Jemena Gas Networks (NSW) Ltd

2025-30 Access Arrangement Proposal

Attachment 10.1

Pricing

Table of contents

List of appendices

Glossary

Boundary Meter	A meter at the boundary of a premises that serves multiple premises, typically a high-rise apartment or office building where internal gas infrastructure (e.g., pipes and meters) does not form part of our network.
Coastal network	The parts of our network includes the Wilton Network Section and serves customers along the coast of NSW, including the Hunter, Newcastle, Central Coast, and Illawarra regions.
Country network	The network sections other than the Wilton section including non-coastal parts of our network across central NSW, including Southern Highlands, Central Tablelands, Central West, Riverina, and South-West Slopes regions.
Demand Market	Customers that consume or are expected to consume 10TJs of gas or more via our network per year, primarily including large industrial customers.
Volume Market	Customers that consume or are expected to consume less than 10TJs of gas via our network per year, including residential, commercial, and small industrial customers.

Abbreviations

AA	Access Arrangement
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AIC	Average Incremental Cost
BYDA	Before-You-Dig-Australia
CAM	Cost Allocation Methodology
Capex	Capital Expenditure
CCP	Consumer Challenge Panel
DC	Demand capacity
DCFR	Demand capacity first response
DMT	Demand major end-user (throughput)
DT	Demand throughput
ENP	Embedded Network Provider
FR	First response
GJ	Gigajoule
LRMC	Long Run Marginal Costs
JGN	Jemena Gas Networks (NSW) Ltd
MDL	Meter Data Logger
NGR	National Gas Rules
NPV	Net Present Value
O&M	Operational and Maintenance
Opex	Operating Expenditure
PTRM	Post-Tax Revenue Model
PV	Present value
RAB	Regulatory Asset Base
TAB	Tax Asset Base
TOU	Time of Use
UAG	Unaccounted for Gas
VB	Volume Boundary
VI	Volume Individual
VRT	Volume residential distributed generation technology
WACC	Weighted Average Cost of Capital
WAPC	Weighted Average Price Cap

Key Messages

- The future of gas is uncertain. Gas policy is evolving and there is heightened competition from alternative energy sources. Many of our customers are—quite understandably—concerned about energy affordability.
- Consistent with feedback from our customers, we need to focus on what we can do to ensure that our tariffs are structured in a way that is ready for the future. Our customers supported five key pricing principles—cost reflectivity, price stability, simplicity, revenue adequacy, and fairness—which we have used to guide our tariff proposal.
- Our 2025 Plan is addressing this uncertainty by actively exploring renewable gas opportunities, refining our asset management approach and how we charge for capital contributions, and accelerating depreciation. Pricing reform is an important complement to these initiatives.
  - With this in mind, we are proposing to:
  - simplify our tariff structures by removing the distinction between coastal and country customers and reducing consumption blocks from six to four for volume market customers
  - improve cost reflectively by introducing a new tariff for our large volume customers and rebalancing revenue from the volume market to the demand market
  - retain our boundary-metered solutions adopted from 2015
  - ensure that prices for our ancillary services reflect the costs of delivering them.
- We are also proposing changes to our tariff variation mechanism to:
  - move to two mechanisms to align with our proposal to split our single Reference Service into a Transportation Reference Service and Ancillary Reference Services
  - convert the mechanism for the Transportation Reference Service into a hybrid form of control that involves some sharing of volume risk between us and our customers.
- Our indicative prices align with economic costs (e.g., standalone, avoidable and long-run marginal costs), and recognise a gradual decline in consumption projected for the 2025–30 AA period.

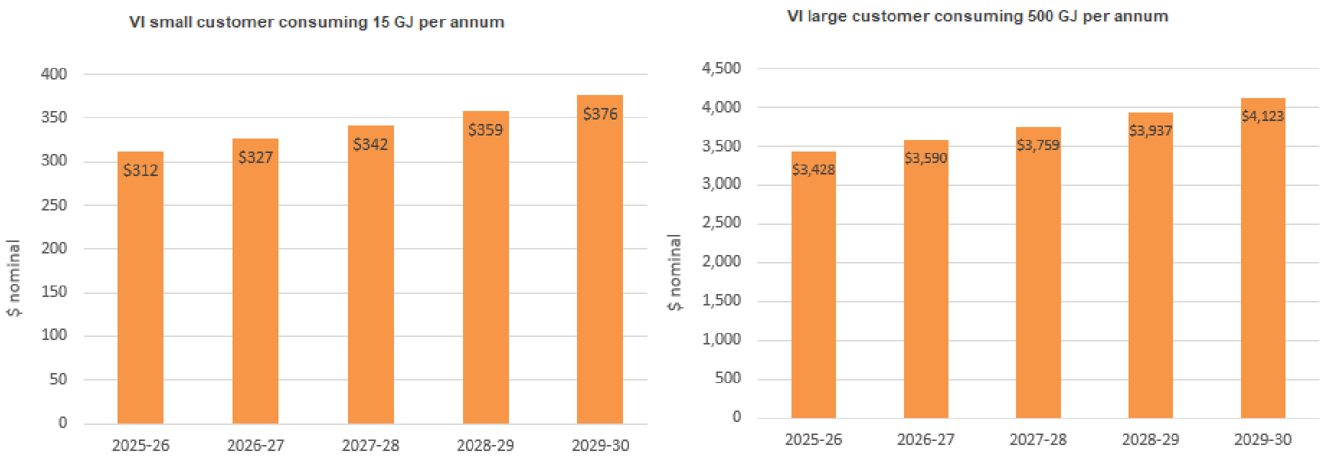
Overview

Chapter 7 of our 2025 Plan derives our total revenue requirements for each year of the 2025–30 Access Arrangement (**AA**) period. JGN recovers this revenue by charging our customers[1]—categorised as "Users" in our AA—for the services we provide.

Chapter 10 of our 2025 Plan provides the key information on our prices targeted at customers. This attachment sets out in detail JGN's proposal for its services and how our associated reference tariffs comply with the National Gas Rules (**NGR**).

Our indicative prices for the 2025–30 period are included in *JGN - Att 7.6.1M - PTRM* and *JGN - Att 7.6.2M - PTRM*. These reflect our proposed price path for that period, which is shown in Figure OV–1 for both our small and large individually-metered volume market customer tariffs. The year-on-year movement is 4.73% in nominal terms.

Figure OV–1: Our proposed network bills and price paths – VI small and VI large customers



We do not discuss these prices or the price path further in this attachment, which are instead covered in Chapter 10 of our 2025 Plan.

The attachment is set out as follows:

- Section 1 summarises how customer and stakeholder feedback has informed our reference service and tariffs parts of our Plan
- Section 2 explores key context and drivers relevant to why we are proposing changes to our tariffs and tariff structure
- Section 3 outlines the pipeline services we can provide, what constitutes our reference service for which we charge reference tariffs and the changes we are proposing for our ancillary charges
- Section 4 summarises our reference tariffs, assignment criteria and charges for the 2025–30 AA period, highlighting proposed changes—including changes to our demand customer reset policy
- Section 5 explains how we have allocated revenue to services

[1] For the purposes of our Access Arrangement, the customers that we bill are retailers and self-contracting users, categorised as "Users". However, our tariffs and charges become part of the bills paid by end-customers—the consumers of gas. For much of our Access Arrangement Information, we refer to our customers as the end-customers who consume gas, but they are not who we bill and we make this differentiation throughout this Attachment.

- Section 6 outlines how we set our network prices, including how we have:
  - developed economically efficient reference tariffs
  - considered transaction costs and the ability of customers to respond to price signals
  - incorporated prudent discounts within the 2025–30 AA period
  - developed our strategy for setting prices
- Section 7 describes our proposed tariff variation mechanism for reference services.

Supporting attachments

Table OV–1: List of supporting attachments

Attachment	Name	Author
2.2	Customer forum engagement report	BD Infrastructure
3.1	Tariffs Consultation Report	BD Infrastructure
3.2	Small Business Retailer and Large User engagement report	JGN
5.1	Capital expenditure	JGN
5.5	Input cost escalation	Oxford Economics
6.1	Operating expenditure	JGN
6.2	Opex step change justification	JGN
6.5	Cost Allocation Methodology	JGN
6.7	Unaccounted for gas	JGN
6.8	UAG report	Frontier Economics
7.2	Ancillary services cost build up approach	JGN
7.2M	Ancillary reference services model	JGN
7.6.1M	PTRM - Step 1	JGN
7.6.2M	PTRM - Step 2	JGN
8.1	Overview of JGN's demand forecast	JGN
8.2	Demand Forecast Report	Core Energy
10.1	Pricing	JGN
10.2	Cost pass through mechanism	JGN
10.3	2025-30 tariff assignment policy	JGN
10.4M	Cost of supply model (COSM)	JGN

1. How customer feedback has informed our plans

1.1 What we heard from our customers when developing our Draft 2025 Plan

To inform our tariff structures and tariff variation mechanism proposals for the 2025-30 period we established a Customer Tariff Forum as discussed in Chapter 2 of the 2025 Plan. In designing the tariff engagement program we consulted with the Advisory Board (via an opt-in session) to consider how we should engage on the tariff options and tariff variation mechanism.

The Customer Tariff Forum adopted elements of deliberative engagement by providing participants with time, information, access to independent expertise (we refer to as a 'Brains Trust'), and a high level of influence over the outcome. In testing the tariff and variation mechanism options, the Customer Tariff Forum was tasked with advising us on the following remit:

> *Net zero 2050 is causing uncertainty and change for the energy sector. Jemena and its regulator are reviewing how gas is priced for customers. Different pricing methods will affect how much customers pay, in different ways, with some winners and some losers. Jemena wants you to answer: Which type of pricing method is in the best interest of customers?*

As part of our tariff engagement, we also established a small business focus group and engaged with large customers and retailers to explore how we should charge for the provision of our services and test the tariff variation mechanism and tariff reform options as considered by the Customer Tariff Forum.

The key things we heard before publishing our Draft 2025 Plan in February 2024 were:

- Affordability is a top priority,[2] and there was concern about potential bill shocks.[3]
- Retail bills are complex for households—and especially socially and economically disadvantaged customers—to understand. Simplicity is valued.[4]
- Small business customers supported reducing the number of tariff blocks and separating small and large customers.[5] Retailers supported these changes as well.[6]
- Differing customer groups were comfortable with a hybrid form of control for our Transportation Reference Services.[7]
- Large business customers supported our approach to reset demand capacity values as at 1 July 2025.[8]

2 JGN - *BD Infrastructure - Att 3.1 Tariffs Consultation Report*, p.13.

3 *JGN - Att 3.2 - Small Business Retailer and Large Customer engagement report*, p.190.

4 Ibid, p.137.

5 Ibid, pp.57&86.

6 Ibid, pp.190&194.

7 Ibid, pp.87&195.

8 Ibid, p.327.

1.2 Response to our Draft 2025 Plan and subsequent engagement

1.2.1 Further engagement

Post the publication of our Draft 2025 Plan, we also held various online workshops and sessions focused on our proposed tariffs and tariff variation mechanism, including:

- a retailers forum session 6 on 23 February 2024
- a large customer forum workshop 3 on 27 February 2024
- a small business customer workshop on 27 March 2024
- two residential customer workshops on the 26 March and 9 April 2024, which explored our proposed hybrid form of control for our Transportation Reference Service.

We captured outcomes from these workshops and sessions and used it to guide our proposals as discussed in chapter 10 of the 2025 Plan.

1.2.2 How we are responding to feedback

We received feedback on our Draft 2025 Plan from our customers and other stakeholders—which we greatly appreciate. These covered a broad range of topics, including affordability and vulnerability, tariff structure, tariff variation mechanism, and chargeable demand resetting.

Table 1-1 sets out the feedback we received regarding our services and tariffs, together with our response.

Table 1-1: Summary of feedback on our Draft 2025 Plan and in subsequent engagement

Topic	Feedback	Proposed charge structures
Affordability and vulnerability	Many small business customers cited price increases as a major factor to tackle now.[9] One retailer expressed surprise that another retailer was not supportive of investment in strategies to support customers experiencing vulnerability or hardship as articulated in the feedback in the Draft 2025 Plan.[10]	We are acutely aware of affordability concerns faced by our customers, including those most vulnerable. We are also mindful that there is a diversity of views over what we should to support customers experiencing vulnerability or hardship. Our proposal retains a declining block tariff structure, which allows disadvantaged customers with large loads to benefit from lower average usage charges. We also propose separating our individually metered volume tariffs into small and large to allow for better tailoring of charges. Finally, we intend to rebalance our tariffs over the 2025–30 AA period to shift some revenue that we recover from our volume market customers to our demand market customers.
Tariff structure	Small business customers support transitioning from a coastal / country split to small and large users with usage at over 200 gigajoules (**GJ**).[11]	We propose removing the coastal / country split and replacing it with a small / large split. Our plan is for these changes to apply from 1 July 2025. These changes are discussed further in sections 0 and 4.2.3.

9 See: *JGN - Att 3.2 - Small Business Retailer and Large Customer engagement report*, p.57.

10 Ibid, p.229.

11 Ibid, p.57.

Topic	Feedback	Proposed charge structures
Tariff blocks	All Tariff Forum participants voted in favour of reducing the number of tariff blocks in the volume market from six to four.[12] Customers considered this would simplify our tariff structures, making them flatter and to some extent reduce reducing the incentive to increase gas consumption.	Some of our tariffs across consumption blocks are currently only marginally different providing us with an opportunity to reduce the number of blocks. While this will lower our ability to rebalance tariffs it will remove redundancy where the tariffs are similar across blocks. This change also supports simplifying simplification of our tariff structures. These changes are discussed further in section 5.2.2.
Tariff variation mechanism	There was general support for the hybrid form of control. Residential customers strongly supported a 5% threshold and a 50:50 sharing ratio outside of that threshold.[13] Small business customers also supported a 5% threshold as it appeared less risky and preferred 50:50 sharing as it was the fairest option.[14] Large customers were also comfortable with our proposed form of control.[15] The Consumer Challenge Panel (**CCP**) raised some concerns with our proposed hybrid form of control.[16]	We propose a hybrid form of control with a 5% threshold and a 50:50 sharing. This is discussed further in sections 7.2.1 and 7.3, including our response to the CCP's concerns.
Chargeable demand reset	Large customers supported our proposal to allow chargeable demand to be reset, but wanted more information about how this would work[17]	We outline the process further in section 4.3.1, which will be available to large customers. The reset will take effect on 1 July 2025 with chargeable demand based on actual consumption over the previous 12 months.

12 See: *JGN - BD Infrastructure - Att 3.1 Tariffs Consultation Report*, p.22.

13 See: *JGN - BD Infrastructure – Att 3.1 Tariffs Consultation Report*, p.26.

14 See: *JGN-Att 3.2 – Small Business Retailer and Large Customer engagement report*, p.13.

15 Ibid, p. 327.

16 See: *JGN - Att 2.1 - Consumer Challenge Panel - feedback and response*.

17 See: *JGN-Att 3.2 – Small business Retailer and Large Customer engagement report*, p.327.

2. Why we are changing our tariffs and tariff variation mechanism

Our proposed changes are in response to important environmental factors, as summarised below.

2.1 Gas policy

Gas policy decisions at the federal, state, and local (e.g., council) level directly influence our investment choices and operating decisions. Uncertainty about future policies—such as carbon pricing, emissions reduction targets, incentives for renewable energy, or bans on new gas connections—can create hesitation in committing to long-term infrastructure projects. However, without clarity on policy direction, it becomes challenging for us to allocate funds efficiently.

At the same time, uncertainty introduces risk. We face uncertainties related to gas supply, demand, and geopolitical factors. These uncertainties can lead to price volatility. Our tariffs need to strike a balance between providing stable pricing for our customers while also allowing us to manage risks effectively. If gas policy changes suddenly—for example, if new gas connections are banned—our cost structure may be affected.

Our tariffs must account for potential changes in network composition and technology, balancing the need for reliability with the need to remain adaptable to such changes. They may also need to incorporate risk management mechanisms, such as adjustment factors, to mitigate the impact of policy-related uncertainties. Ultimately, a transparent and well-communicated tariff structure helps our customers understand the rationale behind pricing decisions, even in an uncertain policy landscape.

2.2 Competition from alternative energy sources

As the energy landscape evolves, non-gas alternatives—such as electricity—are becoming more attractive to our customers for their energy needs. We must consider the growing adoption of these technologies when designing our tariffs. If our customers choose to shift away from traditional gas usage, we face the challenge of maintaining competitiveness.

Our tariffs need to strike a balance: keeping gas affordable while acknowledging the appeal of alternatives to gas. Pricing structures must adapt to encourage efficient energy choices and accommodate the transition toward a low-carbon future.

The rise of alternative energy sources introduces uncertainty. Our tariff design must account for potential disruptions caused by shifts in consumer preferences or government policies. If non-gas options become more attractive due to technological advancements or policy support, our revenue model could be impacted. Tariffs should incorporate mechanisms to manage risk and provide flexibility. By monitoring the competitive landscape and anticipating trends, we can adjust pricing strategies to remain relevant and resilient. Ultimately, staying competitive in an evolving energy market ensures our long-term viability and provides consumers choice in how they consume energy.

2.3 Energy affordability concerns

Affordability concerns play a pivotal role in shaping our tariff design. As an essential utility, natural gas is crucial for households, businesses, and industries. However, ensuring that gas remains accessible and affordable for customers is a key objective.

We know that affordability directly impacts customers' well-being. High gas prices can strain household budgets, especially for customers experiencing hardship. They can also undermine the economic sustainability of businesses that rely on gas, which can adversely affect the NSW economy more generally.

Mindful of this, our tariffs need to balance cost recovery with customer bill impacts. We can better address affordability concerns by designing tariffs for specific customer groups and by adjusting blocks. We can also explore targeted support for consumers experiencing vulnerability or hardship. Ultimately, customer and broader stakeholder input is essential to help us find a balance that promotes longer-term consumer interests.

3. Our proposed services

JGN provides services for which we charge our customers via our tariffs. In our current AA, we define a "User" as a person who has a service agreement with us (e.g., a retailer) or has a right to be provided with a service. As part of our 2025 Plan, we need to describe the pipeline services that we can provide and specify the reference services.

We submitted our reference service proposal to the AER on 28 June 2023 and resubmitted it on 6 September 2023 with some further information. The AER approved our resubmitted proposal on 17 November 2023.[18] We have aligned with that decision when developing our 2025 Plan.

3.1 Our current services

A reference service was previously described in the NGR as a service that is likely to be sought by a significant part of the market. It is governed by a standard set of terms and conditions in our AA. The AA also includes non-reference services, which are pipeline services negotiated on a case-by-case basis and with reference to relevant AA schedules.

We currently provide a single Reference Service, which includes:

- receiving gas injected from an upstream gas pipeline or other gas facility
- transporting gas from the receipt point to each customer's premises
- enabling withdrawal at each customer's premises
- providing gas metering equipment at customers' premises and associated services to read the quantity of gas flowing through the gas meters
- procuring gas to replenish the difference between the measured quantities of gas entering and leaving the network, known as Unaccounted for Gas (or UAG)
- undertaking certain activities requested by Users that are ancillary to transportation services, including special meter reads, disconnection, decommissioning and meter removal, and responding to non-standard requests.

The Reference Service is delivered to Users on the terms and conditions set out in our current Reference Service Agreement.[19]

In addition to the Reference Service, we also currently make non-reference services available to Users. These include:

- the interconnection service—a service to establish delivery point to enable delivery of gas from the network into a downstream network or a receipt point to enable delivery of gas into the network from an upstream facility
- negotiated services—a service for the transportation of gas on terms and conditions different to those applicable under the Reference Service or the Interconnection Service.

[18] AER, *Final Decision*, *Jemena Gas Networks (NSW) Ltd Gas Distribution Determination*, *2025 to 2030*, *Reference Services*, November 2023: link.

[19] A revised Reference Services Agreement is submitted as part of our 2025 Plan.

3.2 The AER's Reference Service Proposal Decision

The AER accepted our reference service proposal, including our proposal to:

- split our current single Reference Service into two separate reference services
- make minor changes to the Interconnection Service
- leave negotiated services as is.

Our rationale for these proposals is contained in our Reference Service Proposal.[20] We further discuss our rationale for splitting our single Reference Service in section 3.3.1 below.

We proposed splitting our single Reference Service so that we can provide a more accurate, transparent description of each activity that makes up our services. Our proposed split was also consistent with the services offered by other gas distribution businesses regulated by the AER.

In making its decision, the AER noted that:[21]

> *the policy context for our decision is dynamic with possible implications for our reference service determination through the access arrangement reset process. We will take careful note of policy positions of national, state and local governments as they relate to the gas pipeline sector in NSW. As policy settings become clearer we may form a view that alternative reference services, or service definitions, may be warranted.*

Like the AER, we recognise that our reference services or service decisions may need revision in light of national, state and local government policy positions. We are not aware of any new or revised policy positions that warrant changes at this stage.

3.3 Our services for the 2025 Plan

We proposed aligning with other gas businesses and respond to recent changes to the NGR by:

- separating our existing Reference Service into a Transportation Reference Service and Ancillary Reference Services, while retaining all the associated service offerings as our current single Reference Service
- largely maintaining our current list of ancillary services
- maintaining our non-reference services, with minor updates to the definitions used for the Interconnection Service.

20 See, for instance: *JGN, Jemena Gas Networks (NSW) Pty Ltd: Reference Service Proposal for the July 2025 – June 2030 Regulatory Period*, 26 October 2023, p.13.

21 AER, *Final Decision*, *Jemena Gas Networks (NSW) Ltd Gas Distribution Determination*, *2025 to 2030*, *Reference Services*, November 2023, p.14.

This is consistent with the AER's Reference Service Proposal Decision and aligns with the services adopted for other Australian gas distribution businesses.

3.3.1 Separating our single reference service

We proposed separating our single Reference Service into a Transportation Reference Service and Ancillary Reference Services to:

- align with other gas distribution businesses
- provide a more accurate, transparent description for each activity
- ensure that the transportation of gas to all delivery points will be treated as a reference service regardless of the use of the gas at the delivery point
- allow for a better response to the evolving energy market
- provide greater flexibility to the user or prospective user.

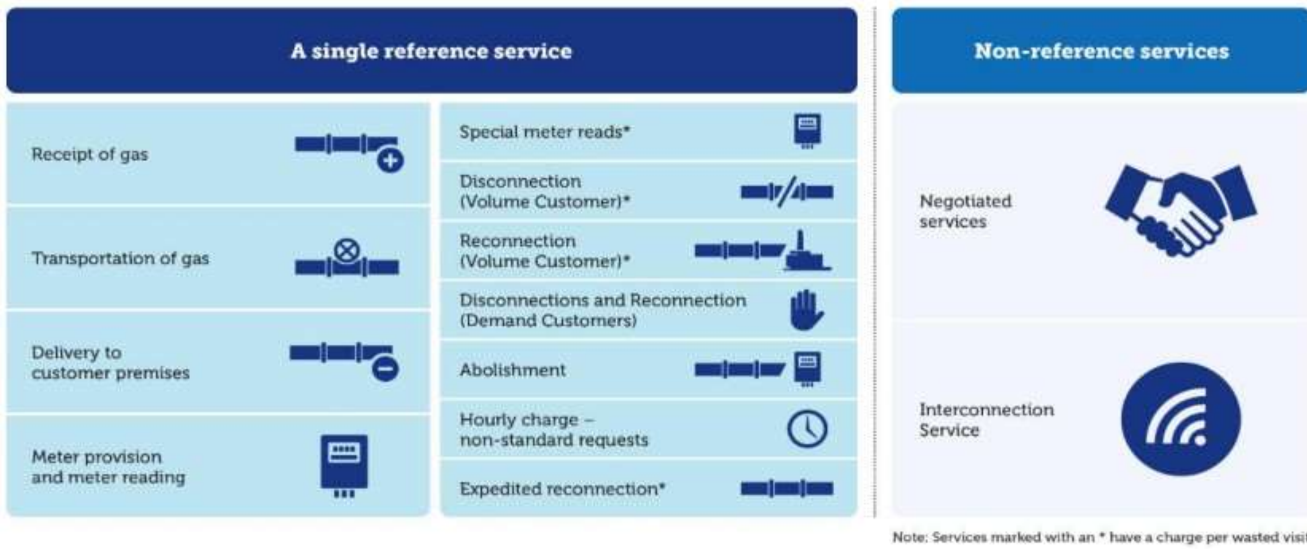
Although this is an important change, we expect there to be little to no impact on our customers as our service of receiving, transporting and delivering gas and associated activities will largely remain unchanged. The AER accepted this rationale.[22]

Our customers and other stakeholders also supported this change.[23]

These changes are shown in Figure 3-1, by comparing our existing reference and non-reference services (Panel A) to those proposed for the 2025–30 AA period (Panel B).

Figure 3-1: JGN's current services and proposed updates

Panel A: Current services



[22] AER, *Final Decision*, *Jemena Gas Networks (NSW) Ltd Gas Distribution Determination*, *2025 to 2030*, *Reference Services*, November 2023, p.13.

[23] See discussion in section 1.

Panel B: Proposed services

3.3.2 Maintaining the list of ancillary services

We are proposing to maintain our current list of ancillary services as part of our 2025 Plan. Our proposed list of ancillary charges is shown in Table 3-1.

Table 3-1: Our proposed ancillary activities and charges from 1 July 2025

Requested ancillary activity	Description	Proposed charge structures
Hourly charge—non-standard retailer-initiated requests and queries	The assessment of a User's requirements, collation of information and provision of a response regarding non-standard requests and queries. Examples include, but are not limited to: • customer connection or upgrade inquiries that, due to the nature of the request, require additional investigation; and • requests for measurement data in addition to data provided in standard reports. This charge does not apply to the processing of connections and alterations under Part 12A of the NGR.	• Hourly charge (minimum charge of 1 hour)
Disconnection – Volume Customer Delivery Points	Disconnection of supply by wadding or locking the meter and where the meter is not to be moved or removed. A request for disconnection is also a request to remove the delivery point from our Customer List. This means that no reference tariffs will be charged once off the customer list until reconnected. The specific method of disconnection will be at our discretion to ensure the site can be left in a safe state.	• Completed service charge • Wasted visit charge

Requested ancillary activity	Description	Proposed charge structures
Reconnection – Volume Customer Delivery Points	The reconnection of a previously disconnected meter in accordance with National Energy Retail Law or Rules, our Reference Service Agreement, or in other circumstances where delivery station components and pipework are still installed at the delivery point and can be re-energised without alteration or replacement. Reconnection in circumstances other than those described above requires a new connection and a new Request for Service to be made.	• Completed service charge • Wasted visit charge
Disconnection & Reconnection – Demand Customer Delivery Points	Disconnection for a Demand Customer Delivery Point where the User also requests that the meter is not to be moved or removed. If requested by the User, the charge for disconnection will also include the subsequent costs of reconnection where the Delivery Station components and pipework are still installed at the Delivery Point and can be re-energised without alteration or replacement. Reconnection in circumstances other than those described above requires a new connection and a new Request for Service to be made.	• Individually priced
Expedited reconnection	Reconnection of a volume customer delivery point in a shorter timeframe than required under Law (typically on the day of the request for reconnection or as otherwise agreed between the User and JGN). The reconnection is performed between 4.00pm and 7.00pm on a Business Day. JGN's ability to perform the reconnection on the requested day will depend upon, among other factors, the extent of notice provided by the User (at a minimum, the request must be received prior to 2.00 PM).	• Completed service charge • Wasted visit charge
Abolishment	Permanent decommissioning of a delivery point, typically including the removal of the meter. A request for abolishment is also a request to remove the delivery point from the Customer List. This means that no reference tariffs will be charged once off the Customer List. The specific method of abolishment will be at our discretion to ensure the site can be left in a safe state. Subsequent reconnection of the delivery point requires a new connection and a new Request for Service to be made.	• Completed service charge for meters at or under 25m^3/hr • Meters over 25m^3/hr will be individually priced • Wasted visit charge
Special meter read	For meter reading that is in addition to the scheduled ordinary meter reading (for instance, when the meter reader makes a special visit to read a particular meter out of the usual meter reading route or schedule). This service must be scheduled in accordance with the NSW Retail Market Procedures.	• Completed service charge • Wasted visit charge

3.3.3 Non-reference services

We are proposing to maintain our existing *Interconnection Service* and *Negotiated Service*, with some minor changes to the definition of the Interconnection Service to:

- ensure consistency with recent Energy Ministers' reforms on improving gas pipeline regulation
- remove references to 'Gas' and replace them with 'Covered Gas' to align with changes to the National Gas Law and NGR.

The AER accepted these proposed changes in its Reference Service Proposal Decision.[24] We are not aware of any material change in circumstances that would support us departing from that decision.

3.4 How our services meet the rule requirements

We must comply with rule 48 when proposing changes to our AA. Rule 48 sets out the information that we must include in our proposal, including those related to our proposed services and tariffs. Table 3-2 sets out how we have complied with that rule.

Table 3-2: How we have met rule 48

Rule	High level description	JGN compliance
48(1)(a)	Identify the pipeline and link to a website where a description exists	The pipeline is identified in clauses 1.2 and 11.1, as well as Schedule 11, of the proposed 2025–30 AA. Further information on the JGN network can also be found on our website here: https://www.jemena.com.au/gas/jemena-gas-network/.
48(1)(b)	Describe all the pipeline services that we can reasonably provide, which must be consistent with the AER's Reference Service Proposal Decision unless there has been a material change in circumstances	JGN can reasonably provide four pipeline services by means of the network: 1. **Transportation Reference Service** – receipt, transportation and delivery of gas including provision of metering equipment and meter reading. 2. **Ancillary Reference Services** – ancillary activities including disconnection, reconnection, special meter reads, and abolishment. 3. **Interconnection Service** – service for establishing a new receipt point to enable injection of gas into the network, or to establish a new delivery point to enable delivery of gas for use in third-party downstream network. 4. **Negotiated Service** – a service where a user has specific needs that cannot be met by the Transportation Reference Service, Ancillary Reference Services or the Interconnection Service. These are described in Chapter 9 of the 2025 Plan and are consistent with the AER's Reference Service Proposal Decision.
48(1)(c)	Specify which services, which must be consistent with the AER's Reference Service Proposal Decision unless there has been a material change in circumstances	The Transportation Service and Ancillary Services are reference services. These are consistent with the AER's Reference Service Proposal Decision.

[24] AER, *JGN Reference Service Proposal 2025-30 – Final decision*; Nov 2023.

Rule	High level description	JGN compliance
48(1)(c1)	If the pipeline or reference services under rule 48(1)(b) or (c) differ from the AER's reference proposal decision, then describe the material change in circumstances have regard to the reference service factors	Not applicable, as we are not proposing to depart from the AER's Reference Service Proposal Decision.
48(1)(d)	For each reference service, specify the reference tariff and the other terms and conditions on which the reference service will be provided	Reference tariffs for the reference service are described in section 5 and set out in Schedule 2 of our 2025–30 AA. The terms and conditions are included within our 2025–30 AA, which includes our updated Reference Service Agreement.
48(1)(f)	Set out the capacity trading requirements	Our capacity trading policy is set out in section 9 of our 2025–30 AA.
48(1)(g)	Set out the extension and expansion requirements	Our extension and expansion policy is set out in section 8 of our 2025–30 AA.
48(1)(h)	State the terms and conditions for changing receipt and delivery points	Our changing receipt and delivery points policy is set out in section 10 of our 2025–30 AA.
48(1)(i)	State the review submission date and the revision commencement date	Our 2025–30 AA (clauses 1.4 and 1.5) includes a review submission date of 30 June 2029 and revision commencement date of 1 July 2030.

4. Our proposed tariff classes and structures

Our tariffs are set to enable us to recover our revenue requirements for each year of the 2025–30 AA period as set out in Chapter 7 of our 2025 Plan. This section is provided to help understand how we charge and to demonstrate we have complied with certain rule requirements that guide how we should construct our charges.

4.1 Summary

We charge retailers, so customers' gas bills won't usually show our charges itemised, particularly for volume customers. However, a customer's retail bill may have a similar structure to ours.

'Charge components', 'Tariff structures', 'tariffs', and 'tariff classes' are the language used to refer to and understand our network charges. The charge components can include:

- *a fixed charge component*—an annual supply or metering charge (depending on customer size) that applies to each premises gas is delivered to ($ per annum)
- *a variable charge component*—a usage charge that applies to the volume of gas a customer uses or requires as capacity ($ per GJ). We offer declining block usage rates, meaning the price per unit falls the more gas is used.
- *ancillary charges*—fees for certain services or activities—such as special meter reads or disconnections—that apply only when Users or customers (or their retailers) have requested those services ($ per service and/or per hour).

The group of charge components is the 'tariff structure'. With our proposal to separate the single Reference Service into the Transportation Reference Service and Ancillary Reference Services, ancillary charges are separated from fixed and variable charges.

Most of our customers pay fixed and variable charges, but the levels they pay vary to reflect their different characteristics and the different ways they use gas. When we include the associated prices, we would call that a customer's 'tariff'. Some customers may also pay an ancillary charge if they request those activities and their retailer may pass on the charge we imposed on them or some different amount.

Not all customers face the same tariffs. The tariff a customer pays depends on their characteristics, such as their size, location, and metering. This is because those characteristics affect the costs that we incur when providing our services—which is why we group customers together to ensure similar customers pay similar prices, reflecting the costs of doing so. These groupings are known as our 'tariff classes'. Our tariff classes and the type of charges for each are shown in Figure 4-1.

At the broadest level, we set our tariff classes by differentiating by **customer size**:

- residential and commercial customers consuming <10TJ per annum ('volume market'), which we are proposing to further split for customers other than volume boundary customers into:
  - smaller residential and commercial customers consuming <200GJ per annum
  - larger volume market customers consuming ≥200GJ but <10TJ per annum
- large industrial customers consuming ≥10TJ per annum ('demand market').

We then differentiate by **location**. Our current tariffs for the volume market distinguish between country and coastal customers.[25] However, we are proposing to remove that differentiation for the 2025–30 AA period to help

[25] Our network serves customers in coastal areas, such as Sydney, Newcastle, Wollongong and the Central Coast, and over 20 country centres including those within the Central Tablelands, Central West, Southern Tablelands and Riverina regions of NSW.

simplify our tariff structures, especially given that our charges were almost the same for our country and coastal customers and retailers do not apply that differentiation in their retail offerings.

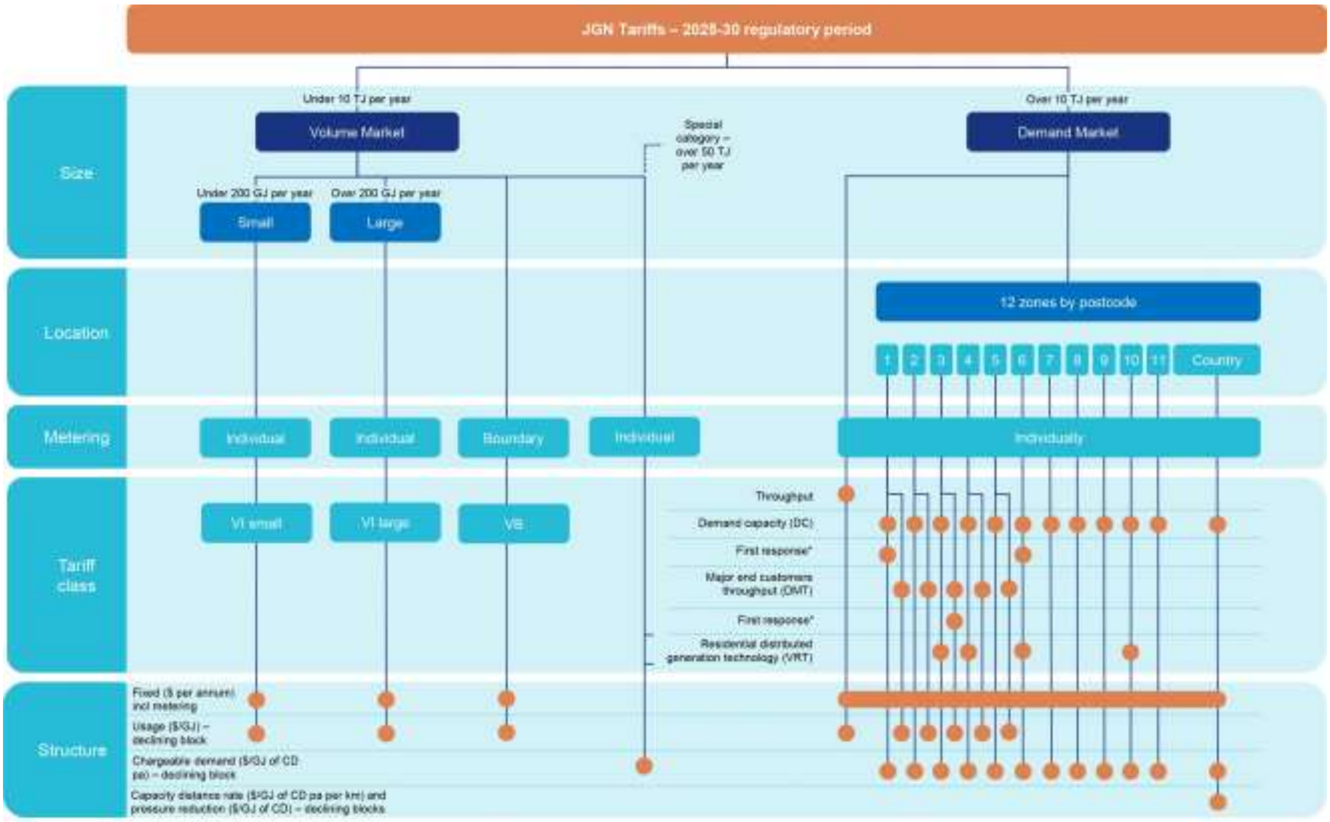
However, we do propose to retain our location-based pricing for the demand market where we split customers into 12 zones based on postcode to reflect the cost of providing gas to different parts of our network.

Finally, we differentiate by **metering**:

- for volume customers, we have different tariff classes depending on whether we meter the end customer individually or whether we use a boundary meter
- for demand customers, the levels of fixed charges will depend on the size and type of metering they require and use.

All our charges are set out in our tariff schedule, which is updated and published annually, applying from 1 July to 30 June each year. As these are our prices for our reference service, they are often referred to as 'reference tariffs'. Our initial tariff schedule for the 2025 Plan is found in Schedule 3 of our proposed AA.

Figure 4-1: Our reference tariff classes



*Grandfathered tariff. Not available to new entrants.

4.2 Residential and Commercial customer tariff classes

We call our residential and commercial customers consuming less than 10TJ per year, ‘volume customers’. We have seven volume customer tariff classes, as set out in Table 4-1. We are proposing three key changes to our volume market tariff structure:

- remove the distinction between country and coastal customers
- reduce the number of tariff blocks from six to four
- differentiate between larger and smaller customers.

These changes are discussed in the following sub-sections.

We are largely keeping the tariff structures for our boundary-metered and distributed generation technology volume customers the same as they are currently, except we are removing the distinction between country and coastal customers.

Table 4-1: Our proposed volume customer tariff classes

<table>
<tr><th>Tariff category</th><th>Tariff classes</th><th>Types of end-customer[26]</th><th colspan="3">Structure (fixed in $/annum and usage in $/GJ)</th></tr>
<tr><td rowspan="13">Volume individual (VI) metered</td><td rowspan="13">VI-small
VI-large</td><td rowspan="13">Most of our 1.4 million existing customers and new customers, including residential and small-medium businesses, with individual metering consuming up to 10TJ per annum.</td><td colspan="3">Fixed charge</td></tr>
<tr><td colspan="3">Small customer usage charge</td></tr>
<tr><td>Usage block</td><td>Block size pa (GJ)</td><td>Typical usage</td></tr>
<tr><td>1</td><td>0 – 7.56</td><td>Residential cooking</td></tr>
<tr><td>2</td><td>7.56 – 15</td><td>Residential hot water or heating</td></tr>
<tr><td>3</td><td>15 – 33</td><td>Residential hot water and heating</td></tr>
<tr><td>4</td><td>33+</td><td>Heating and small commercial load</td></tr>
<tr><td colspan="3">Large customer usage charge</td></tr>
<tr><td>Usage block</td><td>Block size pa (GJ)</td><td>Typical usage</td></tr>
<tr><td>1</td><td>0 – 300</td><td>Heating and small commercial load</td></tr>
<tr><td>2</td><td>300 – 1000</td><td>Heating and small commercial load</td></tr>
<tr><td>3</td><td>1000 – 5000</td><td>Small commercial load</td></tr>
<tr><td>4</td><td>5000+</td><td>Light industrial</td></tr>
<tr><td rowspan="5">Volume boundary (VB) metered</td><td rowspan="5">VB</td><td rowspan="5">Residential end customers in higher-density residential developments and small business customers in commercial developments supplied energy by an energy intermediary, such as an embedded network provider</td><td colspan="3">Fixed charge</td></tr>
<tr><td colspan="3">Usage charge</td></tr>
<tr><td>Usage block</td><td colspan="2">Block size pa (GJ)</td></tr>
<tr><td>1</td><td colspan="2">0 – 250</td></tr>
<tr><td>2</td><td colspan="2">250 – 500</td></tr>
</table>

[26] End-customers are those that consume the energy, rather than an intermediary who on-sells energy or services to end-customers.

Tariff category	Tariff classes	Types of end-customer[26]	Structure (fixed in $/annum and usage in $/GJ)	
		(**ENP**), that sits between the boundary meters and the end customers.	3	500 – 1000
			4	1000+
Residential distribution generation technology (**VRT**)	VRT-03 VRT-04 VRT-06 VRT-10[27]	Predominantly residential end customers supplied energy by an energy intermediary using a large-scale generation unit in a residential precinct (consuming more than 25TJ per annum).	Fixed charge (dependent on meter size) and 6 declining blocks charged on $/GJ of chargeable demand (equivalent to demand capacity tariff in that postcode).	

All customers in the volume customer tariff classes are separately subject to Ancillary Reference Services charges as outlined in Table 4-4 for any ancillary activity that they request.

4.2.1 Removing country and coastal distinction

Our network serves customers in coastal areas, such as Sydney, Newcastle, Wollongong and the Central Coast, and over 20 country centres including those within the Central Tablelands, Central West, Southern Tablelands and Riverina regions of NSW.

We currently group our volume customers by ‘country’ and ‘coastal’ locations but this differentiation is not adopted by retailers and is not passed on to customers. To help simplify our tariff structures, we are proposing to remove this distinction between our country and coastal customers. As retailer tariffs do not currently distinguish between country and coastal customers, this change is not expected to impact any volume market customers.

4.2.2 Reducing tariff blocks from six to four

Our current tariffs include up to six usage (or consumption) blocks that we use for pricing, largely because our tariffs need to cater for small and large volume customers. As well as being complex, some of our charges across consumption blocks are currently only marginally different to each other—providing us with an opportunity to rethink this structure.

To further help simplify our tariff structures, we are proposing to reduce the number of blocks from six to four. While this will lower our ability to rebalance revenue among blocks on a given tariff, it will remove redundancy where the charges are similar across blocks. Moreover, given that we also propose to split the VI metered tariff category into smaller and larger tariff classes (see next section), we will retain the flexibility to send appropriate price signals to volume customers of different sizes.

We also recognise that there is some concern that declining block tariff structures may promote more gas usage.[28] Our proposal to reduce the number of blocks partially addresses the concern, while balancing it against concerns that changing the tariff structure may also harm some customers, especially those experiencing vulnerability or hardship.[29]

4.2.3 Distinguishing smaller and larger customers

Our current tariff structure does not distinguish between smaller and larger customers. This is both a limitation—as it makes it harder to send appropriate price signals—and is inconsistent with the structures adopted by other

27 The VRT tariff classes are differentiated by a number, which indicates their locations. The numbers relate to the same postcodes as the demand tariff class numbering. The four VRT tariff classes are the locations we expect this type of customer to arise. It does not preclude us adding other locations should qualifying customers arise in those locations.

28 AER, *Review of gas distribution network reference tariff variation mechanism and declining block tariffs* – Final decision, p.10.

29 AER, *Review of gas distribution network reference tariff variation mechanism and declining block tariffs* – Final decision, p.10.

gas distributors in Australia.[30] As noted above, our approach to date has been to adopt more than four blocks so that we can use these to distinguish across customer sizes.

However, our large volume market customers—those consuming 200GJ or more—currently pay a very small fixed charge. For example, the fixed charge of a typical bill for a commercial customer consuming 300GJ represents only 4% of the total network bill. This compares to a 22% fixed charge component for a typical 15GJ residential customer. This appears inappropriate to us.

To address this concern, we are proposing to split our VI tariff customers into two tariff classes:

- a small customer tariff class for customers consuming less than 200GJ per year
- a large customer tariff class for volume customers consuming 200GJ or more per year.

Introducing this split will allow us to raise the fixed charge for our large volume market customers to better reflect the nature of the fixed costs that we incur in delivering our Transportation Reference Service. As discussed further in section 6.2.2, we propose to increase the fixed charge proportion of the typical large customer bill to 20% to bring it in line with that of a typical residential customer.

4.3 Large industrial and commercial customer tariff classes

We call our large industrial and commercial customers “demand customers”. Demand customers are expected to use more than 10TJ of gas each year.

We have 18 open demand customer tariff classes, as set out in Table 4-2. We also have three ‘first response’ tariff classes that have been grandfathered since 1 July 2015 and will continue to be for the 2025–30 period. We are not proposing any changes to the tariff structures that apply to demand customers. We will retain our first response tariffs for eligible demand customers.

Table 4-2: Our proposed demand customer tariff classes

Tariff category	Number of tariff classes	Tariff classes	Types of customers	Reason for inclusion
Capacity country	1	DC Country	Most of our large industrial customers.	Maintains existing tariff classes.
Capacity coastal	11	DC1 to DC11		
Throughput (**DT**)	1	DT		
Major end-user (throughput) (**DMT**)	5	DMT1 to DMT5		
First response (**FR**)	3	DCFR-01, DCFR-06 & DMTFR-03	Several large industrial customers with flexibility in operations to reduce demand as a priority response.	These are grandfathered tariff classes that continue to provide benefits to the market and existing users of this tariff class.

30 For instance, Multinet Gas has tariff classes that distinguish between residential and non-residential customers.

4.3.1 Capacity

There are currently 12 capacity tariff classes—one for country customers and 11 for coastal customers based on postcode groupings.[31] We are proposing to maintain the current grouping of postcodes to differentiate by location and have added new postcodes where these have been created.

Capacity tariff classes are the default category for demand customers. These are for customers who pay for gas transportation based on capacity. However, customers can select the throughput demand tariff category discussed below.

Chargeable demand

Most of our large industrial and commercial customers are charged based on the level of network capacity they require—this is referred to as their “chargeable demand”. Chargeable demand is usually the highest of:

- the ninth-highest daily withdrawal in the previous 12 months
- ten times the maximum hourly quantity (MHQ), and
- the maximum daily quantity (MDQ).

To ensure that these customers pay for the network capacity they use, a customer’s chargeable demand automatically goes up (ratchets) if they require additional capacity. As part of our 2020 Plan, we also relaxed the requirements for our demand customers to request a reset by:

- simplifying the time conditions
- removing the materiality threshold that the reduction in demand must be more than 10%, and
- amending the requirement for a “permanent change” to be a “significant change”.

We propose retaining these adjustments for the 2025–30 AA so that customers can continue to share the benefit of making changes to their business that reduce their demand on our network. We also propose to reset their chargeable demand for demand customers at the beginning of the 2025–30 AA period where this will lower their bills.

4.3.2 Throughput

There are six throughput tariff classes.

This tariff category sets a ceiling for the cost of network transportation that allows the price of gas to remain competitive with alternate fuels. There is a throughput tariff class available for any eligible demand customer and five tariff classes for major end-users in specified Sydney postcodes.

4.3.3 Capacity first response

We will continue to offer our grandfathered capacity first response tariffs to customers currently on the tariff. Like our capacity tariffs, these are based on postcode groupings. These are discounted tariffs that reflect the customer’s willingness and capability to participate in network load shedding on a “first response” basis.

[31] The allocation of postcodes to tariff classes is provided in JGN’s Tariff Assignment Policy.

4.3.4 Large industrial and commercial customer tariff structure

Table 4-3 outlines the components relevant to each tariff class and sets out where we have banded these into blocks. We detail our fixed charge and block sizes for our demand customers in Schedule 3 '*Initial reference tariff schedule*' of our 2025 AA.

Table 4-3: Demand and VRT tariff classes—Type of fixed charge

Tariff classes	Fixed charge	Fixed charge – Provision of basic metering equipment charge	Demand capacity (DC) rate	Demand throughput rate	Ancillary charge (via Ancillary Reference Services)
DC Country	×	✓	6 declining blocks	×	✓
DC1 to DC11	×	✓	6 declining blocks	×	✓
DT	×	✓	×	3 declining blocks	✓
DMT-1 to DMT-5	✓	✓	×	3 declining blocks	✓

4.4 Assignment criteria

We use our assignment criteria to group our customers into tariff classes. Our tariff assignment criteria classifies customer delivery points based on three elements—tariff customer groups, tariff categories and classification by location.

Demand customers must have a reasonable MDQ specified per delivery point as they have a larger individual impact on the network than volume customers.

Consistent with our tariff class description above, we no longer propose to group volume customers by 'country' and 'coastal' locations. However, demand and VRT customers will continue to be grouped by postcode. This enables locational variations to be reflected in tariff classes and promotes cost-reflectivity in our network tariffs.

We are proposing two changes to our tariff assignment criteria:

- large volume customers with volumes greater than or equal to 200GJ over a recent 12-month period will be initially assigned to the large volume customer tariff class for 2025-26 pricing purposes
- however, during the 2025–30[32] regulatory period, if a customer demonstrates it requires lower or higher volume than 200GJ and submits a tariff reassignment application through the retailer then we would consider reassigning that customer to the proposed tariff class that aligns with volume
- volume customers will no longer be assigned to a tariff based on their location.

Our assignment criteria are detailed in *JGN - Att 10.3 - 2025-30 tariff assignment policy*.

32 As volume customers are read monthly or quarterly, volumes will be pro-rated over a 12-month period.

4.5 Ancillary activities and charges

Our ancillary charges seek to recover the cost of user-initiated activities. The initial price levels of our ancillary activities we propose from 1 July 2025 are included in Schedule 3 '*Initial reference tariff schedule*' of our 2025 AA and outlined in Table 4-4. Consistent with our approach during the current 2020–25 regulatory period, we have rounded our proposed 2025-26 Ancillary Reference Services charges to the nearest dollar.

Table 4-4: Ancillary charge price levels

Activity	Charge ($2025-26)
Hourly charge—non-standard retailer-initiated requests and queries	$206.00, plus $206.00 per hour after the first hour.
Disconnection – Volume Customer Delivery Points	Completed activity charge: $84.00 Wasted visit charge: $46.00 Charge applies per meter.
Reconnection – Volume Customer Delivery Points	Completed activity charge: $118.00 Wasted visit charge: $118.00 Charge applies per meter.
Disconnection & Reconnection – Demand Customer Delivery Points	Completed activity charge: individually priced Charge applies per meter.
Expedited reconnection	Completed activity charge: $196.00 Wasted visit charge: $196.00
Abolishment	Completed activity charge: • Meters with a capacity of less than or equal to 25m^3/hr: $1,472.00 • Above 25m^3/hr: individually priced Charges apply per meter.
Special meter read	Completed activity charge: $17.00 per meter read Wasted visit charge: $17.00

4.5.1 Why our prices for ancillary activities have changed?

By separating Ancillary Reference Services from the Transportation Service for the 2025–30 period, we needed to determine our ancillary charges so that they reflected the expected costs of providing these services.

We calculated the 2025-26 prices for ancillary activities using a bottom-up build of labour, material, contractor, overhead and other costs. This is included in *JGN - Att 7.2M - Ancillary reference services model* and described in *JGN - Att 7.2 - Ancillary services cost build up approach*. *JGN - Att 7.2 - Ancillary reference services cost build up approach* also demonstrates how our proposed rates benchmark efficient compared to other gas network businesses.

These prices differ from those approved for 2024-25 because they were refreshed to reflect our actual costs. Our ancillary charges over the 2020–25 period were part of our single Reference Service, which meant that those charges were balanced as part of our tariff basket price control. Although we had regard to costs when setting those charges, they were not set at the standalone cost of providing those ancillary services.

4.5.2 How we propose pricing abolishments

We propose retaining an abolishment ancillary service for the 2025–30 AA period and setting the charge so that it is cost-reflective. This was strongly supported by customer feedback.[33]

Our current charge for the abolishment of customer connections (where the meter capacity if less than or equal to 25m3/hr) is $1,470.81, which is payable by the party requesting the abolishment. This cost includes excavating in the footpath or roadway, clamping and cutting the service to separate from the supply pipe, sealing the end of the service, recording a final meter read and serial number, removing the meter and regulator, and purging the service to remove all traces of gas.

We currently process approximately 4,000 abolishments, or permanent disconnections, per year (compared with around 17,000 temporary disconnections and around 15,000 reconnections). An abolishment may be required for safety reasons, for example, a knockdown or rebuild of a property, a renovation or redevelopment of a site. Alternatively, if customers remove all their gas appliances, they might choose to permanently disconnect from the gas network altogether.

In its recent decisions for Victorian gas distribution networks, the AER decided to cap the small customer connection abolishment Ancillary Reference Service tariff at $220 in real terms over the 2023−28 period, and socialise the balance of small customer abolishment costs up to $950 across haulage tariffs.[34] The AER adopted this approach after concerns were raised by Energy Safe Victoria (and others) that charging the customer the full cost of abolishments may encourage them to seek a temporary disconnection service instead, creating a public safety risk (e.g., in the event there is subsequent demolition activity). This customer behaviour was observed in Victoria and the ACT.

In light of the AER's decision for Victorian businesses, we engaged with our customers on whether this ancillary service should be charged on a 'user pay' basis (as currently applies for JGN) or partially socialised across the customer base (as per the AER's Victorian decisions). As part of the package of initiatives considered by the Customer Forum for the Draft 2025 Plan, we asked participants to consider our current approach to permanent disconnections.

- In Customer Forum 7, 84% of the Customer Forum voted for maintaining our current approach, with a clear preference for a 'user pays' model.[35] They did not consider it fair for the costs of abolishments to be shared across the customer base.
- Small businesses that we engaged with were split on this topic. 59% voted for some sharing across the customer base for permanent disconnections.[36] Their reason for voting this way was because they wanted the cost to be spread more across the customer base and subsidised by JGN or the government. However, some small businesses (16%) felt it should be funded by the individual leaving the network.

Although we recognise different views across the customer base on this initiative, in our 2025 Plan, we are proposing to maintain our current approach for abolishments. We are also mindful of the public safety risk that factored into the AER's Victorian decisions; and have strategies in place to manage and monitor that risk, including:

- a temporary disconnection involves the wadding or plugging of the meter to stop gas flow and the closing of the meter control valve—this means no gas can enter the customer premise or be used in the customer appliances. Unless there is interference with the wad, this eliminated the risk downstream of the meter
- monitoring gas usage across our connections, including those that are disconnected but have not been abolished (e.g., by continuing to read meters to see whether any gas has been used)

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33 *JGN - BD Infrastructure - Att 2.2 - Customer forum engagement report*, p.37.

34 AER, Attachment 9 – *Reference tariff setting | Final decision – AGN (Victoria & Albury) Access Arrangement 2023–28*, June 2023.

35 *JGN - BD Infrastructure - Att 2.2 - Customer forum engagement report*, p.37.

36 See: *JGN-Att 3.2 – Small business, Retailer and Large Customer engagement report*, p.9.

- maintaining our Before-You-Dig-Australia (**BYDA**) process, which encourages anyone looking to dig up ground to check before doing so to ensure that there are no active services buried in the ground—unlike some utilities, Jemena does show on its BYDA the indicative location of customer services
- investing in and relying on Piccaro, which uses analytics to detect leaks from our gas network
- maintaining an oversight of lead indicators that can signal any variation in the current level of (safety) risk with respect to the delta between temporary disconnections and abolishments.

We are also considering enhancing our customer awareness strategies, such as sending out notices (e.g., annually) to premises that have disconnections that are not abolished and that services have gas in them. We will focus on disconnections that have been in place for more than 12 months.

The public safety risk facing our network is also likely to differ from that facing the Victorian gas networks, including because we have a higher penetration of individually metered high-rise apartments where the risk of someone damaging disconnected but not abolished services is lower.

5. How we allocate revenue to services

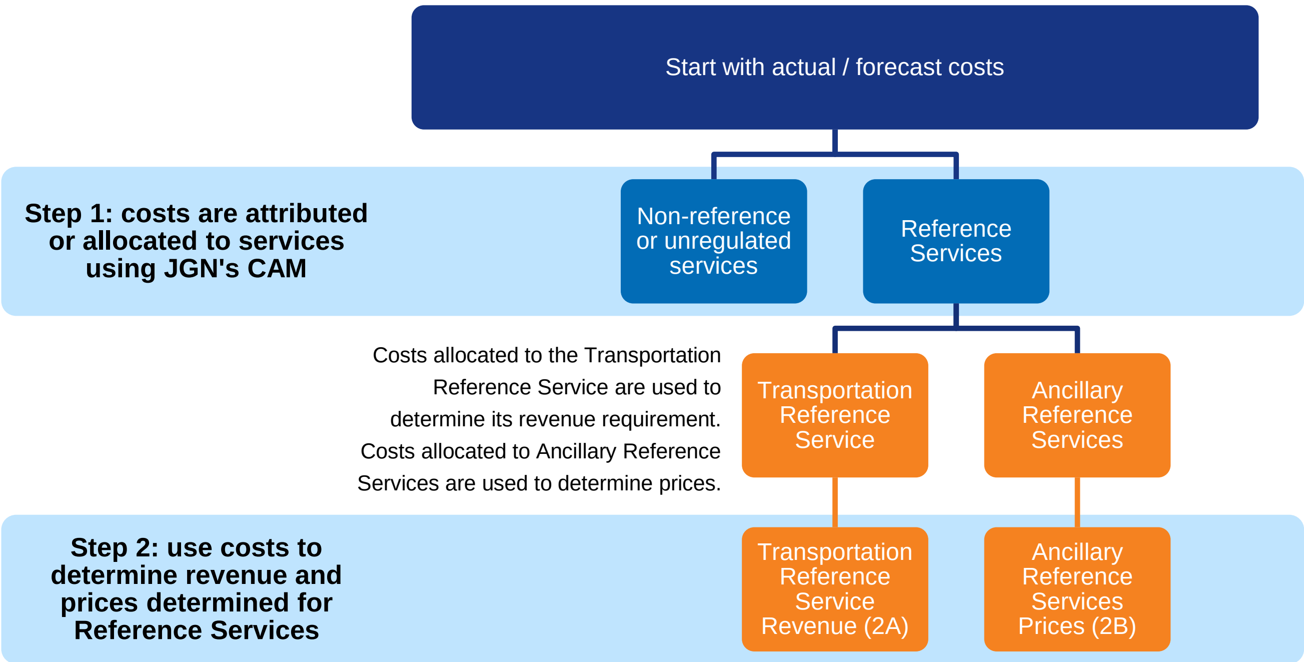
Rule 93 details provisions relating to the allocation of total revenue and costs between reference and other services. To address the cost allocation requirements in Rule 93 of the NGR, we apply the following steps:

- **Step 1:** JGN's cost allocation methodology (**CAM**), which is set out in *JGN - Att 6.5 - Cost Allocation Methodology*, is followed to ensure that all costs attributable to the delivery of non-reference services and any unregulated services are excluded from the building blocks used to calculate JGN's total revenue requirement in accordance with rule 76. Shared costs are allocated using appropriate drivers. Costs attributed or allocated to reference services are further attributed or allocated to the Transportation Reference Service and Ancillary Reference Services.
- **Step 2:** Reference services costs are then used to determine the revenue requirement for the Transportation Reference Service and prices for Ancillary Reference Services using two further steps:
  - **Step 2A:** The total revenue requirement for the Transportation Reference Service is calculated using the AER's building blocks approach (in the PTRM), which incorporates actual and forecast costs attributed or allocated to that service. That revenue is used to derive the reference tariffs discussed in this Attachment.
  - **Step 2B:** Prices for each Ancillary Reference Service are calculated using actual and forecast costs attributed or allocated to each service.

This approach ensures that costs relating to our reference services do not include costs incurred (and recovered) from the provision of non-reference services. Non-reference service revenue is not allocated to our reference services because the underlying costs are not included within our building block revenues for reference services.

Our cost allocation approach is summarised in Figure 5-1.

Figure 5-1: How we allocate revenue to services



JGN's proposed Transportation Reference Service revenue is provided in *JGN - Att 7.6.1M - PTRM* and *JGN - Att 7.6.2M - PTRM*.

6. How we set our network prices

We set our network prices by considering:

- the efficiency measures included in the NGR—section 6.1
- our pricing objectives and strategy—section 6.2
- the limits on annual price changes via our tariff variation mechanism—see section 7.

6.1 The efficiency measures

This section outlines how JGN's tariffs support allocative efficiency and reflect its different customer bases. It provides:

- demonstration of efficient prices including JGN's estimates of:
  - stand-alone and avoidable costs
  - long-run marginal costs (**LRMC**)
- our consideration of transaction costs
- our consideration of customers' ability to respond to price signals
- our prudent discounts.

6.1.1 Stand-alone and avoidable costs

Rule 94(3) requires that the expected revenue recovered for each tariff class should lie on or between the standalone cost of providing the reference service and the avoidable cost of not providing the reference service.[37]

Our stand-alone and avoidable cost estimates for each tariff class are shown in Table 6-1 and compared to our expected revenue. This shows that we expect revenue for each tariff class to sit between the two efficiency measures. We cannot publicly disclose some values in the table due to the limited number of customers in the tariff class potentially revealing confidential customer information.

Our approaches to estimating stand-alone and avoidable costs are set out in section A1 of Appendix A.

Table 6-1: Efficient bounds for expected revenues ($2025 thousands)

Tariff Class	Avoidable Cost	Revenue (2025-26)	Stand-alone Cost
VI-Small	$132,696	$442,013	$1,721,524
VI-Large	$48,770	$79,485	$1,516,553
VB	$784	$7,168	$323,972
DC-1, DCFR-1, DMT-1	$1,100	$3,803	$971,551
DC-2, DMT-2	$1,460	$5,288	$670,890
DC-3, DMT-3, VRT-3, DMTFR-3	$2,922	$10,595	$1,237,162
DC-4, DMT-4, VRT-4	$352	$3,861	$701,912
DC-5, DMT-5	$12	[redacted]	$495,860

[37] We have not estimated standalone and avoidable costs for Ancillary Reference Services as the prices for each service is set to align with opex that we expected to incur in providing them, which effectively means that they reflect the costs that we would avoid if we did not provide the service. This means that they fall within the standalone and avoidable cost bounds. As noted in *JGN-Att 7.2-Ancillary reference services cost build up approach* our labour rates also benchmark efficient to other network businesses.

Tariff Class	Avoidable Cost	Revenue (2025-26)	Stand-alone Cost
DC-6, DCFR-6, VRT-6	$4,327	$4,520	$765,401
DC-7	$360	$2,115	$294,333
DC-8	$38	[redacted]	$290,377
DC-9	$420	[redacted]	$286,350
DC-10, VRT-10	$118	$472	$457,992
DC-11	-	-	$284,856
DC-Country	$696	$3,944	$329,286
DT	$190	$1,099	$170,298

(1) Costs are annualised stand-alone and avoidable costs.

(2) We have grouped demand and VRT tariff classes that fall within the same locational areas together. This is because these customers use the same network and costs are only avoidable if all the customers in those locations were not to be served. Similarly, they would face the same stand-alone cost were a network to be built to service just that location. We demonstrate that the combined revenue of these tariff classes falls between the avoidable cost and the stand-alone cost of serving tariff classes in those locations. Note that while VRT tariff classes are included, there are currently no customers on the VRT tariffs.

6.1.2 Long-run marginal cost

In accordance with rule 94(4), JGN is required to calculate LRMC for each tariff and charging parameter (where there are two or more charging parameters).

Rule 94(4) requires the distribution network service provider to take into account LRMC in setting tariffs. LRMC is a measure of incremental cost calculated with the assumption that all inputs (i.e., all factors of production) can feasibly be altered. This can therefore capture the cost of building additional capacity.

The purpose of taking LRMC into account when setting tariffs and tariff parameters reflects the economic principle that prices should reflect the underlying costs of providing the service. As consumption increases, network capacity requirements increase, and therefore augmentation is required to accommodate the additional demand. Prices should reflect the expected additional costs arising from additional consumption so that customers receive an efficient signal to base their gas consumption decisions on.

When priced in this way, customers can increase their use of the network when they value it more than the cost; they can also reduce their use when they do not. Such responses help signal to us if and when we need to invest to either increase or reduce capacity, to the extent it is valued by our customers.

We have calculated LRMC for each of our Transportation Reference Service volume tariff classes using the average incremental approach. These are shown in Table 6-2.

As was the case in the 2015 AA and 2020 AA periods, and as shown in *JGN - Core Energy - Att 8.2 - Demand Forecast Report*, there is no meaningful growth in the demand market during the forecast horizon and it is not driving incremental growth-related investment on our network. In addition, we have no or very few customers on VRT tariffs.[38] Our approach to estimating LRMC is set out in section A2 of Appendix A.

[38] We have also not presented LRMC values for our Ancillary Reference Services. By basing our proposed Ancillary Reference Services prices on expected opex for providing each service, we have effectively set those prices to match LRMC. We do not expect any difference between that expected opex and the LRMC of providing them because there are no capital components.

Table 6-2: LRMC for our proposed tariff classes ($2025)

Tariff Class	LRMC ($/GJ)
VI-Small	$33.98
VI-Large	$10.44
VB	$10.40

Table 6-3 details our estimated LRMC values for our tariff components in the volume market.

Table 6-3: LRMC for each tariff class by component ($2025)

Tariff Class	Fixed $/annum(1)	Variable $/GJ	Variable $/GJ chargeable demand
VI-Small	$338.60	$14.85	n/a
VI-Large	$2,915.05	$6.91	n/a
VB	$2,797.76	$6.88	n/a

(1) Note that the values are calculated per connection. That is, for the boundary-metered tariff, $2,797.76 is the LRMC for supplying each boundary-metered connection rather than the end-customer.

Taking LRMC into account

Recognising both the benefits and limitations of LRMC, the rules require that we must consider our LRMC estimates when setting our tariff levels (NGR, clause 94(4)(a)).

Our tariff levels have a primary function of recovering our costs as determined by the AER every five years. This is why tariff levels are unlikely to ever be equal to LRMC values. Our costs are made up of more than just expenditure to accommodate growth. They include our funding costs on our previous investments, tax and reinforcement and renewal expenditure as well as fixed overhead costs. NGR 94(5) permits a distribution business to recover its building block cost of services.

As a sense check, we do compare our proposed prices against our estimated LRMC when developing them. As illustrated in Table 6-4, our proposed charges are aligned with our estimated LRMC values.

Table 6-4: LRMC compared to proposed charges for each tariff class by component ($2025)

Tariff Class	LRMC estimates		2025-26 proposed charges	
	Fixed $/annum	Variable $/GJ	Fixed $/annum	Variable $/GJ(1)
VI-Small	$338.60	$14.85	$72.96	$21.79
VI-Large	$2,915.05	$6.91	$408.60	$5.89
VB	$2,797.76	$6.88	$1,503.30	$16.86

(1) This is the charge for the first usage (i.e., consumption) block.

Other factors that we consider when setting gas prices, and which explain why LRMC estimates are not equivalent to JGN's tariff levels, are:

- At an aggregate network level, our capacity requirements are not driven so much by load peaks as by volume market expansion (i.e. new customers).
- Given gas is a discretionary fuel for many customers, fixed charges are a barrier to gas connection as it must be paid in addition to the electricity fixed charge. To ensure gas remains competitive—recovering some costs via usage rather than fixed charges empowers customers to be able to control their bills and increases the attractiveness to new connecting customers.
- LRMC estimates are forward-looking and rely on assumptions made and the quality of input information.
- Seeking stability in end-retail prices—LRMC estimates can be volatile when re-made over time. Recognising that price fluctuations in the cost of services like gas can negatively impact customers' ability to balance household budgets, we have worked towards a smooth network bill by maintaining steady bills over the 2025-30 period.

In addition, demand customers who have large loads and "non-basic" volume customers[39] are considered on an individual basis when they connect to JGN's network. Consistent with rule 79(2)(b), these considerations examine the incremental revenues from the customer relative to the incremental costs. Where the expected costs exceed the revenues, we charge a capital contribution to the connecting customer (see section 3.4 of *JGN - Att 5.1 - Capital expenditure*). The fact that these users pay a contribution for any capacity development costs not covered by our existing charges means the total they pay reflects the costs they impose.

6.1.3 Transaction costs

NGR 94(2)(b)(i) requires each tariff class to be constituted with regard to the need to avoid unnecessary transaction costs. It also requires that a tariff, and each charging parameter for a tariff class, be determined with regard to the transaction costs associated with the tariff or each charging parameter.

We have considered transaction costs such as metering and administrative costs when determining tariffs and tariff classes. This includes how to establish an appropriate balance of transaction costs that supports our pricing objectives noted in section 6.2 below.

We consider that our proposed tariffs and tariff classes for the 2025 Plan provide the correct balance between minimising transaction costs and ensuring that customers have incentives to respond to pricing signals. Our reasons for this are noted here.

- Our proposal to retain a structure for charges based on customer size—small volume customers, large volume customers, and demand customers—is economically efficient. By comparison, it would be inefficient to charge individually metered volume customers consuming less than 10TJ a year on capacity as that would require more sophisticated daily metering and data handling. Such metering costs are avoided by charging these customers on throughput using basic metering equipment. Our proposal to split volume market customers into smaller and larger customers is justifiable to ensure greater cost reflectively for those customers and because it supports reducing the number of usage (i.e., consumption) blocks from six to four.
- Removing the distinction between coastal and country areas avoids transaction costs for VI and VB customers. It would be considerably more costly to charge these customers based on zonal location similar to the demand customer zones for limited benefit in terms of network savings arising from any demand response. We consider the minor additional administrative burden to offer a tariff specific to boundary-metered customers remains justifiable to ensure greater cost reflectivity for these volume tariffs.

[39] Non-basic refers to special site conditions as outlined on our website here: https://www.jemena.com.au/gas/new-connections/.

- We charge demand customers on capacity as they have the necessary metering equipment for daily reads. In addition, demand and VRT customers are charged based on location. This is because:
  - the size of the customers' usage and associated impact on the network warrant the additional costs of targeted price signalling (i.e. to manage capacity demands and network location decisions)
  - this addresses the bypass risk that we may otherwise face as it does not have an exclusive franchise area.
- Our Transportation Reference Service supports low transaction costs by having a single fixed charge component for each tariff class. Recognising our customer feedback regarding the challenges of understanding bills, maintaining this simple approach supports customer understanding of our charges and improved participation in energy markets, as well as minimising the administrative costs and complexity of retail comparator websites.
- Separating ancillary services into the Ancillary Reference Services remains justifiable as customers are only charged for those services when requested, which is what happened when they were included within the single Reference Service that applies over the 2020–25 AA period.

6.1.4 Response to price signals

Rule 94(4)(b)(ii) requires that where a tariff consists of two or more charging parameters, each parameter for a tariff class must be determined having regard to whether the customers belonging to the relevant tariff class are able or likely to respond to price signals.

We consider that we have structured our tariffs and charging components to allow customers to respond to price signals. It is for this reason that we maintain the volume and demand customers' blocks discussed in section 4 and maintain a relatively low fixed charge to empower customers to control their bills.

Our declining block structure for both our volume and demand tariffs means customers face reduced costs for additional gas usage. We consider that this is an appropriate price signal for customers where the marginal costs of supplying additional units are lower than the average costs, encouraging increased network utilisation.

6.1.5 Prudent discounts

We have two prudent discount arrangements in place. Consistent with rule 96(2), the provision of these prudent discounts goes towards improving the efficiency of the network and leads to tariffs lower than they would otherwise face without the discounts. The discounted revenue from these users contributes to reference services revenue. Without this revenue, other sites would be subject to higher reference tariffs.

Our approach to determine whether a prudent discount is appropriate is:

- identify if the customer has a viable alternative
- if there is a viable alternative, negotiate a contract—that may stipulate a tariff, minimum bill or agreed MDQ—with the customer that provides revenue above the costs that JGN would avoid if we did not have to supply the customer (avoidable cost); a starting point for this negotiation is the alternative costs presented by the customer.

In determining what discount to provide, we are mindful that:

- if the prudent discount customer bypasses or disconnects from the network, our remaining customers would benefit from the amount of the avoidable cost—this becomes the basis for comparison for (2) and (3) below
- if the prudent discount customer remains on the network and pays less than the avoidable cost, our remaining customers would suffer via higher tariffs than if the prudent discount customer had disconnected

- if the prudent discount customer remains on the network and pays more than the avoidable cost, our remaining customers would benefit via lower tariffs than if the prudent discount customer had disconnected
- the best outcome for our remaining customers is a negotiated outcome that is as close to the reference tariff as possible but also prevents the prudent discount customer from choosing to bypass, fuel switch or otherwise disconnect.[40]

Importantly, the AER has previously considered and approved the two prudent discounts as part of its decision on our 2020–25 AA revisions proposal,[41] and subsequent tariff variation notices.[42] We are currently proposing to maintain our existing prudent discounts as the economic justifications for them are expected to remain over the 2025–30 AA period.

Table 6-5 details our current prudent discounts and demonstrates that the expected annual revenue from these is above the estimated avoidable cost were the customer to elect to bypass our network or convert to another fuel source.[43] We cannot publicly disclose the customers and the value of the discount in the table due to this revealing confidential customer information.

Table 6-5: Prudent discounts

Name	Details	Justification	Negotiated revenue ($2025)	Estimate of avoidable cost[44] ($2025)
[redacted]				

[40] In the gas of fuel switching, this may include some intrinsic value that the prudent discount customer places on using natural gas compared to another fuel source.

[41] See: AER, F*inal Decision – Jemena Gas Networks (NSW) Ltd Access Arrangement 2020 to 2025, Confidential Attachment: Prudent discounts*, June 2020.

[42] See, for instance: *AER, Statement of reasons: Jemena Gas Networks Annual Gas Tariff Variation*, May 2023.

[43] Avoidable cost represents the savings to us and our customers if we did not have to supply the prudent discount customer. We test whether negotiated revenue is greater than avoidable cost to ensure that there remains a net benefit to other customers of supplying the prudent discount customer at the negotiated tariff. This is similar to the test in NGR 94(3) that ensures that revenue from a tariff class is above the avoidable cost for that tariff class. As noted above, in practice we seek to negotiate a contract from the starting point of the customer's alternative costs.

[44] Avoidable costs are estimated as the sum of (a) meter maintenance costs and (b) the reduction in UAG liability attributable to the customer's meter, estimated as the customers annual consumption (GJ) multiplied by our UAG price ($) multiplied by a meter accuracy estimate (%). On (b), the meter accuracy estimate used is necessarily lower than the UAG coefficient used by JGN to forecast demand market UAG costs because leakage on the shared network is principally determined by network condition, pressure and length. Disconnecting a single customer would not change shared network leakage. The UAG reduction comes from the savings of leakage associated with dedicated assets.

Name	Details	Justification	Negotiated revenue ($2025)	Estimate of avoidable cost[44] ($2025)
		[redacted]		

6.2 Strategy overview

When we initially set our tariffs and price levels, and then when we update them each year, we seek to give effect to the efficiency measures identified in section 6.1 in the context of a broader pricing strategy. This broader strategy seeks to best meet our pricing principles.

Our pricing principles are:

- *Cost reflectivity*—the prices charged for services reflect the underlying costs of providing those services
- *Price stability*—minimising large tariff variations to help customers manage bills in future
- *Simplicity*—understandable and avoiding unnecessarily complex tariff structures
- *Revenue adequacy*—efficient cost recovery to generate sufficient revenue to cover the costs of operating our network
- *Fairness*—usage cost is set according to the costs of the network and covers equity considerations like cost of living pressures.

During the preparation of the 2025 Plan, we engaged with residential and small business customers, and retailers to explore how we should charge for the provision of our services over the next five years. This included engaging on the pricing principles above. Our customers and stakeholders strongly support our pricing principles.[45]

The principles aim to ensure that our tariff structure addresses affordability issues, improves fairness, promotes stable prices so our customers can manage their household and business budgets, and ensures that JGN's services remain competitive into the future.

The principles also reflect the requirements of the NGL—including the requirement that our 2025 Plan should 'promote the long-term interests of customers'. They reflect our understanding of what customers want from their gas service, as well as our ability to deliver on these expectations in the long term.

[45] See, *JGN - Att 3.2 - Small business Retailer and Large Customer engagement report*, p.20.

Table 6-6 sets out how we will aim to meet these principles as part of our 2025 Plan. The following sub-sections expand on the key strategic considerations that will inform our price setting across the 2025–30 period.

Table 6-6: How we propose to deliver on our pricing principles

Principle	How we plan to meet this
Cost reflectivity	• To improve cost reflectivity, we are splitting out large volume market customers as a separate tariff category. This will allow us to develop more cost-reflective tariffs for this category of customers and reduce the number of tariff blocks. Over time, the cost drivers for each customer segment will change and evolve. • To more accurately capture the utilisation of our network by demand customers, we plan to incrementally increase the proportion of revenue we recover from this customer segment.
Price stability	• To avoid bill shock for smaller volume market residential and commercial customers we are continuing with declining tariff blocks.
Simplicity	• For simplicity, we propose to remove the geographic location distinction (that is coastal and country) for volume market customers and reduce the number of tariff blocks.
Revenue adequacy	• The prices we propose will reflect the forecast gas volumes we expect in the next regulatory period and enable us to recover revenue to meet our efficient costs.
Fairness	• The separation of large volume market customers will allow us to charge large volume customers a higher fixed charge relative to smaller customers. In addition, our overarching 2025 Plan proposal seeks to balance the need to act now to support intergenerational equity, while keeping in mind current cost-of-living pressures.

6.2.1 Volume and demand market revenue recovery

We have traditionally recovered less than 10% of smoothed revenue from our large business (demand) customers and more than 90% of our revenue from our residential and commercial (volume) customers.

Our proposed approach seeks to gradually increase the share of revenue recovered from demand customers over the five years of our 2025 Plan. Doing so will:

- enhance the cost reflectivity of our tariffs by more accurately capturing the utilisation of our network by demand customers
- help ensure that our prices remain competitive for smaller customers that are increasingly being attracted to alternative energy sources (e.g., electricity)
- align with large customer feedback,[46] which has supported accelerated depreciation to ensure that those who remain connected to our gas network are not unfairly burdened as customer demand declines.

To support this gradual rebalancing, we have proposed to retain our 10% side constraint so that we have the flexibility to change one group of customers' prices by more than another set of customers in any one year. This is shown in Box 7-1. Lower side constraint levels would limit our ability to deliver what our customers have asked for.

We seek to promote our price stability principle by rebalancing revenue gradually, rather than in a single adjustment, helping to avoid bill shocks for demand customers.

[46] See, *JGN - Att 3.2 - Small business Retailer and Large Customer engagement report*, p.p. 327-328.

6.2.2 Volume customers' fixed charge

Our proposal to split volume customers into small and large gives us more scope to tailor our tariffs based on customer size.

Our large volume market customers—those consuming 200 GJ or more— currently pay a very small fixed charge. For example, the fixed charge of a typical bill for a commercial customer consuming 300GJ represents only 4% of the total network bill. This compares to a 22% fixed charge component for a typical 15GJ residential customer.

We are, therefore, proposing to raise the fixed charge for our large volume market customers to better reflect the nature of the fixed costs we incur in delivering our Transportation Service. We propose to increase the fixed charge proportion of the typical large customer bill to bring it in line with that of a typical residential customer.

This is consistent with our fairness pricing principle. Increasing the fixed charge for larger volume market customers gradually over the period also supports our price stability principle, by helping to avoid significant changes in any one year.

6.2.3 Volume customers' usage charge

We currently have declining block usage charges. This means that the average network price we charge decreases with the more gas that is used. This reflects that the costs of providing additional capacity decrease with volume increases and help improve utilisation of our network and lowering our average prices.

For the regulatory period 2025–30 we are proposing to reduce the number of declining consumption blocks from six to four. This move to fewer declining blocks is enabled by splitting our volume market into smaller and larger customers.

Retaining declining block usage tariffs supports our price stability pricing principle as it can help small volume market residential and commercial customers avoid bill shocks, especially those that have high gas consumption.[47] The AER recognised this concern in its recent review of gas distribution network tariffs:[48]

> *There are widely held stakeholder concerns about the potential impact of network tariff structure changes on low income but high gas consumption residential customers, assuming retailer pass through of network tariff changes. We share those concerns.*

6.2.4 Maintain competitiveness of boundary-metered solutions

Our boundary tariff class was designed on the basis that similar customers should face similar tariffs—it is the same pipelines and other assets required to transport gas to supply energy to these end customers, whether they are individually or boundary metered. We propose maintaining these tariffs over the 2025–30 period.

6.2.5 Demand market

We are not proposing to make any changes to our demand market tariff structures because we consider that these remain appropriate for the 2025–30 period. We are also not aware of any customer support for changes.

However, as noted above, we plan to gradually increase the revenue proportion we recover from our demand customers. This will enhance the cost reflectively of our tariffs. Concurrently, we will provide these customers with

47 This occurs because of the large difference in $/GJ price between our first and last blocks. The more gas a customer consumes when facing a declining block tariff structure, the lower the average $/GJ price. That helps residential customers on low incomes with high gas consumption.

48 *AER, Review of gas distribution network reference tariff variation mechanism and declining block tariffs – Final decision, October 2023*, p.11.

an opportunity to reset their chargeable demand to reflect their use of our network, which will lower their bills if their gas demand is lower.

6.2.6 Ancillary activities

To ensure our ancillary charges continue to reflect the cost of undertaking these activities, we may adjust these year-on-year to reflect changes in the level of inflation and any real price change allowed for (e.g., forecast changes in labour costs, ignoring inflation).

Any change would have to satisfy our tariff variation mechanism for Ancillary Reference Services (refer to section 7.3) and be approved by the AER.

7. Our proposed tariff variation mechanisms

7.1 Introduction

For the 2025–30 AA, we are proposing to split the current single Reference Service into two separate reference services; namely a Transportation Reference Service, and Ancillary Reference Services.

Figure 7-1 shows JGN's existing reference and non-reference services, while Figure 7-2 shows that proposed for the 2025–30 AA period. We discuss our proposed services in sections 7.2 and 0 respectively.

Figure 7-1: JGN's existing reference and non-reference services

Figure 7-2: Proposed pipeline services for the 2025–30 AA period

This split means that we need separate variation mechanisms for our Transportation Reference Service and our Ancillary Reference Services. We discuss these below.

7.2 Transportation Reference Service

7.2.1 Form of price control

For our Transportation Reference Service, we propose to adopt a hybrid form of control that combines elements from a tariff basket price control and a revenue cap in the form of a weighted average price cap (**WAPC**) formula for the 2025–30 AA period. We will implement this WAPC using the CPI-X price control formula and annual tariff variation mechanism.

A WAPC constrains the overall movement in reference tariffs within the AA period. A WAPC ordinarily means that we, and not our customers, bear the risk where actual demand is different from the AER allowance. However, we are proposing to adjust the WAPC so that it caps and shares any under or over-recovery of revenue from such differences.

Under this mechanism,

- we would bear volume risk up to an agreed threshold level, and we and our customers to share the volume risk 50:50 beyond the tolerance level
- if there is volume over or under performance up to the agreed threshold level, the risk of revenue over/under recovery will be borne by us.

This is similar to the current price cap up to the agreed threshold level. Beyond the threshold level, any volume over or underperformance will be equally shared between us and our customers. This lowers the incentive for us to increase volumes compared to the incentive under the current price cap. However, retaining some volume risk—as this hybrid form of control will do—provides us with incentives, consistent with the long-term interests of customers, to:

- respond to market developments and retain efficient price signals over each five-year regulatory period[49]
- increase network utilisation resulting in lower prices for all customers, supporting productive and allocative efficiency.

Customers strongly supported us retaining some volume risk and supported our proposed hybrid form of control over other forms of control, such as a revenue or price cap. They also strongly supported our proposed 50:50 sharing and 5% tolerance threshold inputs when implementing the hybrid.[50] We explain our rationale for that form of control, and our customer feedback, in section 7.3.

The tariff basket approach is consistent with customers' long-term interests by always balancing to the weighted average price. It is also the current form of price control for gas networks subject to full regulation[51] and is consistent with our current tariff variation arrangements. These are both relevant considerations for the AER when deciding the reference tariff variation mechanism for the current regulatory period.[52]

The proposed WAPC formula is shown in Box 7-1. The update made to reflect the hybrid approach is included within the automatic adjustment factor, which we cover in the next section.

[49] Consistent with rule 97(3)(a).

[50] See discussion in section 1.

[51] Multinet, AusNet Services, AGN Vic, AGN Albury, AGN SA, and Evoenergy are all subject to a WAPC.

[52] Rule 97(3)(c) and 97(3)(d).

Box 7-1: Transportation Reference Service: tariff control formulae and side constraint formulae

Tariff basket price control formula:

$$(1 + CPI_t)(1 - X_t)(1 + A_t)(1 + PT_t) \geq \frac{\sum_{x=1}^{n}\sum_{y=1}^{m} p_t^{xy} q_{t-2}^{xy}}{\sum_{x=1}^{n}\sum_{y=1}^{m} p_{t-1}^{xy} q_{t-2}^{xy}}$$

Subject to the rebalancing side constraint formula:

$$(1 + CPI_t)(1 - X_t)(1 + A_t)(1 + PT_t)(1 + 0.1) \geq \frac{\sum_{x=1}^{n}\sum_{y=1}^{m} p_t^{xy} q_{t-2}^{xy}}{\sum_{x=1}^{n}\sum_{y=1}^{m} p_{t-1}^{xy} q_{t-2}^{xy}}$$

Where JGN has n reference tariffs, which each have up to m tariff components, and where:

t is the financial year for which the tariffs are being set;

p_t^{xy} is the proposed tariff for component y of reference tariff x in financial year t, i.e., the new tariff to apply from the commencement of financial year t;

p_{t-1}^{xy} is the proposed tariff for component y of reference tariff x that is being charged at the time the variation notice is submitted to the AER for assessment;

q_{t-2}^{xy} is the quantity of component y of reference tariff x that was sold in financial year $t-2$;

CPI_t means, for financial year t;

i. the CPI for the December quarter immediately preceding the start of the relevant financial year; divided by

ii. the CPI for the December quarter immediately preceding the December quarter referred to in paragraph (i)

iii. minus one

provided that if the Australian Bureau of Statistics does not, or ceases, to calculate and publish the CPI, then in this access arrangement CPI will mean an inflation index or measure agreed upon between the AER and the Service Provider

X_t means the *X* factor for each financial year, determined in accordance with the JGN revenue model, updated for the annual return on debt calculated for the relevant financial year;

A_t is the automatic adjustment factor;

PT_t is the cost pass through factor.

The right-hand side of the equation determines the weighted average of notional revenue in the current AA year compared to the AA year in which the proposed tariffs are to apply. This notional revenue relies upon quantities from two years prior. This is consistent with practice in other jurisdictions. This remains consistent with rule 97(3)(b) because it reduces the administrative burden on the AER relative to the alternative of using estimated data for this purpose.

The left-hand side of the equation provides the price cap that allows tariffs to increase by no more than the CPI less the X factor,[53] cost pass throughs and true-up amounts for licence fees, carbon costs, tax and UAG (the 'automatic adjustment'). These are included because:

- the X factor parameter gives effect to the price path set out in Chapter 7 of our 2025 Plan[54] and aligns the net PV of JGN's cost of service with its forecast revenues

53 Note that the X factor will be updated each year based on the implementation of the trailing average cost of debt.

54 Note that the X factor will be updated each year based on the implementation of the trailing average cost of debt.

- the CPI parameter adjusts JGN's reference services for inflation
- cost pass throughs are adjustments for a predetermined set of unforeseen events[55] outside of JGN's control where JGN's costs are higher or lower than threshold requirements[56] due to these events—these adjustments can be both positive and negative
- true-ups (automatic adjustments) are required for –
  - licence fees, carbon costs, tax, UAG, and
  - now for volumes beyond threshold level in line with our proposed hybrid form of control

  and these true-ups can be both positive and negative.

Individual transportation reference service tariffs will continue to be restricted by a side constraint formula also shown in Box 7-1. This restricts changes to revenues from individual tariffs to 10% over and above the price change permitted by the lefthand side of the tariff control formulae variations. This provides additional certainty to customers on annual price movements recognising that price fluctuations in the cost of services like gas can negatively impact customers' ability to balance household budgets.

The tariff mechanism for transport reference service has been designed to ensure that forecast revenue for the 2025 AA period equals (in present value terms) the portion of total revenue allocated to reference services for the 2025 AA period.

7.2.2 Automatic adjustments (A_t)

Our reference tariff mechanism includes automatic adjustment factors as detailed in Schedule 4 of our AA. The automatic adjustments are traditionally used to ensure that only the actual costs incurred during the period for the following items are passed on to consumers. The **first four** areas for automatic adjustment are the same as the 2020 AA, namely:

1. *Licence fees*—due to realised licence fees varying from the allowed annual licence fee
2. *Unaccounted for gas (**UAG**)*—to procure gas to meet our UAG obligations as compared to our annual allowance. JGN's approach to assessing UAG costs is the same as the 2020–25 AA period, but with updated target rates (see *JGN-Att 6.7-Unaccounted for gas*)
3. *Changes in taxes*—to meet any new or changed tax obligations over and above the annual allowance, and
4. *Carbon costs*—to meet any costs incurred (directly or indirectly) arising from an obligation imposed under a new 'carbon scheme' should one be implemented in the 2020 AA period.[57] The factor is drafted broadly to reflect the significant degree of carbon policy uncertainty over the next 2025–30 AA period.

We propose retaining each of these components in the automatic adjustment factor for the 2025–30 period with the current zero materiality threshold. Each of these events addresses circumstances or potential circumstances over which we have essentially no control, it is appropriate to retain these actual or potential automatic adjustment factors in the tariff variation mechanism for the 2025–30 period. The **fourth** component is intended to cover any costs imposed on federal/state government carbon schemes on us including the Federal Government's Safeguard Mechanism that are not otherwise already allowed for in our opex forecast.[58]

[55] Clause 3.5 of the AA details allowed pass through events. These are also discussed in *JGN-Att 10.2-Cost pass through mechanism*.

[56] Clause 3.5 of the AA details threshold levels.

[57] A 'carbon scheme' refers to any law or regulation with respect to the production or emission of, or to reduce, limit, cease, prevent, offset, remove or sequester greenhouse gas emissions.

[58] See: https://www.dcceew.gov.au/climate-change/emissions-reporting/national-greenhouse-energy-reporting-scheme/safeguard-mechanism.

For the avoidance of doubt, adjustments (up or down) for these components are only made where JGN incurs costs that are different to any allowance provided by the AER.[59] The AER also has the opportunity to scrutinise these costs annually and they must approve them before they are included in JGN's prices.

We are also proposing to add a **fifth** component so that the WAPC formula can give effect to the hybrid form of control that we propose. Namely:

1. *Hybrid revenue*—any volume risk outside of the agreed threshold level of 5% is shared 50:50 with our customers.

The automatic adjustment is set out in Box 7-2. The proposed formula corresponds with that in the AER's 2020 AA final decision. The automatic factor is adjusted through the Tariff Control Mechanism to deal with the time value of money as shown in Box 7-1.

We describe each of the five areas of automatic adjustment in further detail below.

Box 7-2: Automatic adjustment factor

$$A_t = \frac{(1 + A'_t)}{(1 + A'_{t-1})} - 1$$

where

A'_t is the value of A'_t determined in the financial year $t-1$;

and

$$A'_t = \frac{(L_{t-2} + U_{t-2} + C_{t-2} + T_{t-2} + R_{t-2})[(1 + realWACC_{t-1})(1 + realWACC_t)(1 + CPI_{t-1})]}{(1 - X_t)\sum_{x=1}^{n}\sum_{y=1}^{m} p_{t-1}^{xy} q_{t-2}^{xy}}$$

where

L_{t-2}	is the licence fee factor amount, as defined in the AA, for financial year $t-2$;
U_{t-2}	is the UAG factor amount, as defined in the AA, for financial year $t-2$;
C_{t-2}	is the carbon cost factor amount, as defined in the AA, for financial year $t-2$;
T_{t-2}	is the change in tax factor amount, as defined in the AA, for financial year $t-2$;
R_{t-2}	is the revenue true-up factor amount, as defined in the AA, for financial year $t-2$;
	When $t-2$ is financial year 2023-24 or financial year 2024-25, $R_{2023-24} = 0$ and $R_{2024-25} = 0$
$realWACC_t$	is the real vanilla weighted average cost of capital for financial year t as per that set out in the AER's Final Decision and updated annually within the JGN Revenue Model
$realWACC_{t-1}$	is the real vanilla weighted average cost of capital for financial year $t-1$ as per that set out in the AER's Final Decision and updated annually within the JGN Revenue Model
CPI_t	has the same meaning as set out in Box 7-1;
CPI_{t-1}	is the value of CPI_t determined for financial year $t-1$;
X_t	has the same meaning as set out in Box 7-1;
p_{t-1}^{xy}	has the same meaning as set out in Box 7-1;
q_{t-2}^{xy}	has the same meaning as set out in Box 7-1.

59 For example, we are not asking for an allowance from the AER for carbon costs. An automatic adjustment for carbon costs would only occur if a relevant scheme was introduced during the period. Were no scheme to be introduced, or an introduced scheme results in no cost to JGN, then there would be no adjustments made under the carbon cost factor.

Licence fee factor

We pay authorisation fees, licence fees and statutory charges to the AER, the Independent Pricing and Regulatory Tribunal (**IPART**), the Australian Energy Market Operator (**AEMO**), and other relevant regulators, authorities and State and Commonwealth Government bodies, which relate to the ownership or operation of our network. Our opex forecast includes an allowance for the costs we expect to incur for these matters for the 2025–30 period (see *JGN-Att 6.1-Operating expenditure* for details). However, there remains a risk that the actual amounts paid in a given year are more or less than that allowance.

The "Licence Fee Factor" is detailed in clause 2.1 of Schedule 4 of our AA, which relates to these authorisation fees, licence fees and statutory charges that are imposed on us. It adjusts for differences between our actual costs and those assumed in the AER's opex allowance in its Final Decision. This is because these costs are not stable from year to year and are difficult to forecast accurately. Additionally, invoices for these fees are not levied regularly, meaning that the fees payable can fluctuate significantly from year to year.

We note that this is a two-way pass through so it has been common for us to make refunds to customers in some years while in other years we have recovered additional costs. There is a two-year lag in the application of the adjustment, given the differences in timing between when we know costs and when tariffs can be adjusted. This includes the true-up timings as shown in Table 7-1.

We propose retaining this factor in the 2025–30 period.

UAG factor

We procure gas to replenish the difference between the measured quantities of gas entering and leaving our gas network—this difference is known as UAG. We have historically bought gas for this purpose through a competitive tender process.

Our opex forecast includes an allowance for the costs we expect to incur for UAG for the 2020–25 period (see *JGN - Att 6.1 - Operating expenditure* and *JGN - Att 6.7 - Unaccounted for gas* for details). The efficient level of UAG is determined based on two market segments—one applies to daily metered customer withdrawals (referred to as the 'Demand Market') and the other to gas received to supply non-daily metered customers (referred to as the 'Volume Market').

The UAG factor is designed to provide JGN with an incentive to minimise the volume of UAG but does not expose JGN to variations in the wholesale price of gas. It does this by trueing up between the AER Final Decision allowance and a calculated amount based on the product of the following three parameters for each market segment:

- Financial year $t-2$ actual throughout for each segment
- Approved target rate (loss rate) of UAG—we have relied on loss rate forecasts prepared by Frontier Economics. We have provided Frontier's report on UAG in *JGN - Frontier Economics - Att 6.8 - UAG Report*, which provides the target rate calculations, and
- Cost of replacement gas in financial year $t-2$. The "UAG Factor" is detailed in clause 2.2 of Schedule 4 of our AA.

We are proposing only minimal changes to our arrangements for dealing with UAG from those that apply in the 2020–25 period—this includes both the basis for calculating the efficient UAG opex forecast and the UAG factor. The only updates (other than to reference the correct years) are to the proposed UAG target rates themselves and simplify how these are presented.[60]

Otherwise, we propose that the UAG factor be retained in its current form in the 2025–30 period. This includes the true-up timings as shown in Table 7-1.

[60] Given there is a target rate for each market segment, and to recognise that those rates differ between the 2020–25 period and the 2025–30 period we have included these in a table in Schedule 4 of the AA.

Carbon cost factor

The "Carbon Cost Factor" is detailed in clause 2.3 of Schedule 4 of our AA. This factor compensates us for the cost of operating a carbon scheme, such as the Safeguard Mechanism. Our AA includes the following definitions:

> ***Carbon Costs*** *means the costs incurred in connection with an obligation that is imposed under any Carbon Scheme, including without limitation any charges or fees payable in respect of greenhouse gas emissions, costs of acquiring permits, allowances, credits, or certificates, costs associated with undertaking activities to abate or sequester greenhouse gas emissions and costs associated with reducing liability under any Carbon Scheme;*
>
> ***Carbon Scheme*** *means any law or regulation of the Commonwealth of Australia or of a State or Territory of Australia, with respect to the production or emission of, or to reduce, limit, cease, prevent, offset, remove or sequester greenhouse gas emissions.*

The only Carbon Scheme covered at present is the Safeguard Mechanism, which was reformed in 2023.[61] As described in *JGN - Att 6.1 - Operating expenditure*, we have forecast some costs that we expect to incur over the 2025–30 period to comply with that mechanism. The Carbon Cost Factor will allow for an annual true-up of our actual costs against any such costs allowed by the AER in its final determination.

We also propose that this automatic adjustment factor would apply to any other Carbon Schemes introduced during the 2025–30 period. Were no other scheme to be introduced, or an introduced scheme results in no cost to JGN, then there would be no adjustments made under the carbon cost factor.

We therefore propose that the carbon cost factor be retained for the 2025–30 period.

Relevant tax factor

The "Relevant Tax Factor" is detailed in clause 2.4 of Schedule 4 of our AA. This factor relates to any tax other than:

- any tax in the nature of an income tax or a capital gains tax
- penalties, charges, fees and interest on late payments, or deficiencies in payments, relating to any tax
- stamp duty, or similar taxes and duties, and
- any tax that replaces or is the equivalent of or similar to any of the taxes referred to above.

This factor remains relevant in the 2025–30 period if new or varied taxes or similar costs are levied during the period. Under this factor, customers would benefit from a lower corporate tax rate than that assumed in the AER's tax allowance if introduced during the 2025–30 period.

We therefore propose that it be retained. It would only apply if necessary.

Revenue true-up factor

As explained in section 7.3, we are proposing a hybrid form of control that shares some volume risk with our customers. Under our proposal:

- we would bear volume risk up to 5% above or below that allowed, and
- we and our customers will share the volume risk 50:50 beyond that tolerance.

To give effect to that approach, we are proposing to use the formula set out in Box 7-3.

[61] See: Department of Climate Change, Energy, the Environment and Water, Safeguard Mechanism Reforms, May 2023; https://www.dcceew.gov.au/sites/default/files/documents/safeguard-mechanism-reforms-factsheet-2023.pdf.

Box 7-3: Revenue true-up factor

The revenue true-up factor for a financial year $\boldsymbol{t-2}$ is calculated as follows:

$$\boldsymbol{R} = \begin{cases} (\mathbf{1.05} \times \boldsymbol{R^{Allowed}} - \boldsymbol{R^{Actual}}) \times \mathbf{0.5}, \boldsymbol{RR} > \mathbf{1.05} \\ \mathbf{0}, \mathbf{0.95} \leq \boldsymbol{RR} \leq \mathbf{1.05} \\ (\mathbf{0.95} \times \boldsymbol{R^{Allowed}} - \boldsymbol{R^{Actual}}) \times \mathbf{0.5}, \boldsymbol{RR} < \mathbf{0.95} \end{cases}$$

where

$R^{Allowed}$ is calculated as:

$$\sum_{x=1}^{n}\sum_{y=1}^{m} p_{t-2}^{xy}\hat{q}_{t-2}^{xy}$$

where:

p_{t-2}^{xy} is the actual tariff for component y of reference tariff x that was charged in financial year $t-2$;

$\hat{q}_{t-2}^{xy}$ is the forecast quantity of component y of reference tariff x that was included in the AER's determination for the 2025–30 AA period in financial year $t-2$;

R^{Actual} is the actual revenue from the Transportation Reference Service for the financial year $t-2$; and:

RR is the ratio $R^{Actual}/R^{Allowed}$.

Timing of automatic adjustment factor

Box 7-1 outlines the years in which JGN incurs costs and when they are to be trued-up under the automatic adjustment factor described in Box 7-2. These are built into the formulae included in the proposed AA for the 2025–30 period.

Table 7-1: Automatic adjustment true-ups occurring in the 2025 AA period

Year cost incurred (this row)	Year of true-up (year in table below)				
	2023-24	2024-25	2025-26	2026-27	2027-28
Licence fee factor	2026-27	2026-27	2027-28	2028-29	2029-30
UAG factor	2026-27	2026-27	2027-28	2028-29	2029-30
Carbon cost factor	2026-27	2026-27	2027-28	2028-29	2029-30
Relevant tax factor	2026-27	2026-27	2027-28	2028-29	2029-30
Revenue true-up factor	No recovery required	No recovery required	2027-28	2028-29	2029-30

(1) No automatic adjustment true-ups occur in 2025-26 as prices are set by the AER based on 2025-26 smoothed revenues, hence both 2023-24 and 2024-25 true-ups occur in 2026-27.

7.2.3 Cost pass through factor (Pt_t)

The proposed cost pass through factor set out in the tariff control formula provides the mathematical method by which any AER-approved cost pass through is incorporated into WAPC. The pass through factor formula in clause 2.6 of schedule 4 of the 2025 AA is the same as for 2020–25, updated for the relevant years.

The cost pass through events we propose to include in the AA are discussed in *JGN - Att 10.2 - Cost pass through mechanism*.

7.3 Hybrid form of control

For the Transport Reference Service, we are proposing a hybrid form of control that shares some volume risk with our customers. As noted above, under our proposal,

- we would bear volume risk up to a +/- 5% agreed threshold level, and
- we and customers will share the volume risk 50:50 beyond the threshold level.

If there is volume over or underperformance up to the agreed threshold level, the risk of revenue over/under recovery will be borne by us. This is similar to the current price cap and protects our customers up to a threshold level. Beyond the threshold level, any volume over or underperformance will be equally shared between us and our customers. This lowers the incentive for us to increase volumes compared to the incentive under the price cap. However, we nevertheless remain incentivised.

This provides a measured move away from a price cap and balances affordability and environmental concerns as raised by the Tariff Forum.[62] It can also address the AER's issue around gas networks earning higher than forecast revenues by limiting volume outperformance, providing benefits of stable prices relative to a revenue cap tariff variation mechanism and allowing for the sharing of benefits and costs with customers. In its review of gas distribution tariff review last year, the AER concluded that a hybrid form of control was an option available to gas distribution businesses that it would consider on a case by case basis.[63]

In its Conclusions Report, prepared as part of the Early Signal Pathway process, the CCP raised some concerns about our proposed hybrid form of control. We respond to these in the next two sub-sections.

7.3.1 CCP concern about engagement

The CCP expressed an overarching concern about why volume risk sharing is needed:[64]

> *We are concerned that much of Jemena's recent engagement has focused on how to best share the future risk between the network and consumers, without testing whether risks should be shared rather than managed by Jemena.*

We disagree with how the CCP has characterised our engagement. The issue of risk-sharing was discussed extensively throughout the Customer Tariff Forum process, which involved three stages of engagement. Throughout the process customers explored key concepts of risk and fairness, which are important issues to consider when engaging on matters like the tariff variation mechanism (or form of price control).[65]

Because of the complex nature of the form of price control mechanism, members of the Advisory Board and Expert Panel, complemented with external guest speakers, were asked to play a role as the 'Brains Trust'. The 'Brains Trust' functioned as an independent expert to support Customer Tariff Forum participants, providing information and assisting in group deliberations by offering their views on our tariff options and form of price

62 *JGN - BD Infrastructure - Att 3.1 Tariffs Consultation Report*, p.13.

63 AER, *Review of gas distribution network reference tariff variation mechanism and declining block tariffs, Final decision*, pp.1&5–8.

64 See: *JGN - Att 2.1 - Consumer Challenge Panel - feedback and response.*

65 Refer to *JGN - BD Infrastructure - Att 3.1 Tariffs Consultation Report* for an in depth overview of the tariff engagement process.

control we put forward to customers. One workshop during Stage 1 was dedicated to discussing form of price control issues with the 'Brains Trust'.

The 'Brains Trust' in Stage 1 consisted of:

- **Douglas McCloskey** – Public Interest Advocacy Centre (**PIAC**) and Advisory Board member
- **Victoria Jordan** – Customer and Advisory Board Member
- **Zubin Meher-Homji** – Economist and Founder of Dynamic Analysis
- **Dr Matt Pearce** – National Industry Leader, Energy, Mining & Property, KPMG

The 'Brains' Trust in Stage 2 comprised of:

- **Gavin Dufty** – General Manager of Policy and Research at St Vincent de Paul Society and Advisory Board member – Speaking on equity and fairness
- **Zubin Meher-Homji** – Founder and Director of Dynamic Analysis – speaking on gas pricing
- **Matthew Warren** – Principal at Boardroom Energy and also Expert Panel member – speaking on the context of the net zero energy transition
- **Jordan Rigby** – Regulatory Manager at Red Energy – speaking from a retailer perspective.

Stage 1 to the Customer Forum process comprised of three workshops where participants were educated on different forms of price controls. During stage 1, we tested customers initial preferences on a weighted average price cap versus revenue cap form of control. A key aspect to stage 1 was for participants to consider the following question:

> *Who should bear the risk of the uncertain environment? Jemena (through a price cap) or the customer (through a revenue cap)?*

Although the question was not phrased in terms of whether JGN should manage risk – which appears to be the CCP's overarching concern, as highlighted above – the question did allow participants to explore what our role should be in managing risk. For example, throughout stage 1 deliberations participants grappled with understanding the energy sector, the gas network, pricing and tariffs, the future of gas, impacts to customers and notions of fairness and equity.

At the end of stage 1, participants emerged with a definition of customer best interest – in terms of who should bear the risk over the next five years – as follows:

> *Most participants agreed that either Jemena should bear the risk or there should be a hybrid model where there was some risk sharing with customers.* ***It was noted that Jemena was in a better position to manage the risk****, but that to ensure the ongoing business viability of Jemena, that customers felt they should share some portion. Customers did not support a revenue cap, which would see them bearing all of the risk.*[66]

After small group discussion on this issue, half of the participants thought JGN should bear all risk, and half thought that risk should be shared. Participants' commentary and questions leading to this conclusion demonstrated their growing depth of understanding on this complex issue.[67] The overall view of the group was that Jemena should bear most risk as they are better placed to carry it, but customers should bear some risk.

[66] *JGN - BD Infrastructure - Att 3.1 Tariffs Consultation Report*, p.17.

[67] *JGN - BD Infrastructure - Att 3.1 Tariffs Consultation Report,* Appendix A for outputs and verbatims.

In response to feedback garnered from stage 1, we presented participants a range of hybrid forms of price control that combined elements of a price and revenue cap. These options were explored in depth in discussion with us and the 'Brains Trust' during stage 2.

While there was a continued view that JGN should bear most of the risk relating to declining gas consumption, these discussions enabled participants to understand the costs and benefits to customers of sharing some portion of volume risk and become more comfortable with the application of a hybrid form of price control. They opted for an option whereby JGN would bear risk up to a certain threshold after which there would be a 50:50 split of any over or underperformance.

In stage 3, the participants delved deeper into the hybrid form of price control where they considered various combinations of sharing ratios and threshold levels. Sharing ratios of 50:50; 60:40 and 40:60 were presented; along with thresholds of 3% and 5% over or under forecast demand. Indicative bill impacts for these combinations in different volume performance scenarios were also presented to help participants deepen their understanding of what 'taking more risk' might actually mean.

After extensive deliberations on the form of price control, 83% of Customer Tariff Forum participants supported for a 3% threshold and 100% support for a 5% threshold. It was noted, astutely, by the group that the threshold does more of the 'heavy lifting' protecting customers from any risk sharing so long as gas forecasts are reasonably accurate and it allows for greater fluctuations in energy usage without triggering the price control mechanism. When it came to the sharing ratio, all participants supported a 50:50 ratio, believing it to a balanced and fair split. 83% supported a 40:60 ratio and 75% a 60:40 ratio.

In light of our comprehensive approach to the Customer Tariff Forum process, which included a total of 26 hours deliberation, through eight workshops, and supported by independent 'Brains Trust' members and four homework exercises, we do not agree with the CCP observations about our engagement. We also note that the CCP did not attend every session, including the earlier sessions in Stage 1 where the topic of risk sharing was first explored, and where customers indicated that they should bear some risk.[68] More information on this engagement is included in *JGN - Att 3.1 - Tariffs Consultation Report*.

Moreover, as well as strong customer support, there are also economic grounds for sharing volume risk at the present time. Historically, we have managed that risk by rebalancing our tariffs from one year to the next within our weighted average price cap tariff variation mechanism to promote growth in volumes. This also helped ensure price stability for our customers. However, more recent developments support a rethink.

- First, the AER has expressed concern that gas distribution businesses have earned more than their allowed revenue in recent years because actual volumes have been higher than the forecasts it adopts.[69]
- Second, there is growing uncertainty over future gas volumes, in part due to evolving government policies that seek to reduce emissions from natural gas (e.g., by banning new connections), which make it very challenging for gas distribution businesses to manage.

As the AER noted in its *Gas distribution network tariffs review*, one option to address the first concern would be to move to a revenue cap form of control, which would mean that gas distribution businesses get an opportunity to earn up to their allowed revenue, but no more. However, most stakeholders that made submissions to the AER as part of the consultation process did not support revenue caps due to concern that it would effectively assign all volume risk to customers.[70] That lack of support was backed up by our own engagement, whereby customers strongly rejected a move to a revenue cap form of control.[71]

As a middle ground, some gas distribution businesses—including JGN—suggested to the AER as part of its review that a hybrid form of control would limit the potential for businesses to earn more than their revenue

68 Engagement records suggest CCP members did not attend all the Tariff Forum workshops. See: *JGN - BD Infrastructure - Att 3.1 Tariffs Consultation Report*.

69 AER, *Review of gas distribution network reference tariff variation mechanism and declining block tariffs*, Final decision, p.5.

70 AER, *Review of gas distribution network reference tariff variation mechanism and declining block tariffs*, Final decision, p.5.

71 See: *JGN - BD Infrastructure - Att 3.1 Tariffs Consultation Report,* p.17.

allowances by sharing some volume risk with customers. As noted above, our customers also supported this form of control, and expressed strong support for a 50:50 sharing of volume risk outside of a +/- 5% threshold band.[72]

7.3.2 CCP concern about customer detriment

The CCP's report also notes that a hybrid form of control is more likely to detriment customers as it is more likely that actual gas volumes would be lower than those forecast:[73]

> *CCP31 observes that from the many scenarios presented to the Consumer Panel, there were no estimates of probability for the potential outcomes. As we understand the proposal associated with the hybrid model, customers would be better off where actual volume of gas transported is greater than the forecast volume plus x% (likely 5%) while Jemena would be better off if actual volume of gas transported is less than the forecast volume. CCP31 believes that the more probable outcome would be a benefit to Jemena, and a detriment to customers.*
>
> *For customers to benefit assumes a forecast with moderately high levels of gas volume, we think that this outcome has a lower probability than higher than forecast gas volumes. We form this view anticipating that gas use by households and SMEs will decline and that rates of decline will increase over the Access Arrangement period. This would mean that consumers are taking a greater risk than Jemena and so the application of the hybrid model needs further analysis and consideration by the AER.*

We disagree with the CCP's assessment—it is not clear to us that such an outcome is more likely. The CCP's concern does not appear to recognise that it is the probability around the demand forecast that matters, not a view as to the likely direction of gas volumes. If, for instance, those forecasts factor in a significant decline in gas usage, then it could be that the more probable outcome is a benefit to customers.

We appreciate that there is uncertainty over what actual volumes will eventuate and how these will compare to the demand forecast. However, as explained in *JGN - Att 8.1 - Overview of JGN's demand forecast*, the demand forecast has been developed independently by CORE Energy and validated against the Australian Energy Market Operator (**AEMO**) GSOO forecasts, and factors in the type of gas use decline suggested by the CCP. We consider that these forecasts are reasonable and unbiased. The AER will also review these volume forecasts as part of its decision-making.

7.4 Ancillary services

With the split of our single Reference Service into two, we now need to propose a separate tariff variation mechanism and form of control for Ancillary Reference Services.

For ancillary services, we are proposing to continue with a price cap form of control using the formula set out in Box 7-4. A price cap form of control ensures that prices for ancillary services reflect the costs of providing those services and is consistent with that approved by the AER for similar services provided by other gas distribution networks (e.g., those in Victoria).[74] The AER, in its May 2023 issues paper on Review of gas distribution network reference tariff variation mechanism and declining block tariffs, stated:[75]

> *Price caps for individual services are currently applied to ancillary network reference services such as disconnection, meter removal and special meter read. These services are provided to individual customers, in contrast to haulage services which involve shared network assets providing haulage services to large numbers of customers at the same time. In the case of discreet services provided to individual customers,*

[72] See section 1.2.2.

[73] CCP31, *Jemena Gas Networks: CCP31 Conclusions Report (Early Signal Pathway),* 16 April 2024, p.45.

[74] See, for instance, AER, *Multinet Gas: Access Arrangement 2023–28*, June 2023, clause 4.4.2.

[75] AER, *Review of gas distribution network reference tariff variation mechanism and declining block tariffs, Issues paper for stakeholder feedback*, May 2023, p.19.

> *ancillary network services, we consider individual service price caps are reasonable and will remain appropriate going forward.*

The tariff control formula adjusts tariffs for Ancillary Reference Services from one year to the next for inflation and an assumed real price change. We propose that the real price change is set as the forecast real labour input cost changes used to forecast our capital and operating expenditure over the 2025–30 AA period, which are discussed further in *JGN - Att 6.1 - Operating expenditure* and *JGN - Oxford Economics - Att 5.5 - Input cost escalation*. This will ensure that the tariffs reflect expected movements in labour costs, which make up most of the costs that we incur when providing Ancillary Reference Services.

Box 7-4: Ancillary Reference Services tariff control formula

Individual price control formula:

$$ART_t^i = ART_{t-1}^i \times (1 + CPI_t)(1 - X_t) + PT_t^i$$

Where:

t is the financial year for which the tariffs are being set;

ART_t^i is the tariff that will apply to an Ancillary Reference Service i in year t; when t is the 2025-26 financial year, the tariff is set out in the AER determination for the 2025–30 AA period

ART_{t-1}^i is the tariff that will apply to an Ancillary Reference Service i in year $t-1$;

CPI_t means, for financial year t;

i. the CPI for the December quarter immediately preceding the start of the relevant financial year; divided by

ii. the CPI for the December quarter immediately preceding the December quarter referred to in paragraph (i)

iii. minus one

provided that if the Australian Bureau of Statistics does not, or ceases, to calculate and publish the CPI, then in this access arrangement CPI will mean an inflation index or measure agreed upon between the AER and the Service Provider

X_t means the X-factor for each financial year, which for the 2026-27 to 2029-30 financial years are as follows:

2026-27: -0.489%

2027-28: -0.456%

2028-29: -0.533%

2029-30: -0.573%.

PT_t^i is the sum of any adjustments for the Ancillary Reference Service i in year t. Likely to include, but not limited to adjustments for any approved cost pass through amounts (positive or negative) with respect to regulatory year t, as determined by the AER.

7.5 Tariff variation process

Clause 3 of the 2025-30 AA details the proposed reference tariff variation process. This is consistent with the process currently applying during the 2020-25 AA period.

In summary, for our annual process, we will:

- submit our annual reference tariff variation proposal for our Transportation Reference Service and Ancillary Reference Services to the AER for approval by 15 April of each year before the relevant financial year in which the proposed tariffs are to apply
- include updates for actual inflation
- include any update to the X factor for the Transportation Reference Service for the return on debt adjustment previously approved by the AER
- include a pricing model that demonstrates compliance with the tariff variation mechanisms for our Transportation Reference Service and Ancillary Reference Services.

The AER will then review this proposal for compliance with the tariff variation mechanisms and approve or reject the proposal consistent with the AA terms.

There may be very limited instances where we seek to vary its tariff outside of the annual process. This would be via an intra-year tariff variation process.

In summary:

- we can propose to the AER to vary tariffs effective from a date other than the start of the financial year
- our intra-year reference tariff proposal will be made 50 business days before the proposed date it would take effect and include the adjustments to apply for the remainder of the financial year
- we will include a pricing model that demonstrates compliance with the tariff variation mechanism

The AER will review this proposal for compliance with the intra-year tariff variation mechanism and approve or reject the proposal consistent with the AA terms.

Rule 97 sets out the requirements for the mechanics of a reference tariff variation. We consider that this tariff variation process complies with Rule 97 because:

- the submission of a formulaic model minimises the administrative burden on the AER by providing an objective and transparent means for the AER to exercise its oversight and powers of approval for reference tariff variation
- it aligns with equivalent processes in other jurisdictions.

Appendix A
Appendix B Estimating efficient costs

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This appendix describes the approaches we have used to calculate stand-alone and avoidable costs, and long-run marginal costs (or LRMC). It informs the discussion in section 6.1.

A1. Stand-alone and avoidable costs

A1.1 Overall approach

To estimate the stand-alone and avoidable cost for each tariff class, we have, where possible, linked each asset to one or more tariff classes. The linkage depends on an engineering assessment of whether that tariff class would require the asset in a stand-alone network that served only that tariff class.

We then allocate each asset type to tariff classes in three steps:

1. identify asset classes for each tariff class
2. where possible, map the dedicated and shared assets to tariff classes
3. where mapping has not been possible, estimate the asset data (optimised kilometre of pipeline assets, optimised diameter of pipeline assets and the number of optimised non-pipeline assets) by tariff class.[76]

Asset classes for each tariff class are determined based on an assessment of the physical use of the network. Customers in the lowest consumption tariff classes (i.e. the individually and boundary-metered volume tariff classes) utilise almost all of the asset classes. By comparison, larger consumption or demand customers use fewer asset classes as they might generally only need to be connected to higher capacity components of the network, such as the trunk, primary and secondary mains and not to lower capacity assets such as medium and low-pressure mains.

All asset classes (and the asset types associated with each asset class) fall into two broad categories:

- *Dedicated assets*—assets that serve only one particular end customer, such as demand and volume meters and services. Dedicated assets associated with each customer (and their associated tariff classes) are directly allocated to that tariff class.
- *Shared assets*—assets that are utilised by more than one customer. The assets can be shared by customers within the same tariff class and also with customers in different tariff classes.

By establishing this split, JGN is also able to estimate the avoidable cost for each tariff class as the value of the dedicated assets established above.

A1.2 Stand-alone costs

The stand-alone cost for each tariff class comprises both capital expenditure (**capex**) and operating expenditure (**opex**) as follows:

- Capex costs include the costs of building a gas distribution network that only supplies customers within that tariff class to the required standard, availability and quantity. This hypothetical network would be smaller (i.e. dedicated) than our existing shared network, and the annualised replacement cost of this hypothetical network, together with the annualised replacement cost of the dedicated assets, forms the capex component of the stand-alone cost.
- Opex costs include the annual costs of maintaining and operating the assets required to supply gas to customers within that tariff class. This includes targeted aspects of the shared network and the dedicated assets for the tariff class.

[76] The estimation process avoids the need to allocate dedicated and shared assets to tariff classes in recognition of the limited granularity of asset data. It also avoids the need to perform asset scaling (optimisation) as optimised data can be entered straight into the model.

For each tariff class, we calculated the stand-alone cost as follows in Box A-1.

Box A-1: Stand-alone cost calculation

SC = DA + SA + OA + NA

Where:

- SC is the stand-alone cost
- DA is the annualised dedicated asset cost
- SA is the annualised shared asset costs
- OA is the annual operation and maintenance cost and other opex associated with the assets
- NA is the annualised non-system asset costs

A1.3 Avoidable costs

The avoidable cost for each tariff class comprises both capex and opex as follows:

- capex includes the replacement value of dedicated connection assets such as meters and services
- opex includes the costs associated with operating and maintaining the dedicated connection assets.

For each tariff class, we calculated the avoidable cost as follows in Box A-2.

Box A-2: Avoidable cost calculation

AC = DA + OD

Where:

- AC is the avoidable cost
- DA is the annualised dedicated asset cost
- OD is the annual operation and maintenance cost associated with dedicated assets

A2. Long-run marginal costs

A2.1 Overall approach

To ensure a robust approach to calculating LRMC, we considered both the Turvey approach and the average incremental cost (**AIC**). The Turvey approach aims to capture the direct change in expenditure resulting from multiple scenarios of changes in demand whereas the AIC approach captures the average change in expenditure, which is generally easier to apply.

We have, therefore, used the AIC approach to estimate the LRMC for each tariff and each tariff parameter. In opting for an AIC approach, we have considered the approved approaches of other gas and electricity distributors for which an AIC approach is common.

The AIC approach examines a forecast demand profile and the portion of demand that is beyond the current supply capacity. A cost-minimising quantity of capex and opex necessary to supply the incremental demand is then calculated. The present value (**PV**) of the total expenditure necessary to supply the incremental demand is then divided by the present value of the additional demand, to provide an estimate of the LRMC on a dollars per unit (of demand) basis.

This formula can be expressed by the formula shown in Box A-3.

Box A-3: LRMC calculation

LRMC = PV(EC) / PV(AD)

Where:

- EC is the *expected costs of the network*, which includes forecast annual:
  - growth-related capex in shared network assets required to meet additional demand over the forecast period, *plus*
  - growth-related opex required to operate and maintain the shared network assets required to meet additional demand over the forecast, *plus*
  - replacement capital expenditure (and associated opex) needed to promote network capacity in the long run being at a level which consumers value
- AD is the *additional demand supplied*, which is the change in gas demand (in gigajoules) over the forecast period.

Given growth in customer consumption drives expenditure on shared network assets, we have included forecast capex and opex relating to forecast growth of the shared network in the LRMC estimate. Consistent with past AER observations,[77] we have also included replacement capital expenditure and associated operating expenditure where this is needed to maintain network capacity in the long run at a level that consumers value.

However, no forecast expenditure related to connection assets is included as these are dedicated to specific customers and driven purely by customer numbers and not consumption.

77 See: AER, *Draft decision – Jemena Gas Networks (NSW) Ltd Access Arrangement 2020–25*, *Attachment 9: Reference tariff setting*, November 2019, p.14.

We adopted a forecast period of 13 years, which reduces the susceptibility of the model to long-range forecasts with associated reduced levels of reliability. This exceeds the 10 years that the AER has previously considered is the minimum needed to capture the essence of ‘long run’.[78]

A2.2 LRMC for tariff classes and parameters

We calculated the LRMC for each tariff class using the same method as we used for our 2015 and 2020 AAs, except for us now including replacement expenditure. This includes the following steps:

1. The annual customer numbers for the tariff class, as forecast by CORE, are used to determine the annual change in customer numbers for the tariff class.
2. The annual change in customer numbers for the tariff class is used to determine the annual change in demand by multiplying the annual change in customer numbers by the average peak demand (in GJ per customer).
3. The PV of the annual change in demand for the tariff is determined using the annual change in demand and current and forecast Weighted Average Cost of Capital (**WACC**) values.
4. Annual future growth and replacement capex are allocated to each tariff class and each asset class based on the engineering assessment allocations.
5. The PV of the annual future growth and replacement capex is determined using the annual future growth and replacement capex and a forecast WACC value.
6. The annual operational and maintenance (**O&M**) cost, including UAG, is estimated by determining the per-GJ O&M cost based on historical data and determining the incremental O&M cost each year based on the per-GJ O&M cost multiplied by the number of new customers and the annual GJ per customer.
7. An allocation of the UAG cost is also included in the estimated O&M cost based on the Average Energy Cost per GJ multiplied by the number of new customers, the annual GJ per customer and our forecast UAG target rates.[79]
8. The PV of the annual O&M costs associated with the future growth and replacement capex for the tariff class is determined using the annual O&M costs associated with the future growth and replacement capex and the forecast WACC value for the upcoming AA.
9. As a final step, we calculate the AIC LRMC for the tariff class by dividing the PV of the growth-related capex and opex by the PV of the annual change in capacity for the tariff.

Our charging parameters for the volume tariff classes include a ‘dollar per annum’, ‘dollar per GJ’ and ‘dollar per GJ of chargeable demand’. To calculate the LRMC for each charging parameter, we assumed that:

- the fixed charge component should recover the cost of dedicated assets and fixed operational costs (i.e. costs that do not vary depending on consumption or demand)
- the variable charge components should recover the cost of shared assets and variable operational costs (i.e. costs that in some way vary depending on consumption or demand).

To calculate its tariff parameter LRMC values, we followed similar steps to the tariff classes above but tailored these for each charging parameter.

[78] See: AER, *Draft decision – Jemena Gas Networks (NSW) Ltd Access Arrangement 2020–25, Attachment 9: Reference tariff setting*, November 2019, p.14.

[79] See *JGN - Att 6.7 - Unaccounted for gas* for how we derived forecast UAG and target rates.