Jemena Gas Networks (NSW) Ltd

2025-30 Access Arrangement Proposal

Attachment 5.1

Capital expenditure

Table of contents

List of appendices

Overview

Worldwide energy systems are undergoing a once-in-a-generation transformation. A growing urgency to reduce emissions is driving global changes in how energy is produced, transported and consumed.

We are not exempt. High levels of uncertainty around the pathway and pace of the energy transition mean that the future role of our network is unclear. How much longer will we transport natural gas? How many of our customers will electrify? What role will low-emission gases like biomethane and hydrogen play? Uncertainty around our long-term role of our network creates a challenge in developing an optimal investment program.

To help navigate this uncertainty, we established an Expert Panel to develop plausible future scenarios for the future NSW Energy System.[1] Each scenario has materially different outcomes by 2050, in terms of both customer numbers, volumes and the uptake of renewable gas. There is no 'business as usual' scenario. In all cases, the plausible future will be materially different. Our investment program for 2025-30 and beyond will not look like the past.

Despite this uncertainty, there is clarity around the three key investment drivers for the 2025-30 period. We must:

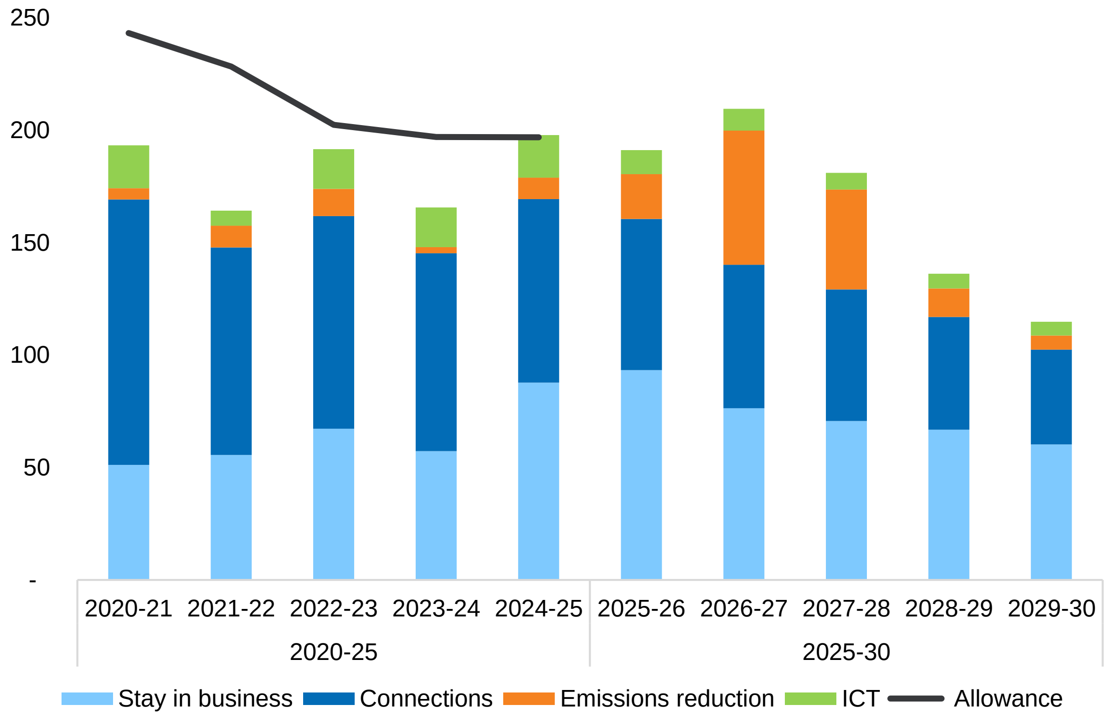
1. **Connect customers and provide access to our network, consistent with our regulatory obligations and customer expectations.** Over the 2025-30 period we will connect 68,829 customers or about 90,000 dwellings, equivalent to a city the size of Newcastle.

2. **Reduce emissions**. We need to play our role in supporting the achievement of the NSW and Australian governments emission reduction targets, consistent with the amended National Gas Objective. We will do this by enabling access to renewable gas (facilitation reductions in customer emissions), moving to direct emissions measurement and reducing emissions from our network activities.

3. **Stay in business, by keeping our network safe and reliable**. Despite the long-term uncertainty around our role, the range of scenarios indicates that customer numbers are unlikely to materially fall before 2030. Our ageing network needs to be kept safe and reliable as long as our customers need us to.

As shown in Figure 1.1 our investment program is about $80 million (9%) lower than 2020-25 capex (which in turn is lower than our current allowance). This is driven by two large shifts both of which are driven by decarbonisation.

Figure 1.1 2020-25 and 2025-30 capex ($2025 millions)



[1] *JGN-KPMG-Att 2.3-Expert Panel Report*.

Table 1.1 Capex over 2020-25 and 2025-30 (Gross, $2025 millions)

	2020-25		2025-30
Category	**Allowance**	**Actual / forecast**	**2025 Plan**
Connections	528.0	474.3	281.8
Emissions: Reducing our emissions	41.0	33.3	59.5
Emissions: Facilitating Renewable Gas	-	5.9	83.4
Stay in business: Metering	152.2	112.3	169.4
Stay in business: Excluding Metering	227.3	206.7	198.0
ICT	119.2	80.1	40.3
Total	**1,067.7**	**912.7**	**832.5**
Total (Excluding ICT)	**948.5**	**832.6**	**792.1**

Note: We present a total excluding ICT costs, as some of these costs while treated as capex in the 2020-25 period will be treated as opex in the 2025-30 period.

Reduction in connection capex

The first shift is the $192.5 million reduction in connection capex. This is primarily due to decarbonisation of the electricity system, policy changes and shifts in consumer preferences. These changes reduce the proportion of new dwellings which will connect to our network. 2025-30 connection numbers are forecast to be 41% lower than experienced over the 2020-25 period.

We have been able to maximise the reduction in connection capex through our long-standing efforts to reduce costs. For example, our forecast includes:

- $65.2 million in unit cost reductions, relative to our current costs.
- $7.1 million reduction in gross capex, or a $10.3 million reduction in net capex (after customer contributions), as a result of our proposed changes to our Model Standing Offer.
- $32.1 million reduction driven by our existing strategy to introduce a volume boundary meter option for high-rise developments.

In the absence of our strategies, connection capex would be $104.5 million higher (or $107.7 million in net terms).

Supporting emissions reductions

The second shift is the $103.7 million increase in investment to support the achievement of NSW and Australian Government emission reduction targets. This has two parts:

1. $59.5 million to reduce our emissions by replacing ageing mains, installing catalytic heaters, and reduce operating pressures across our network. We expect this program to deliver $237.2 million of value, primarily (but not entirely) from emissions reductions.
2. $83.4 million to facilitate the uptake of renewable gas and displace natural gas. Our program will enable complementary third-party investment leading to significant reduction in emissions. This will lead to the annual injection of 6.7 PJs of biomethane into our network reducing emissions by 347,000 tCO2 a year decarbonising 8.3% of the energy we transport by 2030. It will also contribute 1% and 0.4% of the decarbonisation required to achieve the NSW and Australian emissions reduction targets. The net present value of this program is $1.4 billion of value, primarily driven by emissions reductions.

The value of emissions reductions delivered by our program exceeds the cost of our investment and achieves the National Gas Objective.[2]

Keeping our network safe and reliable

Amid all this change, we have been able to constrain capex by reducing or holding steady the level of investment required across most of our program. This is an achievement given that our network, despite the headwinds we face, will continue to grow (in terms of assets in the ground) and that several critical components, including our high-pressure gas mains and facilities, mostly built in the 1970s and early 1980s (40 to 60 years ago), are reaching end of life.

The exception is our meter replacement program. To date, we have been able to materially reduce meter replacement capex through statistical sampling and life extensions. However, our meters are mechanical devices which will wear, become inaccurate over time and require replacement. Over the 2025-30 period, we will need to increase our level expenditure to ensure that customers' bills remain accurate.

Despite applying optimistic forecasting assumptions on future performance of our meters (taking on significant forecasting risk) and embedding in $17.2 million of unit rate reductions, we still expect to increase investment by $57.1 million over the 2025-30 period.[3] While an increase, our forecast remains below the long-run average level of expenditure required to maintain a metering fleet for a network of our size.

ICT

It is difficult to compare ICT costs on a period-on-period basis by looking only at capex, as cloud implementation and customisation costs have been treated as capex in the 2020-25 period but will be treated as opex in the 2025-30 period. Further details on our ICT projects are set out in *JGN-Att 5.4 Technology Plan*.

We have also taken into account the interaction between our ICT and network capex forecast. In particular, we considered the improved ICT capabilities proposed for the 2025-30 period and how they can help us avoid, defer or reduce the costs of our network projects. Further details are included in the ICT investment briefs[4] and in section 1.2.

Uncertainty beyond 2030

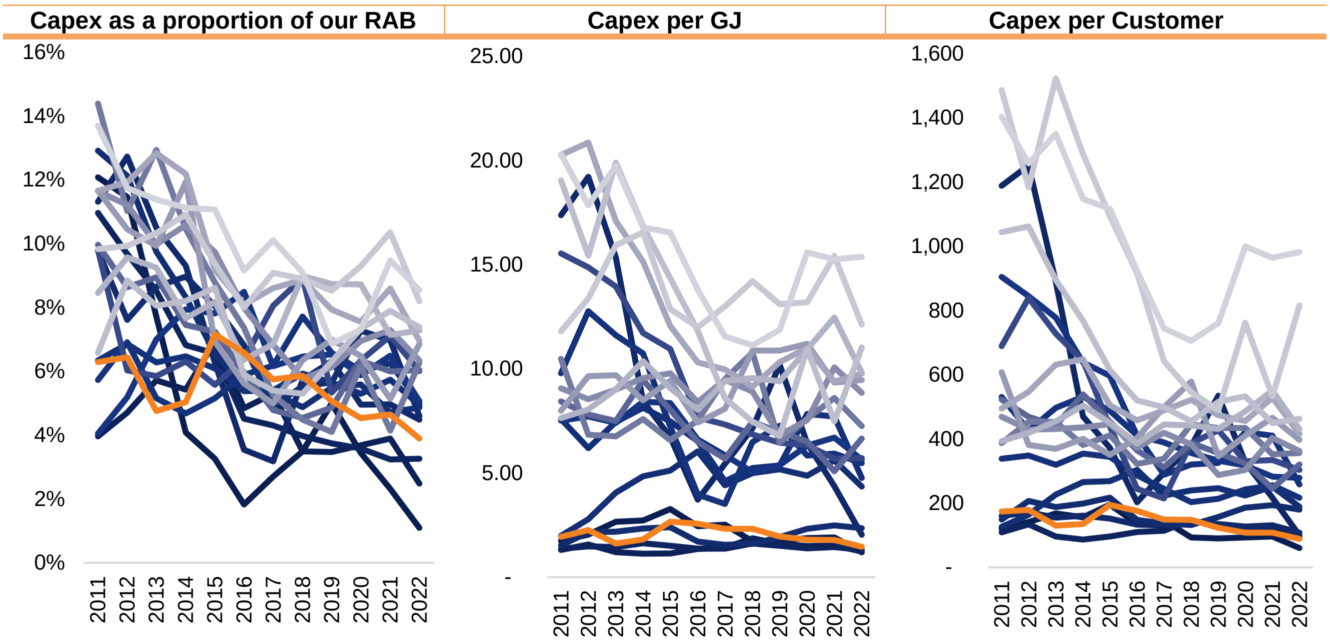
While we have certainty over 2025-30, the plausible future energy scenarios highlight the risk that if our customer numbers and volumes significantly decline, we will likely see material increases in customer prices. It is imperative that we keep capex to a minimum.

However, this is not new. As a provider of a fuel of choice, we have always been conscious of the price implications of our expenditure. Given the risks around the future of gas, over the last 10 years we have implemented a series of measures to constrain capex.

Our success is illustrated by our capex relative to all the 20 other energy networks regulated by the AER. Over the past 5-years, our reducing capex has been the 4th lowest relative as a proportion of the RAB, 4th lowest in terms of energy transported and 2nd lowest on a per customer basis. This is shown in Figure 1.2.

[2] Calculated consistent with the Energy Minister's statement about the interim value of greenhouse gas emissions reduction. See here.
[3] As outlined in sections 4 this is due to $17.1 million in unit cost reductions (relative to our costs in 2022/23) and $30 million by deviating from our usual historical average approach for industrial and commercial meter unit costs.
[4] *JGN-RIN Att 4.3.5.*

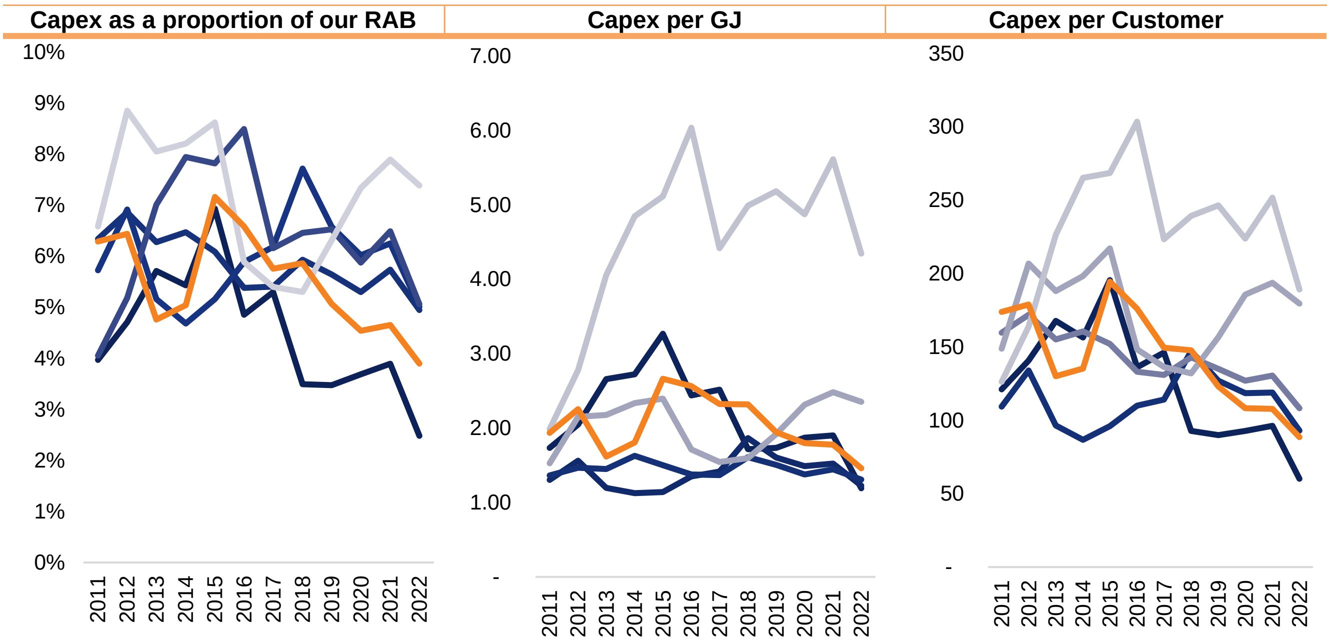
Figure 1.2 AER regulated energy network capex ($2022), JGN in orange, gas and electricity businesses



The pattern holds true when we limit the comparison to other gas businesses, as shown in Figure 1.3. We have the second lowest capex as a proportion of our RAB as well as on a per customer basis. On a per GJ basis our capex is only marginally above the network with the lowest capex, despite significantly lower heating loads (and in turn throughput) than other businesses which operate in colder climates.

These metrics indicate that JGN has one of the lowest capital intensities of all energy networks regulated by the AER – gas or electricity. This is consistent with CEG's benchmarking results which found that JGN consistently ranks in the top 2 or 3 of gas distribution businesses benchmarked using Multilateral Total Factor Productivity, Total Factor Productivity, and Capital Partial Productivity and Multilateral Capital Partial Factor Productivity indices.[5]

Figure 1.3 AER regulated energy network capex ($2022), JGN in orange, gas only



[5] *JGN - CEG - Att 6.4 - Relative efficiency and forecast productivity growth of JGN.*

We have been able to constrain capex, through discipline, best practice asset management and customer strategies. Where possible we adopt targeted risk-based approaches to extending the life of our existing assets, defer investment, adopt reactive approaches or manage risks with operating expenditure solutions. Our stay in business program is lean and limited to items required to maintain the safety and reliability of our network and to comply with regulatory obligations.

For example, there is a real increasing likelihood that third parties will seek to blend hydrogen into our network over the next 5-years. However, we have not included any hydrogen readiness projects in our proposal, even though some projects may be required within the period (noting that we cannot unreasonably refuse a connection).

Given our low levels of investment for an energy network of our scale, age and criticality there are limited opportunities to reduce capex further. Despite the future uncertainty around our network's role, we need to keep the community safe and ensure that we can continue to provide reliable services for as long as our customers depend on us.

Further information

This document supplements Chapter 5 of our 2025 Plan. It provides further context and background to support the detailed technical material provided in project and program specific materials.

As set out in Table 1.2 further information is available in attachments to our 2025 Access Arrangement (**AA**) Proposal together with our response to the AER's Regulatory Information Notice (**RIN**). A more detailed mapping of our documentation is provided in our Document Index.[6]

Table 1.2 List of capex supporting information attached to our RIN response

Category	Documentation
Overarching documents	• Asset Class Strategies (for Facilities, Pipelines, Networks, Measurement, Fleet, Property and SCADA) • Connections and Metering Forecast Methodology • Jemena Infrastructure Cost Estimation Methodology • Pipeline Integrity Program • Minor Capital Works Plan • Capex forecast model
Connections	• Connections Capex Forecast Model
Emission reduction	• Emission reduction program • 1 Opportunity Brief • 21 Project estimating model outputs • 13 Business Cases with supporting Costs and Benefits Analysis Models • 4 Option analysis with supporting Costs and Benefits Analysis Models
Stay in business (Excl. Metering	• Network Pressure Management Plan • SOCI Jemena Gas Network Requirements Overview • JGN Property Capex Program 2025-30 • Fleet Model • 1 Opportunity Brief • 39 Project estimation model outputs • 2 Business Cases with supporting Costs and Benefits Analysis Models • 23 Option analyses with supporting Costs and Benefits Analysis Models

6 *JGN-RIN-Att 19-Document Index*.

Category	Documentation
Stay in Business Metering	• Meter Replacement Plan • Metreteks Replacement Plan • MDL Replacement Plan • Meter Replacement Capex forecast model • Meter Replacement Volume forecast model • 6 Project estimation model outputs • 1 Business Case
ICT	• Technology Plan • 10 Investment Briefs with supporting Costs and Benefits Analysis Models

All capex in this document is presented on a direct costs June $2025 basis unless otherwise stated to ensure all capex is shown on a like-for-like basis.

Supporting attachments

Table 1.3: List of supporting attachments

Attachment	Name	Author
2.2	Customer forum engagement report	BD Infrastructure
2.3	Expert Panel Report	KPMG
2.4	Advisory Board Report	KPMG
4.1	Emissions reduction program	JGN
5.2M	Capital expenditure forecast model	JGN
5.4	Technology plan	JGN
6.2	Opex step change justification	JGN
6.4	Relative efficiency and forecast productivity growth of JGN	CEG
8.2	Demand Forecast Report	Core Energy
RIN 4.3	Jemena Infrastructure Cost Estimation Methodology	JGN
RIN 4.3.5	ICT investment briefs	JGN
RIN 4.4	Emissions Monitoring – Picarro – CBAM	JGN
RIN 19	Document Index	JGN

1. AER Expectations

The AER has developed expectations for businesses capex proposals. These expectations have been at the forefront of our mind in preparing our 2025 Plan. Below we outline how we have met each of these expectations.

1.1 Top-down testing of the total capex forecast and at the category level

The AER considers that comparing a business's total capex forecast can be a reasonable starting point for a top-down test[7] and identifies four expectations to consider.[8] Our proposal achieves each of these expectations as summarised in Table 1.1.

Table 1.1 AER Top-down testing expectations

AER Expectation	Our proposal
Demonstrate total forecast capex is not materially above current period spend.	**Achieved**. Our capex program (excluding ICT) is 5% lower than 2020-25 spend. We have excluded ICT in this comparison, as a portion of this spend is shifting to opex for the 2025-30 period. Analysis of our ICT spend from a total capital and operating expenditure (totex) perspective is set out in our Technology Plan.[9] We note that while decarbonisation is driving a reduction in connection capex it is also driving an increase in emissions reduction expenditure.
Explain where there is a material underspend and forecast step up from the revealed level.	**Achieved**. The only category where there is a material underspend in the 2020-25 period with a step-up is with Stay In Business: Meter Replacement. As outlined in section 4, this is largely due to the remarkable performance of our meters which allowed us to extend specific meters lives. Meter replacement capex increases in the 2025-30 due to the age profile of our meters, but remains below the long-term average required replacement rate.
Top-down testing of forecast recurrent spend against historical actuals at the category level.	**Achieved**. We have tested each category against historical levels of spend. Further, 60% of our program is forecast based on revealed expenditure (connections, metering and minor capex) using historical average spend or historical unit rates. We have made no adjustment to our unit rate forecasts based on 4-year average of historical costs, despite the large post-COVID-19 increase in costs we and others have experienced.
Explain why new categories of spend are required.	**Achieved**. A new category of spend—Emissions reduction—is required for the 2025-30 period to be align with the amended National Gas Objective (NGO). Further details on the basis for this expenditure is provided in Attachment 4.1. Note that to a degree we have always undertaken expenditure which reduces emissions. Given the increased emphasis on reducing emissions we have recategorised historical expenditure into this new category. Further details are provided in section 3.6.

A summary of the application of our top-down testing by category is shown below in Table 1.2.

[7] The AER notes that top-down tests are less useful where capex is predominately made up of large non-recurrent projects or where a capital efficiency sharing scheme is not in place. This is not the case for our forecast.
[8] AER 2021, Better Resets Handbook – Towards Consumer Centric Network, December, pp. 19–23. Available here.
[9] *JGN-Att 5.4-Technology Plan*.

Table 1.2 Top-down and category level testing of our 2025 Plan

Category	2020-25 Allowance	2020-25 Actual / forecast	2025-30 2025 Plan	2025 Plan versus revealed spend
Connections	528.0	474.3	281.8	↓
Emissions: Reducing our emissions	41.0	33.3	59.5	New
Emissions: Facilitating Renewable Gas	-	5.9	83.4	New
Stay in Business: Meter Replacement	152.2	112.3	169.4	↑
Stay in business: Excluding Metering	227.3	206.7	198.0	↓
ICT	119.2	80.1	40.3	N/A
Total	1,067.6	912.7	832.5	↓
Total (Excluding ICT)	**948.5**	**832.6**	**792.1**	↓

1.2 Evidence of prudent and efficient decision-making on key projects and programs

The AER expects that businesses demonstrate prudence and efficiency in decision-making. In our case, there are two layers to this. First, the prudence and efficiency of specific projects and programs. Second, the prudence and efficiency of our program as a whole, in light of the uncertain future of gas. We have also sought to understand and consider customer preferences (which informs prudency and efficiency) in our decision making process, as discussed in section 2.4.

Prudence and efficiency of specific projects and programs

In Table 1.3 we summarised how we have met AER expectations in respect of non-recurrent projects.

Table 1.3 AER expectations of prudent and efficient decision for non-recurrent projects

AER Expectation	Our proposal
Identification and evidence of the need for expenditure	Non-recurrent projects are supported by a suite of Options Analysis and Business Cases which articulate the issue or opportunity, the feasible options, the costs and associated risks of each option and the basis for the preferred option. This typically includes a base-case (or status quo) as well as, where appropriate, deferral.[10]
Quantitative cost benefit analysis assessing all feasible options (including non-network options) which show that the preferred option maximises net benefits.	Each Options Analysis and Business Case is supported by a Cost and Benefits Analysis Model which supports our evaluation of the feasible options. This model produces the net present value of each option relative to the base case. Where appropriate, for example with our emissions reducing mains rehabilitation projects, the costs and benefits are calculated in a supporting spreadsheet which provides the inputs to our Costs and Benefits Analysis Models. The cost of the preferred option is supported by a 'Project Estimation Model' produced by our Front End Engineering Design (FEED) team which produces the best possible estimate of costs in the circumstances.[11] Note while we have submitted Options Analyses and Business Cases these documents have the same content and serve the same purpose.
Account for the trade-off between capex and opex.	At a project level we consider the viability of opex and capex solutions, with the base case generally being to continue to bear the risk or use opex to undertake reactive repairs.

[10] Note that deferral is not always a feasible or useful option to consider. For instance, where the status quo results in unacceptably high risks or is not consistent with standards or regulatory requirements a deferral option does not add significant value to the options assessment.
[11] Consistent with Rule 74.

	By definition our capex proposal only includes issues or opportunities where a capital solution has been identified as the best approach. However, this does not mean that we always select, or even prefer, capital solutions. As we outline in section 5 we adopt a reactive approach for a material proportion of our assets in service and where we do deploy capital solutions, we apply targeted risk-based approaches to constrain expenditure. At the program level, we have considered the trade-off between capex and opex. Key examples include: • the removal of projects (Kotara mains augmentation and Auburn mains rehabilitation which were included in our Draft 2025 Plan) and the inclusion of efficiencies (metering and connection unit rates) on the basis of improved ICT capabilities (Network Management Advanced Analytics and Works Management Schedule Optimisation).[12] • the interaction between our shift to direct emissions measurement[13] and the likely increase in opex (leak repairs) and mains rehabilitation (capex). While these costs are included and taken into account in the direct emissions measurement business case, given their uncertainty along with the uncertainty about the revealed level of actual emissions[14] these costs have not been included in our forecast.

For our recurrent programs, while we outline the need for the expenditure, our submission focusses on setting out the basis for our forecast. For example, while the need to replace inaccurate meters is clear (as we must replace an inaccurate meter to comply with our regulatory obligations), forecasting when we will need to replace each meter is more complex. Accordingly, our documentation for our connection, metering and minor capex programs provides evidence that our forecasts are arrived at on a reasonable basis, represent the best forecast possible in the circumstances and that forecast costs are efficient.[15]

Efficiency and prudency of our program as a whole

To develop the capex forecast which underpins our 2025 Plan, we started with our existing program of work and long-term forecasts of expenditure. This plan was then challenged, tested and refined over a 2-year process through several concurrent processes:

1. Bringing forward our usual strategy, analysis and investment decision making processes, including governance, prioritisation and quality assurance. This ensures that, to the extent possible, we produce and submit documentation akin to what we normally prepare prior to making an investment decision. The key difference is that the documentation for this process is required to be prepared up to 7 years in advance.

2. Undertaking additional internal challenge and review at the total, category, program and project level, in light of the long-term uncertainty around the future of gas.

3. Delivering our Gas Networks 2050 engagement program with several key components including:

    a. Plausible future energy scenarios developed by an Expert Panel to help inform our planning and focus for the 2025-30 period.[16]

    b. Future of gas initiatives filtering undertaken by our Advisory Board,[17] which occurred before we engaged customers. This included initiatives such as replacing assets at a slower pace,

[12] See IT Investment Briefs Work Management Schedule Optimisation (*JGN – RIN – 4.3.5 ICT Investment Brief - Work Management Extend Phase*) and Network Management Advanced Analytics (*JGN – RIN – 4.3.5 ICT Investment Brief - Network Management Advanced Analytics*).
[13] *JGN-RIN- Att 4.4 - Emissions Monitoring*.
[14] As outlined in *JGN-Att 4.1-Emissions reduction program* we currently report on emission using likely inaccurate generic emissions factors.
[15] Consistent with Rule 74.
[16] *JGN-KPMG-Att 2.3- Expert Panel Report*.
[17] *JGN-KPMG-Att 2.4-Advisory Board Report*.

accelerating to 10% hydrogen capability, supporting renewable gas (with a focus on biomethane in the near term) and increasing customer contributions towards connections.

c. Engaging our Customer Forum to understand customer preferences and key considerations.

4. Participating in the AER's Early Signal Pathway, where the AER and its Consumer Challenge Panel have provided feedback on our draft proposal and key components.

The impact of these processes can be seen in Table 1.4Table 1.3, which identifies the program at four key points along its development. While each iteration includes a multitude of changes, refinements and updates the overall impact of these four processes can be seen in Table 1.4 which shows an overall reduction of 11% (excluding ICT) in our capex forecast over the 24-month period. Key examples of this include:

- Customer feedback For example, our customer forum indicated that they did not support our proposed improvements to improve digital communications. This project was removed from our ICT program.

- AER Early Signal feedback on whether the program and specific categories (such as 'Other') capex met the AER's expectations with respect to top-down testing. This triggered an additional internal review of these categories and further prioritisation of our program. For example, we removed the plan to build a new South West Depot ($12 million) – which is a key driver of the reduction in Stay in Business spend between the draft and 2025 Plan.

These factors were not the only drivers of change. Our program was continually updated based on the latest data available (such as the connections forecast), the correct accounting treatment of spend and the timing of key projects. The updated timing of a project is what drove the increase in Emissions: Facilitating Renewable Gas, as some costs moved from RY25 into the 2025-30 period.

Table 1.4 Development of our 5-year forecast for the 2025 Plan ($2025 millions)

Category	Starting point *January 2023*	Early Signal Pathway #1 *November 2023*	Draft Plan & Early Signal Pathway #2 *January 2024*	2025 Plan *June 2024*	Overall Change
Connections	324.6	269.5	269.0	281.8	-13%
Emissions: Reducing our emissions	67.3	84.4	62.5	59.5	-12%
Emissions: Facilitating Renewable Gas	86.2	67.7	74.0	83.4	-3%
Stay in business: Excluding Metering	233.4	243.1	231.5	198.0	-15%
Stay in Business: Meter Replacement	174.3	178.5	184.0	169.4	-3%
ICT	104.8	109.3	109.0	40.3	-62%
Total	990.7	952.4	930.0	832.5	**-16%**
Total (Excluding ICT)	**885.9**	**843.0**	**821.0**	**792.1**	**-11%**

1.3 Evidence of alignment with asset and risk management standards

The AER expects businesses to provide evidence that their asset and risk management are consistent with well-established relevant Australian industry standards.

Overall, our Asset Management System is designed on the principles of continuous improvement (adopting the method of Plan, Do, Check and Act) and is ISO 55001 certified. In addition to ISO 55001, JGN's systems for safety, environmental, quality and risk management comply with good industry practice. We maintain accreditations for AS/NZS 4801 Occupational Health and Safety Management Systems, ISO 14001:2015 Environmental Management Systems, ISO 9001:2015 Quality Management Systems, and AS/NZS ISO 31000:2009 Risk Management Standard.

Our suite of documentation highlights the project / program relevant standards and regulatory obligations which drive our investment program. We list the key elements below.

Connections

Our approach to connecting customers to our network is driven by our obligations in Part 11 and Part 12A of the National Gas Rules which govern how access to our network is provided. Key obligations include providing access if requested,[18] having a standing offer to provide basic connection services to retail customers,[19] and complying to the connection charges criteria in setting customer contributions.[20]

Emissions

Our approach to reducing emissions has been developed in line with customer, community, investor and government expectations that we reduce emissions and support the achievement of both Australian and New South Wales emission reduction targets

Playing our role to reduce emissions is consistent with the achievement of the amended National Gas Objective, our obligations under the Safeguard Mechanism and is consistent with global and Australian good industry practice (as well as good practice outside of the gas industry). Further, our approach to reducing fugitive emissions on our network (see section 3.2.1) is consistent with the Australian Government's commitment with the Global Methane Pledge. See attachment 4.1, *Achieving emissions reductions through our 2025 Plan* for further details on the community, policy and regulatory context in which we operate.

Stay in Business Metering

The primary focus of our metering spend is to ensure that we provide the Transportation Reference Service which customers pay for, which specifically includes the provision and maintenance of a standard metering installation along with the transportation of gas.

We manage our metering assets to comply with relevant accuracy standards (including obligations set out in Gas and Electricity (Consumer Safety) Regulation 2018 Schedule 4 and National Measurement Act 1960 (sections 18GD and 18GE). To assess the performance of our meters we test our meters consistent with Australian Standards (AS/NZS 4944:2006 Gas Meters – In-service compliance testing, AS 1199:2003 Sampling procedures for inspection by attributes).

Stay in business (excluding metering)

Our Stay in business expenditure is focussed on maintaining the safety, integrity, reliability, and performance of our extensive network by adopting best practice standards. Relevant standards include (but are not limited to):

- AS/NZS 2885: This Australian Standard sets out requirements and guidelines for the design, construction, testing, operation, maintenance and risk management of pipelines used to transport gas. This standard applies to our high-pressure mains and facilities which operate at 1050 kPa or above.

- AS/NZS 4645: This standard governs the design, construction, operation, and maintenance of gas distribution networks, ensuring safe and efficient delivery of gas to consumers. This standard applies to our mains and network at or below 1050 kPa.

[18] Rule 105E. We note that we are not required to provide an offer under certain conditions (if it is not technical feasible or consistent with the safe and reliable operation of the pipeline). Notably, this requirement applies to covered gas (rather than natural gas) which means we have an obligation to provide access to a user or prospective user seeking to inject hydrogen (as long as the conditions are met).
[19] Rule 119B
[20] Rule 119M

- AS/NZS 3788 / 4041: This standard provides the means for conformance for the design, inspection, maintenance, and monitoring of in-service pressure equipment to ensure ongoing operational safety. This standard applies to our above and below ground pipework at our facilities.

- AS/NZS 60079: Series of standards concerning the equipment for explosive atmospheres, focusing on installation and protection concepts for ensuring safety in hazardous areas. These standards cover equipment installed at our facilities.

- AS/NZS 3000 (Wiring Rules)**:** This standard sets out the requirements for the electrical installations, ensuring safety against electric shock and fire. It is crucial for the installation, maintenance, and verification of electrical installations within our facilities.

- Electrical (Consumer Safety) Act 2004 and Electrical (Consumer Safety) Regulation 2006: These requirements govern electrical safety in consumer products and installations and are particularly relevant to the electrical and control equipment at our facilities.

1.4 Genuine consumer engagement on capex proposals

As outlined earlier, in preparing our 2025 Plan we engaged our customers through an extensive program and forums made up of residential and business customers. The residential Customer Forum provided the following values on what they considered to be the most important in considering various initiatives:

- **Affordability** – We heard that balancing the rising cost of living is a priority for our customers so that no one is left behind due to the energy transition. Our customers want us to consider affordability over the short and long-term when making decisions.

- **Reliability and safety** – We heard that customers want a safe and reliable gas service.

- **Fairness** – Our customers want us to consider fairness in context of the energy transition, and its impacts on both existing and future generations, and on our more price-sensitive customers.

- **Access to the gas network (Choice)** – We heard that customers want the choice to be able to use gas both now and into the future, and that there should be diversity of supply.

- **Environment** - We heard from customers that they want us to contribute to a more sustainable environment in the future.

We have taken these values into account in developing our 2025 Plan. Our capex proposal will deliver continued reliability and safety while constraining costs to maintain affordability. We will also take action to play our part in reducing emissions and contributing to the NSW and Australian government emissions reduction targets.

We also engaged customers on several specific initiatives[21] several of which affected capex including:

- The approach towards renewable gas. This is considered further in section 3 and *JGN-Att 4.1-Emissions reduction program.*

- Adopting a targeted approach to mains rehabilitation. This has been incorporated into our approach to reducing our emissions via mains rehabilitation, see section 3.2.3 for further details.

- Using Picarro technology to support the reduction of emissions on our network. This is discussed in section 3.2.4 and *JGN-Att 4.1-Emissions reduction program.*.

- Changing our approach to connection charges. This has been reflected in our connection capex forecast, see section 2 for more details.

[21] See chapters 2 and 3 of our 2025 Plan.

- Replacing difficult to access meters with digital meters to ensure that we can regularly read meters. This program is further outlined in section 4.7.
- Improving digital communication options. This program was not supported by customers and has been removed from our forecast.

2. Connections

Although we are forecasting connection capex[22] to reduce by 41%, it will remain the largest part of our 2025-30 capex program.

Connecting new customers benefits all customers by allowing us to spread our largely fixed costs across more customers. It also ensures equal and fair access to the benefits of gas specifically, a lower emissions source of energy (compared to grid electricity in NSW),[23] a source of instantaneous heat (for space heating, continuous flow hot water and cooking), as well as the security and reliability from having dual gas and electricity connections.

Given the uncertainty around the future of gas, there is a risk that we connect customers who, due to government and consumer preferences for alternative sources of energy, subsequently disconnect before we have recovered enough revenue to cover the cost of their connection. This will leave our remaining customers with a higher asset base and, in turn, higher bills.

Stopping new connections altogether is not supported by our customers and is not possible under the regulatory framework in which we operate. Specifically, we cannot unreasonably refuse access to our network.[24] There are limits to how much we can charge retail customers to connect to our network. Specifically, we can only charge retail customers to the extent to which costs of their connection are higher than revenue we expect to earn.[25] As long as the regulatory framework requires us to connect customers to our network, we will continue to incur this expenditure.

We have introduced a range of initiatives which seek to lower the capital intensity of new connections while retaining the bill reducing benefits they provide. For instance, our strategy to offer apartment buildings a single connection (rather than individually meter each dwelling) has reduced 2025-30 forecast capex by $32.1 million.

We intend to continue to constrain and reduce costs were possible. Accordingly, our proposed capex accounts for $65.2 million in unit cost reductions, relative to our 2022-23 costs.

We have also proposed changes to our Model Standing Offer (MSO)[26] which sets out the terms and conditions for the establishment of basic residential connections to our gas distribution network. We expect that this will reduce net capex by:

- $7.1 million due to a reduction in connection numbers, as some applicants will choose not to proceed with a connection. This reduction has been included in an independent demand forecast produced by Core Energy & Resources (Core) and in turn our connections capex forecast.
- $3.2 million due to an increase in the contribution customers contribute towards their connection.

Additionally, we expect that the proportion of new homes built which connect to our network will fall. This is primarily due to decarbonisation of the electricity system and shifts in consumer preferences.

Table 2.1: Connections capex ($2025, Millions)

	2020-25		2025-30
	Allowance	Actuals/estimate	Forecast
Connections capex (gross)	528.0	474.3	281.8
Contributions	12.5	47.4	13.4
Connections capex (net)	**515.5**	**426.9**	**268.4**

[22] Connection capex is justified under Rule 79(2)(c)(iii).
[23] *JGN-Att 4.1-Emissions reduction program*.
[24] Rule 105E.
[25] Rule 119M sets out the connection charges criteria we must comply with in making connection offers to connection to retail customers.
[26] In May 2024, we submitted to the AER for its review proposed revisions to JGN's Model Standing Offer. The revisions to the Model Standing Offer reflect changes to JGN's connection policy so that fewer customers qualify for a free connection.

2.1 Proposed changes to our Model Standing Offer

Our current MSO requires that we provide basic connections free of charge. Basic connections are those that satisfy specific requirements[27] and do not require significant augmentation of our network. Approximately 70% of new connections to our network are basic connections.

As part of our drive to reduce our capex and minimise the growth of our asset base, we engaged our customers to understand whether they support us making changes to our MSO to require more customers to make an upfront contribution to connect to our network. Asking new customers to make an upfront payment will also mean that some customers will choose not to connect to our network.

Our Advisory Board was supportive of testing this initiative with our customers, noting that it would help to minimise the growth in our asset base. In engaging a number of stakeholders as well as our Customer Forum we heard a mix of views, with some caution in terms of reducing growth in customer numbers, but most customers were in support of a medium to high upfront contribution to connect. Participants from our Customer Forum supported us charging customers more to connect to our network; however, they were concerned that if the charge was too high, some customers might not be able to afford to connect to our network. They understood that more customers connecting to our network means a greater customer base over which to spread the recovery of our largely fixed costs.

We tested three options with customers:

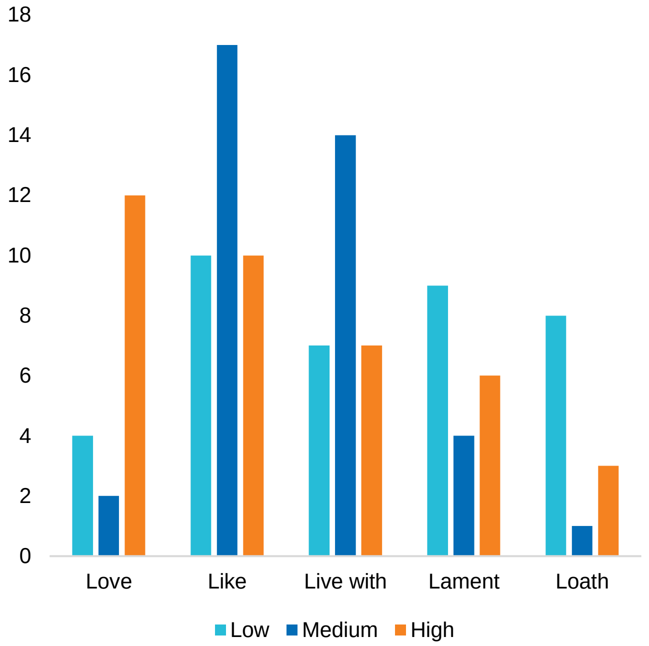
1. Low contribution – a large portion of costs of each new connection is shared by the broader customer base.

2. Medium contribution – some costs are shared across customers.

3. High contribution – a small portion of costs of each new connection is shared by the customer base.

In the final voting customers expressed a preference for the ‘medium’ option see Figure 2.1. Notably, while the Low and High option had more customers who ‘loved’ these options they also had a large number ‘lamenting’ or ‘loathing’ these choices.

Figure 2.1 Customer Forum voting for low, medium and high contribution options[28]



[27] These are set out in Annexure A of our current MSO available here
[28] *JGN-BD Infrastructure-Att 2.2-Customer forum engagement report*.

In line with the feedback we have received from customers, we will adopt a 'moderate' approach. To implement this, we have proposed to change our MSO in May 2024. These changes need to be approved by the AER before they are adopted.

Under our proposed changes to the MSO, we will continue to provide basic connections at no charge. However, we will limit the kind of connections eligible to those which only require a meter kit to be installed. Connections which require a mains extension or service to be installed will no longer automatically qualify. Instead, we will individually assess each connection, consistent with the connection charge criteria in the rules, to determine if a charge should be levied. In some cases, a proportion of the costs to connect a new customer may still be shared by the broader customer base.

As we outline below, our proposed changes to the MSO have been factored into our forecast of new customer numbers as well as our customer contribution forecast.

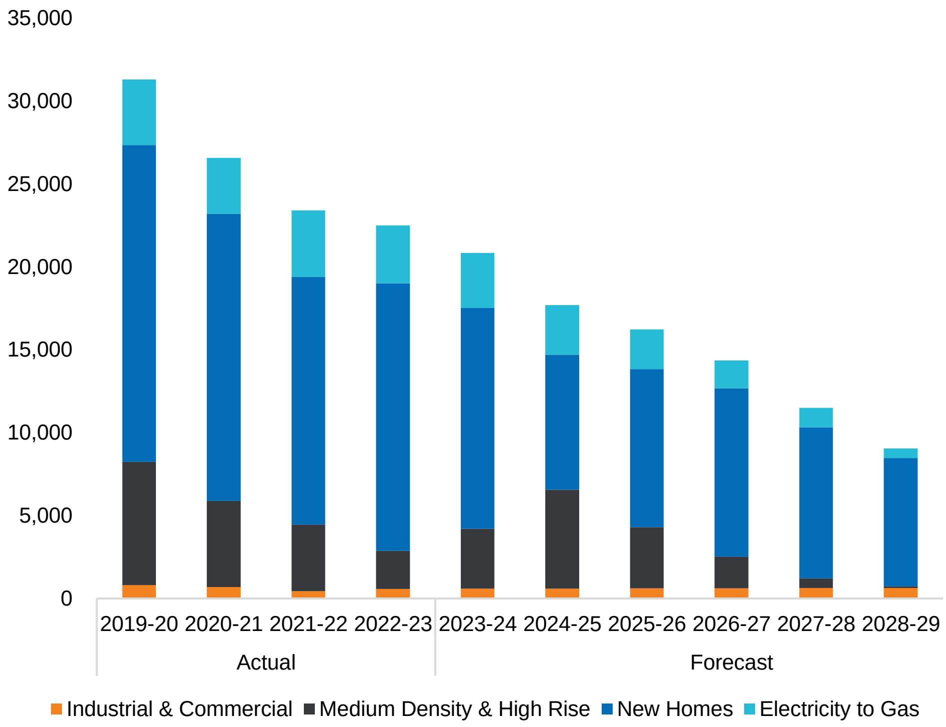
2.2 Forecast volumes

For our 2025 Plan, we engaged Core to develop an independent forecast of the number of new connections.[29] Core has forecast fewer connections to our network over the 2025-30 period compared to the current plan period. Core forecasts that we will connect approximately 69,000 new connections, which is lower than the 125,000 we expect to connect over the current period, as shown in Figure 2.2.

Core's forecast takes into account factors such as:

- Recent changes to building standards which encourage new households to use electric rather than gas appliances – this represents a reversal of previous standards which created incentives for new households to connect to gas.
- Changes to our MSO, which will require more customers to make an upfront contribution in order to connect to our network.

Figure 2.2 Actual and Forecast Connection Numbers by connection type



[29] *JGN-Core Energy-Att 8.2-Demand Forecast Report.*

2.3 Unit rates

To forecast the cost of connecting each customer, we apply a connection cost forecasting methodology initially developed as part of the 2015-20 remittal process and which we subsequently applied for the 2020-25 period.[30]

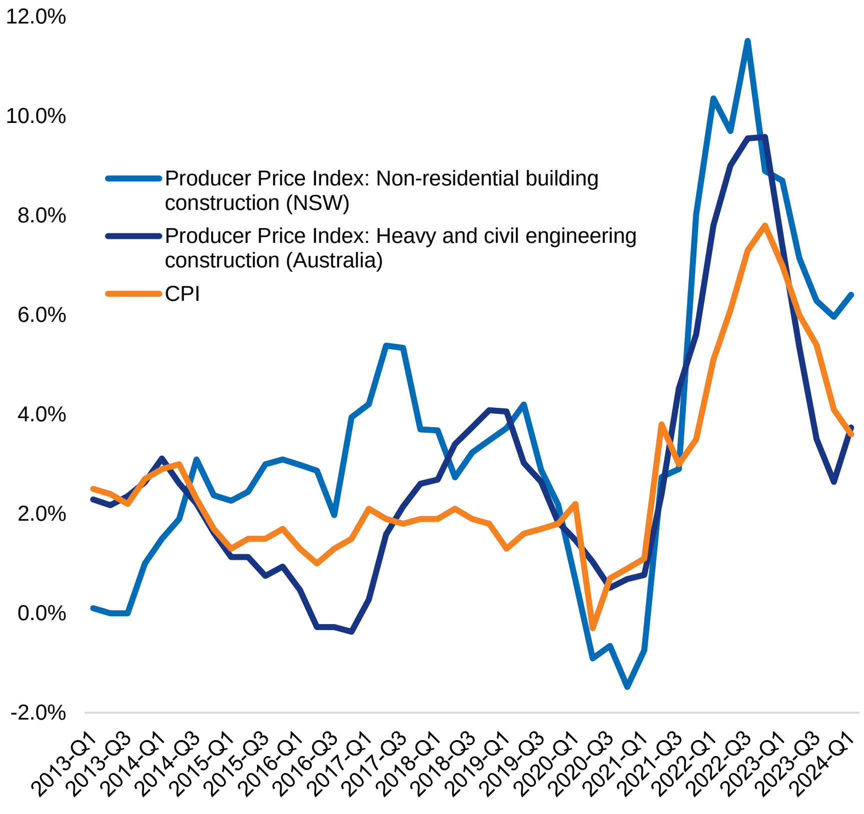
We have forecasts costs based on historical unit rates and volumes (the number of mains, services and meters per connection) averaged over a 4-year period to smooth out year-to-year movements in costs, which can vary depending on the nature of the connections made in each year.

This approach was developed in a low inflationary environment where costs over the 4-year period were relatively stable. However, since COVID-19 there has been significant cost pressure across the economy and particularly above-inflation cost pressures in energy and civil construction sectors.[31] This is reflected in:

- The ABS's Producer Price Indices for the 'heavy and civil engineering construction'[32] (which includes activities such as pipeline construction) and 'non-residential building construction'[33] which both increased much faster than CPI since COVID, as shown in Figure 2.3.

- AEMO's 2023 Transmission Expansion Options report which found that transmission infrastructure construction costs had increased by 30% in real terms between the 2022 and 2024 Integrated System Plans.[34]

Figure 2.3 Consumer Price Index and relevant Producer Price Indices

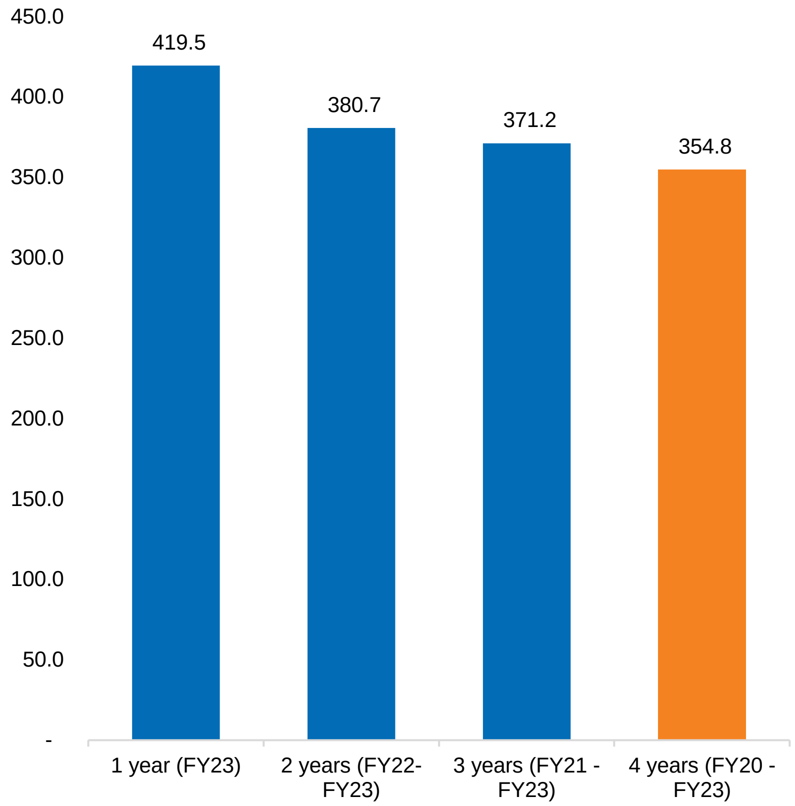


As a consequence, there is a significant difference in the cost we incurred at the start of the 4-year period (2019-20, starting in 2019 Q3) and the end (2022-23, ending in 2023 Q2), noting that 24 data is not yet available but will be for our revised proposal.

[30] Further explanation of our method is set out in *JGN-RIN-Att 4.3 - Connection and Metering Forecast Methodology.*
[31] This is due in part to the large increase in the infrastructure pipeline both as a whole and with respect to the energy sector. See a forecast for the future here.
[32] This includes pipeline construction but is only available for Australia (no NSW specific data).
[33] Building construction available with NSW specific data.
[34] AEMO 2023, *Transmission Expansion Options Report for the Integrated System Plan (ISP).* Available here.

We have calculated the difference in connection capex, depending on the averaging period used. As shown in Figure 2.4, if we had used only RY23 data – effectively data which reflects our current costs – our capex forecast would be $65.2 million higher.

Figure 2.4 Forecast connection capex based on each averaging period ($2025) (prior to overheads and cost escalation)[35]



We have not sought to make an adjustment to this data to reflect the increase in prices over the period. However, we note that to reduce costs below what we are currently experiencing we will need to rely on the additional ICT capabilities we are proposing to deliver over the 2025-30 period, such as the Works Management Schedule Optimisation and Network Management Advanced Analytics.[36]

2.4 Contributions

As outlined above, our proposed changes to the MSO will lead to a reduction in connections and an increase to contributions. The former has been considered by Core in producing a connection forecast for the 2025-30 period (which flows through into our connections capex forecast).

The changes to the MSO will mean that a smaller number of connections will automatically qualify for a free connection and that a larger proportion will need to be individually assessed against the connection charges criteria in the Rules. There will be no change for our commercial or medium density / high-rise connections, as these connections are already provided under negotiated arrangements and individually assessed (as they do not qualify for a basic connection under our current MSO).

Forecasting the impact of the MSO on our contributions is challenging as it is unknown to what extent customers will choose to pay the charge (relative to declining to connect). It is also unknown how many customers will require a connection, or the size of the connection required. This will largely depend on the location of the connection

[35] The cost difference in these charts is $64.7 million in pre-real cost escalation terms (as it is calculated from the output of our connection cost model). Including cost escalation (which occurs in the capex model) the difference in cost is $65.2 million.
[36] See IT Investment Briefs Work Management Schedule Optimisation (JGN – RIN – 4.3.5 ICT Investment Brief - Work Management Extend Phase) and Network Management Advanced Analytics (JGN – RIN – 4.3.5 ICT Investment Brief - Network Management Advanced Analytics).

which determines the cost and expected revenue (customers in our colder country areas use more gas than our coastal customers).

In the absence of other information available to us, our best estimate is that about 25% of the customers who connect (that is after we account for the customers who decline to connect) will require a contribution. Accordingly, we expect that contributions will be about 25% larger than has historically been the case.[37]

As shown in Table 2.2, over the period from 2018-19 to 2022-23 connection contributions, as a proportion of connection capex, has varied between 2.86% and 26.87%. This variability has been driven by a small number of customer contributions which relate to connecting industrial and commercial customers as well as a large developer funded secondary mains extension to connect a new estate to gas (which drove the increase in 2022-23).

Table 2.2 Historical connections capex and customer contributions ($2025 millions)

	2018-19	2019-20	2020-21	2021-22	2022-23
Connection capex	121.9	99.5	109.6	103.9	96.4
Total customer contributions					
Detached residential	2.4	1.7	3.0	3.8	21.6
All others (I&C, high-rise etc.)	1.1	2.2	3.1	2.2	4.3
Contribution percentage (connections contributions / connections capex)	2.86%	3.91%	5.52%	5.83%	26.87%

To forecast contributions for the 2025-30 period we first calculated the 4-year average contribution percentage (total contributions as a proportion of connections capex) over 2018-19 to 2021-22. We did not include 2022-23 as it was an outlier year due to the large customer contribution. This resulted in an average contribution proportion of 4.53%.

We then scaled up total customer contributions up by 25% to 5.66%. This increase reflects the increase in contributions expected from our proposed changes to the MSO. This equates to an increase of $3.2 million.

We note that this estimate is conservative (likely to be on the higher side) as we apply the 25% uplift to *total* contributions. Total contributions include those from our historical I&C and medium density / high-rise connections which are unaffected by the change to our MSO. If we had restricted the scaling factor to detached residential contributions (which amounts to 2.51%), we would have only increased the contributions percentage to 5.16%.[38]

As we are not aware of any large connections requiring a contribution we have not forecast and project-specific contributions. Similarly, have not forecast any projects in our load driven augmentation category which require a contribution.

We note that while this estimate is uncertain, our connections forecast and associated contributions are excluded from the Capital Expenditure Sharing Scheme (CESS).

[37] Consistent with Rule 74 this is the best estimate possible in the circumstances.
[38] 5.16% is calculated by adding 25% of 2.51% (0.63%) to the historical total percentage of 4.53%.

3. Emissions reductions

Over the 2025-30 period, consistent with the amended National Gas Objective, we will support the achievement of the NSW and Australian governments emission reduction targets. We will do this by:

1. **Facilitating reductions in customer emissions** by building mains to connect 6.7 PJs of local renewable gas to our network and decarbonise 8.3% of the gas we transport by 2030. This will reduce emissions by about 347,000 tCO2e a year by 2030 or 1% and 0.4% of the emissions reductions needed to achieve the NSW and Australian government's 2030 emission reduction targets.[39]

2. **Moving to direct emissions measurement (using Picarro technology).** This technology will allow us to report our actual emissions rather than rely on estimates based on likely inaccurate generic emission factors and high-level assumptions of our network performance. It will also provide granular data to identify the size and location of leaks on our network and optimise our asset management strategies.

3. **Undertake no-regrets targeted actions to reduce our emissions.** This includes replacing deteriorating cast iron mains, reducing pressures across our network, and installing low/no emissions equipment (e.g. catalytic heaters).

Together these strategies will provide $2.6 billion in consumer value. This is shown in Table 3.1 which presents the net present value of each component of our emissions reduction program. The net present value evaluates the costs we (and others) incur on behalf of consumers as well as the consumer benefit which is primarily, but not entirely, in the form of emission reductions.

Table 3.1: Net Present Value (NPV) of our emissions reduction program ($2025 millions)

Element	Expenditure	NPV
Renewable Gas Facilitation	Capex	1,412.3
Direct Emissions Measurement (and leak repairs)	Opex	936.6
JGN Emissions Reduction	Capex	237.2
Total		**2,586.1**

The capex requirements to deliver these initiatives are set out in Table 3.2. Importantly, the 2025-30 capex is significantly less than the overall consumer value these programs will deliver.[40]

Table 3.2: Emissions Reduction capex ($2025 millions)

	2020-25		2025-30
	Allowance	Actuals/estimate	Forecast
Renewable Gas Facilitation	-	5.9	83.4
JGN Emissions Reduction	41.0	33.3	59.5
Total	**41.0**	**39.3**	**142.9**

Overall, our emissions reduction expenditure is higher in the 2025-30 period to ensure that we support the achievement of the NSW and Australian emissions reduction targets, consistent with the amended NGO.

[39] *JGN-Att 4.1-Emissions reduction program* and the individual renewable gas business cases in *JGN-RIN Att 4.3 Coolabah, Blue Gum, Iron Bark, Red Gum, Huon Pine, Kauri and Wollemi*.
[40] While the 2025-30 period covers most of the investment some of the projects cross regulatory periods with spend in 2020-25 and 2030-35. The full cost of each project is reflected in the NPVs outlined in Table 3.1. This also includes consideration of additional costs (such as costs incurred by project developers) and opex costs not part of our 2025-30 capex program.

As renewable gas facilitation and direct emissions measure are new areas of expenditure and include capex and opex initiatives, we outline the basis for these elements in a separate attachment *JGN-Att 4.1-Emissions reduction program*.

In this attachment, we provide an overview of our plan to facilitate renewable gas and provide further details on the initiatives to reduce our own emissions.

3.1 Renewable gas

Our customers, in consuming gas transported by us, produce 4.70 MtCO2e of emissions. This makes up 1.1% and 4.2% of total NSW (111 MtCO2e) and Australian (433 MtCO2e) emissions.

As recognised by the Australian Government's Future Gas Strategy,[41] renewable gases provide an opportunity to reduce emissions by displacing natural gas with low or zero emission renewable gas alternatives such as biomethane, green hydrogen and synthetic methane.

Over the past five years we have laid the foundation for substantial emission reductions. We have helped drive the development of the market for renewable gas, through undertaking biomethane and hydrogen pilots and working with GreenPower to launch a renewable gas certification scheme.

While there is growing momentum and support from potential renewable gas producers and users, development has been hindered by regulatory, market and technological barriers. For example, the historical absence of renewable gas certification, a lack of clarity on how technical and economic regulatory frameworks apply to renewable gas, as well as changes needed to existing market, regulatory and commercial frameworks (which are premised on large-scale production in remote gas fields and transport via high-pressure transmission pipelines to demand centres).

In contrast to international experience, there has been no large scale commercial renewable gas injections into any Australian gas network. Project developers tell us while there is interest and opportunities to produce material levels of renewable gas. Based on these discussions, we estimate that about 50PJ/year is near our network (of which 30 PJ/year is available now) and cost competitive to natural gas. However, barriers and the lack of project precedents increase the project risk (and required rate of return[42]) creating challenges in obtaining the funding necessary to proceed.

Our approach is to support, de-risk and reduce the project developer costs of potential projects to ensure that, where economic, renewable gas is supplied into our network to displace natural gas. We will do this by incurring pipeline service expenditure (such as laying mains to sources of renewable gas).

We plan to connect eight renewable gas projects which will enable 6.7 PJs of biomethane to be injected into our network by 2030. This will reduce customer emissions by 0.35 MtCO2e per year and decarbonise 8.3% of the gas we transport by 2030. It will contribute 1% and 0.4% of the reduction in emissions required to achieve the NSW and Australia 2030 emission reduction targets.[43]

Our renewable gas program is consistent with the amended NGO and good industry practice. The program is justified as the overall economic value of the expenditure is positive,[44] as demonstrated by the business cases for each of the eight renewable gas projects, and because they will contribute to meeting emissions reduction targets through the supply of pipeline services.[45] The net present value of our renewable gas facilitation projects sum to $1.4 billion.

In additional to the quantified benefits (such as emissions reductions), our expenditure will:

- Unlock a gas decarbonisation pathway for our customers. This is particularly important for our customers who cannot electrify.

[41] Australian Government 2024, *Future Gas Strategy,* p.29, 30 and 34 Available here.
[42] Media reports indicate that green gas businesses are pitching returns of 30% to seek funding. See here.
[43] As a result, the program is justified under Rule 79(2)(c)(v).
[44] Rule 79(2)(a).
[45] Rule 79(2)(c)(v).

- Ensure that hard to abate manufacturing sectors can reduce or avoid emissions, rather than purchasing offsets, enabling continued economic viability.

- Avoid significant whole of economy consequences from a higher cost electricity only pathway to net-zero by supporting renewable energy choice.

- Avoid placing additional cost and operational pressures on the electricity system.

- Reduce gas network stranding asset risk and, in turn, constraining the overall higher level of accelerated deprecation required, given the reduced opportunity to recover at least our efficient costs. Without renewable gas, our proposal would need to assume that our network has a limited role to play to a decarbonised future and in turn seek a higher level of accelerated depreciation.

Notably, the pipeline expenditure we incur, and renewable gas plant costs project developers incur, are complementary investments – both are required to enable the production and distribution of renewable gas to our customers.

If the AER does not approve our renewable gas program, we will not be able to proceed. This will mean renewable gas supply will not occur, stifling broader investment in the emerging renewable gas industry in New South Wales. The $1.4 billion of net value we have identified will not be realised and consumers will be worse off.

3.2 Our no-regrets and targeted approach to reducing our emissions

In developing our approach to reducing our own emissions we had regard to the following factors:

1. The need to play our role in reducing emissions – in particular, we have considered the increasing value of reducing emissions, as determined by Energy Ministers, and how we can support the achievement of NSW and Australian government emission reduction targets.

2. Improved leak detection technology – which enables us to optimise our approach to asset management by taking a targeted approach to mains rehabilitation - aligned with customer expectations - given the uncertain future of gas and need to constrain capital investment.

3. Moving to direct emissions measurement – to report on actual emissions, rather than estimates based on generic assumptions. This will ensure that the emissions reductions we achieve are accurately reported and recognised.

4. Other drivers for investment – including safety, integrity, reliability, capacity and efficiency.

Based on these factors our strategy is to adopt a no-regrets, targeted approach. This means we will undertake projects which will deliver material benefits over the 2025-30 period – in all plausible future. This includes delivering:

- A targeted mains rehabilitation program to address the areas of our network in the worst condition where a reactive repair-based approach will not be economic.

- Pressure reductions across our network to reduce the rate at which gas leaks and in turn fugitive emissions.

- The installation of catalytic heaters to reduce the amount of gas used for operational purposes.[46]

While additional mains rehabilitation projects are justified under the Rules, these projects not been included due to the uncertainty around the results of our shift to direct emissions measurement. We note that we expect that moving to direct emissions measurement will trigger a further increase in expenditure as we will have more data on the size, location and kind of investments required to address leaks.

[46] We pre-heat gas to counteract the temperature drop due to the Joule-Thompson effect.

Table 3.3 JGN Emissions reduction capex ($2025 millions)

	2020-25		2025-30
	Allowance	Actuals/estimate	Forecast
Mains Rehabilitation	41.0	26.4	55.7
Emissions measurement[47]	-	4.4	0.0
Pressure reduction	-	0.5	2.0
Catalytic heaters	-	2.0	1.8
Total	**41.0**	**33.3**	**59.5**

Below we provide further detail on the value of reducing fugitive emissions, customer feedback on adopting a targeted approach and the implications of the shift to direct emissions measurement.

3.2.1 The increasing value of reducing fugitive emissions

In providing pipeline services we produce around 290,000 tonnes of carbon dioxide equivalent (tCO2e) greenhouse gas emissions.[48] 98.8% of our emissions are due to 'fugitives' – the release of natural gas to the atmosphere from leaks and operational activities.[49]

Most of the leaks in our network occur in our medium and low-pressure sections.[50] These leaks predominantly occur in older areas where materials such as cast iron and earlier generation plastics (PE63) are deteriorating. In the newer sections of our network, leaks typically arise due to degradation of seals between joints. Modern pipeline materials like nylon and PE100 are less susceptible to leaking. Factors influencing leak rates include soil composition as well as moisture.

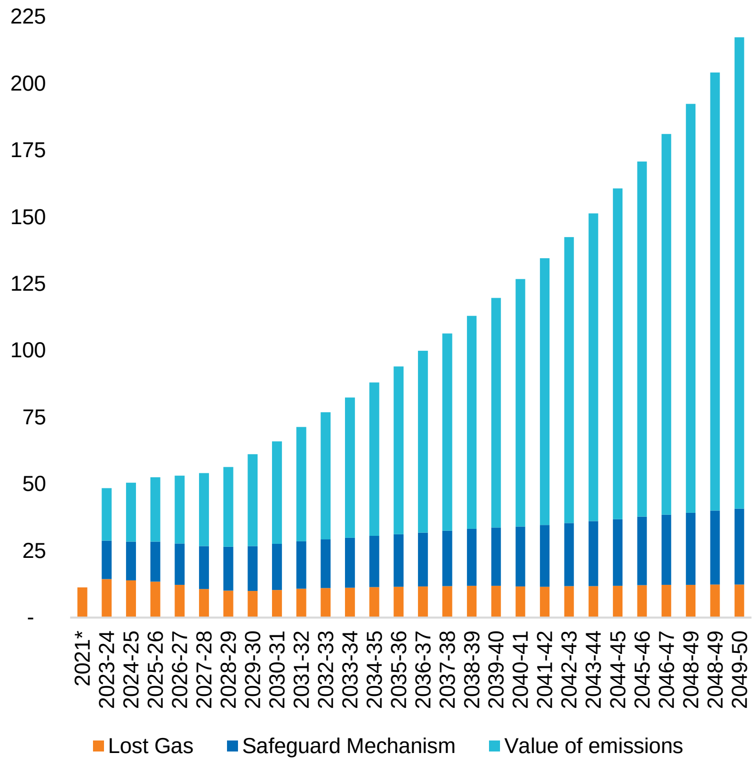
We have always sought to reduce the number and extent of these leaks for safety, reliability, cost and environmental reasons. Until recently we have only been able to quantity the cost of the lost gas as well as associated ad-hoc repairs. We are now able to quantify the environmental costs of fugitive emissions. This has two parts: penalties under the Safeguard Mechanism as well as using the value of reducing emissions published by Energy Ministers.

Figure 3.1 shows the quantified cost of releasing 1 GJ of gas into the atmosphere over time. In 2021 this only included the cost of replacing lost gas, which was about $11 (grey bar). In 2023-24 the cost of leaking 1 GJ of gas has increased to $49 – an increase of 431%.

Most of the increase is due to the quantification of the environmental impact of the emissions produced.[51] This cost increases overtime as the value of reducing emissions rises.

[47] This relates to the initial purchase of vehicles for the initial Picarro vehicles used for leak surveys.
[48] tCO2e is a standardised measure of the climate impact of different greenhouse gases by expressing their effect in terms of the amount of CO2 that would have the same global warming potential.
[49] The remainder of our emissions are due to fleet (0.9%) and our Water Bath Heaters see section 5.3.2, and 3.5 respectively.
[50] Leaks generally occur across our mains and services. While many publicly reported leaks are due to our gas meters, this is due to venting as part of their function rather than a leak.
[51] In calculating the value of emissions, we netted off the value already reflected in Safeguard Mechanism costs.

Figure 3.1 Cost of a 1 GJ of leakage on our network ($2025)[52]



Further details on our emissions, how the Safeguard Mechanism applies, and Energy Minister's value of emissions reductions is provided in *JGN-Att 4.1-Emissions reduction program*.

3.2.2 Improvements to emission surveying technology

Over the 2020-25 period, we commenced surveying our network, required for compliance purposes over a 5-year period, using vehicle-based emission detection technology (Picarro).[53]

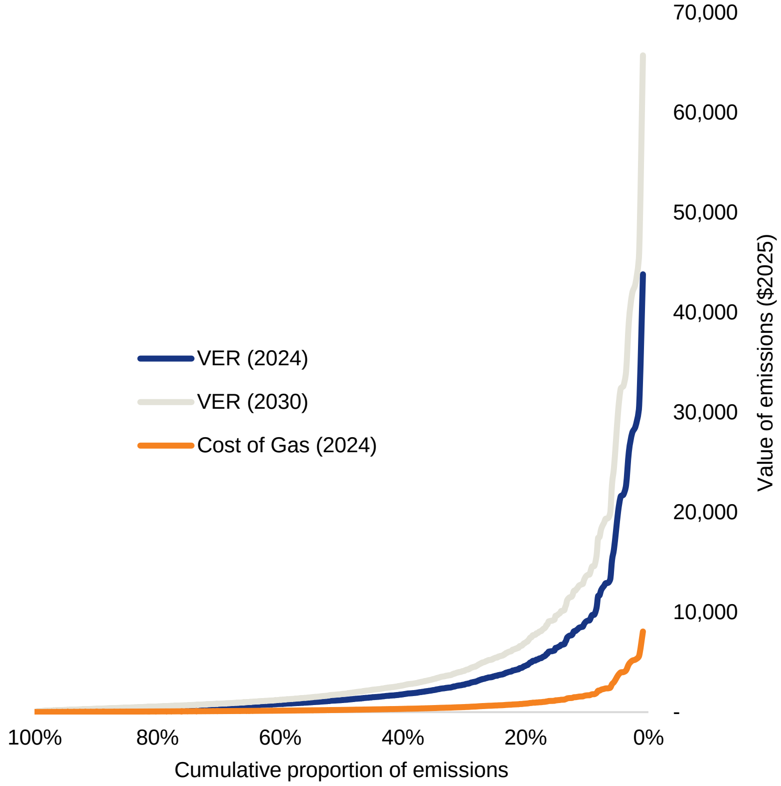
This advanced technology provides granular data on the location and size of leaks across our network which we can use to optimise our approach to managing our asset. We use this technology to identify the emissions reduction of operational strategies and the performance of each section of our network.

As the technology identifies the size of each leak, we can calculate emissions on a leak-by-leak basis and in turn the cost. Figure 3.2 shows leak data collected across approximately 20% of our network presented in terms of the cost of lost gas as well as the value of reducing emissions in 2024 and 2030. We note that:

- A relatively small proportion of leaks are responsible for most fugitive emissions.
- The cost of some leaks is very high. The largest identified leak emitted gas at a rate of 562 tCO2e per year. This results in annual costs of $8,076 in gas replacement costs and has an environmental cost of $43,838, calculated using Energy Minister's 2024 value of emission reductions.
- The quantifiable value of leak reductions will continue to increase over time.

[52] As our actual gas costs are confidential, we have used public gas price data published as part of the GSOO to prepare this chart. For 2021 we used prices forecasts prepared by Lewis Grey Advisory (see here) for the 2021 GSOO. For 2024 and beyond prices we used forecasts prepared by ACIL Allen for the 2021 IASR and 2024 GSOO (see here).
[53] *JGN-Att 6.2-Opex step change justification* for more information.

Figure 3.2 Annual cost of each leak identified on our network using Picarro Technology ($2025)



We can use this data on the size of each leak (together with location data) to determine optimal asset management strategies. For instance, whether we replace whole sections of our network or undertake reactive repairs. We can also optimise the overall program. For instance, we can compare the cost of repairing a leak (on average about $2,000 per repair) to the cost of taking no action which comprises: the cost of gas, Safeguard Mechanism costs as well as the value using the Energy Ministers value of emissions.

One factor we have considered is the materials used in each network section. Undertaking leak repairs on cast iron mains is more difficult than on modern plastic mains. Methods like clamping, which are straightforward for plastic, can cause further damage, such as additional cracks. In contrast, plastic main leaks typically occur at joints which can be repaired using more conventional methods. Given these difficulties, it is generally more practical and cost-effective to undertake mains rehabilitation projects for cast iron mains rather than perform a number of reactive repairs. Conversely, for plastic mains, if all leaks can be quickly identified as they arise, reactive repairs could be the more economic option.

3.2.3 Customer feedback on our asset management approach

Given the potential to make greater use of this emission detection technology as well as the uncertain future of gas, we asked our Customer Forum for their views on how we should approach asset management, with a focus on our mains rehabilitation program.

We provided three options and highlighted the bill impact for both the short term (2025-2030) and long term (2031 and beyond) for each option. The options were also overlaid with the Expert Panel plausible future scenarios to give customers an indication of the trade-off decisions we can consider in terms of managing the challenges presented by the energy transition.

The options considered by the Customer Forum were:[54]

- Maintain current approach: replacing mains across whole sections of a networks at a time to maximise economies of scale. Undertaking this approach would require replacing significantly more mains in the next regulatory period given the size of the networks where we are experiencing issues – almost 1,000 km of main which would cost around $380 million to replace.
- Targeted rehabilitation: Using emission detection technologies to identify gas leaks using a more targeted approach. Under this option we will still target the same areas but only replace those mains in the worst condition (about 130 km).
- Deferred rehabilitation: Deferring mains rehabilitation over the 2025 Plan period to wait for certainty about the future of gas.

We emphasised to customers that all options would involve repairing assets when required to ensure that safety is not compromised.

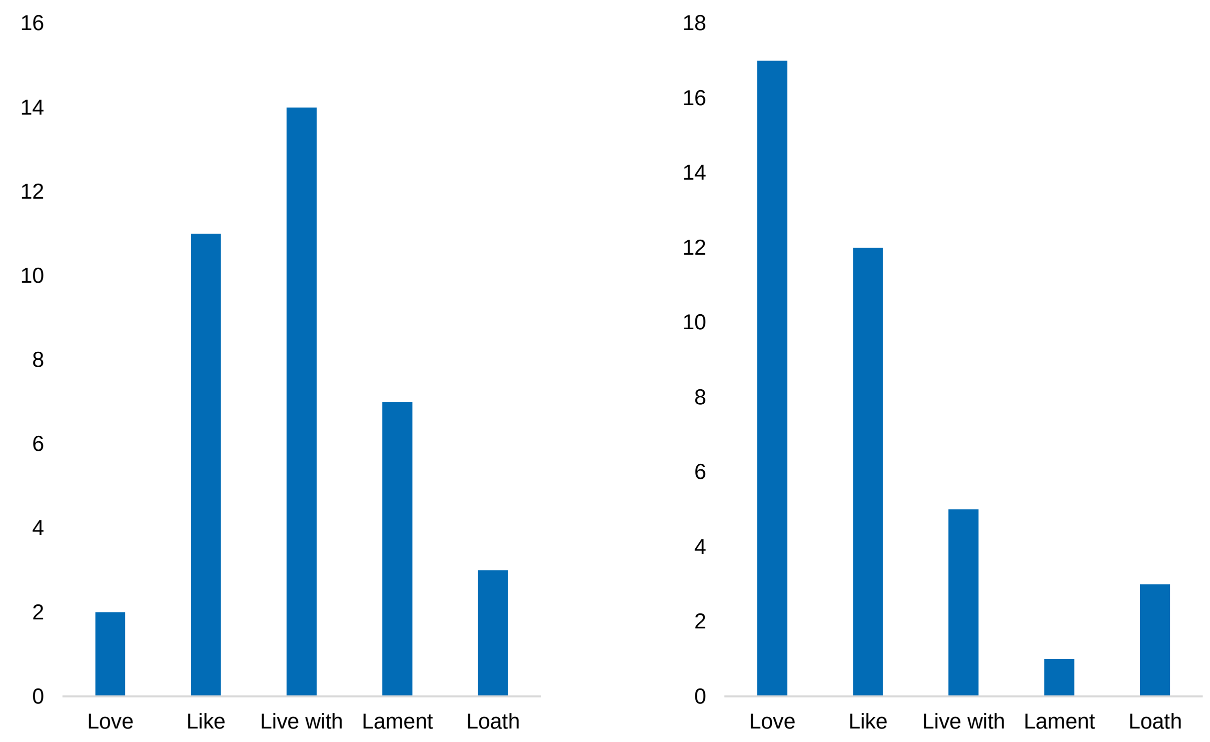
When asked to cast their first round of votes on their preferred option, Customer Forum participants were split between targeted and deferred rehabilitation. No participants supported maintaining the current approach.

Participants appreciated the challenges we faced in the context of an uncertain future and that doing nothing was not an option they were willing to consider and trade-off. Although customers were split between deferring our program and undertaking a targeted approach, participants felt that either option was fair for customers as safety and reliability would be maintained with minimal impact to the long-term interest of customers.

Following a second round of Customer Forum deliberations, when customers reconsidered the mains rehabilitation options against the full suite of initiatives, 90% of customers voted in favour of a targeted approach. The majority of Customer Forum participants supported this option as it falls into the ‘middle ground’ that supports the ongoing investment to ensure a reliable gas network while avoiding excessive works into the future.

Figure 3.3 Customer forum feedback on asset management approach

Deferred rehabilitation | **Targeted rehabilitation**



[54] *JGN-BD Infrastructure-Att 2.2-Customer Forum Engagement Report*, p.34.

3.2.4 Direction emissions measurement

One challenge we face is that fugitive emissions are not currently measured. Emissions are reported, using a 'lower order' method that relies on generic assumptions, in line with the National Greenhouse and Energy Reporting (NGER) Scheme. The NGER Scheme is based on the historical assumption that fugitive emissions cannot be directly measured.

We have explored the potential to move to direct emissions measurement using Picarro technology (rather than just undertaking 5-yearly leakages surveys). This will enable us to measure fugitive emissions across our entire network once each year (and in turn requiring more vehicles to survey our network).

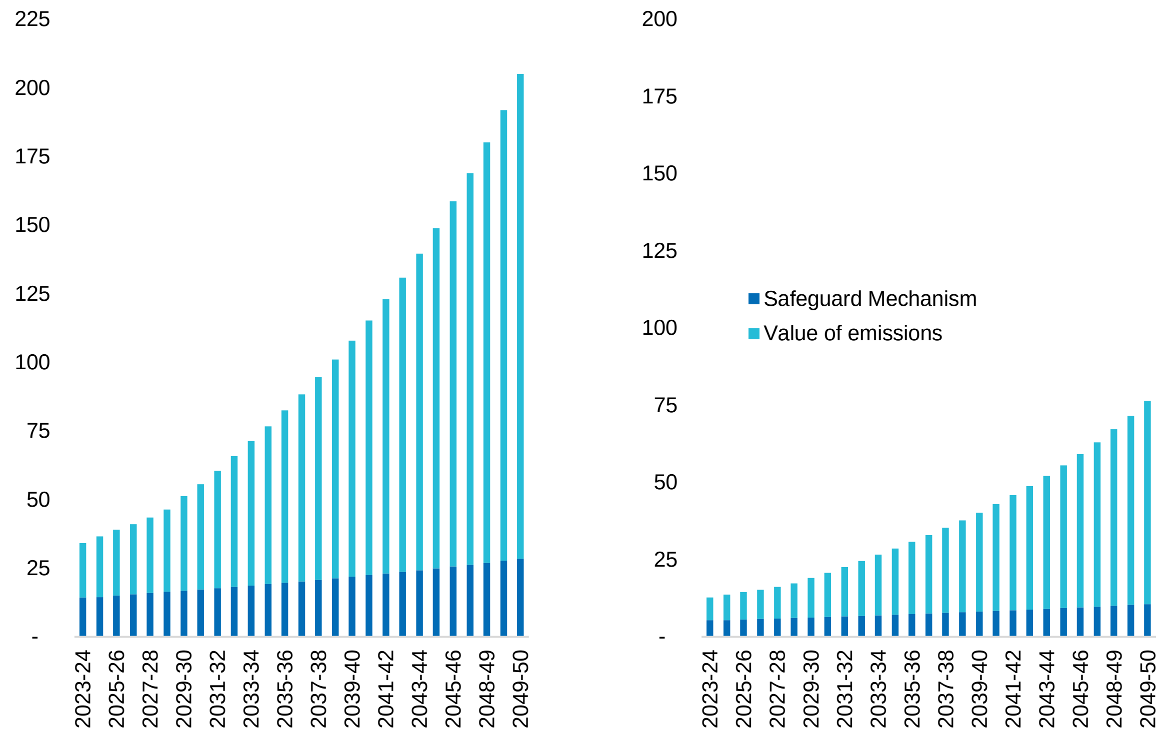
We found that this strategy will reduce costs. While it will result in additional costs to measure emissions and repair the identified leaks, these costs will be more than offset by reductions in Safeguard Mechanism compliance costs.

In Customer Forum 8, in addition to reminding participants of Picarro's role in supporting a targeted approach to mains rehabilitation, we also discussed its role in helping us reduce carbon emissions. Two options, with indicative bills impacts, were presented; option 1 – relying on carbon credits to offset emissions; and option 2 – investing in technology (Picarro). Notably, when we presented option 2, we presented it as the higher cost approach.[55] Customer Forum participants expressed strong support for us investing in Picarro to enable us to reduce network emissions rather than relying on the purchase of carbon credits.[56] Further details on the move to direct measurement are provided in *JGN-Att 4.1-Emissions reduction program* as well as the direct emissions business case.[57]

An additional benefit of the shift to direct emissions is that it will ensure that the full emissions reduction benefit is recognised in our emissions reporting. Without direct emissions measurement only 37.5% of the benefit will be reflected in our reporting, as shown in Figure 3.4.

Figure 3.4 Reported emissions reduction benefits of reducing 1 GJ of leakage on our network ($2025)

Direct emissions measurement	No direct emissions measurement



[55] This engagement proceeded subsequent analysis which found that once the Safeguard Mechanism was considered it would reduce costs.
[56] *JGN-BD Infrastructure-Att 2.2-Customer Forum Engagement Report*, p.34.
[57] *JGN-RIN Att 4.4-Emissions Monitoring – Picarro – CBAM.*

Figure 3.4 shows the value of reducing 1 GJ of leakage (0.44 tCO2e in emissions terms) each year:

- With direct emissions measurement the full value of reducing emissions by 0.44 tCO2e would be recognised in our emissions reporting, as it will be based on actual measurement emissions.

- Without direct emissions measurement, due to the application of generic assumptions,[58] only 37.5% of the reduction in emissions would be recognised. As a result, our reported emissions will only fall by 0.16 tCO2e. In turn, this would also mean that we would incur higher Safeguard Mechanism costs (which are calculated on reported not measured emissions), of about $9 per GJ leaked (using 2023-24 values). Notably this is not a one-off cost but something we will incur every year until we move to direct emissions measurement.

3.3 Mains Rehabilitation

Our mains rehabilitation program involves inserting new plastic mains into the existing older mains. Our network predominately consists of modern material such as nylon and polyethylene due to upgrades undertaken in the 1990s. Not all of our older mains have been rehabilitated. Several pockets of our network are still made up of cast iron, unprotected steel or older generation plastics.[59]

Rehabilitating ageing mains delivers a range of benefits. While emissions reduction is a key consideration[60] replacing deteriorating mains also reduces safety risks,[61] reduces cost increases from rising repair costs[62] and improves supply reliability.[63] Rehabilitation also limits trenching and restoration costs (relative to the approach of laying new mains).

Over the 2020-25 period, we focussed on replacing cast iron and steel mains in Matraville and Kurri Kurri, with some additional minor rehabilitation in Dubbo, Maitland and Mittagong. We had forecast to replace 104 km of cast iron and steel mains in Newcastle. However, with the benefit of our Enterprise Asset Management tool we were able to focus on streets with higher opex costs as well as new Picarro emissions detection technology (which we did not forecast or include costs for in our 2020 Plan) we have been able to apply a more targeted approach. This has reduced the scope of works. This change in approach is the primary driver of the underspend against our allowance in the 2020-25 period, as shown in Table 3.4.

Table 3.4: Mains rehabilitation capex ($2025 millions)

	2020-25		2025-30
	Allowance	Actuals/estimate	Forecast
Newcastle	19.0	4.8	24.4
All other projects	22.0	21.5	31.3
Total	**41.0**	**26.4**	**55.7**

This change in approach in 2020-25 has enabled significant cost reductions for the 2025-30 period. Our plan, consistent with customer feedback is to target cast iron mains and unprotected steel in the poorest condition where a reactive repair approach will unlikely be the most efficient option to reduce emissions.

The projects we will undertake are outlined in Table 3.5. This table also shows the alternative approach – without the benefit of Picarro technology - where we replace whole areas of these networks.

[58] *JGN-Att 4.1-Emissions reduction program.*
[59] 19,858 km of Nylon, 3,752 km of Polyethylene, 255 km of cast Iron and 140 km of steel.
[60] Justified under Rule 79(2)(c)(v) to contribute to meeting emissions reduction targets through the supply of services.
[61] Justified under Rules 79(2)(i)-79(2)(iii) to maintain the safety and integrity of our network and comply with our regulatory obligations.
[62] Justified under Rule 79(2)(a) where the project delivers cost savings (generally by halting increases in repair and lost gas costs) that exceed the costs of investment.
[63] Justified under Rule 79(2)(c)(ii) to maintain the integrity of the network. If the project strengthens the network to provide additional capacity for existing or new customers then it is also justified under either Rule 79(2)(c)(iv) (to maintain our capacity to meet levels of demand for services existing at the time the capex is incurred) or Rule 79(2)(b) (present value of the expected incremental revenue to be generated as a result of the expenditure exceeds the present value of the capex).

Table 3.5 Mains Rehabilitation Projects for the 2025-30 period: replacement approach

	Targeted approach		Alternative approach	
Area	**Material**	**km**	**Material**	**km**
Bankstown / Chullora / Greenacre	Cast iron	23.0	Cast iron and older plastics	230.0
Haberfield / Strathfield / Campsie	Cast iron	32.0	Cast iron and older plastics	415.0
Kurri Kurri Stage 2	Unprotected steel	24.0	Unprotected steel	24.0
Newcastle	Targeted cast iron	37.0	Cast iron, steel, older plastics	260.0
Strathfield	Cast iron	7.4	Cast iron and older plastics	77.5
Richmond Rd	Unprotected steel	0.8	Unprotected steel	0.8
Pennant Hills	Unprotected steel	1.2	Unprotected steel	5.4
Total		**125.4**		**1,012.7**

Our program does not include any older generation plastic mains where, depending on the results of our emissions measurement, we may be able to manage leaks using a reactive approach.

We will continue to optimise our mains rehabilitation program over the period. In measuring emissions across our network, we will find areas which perform better and worse than we expect. However, at this stage our proposed program is the best forecast possible of the work we will need to undertake.[64]

The quantum and value of the emissions reductions achieved by our proposed program by 2040 is set out in Table 3.6. This value is greater than the capex required to implement these projects. While the emissions reductions will be delivered the full value of this reduction will only be realised in reported emissions if our shift to direct emissions measurement also goes ahead.

Importantly, the value of these emissions are *in addition* to the other benefits these projects will deliver such as improved safety, reliability, reduction in gas costs, reductions in maintenance costs and so forth. Further details on the costs and benefits of each project are provided in each supporting business case.[65]

Table 3.6 Mains rehabilitation emission reductions over the period to 2040

	Direct Emissions Measurement		No direct Emissions Measurement	
Area	**Actual emissions reduction (tCO2e)**	**Value ($millions)**	**Reported Emissions Reduction (tCO2e)**	**Value ($millions)**
Bankstown / Chullora / Greenacre	56,733	7.5	21,161	2.8
Haberfield / Strathfield / Campsie	104,685	14.2	39,048	5.3
Kurri Kurri Stage 2	189,405	27.4	70,648	10.2
Newcastle (stage 1, 2, 3)	224,259	29.1	83,649	10.9
Strathfield	22,305	3.0	8,320	1.1
Total	**597,387**	**81.3**	**222,825**	**30.3**

[64] Consistent with Rule 74.
[65] *JGN-RIN Att 4.3.*

Overall, our mains rehabilitation program will be larger in the 2025-30 period reflecting:

- The increasing value of reducing emissions to support the achievement of NSW and Australian government emissions reduction targets.
- Our targeted approach which improves the cost-effectiveness of each program (as we can target the areas of our network in the worst condition).
- The condition of some areas of our network, as pipeline materials age and degrade.

Other projects

In addition, we will also rehabilitate sections of ageing steel mains, where we are experience integrity issues and a large number of reactive repairs, along Pennant Hills Rd and Richmond Road.[66]

3.4 Pressure reduction

Our network is made up of a series of pipelines and sub-networks which operate at various pressures depending on network design and gas demand at any given time. This includes high-pressure steel trunk, primary and secondary mains and medium and low pressure (generally plastic) sub-networks.

Generally, these sub-networks are supplied directly from a secondary main. Gas flows from a regulator through the network to supply residential and commercial customers. The pressure is highest closest to the regulator and lowest at the extremities of the network. Pressures vary depending on various factors, such as the load (including location), the level of interconnectivity as well as the diameter of the mains.

Our standard design is for our networks to operate at 210 kPa. However, this varies. Some of our medium pressure mains operate up to 400 kPa or at 100 kPa. We also operate low pressure mains (at 2, 7 or 30 kPa). This generally occurs with our older cast iron mains (due to integrity reasons) or mains in CBD areas (for safety reasons).

Since the conversion of our network to plastic in the early 1990s, we have managed pressures across our network with the primary goals of ensuring our networks have sufficient capacity to maintain supply.

Given the recent increases in the cost of gas and the need to reduce emissions, we have commenced a program to reduce pressures across our network. Reducing pressure reduces the flow of gas through small leaks (as the rate of leakage is proportional to pressure) and in turn reduces lost gas and fugitive emissions.

Initially we have focussed on the areas where we could reduce pressures at low or no cost – e.g. by adjusting regulator settings to reduce pressures.

Over the 2025-30 period, we will continue this program on a network-by-network basis. This will require additional expenditure to ensure that we can maintain supply. We will reduce pressures by undertaking additional interconnections and using dynamic pressure control. For instance, we will investigate and where prudent implement a range of pressure management techniques that may include seasonal or time-of-day pressure control as well as exploring the potential to set pressures based on live readings at the extremities of our network. This will allow us to increase pressure when required to maintain supply while reducing pressures at other times to reduce leakage.

This program will reduce the cost of lost gas, Safeguard Mechanism compliance costs as well as realise value from reducing emissions, as shown in Table 3.7.

[66] Justified under Rules 79(2)(i)-79(2)(ii) to maintain the safety and integrity of our network.

Table 3.7 NPV of pressure reduction program

Direct Emissions Measurement		No direct Emissions Measurement	
Actual emissions reduction (tCO2e)	NPV ($millions)	Reported Emissions Reduction (tCO2e)	NPV ($millions)
20,267	6.6	7,600	2.9

3.5 Catalytic Heaters

Our network reduces the pressure of gas as it is transported through the layers of our network. Pressure reduction, due to the Joules-Thomson effect, reduces the temperature of the gas and in turn leads to icing-over or condensation on process equipment and piping which can damage or degrade components of our network.

To mitigate this risk, 15 Water Bath Heaters, located across our network mainly at Trunk Receiving and Packaged Off-take Stations, pre-heat gas before we reduce the pressure. These Water Bath Heaters submerge a portion of the gas into water heated by burning gas. These units are responsible for 0.3% of our emissions (930 tCO2e) each year.

A different technology is now available on the market – catalytic heaters which are able to preheat the gas via an enclosed heating element that directly heats the process piping. While this technology still uses gas it is more efficient as it removes the need to heat the immersion water.

These projects are primarily justified on the reduction in annual maintenance costs (noting that overall, our maintenance costs will continue to rise due to the age and condition of our network). However, they will also reduce gas consumed and in turn the emissions we produce. We estimate that our program of work will reduce emissions by 1,265 tCO2e over the period to 2040 which has a value of $0.16 million. Note that these emissions are not fugitive emissions and will not be affected by our move to direct measurement.

3.6 Overlap between emissions and stay in business category

As outlined in section 3.2, activities which reduce emissions (such as mains rehabilitation) also provide material other benefits such as maintaining the safety, integrity, reliability and efficiency of our network. This means that many projects could have also been included in our Stay in Business driver category.

We have decided to categorise projects which materially reduce emissions into this emissions driver category. This is to provide transparency on how the amendments to the NGO and the increased focus on emissions has influenced our investment program. In categorising expenditure to drivers, we have also been consistent across the 2020-25 and 2025-30 periods. For instance, we have also categorised historical mains rehabilitation programs in this emissions driver category. This is to ensure consistency and transparency in cost trends over time.

4. Stay-in business: metering

An essential part of the service we provide is metering each customer's gas consumption.[67] We use this information to accurately charge customers for usage of our network and for the cost of gas (purchased and shipped by retailers).

Our metering program maintains the performance of our fleet of gas meters to ensure we:

- Deliver the Transportation Reference Service which includes "…meter reading and associated data activities, and the provision and maintenance of a standard metering installation at the Delivery Point as appropriate for the required capacity and meter reading frequency."[68]
- Replace meters prior to failure to avoid estimated bills and customer frustration.
- Meet our obligations to provide at least two actual meter reads every 12 months.[69]
- Accurately bill customers to ensure network and gas usage charges are fair.

Over the 2020-25 period we have been able to find efficiencies in our planned residential as well as Industrial and Commercial (I&C) gas meter replacement programs by extending the life of our metering fleet. These efficiencies have led to material reductions in capex, a lower regulatory asset base and, in turn, lower customer bills.

To forecast future costs, we have applied optimistic forecasting assumptions with respect to:

- Unit rates – Consistent with our approach for connections (see section 2.3), we have applied unit rates based on a 4-year average of historical costs. This embeds $17.2 million of efficiency savings relative to 2022/23 costs.
- Volumes – We have updated our forecasting assumptions to reflect the observed performance and made no allowance for earlier than expected failures.

Despite these optimistic assumptions, which means we are absorbing forecasting risk rather than passing it onto customers, we are projecting metering capex to increase in 2025-30. This is primarily because we cannot extend the life of our meters indefinitely.

Other factors driving our 2025-30 program include the need to replace key elements of our obsolete Meter Data Loggers and Metreteks which respectively support the metering of high-rise buildings and our largest I&C customers. We will also deploy innovative digital metering technology to solve a long-standing challenge on how to ensure we can regularly read (as per our Transportation Reference Service) the meters of our chronic no access customers.

[67] Meter replacement capex is justified under Rules 79(2)(c)(i)-(iii). It is required to maintain the safety and integrity of services as well as to comply with our jurisdictional obligations.
[68] See Clause 2.2 of our proposed 2025-2030 - Access Arrangement.
[69] Retail Market Procedures (NSW and ACT), clause 3.6.6(a). See here.

Table 4.1: Meter replacement capex ($2025 millions)

	2020-25		2025-30
	Allowance	Actuals/estimate	Forecast
Planned Residential	74.3	47.0	62.9
Planned I&C	27.0	10.3	36.0
Meter Access Program	3.1	3.1	9.4
Meter Data Loggers	4.6	6.4	5.9
Metreteks	1.1	5.8	11.5
Defective / meter upgrades	42.1	39.8	43.7
Total	**152.2**	**112.3**	**169.4**

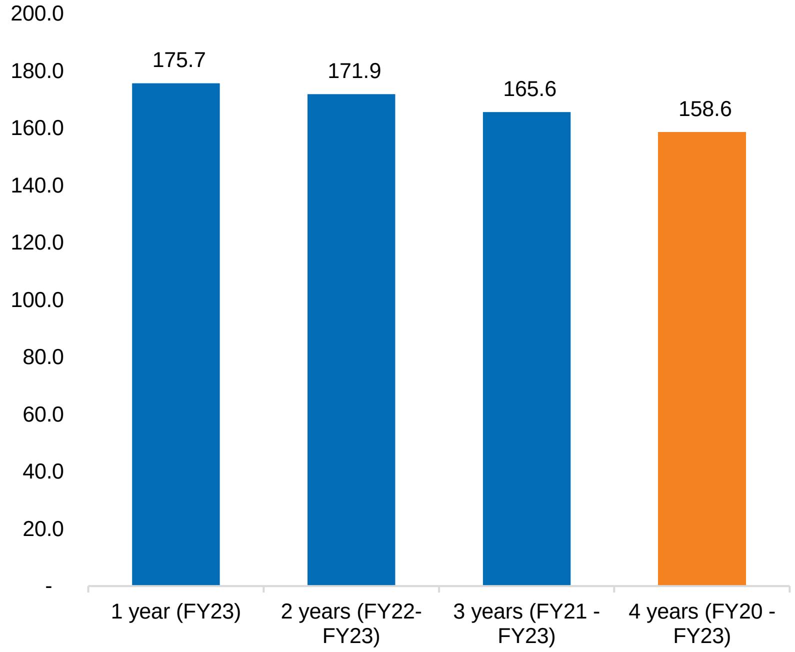
4.1 Forecasting approach

Our forecasting approach,[70] wherever possible, uses revealed historical costs:

- Where costs are recurrent, such as our defective meter replacement programs, we have relied on an average of total historical costs.
- Where costs vary based on volumes, we apply an average unit rate based on the last 4-years of costs and then apply it to the forecast volume of meters expected to be replaced.

As outlined in section 2.3, the use of a 4-year average forecasting approach was developed when costs were relatively stable. Since COVID-19 there has been significant cost pressures across the economy. This results in a material difference between average and current costs. As shown in Figure 4.1, using a 4-year average effectively builds in $17.2 million of efficiencies relative to our 2022-23 actual costs.

Figure 4.1 Metering capex by averaging period ($2025 millions) (prior to overheads and cost escalation)[71]



[70] *JGN-RIN Att 4.3 Connection and Metering Forecast Methodology* for further details.
[71] The cost difference in these charts is $17.1 million in pre-real cost escalation terms (as it is calculated from the output of our connection cost model). Including cost escalation (which occurs in the capex model) the difference in cost is $17.2 million.

Where using a revealed cost forecasting approach has not been possible, for instance where we deliver projects to replace components of our systems, we have estimated costs using our Project Estimation Methodology.

Table 4.2 Stay in business: Metering forecasting approach

Category	Forecasting Approach
Planned Residential	Forecast volume & historical unit rates
Planned I&C	Forecast volume & historical unit rates *or* project cost estimate
Meter Access Program	Project cost estimate
Meter Data Loggers	Project cost estimate
Metreteks	Project cost estimate
Defective / meter upgrades/downgrades	Historical average

4.2 Planned residential

We meter the consumption of our residential (and small commercial) customers through a combination of gas and hot water meters.

Most of our detached residential customers have a single gas meter. Gas meters are mechanical devices which wear over time.[72] They contain internal diaphragms which inflate and deflate as gas passes through. These diaphragms are connected to levers which power an internal odometer-like device to record consumption.

We test the accuracy of each 'lot' of gas meters at periodic intervals. We do this by removing a sample of the meters and undertaking statistical tests to determine if the lot as a whole is still accurately recording consumption. If the sample meters are inaccurate then the whole 'lot' is scheduled to be replaced. If they are accurate then they are generally given a 5-year life extension.

For high-rise customers, there are a range of different metering configurations. The approach for new high-rise buildings is to install a single 'volume boundary' meter which measures the consumption of the whole building. An embedded service provider then bills each customer individually.

Historically, we installed gas and hot water meters for each individual high-rise unit. While we do not operate the centralised hot water systems in these buildings, we do measure the amount of hot water used. This data is used to allocate the gas used to heat the water to each individual dwelling.

Hot water meters contain an internal turbine which spins as the water passes through. These meters send pulses to a Meter Data Logger (MDL) to record consumption. The life of these meters is limited by the life of the internal battery. While it is possible to replace the batteries it is more cost effective to replace the whole meter. As outlined in Table 4.3 over the 2025-30 period we are forecasting a reduction in hot water meter capex.

The underspend and then increase in gas meter replacements, shown in Table 4.3, is due to the performance of our fleet of gas meters. We have been able to extend our meters lives and avoid incurring costs in the 2025-30 period. It would not have been prudent to replace accurate meters.

The better than-expected performance has been integrated into our 2025-30 forecasting assumptions, as outlined in section 4.2.10 below. This means that this performance is resulting in efficiencies being not only realised in the 2020-25 period but also embedded in the 2025-30 forecast.

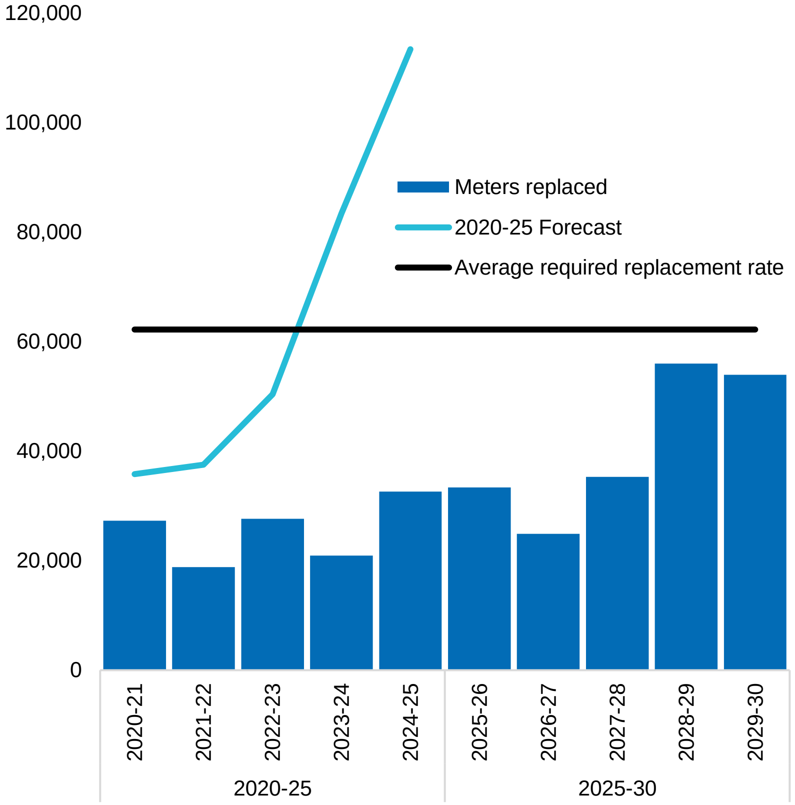
[72] A limited number of our meters (less than 500) use ultrasonic technology which does not have mechanical components.

Table 4.3: Planned residential metering capex ($2025 millions)

	2020-25		2025-30
	Allowance	Actuals/estimate	Forecast
Gas Meters	53.3	28.8	50.1
Hot Water Meters	21.2	18.2	12.8
Total	**74.3**	**47.0**	**62.9**

While our residential gas meter capex has increased this is primarily due to the age profile of our fleet of meters. Notably, our forecast remains 35% lower than the long-term average required replacement rate (total meters divided by their expected life) for our meter fleet, as shown in Figure 4.2. This indicates that the level of capex required to maintain a meter fleet of our networks size over the long-term – even with our optimistic forecasting assumptions as outlined below – is materially higher than what we have proposed.

Figure 4.2 Planned meter replacement forecast versus long-term required replacement rate



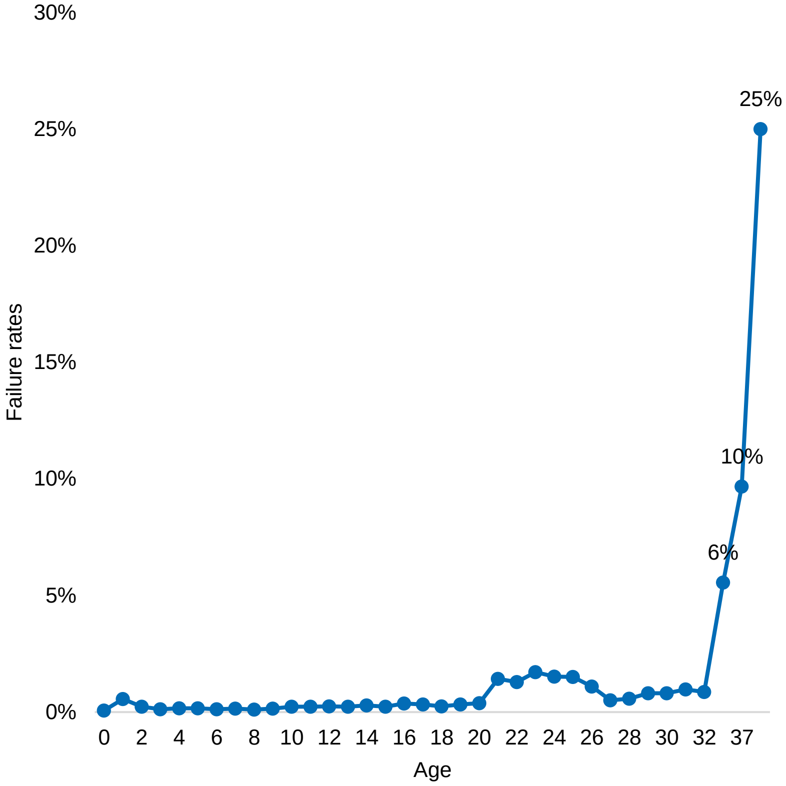
4.2.1 Residential gas meters volumes

Our meters have performed better than expected over the 2020-25 period with some 'lots' of meters continuing to be accurate at their 30-year test. We had expected that we would find these meters to be inaccurate at 25-years, as summarised in Table 4.4.

While some meters have passed their 30-year life extension test, this performance has not been uniform. 9% of meters failed their 15, 20 and 25-year tests.

Although preliminary (due to the small numbers of meters older than 30 years), we have started to also see a rise in defective rates of our older meters as shown in Figure 4.3. Defective meters are meters which fail to operate rather than just inaccurately record consumption. These failure rates are not unexpected given that our meters are mechanical devices which wear and deteriorate over time. The failure rates observed so far indicate a 'bath tub' failure curve, which is consistent with what is often experienced with electrical and mechanical equipment.[73]

Figure 4.3 2023 residential gas meter failure rates (failures / meter population)



To forecast our planned residential meter replacement program, we assume that:

1. All meters will pass their statistical life extension tests (up to and including at 30 years of age).
2. Defective rates will continue to rise, particular for meters above 30 years of age by an additional 2.5% (which is conservative relative to observed rates).
3. We will not test meters at 35-years of age, as given the defective rates seen so far, it will not be worthwhile undertaking accuracy tests.

Overall, this is an optimistic forecast, especially given the historical rate of inaccurate meters. Of the 108 lots of meters due for 15, 20, 25 and 30 years testing in the 2025-30 period, based on past performance, it is likely that 9% will be found to be inaccurate.

We also note that other gas businesses in Australia only have regulatory approval to extend their meters up to 25 years in age.[74] We are not aware of any other gas business extending the lives of their meters to 35 years.[75]

[73] While not observed this period, prior to 2020 we did see high levels of relatively young meters fail as shown in Table 4.4. This is consistent with the first part of the typical bathtub failure curve.
[74] Economic Regulation Authority 2024, *Draft decision on revisions to the access arrangement for the Mid-West and South-West Gas Distribution Systems, Attachment 4: Regulatory Asset Base,* p.30 Available here.
[75] See for instance, AGIG 2022, *Attachment 9.8 Meter Replacement Plan, Final Plan 2023/24 – 2027/28,* p.24 Available here

Table 4.4 Residential metering forecasting assumptions

Test	Performance data (prior to 2020)		2020 Plan	2020-25 Performance data		2025 Plan
Meter age	**Pass**	**Fail**	**Assumptions**	**Pass**	**Fail**	**Assumptions** (lots due for testing)
15	7	3	Pass	19	1	Pass (29)
20	13	0	Pass	16	2	Pass (38)
25	7	2	Fail	23	3	Pass (24)
30	No data	No data	N/A	12	1	Pass (17)
35	No data	No data	N/A	No data	No data	No test (36), based on observed defective rates.

4.3 Industrial and commercial meters

We have a variety of gas meters for our I&C customers who use larger volumes of gas. Each customer is supplied with a meter that is appropriately sized for how much gas they use. We categorise our meters into three groups based on their internal mechanism: diaphragm, turbine and rotary.

Small & medium I&C diaphragm meters function and are managed in the same way as residential gas meters. We test these meters, using statistical sampling, to determine if we can extend their life.

Our rotary and turbine meters are used for connections which have higher capacity requirements. Rotary meters are for connections that cannot be metered with a diaphragm meter. Turbine meters are used by our largest demand market customers.

We replace our turbine and rotary meters at 5 and 10 year intervals respectively. Over the 2020-25 period we undertook throughput analysis[76] to extend some meters lives of our turbine and rotary meters on a case-by-case basis to 7 and 15 years respectively. This allowed us to reduce metering capex against our allowance.

However, while we have found that our meters have mechanically continued to functional accurately, the electric components have deteriorated. Given this experience we will no longer extend the lives of these meters.

While we will not extend the lives of these meters in the field, we will continue to refurbish these meters (rather than purchase new meters) where possible to constrain costs. This process ensures that we can reuse the mechanical components which are still functional while ensure that the meter as a whole continues to function as designed.

[76] This is where we review how much gas has actually flowed through the meter to determine if it will continue to read accurately.

Table 4.5: Planned I&C metering capex ($2025 millions)

	2020-25		2025-30
	Allowance	Actuals/estimate	Forecast
Diaphragm	19.5	8.1	25.6
Rotary	6.3	1.6	9.6
Turbine	1.1	0.7	0.8
Total	**27.0**	**10.3**	**36.0**

4.3.1 I&C meter unit rates

As we use a variety of gas meters for our I&C customers the cost in replacing each meter also varies significantly. To take into account the differences in cost we have applied a bottom-up forecast cost using our Project Estimation Methodology,[77] rather than applying historical unit rates.

Applying our Project Estimation Methodology, rather than revealed costs, in this instance (given the variability in replacement costs) results in the best forecast possible. It also produces forecast capex $15.4 million lower than applying revealed costs.

4.3.2 I&C diaphragm meter volumes

As with our residential gas meters, our small I&C diaphragm meters performed better than expected over the 2020-25 period. Given the similarity between our residential meters and smaller I&C diaphragm meters, despite an absence of data, we applied the same forecasting assumptions and assumed that we will replace meters at 35 years of age. This is shown in Table 4.6.

Table 4.6 Small I&C gas meters (≤10m3/hr) forecasting assumptions

Test	Performance data (prior to 2020)		2020 Plan	2020-25 Performance data		2025 Plan
Meter age	**Pass**	**Fail**	**Assumptions**	**Pass**	**Fail**	**Assumptions (lots due for testing)**
15	No data	No data	Pass	6	1	Pass (10)
20	No data	No data	Pass	1	0	Pass (5)
25	No data	No data	Fail	No data	No data	Pass (1)
30	No data	No data	N/A	No data	No data	Pass
35	No data	No data	N/A	No data	No data	No test based on observed defective rates.

For our medium diaphragm meters, set out in Table 4.7, we are not as confident that these meters will continue to be accurate as they age. This is for several reasons: the higher volumes of gas they meter, the higher degree of wear on the mechanical components, and because we use refurbished meters where possible (rather than new meters). We are forecasting to replace these meters at 25-years of age.

[77] *JGN-RIN Att 4.3-Jemena Infrastructure Cost Estimation Methodology*.

Table 4.7 Medium I&C gas meters (>10m3/hr and ≤25m3/hr) forecasting assumptions

Test	Performance data (prior to 2020)		2020 Plan	2020-25 Performance data		2025 Plan
Meter age	**Pass**	**Fail**	**Assumptions**	**Pass**	**Fail**	**Assumptions** (lots due for testing)
15	6	0	Pass	12	0	Pass (10)
20	2	0	Fail	12	0	Pass (9)
25	No data	No data	N/A	4	0	Fail (9)
30	No data	No data	N/A	No data	No data	N/A
35	No data	No data	N/A	No data	No data	N/A

4.4 Meter Data Loggers

Meter Data Loggers (MDLs) record consumption from each meter in a high-rise building then communicate usage back to a central server. We have about 17,000 MDLs which collect readings from about 440,000 gas and hot water meters.

Over the 2020-25 period we have replaced the modems on our MDLs, to adjust for the shifting to Narrow Band Internet of Things (NB-IOT) gateways, to ensure they continue to function following the obsolescence of 3G networks.

MDLs are a bespoke solution build specifically for Jemena over 20 years ago. This technology is now obsolete, with high risks around the continuation of ongoing support. Over the 2025-30 period we will commence a trial of new remote reading technology. We will test shortlisted solutions on 500 meters across several high-rise buildings. The results of this trial will enable the identification of the replacement system for our MDLs.

We will also continue to replace the internal batteries of our MDL units, to ensure that data is retained if mains power is interrupted.

Table 4.8 Meter data logger capex ($2025 millions)

	2020-25		2025-30
	Allowance	Actuals/estimate	Forecast
3G obsolescence	0.6	2.6	-
Battery replacement	4.0	3.8	5.7
Technology trial	-	-	1.3
Total	**4.6**	**6.4**	**5.9**

4.5 Metreteks

Metreteks are devices which enable us to remotely read consumption for about 500 of our largest customers. These devices are critical to the accurate billing of our large customers and in many cases the function of the Sydney Short Term Trading Market, and our ability to manage Unaccounted for Gas.

Metretek technology is 20 years old with key components obsolete or discontinued. Maintaining the ongoing functionality of these systems is a high risk, given the risks around ongoing vendor support and our ability to obtain spare components.

We have also experienced challenges with the underpinning communication technologies. Metreteks were originally designed to communicate via dial-up connections (over the wired telephone system). With the roll-out of the NBN, we converted our devices to use the 3G wireless network. Due to the August 2024 planned shutdown of the 3G network, we have had to again retrofit our units to move them over to the 4G network.

Over the 2025-30 period, we will replace key components of the Metretek system (the volume corrector and modem – which were discontinued in 2022) deployed at 300 sites where consumption is above 27 TJ/annum. We will deploy a similar alternative product to maintain our ability to obtain the data required for accurate billing and to support the function of wholesale markets.

However, given obsolescence issues (with respect to components of our current system as well as the underpinning communication platforms), high costs and vendors risks we intend to explore alternative options. For instance, alternative remote reading technologies of digital smart meters designed for larger customers (i.e. with integrated flow correction and data transmission capabilities). We will do this through a technology trial at 10-15 sites with the outcomes to inform our future replacement strategy.

Table 4.9 Metretek capex ($2025 millions)

	2020-25		2025-30
	Allowance	Actuals/estimate	Forecast
NBN rollout	1.1	1.2	-
3G obsolescence		3.2	-
Obsolete component replacement with alternative product	-	1.3	9.7
Technology trial	-	-	0.5
Total	**1.1**	**5.8**	**11.5**

4.6 Defective and meter upgrades / downgrades

The last component of our metering program is our defective and meter upgrade/downgrade programs. These programs include the replacement of defective meters, regulators and associated equipment. It also includes replacing meters that need to be upgraded or downgraded to align the meter capacity with customer usage.

To forecast our capex in these programs, we generally apply the average of revealed annual costs incurred over the last four years.

Over the 2020-25 period, we have found that this approach materially underestimated the costs of our residential defective gas and hot water meters. This is because an average approach does not reflect the expected rise in failure rates as our fleet of meters lives are extended and due to the growth in our customer base. Given that we are extending the life of these meters further we expect that the defective rate will continue to increase.

As a result, we have adjusted our forecast of residential gas meter defective replacement rates by 1% for those meters older than 30 years. We note that our forecast planned program takes into account defective meters in forecasting the meters due for replacement, to ensure that we do not double count meter replacements in both our defective and planned programs.

Over the 2020-25 period we also found that our defective regulator and meter upgrade/downgrade costs were lower than expected. As we use historical costs to project forward our defective meter program, these cost savings have been incorporated into our 2025-30 forecast.

Table 4.10: Defective and meter upgrades capex ($2025 millions)

	2020-25		2025-30
	Allowance	Actuals/estimate	Forecast
Defective Regulators	10.9	5.6	5.2
Defective Residential Gas Meters	6.0	9.3	11.2
Defective Residential Hot Water Meters	10.0	11.0	13.1
Meter Upgrade/downgrade	9.6	6.5	6.6
All others	4.8	3.2	3.3
Total	**42.1**	**39.8**	**43.7**

4.7 Customer Access Program

We currently have a large number of 'chronic no access' meters which we cannot regularly read. This is generally due to the meters being located in an inaccessible area of a customer's home or premise (and the customer has not provided means for access).

Over the 2020-25 period we have reduced the number of chronic no access customers using various strategies including:

- Operational changes – including seeking access to Abloy keys, sending meter readers out at different times of the day (e.g. to access a meter located inside a restaurant), and coordinating with retailers to seek access.
- Deploying wireless radio frequency technology – this allows us to read meters without entering each dwelling.
- Gas Meter Mate – a mobile app which enables customers to submit a self-read.

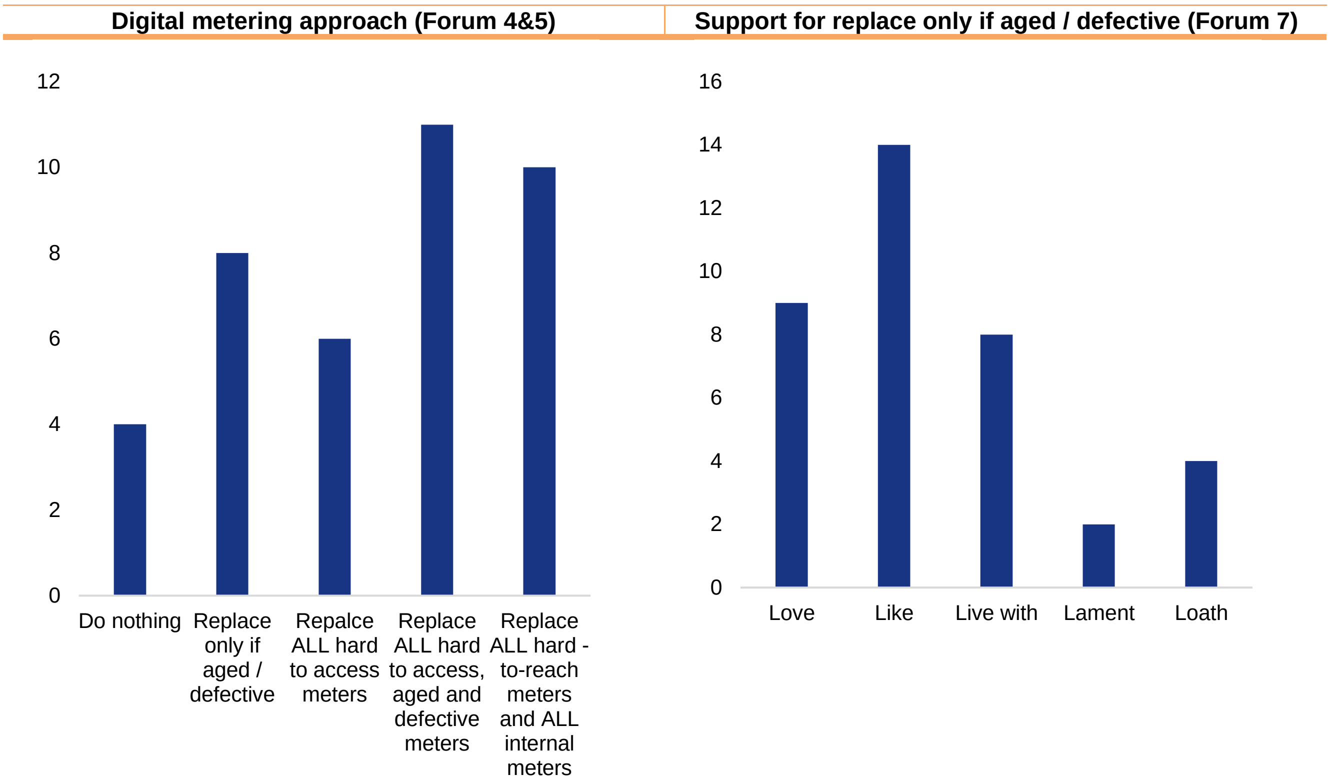
Despite these endeavours, accessing our customers meters continues to be a challenge. This makes it difficult to deliver our Transportation Reference Service (which includes meter reading), provide data to the market and ensure customers have accurate usage information.

Digital meters are a solution to this long-standing problem. Across Australia, water utilities and the electricity market are moving to digital metering. Globally there is a shift towards using digital meters in gas. More recently, AGIG have proposed (and the AER accepted) deploying 4,693 meters identified as inaccessible or difficult/dangerous to access.[78]

We engaged our Customer Forum on both whether to use digital meters and the extent of the rollout, as outlined in Figure 4.4.[79]

[78] See here (page 2) for example.
[79] *JGN-BD infrastructure-Att 2.2-Customer Forum Engagement Report*, p.38

Figure 4.4 Customer Forum Feedback on the options presented



Aligned with customer support for the aged / defective option (8,000 meters) and the need to ensure that our customers meters are read accurately, over the 2025-30 period we will provide those customers considered the worst affected with chronic no access issues with a digital meter.

The costs for this program include the incremental digital meter costs (above what is already included in our planned residential gas meter program) as well as the ICT component required to integrate these reads with our internal billing systems.

Table 4.11: Meter Access ($2025 millions)

	2020-25		2025-30
	Allowance	Actuals/estimate	Forecast
RF Program	3.1	1.3	0.0
Gas Meter Mate	0.0	1.1	0.0
Digital meters	0.0	0.8	3.8
Digital meters (ICT component)	0.0	0.0	5.6
Total	**3.1**	**3.1**	**9.4**

5. Stay in business

Stay in business includes the expenditure we need to incur to continue to operate our network and keep it safe, reliable and secure.

While the future role of our network is uncertain, the plausible future scenarios developed by the Expert Panel indicate that customer numbers are unlikely to fall before 2030, and that our ageing network needs to be kept safe and reliable whilst aiming to lower our emissions until at least the mid-2040s.

Given this uncertainty it is imperative that we keep capex to a minimum. Over the 2025-30 period we will continue to constrain capex through our targeted risk-based approach to asset management. As outlined in Table 5.1, stay in business capex will be flat over the 2020-25 and 2025-30 periods. The increase required to extend the life of our high-pressure infrastructure is mostly offset by the reduction in mains augmentation expenditure (consistent with the reduction in forecast connections).

Table 5.1 Facilities and pipes replacement capex ($2025 millions)

	2020-25		2025-30
	Allowance	Actuals/estimate	Forecast
Integrity, safety and security	152.2	149.1	158.9
Mains Augmentation	43.8	25.5	11.5
Non-network	31.3	32.1	27.6
Total	**227.3**	**206.7**	**198.0**

5.1 Integrity, safety and security

Our gas network is the largest in Australia. It spans from Wollongong to Newcastle and includes several country networks. Our network has a high-pressure transmission backbone which enables us to supply large industrial customers (including power stations) as well as small residential and commercial customers. Accordingly, our network includes an extensive number of assets outlined in Table 5.2.

Despite the size of our network, our stay-in-business program is extremely lean, given the age and size of our network. This is why we have one of the lowest capital intensities of all energy networks regulated by the AER (as shown by Figure 1.2 presented in the overview). To remain capital efficient, we have been able to constrain capex by applying a targeted risk-based approach. We always seek to extend the life of our assets (with many operating well beyond their design life), without comprising on safety, and exploring non-network or reactive approaches to maintaining our assets.

Table 5.2 JGN Network Summary

Level	Component	Number
High-pressure	Trunk Pipelines (km)	271
	Primary Pipelines (km)	144
	Secondary Pipelines (km)	1,459
	Trunk Receiving Stations (TRS) and Packaged Offtake Stations (POTS)	55
	Primary Receiving Stations (PRS)	16
	Services	2,205
Medium and low pressure	Mains (km)	24,441
	High-risk areas	965
	Services	1,061,000
	Secondary District Regulator Sets	570
	Medium and low pressure District Regulator Sets	77
	Boundary Regulators	4,550

Over the 2025-30 period we will continue our existing programs to extend the life of our high-pressure infrastructure to maintain the safety, reliability and integrity of our network. These programs focus on assets that are now 40-50 years old and require additional investment to maintain their safety, reliability and integrity. We will undertake two broad programs:

- Pipeline integrity – Managing the integrity of our high-pressure mains, for instance by reconfiguring the pipeline to allow integrity assessments using In-line Inspection Technology.
- Obsolescence – Replacing obsolete equipment at our facilities, ensuring they meet modern standards and regulatory requirements and simplify their operational design to reduce costs.

The remainder of our program addresses a range of issues and risks we have identified, such as security risks as well as integrity issues due to water ingress at our facilities. We are also forecasting to continue to incur minor capex. This category captures all of the reactive works we undertake (rather than large-scale replacement programs) to retain network reliability.

As shown in Table 5.3, our integrity, safety and security capex is broadly in line with historical spend, with a small increase largely to continue our existing programs to extend the life of our high-pressure assets.

Table 5.3: Integrity, safety and security capex ($2025 millions)

	2020-25		2025-30
	Allowance	Actuals/estimate	Forecast
Pipeline integrity	69.6	39.9	53.6
Obsolescence	14.1	23.4	31.4
Other, including security	35.7	32.3	21.0
Minor capex, tools and equipment	32.8	53.5	52.9
Total	**152.2**	**149.1**	**158.9**

5.1.1 Pipeline integrity

Our trunk and primary mains are the central arteries of our gas network. Our trunk mains, which operate up to 6,895 kPa, run from Wollongong through to Sydney (Horsley Park) all the way up the Central Coast to Kooragang Island in Newcastle. Our primary mains, which operate at 3,500 kPa, are located in Wollongong and metropolitan Sydney.

Maintaining the integrity of these high-pressure mains is essential to keeping the community safe and continuing to be able to provide a reliable source of energy. Threats to pipeline integrity include corrosion, cracking, natural disasters (and other environmental events) and external third-party damage. These threats can lead to catastrophic failures and, if ignition occurs, injuries, fatalities, damage to nearby infrastructure and a disruption to supply.

We apply a risk-based approach to safety, through the application of AS2885, to reduce identified risks to as low as reasonably practicable (ALARP) through a combination of design, physical and procedural controls. We do this to assure ourselves and the wider community that our pipelines are safe and reliable. The identification of risk considers factors such as the pipelines age (where condition is difficult to ascertain), material, condition and location (including whether it traverses through urban or rural settings).

Over the 2025-30 period, we will:

- Continue our program of work to reduce the risks on the Sydney Primary Main (SPM).
- Reduce the pressure on the Wollongong Primary Main.[80] This will allow us to reduce the risk on the pipeline without spending a higher level of capex to reconfigure the pipeline to allow In-line Inspection (ILI), see box out below.
- Reconfigure the last section of the Northern Trunk to enable ILI, now required due to an updated risk assessment using data from the other sections on the pipeline.

[80] As outlined in our Pipelines Asset Class Strategy (*JGN-RIN Att - 4.3 - Pipelines Asset Class Strategy*) we always consider pressure reduction as an option (this is also our approach for the Lane Cove to Willough final section of the Sydney Primary Main). However, it is not always economically viable to maintain supply due to additional significant augmentation of the wider network required (which may also not be physically or practically possible).

Table 5.4 Pipeline integrity capex ($2025 millions)

	2020-25		2025-30
	Allowance	Actuals/estimate	Forecast
SPM: Depth of Cover, relocation	4.3	5.8	-
SPM: Enabling Inline Inspection	28.4	13.7	26.2
SPM: Coating Rehabilitation	1.3	2.3	-
SPM North: Enabling pressure reduction Stage 1	13.0	9.6	-
SPM North: Enabling pressure reduction Stage 2	19.0	5.0	18.2
Wollongong Primary Main: Pressure reduction	-	0.7	1.5
Northern Trunk: Enabling Inline Inspection	-	-	7.6
Total	**69.6**	**39.9**	**53.6**

Use of Inline Inspection (ILI)

Good industry practice, is to regularly inspect pipelines through the use of In-line Inspection (ILI) tools, commonly referred to as 'pigs.' Pigging a pipeline is the most efficient and effective way to identify defects which could have arisen since the main was first laid, due to threats such as corrosion or damage from an unreported third party hit.

We regularly inspect all of our newer pipelines. However, several of our high-pressure mains were built before ILI was industry standard. As our pipelines age the risk of failure increases. Without ILI, we cannot identify, monitor or rectify any defects which may result in a catastrophic failure.

Given the benefits of ILI, pipeline operators around Australia, where possible, are reconfiguring their older pipelines to facilitate ILI. For example, APA has reconfigured sections of its Victorian Transmission System to allow ILI.[81]

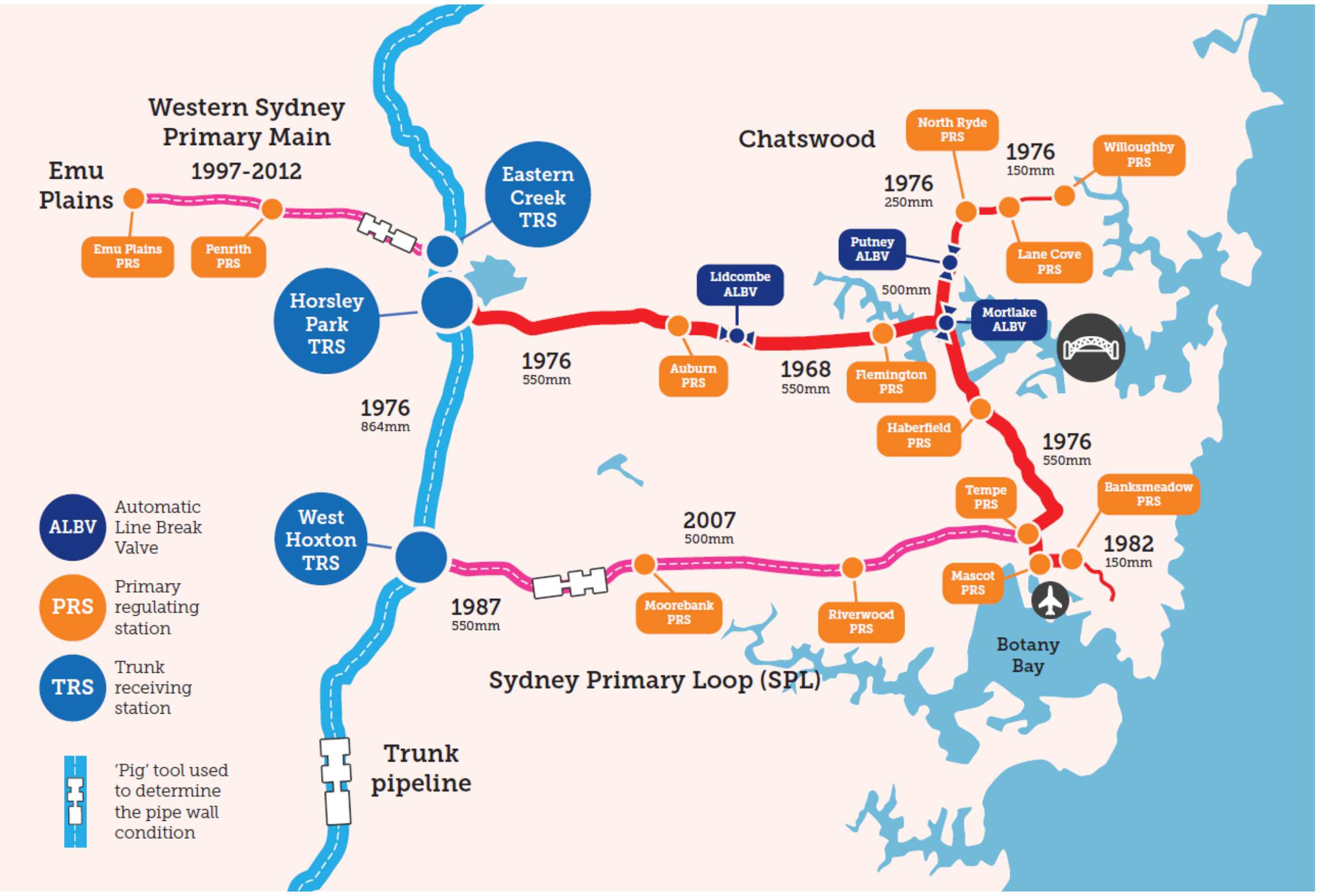
The works typically include installing 'pig launchers' and 'pig receivers' as well as bend inspection and rectification to ensure that the ILI tool can traverse the entire length of the pipeline section.

Sydney Primary Main

The Sydney Primary Main (SPM) is the central artery of the Sydney section of our gas network and travels through high density populated areas of Sydney. Figure 5.1 shows the SPM (red) as well as the Sydney Primary Loop and Western Sydney Primary Main[82] (both pink), along with our Trunk (light blue).

[81] See here.
[82] The Western Sydney Primary Main is made up of the Penrith Primary Main and another section from Penrith to Emu Plains.

Figure 5.1 Our Primary and Trunk mains in Sydney



The SPM is made up of several sections built at different times with different specifications by different organisations. The SPM is an ageing asset which has reached the end of its original design life. Without ILI, there is a significant risk that unmitigated or undetected material degradation could potentially lead to a catastrophic failure.

Accordingly, over the 2020-25 period, we commenced a program of work to reduce risks associated with our SPM to ALARP. This included:

1. Improving the depth of cover (to protect against third party hits which can resulting in gas escape and rupture of the pipeline.
2. Relocating a section of the pipeline in Canada Bay.
3. Enabling Inline Inspection (ILI). This project included the construction of ILI facilities (launchers and receivers) and bend rectification to ensure that the ILI tool can travel through the pipeline. This project is undertaken in stages:
    a. Horsley Park to Lidcombe.
    b. Lidcombe to Mortlake.
    c. Mortlake to Banksmeadow.
    d. Mortlake to Lane Cove (Stringybark). This section has been the final phase in the plan due to complexities arising from its single feed configuration and two different pipeline sizes.

A staged approach was undertaken to ensure security of supply, allow the overall strategy and program continuation to be reconfirmed at each stage and ensure that the insights and operational learnings can be integrated into the subsequent sections.

4. Reducing the pressure in the last northern section from Lane Cove to Willoughby.[83] Reducing the pressure in the northern section of the SPM requires additional secondary mains (stage 1 and stage 2) to be laid to ensure our network could meet current levels of demand.

There were some movements to our program throughout the period largely due to three factors:

1. The significant post-COVID supplier cost increases which increased the cost of relocation work, works to enable ILI and rehabilitating coatings. For example, the cost of relocating a section of the SPM had risen from $3 million to about $25 million. Given these cost increases, we re-evaluated the preferred solution and identified alternative solutions, such as adopting mechanical protection using HDPE plates or concrete slabs. We also limited our coating rehabilitation program to the two areas in the poorest condition. For the remainder of the SPM we have moved to a reactive (opex based) repair approach. Both strategies have significantly reduced capex.

2. Delays during construction of the modifications of the Horsley Park to Lidcombe ILI facilities. This was due to quality issues with the piping resulting in a completed spool (prefabricated piping) failing its hydrostatic pressure test. This resulted in the procurement of new pipe (a long-lead item) and the refabrication of the spooling. The inspection of this pipeline section was also delayed due to COVID-19 travel restrictions applying to our ILI suppliers. This section has now been successfully completed and inspected. However, the delays have flow on consequences delaying the completion of the subsequent sections.

3. Our decision to explore an innovative non-network option (biomethane injection) in the north of our network, to support network pressures rather than traditional network augmentation. This option had the potential to materially reduce capex by removing the need for stage 2 of the reinforcement of our secondary network as well as reducing customer emissions. However, this option was found not to be viable with the local biomethane resources available.

Over the 2025-30 period, we will complete the remainder of the SPM risk reduction program. The program reflects our best estimate of the remainder of the costs to complete the program.[84]

We note that we had previously sought advice from GPA Engineering to assess whether the costs of the program are proportionate to the risk.[85] If the costs are proportionate, then we are required to invest to ensure the risks from our network are ALARP as required under AS2885.6.

GPA Engineering considered the program by semi-quantifying the difference in risk based on the effectiveness of each option. This was then used in calculating a ‘maximum justified spend’ based on the UK’s Health and Safety Executive’s Cost Benefit Analysis checklist. GPA Engineering recognised that there is a large degree of uncertainty in attempting to numerically calculate the consequences and in turn costs of a distribution network incident. The maximum justified spend figures provides an order of magnitude indication on whether the proposed spend is proportionate to the risk as a means to demonstrate ALARP. This maximum justified spend calculations indicate that our program continues to be proportionate and is required to achieve ALARP.

5.1.2 Obsolescence

Our high-pressure facilities receive, measure, filter and reduce the pressure of gas as it flows through our network. They are critical components of our network both in terms of safety (responsible for the control and regulation of high-pressure gas, and isolation of gas in case of an incident) and reliability (each supplying thousands of customers).

[83] A different approach was taken with the last section as it is in the worst condition, has the smallest diameter (which means it will need the most works to reconfigure to allow ILI) and traverses through densely populated areas.
[84] Consistent with Rule 74.
[85] *JGN-RIN Att 4.3-GPA Risk Cost Method Report*.

Components of our ageing facilities – several approaching 50 years old – have reached end of life and must be replaced to ensure ongoing functionality.

While we have been able to extend the lives of our facilities well-beyond their original design life this is no longer possible. Given the change in good industry practice, standards and regulatory requirements, replacing these components of our facilities also requires that we replace the associated obsolete electrical instrumentation and control equipment (EI&C).

To identify opportunities to constrain capex given the uncertain future of gas, and deliver ongoing operational improvements, rather than undertake a like-for-like replacement, we have identified opportunities to simplify our station operating configuration. This reduces capex while addressing the identified safety, reliability and integrity risks.

This program is not new. We commenced this program of work in 2020-25 and have completed works at Haberfield PRS and Banksmeadow PRS.

Table 5.5 Obsolescence program ($2025 millions)

	2020-25		2025-30
	Allowance	Actuals/estimate	Forecast
Total	**14.1**	**23.4**	**31.4**

Over the 2025-30 period, as shown in Table 5.6, we will continue our program to replace obsolete components at our critical high-pressure facilities. Importantly, we note that this expenditure cannot be avoided or deferred given the age (and in turn condition) of these facilities as well as their criticality in ensuring that the safety, reliability and integrity of supply is maintained.

Table 5.6 Facilities included in our 2025-30 obsolescence program

Facility	Built	Customers
Horsley Park TRS	1977	320,000
Kooragang Island TRS	1980	1,500 (including one of our largest customers)
Hexham TRS	1984	70,000
Plumpton TRS	1977	90,000
Mascot PRS	1976	104,000
Flemington PRS	1976	110,000
Tempe PRS	1976	50,000
Penrith PRS	2010s	45,000

Further details on our facilities obsolescence program

Our facilities are comprised of:

- Above and below ground pipework – generally with multiple runs for redundancy or for supply of multiple downstream network sections (e.g. primary and secondary pressure pipework) and associated control values.
- Mechanical components – including regulators, control valves and automatic line break valves (ALBVs).
- Electrical, Instrumentation and Control (EI&C) equipment – such as control systems, air/power gas systems, remote telemetry units, communication equipment etc.

- Other equipment (depending on location) – such as water bath heaters, ILI launchers / receivers, filters, meters, gas chromatographs, cathodic protection units and security systems.

The overall design life for a high-pressure facility is about 30 - 40 years. However, the design life of various pieces of equipment is generally shorter. EI&C equipment generally has a design life of about 15 years due to significant changes in hardware, software and regulatory requirements (especially concerning cybersecurity) leading vendors to develop new replacement products and platforms. Mechanical elements (such as valves) generally have a life of about 20-30 years, as over time wear leads to performance degradation and thus safety, reliability and integrity risks.

Over the 40-year life of a facility there is also significant change with respect to:

- Good industry practice, design and regulatory requirements. For example, 'the standard' AS 2885 was first published in 1987 (after when some of our facilities were constructed). Another example is to remove pneumatic valves as the preferred regulation technology, which in turn removes the need of an air or natural gas power system.
- Products and support available from manufacturers. Often specific products are withdrawn from sale (and replaced with newer models) or manufacturers no longer exist.

We have been able to extend the life of several elements of our facilities. For instance, by periodically refurbishing the pressure control valves by machining them back to specification. However, the valves are now in a condition where this is no longer possible and need replacement. In replacing the control valves, we need to ensure that the associated EI&C components comply with current good industry practice, standards and regulatory requirements.

5.1.3 Other

In addition to our pipeline integrity and obsolescence programs, to maintain the safety, reliability and integrity of our network we will need to undertake a series of other works.

Over the 2020-25 period we addressed risks with our shallow secondary mains in densely populated areas and pipework in pits (where the structural integrity was compromised) and improve the security of our facilities.

Overall, our spend in the 2020-25 period will be consistent with the allowance. We were able to use the efficiency savings from the optimised scope of the shallow mains program (enabled by the results of our depth of cover surveys and ability to deploy protection measures rather than relocate mains in several locations) to address other risks relating to our Automatic Line break Valves (ALBVs), security of our facilities as well as higher costs to complete the pipework in pits program.

For the 2025-30 period we are forecasting other capex spend to fall. We plan to address identified security risks at our high-pressure facilities and complete our ALBV and facility water ingress programs of work.

Table 5.7 Stay in business other capex ($2025 millions)

	2020-25		2025-30
	Allowance	Actuals/estimate	Forecast
Shallow mains	22.1	9.7	-
Pits	3.6	4.2	-
Facility Water Ingress	-	1.3	4.0
Automatic Line Break Valves	-	3.4	3.7
Security	2.5	4.7	9.2
Other	7.4	8.3	4.2
Total	**35.7**	**31.5**	**21.0**

5.1.4 Minor capex, tools and equipment

The category 'Minor capex, tools and equipment' covers ad hoc expenditure to address issues and purchase tool and equipment. This category covers items where risks are identified and corrected in short timeframes to maintain the integrity, sustainability, safety and reliability of our ageing network.

This category can be split into the following components:

- Replacement – Replacing components or rectifying issues across our pipework which includes our critical cathodic protection systems and high-risk valves, 55 Trunk Receiving Stations / Packaged Off-take Stations, 16 Primary Receiving Stations, 647 District Regulator Sets, 1,061,000 million customer services and 4,550 boundary regulators.

- Relocations – From time to time, government authorities or private landowners require us to move gas mains or facilities to enable the authority to perform works such as road re-alignment or widening, or to make way for activities that the land owner has planned. Where arrangements with the relevant authority or landowner do not provide us with a right guaranteeing the location of our assets, we are bound to relocate them as required by the authority or landowner at our own expense. In cases where we do have rights, we will recover the cost of relocation from the authority or landowner.

- Tools and equipment – This minor expenditure is necessary to safely operate the gas network and includes, but not limited to gas masks, gas detectors, bench grinders, heavy duty battery drills, road drillers, wet and dry vacuums, safety equipment, purge burners, temperature probes and Dräger gauges

- Interconnects – This category includes the cost of undertaking small mains interconnects on our existing low and medium pressure networks to prevent (or in response to) low pressure that would lead to loss of supply or enable reduction in emissions through pressure management. This expenditure complements the larger mains rehabilitation projects outlined in section 5.2, which require more substantial augmentation, generally in the form of laying additional mains to reinforce the local network.

While this expenditure varies year-to-year it is broadly recurrent over time. Accordingly, we generally forecast this capex component using a 3-year average of expenditure over 2020-21, 2022-23 and 2022-23.

However, for two sub-categories we have shifted to applying a two-year average where there has been a step increase in costs (and a three-year average would not produce the best estimate in the circumstances). Specifically, these step increases in costs are for:

- District regulator sets – to modify the lid and drainage systems to reduce water ingress and reduce the risk of accelerated corrosion and avoid early full replacement. This adds $1.3 million to the forecast.

- Pipework – to inspect and remediate seven river crossings. This adds $1.3 million to the forecast.

The move to direct emissions measurement will likely result into an increase in ad hoc mains replacement. However, given the uncertainty around the size of the anticipated increase this has not been factored into our forecast.

Aside from the adjustments to the district regular sets and river crossings, this category does not include planned projects to address identified risks or opportunities. Expenditure related to these items is included as project specific line items.

Table 5.8 Minor capex, tools and equipment capex ($2025 millions)

	2020-25		2025-30
Driver	Allowance	Actuals/estimate	Forecast
Replacement	21.6	40.2	38.9
Relocations	3.8	2.7	3.4
Tools and equipment	3.4	6.0	5.6
Interconnects	4.0	4.6	4.9
Total	**32.8**	**53.5**	**52.9**

Further information on this category is available in our Minor Capital Works Plan.[86]

5.2 Load driven augmentation

Load driven augmentation includes capex related to installing new gas mains and district regulators to ensure that our network has sufficient capacity to support:

- New customers – typically to enable us to supply gas to existing areas which are being developed through the construction of medium density and high-rise apartment buildings. [87]
- Peak demand growth from existing customers – historically, from the roll-out of continuous flow hot water and, more recently in select pockets of our network, higher levels of peak gas demand due to a post COVID shift towards working from home.[88]

We also augment our network when we replace mains or as part of activities to maintain the integrity of our network or to enable the reduction in network pressures to reduce emissions (see section 3.40). As the primary driver of this expenditure and associated categories is not load driven, expenditure of this nature is not included in this category.[89]

We are forecasting load driven augmentation to fall by 58%, which is larger than the drop in connection numbers (43%) and dwelling numbers (41%) expected over the 2025-30 period. This is shown in Figure 5.2 and Table 5.9. This is due to the drop off in expected augmentation that would support the supply of gas to new estate areas and cities (such as the Aerotropolis).

We will need to continue to reinforce our low-pressure networks in areas where high-rise apartments will continue to connect and to address peak demand growth issues in isolated pockets of our network.

We also note that the reduction in new connections will reduce the additional supporting mains and interconnections which would normally be laid as the network is extended. As a result, additional reinforcement may be required in these areas as these estates are completed. This is difficult to forecast as it will depend on the number of customers on line-of-main in these areas which connect. Given the uncertainty around these locations no expenditure has been forecast.

[86] *JGN-RIN Att 4.3-Minor Capital Works*.
[87] Justified under Rule 79(2)(b) as the present value of the expected incremental revenue to be generated as a result of the expenditure exceeds the present value of the capex. NPV models are attached which demonstrate this for all augmentation projects in our 2020 Plan.
[88] Justified under Rule 79(2)(iv) to maintain capacity to meet levels of demand for services existing at the time capex is incurred.
[89] Mains rehabilitation is included in the *JGN Emissions Reduction* category see section 2. Integrity related expenditure is included in *Pipeline Integrity* see section 4.6.

Figure 5.2 Load driven augmentation (left hand side) and connection numbers (right hand side) ($2025 millions)

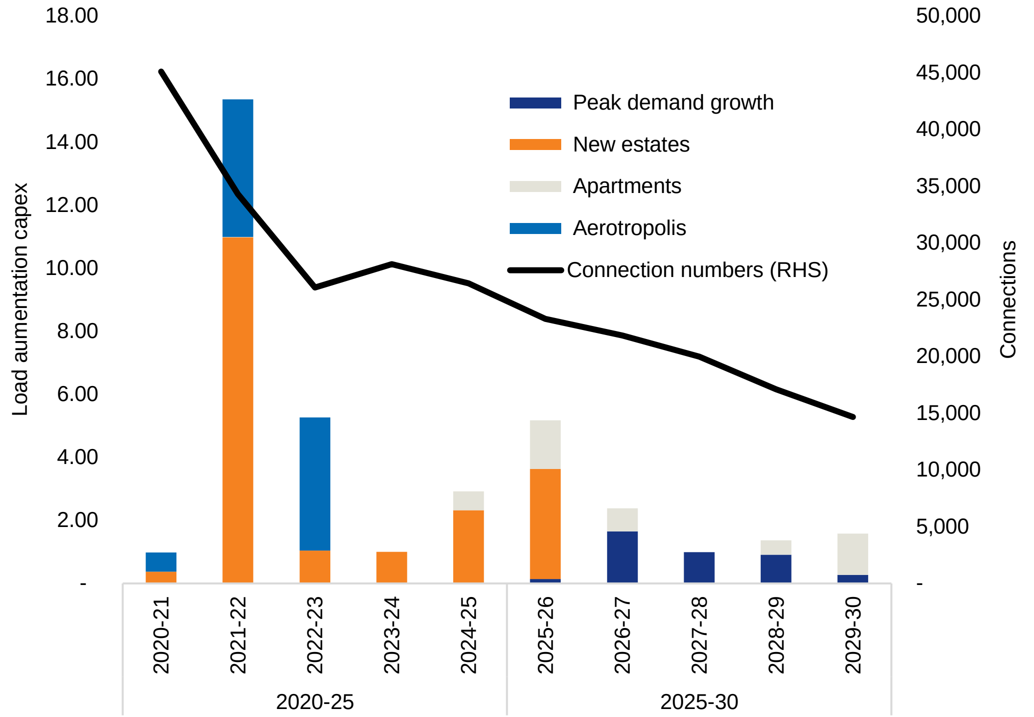


Table 5.9 Load driven augmentation capex ($2025 millions) and connection numbers

	2020-25		2025-30
Driver	Allowance	Actuals/estimate	Forecast
New estates	25.0	15.7	3.5
Apartments	2.3	0.6	4.0
Aerotropolis	16.5	9.2	-
Peak demand growth	-	-	4.0
Total	**43.8**	**25.5**	**11.5**
Connections (number)	144,711	124,633	68,829
Dwellings (number)	217,947	160,053	96,889

Further information on this category is provided in our Network Pressure Management Plan[90] and the Box Hill Options Analysis.[91]

5.2.1 New customer driven augmentation

Connecting new customers often requires our existing network to be strengthened. This generally involves installing new feeder mains and regulators.

Over the 2025-30 period, we are forecasting to connect 44,679 new homes and 37,246 high-rise dwellings. While lower than the 2020-25 period, this is still a significant amount. It is equivalent to connecting the whole of Newcastle over 5-years.[92]

[90] *JGN - RIN - 4.3 - Network Pressure Management Plan.*
[91] *JGN-RIN Att 4.3-10068428 - Box Hill CDP – OA.*
[92] With 106,000 dwellings, see here.

To support the connection of these customers we are proposing a limited number of augmentation projects. These include:

- Completing the final stages of projects to supply new areas in Edmondson Park and Box Hill by 2025-26. We are not forecasting any new estate augmentation projects for the remainder of the 2025-30 period.

- Undertaking three projects (in North Sydney, Auburn and Campsie) to address poor or no supply issues in low pressure CBD areas with limited or no spare capacity and the forecast connection of new high-rise apartments and medium density housing.

5.2.2 Peak demand growth

Historical approach and strategies to reduce capex

Growth in peak gas use reduces the pressure within the network and can lead to poor or no supply outcomes. Historically we have seen peak growth occur due to several factors:

- Appliance upgrades – Customers installing high-demand appliances, such as continuous flow hot water systems, significantly increase peak consumption. These systems use large quantities of gas in short periods during peak hours.

- Housing development – Renovations or additions to existing homes often lead to the installation of additional or new high-demand appliances, such as multiple continuous flow hot water services and pool heaters.

- Changes in commercial use – The repurposing of commercial spaces, such as a building transitioning from general office use to a small manufacturing facility or a restaurant, can also elevate peak demand.

Peak demand continues to grow, although at a slower rate. The reduced growth rate is due to several factors including the saturation of continuous flow hot water systems as well as the shift towards reverse cycle heating. We also expect customer connections in existing areas to reduce. Over the 2025-30 period, we expect to connect in existing areas around 9,000 residential customers and 3,000 new industrial and commercial customers.

We have sought to take advantage of this slowdown to reduce the threshold for investment. We previously augmented our network to provide additional capacity when network pressures fell below 70kPa.[93] With the use of new electronic gauges, which allow us to monitor more locations with greater data granularity, we now use 40kPa as a guide in existing areas and 70 kPa in new estate areas.

It is only possible to apply this lower threshold as the increase in peak demand (and drop in pressure) is slow enough that we have sufficient time to identify the issue and take action to avoid poor or no supply outcomes. However, this is generally only possible in the larger interconnected parts of our network. Greater caution is required with our smaller, longer, small bore, isolated networks and for new estate areas where pressure drops occur rapidly and we need to react quickly.

Improving capacity in existing areas has the ancillary benefit of enabling pressure reduction in upstream network sections and supporting broader measures to reduce fugitive emissions, see section 3.4.

COVID-19 and our forecast constraints

One outcome of the COVID-19 pandemic is a shift in working from home. People who previously relied on workplace heating have found themselves needing to keep their own homes warm throughout the day, leading to higher winter heating loads and in turn peak demand.

During the COVID-19 lockdowns we saw gas consumption increase and pressures, particularly in some pockets fall below pressures which would normally trigger investment. We held off investing as we were unsure whether

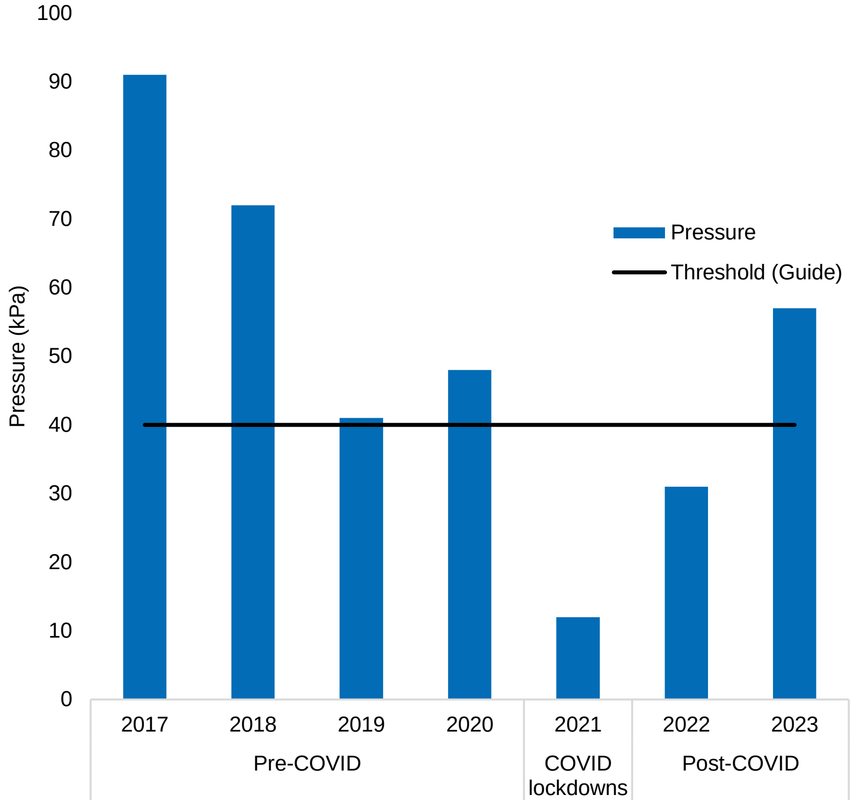
[93] We also need to consider the interactions between each layer of our network. For instance, lower pressures on our secondary network may cause capacity constraints at the medium pressure level.

this increase will be a one-off or will continue. We have found that in some areas post-COVID increase in peak demand has been sustained, likely as hybrid work has become the norm.

Take for example, the minimum pressures observed in Figtree (a suburb in Wollongong) shown in Figure 5.3. Prior to COVID pressures were around 70 - 80 kPa but fell to 12 kPa in 2021 when COVID lockdowns were in place.

To date in 2022 and 2023 we have seen minimum pressures rise – but they remain below pre-COVID levels, even though recent winters have been relatively warm. There is a risk that on severe winter days when people are working from home pressures may drop below critical thresholds and lead to a loss of supply.

Figure 5.3 Figtree minimum pressures



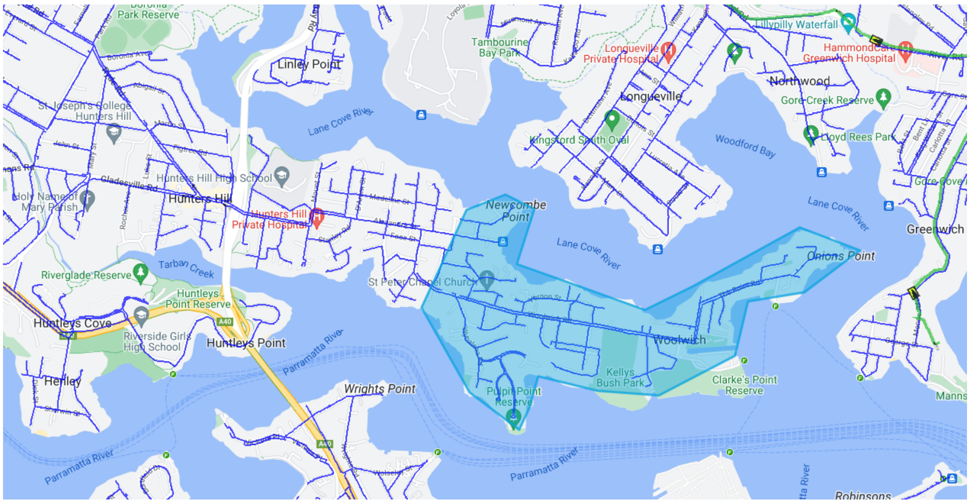
A challenge we face is that hybrid work complicates the relationship between weather and peak demand. The impact of cold weather on peak demand will increasingly depend on whether the peak cold day occurs mid-week (when people tend to be in the office) or on a Monday or Friday when people tend to work from home. This increases the uncertainty of our pressure modelling. For instance, the day with the lowest maximum temperature in June 2023 occurred on a Wednesday. This makes it difficult to forecast the peak demand if the coldest day had occurred on a Monday or Friday.

Nevertheless, across most of our 25,000 km network, there is sufficient capacity on our network to accommodate post-COVID changes in peak demand. However, low pressure risks are particularly high in certain pockets where:

1. Working from home is more prevalent, such as areas with larger numbers of office workers.

2. Our networks are made up of longer linear mains with a limited number of interconnects – both of which lead to higher pressure drops at the extremities of the network.

Figure 5.4 Our Woolwich network made up of long single bore feeds



As a result, we will need to augment several smaller pockets of our network in Woolwich, Bayview, Gymea Bay, Figtree and Umina Beach. Each of these locations can be supported with cost-effective plastic main extensions to reinforce the local network. No augmentation to our secondary steel secondary network or additional regulators are required.

In addition to these projects, we will also augment our Goulburn network which largely serves the town's commercial areas. The challenge with this network is that it is a low-pressure network (7kPa) – most of our network is made up of medium pressure mains operating at 210 kPa – which cannot accommodate an increase in peak demand without augmentation. Again, this constraint can be resolved with a cost effective (relative to secondary steel mains) plastic mains extension.

Overall, while we have identified a number of constraints across our 25,000 of mains largely due to changes in post-COVID consumer behaviour, the overall capex requirement is low as all of these constraints can be resolved with plastic mains extensions.

5.2.3 Alignment with RIN categories

The RIN includes two overlapping categories:

- Mains augmentation capex: Capex incurred by a *pipeline service provider* due to a change in the capacity requirements of mains and services in the gas distribution network or gas transmission pipeline to meet the demands of existing and future *customers (gas)*.

- Connections capex: Capex incurred when connecting *customers (gas)* to the *pipeline service provider's gas distribution network* or *transmission pipeline*.

The categories overlap as sometimes it is necessary to augment our network to enable a customer to connect.

For the RIN, if augmentation expenditure is incurred as a result of a connection offer being made in accordance with Part 12 of the National Gas Rules, we have categorised the costs as connections capex. This ensures alignment with the Capital Expenditure Incentive Mechanism (specifically clause 13.1(b)(v)) in our Access Arrangement).

However, several recent projects allocated to 'connections capex' in the RIN provide capacity for multiple connections. For example, the mains connecting the Aerotropolis and a developer funded secondary main extension were constructed to provide capacity for thousands of connections in these areas, rather than sufficient capacity for one specific customer.

To show a consistent relationship between load driven augmentation and our overall connection program over time we have also included these projects in this 'Load driven Augmentation driver category.

5.3 Non-network

Non-network capex includes property and vehicle costs required to support the operations of our networks. Our 2020-25 non-network capex[94] was largely in line with the allowance. We are not forecasting any material change in either property or vehicle costs for the 2025-30 period, as shown in Table 5.10. We will continue to spend the minimum required to maintain our properties and fleet to ensure that they remain fit-for-purpose to support the efficient delivery of our services.

Table 5.10 Non-network capex ($2025 millions)

	2020-25		2025-30
	Allowance	Actuals/estimate	Forecast
Property	12.6	15.5	7.5
Vehicles	18.7	16.6	20.0
Total	**31.3**	**32.1**	**27.6**

5.3.1 Property

To support the delivery of services, we own or lease a range of properties. This includes office buildings, depots, Emergency Equipment Holding Areas and warehouses. Each year we incur costs to maintain the function and quality of these properties, periodic costs to fit-out and refresh these sites or when we move locations. This can be driven by changes in the property market or a change in operational requirements.

Our property costs in 2020-25 are higher than forecast, largely attributable to the consolidation of our operations with the likely outcome that we move to a more central CBD location. Over the 2025-30 period, we are not forecasting any material change in our property spend and we will continue to maintain the condition of our existing property portfolio.

Further information on our property spend is included in our Property Paper[95] and Property Asset Class Strategy.[96]

5.3.2 Fleet

To ensure we can deliver our investments and respond to network incidents we continually invest in our fleet of vehicles. A modern fleet, and adoption of the latest technology such as autonomous emergency braking, is essential to maintaining the safety of our staff and the wider community as well as reducing lifecycle costs, emissions and ensuring our ongoing operational capability.

Accordingly, we replace our vehicles based on their individual performance and condition and consistent with good industry practice replacement timeframes. For our light commercial and passenger vehicles this is generally at the 150,000km mark (about 5 years old). However, we do replace some vehicles slightly earlier (4 years) based on historical data where we have seen increases in maintenance costs and down-time in specific vehicle models.

Overall, we are forecasting to replace a similar number of vehicles over the 2025-30 period as we have over the 2020-25 period (~220 vehicles).

While the number of vehicles replaced is steady, forecast capex is 17% higher primarily due to the increase in the cost of vehicles. Since COVID-19, due to global supply chain issues and microchip shortages, have led to higher

[94] Our proposal represents the minimum cost to maintain these supporting assets and in turn will achieve the lowest sustainable cost of providing services consistent with Rule 79(1)(a). These items are justified under Rule 79(2)(c)(i) and (ii) as this capex is required to maintain the safety and integrity of services.
[95] *JGN-RIN Att 4.3-JGN Property Capex Program 2025-30*.
[96] *JGN-RIN Att 4.3-Property Asset Class Strategy*.

vehicle prices. While supply chains are recovering, we expect that prices for our predominately light commercial fleet will continue to increase with the introduction of:

- The Australian Government's New Vehicle Efficiency Standard which is expected to come into effect from 1 January 2025 with a catch-up period until around 2028. This standard implements a maximum annual average level of carbon emissions across a manufacturer's overall car sales. To sell the larger vehicles manufacturers will need to sell more fuel-efficient models as an offset or purchase credits from another supplier. This will increase the cost of vehicles we require.

- 'Euro 6d' equivalent noxious emissions standards for light vehicles (including commercial vehicles with a gross vehicle mass up to 3.5 tonnes). All light vehicle models approved and supplied to Australia for the first time on or after 1 December 2025 will need to comply with these standards. This will increase the costs of new vehicles as they will need to be fitted with new emission reduction technologies.[97]

Over the 2025-30 period, we will continue to evaluate the adoption of new technologies, including consideration of hybrid, electric and hydrogen powered vehicles. We expect that these will become an increasing practicable and efficient option. This is due to the expected cost increases for internal combustion engine options (as outlined above), as well as lower cost of alternative fuels and their lower emissions footprints.

Accordingly, we have set ourselves an aspirational target of converting 25% of our fleet to either hybrid, electric of hydrogen powered vehicles over the next 5-years. While these vehicles will bring significant benefits, they also cost more to purchase. However, as we expect the costs of the various options to become more comparable and to ensure we balance our customers' expectations of cost and emissions, we have not included these additional costs in our forecast. Our forecast has been prepared on the basis that we will continue to use like-for-like vehicle types.

Further information is available in our Fleet Asset Class Strategy[98] and Fleet Model.[99]

[97] Department of Climate Change, Energy, the Environment and Water and Department of Infrastructure, Transport, Regional Development, Communications and the Arts 2023, *Improving Australia's fuel and vehicle emissions standards – Final impact analysis*. p.71 and 82 Available here.
[98] *JGN-RIN Att 4.3-Fleet Asset Class Strategy*.
[99] *JGN-RIN Att 4.3-Fleet Model*.

Appendix A
NGR Compliance

NGR Compliance

For capex to be included in the capital base it must conform with the three criteria outlined in Rule 79 of the NGR.

Efficient

The first criteria is that the expenditure must be efficient, or specifically what *"...would be incurred by a prudent service provider acting efficiently in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services in a manner consistent with the achievement of the national as objective..".*

We have a long history of efficient delivery. Our strong performance has led to:

- An track record of relatively low expenditure, as outlined in the overview and in Figure 1.2, while keeping our ageing network safe.
- Being one of the first businesses in Australia to achieve ISO 55001 Asset Management certification demonstrating that our processes and systems are robust and consistent with industry best practice and in turn support the efficient delivery of our investment program.
- Ensuring that the network continues to perform to our customers' expectations around safety and reliability while reducing emissions. This is evidenced by our consistently strong performance in responding to emergency incidents and comparable reliability performance across Australian gas businesses.

Our focus on cost efficiency and delivering gas network services in line with accepted good industry practice is weaved throughout our proposal. For instance, our forecast costs are generally based on our past costs to ensure that the historical cost savings we have achieved flow through to our forecast.

We also note that, with the addition of an emissions reduction objective this rule changed to explicitly reference the National Gas Objective to ensure that lowest sustainable cost is considered in the context of achieving emissions reduction targets. Accordingly, our proposal seeks to efficiently reduce emissions through the delivery of pipeline services. For further details see *JGN-Att 4.1-Emissions reduction program* and section 3.

Justified

The second criteria outlines what capex must achieve for it to be justified. All of our capex programs achieve one (or sometimes several) outcomes specified by Rule 79.

Table 5.11 below provides an overview of the justification of each capex category against Rule 79(2).

Table 5.11: Justification of capex driver categories against NGR

Driver category	Justification

Connections	Connections expenditure is justified as this expenditure:
	• Provides positive economic value to our customers (Rule 79(2)(a)). This is true for both:
	  – New customers – who choose to connect to our network as they consider the value from a gas connection is higher than the cost, made up of the combined connection charge (if any) and ongoing charges (which are always higher than the connection cost).
	  – Existing customers – who will receive bill reductions as a result of these new connections sharing more of the largely fixed costs of running the gas network.
	• Leads to incremental revenue greater than the incremental cost (Rule 79(2)(b)). We ensure that all of our connections (and any required augmentation) results in revenue that at least covers the cost of these new connections. Any additional revenue (above the connection cost) flows through to bill reductions for existing customers.

	• Is necessary to comply with Rule 119 (Rule 79(2)(c)(iii)) If the revenue from a connection does not exceed the cost we ask for a capital contribution in accordance with Part 12A of the NGR. This ensures that our connections expenditure (net of contributions) is justified against all three of the outcomes above.
Emission reductions	Emissions reduction expenditure is justified as it: • Contributes to the meeting of NSW and Australian Government emissions reduction targets (Rule 79(2)(c)(v)). • The overall economic value of the expenditure is positive, particularly when the economic value of changes to Australia's greenhouse gas emissions is considered (Rule 79(2)(b) and Rule 79(3)(b). Notably, several projects in the emissions reduction category are also justified on the basis of being necessary to: • Maintain the safety of services (Rule 79(2)(c)(i)). • Maintain the integrity of services (Rule 79(2)(c)(ii)) • Comply with regulatory obligations or requirement (generally due to a requirement to comply with a particularly standard such as AS29885 or AS4645) (Rule 79(2)(c)(iii)) Other projects are justified on the basis of a reduction in operating and maintenance costs (Rule 79(2)(a)), such as our Catalytic Heater program,
Stay in Business: Meter Replacement	The majority of our metering expenditure is justified as it is required to provide our reference service which includes "…meter reading and associated data activities, and the provision and maintenance of a standard metering installation at the Delivery Point as appropriate for the required capacity and meter reading frequency." It is also required to meet the requirements of the Gas and Electricity (Consumer Safety) Regulation 2018 (Rule 79(2)(c)(iii)) as well as to maintain the integrity of services (Rule 79(2)(c)(ii)) – without this spend we will not be able to continue accurately billing our customers.
Stay in Business: Load driven augmentation	We augment our network for several reasons including: • To cater for higher levels of demand when peak demand grows (Rule 79(2)(c)(iv)). • Enable new customers to connect to our network. This expenditure is justified for the same reasons as connections above. For each connection driven augmentation project we show that the incremental revenue is greater than the incremental cost of each project we are proposing (Rule 79(2)(b)). Improve the integrity of our network (Rule 79(2)(c)(ii)) or manage the safety risks borne by our customers, employees and the general public (Rule 79(2)(c)(i)). This is the case for the two additional secondary mains in northern Sydney which will maintain the safety and integrity of services and comply with our regulatory requirement to keep risks to ALARP. This expenditure will also lower our overall costs in operating the network leading to provide positive economic value to our customers (Rule 79(2)(a)).
Stay in Business: All other components.	This expenditure is justifiable as it is necessary to: • Maintain the safety of services (Rule 79(2)(c)(i)). • Maintain the integrity of services (Rule 79(2)(c)(ii)) • Comply with regulatory obligations or requirement (generally due to a requirement to comply with a particularly standard such as AS29885 or AS4645) (Rule 79(2)(c)(iii)) In some cases, this expenditure will also help reduce costs as it will result in reduce operating and maintenance costs (Rule 79(2)(a)).

Our document index[100] includes a list of our proposed capex projects and which rule(s) each project is justified against. This document also identifies all of our supporting documents mapped to each project.

[100] *JGN-RIN-Att 19-Document Index*.

Properly allocated to the reference service

The last criteria is that the capex included must be properly allocated between our reference service and our non-reference services (other pipeline services we provide by means of the covered pipeline). The pipeline services we provide are described in chapter 9 of the Final Plan.

We allocate our costs via the JGN Cost Allocation Methodology. It prescribes allocation of costs to the reference service and non-reference services provided by means of the pipeline, in accordance with Rule 93(2) of the NGR. The JGN Cost Allocation Methodology is included in *JGN - RIN - 4.10 - Jemena - Cost Allocation Methodology*. We have applied the JGN Cost Allocation Methodology to remove any non-reference service costs from the building block cost stack, and therefore the capex presented in this Attachment only includes that relating to the reference service.

Appendix B
RIN and capex driver category mapping

RIN and capex driver category mapping

We have grouped expenditure in our proposal by key driver to provide transparency on which is driving change in our expenditure over time. This categorisation doesn't necessary reflect the RIN categories. Accordingly, we provide a mapping to show the difference. A project level mapping is also provided *JGN-RIN-Att 19-Document Index* as well as the *JGN-Att 5.2M - Capital expenditure forecast model*.

Table 5.12 Mapping of driver and RIN categories

Driver Category	Driver subcategory	RIN Category
Connections		Connections, except: renewable gas connections and projects which provide capacity for multiple connections or connections for a broad area (see section 5.2.3)
Emissions reduction	Renewable Gas Facilitation	Renewable gas connections
	JGN emissions reduction	Mains replacement and other capex where projects result in material emissions reductions (see section 3.6)
Stay in business: Metering		Meter replacement
Stay in business	Integrity, safety and security	Other capex not included elsewhere.
	Load driven augmentation	Augmentation. Plus, Connections projects which provide capacity for multiple connections or connections for a broad area (see section 5.2.3)
	Non-network	Other capex which relates to fleet or property.
ICT		ICT and Telemetry

Appendix C
Capital Expenditure by Asset Class

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Capital Expenditure by Asset Class

In Table 5.13 below we provide a summary of capital expenditure by asset class.

Table 5.13 Capital Expenditure by Asset Class over the earlier 2020-25 access arrangement period ($2025 millions)

Asset Class	2020-21	2021-22	2022-23	2023-24	2024-25
Trunk Wilton-Sydney	-	-	0.8	0.1	-
Trunk Sydney-Newcastle	0.0	0.1	0.6	0.7	0.2
Trunk Wilton-Wollongong	-	-	0.0	0.0	0.7
Contract Meters	1.2	1.3	0.8	3.8	2.0
Fixed Plant - Distribution	9.1	6.3	1.6	8.2	25.5
HP Mains	9.5	16.4	29.9	19.4	28.1
HP Services	2.6	1.4	0.8	1.5	1.5
MP Mains	34.6	41.7	28.5	25.2	28.5
MP Services	71.9	58.3	66.2	53.2	50.5
Meter Reading Devices	2.8	1.6	2.7	1.8	1.8
Country POTS	0.0	0.2	0.4	0.0	-
Tariff Meters	33.9	25.0	28.4	26.2	31.2
Computers - IT Infrastructure	1.6	1.8	3.3	0.2	0.2
Fixed Plant	0.3	0.5	0.8	-	-
Furniture	-	-	-	-	-
Land	0.2	-	-	-	-
Low value assets	-	-	-	-	-
Mobile Plant	1.7	1.4	5.3	1.1	1.1
Vehicles	5.3	3.1	4.5	1.7	2.1
Leasehold Improvements (SL)	0.3	0.5	2.8	-	-
Buildings (SL)	0.1	0.2	0.7	5.1	5.7
Software - Inhouse (SL)	18.3	11.3	15.6	17.5	18.8
Total	**193.3**	**171.1**	**193.6**	**165.7**	**197.9**