothed revenues using a nominal WACC for the period 2016-20. Step 2: Calculate the relative share of the building block components that contribute to the NPV calculations. Step 3: Restate the building block and smoothed revenues to nominal dollars using actual CPI instead of the AER CPI forecast.	

Variable	Source and why actual	Methodology	Assumptions
		Step 4: Break down the smoothed revenue into building block components (using the relative share calculated in step 2). Step 5: Apply the EBSS relative share from the building block for the 2016-2020 regulatory period to the actual revenue earned for each calendar year.	
DREV0302	The STPIS component variables are derived from other records used in ordinary course of business and so is categorised as actual information on the basis that it is materially dependent on information recorded in JEN's business records and its presentation for the purposes of the Notice is not contingent on judgement and assumptions for which there are valid alternatives, which could lead to a materially different presentation in the response to the Notice. The 2020 calendar year S factor dollar value is obtained from the 2020 Economic Benchmarking RIN template table 3.1.3.	The S factor for regulatory year 2021 is calculated based on the S factor for the last 6 months of 2020 (2nd half of 2020) and the first six months of 2021. The methodology for calculating the S factor for the second half of 2020 is to multiply the calendar year 2020 S factor dollar value with the proportion of actual revenue in the second half of 2020 to the total 2020 revenue: *S factor (2nd half of 2020) = S factor (2020)* (actual revenue earned[1] in 2nd half of 2020/ actual revenue earned in 2020)* *S factor = actual revenue earned – [actual revenue earned/ (1+ S")]* Where actual revenue earned = actual revenue reported	

[1] Based on actual electricity consumption from July 2020 to December 2020.

Variable	Source and why actual	Methodology	Assumptions
		As per the AER decision for the interim period, there is no S factor for the first half of 2021, hence the value is zero.	
DREV0303	The 2020 calendar year F factor dollar value is obtained from the 2020 Economic Benchmarking RIN template table 3.1.3.	The F-factor for 2021 is calculated based on the F-factor for the last 6 months of 2020 (2nd half of 2020) and the first six months of 2021. The methodology for calculating the F-factor for the second half of 2020 is to multiply the calendar year 2020 F-factor dollar value with the proportion of actual revenue in the second half to 2020 to the total 2020 revenue: *F-factor (2nd half of 2020) = F-factor (2020)* (actual revenue earned in 2nd half of 2020/ actual revenue earned in 2020)* As per the AER decision for the interim period, there is no F-factor for the first half of 2021, hence the value is zero.	
DREV0304	The S factor true-up forms part of the building block revenue determined at the beginning of each regulatory period. This particular variable is derived from other records used in ordinary course of business and so is categorised as actual information on the basis that it is materially dependent on information recorded in JEN's business records and its presentation for the purposes of the	The S factor true-up for regulatory year 2021 is calculated based on the S Factor for the last 6 months of 2020 (2nd half of 2020) and the first six months of 2021. That is: *S factor true-up (RY2021) = S factor (2nd half of 2020) + S factor true-up (1st half of 2021)* The methodology for calculating the S factor true-up for the second half of 2020 is to multiply the calendar	

Variable	Source and why actual	Methodology	Assumptions
	Notice is not contingent on judgement and assumptions for which there are valid alternatives, which could lead to a materially different presentation in the response to the Notice. The 2020 calendar year S factor true-up dollar value is obtained from the 2020 Economic Benchmarking RIN template table 3.1.3.	year 2020 S factor true-up dollar value (calculated from Steps 1 to 5 below) with the proportion of actual revenue net of incentive schemes (STPIS and F-factor) in the second half to 2020 to the total 2020 revenue: *S factor true-up (2nd half of 2020) = S factor true-up (2020)* (actual revenue earned in 2nd half of 2020/ actual revenue earned in 2020)* Where: actual revenue earned = actual revenue reported net of any incentive mechanism schemes, and S factor true-up relative share is an average for each regulatory period. As per the AER decision for the interim period, there is no S factor true-up for the first half of 2021, hence the value is zero. Step 1: Replicate the ESC and AER's calculations to calculate the NPV of the building block revenues and the smoothed revenues using a nominal WACC for the period 2016-20. Step 2: Calculate the relative share of the building block components that contribute to the NPV calculations. Step 3: Restate the building block and smoothed revenues to nominal dollars using actual CPI instead of the AER CPI forecast.	

Variable	Source and why actual	Methodology	Assumptions
		Step 4: Break down the smoothed revenue into building block components (using the relative share calculated in step 2). Step 5: Apply the S factor true-up relative share from the building block for the 2016-2020 regulatory period to the actual revenue earned for each calendar year.	

Estimated information

No estimated information is provided.

3.2 OPERATING EXPENDITURE

3.2.1 OPEX CATEGORIES

Actual Information

Variable	Source and why actual	Methodology	Assumptions
SCS DOPEX0101 - SCS - Vegetation management DOPEX0102 – SCS - MaintenanceDOPEX0103 - SCS - Emergency response DOPEX0104 - Non-network DOPEX0105 - SCS - Metering DOPEX0106 – SCS - Network overheads DOPEX0107 – SCS - Corporate overheads DOPEX0108 SCS - Debt raising costs	JEN uses its ERP system (**SAP**) to capture costs associated with operating and maintenance expenditure. Data (maintenance and opex) is sourced from Appendix B of JEN's Annual RIN response. Refer to the Basis of Preparation in JEN's Annual Reporting RIN for detailed descriptions of its cost collection and financial recording processes. The information obtained in the reports is consistent with the AER's definition of actual information as per section 2.2.2 of the Better Regulation Explanatory Statement: regulatory information notices to collect information for economic benchmarking November 2013.	JEN has enhanced its regulatory reporting capability by developing a suite of reports that were designed to provide data that facilitates the population of the annual RIN templates. Project Cost information and general ledger data are extracted from SAP's business warehouse (**BW**) using a data extraction tool, Business Objects (**BO**) and exported into Excel. BO reports were developed based on a requirement to provide data that will populate the tables within these templates. The reports use underlying data models and queries to report the data. JEN executes the BO Reports that are associated with the templates, based on the report selection criteria. The report output provides the data required by the table in this template.	N/A
ACS DOPEX0109 - ACS - Connections DOPEX0110 - ACS – Metering	Refer to JEN's source of information, cost collection and financial recording processes for the templates as described above.	Refer to JEN's methodology for the tables within the templates as described above.	N/A

Variable	Source and why actual	Methodology	Assumptions
DOPEX0111 - ACS - Public lighting DOPEX0112 - ACS - Fee and quoted DOPEX0113 - ACS - Network overheads DOPEX0114 - ACS - Corporate overheads			
			N/A
			N/A

3.2.2 OPEX CONSISTENCY

Actual Information

Variable	Source and why actual	Methodology	Assumptions
SCS DOPEX0203 - Opex for connection services	Opex for connection services is derived from WBSs relating to Premise Faults activities. Refer to JEN's source of information, cost collection and financial recording processes for the templates as described under SCS above.	Refer to JEN's methodology for the tables within the templates as described under SCS above.	N/A
SCS	Opex for transmission connection point planning is derived from the PM Order that relates to this activity.	Refer to JEN's methodology for the tables within the templates as described under SCS above.	

Variable	Source and why actual	Methodology	Assumptions
DOPEX0206 - Opex for transmission connection point planning (TCPP)	Refer to JEN's source of information, cost collection and financial recording processes for the templates as described under SCS above.		
SCS DOPEX0201 - Opex for network services	DOPEX0201 is a result of DOPEX01 less DOPEX0203 and DOPEX0206.	Opex for network services is the residual amount after reducing the Total DOPEX01 (SCS) by DOPEX0203 (Opex for connection services) and DOPEX0206 (Opex for Transmission connection point planning).	N/A
ACS DOPEX0202 - Opex for metering	DOPEX0202 equals to ACS Metering direct and overhead expenditure as reported in RIN A – 8.4 Opex template.	Opex for metering equals ACS Metering direct and overhead expenditure.	N/A
ACS DOPEX0204 - Opex for public lighting	DOPEX0204 equals to ACS Public Lighting direct and overhead expenditure as reported in RIN A – 8.4 Opex template.	Opex for public lighting equals ACS Public Lighting direct and overhead expenditure.	N/A

3.2.4 OPEX FOR HIGH VOLTAGE CUSTOMERS

Estimated Information

Variable	Why estimate, not actual	Basis for estimate
DOPEX0401 - Opex for high-voltage customers	This is an estimate as the costs are not incurred by JEN and are therefore not maintained within JEN's internal systems.	The engineering team provided an estimate of activities and their costs that may have been incurred for the current reporting year had the transformers owned by the high voltage customers been owned by Jemena Inspection of Distribution Substation (including thermo-vision) with report costs were calculated by determining the number of high voltage customer installations multiplied by the rate per distribution substation. Distribution Substation Grounds Maintenance costs were calculated by determining the number of high voltage customer installations multiplied by the rate per distribution substation. Fault attendance costs were calculated by determining the number of faults during the year multiplied by the rate per fault attendance. This approach is the most reasonable given the availability of data. JEN is not aware of a superior technique, given the data availability constraints.

3.2.3 PROVISIONS

Actual Information

Variable	Source and why actual	Methodology	Assumptions
All variables (DOPEX0301A – DOPEX0314A) Provision for doubtful debts	The data is considered actual as it is extracted from the relevant General Ledger accounts from SAP, the Enterprise Resource Planning (**ERP**) system that JEN uses to capture its financial and other information.	When JEN writes-offs bad debt from its customers, these are recognised in the Provision Account and disclosed under variable DOPEX0305A, “Amounts used”. JEN adjusts these provisions in accordance with its internal policies to ensure that provisions are recognised, measured and disclosed in its Special Purpose Financial Report (**SPFR**) and in accordance with Australian Accounting Standards. Routine increases in provisions are disclosed against variable DOPEX0302A, “Additional provisions made in the period, including increases to existing provisions”. Similarly excess routine provisions are reversed and disclosed under variable DOPEX0308A, “Unused amounts reversed during the period”. JEN’s doubtful debt provisions are Opex in nature and disclosed accordingly in the template.	N/A

Variable	Source and why actual	Methodology	Assumptions
All variables (DOPEX0301B – DOPEX0314B) Provision for claims from customers	The data is considered actual as it is extracted from the relevant General Ledger accounts from SAP.	JEN provides for Claims/Compensation. JEN receives claims from its customers for damages to their property as a result of an incident on its network. JEN provision for claims is calculated based JEN's Customer Service Manager's assessment of the claim including supporting information provided by the customer. When JEN provides for potential claims, this is carried to variable DOPEX0302B "Additional provisions made in the period, including increases to existing provisions." The provision increases or decreases against a database where the customer service manager tracks the claims. JEN records changes in the Profit & Loss Statement, in conjunction with it being recognised, measured and disclosed in its SPFR and in accordance with Australian Accounting Standards. When JEN accepts and pays the claim from its customers, this is disclosed under variable DOPEX0305B, "Amounts used" and recorded in the Profit & Loss Statement. JEN has functionality within its ERP system to extract data from its Profit & Loss Statement and distinguish between usage of and changes in the provision. Similarly excess routine provisions are reversed and disclosed under variable DOPEX0308B, "Unused amounts reversed during the period". JEN's claims provisions are Opex in nature and disclosed accordingly in the template.	N/A

Variable	Source and why actual	Methodology	Assumptions
All variables (DOPEX0301C – DOPEX0314C) Provision for legal costs	The data is considered actual as it is extracted from the relevant General Ledger accounts from SAP.	JEN provides for legal costs. JEN provides for legal costs on contested claims from its customers for damages to their property as a result of an incident on its network. JEN provision for claims is calculated based JEN's Customer Service Manager's assessment of the claim including supporting information provided by the customer. When JEN provides for potential legal costs, this is carried to variable DOPEX0302B "Additional provisions made in the period, including increases to existing provisions." The provision increases or decreases against a database where the customer service manager tracks the contested claims. JEN records changes in the Profit & Loss Statement, in conjunction with it being recognised, measured and disclosed in its SPFR and in accordance with Australian Accounting Standards. When JEN pays legal costs, this is disclosed under variable DOPEX0305B, "Amounts used" and recorded in the Profit & Loss Statement. JEN has functionality within its ERP system to extract data from its Profit & Loss Statement and distinguish between usage of and changes in the provision. Similarly excess routine provisions are reversed and disclosed under variable DOPEX0308B, "Unused amounts reversed during the period". JEN's legal costs provisions are Opex in nature and disclosed accordingly in the template.	N/A

3.3 ASSETS (RAB)

JEN submitted its first economic benchmarking RIN (**RIN B**) to the AER on 30 April 2014. This document explains our approach (see section 3.3.2) to preparing the information required under Excel tab 3.3 RAB and demonstrates that the approach to prepare this information for our current RIN response is the same approach used in our previous RIN responses.

STANDARD CONTROL ASSET BASE

JEN adopted the AER's standard approach to disaggregate its reporting period RAB

JEN has rolled-forward the RAB to the reporting period using the AER's prescribed standard approach outlined in the RIN B Notice.

To disaggregate the RAB using the AER's prescribed standard approach—refer to *section 3.3* for more detail—JEN is required to allocate its RAB, in direct proportion to the relevant RIN B category's share of either:

- total estimated depreciated replacement cost (**DRC**) for 2013, or
- total book value for the regulatory year 2013.

JEN has maintained a consistent methodology to disaggregate its reporting period RAB as we applied in our response to the RIN B on 29 April 2015

To ensure consistency, we have used the 2013 splits[1] to disaggregate the reporting year RAB, which aligns to our methodology for disaggregating the 2006 to 2013 RAB, where we also used the 2013 splits (as per the AER's guidance).

JEN notes that the information relating to the RAB are estimates rather than actuals

Consistent with our previous submission, we note that these RAB variables are estimates rather than actuals.

Since the AER Final Decision (**FD**)[2], we made some minor, but key changes

On 26 May 2016, the AER released its final decision on Jemena's distribution determination for the 2016-20 regulatory control period. This decision included opening RAB balances for 2016 by RAB asset class.

On 15 December 2016, the AER published its final decision regarding amendments to version 1 of the Roll Forward Model (**RFM**) for distribution network service providers (**DNSPs**). This decision included a revised Distribution RFM, described as version 2, which the distribution businesses are now required to use.

As a result of these two decisions JEN applied the new framework to roll forward the RAB by:

- Adopting version 2 of the RFM;
- Transferring the AER FD outcomes into the new version 2 RFM;
- Replacing reporting period forecast values from the final decision for gross capex, asset disposals and customer contributions with actual information; and

[1] *The 'splits' refer to the direct proportion to the relevant RIN B category's share of either total estimated DRC or total book value.*

[2] Also known as a substitute decision per NER, s 11.60.4(c)

- Updating the lagged inflation assumption which applies to reporting period consistent with the inflation series used in the price control formula.

Consequences of adopting version 2 of the RFM

- Version 2 of the RFM for Standard control services applies forecast regulatory depreciation rather than actual regulatory depreciation.
- The AER now applies the Capital Expenditure Sharing Scheme (**CESS**) to JEN and has implemented a 'forecast depreciation' approach—where the real forecast depreciation amount (based on forecast capex) approved at the 2011-15 EDPR decision is used to roll forward the RAB.
- In future years the Nominal WACC assumption will also need to be updated as the cost of debt transition methodology is implemented.
  - Version 2 of the RFM accommodates different annual WACC inputs over the regulatory control period within the 'RFM input' worksheet. This change is consistent with the changes to the PTRM and gives effect to the AER's rate of return guideline, which allows for an annual update for the return on debt.
  - Cost of debt transition method is consistent with AER's 2013 Rate of Return Guideline.

Transferring AER FD values into version 2 of the RFM

JEN transferred the final decision values into the "RFM input" worksheet to populate version 2 of the RFM.

The primary source for this process was the Post Tax Revenue Model (PTRM) titled "CONFIDENTIAL - AER - Final decision Jemena - Post tax revenue model (incl depreciation tracking) - May 2016.xls".

For all "in-period" cash flows, a half year adjustment was required to convert the "End of Period" values presented in the PTRM to the mid period values required in the RFM. This was required to reconcile the closing balances shown in "Total RAB roll forward" prior to making further changes.

JEN notes that the new "Land" asset class was included as part of this process.

Inflation assumptions are based on a lagged method

JEN maintains the 'all-lagged' methodology aligns with the annual tariff setting approach and the AER agreed with this position in the final decision (refer to RAB RFM and PTRM calculations).

The new functionality in version 2 of the RFM allows JEN to select the "All-lagged Inflation" option presented within the drop down box in cell F177 of "RFM input".

For transparency, JEN added a section on the "RFM input" worksheet to capture movements in inflation indexes. In rows 265 to 274 JEN highlights the AER's decision to switch from a September quarter end basis to a June quarter end basis.

The input for actual inflation applied to reporting period in row 182 of "RFM input" is therefore calculated from the indexes in rows 265 to 274.

Implementation of the AER's 5.5-year RFM transitioning from calendar to financial year

The AER's final decision for the 2021-26 regulatory control period included a 5.5-year RFM which rolled forward JEN's RAB for calendar years 2016 to 2020 and the half-year transitional period from 1 January to 30 June 2021.[3]

To report JEN's RAB roll-forward for financial year (FY) 2020-21, it requires an opening RAB balance as of 30 June 2020 and a closing RAB balance as of 30 June 2021. The AER's 5.5-year RFM only outputs the closing RAB as of 30 June 2021 but does not provide an opening RAB as of 30 June 2020. Instead, the RFM outputs the RAB balance as of 31 December 2019 and 31 December 2020. Therefore, the RAB value as of 30 June 2020 needs to be estimated.

We have taken the following steps to estimate the RAB value as of 30 June 2020 by RAB asset class based on the AER's 5.5-year RFM –

1. derive the regulatory depreciation for FY2021 (30 June 2020 to 30 June 2021) as half of the CY2020 (31 December 2019 to 31 December 2020) value plus the HY2021 (31 December 2020 to 30 June 2021) value from the 5.5-year RFM[4]

2. derive the WACC adjusted net capex for FY2021 as the CY2020 value multiplied by the proportion of capex incurred in the second half of CY2020 (i.e. 30 June to December 2020) plus the HY2021 value from the 5.5-year RFM

3. derive the opening RAB as of 30 June 2020 as the closing RAB at 30 June 2021 plus the regulatory depreciation calculated in step 1 minus the WACC adjusted net capex calculated in step 2

For more detail relating to the estimation of FY2021 RAB roll forward, please refer to **Attachment 3—JEN EBT allocation model**.

ACS METERING ASSET BASE[5]

On 26 May 2016, the AER released its final decision on Jemena's distribution determination for the 2016-20 regulatory control period. This decision included a reclassification of a portion of Metering assets from SCS into a new ACS Metering service category.

As a result the AER FD included an ACS Metering PTRM and a RAB RFM which are the models used as the basis for this section of the RIN.

Since the AER FD, we made some minor, but key changes in line with the approach for the SCS RAB.

The AER FD on 26 May 2016, regarding Jemena's distribution determination for the 2016-20 regulatory control period, included opening RAB balances for 2016 by metering RAB asset class.

On 15 December 2016, the AER published its final decision regarding amendments to version 1 of the Roll Forward Model for distribution network service providers. This decision included a revised Distribution RFM, described as version 2, which the distribution businesses are now required to use.

As a result of these two AER decisions JEN applied the AER framework to roll forward the RAB by:

- Adopting version 2 of the RFM;

---

[3] AER, *AER - Final decision - Jemena distribution determination - 2021-26 - Roll forward model - April 2021.xlsm*

[4] This assumes that depreciation incurs evenly throughout the year

[4]ACS Metering refers to the type 5, 6 and smart metering alternative control service asset class.

- Transferring the AER FD outcomes into the new version 2 RFM;
- Replacing reporting period forecast values from the final decision for gross capex, asset disposals and customer contributions with actuals; and
- Updating the lagged inflation assumption which applies to reporting period.

Note: AMI RFM uses the "Actual Real SL depreciation" approach

Consequences of adopting version 2 of the RFM

As per the equivalent section within the SCS Asset Base methodology described above.

Transferring AER FD values into version 2 of the RFM

JEN transferred the final decision values into the "RFM input" worksheet to populate version 2 of the RFM.

The primary source for this process was the Post Tax Revenue Model (PTRM) titled "AER - Final Decision Jemena - Metering PTRM & Exit Fees - May 2016".

For all "in-period" cash flows, a half year adjustment was required to convert the "End of Period" values presented in the PTRM to the mid period values required in the RFM. This was required to reconcile the closing balances shown in "Total RAB roll forward" prior to making further changes.

Inflation assumptions are based on a lagged methodology

JEN maintains the 'all-lagged' methodology aligns with the annual tariff setting approach and the AER agreed with this position in the final decision.

The new functionality in version 2 of the RFM allows JEN to select the "All-lagged Inflation" option presented within the drop down box in cell F177 of "RFM input".

For transparency JEN added a section on the "RFM input" worksheet to capture movements in inflation indexes. In rows 265 to 274 JEN highlights the AERs decision to switch from a September quarter end basis to a June quarter end basis.

Implementation of the AER's 5.5-year RFM transitioning from calendar to financial year

As per the equivalent section within the SCS Asset Base methodology described above.

The input for actual inflation applied to reporting period in row H182 of "RFM input" is therefore calculated from the indexes in rows 265 to 274.

PUBLIC LIGHTING ASSET BASE

The Public Lighting RAB has also been updated during the latest JEN price review

On 26 May 2016, the AER released its final decision on JEN's distribution determination for the 2016-20 regulatory control period. This decision included opening 2016 balances for public lighting assets.

JEN has taken the final decision model titled "AER - Final Decision Jemena - Public Lighting model - May 2016.xls" and updated the reporting year forecast values for net capital expenditure with actual information.

Implementation of the AER's final decision transitioning from calendar to financial year

As per the equivalent section within the SCS Asset Base methodology described above.

3.3.1 REGULATORY ASSET BASE VALUES

Actual Information

No actual information is provided.

Estimated Information

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
DRAB0101 – DRAB0107	These variables are estimated as they are the summation of a series of estimated inputs set out in Table 3.3.2.	Table 3.3.1 is the summation of the individual asset categories in table 3.3.2	None	This is JEN's best estimate as these variables are simply the summation of a series of JEN's best estimates of individual asset categories in table 3.3.2

3.3.2 ASSET VALUE ROLL FORWARD

Actual Information

No actual information is provided.

Estimated Information

For more detail relating to the variables explained in section 3.3.2 Asset value roll forward and section 3.3.3 Total disaggregated RAB values, please refer to **Attachment 3—JEN EBT allocation model**.

Explain why the variable is estimated and why actual information could not be provided

JEN notes that the information relating to the regulatory asset base are estimates rather than actuals.

The variables are estimates rather than actual information for three main reasons:

1. The information relating to the RAB does not meet the AER's definition of actual because this information is not recorded within JEN's financial system and cannot be reconciled to. JEN does not report this information in the normal course of business. As such, this is consistent with the AER's definition of 'estimates'.
2. JEN was unable to directly allocate the asset categories within the AER's approved RAB for JEN (hereafter referred to as **regulatory categories**) to the AER's economic benchmarking asset categories (hereafter referred to as **EBT categories**). Therefore, an allocation methodology was applied. Also note that JEN does not capture RAB data within its financial systems.
3. The AER has never approved a network services RAB and therefore it had to be estimated.

The sections below provide further detail.

Allocation of regulatory categories to EBT categories

The regulatory categories that were able to be directly allocated to EBT categories are set out in table A below.

Table A: Direct allocation of regulatory categories to EBT categories

Regulatory category	EBT category
Standard metering[6]	Meters
Metering (ACS)	Meters
Public lighting	Other assets with long lives
SCADA/Network control	Other assets with short lives
Non-network general assets - IT	Other assets with short lives
IT, Communications and Other (ACS metering)	Other assets with short lives

[6] *Standard metering* relates to residual metering in the standard control service RAB, it is distinct and separate from the *type 5, 6 and smart metering* alternative control service asset class.

The regulatory categories that were allocated to a group of EBT categories are set out in table B below.

Table B: Allocation of regulatory categories to group of EBT categories

Regulatory category	Group of EBT categories
Sub-transmission	Overhead network assets 33kV and above (wires and towers / poles etc.)
	Underground network assets 33kV and above (cables, ducts etc.)
	Zone substations and transformers
Distribution system assets	Overhead network assets less than 33kV (wires and poles)
	Underground network assets less than 33kV (cables)
	Distribution substations including transformers
Non-network general assets - Other	Other assets with long lives
	Other assets with short lives

JEN does not capture data for easements. JEN did not report any values for easements and were intentionally left blank in the template.

Explain the basis upon which the estimate was made and the methodology used

JEN rolled forward its SCS RAB by applying the AER's RAB framework. For the regulatory years 2006 to 2010 and 2010 to 2015, the SCS RAB reconciles back to the AER's approved roll-forward model (**RFM**).[7]

JEN rolled forward its ACS Metering RAB[8] for the first time by applying the AER's RAB framework.

JEN rolled forward its ACS RAB in accordance to the AER's approved public lighting model

JEN rolled forward its ACS RAB by applying the AER's RAB framework. For the regulatory years 2006 to 2010 and 2010 to 2015, the ACS RAB reconciles back to the AER's approved RFM.[9]

JEN adopted the AER's standard approach to disaggregate its RAB

JEN disaggregated its RAB into the EBT categories using the AER's prescribed standard approach, where JEN is required to allocate its RAB, in direct proportion to the relevant EBT category's share of either:

- total estimated depreciated replacement cost for 2013, or
- total book value for the regulatory year 2013.

The DRC was used to estimate the following EBT categories:

- Overhead network assets less than 33kV (wires and poles)

[7] *AER, Jemena Electricity Networks (Victoria) Ltd, distribution determination, Pursuant to Orders of the Australian Competition Tribunal in Application by United Energy Distribution Pty Limited (No 2) [2012] ACompT 8, September 2012.*

[8] ACS metering relates to the type 5, 6 and smart metering alternative control service asset class.

[9] *AER, Jemena Electricity Networks (Victoria) Ltd, distribution determination, Pursuant to Orders of the Australian Competition Tribunal in Application by United Energy Distribution Pty Limited (No 2) [2012] ACompT 8, September 2012.*

- Underground network assets less than 33kV (cables)
- Distribution substations including transformers
- Overhead network assets 33kV and above (wires and towers / poles etc.)
- Underground network assets 33kV and above (cables, ducts etc.)
- Zone substations and transformers.

The book value within JEN's statutory asset register has been used to estimate the following EBT categories:

- Other assets with long lives
- Other assets with short lives.

The EBT category 'meters' was populated as a direct allocation from the RAB category 'standard metering'.

JEN has used estimated depreciated replacement costs to allocate its SCS network assets

Consistent with the AER instructions, the DRC for each EBT Category was estimated by the following formula:

> ***DRC*** *= Estimated weighted average unit rate replacement costs x physical asset data x weighted average remaining asset lives (existing assets) / weighted average service lives (existing assets), where:*

- The estimated weighted average unit rate replacement costs were estimated using best endeavours, based on most recent project estimates. Due to lack of information, the project sample includes both (a) partially completed and (b) completed projects. The projects within the sample were assigned physical characteristics such as (a) line length in kms and (b) capacity in MVA, based on engineering judgement. The estimated weighted average unit rate is then calculated as the project cost estimates ($) / length line (kms) x capacity (MVA). Importantly, JEN assumed that the same unit replacement costs for both overhead and underground network assets 33kV.
- Physical asset data is sourced from RIN sheet 6 (Physical assets).
- The weighted average remaining asset lives (existing assets) are sourced from table 4.4.2 of RIN sheet 4 (RAB assets).
- The weighted average service lives (existing assets) are based on the lives in table 4.4.1 of RIN sheet 4 (RAB assets), but amended to reflect the service lives of existing assets rather than new assets installed in the relevant year.

The estimated DRCs for the regulatory year 2013 were used to allocate the RAB categories to EBT categories for the whole period (2006 to 2013), as per the AER's instructions.

Table C sets out the DRC that is calculated by applying the prescribed DRC formula. The estimated DRC is explicitly used to derive the percentage allocation for the RAB, and is not indicative of the actual network replacement costs. **Table D** sets out the allocation of RAB categories to EBT Categories based on 2013 DRC.

Table C: 2013 depreciated replacement costs by EBT category

EBT Category	Unit	CY13
Overhead network assets less than 33kV (wires and poles)	$000/km^2/MVA	9,152
Underground network assets less than 33kV (cables)	$000/km^2/MVA	659

EBT Category	Unit	CY13
Distribution substations including transformers	$000/km/MVA^2	495
Overhead network assets 33kV and above (wires and towers / poles etc.)	$000/km^2/MVA	190
Underground network assets 33kV and above (cables, ducts etc.)	$000/km^2/MVA	7
Zone substations and transformers	$000/km/MVA^2	178

Table D.: Percentage allocations of RAB categories to EBT categories based on 2013 DRC

RAB category	Allocation to EBT categories	
Sub-transmission	Overhead network assets 33kV and above (wires and towers / poles etc.)	50.56%
	Underground network assets 33kV and above (cables, ducts etc.)	1.94%
	Zone substations and transformers	47.50%
	Total	100.00%
Distribution system assets	Overhead network assets less than 33kV (wires and poles)	88.81%
	Underground network assets less than 33kV (cables)	6.39%
	Distribution substations including transformers	4.80%
	Total	100.00%

JEN used the relative share of book value to allocate its non-network assets

JEN mapped each regulatory category to an EBT category. The relative share of book value was only used to allocate the regulatory category 'non-network general assets – other' to the two EBT categories 'other assets with short lives' and 'other assets with long lives'.

Table E sets out the resulting allocation of 2013 book value.

Table E. Percentage allocations of regulatory categories to EBT categories based on 2013 book value

Regulatory category	Allocation to EBT categories	
Non-network general assets - Other	Other assets with long lives	6.93%
	Other assets with short lives	93.07%
	Total	100.00%

JEN estimated a network services RAB

The AER approved a SCS and Public Lighting alternative control services (**ACS**) RAB for JEN during the 2010 electricity distribution price review, but did not approve network services (**NS**).

JEN notes the AER's guidance that the NS RAB is a subset of the SCS RAB. The NS RAB was estimated by removing any portion of assets from the SCS RAB, which relate to the provision of:

- connection services
- standard metering
- public lighting
- fee & quoted based services.

JEN faced difficulties identifying assets related to connection services because—unlike standard metering and public lighting—JEN does not have a separate regulatory category for connection services assets.

Faced with this difficulty, JEN estimated the NS RAB by:

- step 1—estimating the proportion of total capital contributions related to connection services over 2010 to 2013, where data was available
- step 2—multiplying gross (net) demand connection capex over 2006 to 2013 by this proportion to estimate the gross (net) capex related to connection services
- step 3—using this net capex to estimate the share of the opening 2006 RAB related to connections.

No assets were deducted for fee and quote based services because the AER did not approve any FQ RAB.

Further detail follows.

Step 1. The approach starts with total capital contributions for the regulatory years 2010 to 2013 by activity (e.g. medium density housing, dual and multiple occupancy, business supply projects, etc.). Because JEN does not have a connection services RAB, it assumed that all contributions relating to business supply projects and low density & small business supplies <10kVA are associated with connection services.

This represents an average of 43% over the four years, calculated using the following:

Portion of connection services = (CC1 + CC2) / total capital contributions, where:

> ***CC1 =** capital contributions relating to business supply projects*
>
> ***CC2 =** capital contributions relating to low density & small business supplies <10kvA.*

Step 2. To then determine the gross capex and capital contributions amounts (relating to connection services) for the whole period (2006 to 2013), JEN applied the above percentage to the gross demand connection capex and total contributions to the regulatory years 2006 to 2009.

Step 3. JEN also identified an estimated portion of the opening distribution system assets RAB (2006), that relates to connection services based on the relative proportion of net connection services capex to net distribution system assets capex for the whole period.

The formula used is set out below:

Opening 2006 RAB (connection services) = Cp:Dp x opening 2006 RAB, where:

> ***Cp:Dp** = Ratio of net connection services capex to ratio of net distribution system assets capex*
>
> ***Net capex** = gross capex less capital contributions*
>
> ***Opening 2006 RAB** = AER approved 2006 opening RAB for distribution system assets.*

The identified opening connection services RAB was then rolled-forward in accordance with the AER's RAB framework, using connection services capex, customer contributions and asset disposals. The regulatory depreciation for the connection services net capex was assumed to be a portion (calculated above) of the regulatory depreciation for distribution system assets.

Explain the assumptions made when applying the chosen methodology

JEN interpreted the AER's guidance to use DRC for the regulatory year 2013 retrospectively

- When calculating depreciated replacement costs, JEN interprets the AER's instruction "*where disaggregation is required for the whole period then this will be the 2013 regulatory year*" to mean that the DRC estimates for the regulatory year 2013 are used to allocate the regulatory categories to the network-related EBT categories for the regulatory years 2006 to 2013. The same approach was used to allocate regulatory categories to non-network-related EBT categories based book values.
- When calculating the DRC estimates, JEN applied the weighted average service lives of *existing assets*, rather than *new assets*.

JEN made assumptions to estimate a notional NS RAB

- The 2006 opening RAB for connection services was assumed to equal the historical (2006 to 2013) cumulative share of connection related net capex, multiplied by the opening RAB of distribution system assets.
- The proportion of capital contributions related to connection services over 2006 to 2009 equals the average proportion over 2010 to 2013.
- The activities that relate to connection services are assumed to be business supply projects and low density & small business projects <10kvA.

- The proportion of gross connection services capex over 2006 to 2013 related to connection services is the same as the equivalent proportion for capital contributions over this period.
- RAB escalation and straight line depreciation for connection services equals the equivalent value for the SCS RAB multiplied by the share of the opening SCS RAB related to connection services.

JEN made other general assumptions to estimate the RABs

- All information is presented in nominal dollars.
- All information is presented to the nearest thousand ($000), rounded to the nearest whole number.
- Straight line depreciation and regulatory depreciation are expressed as negative values.
- Actual additions are assumed to equal gross capex less customer contributions.
- The same allocation percentages were used to allocate RAB categories to EBT categories for each of the RABs (SCS, NS, ACS).

Explain why the estimate is JEN's best estimate given the information sought

JEN uses, where possible, data that are within its financial system, AER approved data and its best endeavours when estimating the relevant RABs.

JEN's best estimate follows, as close as possible, the AER's explanatory statement, instruction and definition document or the AER's preferred methodology for rolling forward RABs, such as:

- using ABS data to estimate actual CPI
- applying the RAB framework to roll-forward its RAB, and
- adopting the standard allocation approach to disaggregate its RAB.

For financial information only: Identify whether accounting policies materially changed during any of the years covered within the Notice

No.

Only if response to above was yes: Explain the nature of the change identified in e. and the impact of that change

Not Applicable.

3.3.3 TOTAL DISAGGREGATED RAB ASSET VALUES

Actual Information

No actual information is provided.

Estimated Information

Variable DRAB1201 – 1210 - These variables are assumed to equal the average of the opening and closing value (for each asset category) in Table 3.3.3. This is consistent with the AER's guidance in its explanatory statement.

Variable DRAB13 - AER approved actual values for Standard Control Services and Alternative Control Services. Network Services values are allocated in the same way as described above for variables DRAB0201 – DRAB1107.

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
DRAB1201 - 1210	JEN considers these variables to be estimates as they are a function of estimated variables.	These variables are the summation of variables DRAB0201 – DRAB1107	n/a	Refer to section 3.3.2
DRAB13	Refer to section above titled “JEN estimated a network services RAB”. JEN made assumptions to estimate a network services RAB’	Refer to section above titled “JEN estimated a network services RAB”. JEN made assumptions to estimate a network services RAB’	Refer to section above titled “JEN estimated a network services RAB”. JEN made assumptions to estimate a network services RAB’	Refer to section above titled “JEN estimated a network services RAB”. JEN made assumptions to estimate a network services RAB’

3.3.4 ASSET LIVES

Actual information

4. Assets applicable to ACS are public lighting and (ACS) metering. Public lighting assets apply to the “other” long asset lives category (the ACS column for DRAB1408, DRAB1508), and metering to the meters and “other” short asset lives categories (the ACS column for DRAB1407, DRAB1409, DRAB1507, DRAB1509).
5. All assets for SCS have the same estimated service life for network services because connection fees in SCS does not affect the estimated average life of the assets, except for DRAB1401, DRAB 1402, DRAB1501, DRAB1502. Services assets apply to the category of DRAB1401, DRAB1402, DRAB 1501, DRAB1502 and are only included in SCS Section.

Variable	Source and why actual	Methodology	Assumptions
DRAB1401, DRAB1402, DRAB1403, DRAB1404, DRAB1405, DRAB1406, (SCS and NS only)	Standard asset lives have been applied based on final PTRM determination from the model (PTRM) titled “CONFIDENTIAL - AER - Final decision Jemena - Post tax revenue model (incl depreciation tracking) - May 2016.xls	Standard lives, sourced from the AER FD, are calculated based on the existing mapping between RAB asset classes and EB RIN asset classes located in EBT allocation model	Standard lives of NS are assumed to be same SCS
DRAB1407, DRAB1408 and DRAB1409 (ACS only)	The AER-determined standard asset lives are provided.	ACS metering assets (regulatory category) are mapped directly to the ‘Meters’ EBT category. Public lighting assets are mapped directly to the ‘“Other” assets with long lives‘ category IT, Communications and Other (ACS metering) are mapped directly to the ‘“Other” assets with short lives’ category.	N/A
Network services and alternative control services	The AER’s explanatory statement states network services are defined as a subset of standard control services—i.e. network services excludes metering, connection services, public lighting and fee based and quoted services. Consequently, JEN has excluded metering asset service and residual lives from the		

Variable	Source and why actual	Methodology	Assumptions
	network services section and included asset service and residual lives for public lighting and ACS metering within the ACS section (under DRAB1407-DRAB1409 and DRAB1507-DRAB1509). JEN has also not reported any asset service and residual asset lives for the following variables (DRAB1401-DRAB1406 and DRAB1501-DRAB1506) within the ACS section because JEN has no ACS assets that fall within these categories.		

Estimated information

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
DRAB1408-DRAB1409 (SCS only)	The asset lives for other short and other long categories are unable to be sourced directly from JEN's internal business records	1. Calculate the relative capex weight for short and long life assets 2. Estimate the standard life of the assets by multiplying relative capex weight to life of assets within each category	JEN has changed the methodology to align with the definition of short term and long term asset lives.	JEN is not aware of a superior estimation technique.
DRAB1501, DRAB1502, DRAB1503, DRAB1504, DRAB1505, DRAB1506, DRAB1507, DRAB1508-DRAB1509	JEN is unable to source data directly from internal business systems and has hence used an accounting proxy method.	An accounting proxy method is applied. The period opening value (by category) is divided by straight line depreciation (for the current period) to calculate the estimated remaining life.	JEN has changed methodology to align with the approach applied to other assets.	JEN is not aware of a superior estimation technique.

3.4 OPERATIONAL DATA

3.4.1 ENERGY DELIVERY

Actual information

Variable	Source and why actual	Methodology	Assumptions
DOPED01	The data is sourced from JEN's two billing systems, SAP ERP and SAP ISU. JEN therefore considers this information to be actual information. The data is then captured in a line charge file on a monthly basis and is summated in worksheet Year to date.	The data is obtained from JEN's billing systems where a monthly report is produced from each billing system to record quantities and revenue by tariff component. The data is then captured in a line charge file on a monthly basis and is summated in worksheet Year to date.	The tariff codes listed below are incorporated in JEN's approved annual tariffs which are published by the AER. **DOPED01**: Sum of Peak energy, Off Peak energy and Shoulder energy all tariff codes.
DOPED0201 – DOPED0206	The data is sourced from JEN's two billing systems, SAP ERP and SAP ISU. JEN therefore considers the information to be actual information. The data is then captured in a line charge file on a monthly basis and is summated in worksheet Year to date.	The data is obtained from JEN's billing systems where a monthly report is produced from each billing system to record quantities and revenue by tariff component. The data is then captured in a line charge file on a monthly basis and is summated in worksheet Year to date.	The tariff codes listed below are incorporated in JEN's approved annual tariffs which are published by the AER. **DOPED0201:** Comprises of peak energy for A100, A10D and A200, A20D tariff codes. **DOPED0202:** Comprises of Peak energy for all tariff codes with the exception of A100, A10D, A200, A20D and A290. **DOPED0203:** Comprises of Shoulder energy for all tariff codes. **DOPED0204:** Comprises of all Off-Peak energy for all tariff codes with the exception of A180 and A290.

Variable	Source and why actual	Methodology	Assumptions
			DOPED205: Comprises of Off Peak energy for A180 tariff code **DOPED206**: Comprises of Peak energy and off peak energy for A290 tariff code.
DOPED0301 – DOPED0304	The TNSP data obtained by JEN as a monthly value from the wholesale metering database. This is the actual data that determines the total energy received. The information is considered to be actual: - the total energy received from TNSP is the actual data obtained as a monthly value	JEN extracts the actual total TNSP data for the regulatory year. Net Cross Boundary Flows in and out Jemena are also calculated for the entire regulatory year using energy data as calculated by the Jemena Wholesale Metering Database (CitiPower and Powercor) and supplied by AusNet Services. The total net boundary flow into Jemena is then added onto the total Boundary Load. JEN has reported its total energy receipts from TNSP and other DNSPs under DOPED0304, as the on-peak, shoulder and off-peak times differ between the tariffs we offer.	
DOPED0401 – DOPED0403 DOPED0405 – DOPED0407	JEN does not record data for variables DOPED0401 to DOPED0403 and DOPED0405 to DOPED0407. The energy received from Embedded Generation on an accumulation basis is provided under variable DOPED0404 and DOPED0408.		
DOPED0404	JEN considers this information is actual as energy received into JEN from non-residential	The generation data for each non-residential embedded generator is obtained from Itron and then summated.	The data is embedded generation data only; it does not include the energy consumed by embedded generation.

Variable	Source and why actual	Methodology	Assumptions
	embedded generation is extracted from JEN's Itron system.	The data includes the energy received from non-residential embedded generation on an accumulation basis. Embedded generator excluded is: Somerton Power Station	
DOPED0408	JEN considers this information is actual as energy received into JEN from residential embedded generation is extracted from JEN's Itron system.	The generation data for each residential embedded generator is obtained from Itron and then summated	The data is embedded generation data only; it does not include the energy consumed by embedded generation.
DOPED0501 – DOPED0505	The data is sourced from JEN's two billing systems, SAP ERP and SAP ISU. JEN therefore considers the information to be actual information. The data is then captured in a line charge file on a monthly basis and is summated in worksheet Year to date.	The data is obtained from JEN's billing systems where a monthly report is produced from each billing system to record quantities and revenue by tariff component. The data is then captured in a line charge file on a monthly basis and is summated in worksheet Year to date.	The tariff codes listed below are incorporated in JEN's approved annual tariffs which are published by the AER. **DOPED0501**: Comprises of peak energy, off peak energy and shoulder energy for A100 to A180 tariff codes. **DOPED502:** Comprises of peak energy, off peak energy for A200, A210, A23N, and A250 tariff codes. **DOPED503:** Comprises of peak energy, off peak energy for A20D, A230, A270 and A300 to A37M tariff codes. **DOPED504**: Comprises of peak energy, off peak energy for A400 to A50E tariff codes. **DOPED505:** Comprises of peak energy and off peak energy for A290 tariff code.

Estimated information

No estimated information is provided.

3.4.2 CUSTOMER NUMBERS

Actual information

Variable	Source and why actual	Methodology	Assumptions
DOPCN0101 - DOPCN0104	JEN's AMI SAP and ERP SAP systems are the source of actual data for network customer numbers. The above systems do not split customer numbers by tariff types. Customer accounts by tariff type are based on the billing system (SAP ISU module) which does not include unmetered customers	The total network customers reported is the average number of customers at the start and at the end of the reporting period. Business Objects report ASM497 is used to report customer numbers. Customer numbers include all active and de-energised NMIs and unmetered customers. Customers at the start of the regulatory year = customer numbers at the last day of June 2020. Customers at the end of the regulatory year = customer numbers at the last day of June of the current regulatory year. The percentage split of customers by tariff type is provided by Pricing Strategy based on information from the billing system. The percentage split adjusted for the High Voltage demand tariff customer percentage split is then applied to the net of total network customers minus unmetered customers and minus the High Voltage demand tariff customer	No assumptions have been made.

Variable	Source and why actual	Methodology	Assumptions
		numbers to calculate customer numbers by other tariff types.	
DOPCN0105	JEN's ERP SAP system is the source of actual data for unmetered customer numbers.	The data is extracted using Business Objects report ASM497.	No assumptions have been made.
DOPCN0106	Jemena does not have any customers that fit into the "Other Customer Numbers" category and is therefore entered as zero.		
DOPCN0202 - DOPCN0203	JEN's AMI SAP and ERP SAP systems are the source of actual data for customer numbers.	Business Objects report ASM497 is used to report customer numbers. Customer numbers by feeder is extracted from ASM497 report. Customers at the start of the regulatory year = customer numbers at the last day of June 2020. Customers at the end of the regulatory year = customer numbers at the last day of June of the current regulatory year. The definition of urban and rural short feeders based on 3-year average load density has been used to determine the categorisation of each feeder. JEN PR 0502 Section 3.2.3.1 outlines the methodology that JEN has applied to calculate urban and rural customer numbers which basically derives the urban/rural short customer split ratio from the categorised feeder customer numbers at the start of the period and at the end of the period.	No assumptions have been made in providing this information.

Variable	Source and why actual	Methodology	Assumptions
		The ratios are then applied to the actual network customer numbers including unmetered and de-energised customers respectively to calculate the number of urban and rural short customers.	
DOPCN0201 and DOPCN0204	JEN has no customers of these types on its network and is therefore entered as zero.	N/A	N/A
DOPCN0301 to DOPCN0303	TasNetworks (D) only, not applicable for JEN	N/A	N/A

Estimated information

No estimated information is provided.

3.4.3 SYSTEM DEMAND

Actual information

Variable	Source and why actual	Methodology	Assumptions
DOPSD0101	JEN considers this information is actual as it can be directly drawn from the internal business records. The information is obtained from SCADA metering data. Throughout the JEN network there is a significant number of measurements (voltage and current), predominantly at JEN zone sub-stations, being provided to the Real Time Systems. All historical SCADA data (2008	This is derived from metered actual zone substation data, adjusted for abnormal changes—un-anticipated temporary load changes due to transfers, interruption caused for network contingencies—but excludes any embedded generation. $$MD = \sum_{1}^{n} MD_{ZSSn}$$ Where	The data includes JEN owned zone substations only (i.e. it does not include the customer substation and other DNSP owned zone substations).

Variable	Source and why actual	Methodology	Assumptions
	onwards) can be interrogated using PI (user interface developed by OSIsoft) JEN has referred to the following report to obtain the data. JEN maximum demand forecast excel spread sheet 2021. Note: The PI System is a proprietary software developed by OSIsoft for the management of real-time data and events. JEN uses this software to store (and retrieve) real-time meter data, in which the real-time meter data comes from the field via the SCADA system.	MD = non-coincident summed raw unadjusted annual maximum demand at ZSS level (MW) n = number of JEN zone substations MD_{ZSSn} = non-coincident raw unadjusted annual maximum demand at ZSS n (Mega Watts (MW))	
DOPSD0104	JEN considers this information is actual as it can be directly drawn from the internal business records. The source of actual information is PI system which stores the historical SCADA metering data. JEN has referred to the following report to obtain the data. JEN Load Demand Forecasts 2021 Model.	The coincident maximum demand data for each zone substation is extracted from PI at the time of coincident system peak demand at the transmission network connection points and provided the summation. $$MD = \sum_{1}^{n} MD_{ZSSnt}$$ Where MD= coincident summated raw system annual maximum demand at Zone Substation level (MW) n = number of JEN Zone Substations t = time of system coincident maximum demand as determined at the transmission connection point level. MD_{ZSSnt} = coincident raw unadjusted annual maximum demand at Zone Substation n (MW) at time t.	JEN assumed that the summation of actual raw demands for the zone substation is the greatest at the time of coincident peak system demand. Time of system coincident maximum demand is recorded in average 15 minute intervals using wholesale market meters. It is assumed that the difference in demand between the 15 minute interval and the precise time of the MD is negligible.

Variable	Source and why actual	Methodology	Assumptions
DOPSD0107	JEN considers this information is actual as it can be directly drawn from wholesale market meter data.	This is derived from metered actual (transmission network connection point 15 min- data excluding any embedded generation adjustment. $$MD = \sum_{1}^{n} MD_{TCPn}$$ Where MD = non-coincident summed raw system annual maximum demand at Transmission Connection Point level (MW) n = number of JEN Transmission Connection Points MD_{TCPn} = non-coincident raw unadjusted annual maximum demand at Transmission Connection Point n (MW)	This includes JEN load flowing on JEN's subtransmission network only. E.g. Thomastown zone substation (TT) station load is excluded as TT load is supplied by non-JEN subtransmission lines.
DOPSD0110	JEN considers this information is actual as it can be directly drawn from wholesale market meter data.	Time of system coincident maximum demand is recorded in average 15 minute intervals using wholesale market meters. This is the actual, unadjusted (i.e. not weather normalised) summation of actual raw demands for the transmission connection points at the time when this summation is greatest. The Maximum Demand (**MD**) does not include Embedded Generation. $$MD = \sum_{1}^{n} MD_{TCPnt}$$ Where MD = coincident summed raw system annual maximum demand at Transmission Connection Point level (MW)	This includes JEN load flowing on JEN subtransmission network only. E.g. TT station load is excluded as TT load is supplied by non-JEN subtransmission lines.

Variable	Source and why actual	Methodology	Assumptions
		n = number of JEN Transmission Connection Points t = time of system coincident maximum demand as determined at the transmission connection point level. MD_{TCPnt} = coincident raw unadjusted annual maximum demand at Transmission Connection Point n (MW) at time t	
DOPSD0201	JEN considers this information is actual as it is calculated from actual metered MW MD and MVAr drawn from the internal business records. The source of actual information is PI system which stores the historical SCADA metering data.	The MVA MD is calculated from MW MD and MVAr at the time of MW MD. Therefore, MVA MD is the same date and time as MW MD. $$MD = \sum_{1}^{n} MD_{ZSSn}$$ Where MD = non-coincident summated raw system annual maximum demand at Zone Substation level (MVA) n = number of JEN Zone Substations MD_{ZSSn} = non-coincident raw unadjusted annual maximum demand at Zone Substation n (MVA) The MVA MD is calculated from MW MD and MVAr via the Pythagorean Theorem: $$MVA = \sqrt{(MW^2 + MVAr^2)}$$ The source of MW and MVAr information is PI system and JEN maximum demand forecast excel spread sheet model 2020.	The MVAr comes after the application of power factor correction measures at zone substation (e.g. capacitor bank), where applicable. The data includes JEN owned zone substations only (i.e. it does not include customer substations and other DNSP owned zone substations).
DOPSD0204	JEN considers this information is actual as it is calculated from actual metered MW MD and MVAr drawn from the internal business records.	The zone substation MW MD and MVAr from PI at the time of system peak are utilised to estimate the data as per the definition of this variable.	JEN assumed that the summation of actual raw demands for the zone substation is the greatest at the time of coincident peak system demand.

Variable	Source and why actual	Methodology	Assumptions
	The source of actual information is PI system which stores the historical SCADA metering data.	The MVA MD is calculated from MW MD and MVAr at the time of MW MD. Therefore, MVA MD is the same date and time as MW MD. $$MD = \sum_{1}^{n} MD_{ZSSnt}$$ Where MD = coincident summed raw system annual maximum demand at ZSS level (MVA) n = number of JEN zone substations t = time of system coincident maximum demand at transmission connection point level MD_{ZSSnt} = coincident raw annual maximum demand at ZSS n (MVA) at time t The MVA MD is calculated from MW MD and MVAr via the Pythagorean Theorem: $$MVA = \sqrt{(MW^2 + MVAr^2)}$$	Time of system coincident maximum demand is recorded in average 15 minute intervals using wholesale market meters. It is assumed that the difference in demand between the 15 minute interval and the precise time of the MD is negligible.
DOPSD0207	JEN considers this information is actual as it is calculated from actual metered MW MD and MVAr drawn from the internal business records. Wholesale market meter data and JEN maximum demand forecast excel spread sheet model 2021 are the sources of actual data.	The MVA MD is calculated from metered actual (transmission connection point 15 min- data) MW MD and MVAr at the time of MW MD. Therefore, MVA MD is the same date and time as MW MD. $$MD = \sum_{1}^{n} MD_{TCPn}$$ Where	Time of system coincident maximum demand is recorded in average 15 minute intervals using wholesale market meters. It is assumed that the difference in demand between the 15 minute interval and the precise time of the MD is negligible. MVA MD is assumed to occur at the same date and time as MW MD

Variable	Source and why actual	Methodology	Assumptions
		MD = non-coincident summed raw system annual maximum demand at Transmission Connection Point level (MVA) n = number of JEN Transmission Connection Points MD_{TCPn} = non-coincident raw unadjusted annual maximum demand at Transmission Connection Point n (MVA) The MVA MD is calculated from MW MD and MVAr via the Pythagorean Theorem: $$MVA = \sqrt{(MW^2 + MVAr^2)}$$ Wholesale market meter data and JEN maximum demand forecast excel spread sheet model are the sources of MW and MVAr data.	
DOPSD0210	JEN considers this information is actual as it is calculated from actual metered MW MD and MVAr drawn from the internal business records. Wholesale market meter data and JEN maximum demand forecast excel spread sheet model 2021 are the sources of actual data.	MW MD is derived by summation of metered actual raw demands for the transmission connection points (terminal station average 15-min data) at the time when this summation is greatest. The MVA MD is calculated from metered actual of MW MD and MVAr at the time of MW MD therefore MVA MD is the same date and time as MW MD. $$MD = \sum_{1}^{n} MD_{TCPnt}$$ Where MD = coincident summated raw system annual maximum demand at Transmission Connection Point level (MVA) n = number of JEN transmission connection points	Time of system coincident maximum demand is recorded in average 15 minute intervals using wholesale market meters. It is assumed that the difference in demand between the 15 minute interval and the precise time of the MD is negligible. MVA MD is assumed to occur at the same date and time as MW MD.

Variable	Source and why actual	Methodology	Assumptions
		t = time of system coincident maximum demand as determined at the transmission connection point level. MD_{TCPnt} = coincident raw unadjusted annual maximum demand at Transmission Connection Point n (MVA) at time t The MVA MD is calculated from MW MD and MVAr via the Pythagorean Theorem: $$MVA = \sqrt{(MW^2 + MVAr^2)}$$ Wholesale market meter data and JEN maximum demand forecast excel spread sheet model are the sources of MW and MVAr data.	
DOPSD0102, DOPSD0103, DOPSD0105, DOPSD0106, DOPSD0108, DOPSD0109, DOPSD0111, DOPSD0112, DOPSD0202, DOPSD0203, DOPSD0205, DOPSD0206, DOPSD0208, DOPSD0209, DOPSD0211, DOPSD0212,	These particular variables are derived from other records used in ordinary course of business, and are categorised as actual information on the basis that they are materially dependent on information recorded in JEN's business records and their presentation for the purposes of the Notice is not contingent on judgement and assumptions for which there are valid alternatives which could lead to a materially different presentation in the response to the Notice. These variables include a temperature sensitivity assumption in order to provide weather corrected data. To derive this method, we used a recorded sample of actual historical weather and demand data to determine the temperature sensitivity relationship.	Coincident/Non-coincident summated weather adjusted MW MD at zone substation level / transmission connection point are derived by summation of respective weather adjusted MW MDs of individual zone substation / transmission connection point $$Weather\ adjusted\ MW\ MD = \sum_{1}^{n} MD_b$$ Where: n = number of JEN transmission connection points/JEN owned zone substations $$MD_b = MD_a \times \frac{A.t_b{}^2 + B.t_b + C}{A.t_a{}^2 + B.t_a + C}$$ A, B, C = coefficients determined based on historical data for each station. These values are as recorded in the load demand forecast. MD_b = MW MD after temperature adjustment MD_a = actual unadjusted MW MD	It is assumed that the 10% POE and 50% POE average daily temperatures and MD temperature sensitivity relationship is consistent for 2020.

Variable	Source and why actual	Methodology	Assumptions
	The data source of actual weather unadjusted MW and MVAr for transmission connection points is Wholesale market meter data. The data source of actual weather unadjusted MW and MVAr for JEN zone substations is the PI system.	t_b = average daily temperature to adjust to (32.9°C for 10% POE or 29.4°C for 50% POE) t_a = average daily temperature on day of actual unadjusted MW MD Average daily temperature is calculated as follows: $$t = \frac{(t_{max} - t_{min})}{2}$$ Where: t = average daily temperature t_{max} = maximum temperature of the day (24 hour period) (data sourced from PI) t_{min} = minimum temperature of the day (24 hour period) (data sourced from PI) Weather corrected values are assumed to have the same MW/MVA ratio as raw adjusted data. Therefore weather corrected MVA is calculated as: $$\mathrm{MVA_{adjusted}} = \frac{\mathrm{MVA_{raw}}}{\mathrm{MW_{raw}}} \times \mathrm{MW_{adjusted}}$$	
DOPSD0301	JEN considers this information is actual as it is calculated from actual metered MW MD and MVAr drawn from the internal business records. Wholesale market meter data is the sources of actual MW and MVAr data.	As per the Economic Benchmarking RIN definition of power factor $$\text{The average overall network power factor} = \frac{\sum_{x=1}^{x=n} MW_x}{\sum_{x=1}^{x=n} MVA_x}$$	None.

Variable	Source and why actual	Methodology	Assumptions
		MW_x =Sum of MW measured in every 15 minute average interval by wholesale market meters in JEN sub transmission connection points MVA_x= Sum of MVA calculated from MW_x and corresponding MVAr measured in every 15 minute average interval by wholesale market meters in JEN sub transmission connection points	
DOPSD0311	JEN considers this information is actual as it is calculated from actual metered MW MD and MVAr drawn from the internal business records. Wholesale market meter data is the sources of actual MW and MVAr data.	As per the Economic Benchmarking RIN the definition of power factor $\text{The average overall network power factor} = \frac{\sum_{x=1}^{x=n} MW_x}{\sum_{x=1}^{x=n} MVA_x}$ MW_x =Sum of MW measured in every 15 minute average interval by wholesale market meters in JEN 66kV sub transmission connection points MVA_x= Sum of MVA calculated from MW_x and corresponding average MVAr measured in every 15 minute average interval by wholesale market meters in JEN 66kVsub transmission connection points	The data for this variable is different from DOPSD0301 as DOPSD0301 includes both 66kV and 22kV sub transmission connection points.
DOPSD0304, DOPSD0306, DOPSD0308	These particular variables are derived from other records used in ordinary course of business, and so they are categorised as actual information on the basis that they are materially dependent on information recorded in JEN's business records and their presentation for the purposes of the Notice are not contingent on judgement and assumptions for which there are valid alternatives which	As per RIN requirement the Total MW and MVA are calculated as below. $\text{Total MVA} = \sum_{x=t1}^{tn} a_x + \cdots \sum_{x=t1}^{tn} n_x$ Where t1 … tn are 15 minute time intervals from 1 January to 31 December. The feeder currents are recorded in every 15 minute interval in OSI PI.	The data provided excludes customer substations and other DNSP owned zone substations for HV feeders

Variable	Source and why actual	Methodology	Assumptions
	could lead to a materially different presentation in the response to the Notice. These variables include assumptions of nominal voltage (i.e. 6.6kV, 11kV and 22kV) rather than actual measured voltage at each zone substation every 15 minutes. We consider these voltages to be a reasonable proxy for actual voltage. This assumption is based on the fact that on average, JEN's historical actual voltage is regulated/targeted to equal the nominal voltage value. The data source for JEN zone substation average MW and average feeders MVA is PI system.	$a_x \ldots n_x$= Feeder MVA at time interval x $=\sqrt{3}$ X nominal voltage of the feeder X Feeder current at time interval $\text{Total MW} = \sum_{x=t1}^{tn} A_x + \cdots \sum_{x=t1}^{tn} N_x$ Where, $A_x \ldots N_x$= Feeder MW at time interval x Average power factor = $\frac{\text{Total MW}}{\text{Total MVA}} = \frac{\sum_{x=t1}^{tn} a_x + \cdots \sum_{x=t1}^{tn} n_x}{\sum_{x=t1}^{tn} A_x + \cdots \sum_{x=t1}^{tn} N_x}$ Since only the historical interval data for zone substation MW and Feeder currents are available, the above equation is simplified as below by dividing the numerator and denominator by the number of time intervals Average power factor = $\frac{\text{Total MW}}{\text{Total MVA}} = \frac{\text{Average MW of zone substation 1} + \cdots + \text{Average MW of zone substation N}}{\text{Average MVA of Feeder 1} + \cdots + \text{Average MVA of feeder N}}$ The zone substations and the feeders in above equation are at same voltage level	
DOPSD0303, DOPSD0305, DOPSD0307, DOPSD0309, DOPSD0310, DOPSD0312,	These variables are not applicable to JEN as JEN does not have any lines with these voltage levels.		

Variable	Source and why actual	Methodology	Assumptions
DOPSD0313, DOPSD0314			
DOPSD0401- DOPSD0402	The data is sourced from JEN's two billing systems, SAP ERP and SAP ISU. JEN therefore considers the information to be actual information. The data is then captured in a line charge file on a monthly basis and is summed in worksheet Year to date.	The data is obtained from JEN's billing systems where a monthly report is produced from each billing system to record quantities and revenue by tariff component. The data is then captured in a line charge file on a monthly basis and is summed in worksheet Year to date.	None
DOPSD0403- DOPSD0404	The data is sourced from JEN's two billing systems, SAP ERP and SAP ISU. JEN therefore considers the information to be actual information. The data is then captured in a line charge file on a monthly basis and is summed in worksheet Year to date.	The data is obtained from JEN's billing systems where a monthly report is produced from each billing system to record quantities and revenue by tariff component. The data is then captured in a line charge file on a monthly basis and is summed in worksheet Year to date.	None

Estimated information

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
DOPSD0302	The variable is estimated due to the assumptions made and that it could not be directly drawn from JEN's internal business records.	In the normal course of business JEN does not record the power factor of each individual LV line. However, AMI meters record the power factor for each individual customer. The overall LV power factor is calculated by taking an average of 10,000 LV customers' power factors in the regulatory year.	It is assumed that the average power factor of this sample of 10,000 LV customers gives a representative estimate of the LV power factor for JEN's network.	This approach is the most reasonable given the availability of data. JEN is not aware of a superior technique, given the data availability constraints.

3.5 PHYSICAL ASSETS

3.5.1 NETWORK CAPACITIES

3.5.1.1 – Overhead network length of circuit at each voltage

Variable	Source and why actual	Methodology	Assumptions
DPA0101 - Overhead low voltage distribution DPA0103 - Overhead 6.6kV DPA0105 - Overhead 11kV DPA0107 - Overhead 22kV DPA0110 - Overhead 66kV	**Source of the data:** SAP ERP equipment. The count of all in service equipment with equipment type = LV COND, HV COND, ST COND. For LV COND, only usage = Mains (distributor) has been included.	The following BO Report is run to extract the required details for all the categories. • **ASM430 JEN RIN Equipment In Service (PHYS ASSETS 3.5)** The equipment are filtered by: ➢ **"Date Installed"** in the date range covering the regulatory year ➢ Equipment Type ➢ Equipment Characteristics 22kV sub transmission conductor has been included in the Overhead 22kV categorisation.	No assumptions have been made.

Variable	Source and why actual	Methodology	Assumptions
DPA0102 - Overhead 2.2kV DPA0104 - Overhead 7.6kV DPA0106 - Overhead SWER DPA0108 - Overhead 33kV DPA0109 - Overhead 44kV DPA0111 - Overhead 110kV DPA0112 - Overhead 132kV DPA0113 - Overhead 220kV DPA0114 - Other	JEN does not have any of these specified ratings, therefore no data can be provided.	N/A	N/A

3.5.1.2 – Underground network length of circuit at each voltage

Variable	Source and why actual	Methodology	Assumptions
DPA0201 - Underground low voltage distribution DPA0203 - Underground 6.6kv DPA0205 - Underground 11 kV DPA0207 - Underground 22 kV DPA0209 - Underground 66 kV	**Source of the data:** SAP ERP equipment. The count of all in service equipment with equipment type = LV CABLE, HV CABLE, ST CABLE. Characteristic COMPUTED_LENGTH on the cables maintained in SAP provides the length. For LV CABLE, only usage = Mains (distributor) has been included.	The following BO Report is run to extract the required details for all the categories • **ASM430 JEN RIN Equipment In Service (PHYS ASSETS 3.5)** The equipment are filtered by: ➢ **"Date Installed"** in the date range covering the regulatory year ➢ Equipment Type • Equipment Characteristics 22kV sub transmission cable has been included in the Underground 22kV categorisation.	No assumptions have been made.

Variable	Source and why actual	Methodology	Assumptions
DPA0202 - Underground 5kV DPA0204 - Underground 7.6kV DPA0206 - Underground SWER DPA0208 - Underground 33kV DPA0210 - Underground 110kV DPA0211 - Underground 132kV DPA0212 - Other	JEN does not have any of these specified ratings, therefore no data can be provided.	N/A	N/A

3.5.1.3 – Circuit Capacity MVA - Estimated overhead network weighted average MVA capacity by voltage class

Variable	Source and why actual	Methodology	Assumptions
DPA0301 - Overhead low voltage distribution DPA0302 - Overhead 6.6kV DPA0304 - Overhead 11kV DPA0306 - Overhead 22kV	**Source of the data:** SAP ERP equipment. The count of all in service equipment with equipment type = LV COND, HV COND Characteristic MVA_RATING on the conductor maintained in SAP provides the capacity. For LV COND, only usage = Mains (distributor) has been included.	The following BO Report is run to extract the required details for all the categories. • **ASM430 JEN RIN Equipment In Service (PHYS ASSETS 3.5)** The equipment are filtered by: ➢ **"Date Installed"** in the date range covering the regulatory year ➢ Equipment Type • Equipment characteristics • 22kV sub transmission conductor has been included in the Overhead 22kV categorisation Below calculation is done in GIS to get the MVA_RATING which is then stored as a characteristic on the equipment in SAP	Ratings are based on standard design depth, temperature, proximity to other cables etc and do not allow for any variations from this that may exist in the field.

Variable	Source and why actual	Methodology	Assumptions
		$$\sum_{1}^{n} (s_n l_n)$$ Where: n = number of sections of conductor in service on JEN network s_n= MVA rating of section n of OH conductor l_n= length of section n of OH conductor Below calculation is done to get the weighted average capacity MVA by voltage class. $$= \frac{\sum_{1}^{n} (s_n l_n)}{\sum_{1}^{n} (l_n)}$$	
DPA0309 - Overhead 66kV	This particular variable is derived from other records used in the ordinary course of business. It is categorised as actual information on the basis that it is materially dependent on information recorded in JEN's business records and its presentation for the purposes of the Notice is not contingent on judgement and assumptions that could lead to a materially different presentation in the response to the Notice. Line Circuit Data Sheets (**CDS**) are the source for length and ratings of the 66kV line sections. A CDS is an AutoCAD drawing that is used to capture and store the	$$Weighted\ average\ Capacity\ of\ 66kV\ subtransmission$$ $$OH\ \ line\ = \frac{\sum_{1}^{n} (s_n l_n)}{\sum_{1}^{n} (l_n)}$$ Where: n = number of sections of 66kV overhead conductor in service on JEN network s_n= Summer MVA rating of section n of 66kV OH conductor l_n= length of section n of the 66kV OH conductor	Only JEN owned 66kV subtransmission lines are included in the calculation. As JEN is a summer peaking network, the summer ratings of OH conductors have been utilised to calculate the MVA capacity.

Variable	Source and why actual	Methodology	Assumptions
	engineering data (such as circuit length, ratings, conductors spacing, and line impedances) for the sub-transmission network. This variable is dependent upon assumptions that actual capacity is equal to the design standard of each type of conductor. These design standards are recorded and provided by JEN's conductor manufacturers.		
DPA0303 - Overhead 7.6kV DPA0305 - Overhead SWER DPA0307 - Overhead 33kV DPA0308 - Overhead 44kV DPA0310 - Overhead 110kV DPA0311 - Overhead 132kV DPA0312 - Overhead 220kV DPA0313 - Other	JEN does not have any of these specified ratings, therefore no data can be provided.	N/A	N/A

3.5.1.4 – Circuit Capacity MVA - Estimated underground network weighted average MVA capacity by voltage class

Variable	Source and why actual	Methodology	Assumptions
DPA0401 - Underground low voltage distribution DPA0403 - Underground 6.6kV DPA0405 - Underground 11kV DPA0408 - Underground 22kV	**Source of the data:** SAP ERP equipment. The count of all in service equipment with equipment type = LV CABLE, HV CABLE Characteristic MVA_RATING on the cables maintained in SAP provides the capacity. For LV CABLE, only usage = Mains (distributor) has been included.	The following BO Report is run to extract the required details for all the categories. • **ASM430 JEN RIN Equipment In Service (PHYS ASSETS 3.5)** The equipment are filtered by: ➢ **"Date Installed"** in the date range covering the regulatory year ➢ Equipment Type • Equipment Characteristics 22kV sub transmission cable has been included in the Underground 22kV categorisation. Below calculation is done in GIS to get the MVA_RATING which is then stored as a characteristic on the equipment in SAP. $$UG\ line\ = \frac{\sum_1^n (s_n l_n)}{\sum_1^n (l_n)}$$ Where: n = number of sections of UG cable in service on JEN network. s_n= Summer MVA rating of section n of the UG cable l_n= length of section n of the UG cable	Ratings are based on standard design depth, temperature, proximity to other cables etc and do not allow for any variations from this which may exist in the field.

Variable	Source and why actual	Methodology	Assumptions
DPA0410 - Underground 66kV	This particular variable is derived from other records used in ordinary course of business. It is categorised as actual information on the basis that it is materially dependent on information recorded in JEN's business records and its presentation for the purposes of the Notice is not contingent on judgement and assumptions for which there are valid alternatives which could lead to a materially different presentation in the response to the Notice. Line Circuit Data Sheets are the source for length and ratings of the 66kV underground cable sections. A CDS is an AutoCAD drawing that is used to capture and store the engineering data (such as circuit length, ratings, conductors spacing, and line impedances) for the sub-transmission network. This variable is dependent upon assumptions that actual capacity is equal to the design standard of each type of conductor. These design standards are recorded and provided by JEN's conductor manufacturers.	$Weighted\ average\ Capacity\ of\ 66kV\ subtransmission$ $UG\ line\ = \frac{\sum_1^n (s_n l_n)}{\sum_1^n (l_n)}$ Where: n = number of sections of 66kV UG cable in service on JEN network. s_n= Summer MVA rating of section n of 66kV UG cable l_n= length of section n of the 66kV UG cable	Only JEN owned 66kV sub transmission lines are included in the calculation.

Variable	Source and why actual	Methodology	Assumptions
DPA0402 - Underground 5kV DPA0404 - Underground 7.6kV DPA0406 - Underground SWER DPA0407 - Underground 12.7kV DPA0409 - Underground 33kV DPA0211 - Underground 110kV DPA0212 - Underground 132kV DPA0213 - Other	JEN does not have any of these specified ratings, therefore no data can be provided.	N/A	N/A

3.5.2 TRANSFORMER CAPACITIES

3.5.2.1 - Distribution transformer total installed capacity

Variable	Source and why actual	Methodology	Assumptions
DPA0501 - Distribution transformer capacity owned by utility	**Source of the data:** SAP ERP equipment. The count of all in service equipment with equipment type = DIST TRANS Characteristic RATING on the distribution transformers maintained in SAP provides the capacity.	The following BO Report is run to extract the required details for all the categories. • **ASM430 JEN RIN Equipment In Service (PHYS ASSETS 3.5)** The equipment are filtered by: ➢ **“Date Installed”** in the date range covering the regulatory year ➢ Equipment Type • Equipment Characteristics Number of Distribution Spare Emergency stock Transformers is added to the number returned by the above report to arrive at the final number to be reported.	No assumptions have been made.

Variable	Source and why actual	Methodology	Assumptions
DPA0502 - Distribution transformer capacity owned by High Voltage Customers	As per the AER RIN explanatory statement where this information is not available to the NSP, it is to report a summation of non-coincident individual maximum demands of each such directly connected customer whenever they occur (i.e. the summation of a single annual MD for each customer) as a proxy for capacity within the customer's installation. The variable should be the sum of the direct information where this is available and of the proxy MVA measure where the direct measure is not available. Although JEN does not currently record the distribution transformer capacity owned by high voltage customers, JEN considers the information provided to be actual as the proxy MVA measure can be directly extracted from SAP system.	The maximum demand (KVA) for each HV customers is extracted from JEN's Billing system. The data provided is the summation of actual MVA MD of individual HV customers.	The data provided does not include the sub transmission customers.
DPA0503 - Cold spare capacity included in DPA0501	JEN considers this information to be actual information as it can be directly extracted from JEN's SAP, which has a specific flag as emergency stock.	This is the summation of JEN owned distribution transformers stored in JEN's warehouse as emergency stock.	JEN has applied the assumption that only the capacity that is held in emergency stock should be classified as cold spare capacity. Capacity that is held as stock that is reserved for construction projects has not been classified as cold spare capacity.

3.5.2.2 - Distribution transformer total installed capacity

Variable	Source and why actual	Methodology	Assumptions
DPA0601 - Total installed capacity for first step transformation where there are two steps to reach distribution voltage DPA0602 - Total installed capacity for second step transformation where there are two steps to reach distribution voltage	JEN does not have any two-step transformations and has therefore not provided information relating to these variables.		
DPA0603 - Total zone substation transformer capacity where there is only a single step transformation to reach distribution voltage DPA0604 - Total zone substation transformer capacity DPA0605 - Cold spare capacity of zone substation transformers included in DPA0604	**Source of the data:** SAP ERP equipment. The count of all in service equipment with equipment type = ZS TRANS Characteristic RATING on the distribution transformers maintained in SAP provides the capacity.	The following BO Report is run to extract the required details for all the categories. • **ASM430 JEN RIN Equipment In Service (PHYS ASSETS 3.5)** The equipment are filtered by: ➢ **"Date Installed"** in the date range covering the regulatory year ➢ Equipment Type • Loading status = 10 (on load) [For DPA0603] • Loading status = 10, 20, 30 (on load, hot spare, cold spare) [For DPA0603] Loading status = 20,30 (hot spare, cold spare) [For DPA0605]	This does not include the customer substation and other DNSP owned zone substations supplying JEN customers. Not all capacities of zone substations are the nameplate ratings of the transformers. Some are de-rated due to limiting capacity of zone substation exit feeder capacity, some due to voltage drop limitation etc.

3.5.2.3 - Distribution - other transformer capacity

Variable	Source and why actual	Methodology	Assumptions
Distribution other - transformer capacity owned by utility	JEN does not have Distribution other - transformer capacity. As all the capacity reported already covered all of JEN owned and all owned by HV Customer, this other - transformer capacity owned by utility is zero.	N/A	N/A

3.5.3 PUBLIC LIGHTING

Actual information

Variable	Source and why actual	Methodology	Assumptions
DPA0701 Public lighting luminaires	**Source of the data:** SAP ERP equipment.	The following BO Report is run to extract the required details for all the categories. • **ASM430 JEN RIN Equipment In Service (PHYS ASSETS 3.5)** The equipment are filtered by: ➢ **"Date Installed"** in the date range covering the regulatory year ➢ Equipment Type = PUB LIGHT ➢ Tariff Type = Standard	No assumptions have been made.

Variable	Source and why actual	Methodology	Assumptions
DPA0702 - Public lighting poles	**Source of the data:** SAP ERP equipment.	The following BO Report is run to extract the required details for all the categories. • **ASM430 JEN RIN Equipment In Service (PHYS ASSETS 3.5)** The equipment are filtered by: ➢ **“Date Installed”** in the date range covering the regulatory year ➢ Equipment Type = POLE ➢ Classification = “Public Lighting”	No assumptions have been made.

3.6 QUALITY OF SERVICE

3.6.1 RELIABILITY

Actual information

Variable	Source and why actual	Methodology	Assumptions
DQS0101-DQS0108	JEN considers this information to be actual information as it is maintained directly within its Outage Management System (**OMS**). JEN's OMS is the repository for all outage information, including outage dates and times, the number of customers affected, restoration dates and times and restoration stages. JEN's SAP ISU and SAP ERP systems are the source of actual data for network customer numbers.	The data used to calculate the reliability variables (Key Performance Indicators (**KPI**)) is extracted from the OMS at the end of each month and is validated and cleansed to correct data errors. The cleansed data is loaded into the Customer Minutes Off Supply (CMOS) database. The reliability KPIs are then calculated. Unplanned SAIDI associated with outages greater than 1 minute duration was calculated using the following equations: DQS0101-0104 inclusive of MED DQS0101 = Total unplanned SAIDI = sum of Unplanned minutes off supply divided by average network customer numbers at the start and at the end of the regulatory year. DQS0102 = Unplanned SAIDI (excluding excluded outages) applies the same principle of calculation of total unplanned SAIDI with unplanned customer minutes off supply associated with the excluded events as per Clause in 3.3(a) in STPIS subtracted from the total unplanned minutes off supply before divided by average customer numbers.	No assumptions have been made in providing this information.

Variable	Source and why actual	Methodology	Assumptions
		Similarly, DQS0103 = Total Unplanned SAIFI = sum of Unplanned customer interruptions divided by average network customer numbers at the start and at the end of the regulatory year DQS0104 = Unplanned SAIFI (excluding excluded outages) applies the same principle of calculation of total unplanned SAIFI with unplanned customer interruptions associated with the excluded events as per Clause in 3.3(a) in STPIS subtracted from the total unplanned customer interruptions before divided by average customer numbers. DQS0105-0108 exclusive of MED DQS0105 = DQS0101 – Unplanned SAIDI (MED) DQS0106 = DQS0102 – Unplanned SAIDI (MED) DQS0107 = DQS0103 – Unplanned SAIFI (MED) DQS0108 = DQS0104 – Unplanned SAIFI (MED) where: Unplanned SAIDI (MED) = sum of Unplanned minutes off supply on Major Event Days as per Clause 3.3 (b) in STPIS divided by average customer numbers; Unplanned SAIFI (MED) = sum of Unplanned customer interruptions on Major Event Days as per Clause 3.3 (b) in STPIS divided by average customer numbers	

Estimated information

No estimated information is provided.

3.6.2 ENERGY NOT SUPPLIED

Actual information

No actual information is provided.

Estimated information

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
DQS0201-DQS0202	JEN has estimated these variables because it is calculated and is not an actual measured value. The energy not supplied has been routinely reported by JEN at the end of each regulatory year. JEN has referred to these reports to populate these variables. The feeder maximum demand, load factor, power factor and number of customers are calculated using data from JEN's core asset management systems.	The methodology that has been used is the fourth option, outlined on page 37 of "Economic benchmarking RIN for distribution network service providers – Instructions and Definitions (November 2013)". That is, JEN has used the average feeder demand derived from feeder maximum demand, estimated load factor and power factor, divided by the number of customers on the feeder. Unplanned energy not supplied is a function of unplanned customer-minutes- off-supply. As the RIN unplanned energy not supplied definition required the exclusion of excluded outages.	The planned energy not supplied has been consistently calculated with a factor of 0.3 since 1997. The assumption has considered that customers have been given notice 4 days before the outage, energy usage would just be diverted to times when supply is available and the actual energy not supplied would only be the base continuous consumption such as operating a fridge. The assumption and the adjustment factor was communicated to the Regulator (Office of the Regulator General (ORG)) before the 1997 annual report was submitted. There has been no instruction from the Regulator since indicating that the assumption should not be applied. JEN has used the average feeder demand derived from feeder maximum demand, estimated load factor and power factor divided by the number of customers on the feeder.	JEN has adopted the fourth estimation option for average customer demand because all inputs to calculate average customer demand on a feeder are readily available. Options 1 to 3 could not be used by JEN due to limitations of the IT system to merge the information from various sources. JEN is not aware of a superior estimation technique for these variables.

3.6.3 SYSTEM LOSSES

Actual information

Variable	Source and why actual	Methodology	Assumptions
DQS03	Wholesale market meter data, embedded generation data and cross boundary flow energy meter data are the sources for energy import and delivered data. System loss is based on actual energy imported and delivered data hence JEN considers this information as actual. This particular variable is derived from other records used in ordinary course of business. It is categorised as actual information on the basis that it is materially dependent on information recorded in JEN's business records and its presentation for the purposes of the Notice is not contingent on judgement and assumptions for which there are valid alternatives, which could lead to a materially different presentation in the response to the Notice.	The system loss is calculated as below as per the definition of the variable. $System\ losses = \frac{electricity\ imported\ (MWh) - electricity\ delivered\ (MWh)}{electricity\ imported\ (MWh)}\ x\ 100$ Electricity imported is the total electricity inflow into JEN's distribution network (including from Embedded Generation) minus the total electricity outflow into the networks of the adjacent connected distribution network service providers or the transmission network(s). Electricity delivered is the amount of electricity transported out of JEN's network to its customers as metered (or otherwise calculated) at the customer's connection. As part of Distribution Loss Factor (**DLF**) submission to AER in March each year, JEN calculates the actual system loss for previous financial year and forecast system loss for next financial year, which is certified by an independent consultant. Consistent with DLF reporting, JEN has reported the system loss for the relevant regulatory year as the forecast for the 2020-21 financial year.	No assumptions have been made in providing this information.

Estimated information

No estimated information is provided.

3.6.4 CAPACITY UTILISATION

Actual information

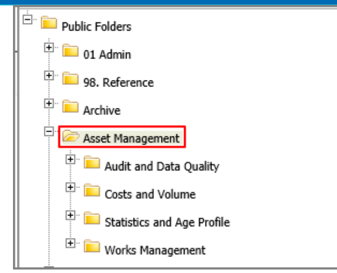
Variable	Source and why actual	Methodology	Assumptions
DQS04	JEN considers this variable to be actual information as the data is calculated from the variable code DOPSD0201, which is zone substation raw actual maximum demand (MVA), and variable code DPA0604, which zone substation transformer MVA capacity. Both are sources of actual data and so the derived capacity utilisation should be considered actual information also.	The overall utilisation for JEN owned zone substations is calculated each year by dividing the sum of non-coincident summated raw system maximum demand at the zone substation level by summation of zone substation thermal capacity. $$U_{ave} = \frac{MD_{ZSS}}{C_{ZSS}}$$ Where:U_{ave} = Overall utilisation of JEN owned zone substations MD = sum of non-coincident raw Maximum Demand (MVA) at the zone substation level (only JEN owned zone substations). This is equal to variable DOPSD0201. C_{ZSS} = summation of JEN owned zone substation thermal capacity. This is calculated as DPA0604 minus DPA0605.	As per variable codes DOPSD0201 and DPA0604.

Estimated information

No estimated information is provided.

3.7 OPERATING ENVIRONMENT FACTORS

Variable	Source and why actual	Methodology	Assumptions
GENERAL COMMENTS Applicable to: 3.7.2 – Terrain Factors and 3.7.3 – Service Area Factors	JEN GIS System.	SAP Business Objects (BO) reports have been developed to cater to the required details in this template. These reports extract data from the JEN Business Warehouse (BW), which sources the data from the SAP ERP and AMI environments. Data models (joins, associations and merging of data) and queries (filtering of data) have been developed to associate the data from different sources to present in the format required in the template. The logic for the queries for each category has been detailed in the sections below. There are different buttons in the report for each category with different filter criteria. Each button is used to get the final numbers for each category to be reported in the template Data loaded from SAP ERP and AMI into the business warehouse (BW) occurs every night as a batch job. The reports reside in BO Portal at the below locations:	N/A

Variable	Source and why actual	Methodology	Assumptions
			

3.7.1 – DENSITY FACTORS

Variable	Source and why actual	Methodology	Assumptions
DOEF0101 - Customer density	JEN considers this variable to be actual information as the data is calculated from the variable code DOEF0301, which is route line length, and variable code DOPCN01, which is total customer numbers. Both are sources of actual data and so the derived customer density should be considered actual information and are directly reconcilable with JEN's internal business records.	The data is calculated by dividing the variable code DOPCN01, which is total customer numbers, by the variable code DOEF0301, which is the route line length.	No assumptions have been made.

Variable	Source and why actual	Methodology	Assumptions
DOEF0102 - Energy density	JEN considers this variable to be actual information as the data is calculated from the variable code DOPED01, which is total energy delivered, and variable code DOPCN01, which is total customer numbers. Both are sources of actual data and so the derived energy density should be considered actual information and are directly reconcilable with JEN's internal business records.	DOEF0102 is derived as follows: variable DOPED01 is converted to MWh and divided by variable DOPCN01. Formula: (DOPED01*1000)/DOPCNO1	No assumptions have been made.
DOEF0103 - Demand density	JEN considers this variable to be actual information as the data is calculated from the variable code DOPSD0201, which MVA non-coincident maximum demand at zone substation level, and variable code DOPCN01, which is total customer numbers. Both are sources of actual data and so the derived demand density should be considered actual information and are directly reconcilable with JEN's internal business records.	Calculated as per the definition of variable i.e. kVA non-coincident maximum demand (at zone substation level) / no of customers: $DF_x = \frac{MD_x}{C_x}$ Where: DF_x = Density Factor for year x MD = non-coincident maximum demand at zone substation level (MVA) in year x as per variable code DOPSD0201 x 1000 C = total number of customers on JEN network in year x as per variable code DOPCN01	No assumptions have been made.

3.7.2 – TERRAIN FACTORS

Variable	Source and why actual	Methodology	Assumptions
DOEF0201 - Rural proportion DOEF0202 - Urban and CBD vegetation maintenance spans DOEF0203 - Rural vegetation maintenance spans DOEF0204 - Total vegetation maintenance spans DOEF0205 - Total number of spans DOEF0208 - Average number of trees per urban and CBD vegetation maintenance span DOEF0209 - Average number of trees per rural vegetation maintenance span DOEF0210 - Average number of defects per urban and CBD vegetation maintenance span DOEF0211 - Average number of defects per rural vegetation maintenance span DOEF0213 - Standard vehicle access	**Source of data**: The data is sourced from GIS where the data is uploaded from VMS.	The following BO Reports are run to extract the required details for all the categories: **ASM420 JEN Network Asset Statistics** This report is used to extract HV feeders, which are categorised as urban or rural. HV feeder length is then adjusted for parallel cable or conductor to determine the true feeder circuit length. **ASM450 JEN RIN Vegetation Management (Terrain Factors 3.7.2 & Service Area Factors 3.7.3)** This report extracts data from the new business warehouse where it is loaded from the GIS. GIS has following rules to determine the various metrics: ➢ The data collected in the field and loaded into the VMS that goes into GIS includes the feeder that the span is connected to, thus it is possible to determine whether the feeder is in the rural or urban area and whether it is in a bushfire risk area as defined by the Country Fire Authority (**CFA**). ➢ Jemena records the number of poles and does not record the number of spans. The total number of spans is the total number of poles less one. ➢ Average number of trees is copied over to GIS from VMS. ➢ The average number of defects is calculated by dividing the number of defects (action spans) with total number of spans at the end of each regulatory year.	N/A

Variable	Source and why actual	Methodology	Assumptions
DOEF0214 - Bushfire risk		JEN refers to this average as the "find rate" for a given regulatory year. ➢ A standard report is available in GIS, which when run, generates a list of all poles and related span lengths that have been identified in the field as accessible or not accessible by a standard vehicle. This report includes a summation indicating the total network length for poles accessible by a standard vehicle.	
DOEF0206 - Average urban and CBD vegetation maintenance span cycle DOEF0207 - Average rural vegetation maintenance span cycle	The source of the information is the Jemena Electric Line Clearance Management Plan 2020-2021, which documents the actual vegetation maintenance span cycles applied to each of the specified areas.	The methodology that has been used is to determine the optimum cycle that is compliant with the Electricity Safety (Electric Line Clearance) Regulations 2015.	Jemena's Electric Line Clearance Management Plan specifies the cycle times for CFA fire rated areas. For variable DOEF0206, it is assumed that all sections of urban and CBD feeders are within the Low Bushfire Risk Area (**LBRA**) and all sections of rural feeders are within the Hazardous Bushfire Risk Area (**HBRA**).
DOEF0212 - Tropical proportion	JEN considers this variable to be actual information as Victoria has no tropical areas.	N/A	N/A

3.7.3 – SERVICE AREA FACTORS

Variable	Source and why actual	Methodology	Assumptions
DOEF0301 – Route Line Length	**Source of data**: The data is sourced from GIS.	The following BO Report is run to extract the required details for all the categories: **ASM450 JEN RIN Vegetation Management (Terrain Factors 3.7.2 & Service Area Factors 3.7.3)** This report extracts data from the business warehouse where it is loaded from the GIS. An application in GIS is used to determine the route line length at the end of the regulatory year. The number provided here includes the route line length of the JEN above ground and underground network. The same as for overhead lines, an application in GIS is used to extract the route length of underground cables. For overhead conductor, the application looks for multiple lines between poles and only counts this distance once. For underground cables, each cable is divided into 1m lengths and if a 1m segment from another cable is within 3m of any other segment then only one segment is counted.	No assumptions have been made.