December 2016

2018 to 2022 Access Arrangement Information

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1. A message from our Chief Executive

Natural gas has been a part of our lives since the 1850s, powering industry, warming homes, and enabling small businesses to keep our neighbourhoods vital.

Our 2018 to 2022 Access Arrangement proposal is our plan for how we will continue to provide the safe, reliable, and economical source of energy generations of Victorians have come to rely on.

Although it is not immune from the pressures of a changing energy landscape, our proposal reflects the inherent stability of gas in Victoria. It is more than just a fuel of choice, it is an everyday part of life.

We have consulted widely about our five-year plan and the message from our stakeholders is consistent: the demand for natural gas remains strong and so too does the expectation that we will play our role in keeping it accessible, economical, and reliable.

Throughout our consultation, we have challenged ourselves to have tough conversations with our stakeholders about what they want and value in their gas supply and how our plan can better reflect their priorities and interests.

By seeking a broad range of views from households, industry and small business, we have developed a plan that strikes the right balance between efficient and cost-effective investment, and ensuring the network is safe, reliable and ready for future demand.

We know our customers and stakeholders have high expectations of us and, as one of the most efficient gas networks in the country, our commitment to meeting those expectations is reflected in our 2018 to 2022 Access Arrangement proposal.

Tony Narvaez

Chief Executive Officer
Multinet Gas

2. Proposal snapshot

We set out in Table 2-1 the key elements of our Access Arrangement Information, which we explain and justify in the remainder of this document.

Table 2-1: Access Arrangement Information snapshot – Haulage Reference Services unless otherwise stated ($M, Real 2017)

	2018	2019	2020	2021	2022	Total
Capital expenditure forecast (gross) – includes equity raising costs*	115.8	98.9	103.1	103.4	96.1	517.3
Customer contributions	9.1	9.1	9.1	9.1	9.1	45.6
Regulatory asset base (end of year)	1,234.2	1,259.0	1,287.9	1,314.4	1,330.5	n/a
Revenue requirements						
Return on capital (WACC 6.12%)	52.0	53.9	55.0	56.3	57.4	274.6
Regulatory depreciation (forecast)	65.5	67.0	67.1	69.9	72.7	342.1
Operating expenditure (including debt raising costs, excluding Ancillary Reference Services)	74.8	75.7	76.7	78.0	79.4	384.7
Efficiency benefit sharing scheme (carryover amounts)	0.9	6.4	(0.4)	(3.2)	-	3.7
Corporate tax allowance (Gamma 0.25)	17.4	16.0	20.8	21.1	20.8	96.1
Annual revenue requirement (unsmoothed)	210.6	219.0	219.2	222.1	230.4	1,101.3
X factor (%)	(9.12%)	(2.00%)	(2.00%)	(2.00%)	(2.00%)	n/a
Tariff V – residential (TJs) (weather normalised, including marketing)	37,810	37,421	37,061	36,620	36,222	185,134
Tariff V – commercial (TJs) (weather normalised)	4,832	4,712	4,588	4,448	4,334	22,914
Tariff L (TJs) (weather normalised)	68	67	66	66	65	332
Total energy Tariff V and L (TJs) (weather normalised, including marketing)	42,710	42,199	41,715	41,134	40,621	208,379
Tariff D and L (MHQs - GJ/hr) (weather normalised)	3,672	3,638	3,599	3,578	3,545	18,032
Forecast customer numbers (including marketing)	700,865	704,501	708,154	711,571	715,071	n/a

Service classification and Reference Tariff Variation Mechanism	Service classification	Reference Tariff Variation Mechanism
Haulage Reference Services	No changes from current Access Arrangement period	Revenue cap
Ancillary Reference Services	One new service for the “installation of a service valve”	Schedule of fixed tariffs, adjusted by CPI

Non-Reference Services	Current listed services plus new general provision about other services requested by individual customers that differ from Reference Services	Not applicable
Incentive schemes		
Efficiency Benefit Sharing Scheme	No changes from current Access Arrangement period – see Chapter 18	
Network Innovation Competition	Proposed new mechanism – see Chapter 18	

* Gross capex forecast relates to Reference Services because it includes the cost of asset relocations (which are treated as Ancillary Reference Services), - these costs are netted out through customer contributions. This forecast also includes $2.3 million of capitalised equity raising costs.

3. About our Access Arrangement Information

This is our Access Arrangement Information that we are submitting to the Australian Energy Regulator (AER) for our forthcoming Access Arrangement period, 1 January 2018 to 31 December 2022.

We have developed this Access Arrangement Information following extensive communication and engagement with our customers and other stakeholders. It details, in particular, the revenues that we require to maintain the quality, safety, reliability and security of our distribution services, and of our assets that we use to deliver them.

We have also provided to the AER with this Access Arrangement Information:

- Our revised Access Arrangement Parts A, B and C;
- A range of supporting documents and models that provide further detail about our proposal – these are discussed in chapter 24; and
- Our responses to the AER's Regulatory Information Notice (RIN).

3.1. Regulatory context

We operate under a gas distribution licence issued by the Essential Services Commission of Victoria (ESCV). This licence sets out the conditions under which we provide services to our customers. Amongst other things, this licence obliges us to comply with various state-based regulatory requirements. One relevant instrument is the Victorian Gas Distribution System Code. This Code sets out the minimum standards for the operation and use of our gas distribution system. It imposes various obligations both on us as the gas distributor and on our customers.

In April 2013, the AER made its Final Decision to approve our Access Arrangement (including the terms and conditions and Access Arrangement Information) for our gas distribution network for the access arrangement period 1 January 2013 to 31 December 2017. We successfully appealed the Final Decision to the Australian Competition Tribunal (Tribunal) in relation to how the AER calculated our opening capital base. The AER remade its decision in October 2013 in accordance with the Tribunal's orders.

We have since provided our services in accordance with our approved Access Arrangement.

The AER's Final Decision for our forthcoming Access Arrangement period, 1 January 2018 to 31 December 2022, will determine the terms and conditions on which we provide our gas distribution services for the next five years, including the revenues that we can earn and the prices that we can charge for our services.

Section 28 of the National Gas Law (NGL) requires the AER to perform or exercise its functions or powers in a manner that "will or is likely to contribute to the achievement of the National Gas Objective" (NGO).[1] The NGO is set out in section 23 of the NGL and is to:

> *promote efficient investment in, and efficient operation and use of natural gas services for the long term interest of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas.*[2]

The AER must also have regard to the Revenue and Pricing Principles (RPP) in setting our revenues and prices for the next five years. The RPP are set out in section 24(2) of the NGL, which provides that:

> *A service provider should be provided with a reasonable opportunity to recover at least the efficient costs the service provider incurs in –*
>
> *a. providing reference services; and*

[1] Section 28 (1) (a) NGL

[2] Section 23 NGL

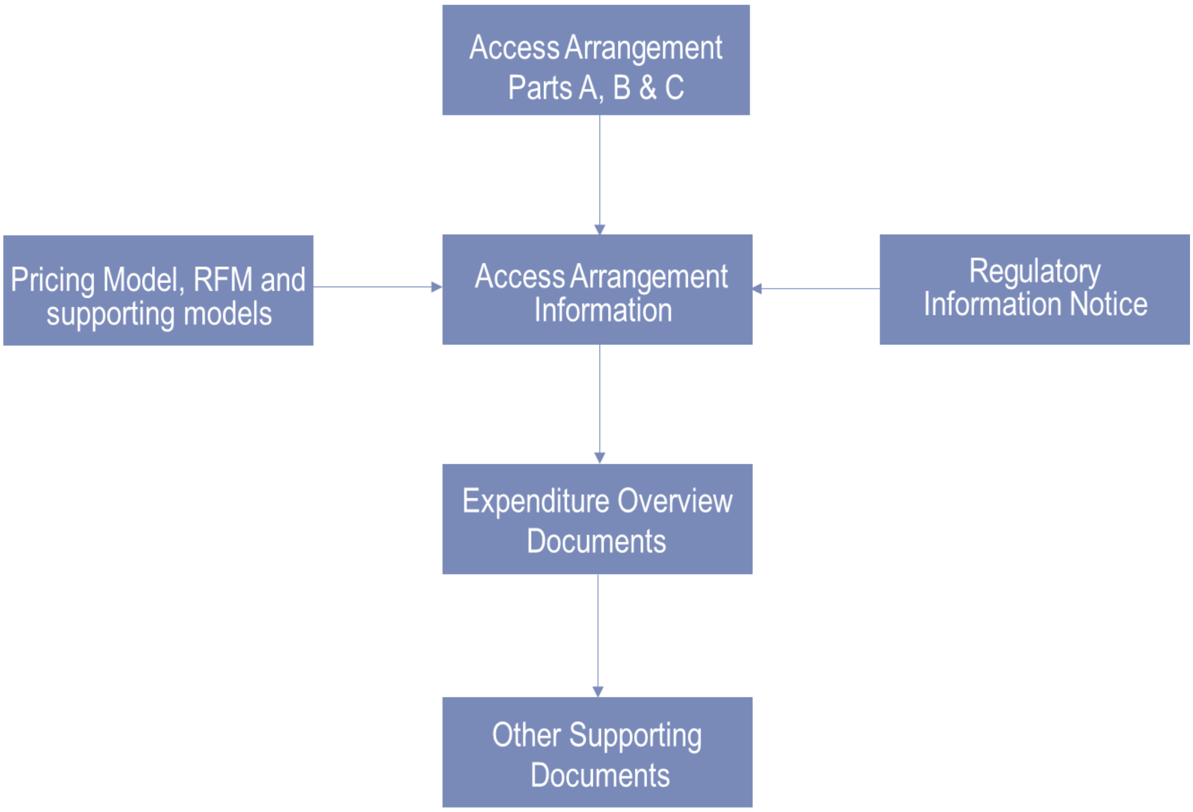
b. complying with a regulatory obligation or requirement or making a regulatory payment.

We have prepared this Access Arrangement Information to promote the NGO and the RPP.

3.2. Access Arrangement Information and supporting documents' structure

Our Access Arrangement Information and supporting documents are structured as follows to be as clear and accessible to our readers as possible.

Figure 3-1: Structure of our Access Arrangement documentation



4. Next steps and our stakeholders' feedback

Our customers and other stakeholders' views on our Access Arrangement Information are important to us. We welcome feedback through any of the following channels:

Channel	Details
Email	stephanie.mcdougall@ue.com.au
Post	Stephanie McDougall Price Review Manager Access Arrangement Review Feedback PO Box 449 Mount Waverley VIC 3149
Phone	(03) 8846 9900
Website	www.multinetgas.com.au

The AER has indicated that it will invite submissions on our Access Arrangement Information up until 28 February 2017. We will continue to engage with our stakeholders during (and after) this period, including to explain what we have proposed.

The AER will issue its Draft Decision in May 2017. We will then submit our Revised Access Arrangement Information to the AER in July 2017 and the AER will issue its Final Decision by 31 October 2017.

5. Business Overview

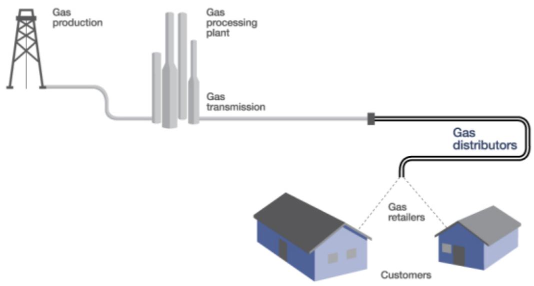
This chapter overviews our business and the customers that we serve. It also highlights our operating environment, our vision and our key future challenges.

5.1. About us and our network

We distribute gas to more than 690,000 customers in Melbourne's inner and outer east, the Yarra Ranges, and South Gippsland through a network of transmission and distribution pressure pipelines covering approximately 1,860 square kilometres.

We operate one of three separate regulated gas distribution businesses in Victoria. Our network consists of more than 10,000 kilometres of gas mains, seven city gate pressure reduction stations, 121 field regulator sites and 144 district regulator sites.

Assets on our network were first installed as early as the 1890's, although it wasn't until the 1950s that network assets started being installed in large numbers. From the late 1960s, the advent of low-cost and abundant natural gas in lieu of manufactured gas kick-started growth. The climate in our service area is temperate with cool winters that drive heating load. Due to Victoria's climate, relatively inexpensive and available gas supply and heavy marketing efforts through the 1970s and 1980s, residential gas heating penetration is now high.



Our pipeline network now covers about 43 per cent of Melbourne's metropolitan area. Our service area extends from Port Melbourne, near Melbourne's central business district, north-east along the Yarra River to the Dandenong Ranges, south-east to Gembrook, west to Lysterfield, south-west to Patterson Lakes on the shores of Port Phillip Bay and back along the bay to Port Melbourne.

In 2005, we extended the metropolitan network to nine towns in the Yarra Ranges as far east as Millgrove. We have connected customers in the South Gippsland and Yarra Ranges townships as part of the State Government's natural gas extension program. Most recently, we have completed gas reticulation in Warburton.

Multinet Gas' story began in July 1997 when the Victorian Government broke up Gascor to create three independent, competitive retail businesses. Each retail entity was 'stapled' to a distribution business, but with different franchise areas.

In March 1999, the 'stapled' distributor/retailer companies (Multinet Gas and Ikon Energy) were purchased by Energy Partnership Pty Ltd and were managed by United Energy Distribution under a management agreement. The retail company was moved to a joint venture between Shell and Woodside in September 2000 and re-badged as Pulse Energy. Pulse Energy was subsequently sold to AGL in July 2002.

MGH was established with DUET and Alinta Limited as shareholders in 2003 and this company acquired the equity in Energy Partnership Pty Ltd. Energy Partnership Pty Ltd was the holding company for the Multinet Gas gas distribution business. The Alinta Limited shareholding (20.1 per cent) of MGH was sold to Prime Infrastructure, who eventually sold their interest to DUET on 29 July 2011. DUET is now the sole owner of Multinet Gas.

5.2. Our customers

Our customer base is dominated by the stable, established residential sector, which makes up 98 per cent of our total customers, contributing 70 per cent of total consumption on our network and 94 per cent of our revenue.

Figure 5-1: Consumption profile by customer type

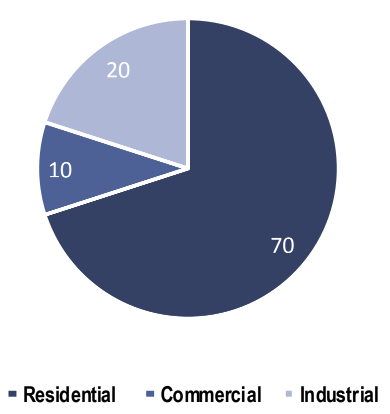
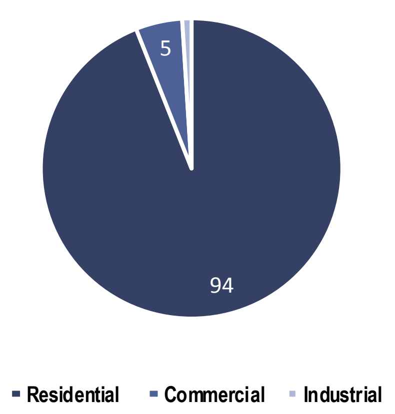


Figure 5-2: Distribution revenue profile by customer type



5.2.1. Residential customers

We have the highest residential connection per kilometre of main density in Victoria. This is because our service area is more compact than the two other Victorian gas distributors. Residential gas consumption per customer in our network is higher than both the other Victorian gas distributors and our customer base is continuing to grow, as shown in Table 5-1 and Table 9-4.

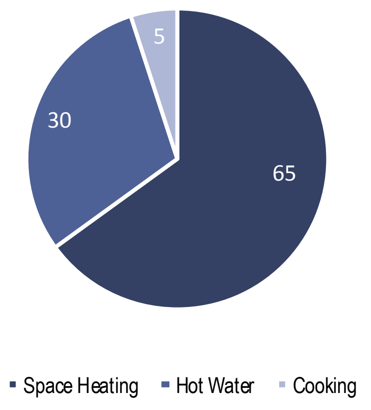
Table 5-1: Annual customer growth (per cent)

	2013	2014	2015	2016
Customer Growth (year on year change)	0.67	0.69	0.54	0.41

Average residential gas usage in Victoria rose rapidly over the 1970s and 1980s, and continued to increase until early 2000. However, since 2000, average residential usage has fallen. Residential weather normalised aggregate consumption has declined by about four per cent over the last five years and this trend is forecast to continue over the next five years. The drivers of this change include:

- Improvements in the efficiency of residential appliances and the thermal efficiency of new and existing homes (as a result of five-star building standard being phased in post 2005);
- A higher share of 'other' dwellings (i.e. multi-unit) being completed in recent years where electric reverse cycle heating/cooling is installed as an alternative to gas central heating;
- Behavioural changes in customers such as the increased use of electric reverse-cycle air conditioning, reduced hot water usage and higher penetration of solar water heaters;
- Rising wholesale gas prices, which AEMO has found will have the most significant impact on demand in the short term; and
- Urban warming weather trends.

Figure 5-3: Residential average appliance usage % mix



5.2.2. Commercial and industrial customers

Commercial and industrial customers account for approximately 30 per cent of our overall consumption and cover a broad range of industries.

Consumption patterns vary between industries but we have seen a fall in consumption in recent years due to reduced industrial load resulting, in particular, from the impact of the high Australian dollar on Australian industry and the contraction of domestic manufacturing.

5.3. Stakeholder engagement

We are committed to improving our stakeholder engagement, which means understanding what our customers expect from us and taking action to address their concerns. The following commitment underpins our stakeholder engagement strategy:

> *We will be an outwardly focussed business. We will embed effective stakeholder engagement throughout our operations and develop mature relationships with our stakeholders based on effective two-way communication and understanding*.

Our objective in adopting this approach is to place customers at the centre of our business. An important part of this cultural change is reflected in our goal of providing an effortless customer experience.

We discuss in chapter 7 the outcomes of our recent stakeholder engagement and how they have informed our proposals in this Access Arrangement Information.

5.4. Our corporate mission and objectives

Our mission is the safe, reliable and efficient distribution of gas to customers within our distribution area.

Our objectives are to deliver value by:

- Maximising shareholder returns while ensuring long term financial sustainability;
- Aligning the interests of customers, shareholders, financiers and other stakeholders through delivering:
    - good customer service;

  - an efficient cost structure; and
  - a good corporate reputation.
- Managing assets to optimise, on a whole of life basis, the expenditure needed to ensure safe and cost effective energy supply to customers;
- Ensuring we manage our operations in light of the changing requirements of customers, changes in technology and markets, and changes in community and government expectations; and
- Innovating to maintain industry leadership.

The next chapter discusses how we have delivered on our objectives in the current Access Arrangement period in five areas: safety, customer service, efficiency, growth and compliance.

6. What we have delivered in the current period

Since our privatisation in 1999, we have delivered significant price reductions to our customers. Today, our charges are some 12 per cent lower in real terms than they were in 2000. This is a great outcome for our customers.

In addition to delivering lower prices, we have successfully restructured our business during the current Access Arrangement period so that we continue to deliver better value to our customers while delivering against our network key performance indicators (KPI) in five areas: safety, customer service, efficiency, growth and compliance. Key highlights in this period include:

- Laying 527 kilometres of replacement mains;
- Delivering the Government's Energy for the Regions' program, including laying 28 kilometres of mains and providing for the connection of around 500 new customers in the Warburton area; and
- Out-performing the network reliability requirements in the Gas Distribution System Code at no additional cost to customers.

The efficiency of our operations is borne out by industry benchmarking by Economic Insights that we commissioned with the other Victorian gas distributors.

6.1. Restructuring has delivered benefits and will continue to do so

We pride ourselves on delivering on our commitments. Our Access Arrangement Information to the AER for the current Access Arrangement period outlined a comprehensive strategy to transform our business model to:

- Lock in the cost efficiencies we have achieved to date;
- Establish greater business flexibility to best manage future change and risk; and, most importantly
- Improve our value proposition to our current and future customers.

The business transformation we have now implemented has:

- Delivered cost efficiencies through a hybrid insource/outsource business model, while ensuring that we retain internal control of our strategy and planning;
- Created competitive tension and aligned incentives to deliver cost and service improvements through the division of the network into two regions with separate competitively-sourced service providers;
- Built a solid foundation to improve service delivery by consolidating our Information and Communications Technology (ICT) systems and introducing new ICT and back-office providers; and
- Brought our strategy and planning functions in-house.

We have delivered savings in our opex, particularly in the latter stages of this period as the synergies of our new business model have been realised.

Our business transformation has established a strong team with a proven ability to deliver on our commitments. We will build on this transformation in the forthcoming Access Arrangement period.

6.2. Delivering on our Network KPIs

We have five KPIs that provide a focus for how we operate and maintain our network.

We set out below how we have performed against these KPIs in the current Access Arrangement period, by reference to our objectives, outputs and outcomes in each area.

6.2.1. Safety

The safe and reliable supply of natural gas is the core objective of our business and the primary expectation of our customers. We continuously strive to achieve zero harm in our network operations.

During the current Access Arrangement period, we have delivered industry-leading safety performance as measured by our lost-time injury frequency rate (LTIFR) and our serious injury frequency rates (SIFR).

Our safety objectives, outputs and outcomes for the current Access Arrangement period are as follows.

Table 6-1: Safety objectives, outputs and outcomes

Objectives (i.e. what we aimed to achieve)	Maintain network safety for our customers / public and our employees / contractors
Outputs (i.e. what we did / delivered)	– Laid 527 kilometres of mains replacement – Conducted leakage surveys on our network on a scheduled basis – Replaced 76,800 meters with new or refurbished meters between 2013 and 2015 – Undertook intelligent pigging of the South Gippsland Pipeline – Restructured our Gas Safety Case – Redesigned our records and document management system to support safety outcomes – Redefined our internal audit program on systems and processes referred in the Safety Case – Incentivised our service providers by redefining safety targets
Outcomes (i.e. what we gained)	– Safer network for customers, public, employees and contractors measured by: o Reduced network leaks to an average of 18.1 escapes per 1,000 customers per annum compared to a compliance target of 25 o Exceeded 95% benchmark for Priority 1 response times within 60 minutes o Consistently maintained LTIFR below targets and achieved a downward trend for SIFR. LTIFR of 0.9 and SIFR of 5.7 per million hours worked

6.2.2. Customer service

Our customers are the main driver behind our business performance, subject to the safe and reliable operation of our network. We constantly aim to reduce the duration and frequency of interruptions to our customers and minimise customer inconvenience from new connections and meter replacements. We continuously engage with our customers throughout our works' program to promote overall customer satisfaction.

Our customer service objectives, outputs and outcomes for the current Access Arrangement period are as follows.

Table 6-2: Customer service objectives, outputs and outcomes

Objectives **(i.e. what we aimed to achieve)**	Meet our customers' expectations while providing an effortless customer experience
Outputs **(i.e. what we did / delivered)**	– Rolled out a shared United Energy / Multinet Gas customer portal – Connected on average 8,428 gross residential customer connections per annum – Expanded further into areas of older infrastructure as part of our prioritised mains replacement program – Rolled out our Effortless Customer Experience program – Surveyed customers during priority services, asset maintenance and mains renewal works – Delivered efficient capex and opex programs
Outcomes **(i.e. what we gained)**	Reliable supply – measured by: – SAIFI of 6 interruptions per 1,000 customers p.a. (2013-15) compared to our benchmark of 16.2 per 1,000 customer p.a. with a reported downward trend – SAIDI of 3.4 minutes per customer p.a. (2013-15) compared to our benchmark of 5 minutes per customer – Unplanned outage about once every 40+ years – Achieved an average score of 83.6 (out of 100) from customer surveys covering Priority Services and Asset maintenance.

6.2.3. Efficiency

Efficiency involves delivering what we say we will, and what customers want and expect, at the lowest possible cost. During the current Access Arrangement period we have upgraded our network, connected new customers and delivered strong network performance. At the same time, we have transitioned to a new business model based on two competitively-procured service providers and two operating regions. We have reflected this business efficiency into sustainable and economic tariffs for our customers.

Our efficiency objectives, outputs and outcomes for the current Access Arrangement period are as follows.

Table 6-3: Efficiency objectives, outputs and outcomes

Objectives (i.e. what we aimed to achieve)	Incur capex and opex efficiently to meet our customers' service expectations
Outputs (i.e. what we did / delivered)	– Undertook a business transformation to leverage cost efficiencies through: o A mix of insourced and outsourced business functions o Establishing two regions with separate service providers to optimise efficiency o Tendering large projects to separate service providers regardless of region. – Applied our asset management and expenditure governance frameworks – these are discussed in Chapter 13 and were found by Jacobs to be fit-for-purpose and in accordance with good practice – Delivered our capex and opex programs – Responded to the incentives in the AER's economic regulatory framework – Oakley Greenwood and Advisian's independent reports support our view that our Mains Replacement and Connections capex are prudent and efficient
Outcomes (i.e. what we gained)	– Efficient prices for our services based on competitively-tendered service provider contracts – A resilient network that meets our customers' long-term service expectations – Delivered above the AER's Final Decision mains replacement allowance through the cost-pass through arrangements

6.2.4. Growth

We have grown our gas network during the current Access Arrangement period, including through in-fill development and by delivering on Victorian Government policies to introduce gas in regional areas. These works complement our Mains Replacement program and allow us to provide a reliable high pressure gas supply to dense population areas which otherwise would not be supported by existing low and medium pressure networks. High pressure natural gas is an attractive fuel choice for customers. It provides the potential to increase gas consumption and to reduce tariffs further.

Our growth objectives, outputs and outcomes for the current Access Arrangement period are as follows.

Table 6-4: Growth objectives, outputs and outcomes

Objectives (i.e. what we aimed to achieve)	– Service new regions and new infill customers – Help to deliver Victorian Government policies to introduce gas in regional areas and to implement major projects
Outputs (i.e. what we did / delivered)	– Delivered Energy for the Regions by laying 28 kilometres of mains, which will allow around 500 new customers to be connected over the next three years in the Warburton area – Worked closely with various other government initiatives such as the rail crossing removal projects throughout Victoria. The Greater North Rail Crossing Removal Project has been a prime example of complying with government initiatives to further improve Victoria's transportation network – Connected 42,141 gross new residential connections
Outcomes (i.e. what we gained)	– New customers are being supplied gas from our network – Consumers are receiving an alternative choice of fuel to electricity

6.2.5. Compliance

Complying with our legislative and regulatory obligations is a key business focus. It underpins all our operations and work practices.

Our compliance objectives, outputs and outcomes for the current Access Arrangement period are as follows.

Table 6-5: Compliance objectives, outputs and outcomes

<table>
<tr><td>Objectives
(i.e. what we aimed to achieve)</td><td colspan="4">Comply with our technical and other regulatory obligations</td></tr>
<tr><td>Outputs
(i.e. what we did / delivered)</td><td colspan="4">– Embedded policies and procedures into our work practices that address our technical and other regulatory obligations
– Implemented internal monitoring and reporting of our technical and other regulatory obligations
– Redesigned our records and document management system
– Redefined our internal audit program on systems and processes referred in the Safety Case</td></tr>
<tr><td>Outcomes
(i.e. what we gained)</td><td colspan="4">Our performance against our key compliance targets between 2013 and 2015 was as follows:</td></tr>
<tr><td rowspan="5"></td><td>2013-2015</td><td>Actuals</td><td>Target</td><td>Favourable (✓) / Unfavourable (×)</td></tr>
<tr><td>SAIFI (interruptions per 1,000 customers per annum)</td><td>6</td><td>16.2</td><td>✓</td></tr>
<tr><td>SAIDI (minutes per customer per annum)</td><td>3.4</td><td>5</td><td>✓</td></tr>
<tr><td>Priority 1 response (in no more than 60 minutes)</td><td>97.7%</td><td>95%</td><td>✓</td></tr>
<tr><td>Public Reported Escapes (confirmed leaks per thousand customers per annum)</td><td>18.1</td><td>25</td><td>✓</td></tr>
</table>

6.3. Our network reliability

Network performance is measured against reliability indicators, which track the frequency and duration of unplanned outages and safety indicators, such as the number of publicly reported leaks repaired. Raw data on these measures is reported to Energy Safe Victoria (ESV) on a quarterly basis.

Table 6-6: Our safety performance indicators

Performance Indicators	Target	2011-12	2012-13	2013-14	2014-15	2015-16
Priority Emergency Response	95.0%	97.7%	96.5%	97.7%	97.9%	97.8%
Number of unplanned outages affecting 5 or more customers	35	6	17	12	14	24
Public reported escapes per 1,000 customers	25	15	18	19	17	17

Industry standard index measures compiled from this and other ESV reported data demonstrate our performance relative to other similar networks. Figure 6-1 to Figure 6-5 show our key measures as benchmarked by the Energy

Supply Association of Australia (ESAA) (now part of Australian Energy Council) and demonstrate how well our network performance compares to other Australian gas distributors.

Figure 6-1: Unplanned outages affecting five or more customers per 1,000 customers

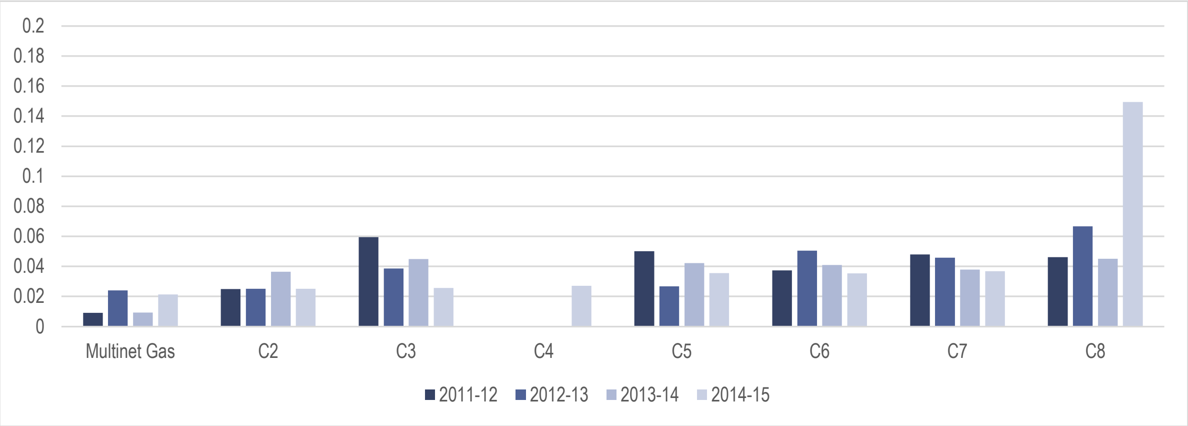
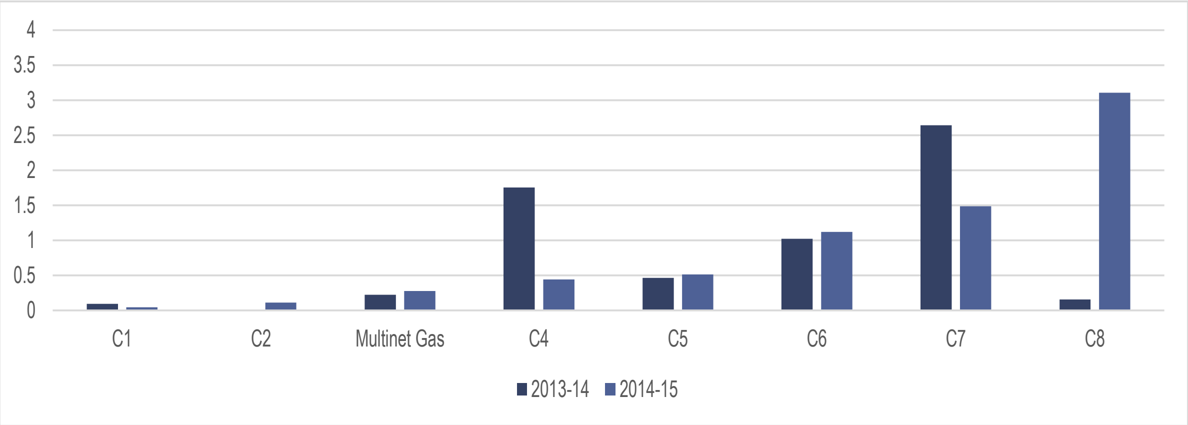
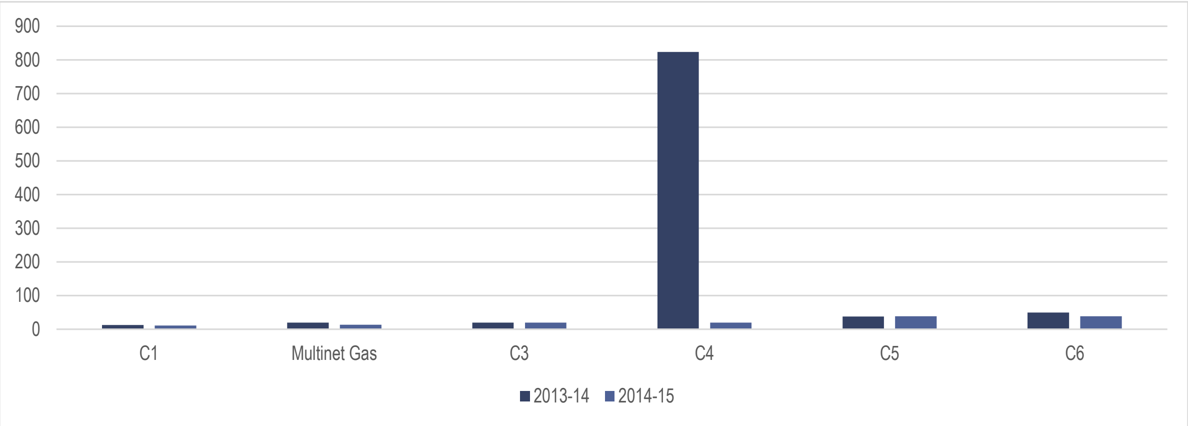


Figure 6-2: Unplanned SAIFI (Interruptions caused by outages affecting five or more customers)



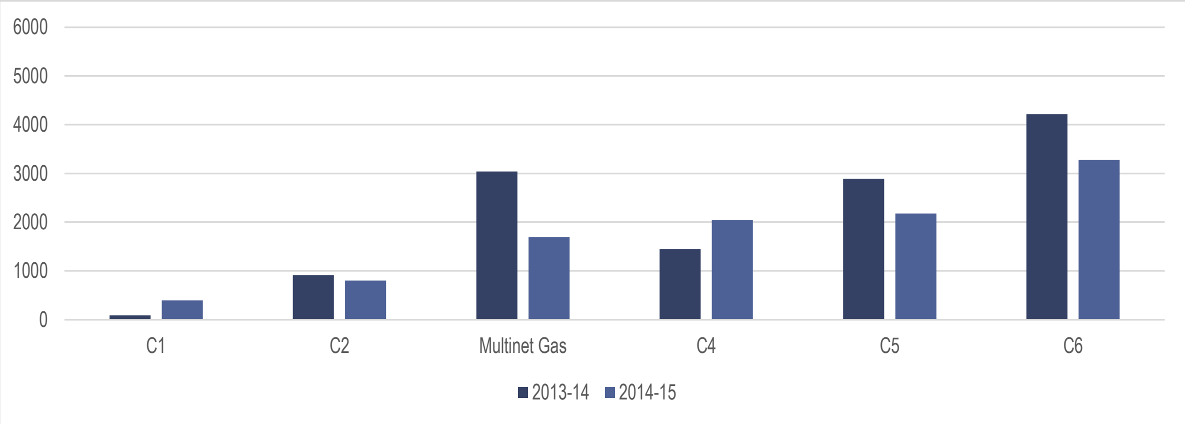
Note Interruptions refer to the number of customers who experience loss of supply as a result of network outages.

Figure 6-3: Unplanned SAIFI (Interruptions caused by all outages)



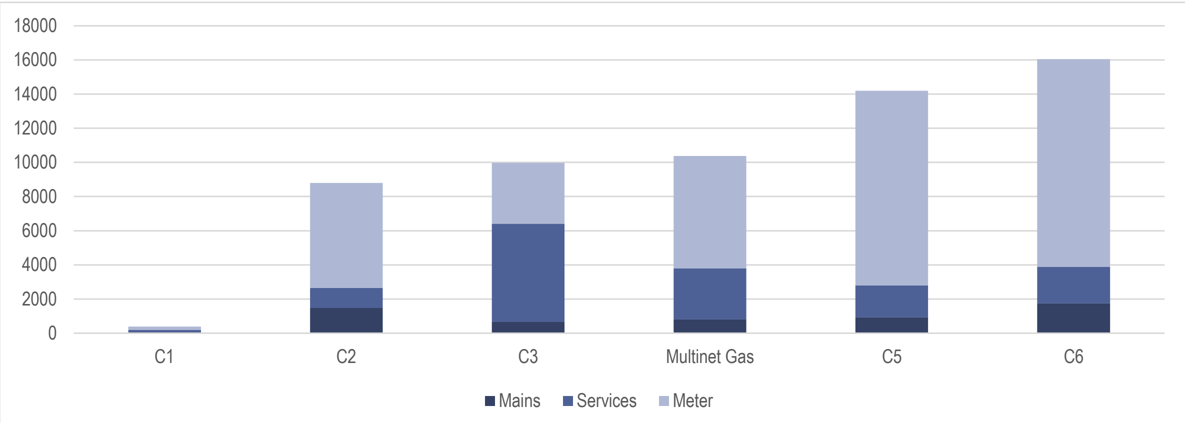
Note Interruptions refer to the number of customers who experience loss of supply as a result of network outages.

Figure 6-4: Unplanned SAIDI (Interruptions caused by all outages)



Note Interruptions refer to the number of customers who experience loss of supply as a result of network outages.

Figure 6-5: Repaired publicly reported leaks (July 2014 to June 2015)



The high engineering standards that we apply together with the inherent reliability of underground, meshed gas supply networks have delivered a very reliable system. Challenges to reliability generally relate to small sections of the low-pressure network where water ingress during extended wet weather can cause temporary supply interruptions. This issue is managed by pumping of syphons, tracing water ingress and selective mains replacement programs.

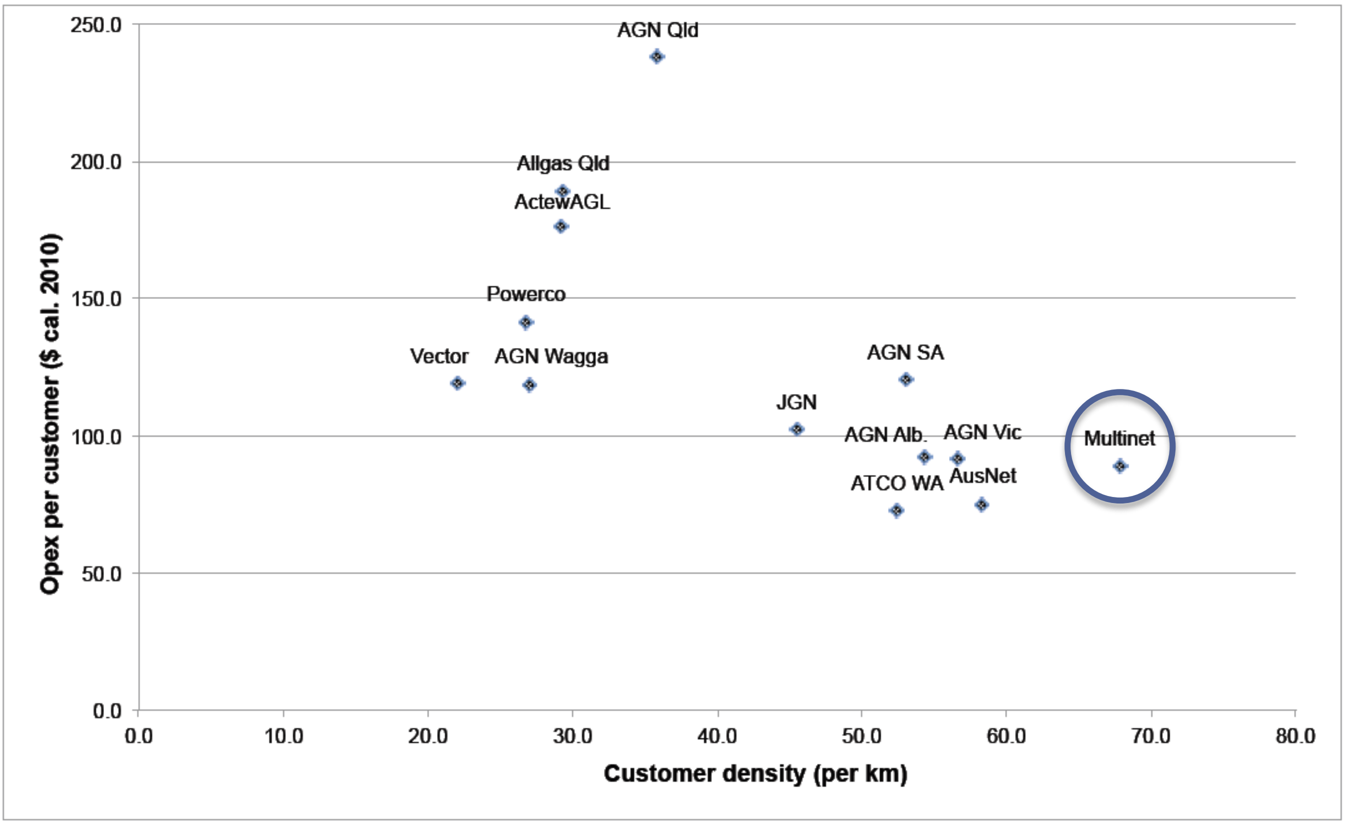
6.4. Benchmarking shows that we are an efficient business

The three Victorian gas distributors commissioned Economic Insights to benchmark their expenditure performance against 13 Australian and New Zealand gas distributors for the period 2011 to 2015. Economic Insights focussed on three measures:

- Opex per customer relative to customer density;
- Capital asset cost per customer relative to customer density; and
- Total cost per customer relative to customer density.

Economic Insights found that we had average opex per customer of $89 for the period 2011 to 2015, which is the third lowest of the 13 gas distributors surveyed, as shown in Figure 6-6.

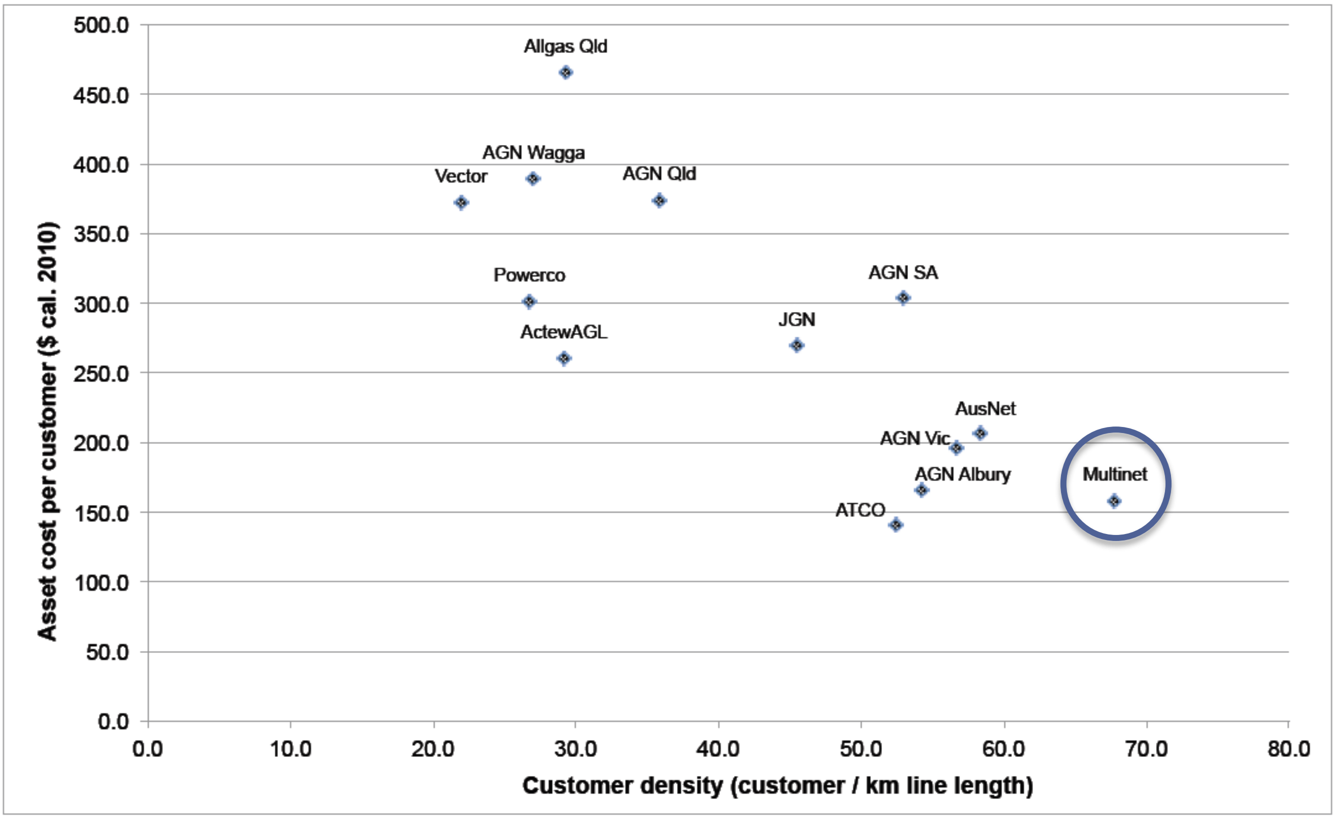
Figure 6-6: opex per customer relative to customer density (avg. 2011–2015) [3]



Economic Insights found that we had an average annual capital asset cost of $158 per customer. This was the lowest of the Victorian gas distributors and the second lowest of the 13 gas distributors surveyed, as shown in Figure 6-7.

[3] Economic Insights, "Benchmarking the Victorian Gas Distribution Businesses' Operating and Capital Costs Using Partial Productivity Indicators", 15 June 2016, page 10

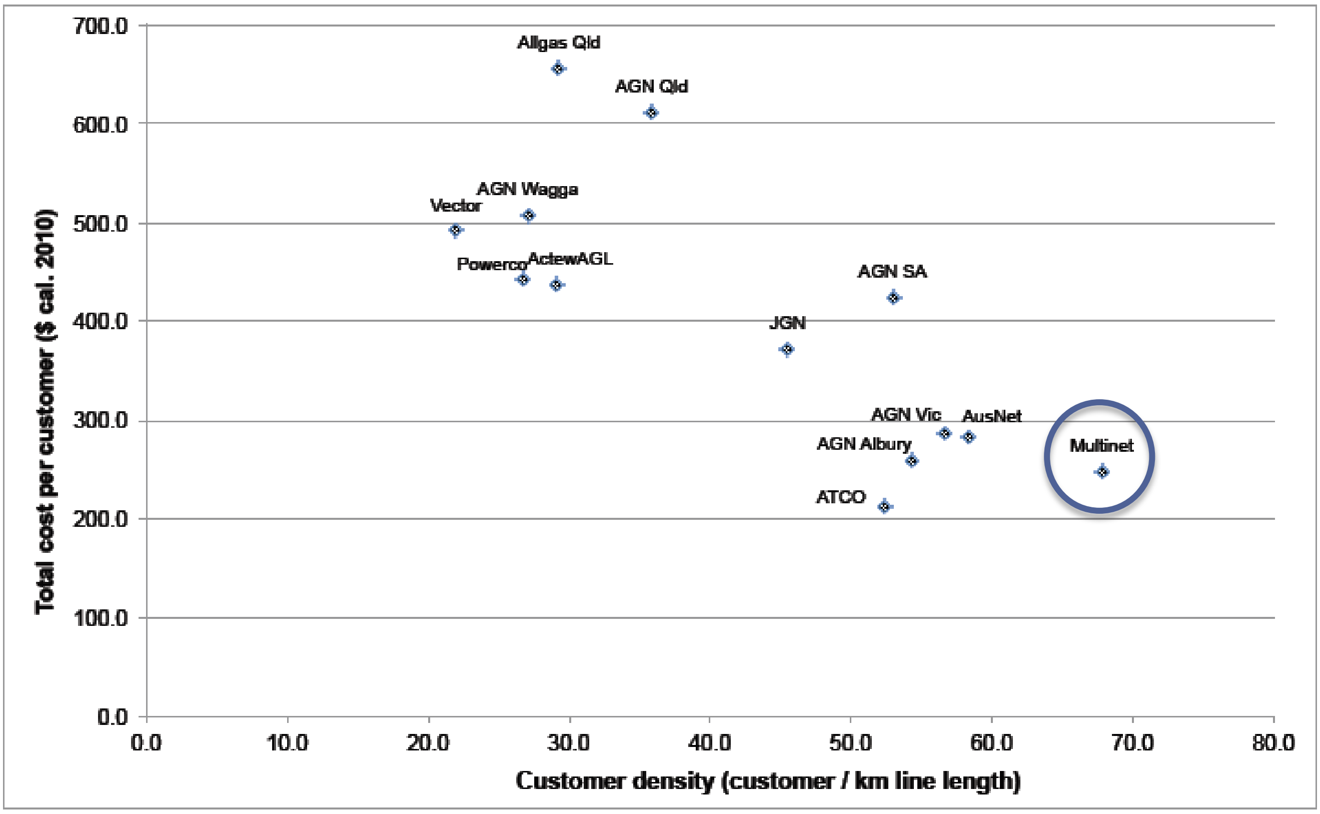
Figure 6-7: Asset cost per customer relative to customer density (avg. 2011–2015) [4]



Economic Insights added the opex and asset costs per customer to determine the overall cost efficiency per customer. It found that we had the second lowest overall cost efficiency per customer of the 13 gas distributors surveyed, as shown in Figure 6-8.

[4] Economic Insights, "Benchmarking the Victorian Gas Distribution Businesses' Operating and Capital Costs Using Partial Productivity Indicators", 15 June 2016, page 11

Figure 6-8: Total cost per customer relative to customer density (avg. 2011–2015) [5]



Economic Insight's benchmarking analysis supports our view that our capex and opex is efficient and that we are operating at or close to the efficient frontier of gas distributors. This confirms that our new business model is delivering efficient outcomes and provides a strong basis for us to continue to deliver efficient outcomes.

We discuss Economic Insights' benchmarking further in chapters 13 and 14 in the context of our capex and opex forecasts for the forthcoming Access Arrangement period.

[5] Economic Insights, "Benchmarking the Victorian Gas Distribution Businesses' Operating and Capital Costs Using Partial Productivity Indicators", 15 June 2016, page 12

7. What our stakeholders are telling us

During the current Access Arrangement period, we have principally focused on transforming our business model and ensuring that the planned efficiency improvements were achieved. Our focus for the forthcoming Access Arrangement period is to put customers at the centre of our business.

We recognise that best practice engagement should be an integral and on-going part of our operating model. This requires a shift in culture, the introduction of new specialist skills and time to build understanding and trust with an extensive group of stakeholders who have an interest in our services.

7.1. Stakeholder engagement activity

We undertook the following stakeholder engagement activity to inform our proposals in this Access Arrangement Information:

- A Gas Access Arrangement Review (GAAR) Reference Group comprising the following invitees: Alternative Technology Association, St Vincent de Paul, Consumer Utilities Advocacy Centre, Energy Consumers Australia, Brotherhood of St Laurence, South East Community Links, Council of the Aged and Kildonen. We met regularly both as a Group and with individual stakeholders between March and November 2016 to discuss issues and hear proposals relevant to this Access Arrangement Information;
- A joint Victorian distributor stakeholder forum attended by 29 participants including the AER, a public Issues Paper[6] (on which stakeholders made written submissions) and a public Final Report[7] that dealt with possible future incentive mechanisms that could apply to the Victorian gas distributors;
- Eight focus groups – four for residential customers and four for small business customers – that discussed issues relevant to our Access Arrangement Information in 90 minute sessions that were independently facilitated. 67 participants attended these focus groups;
- A survey of our Tariff D customers (representing 30 to 35 per cent of our Tariff D consumption and 21 to 23 per cent of our Tariff D MHQ) about anticipated changes in their future loads; and
- A retailer workshop on 22 November to discuss our proposed changes to Parts A, B and C of our Access Arrangement and seek their views on these changes and any other changes that they would like made. The following retailers attended the workshop: Origin Energy, AGL, M2 Energy (DODO), Lumo Energy, Red Energy and Globird. We will continue to engage with our stakeholders throughout our Access Arrangement review process and during the forthcoming Access Arrangement period.

7.2. Key findings from our stakeholder engagement

The key findings from our stakeholder engagement are detailed in Table 7-1.

[6] FSC, Incentive Mechanisms for the Victorian Gas Distribution Businesses 2018 to 2022 Gas Access Arrangement Review (Issues Paper), Document MG 17.1

[7] FSC, "Findings Report - Victorian Gas Distribution Businesses' consultation on Incentive Mechanisms Issues Paper" – Document MG 17.3

Table 7-1: Stakeholder engagement feedback

Issue	
Mains replacement	Strong general support for our LP to HP Mains Replacement capex program given its focus on safety and reliability and for completing this 30-year program. Retailers also strongly supported not relying on a cost pass through but instead approving an up-front allowance because it provides greater certainty and transparency of pricing impacts.
Incentives	General support for an incentive to reduce capex although there was concern that any inefficient reduction in capex could compromise reliability and necessitate future catch-up expenditure – this indicated that customers were mindful of their long-term interests.
Marketing step change	Some feedback that would need to be further convinced of the need for, and benefits of, any marketing step change before supporting it.
Reference Tariff Variation Mechanism	General support for moving to a revenue cap given the difficulty in the AER accurately forecasting future demand, although retailers questioned whether a revenue cap provides appropriate incentives to grow demand.
Demand	Customer sentiment is generally consistent with our forecast decline in gas demand.
Digital meters	Strong general support for a controlled pilot program, including from retailers, particularly one that focusses on replacing faulty meters and new connections, provided that it avoids the costly problems associated with the electricity AMI rollout. Retailers supported leveraging existing infrastructure, such as United Energy's IT communications.
GSL	General support for retaining the current GSL scheme but that payments should be increased for inflation. Also, support for raising public awareness about GSL scheme.
Tariffs	General support for the stability in tariffs between Access Arrangement periods.
Network KPIs	General support for our Network KPIs (detailed in Chapter 6) – in particular the safety KPI – but considered they could be framed to be more readily understood by external stakeholders. Retailers requested: • Regular reporting of our service performance against targets; and • Introducing a new process to deal with any poor performance issues if not addressed in 30 days.
Communications	Strong support for providing information to customers on GSLs, LP to HP Mains Replacement capex and emergency matters, otherwise communication should be minimised. Post, website and email were the preferred communication media, with less support for social media. Clear preference for a call centre, rather than a digital self-service call centre.
Retail issues	Retailers requested the introduction of a new service being "installation of a service valve". This would provide an alternative to cutting the pipe in the street where a disconnection has been requested but access a property is not available to either lock or plug the meter.

We have provided the AER with supporting documentation that further explains our stakeholder engagement feedback.

7.3. Our response to stakeholder feedback

Table 7-2 details how we have responded to our stakeholders' feedback in preparing this Access Arrangement Information.

Table 7-2: Key customer outcomes

Issue	Our proposed action	AAI Chapter
Mains replacement	Consistent with stakeholder feedback, our Mains Replacement Capex includes 625 kilometres of LP to HP mains replacement, consistent with completing the program by 2033.	13
Incentives	We are not proposing to introduce either a Capital Expenditure Sharing Scheme or a Customer Service Incentive Scheme as we consider that there is not an existing "problem" needing to be addressed. Any such schemes should only be introduced on a national, rather than on a jurisdiction-specific, basis.	18
Marketing step change	We propose an opex step change for marketing in order to arrest the decline in demand by: promoting gas as a fuel of choice; increasing the rate of new residential connections and average residential consumption; and increasing the take-up of gas in regional areas.	14
Reference Tariff Variation Mechanism	We propose changing our reference tariff variation mechanism for our Haulage Reference Services from a weighted average price cap to a revenue cap given the risk of the AER not accurately forecasting demand and therefore of us not recovering our efficient costs, consistent with the Revenue and Pricing Principles. We have a strong incentive to price our services as competitively as possible and to grow demand given that gas is a fuel of choice.	12
Demand	We engaged the NIEIR to forecast our demand. They are forecasting a general decline in consumption in the forthcoming Access Arrangement period, although this would be partially arrested by the marketing step change.	9
Digital meters	Consistent with stakeholder feedback, we propose undertaking a pilot scheme trial to install 10,000 digital meters in the forthcoming Access Arrangement period. This will inform a cost / benefit study to determine whether the AMI information and communications technology developed for United Energy's electricity distribution network can be leveraged to facilitate the mass rollout of digital gas meters	13
GSL	We will continue to apply the GSL scheme in the Victorian Gas Distribution System Code.	14
Tariffs	We are not proposing any changes to our tariff structure in the forthcoming Access Arrangement period.	21
Network KPIs	We have explained in Chapter 8 what outcomes we will deliver in the forthcoming Access Arrangement period – we will actively engage with our stakeholders on these matters. We have also developed a service performance reporting template (see supporting document 8.1) and will use this to undertake regular reporting of our service performance against targets. We will continue to work with retailers to develop a new process to deal with any performance issues.	8
Retail issues	Consistent with retailer feedback we have included an additional Ancillary Reference Service for "installation of a service valve", as discussed in Chapter 11.	11

8. What we will deliver

We have identified the following priorities for the forthcoming Access Arrangement period. We will:

- Continue to focus on safety as our top priority, including by replacing 625 kilometres of low pressure mains with high pressure mains;
- Meet our customers' needs for a reliable network;
- Positively respond to efficiency incentives; and
- Grow our network.

We discuss each of these priorities in turn below.

8.1. Continue to focus on safety as our top priority

The safety of our customers, community, staff and contractors remains our primary focus. Chapter 6 overviews the work we have undertaken in the current Access Arrangement period to ensure a high standard of safety. Our expenditure plans for the forthcoming Access Arrangement period build on that work. They address all of our compliance obligations and include several measures to improve safety, particularly in relation to mains replacement.

Our safety objectives, outputs and outcomes for the forthcoming Access Arrangement period are as follows.

Table 8-1: Safety objectives, outputs and outcomes

Objectives (i.e. what we aim to achieve)	Maintain network safety for our customers / public and our employees / contractors
Outputs (i.e. what we aim to deliver - actions)	– Lay 625 kilometres of high pressure mains to replace low pressure mains – Undertake reactive mains replacement – Undertake unplanned service renewals
Outcomes (i.e. what we will gain)	– Continue to provide safe network for customers, public, employees and contractors measured by out-performing: ○ Target for network leaks of no more than 25 escapes per 1,000 customers per annum ○ 95% benchmark for Priority 1 response times within no more than 60 minutes ○ LTIFR targets of 0.9 and SIFR of 5.7 million hours worked – Achieve Gas Safety Case approval

8.2. Meet our customers' needs for a reliable network

We know that if our customers are without gas when they need it is more than an inconvenience – it impacts the entire business or household.

We asked our customers about the current balance between the prices we charge for our services, the long-term safety of these services, and the service levels our network provides to current and new customers. While we found there is some support for modest improvements, our customers are generally satisfied with our current service levels.

Our customer service objectives, outputs and outcomes for the forthcoming Access Arrangement period are as follows.

Table 8-2: Customer service objectives, outputs and outcomes

Objectives (i.e. what we aim to achieve)	Meet our customers' expectations while providing an effortless customer experience
Outputs (i.e. what we aim to deliver - actions)	– Invest in specialist skills and resources – Survey customers during priority services, asset maintenance and mains renewal works – Replace assets at end of life to minimise total life cycle costs – Connect an average of 8,402 gross new residential connections per annum – Introduce regular reporting of our service performance against targets – see – Introduce a new process to deal with any poor performance issues
Outcomes (i.e. what we will gain)	– Trusted relationship with our stakeholders – Fully understand our customers' needs and expectations – High customer satisfaction measured by out-performing: o SAIFI target of 16.2 per 1,000 customers o SAIDI target of 5 minutes per customer o Unplanned outages – High customer satisfaction during works delivery

8.3. Positively respond to efficiency incentives

The economic regulatory framework provides us with strong incentives to continually improve the efficiency of our operations.

By responding positively to these incentives, we can provide the same or better service levels for less cost. This helps us to ensure that gas remains a competitive, value-for-money fuel option in line with customers' long-term interests. Chapter 18 explains how we will continue to do this in the forthcoming Access Arrangement period.

Our efficiency objectives, outputs and outcomes for the forthcoming Access Arrangement period are as follows.

Table 8-3: Efficiency objectives, outputs and outcomes

Objectives (i.e. what we aim to achieve)	Incur expenditure efficiently to meet our customers' service expectations
Outputs (i.e. what we aim to deliver- actions)	– Deliver our capex and opex programs having regard to our expenditure allowances and the Efficiency Benefit Sharing Scheme – Participate in the proposed new Network Innovation Competition (discussed in chapter 18) – Apply our asset management and expenditure governance frameworks – Competitively tender large projects to separate service providers regardless of region (two party tender for all projects).
Outcomes (i.e. what we will gain)	– Efficient prices for the service delivered based on competitively-tendered service provider contracts – Resilient network that meets customers' long-term service expectations.

8.4. Grow our network

We will continue to grow our network in the forthcoming Access Arrangement period including through in-fill development and by cooperating with the Victorian Government to support major projects. Chapter 14 details the marketing activity that we propose undertaking that will support this network growth.

Our growth objectives, outputs and outcomes for the forthcoming Access Arrangement period are as follows.

Table 8-4: Growth objectives, outputs and outcomes

Objectives **(i.e. what we aim to achieve)**	Grow our customer base to deliver lower prices under a revenue cap.
Outputs **(i.e. what we aim to deliver- actions)**	Connect 42,009 gross new connections, as detailed in Chapter 9.
Outcomes **(i.e. what we will gain)**	– More customers are supplied from our gas network, including customers in Warburton who can choose gas for the first time – More customers receive a cost-effective alternative choice of fuel to electricity

9. Energy, demand and customer forecasts

Key messages:

- The AER accepted our consumption forecast for the current access arrangement period, which was prepared by NIEIR. We estimate that there will be less than a 1.0 per cent difference between our actual total Tariff V consumption and the forecast that the AER accepted. The high level of accuracy of NIEIR's forecast supports their credibility and justifies our continued reliance on them for the forthcoming access arrangement period.
- In the current Access Arrangement period, we expect our:
  - Actual Tariff V residential consumption in 2016 and 2017 to be below that in 2015;
  - Actual Tariff V commercial consumption to be below the AER's benchmark in each year of the current period;
  - Actual Tariff D demand in 2016 and 2017 to be below 2015 levels; and
  - Total customer numbers to be below the AER's benchmark in each year of the current period, except for 2013.
- We engaged the National Institute of Economic and Industry Research (NIEIR) to forecast consumption and customer numbers on our gas network in the forthcoming Access Arrangement period.
- For residential customers, NIEIR forecasts for the forthcoming Access Arrangement period that:
  - Our customer numbers will grow on average by about 0.5 per cent per annum; and
  - Our consumption will decline of about 1.3 per cent per annum.
- For small business customers, NIEIR forecasts for the forthcoming Access Arrangement period that:
  - Our customer numbers will decline on average by about 1.0 per cent per annum; and
  - Our consumption will decline of about 2.7 per cent per annum.
- NIEIR forecasts that total MHQ for our large industrial customers will fall by about 0.9 per cent per annum over the forthcoming Access Arrangement period.

This chapter presents our forecasts of energy, demand and customer numbers for the forthcoming Access Arrangement period.

9.1. NGR requirements and chapter structure

Our energy, demand and customer numbers forecasts are used in two ways in the revenue and tariff setting process:

- As a driver for our expenditure forecasts, as explained in chapters 13 and 14; and
- As a basis for recovering our total revenue that is detailed in chapter 20, based on our reference tariffs that are detailed in chapter 21.

Rule 74 of the NGR provides that:

> (1) *Information in the nature of a forecast or estimate must be supported by a statement of the basis of the forecast or estimate.*
>
> (2) *A forecast or estimate:*
>
> a. *must be arrived at on a reasonable basis*

b. *must represent the best forecast or estimate possible in the circumstances.*

Our energy, demand and customer forecasts presented in this chapter comply with the requirements of Rule 74. The remainder of this chapter is structured as follows:

- Section 9.2 overviews the consumption, demand and customer numbers on our gas network in the current Access Arrangement period;
- Section 9.3 describes our forecasting methodology for the forthcoming Access Arrangement period; and
- Section 9.4 overviews our consumption, demand and customer number forecasts for the forthcoming Access Arrangement period.

9.2. Current Access Arrangement period consumption, demand and customer numbers

Rule 72(1)(iii) requires that we provide the following information in this Access Arrangement Information:

Usage of the pipeline over the earlier access arrangement period showing:

(A) for a distribution pipeline, minimum, maximum and average demand

(B) for a distribution pipeline, customer numbers in total and by tariff class.

We have provided this information in the RIN, which forms part of this Access Arrangement Information.

Table 9-1 to Table 9-4 compare the actual demand and customer numbers on our gas network with the AER's forecasts in its Final Decision for the current Access Arrangement period. The 2016 and 2017 values are our best estimates based on our most recent available data.

The AER accepted our consumption forecast for the current access arrangement period, which was prepared by NIEIR. We estimate that there will be less than a 1.0 per cent difference between our actual total Tariff V consumption and the forecast that the AER accepted. The high level of accuracy of NIEIR's forecast supports their credibility and justifies our continued reliance on them for the forthcoming access arrangement period.

The tables show that we expect:

- Actual Tariff V residential consumption in 2016 and 2017 to be below that in 2015;
- Actual Tariff V commercial consumption to be below the AER's benchmark in each year of the current period;
- Actual Tariff D demand in 2016 and 2017 to be below 2015 levels; and
- Total customer numbers to be below the AER's benchmark in each year of the current period, except for 2013.

Table 9-1: Tariff V residential consumption - comparison of 2013-17 actual and AER benchmark (TJs)

Category	2013	2014	2015	2016 (E)	2017 (E)
Benchmark	39,074	38,753	38,592	38,519	38,446
Actual (and estimated)	39,792	38,792	38,357	38,121	38,072
Variance	718	39	(235)	(398)	(374)

Table 9-2: Tariff V commercial consumption - comparison of 2013-17 actual and AER benchmark (TJs)

Category	2013	2014	2015	2016 (E)	2017 (E)
Benchmark	5,564	5,515	5,487	5,472	5,457
Actual (and estimated)	5,448	5,528	4,958	4,918	4,912
Variance	(116)	13	(529)	(554)	(545)

Table 9-3: Tariff D demand - comparison of 2013-17 actual and AER benchmark (MHQs - GJ/hr)

Category	2013	2014	2015	2016 (E)	2017 (E)
Benchmark	3,441	3,386	3,343	3,310	3,279
Actual (and estimated)	3,565	3,727	3,727	3,673	3,639
Variance	124	341	384	363	360

Table 9-4: Total customer numbers (Tariffs V, D and L) - comparison of 2013-17 actual and AER benchmark (numbers)

Category	2013	2014	2015	2016 (E)	2017 (E)
Benchmark	682,436	688,024	693,593	699,028	704,234
Actual (and estimated)	682,734	687,432	691,129	693,932	697,317
Variance	298	(592)	(2,464)	(5,096)	(6,917)

9.3. Forecasting methodology and factors affecting our forecasts

9.3.1. Introduction

Given the accuracy of their forecasts for the current access arrangement period we engaged NIEIR to forecast consumption and customer numbers on our gas network for the forthcoming Access Arrangement period. NIEIR has demonstrated that it has a thorough understanding of our business and the factors that drive residential, commercial and industrial gas usage and customer numbers on our gas network.

NIEIR has prepared forecasts for:

- Residential customers that use gas for cooking, water heating and space heating in their dwellings;
- Small business / commercial customers that use less than 10 terajoules of gas each year; and
- Large industrial business customers that use more than 10 terajoules of gas per year.

NIEIR has prepared forecasts for our three pricing zones – Melbourne, Yarra Valley and South Gippsland.

NIEIR applied the same methodologies that it used to develop forecasts for our current Access Arrangement period, and for the previous Access Arrangement (2008 to 2012) for the three Victorian gas distribution businesses. As discussed above, these methodologies provided to be extremely accurate for the current access arrangement period.

NIEIR considered the Australian Energy Market Operator's (AEMO) forecasts of gas demand in preparing its forecasts for our network. NIEIR prepared the AEMO gas projections for the Gas Statement of Opportunities up to 2013.

We have provided NIEIR's report as an attachment to this Access Arrangement Information.

9.3.2. Forecasting approach

NIEIR used its national, state and regional economic models to develop the driver variables for its forecasts of our gas volumes and customer numbers.

It modelled our residential and small business customers based on average consumption per connection. It calculated the total volumes based on its forecast net customer connections and the average usage per connection.

NIEIR modelled industrial volumes on an industry basis. The key driver variables for this modelling were industrial output growth, real price impacts and other information on expansions and closures that was obtained from a survey of our top gas customers, who answered questions about their recent and expected gas usage. The survey results are summarised in an attachment to this Access Arrangement Information.

Weather correction

Temperature is one of the main drivers of residential gas demand. This is typically driven by space and water heating. As temperatures fall, consumers use gas heating more intensively to maintain a level of comfort indoors. Heating Degree Days (HDDs) are a popular index for analysing the impact of temperature on energy demand. HDDs are an index of the temperatures below a threshold value of 18 degrees, and are set to zero for temperatures above 18 degrees.

The Effective Degree Day (EDD) index captures the impact of additional weather effects on Victorian gas demand. The EDD index incorporates wind, sunshine, a seasonal effect and temperature. This is because the demand for heating is typically higher on windier days than it is on calmer days. Customers also tend to use more heating on cloudier days, than sunnier days. The seasonal effect is a measure of customers' preference to use heating appliances more intensively in the later stages of winter, and less during the summer months.

Over the years, there have been many different versions of the EDD index. These reflect corrections to raw weather station data, changes to the Victorian gas day and updates to the parameters to apply indices more accurately to the demand-weather relationship with Victorian gas demand.

NIEIR prepared an extensive review paper in April 2016[8] (provided as an attachment to this Access Arrangement Information) that examined the weather standards for Victorian gas forecasting. This paper recommends that an annual warming trend reduction of 7.6 EDDs per annum be adopted for the 2018 to 2022 Access Arrangement period, based on the experience between 1970 and 2015. NIEIR's report does not accept AEMO's claim in its 2015 National Gas Forecasting Report that there is little evidence of warming over the period 2000 to 2014, and that the median (1,340) of this period should be the standard EDD forecast.

NIEIR considers that AEMO's approach is inconsistent with scientific evidence on global and urban warming. Furthermore, NIEIR considers that 2000 to 2014 is too short a period to assess accurately the long-term warming trend (AEMO itself acknowledged that this is an interim measure and indicated that it plans to complete a long-range climate survey during 2016) NIEIR believes that climate trends over the short to medium term are volatile and do not necessarily reflect historical or future long-term climate trends. NIEIR's statistical analysis and report indicates that the warming trend has been more certain over the longer term, therefore we recommend an annual warming trend reduction of 7.6 EDDs (EDD 312) per annum, based on the 1970 to 2015 period. This declining trend is consistent with well-documented global and urban warming effects impacting Victoria's climate and is similar to the declining 7.7 EDDs per annum assumption that the AER endorsed in its Final Decision for our current Access Arrangement period.

On this basis, Table 9-5 details the forecast EDD index for 2016 to 2022 that is used for our forecasts.

[8] NIEIR, NIEIR Review of EDD weather standards for Victorian gas forecasting April 2016

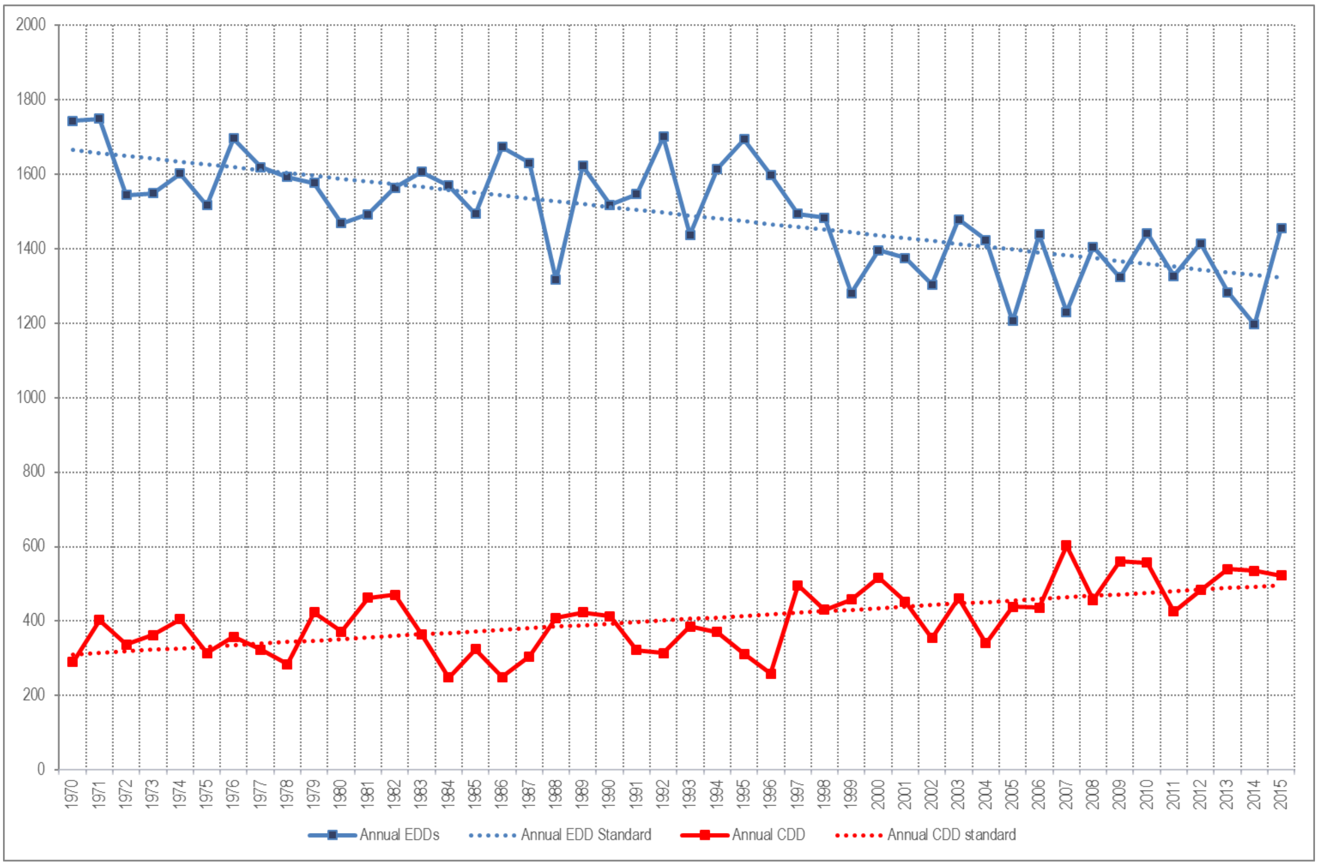
Table 9-5: Forecast EDD index for 2016 to 2022

	2016	2017	2018	2019	2020	2021	2022
EDD 312	1,314	1,306	1,299	1,291	1,284	1,276	1,268

The EDD index has been designed primarily to measure the weather conditions during the non-summer months. It does not reflect weather conditions in the summer months. Typically, daily readings of the index during the summer months are zero. However, an extremely hot or an unusually cool summer can affect gas demand. For instance, the need for water heating is reduced by hot weather, with consumers more likely to have cooler-than-normal showers on hot summer days.

In contrast to the EDD index, the annual number of Cooling Degree Days (CDD) has steadily increased in recent decades. On average, the rate of increase has been around 4.14 CDDs per annum. The trend increase in CDDs also has the effect of depressing gas demand in the summer months, and therefore adds to the total downward impact of weather on gas demand.

Figure 9-1: Historical trends in EDDs and Cooling Degree Days (CDDs)



NIEIR's modelling of Tariff V gas consumption has considered the long-terms trends in EDDs and CDDs.

Price elasticities for gas

NIEIR considered own (i.e. of gas), and cross-price (i.e. between gas and electricity) elasticities in preparing its demand forecasts, as detailed in its report that is attached to this Access Arrangement Information.

NIEIR undertook its own work, and reviewed overseas and Australian literature, in relation to own-price elasticities and adopted a distributed lag structure for the short-term price impacts.

NIEIR found that the own gas price elasticities were slightly lower than those used for previous access arrangements submitted by gas networks around Australia and accepted by the AER. This continues the downward trend found in own gas price elasticities found within the literature survey that it conducted.

NIEIR found that across the three customer demand classes, gas demand is most responsive in the industrial sector, where a one per cent fall in price will result in an increase in natural gas demand in the long run by 0.32 per cent.

NIEIR found that the residential sector is the next most responsive, where a one per cent fall in price will result in a 0.28 per cent increase in natural gas demand. The commercial sector is the least price responsive. This is most likely due to the small share of gas demanded by the commercial sector compared to total demand. Here a one per cent fall in price will lead to an estimated 0.21 per cent increase in natural gas demand.

The estimates of cross-price elasticities of gas demand to changes in the price of electricity show that the residential and commercial markets are quite responsive to the price of electricity. In contrast, industrial customers seem to adjust their gas demand only marginally to the price of electricity in the long run (at least this seems to be the Australian experience).

NIEIR found that price elasticities and demand responses depend on the actual price and the magnitude of the price change. It found that the low price elasticities for gas mainly reflect the composition and turnover rates for gas consumption appliances and equipment. For example, in the residential sector the major gas consumption appliances are water heaters, space heaters and cooking. The average life of these appliances is well over ten years. Similarly, in the industrial sector, major gas consumption equipment, may only be replaced when the plant is expanding capacity. There are usually only limited opportunities for improving the energy efficiency of particular equipment.

NIEIR found that gas faces some competition from alternative fuels such as electricity, oil, coal and LPG. However, cross elasticities of demand are low in the short run, particularly in the household market. This is because consumers have, for example, sunk investments in central heating systems which are generally fuel specific. Cross-price elasticities tend to be higher for those, mainly industrial users, who can quickly and cheaply switch to alternative fuels. To reflect this inelastic response, NIEIR used a cross price elasticity of 0.08, based on a survey of literature.

Federal and State Government policy initiatives

There are several complementary energy and greenhouse gas abatement policies that will affect Victoria's future gas usage. National and State government initiatives such as subsidies and rebates are driving changes in gas demand in both residential and commercial sectors. A summary of the relevant Federal and State Government policy initiatives is provided in Table 9-6.

Table 9-6: Key policy impacts on gas demand

Policy	Measure	Description of impact
National		
Emissions Reduction Fund	Government funds projects that reduce carbon emissions through a reverse auction process. Majority of projects related to vegetation and waste management.	Minimal impact on gas consumption due to project mix.
Renewable Energy Target	Small-scale Renewable Energy Target offers incentives to install solar hot water and heat pump hot water.	Reduces electricity and gas consumption for hot water.
Minimum Energy Performance Standards (MEPS)	4 star minimum MEPS for gas hot water. Gas space heater MEPS under consideration.	Removes least efficient gas storage hot water systems from new hot water market. MEPS for air conditioners also encourage fuel switching.

Policy	Measure	Description of impact
Energy Labelling	Australian Gas Association (AGA) administers gas energy labelling. Coverage on most gas appliances. E3 runs the electricity appliance energy labelling.	Encourages adoption of more efficient appliances, reduces energy consumption.
Commercial Building Disclosure Program (CBD)	Disclosure of energy efficiency information required when commercial buildings leased or sold with floor area greater than 2000m2. Threshold lowered to 1000m2 in July 2017.	Encourages energy efficiency in commercial sector. Expansions will require additional 1000 Australian buildings to disclose energy efficiency information.
Clean Energy Finance Corporation (CEFC)	Provides finance exclusively to renewable energy, low emissions and energy efficiency projects.	Projects reduce energy consumption, usually in government, commercial and industrial sectors.
Australian Renewable Energy Agency (ARENA)	Government support for renewable energies.	Direct impact on network gas demand minimal. Most projects aimed at large scale renewable and research and development.
Clean Energy Innovation Fund (CEIF)	New $1 billion fund to finance clean energy projects/new businesses that are beyond R&D stage. Jointly managed by CEFC and ARENA.	Encourages shift to renewables, energy efficiency and low carbon. Similar in scope to CEFC and ARENA.
Ministerial Council on Energy (2010-12)	Phase-out of electric resistance hot water.	Various incentives to switch away from electric resistance hot water.
National Strategy on Energy Efficiency (2009)	All gas appliances across all sectors. National standards.	Impact uncertain and difficult to quantify.
National Energy Productivity Plan (2015)	Target 40 per cent improvement in energy productivity by 2030.	Strategy to direct other programs.
State		
6-star building standards	Requirements to improve buildings thermal performance and energy consumption (insulation, building design. Required to install rainwater tank or solar hot water.	Reduces average consumption for new dwellings.
Victorian Energy Efficiency Target (VEET)	Incentives to replace inefficient gas and space heaters with more efficient models and technologies. Incentives to replace inefficient electric appliances with high efficiency gas appliances.	Activities that increase and activities that decrease gas consumption. Net impact on gas is close to zero.
Showerhead Exchange Program	Free 3 star WELS low flow shower heads to replace old shower heads.	Reduce gas consumption for hot water heating.
Other state-based incentive and rebate programs	Cash rebates for installing solar hot water and gas space heating.	Usually small programs but with some impacts on gas use. Most now closed.
Victorian Emissions Reduction Target	Announced June 2016. Emissions reduction target of net zero by 2050 with interim targets every five years.	
Victorian Renewable Energy Target	Renewable Energy Targets of 25 per cent by 2020 and 40 per cent by 2025.	
Victorian Energy Efficiency and Productivity Strategy	April 2016 announced programs include: • retrofitting public housing stock and homes for people with health conditions • Energy efficient assessment program for small and medium business • Home energy efficiency rating tool	

Victorian average annual gas consumption per residential customer has been dropping in recent years and is forecast to continue to decline. Changes in water heating and space heating by households are key contributors to this decline. Some of the key impacts on water heating are:

- Improvements in gas appliance efficiency mainly driven by MEPS;
- Water conservation initiatives impacting on hot water loads (e.g. low flow shower heads);
- Shifts to solar hot water and heat pumps for water heating.

Residential demand for gas for space heating is affected by:

- Increasing market penetration of reverse cycle air conditioners which are used for heating as well as cooling; and
- Improved envelope thermal efficiency of existing and new dwellings due to changes to building standards and shell upgrades (e.g. 5-star, 6-star).

In modelling gas demand, residential policy impacts are usually separated into their impacts on new and existing dwellings, since this allows the quantitative impact of individual policies to be assessed.

Customer growth

We currently have more than 693,000 residential and small business customers connected to our gas network. These customers account for around 78 per cent of our total gas volumes. We currently have around 265 large industrial customers, which contribute the remaining 22 per cent of our total gas volumes.

NIEIR forecast residential customer growth based on our share of Victoria's dwelling completions and the consequent growth in dwelling stock within our service area. It forecast net customer growth as the difference between total new connections and forecast disconnections. It separately forecast existing and new residential customers.

NIEIR forecasts small business customers from the forecasts of total small business volumes and forecast average usage for these customers.

It forecasts large industrial customer growth volumes on an industry basis and average usage for these customers on an industry basis.

Volume forecasts

As noted above, the AER accepted our consumption forecast for the current access arrangement period, which was prepared by NIEIR. We estimate that there will be less than 1.0 per cent difference between our actual total Tariff V consumption and the forecast that the AER accepted. The high level of accuracy of NIEIR's forecast supports their credibility and justifies our continued reliance on them for the forthcoming access arrangement period.

NIEIR forecasts our volume forecasts from a modelling methodology that takes account of several different drivers – this is the same methodology that they used for the current access arrangement period. These drivers include the following:

- The effect of trend warming in temperatures on gas demand;
- Changing levels of gas usage by existing and new residential customers. Differences in average consumption for new and existing gas customers reflect the characteristics of new dwellings, which are predominantly apartments or higher density, infill housing with lower average levels of gas usage;
- Income and economic growth impacts;
- Price impacts; and
- Policy impacts on gas usage, including:

- The impact of more efficient appliances, including: storage water heaters with instantaneous heaters or solar heaters; appliance stock efficiency improvements; and reverse cycle air conditioning replacing gas heating; and
- Federal and State Government initiatives – including the introduction of a carbon tax; 6-star housing requirements; solar hot water incentives; and energy efficiency measures that are all designed to lower energy consumption, including gas.

NIEIR modelling methodology employs a multi-variate approach and does not simply rely upon trend extrapolations.

Victorian gas usage is highly weather sensitive, mainly due to space and central heating system loads. NIEIR's forecasts of our volumes for our residential, small business and large industrial sectors are adjusted for weather conditions which vary from month to month and year to year.

A weather standard is calculated and applied across each class of customer. The approach used for our network is similar to the approach used by AEMO in its National Gas Forecasting report.

NIEIR's forecasts of our residential volumes are determined from a model that separates out existing and new customer usage. Our existing customers have average usage of around 56 GJ per customer and typically have gas hot water, gas cook tops and space or central heating. Our new customers, on the other hand, consume only 41 GJ per customer on average and have much more efficient appliances, as well as more thermally efficient dwellings. In addition, NIEIR's modelling takes account of the fact that smaller townhouses may not have gas space heating but rather have electric reverse cycle heating.

NIEIR's modelling of our residential usage is also impacted by the growth in real household income per capita, real energy prices and assessed policy impacts.

NIEIR's forecast of our small business volume growth is linked to a model that includes projections of business output growth and real energy prices. Small business volumes have been declining in our region in recent years.

NIEIR's forecast of our large industrial volume growth is modelled across 17 industries. The model is driven by output growth by industry and the change in real energy prices. NIEIR's forecasts are supplemented with information collected from a large industrial customer survey.

9.4. Forthcoming Access Arrangement period consumption, demand and customer numbers

9.4.1. Residential customer forecasts

NIEIR's residential customer forecasts are based on average consumption for new and existing customers and customer growth.

NIEIR forecasts that our residential customers will grow on average by 0.5 per cent per year over the 2018 to 2022 period. This is similar to the actual growth over the current Access Arrangement period. NIEIR forecasts that total residential gas connections will grow from around 674,931 in 2015 to 684,783 by 2018 and then to 698,507 by 2022.

Residential consumption per connection has been declining steadily in Victoria. Our residential customers' average usage has fallen from 62.6 GJ in 2008 to 56.8 GJ per connection in 2015. The decline in average residential usage reflects several factors including, the marked increase in the thermal efficiency of new dwellings, improvements in appliance efficiencies, and the substitution of electricity for gas in space heating. The latter point is reinforced by the shift away from detached houses to small townhouses and apartments in our service area. These smaller dwellings typically use reverse cycle electric heating. The average consumption of new residential customers is about 41 GJ.

The trend rate of decline in average residential consumption in our service region was 1.5 per cent per annum between 2008 and 2015. Over the period 2016 to 2022, NIEIR forecasts a very similar rate of decline of 1.8 per cent per annum. NIEIR forecasts that average usage will fall to 51.2 GJ per connection by 2022.

Figure 9-2 shows our actual, estimated and forecast average residential customer demand per connection over the previous, current and forecast Access Arrangement periods. Figure 9-3 shows our actual, estimated and forecast total residential customer demand over the same three periods.

Figure 9-2: Residential consumption per connection (GJ) – Weather normalised

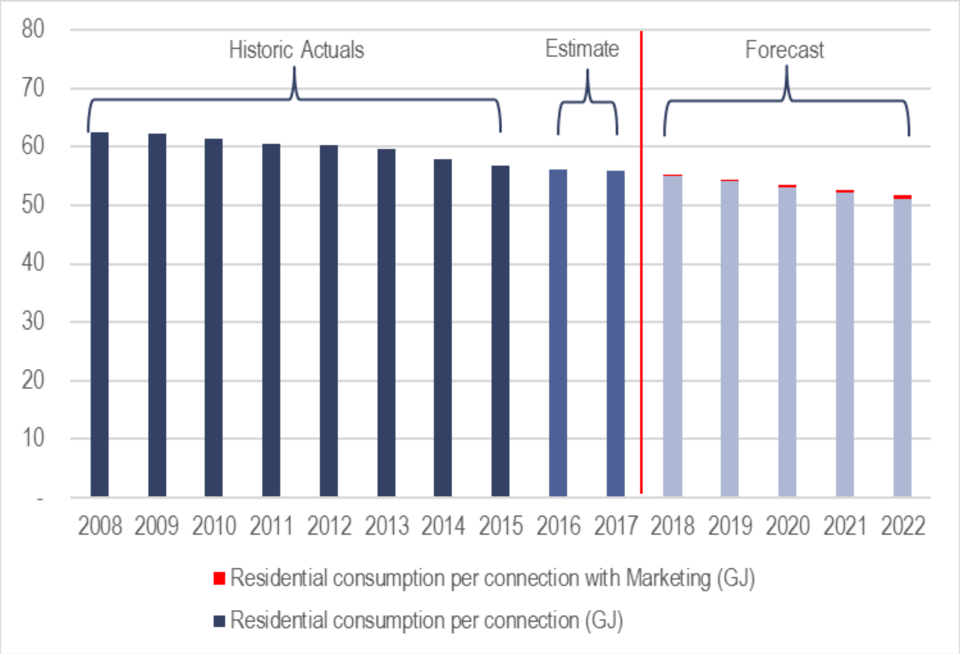


Figure 9-3: Residential demand (TJ) – Weather normalised

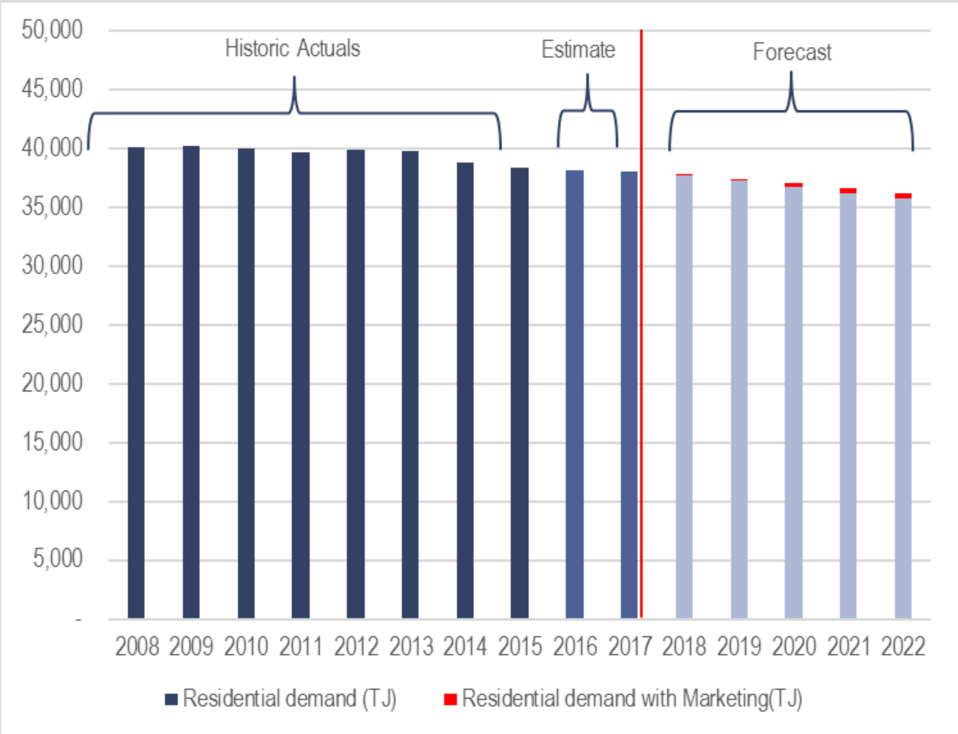


Table 9-7 details NIEIR's forecasts of our net customer numbers, average consumption per connection and total consumption for residential customers over the forthcoming Access Arrangement period.

Table 9-7: Residential demand forecast

Category	2018	2019	2020	2021	2022
Excluding marketing step change					
Net customer numbers	684,783	688,279	691,752	695,209	698,507
Consumption per connection (GJ) (weather normalised)	55.1	54.1	53.2	52.1	51.2
Total consumption (TJ) (weather normalised)	37,715	37,231	36,777	36,241	35,748
Including marketing step change					
Net customer numbers	685,064	688,840	692,594	696,332	699,910
Consumption per connection (GJ) (weather normalised)	55.2	54.3	53.5	52.6	51.8
Total consumption (TJ) (weather normalised)	37,810	37,421	37,061	36,620	36,222

Note: Figures may not reconcile exactly due to rounding

9.4.2. Small business customer forecasts

Our small business volumes and customers have also been declining in recent years. Our total gas volumes fell by 2.2 per cent per annum between 2008 and 2015. Our small business customer numbers fell by 0.6 per cent per annum over the same period. As a result, our consumption per connection has also declined significantly and is forecast to decline further in the forthcoming Access Arrangement period. NIEIR forecasts that our total small business volumes will fall by 2.7 per cent per annum between 2018 and 2022, while small business customers will fall by 1.0 per cent per annum.

Figure 9-4 shows our actual, estimated and forecast average small business consumption per connection over the previous, current and forecast Access Arrangement periods. Figure 9-5 shows our actual, estimated and forecast total small business customer demand over the same three periods.

Figure 9-4: Small business consumption per connection (GJ) – Weather normalised

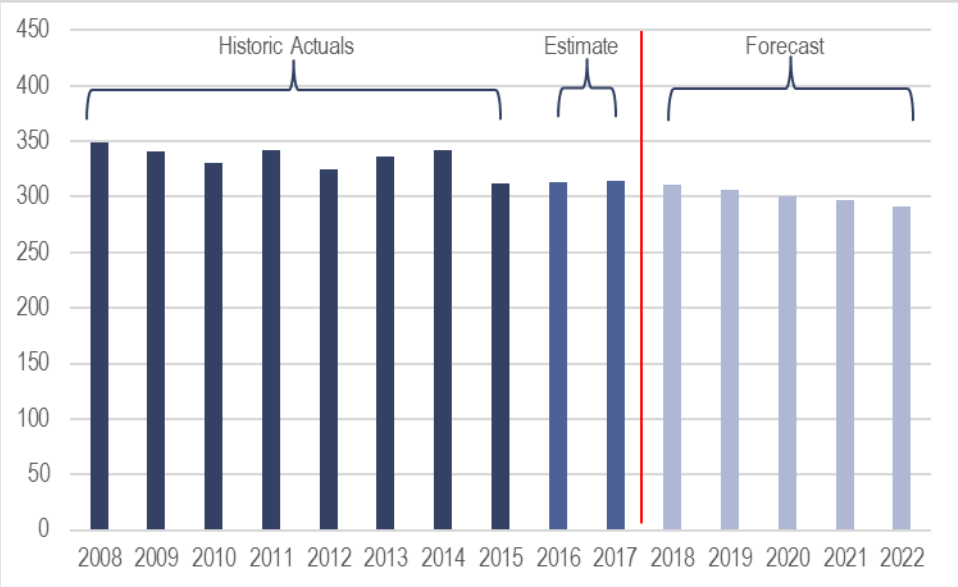


Figure 9-5: Small business demand (TJ) – Weather normalised

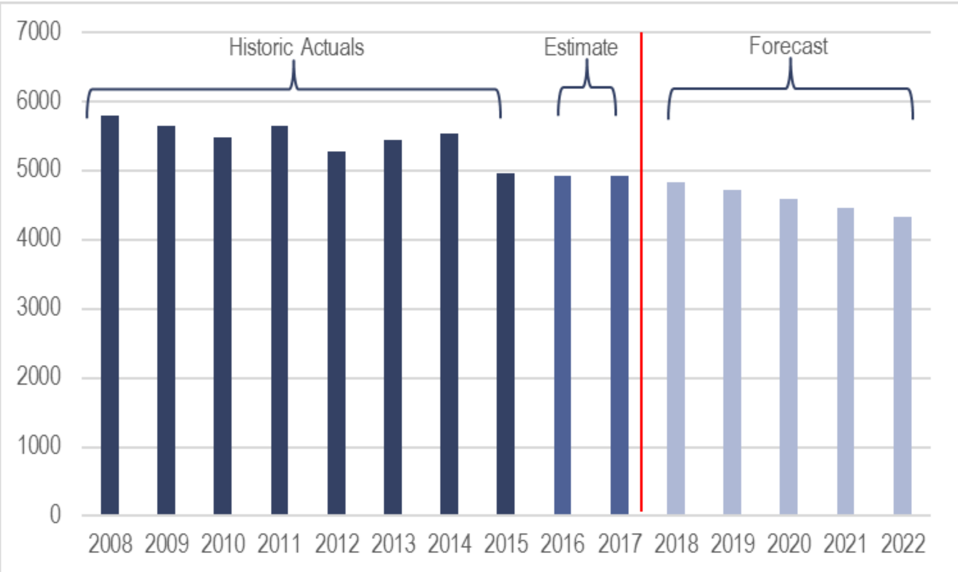


Table 9-8 details NIEIR's forecasts of our net customer numbers, average consumption per connection and total consumption for small business customers over the forthcoming Access Arrangement period.

Table 9-8: Small business demand forecast

Category	2018	2019	2020	2021	2022
Net customer numbers	15,524	15,388	15,290	14,974	14,898
Consumption per connection (GJ) (weather normalised)	311	306	300	297	291
Total consumption (TJ) (weather normalised)	4,832	4,712	4,588	4,448	4,334

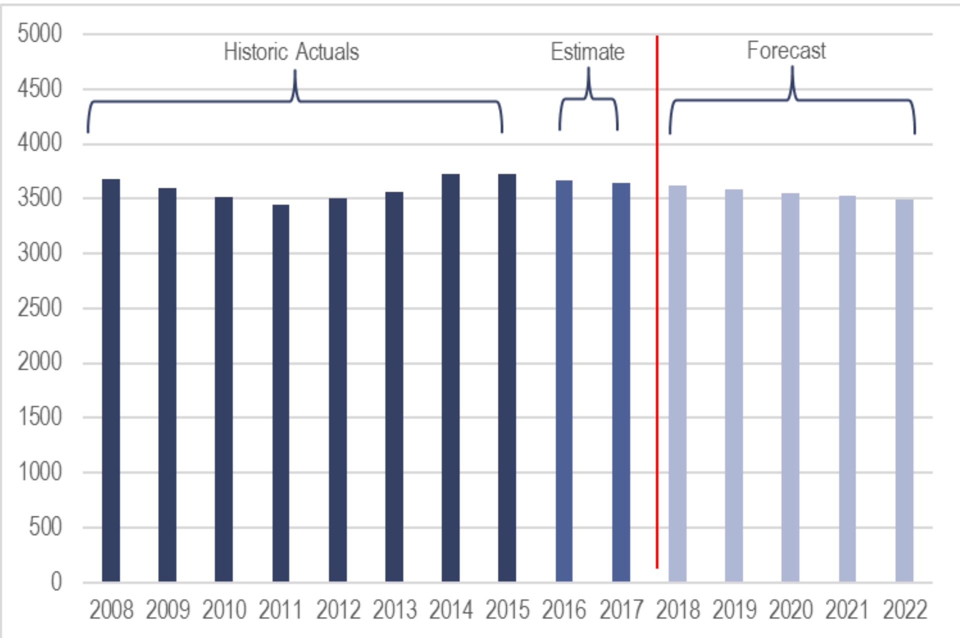
Note: Figures may not reconcile exactly due to rounding

9.4.3. Large industrial customer forecasts

Our large industrial volumes have fallen significantly over the last 10 years. Total volumes were 14.3 petajoules in 2006, but fell to 12.2 petajoules in 2015.

Our large industrial demands – maximum hourly quantity (MHQ) – have not fallen as rapidly as our large industrial total volumes. This partly reflects the addition of two new customers on our South Gippsland network. Our actual, estimated and forecast total MHQ for our large industrials is shown in Figure 9-6. NIEIR forecasts that total MHQ for our large industrial customers will fall by 0.9 per cent per annum over the forthcoming Access Arrangement period.

Figure 9-6: Tariff D MHQ (GJ/hr)



The decline in manufacturing in Victoria, with increased competition from Asian countries, underlies the historical and forecast gas demand for large industrial customers.

Table 9-9 details NIEIR's forecast of our MHQ over the next Access Arrangement period.

Table 9-9: Tariff D MHQ demand forecast (GJ/hr)

Category	2018	2019	2020	2021	2022
MHQ	3,621	3,588	3,549	3,529	3,496

9.4.4. Overview of our gas consumption, demand and customer number forecasts

Table 9-10 details our forecast gas consumption and demand for the next Access Arrangement period.

Table 9-10: Forecast gas consumption and demand – 2018 to 2022 (weather normalised)*

Category	2018	2019	2020	2021	2022
Tariff V – residential consumption (TJs) – excluding marketing step change	37,715	37,231	36,777	36,241	35,748
Tariff V – residential consumption (TJs) - including marketing step change	37,810	37,421	37,061	36,620	36,222
Tariff V – small business consumption (TJs)	4,832	4,712	4,588	4,448	4,334
Tariff L – consumption (TJs)	68	67	66	66	65
Total – consumption Tariff V and L (TJs) – excluding marketing step change	42,616	42,009	41,431	40,755	40,147
Total – consumption Tariff V and L (TJs) - including marketing step change	42,710	42,199	41,715	41,134	40,621
Tariff D and L – demand (MHQs - GJ/hr)	3,672	3,638	3,599	3,578	3,545

* *Figures may not reconcile exactly due to rounding*

Table 9-11 details our forecast customer growth for the forthcoming Access Arrangement period.

Table 9-11: Forecast customer numbers – 2018 to 2022*

Category	2018	2019	2020	2021	2022
Excluding marketing step change					
Opening balance	697,317	700,584	703,940	707,312	710,449
Closing balance	700,584	703,940	707,312	710,449	713,668
Net New Customers	3,267	3,356	3,372	3,137	3,220
Including marketing step change					
Opening balance	697,317	700,865	704,501	708,154	711,571
Closing balance	700,865	704,501	708,154	711,571	715,071
Net New Customers	3,548	3,637	3,652	3,417	3,500

* *Figures may not reconcile exactly due to rounding*

Table 9-12: Reconciliation of customer connections – 2018 to 2022 [9]

Category	2018	2019	2020	2021	2022
Opening Connections	697,317	700,865	704,501	708,154	711,571
New Connections	8,914	8,454	8,022	8,169	8,450
Abolishments (Residential)	(5,366)	(4,817)	(4,370)	(4,752)	(4,950)
Closing Connections	700,865	704,501	708,154	711,571	715,071

[9] We assume that disconnections and reconnections will net to zero for each year of the forthcoming access arrangement period

10. Unaccounted for gas

Key messages:

- We have not proposed unaccounted for gas (UAFG) benchmarks in this Access Arrangement Information, nor have we reflected the revenues or costs that we may receive or pay from positive or negative reconciliation amounts in the period.
- The AER should not have regard for UAFG in making its Draft and Final Decisions on our Access Arrangement Information.
- We will make a submission to the ESCV's upcoming review of UAFG benchmarks.

Rule 317(1) of the NGR requires the Australian Energy Market Operator (AEMO) to make procedures for dealing with UAFG. The Rule states:

> *AEMO must make Procedures (Distribution UAFG procedures):*
>
> *(a) requiring AEMO to calculate gas unaccounted for in a declared distribution system and to determine the payments to be made (and when they are to be made) as between a Retailer and Distributor for that gas; and*
>
> *(b) provide for how the calculation and determination are to be made.*

Under AEMO's Procedures,[10] AEMO calculates unaccounted for gas and any associated payments using benchmarks set by the ESCV. The benchmarks are detailed in Schedule 1 of Part C of the Victorian Gas Distribution System Code. They are expressed as a percentage of the aggregate quantity of gas that we (and the other two Victorian gas distributors, respectively) receive at transfer points into our distribution systems. The benchmarks vary from year to year and by distribution system.

Where the percentage volume of UAFG in a year is different to the UAFG benchmark then a reconciliation amount is payable. We (and the other gas distributors) pay retailers when the reconciliation amount is negative and we receive a payment from retailers when the reconciliation amount is positive.

The current benchmarks in Schedule 1 of Part C of the Victorian Gas Distribution System Code are for the period 2013 to 2017. The ESCV is in the process of setting new benchmarks that will apply from 2018. We are engaging actively in the ESCV's process of setting the future benchmarks.

The process of setting the new benchmarks, the benchmarks themselves and the reconciliation amounts that are payable by, or to, us are not matters that are directly relevant to this Access Arrangement Information. This was recognised by the AER in its Draft Decision for our current Access Arrangement period where it stated:

> *UAFG is regulated under Part 19 of the NGR by AEMO and the current AEMO Procedures refer only to benchmarks set under the Gas Distribution System Code. The AER cannot set the benchmarks.*[11]

The AER confirmed this position in its Final Decision where it stated:

> *In its draft decision the AER concluded that it could not set Unaccounted for Gas (UAFG) benchmarks.*[12]

On this basis, this Access Arrangement Information does not propose UAFG benchmarks for the forthcoming Access Arrangement period, nor does it reflect the revenues or costs that we may receive or pay from positive or negative reconciliation amounts in the period. We also consider that the AER should not have regard for UAFG in making its Draft and Final Decisions on our Access Arrangement Information.

[10] AEMO Wholesale Market Distribution UAFG Procedures (Victoria), Version No. 2.

[11] AER, "Access arrangement draft decision - 2013–17 - Part 2: Attachments – September 2012", page 175

[12] AER, "Access arrangement final decision - 2013–17 - Part 2: Attachments - March 2013", page 195

11. Pipeline services

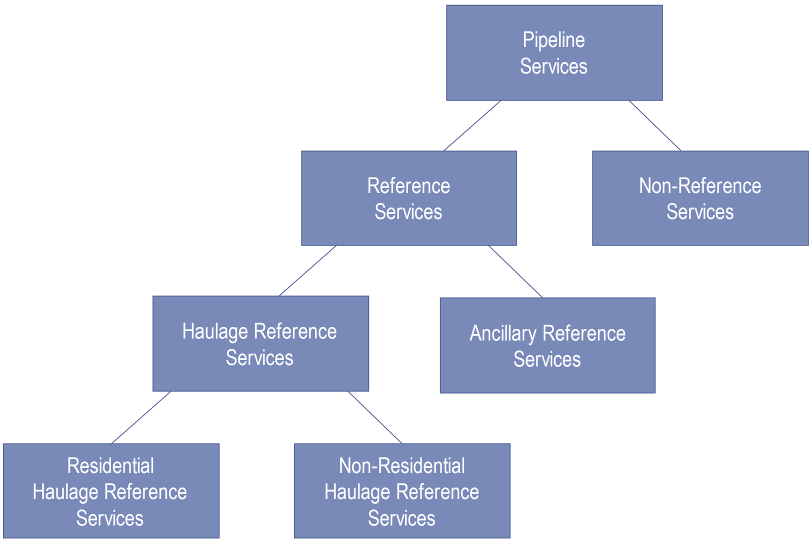
Key messages:

- We are not proposing any changes to our Haulage Reference Services. Our services policy is specified in section 5.1 of Part A of our current Access Arrangement.
- We propose one additional Ancillary Reference Services in response to a request from retailers. This will be for the "installation of a service valve". Our Ancillary Reference Services are specified in Schedule 1 of Part A of our current Access Arrangement.
- We propose that our Non-Reference Services comprise:
  - The list of services specified in Schedule 2 of Part C of our current Access Arrangement; and
  - A new general provision covering other services requested by individual customers that differ from Reference Services (i.e. that are not sought by a significant part of the market and therefore cannot be classified as a Reference Service).

11.1. Our service categories

Figure 11-1 illustrates the relationship between the various services that we provide.

Figure 11-1: Our gas distribution services



We provide:

- Two types of Pipeline Services – Reference Services and Non-Reference Services;
- Two types of Reference Services – Haulage Reference Services and Ancillary Reference Services; and
- Two types of Haulage Reference Services – Residential Haulage Reference Services and Non-Residential Haulage Reference Services.

Sections 11.2 and 11.3 explain each service category and section 11.4 explains the relevance of our service categories to the rest of this Access Arrangement Information.

11.2. Reference Services

Rule 101 of the NGR states that:

> *(1) A full access arrangement must specify as a reference service:*
>
> *(a) at least one pipeline service that is likely to be sought by a significant part of the market; and*
>
> *(b) any other pipeline service that is likely to be sought by a significant part of the market and which the AER considers should be specified as a reference service.*
>
> *(2) In deciding whether to specify a pipeline service as a reference service, the AER must take into account the revenue and pricing principles.*

Our Services Policy in section 5.1 of Part A of our Access Arrangement proposes three classes of Reference Services:

- Residential Haulage Reference Services;
- Non-Residential Haulage Reference Services; and
- Ancillary Reference Services.

We are only proposing to make one change to our current Reference Services in the next Access Arrangement period, being for the introduction a new Ancillary Reference Services for the "installation of a service valve". This change is in response to a request from retailers.

We assign the following tariffs to each class of Haulage Reference Service:

- Residential Haulage Reference Service – Tariff V; and
- Non-Residential Haulage Reference Service – Tariff D, Tariff L and Tariff V.

11.2.1. Residential Haulage Reference Service – Tariff V

The Residential Haulage Reference Service is the Haulage Reference Service for allowing the injection, conveyance and withdrawal of gas by, or in respect of, a residential customer, being a customer who uses gas primarily for domestic purposes. This service includes the basic connection service (within the meaning of Part 12A of the NGR), being expansions or extensions comprising work on the main, service pipe, metering installation and scheduled meter reading.

The costs of basic connection services for residential customers are assumed to satisfy:

- The test in rule 119M(1)(a) that the present value of the expected incremental revenue exceeds the present value of the capital expenditure; and
- The test in rule 79 in relation to conforming capital expenditure.

Forecasts of these costs have been included in the calculation of our total revenue and no connection charge will be levied for a basic connection service for residential customers.

We will subject the costs of the connection assets for Residential Haulage Reference Services that do not comprise a basic connection service to the tests in proposed Rule 119M and Rule 79 of the NGR, in accordance with the Extensions and Expansions requirements of Part A of our Access Arrangement.

11.2.2. Non-Residential Haulage Reference Service – Tariff V

The Non-Residential Haulage Reference Service is the Haulage Reference Service for allowing the injection, conveyance and withdrawal of gas by, or in respect of, a non-residential customer, being a customer other than a residential customer. Where relevant, a distribution supply point is assigned to Non-Residential Haulage Reference Service – Tariff V. This service includes the basic connection service within the meaning of Part 12A of the NGR, being expansions or extensions comprising work on the main, service pipe, metering installation and scheduled meter reading services.

The costs of basic connection services for non-residential Tariff-V customers are assumed to satisfy:

- The test in rule 119M(1)(a) that the present value of the expected incremental revenue exceeds the present value of the capital expenditure; and
- The test in rule 79 in relation to conforming capital expenditure.

Forecasts of these costs have been included in the calculation of the total revenue and no connection charge will be levied for a basic connection service for Non-Residential Tariff V customers.

We will subject the costs of the connection assets for Non-Residential Tariff V Haulage Reference Services that do not comprise a basic connection service to the tests in proposed rule 119M and rule 79 of the NGR, in accordance with the Extensions and Expansions requirements of Part A of our Access Arrangement.

11.2.3. Non-Residential Haulage Reference Service – Tariff D

The Non-Residential Haulage Reference Service Tariff D allows for the injection, conveyance and withdrawal of gas at a Tariff D distribution supply point. This service and associated tariff does not include the provision and maintenance of connection assets forming a Tariff D distribution supply point.

The connection of a Tariff D distribution supply point will be provided as a non-Reference Service and the costs of these works and related operations and maintenance are not recovered through the Non-Residential Tariff D Reference Tariff. A charge will be determined for this service in accordance with proposed rule 119M and rule 79 and applied in accordance with the Extensions and Expansions requirements of Part A of our Access Arrangement.

11.2.4. Non-Residential Haulage Reference Tariff – Tariff L

The Non-Residential Haulage Reference Service – Tariff L allows for the injection, conveyance and withdrawal of gas at a Tariff L distribution supply point. This service and associated tariff does not include the provision and maintenance of connection assets forming a Tariff L Distribution Supply Point.

The connection of a Tariff L distribution supply point is to be provided as a non-Reference Service and the costs of these works and related operations and maintenance are not recovered through the Non-Residential Tariff L Reference Tariff. A charge will be determined for this service in accordance with proposed rule 119M and rule 79 and applied in accordance with the Extensions and Expansions requirements of Part A of our Access Arrangement.

11.2.5. Ancillary Reference Services

Ancillary Reference Services are Reference Services provided in connection with the injection, conveyance and withdrawal of gas. We offer the Ancillary Reference Services set out in Schedule 1 of Part A of our Access Arrangement, which are as follows:

- Meter and gas installation tests;
- Disconnections, being:
  - Removal of the meter at a metering installation; and
  - The use of locks or plugs at a metering installation.
- Energisation and reconnection;
- Special meter reading; and

- Installation of a service valve.

Other than the last service, these are the same Ancillary Reference Services that we have in the current Access Arrangement period. We have added the "installation of a service valve" at the request of retailers, who are seeking this as an alternative to cutting the pipe in the street where a disconnection has been requested but access a property is not available for them to either lock or plug the metering installation.

11.3. Non-Reference Services

Pipeline services other than Reference Services – often referred to as "Non-Reference Services" – will be made available to users or prospective users as agreed or as determined in accordance with Part 12A of the NGR and relevant regulatory instruments.

We propose supplying our Non-Reference Services on the reasonable terms and conditions set out in Part C of our Access Arrangement.

Schedule 2 of Part C of our Access Arrangement for the current Access Arrangement period details our Non-Reference Services as follows:

- Tariff D and Tariff L Connections and Tariff V complex Connections. We note that the Tariff D Connections are subject to the default terms and conditions in Part C of our Access Arrangement. We agree to the terms and conditions for Tariff L Connections and Tariff V complex Connections downstream of the main at the time that we sign the contract for services with the user;
- After Hours connection and re-connection for tariff V customers between the hours of 4.00pm and 8.00pm;
- Meter and Gas Installation Test:
  - (i) On-site testing (other than for a Tariff V Customer); or
  - (ii) At NATA accredited laboratory.
- Disconnection by the carrying out of work being excavating and shutting the service tee in the street; and
- Re-connection by the carrying out of work being excavating and reconnecting the service tee in the street.

We propose that these continue to be Non-Reference Services in the forthcoming Access Arrangement period.

In addition, we propose that where an individual customer requires another service that differs from a Reference Service (i.e. not sought by a significant part of the market and therefore cannot be classified as a Reference Service), we will treat this as a Non-Reference Service and negotiate a price on a case-by-case basis with the customer. The price for services of this kind will depend on the specific conditions attached to the provision of the service required by the customer. Examples of these other Non-Reference Services include:

- Removal of service pipe; and
- Asset relocation.

We note that this approach is consistent with the AER's recent decisions for JGN and AGN SA.

The terms and conditions in Part C of our Access Arrangement make provision for Schedule 2 to be amended from time-to-time by agreed notice between the parties or as a result of arbitration. We can readily update Schedule 2 each time a new Non-Reference Service is agreed or determined. We consider this is a sensible and pragmatic approach to finalising contracts that relate to the provision of Non-Reference Services.

11.4. Role of service categories in this Access Arrangement Information

Our Non-Reference Services are not dealt with in this Access Arrangement Information. Rather, as noted in section 11.3, they are dealt with in Part C of our Access Arrangement.

This Access Arrangement Information therefore deals only with Haulage Reference Services and Ancillary Reference Services.

The Total Revenue forecast in chapter 20 of this Access Arrangement Information relates exclusively to Haulage Reference Services. All of the building block forecasts that contribute to the Total Revenue therefore also only relate to Haulage Reference Services. While the opex chapter 14 covers both Haulage Reference Services and Ancillary Reference Services, we split the forecast in between the two service categories, as detailed in section 14.6. The opex for Haulage Reference Services contributes to the Total Revenue forecast in chapter 20 and the opex for Ancillary Reference Services is recovered through the Ancillary Reference Service tariffs in section 21.9.

We incur no Capex on Ancillary Reference Services. Each of our forecasts of demand, the Capital Base, Capex, Depreciation and the Rate of Return therefore relate only to our Haulage Reference Services.

Our forecast of the Cost of Corporate Income Tax, proposed Incentive Mechanisms and cost pass throughs in each of chapters 17, 18 and 19 respectively also relate exclusively to Haulage Reference Services.

We are proposing separate Reference Tariff Variation Mechanisms for Haulage Reference Services and Ancillary Reference Services in chapter 12.

Chapter 21 proposes tariffs for our Haulage Reference Services and Ancillary Reference Services.

12. Reference tariff variation mechanism

Key messages:

- We propose changing our reference tariff variation mechanism for our Haulage Reference Services from a weighted average price cap to a revenue cap for the forthcoming Access Arrangement period. We have based our revenue cap formulae on those approved by the AER in its final 2016 to 2020 Distribution Determinations for the Victorian electricity distribution businesses, subject to limited modifications.
- We propose maintaining our current Schedule of Tariffs for our Ancillary Reference Services over the forthcoming Access Arrangement period, subject to an annual CPI increase. Our proposed Schedule of Tariffs is detailed in Chapter 21.

This chapter details the proposed reference tariff variation mechanism for Haulage Reference Services and Ancillary Reference Services that is reflected in the Reference Tariff Policy in Part B of our Access Arrangement. Chapter 11 discusses the nature of the Haulage Reference Services and Ancillary Reference Services that we provide to our customers.

12.1. Introduction

Chapter 21 details our proposed reference tariffs to apply during the forthcoming Access Arrangement period. This chapter 12 describes how our tariffs will adjust over this period, including the annual process for the AER approving tariffs to apply in a given regulatory year.

Rule 97 of the NGR requires that:

(1) A reference tariff variation mechanism may provide for variation of a reference tariff:

(a) in accordance with a schedule of fixed tariffs; or

(b) in accordance with a formula set out in the access arrangement; or

(c) as a result of a cost pass through for a defined event (such as a cost pass through for a particular tax); or

(d) by the combined operation of 2 or more of the above.

(2) A formula for variation of a reference tariff may (for example) provide for:

(a) variable caps on the revenue to be derived from a particular combination of reference services; or

(b) tariff basket price control; or

(c) revenue yield price control; or

(d) a combination of all or any of the above.

(3) In deciding whether a particular reference tariff variation mechanism is appropriate to a particular access arrangement, the AER must have regard to:

(a) the need for efficient tariff structures; and

(b) the possible administrative effects of the reference tariff variation mechanism on administrative costs of the AER, the service provider, and users or potential users; and

(c) the regulatory arrangements (if any) applicable to the relevant reference service before the commencement of the proposed reference tariff variation mechanism; and

(d) the desirability of consistency between regulatory arrangements for similar services (both within and beyond the relevant jurisdiction); and

> (e) *any other relevant factor.*
>
> (4) *A reference tariff variation mechanism must give the AER adequate oversight or powers of approval over variation of the reference tariff.*
>
> (5) *Except as provided by a reference tariff variation mechanism, a reference tariff is not to vary during the course of an access arrangement period.*

The remainder of this chapter is structured as follows:

- Section 12.2 describes our proposed reference tariff variation mechanism for our Haulage Reference Services;
- Section 12.3 sets out the formulae that we propose using to adjust our tariffs each year; and
- Section 12.4 sets out our proposed tariff variation mechanism and formula for our Ancillary Reference Services.

12.2. Proposed Tariff Variation Mechanism for Haulage Reference Services

In the current Access Arrangement period, we have operated under a weighted average price cap reference tariff variation mechanism for our Haulage Reference Services.

We consider that, consistent with the control mechanism that now applies to our related business United Energy, a revenue cap would be a more appropriate reference tariff variation mechanism for our Haulage Reference Services in our next Access Arrangement period. A revenue cap is permitted for the forthcoming Access Arrangement period under Rule 97(2)(a).

A revenue cap on our Haulage Reference Services means that we have no scope to recover more or less from our approved tariffs than the allowed revenue that is set each year by the AER for the next Access Arrangement period. This is achieved by forecasting sales and setting tariffs in the period such that the expected revenue is equal to or less than the maximum allowed revenue in each year. At the end of each year, we would report our actual revenues to the AER and the difference between the actual revenue recovered and the Maximum Allowed Revenue would be accounted for in future years through an "overs and unders" account, whereby any over-recovery (or under-recovery) is deducted (or added) from the maximum allowed revenue in future years.

We consider that a revenue cap would best satisfy the criteria that the AER must consider in deciding what reference tariff variation mechanism to apply to our Haulage Reference Services. In particular, we consider that a revenue cap is more appropriate than a weighted average price cap in the current (and future) environment of declining demand – this is discussed in chapter 9. This is because, in such an environment, under a weighted average price cap, we would be exposed to volume risk associated with declining gas sales which may result in us not recovering our efficient costs. The challenge in such an environment is to forecast demand accurately. Under a revenue cap we are less reliant on the accuracy of energy forecasts.

Retaining a weighted average price cap would not be consistent with the pricing principles in section 24(2) of the NGL, which require that we are provided with a reasonable opportunity to recover at least our efficient costs of providing reference services and complying with our regulatory obligations or requirements.

We agree with the AER's view in its final Framework and Approach (F&A) for the Victorian electricity distribution businesses (DNSPs) for their 2016 to 2020 regulatory control period (Victorian F&A) that[13]:

> *We consider that a revenue cap will result in benefits to consumers through a higher likelihood of revenue recovery at efficient cost, better incentives for demand side management, less reliance on energy forecasts and better alignment with the introduction of efficient prices. Furthermore, we*

[13] AER, Framework and approach Victorian Distribution 2016–2020, p.20 and p. 79

> *consider that the detriments of a revenue cap – within period pricing instability and weak pricing incentives – are able to be mitigated.*

The AER clarified in its Victorian F&A that some of the criteria it must consider under the National Electricity Rules (NER) in assessing which control (or reference tariff variation) mechanism to apply should be treated as secondary considerations to other more important factors, particularly revenue recovery.[14] The AER made the following comments in relation to each of what it considered to be secondary criteria:

- *Minimising administration costs – "… there is little difference in administrative costs between control mechanisms under the building block framework in the long run"*.[15]
- *Existing regulatory arrangements – "…this factor needs to be weighed against the other factors under clause 6.2.5(c) of the rules. We consider this is appropriate because consistency in and of itself has no direct effect on distributors, us or customers".*[16]
- *Consistency across jurisdictions and control periods - "consistency between regulatory arrangements is generally desirable but is not primary to our considerations in this instance. Consistent regulatory arrangements need to be weighed against the other factors….[that] better achieve the national electricity objective and are consistent with the revenue and pricing principles".*[17]

We also accept the AER's views that it set out in its Victorian F&A that "*price flexibility for existing tariffs and tariff structures is similar for all forms of control*"[18] .

In relation to the criterion in Rule 97(3)(a) about "incentives to set efficient prices", we note that our approach to setting tariffs is set out in our chapter 21 and in our Reference Tariff Policy in Part B of our Access Arrangement. The guiding principles that underpin our tariffs are the same under a revenue cap as a weighted average price cap. Cost reflectivity is one of these key principles. We must also demonstrate that our expected revenue for each tariff class is between the stand alone cost of providing the services and the avoidable cost of not providing the service – the "efficient pricing band" (in accordance with Rule 94(3) of the NGR). We have a strong incentive to price our services as competitively as possible given that gas is a fuel of choice. This means that we will always have a strong incentive to grow demand. This contrasts with electricity, which is not a fuel of choice.

Further, the AER applies a robust approval process which ensures that our proposed prices meet the pricing principles in section 24(2) of the NGL as well as the tariff requirements under Rule 94 of the NGR. This in turn requires the AER to be satisfied that, among other things, the revenue from tariff groups is within reasonable ranges and that tariffs reflect long run marginal costs.

We agree with the AER's view expressed in its F&A for the Victorian electricity DNSPs that "…*we consider that a revenue cap is unlikely to give rise to inefficient pricing for the five Victorian electricity distributors"*[19].

Considering the above, the criteria that are clearly the most important to consider in choosing our reference tariff variation mechanism for our Haulage Reference Services are volume risk and revenue recovery. We consider that a revenue cap is more appropriate than a weighted average price cap to meet these criteria in the current (and possible future) environment of declining gas demand on our network.

We propose applying the revenue cap to our Haulage Reference Services using the formula set out in section 12.3.

[14] AER, Framework and approach Victorian Distribution 2016–2020, p.76

[15] AER, Framework and approach Victorian Distribution 2016–2020, p.81

[16] AER, Framework and approach Victorian Distribution 2016–2020, p.80

[17] AER, Framework and approach Victorian Distribution 2016–2020, p.83

[18] AER, Framework and approach Victorian Distribution 2016–2020, p.84

[19] AER, Framework and approach Victorian Distribution 2016–2020, p.80

12.3. Revenue cap formulae for Haulage Reference Services

Box 1 below sets out the approach we propose to use when applying the revenue cap to our Haulage Reference Services in the forthcoming Access Arrangement period. We have based this on the revenue cap formulae approved by the AER in its Final Determination for United Energy for its 2016 to 2020 regulatory period, subject to the modifications set out below.

Our proposed formulae will ensure that prices will be set each year so that forecast revenue will not exceed the maximum allowable revenue and will enable us to vary our reference tariffs through time to take into consideration:

- CPI;
- The X factor;
- Licence fees;
- Any allowed cost pass-throughs; and
- The operation of the revenue cap mechanism.

Only the final component is a new consideration. The others are consistent with our considerations in the current Access Arrangement period. We note that the other impact on the formula relates to a change to the weighted average cost of capital, such that the annual update mechanism for debt means that we will no longer have a single weighted average cost of capital that is set for the entire period. Rather, we will have a different weighted average cost of capital for each year of the forthcoming Access Arrangement period.

The revenue cap mechanism has been designed to ensure revenue neutrality with the outcomes of the AER's Post Tax Revenue Model using an 'unders and overs account', which is set out in Box 3 with an example in Box 4. This mechanism ensures that, if the AER's Post Tax Revenue Model's output is a net present value of real revenues of, say, $1 billion over the course of the Access Arrangement period, then the revenue cap mechanism must also deliver an NPV of real revenues of the same $1 billion over the course of the Access Arrangement period. If it does not, then either we or our customers will obtain an advantage due solely to the operation of the revenue cap mechanism. This is not the intention of the mechanism, nor is it an efficient outcome.

Box 1 - Revenue cap formula for Haulage Reference Services (Formula 1)[20]

(1) $MAR_t \geq \sum_{i=1}^{n} \sum_{j=1}^{m} p_t^{ij} q_t^{ij}$ $\quad i = 1, \ldots, n$ and $j = 1, \ldots, m$ and $t = 1, \ldots, 5$

(2) $MAR_t = AR_t + I_t + B_t$ $\quad t = 1, \ldots, 5$

(3) $AR_t = [\text{ADD 2018 ALLOWED REVENUE}]$ $\quad t = 1$

(4) $AR_t = AR_{t-1}(1 + \Delta CPI_t)(1 - X_t)$ $\quad t = 2, \ldots, 5$

Where:

MAR_t is the maximum allowed revenue in regulatory year *t*

p_t^{ij} is the price of component '*j*' of tariff component '*i*' in regulatory year *t*

q_t^{ij} is the forecast quantity of component '*j*' of tariff '*i*' in regulatory year *t*

AR_t is the annual smoothed revenue requirement as stated in the AER's final decision for regulatory year *t* (when year *t* is the first year of the 2018 to 2022 Access Arrangement period)

I_t is any additional incentive payments allowed in year *t*

B_t is the sum of:

- the recovery of licence fee charges paid to the Essential Services Commission of Victoria indexed by one and a half years of interest, calculated using the following method:

[20] All parameters are in nominal terms unless otherwise specified.

$L_{t-1} \times (1 + WACC_t) \times (1 + WACC_{t-1})^{1/2}$

where:

L_{t-1} are the licence fees paid by Multinet Gas to the Victorian Essential Services Commission of Victoria in the financial year ending in June of regulatory year *t-1*

$WACC_t$ is the approved nominal weighted average cost of capital (WACC) for regulatory year *t* calculated as $Nominal\ vanilla\ WACC_t = \left((1 + real\ vanilla\ WACC_t) \times (1 + \Delta CPI_t)\right) - 1$, where the $real\ vanilla\ WACC_t$ is as set out in the AER's final decision and updated annually (refer Chapter 16 of this Access Arrangement Information)

- the recovery of carbon emissions costs indexed by one and a half years of interest, calculated using the following method:

$C_{t-1} \times (1 + WACC_t) \times (1 + WACC_{t-1})^{1/2}$

where:

C_{t-1} are the carbon emissions costs paid by Multinet Gas in the financial year ending in June of regulatory year *t-1* being costs incurred by the Service Provider under (including costs of purchasing Australian Carbon Credit Units) the "Carbon Safeguard Mechanism" applying under the *National Greenhouse and Energy Reporting Act 2007* and any other costs incurred under Regulatory Instruments relating to carbon emissions.

$WACC_t$ is the approved nominal weighted average cost of capital (WACC) for regulatory year *t* calculated as $Nominal\ vanilla\ WACC_t = \left((1 + real\ vanilla\ WACC_t) \times (1 + \Delta CPI_t)\right) - 1$, where the $real\ vanilla\ WACC_t$ is as set out in the AER's final decision and updated annually (refer Chapter 16 of this Access Arrangement Information)

- any under or over recovery of actual revenue collected through Haulage Reference Service tariffs in regulatory year *t-2* as calculated using the method set out in Box 3
- AER approved pass through amounts in respect of Haulage Reference Services (positive or negative) with respect to regulatory year *t*.

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities[21] from the June quarter in regulatory year *t-2* to the June quarter in regulatory year *t-1*, calculated using the following method:

$$\frac{\begin{array}{l}The\ ABS\ CPI\ All\ Groups, Weighted\ Average\ of\ Eight\ Capital\\ \quad Cities\ for\ the\ June\ quarter\ in\ regulatory\ year\ t-1\end{array}}{\begin{array}{l}The\ ABS\ CPI\ All\ Groups, Weighted\ Average\ of\ Eight\ Capital\\ \quad Cities\ for\ the\ June\ quarter\ in\ regulatory\ year\ t-2\end{array}} - 1$$

For example, for the 2019 regulatory year, *t-2* is the June quarter 2017 and *t-1* is the June quarter 2018; and for the 2020 regulatory year, *t-2* is June quarter 2018 and *t-1* is June quarter 2019 and so on.

X_t is the X factor for each year of the 2018 to 2022 Access Arrangement period as determined in the AER's final decision, and annually revised for the return on debt update in accordance with the formula specified in Chapter 16 of this Access Arrangement Information calculated for the relevant regulatory year.

21 If the ABS does not or ceases to publish the index, then CPI will mean an index which the AER considers is the best available alternative index.

Box 2 - Rebalancing Control Formula (Formula 2)

(1) $\frac{\sum_{i=1}^{n}\sum_{j=1}^{m} p_t^{ij} q_t^{ij}}{\sum_{i=1}^{n}\sum_{j=1}^{m} p_{t-1}^{ij} q_t^{ij}} \leq (1+\Delta CPI_t) \times (1-X_t) \times (1+10\%) + I_t' + B_t'$

Where:

p_t^{ij} is the price of component '*j*' of tariff '*j*' in year regulatory year *t*

q_t^{ij} is the forecast quantity of component '*j*' of tariff '*j*' in year regulatory year *t*

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities[22] from the June quarter in regulatory year *t-2* to the June quarter in regulatory year *t-1*, calculated using the following method:

$$\frac{\begin{array}{c}The\ ABS\ CPI\ All\ Groups, Weighted\ Average\ of\ Eight\ Capital\\ Cities\ for\ the\ June\ quarter\ in\ regulatory\ year\ t-1\end{array}}{\begin{array}{c}The\ ABS\ CPI\ All\ Groups, Weighted\ Average\ of\ Eight\ Capital\\ Cities\ for\ the\ June\ quarter\ in\ regulatory\ year\ t-2\end{array}} - 1$$

For example, for the 2019 regulatory year, *t-2* is the June quarter 2017 and *t-1* is the June quarter 2018; and for the 2020 regulatory year, *t-2* is June quarter 2018 and *t-1* is June quarter 2019 and so on.

X_t is the X factor for each year of the 2018 to 2022 Access Arrangement period as determined in the AER's final decision, and annually revised for the return on debt update in accordance with the formula specified in Chapter 16 of this Access Arrangement Information calculated for the relevant regulatory year. If $X_t > 0$, then X_t will be set equal to zero for the purposes of the rebalancing control formula.

I_t is the annual percentage change from any additional incentive payments allowed in year *t*

B_t' is the annual percentage change from the sum of:

- the recovery of licence fee charges paid to the Essential Services Commission of Victoria indexed by one and a half years of interest, calculated using the following method:

  $L_{t-1} \times (1+WACC_t) \times (1+WACC_{t-1})^{1/2}$

  where:

  L_{t-1} are the licence fees paid by Multinet Gas to the Essential Services Commission of Victoria in the financial year ending in June of regulatory year *t-1*

  $WACC_t$ is the approved nominal weighted average cost of capital (WACC) for regulatory year *t* calculated as $Nominal\ vanilla\ WACC_t = \left((1+real\ vanilla\ WACC_t) \times (1+\Delta CPI_t)\right) - 1$, where the $real\ vanilla\ WACC_t$ is as set out in the AER's final decision and updated annually (Chapter 16 of this Access Arrangement Information)

- any under or over recovery of actual revenue collected through Haulage Reference Service tariffs in regulatory year t–2 as calculated using the method in Box 3

- AER approved pass through amounts in respect of haulage reference services (positive or negative) with respect to regulatory year *t*.

[22] If the ABS does not or ceases to publish the index, then CPI will mean an index which the AER considers is the best available alternative index.

With the exception of the ΔCPI_t and X_t, the percentage for each of the other factors above can be calculated by dividing the incremental revenues (as used in the revenue cap formula in Box 1) for each factor by the expected revenues for regulatory year *t-1* (based on the prices in year *t-1* multiplied by the forecast quantities for year *t*).

Box 3 - Revenue unders and overs account (Formula 3)

Multinet Gas proposes to maintain an Haulage Reference Services unders and overs account as part of our annual tariff variation proposals during the 2018 to 2022 Access Arrangement period.

We will provide the following entries in this account for the most recently completed regulatory (*t-2*), the current regulatory year (*t-1*) and the next regulatory year (*t*):

1. An opening balance for year t–2, year t–1 and year t;
2. An interest charge for one year on the opening balance for each regulatory year (*t–2*, *t–1* and *t*). These adjustments are to be calculated using the respective nominal weighted average cost of capital for each intervening year between regulatory year *t–2* and year *t*. The WACC applied for each year will be calculated using the approach set out in Box 1
3. The amount of revenue recovered from Haulage Reference Services tariffs in respect of that year, less the annual maximum allowed revenue for the year in question;
4. An adjustment to the net amount in item 3 by six months of interest. These adjustments are to be calculated using the nominal WACC calculated using the approach set out in Box 1;
5. The total sum of items 1–4 to derive the closing balance for each year.

We provide details of calculations in the format set out in Box 4 below. Amounts provided for the most recently completed regulatory year (*t–2*) will be audited. Amounts for the current regulatory year (t-1) will be regarded as an estimate. Amounts for the next regulatory year (*t)* will be forecasts.

Our annual tariff variation proposals will seek to achieve a closing balance (of the Haulage Reference Service unders and overs account) as close to zero as practical in each forecast year during the 2018 to 2022 Access Arrangement period. Any unders or overs at the end of that period will be carried over as pass-through amounts into the Sixth Access Arrangement Period.

Box 4 - Example calculation of Haulage Reference Services' unders and overs (extract from AER Final 2016–20 Determination for United Energy) [23]

	Year *t-2* (actual)	Year *t-1* (estimate)	Year *t* (forecast)
(A) Revenue from Haulage Reference Services	**1,100**	**1,050**	**1,093**
(B) Less MAR for regulatory year =	**1,090**	**1,080**	**1,120**
+ Annual smoothed revenue requirement (AR_t)	1,000	1,050	1,100
+ Any incentive payments (I_t)	50	0	0
+ Annual adjustments (B_t) [a]	40	30	20
+ *License fee recovery*	20	30	20
+ *Approved pass through amounts*	20	0	0
(A minus B) Under/over recovery of revenue for regulatory year	**10**	**-30**	**-27**

[23] AER, 26 May 2016, *Final Decision, United Energy distribution determination 2016 to 2020, Attachment 14 – Control mechanisms*, Table 14.1.

Haulage Reference Services unders and overs account			
Nominal WACC (per cent)	6.12%	6.12%	6.12%
Opening balance	40	53 [c]	26 [c]
Interest on opening balance	3	4	2
Under/over recovery of revenue for regulatory year	10	-30	-27
Interest on under/over recovery for regulatory year	0	-1	-1 [b]
Closing balance	**53**	**26**	**0** [d]

Notes:
(a) B_t parameter calculations in the HRS unders and overs account exclude HRS under/over recovery for the regulatory year.
(b) Approved Haulage Reference Services revenue under/over recovery for regulatory year *t*.
(c) Opening balance is the previous year's closing balance.
(d) Multinet will target a closing balance as close to zero as praticable in our HRS unders and overs account in each forecast year in our annual tariff variation notice submissions over the 2018 to 2022 Access Arrangement period.

12.4. Tariff Variation Mechanism for Ancillary Reference Services

We propose to maintain our reference tariffs for our Ancillary Reference Services over the forthcoming Access Arrangement period. We also propose to continue to adjust these tariffs by changes in inflation only.

Specifically, we propose to vary Reference Tariffs for Ancillary Reference Services on the basis of the tariff control formula set out in Box 5.

Box 5 – Ancillary Reference Tariff Variation Mechanism

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

Where:

ART_t^i is the Reference Tariff that will apply to Ancillary Reference Service *i* in year *t*

ART_{t-1}^i is the Reference Tariff that will apply to Ancillary Reference Service *i* in year *t-1*

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities[24] from the June quarter in regulatory year *t-2* to the June quarter in regulatory year *t-1*, calculated using the following method:

$$\frac{\begin{array}{c}The\ ABS\ CPI\ All\ Groups, Weighted\ Average\ of\ Eight\ Capital\\ Cities\ for\ the\ June\ quarter\ in\ regulatory\ year\ t-1\end{array}}{\begin{array}{c}The\ ABS\ CPI\ All\ Groups, Weighted\ Average\ of\ Eight\ Capital\\ Cities\ for\ the\ June\ quarter\ in\ regulatory\ year\ t-2\end{array}} - 1$$

For example, for the 2019 regulatory year, *t-2* is the June quarter 2017 and *t-1* is the June quarter 2018; and for the 2020 regulatory year, *t-2* is June quarter 2018 and *t-1* is June quarter 2019 and so on.

[24] If the ABS does not or ceases to publish the index, then CPI will mean an index which the AER considers is the best available alternative index.

13. Capex forecasts

Key messages:

- Our capex for the current Access Arrangement period satisfies the conforming capex criteria under Rule 79 of the NGR. This view is supported by Oakley Greenwood's finding that our historical unit rates for Mains Replacement and Connections capex are prudent and efficient.
- Our forecast capex for the forthcoming Access Arrangement period is also conforming capex.
- The prudence and efficiency of our capex forecasts are aided by:
  - Our two-party service provider model that provides continuous competitive pressure for delivering our capex program. We recently established this model following a competitive tender process;
  - Robust capital governance systems that have recently been reviewed and endorsed by Jacobs; and
  - Our asset management framework and systems that align with key elements of ISO 55001 to ensure that network risks and costs are systematically analysed and optimised.
- We benchmark favourably against our peers. Economic Insights' recent benchmarking found that we are one of the two most efficient gas distributors in Australia and New Zealand in using our assets and that we are operating at or close to the efficient frontier of gas distributors. This further supports our view that our new service delivery model is efficient. Our customers benefit from this through lower network prices.
- Our Mains Replacement capex forecast is primarily based on continuing to deliver our 30-year initiative that commenced in 2003 to replace (principally for safety reasons) our ageing, predominantly cast iron, low pressure network with high pressure polyethylene mains. The AER again accepted and endorsed this initiative in its September 2015 decision on our mains replacement cost pass-through for the current access arrangement period, having previously accepted this initiative in its May 2013 Final Determination for our current Access Arrangement.
- Our Residential and C&I Connections capex forecast is based on trend analysis and benchmarking, which is consistent with the AER's historical approach to assessing this capex category.
- Our Metering capex forecast is primarily driven by our regulatory obligations to test meter families. This program recognises that only a small percentage of meters that fail the testing regime will need to be replaced with a new meter and that most meters that are removed will be repaired.
- Our Augmentation capex forecast comprises four network plans, each of which are targeted at ensuring the security of supply and maintenance of fringe pressures in accordance with the Gas Safety Case and the Gas Distribution System Code.
- We propose maintaining our Non-Network ICT capex at current levels. This capex is mainly recurrent and is needed to maintain the integrity of our services and to achieve the levels of demand required by our customers.
- Our forecast SCADA capex comprises eight work programs, each of which is underpinned by the need to maintain an effective and reliable SCADA system so that we can continue to operate the gas distribution network safely, reliably and efficiently.
- Our Non-Network Other capex consists of seven programs that are critical to supporting the following network and corporate functions: recoverable works; property and accommodation; vehicles and tools; corrosion protection; regulators, valves and equipment enclosures; gas heaters; pig rectification.

13.1. Introduction

This chapter is structured as follows:

- Section 13.2 explains why our capex for the current Access Arrangement period satisfies the conforming capex criteria under Rule 79 of the NGR.
- Section 13.3 overviews our capex forecast for the forthcoming Access Arrangement period, and explains our prudent approach to satisfying our customers' expectations and our regulatory obligations;
- Section 13.4 details how our business transformation supports our prudent and efficient capex;
- Section 13.5 explains how our expenditure governance framework supports our prudent and efficient capex;
- Section 13.6 overviews our asset management framework;
- Section 13.7 explains how we have applied cost escalators in preparing our capex forecasts;
- Section 13.8 explains how recent benchmarking supports the efficiency of our capex;
- Section 13.9 details and justifies our forecast Mains Replacement capex;
- Section 13.10 details and justifies our forecast Residential Connections capex, Commercial and Industrial Connections capex and customer contributions;
- Section 13.11 details and justifies our forecast Meters capex;
- Section 13.12 details and justifies our forecast Augmentation capex;
- Section 13.13 details and justifies our forecast Non-Network ICT capex;
- Section 13.14 details and justifies our forecast SCADA capex; and
- Section 13.15 details and justifies our forecast Other capex.

Consistent with Rule 69 of the NGR, the capex forecasts discussed in this chapter relate to our Pipeline Services, which includes both our Reference Services and our Non-Reference Services.

The information presented in this chapter is intentionally 'high level' to enable the AER, our customers and other stakeholders to understand the key drivers for our capex forecasts and the principal causes of any proposed increases in expenditure at the category level. This chapter should be read in conjunction with our capex category "Overview Documents" and other supporting documents that we have provided to the AER with this Access Arrangement Information.

13.2. Current period conforming capex

Rule 79 of the NGR states that:

> *(1) Conforming capital expenditure is capital expenditure that conforms with the following criteria:*
>
> > *(a) The capital expenditure must be such as 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;*
> >
> > *(b) The capital expenditure must be justifiable on a ground stated in subrule (2)*
>
> *(2) Capital expenditure is justifiable if:*
>
> > *(a) The overall economic value of the expenditure is positive; or*
> >
> > *(b) The present value of the expected incremental revenue to be generated as a result of the expenditure exceeds the present value of the capital expenditure; or*

(c) The capital expenditure is necessary:

(i) To maintain and improve safety or services; or

(ii) To maintain the integrity of services; or

(iii) To comply with a regulatory obligation or requirement; or

(iv) To maintain the service provider's capacity to meet levels of demand for services existing at the time the capital expenditure is incurred (as distinct from projected demand that is dependent on an expansion of pipeline capacity);

(d) The capital expenditure is an aggregate amount divisible into 2 parts, one referable to incremental services and the other referable to a purpose referred to in paragraph (c), and the former is justifiable under paragraph (b) and the latter under paragraph (c).

Table 13-1 shows that we are expecting to spend in line with the AER's capex allowance for the current access arrangement period. We expect to significantly over-spend the AER's capex allowance in two capex sub-categories – Mains Replacement and Connections.

Table 13-1: Variance between allowed and actual capex 2013-2017 ($M, Real 2017)

	AER Allowance	Actual / Estimated	Variance
Mains replacement (Adjusted for Pass Through)	118.7	139.2	20.5
Residential connections	76.5	89.0	12.4
Commercial and industrial connections	7.2	16.4	9.1
Meters	13.4	9.5	(3.9)
Augmentation	26.0	8.0	(17.9)
IT	50.8	44.3	(6.5)
SCADA	0.5	2.5	2.0
Other	38.1	45.2	7.1
Internal Direct Overheads	13.9	9.5	(4.4)
Indirect Overheads	-	-	-
Energy for the Regions NGEP		5.7	5.7
Gross Total	**345.1**	**369.2**	**24.0**
Customer Contributions	(22.7)	(46.3)	(23.6)
Government Contributions	-	(1.4)	(1.4)
Net Total	**322.4**	**321.4**	**(1.0)**

We consider our capex for the current access arrangement period to be prudent and efficient and to be consistent with the requirements for conforming capex because:

- Our two-party service provider model provides continuous competitive pressure for delivering our capex program. We recently established this model following a competitive tender process. We will continue to monitor these arrangements to ensure that they continue to provide value for money and keep us at the efficiency frontier;
- Robust capital governance systems that have recently been reviewed and endorsed by Jacobs; and
- Our asset management framework and systems align with key elements of ISO 55001 to ensure that network risks and costs are systematically analysed and optimised.

We have recently engaged two consultants to review whether our expenditure is consistent with conforming capex – Oakley Greenwood and Advisian. We have provided their reports to the AER with this Access Arrangement Information.

13.2.1. Oakley Greenwood review

We engaged Oakley Greenwood to assess whether our estimated Mains Replacement and Connections capex constitutes conforming capex for the purposes of Rule 79 of the NGR. We have provided their report to the AER with this Access Arrangement Information. Oakley Greenwood concluded:

> ***Customer Connections***
>
> *In our opinion, MG's expenditure on customer connections is consistent with the prudency requirements reflected in Rule 79 (subsection 2). We base this opinion on the fact that MG's customer initiated capital works are customer driven, and undertaken subject to the present value of the expected incremental revenue being generated exceeding the present value of that capital expenditure (and where this is not the case, a connection charge may be imposed to overcome this shortfall). This screening aligns with the requirements of Rule 79 (subsection 2), as it ensures that the overall economic value of the expenditure is positive.*
>
> *Furthermore, in our opinion, MG's outturn unit rates for connections are likely to be consistent with those that 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 – which accords with Rule 79. Our basis for this statement includes:*
>
> - *The contracts underpinning the rates were competitively tendered, which, everything else being equal, should lead to the market revealing the efficient cost of supply,*
> - *The approach for revising those rates over the life of the contract is, in our opinion, reasonable, and likely to provide a robust approach to applying competitive tension to the annual process for deriving new unit rates.*
> - *MG's outturn unit rates for its industrial/commercial customers – even after including its Tariff D customers - are still well below those the rates the AER approved as being efficient for AGN and AusNet Services' Tariff V customers as part of the last GAAR determination process, and*
> - *MG's outturn unit rates for its residential customers are comparable, if not lower, than the rates the AER approved for AGN and AusNet Services.*
>
> ***Mains Replacement***
>
> *In our opinion, MG's expenditure on mains replacement is consistent with the prudency requirements reflected in Rule 79 (subsection 2), as MG's mains replacement program is undertaken to (a) maintain the integrity of services, (b) maintain and improve safety or services; and/or (c) comply with a regulatory obligation or requirement, all of which are limbs under Rule 79 of the National Gas Rules.*

Furthermore, in our opinion, the mains replacement capital expenditure incurred by MG over the current regulatory control period is likely to be consistent with that of a prudent and efficient service provider, and therefore, consistent with Rule 79 of the National Gas Rules. We base this opinion on our view that:

- *MG undertook a competitive tendering process for the provision of services for operational, maintenance and capital work, including mains replacement services.*
  - *The AER accepted that this process was competitive as part of the last GAAR process.*
  - *Our review also comes to the same conclusion.*
- *The process for generating competitive tension throughout the current regulatory period under the current contracting arrangements is reasonable, and likely to incentivise efficient outcomes:*
  - *During the period July 2013 to June 2015, even though work was allocated to the Service Providers based on the geographic area they covered, because of (a) the implicit "threat" of having engaged an independent estimator to review target cost estimates for construction projects, which is recognised as being good practise within the infrastructure and construction industries.*
  - *Except for the requirement for MG to tender one project to each Service Provider, all other projects from July 2015 onwards were tendered to both Service Providers, hence creating competitive tension between the two Service Providers. Note that in our opinion, providing a baseload level of work to each Service Provider (i.e., one project) is also likely to have been efficient, if this base load level of work then allowed the Service Providers to "resource up" and therefore being capable of being a robust bidder against the other service provider.*
- *The underlying contracting structure (P50), which means the contractor shares in any gain or loss relative to budget, incentivises Service Providers to adopt the least cost means of undertaking mains replacement services, given the conditions faced.*
- *The evidence indicates that budgets set through the contractual process for mains replacement projects are not systemically too high (resulting in Service Providers benefiting systemically from over estimating budgets) or too low (resulting in Service Providers being penalised systemically, which may indicate inappropriate risk sharing.*
- *We compared the cost of the two sample mains replacement projects with the cost allowed for by the AER in its decisions on Mains Replacement Event Cost Pass Through applications from MG, AGN and Ausnet Services and found that the derived unit rates for the sample projects were at the low end of the derived unit rates approved by the AER.*

We agree with these assessments. This chapter 13, and our Overview Documents for each capex sub-category, provide further justifications for our expenditure in the current period.

13.2.2. Advisian review

In support of our May 2015 mains replacement cost pass through application, we engaged Advisian to review whether our mains replacement capex for the 2013 to 2017 period represented conforming capex. Their report supported our view that our expenditure is conforming capex. The report concluded:

Advisian have independently examined all information received and confirm the lengths and costs summarised in the Executive Summary of the report to be a true and accurate assessment of the works undertaken from 1 January 2013 to 30 April 2015. Advisian also advise that based on current market knowledge, construction costs associated with these projects are within industry expectations.

Advisian is satisfied that the Capital Expenditure for the current Regulatory period from 1 January 2013 to 31December 2017 satisfy the new Capex criteria, set out in rule 79 of the NGR which permit expenditure to be included in the opening capital base and subsequently recovered from their customers through tariffs. The expenditure is that of a prudent operator based on performance and generally meeting Levels of Service targets.[25]

The AER accepted that our expenditure constituted conforming capex by approving our cost pass-through application.

13.3. Capex forecast overview

13.3.1. Our forecast and historical capex

Our capex forecasts for each year of the forthcoming Access Arrangement period are shown in Table 13-2.

Table 13-2: Forecast capex 2018-2022 ($M, Real 2017) *

	2018	2019	2020	2021	2022	Total
Mains replacement	57.2	51.4	53.0	56.5	48.8	266.9
Residential connections	19.9	18.9	17.9	18.3	19.0	94.0
Commercial and Industrial connections	4.2	4.2	4.3	4.4	4.4	21.6
Meters	3.9	1.5	2.8	1.3	1.1	10.6
Augmentation	4.4	6.1	3.7	1.8	1.3	17.3
Non-Network ICT	11.1	6.0	10.1	11.3	10.4	48.8
SCADA	1.9	1.7	1.2	1.2	1.1	7.1
Other	10.9	9.2	10.0	8.5	10.0	48.7
Gross total - excludes equity raising costs	**113.5**	**98.9**	**103.1**	**103.4**	**96.1**	**515.0**
Less customer contributions	(9.1)	(9.1)	(9.1)	(9.1)	(9.1)	(45.6)
Net capex	**104.3**	**89.8**	**93.9**	**94.3**	**87.0**	**469.4**

* Does not include capitalised equity raising costs so total differs from Table 2-1.

We understand that the credibility of our capex forecasts depends, in part, on our performance record. In particular, customers want to understand how our capex forecasts compare with both our actual capex and our capex allowances during the current period.

Table 13-2 shows our actual capex compared to the AER's allowance for the current Access Arrangement period and our forecast capex for the forthcoming Access Arrangement period.

[25] Advisian, AER Pipework Projects – Independent Validation Report, 31 May 2015, page 7

Figure 13-1: Historical and forecast capex ($M, Real 2017)

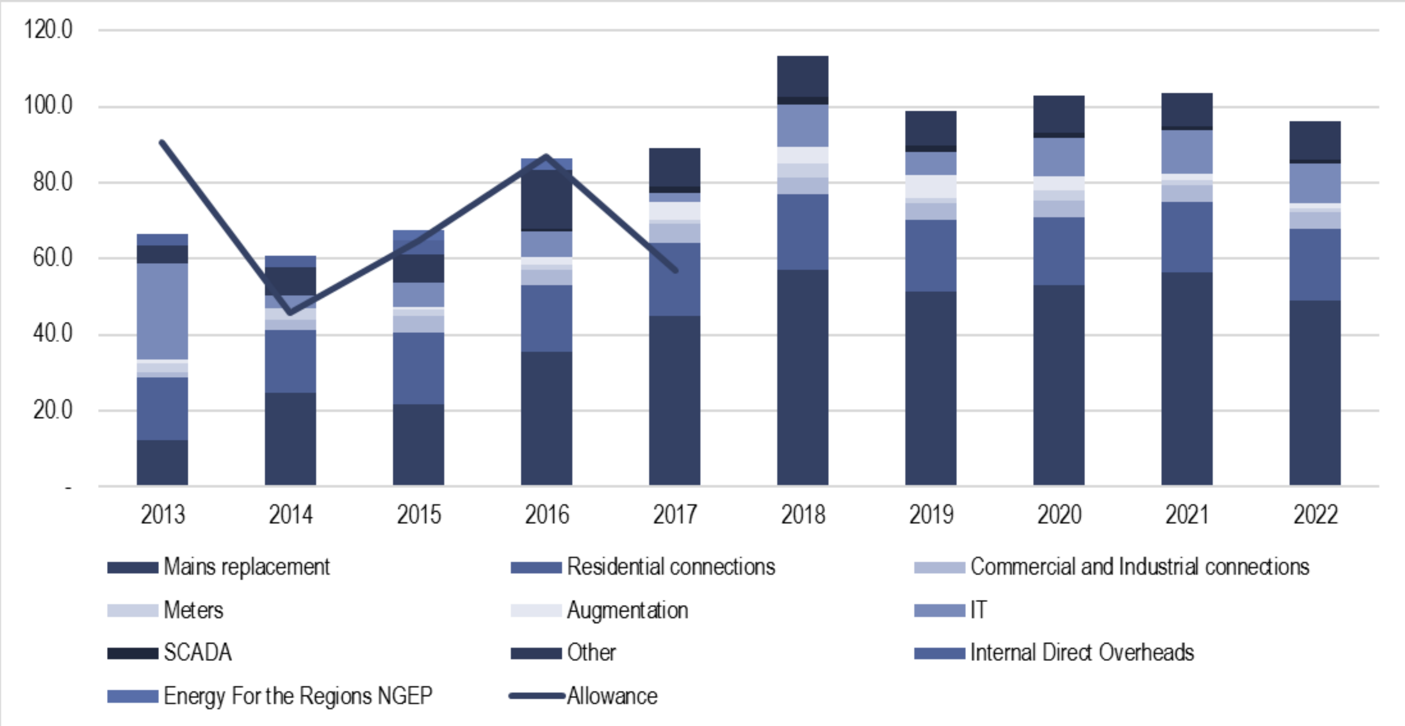


Table 13-3 shows that we expect our total gross capex during the current Access Arrangement period to exceed the allowance in the AER's Final Decision by $24.0 million or approximately 7 per cent. However, we expect our net capex to be in line with the AER's Final Decision.

Table 13-3: Actual / estimated and allowed capex 2013-2017 ($M, Real 2017)

	2013	2014	2015	2016	2017	Total
Gross capex						
AER Final Decision	90.8	45.8	64.8	86.9	57.0	345.1
Actual / Estimated	66.3	60.8	67.6	86.3	88.1	369.2
Variance (Actual – Final Decision)	(24.4)	15.0	2.8	(0.6)	31.2	24.0
Net capex						
AER Final Decision	78.0	41.0	63.0	85.1	55.2	322.4
Actual / Estimated	60.3	54.0	61.3	74.4	72.9	322.8
Variance (Actual – Final Decision)	(17.8)	13.0	(1.7)	(10.8)	17.7	0.4

13.3.2. Why our forecasts are conforming capex

Our capex forecasts for the forthcoming Access Arrangement period are conforming capex for the purposes of Rule 79(1)(a) of the NGR (detailed in section 13.2 above). They are consistent with a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services. This is because:

- Our forecast work volumes:
  - Have been prepared using tailored expenditure forecasting methods – these are discussed in sections 13.9 to 13.15 and are set out in detail in our supporting capex Overview Documents; and
  - Are supported by expenditure governance and asset management systems that result in prudent and efficient capex decisions – these systems are described in section 13.5. We engaged Jacobs to review these system who found them to be fit-for-purpose and are in accordance with good practice – this is also discussed in section 13.5.
- Our forecast unit rates are efficient because they are derived from our competitive service provider model – these unit rates are supported by Oakley Greenwood's independent expert assessment and are detailed in our supporting capex Overview Documents;
- We have not applied any real cost escalator for our materials in preparing our capex forecasts and have applied a real cost escalator for our labour based on advice from the leading independent expert, BIS Shrapnel – this is discussed further in section 13.7 and in the accompanying report from BIS Shrapnel; and
- The efficiency of our business model is further demonstrated by our benchmarking against our peers. According to Economic Insights, we are one of the two most efficient gas distributors in Australia and New Zealand in using our assets and operate at or close to the efficient frontier of gas distributors – this is discussed further in section 13.7 and in the accompanying reports from Economic Insights.

Our capex forecasts are justifiable for the purposes of Rules 79(1)(b) and 79(2) of the NGR (detailed in section 13.3.2 above) because they are necessary to maintain the safety and integrity of our services and the capacity of our gas network as well as to comply with our regulatory obligations. This is summarised in Table 13-4 below and discussed in sections 13.9 to 13.14 and in our supporting capex Overview Documents.

Table 13-4: Drivers of capex by category

	Safety	Service integrity	Compliance	Capacity
Mains replacement	Primary	Secondary	Secondary	Secondary
Residential and C&I connections			Primary	Secondary
Meters	Secondary	Secondary	Primary	
Augmentation	Secondary			Primary
IT		Primary		
SCADA	Secondary	Primary	Secondary	Secondary
Other	Varies by program			

Sections 13.9 to 13.14 justify in further detail why each category of capex is conforming capex.

13.4. Our business transformation

13.4.1. Outcomes of our business transformation project

We implemented a business transformation project during the current Access Arrangement period. We foreshadowed this transformation to the AER in our 2012 Access Arrangement Information.

Our business transformation project built on the benefits that our previous business model had achieved, but it has created greater flexibility to manage future change and risk, and to deliver better value to our customers.

We adopted a 'best of breed' contractor model, through which we obtain the cost and service benefits from the best available contractors to bring specialist knowledge, skills and economies of scale and scope.

Our current business model is based on adopting a two-region model for delivering network operations, with separate service providers for each region – previously, our business model was centred on a single outsourcing agreement with Jemena Asset Management. For information technology and customer and market service functions, we jointly engage specialist service providers with United Energy.

For network operations, we undertook a competitive tender process to identify our preferred suppliers. A total of 11 potential suppliers submitted responses to our Expression of Interest, of which eight respondents were assessed as being capable of providing some of the services being tendered. This level of response – which was subsequently shortlisted to two respondents at the final evaluation stage – demonstrated the competitive nature of the tender process and confirmed the market's appetite for our new business model. We adopted strict probity protocols to ensure the integrity of the tender process. We compared the tendered costs (including 'restructuring' or 'transformation' costs) with other options, including a projection of our existing cost structure at that time.

Comdain was the successful tenderer on the basis that it would deliver much improved outcomes, demonstrating the benefits of our proposed restructuring and "best of breed" model. ZNX was retained to service one half of our network. As a result, Comdain and ZNX (a Jemena subsidiary) became the Network Operations Services suppliers for our two regions.

The new business model optimises the mix of services to be provided internally and those to be procured through outsourced contracts. It establishes best-practice procurement arrangements for those outsourced services. Most our network capex and opex is exposed to continuous competitive pressure between our two service providers, while ensuring that each network region is sufficiently large to avoid inefficiencies that may arise with smaller packages of work.

An important outcome of our business model is ensuring that best practice contractual and governance arrangements are in place. These have been reflected in Operational and Management Services Agreements (OMSAs) with each service provider. The OMSAs have been designed to create a collaborative contractual relationship between us and our service providers to achieve our desired outcomes, and to deliver these as efficiently as possible.

We continuously review the efficiency of these arrangements given the nature of the market and may make further refinements to our business in the future to ensure that we can deliver value for money outcomes for our customers.

13.4.2. ICT operating model

Our business transformation and the resulting benefits could not have been achieved without the successful completion of a major ICT program to replace our core systems during the current Access Arrangement period.

During this period, we successfully delivered several critical ICT projects, including a major SAP ERP replacement, infrastructure and data warehouse initiatives, a data centre relocation and updates of our SCADA and GIS systems. We completed these major projects in accordance with their individual business cases. The overall 2013 to 2017 ICT program will be delivered below the AER's allowance for the period.

As a result of the ICT capital program in the current Access Arrangement period, we have:

- Implemented a suite of foundation systems that provide a robust platform to meet future customer, business and regulatory requirements;
- Removed all dependence on the ICT capability of Jemena Asset Management; and
- Consolidated and rationalised our legacy applications.

As part of the business transformation, we have established a new ICT operating model. In line with our overall business operating model, we now have a small internal ICT team of approximately 20 employees that has responsibility for ICT asset management, strategy and management of the ICT project portfolio for both ourselves and United Energy.

Our ICT projects are delivered by a panel of external service providers. The panel was formed following a formal procurement process. At the start-up phase of each ICT project, formal quotations are requested from two or more of the service providers on our panel. Work is then commissioned under rates and commercial mechanisms defined when the panel was established. In some cases, service provider resources are supplemented with our staff and/or other contract resources. In addition, we have established a specific contract with a commercial service provider for smaller projects and enhancements to existing systems. All ICT operations are carried out by specialist ICT service providers, again appointed following commercial tendering processes.

Our ICT operating model provides us with access to leading ICT expertise at competitive, market-tested rates. The model provides us with the flexibility to bring on resources as required to meet fluctuating patterns of project demand.

13.4.3. Benefits of our new business model

Our new business model builds on the cost efficiencies that our earlier outsourcing arrangements delivered, but further improves our financial and operational performance by:

- Providing us with strengthened and increased internal management resources, thereby providing us with greater strategic management capability;
- Internalising the asset management and IT strategy functions, thereby further strengthening our capabilities in these critical areas of our core business;
- Removing our reliance on any one contractor and adopting a “best of breed” outsourcing model that includes multiple contracts and multiple service providers;
- Adopting best practice forms of collaborative contracting with suppliers while maintaining continuous competitive pressures on contractors throughout the contract period;
- Ensuring high levels of transparency and robust governance arrangements in all contracts for the procurement of business inputs;
- Achieving the right balance between delivering operating cost efficiencies and maintaining an appropriate longer term risk profile for asset performance;
- Addressing historical regulatory concerns about holistic service outsourcing to a related party;
- Demonstrating efficiency through market-based pricing;
- Adopting pricing and incentive structures in the contractual arrangements that are best practice and fit-for-purpose having regard to the objectives of providing efficient cost and service outcomes for us and our customers in the short, medium and long term;
- Reducing the risk of inefficient or sub-optimal service performance, by adopting a commercial framework that is free of mechanisms that provide incentives to service providers to engage in under or over-servicing;
- Reducing financial, regulatory and service performance risks that can arise through a misalignment of asset owner and service provider objectives, by establishing an alliance contract based on jointly agreed objectives and budgets, and a shared focus on how to achieve the best outcomes; and
- Enabling us to adapt to the changes that are impacting gas distributors worldwide by having a business structure that has greater strategic management capability and flexibility.

13.5. Our expenditure governance framework

We have a high degree of confidence that we will deliver our total capex forecast. This is based upon our proven ability to deliver against our capex allowance in the current Access Arrangement period. We recognise the importance of sound asset management in ensuring the efficient delivery of services that meet customers' and stakeholders' current and future needs. Network design, network construction, maintenance, operations and asset investment are vital components of asset management. Effective asset management directly impacts customer service, safety and shareholder value.

Having completed our business transformation and gained valuable experience in working with our Network Operations Services suppliers and our ICT service providers, we have established a set of robust capital governance processes (i.e. our investment framework). This framework enables us to be confident that we are making prudent and efficient investment decisions that will deliver a satisfactory and sustainable return on our assets in a legally and environmentally compliant, safe and sustainable manner.

Our Investment Framework comprises the following components: the Gas Access Arrangement Review (GAAR) Steering Committee, the Capital Investment Review Board (CIRB), the Gas Capital Works Steering Committee, monthly project governance meetings, the Gas Network Governance Framework and the ICT Executive Forum. Further details on each of these components are provided below.

As discussed below, we engaged Jacobs to review our expenditure governance framework, who found them to be fit-for-purpose and are in accordance with good practice.

13.5.1. GAAR Steering Committee

The GAAR Steering Committee was formed in mid-2015 and consists of key members of our Executive (the Chief Executive Officer (CEO), Chief Financial Officer (CFO), General Manager (GM) Gas Networks and GM Regulation). It has met regularly since its establishment. It determined our strategic position on key issues and endorsed this Access Arrangement Information for submission to the Board to approve lodgement with the AER.

The GAAR Steering Committee's role has included evaluating and approving the proposed network and ICT capex for the forthcoming Access Arrangement period. The proposed capex was subjected to our business governance framework set out in section 13.5.3, before being submitted to the GAAR Steering Committee. This has ensured that our capex proposal was subjected to rigorous analysis and justification before being submitted to the GAAR Steering Committee for consideration.

13.5.2. CIRB and Network Capex Governance

During an Access Arrangement period, network capex is subject to a review by our CIRB which has executive and general manager level representation across the business. The CIRB reviews and endorses business cases above $2 million. The CIRB's scrutiny of capex proposals ensures that all significant investment is prudent and efficient.

The objectives of the CIRB are to:

- Provide a consistent and rigorous approach to investment decisions;
- Ensure that an appropriate level of governance is applied to all significant investment decisions through the appropriate level of management scrutiny;
- Demonstrate to our Board, shareholders and other key stakeholders that investments are efficient and prudent; and
- Ensure that all investment accords with our compliance obligations and regulatory requirements.

13.5.3. Gas Capital Works Steering Committee

The Gas Capital Works Steering Committee was formed in 2016 to monitor the project execution and implementation phases of projects that are:

- High public profile;
- High risk to the business;
- Greater than $1 million in value; and
- As determined on a case by case basis.

13.5.4. Monthly project governance meetings

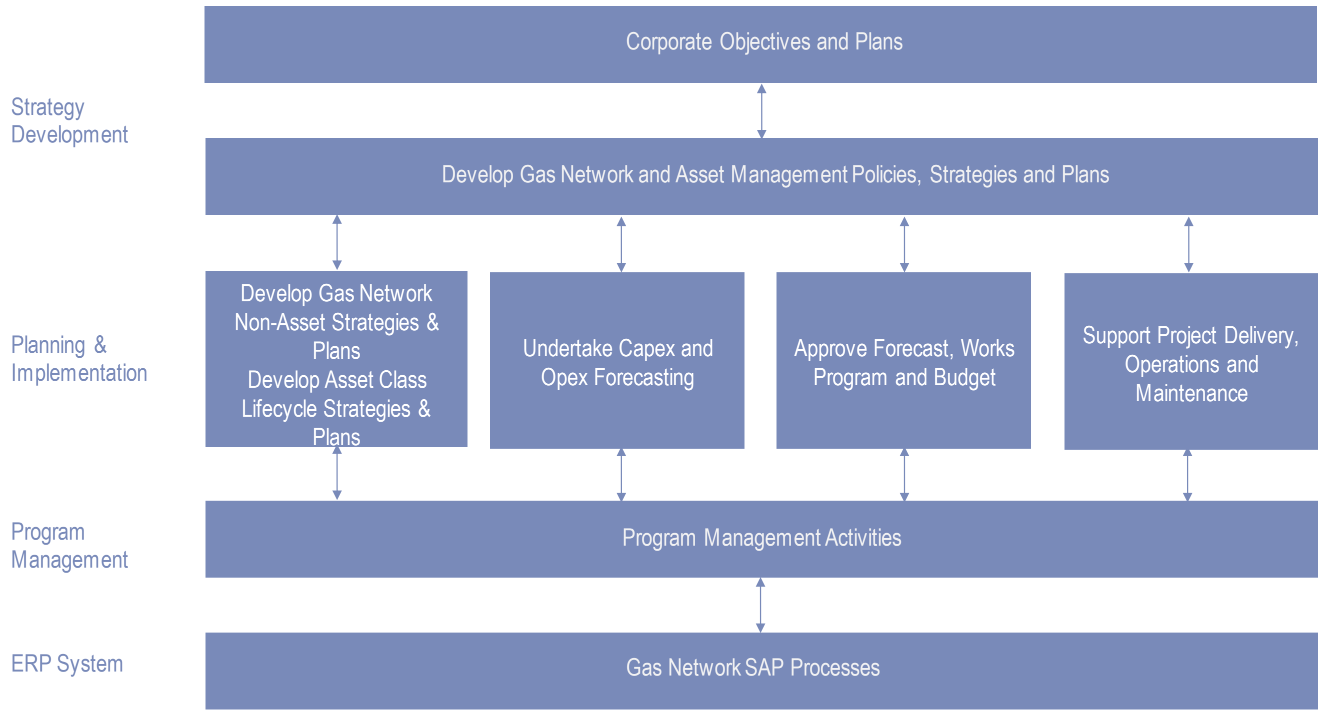
All projects not under a specific steering committee's governance falls under the Monthly Project Governance Meetings, which are standing meetings for each of our contracted service providers. The meetings are attended by:

- The service providers (Chair);
- Asset Management representative;
- Asset Strategy representative; and
- Service Delivery representative.

13.5.5. Gas Network Governance Framework

The Gas Network Governance Framework is a hierarchy of business processes that support the development and integration of the asset management activities. The framework takes a governance approach, outlining business rules and responsibilities in relation to key deliverables. Key components are explained below.

Figure 13-2: Gas network business governance framework



Each main component of the framework is described below.

Strategy development

The key corporate business planning outputs are the following documents:

- Corporate Business Plan;
- Corporate Vision and Mission Statements; and
- Corporate Risk Appetite Statement.

These documents provide overarching guidance for the development of our Asset Management framework, which is discussed below in section 13.5.8.

Activities undertaken to develop strategies and objectives include:

- Analysing external long term trends and potential strategic impacts;
- Determining long term future scenarios to be addressed;
- Determining strategies to address selected scenarios; and
- Executive Leadership Team endorsement of scenarios and strategic response.

Planning and implementation

Planning and implementation activities take place in alignment with the Corporate Business Plan and Asset Management Policies.

Asset and non-asset class strategies and plans are updated annually, along with capex and opex forecasting and the development of the Capex and Opex Works Program (COWP).

The COWP is provided to our Service Delivery group to oversee the implementation of the program of works by our service providers.

Program management

Program management activities are undertaken on an ongoing basis to manage the program of works. Regular interaction between our Corporate Finance and Service Delivery groups occurs throughout this phase.

Enterprise Resource Planning (ERP) Systems

ERP systems underpin all asset management activities and key systems and processes. Asset information is collected, stored, utilised and managed by us and our service providers.

13.5.6. ICT Governance

Our ICT governance structure provides oversight, guidance and direction to our ICT capex program. A high-level committee, including key members of our Executive, meets monthly to approve new projects, track and monitor existing projects and ensure overall alignment of ICT expenditure with business, customer and regulatory requirements.

We will continue to operate a robust ICT governance framework over the forthcoming Access Arrangement period.

Currently, our ICT governance framework consists of the following joint business ICT governance and advisory groups:

- ICT Executive Forum – this is our peak ICT governance forum in which our Executive Management Team (including the CEO) oversees all ICT capex and ensures that ICT investment is aligned with business strategies and priorities;

- Architecture Review Board – this Board ensures that proposed solutions are aligned with business and ICT architectural requirements and total cost of ownership considerations;
- Information Security Management System (ISMS) Governance Group – this group oversees the implementation of the ISMS across our business and ICT functions;
- Project Steering Committee – a project steering committee is formed for every major project; and
- Application Change Control Board – this body approves and prioritises small enhancements and business change requests.

13.5.7. Capex-opex substitution

In developing our capex forecasts, we have considered the substitution possibilities between capex and opex as well as substitution between different sub-categories of capex. These substitution possibilities are considered through 'trade-off' and / or synergy analysis and are overseen by the various management expenditure committees, discussed above. They are responsible for reviewing our capex and opex forecasts to ensure that they are prudent and efficient before being aggregated and provided to the Board for approval. Further specific details of our analysis of capex-opex substitution are provided in later sections of this chapter, and in our relevant supporting documents.

13.5.8. Regulatory Information Notice (RIN) approvals

We prepare all financial information to meet the annual RIN requirements in accordance with the relevant instrument issued by the AER:

- The actual information is independently audited and our Chief Executive signs it out as being true and accurate, in accordance with the required statutory declaration; and
- The estimated information is our best estimate available and is also signed out by our Chief Executive.

We draw on this annual RIN information to populate the historical information in our Reset RIN. Our Chief Executive signs out the financial information that underpins the revenue and price impacts in this Access Arrangement proposal.

13.5.9. Jacobs' governance review

We engaged Jacobs to review our capital governance systems. Jacobs found that:

- *Selection of projects* - "Multinet Gas utilises appropriate assessments of projects including business cases and economic assessments for projects that are not driven by other requirements. The other requirements are regulatory (e.g. meter replacement), safety (e.g. pipe replacement) or service continuity (e.g. asset replacement upon field failure)"[26];
- *Approval of projects* – "Multinet Gas has processes for approving projects for implementation that are appropriate, and financial controls and delegations of authority related to the projects are considered robust.

  The governance structure for the approval of large projects include the Capital Investment Review Board and for smaller projects includes sign-offs by the key stakeholders" [27];
- *Implementation of projects* – "The Multinet Gas system has appropriate governance features as recommended in project management best practice guidelines including that (i) the project structure is outside the operating structure, (ii) that the supervisory structure has representation from the prime stakeholders and

[26] Jacobs, Review of governance structures and processes for capital expenditure, November 2016, page v

[27] Jacobs, Review of governance structures and processes for capital expenditure, November 2016, page v

(iii) the supervisory structure has the authority to make decisions on the project, subject to the financial delegation authorities"[28].

We have provided a copy Jacobs' report to the AER with this Access Arrangement Information.

13.6. Asset Management Framework

Our asset management framework and systems are aligned with key elements of ISO 55001. These processes and systems ensure that network risks and costs are systematically analysed and optimised. The systematic consideration of risks and costs underpin our capex forecast.

13.6.1. Key asset management principles

The following key asset management principles describe the overarching objectives of our asset management framework. We:

- Employ good asset management practices to prudently manage and operate the assets over their total life cycle;
- Minimise our long-term cost structure considering the potential downturn in future gas consumption;
- Build our reputation as a trusted company with customers and stakeholders by striving for active industry leadership, agility, reliability, safety and good customer service in light of changing customer and community expectations;
- Meet all legal and regulatory requirements;
- Adhere to the relevant Australian, international and industry standards and any other requirements to which we subscribe;
- Prudently manage reasonably foreseeable and critical credible safety hazards and risks to as low as reasonably practicable;
- Develop high performance operations by engaging our people and having the right skills and capabilities within our business;
- Embed continuous improvement and innovate to drive efficiency; and
- Monitor and evaluate appropriate metrics to effectively manage our network.

13.6.2. Asset Management System

The key objective of our asset management system is to maximise value by delivering optimum performance with maximum expenditure efficiency across the combination of capex and opex. Our asset management system, which is illustrated in Figure 13-3, encompasses a series of interlocking processes that cover most functions across our business and define how the assets are managed over the long, medium and short term. To achieve this, we have three key asset management processes, each optimising over a distinct time horizon:

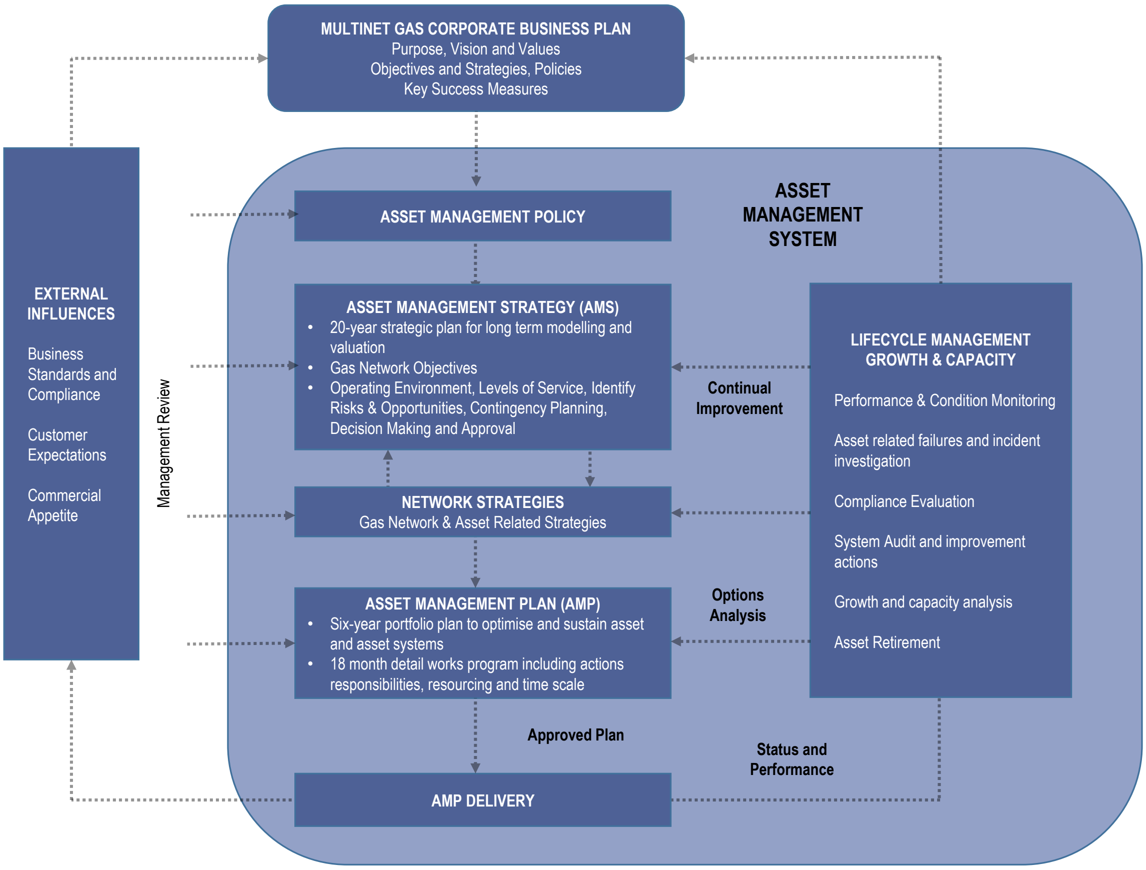
- **Asset Management Strategy**: this determines the key whole-of-life strategies and long term assumptions the business anticipates over a five to 20-year horizon, as well as the overall activity volumes and spend envelope for the period.
- **Network Strategies:** these are gas network and asset related strategies which provide an overview of the asset class, their performance, life cycle management and the associated capital forecast.

[28] Jacobs, Review of governance structures and processes for capital expenditure, November 2016, page v

- **Asset Management Plan**: this is a rolling six-year plan of our priorities, main projects and expenditure as well as the baseline information for this Access Arrangement Information and our OMSAs.

These elements optimise our expenditure within the context of a holistic model that ensures economic returns to shareholders are optimised over the long term. We have provided these to the AER as attachments to this Access Arrangement Information.

Figure 13-3: Asset management system



13.7. Cost escalators

We are proposing no real increases in our input costs of materials over the next Access Arrangement period.

However, we have escalated our capex forecast for expected changes in the real input costs of labour over the forthcoming Access Arrangement period.

The escalators applied to labour are consistent for both capex and opex and are detailed in section 14.5.5 below. They are based on advice from the leading independent expert, BIS Shrapnel. A copy of BIS Shrapnel's report entitled "Utilities Sector and Construction Industry Wage Forecasts to 2022 – Australia and Victoria" has been provided to the AER as an attachment to this Access Arrangement Information.

13.8. Capex and Asset-Related Benchmarking

Unlike for electricity DNSPs, the AER has not published any comparative benchmarking of gas distributors in recent years.

For this reason, the three Victorian gas distributors commissioned Economic Insights to benchmark their:

- Expenditure using partial productivity indicators; and

- Productivity performance using various econometric techniques.

We have provided with our Access Arrangement Information the Economic Insights' reports dated 15 June 2016 entitled:

- "Benchmarking the Victorian Gas Distribution Businesses' Operating and Capital Costs Using Partial Productivity Indicators"; and
- "The Productivity Performance of Victorian Gas Distribution Businesses".

13.8.1. Expenditure benchmarking

Economic Insights benchmarked 13 Australian and New Zealand gas distributors using:

- Public data, including data sourced mainly from Access Arrangement Information filings, regulators' final review reports and the gas distributors' annual reports; and
- Data provided in response to common detailed surveys, covering key output and input value, price and quantity information for the calendar years 1998 to 2015 (or 2014, in the case of Jemena NSW).[29]

Economic Insights' analysis found that the three Victorian gas distributors have:

- Amongst the highest customer numbers, gas deliveries (TJ) and network length (kilometres) – only Jemena NSW is larger and ATCO is of comparable size;
- The highest customer density per kilometre of mains; and
- Average energy density per customer and high energy density per kilometre of mains.

Economic Insights found that of the 13 gas distributors sampled, we had:

- The third highest customer numbers (and the highest of the Victorian gas distributors);
- The third highest gas throughput; and
- The fifth highest network length.[30]

Economic Insights noted that the energy use (TJ) per customer (also referred to as energy density per customer) has declined for all gas distributors in recent years – including for us and the other two Victorian gas distributors. It attributed this general decline to decreased gas demand by energy-intensive industries and improved residential energy efficiency. It found that we have the lowest energy use per customer of the Victorian gas distributors, but that we also faced the smallest decline in recent years. Economic Insights also noted that network energy density has declined for most gas distributors over the sample period, although it has been comparatively stable for us.[31]

Against this background, Economic Insights benchmarked the 13 gas distributors expenditure over 2011 to 2015. It focussed on inputs per customer of gas distributors compared to their network customer densities, to control for differences in the size and customer density of the gas distributors. It examined three measures:

- Opex per customer relative to customer density – this is discussed in chapter 14 of this Access Arrangement Information;
- Capital asset cost per customer relative to customer density; and
- Total cost per customer relative to customer density.

[29] Economic Insights, "Benchmarking the Victorian Gas Distribution Businesses' Operating and Capital Costs Using Partial Productivity Indicators", 15 June 2016, page iii

[30] Economic Insights, "Benchmarking the Victorian Gas Distribution Businesses' Operating and Capital Costs Using Partial Productivity Indicators", 15 June 2016, pages 2 to 5

[31] Economic Insights, "Benchmarking the Victorian Gas Distribution Businesses' Operating and Capital Costs Using Partial Productivity Indicators", 15 June 2016, page 5

Economic Insights found that we had an average annual capital asset cost of $158 per customer for the 2011 to 2015 period. This was the lowest of the Victorian gas distributors and the second lowest of the sample of 13 gas distributors. It concluded that:

> *These comparisons are influenced among other things by asset age, original network asset valuations, and various factors not controlled-for which influence the quantity of assets per customer, and hence asset cost per customer. Thus, only qualified conclusions can be drawn from this chart. It suggests that the Victorian gas distributors are amongst the more efficient in terms of asset use.*[32]

Economic Insights added the opex and asset costs per customer to determine the overall cost efficiency per customer for the 2011 to 2015 period. It found that we had the second lowest overall cost efficiency per customer of the 13 gas distributors surveyed. Economic Insights observed that:

> *Once again, caution is needed in drawing strong conclusions for these comparisons alone. That said, the results tend to indicate that the Victorian gas distributors are amongst the more efficient of those included in the sample.*[33]

Economic Insights concluded by saying:

> *The Victorian gas distributors therefore have a substantial degree of economies of scale. Even so, their opex per customer and asset cost per customer are amongst the lowest of those for gas distributors of comparable scale. Similarly, comparisons of total cost per customer suggest that the Victorian gas distributors are comparable to the most efficient peers, and hence amongst the most efficient of the gas distributors in the sample.*
>
> *The partial indicators analysis presented in this report does not enable influences such as scale economies or different mixes of inputs to be controlled for in a rigorous fashion. This means that care needs to be taken when drawing inferences. Based on these indicators and recognising the nature of their networks, the Victorian gas distributors appear to have performed at better than average levels, achieving comparatively low levels of opex per customer, asset cost per customer and hence total cost per customer.*[34]

13.8.2. Productivity benchmarking

Economic Insights examined the productivity levels of the three Victorian gas distributors and Jemena NSW, AGN SA and AGN Queensland using data provided by the gas distributors in response to detailed surveys. Specifically, Economic Insights detailed the Victorian gas distributors':

- Input index – this is the weighted average of separate opex and capital input indexes;
- Output index – this is based on the gas distributors' throughput, customer numbers and system capacity;
- Total factor productivity (TFP) – this is the ratio of the output and input indexes;
- Partial factor productivity (PFP) – this measures for each gas distributor one or more outputs relative to one particular input:
  - The opex PFP index measures output produced per unit of opex (non-capital) inputs; and
  - The capital PFP index measures output per unit of capital inputs.

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32 Economic Insights, "Benchmarking the Victorian Gas Distribution Businesses' Operating and Capital Costs Using Partial Productivity Indicators", 15 June 2016, page 12

33 Economic Insights, "Benchmarking the Victorian Gas Distribution Businesses' Operating and Capital Costs Using Partial Productivity Indicators", 15 June 2016, page 11

34 Economic Insights, "Benchmarking the Victorian Gas Distribution Businesses' Operating and Capital Costs Using Partial Productivity Indicators", 15 June 2016, pages 12-13

- Multilateral TFP – this measures the relative productivity levels and productivity growth rates of the gas distributors.

Economic Insights' TFP analysis for the period 1999 and 2015 found that:

- Our capital input index grew steadily over the period and at a similar rate to the output index – it therefore had little bearing on TFP trends. The other two Victorian gas distributors had a similar experience;
- The opex input index played a key role in determining our TFP trends. Our opex inputs' usage decreased at an average annual rate of 3.7 per cent over 1999 to 2008 but increased at an average annual rate of 1.2 per cent between 2008 and 2015. This increase was largely caused by a one-off increase in opex in 2012. Over the period 1999 to 2015, our opex input index decreased on average by 1.6 per cent per annum[35];[36]
- Our input index (being the weighted average of opex and capital input indexes) declined by 0.9 per cent per annum between 1999 and 2008) and increased by an annual average of 0.9 per cent from 2008 to 2015. Our input index decreased at an average annual rate of 0.1 per cent between 1999 and 2015. Economic Insights noted that this "compares favourably to AGN Vic's average input increase of 0.4 per cent and AusNet's average input increase of 0.6 per cent per year over the same period"[37]. This indicates that we have had the most favourable trend in input use of the three Victorian gas distributors over the analysis period[38];
- Our output index grew by 0.9 per cent per annum over the 1999 to 2015 period. This rate is much slower than that for AGN Victoria and AusNet. Economic Insights noted that "This difference probably reflects the nature of its distribution region, which does not include any major residential growth corridors. Further, the growth rate of outputs slowed in the latter half of the period. It averaged 1.2 per cent per year between 1999 and 2008, decreasing to 0.5 per cent per year from 2008 to 2015"[39]. In reference to the lower output index growth, Economic Insights also noted "It is reasonable to expect that this factor would explain much of the difference between the TFP growth results of Multinet and the other two Victorian gas distributors"[40]; and
- Our TFP increased by 2.0 per cent per annum from 1999 to 2008 but decreased at an average rate of 0.4 per cent from 2008 to 2015, driven largely by a significant downturn in 2012. Over the 1999 to 2015 period, our TFP increased at an average annual rate of 1.0 per cent. Economic Insights concluded that "although Multinet's inputs have been slightly more contained than those of AGN Vic and AusNet, the much slower growth of its outputs has resulted in a lower average rate of TFP growth than those two businesses" over the period 1999 to 2015.[41]

Economic Insights' PFP analysis for the period 1999 and 2015 found that the capital PFP index for each of the three Victorian gas distributors, including ourselves, grew steadily over the period, averaging 0.1 per cent per annum[42].

Economic Insights used:

- Multilateral TFP analysis to show that our productivity level in recent years was lower than AGN Victoria's, similar to AusNet's and Jemena NSW's and higher than each of AGN SA and AGN Queensland;[43] and

[35] A decrease in opex inputs is favourable and an increase is unfavourable.

[36] Economic Insights, "The Productivity Performance of Victorian Gas Distribution Businesses", 15 June 2016, page 26

[37] Economic Insights, "The Productivity Performance of Victorian Gas Distribution Businesses", 15 June 2016, page 26

[38] Economic Insights, "The Productivity Performance of Victorian Gas Distribution Businesses", 15 June 2016, page 25

[39] Economic Insights, "The Productivity Performance of Victorian Gas Distribution Businesses", 15 June 2016, page 25

[40] Economic Insights, "The Productivity Performance of Victorian Gas Distribution Businesses", 15 June 2016, page 38

[41] Economic Insights, "The Productivity Performance of Victorian Gas Distribution Businesses", 15 June 2016, page 25

[42] Economic Insights, "The Productivity Performance of Victorian Gas Distribution Businesses", 15 June 2016, page 26

[43] Economic Insights, "The Productivity Performance of Victorian Gas Distribution Businesses", 15 June 2016, page 27

- Multilateral PFP indexes to show the levels of Capex PFP for the six gas distributors. It found that our Capex levels are below those of AGN Victoria in 2015 but higher than those of Ausnet.[44] Our Capex PFP levels have been relatively stable since 1999.[45]

13.8.3. Conclusions on benchmarking

We draw the following conclusions from Economic Insight's benchmarking analysis:

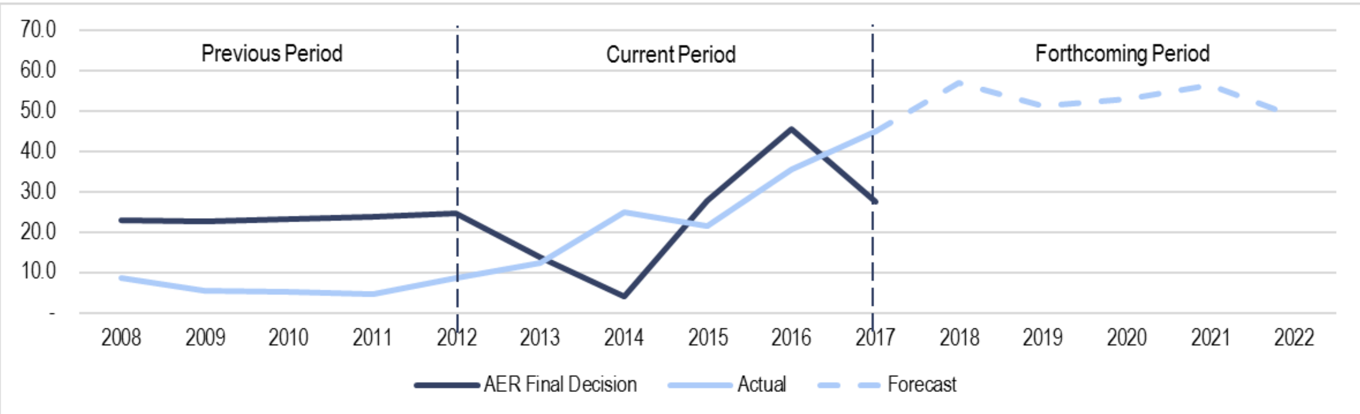
- We are one of the two most efficient gas distributors in using our assets;
- Each of the benchmarking techniques supports the fact that our capex is efficient and that we are operating at or close to the efficient frontier of gas distributors;
- We have sustained an efficient level of performance over a long period. We have not just arrived at our efficient levels of capex recently. This means that assessments of our efficiency are not just a function of which year, or years, are chosen for the benchmarking analysis;
- Our new business model – that has resulted from our recent business transformation program – is successful and is delivering efficient capex outcomes. The new business model provides a strong basis for us to continue to deliver efficient outcomes;
- We have continually responded to the incentives that the AER and, prior to this, the ESCV, have provided to us through the economic regulatory framework. This is reflected in the efficiency of our capex. Our customers are sharing in the resultant benefits; and
- We are delivering value for money to our customers through our efficient capex.

13.9. Mains Replacement capex

13.9.1. Overview

Mains Replacement capex involves replacing gas distribution mains operating at pressures from 1.5 kPa to 1,050 kPa[46]. Figure 13-4 below shows our actual, estimated and forecast Mains Replacement capex over the previous, current and forthcoming periods.

Figure 13-4: Actual and forecast Mains Replacement capex ($M, Real 2017)



[44] Economic Insights, "The Productivity Performance of Victorian Gas Distribution Businesses", 15 June 2016, page 27

[45] Economic Insights, "The Productivity Performance of Victorian Gas Distribution Businesses", 15 June 2016, page 36

[46] The supporting document titled Distribution Mains Strategy (MG-SP-0009) applies to gas distribution mains operating at pressures from 1.5 kPa to 515 kPa. By definition under the current Australian Standards, mains operating up to 1,050 kPa are deemed to be distribution mains. For the purposes of maintenance and replacement, Multinet's 1,050 kPa system is covered by the document titled Transmission Pipeline Integrity Management Plan (MG-SP-0001).

We group our Mains Replacement capex in the current Access Arrangement period into four programs:

- Low pressure (LP) to high pressure (HP) replacement program;
- Large Diameter Cast Iron (LDCI) Mains replacement program;
- Low Pressure Designated Zone (LPDZ) mains replacement program; and
- Unplanned service renewals program.

We propose five programs in the forthcoming Access Arrangement period:

- LP to HP Mains Replacement program;
- Replacement of medium pressure (MP) cast iron mains program;
- Replacement of early generation high-density polyethylene pipes program;
- Reactive mains replacement program; and
- Unplanned service renewals program.

Over 95 per cent of our Mains Replacement capex in the current access arrangement period relates to our LP to HP Mains Replacement program. We forecast that it will comprise over 80 per cent in the forthcoming Access Arrangement period, as shown in Table 13-5.

Table 13-5: Forecast Mains Replacement capex by category – 2018 to 2022 ($M, Real 2017)

Expenditure subcategory	2018	2019	2020	2021	2022	Total
LP to HP mains replacement	48.0	45.1	44.8	45.8	39.6	**223.4**
Replacement of MP cast iron mains	7.7	4.9	6.7	-	-	**19.3**
Replacement of high-density polyethylene pipes	-	-	-	9.3	7.8	**17.0**
Reactive mains replacement	0.2	0.2	0.2	0.2	0.2	**1.1**
Unplanned service renewals	1.2	1.2	1.2	1.2	1.2	**6.1**
Total	**57.2**	**51.4**	**53.0**	**56.5**	**48.8**	**266.9**

Our LP to HP Mains Replacement program is based on a 30-year initiative, which commenced in 2003 and is scheduled to be completed by 2033. The AER accepted and endorsed the basis for this initiative in, amongst other decisions, its September 2015 determination on our mains replacement cost pass-through for the current access arrangement period, in which it stated:

> *Under Multinet's Asset Management Plan it is scheduled to complete its mains replacement work program over a 30 year period, concluding in 2033. This end date is a critical factor in considering what is an efficient and prudent volume of mains replacement under r.79(1) given the long term safety objective of removing all cast iron and unprotected steel mains from Mulinet's (sic) network. We noted in our final decision that the mains replacement pass through provides a means by which Multinet can complete the mains replacement program by 2033. Therefore we have had regard to Multinet's ability to meet this timeframe for completing its mains replacement in considering the efficiency and prudency of the proposed volumes.*[47]

[47] AER, Multinet Gas Mains Replacement Cost Pass-Through AER Decision, September 2015, page 9

Table 13-6 overviews the allowed and actual / estimated volumes (in kilometres) associated with the LP to HP Mains Replacement program since its inception. For technical and practical reasons, the new pipeline volumes differ slightly from the decommissioned network.

Table 13-6: Actual and forecast LP mains decommissioned and HP mains installed under LP to HP Mains Replacement program (kilometres)

	2003 to 2007	2008 to 2012	2013 to 2017	2018 to 2022
ESC / AER allowance	540	557	527 *	625
Actual / Estimated delivered	537	255	527	n.a.

* Final Determination of 255 kilometres plus cost pass-through allowance of 272 kilometres

We expect to replace a total of 527 kilometres of LP mains with HP mains during the current access arrangement period, which is more than double the AER's original forecast. The increased volume ensures that our LP to HP Mains Replacement program remains on track for completion by 2033. We also expect during the current access arrangement period to decommission seven kilometres of MP cast iron mains through efficient incorporation into the LP replacement program.

Consistent with our 30-year LP to HP capex replacement program, we are forecasting to replace 625 kilometres of LP mains with HP mains over the forthcoming access arrangement period. In addition, we are targeting replacing the remaining 27 kilometres of our cast iron mains operating at MP by 2022 along with replacing 31 kilometres of early generation high density polyethylene. The rationale for these programs is discussed in our Mains Replacement Overview Document, which is an attachment to this Access Arrangement Information.

We expect the costs of our LP to HP replacement capex program to increase over the forthcoming access arrangement period. In part, this reflects an increase in volume consistent with the overall timetable for completion. However, the larger effect relates to unit rates. As the LP to HP replacement capex program progresses into the inner suburban areas of our network, population density increases markedly, which leads to higher replacement costs per metre. In addition, other factors such as the reinstatement of sealed surfaces following pipe replacement, increased traffic management requirements in more densely populated areas, and challenges in gaining access to undertake works will contribute to higher unit rates.

13.9.2. Key inputs and drivers

The requirement to provide a safe and reliable supply of natural gas drives our Mains Replacement capex. Mains Replacement capex has a significant positive impact on network performance by reducing the risks to both public safety and property damage associated with gas leakage from the network.

Most of our Mains Replacement capex relates to replacing ageing cast iron and unprotected steel mains with current generation HP polyethylene mains to mitigate the following risks:

- Cast iron pipe fractures that could have the potential to result in the uncontrolled release of gas; and
- Cast iron and bare steel leaks which when compared to other gas network materials account for the highest proportion of leaks.

The principle driver for the cast iron replacement program is the 'societal risk' arising from the failure of cast iron mains and the resultant risk of incidents leading to loss of life or significant property damage. The risk associated with cast iron mains is a quantifiable risk and both UK and US safety regulators accept that cast iron is an obsolete material.

If a cast iron fracture remains undetected for a period of time then it can result (and has resulted in both the UK and US) in fatalities. For this reason, replacing cast iron pipes (and in particular those with a history of brittle fracture) is the highest priority of our Mains Replacement capex.

Our Mains Replacement capex also delivers several other benefits, including:

- Optimising network capacity by replacing MP and LP mains with HP mains, enabling us to meet the service needs of existing and future customers at an efficient cost, to achieve the lowest sustainable cost of providing services;
- Securing network reliability by reducing the incidence of leaks and associated unplanned outages on the network; and
- Ensuring the on-going efficiency of the operating and maintenance costs associated with our distribution mains.

The primary drivers of our Mains Replacement capex are, and will remain, mitigating the safety risk of gas leaks and securing reliability of supply. The replacement of the ageing cast iron and unprotected steel mains is a fundamental element of managing the safety risk of our gas distribution network.

13.9.3. Replacement strategy and forecasting approach

Our Mains Replacement strategy primarily focuses on minimising, to the greatest extent practicable, public and maintenance personnel safety risks by targeting mains in areas that have a high incidence of mains fracture and leakage. Further, the strategy targets the integrity and performance of mains in areas that have:

- Suffered from loss of supply associated with water in mains incidents; and
- Limited capacity to service additional demand from existing and new customer connections.

Our Mains Replacement program leads to the lowest sustainable costs over the long-term as it:

- Reduces the need to undertake leak repair work – this work does not substitute for the requirement to replace the deteriorating mains;
- Is undertaken, where possible, by insertion techniques on a ‘block’ renewal basis, which is considered the most cost efficient technique: and
- Provides increased capacity from renewal to HP to meet increasing peak loads resulting from increasing penetration of high instantaneous demand gas appliances.

The timeframe of our LP to HP Mains Replacement program has been established at a high level by modelling industry accepted asset lives against individual asset installed dates. As already noted, the original timeframe for replacing the LP network was 2033, being a 30-year period commencing in 2003. However, substantial replacement volumes have now been undertaken since the original timeframes were established. It is appropriate for these initial timeframes to be revisited considering the current information.

Accordingly, our forecasting methodology begins with an initial ‘top down’ assessment of the replacement volume required by the end of the forthcoming access arrangement period, considering current asset ages and technical lives. This ‘top down’ analysis has been supplemented by an analysis of pipe fracture and leakage rates, which indicates whether the implied rate of replacement is appropriate - given the current and projected performance of the assets - or whether it should be deferred or accelerated. Through this analysis, we identify the volume of pipe replacement works that must be undertaken to ensure that fracture and leakage rates are not allowed to deteriorate from current levels.

From a safety perspective, it is essential that the network does not expose the public or our contractors to unacceptable risks. While the LP to HP Mains Replacement program is the largest single component of our Mains Replacement capex category, the scheduling of work under this program must be optimised by taking into consideration other works, most notably the planned removal of the MP cast iron mains. As already noted, those assets pose a significant safety risk, particularly due to the increased release of gas between MP mains and LP mains. The replacement of the MP cast iron mains is, therefore, a key objective for the forthcoming access arrangement period.

The location of the LP pipe replacement works for the forthcoming access arrangement period targets those areas where synergies can be achieved by coordinating LP pipe replacement with the removal of MP cast iron mains.

The forecasting methodology therefore seeks to optimise our mains replacement work to achieve the lowest sustainable costs over the long-term, considering the following factors, in order of priority:

1. Maintain and improve safety in accordance with Rule 79(2)(c)(i), by focusing on the replacement of MP cast iron mains as this:
   - Mitigates the risk of a catastrophic failure that would threaten the safety of the public, our field personnel and property; and
   - Provides the most effective means of minimising, to the extent practicable, public safety risks.
2. Address local capacity constraints;
3. Minimise local interruptions to supply associated with planned replacement works; and
4. Optimise maintenance costs.

On this basis, our proposed Mains Replacement program will replace the following in the forthcoming access arrangement period:

- An annual average of 125 kilometres of LP mains with HP mains in the forthcoming access arrangement period. This is consistent with the average annual volume of work that we need to undertake to complete our LP to HP Mains Replacement program by 2033 (based on there being around 2,000 kilometres of LP mains needing to be replaced as at the end of 2017);
- 24 kilometres of MP cast iron main;
- The earliest 31 kilometres of early generation high-density polyethylene pipes in the next five years; and
- Similar levels of reactive mains replacement to the current access arrangement period.

Our Mains Replacement capex forecast also includes an allowance for unplanned service renewals and reactive replacement of mains.

Further details of how we have arrived at the proposed volume of work are set out in our Mains Replacement Overview Document.

In terms of unit rates, we used four methods to determine the unit rates that we applied to forecast our LP to HP Mains Replacement capex. Our preferred method is to undertake a two-party tender using our competitively-sourced service providers, Comdain and ZNX. We can only use this method where the works are sufficiently well-defined to enable us to approach our service providers to provide a firm quotation and we intend proceeding with the successful tender.

However, where this is not possible, we rely on actual historical rates where we have previously undertaken work in the postcode. Otherwise:

- We engage our independent estimator – Advisian; or
- Where we don't either have actual unit rates for a postcode, or it is premature to undertake a two-party tender, we undertake postcode density correlation to establish unit rates in similar postcodes based on actual historical rates and two-party tenders.

Our Mains Replacement Strategy details which of these four methods we have used to cost works in each postcode.

In terms of the other Mains Replacement programs, we have adopted the following approach to forecast capex for the next access arrangement period:

- MP Cast Iron Mains Replacement program – this has been costed by our Independent Estimator, Advisian, except for the supply regulator works at our Graham Street, Port Melbourne and Aughtie Drive, Albert Park projects. These costs have been prepared through an internal estimate based on a combination of a bottom-up build and historical rates;

- Early Generation High-Density Polyethylene Pipes' capex – these projects have been costed by our Independent Estimator, Advisian;
- Reactive Mains Replacement program - we have based our forecast on the annual average of $0.2 million per annum that we incurred over the period 2013 to 2015; and
- Unplanned service renewals - our forecast capex of $1.2 million is in line with our historical expenditure.

13.9.4. Mains Replacement Justification

Our Mains Replacement capex forecast, as explained in detail in our Mains Replacement Capex Overview Document and its supporting documents, is consistent with a prudent service provider, acting efficiently and in accordance with good industry practice to achieve the lowest sustainable cost of providing services. In particular, our Mains Replacement capex forecast is justifiable under Rule 79(2) of the NGR for the following reasons:

- Rule 79(2)(c)(i) – The forecast capex is required to maintain and improve safety by reducing the incidence of gas leaks, to the extent practicable, thereby mitigating both the hazards and risks to the safety of both the public and field personnel, along with the risk of property damage associated with gas supply;
- Rule 79(2)(c)(ii) – The forecast capex is required to maintain the integrity of services by:
    - eliminating outages due to water ingress;
    - eliminating supply loss arising from leak repair works; and
    - eliminating poor pressure (or loss of supply) at the customer connection point due to peak loading on LP mains.
- Rule 79(2)(c)(iii) - The forecast capex is required to comply with the Gas Safety Case (as per section 44(2) of the Act), which requires us to minimise as far as practicable the hazards and risks to the safety of the public and customers of gas supply, including the risk of property damage; and
- Rule 79(2)(c)(iv) – The forecast capex is required to maintain our capability to meet levels of demand in those areas where LP mains are unable to satisfy peak demand and/or allow for the connection of new customers.

Given the above, the Mains Replacement capex forecast for the 2018 to 2022 access arrangement period is consistent with the National Gas Objective, in that it promotes efficient investment in natural gas services that is in the long-term interests of consumers in terms of price, quality, safety, reliability and security of supply of natural gas services.

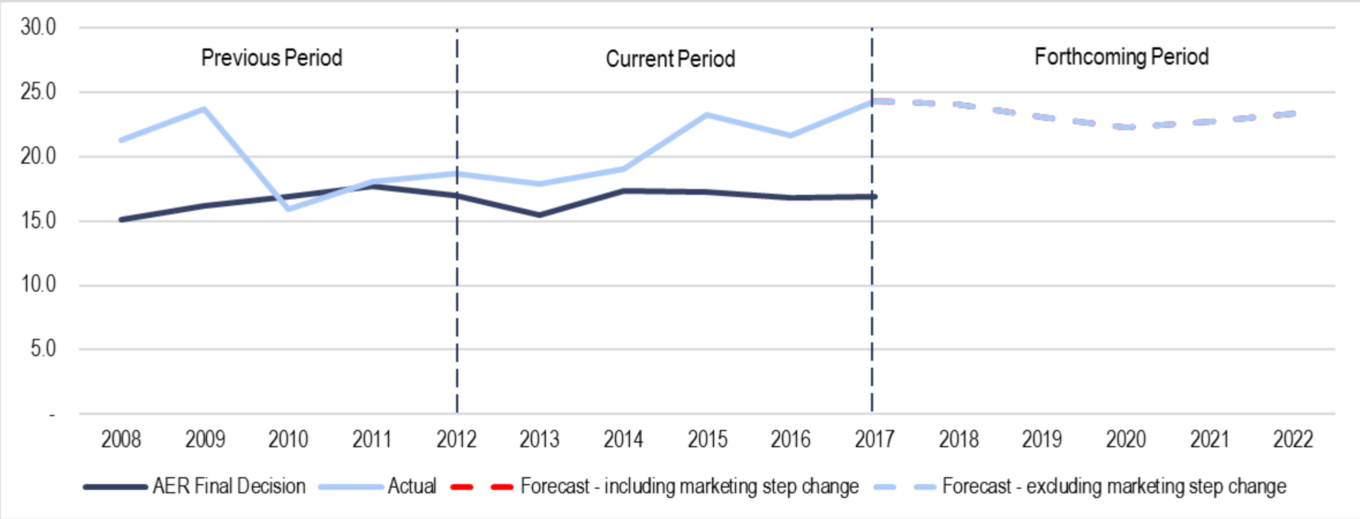
13.10. Residential and Commercial and Industrial Connections capex

13.10.1. Overview

Connection projects involve establishing new connections or modifying or extending our existing distribution system to accommodate new customers' demand. Customer connections are undertaken in accordance with the Gas Distribution System Code on a least cost technically acceptable basis.

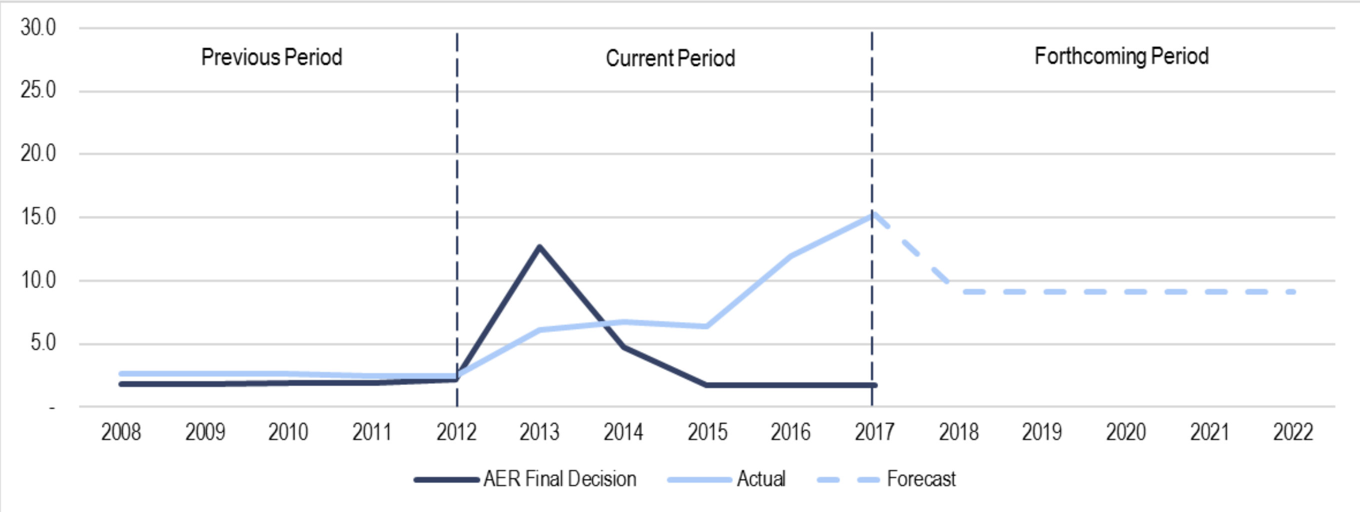
The figure below shows our actual and forecast Connections capex over the previous, current and forthcoming periods.

Figure 13-5: Actual and forecast Residential and Commercial and Industrial Connections capex ($M, Real 2017)



The figure below shows our actual and forecast Customer Contributions over the previous, current and forthcoming periods.

Figure 13-6: Actual and forecast Customer Contributions ($M, Real 2017)



All new connections are initiated, and carried out, at the request of customers. The timing and level of connections is therefore largely outside of our control.

We undertake new customer connections by delivering "unitised jobs", rather than by delivering a single consolidated project. Each customer connection therefore comprises a series of unitised jobs. We assign a three-letter Activity Code to each type of unitised job. Each unitised job has a standard cost, or unit rate, that has been agreed with our competitively contracted service providers, Comdain and ZNX. We do not individually cost unitised jobs for a new connection (i.e. all costing is standardised based on unitised jobs).[48]

We forecast our connections capex (other than for tariff D) and our customer contributions in four steps.

Our first step is to determine our volumes of unitised jobs. Our forecast volumes are the count of unitised jobs by Activity Code that are initiated each year. We forecast these volumes based on the number of unitised jobs that have been undertaken over the last two to three years (depending on data availability) for each Activity Code and apply growth indices to forecast the number of projects for each Activity Code over the forthcoming Access

[48] This is different to the approach taken by our sister business United Energy, where it has both non-unitised projects that are individually costs and unitised projects that are costed based on standardised unit rates.

Arrangement period. We determine the growth indices for each Activity Code based on indices that are prepared annually by the Australian Construction Industry Forum (ACIF). The ACIF Melbourne forecast provides an economic/industry growth forecast at a more granular level and at wider areas than our supply area. This enables us to include the influence of activities in the surrounding areas that will impact our Residential and C&I Connections capex in the future. These indices have been checked against our historical works and have a strong correlation to actual works for their specific categories.

Our second step is to multiply our forecast capex volumes for our unitised jobs by our:

- Standardised unit rates for each unitised job that we have contractually agreed with our Service Providers; and
- Real labour cost escalations – as noted in section 13.7, we are proposing zero real material cost escalations for the forthcoming year.

Our standardised unit rates for each unitised job are sourced from our current OMSAs with our competitively-sourced Service Providers. These rates are the best we have available for developing our capex forecasts given that they are market-tested through the establishment of the OMSAs under competitive arrangements. They are our 2016-17 rates that are based on the actual outturn costs that we incurred from 1 July 2015 to 30 June 2016. Our real labour cost escalations are based on advice from BIS Shrapnel.

Our third step is to forecast our customer contributions by Activity Code. Our customer contributions comprise only cash contributions – we do not have any gifted assets. We forecast our customer contributions based on the historical trend in our customer contributions in recent years. We consider this to be the most accurate and justifiable basis for forecasting our future customer contributions.

Our final step is to undertake a top-down validation of our connections capex forecast.

Each of these steps is discussed in detailed in our Residential and C&I Connections Overview Document.

Our forecasting method for tariff D connections is based on our historical expenditure. We have adopted this method given the low volume and unique nature of Tariff D connections. This forecasting method is consistent with the AER's approach to forecasting capex for this connection type for the current access arrangement period.

Table 13-7 and Table 13-8 detail our forecast Connections capex and customer contributions for the forthcoming Access Arrangement period.

Table 13-7: Forecast Connections capex 2018-2022 ($M, Real 2017)

		2018	2019	2020	2021	2022	Total
AAI Proposal	**Residential**	19.3	18.2	17.3	17.7	18.3	90.8
	C&I	4.2	4.2	4.3	4.4	4.4	21.6
	Total	**23.5**	**22.4**	**21.6**	**22.1**	**22.7**	**112.4**
AAI Proposal with marketing	**Residential**	19.9	18.9	17.9	18.3	19.0	94.0
	C&I	4.2	4.2	4.3	4.4	4.4	21.6
	Total	**24.1**	**23.1**	**22.3**	**22.8**	**23.4**	**115.6**

Table 13-8: Forecast Customer Contributions 2018-2022 ($M, Real 2017)

	2018	2019	2020	2021	2022	Total
Connection contributions	(9.1)	(9.1)	(9.1)	(9.1)	(9.1)	(45.6)

13.10.2. Key inputs and drivers

We prepare our Connections capex forecasts based on the following components:

- Volumes – we determine the count of unitised jobs by Activity Code based on the historical average over the last two to three years;
- Growth indices – we apply to the historical average volumes indices that have been prepared by the Australian Construction Industry Forum;
- Unit rates – we apply our standardised unit rates that we have contractually agreed with our service providers; and
- Real cost escalators – we apply labour cost escalators provided by BIS Shrapnel.

We forecast our customer contributions based on the historical trend in our customer contributions in recent years.

13.10.3. Residential and Commercial and Industrial Connections Justification

Our Connections capex, as explained in detail in our Residential and C&I Connections Capex Overview Document and its supporting documents, is consistent with a prudent service provider, acting efficiently and in accordance with good industry practice to achieve the lowest sustainable cost of providing services. In particular, our Residential and C&I Connections capex forecast is justifiable under Rule 79(2) for the following reasons:

- Rule 79(2)(c)(iii) – it is necessary to comply with our regulatory obligations associated with providing our connection services, including our requirement to connect "a customer that resides within the minor or infill extension area on fair and reasonable terms and conditions"[49]; and
- Rule 79(2)(c)(iv) – Connections are initiated by, and are carried out at the request of, our customers. Our proposed capex is necessary to maintain our capacity to meet the demand for our services at the time the connections are requested. In effect, this means that we can connect customers to our gas distribution network as they apply for connection.

Our Residential and C&I Connections capex forecast:

- Are in line with our actual (and estimated) capex for the current Access Arrangement period;
- Is consistent with the approach that we applied in our Access Arrangement Information for the current access arrangement period to forecast our Residential and C&I Connections capital expenditure;
- Is based on trend analysis and benchmarking, which is consistent with the AER's historical approach to assessing Residential and C&I Connections capex;
- Is based on ACIF growth indices, which historically show a strong relationship to our historical connections capex;
- Uses our most current unit rates for our unitised jobs, which we have sourced from our service providers Comdain and ZNX through market-tested, competitive processes;
- Forecasts customer contributions consistent with both our "Multinet Gas Customer Contribution Policy" and the ESCV's Gas Distribution System Code. This is consistent with the current practice that normal residential connections are not subject to the EFT;
- Is the same method that we recently used to forecast our Connections capex for United Energy in its recent Regulatory Proposal and Revised Regulatory Proposal. The AER accepted our forecasts for United Energy in full in both its Draft and Final Distribution Determinations; and

[49] Clause 3.1(c) of the Gas Distribution System Code

- Includes a top-down check of our bottom-up forecast. This top-down check is based on forecast connection, whereas our bottom-up forecast is based on unitised jobs.

Given the above, our proposed Residential and C&I connections capital expenditure forecast for the 2018 to 2022 access arrangement period is consistent with the NGO, in that it promotes efficient investment in gas distribution services that is in the long-term interests of consumers in terms of price, quality, safety, reliability and security of supply.

13.11. Meters capex

13.11.1. Overview

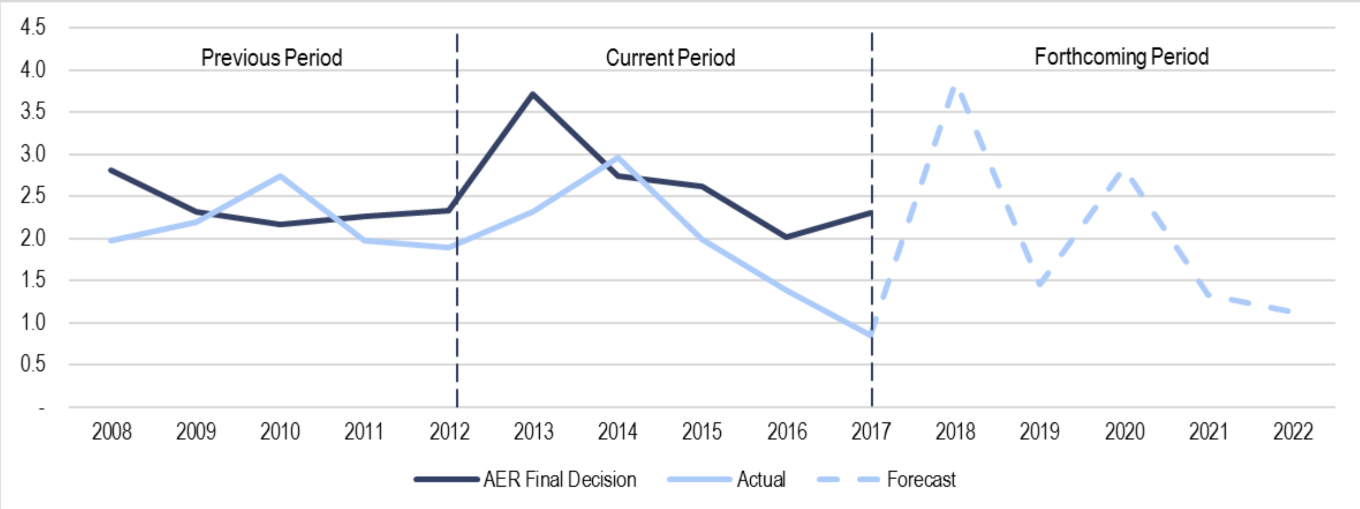
The Meters capex category includes the costs of:

- Procuring meters to replace existing ones when they fail to read data accurately;
- Procuring data capture equipment, such as data loggers, flow computers and Portable Data Entry units when these devices are no longer serviceable or are needed to serve new customers; and
- The incremental costs, including ICT capex, to implement Stage 2 (i.e. a full pilot study) of an investigation into the rollout of digital meters.

Our metering capex is primarily driven by compliance obligations. In particular, section 7.2.3 of the Victorian Gas Distribution System Code requires the testing of meter families. We must comply with Australian Standard AS/NZS 4944:2006 “Gas meters - In service compliance testing”. The testing regime dictates when meters are no longer operating satisfactorily. The meter replacement capex is therefore not discretionary.

Our Meter capex forecasts recognise that only a small percentage of meters that fail the testing regime will need to be replaced with a new meter. The vast majority of meters that are removed will be repaired. While it is difficult to forecast the number of meters that will fail the testing regime, historically our forecasts have proved to be relatively accurate as shown below.

Figure 13-7: Previous, current and forecast meter capital expenditure, excluding digital meter trial costs ($M, Real 2017)



In addition to replacing failed meters, our Meter capex for the forthcoming Access Arrangement period includes an amount for Stage 2 of our investigation into the rollout of digital gas meters. Similar to AMI in electricity, digital gas meters have the potential to deliver significant benefits to customers, including:

- The ability to utilise remote communications using United Energy’s AMI platform;
- Remote shutoff; and

- Remote reads for retailer transfer.

We are currently completing Stage 1 of this investigation. This involves working with Silver Springs Networks to integrate 100 ultrasonic gas meters with United Energy's AMI communications network. We propose to undertake a full pilot study in Stage 2 in the forthcoming Access Arrangement period. This will involve installing 10,000 functional ultrasonic remotely read gas meters, which will communicate with United Energy's AMI network.

The purpose of Stage 2 is to determine the costs and benefits of the rollout of digital gas meters across our residential and small commercial customer base. The incremental costs of the pilot, including the ICT component, are included in our Meters capex forecast, as shown in Table 13-9. As explained in our Digital Metering Overview Document, our customer engagement has indicated strong support for the pilot study and the proposed capex satisfies the NGR requirement that it must be "conforming capital expenditure".

Table 13-9: Meters capex forecast for 2018-2022 ($M, Real 2017)

	2018	2019	2020	2021	2022	Total
Meters	3.2	0.8	2.2	1.1	1.1	8.5
Digital metering trial – network costs only	0.6	0.6	0.6	0.2	-	2.1
Total metering capital expenditure	**3.9**	**1.5**	**2.8**	**1.3**	**1.1**	**10.6**

13.11.2. Key inputs and drivers

Our metering capex comprises six elements, each with their own drivers and input assumptions as explained in the table below.

Table 13-10: Meter capex drivers

Expenditure Driver	Description
1. Replacement driven by compliance with the Gas Distribution System Code and Australian Standards	Meter replacement is an ongoing activity, which is necessary to ensure that gas meters in the field read data accurately. We test and remove meters according to the relevant industry standard, as set out below. For repairable meter families we assume that 90 per cent of the meters that are removed are repairable – the remaining 10 per cent are replaced. Non-repairable meter families are scrapped. Our capex forecasts for meter replacements reflect the 10 per cent replacement assumption and include replacements for scrapped meter families, which is reasonable based on our historical experience. <u>Small consumer meters</u> There are approximately 667,000 small consumer meters installed on our network. We sample test each small meter family (that is, a particular year and model type) at the end of its initial 15 year life, in accordance with Australian Standard AS/NZS 4944:2006. Depending on the results of sample testing: • The meter family may be assessed as having some on-going life, in which case it is scheduled for re-testing in 1, 3 or 5 years, depending on the most recent test results; or • The meter family may be assessed as failing, in which case the family is removed in the following year. Criteria for meter accuracy and re-testing are set out in AS/NZS 4944:2006.

Expenditure Driver	Description
	Large consumer meters Approximately 27,000 of the meters installed on our network are large consumer meters. The AL425 and AL1000 families are large enough to warrant statistical sampling. These meters are tested in accordance with AS/NZS 4944:2006. From 2019, other meter families such as the AL800 will have sufficient annual populations to support sample testing. We will begin testing these new meter families from 2019 onwards. For other meter families, meters are repaired at regular intervals of 10 of 15 years depending on the capacity of the meter. Specifically, meters with a capacity greater than $100m^3$ per hour are removed and repaired after 10 years, whereas meters with less capacity are removed and repaired after 15 year.
2. Defective or faulty meters	Separately to the above testing program, faulty or defective meters are identified from time to time and must be removed. Our forecasting assumes that 50 per cent of these meters are repairable.
3. Data loggers and flow computers	These devices are used for large customers who require interval metering. Our capex forecast provides for replacing existing devices that are no longer serviceable, and for procuring devices to service new customers.
4. Portable Data Entry units	Meter readers in the field use these hand-held devices to record meter readings of Tariff V customers. The capex forecast includes an allowance for the periodic replacement of these devices.
5. Digital meter pilot	Digital meters are expected to provide net benefits within the next five-year period compared to the current manually-read mechanical meters by leveraging United Energy's AMI communications. The proposed capex relates to the incremental costs of 10,000 digital meters, which will be installed in new sites instead of standard gas meters. Our capex forecast also includes an ICT to enable the remote communication with the digital meters.

13.11.3. Meters capex Justification

Our Meters capex, as explained in detail in our Metering Capex and Digital Metering Overview Documents and supporting documents, is consistent with a prudent service provider, acting efficiently and in accordance with good industry practice to achieve the lowest sustainable cost of providing services. In particular, our Meters capex forecast is justifiable under Rule 79(2) for the following reasons:

- Rule 79(2)(a) – The forecast capex in relation to the digital meter trial is justified because the overall economic value of the proposed expenditure is positive. Our consumer engagement has indicated support for the next stage. The digital meter pilot delivers a net benefit compared to the alternatives, which include:
  - Proceeding with the mass rollout without the benefit of the information that will be provided by the pilot study; or
  - Adopting a 'do nothing' approach, which would deny customers the potential benefits of digital metering.

  As explained in further detail in the Digital Metering Overview Document, Stage 2 of the investigation into the rollout of digital meters is justified on a cost-benefit basis and satisfies the definition of 'conforming capital expenditure'. On this basis, the proposed capex to complete Stage 2 should also be approved by the AER.
- Rule 79(2)(c)(ii) – The forecast metering capex is required to maintain the integrity of services by ensuring that the accuracy of meters is maintained in accordance with the standards set out in Australian Standard AS/NZS 4944:2006. As already noted, we have no discretion regarding meter replacement decisions. The volume of meters to be replaced is determined by the testing regime, and therefore must be regarded as prudent and efficient. Our unit rates are based on competitively tendered contracts in place to ensure that all new meters are procured at market prices.
- Rule 79(2)(c)(iii) - The forecast metering capex is required to comply with section 7.2.3 of the Victorian Gas Distribution System Code, which sets out requirements relating to testing of meter families, including a requirement to comply with Australian Standard AS/NZS 4944:2006 "Gas meters - In service compliance testing".

13.12. Augmentation capex

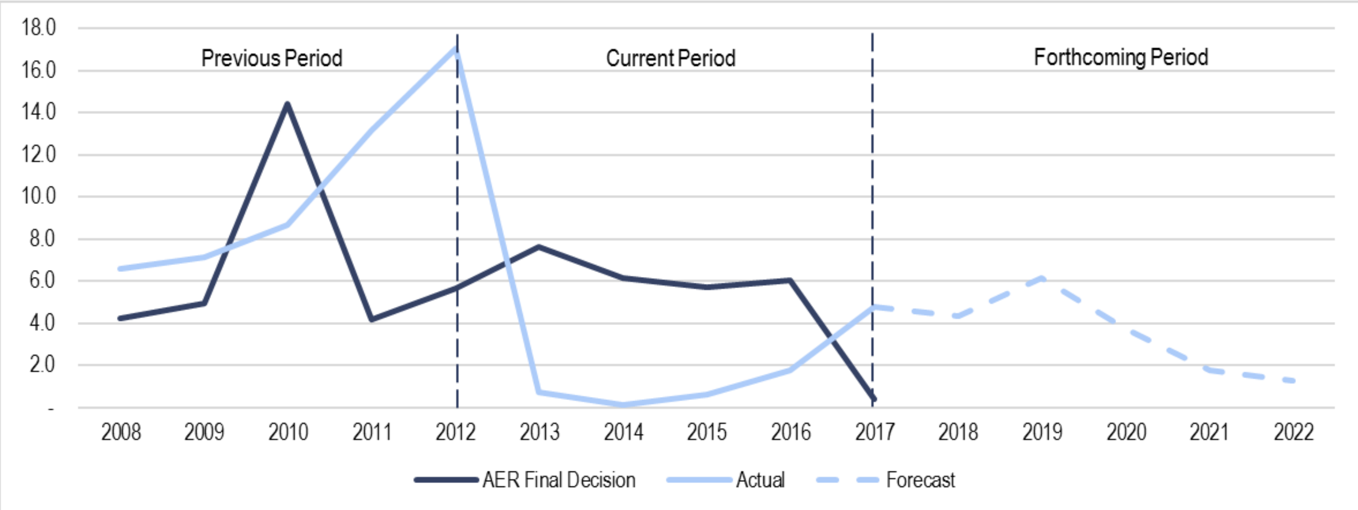
13.12.1. Overview

Our Augmentation capex includes network reinforcements to meet changes in customer numbers and throughput. It involves:

- Installing new mains to reinforce the existing network;
- Upgrading existing regulating facilities, including auxiliary equipment; and
- Installing new regulating facilities, including auxiliary equipment.

Figure 13-8 shows our actual and forecast Augmentation capex over the previous, current and forthcoming periods.

Figure 13-8: Actual and forecast Augmentation capex ($M, Real 2017)



We underspent the AER's Augmentation capex allowance for the current Access Arrangement period by $17.9 million. This was due to:

- The deferral of certain projects:
  - Due to lower network growth than originally forecast;
  - By reconfiguring our network; and
  - By running our systems at higher than normal operation pressure.
- Certain projects no longer being required as they were integrated into our Mains Replacement capex program. We have accounted for this in our capex forecast for the forthcoming access arrangement period.

We discuss each of these reasons further in our Augmentation Capex Overview Document.

Customers have benefited from these capex savings because:

- We have continued to comply with our obligations in the Gas Distribution System Code in the current Access Arrangement period and we have made all reasonable efforts to maintain minimum network pressures above those outlined in the Code; and
- Our Regulatory Asset Base will be lower in future Access Arrangement periods and we will therefore earn a lower return on, and of, our assets.

We have prepared our Augmentation capex forecast for the forthcoming Access Arrangement period by reference to four networks, as detailed in Table 13-11.

Table 13-11: Augmentation capex forecast by network – 2018 to 2022 ($M, Real 2017)

	2018	2019	2020	2021	2022	TOTAL
Oakleigh HP	3.3	2.7	3.7	-	-	**9.8**
South Melbourne HP	-	-	-	-	1.3	**1.3**
Korumburra HP	-	0.8	-	-	-	**0.8**
Eastern HP	1.0	2.6	-	1.8	-	**5.4**
Total	**4.4**	**6.1**	**3.7**	**1.8**	**1.3**	**17.3**

Table 13-12 summarises our total Augmentation capex forecast for the forthcoming Access Arrangement period by asset type.

Table 13-12: Augmentation capex forecast by asset type – 2018 to 2022 ($M, Real 2017)

	2018	2019	2020	2021	2022	TOTAL
Network Reinforcement	3.8	3.6	2.8	1.8	1.3	**13.2**
Supply Regulator Capacity Upgrades	0.5	2.6	-	-	-	**3.1**
New Supply Regulators	-	-	1.0	-	-	**1.0**
Total	**4.4**	**6.1**	**3.7**	**1.8**	**1.3**	**17.3**

13.12.2. Key inputs and drivers

Our gas distribution networks are continually changing due to residential growth and commercial and industrial development, as well as changes in usage patterns across our network. We apply computer-calibrated models to predict the operation of the networks in the field. Our models are based on one-in-two winters' peak day (also known as a 14.21 EDD). This standard is based on the system coincident peak day with a 50 per cent probability of exceeding this value in any given year.

We use this model of forecast gas consumption to identify the need for future network augmentation to ensure the security of supply and to maintain fringe pressures in accordance with the Gas Safety Case and the Gas Distribution System Code.

We identify required augmentations by simulating forecast growth and demand, which in turn determine the appropriate timing of individual projects. This includes the identification of network reinforcement (i.e. the installation of new distribution mains to increase capacity to a region) and installing new or upgrading existing network regulating stations to meet network demand.

A major input to our augmentation planning is our winter testing program. This is a detailed pressure monitoring program that is conducted at selected locations across the network during peak load conditions. Winter testing data is then analysed and used to ensure the accuracy of network models, as well as to identify required reinforcements to ensure that network fringe pressures remain above required minimum levels, even in peak load conditions.

Our network models are validated periodically, or as required, including following a major augmentation project on the network.

Table 13-13 details the drivers and input for the five proposed elements of our forecast Augmentation capex.

Table 13-13: Augmentation capex drivers

	Description
1. Oakleigh HP	The Oakleigh HP network supplies the suburbs of Oakleigh, Box Hill, Burwood, Mt Waverley, Surrey Hills and Chadstone. We need to augment it to increase minimum pressures to maintain minimum code requirement and to allow for the operation of the network within accepted industry guidelines. Our proposed augmentation works include installing a new field regulating station in Darling Road, Oakleigh and a total of 6.7 kilometres of 300NB Steel mains interconnecting the supply point to the Oakleigh HP from 2017 to 2020. The total forecast project cost is $9.8 million.
2. South Melbourne HP	The South Melbourne HP network services the rapidly expanding areas of South Wharf, Fishermans Bend, Docklands and Yarras Edge. We need to augment this HP network to meet Gas Distribution System Code target pressures. Our proposed reinforcement works includes 1.5 kilometres of 180NB polyethylene main in Lorimer Street, Fishermans Bend at a forecast cost of $1.3 million.
3. Korumburra HP	The Korumburra HP network is supplied solely by Korumburra City Gate (P4-290) and supplies the towns of Korumburra, Wonthaggi and Inverloch. We need to reinforce this HP network to maintain the targeted minimum pressure in the Gas Distribution System Code. Our proposed reinforcement includes 0.5 kilometres of 100NB Steel mains and 1.9 kilometres of 125NB polyethylene at a cost of $0.8 million.
4. Eastern HP	The Eastern HP network is our largest network and covers approximately 35 per cent of our distribution area and supplies approximately 30 per cent of our customers. Modest but steady growth within pockets of the Ringwood HP, Olinda HP and Knox HP sub-networks has resulted in supply-related network constraints, which require reinforcements. In addition, five field regulators within the Eastern HP system have reached their capacity and will require upgrading. The total forecast project cost is $5.4 million.

13.12.3. Augmentation Justification

Our Augmentation capex forecast, as explained in detail in our Augmentation Capex Overview Documents and supporting documents, is consistent with a prudent service provider, acting efficiently and in accordance with good industry practice to achieve the lowest sustainable cost of providing services. In particular, our Augmentation capex forecast is justifiable under Rule 79(2) of the NGR for the following reasons:

- Rule 79(2)(c)(iv) – The forecast capex is required to maintain our capability to meet levels of demand in those areas where the existing network is unable to satisfy peak demand and/or allow for the connection of new customers; and
- Rule 79(2)(c)(i) to (iii) – The forecast capex is required to maintain the safety and integrity of services and to comply with regulatory obligations or requirements by maintaining network pressures above the minimum levels specified in Schedule 1 of Part A of the Gas Distribution System Code.

13.13. Non-Network ICT capex

13.13.1. Overview

Our ICT systems are integral to our business operations. Continued investment is essential to maintain these systems in-line with the industry standards. If we do not maintain and refresh our ICT systems then we will not be able to sustain the integrity of our services, meet the needs of our customers and achieve cost efficiency improvements.

Our ICT systems include corporate, asset management, network management and geospatial applications, as well as our ICT infrastructure and facilities. Our ICT capex includes expenditure on central elements of SCADA and network control systems, but excludes the costs of devices that are deployed throughout the distribution network.

In the first four years of the forthcoming Access Arrangement period we will focus on maintaining our systems at industry standard. In the final year, we will commence a program to upgrade our core SAP system.

In the 2018 to 2022 period, our ICT capex will be $48.8 million, as shown in Table 13-14.

Table 13-14: Forecast Non-Network ICT capex 2018-2022 ($M, Real 2017)

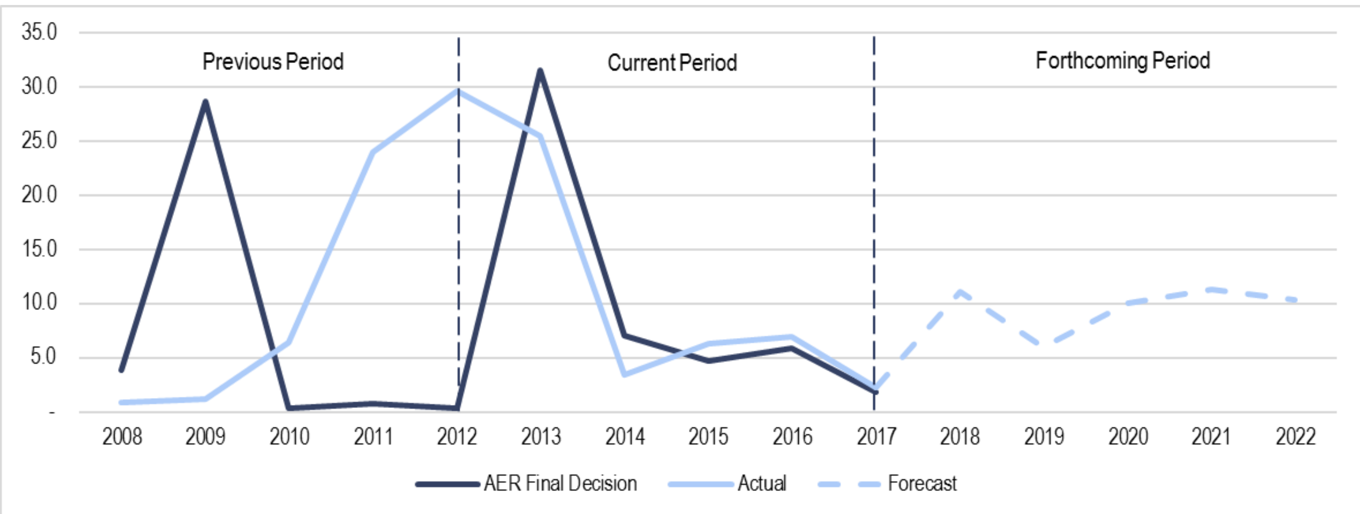
	2018	2019	2020	2021	2022	Total
Non-Network General Assets – ICT	11.1	6.0	10.1	11.3	10.4	48.8

Figure 13-9 compares our forecast for the forthcoming Access Arrangement period with our ICT capex in our previous and current Access Arrangement periods:

- In our previous Access Arrangement period, we invested heavily in a major program to bring our ICT systems up to the required standard and to deliver systems that met the requirements of our business transformation. The capex in that period followed several years of under-investment in ICT;
- In the current Access Arrangement period, we successfully completed our upgrade program and have continued to invest so that our systems are maintained at industry standard. Our spending in this current period will be below the AER's capex allowance; and
- Our forecast ICT capex for the forthcoming Access Arrangement period will be slightly higher (an increase of $2.4 million or 5 per cent) than in the current period. Most the investment will be recurrent capex which is necessary to ensure that we meet the information needs of our customers, maintain the integrity of our services and achieve the levels of demand required by customers. The slight increase in expenditure in the forthcoming period compared with the current period is largely due to the timing of the required maintenance of systems. For example, towards the end of the forthcoming period we will need to commence a further upgrade of our SAP systems. The vendor (SAP) has stated that it will withdraw support for the current version of the current systems in 2025. Commencing the project in 2022 is prudent given the complexity of the upgrade. By that time, the systems will have been in operation for almost ten years.

Figure 13-9: Comparison of ICT capex across the previous, current and future Access Arrangement periods ($M, Real 2017)

Major IT upgrade program – following a period of under investment	**Completion of upgrade program in 2013 – then focus on on-going maintenance**	**Focus on maintenance – then commencement of SAP upgrade in 2022**



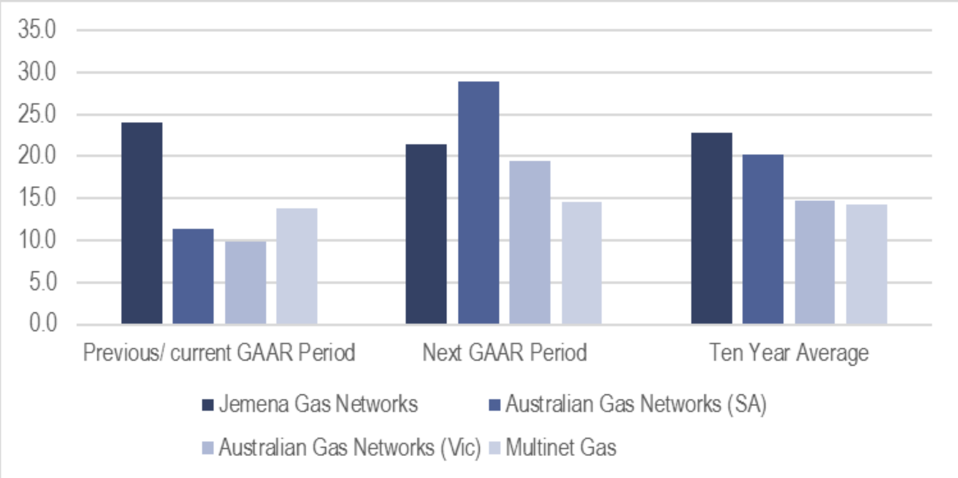
13.13.2. Key inputs and drivers

We explain below the strategic inputs and drivers impacting our ICT capex forecast for our forthcoming Access Arrangement period.

As outlined above, the ICT capex requirements of a gas distributor vary over time in line with the replacement lifecycles of major IT systems.

When assessed over a ten-year period, our ICT capex per customer is below the capex of other comparable gas distributors, as shown in Figure 13-10.

Figure 13-10: Historical and forecast annual ICT Capex per customer[50] ($M, Real 2017)



The functions supported by our ICT systems are outlined in Table 13-15.

Table 13-15: Functions supported by ICT systems

Function	Explanation
Customer and Stakeholder Management	Provision of services and/or information to internal and external stakeholders (including customers, retailers, government agencies, regulator, partners and employees).
Network Management	Management, monitoring and control of the distribution network including responding to faults/emergencies, and analysis and optimisation of the network.
Asset Management	Strategic planning and management of assets, work programs and resources, including network extensions, inspections, maintenance and construction.
IT Management	IT for managing IT applications, the IT project portfolio, infrastructure, architecture, security and IT services.
Works Management	Management of work programs and resources for network extensions, inspections, maintenance and construction.
Meter Data and Revenue Management	Management of meter data, connection points and meter services, including the provision of data to market and management of service orders and metering faults.
Information Management	Capabilities required to effectively manage large amounts of structured and unstructured information across the business.
Business Support Management	Corporate capabilities required to support the business including finance, HR, risk & audit, legal, supply chain & logistics and OH&S.

Our ICT capex in the 2018 to 2022 Access Arrangement period will focus on the following strategic themes:

- **Maintain systems to industry standard –** We will build on the major overhaul of our ICT systems that we have completed in recent years and will continue to invest to ensure that these systems are refreshed to

[50] Note - no publicly data available for Ausnet's actual or planned ICT capex. JGN figures sourced from JGN GAAR 2015-20 Post Tax Revenue Model. AGN (SA) 2011/12 to 2015/16 figures sourced from 'Attachment 8.12 to 'Response to Draft Decision SA AGN - Information Technology Cost Benchmarking', 2016/17 to 2020/21 figures sourced from AER final decision PTRM May 2016. AGN (Vic) figures sourced from 'AGB Draft Plan' July 2016.

maintain the required industry standard. We will particularly focus on IT security as this is an emerging and material issue. We will commence a major upgrade to a new version of our SAP Enterprise Resource Planning, Customer Management and Billing systems towards the end of the forthcoming Access Arrangement period. This upgrade is required as SAP is withdrawing support for the current system;

- **Improve asset planning and management through improved data quality and reporting –** We will enhance our systems to increase data synchronisation and quality. Improved data quality will improve our planning and management of assets;
- **Ensure the ongoing integrity and safety of our distribution network –** We will implement ICT solutions and IT Security Programs so that our gas distribution network can maintain the integrity of our services and meet the levels of demand required by our customers;
- **Deliver new capability to meet changing customer needs and growing expectations** – We will implement ICT solutions that address the needs and expectations of customers for web-based interaction and transactions;
- **Utilise field mobility to automate field work processes with service providers –** We will combine increasingly mature and low-cost mobility technologies with our ERP system to reduce manual intervention in processes for managing the work carried out by field work forces.

Table 13-16 breaks down our ICT capex forecast of $48.8 million for the forthcoming Access Arrangement period against these six strategic themes. The majority (75 per cent) of this capex is recurrent, which is required to maintain our ICT systems at industry standard. Non-recurrent expenditure on new initiatives is necessary to maintain the integrity of our services, meet the needs of our customers and maintain our level of cost efficiency.

Table 13-16: ICT Capex by Strategic Theme ($M, Real 2017)

IT Strategic Theme	Recurrent Expenditure	New initiatives
Maintain systems to industry standard.	31	1.4
Improve asset planning and management through improved data quality and reporting.	2.1	2
Ensure the ongoing integrity and safety of our distribution network.	3.5	2
Deliver new capability to meet changing customer needs and growing expectations.	-	2.2
Ensure readiness to achieve regulatory requirements	-	-
Utilise field mobility to automate field work processes with service providers	-	4.6
Total	36.6 (75%)	12.2 (25%)
Total Expenditure	**48.8**	

* Numbers may not add due to rounding

13.13.3. ICT Capex Justification

Our ICT capex forecast, as explained in detail in our ICT Capex Overview Document and its supporting documents, is consistent with a prudent service provider, acting efficiently and in accordance with good industry practice to achieve the lowest sustainable cost of providing services. In particular, our ICT capex forecast is justifiable under Rule 79(2)(c)(ii) to maintain the integrity of our services, meet the needs of our customers and maintain our level of cost efficiency.

The new initiatives included in this cost submission are justified on the basis that they are necessary to maintain and/or improve safety, maintain integrity of services or maintain our capacity to meet demand. While new initiatives may have a position economic value, they will not produce an immediate reduction in operating expenditure in the forthcoming Access Arrangement period. Where we identify opportunities to invest in ICT to produce immediate financial benefits such as operational cost savings, this investment would be self-funded and would not be included in our capex forecast.

The ICT systems implemented in the previous and current Access Arrangement periods provide a sound foundation for the delivery of further projects in the forthcoming Access Arrangement period. The focus on robust governance of ICT projects will continue. The success of the ICT program in the previous and current Access Arrangement periods shows that we are well positioned to deliver the proposed program in the forthcoming Access Arrangement period.

13.14. SCADA capex

SCADA systems provide continuous monitoring, recording and optimal control of the gas distribution network, to enable us to:

- Operate the network safely;
- Maximise utilisation of the distribution network for the efficient supply of energy to customers;
- Monitor and optimise pressure performance to ensure a reliable supply above the minimum average system pressures; and
- Monitor and optimise network pressures to minimise the volume of leakage from the network.

SCADA assets include:

- Field instrumentation and sensors for SCADA monitoring and control systems, for example, pressure transmitters, temperature transmitters, flow transmitters and limit switches;
- Motorised actuators and solenoids for gas pilots and electrical equipment that may be found in the hazardous area of the site;
- RTU (Remote Terminal Units) and their interface hardware, firmware and applications;
- RTU and communications equipment power supplies (AC-DC), power converters (DC-DC), solar panels, chargers and backup batteries;
- Aerials, antennas, masts, RF feeder cables and lightning arrestors used for SCADA monitoring;
- Communications equipment including modems, radio modems and transceivers, of wireless and wired technologies; and
- Communications networks and services used exclusively for SCADA.

In broad terms, SCADA capex is required when:

- Ageing or poorly performing equipment needs replacing, especially if manufacturer support or spare parts are no longer available;
- Developments in communications and SCADA system technology lead to obsolescence of existing equipment; and
- Changes in operating arrangements or criteria result in existing equipment no longer being able to perform at the required standard.

Additional SCADA equipment - such as RTUs - may need to be installed to provide more detailed coverage of the existing service area, or to cover new service areas or network extensions / augmentations. SCADA investment may also be required to provide enhanced capability to control flows on the network or to maintain or improve the safety, security and reliability of pipeline services in accordance with our compliance obligations.

Figure 13-11 shows our actual and forecast SCADA capex.[51]

Figure 13-11: Previous, current and forecast SCADA capital expenditure ($M, Real 2017)

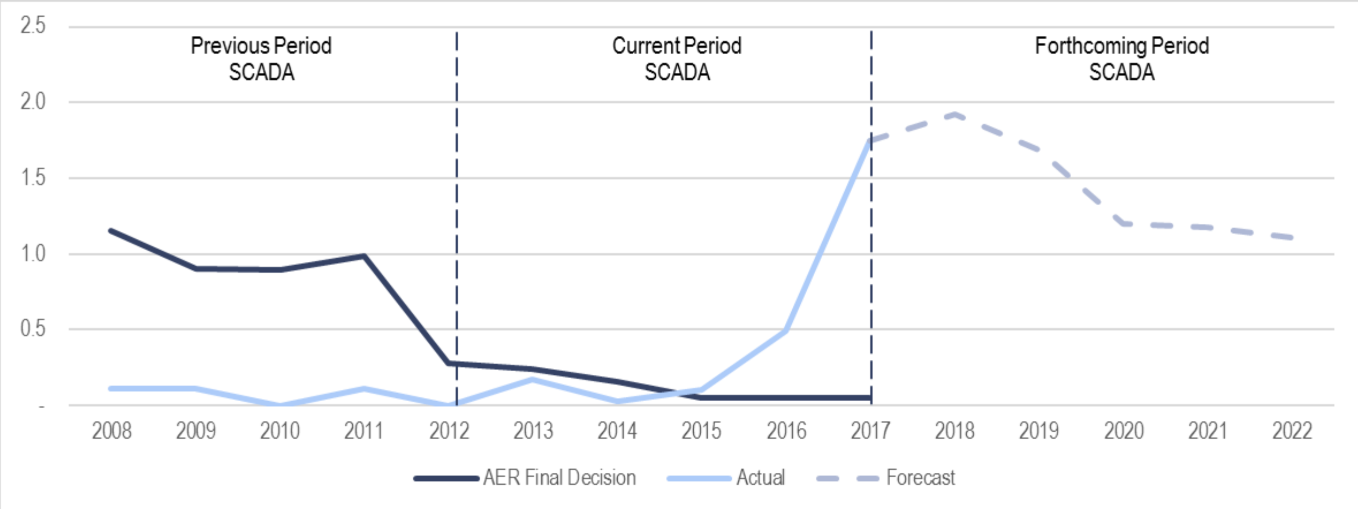


Figure 13-11 shows that we are forecasting an increase in SCADA capex above to historical levels. As explained in further detail below, our forecast SCADA capex reflects the costs of eight work programs. Each program is underpinned by the need to maintain an effective and reliable SCADA system, so that we can continue to operate the gas distribution network safely, reliably and efficiently.

Table 13-17 details our forecast SCADA capex.

Table 13-17: SCADA capex forecast for 2018-2022 ($M, Real 2017)

	2018	2019	2020	2021	2022	Total
SCADA	1.9	1.7	1.2	1.2	1.1	7.1

13.14.1. Key inputs and drivers

The following projects are required for the forthcoming Access Arrangement period to ensure that our SCADA systems are fit-for-purpose.

Table 13-18: SCADA projects for the forthcoming Access Arrangement period

Project	Rationale for proposed expenditure
1. Network control	
(a) Variable control on HP network	At present, some of the HP network is operated on variable control. During the forthcoming Access Arrangement period, we propose upgrading the remainder of the HP network that is still operated on step control. This will deliver improved safety and reliability of our pipeline services. The planned program of works involves installing variable control at two sites (i.e. Church Street, Keysborough and Lorimer Street, South Melbourne) in 2018, at a total cost of $34,500. Our capex forecast is based on unit rates that reflect the actual cost of similar work completed recently under our competitively tendered outsourced service provider model.

[51] It should be noted that the forecasts only include SCADA hardware, whereas historical data also includes SCADA IT expenditure.

Project	Rationale for proposed expenditure
(b) Control on Eastern MP network	As part of our Mains Replacement capex, much of the MP network will need to be maintained to target the LP zones. In order to maintain reliability and to control leaks on the remaining MP network, we propose to establish variable control on key sites that will not be upgraded in the forthcoming Access Arrangement period. The planned program of works involves installing variable control at 23 sites, at a total cost of $1.4 million. Forecast unit costs are based on competitive quotes we have sought from our service providers.
(c) Step control on district regulators	The duration of the Mains Replacement capex program also raises network control issues on the remaining LP networks. Step control will provide a higher level of control over the LP network, delivering safety and reliability improvements compared to the current arrangements. The planned work involves installing step control on five district regulators in each year of the forthcoming Access Arrangement period (i.e. a total of 25 district regulators). Forecast capex for this work are also based on competitive quotes from our service providers. The total forecast expenditure for this work over the forthcoming access arrangement period is $1.3 million.
2. RTU fringe installation	Installing fringe RTUs is required to ensure that we maintain adequate pressure monitoring capability in areas of the network that are subject to new connection growth. We forecasting total capex of $0.1 million for the installation of five additional fringe point RTUs in the forthcoming Access Arrangement period.
3. Kingfisher RTU replacement	The Kingfisher RTUs are no longer in production and they are approaching end-of-life. Our capex forecast includes an allowance of $1.1 million to replace 200 RTUs over the forthcoming Access Arrangement period. This forecast is based on price quotations from equipment suppliers, and competitive quotes from our service providers for installation.
4. TRIO radio replacement and streamlining	We plan to replace the TRIO radio network with new, more secure technology to ensure the prudent and efficient management of cyber security risks. Our forecast capex for these works is $0.9 million. This is based on historical unit rates (where applicable) and competitive quotations from service providers.
5. Data logger implementation	Our existing Cello dataloggers monitor our corrosion protection (CP) systems. They are approaching end-of-life and are still running on the 2G network. Following the closure of 2G services by Telstra, Vodafone is the only remaining 2G network provider. Accordingly, we propose to implement data loggers. These data loggers send daily corrosion protection information to a server, with alarms raised as necessary. The dataloggers also provide us with an efficient means of conducting crucial network planning activities such as winter testing and outage management. We are planning to invest a total of $1.0 million on data logger implementation, including Winter testing, over the forthcoming regulatory period. Our forecast is based on price quotes from equipment suppliers, and competitive quotes from our service providers.
6. Gas detector installation	We have already installed gas detectors at various locations across the network, however there remain a small number of sites where installation of this key safety monitoring device is prudent. We plan to invest a total of $0.2 million on the installation of gas detectors at 13 sites over the forthcoming Access Arrangement period. The forecast is based on historical unit rates.
7. Hazardous zone non-compliant installation refurbishments	There are several sites on our network that do not meet the current hazardous zone regulations for electrical equipment located within a gas/air environment (Australian Standard AS 3000). We plan to undertake modification works at a total of 92 substandard installations over the forthcoming Access Arrangement period at a cost of $0.9 million. This forecast is based on historical unit rates.
8. Vortex flowmeter installation	Flow metering at sites that have a large throughput of gas allows us to differentiate flows that enter our networks. This enables us to better calibrate the network models that we use to identify the need for future investment or other corrective action. We plan to invest a $69,000 installing vortex flowmeters at Lilydale, Korumburra and Leongatha over the forthcoming Access Arrangement period. Our forecast is based on cost estimates provide by an independent consultant.

13.14.2. SCADA Capex Justification

Our SCADA capex forecast, as explained in detail in our SCADA Capex Overview Document and its supporting documents, is consistent with a prudent service provider, acting efficiently and in accordance with good industry practice to achieve the lowest sustainable cost of providing services. Our forecast comprises eight programs of work, each of which is justified by our compliance obligation to maintain the integrity of our services, and to operate the gas distribution network reliably, safely and efficiently. Our proposed capex reflects the actual costs incurred in delivering similar projects or competitively sourced cost estimates.

Our SCADA capex forecast is justifiable under Rule 79(2) for the following reasons:

- Rule 79(2)(c)(i) – The forecast capex is required to maintain safety, by enabling us to operate the system in a way that mitigates the hazards and risks to the safety of the public, and the risk of property damage associated with gas supply; and
- Rule 79(2)(c)(ii) – The forecast capex is required to maintain the integrity of services by ensuring that we have the SCADA systems we require in order to operate the gas distribution network reliably, safely and efficiently.

13.15. Other capex

Our Other capex consists of seven components or subcategories, as set out in Table 13-19.

Table 13-19: Other capex subcategories

Subcategory of Other capex	Definition
Recoverable Works	This capex relates to the relocation of assets undertaken at the request of a customer or a third party. The costs of such works are recovered from the party who requests them, and are not recovered through Reference Tariffs.
Property and accommodation	This capex relates to fitting-out office space to accommodate our employees and contractors involved in delivering pipeline services.
Vehicles and tools	This capex relates to vehicles, tools and equipment.
Corrosion Protection	This capex relates to corrosion protection assets and services applied to the transmission, high pressure, medium pressure and low pressure steel piping systems located throughout our gas distribution system. This includes corrosion protection units, test points, anodes, and ancillary equipment.
Regulators, valves and equipment enclosures	This capex relates to replacing: • supply regulators (including district regulators, field regulators, above ground regulators, and city gates); • small and large consumer regulators; • distribution valves (including removal of redundant syphons from the network); and • equipment enclosures, such as masonry buildings, pits, chain-wire fences, steel kiosks and gatic covers.
Gas Heaters	This capex relates to replacing the gas heater facilities located throughout our gas distribution network that are operating at pressures up to 8,700 kPa.
Pig rectification	This capex relates to the rectification of pipelines so that internal inspection using an intelligent in-line inspection (or “pigging”) tool can be accommodated.

Figure 13-12 shows our historical actual and forecast for Other capital expenditure.

Figure 13-12: Previous, current and forecast Other capital expenditure ($M, Real 2017)

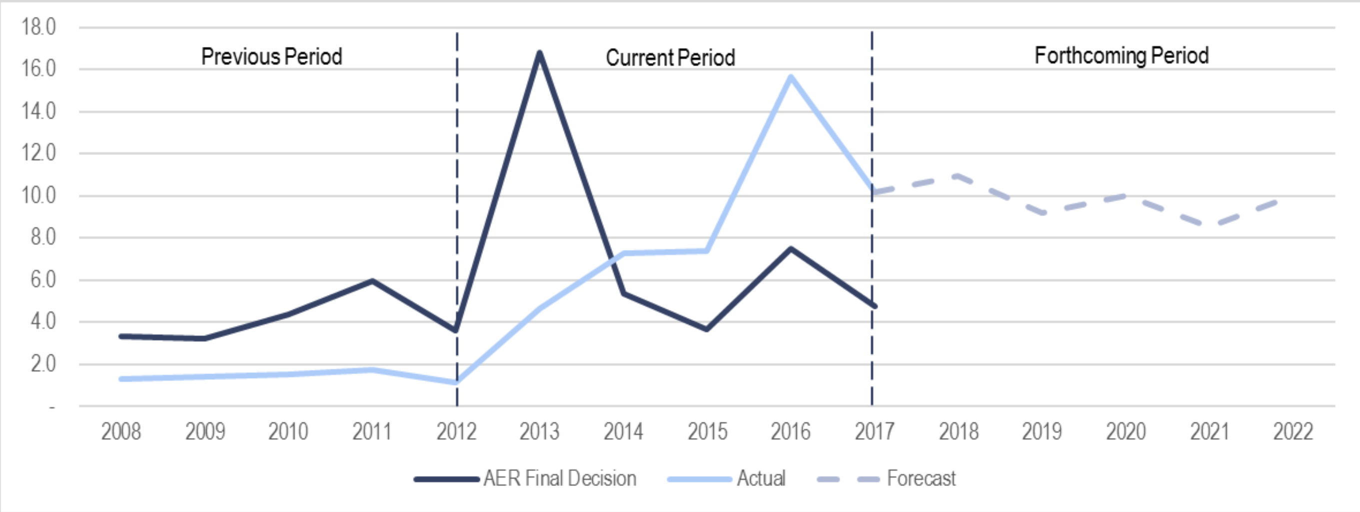


Table 13-20 provides a breakdown of our Other capex forecast for the forthcoming Access Arrangement period.

Table 13-20: Non-Network Other capex 2018-2022 ($M, Real 2017)

	2018	2019	2020	2021	2022	Total
Recoverable works	6.3	6.3	6.3	6.3	6.3	**31.5**
Property and accommodation	0.4	0.1	0.1	0.1	0.1	**0.9**
Vehicles and tools	-	-	-	-	-	**-**
Corrosion Protection	0.3	0.4	0.3	0.2	0.2	**1.3**
Service and service renewals	0.1	0.1	0.1	0.1	0.1	**0.6**
Regulators, valves and equipment enclosures	2.7	2.3	1.5	1.7	1.6	**9.9**
Gas heaters	0.0	-	-	-	-	**0.0**
Pig rectification and marker posts	1.1	0.0	1.6	0.0	1.7	**4.5**
Total Other	**10.9**	**9.2**	**10.0**	**8.5**	**10.0**	**48.7**

13.15.1. Key inputs and drivers

The diverse nature of the components of our Other capex means that the drivers and inputs are specific to each component, as explained in Table 13-21.

Table 13-21: Key inputs and drivers of Other capex

<table>
<tr><th>Subcategory of Other capex</th><th>Rationale for proposed capex</th></tr>
<tr><td>Recoverable Works</td><td>The costs of recoverable works are charged to the party requesting or causing them, so actual recoverable works capex has no effect on Reference Tariffs. Our recoverable works forecast reflects the planned completion of known future and existing projects.</td></tr>
<tr><td>Property and accommodation</td><td>Our planned office accommodation requirements reflect our assessment of:
• The on-going in-house staff and contract resources required to continue to manage the current two service provider / two region business model efficiently; and
• Changes in resource requirements arising from future initiatives aimed at improving the value of the services we provide, and the efficiency of current operations.
The forecast is modest compared to actual capex incurred during the current Access Arrangement period and reflects the share of property and accommodation costs that the AER approved for United Energy for its 2016-20 regulatory control period.</td></tr>
<tr><td>Vehicles and tools</td><td>Our vehicles capex forecast reflects the programmed replacement of two of our three fleet vehicles in the forthcoming Access Arrangement period. The replacement of vehicles is scheduled to minimise the total cost of ownership.</td></tr>
<tr><td>Corrosion Protection</td><td>The replacement of corrosion protection equipment will be carried out when corrosion protection monitoring and testing results indicate that the stipulated level of protection can no longer be provided by the existing installations. Accordingly, our decisions on the precise timing and scope of work to replace or install additional corrosion protection equipment is informed by the results of our testing and monitoring activities.
Our forecast volume of work is based on analysis of actual work completed over the current period, plus the latest available information from tests and monitoring. Our forecasts are derived by applying unit rates (based on competitive market prices) to the volume forecasts.</td></tr>
<tr><td>Regulators, valves and equipment enclosures</td><td>We plan to complete the following capital works programs on our supply regulators to ensure that we meet our regulatory obligations under the Gas Distribution System Code, which requires us to comply with Australian Standards AS 4645 and AS 2885:
• Hydraulic Regulator Replacement Program;
• Obsolete Supply Regulator Replacement Program;
• Environmental Noise Improvement Investigation Program;
• Valve Actuator Replacement; and
• Miscellaneous Works.
We plan to complete the following valve programs to comply with Standards AS 4645 and AS 2885:
• HP2 Syphon Removal Program;
• District Regulator Isolation Valves Rectification Program;
• Miscellaneous Replacement / Rectification works.
Our forecast capex for large consumer regulators is a bottom-up build of the estimated costs of:
• The planned replacement of certain regulator models and configurations to:
    o ensure that network safety and reliability are maintained, our regulatory compliance obligations are met, and pipeline services are delivered at the lowest sustainable cost;
    o ensure that the necessary spare parts are available (through in-house inventory and through suppliers) to return a regulator to service in the event of a failure;
    o optimise maintenance expenditure;
    o rationalise the range of regulator models and configurations to reduce the burden on staff training.
• Routine replacement or refurbishment of existing assets, where:
    o serviceable components are no longer available;</td></tr>
</table>

Subcategory of Other capex	Rationale for proposed capex
	○ consumer and network driven gas load / pressure changes are expected to cause components to exceed original design ratings; and ○ old sites which no longer meet current industry standards require re-work/replacement to meet current operational requirements. We must comply with our regulatory obligations under the Gas Distribution System Code (Australian Standards AS 4645 and AS 2885) for our equipment enclosures. The required programs are: • Structural Engineering Rectification Works Program; and • Miscellaneous Works. The total capex for regulators, valves and equipment enclosures is $9.9 million over the forthcoming Access Arrangement period. The detailed justification and costing for each program of work is provided in the Other Capex Overview Document, which forms part of this Access Arrangement Information.
Gas Heaters	All the heaters in our network are performing well within requirements, and this is expected to remain the case over the forthcoming Access Arrangement period. On this basis, we do not expect the need for replacement capex on heaters in the forthcoming Access Arrangement period.
Pig rectification	Pigging is an important element of our Transmission Pipeline Integrity Management Plan, which identifies the pipelines that must be rectified to enable a PIG device to be used. Our forecast of PIG rectification capex is a based on a bottom-up estimate of the costs of rectifying the identified pipelines.

13.15.2. Other capex Justification

Our Other capex forecast, as explained in detail in our Other Capex Overview Document and its supporting documents, is consistent with a prudent service provider, acting efficiently and in accordance with good industry practice to achieve the lowest sustainable cost of providing services. In particular, our Other capex forecast is justifiable under Rule 79(2) to:

- Maintain and improve the safety of services; or
- Maintain the integrity of services; or
- Comply with a regulatory obligation or requirement; or
- Maintain the service provider's capacity to meet levels of demand for services existing at the time the capital expenditure is incurred (as distinct from projected demand that is dependent on an expansion of pipeline capacity).

The assets and facilities procured through our Other capex are critical to supporting our network and corporate functions. Those functions, and in particular, our network functions must be undertaken in accordance with our regulatory obligations, including the Gas Safety Act 1998 and the Victorian Distribution Gas Code.

The detailed development of our forecasts for Other capex:

- Provide for the efficient replacement of key facilities such as corrosion protection systems, regulators, valves, and equipment enclosures, to enable us to provide services safely, reliably and at the lowest total sustainable cost; and
- Ensure essential functions support and facilitate the efficient and safe delivery of services to our customers, including the provision of recoverable works requested by customers and appropriate office accommodation for our staff.

14. Opex forecasts

Key messages:

- We have structured our opex forecasts to be consistent with a prudent service provider acting efficiently, in accordance with good industry practice, to achieve the lowest sustainable cost of delivering pipeline services.
- We benchmark favourably against our peers. Economic Insights found that:
    - We operated below the average opex per customer for the seven gas distributors with relatively high customer density for the 2011 to 2015 period (and considerably below the average of the 13 gas distributors in its survey analysis);
    - We had the second lowest overall cost efficiency per customer of the 13 gas distributors surveyed; and
    - Our opex PFP index increased at an average annual rate of 2.5 per cent between 1999 and 2015 and 0.7 per cent from 2008 to 2015 – we had the most favourable trend in input use of the three Victorian gas distributors over this period.
- We have applied a base-step-trend (BST) forecasting methodology to prepare our opex forecast. This is the AER's preferred opex forecasting method that it has used in its recent gas and electricity determinations.
- Our 2016 opex of $69.6 million provides an efficient starting point for calculating our base year opex of $71.0 (including adjustments and excluding debt raising costs).
- We have applied a real cost escalator for our labour based on advice from the leading independent expert, BIS Shrapnel. This increases our opex by $7.7 million over the forthcoming Access Arrangement period.
- Our opex forecast for the forthcoming access arrangement period includes an allowance of $7.2 million for the impact of output growth – as measured by customer numbers and pipeline length. This reflects the fact that greater output costs us more to operate and maintain.
- We have included one step change in our opex forecast to account for additional marketing costs in the forthcoming Access Arrangement period that we did not incur in our base year. This increases our opex by $23.3 million over the forthcoming Access Arrangement period.
- We split our total opex forecast between our Haulage Reference Services and our Ancillary Reference Services because different Reference Tariff Adjustment Mechanisms apply to each type of service.

14.1. Introduction

Our opex is the operating, maintenance and other non-capex that we incur to provide our Reference Services to our customers. This chapter explains and justifies our opex forecast for our Reference Services for the forthcoming Access Arrangement period. Our opex forecasts must comply with the NGR requirements.

We have used a BST approach to prepare our opex forecast for the forthcoming Access Arrangement period, the build-up of which is set out in Table 14-1.

Table 14-1: Forecast opex – Reference Services ($M, Real 2017)

	2018	2019	2020	2021	2022	TOTAL
Base (including adjustments) [52]	71.0	71.0	71.0	71.0	71.0	354.9
Price Growth	0.4	0.8	1.3	2.1	3.0	7.7
Output Growth	0.5	0.9	1.4	1.9	2.4	7.2
Productivity Growth	-	-	-	-	-	-
Step Changes	4.7	4.7	4.7	4.7	4.7	23.3
GSLs	-	-	-	-	-	-
Debt raising costs	0.6	0.7	0.7	0.7	0.7	3.4
Total	**77.2**	**78.0**	**79.1**	**80.4**	**81.8**	**396.4**

The information presented in this chapter is intentionally 'high level' to enable the AER, our customers and other stakeholders to understand readily our opex forecasts and the changes from our opex in the current Access Arrangement period. Our Operating Expenditure Overview Document that we have provided to the AER with this Access Arrangement Information provides a detailed substantiation of our opex forecasts. Stakeholders that are seeking a more detailed explanation of our opex forecasts should refer to that document.

14.2. Our historical opex

Table 14-2 details our actual and estimated opex for the previous and current Access Arrangement periods.

Table 14-2: Previous and current period opex – Reference Services ($M, Real 2017)

	2008	2009	2010	2011	2012	2013	2014	2015	2016 *	2017 *
Final Decision	52.4	52.4	51.8	51.5	51.3	62.8	68.8	71.3	70.9	71.8
Actual / Estimated	60.8	58.1	60.0	63.5	84.2	68.0	67.1	66.9	69.6	71.0
Variance (Actual – Determination)	8.4	5.7	8.2	12.0	32.9	5.2	(1.7)	(4.4)	(1.3)	(0.8)

* = Estimated

Table 14-2 shows that our actual opex was in a stable band between $58.1 million and $63.5 million per annum over the period 2008 to 2011 but increased to $84.2 million in 2012. Our overspend in 2012 against the AER's allowance was driven by:

- The costs of implementing our internal business transformation project based on a new competitive service provider model. We refer to this as our "Seven 13 project", in reference to the month and year in which the new model took full effect;
- The carbon tax that was separately recovered; and
- Low opex benchmark allowances in the ESCV's Final Decision for the period. The ESCV's allowances declined year on year throughout the 2008 to 2012 period.

[52] See Table 6 of Opex Overview Document.

In total, we overspent against the ESCV's opex allowance for the period by $67.3 million. Almost half of this overspend, $32.9 million, was in 2012 alone.

Importantly, we fully absorbed the cost of this overspend – our customers did not pay for it. Our opex in the current Access Arrangement period has reduced dramatically from the one-off high in 2012.

Table 14-2 also shows that our actual and estimated opex is in a stable band between $66.9 million and $69.6 million per annum for the period 2013 to 2016.

Our current Access Arrangement period opex performance demonstrates:

- The success of our internal business transformation project, which has allowed us to manage our opex within a very stable band over the period (which has varied by only $2.7 million per annum);
- We are continuing to respond to the AER's incentives. We are forecasting to underspend the AER's opex allowance, including in our 2016 base year. We expect to underspend the AER's benchmark opex allowance by $2.2 million between 2013 and 2016; and
- 2016, being the penultimate year of the current period, is an efficient base year for our forthcoming Access Arrangement period. We expect to underspend the AER's allowance by $1.3 million in 2016. This shows that we have not sought to "game" the regulatory framework by back-ending our opex to inflate our proposal for the forthcoming Access Arrangement period.

14.3. Opex benchmarking

As discussed in section 13.8, the three Victorian gas distributors commissioned Economic Insights to benchmark their:

- Expenditure using partial productivity indicators; and
- Productivity performance using various econometric techniques.

We have provided with this Access Arrangement Information the Economic Insights' reports dated 15 June 2016, entitled:

- "Benchmarking the Victorian Gas Distribution Businesses' Operating and Capital Costs Using Partial Productivity Indicators"; and
- "The Productivity Performance of Victorian Gas Distribution Businesses".

Economic Insights found the following in relation to opex per customer relative to customer density for the 13 gas distributors it benchmarked for the 2011 to 2015 period:

- There was a group of six gas distributors with relatively low customer density and a group of seven gas distributors with relatively high customer density. The Victorian gas distributors, including ourselves, were in the latter category;
- The six gas distributors with relatively low customer density generally had high opex per customer – they had average opex per customer of $164;
- The seven gas distributors with relatively high customer density generally had low opex per customer – they had average opex per customer of $92; and
- We had average opex per customer of $89 for the 2011 to 2015 period, which is the third lowest of the 13 gas distributors sampled.

Economic Insights concluded that:

> *The three Victorian gas distributors are either at or below the average opex per customer for gas distributors with relatively high customer density. This suggests that they are among the more efficient of the gas distributors in the sample. That said, a comparison of this kind does not control for other drivers of opex costs that may be relevant, and only qualified conclusions can be drawn from it.*[53]

Economic Insights examined productivity levels of the three Victorian gas distributors and Jemena NSW, AGN SA and AGN Queensland using data provided by the gas distributors in response to detailed surveys. Specifically, Economic Insights detailed the Victorian gas distributors':

- Input index – this is the weighted average of separate opex and capital input indexes;
- Output index – this is based on the gas distributors' throughput, customer numbers and system capacity;
- TFP – this is the ratio of the output and input indexes;
- PFP – this measures for each GDB one or more outputs relative to one particular input:
    - The opex PFP index measures output produced per unit of opex (non-capital) inputs; and
    - The capital PFP index measures output per unit of capital inputs.
- Multilateral TFP – this measures the relative productivity levels and productivity growth rates of the gas distributors.

Economic Insights' TFP analysis for the period 1999 and 2015 found that:

- Our capital input index grew steadily over the period and at a similar rate to the output index – it therefore had little bearing on TFP trends. The other two Victorian gas distributors had a similar experience;
- The opex input index played a key role in determining our TFP trends. Our opex inputs' usage decreased at an average annual rate of 3.7 per cent over 1999 to 2008 but increased at an average annual rate of 1.2 per cent between 2008 and 2015. This increase was largely caused by a one-off increase in opex in 2012. Over the period 1999 to 2015, our opex input index decreased on average by 1.6 per cent per annum[54];[55]
- Our input index (being the weighted average of opex and capital input indexes) declined by 0.9 per cent per annum between 1999 and 2008) and increased by an annual average of 0.9 per cent from 2008 to 2015. Our input index decreased at an average annual rate of 0.1 per cent between 1999 and 2015. Economic Insights noted that this "compares favourably to AGN Vic's average input increase of 0.4 per cent and AusNet's average input increase of 0.6 per cent per year over the same period"[56]. This indicates that we had the most favourable trend in input use of the three Victorian gas distributors over the analysis period[57];
- Our output index grew by 0.9 per cent per annum over the 1999 to 2015 period. This rate is much slower than that for AGN Victoria and AusNet. Economic Insights noted that "This difference probably reflects the nature of its distribution region, which does not include any major residential growth corridors. Further, the growth rate of outputs slowed in the latter half of the period. It averaged 1.2 per cent per year between 1999 and 2008, decreasing to 0.5 per cent per year from 2008 to 2015"[58]. In reference to the lower output index

[53] Economic Insights, "Benchmarking the Victorian Gas Distribution Businesses' Operating and Capital Costs Using Partial Productivity Indicators", 15 June 2016, page 9

[54] A decrease in opex inputs is favourable and an increase is unfavourable.

[55] Economic Insights, "The Productivity Performance of Victorian Gas Distribution Businesses", 15 June 2016, page 26

[56] Economic Insights, "The Productivity Performance of Victorian Gas Distribution Businesses", 15 June 2016, page 26

[57] Economic Insights, "The Productivity Performance of Victorian Gas Distribution Businesses", 15 June 2016, page 25

[58] Economic Insights, "The Productivity Performance of Victorian Gas Distribution Businesses", 15 June 2016, page 25

growth, Economic Insights also noted “It is reasonable to expect that this factor would explain much of the difference between the TFP growth results of Multinet and the other two Victorian gas distributors”[59]; and

- Our TFP increased by 2.0 per cent per annum from 1999 to 2008 but decreased at an average rate of 0.4 per cent from 2008 to 2015, driven largely by a significant downturn in 2012. Over the 1999 to 2015 period, our TFP increased at an average annual rate of 1.0 per cent. Economic Insights concluded that “although Multinet’s inputs have been slightly more contained than those of AGN Vic and AusNet, the much slower growth of its outputs has resulted in a lower average rate of TFP growth than those two businesses” over the period 1999 to 2015.[60]

Economic Insights’ PFP analysis for the period 1999 and 2015 found that our opex PFP index increased strongly between 1999 and 2008 at an average annual rate of 5.1 per cent, and increased at an average annual rate of 0.7 per cent from 2008 to 2015 so that it experienced an average annual rate of 2.5 per cent over the 1999 to 2015 period. Economic Insights noted that “This overall average opex PFP growth rate is lower than those of AGN Vic and AusNet, again reflecting Multinet’s lower output growth rate in its more established supply region”[61]. Indeed, Economic Insight found that we had the lowest comparative output index between 1999 and 2015 of the six gas distributors examined in the study.

Economic Insights used:

- Multilateral TFP analysis to show that our productivity level in recent years was lower than AGN Victoria’s, similar to AusNet’s and Jemena NSW’s and higher than each of AGN SA and AGN Queensland;[62] and
- Multilateral PFP indexes to show the levels of opex PFP for the six gas distributors. It found that our opex levels were below those of AusNet in 2015 but much higher than AGN SA and AGN Queensland.[63] Our opex PFP levels are steadily recovering after a one-off drop in 2012.[64]

14.4. Conclusions about our current period opex

Our trend analysis discussed in sections 14.2 and Economic Insights’ independent benchmarking analysis discussed in section 14.3 show that our current Access Arrangement period opex has been efficient and we are operating at or close to the efficient frontier of gas distributors. In particular:

- We expect to underspend the AER’s benchmark opex allowance by $2.2 million between 2013 and 2016 and to underspend the 2016 base year by $1.3 million;
- We have sustained an efficient level of performance over a long period – although there was a one-off increase in opex in 2012 due to our corporate transformation project, as discussed in Chapters 6 and 13. We have therefore not just arrived at our efficient levels of opex recently. This means that assessments of our efficiency are not just a function of which year, or years, is chosen for the benchmarking analysis;
- Economic Insights’ expenditure benchmarking shows that we operated below the average opex per customer for the seven gas distributors with relatively high customer density for the 2011 to 2015 period (and considerably below the average of the 13 gas distributors in its survey analysis). It also found that we had the second lowest overall cost efficiency per customer of the 13 gas distributors surveyed;
- Economic Insights’ productivity benchmarking shows that our TFP increased at an average annual rate of 1.0 per cent between 1999 and 2015 and 0.4 per cent from 2008 to 2015. Our opex PFP index increased at an average annual rate of 2.5 per cent between 1999 and 2015 and 0.7 per cent from 2008 to 2015. The reason these rates were lower than the two other Victorian gas distributors is that our outputs grew more

[59] Economic Insights, “The Productivity Performance of Victorian Gas Distribution Businesses”, 15 June 2016, page 38
[60] Economic Insights, “The Productivity Performance of Victorian Gas Distribution Businesses”, 15 June 2016, page 25
[61] Economic Insights, “The Productivity Performance of Victorian Gas Distribution Businesses”, 15 June 2016, page 26
[62] Economic Insights, “The Productivity Performance of Victorian Gas Distribution Businesses”, 15 June 2016, page 27
[63] Economic Insights, “The Productivity Performance of Victorian Gas Distribution Businesses”, 15 June 2016, page 27
[64] Economic Insights, “The Productivity Performance of Victorian Gas Distribution Businesses”, 15 June 2016, page 36

slowly than theirs. This is largely beyond our control and reflects the nature of our distribution region, which does not include any major residential growth corridor. Indeed, Economic Insights found that we have had the most favourable trend in input use of the three Victorian gas distributors over the analysis period – this is within our control;

- Our new business model – that has resulted from our business transformation program – is successful and is delivering efficient opex outcomes. This transformation provides a strong basis for us to continue to deliver efficient outcomes;
- We have continually responded to the incentives that the AER and, prior to this, the ESCV, have provided to us through the regulatory regime. This is reflected in the efficiency of our opex. We are delivering value for money to our customers through our efficient opex and our customers are sharing in the associated benefits; and
- Our 2016 opex provides an efficient base year for determining our opex forecast for the forthcoming Access Arrangement period. There is no need for the AER to make any adjustment (over and above those that we have proposed) to our base year opex. We discuss this further below.

14.5. Our forecast opex

14.5.1. Why our forecasts comply with the NGR

This section provides a high-level explanation of why our forecasts should be accepted by the AER. It should be read in conjunction with our "Operating Expenditure Overview" document that we have provided to the AER with this Access Arrangement Information.

Rule 91(1) of the NGR requires:

> *Operating expenditure must be such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services.*

Our opex forecast is prudent and efficient and meets this requirement because:

- Economic Insight's benchmarking indicates that our historical opex is at, or close to, the efficient frontier of gas distributors;
- We have applied the AER's preferred BST approach to forecasting opex, which is based on an efficient build-up of costs;
- We have been operating under the AER's efficiency benefit sharing schemes which shares efficiency gains and losses between ourselves and consumers and provides a continuous incentive to achieve efficient opex outcomes;
- Our 2016 opex provides an efficient base year for our opex forecast;
- Our real labour cost escalators have been determined by independent experts, BIS Shrapnel;
- Our output growth forecast has been determined based on movements in customer numbers and line length, which according to Economic Insights are the two most appropriate parameters;
- We are only proposing only one step change – for marketing – in the forthcoming Access Arrangement period; and
- We have structured our opex forecasts to maintain the quality, reliability and security of supply of our Reference Services.

This chapter provides further information on our forecast opex and identifies the relevant supporting documents where additional detailed analysis demonstrating compliance with the NGR requirements is provided.

14.5.2. Key assumptions – opex

The key assumptions underpinning our opex forecasts are that:

- The 2016 base year is efficient but should be adjusted for changes in input costs, outputs and productivity growth in the forthcoming Access Arrangement period;
- The base year opex should be increased for a marketing step change in the forthcoming Access Arrangement period;
- The forecast opex will allow us to maintain our service performance in the next Access Arrangement period; and
- Our current legislative and regulatory obligations will not change materially in the next Access Arrangement period.

14.5.3. Opex forecasting method

We have used a BST approach to forecast our opex for the forthcoming Access Arrangement period. This is consistent with:

- The AER's preferred approach for preparing our opex forecast; and
- The approach that the AER has applied in its recent decisions for other gas distributors, including for Jemena NSW's network, ActewAGL's ACT, Queanbeyan and Palerang network and AGN SA's network.

A BST approach involves forecasting our opex at an aggregate level, rather than preparing individual forecasts for each category of opex, as detailed in the AER's Annual RIN.

The starting point for the BST approach is that the incentive properties of the AER's opex incentive mechanism – the EBSS – mean that our base year opex reflects prudent and efficient costs. This is because the efficiency carryover mechanism under the EBSS incentivises us to minimise our opex, while ensuring that we continue to meet our regulatory obligations and to achieve our service performance targets.

The BST approach involves the following stages:

1. Nominating a base year;
2. Adding or subtracting, as relevant, adjustments to the base year opex. These could include adjusting for:
   a. Changes in service classification;
   b. Non-recurrent costs;
   c. Efficient incremental opex in the final regulatory year of the current access arrangement period; and
   d. Costs determined through a bottom-up build (rather than the BST approach).

   Applying these adjustments results in an efficient base year for use in the forthcoming period.
3. Applying rate of change adjustments to the efficient base year opex for growth in:
   a. Real labour and non-labour prices;
   b. Output; and
   c. Productivity.
4. Adding or subtracting, as relevant, step changes (otherwise known as scope changes) to the efficient base year opex.

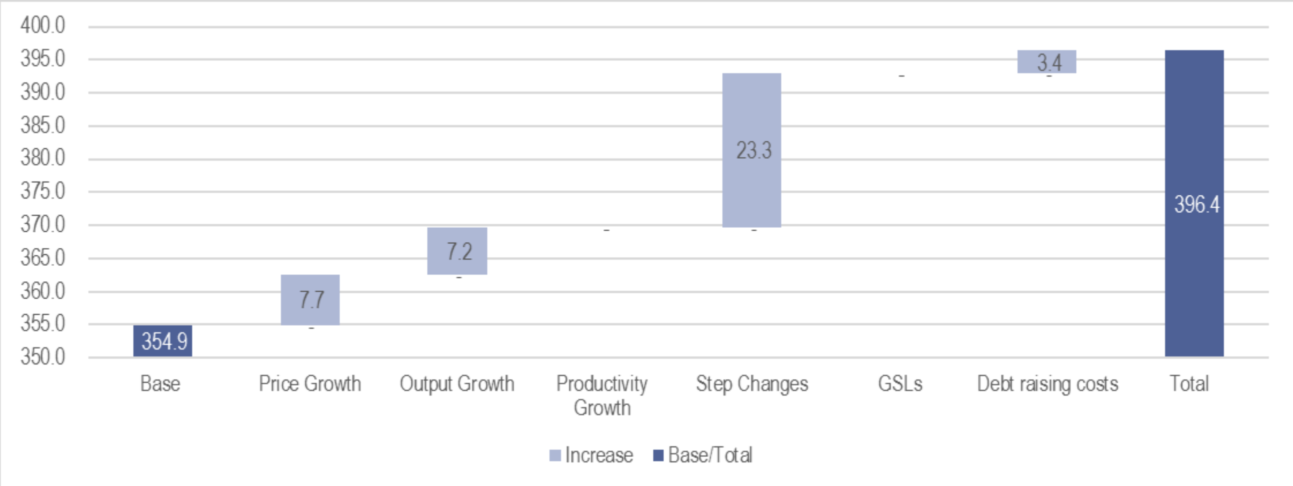
The following section details how we have applied these four stages to achieve an efficient opex forecast for the forthcoming Access Arrangement period. It also explains how we have checked and tested our opex forecast using trend analysis and benchmarking to confirm that our opex forecast is efficient.

We have also ensured that our opex forecast prepared using the BST approach aligns with our internal budget.

We have forecast Debt raising costs using a bottom-up build.

Our opex forecast for the forthcoming Access Arrangement period is set out in Figure 14-1.

Figure 14-1: Forecast period opex – Reference Services ($M, Real 2017)



14.5.4. Efficient base year inclusive of adjustments

We have chosen 2016 as our base year for our opex forecast because:

- It is the most recent full regulatory year of actual reported expenditure at the time of preparing this Access Arrangement Information;
- It is representative of our underlying operating conditions in the current and forthcoming Access Arrangement periods;
- It reflects the efficiencies that we have achieved in transitioning to our new business model;
- We benchmark at the efficient frontier compared with our peers, based on the independent analysis undertaken by Economic Insights that is discussed in section 14.3; and
- It reflects our response to the incentives of the regulatory regime and shows that the incentives are working.

Our 2016 opex includes an adjustment for movement in provisions of $1.4 million. We have considered what adjustments are required to our 2016 opex to achieve an efficient base year for the forthcoming Access Arrangement period. We have:

- Applied a half a year of inflation to the 2016 opex on the basis that it is a mid-year value – this adds $0.4 million to the base year; and
- Added $0.9 million in efficient incremental costs associated with the 2017 regulatory year, which will be recurrent in the forthcoming Access Arrangement period. This is based on the difference between the AER's opex allowance for 2016 and 2017, as set out in its Final Decision for the current Access Arrangement Period. We note that the application of this increment is consistent with the equivalent allowance that the AER made for United Energy in its Final Decision for opex for its 2016 to 2020 regulatory control period[65].

[65] In this case, the difference between United Energy's regulatory opex allowance for its 2014 (base year) and 2015 (final year) for its previous Access Arrangement period was $1.7 million. The AER added this full $1.7 million as a base year adjustment to the 2016 opex allowance.

Table 14-3 details our efficient base year opex, inclusive of these adjustments, for each year of the forthcoming Access Arrangement period. Table 6 in our Opex Overview Document provides a full build-up of our base year opex.

Table 14-3: Efficient base year opex including adjustments – Reference Services ($M, Real 2017)

	2018	2019	2020	2021	2022	TOTAL
Efficient base year opex including adjustments	71.0	71.0	71.0	71.0	71.0	354.9

14.5.5. Rate of change – price

Our opex involves two inputs – labour and materials.

The AER adopted a weighting of 62 per cent for labour and 38 per cent non-labour for the purposes of determining the rate of price change in its:

- Final Decisions for AGN's South Australian network for their 2016-17 to 2020-21 Access Arrangement period and for Jemena Gas Networks' NSW network for their 2015-16 to 2019-20 Access Arrangement period; and
- Distribution Determinations for the Victorian electricity DNSPs' opex for their 2016 to 2020 regulatory period.

We have adopted these same percentages to determine the real price growth for our opex forecast for our forthcoming Access Arrangement period.

We expect that the input costs of materials will increase in line with the consumer price index (CPI) in the forthcoming Access Arrangement period. We therefore are not proposing any rate of change for materials in our opex forecast.

We are proposing an allowance to our opex forecast for real price growth in labour in the forthcoming Access Arrangement period. This is because we expect that our labour costs will increase at a faster rate than the CPI.

We engaged an independent expert, BIS Shrapnel, to forecast real labour cost escalations relevant to our opex for the forthcoming Access Arrangement period. We have provided a copy of their report to the AER with this Access Arrangement Information.

BIS Shrapnel prepared its forecasts using top-down and bottom-up approaches. Its bottom-up approach models various industry sectors at a regional and individual category level, which are aggregated to a national level. The top-down modelling reconciles the bottom-up forecasts with prevailing trends, investment and business cycles and assumptions about the general macroeconomic outlook.[66]

BIS Shrapnel is forecasting that:

> *Wages within the Australian Electricity, Gas, Water and Waste Services (EGWWS or 'Utilities) sector are (sic) forecast to exceed the all industry result. A stronger union presence, a pick-up in employment and a turnaround in wage increases awarded to staff on individual agreements are the key drivers.*[67]

The report states that for Australia as a whole:

> *BIS Shrapnel is forecasting an average of 3.7 per cent per annum (also 0.5 percentage points higher than the national 'All Industries' WPI average of 3.2 per cent per annum) over the five years to 2022.*[68]

[66] BIS Shrapnel, "Utilities Sector and Construction Industry Wage Forecasts to 2022 – Australia and Victoria", October 2016, page 1

[67] BIS Shrapnel, "Utilities Sector and Construction Industry Wage Forecasts to 2022 – Australia and Victoria", October 2016, page ii

[68] BIS Shrapnel, "Utilities Sector and Construction Industry Wage Forecasts to 2022 – Australia and Victoria", October 2016, page ii

In relation to Victoria, the report states that:

> *The utilities wage forecasts for Victoria are expected to slightly exceed the national average over the five years to December 2022 (i.e. the distributors' next Access Arrangement period). Victorian utilities WPI growth is forecast to average 3.8 per cent per annum compared with Australian utilities industry wage forecast of 3.7 per cent per annum over the same period.*[69]

BIS Shrapnel's forecasts of growth in the Wage Price Index (WPI) are detailed in Table 14-4 below.

Table 14-4 – Wage Price Index – 2018 to 2022 (per cent) [70]

		2018	2019	2020	2021	2022	Average
Nominal Price Changes	Electricity, Gas, Water and Waste Services – Victoria	3.1	3.4	3.7	4.2	4.5	3.8
	Contractor – Victoria	2.8	3.3	3.7	4.3	4.5	3.7
Real Price Changes	Electricity, Gas, Water and Waste Services – Victoria	1.1	0.9	1.2	1.7	2.0	1.4
	Contractor – Victoria	0.8	0.8	1.2	1.8	2.0	1.3

We applied the BIS Shrapnel labour cost escalators to our mix of employees and contractors to determine our forecast real labour cost increases.

Table 14-5 details our forecast opex increase attributable to real labour price growth in the forthcoming Access Arrangement period.

Table 14-5 - Real rate of change – labour price – Reference Services ($M, Real 2017)

	2018	2019	2020	2021	2022	TOTAL
Real Price Growth	0.4	0.8	1.3	2.1	3.0	7.7

14.5.6. Rate of change – output

We have included an allowance in our opex forecast for the impact of output growth in the forthcoming Access Arrangement period. This reflects the fact that greater output costs more to operate and maintain.

We have applied the following output change measures and respective weightings for the forthcoming Access Arrangement period:

- Customer numbers (45 per cent); and
- Pipeline length (55 per cent).

We have chosen these measures having regard for economic modelling analysis by Economic Insights, whom we engaged to undertake econometric estimation of the opex cost function for gas distributors, including network length, customer numbers and gas throughput as outputs. They examined Australian and New Zealand gas distributors using historical data that generally covered the period 1999 to 2015.

Economic Insights' report, which we have provided to the AER in support of this Overview Document and our Access Arrangement Information, stated:

[69] BIS Shrapnel, "Utilities Sector and Construction Industry Wage Forecasts to 2022 – Australia and Victoria", October 2016, page 40

[70] BIS Shrapnel, "Utilities Sector and Construction Industry Wage Forecasts to 2022 – Australia and Victoria", October 2016, page ii

The conclusions of this study in regard to the significance of outputs are as follows:

- *gas throughput is not a statistically significant determinant of real opex;*
- *network length is a statistically significant determinant of real opex; and*
- *customer numbers are a statistically significant determinant of real opex.*[71]

We are using the same weightings for our two output measures as the AER used in its recent Final Decision for the Victorian electricity DNSPs' 2016 to 2020 regulatory period, although we have proportionately scaled them up as we are not applying the maximum demand measure that was used for electricity.

Table 14-6 details our forecast opex increase attributable to the impact of output growth in the forthcoming Access Arrangement period.

Table 14-6: Rate of change – output – Reference Services ($M, Real 2017)

	2018	2019	2020	2021	2022	TOTAL
Output Growth	0.5	0.9	1.4	1.9	2.4	7.2

14.5.7. Rate of change – productivity

We propose that a rate of change productivity adjustment of zero per cent be applied in each of the five years of the forthcoming Access Arrangement period. This is consistent with the AER's position in its Final Decisions for AGN SA's gas network and for the Victorian electricity DNSPs.

We agree with the assessment that AGN SA made in its Access Arrangement Information for its 2016-17 to 2020-21 period, where it stated:

> *a forecast of productivity growth cannot be arrived at on a reasonable basis and therefore cannot meet the criteria as detailed in Rule 74 of the NGR. As such, AGN has removed the productivity adjustment from the Rate of Change formula incorporated into the opex Model.*[72]

AGN SA went on to reject the 0.5 productivity adjustment that the AER had proposed in its Draft Decision[73] for the following reasons:

- *The labour cost escalation rate does not compensate the business for forecast productivity improvements;*
- *AGN does not consider that a forecast of productivity growth can be arrived at on a reasonable basis;*
- *AGN considers the forecast of productivity growth applied by the AER to forecast opex does not meet the AER's forecast assessment principles;*
- *AGN has absorbed significant opex costs in its Revised AA Proposal (effectively applying a productivity adjustment of 0.7%), so it is not necessary for the AER to apply an additional productivity adjustment;*
- *the productivity adjustment applied by the AER in its Draft Decision is irrelevant to AGN.*[74]

In its Final Decision for AGN SA, the AER stated:

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[71] Economic Insights, *Gas Distribution Businesses opex Cost Function*, 22 August 2016, page ii

[72] AGN SA, "Australian Gas Networks Revised SA - Access Arrangement Information, January 2016", page 17

[73] The AER's proposed 0.5 per cent productivity adjustment was based on advice from ACIL Allens in relation to ActewAGL.

[74] AER, "Attachment 7 – Operating expenditure – Final Decision: Australian Gas Networks Access Arrangement 2016-21", page 7-19

> *Based on a review of the material and our own analysis, we were unable to identify a better productivity factor estimate than that proposed by AGN. Therefore, we have concluded that it is reasonable to accept AGN's proposal to apply a zero productivity factor for the forecast period. We consider this is the best estimate available in the circumstances.*[75]

We consider that this logic applies equally to our gas distribution network. For this reason, we are also proposing that a rate of change productivity adjustment of zero per cent be applied for the next Access Arrangement period.

Table 14-7: Rate of change – productivity – Reference Services ($M, Real 2017)

	2018	2019	2020	2021	2022	TOTAL
Productivity Growth	0.0	0.0	0.0	0.0	0.0	0.0

We note that in proposing a zero rate of change productivity adjustment we are absorbing a range of cost increases that we expect to face in the forthcoming Access Arrangement period, including in relation to:

- **Real increase in material costs** – we have not applied any real cost escalations in relation to our material inputs although we expect to incur some cost increases. Rather, we have confined our real cost escalations to our labour inputs, as discussed in section 14.5.5. In effect, we are implicitly applying a productivity saving equivalent to the real increase in material costs that we will face in the next period.
- **Custody transfer meters** – we will incur additional opex in the next period because of the APA Group's proposed lifecycle replacement of Custody Transfer Meters (CTMs) on its Victorian Transmission System. APA Group has identified, as part of its Metering Strategy Plan, seven CTMs for lifecycle replacement. We support the need for their replacement but have chosen not to include the additional cost as an opex step-change for the forthcoming Access Arrangement period. As a result, we are implicitly applying a productivity saving of about $0.4 million, which is the estimated cost of the APA Group's works that will be passed through to us.
- **Insurance** – we expect our total insurance costs to increase by about $0.9 million over the next Access Arrangement period relative to 2016 levels due to changes in market conditions for our existing insurance program and also the addition of cyber insurance. We note that the AER accepted Jemena Gas Networks' application for increase insurance costs for their current Access Arrangement period because the AER considered that insurance reflects a prudent and efficient risk management practice. We have chosen not to include the additional cost as an opex step-change. As a result, we are implicitly applying a productivity saving of about $0.9 million in the next Access Arrangement period.
- **High Pressure Pipeline In-line inspection** – we are due to carry out in-line inspection (ILI) of the Inner Ring Main in conjunction with AGN, Ausnet and APA in 2019-20. It has been ten years since the last ILI was run. Ten yearly ILI is industry good practice in the absence of measured deterioration rates and engineering assessment. We will incur additional opex cost of approximately $0.5 million on this project. Two other ILI pigging projects are forecast within the Access Arrangement period, which will incur opex costs of approximately $0.4 million each.

[75] AER, "Attachment 7 – Operating expenditure – Final Decision: Australian Gas Networks Access Arrangement 2016-21", page 7-19

14.5.8. Guaranteed Service Levels

We apply the jurisdictional GSLs scheme that is detailed in section 6 of the Gas Distribution System Code. It requires us to make payments to customers where we do not meet specific performance standards in relation to timeliness of attending appointments, timeliness of connections, repeated interruptions and lengthy interruptions.

Our Capex and opex forecasts for the forthcoming Access Arrangement period are based on maintaining our performance at the average of our last five years' performance.

We are expecting that our GSL payments will remain at our historical levels. We are therefore assuming that our 2016 base year GSL payments of around $50,000 will continue throughout the forthcoming Access Arrangement period.

Table 14-8 details our forecast GSL costs in the forthcoming Access Arrangement period.

Table 14-8 - GSL costs – Reference Services ($M, Real 2017)

	2018	2019	2020	2021	2022	Total
GSL	0.0	0.0	0.0	0.0	0.0	0.0

14.5.9. Step change

Our opex forecast for the forthcoming Access Arrangement period includes the marketing step change detailed in Table 14-9. This sub-section explains and justifies this proposal.

Table 14-9: Step Change – Reference Services ($M, Real 2017)

	2018	2019	2020	2021	2022	TOTAL
Marketing Step Change	4.7	4.7	4.7	4.7	4.7	23.3

AEMO is projecting that demand will fall in Victoria by 1 per cent between 2015 and 2022. While AEMO expects some growth in the number of new residential connections, it expects this to be offset by a reduction in average consumption per connection. AEMO's forecast is largely consistent with our analysis discussed in Chapter 9, where we also forecast that our average residential consumption will continue to decline over the forthcoming Access Arrangement period.

This means that there is a risk of our future average network prices increasing as we recover our largely fixed costs over a smaller consumption base. As discussed in in Chapter 9, the decline in average residential consumption on our network is being driven by:

- The reduced competitiveness of gas compared with electricity, as wholesale gas prices rise and wholesale and network electricity prices fall;
- The increased penetration of reverse-cycle air conditioners;
- Increased energy and thermal efficiency, which is causing average residential gas consumption to decline, particularly for new customers who need to comply with minimum energy performance standards;
- Growth in the proportion of smaller, all-electric apartment in high risk buildings; and
- A lack of growth corridors in our gas network, which means that our forecast rate of new connections is relatively low.

Gas must be financially attractive to encourage new customers to connect to the gas network and to encourage them to purchase additional gas appliances.

Research indicates that potential new customers see the upfront costs of purchasing new gas appliances, and getting them installed, as barriers to connecting to our network and to using gas, particularly when they have alternatives such as electricity readily available.

We therefore need to be proactive in:

- Promoting gas as a fuel of choice;
- Increasing the rate of new residential connections and average residential consumption; and
- Increasing the take-up of gas in regional areas, including those areas that have recently been connected through the "Energy for the Regions" program.

Other gas distributors have proven that incentive rebate programs can be effective in addressing these barriers. They can be targeted at influencing customer behaviour by helping them with the upfront costs of buying natural gas appliances.

Our proposed marketing step change would support a targeted marketing campaign in the forthcoming Access Arrangement period, in conjunction with the two other Victorian gas distributors. The campaign would have four elements:

- Appliance rebates – we would provide appliance rebates on central heating, space heating and hot water systems;
- Advertising campaign – we would promote the use of gas and appliance rebates to residential customers, including through the development of a joint website;
- Industry representation – we would promote gas to builders, developers, plumbers, gas fitters and appliance retailers; and
- Connection incentive program – we would pay incentives to plumbers, gas fitters and appliance retailers where their actions clearly result in new connections.

As noted in chapter 9, NIEIR prepared an independent expert demand forecasts of our gas network for the forthcoming Access Arrangement period. NIEIR updated its demand forecast for our proposed step change in marketing opex.

Based on NIEIR's analysis, we forecast that over the forthcoming Access Arrangement period, the marketing step change will:

- Grow our customer base by a total of 1,405 new connections;
- Increase total residential consumption by 1.42 PJ;
- Increase average annual consumption by 0.6 GJ per residential customer by 2022; and
- Reduce average network prices over time, in the long-term interests of customers.

We have engaged with our stakeholders about our proposed marketing step change. They have told us that they support this strategy and see that it will promote customers' long-term interests with respect to price and gas availability.

We note that in 2015 the AER approved a marketing allowance for JGN of $45 million (Real 2016) and the Economic Regulation Authority of Western Australia (ERA) approved a business development and marketing opex allowance for ATCO of $12.3 million (Real 2016) over their respective Access Arrangement periods. This followed the AER's approval allowance of $16.6 million (Real 2016) for AGN Victoria for its current Access Arrangement period and $29.1 million (Real 2016) for AGN SA from 2011.

We currently have no provision for marketing in our base year opex. By contrast, we note that AGN Victoria already has a marketing allowance included in its base year opex.

We have provided to the AER with this Access Arrangement Information an independent expert report prepared by Axiom Economics, which sets out the net benefit of our proposed market opex step change. The report explains how:

- Our proposal is in users' long-term interests by showing that our reference tariffs will be lower than they otherwise would have been, consistent with the NGO;
- The benefits of our proposal exceed the costs;
- Our proposal is consistent with the opex incurred by a prudent service provider, acting efficiently, in accordance with good industry practice, as is required by Rule 91;
- Our proposal has been arrived at on a reasonable basis and represents the best forecast or estimate possible in the circumstances, as is required by Rule 74(2); and
- The incremental load and / or connections arising from our proposal have been considered in our demand forecasts.

We have also provided a marketing strategy that details how we will deliver the step change in the forthcoming Access Arrangement period.

14.5.10. Debt raising costs

Table 14-10 details our forecast debt raising costs in the forthcoming Access Arrangement period. These costs are explained and justified in chapter 16.

Table 14-10: Debt raising costs – Reference Services ($M, Real 2017)

	2018	2019	2020	2021	2022	TOTAL
Debt raising costs	0.6	0.7	0.7	0.7	0.7	3.4

14.6. Split of opex forecast between Haulage and Ancillary Reference Services

Our opex forecast described in this Chapter relates to our Reference Services.

Table 14-11 splits the total opex between our Haulage Reference Services and our Ancillary Reference Services because different Reference Tariff Adjustment Mechanisms apply to each type of service, as described in chapter 12.

Table 14-11: Split of Total opex for Reference Services ($M, Real 2017)

	2018	2019	2020	2021	2022	TOTAL
Controllable opex – Reference Services	76.5	77.4	78.4	79.7	81.1	393.0
Debt raising costs	0.6	0.7	0.7	0.7	0.7	3.4
Total opex – Reference Services	**77.2**	**78.0**	**79.1**	**80.4**	**81.8**	**396.4**
Opex – Ancillary Reference Services	(2.3)	(2.3)	(2.3)	(2.3)	(2.4)	(11.7)
Opex – Haulage Reference Services	**74.8**	**75.7**	**76.7**	**78.0**	**79.4**	**384.7**

Our opex forecast for our Haulage Reference Services is reflected into our Total Revenue forecast for Haulage Reference Services in Chapter 20.

15. Regulatory Asset Base and Depreciation

Key messages:

- We have adopted a value of $1,210.8 million (Nominal), or $1,190.8 million (Real 2017), as our opening regulatory asset base as at 1 January 2018. We determined this value using the AER's Roll Forward Model.
- We have rolled forward our regulatory asset base value using the depreciation allowance determined by the AER in its 2012 Final Decision for the current Access Arrangement period.
- We have forecast our depreciation and regulatory asset base for the forthcoming Access Arrangement period by applying forecast capex and asset lives in accordance with our Access Arrangement Pricing Model.
- Our asset category and standard lives are the same as those accepted by the AER in its Final Decision for the current Access Arrangement period, except for including:
  - Four additional asset categories that we have added to account for our Mains Replacement capex program; and
  - One additional category for new meters.
- We have applied the AER's preferred "year-by-year tracking" approach to determining regulatory depreciation. The AER applied this approach in its recent Distribution Determinations for the South Australian and Victorian electricity distribution businesses.
- Our forecast regulatory depreciation includes an allowance for:
  - The additional LP mains (and associated services) that were removed and replaced in the current Access Arrangement period that were subject to the AER's September 2015 cost pass through decision – this decision did not give an allowance for this in the current Access Arrangement period; and
  - Removing and replacing 625 kilometres of mains and associated services in the forthcoming Access Arrangement period under our LP to HP Mains Replacement program.
- Consistent with the Australian Taxation Office's ruling TR 2016/1, we propose reducing our standard asset lives for:
  - Buildings from 50 years to 35 years; and
  - New meters from 30 years to 15 years.
- We propose fully depreciating our existing meters in the forthcoming Access Arrangement period, given that they will only have 6.62 years of remaining life at the start of the forthcoming Access Arrangement period.

15.1. Introduction

This chapter presents information on our regulatory asset base and regulatory depreciation for our Haulage Reference Services.

We have calculated the regulatory asset base value in accordance with the NGR, specifically Rule 77(2). Our proposed depreciation allowance also complies with the requirements in Rules 88 to 90.

The remainder of this chapter is structured as follows:

- Section 15.2 explains the derivation of the opening regulatory asset base as at 1 January 2018, being the start of the forthcoming Access Arrangement period;

- Section 15.3 explains the derivation of our forecast regulatory asset base for each year of the forthcoming Access Arrangement period;
- Section 15.4 details our regulatory depreciation for the current Access Arrangement period;
- Section 15.5 details our proposed methodology for forecasting our regulatory depreciation, and our proposed asset lives, for the forthcoming Access Arrangement period; and
- Section 15.6 details our proposed regulatory depreciation allowance for the forthcoming Access Arrangement period.

15.2. Opening regulatory asset base as at 1 January 2018

We are required to establish an opening value for the regulatory asset base as at 1 January 2018, which is the starting date for the forthcoming Access Arrangement period. We have applied the AER's Roll Forward Model and our own Access Arrangement Pricing Model to calculate this value.

Table 15-1 reconciles our 1 January 2018 regulatory asset base with the AER's estimate in its Final Decision for the current Access Arrangement period.

Table 15-1: Reconciliation of opening Regulatory Asset Base at 1 January 2018 to AER's Final Decision ($M, Nominal unless otherwise stated)

RAB Components	AER's 2012 determination	Actual data	Comments / Reference
2012 opening RAB	1,034.2	1,034.2	No difference
2012 net capex	75.7	75.7	No difference
2012 Depreciation	(54.9)	(54.9)	No difference
Opening RAB 2013	**1,055.0**	**1,055.0**	No difference
2013 to 17 capex (Gross)	339.8	358.7	Increased capex due to increased Customer initiated works
Equity raising (Capex)	-	-	As per the AER's Distribution Determination
2013 to 17 contributions	(21.7)	(46.7)	Higher than forecast customer contributions
2013 to 17 disposals	-	(0.2)	Total value of disposals was slightly higher than forecast
2013 to 17 depreciation	(292.8)	(288.2)	Actual inflation rather than forecast inflation has been applied
2013 to 17 funding of capex	7.0	9.7	Nominal cost of capital applied, as required by the application of the Roll Forward Model
2013 to 17 inflation on RAB	116.1	81.3	Actual inflation rather than forecast inflation has been applied. Details are set out in the Roll Forward Model
Indexation of the 2012 RAB	26.4	21.1	Reduced due to lower actual inflation rate
Closing RAB 2017	**1,229.7**	**1,190.8**	$M, Real 2017

RAB Components	AER's 2012 determination	Actual data	Comments / Reference
Application of revised 2017 CPI forecast	30.7	20.0	A revised 2016 inflation forecast of 1.8 per cent applied instead of the forecast of 2.5% which was adopted by the AER in its 2012 Determination. This has the effect of reducing the RAB escalation amount
Opening RAB 2018	**1,260.5**	**1,210.8**	$M, Nominal

As detailed in Table 15-1 we are proposing an opening regulatory asset base value of $1,210.8 million (Nominal) for the forthcoming Access Arrangement period.

15.3. Regulatory Asset Base for the 2018 to 2022 Access Arrangement period

Table 15-2 summarises the amounts, values and inputs used to derive our forecast regulatory asset base value for each year of the forthcoming Access Arrangement period.

We have assumed the following in rolling forward the regulatory asset base in the forthcoming Access Arrangement period:

- Forecast capex is consistent with the categories and amounts presented in this Access Arrangement Information;
- Regulatory depreciation is calculated on a straight-line basis, using the asset lives in Table 15-4, in accordance with Rule 89(1), as described in section 15.5; and
- Forecast asset disposals are zero.

Table 15-2: Regulatory asset base for 2018 – 2022 ($M, Real 2017)

	2018	2019	2020	2021	2022
Opening Regulatory Asset Base	1,190.8	1,234.2	1,259.0	1,287.9	1,314.4
Inflation on Opening Regulatory Asset Base	-	-	-	-	-
Plus capex (Excl. Funding)	115.8	98.9	103.1	103.4	96.1
Plus Funding Costs	2.3	1.9	2.0	2.0	1.9
Less customer contributions	(9.1)	(9.1)	(9.1)	(9.1)	(9.1)
Less regulatory depreciation	(65.5)	(67.0)	(67.1)	(69.9)	(72.7)
Less disposals	-	-	-	-	-
Closing Regulatory Asset Base	**1,234.2**	**1,259.0**	**1,287.9**	**1,314.4**	**1,330.5**

Note: The values contained in this table have been calculated as per the requirements of the AER's Post-Tax Revenue Model.

15.4. Regulatory depreciation for the 2013-17 Access Arrangement period

Rule 77(2) sets out provisions relating to the opening capital base (i.e. regulatory asset base) for an Access Arrangement period that follows immediately on the conclusion of a preceding Access Arrangement period. Rule 77(2)(d) requires that the depreciation over the earlier Access Arrangement period must be calculated in accordance with any relevant provisions of the Access Arrangement governing the calculation of depreciation for establishing the opening regulatory asset base.

The effect of the above provisions is to require us to roll forward our regulatory asset base value using the depreciation allowance determined by the AER in its 2012 Final Decision for the current Access Arrangement period, as set out in Table 15-3. As discussed in section 15.5 below, the allowed depreciation does not include an amount to write-off redundant assets because of our mains replacement program.

Table 15-3: AER regulatory depreciation allowance for 2013-17 Access Arrangement period ($M, Real 2017)

	2013	2014	2015	2016	2017
Regulatory depreciation	49.4	58.1	60.8	63.1	65.5

15.5. Forecast regulatory depreciation methodology and asset lives

We have used our own Pricing Model to calculate our regulatory depreciation. In accordance with the requirements of Rule 89(1) we have adopted a straight-line approach to forecast regulatory depreciation based on defined asset categories and asset lives. New assets are depreciated according to the standard lives for each asset class. Existing assets are depreciated over their remaining asset lives. The opening asset value as at 1 January 2018 has been calculated by applying the AER's Roll Forward Model.

Rule 89(3) states in reference to Rule 89 that "The AER's discretion under this rule is limited". Rule 40(2) states that:

> *If the Law states that the AER's discretion under a particular provision of the Law is limited, then the AER may not withhold its approval to an element of an access arrangement proposal that is governed by the relevant provision if the AER is satisfied that it:*
>
> *(a) complies with applicable requirements of the Law; and*
>
> *(b) is consistent with applicable criteria (if any) prescribed by the Law.*
>
> *Example:*
>
> *The AER has limited discretion under rule 89. (See rule 89(3).) This rule governs the design of a depreciation schedule. In dealing with a full access arrangement submitted for its approval, the AER cannot, in its draft decision, insist on change to an aspect of a depreciation schedule governed by rule 89 unless the AER considers change necessary to correct non-compliance with a provision of the Law or an inconsistency between the schedule and the applicable criteria. Even though the AER might consider change desirable to achieve more complete conformity between the schedule and the principles and objectives of the Law, it would not be entitled to give effect to that view in the decision making process.*

This means that the AER must approve our proposed depreciation schedule unless it considers that it does not comply with the Law or that it is inconsistent with applicable criteria.

15.5.1. Asset lives

Table 15-4 below shows the standard asset lives for each asset class and their remaining lives. The remaining asset lives have been adjusted to reflect the actual capex during the current Access Arrangement period. The remaining life calculation has considered the original calculation approved by the AER in 2012. The Roll Forward Model has been used to establish the remaining lives of assets as at 1 January 2018.

The asset classes and standard lives shown in Table 15-4 are the same as those accepted by the AER in its Final Decision for the current Access Arrangement period, except for:

- Four additional asset classes that we have added to account for our mains replacement program; and
- New meters from 2018.

We explain and justify the need for these new asset classes below, noting that our proposed lives satisfy the requirements in Rule 89(1)(b) that "each asset or group of assets is depreciated over the economic life of that asset or group of assets" and Rule 89(1)(d) that an asset is depreciated only once.

We propose that these new asset classes come into effect from 1 January 2018.

Table 15-4: Asset lives

Asset class	Standard lives approved by AER for 2013-17	Proposed standard lives for 2018-22	Remaining life as at 1 January 2018
Transmission and Distribution	50	50	36.0
Pipeworks Mains (New)	Category did not exist	5	5.0
LP mains – Residual (New)	Category did not exist	50	15.0
Services	50	50	34.7
Pipeworks Services (New)	Category did not exist	5	5.0
LP Services – Residual (New)	Category did not exist	50	15.0
Cathodic protection	50	50	44.3
Supply regs / valve stations	50	50	17.3
Meters to 2017	30	15	5.0
Meters from 2018 (New)	Category did not exist	15	n.a.
Land	n/a	n/a	n.a.
Buildings	50	35	45.5
IT	5	5	2.1
SCADA	15	15	10.0
Other	10	10	5.5

We note that, for the purposes of this Access Arrangement Information, we have not removed any current asset classes and reallocated their residual values to other asset classes. However, we reserve the right to do so following the AER's Draft Decision.

The remainder of this section explains our proposal to:

- Apply the "year-by-year tracking" depreciation approach;
- Change the approach for depreciating assets subject to our Mains Replacement capex program;
- Reduce the standard asset lives for buildings and to scale down the remaining asset lives accordingly
- Fully depreciate our existing meters over the forthcoming Access Arrangement period; and
- Introduce an asset category for new meters with an asset life of 15 years.

15.5.2. "Year-by-year tracking" approach to depreciation

We have applied the AER's preferred "year-by-year tracking" approach to determining regulatory depreciation. The AER applied this approach to the South Australian and Victorian electricity distribution businesses in its recent Distribution Determinations.

The AER described the "year-by-year tracking" approach as follows:

> *Under the year-by-year tracking approach:*
>
> - *assets in existence at 1 January 2011*[76] *are depreciated by asset class using straight-line depreciation with the remaining lives determined in the 2010*[77] *final decision; and*
> - *capex in each year of the 2011 to 2015 period is grouped by asset classes and separately depreciated over their standard lives as approved in the 2010 final decision.*[78]

The AER explained the benefits of the "year-by-year tracking" approach as follows:

> *Each asset class will now have an expanding list of sub-classes to reflect every regulatory year in which capital expenditure on those assets was incurred. This extra data helps track remaining asset values, lives and associated depreciation. The year-by-year tracking approach is more disaggregated, compared with the other approaches, and involves multiple depreciation calculations within each asset class, separately tracking capex by the regulatory year it was incurred. For this reason, it does not combine capex incurred during 2011 to 2015 with existing assets in 2011, and so does not require average remaining asset lives to be estimated at 1 January 2016.*[79]

The AER went on to add:

> *In summary, and consistent with our previous assessment, we consider that the year-by-year tracking approach:*
>
> - *produces depreciation schedules that reflect the nature of the assets and their economic life*
> - *ensures that total depreciation (in real terms) equals the initial value of the assets.*[80]

We consider that the "year-by-year tracking" approach is equally appropriate for us and should be adopted for the same reasons that the AER gave in applying it to the South Australian and Victorian electricity distribution businesses. This approach is consistent with promoting each of the depreciation criteria in Rule 89.

This approach does not change the depreciation profile of the assets or the price to customers. The approach is consistent with standard accounting practice.

15.5.3. Regulatory depreciation of assets subject to Mains Replacement capex program

We propose several changes to the way we depreciate assets that are subject to our Mains Replacement capex program, to meet the depreciation criteria in Rule 89.

a. Framework for depreciating LP mains and associated services

Our initial regulatory asset base was established at privatisation in 1999. This value was $1,214.0 million (Real 2017) or $740.2 (Real 1997)[81]. Two of the asset classes in our RAB have been:

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[76] First year of the regulatory control period.

[77] Last year of the regulatory control period.

[78] AER, "Attachment 5 – Regulatory depreciation | United Energy distribution determination final decision 2016–20", May 2016, page 5-11

[79] AER, "Attachment 5 – Regulatory depreciation | United Energy distribution determination final decision 2016–20", May 2016, page 5-11

[80] AER, "Attachment 5 – Regulatory depreciation | United Energy distribution determination final decision 2016–20", May 2016, page 5-11

[81] "Victorian Third Party Access Code for Natural Gas Pipeline Systems: Access Arrangement Information for Distribution Pipeline by Multinet Gas Pty Ltd and Multinet (Assets) Pty Ltd, Final as at 30 November 1998", page 4 – available at http://www.aemc.gov.au/getattachment/e6130d62-d95a-4b24-9d7a-c7c20f2923d2/Revised-access-arrangement-information-EPD-for-Vic.aspx

- "Transmission and Distribution"; and
- "Services".

We no longer install LP mains (and associated services). We therefore have not added any capex into our RAB for either of these two asset classes for LP mains (and associated services) in recent Access Arrangement periods.

Rather, we are removing and replacing LP mains (and associated services) with HP mains (and associated services) through our LP to HP Mains Replacement capex program. As discussed in section 13.9, we commenced this program in 2003. This is scheduled to be a 30-year program that will be completed by 2033.

Each Access Arrangement period the AER approves:

- A forecast of how many kilometres of LP mains (and associated services) we can remove and replace with HP mains (and associated services) for the purposes of determining our capex allowance for our LP to HP Mains Replacement; and
- A forecast of our regulatory depreciation, which includes accelerated depreciation of the LP mains (and associated services) that we have removed and replaced.

Up to and including the current Access Arrangement period we have depreciated the LP mains (and associated services) that we have removed over five years. We have accounted for our removed:

- LP mains in the "Transmission and Distribution" asset class; and
- Services in the "Services" asset class.

We propose continuing to depreciate these removed LP mains (and associated services) over five years in the forthcoming Access Arrangement period. However, we propose changing our asset classes.

We will continue our current practice of accounting for capex in the current existing asset classes:

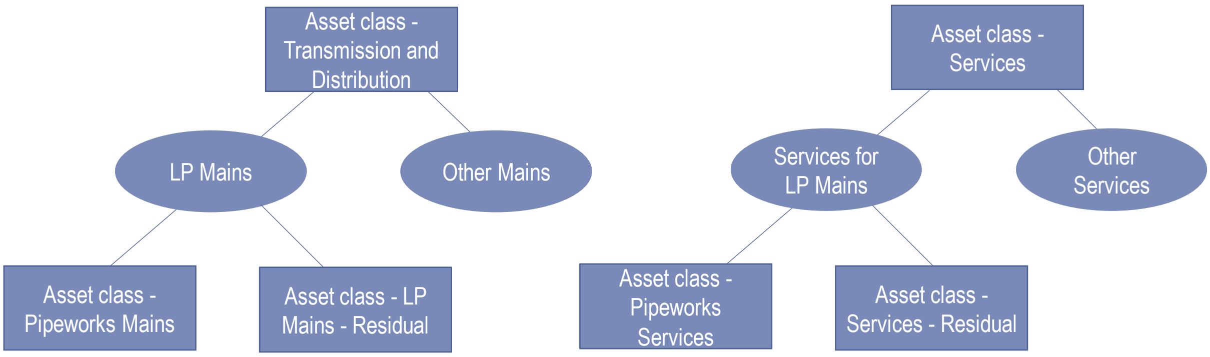
- Class 1 - "Transmission and Distribution" – this will contain new HP and other mains; and
- Class 2 – "Services" – this will contain new services serviced from HP and other mains.

We propose introducing the following new asset classes:

- Class 3 - "Pipeworks Mains" – this will contain our LP mains that we have either previously removed or will be removing over the forthcoming Access Arrangement period;
- Class 4 - "LP mains – Residual" – this will contain our LP mains that have not yet been removed but will be removed and replaced over the remainder of the 30-year replacement program (i.e. after the forthcoming Access Arrangement period);
- Class 5 - "Pipeworks Services" – this will contain our LP services that we have removed and replaced; and
- Class 6 - "LP Services – Residual" – this will contain our services that relate to our LP mains that have not yet been removed but will be removed and replaced over the remainder of the 30-year replacement program.

Figure 15-1 illustrates our asset classes relevant to our mains replacement program that we propose applying in the forthcoming Access Arrangement period.

Figure 15-1: Propose asset classes for mains and services in forthcoming Access Arrangement period



We seek the AER's approval of these asset classes. The change in our framework will improve clarity and transparency about the future regulatory treatment of:

- LP mains (and services) that we have removed and replaced;
- LP mains (and services) still in service but which we intend to remove and replace in accordance with our 30-year mains replacement program; and
- HP and other mains (and services).

Table 15-5 can be seen as a transition. It shows:

- The breakdown of the current two asset classes – Transmission and Distribution, and Services;
- The effect of then separating out from the current two asset classes the LP mains and Services that have not yet been, but will be, removed and replaced over the remainder of the 30-year replacement program; and
- The effect of further separating out the Pipeworks Mains and Pipeworks Services to create the proposed six asset classes.

Table 15-5 shows that the total regulatory asset base remains unchanged under each scenario but that our proposed approach will increase our annual depreciation in the forthcoming Access Arrangement period because:

- The LP mains and Services will be depreciated over 15 years; and
- The Pipeworks Mains and Pipeworks Services assets will be depreciated over five years.

Table 15-5: Roll forward of mains and services using new asset classes – as at 1 January 2018 ($M, Real 2017)

	Current - Two asset classes				Split out Residual LP Mains and Services				Proposed - Split between six asset classes			
	$ RAB value	Distance / Quantity	Asset lives	$ Annual depreci-ation	$ RAB value	Distance / Quantity	Asset lives	$ Annual depreci-ation	$ RAB value	Distance / Quantity	Asset lives	$ Annual depreci-ation
Transmission and Distribution	650.3	10,141.0	31.9	20.4	605.2	7,963.0	34.8	17.4	605.2	7,963.0	34.8	17.4
Pipeworks Mains									17.6	847.0	5.0	3.5
LP Mains Residual					45.2	2,178.0	15.0	3.0	27.6	1,331.0	15.0	1.8
Services	421.8	628,400.0	28.5	14.8	365.8	443,270.0	33.0	11.1	365.8	443,270.0	33.0	11.1
Pipeworks Services									21.8	71,995.0	5.0	4.4
LP Services Residual					56.0	185,130.0	15.0	3.7	34.2	113,135.0	15.0	2.3
Total	**1,072.1**			**35.2**	**1,072.1**			**35.2**	**1,072.1**			**40.4**

We seek the AER's approval of the proposed treatment in Table 15-5 for calculating our regulatory depreciation allowance for the forthcoming Access Arrangement period.

b. Specific Issues

There are three other consequential issues that are relevant to determining the value of our regulatory depreciation for LP mains (and associated services) in the forthcoming Access Arrangement period arising from the AER's treatment of LP mains (and associated services) in the previous and current Access Arrangement periods.

Issue 1 – No regulatory depreciation allowance in the current Access Arrangement period

The AER made no regulatory depreciation allowance in the current Access Arrangement period for LP mains (and associated services). This is because:

- It considered that we "over-recovered" regulatory depreciation in the previous Access Arrangement period (i.e. 2008 to 2012) by virtue of receiving a regulatory depreciation allowance based on replacing 500 kilometres of LP mains but in fact we only replaced 257 kilometres of LP mains in that period;
- Our capex allowance for the current Access Arrangement period was based on replacing 255 kilometres of LP mains; and
- The AER therefore assessed that the regulatory depreciation over-recovery in the previous Access Arrangement period offset the need for any regulatory depreciation allowance in the current Access Arrangement period on our LP mains replacement capex.

We are not contesting this regulatory treatment. We accept that this issue was settled in the AER's Final Determination for the current Access Arrangement period.

Issue 2 – Regulatory depreciation shortfall in the current Access Arrangement period

Despite our acceptance of the regulatory treatment of Issue 1, we have had a regulatory depreciation shortfall in the current Access Arrangement period. This is illustrated in Table 15-6.

Table 15-6: Difference between Allowed and Actual LP to HP Mains Replacement (Kilometres)

Mains	2003 to 2007	2008 to 2012	2013 to 2017		Total
			Final Determination	Pass through	
ESC / AER allowed to remove	540	557	255	272	1,624
Actual removed	537	255	255	272	1,319
Accelerated depreciation applied	540	557	-	-	1,097
Accelerated depreciation shortfall by period	3	302	(255)	(272)	(222)
Cumulative accelerated depreciation shortfall	3	305	50	(222)	(222)

Table 15-6 shows that:

- For the 2003 to 2007 period - the ESCV's regulatory allowance was based on us replacing 540 kilometres of LP mains (and associated services), whereas we actually replaced 537 kilometres. The ESCV's allowance was based on accelerated depreciation of the full 540 kilometres of mains (and associated services). We in effect received an "over allowance" for this period based on 3 kilometres of LP mains (and associated services) that were not ultimately removed and replaced;
- For the 2008 to 2012 period – the AER's regulatory allowance was based on us replacing 557 kilometres of LP mains (and associated services), whereas we actually replaced 255 kilometres (and associated services). The AER's allowance was based on accelerated depreciation of the full 557 kilometres of mains (and associated services). We in effect received an "over allowance" for this period based on 302 kilometres of LP mains (and associated services) that were not ultimately removed and replaced – bringing the cumulative total to 305 kilometres of LP mains (and associated services) over the two periods;
- For the current period:
  - The AER's regulatory depreciation allowance in its Final Determination was based on us replacing 255 kilometres of LP mains (and associated services), although none of this was subject to accelerated depreciation – rather, the depreciation allowance was based on the asset's standard remaining lives. This reduced the cumulative over allowance to 50 kilometres of LP mains (and associated services) over the three periods; and
  - The AER's regulatory allowance in its pass through was based on us replacing 272 kilometres of LP mains (and associated services), and again none of this was subject to accelerated depreciation. This therefore results in a cumulative shortfall of 222 kilometres of LP mains (and associated services) that has not been subject to accelerated depreciation.

The financial impact of the above is therefore calculated as the difference between the 222 kilometres of LP mains (and associated services) that were depreciated based on their standard remaining lives, rather than accelerated depreciation over five-years. This equates to the opening remaining value of these assets at the start of 2018, which is $10.3 million (Real, 2017).

Table 15-7 shows the length of LP mains that:

- Was in place when the LP replacement program commenced in 2003;
- Has been removed between 2003 and 2017; and
- Will be removed between 2018 and 2022.

Table 15-7: Length of LP Mains (Kilometres)

	Removed	Cumulative removed	Balance remaining
2003 – start of LP replacement program	n.a.	n.a.	3,275
2003 to 2017 – LP mains removed and depreciated	(1,097)	(1,097)	2,178
2003 to 2017 – LP mains removed but not depreciated in period	(222)	(1,319)	1,956
2018 to 2022 – LP mains removed and depreciated	(625)	(1,944)	1,331

Issue 3 – Regulatory depreciation for LP to HP mains replacement in forthcoming Access Arrangement period

We propose removing and replacing 625 kilometres of LP mains (and associated services) in the next Access Arrangement period under our LP to HP Mains Replacement capex program.

We propose that this regulatory depreciation allowance be added to the shortfall described under Issue 2 and also be treated using the framework and asset classes discussed above.

The total accelerated depreciation of our LP mains (and associated services) that will be recovered in the forthcoming Access Arrangement period (including the shortfall in Issue 2) is therefore $39.4 million (Real 2017).

15.5.4. Reduce standard asset lives for buildings

Our existing standard asset life for regulatory purposes for buildings is 50 years.

We are proposing to reduce this to 35 years. This is consistent with the standard life for buildings for tax purposes approved by the Australian Taxation Office in its ruling TR 2016/1. We consider that this provides a sound basis for future regulatory asset lives.

We have proportionately scaled down our remaining asset lives at the start of the forthcoming Access Arrangement period to reflect this change.

15.5.5. Fully depreciate our existing meters over the forthcoming Access Arrangement period

The remaining life of our existing meters will be 6.62 years at the start of the forthcoming Access Arrangement period.

We propose accelerating the regulatory depreciation so that our existing meters are fully depreciated over the five years of the forthcoming Access Arrangement period. This will simplify our regulatory asset base by removing this asset category for the following Access Arrangement period.

15.5.6. Introduce an asset category for new meters

We propose introducing an asset category for new meters in the forthcoming Access Arrangement period so that they can be treated separately from existing meters.

The standard lives for existing meters are 30 years. We propose that a standard life for new meters of 15 years. This is consistent with the standard life for new meters for tax purposes approved by the Australian Taxation Office in its ruling TR 2016/1 and what the AER applies for other gas distributors. We consider that this provides a sound basis for future regulatory asset lives.

15.6. Forecast regulatory depreciation for the forthcoming Access Arrangement period

Table 15-8 details our forecast depreciation for the forthcoming Access Arrangement period.

Table 15-8: Forecast depreciation ($M, Real 2017)

	2018	2019	2020	2021	2022
Regulatory depreciation	65.5	67.0	67.1	69.9	72.7

Our forecast regulatory depreciation reflects:

- The opening asset base and forecast RAB values described in section 15.2;
- The standard and remaining asset lives set out in Table 15-4; and
- The continued use of a straight-line depreciation approach, consistent with section 15.5.

16. Rate of return, inflation and debt and equity raising costs

Key messages:

- Our approach to the cost of debt follows the Rate of Return Guideline's (Guideline) approach, with the addition of a third index from Thomson Reuters to complement those from the Reserve Bank and Bloomberg currently used by the AER.
- Our approach to the cost of equity follows the Guideline approach in using the SL-CAPM as a foundation model and making an adjustment for the downward bias of this model, and in using historical averages and the dividend growth model to estimate the Market Risk Premium. The raw numbers for the equity risk premium have changed because the market data have changed.
- Our approach to inflation is based on the inflation that is embedded in bonds (and thus the WACC) rather than on the Reserve Bank mid-point used by the AER because the latter approach gives answers which are clearly inconsistent with market expectations about inflation and thus could not contribute to the ARORO.

In this section, we summarise our approach to the estimation of the rate of return, inflation and debt and equity raising costs.

Our Rate of Return Overview Document that is an attachment to this Access Arrangement Information further explains and justifies our proposal. We have also provided a range of other supporting documents that explain and justify our approach, which are listed at Chapter 24.

16.1. Rate of return

16.1.1. Overview of the rate of return

The NGR provides that our return on capital should be calculated as the allowed rate of return multiplied by the Regulatory Asset Base. Our allowed rate of return should be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the service provider in respect of the provision of reference services. In other words, the allowed rate of return objective should be satisfied.[82] In addition, the rate of return must be calculated as the weighted average of the return on equity and the return on debt, determined on a 'nominal vanilla basis' that is consistent with an estimate of the value of imputation credits.[83]

We need to earn an appropriate and fair rate of return so that we can continue to invest in our $1.2 billion network in a manner that best supports the long-term interests of our customers. The return on capital aims to compensate our debt and equity holders for the opportunity cost of either lending or investing their funds in our network — these funds are essential to deliver safe and reliable electricity distribution services to our customers.

For the forthcoming regulatory period, we propose an allowed rate of return of 6.12 per cent per annum, which has been derived using the formula for a standard, nominal vanilla WACC.[84] The overall return on capital is comprised of a proposed return on debt of 4.67 per cent, a proposed return on equity of 8.31 per cent, and a proposed gearing of 60 per cent. Table 16-1 details the key components of our proposed rate of return.

[82] NGR 87(2)

[83] NGR 84(4(b))

[84] That is, the WACC is the sum of gearing*(cost of debt) + (1-gearing)*(cost of equity)

Table 16-1: Elements of WACC Estimate

Element	Value
Return on equity	8.31%
Risk-free rate	1.92%
Market risk premium	7.50%
Beta	0.7
Bias adjustment (alpha)	1.14%
Return on debt	4.67%
Gearing	0.6
Post-tax nominal WACC	**6.12%**
Inflation	1.68%

Our approach in respect of the cost of debt follows the Guideline in respect of the tenor, the use of third party BBB-band indices and the transition from the on-the-day approach which presently prevails. Our gearing level also follows the Guideline at 60 percent. Our only departure in respect of the Guideline is that we rely upon three third-party indices (from Bloomberg, Thomson Reuters and the RBA) rather than the two relied upon in the Guideline (Bloomberg and the RBA). We note that the Thomson Reuters index was not available at the time of the Guideline, and we have adopted it for two reasons. Firstly, all indices are imperfect, and we consider the addition of a third index assists in addressing some of the imperfections in the two indices currently relied upon by the AER. Secondly, the NGR (87(5)) requires us to consider market data, and many market players get their bond information from Thomson Reuters, so including its index is more in keeping with NGR 87(5)) than relying on only one commercial index from Bloomberg.

In respect of the cost of equity, we follow the approach the AER took in its Guideline of relying primarily upon the SL-CAPM, but adjusting to compensate for known problems in the model, such as the downward bias it exhibits in respect of low beta stocks. Likewise, we make use of historical (or Ibbotson) estimates as well as those from the dividend grown model (DGM) to estimate the MRP, and do so in the same way the AER suggests it does in the Guideline.

Our issue, however, is that the Guideline is now three years old, and markets have moved. We believe that approaches to the WACC need to be flexible to changing market conditions and allow new information to be incorporated.[85] Our point of departure is not, essentially, methodological, but merely reflects an update of the numbers used, following as best we can the AER's approach for deriving those numbers in the Guideline.

In respect of the MRP, the AER's approach at the time of the release of the Guideline yields 6.5 percent, but that same approach now yields 7.5 percent. We acknowledge that the AER has used an MRP of 6.5 percent in recent decisions, but contend that this represents a change from the Guideline as it would be mathematically impossible to give the same weight to the same information as the AER did in the Guideline and still obtain an MRP estimate of 6.5 per cent.

In respect of beta, the mean or best estimate was around 0.5 at the time of the Guideline, and this was adjusted to the top of a range the AER determined reasonable (0.4 to 0.7) to account for other information such as the

[85] AER, *Rate of Return Guidelines*, December 2013, p6

problem of downward bias in respect of the SL-CAPM. The mean beta estimate is now around 0.7, so one could not use a beta of 0.7 and be consistent with the approach the AER took in its Guideline.

Our problem is that, although the AER's Rate of Return Guideline explains what information the AER did and did not consider relevant, it does not say how the AER moved from its mean to its adjusted beta. We have therefore attempted to make an adjustment in a transparent, empirically based fashion. Additionally, taking advice from the AER's own experts, rather than making our adjustment to beta (although we cross check with a beta adjustment) we add part of the "alpha" or intercept in Henry's version of the SL-CAPM. In fact, we add just enough of this alpha to remove the well-known problem of downward bias in the SL-CAPM, which is why this is referred to as a "bias adjustment" in Table 16-1.

16.2. Inflation

The estimate of expected inflation influences the determination of several building blocks, including the indexation of the regulatory asset base, depreciation and the return on capital. If the estimate of expected inflation used to derive the building blocks is not consistent with inflation expectations, the result will be a potential under-recovery of costs (if the forecast of inflation is too high) or an over-recovery (if the forecast is too low) compared to what is expected in the market. This is most particularly the case when the estimate used in one part of the regulatory determination (the AER's PTRM) is significantly different from the estimate used in other parts (the WACC). The estimates of inflation must be consistent throughout the regulatory decision and we consider that basing all estimates on the inflation rate implicit in bond rates is the most appropriate course to take. We have therefore not used the AER's PTRM, which is not a requirement under the National Gas Rules. Rather we have used a tailored model called the MG AAR Pricing Model, which ensures a consistent use of inflation.

The AER's estimate of expected inflation influences several building blocks, including the indexation of the regulatory asset base, depreciation and the return on capital. Its estimate of expected inflation would in fact have recently implied negative real bond rates, despite the fact that positive indexed bonds are available in the marketplace and still implies a much lower real rate than is available on inflation indexed government bonds. The consequence is that the (negative) adjustment made to the revenue requirement for expected inflation is larger than the compensation the market expects we will receive for inflation during the coming Access Arrangement period. Such expected under-compensation means we cannot expect to recover at least our efficient costs and the AER's decision will not contribute to the achievement of the NGO.

Our proposal is to estimate expected inflation by reference to a market-based approach (the break-even approach) which we submit gives rise to an estimate of expected inflation which is consistent with market expectations, most particularly those implicit in bond rates. This breakeven estimate, which will be updated prior to the Final Decision along with other market numbers, is 1.68 per cent per annum.

16.3. Inter-relationships

The most important inter-relationships are between gamma and the MRP, and between inflation in the WACC and inflation in the AER's PTRM. The latter is discussed above. In respect of the former our proposed MRP of 7.5 per cent considers this interrelationship. Frontier Economics conclude that the current evidence supports an estimate of at least 7.5 per cent based on calculations of the MRP which assume a theta value of 0.35, as we have proposed.[86]

If the AER were to adopt an estimate of theta to 0.35, as we propose, while maintaining its current approach to estimating the MRP (which we submit to be incorrect), no adjustment to the AER's MRP estimate of 6.5 per cent would be necessary. This is because the historical excess return estimates on which the AER primarily relies for its MRP are relatively insensitive to the estimate of theta.[87]

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[86] Supporting Submission 16.4, section 8.6

[87] Supporting Submission 16.4, section 8.7.

16.4. Cost of debt and equity raising

We adopt the same approach to debt and equity raising costs as was accepted by the AER for United Energy. This gives rise to equity raising costs of $2.3 million and debt raising costs of 9.1 bps per annum on an assumed debt portfolio of between $715 million and $730 million (that is, 60 percent of the RAB), or between $650,000 and $730,000 per annum over the next five years.

17. Estimated cost of corporate income tax

Key message:

- We propose a value of imputation credits of 0.25, being the product of a distribution rate of 0.7 and theta of 0.35.
- The components of the cost of corporate income tax calculation are presented in our Tax Model, AAR Pricing Model and Roll Forward Model which are submitted as part of this Access Arrangement Proposal.

Our approach to gamma mirrors that proposed by service providers consistently since the AER's Rate of Return Guideline was finalised. Prior to the AER's Guideline being published, gamma was set based on market value studies as directed by the Tribunal in 2011 and given a value of 0.25.[88] In its Guideline, the AER sought to change both the basis for, and value of, gamma. It changed the basis from a market value to a utilisation rate, which meant that market value studies were given limited weight and equity ownership rates and taxation studies (previously only used as upper bounds) gained higher prominence. This has the effect of changing the value for gamma to 0.4 (0.5 in the Guideline and subsequently amended by the AER).

The AER's conceptual approach, relying on the pre-personal tax and pre-personal costs value of imputation credits, and the evidence on which it relies to derive its gamma estimate, has not changed from its NSW/ACT decisions made in October 2015. In its most recent decisions[89] the AER has continued to apply an estimate of the value of imputation credits of 0.4, selected from within a range of 0.3 to 0.5.

There have been several recent merits and judicial reviews of the AER's approach to gamma which have resulted in conflicting outcomes. At the time of this proposal several legal reviews of gamma remain unresolved.[90]

For the reasons set out in our Corporate Income Tax Overview Paper and the accompanying expert reports, we remain of the view that the correct estimate of the value of imputation credits is 0.25 (the product of a distribution rate of 0.7 and theta of 0.35) and that estimate is adopted in this proposal.[91] The estimate is based on the post personal tax and personal cost market value of imputation credits to shareholders, consistent with the correct interpretation of the National Gas Rules and the most up to date and best estimate of the value of imputation credits.

17.1. Calculation of corporate income tax allowance

We have applied the AER's Roll Forward Model to assess the progression of the tax asset base over the current regulatory period, from January 2013 to December 2017. The method used for determining the opening tax asset base in January 2018, in the current Roll Forward Model, is consistent with the method that was used by the AER to perform tax asset calculations in its PTRM for 2013 to 2017. The classification of assets in the tax asset base of the Roll-Forward Model, as at January 2018, corresponds with the classification of assets in the RAB.

In the AER's PTRM for the forthcoming regulatory period, there is a similar alignment between the classification of assets in the tax asset base and in the RAB. A straight-line method of depreciation has been used in the Tax Asset Base, consistent with the method that has already been adopted for the RAB.

The AER's PTRM calculates tax depreciation on a straight line or "prime cost" method. Under this method, the original cost of the asset is depreciated over the effective life of that asset for tax purposes, which generally gives rise to the same amount of depreciation deductions in each year for that asset. In the AER's PTRM, forecast

[88] [2011] ACompT 9, *Application by EnergexLimited*.

[89] For example, in the AER, *Draft Decision Powerlink Transmission Determination 2017-18 to 2021-22: Attachment 4 – Value of imputation credits,* September 2016

[90] Including the AER's judicial review application in respect of the Australian Competition Tribunal's decision in [2016] ACompT 1 (Ausgrid), [2016] ACompT11 (SAPN decision) and the merits review applications by the Victorian Electricity distributors and ActewAGL Gas, currently reserved by the Tribunal.

[91] Based on the update of the SFG dividend drop off study to 2016 in Supporting Document 17.1, and on Supporting Document 17.3

capex is treated in a comparable manner in the sense that it is depreciated on a straight-line method over the effective life of the asset for tax purposes.

In order to produce tax standard lives, information was sourced from tax rulings published by the ATO, the most pertinent ruling being TR 2014/4 from July 2014. A process was adopted to combine the lives for published tax asset categories into effective groupings which corresponded with the tax asset base categories in the AER's PTRM. In effect, weighted average standard asset lives were determined for the broad, higher level categories that are represented in the 'Inputs' worksheet of the PTRM. The discussion which accompanies Table 17-1 explains the rationale for the approach, and refers to the other data sources used.

Tax remaining lives were calculated after making use of the existing information on RAB standard lives and RAB remaining lives. The preferred approach was to set the remaining lives of assets in the tax asset base categories to be equal to the remaining lives used in the corresponding RAB categories.

Table 17-1: The calculation of weighted average tax standard lives nominal

ATO Tax Asset Descriptions	ATO standard lives	AER Post-Tax Revenue Model RAB categories	Weighted average tax standard lives
Pipelines - transmission, spur or lateral/Pipelines (including high, medium and low pressure)	50.0	Transmission and distribution	34.8
Pipelines (including high, medium and low pressure)	50.0	Services	33.0
Pipelines (including high, medium and low pressure)	50.0	Cathodic Protection	44.3
Regulators	40.0	Supply Regs/Valve stations	13.9
		Meters to 2017	5.0
Gas meters	15.0	Meters from 2018 (New)	-
		Land	-
Building maintenance units	35.0	Buildings	31.8
Computers: Generally	4.0	IT	1.7
Control systems (excl computers)	10.0	SCADA	-
		Other	11.1

Source: ATO (2014), Tax Ruling, TR 2014/4, Australian Taxation Office, July 2014.

The tax asset lives that were sourced from the ATO were inserted into Table 17-1 as shown above. The ATO tax asset categories, for which the lives were collected, appeared to offer an approximate concordance back to the RAB categories. When the capex based weights were applied to the ATO tax asset lives, presented for different types of electricity network assets, weighted average tax standard lives were produced, and these have been reported in Table 17-1.

The components of the cost of corporate income tax calculation are presented in our Tax Model, AAR Pricing Model and Roll Forward Model which are submitted as part of this Access Arrangement Proposal. Table 17-2 below details our forecast of the cost of corporate income tax for the forthcoming Access Arrangement period.

Table 17-2: Cost of Corporate Income Tax ($M, Real 2017)

	2018	2019	2020	2021	2022	Total
Cost of corporate income tax	17.4	16.0	20.8	21.1	20.8	96.1

18. Incentive schemes

Key messages:

- We propose making no changes to the current Efficiency Benefit Sharing Scheme for the forthcoming Access Arrangement period, other than to revise the relevant years and the table of opex forecasts in clause 6.4(k) of Part B.
- We propose introducing a new Gas Network Innovation Competition in the forthcoming Access Arrangement period, similar to Ofgem's arrangement for gas distributors in Great Britain.
- We consider that there is no justification for introducing either a Capital Expenditure Sharing Scheme or a Customer Service Incentive Scheme in the forthcoming Access Arrangement period as there is no existing "problem" that needs to be addressed. Any such schemes should only be introduced on a national, rather than on a one-off, basis for individual jurisdictions.

This chapter describes and justifies our proposed incentive mechanisms.

Rule 98 of the NGR provides that an Access Arrangement may include (or the AER may require it to include) one or more incentive mechanisms to further encourage efficiency in the provision of services by the service provider. Under Rule 98 an incentive mechanism must be consistent with the revenue and pricing principles (RPPs) in the NGR.

The RPPs are set out in section 24 of the NGL. The AER in past decisions[92] on incentive mechanisms proposed by other gas distributors has stated that the following RPP is, in its view, the most relevant:

> *A service provider should be provided with effective incentives in order to promote economic efficiency with respect to reference services the service provider provides. The economic efficiency that should be promoted include –*
>
> *(a) efficient investment in, or in connection with, a pipeline with which the service provider provides reference services; and*
>
> *(b) the efficient provision of pipeline services; and*
>
> *(c) the efficient use of the pipeline.*[93]

The AER's past consideration of incentive mechanisms has focused on incentives for efficient investment and the efficient provision of pipeline services.[94]

Rule 72(1)(l) provides that the Access Arrangement Information for a full Access Arrangement proposal must set out the service provider's rationale for any proposed incentive mechanism.

18.1. Proposed incentive mechanisms

We propose that the following incentive mechanisms apply in the forthcoming Access Arrangement period:

- An Efficiency Benefit Sharing Scheme (EBSS) in relation to our opex; and
- A Network Innovation Allowance.

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[92] AER Final Decision, Jemena Gas Networks (NSW) Access Arrangement 2015-20, November 2015, Attachment 9, Efficiency carryover mechanism, p. 9-7 ;; and Attachment 14 – Other Incentive schemes, AER Draft decision, Australian Gas Networks Access Arrangement, p. 14-7

[93] Section 24(3**) NGL**

[94] Efficient use of pipelines generally concerns the design of tariffs and the efficient recovery or revenue over time which are not matters generally considered in discussion of incentive schemes.

18.1.1. Efficiency Benefit Sharing Scheme

We propose continuing to apply the existing EBSS in the forthcoming Access Arrangement period that is set out in clause 6.4 of Part B of our current Access Arrangement. There was no disagreement amongst our stakeholders that we consulted that the EBSS should continue to apply in its current form.

The EBSS provides us with a continuous incentive to find opex efficiencies through a combination of:

- An ex ante forecast of opex; and
- Increments or decrements that allow us to retain efficiency gains or losses for five years.

We proposed the EBSS for the current Access Arrangement period in accordance with Rule 98 of the NGR and it was approved, with some modifications, by the AER. The mechanism also applied in the previous 2008 to 2012 Access Arrangement period.

We propose making no changes to the current EBSS for the forthcoming Access Arrangement period, other than to revise the relevant years and the table of opex forecasts in clause 6.4(k) of Part B of our current Access Arrangement, consistent with those detailed in Chapter 14 of this Access Arrangement Information.

As noted in section 14.4, our strong efficiency performance relative to our peers indicates that we are continuing to respond positively to the EBSS in the current Access Arrangement period and are operating at or close to the efficient frontier of gas distributors. In particular:

- We expect to underspend the AER's opex benchmark allowance by $2.2 million between 2013 and 2016;
- Economic Insights' benchmarking shows that we operated below the average opex per customer for the seven gas distributors with relatively high customer density for the 2011 to 2015 period and our opex PFP index increased at an average annual rate of 2.5 per cent between 1999 and 2015 and 0.7 per cent from 2008 to 2015; and
- Our 2016 opex provides an efficient base year for determining our opex forecast for the forthcoming Access Arrangement period.

We consider that the EBSS is consistent with the RPP because it is specifically designed to incentivise gas distributors to pursue continuous opex efficiency improvements over time and to share the benefits of these improvements fairly with consumers. The current EBSS has the effect of allowing gas distributors to retain about 30 per cent of the efficiency gain (or loss) achieved at any time within the Access Arrangement period and customers receiving the remaining 70 per cent.

We noted that the AER has set essentially the same EBSS incentive mechanism for all electricity and gas distributors with a five-year regulatory or Access Arrangement period. Maintaining the EBSS is therefore consistent with accepted regulatory practice for Australian energy networks.

18.1.2. Network Innovation Competition

We consider that there is a gap in the regulatory framework because it does not currently provide any funding for, or explicit incentives for gas distributors to pursue, network innovation.

Innovation involves entrepreneurship with a view to reducing costs or improving performance outcomes, including in relation to safety, reliability, customer service and workforce renewal.

For a business such as ours, innovation would typically involve investigating whether and how to adopt emerging but as yet unproven technologies.

Innovation is particularly important for us in the forthcoming Access Arrangement period because:

- Gas is a fuel of choice and we need to be able to differentiate our offering, in terms of both price and service, from our competitors;
- Our operating environment will continue to change and we need to be able to respond accordingly; and

- Economic Insights' recent benchmarking indicates that we are currently operating close to, or at, the efficient performance frontier. We need to improve continually to provide cost efficient and customer-focussed services in the future.

We consider that investing in network innovation is essential to enable us to continue to deliver on the NGO, which is to:

> *promote efficient investment in, and efficient operation and use of natural gas services for the long term interest of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas.*[95]

We propose that the AER give effect to the need to promote innovation through a new Gas Network Innovation Competition (Gas NIC). We propose that this be structured similarly to the arrangement that Ofgem has implemented for the gas distributors in Great Britain. Ofgem describes its Gas NIC as follows:

> *The Gas NIC is an annual opportunity for Gas network companies to compete for funding for the development and demonstration of new technologies, operating and commercial arrangements. Funding will be provided for the best innovation projects which help all network operators understand what they need to do to provide environmental benefits, cost reductions and security of supply as Great Britain (GB) moves to a low carbon economy. Up to £18m per annum is available through the Gas NIC.*[96]

We also consider that a Gas NIC is consistent with the RPP because it would be specifically designed to encourage gas distributors to pursue entrepreneurship with a view to reducing costs or improving performance outcomes, including in relation to safety, reliability, customer service and workforce renewal.

The Victorian gas distributors engaged Farrier Swier Consulting to consult stakeholders on alternative incentive mechanisms for the forthcoming Access Arrangement period. Their Findings Report noted that:

> *There was support for the proposition that network innovation is likely to promote the long-term interests of consumers. The ENA supported the need to incentivise innovation. CUAC stated that it "recognise(d) the value of innovation to develop further efficiencies to deliver benefits for DBs and their customers through lower prices".*[97]

We would be pleased to work with the AER to develop how a Gas NIC could be introduced for the Victorian gas distributors in the forthcoming Access Arrangement period.

18.2. Not proposing a Capital or Customer Service Incentive Mechanism

We consulted stakeholders about potentially introducing a Capital Expenditure Sharing Scheme (CESS) and a Customer Service Incentive Scheme (CSIS) in the forthcoming Access Arrangement period. We also note that the AER's "Statement of Intent 2016-17" foreshadowed the possibility of extending its current CESS from electricity to gas in the coming years.

We consider that there is no justification for introducing either of these mechanisms at this time as there is no existing "problem" that needs to be addressed. There was also no compelling support from our stakeholder consultations for introducing either of these mechanisms. In particular:

- We do not support introducing a CESS. The key rationale for introducing such a scheme is to incentivise a gas distributor not to trade-off capex and opex inappropriately and to counter-balance an EBSS. There is no evidence that we have been making any such inappropriate trade-offs or that we have been inappropriately

[95] Section 23 NGL

[96] See - https://www.ofgem.gov.uk/network-regulation-riio-model/network-innovation/gas-network-innovation-competition

[97] Farrier Swier Consulting, "Findings Report: Victorian Gas Distribution Businesses' consultation on Incentive Mechanisms - 2018 to 2022 Gas Access Arrangement Review", September 2016, page 17

preferencing one form of expenditure over another. There is therefore no need or justification for us to have a CESS in the forthcoming Access Arrangement period; and

- We do not support introducing a CSIS. The key rationale for introducing such a scheme is to incentivise a gas distributor to improve its customer service – especially its reliability – performance and not to reduce its expenditure inappropriately at the expense of customer service outcomes. We have consistently delivered extremely high reliability performance, as detailed in section 6.3, and there is no evidence that we have been inappropriately reducing our expenditure at the expense of service outcomes. There is therefore no need or justification for us to have a Customer Service Incentive Scheme in the forthcoming Access Arrangement period.

The AER should only consider introducing any such schemes where there is a compelling reason for doing so. This should only be undertaken on a national, rather than a one-off, basis for individual jurisdictions.

19. Pass through events

Key messages:

- Pass through events allow risks of unpredictable events to be managed in a way that minimises costs to our customers.
- We are proposing the following defined events – change in taxes event, Retailer Insolvency event, insurer credit risk event, insurance cap event, regulatory change event, service standard change event, terrorism event, disaster event, National Energy Customer Framework event and Major Upstream Failure event.

19.1. Overview

We are exposed to unpredictable, high-cost events that are beyond our control. Rule 97 of the NGR allows a reference tariff variation mechanism to accommodate cost pass throughs for defined events to manage these risks. The regulatory principle of allowing pass through events is that it is better to provide arrangements for cost recovery if these uncertain events arise, rather than providing gas distributors with a forecast amount in its total revenue requirement. This approach ensures that costs are only recovered from customers if they arise from pre-defined events and are efficiently incurred.

The application of the weighted average cost of capital to the regulatory asset base does not compensate for non-systematic risks. Even if adjustments were made to the weighted average cost of capital to compensate for the risks of pass through events, the high level of uncertainty regarding the actual costs of uncertain events means that this form of compensation is unlikely to prove satisfactory to us or customers. It is therefore better to deal with the costs of uncertain events as they arise.

The NGR allow gas distributors to define cost pass through events. We propose the following events should apply in the forthcoming regulatory period and have included these in Part A of our Access Arrangement.

- Change in Taxes Event;
- Retailer Insolvency event;
- Insurer Credit Risk Event;
- Insurance Cap Event;
- Regulatory Change Event;
- Service Standard Event;
- Terrorism Event;
- Disaster Event;
- National Energy Customer Framework Event; and
- Major Upstream Failure Event.

These proposed pass through events are consistent with those in the current Access Arrangement, except for:

- The Mains Replacement Event and Declared Retailer of Last Resort Event, which have been removed; and
- The Retailer Insolvency Event and Major Upstream Failure Event, which have been added.

The remainder of this chapter addresses each of the pass through provisions in turn.

19.2. Change in Taxes event

Our current Access Arrangement includes a Change in Taxes Event. We propose continuing this event in the forthcoming Access Arrangement period. The nature of a change in tax event makes it impossible to forecast either its occurrence or the cost impact. A pass through mechanism is therefore an appropriate regulatory mechanism to address the impact of a change in tax event. A pass through mechanism avoids the need to make prior allowance for the cost of a Change in Tax Event in our building block requirement. We propose no change to our current Access Arrangement:

***Change in Taxes Event** means an event where:*

(a) *any of the following occurs during the course of the Access Arrangement period:*

(1) *a change in a Relevant Tax, in the application or official interpretation of a Relevant Tax, in the rate of a Relevant Tax, or in the way a Relevant Tax is calculated;*

(2) *the removal of a Relevant Tax;*

(3) *the imposition of a Relevant Tax; and*

(b) *in consequence:*

the costs to the Service Provider of providing Reference Services are Materially increased or decreased.

19.3. Insurer Credit Risk Event

We operate with a prudent level of insurance provided by our nominated insurers. If our insurers became insolvent, we could incur potential costs. We consider that this risk is uncontrollable and that we are not in a position to take prudent and efficient actions to mitigate such a risk.

This definition accords with the requirements of the pass through event considerations because:

- The event is clearly identified;
- A prudent service provider could not reasonably prevent the event from occurring or substantially mitigate the cost impact of such an event as it depends on the business decisions and action of the insurer. We manage our risk of insurer insolvency at the time of placing insurance by selecting insurers with a Standard and Poor's credit rating of A- or better. In addition, our public liability and property (ISR) insurance policies include multiple insurers which allow us to diversify our insurer insolvency risk for these policies. While we monitor the credit ratings of our insurers to assess any deterioration in insurer credit risk, the possibility of an insurer becoming insolvent following placement is ultimately uncontrollable;
- As part of this annual process the ongoing viability and credit rating of the insurance company is assessed. We have no incentive to obtain insurance from providers who are not capable of paying large claims because this has the potential to leave us exposed. We can assess the viability of an insurer by reviewing its track record, size, credit rating and reputation but, despite these efforts, the possibility of an insurer becoming insolvent is ultimately uncontrollable;
- We cannot insure against the event on reasonable economic terms;
- We cannot self-insure the event on the basis that it is not possible to calculate the self-insurance premium and the potential cost would have a significant impact on our ability to provide network services; and
- The event is consistent with nominated pass through events for the Victorian electricity distribution businesses in the last AER determination.

We propose no change to the current access arrangement for this event:

***Insurer Credit Risk Event** means an event where the insolvency of the nominated insurers of the Service Provider occurs, as a result of which the Service Provider:*

(a) *incurs Materially higher or lower costs for insurance premiums than those incurred immediately prior to the insolvency; or*

(b) *in respect of a claim for a risk that would have been insured by the Service Provider's insolvent insurers, is under a new policy subject to a materially higher or lower claim limit or a materially higher or lower deductible than would have applied under the policy with the insolvent insurer; or*

(c) *incurs additional costs associated with self-funding an insurance claim which would have otherwise been covered by the insolvent insurer.*

19.4. Insurance Cap Event

We consider that the probability of a significant insurance event that materially exceeds the limit of our insurance cover is low. However, should such an event occur, it could have a material impact on the cost of providing Haulage Reference Services.

We propose no change to the current access arrangement for this event:

***Insurance Cap Event** means an event whereby:*

(a) *the Service Provider makes a claim or claims on an insurance policy;*

(b) *the Service Provider incurs costs beyond the relevant policy limit of that insurance policy;*

(c) *the costs beyond the relevant insurance policy limit Materially increase the costs to the Service Provider of providing Reference Services;*

(d) *The relevant policy limit is the greater of Multinet's actual policy limit at the time of the event that gives rise to the claim and its policy limit at the time the AER made its Final Decision on Multinet's access arrangement proposal for the period 2018-22, with reference to the forecast operating expenditure allowance approved in the AER's Final Decision and the reasons for that decision; and*

(e) *A relevant insurance policy is an insurance policy held during the 2018-22 Access Arrangement Period or a previous period in which access to the pipeline services was regulated.*

19.5. Regulatory Change Event

We are not able to foresee all regulatory changes. Changes in our obligations in the forthcoming Access Arrangement period can include requirements mandated by a regulatory authority, act of parliament, market operator or government requirement.

Changes in obligations in this area could include, amendments in any part of the regulatory framework, including:

- Lifting of the National Measurement Act exemption for gas metering and the introduction of new metering/metrology arrangements;
- National or jurisdictional policy reforms; and
- Changes in gas market obligations in relation to transactions or procedure harmonisation.

Where the detail of the obligations and timing of any possible impact is unclear, we cannot accurately forecast the costs.

We propose no change to the current access arrangement for this pass through event:

> ***Regulatory Change Event*** *means the introduction of, or a change in, a regulatory obligation or requirement that:*
>
> (a) *falls within no other category of Relevant Pass Through Event; and*
>
> (b) *occurs during the course of an Access Arrangement Period; and*
>
> (c) *affects the manner in which the Service Provider provides Reference Services; and*
>
> (d) *Materially increases or Materially decreases the costs of providing those Reference Services.*

19.6. Service Standard Event

There is a potential that a legislative or administrative act could vary the pipeline services that we provide during the forthcoming Access Arrangement period by imposing new or varied standards in the provision of these services. A service standard change could increase or decrease our costs. This is a foreseeable event given the level of change in the industry, but is not able to be accurately forecast and is outside of our control.

We propose no change to the current access arrangement for this pass through event:

> ***Service Standard Event*** *means a legislative or administrative act or decision that falls within no other category of Relevant Pass Through Event that:*
>
> (a) *has the effect of:*
>
> *(1)* *varying, during the course of an access arrangement period, the manner in which the Service Provider is required to provide a Reference Service;*
>
> *(2)* *imposing, removing or varying, during the course of an access arrangement period, minimum service standards applicable to Reference Services; or*
>
> *(3)* *altering, during the course of an access arrangement period, the nature or scope of the Reference Services, provided by the Service Provider; and*
>
> (b) *Materially increases or Materially decreases the costs to the Service Provider of providing Haulage Reference Services.*

19.7. Terrorism Event

The nature of a terrorism event makes it impossible to forecast either its occurrence or the cost impact. A pass through mechanism is therefore an appropriate regulatory mechanism to address the impact of a terrorism event. A pass through mechanism avoids the need to make a prior allowance for the cost of a terrorism event in our building block revenue requirements.

The terrorism event accords with the pass through event considerations:

- The event is clearly identified;
- A prudent service provider could not reasonably prevent the event from occurring or substantially mitigate the cost impact of such an event as each is effectively uncontrollable;
- We cannot insure against the event on reasonable economic terms;
- We cannot self-insure the event on the basis that it is not possible to calculate the self-insurance premium and the potential cost would have a significant impact on our ability to provide distribution services;
- The event is consistent with pass through events accepted by the AER in our current access arrangement and in the AER's recent SA and Vic final determinations.

We propose no change to the current access arrangement for this pass through event:

***Terrorism Event** means an act (including, but not limited to, the use of force or violence or the threat of force or violence) of any person or group of persons (whether acting alone or on behalf of or in connection with any organisation or government), occurring during the Access Arrangement period, which from its nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons (including the intention to influence or intimidate any government or put the public, or any section of the public, in fear) and which Materially increases the costs to the Service Provider of providing a Reference Service.*

19.8. Disaster Event

The same rationale applies for a disaster event as for the terrorism event. We propose the following definition consistent with the current access arrangement;

Disaster Event means:

(a) *major fire, flood, earthquake or other natural disaster;*

(b) *pandemic or plague;*

(c) *major civil disturbances;*

(d) *acts of war (but excluding any Terrorism Event),*

(but excluding those events for which external insurance or self-insurance has been included within the Service Provider's forecast operating expenditure for the relevant Access Arrangement period) that occurs during the Access Arrangement period and Materially increases the costs to the Service Provider of providing Reference Services (including without limitation because of the need to undertake repairs to the Distribution System).

19.9. National Energy Customer Framework

The timing of the adoption of all or parts of NECF in Victoria is currently unknown.

The previous Victorian Government issued a Victorian Energy Statement in October 2014. Priority 1.3 stated that:

The Victorian government's retail energy regulatory arrangements will transition to NECF by 31 December 2015. A review of the NECF in Victoria will be undertaken in 2018 to ensure that it is benefitting Victorian consumers.

Prior to the last Victorian state election, the then ALP opposition issued material which stated:

Labor does not currently support the move to the National Energy Customer Framework (NECF) because it would not offer the same sort of existing consumer protections – in fact it would lower protections. Recent developments in the energy retail market particular to Victoria have raised some serious challenges which an Andrews Labor government would tackle. Labor commits to working with NECF to ensure that necessary consumer protections become a feature of the national framework, and supports harmonisation wherever possible.[98]

Whilst this implies no adoption of NECF in the near term, it does contemplate that NECF will commence at some point, as the ALP supports eventual harmonisation. A recent Victorian Government paper stated:

This acknowledges the Victorian Government's position that it will not implement the national energy customer framework at this time and will ensure Victorian customers remain front and centre of energy market regulation.[99]

[98] ALP 2014 Campaign Material – ESC Powers, page 6

[99] Victorian State Government, General Exemption Order, Draft Position Paper, issued July 2016, page 9

Our capex and opex forecasts in this Access Arrangement Information do not include any future NECF requirements as the supporting Victorian instruments are not available. Given that the NECF commencement date, incremental commencement of NECF or a change of government or government policy make the timing of these regulatory obligations unclear, we seek a cost pass through that operates in a similar manner to the current access arrangement.

Changes to incrementally adopt NECF in gas are significant and will require lengthy lead times. Retailers are the Users of the network and network services, market processes for gas connections and metering are undertaken via the retailer not direct with customers. There would need to be significant changes in gas market procedures, transactions and systems to accommodate the NECF changes.

We propose the following definition should apply for the forthcoming regulatory period, consistent with the current definition:

> ***National Energy Customer Framework Event*** *means a legislative act or decision that:*
>
> (a) *occurs during the Access Arrangement period;*
>
> (b) *has the effect of implementing in Victoria, either in part or in its entirety, the National Energy Customer Framework; and*
>
> (c) *increases the costs to the Service Provider of providing Reference Services.*
>
> *For the purposes of this definition, the "National Energy Customer Framework" means any legislation, regulations or rules that give effect, in Victoria, to any or all of the Schedule to the National Energy Retail Law (South Australia) Act 2011, the National Energy Retail Regulations (South Australia) and the National Energy Retail Rules (South Australia) as amended from time to time including any amendment, withdrawal or introduction of any associated Victorian legislation, regulations or rules.*

19.10. Retailer Insolvency Event

Recent national policy reform Review of National Electricity Market (NEM) Financial Market Resilience is likely to result in changes to the National Energy Retail Law and Regulations and changes to the National Electricity Rules to implement recommendations set out in the AEMC's Final Report.

Several rule changes are currently under review by the AEMC relating to AEMO discretion to suspend a market participant and delay a ROLR event, retailer insolvency rule changes by COAG and JGN and changes in credit risk sharing between electricity and gas distributors and retailers. These proposed changes mainly relate to NECF adopting jurisdictions.

We believe that even though Rule 531 of Part 12 of the NGR includes a retailer insolvency event, in Victoria that inclusion fails for want of a supporting definition and the scheme of Rule 531 fails for want of certain supporting provisions. It is unclear when the AEMC will make a final determination on the gas retailer insolvency rule change request and whether this rule would apply in practice in Victoria.

The definition accords with the requirements of the cost pass through event considerations because:

- The event proposed is not already in the NGR in a legally effective manner;
- The event is clearly identified;
- A prudent service provider could not reasonably prevent the event from occurring or substantially mitigate the cost impact of such an event as it cannot refuse to do business with a retailer even if considered not credit worthy;
- We cannot insure against the event on reasonable economic terms;

- We cannot self-insure the event on the basis that it is not possible to calculate the self-insurance premium because the probability of the event occurring cannot be readily estimated and the potential cost would have a significant impact on our ability to provide network services;
- A retailer insolvency event is included within the Rules and is effective in all jurisdictions other than Victoria. The AER has approved consistent wording for Victorian distributors to deal with the issue.

We therefore rely on consistency with other participating jurisdictions that have started the NECF as a relevant matter to be considered by the AER. We also rely on the submission of the COAG Energy Council referred to in the event definition dated March 2014.

We propose that the following nominated pass through event should apply for the forthcoming regulatory period:

Retailer Insolvency Event means that the Service Provider incurs additional costs or is unable to recover from a Retailer amounts billed to that Retailer or amounts accrued due but not yet billed due to:

(a) *the failure of a Retailer, who has had an Insolvency Official appointed to them, to pay an amount for Reference Services to the Service Provider which amount the Service Provider is entitled to under its contract with that Retailer but only to the extent the Service Provider is not entitled to recoup that amount under any Bank Guarantee provided in respect of that Retailer; and*

(b) *from the time the National Energy Retail Law applies in Victoria, the occurrence of an event where:*

(1) a Retailer of Last Resort (RoLR Event as described in section 122 of the National Energy Retail Law) has occurred; and

(2) the Service Provider incurs costs in responding to the RoLR Event in accordance with its obligations under the National Energy Retail Law, National Energy Retail Rules, National Gas Law or National Gas Rules (including guidelines and procedures that are binding under those instruments); and

(3) those costs are not recoverable by the Service Provider under other provisions of the National Energy Retail Law, National Energy Retail Rules, National Gas Law or National Gas Rules as in force at the time of the RoLR Event or under other Relevant Pass-Through Events in this Access Arrangement.

Note for the avoidance of doubt, in making a determination under this paragraph (b) in respect of a Retailer Insolvency Event, the Regulator will have regard to, amongst other things, the extent to which the Service Provider has taken steps to minimise the costs associated with its responsibilities in the ROLR Event, both prior to, and after the RoLR Event was triggered

19.11. Major Upstream Event

A major upstream failure event could conceivably occur during the next regulatory period. These types of extreme and unpredictable event are outside of Multinet's control. A major upstream failure incident could occur and affect supply or production facilities or events affecting the Transmission System which impact our ability to provide Reference Services and causes the inability to recover our building block costs

These events by their nature are rare and the timing and cost impact cannot be foreshadowed. For an event of such magnitude it is also likely that Emergency Management Protocols in the market, including government intervention would occur.

Multinet believes that the AER should approve a major upstream failure event because:

- Multinet is unable to exercise control over major upstream failure events;

- It is not included in another category of pass through event;
- It is not covered under Multinet's self-insurance allowance; and
- It results in material increases in the costs incurred by Multinet in providing haulage reference services.

Multinet submits that such events are rare and have the potential to be catastrophic to business continuity.

Furthermore, the costs of insuring or including in forecasts such events would be prohibitive and would not be consistent with the pricing principles in the NGL.

Multinet considers that this event is consistent with the natural disaster event or terrorism events approved by the AER where the costs of providing reference services are able to be recovered from events outside of Multinet's control. In these situations, Multinet may be in a position ready to continue to provide access and haulage services but may not be able to due to the event.

Multinet's defined pass through event is:

> *Major Upstream Failure Event means a failure of, or event affecting (including without limitation fire, explosion or major mechanical failure), the Transmission System or any production facility upstream of the Transmission System which:*
>
> (a) *results in or necessitates a material curtailment in the quantities of Gas able to be Supplied by the Service Provider to Customers; or*
>
> (b) *would have resulted in or necessitated such a material curtailment but for steps taken by the Service Provider to overcome or mitigate the impact on Customers (for example the trucking or injection into the Distribution System of CNG or LNG),*
>
> *(but excluding those events for which external insurance or self-insurance has been included within the Service Provider's forecast operating expenditure for the relevant Access Arrangement period) that occurs during the Access Arrangement period and that causes an inability for the Service Provider to recover the building block costs which make up its total revenue allowance or which Materially increases the costs to the Service Provider of providing Reference Services (including without limitation because of the need to undertake repairs to the Distribution System or because the Service Provider incurs costs in sourcing replacement supplies of Gas or substitute supplies for Gas).*

19.12. Materiality thresholds for pass through events

In the previous section, we proposed ten cost pass through events. The only cost pass through events that are new compared to the current Access Arrangement period is the retailer insolvency event and major upstream failure event.

We note that rule 97(3) requires the AER to have regard to efficient tariff structures and the possible effects of the reference tariff variation mechanism on the administrative costs of the AER, ourselves and Users. We consider that the materiality threshold for the defined pass through events above should recognise the cost of developing and reviewing a pass through submission. We submit a materiality threshold of 1 per cent of annual revenue per event is appropriate for all of our proposed pass through events, other than National Energy Customer Framework event and the retailer insolvency event, which should have no materiality thresholds.

In the current access arrangement, the AER approved two cost pass throughs with no materiality threshold:

> *Multinet has made an amendment to specify which cost pass through events are subject to the materiality threshold.*
>
> *The AER considers that this is a reasonable approach. The mains replacement event and the national energy customer framework event are not subject to a materiality threshold. Multinet's*

> *amendment makes this clear. If this amendment was not included, the approval mechanism would act to add the materiality requirement to those two events. The AER did not intend this.*[100]

We propose that the National Energy Customer Framework event continue to have no materiality threshold. In light of the JGN rule change to the AEMC, we also propose that the retailer insolvency event as intended by COAG policy and the proposed rule change to the AEMC also have no materiality threshold.

100 AER Access Arrangements Multinet, Final decision 2013-2017, Part 2 Attachments

20. Total revenue, X-factors and indicative bill impacts

Key messages:

- Our total revenue requirement for our Haulage Reference Services has been calculated in accordance with the building block approach set out in the Chapter 9 of the NGR using the AER's Post-Tax Revenue Model.
- We propose a P^0 for our Haulage Reference Services in 2018 of –9.12 per cent and an X factor of –2.00 per cent per annum for the period 2019 to 2022.

This chapter summarises our building block proposal and X factor for the forthcoming Access Arrangement period as well as the indicative prices and bill impacts for our customers.

20.1. Annual building block revenue requirements

Table 20-1 below summarises the composition of the unsmoothed building block revenue requirements for the forthcoming Access Arrangement period for our Haulage Reference Services. In developing this table, we have allocated our Total revenue between reference and other services in accordance with Rule 93 of the NGR.

Table 20-1: Total revenue requirement ($M, Nominal) *

	2018	2019	2020	2021	2022	Total
Return on Capital	52.9	55.7	57.8	60.1	62.4	**289.0**
Depreciation	66.6	69.3	70.5	74.7	79.1	**360.1**
Opex (incl. Debt Raising)	76.1	78.3	80.7	83.4	86.3	**404.7**
Efficiency Benefit Sharing Scheme	1.0	6.6	(0.4)	(3.4)	-	**3.7**
Cost of corporate income tax	17.7	16.6	21.9	22.6	22.6	**101.3**
Total Revenue Requirement (unsmoothed)	**214.2**	**226.5**	**230.4**	**237.4**	**250.4**	**1,158.8**

* Note - This Table 20-1 is presented in Nominal dollars, whereas the same information is presented in Table 2-1 in Real 2017 dollars.

Each of the elements in Table 20-1 has been addressed in earlier chapters of this Access Arrangement Information (although they presented values in Real 2017, rather than Nominal, dollars).

The total revenue requirements shown in Table 20-1 have been calculated using the AER's Post-Tax Revenue Model.

20.2. X Factor

We propose a P^0 of –9.12 per cent in 2018 and an X factor of –2.00 per cent in each of the four years between 2019 and 2022 as this ensures that our allowed revenues and building blocks costs will be closely aligned in 2022 and provides a relatively stable price path over the forthcoming Access Arrangement period.

In our Revised Access Arrangement Information, we may propose different X factors in the early years of the forthcoming Access Arrangement period to meet our cash flow requirements.

Our P^0 is driven by:

- The declining profile of our revenues in the current access arrangement period as determined by the AER. Our allowed revenues for 2017 are lower than the average of the allowed revenues for the period. Even maintaining the average of the current period into the forthcoming period would result in a negative P^0 adjustment (i.e. an increase in average prices); and

- Our proposed revenue for the forthcoming period.

20.3. Indicative residential bill impact

Table 20-2 provides an indication of the pricing outcomes under the proposed Access Arrangement for a typical residential customer, based on the Total Revenues, P^0 and X factors detailed above.

Table 20-2: Indicative residential bill (excluding GST)

Tariff type	Estimated $ invoice (2017)	Estimated $ invoice (2018)	% Change 2018/2017
Cost of Gas (including Retail)	985	1,004	2.0%
Transmission	18	19	2.4
Distribution	281	312	11.0
Total Gas Invoice	1,285	1,335	3.8

21. Reference tariffs

21.1. Introduction

This chapter explains our proposed reference tariffs for the forthcoming Access Arrangement period.

Rule 72(1)(j) requires our Access Arrangement Information to describe our proposed approach for setting our tariffs, including:

(i) *the suggested basis of reference tariffs, including the method used to allocate costs and a demonstration of the relationship between costs and tariffs; and*

(ii) *a description of any pricing principles employed but not otherwise disclosed under this rule.*

Rule 93 details provisions relating to the allocation of total revenue and costs between reference and other services. Rule 94 details the following requirements relating to tariffs for distribution pipelines:

(1) *For the purpose of determining reference tariffs, customers for reference services provided by means of a distribution pipeline must be divided into tariff classes.*

(2) *A tariff class must be constituted with regard to:*

(a) *the need to group customers for reference services together on an economically efficient basis; and*

(b) *the need to avoid unnecessary transaction costs.*

(3) *For each tariff class, the revenue expected to be recovered should lie on or between:*

(a) *an upper bound representing the stand alone cost of providing the reference service to customers who belong to that class; and*

(b) *a lower bound representing the avoidable cost of not providing the reference service to those customers.*

(4) *A tariff, and if it consists of 2 or more charging parameters, each charging parameter for a tariff class:*

(a) *must take into account the long run marginal cost for the reference service or, in the case of a charging parameter, for the element of the service to which the charging parameter relates;*

(b) *must be determined having regard to:*

(i) *transaction costs associated with the tariff or each charging parameter; and*

(ii) *whether customers belonging to the relevant tariff class are able or likely to respond to price signals.*

(5) *If, however, as a result of the operation of subrule (4), the service provider may not recover the expected revenue, the tariffs must be adjusted to ensure recovery of expected revenue with minimum distortion to efficient patterns of consumption.*

(6) *The AER's discretion under this rule is limited.*

The remainder of this chapter is structured as follows:

- Section 21.2 describes our overarching principles that guide our tariff setting;
- Section 21.3 details our tariff setting methodology;
- Sections 21.4 to 21.6 detail our Tariffs V, D and L;
- Section 21.7 details our long-run marginal costs;

- Section 21.8 explains the price signals provided by Tariffs V and D; and
- Sections 21.9 details our charging arrangements for Ancillary Reference Services.

21.2. Tariff principles

Our Reference Tariff Policy in Part B of our Access Arrangement details our Reference Tariffs. We will provide our Reference Services:

- In accordance with the relevant Regulatory Instruments; and
- On reasonable terms and conditions as set out in Part C of our Access Arrangement.

We consider the following principles when setting our tariffs and when undertaking any annual tariff rebalancing:

- **Simple:** Ability for customers to react and understand.
- **Attractive:** Desire of retailer to pass the tariff through to customers.
- **Forward Looking:** Ability to deal with changing market conditions while being technology and policy agnostic.
- **Manage Volatility**: Desire for low year-on-year volatility.
- **Predictable:** Ability for customers to forecast and understand impacts - no bill shock.
- **Cost-reflective:** Tariffs should be cost reflective whilst also recognising the practical limitations of setting network tariffs, including cost allocation methodologies and constraints in tariff rebalancing.
- **Compliant:** Compliance within the various regulatory and legislative criteria.

We cannot fully satisfy all principles while fully complying with the Access Arrangement, particularly as some principles have conflicting implications. We must make some trade-offs, while promoting these principles as far as possible. Our principles are useful in describing the matters that guide our tariff design and annual price adjustments.

21.3. Methodology for setting reference tariffs

21.3.1. Avoidable and stand-alone costs

Rule 94(3) of the NGR requires that, for each tariff class, the revenue expected to be recovered should lie on or between an upper bound, representing the stand-alone cost of providing our Reference Service, and a lower bound, representing the avoidable cost of not providing our Reference Service. This is commonly known as the 'efficient pricing band'.

There are several methodologies that can be utilised to estimate the stand-alone cost of servicing a customer, or group of customers. These broadly include:

- A 'bottom-up' build of stand-alone costs, via the construction of a modern-day equivalent, optimised, asset base in support of the delivery of services to each customer or group of customers; and
- A 'top-down' approach, which involves allocating each existing asset / asset type to a customer or group of customers, based on an appropriate cost allocation methodology.

There are several practical and theoretical issues that need to be considered in determining which approach should be used to calculate the stand alone cost for each group of customers. In particular, the adoption of an average stand-alone cost to serve a group of customers – which effectively underpins both of the aforementioned approaches – may not capture what could be termed 'outlier' (non-average) customers, for example those that are particularly close to the transmission network, or have particularly large usage (and therefore, economies of scale in their servicing). It is also worth noting that the most likely substitute for existing (residential) customers is not a network solution, but rather a bottled gas solution.

As a result, we focus on the potential for individual customers within a broader customer class to by-pass our network, as well as assessing the potential for an entire customer class to bypass its network. This is a practical and robust application of the underlying economic principles that underpin the NGR. In particular, it focuses attention on the ability of particular customers within a tariff class to bypass the network.

Our cost of supply model allocates the costs of supplying customers for each reference tariff via appropriate methodologies to establish the upper and lower limits by Tariff V residential, Tariff V non-residential, Tariff L and Tariff D. The upper costs are the stand-alone costs to by-pass the network. These costs were calculated using the Optimised Replacement System Costs of the network multiplied by the current WACC, and adding depreciation and consumption weighted share of opex. These costs were then apportioned by volume of each customer class to obtain an average $/GJ. The lower cost is the marginal or avoidable cost of supply. The lower costs were calculated using consumption weighted share of opex and apportioning by volume for each customer class to obtain an average $/GJ.

Our analysis shows that for all customer classes, the standalone cost exceeds the revenue that is generated from that tariff class, given the application of our proposed tariffs. Further, for tariff D customers, this situation stands for all reasonable distances away from the transmission network, and all reasonable usage ranges. Further, the average revenue that is generated from each customer class exceeds the avoidable cost of supply in all cases.

In relation to the avoidable cost assessment, we have calculated the short run marginal cost of supplying each tariff class and multiplied this amount by the estimated usage for that customer/customer class.

Our assessment of the standalone and avoidable costs, compared to average revenue, for Tariff V Residential, Tariff V Non-residential, Tariff L and Tariff D is detailed below.

Table 21-1: Proposed Average Tariffs for 2017 versus Upper and Lower Cost Limits

Type	Tariff	Units	2017 Upper Bound "Standalone Cost"	2017 Lower Bound "Avoidable Cost"	2017 Average DUoS
Volume	Residential V	$/GJ	5.69	2.12	4.66
Volume	Non-residential V	$/GJ	2.38	0.50	1.66
Volume	Tariff L	$/GJ	2.38	0.50	0.52
Demand	Tariff D	$00/MHQ	9.31	1.06	5.00

Figure 21-1: 2017 Average Tariffs versus Upper and Lower Cost Limits Tariff V and Tariff L

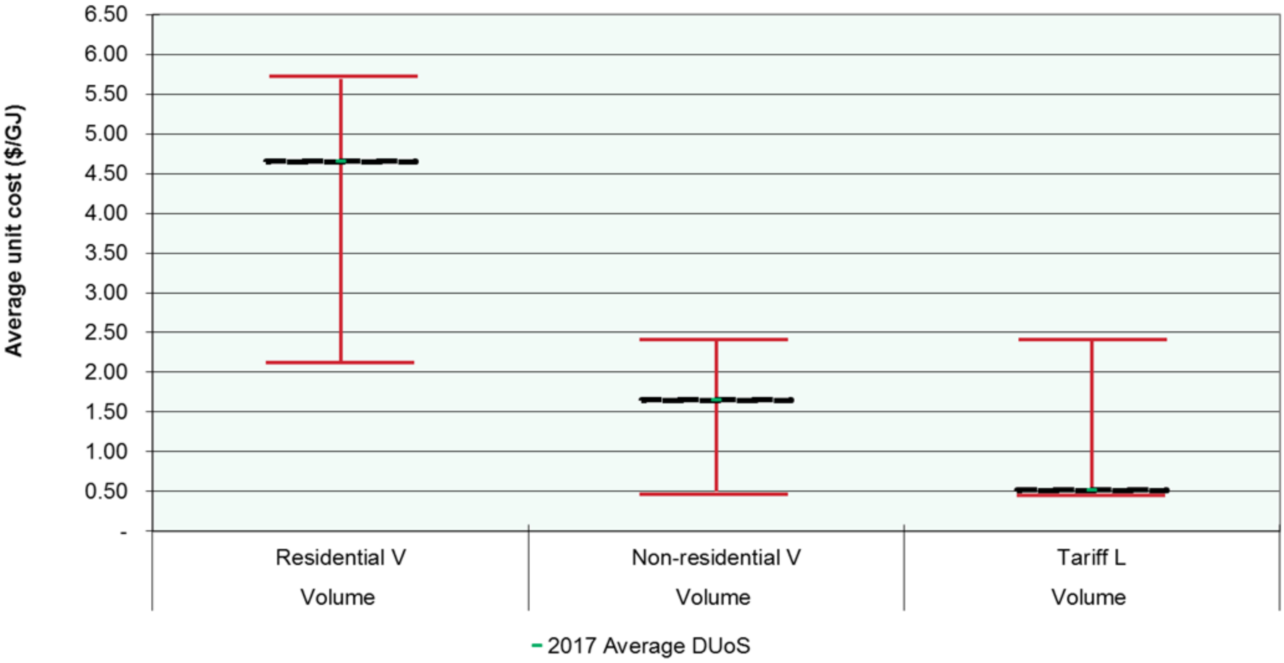
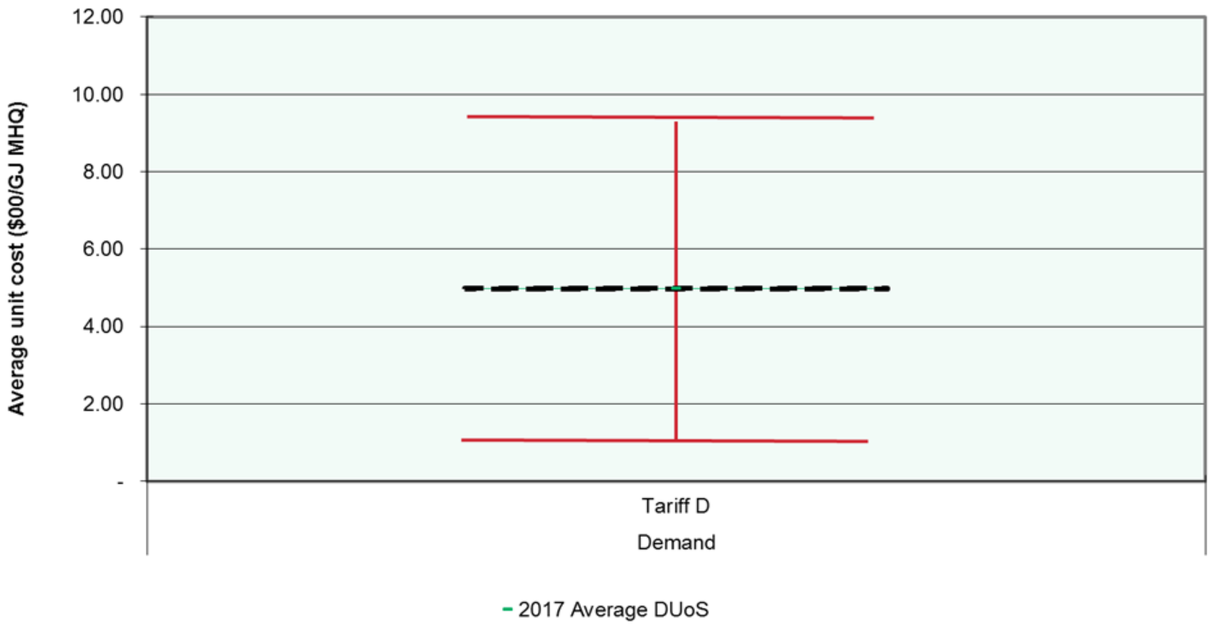


Figure 21-2: 2017 Average Tariffs versus Upper and Lower Cost Limits Tariff D



21.3.2. Cost differences between zones

We have three pricing zones:

- Metropolitan;
- Yarra Valley; and

- South Gippsland.

Both Yarra Valley and South Gippsland are relatively new networks and have been connected with the assistance of funding from Regional Development Victoria (RDV). Despite this assistance, both of these networks require additional revenue to recover the projected shortfall of revenue to costs and this is reflected in pricing.

During 2016 Warburton was connected to the existing Yarra Valley network. Warburton customers receive the existing Yarra Valley network tariffs which were used in the calculation of the complementary funding from RDV required to build the additional gas and distribution mains.

21.4. Tariff V

Tariff V applies to customers using less than 10,000 GJ a year and less than 10 GJ MHQ. There are two classifications Within Tariff V: Residential and Non-Residential. Any new customer eligible for Tariff V is assigned their appropriate residential or non-residential classification by their retailer.

Tariff V contains a fixed and variable charge. The fixed charge recovers unavoidable network infrastructure costs such as service connection, standard meters, and systems for billing and collection. The variable peak, shoulder and off peak charges recover all other costs associated with the Distribution Use of System.

The Tariff V variable charge (price per GJ) decreases with increased usage. There are currently five usage blocks for Residential and Non-Residential Customers, as shown in Table 21-2 and Table 21-3.

Table 21-2: Tariff V Residential usage blocks

	Consumption Range (GJ/day)
Usage Block 1	0 - 0.05
Usage Block 2	>0.05 - 0.1
Usage Block 3	>0.1 - 0.15
Usage Block 4	>0.15 - 0.25
Usage Block 5	>0.25

Table 21-3: Tariff V Non-Residential usage blocks

	Consumption Range (GJ/day)
Usage Block 1	0 - 0.25
Usage Block 2	>0.25 - 1.0
Usage Block 3	>1.0 - 1.5
Usage Block 4	>1.5 - 5.0
Usage Block 5	>5.0

Both Residential and Non-Residential Tariff V customers have seasonal usage charges ($/GJ) for the following periods:

- Off Peak Summer Period (November to April inclusive);
- May Shoulder period (May);

- Peak Winter period (June to September inclusive); and
- October Shoulder period (October).

21.5. Tariff D

Tariff D applies to customers using more than 10,000 GJ a year or more than 10 GJ MHQ. Customers are charged based on their MHQ measured in GJ per hour. The MHQ unit rates are stepped as follows:

Table 21-4: Steps in MHQ unit rates

	Maximum Hourly Quantity (GJ/hr)
Demand Step 1	0 - 50
Demand Step 2	> 50

We explain below how Tariff D MHQ bills are calculated.

Distribution Demand Charge = (Estimated Annual Charge – Charges to Date) / Remaining Bill Periods, where the Estimated Annual Charge is:

For billing periods between January and September:

If Actual Annual MHQ>Forecast Annual MHQ then:

- Estimate Annual Charge = Actual Annual MHQ * Rate
- Estimate Annual Charge = Forecast Annual MHQ * Rate

For billing periods between October and December:

If the Maximum Annual MHQ for the last 9 months is less than the Forecast Annual MHQ then:

- Forecast Annual MHQ = Maximum Annual MHQ * Rate; or
- Estimated Annual Charge = Forecast Annual MHQ * Rate

Note:

A minimum MHQ of 1.15GJ applies to the Estimated Annual Charge. If the MHQ (either the Actual Annual MHQ or the Forecast Annual MHQ) used for the Estimated Annual Charge is less than 1.15MJ then 1.15MJ will be used to calculate the charge.

Charges to Date is the sum of the Distribution Demand Charges that have been charged in the current year.

Remaining Billing Periods is set using the table below:

Table 21-5: Remaining Billing Periods

Billing Period	Remaining Billing Period
January	12
February	11
March	10
April	9
May	8
June	7
July	6
August	5
September	4
October	3
November	2
December	1

If there is a change in the retailer for a service point, then the distribution charges for the entire month are charged to the new retailer.

Where the relevant Distribution Supply Point is assigned to Haulage Reference Tariff Non-residential Tariff D, this Non-Residential Haulage Reference Service is for allowing the injection, conveyance and withdrawal of Gas at a Tariff D Distribution Supply Point. This Tariff does not include the provision and maintenance of connection assets forming a Tariff D Distribution Supply Point.

Connection of a Tariff D Distribution Supply Point is to be provided as a non-Reference Service and the costs of these works and related operations and maintenance are not recovered through the Non-Residential Tariff D Reference Tariff. For these services, a fair and reasonable charge is to be levied in accordance with the provisions of the Gas Distribution System Code.

21.6. Tariff L

Tariff L is open to customers who consume more than 1TJ per annum or less than 10TJ per annum and have an MHQ demand of less than 10 GJ per hour.

The tariff structure of Tariff L is a hybrid of the Tariff V and D tariff structures. Tariff L has no fixed charge, however it contains seasonal stepped usage charges and two demand charges. There are currently two usage blocks for Tariff L customers:

Table 21-6: Tariff L usage blocks

	Consumption Range (GJ/day)
Usage Block 1	0 - 5
Usage Block 2	>5

Tariff L also contains seasonal usage charges ($/GJ) for the following periods:

- Off Peak Summer Period (November to April inclusive);
- May Shoulder period (May);
- Peak Winter period (June to September inclusive); and
- October Shoulder period (October).

Tariff L also contains two Demand Charges as follows:

- A Rolling 12 month Maximum MHQ charge which is a daily charge based on the highest demand (MHQ) delivered over 12 months to the end of the billing period
- A Peak MHQ Demand Charge which is based on the highest demand (MHQ) delivered in any billing period during the hours 6am to 10am weekdays over the four peak months June to September.

21.7. Long run marginal costs

Rule 94(4) of the NGR requires that charging parameters consider the long run marginal cost (LRMC) for the reference service or, in the case of a charging parameter, for the element of the service to which the charging parameter relates.

The LRMC for a network service can be calculated in several different ways. We have applied the Average Incremental Cost (AIC) approach. This approach calculates the growth-related expenditure in present value terms and divides this amount by the present value of the projected growth in demand.

We previously undertook this calculation on a system-wide basis. However, as our system-wide forecast of growth in MHQ is negative, continuing this approach may lead to unintended consequences (namely a negative LRMC). Therefore, we have revised our approach and based our LRMC calculation on the forecast Augmentation capex and MHQs in our network regions for which we are forecasting Augmentation capex in forthcoming Access Arrangement period (i.e. Eastern, Korumburra, Yarra Glen, South Melbourne).

We have assumed the following in estimating our LRMC:

- Only the costs that are attributable to growth in MHQ are included in the LRMC calculation – i.e. Augmentation capex. We have therefore excluded all replacement and other capex from our LRMC calculation on the basis that these costs do not vary with future changes in MHQ;
- All growth-related (i.e. Augmentation) capex is required to alleviate capacity constraints during peak periods. Therefore, all growth-related capex has been allocated to the peak period parameter and none has been allocated to the off-peak period parameter. Table 21-7 details our LRMC for our peak period; and
- The estimated incremental opex we incur in delivering an extra gigajoule of gas to an end customer is added to the LRMC estimate.

The raw LRMC is denominated in $/MHQ as MHQ is the underlying driver of our augmentation costs. For clarity, we have converted this to a $/GJ value using the estimated amount of gas that a customer in each tariff class will consume in the period covered by the peak charge.

Table 21-7: LRMC analysis results

Tariff Class	LRMC – Peak
Tariff V - Residential	$4.48 per GJ
Tariff V - Commercial	$2.60 per GJ
Tariff D	$0.58 per GJ or $2474 per GJ/hr

The above results are only relevant for our four regions where we forecast augmenting our network over the next Access Arrangement period. In regions where no augmentation capex is forecast, the peak LRMC would equate to the off-peak charge, which in turn reflects our estimate of the additional opex that we will incur to deliver an extra gigajoule of gas to an end customer (which is $0.2 per GJ for Tariff V, and $0.1 per GJ for Tariff D). Moreover, the calculations in Table 21-7 are sensitive to the assumptions that are made around several different variables. As such, and consistent with the Rule 94 (4)(a), these should only be used as a guide when assessing price levels and structures that are applied across all of our region.

The results of our analysis indicate that, for all customer classes, the standalone cost far exceeds the revenue that is generated from that tariff class, given the application of our proposed tariffs. Further, for tariff D customers, this situation stands for all reasonable distances away from the transmission network, and all reasonable usage ranges. Further, the average revenue that is generated from each customer class exceeds the avoidable cost of supply in all cases.

21.8. Response to price signals

Rule 94(4)(b) of the NGR requires that, if a tariff consists of two or more charging parameters, we must have regard to how customers can or likely to respond to price signals. We are not proposing any change to the tariff structures over the forthcoming Access Arrangement period and believe that tariffs are currently structured to allow end-use customers to respond to price signals.

Chapter 20.3 details indicative bill impacts for typical residential customers for the forthcoming Access Arrangement period. The remainder of this section comments briefly on the price signalling properties of the current tariff design.

21.8.1. Residential and commercial tariffs

Tariff V is structured on a declining block structure. Therefore, customers obtain on average a cheaper cost for additional gas usage. We consider that this price signal is appropriate for Tariff V customers where the marginal costs of supplying additional units is materially lower than the average costs, and increased network utilisation is to be encouraged.

21.8.2. Demand tariffs

Tariff D and Tariff L have been designed so that customers can respond to price signals. Tariff D has also been designed on a declining block structure based on MHQs. These are reset every year based on prior year actual data. Customers are provided with a price signal to manage their consumption within the nominated MHQs. This enables us to manage the risk of any network capacity constraints.

Tariff L also provides a seasonal component to the charging arrangements, which encourages customers to increase load in off-peak or shoulder periods. This price signalling appropriately reflects the lower levels of network utilisation during those periods.

21.9. Ancillary Reference Services

Our current Ancillary Reference Services are provided in Part B of the Access Arrangements.

The indicative prices for our Ancillary Reference Services are provided in the table below.

Table 21-8: Indicative prices for Ancillary Reference Services - Exclusive of GST (Real 2017)

Service	Year Ending 31 December				
	2018	2019	2020	2021	2022
Special meter reading					
Volume	197,112	198,132	199,032	199,896	200,892
Price ($)	6.42	6.42	6.42	6.42	6.42
Total revenue ($m)	**1.27**	**1.27**	**1.28**	**1.28**	**1.29**
Meter Investigation					
Volume	120	120	120	120	120
Price ($)	142.93	142.93	142.93	142.93	142.93
Total revenue ($m)	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**
Meter Disconnection					
Volume	7,764	7,836	7,896	7,968	8,040
Price ($)	50.06	50.06	50.06	50.06	50.06
Total revenue ($m)	**0.39**	**0.39**	**0.40**	**0.40**	**0.40**
Meter removal					
Volume	4,590	4,614	4,638	4,674	4,698
Price ($)	59.81	59.81	59.81	59.81	59.81
Total revenue ($m)	**0.27**	**0.28**	**0.28**	**0.28**	**0.28**
Reconnection					
Volume	8,220	8,292	8,376	8,460	8,544
Price ($)	42.21	42.21	42.21	42.21	42.21
Total revenue ($m)	**0.35**	**0.35**	**0.35**	**0.36**	**0.36**
Total revenue ($m)	**2.29**	**2.31**	**2.32**	**2.34**	**2.35**

22. Other Access Arrangement matters

This Chapter details other matters relating to our access arrangement proposal, as required under various provisions of the NGR.

22.1. Revisions to our Access Arrangement

Supporting Document 22.1 outlines the substantive changes we propose to apply to Parts A to C of our current Access Arrangement from 1 January 2018. In summary, we have made:

- Minor revisions to the access arrangements to reflect the new access period, some changes in laws; and
- Material changes to the access arrangements in the reference tariff policy, Part B to reflect the change to a revenue cap mechanism for tariff variation, to amend the CPI to a June date from September, realign the tariffs to commence at the start of the calendar year and remove the carbon tax.

22.2. Review submission date and revision commencement date

We propose that the duration of the forthcoming access arrangement period will be five years.

The review submission date is 30 December 2016. This is consistent with the timing of revisions provided for under our current access arrangement. Our experience is that this review submission date provides sufficient time for the consideration of the proposed revisions. It also enables the review submission to include more up-to-date information than would be the case if the review submission date were to be set, say, 18 months prior to the commencement of the next access arrangement period. We therefore consider that our proposed review submission date meets the requirements of rule 50.

The revision commencement date will be 1 January 2023.

In accordance with the requirements of rule 49(1)(i)(b), our access arrangement does not contain an expiry date.

22.3. Fixed Principles

Clause 7.2 of Part B of Our existing Access Arrangement contains fixed principles which were approved by the AER for the current Access Arrangement period in relation to:

- The AER using an incentive-based regulation adopting a CPI-X approach;
- The application of a single X factor for years 2 to 5 of the Access Arrangement period;
- Determining the value of the opening capital base;
- Determining the rate of return on the capital base; and
- Applying the Capital Asset Pricing Model to determining the rate of return.

In the interests of providing ongoing regulatory certainty, we propose to retain the current fixed principles, except for the fixed principle in relation to the X factor for years 2 to 5 of the Access Arrangement period.

We also propose adding new fixed principles in clause 7.2 of our Access Arrangement for:

- Any unders or overs recovery of actual revenue collected through Haulage Reference Service Tariffs which remain as at the end of the forthcoming Access Arrangement Period to be carried over as pass-through amounts into the following Access Arrangement Period; and
- Any Relevant Pass Through Event that occurs, but is not fully recovered or reflected, in an Access Arrangement period can be reflected or recovered in the next Access Arrangement period.

22.4. Key Performance Indicators

Rule 72(1)(f) requires that our Access Arrangement Information include key performance indicators (KPIs) that support our expenditure for the Access Arrangement period. We propose the KPIs detailed in Table 22-1.

Table 22-1: Key Performance Indicators ($, Real 2017)

	2018	2019	2020	2021	2022
Opex per metre of circuit length	7.4	7.4	7.4	7.5	7.6
Opex per customer	106.8	107.5	108.3	109.6	111.1

22.5. Queuing requirements

Rule 103(1)(a) states that an access arrangement must contain queuing requirements if the access arrangement is for a distribution pipeline and the AER notifies the service provider that the access arrangement must contain queuing requirements. Rules 103(3) and 103(5) set out the queuing requirements.

The AER has not notified us that the access arrangement must contain a queuing requirement, therefore one has not been proposed.

22.6. Capacity Trading requirements

Rule 48(1)(f) requires a full access arrangement to set out the capacity trading requirements. Rule 105 specifies the circumstances under which capacity trading requirements must provide for transfer of capacity. Under the Market Rules, the Victorian Market has transportation rights which come in the form of authorised MDQ (Maximum Daily Quantity). In Victoria:

- AEMO and the transmission pipeline owner have entered agreements relating to the capacity of the transmission system;
- At the commencement of the market, AEMO allocated the initial transmission pipeline capacity to individual large (tariff D) customers in the form of authorised MDQ and the balance collectively to the small customer load (tariff V – residential and small to medium sized commercial/industrial customers);
- Market Participants and/or tariff D customers may trade authorised MDQ; and
- Distribution networks do not grant a right to capacity in any section of the network, hence the issue of transferring capacity on the distribution network does not arise.

In accordance with the Market Rules and Rule 105(1) of the National Gas Rules, we do not provide for the transfer of capacity on our distribution pipeline.

23. Glossary

Abbreviations	
ABS	Australian Bureau of Statistics
ACIF	Australian Construction Industry Forum
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AIC	Average Incremental Cost
ARENA	Australian Renewable Energy Agency
Bp	basis points
bppa	basis points per annum
BST	Base-Step-Trend
BVAL	Bloomberg Valuation
C&I	Commercial and Industrial
Capex	Capital expenditure
CAPM	Capital Asset Pricing Model
CBD	Central Business District
CDD	Cooling Degree Day
CEFC	Clean Energy Finance Corporation
CEIF	Clean Energy Innovation Fund
CEO	Chief Executive Officer
CESS	Capital Expenditure Sharing Scheme
CIRB	Capital Investment Review Board
COWP	Capex and Opex Works Program
CPI	Consumer price index
CSIS	Capital Sharing Incentive Scheme
CTM	Custody Transfer Meters
DNSP	Distribution network service provider
DRP	Debt risk premium
DUOS	Distribution use of system

Abbreviations	
EBSS	Efficiency Benefit Sharing Scheme
EDD	Effective Degree Day
EGWWS	Electricity, Gas, Water and Wastewater services
ERA	Economic Regulation Authority of Western Australia
ERP	Enterprise Resource Planning
ESAA	Energy Supply Association of Australia
ESCV	Essential Services Commission of Victoria
ESV	Energy Safe Victoria
F&A	Framework and Approach
GAAR	Gas Access Arrangement Review
GJ	Gigajoule
GM	General Manager
GSL	Guaranteed Service Level
HDD	Heating Degree Day
HP	High Pressure
ICT	Information and Communications Technology
ILI	In-Line Inspection
ISMS	Information Security Management System
KPI	Key Performance Indicator
LDCI	Large Diameter Cast Iron
LP	Low Pressure
LPDZ	Low Pressure Designated Zone
LRMC	Long-Run Marginal Cost
LTIFR	Lost-Time Injury Frequency Rate
M	Millions
MEPS	Minimum Energy Performance Standards
MHQ	Maximum Hourly Quantity
MP	Medium Pressure
MRP	Market risk premium

Abbreviations	
MTFP	Multilateral Total Factor Productivity
NEL	National Electricity Law
NER	National Electricity Rules
NGL	National Gas Law
NGO	National Gas Objective
NGR (Rules)	National Gas Rules
NIC	Network Innovation Competition
NIEIR	National Institute of Economic and Industry Research
OMSA	Operational and Management Services Agreements
Opex	Operating expenditure
PFP	Partial Factor Productivity
PTRM	The AER's Post-Tax Revenue Model
RAB	Regulatory Asset Base
RDV	Regional Development Victoria
RFM	The AER's Roll-forward Model
RIN	Regulatory Information Notice
ROE	Return on equity
RPP	Revenue and Pricing Principles
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SIFR	Serious Injury Frequency Rates
SL-CAPM	Sharpe-Lintner Capital Asset Pricing Model
TFP	Total Factor Productivity
TJ	Terajoule
Tribunal	Australian Competition Tribunal
UAFG	Unaccounted for Gas
UE	United Energy
VEET	Victorian Energy Efficiency Target

Abbreviations	
WACC	Weighted average cost of capital
WPI	Wage Price Index
ZNX	Zinfra Group

24. Supporting documentation

This Chapter lists the supporting documents that we have provided to the AER with this Access Arrangement Information. These supporting documents are incorporated within, and form a part of, our Access Arrangement proposal.

Attachment 22.5 lists and justifies our confidentiality claims in relation to certain of our supporting documents.

Chapter reference	Document name
1	**A message from our Chief Executive**
1.1	CEO Statutory Declaration
7	**What our stakeholders are telling us**
7.1	GAAR Stakeholder Engagement Overview Document
7.2	GAAR Stakeholder Engagement Strategy - Access Arrangement 2018-2022
7.3	UE and MG Customer Engagement Strategy-FINAL
7.4	Farrier Swier_ GAAR Residential and Small Business - Focus Group presentations - 29082016 - FINAL
7.5	Farrier Swier_Focus Groups - Residential and Small Business Group feedback -Aug2016- FINAL
8	**What we will deliver**
8.1	Retailer Reporting template sample GAAR 2016
9	**Demand**
9.1	NIEIR_ Natural gas, customer number and MHQ forecasts for Multinet Gas to 2026 (Calendar year basis) Volume One A report for Multinet Gas
9.2	NIEIR_Peak day, peak hour and postcode projections for Multinet Gas to 2026 Volume two
9.3	NIEIR_gas projection models for volume 1 and volume 2
9.4	NIEIR_ Review of EDD weather standards for Victorian gas forecasting, April 2016
13	**Capex forecasts**
13.2	**Current period conforming capex**
13.2.1	Oakley Greenwood_Assessment of Prudency and Efficiency of Mains Replacement and Connection Capex, December 2016
13.5	**Our expenditure governance framework**
13.3.5	Jacobs_Review of governance structures and processes for capital expenditure MULTINET GAS 21 November 2016
13.6	**Asset Management Framework**
13.5.1	Asset Management Plan (MG-PL-0005) - public
13.5.1.1	Asset Management Plan (MG-PL-0005) - confidential
13.7	**Cost escalators**
13.7.1	BIS Shrapnel_Utilities Sector and Construction Industry Wage Forecasts to 2022 – Australia and Victoria, October 2016
13.8	**Capex and Asset-Related Benchmarking**
13.8.1	Economic Insights_Benchmarking the Victorian Gas Distribution Businesses' Operating and Capital Costs Using Partial Productivity Indicators, 15 June 2016

Chapter reference	Document name
13.8.2	Economic Insights_The Productivity Performance of Victorian Gas Distribution Businesses productivity, 15 June 2016
13.9	**Mains Replacement**
13.9.1	Capital Expenditure Overview Document - Mains Replacement
13.9.2	Mains Replacement Strategy (MG-SP-0009) - public
13.9.2.1	Mains Replacement Strategy (MG-SP-0009) - confidential
13.9.3	Distribution Services Strategy (MG-SP-0010) - public
13.9.3.1	Distribution Services Strategy (MG-SP-0010) - confidential
13.9.4	Advisian Independent Estimate Report Augmentation and Mains Replacement Projects - 7 November 2016
13.9.5	Advisian AER Pipework Projects - Independent Validation Report_May 2015_Public
13.10	**Residential and Commercial and Industrial Connections capex**
13.10.1	Capital Expenditure Overview Document - Residential and Commercial and Industrial Connections
13.10.2	ACIF_ Australian Construction Market Report May 2016
13.10.3	Multinet Gas Customer Contribution Policy - for the expansion and augmentation of the multinet gas distribution system
13.11	**Meter Capex**
13.11.1	Capital Expenditure Overview Document - Metering
13.11.2	Capital Expenditure Overview Document - Digital Gas Metering Pilot Study
13.11.4.1	Small meter strategy (MG-SP-0007) - confidential
13.11.4	Small meter strategy (MG-SP-0007) - public
13.11.5.1	Large meter strategy (MG-SP-0008) - confidential
13.11.5	Large meter strategy (MG-SP-0008) - public
13.12	**Augmentation capex**
13.12.1	Capital Expenditure Overview Document - Augmentation
13.12.2	Network Planning Report - Eastern HP (PR-2016-01)
13.12.3	Network Planning Report - Korumburra HP (PR-2016-02)
13.12.4	Network Planning Report - Oakleigh HP (PR-2016-03)
13.12.5	Network Planning Report - South Melbourne HP (PR-2016-04)
13.12.6	Capital Growth Plan (MG-PL-0002) - public
13.12.6.1	Capital Growth Plan (MG-PL-0002) - confidential
13.13	**Non-Network ICT capex**
13.13.1	Capital Expenditure Overview - ICT_20161021
13.13.1.2	IT Capital Program 2018 to 2022_2016102
13.13.1.3	IT Capital Plan Cost Model 2018 - 2022 FINAL_20161102_CONFIDENTIAL
13.13.1.3.1	IT Capital Plan Cost Model 2018 - 2022 FINAL_20161102_Public
13.13.1.4	IT Project Delivery Framework_20150115

Chapter reference	Document name
13.13.1.5	IT Asset Management Policy_20160919
13.13.3	
13.13.3.1	IT01 Asset Data Quality Program_20160930
13.13.3.2	IT06 Enterprise Content Management_20160930
13.13.3.3	IT07 Network Monitoring Capability_20160930
13.13.3.4	IT09 Digital Meters IT Support_20160930
13.13.3.5	IT15 WebMethods Refresh_20160930
13.13.3.6	IT16 SCADA Refresh_20160930
13.13.3.7	IT18 Small Applications Refresh Program_20160930
13.13.3.8	IT19 GIS Refresh_20160930
13.13.3.9	IT20 EDMS Drawing Management System Refresh_20160930
13.13.3.10	IT21 IT Infrastructure Refresh - Client Device lifecycle_20160930
13.13.3.11	IT22 IT Infrastructure Refresh - Data Protection_20160930
13.13.3.12	IT23 SAP CRM Refresh_20160930
13.13.3.13	IT24 IT Infrastructure Refresh - Reporting Platfrom_20160930
13.13.3.14	IT29 Legacy Application Replacement Program_20160930
13.13.3.15	IT30 Tableau Refresh_20160930
13.13.3.16	IT33 UAFG Reconciliation Refresh_20160930
13.13.3.17	IT35 Time Expired Meters Refresh_20160930
13.13.3.18	IT39 Enterprise Project and Portfolio Management_20160930
13.13.4	
13.13.4.1	IT03 Gas Transmission Pipelines_20161027
13.13.4.2	IT08 Mobility Integration_20161027
13.13.4.3	IT12 IT infrastructure Refresh_20161027
13.13.4.4	IT13 Applications Enhancement Factory_20161027
13.13.4.5	IT14 IT Security Program_20161027_CONFIDENTIAL
13.13.4.5.1	IT14 IT Security Program_20161027_Public
13.13.4.6	IT17 SAP ERP ISU Refresh_20161027
13.13.4.7	IT38 Customer Experience Improvements_20161027
13.13.4.8	IT40 Business Intelligence_20161027
13.14	**SCADA capex**
13.14.1	Capital Expenditure Overview Document - SCADA
13.14.2	SCADA Strategy (MG-SP-0002) - public
13.14.2.1	SCADA Strategy (MG-SP-0002) - confidential
13.15	**Network Other capex**

Chapter reference	Document name
13.15.1	Capital Expenditure Overview Document - Other capex
13.15.2	Supply Regulator Strategy (MG-SP-0003) - public
13.15.2.1	Supply Regulator Strategy (MG-SP-0003) - confidential
13.15.3	Large Consumer Regulator Strategy (MG-SP-0005) - public
13.15.3.1	Large Consumer Regulator Strategy (MG-SP-0005) - confidential
13.15.4	Distribution Valve Strategy (MG-SP-0011) - public
13.15.4.1	Distribution Valve Strategy (MG-SP-0011) - confidential
13.15.5	Corrosion Protection Strategy (MG-SP-0013) - public
13.15.5.1	Corrosion Protection Strategy (MG-SP-0013) - confidential
13.15.6	Equipment Enclosure Strategy (MG-SP-0014) - public
13.15.6.1	Equipment Enclosure Strategy (MG-SP-0014) - confidential
13.15.7	Gas Heater Strategy (MG-SP-0015) - public
13.15.7.1	Gas Heater Strategy (MG-SP-0015) - confidential
13.15.8	Transmission Pipeline Strategy (MG-SP-0001) - public
13.15.8.1	Transmission Pipeline Strategy (MG-SP-0001) - confidential
14	**Opex**
14.1	Operating Expenditure Overview Document
14.2	Economics Insights Gas Distribution Businesses Opex Cost Function, 22 August 2016
14.3	Axiom Consistency of the Vic gas DBs joint marketing campaign with NGR - DEC 2016 - PUBLIC
14.4	Axiom Consistency of the Vic gas DBs joint marketing campaign with NGR Dec 2016 - CONFIDENTIAL
15	**Regulatory Asset Base and Depreciation**
0.2	Roll-forward Model
15.2	ATO TR 2016/1Taxation Ruling Income tax: effective life of depreciating assets (applicable from 1 July 2016)
16	**Rate of return, inflation and debt and equity raising costs**
16.1	Rate of Return Overview Document
16.1.1	MG letter to AER re debt and equity averaging periods - CONFIDENTIAL
16.1.2	MG letter to AER re debt and equity averaging periods - PUBLIC
16.2	CEG, *Replication and Extension of Henry's Beta Analysis*, November 2016
16.3	HoustonKemp, *The Cost of Equity and the Low Beta Bias*, November 2016
16.4	Frontier, *The Market Risk Premium: A report prepared for AGN, Multinet Gas, Ausnet Transmission and Ausnet Gas*, September 2016
16.5	AER, Rate of Return Guidelines, December 2013
16.6	Partington, G and Satchell, S, Report To The ERA: The Cost Of Equity And Asset Pricing Models, May 2016
16.7	Henry, *Estimating Beta: an Update*, April 2014

Chapter reference	Document name
16.8	*ERA, Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline 2016 – 2020: Appendix 4 –Rate of Return*, June 30 2016
16.9	AER, *Rate of Return Guidelines: Explanatory Statement – (and Appendices,)* December 2013
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16.11	NERA, *Empirical Performance of Sharpe-Lintner and Black CAPMs: A report for Jemena Gas Networks, Jemena Electricity Networks, ActewAGL, AusNet Services, CitiPower, Energex, Ergon Energy, Powercor, SA Power Networks, and United Energy,* February 2015
16.12	Partington, G. and S. Satchell, *Report to the AER: Cost of equity issues 2016 electricity and gas determinations*, April 2016
16.13	Partington, G. and S. Satchell, *Report to the AER: Analysis of criticism of 2015 determinations*, October 2015
16.14	AER, *Draft decision AusNet Services transmission determination 2017-18 to 2021-22: Attachment 3 – Rate of return*, July 2016
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16.19	McKenzie, M and Partington, G, *Risk, Asset Pricing Models and WACC: Report to the AER*, June 2013
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16.21	ESQUANT, *Estimating the Market Risk Premium: DBP Submission 12 Appendix E,* December 2014, available from https://www.erawa.com.au/gas/gas-access/dampier-to-bunbury-natural-gas-pipeline/access-arrangements/proposed-access-arrangement-for-period-2016-2020
16.22	Deloitte, CFO Survey: Looking beyond the clouds Q3 2014, available from https://www2.deloitte.com/au/en/pages/media-releases/articles/cfos-looking-beyond-clouds-161014.html
16.23	CEG, *Criteria for Assessing Fair Value Curves: An update,* September 2016
16.24	Hong, H. and D.A. Sraer, *Speculative betas*, Journal of Finance, 2016, pages 2095-2144
16.25	UKRN, Market Returns and Cost of Capital: A Refresh, 11 February 2015, available from http://www.ukrn.org.uk/wp-content/uploads/2016/07/2015DecMarketReturnsAndCoC-ARefresh.pdf
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16.28	CEG, Inflation Compensation: Addendum to September report, December 2016
16.29	CEG: *Best estimate of expected inflation,* September 2016
16.30	CEG, Measuring Expected Inflation for the PTRM June 2015
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Chapter reference	Document name
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16.37	Incenta Economic Consultants, *Debt Raising Transaction Costs – United Energy*, April 2015
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16.41	Frontier Economics, *Estimating the equity beta for the benchmark efficient entity*, January 2016
16.42	AER, *Draft Decision Powerlink Transmission Determination 2017-18 to 2021-22: Attachment 3 – Rate of Return*, September 2016
17	**Estimated Cost of Corporate Income Tax**
17.0.1	Corporate Income Tax Overview Document
17.1	Frontier Economics, *An Updated Dividend Drop-off Estimate of Theta*, September 2016
17.2	Frontier Economics, *Issues in the Estimation of Gamma*, September 2016
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17.6	SFG Consulting, *An Appropriate Regulatory Estimate of Gamma*, May 2014
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17.8	AER, *Preliminary Decision SA Power Networks Determination 2015-16 to 2019-20: Attachment 4 – Value of imputation credits*, April 2015
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17.10	SFG, *Estimating Gamma for Regulatory Purposes*, February 2015
17.11	Lally, M, *Gamma and the ACT Decision*, May 2016
17.12	AER, *Draft Decision AusNet Services Transmission Determination 2017-18 to 2021-22: Attachment 4 – Value of imputation credits,* July 2016,
17.13	AER Draft Decision Powerlink Attachment 4 Value of imputation credits_September 2016
18	**Incentives Scheme**

Chapter reference	Document name
18.1	FarrierSwier Incentive Mechanisms for the Victorian Gas Distribution Businesses 2018 to 2022 Gas Access Arrangement Review (Issues Paper) 10 June 2016
18.2	FarrierSwier Vic Gas DBs incentive mechanisms - stakeholder forum – July 2016
18.3	FarrierSwier Findings Report - Victorian Gas Distribution Businesses' consultation on Incentive Mechanisms Issues Paper
20	**Total revenue and X-factors indicative bill impacts**
0.1	MG AAR Pricing Model
22	**Other Access Arrangement Matters**
22.1	Proposed Access Arrangement revisions -151216
22.2	Access Arrangement - Part A – Principal Arrangements - 151216
22.2.1	Access Arrangement - Part A – Principal Arrangements - Mark-up 151216
22.3	Access Arrangement - Part B – Reference Tariffs and Reference Tariff Policy 151216
22.3.1	Access Arrangement - Part B – Reference Tariffs and Reference Tariff Policy - Mark-up 151216
22.4	Access Arrangement - Part C - Terms and Conditions - 151216
22.4.1	Access Arrangement - Part C - Terms and Conditions - Mark-up 151216
22.5	Confidentiality Claims
22.6	MG 2018 to 2022 Access Arrangement Proposal Document Map
	Other supporting documents
0.1	MG AAR Pricing Model
0.2	Roll Forward Model
0.3	Capex Model
0.4	Accelerated Depreciation
0.5	Opex and ECM Model
0.6	Tax Model
0.7	Rate of Return calculator
0.8	NIEIR detailed Volumes
0.9	Multinet Gas' 2018 to 2022 Access Arrangement - National Gas Law and National Gas Rules Compliance Checklist
0.1	Written RIN compliance
0.11	Reset RIN Templates - MG Response
0.12	Reset RIN templates Basis of Preparation