Gas network performance report

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AUSTRALIAN ENERGY REGULATOR

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Contents

About us

We, the Australian Energy Regulator (AER), work to make all Australian energy consumers better off, now and in the future. We are the independent regulator of energy network service providers (NSPs) in all jurisdictions in Australia except for Western Australia. We set the revenue requirements these NSPs can recover from customers using their networks.

The National Electricity Law and Rules (NEL and NER) and the National Gas Law and Rules (NGL and NGR) provide the regulatory framework that governs the NSPs. Our role is guided by the National Electricity and Gas Objectives (NEO and NGO).

NEO:[1]

> …to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system.

NGO:[2]

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

The decisions we make and the actions we take affect a wide range of individuals, businesses and organisations. Effective and meaningful engagement with stakeholders across all our functions is essential to fulfilling our role, and it provides stakeholders with an opportunity to inform and influence what we do.

Engaging with those affected by our work helps us make better decisions, provides greater transparency and predictability, and builds trust and confidence in the regulatory regime.

This is reflected in our Stakeholder Engagement Framework and in the consultation process we have followed in this review.[3]

1 NEL, s. 7.

2 NGL, s. 23.

3 AER, *Revised stakeholder engagement framework*, September 2017. NER clause 8.7.4 and NGR rule 140 set out the minimum process we must follow when preparing an NSP performance report for electricity and gas NSPs, respectively.

1 This gas network performance report

The 2021 gas network performance report is the first of what will be annual network performance reports for gas NSPs. The report analyses key outcomes and trends in the operational and financial performance data for gas distribution NSPs.

Our key findings in this report are that:

- In total, consumers are spending more on reference services than they were in 2011. However, this cost is being spread across a larger number of consumers, resulting in lower individual costs for each customer.
- Reference service revenue increased in 2020. Revenue is higher than it was in 2011, but remains below a peak in 2015.
- In contrast, revenue per customer is materially below what it was in 2011 due to growth in residential customer numbers.
- Fully regulated gas distribution NSPs have invested substantially in new connections and mains replacement programs.
- Actual and forecast returns have declined, driven by lower forecast returns on capital, but gas distribution NSPs have consistently generated returns above our forecast.
- Gas distribution NSPs are inherently reliable with very low albeit rising rates of outages.
- Unaccounted for gas (UAFG) levels have declined overall from their peak in 2015. This was driven by major reductions in South Australia, which appear to be a consequence of AGN (SA)'s mains replacement program.
- The fully regulated gas distribution NSPs exhibit material differences in customer bases and material composition. However, as mains replacement programs continue in Victoria and South Australia, the material composition of the networks will converge to be predominantly plastic (polyethylene and polyamide), high and medium pressure mains pipelines.

Gas pipeline networks in Australia transport gas from upstream producers to energy users. These networks consist of:

- Long haul transmission pipelines that transport gas from producing basins to major population centres, power stations and large industrial and commercial plants
- Urban and regional distribution networks, which are clusters of smaller pipes or mains that transport gas to customers in local communities.

This inaugural report focuses solely on the six fully regulated gas distribution NSPs in NSW, South Australia, Victoria and the ACT. The greatest number of customers are directly connected to and access the reference services offered by these networks.

We plan to extend our reporting to cover fully regulated gas transmission NSPs. These include Amadeus in the Northern Territory, Roma to Brisbane in Queensland and Victoria Transmission System (VTS) in Victoria in subsequent gas network performance reports. These transmission pipelines transport gas to many industrial customers through a direct connection.

Under full regulation, we set reference tariffs (prices) for regulated reference services based on an assessment of the efficient costs of providing those services. For gas distribution NSPs, these are called haulage reference services and for gas transmission NSPs, these are called reference services.

A number of gas pipelines are unregulated or face only light regulation. These pipelines operate throughout Australia, in all states except Western Australia and have not been included in the report.[4] Our role varies depending on the type of regulation applying to the specific pipeline.

Light regulation and Part 23 regulation

Light regulation

Light regulation uses a commercial negotiation approach supported by mandatory information disclosure. It requires gas pipeline businesses to publish access prices and other terms and conditions on their website. They cannot engage in inefficient price discrimination or other conduct adversely affecting access or competition in other markets. If a party is unable to negotiate access to a pipeline, they may request the AER arbitrate a dispute.

Part 23 regulation

Gas pipelines not subject to full or light regulation are 'unregulated', so can set their own prices and other terms and conditions. A number of independent reviews raised concerns that this allowed monopolistic practices by some pipeline operators.

These concerns led to introducing Part 23 provisions in the NGR, which took effect in 2018. Part 23 aims to make it easier for gas customers to negotiate access to unregulated pipelines at a reasonable price. The rules require otherwise unregulated pipeline businesses to disclose certain financial, service and access information following guidelines published by the AER.

Further information can be found in the regulated gas pipeline chapter of our State of the Energy Market report.

4 A geographical map showing the location of the fully regulated gas NSPs, unregulated pipelines and pipelines under light regulation is included on page 221 of the 2021 State of the Energy Market report.

There may be future reforms to gas pipeline regulation in Australia. The Energy National Reform Cabinet released a Regulatory Impact Statement for Decision in July 2021[5] recommending a package of reforms that could materially change the regulatory and reporting frameworks for gas pipelines.

We will monitor the regulatory reform process and revisit the scope of this reporting as needed to ensure it continues to add value whilst avoiding duplication. Performance reporting will continue to be an important step in evaluating the effectiveness of the building block regulatory framework, which is at the core of our decisions for the fully regulated gas NSPs.

1.1 Stakeholder engagement

When planning the report, we consulted with stakeholders on our proposed content. We also previously had extensive stakeholder engagement in:

- Developing our priorities and objectives for reporting on network performance
- Completing our profitability measures review, which has been an important input into this report.

In developing this report, we invited gas NSPs to comment on the accuracy of the data and analysis. We will continue to undertake this consultation for future reports.

We plan to continue to engage early and widely with stakeholders on the emerging issues, which we will investigate in the 2022 report.

5 National Cabinet – Energy Ministers Meeting, *Gas pipeline regulation – Regulation impact statement*, National Cabinet – Energy Ministers Meeting, 2021, accessed 3 December 2021.

2 Contents and structure of the report

2.1 The structure of this report

An effective gas network regulatory regime should contribute to consumers paying no more than is necessary for a safe and secure supply of natural gas.

Implicit in this vision is a balance between the costs of providing network services and the outcomes arising from those costs. We have structured this report to address a series of questions that should assist us and stakeholders in reaching a view on whether this balance is being achieved. We have also sought to link these questions back to our performance reporting priorities, determined with the input of stakeholders.

The structure of the report is set out in Table 2-1.

Table 2-1 The structure of this report

Section	Contents	Network performance reporting priority
1	This gas network performance report	n/a
2	Contents and structure of the report	n/a
3	The fully regulated gas distribution NSPs	Operational performance and efficiency
4	Revenue collected from customers	Operational performance and efficiency Financial performance
5	Network expenditure	Operational performance and efficiency
6	Network service outcomes	Operational performance and efficiency
7	Profitability	Financial performance
8	Looking ahead to 2022	Emerging issues
Appendix A	Objectives of network performance reporting	n/a
Appendix B	Figures source data	n/a

Source: AER analysis.

2.2 How we refer to regulatory years

This network performance report covers network data for regulatory year 2020 which is:

- July 2019 to June 2020 for Evoenergy Gas, Jemena Gas Networks (JGN) and AGN (SA)
- January 2020 to December 2020 for AGN (Albury & Victoria), AusNet Gas and Multinet Gas.

This is our naming convention wherever we refer to specific regulatory years in this report. So, for example, regulatory year '2018' refers to 2017-18 for a financial year NSP and 2018 for a calendar year NSP.

Impact of COVID-19 on fully regulated gas NSPs

Due to timing of the regulatory years, the data included in this report does not cover the full effects of COVID-19 on the gas distribution NSPs. We expect that the lockdown restrictions introduced to curtail the spread of the virus would have affected the energy needs and gas consumption of residential, commercial and industrial customers.

We may use this report in future years to look at the impact of COVID-19 on the fully regulated gas NSPs by investigating several factors, including whether:

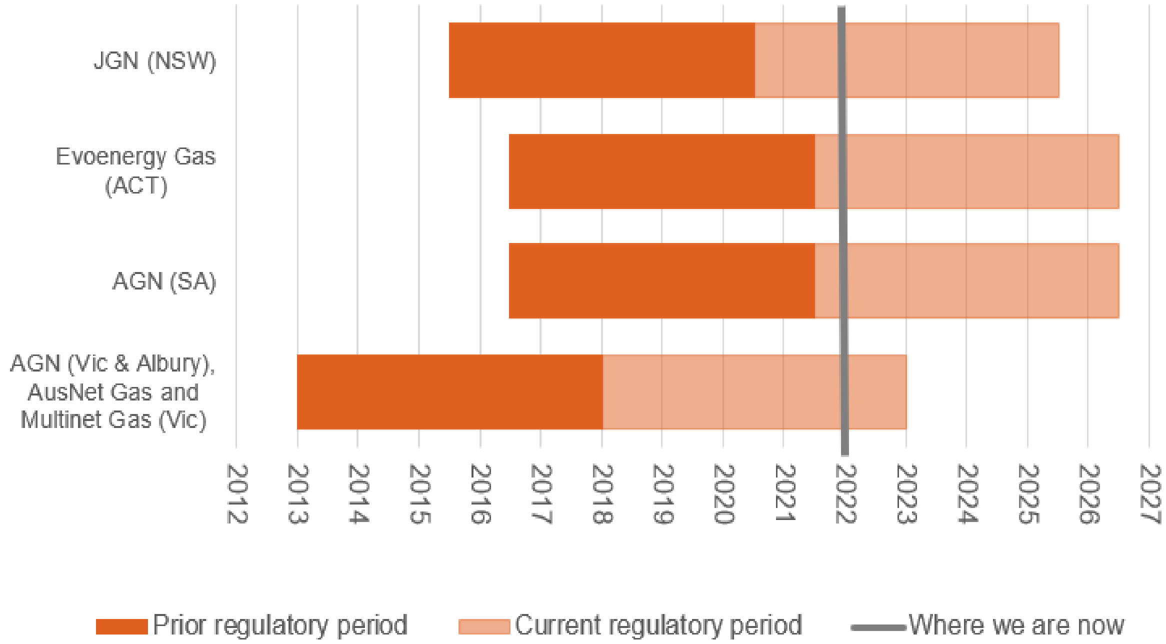
- Residential consumption increased due to lockdown requirements and more residential customers working from home
- Consumption of industrial customers connected to the gas distribution networks decreased
- Activity in the residential construction sector during the pandemic led to an increase in customer numbers

2.2.1 Where 2020 sits in the regulatory cycle

Generally, our regulatory determinations apply over five year periods. We make these decisions for regulated NSPs in a staggered cycle over time.

An important consequence of this approach is that changes in regulatory approaches or market conditions feed gradually into access arrangements.

Figure 2-1 The staggered revenue decision timetable



Source: AER analysis.

The 2020 regulatory year was:

- The last year in JGN’s 2015 to 2020 access arrangement period
- The second last year in Evoenergy Gas and AGN (SA)’s 2016 to 2021 access arrangement period
- The third year in the Victorian gas distribution network’s 2018 to 2022 access arrangement period.

3 The fully regulated gas distribution NSPs

This section discusses the different characteristics of the gas distribution NSPs we regulate, and how these differences influence the prices charged for core regulated services.

We apply full regulation to six gas distribution NSPs. These NSPs provide reference services under an access arrangement and are subject to a price cap and an approved annual tariff variation mechanism. This report focuses on the core regulated services of distribution NSPs – haulage reference services.

These six gas distribution NSPs differ materially in terms of:

- The environments in which they operate
- Pipeline composition in terms of material and pressure
- The number and type of customers who use the gas they distribute.

An analysis of these differences provides important background for understanding network performance and the effectiveness of the regulatory framework. These differences affect the outcomes for gas distribution NSPs discussed in the following chapters, including revenues, expenditures and network service outputs.

Gas distribution NSPs typically offer haulage reference services, which are defined in their access arrangements. These services involve allowing gas injections into a pipeline, transporting gas to supply points and allowing the gas to be withdrawn.[6] We determine reference tariffs (prices) for the haulage reference services following an assessment of the NSP's forecast demand, efficient costs and revenue needs. Section 4 discusses how revenue is collected from customers.

[6] AER, *State of the Energy Market 2021 – Chapter 5 Regulated gas pipelines*, 2021, p 220.

Our key findings are that:

- Gas distribution NSPs are substantially different to each other in terms of the material composition of their pipelines and the proportion of their services used by different customer types (residential, commercial and industrial).
- Since 2011 there has been substantial growth in the numbers of residential customers connected to gas distribution NSPs.
- The volume of gas delivered to residential customers has remained relatively steady, implying a slight decline in gas usage per residential customer.
- Industrial connections to gas distribution NSPs have remained relatively stable, but there has been a material decline in the amount of gas delivered to industrial customers.
- In general, most gas distribution NSPs have or are moving to replace cast iron and steel pipes with longer-lived polyethylene and polyamide pipes.

3.1 What are our fully regulated gas distribution NSPs?

There are six fully regulated distribution NSPs, which operate in three different states and one territory.

Figure 3-1 The fully regulated gas distribution NSPs

Source: AER analysis.

- JGN (light blue) serves most of NSW and is connected to the Moomba (to) Sydney Pipeline and the Eastern Gas Pipeline where gas is sourced from the Cooper Basin (Queensland/South Australia), Bowen/Surat Basins (Queensland) and Gippsland Basin respectively (Victoria).[7]
- Evoenergy Gas (pink) serves the ACT region and is connected to the Moomba (to) Sydney Pipeline and the Eastern Gas Pipeline where gas is sourced from Cooper Basin and Longford.[8] The Longford gas plant is an onshore receiving point of natural gas output from the Bass Strait, the strait separating Tasmania from the Australian mainland.
- AGN (Albury and Victoria) (orange) serves the Albury and Jindera region and the northern, eastern and southern areas of metropolitan Melbourne, the Mornington Peninsula, and northern, eastern and south eastern areas of Victoria.[9] This distribution network is connected to the VTS, where gas can be sourced from the offshore Bass Strait gas fields, Dandenong LNG gas storage facility (Victoria), Iona underground storage (Victoria) and Cooper Basin.
- Multinet Gas (light green) serves the southern and eastern areas of metropolitan Melbourne, Yarra Ranges and towns in south Gippsland.[10] This distribution network is connected to the VTS, where gas can be sourced from the offshore Bass Strait gas fields, Dandenong LNG gas storage facility, Iona underground storage and Cooper Basin.
- AusNet Gas (brown) serves the outer western metropolitan Melbourne and central and western areas of Victoria.[11] This distribution network is connected to the VTS, where gas can be sourced from the offshore Bass Strait gas fields, Dandenong LNG gas storage facility, Iona underground storage and Cooper Basin.
- AGN (SA) (dark green) serves Adelaide and its surrounds, and the regional centres of Mount Gambier, Whyalla, Port Pirie, Barossa Valley, Murray Bridge and Berri. This distribution network is connected to Moomba to Adelaide Pipeline System and the Sea Gas, South East and Riverland transmission pipelines, all of which are in South Australia.[12]
- On 28 January 2021, AEMO expanded the boundary of the Gas Supply Hub to include new gas trade locations at Wilton (NSW) and Culcairn (NSW – Victoria).[13] This can be used to supply gas to the NSW and Victorian gas distribution networks from Queensland.[14]

These six gas distribution NSPs and the three gas transmission NSPs; Amadeus in the Northern Territory, Roma to Brisbane in Queensland and VTS in Victoria (which we will cover in subsequent gas network performance reports) are the only gas pipeline networks we fully regulate. A number

7 Australian Energy Market Commission (AEMC), *NSW: NSW Gas Network*, AEMC, 2021, accessed 28 August 2021.

8 AEMC, *ACT: Canberra System*, AEMC, 2021, accessed 28 August 2021.

9 AEMC, *NSW: AGN Albury Gas Distribution Network*, AEMC, 2021, accessed 28 August 2021; AEMC, *VIC: AGN Vic Gas Distribution Network*, AEMC, 2021, accessed 28 August 2021.

10 AEMC, *VIC: Multinet Gas Distribution Network*, AEMC, 2021, accessed 28 August 2021.

11 AEMC, *VIC: SP AusNet Distribution Network*, AEMC, 2021, accessed 28 August 2021.

12 AEMC, *SA: AGN SA Gas Distribution Network*, AEMC, 2021, accessed 28 August 2021.

13 AER, *Wholesale Markets Quarterly Q2 2021 April – June,* 2021, p 47.

14 AER, *Wholesale Markets Quarterly Q2 2021 April – June,* 2021, p 47.

of gas pipelines are unregulated or face only light regulation, which have not been included in the report. This is discussed in more detail in the regulated gas pipeline chapter of our State of the Energy Market report.

3.2 The length, pressure and composition of the gas distribution networks

The length and construction materials of the networks differ amongst the gas distribution NSPs, affecting both the NSPs' efficiency and the cost of the haulage reference services.

The gas distribution networks are characterised by clusters of smaller pipes or mains that transport gas to customers in local communities. This clustered structure has enabled the network to be progressively extended to connect more customers and facilitate the progressive replacement of segments of the distribution networks.

The sum of these clustered small pipes or mains and the transmission pipeline under the control of the gas distribution NSPs determine their network length. In general terms, increasing network length is important because, holding other factors constant, it suggests a greater level of pipeline investment and maintenance. The network length differs according to each gas distribution NSP and is not only based on the geographical size of the network, but also its customer density. An example of this is AusNet Gas's distribution zone,[15] which covers an area of 60,000km^2, with a network length of 10,143km, whilst Multinet Gas's distribution zone[16] covers an area of 1,790km^2 with a network length of 12,337km.

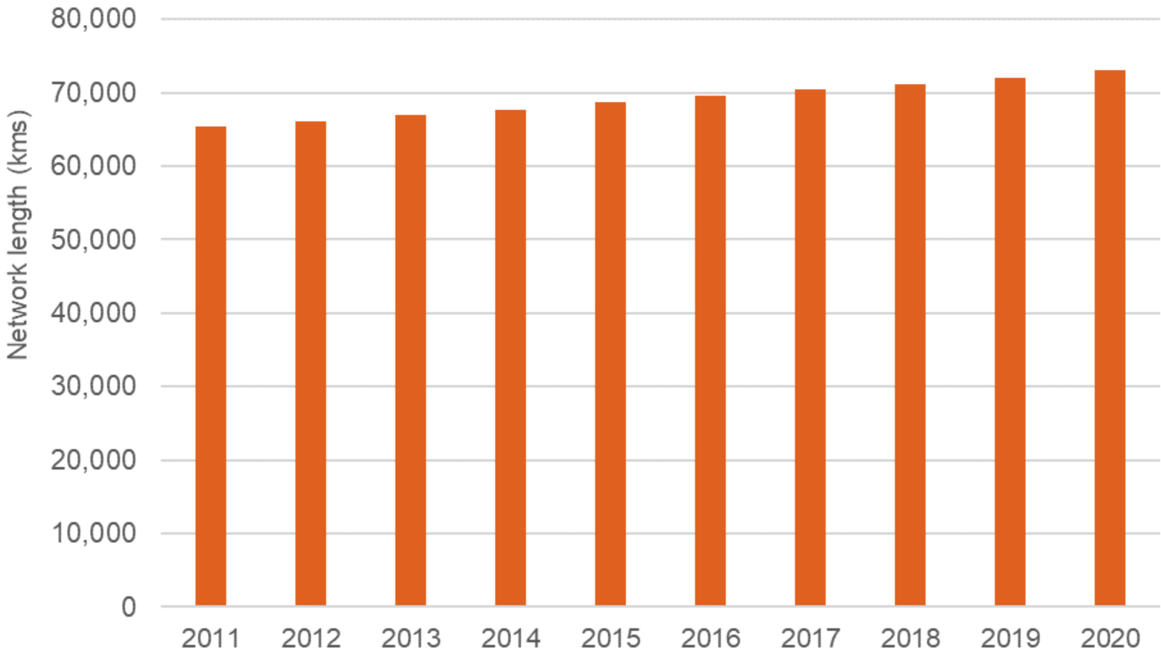
We observe that:

- Since 2011 the total length of the gas distribution NSPs has increased annually by, on average, just over 1% (Figure 3-2)

15 AEMC, *VIC: SP AusNet Distribution Network*, AEMC, 2021, accessed 28 August 2021.

16 AEMC, *VIC: Multinet Gas Distribution Network*, AEMC, 2021, accessed 28 August 2021.

Figure 3-2 Network length – Gas distribution NSPs



Source: Operational performance data, AER analysis

In analysing the network length to evaluate the different characteristics of each gas distribution NSP, we need to assess the pressure and asset types of each NSP or jurisdiction. We discuss these below.

3.2.1 Network length by pressure type

We categorise segments of distribution pipelines within several different pressure types, including:

- Low pressure – pressures of up to 7 kPa
- Medium pressure – pressures of between 7 kPa and 1050 kPa
- High pressure – pressures greater than 1050 kPa.

Some gas distribution NSPs include assets operating at a sufficiently high pressure to be classified as transmission pipelines. Typically, transmission pipelines operate between 10,000 and 15,000 kPAs.[17]

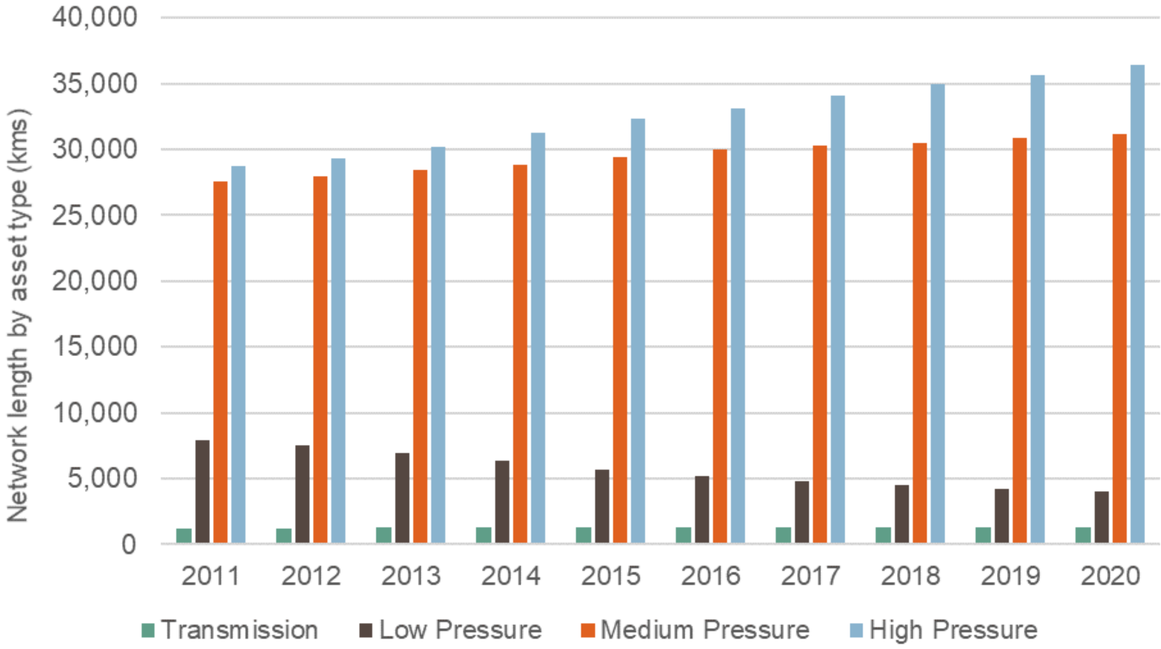
The differing pressure types play an important role in delivering gas to customers. The high and medium pressure mains provide a 'backbone' that services areas of demand and transports gas between population concentrations within a distribution area.

17 Australian Pipelines and Gas Association (APGA), *Pipeline Facts and Figures*, APGA, 2021, accessed 29 August 2021.

Over 2011 to 2020, we observe that:

- The majority of gas distribution NSPs' networks, by length, are high pressure mains.
- The overall increasing length of the gas distribution networks also takes place alongside programs to replace low pressure mains with medium and high pressure mains.

Figure 3-3 Network length by pressure type – Gas distribution NSPs

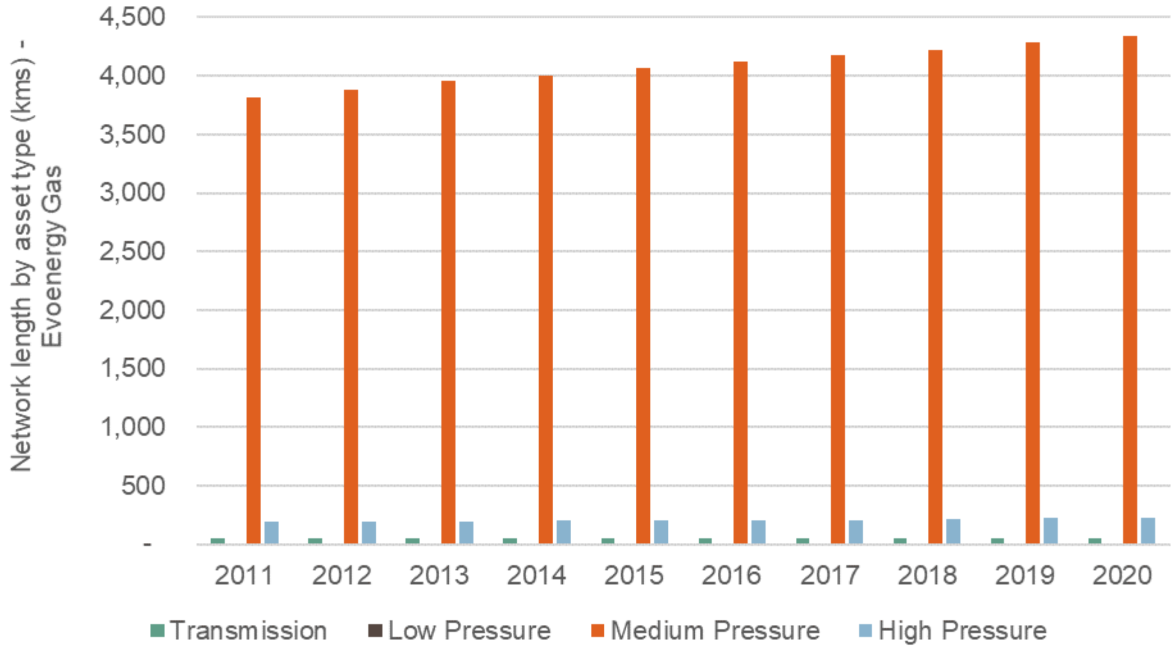


Source: Operational performance data, AER analysis

Pressure distribution varies materially between states and gas distribution NSPs. Figure 3-3 illustrates the network length disaggregated into the differing pressures and transmission. This illustration highlights that most of the network is medium and high pressure, with the increase in high pressure pipeline length being comparable to the decrease noted in low pressure pipeline length.

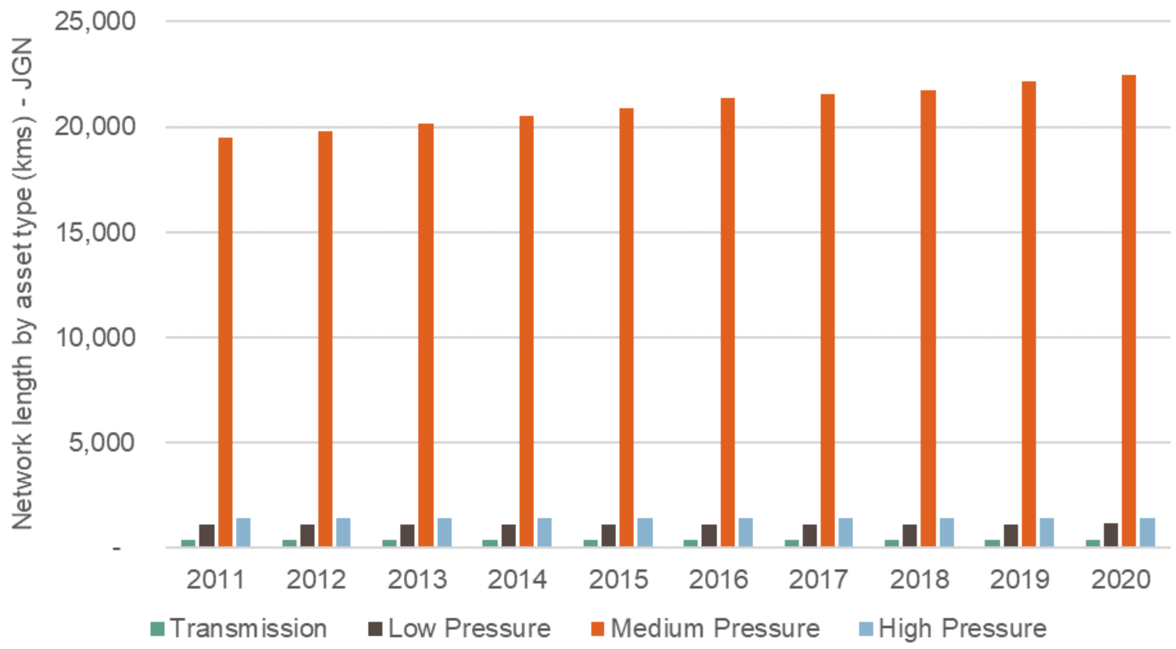
When comparing the gas distribution NSPs pressure type across the jurisdictions, different characteristics can be noted. In Figure 3-4 and Figure 3-5, Evoenergy Gas and JGN's network length is primarily medium pressure, with minimal movement in the other pressure types.

Figure 3-4 Network length by pressure type – Evoenergy Gas



Source: Operational performance data, AER analysis

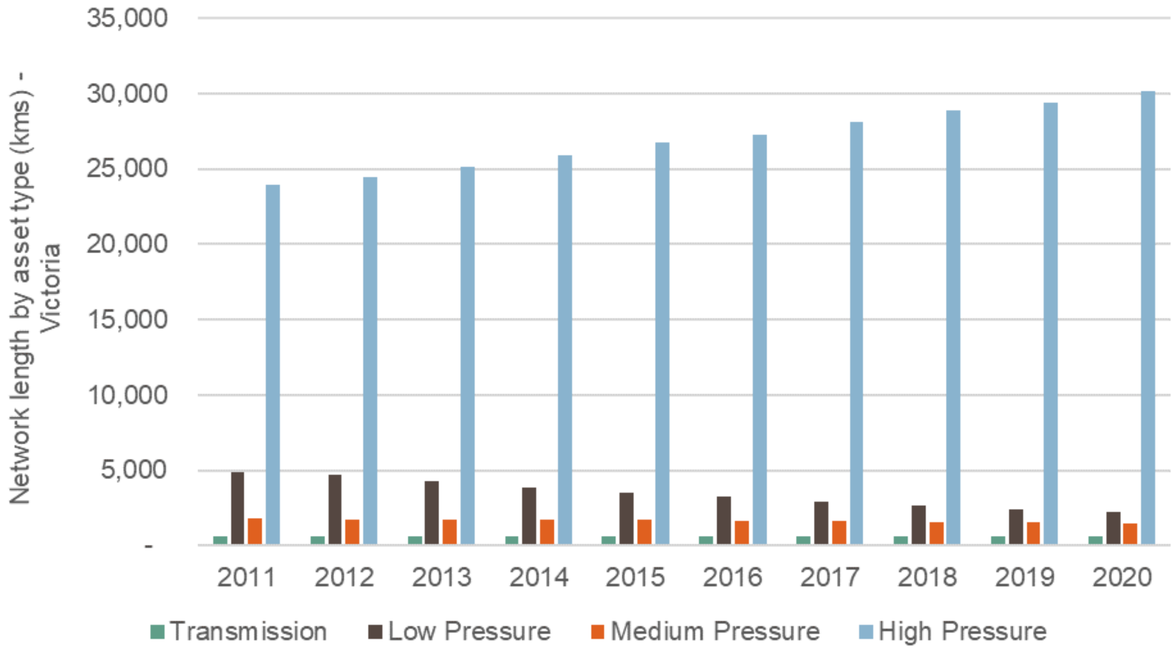
Figure 3-5 Network length by pressure type – JGN



Source: Operational performance data, AER analysis

In contrast, the Victorian gas distribution NSPs (Figure 3-6) are primarily and increasingly made up of high pressure pipelines, with a declining proportion of low pressure pipelines.

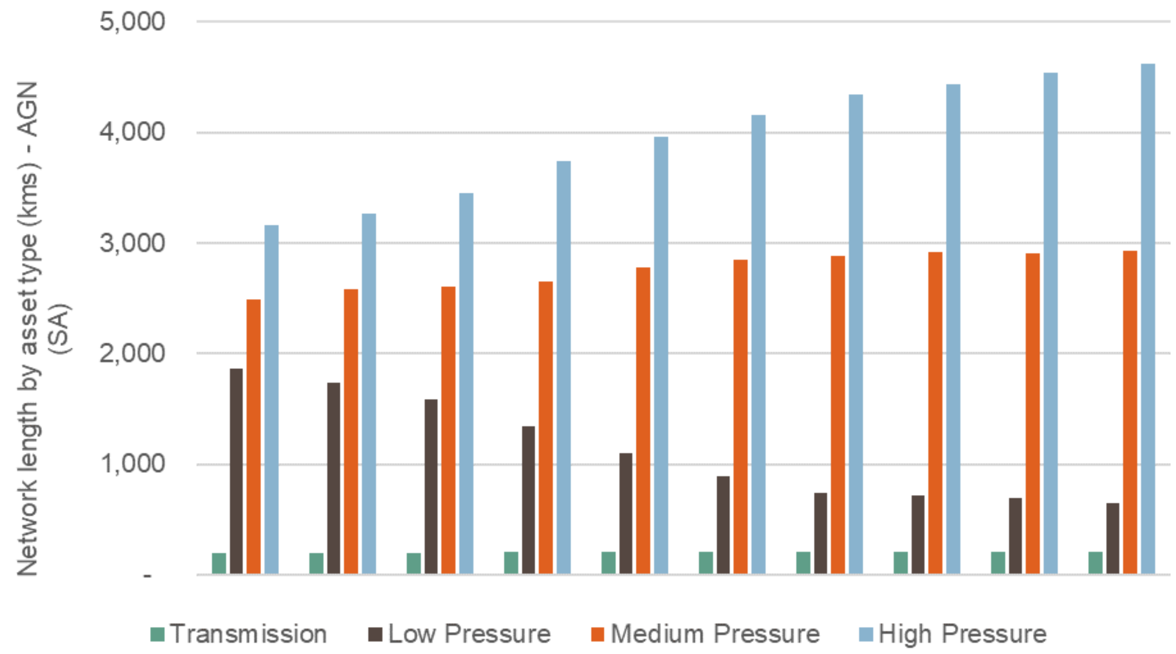
Figure 3-6 Network length by pressure type – Victorian Gas distribution NSPs



Source: Operational performance data, AER analysis

AGN (SA), in turn, has a more even distribution of pressure types, including a majority of high pressure, sizeable portion of medium pressure and declining amount of low pressure pipelines.

Figure 3-7 Network length by pressure type – AGN (SA)



Source: Operational performance data, AER analysis

Decreases in low pressure pipelines in Victoria[18] and AGN (SA)[19] reflect the forecast capital expenditure intentions of the gas distribution NSPs in their current access arrangements.[20] These gas distribution NSPs have been undertaking mains replacement programs across multiple access arrangements to replace their low pressure cast iron pipes.

3.2.2 Network length by material type

The current distribution networks are made up in varying proportions of pipelines of different materials, being a combination of:

- Polyethylene
- Polyamide
- Steel
- Cast iron
- PVC
- Other materials.

Over 2011 to 2020, we observe that:

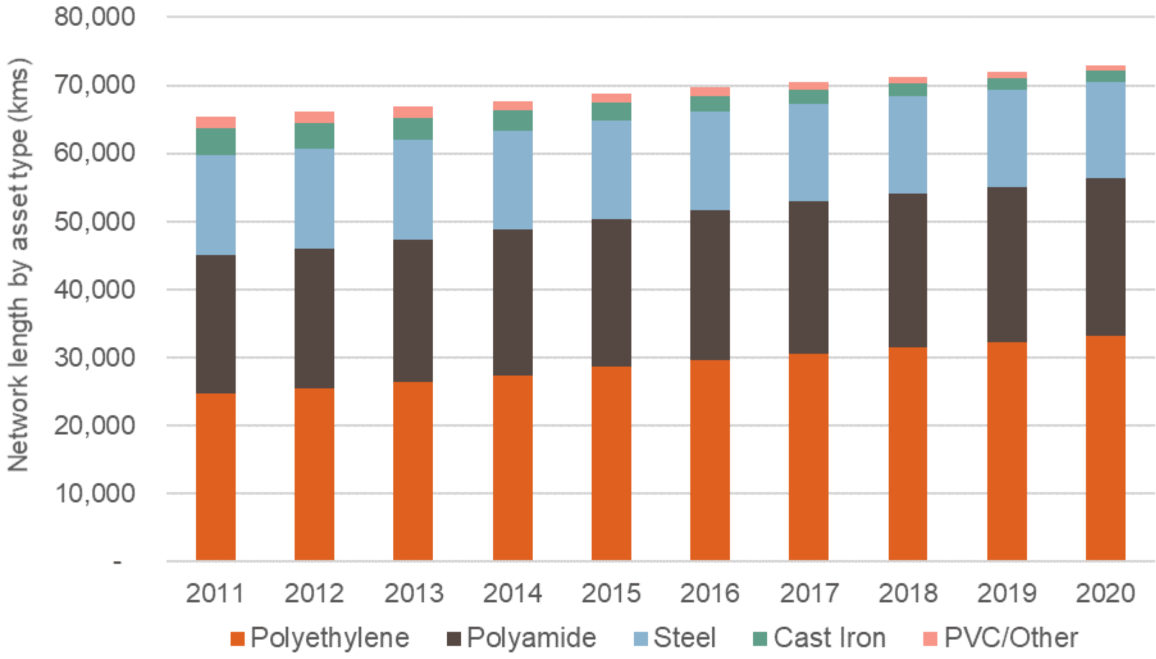
- The gas distribution NSPs' networks are increasingly made up of plastic (polyethylene and polyamide) pipes, and less of steel and cast iron pipes.
- The transition to a plastic-based network reflects the replacement of low pressure mains with medium and high pressure mains, alongside expansion of the networks.

18 AGN (Albury & Victoria), *AGN (Albury & Victoria) – 2018 to 2022 access arrangement information*, 2016, pp 81-82; AusNet Gas, *Ausnet Gas – 2018 to 2022 access arrangement information*, 2016, p 100; Multinet Gas, *Multinet Gas – 2018 to 2022 access arrangement information*, 2016, p 56.

19 AGN (SA), *AGN (SA) – 2018 to 2022 access arrangement information*, 2015, p 133.

20 For the 2020 regulatory year, the access arrangement period for Victorian gas distribution NSPs is 1 January 2018 to 31 December 2022 and 1 July 2016 to 30 June 2021 for AGN (SA).

Figure 3-8 Network length by asset type – Gas distribution NSPs



Source: Operational performance data, AER analysis

What are polyethylene and polyamide pipelines?

Polyethylene and polyamide (or nylon) pipes are the main asset type used in the gas distribution networks, with almost all gas mains replacements involving the installation of polyethylene or polyamide materials. These materials, which we collectively refer to as plastic pipelines, are constructed using raw materials from polyamides.

The Victorian gas distribution NSPs and AGN (SA) use polyethylene in their networks, whilst JGN and Evoenergy Gas mostly use polyamide, with smaller amounts of polyethylene.

These materials have a number of operational advantages, including:

- Resistance to damage from corrosion or the effects of gas
- Ease of installation
- Cost effectiveness.

These materials enable gas distribution NSPs to transport gas at predominately medium or high pressure.

As noted in Figure 3-8, there has been a decrease in cast iron and an increase in the installation of polyethylene and polyamide. This has directly caused both the decrease in low pressure pipelines and increase in medium and higher pressure pipelines noted in section 3.1.2.

There is also a significant portion of steel mains and service lines within the gas distribution networks. This steel can be divided into two types of materials:

- Protected steel—where there is a polyethylene coating on the steel mains and service lines.
- Unprotected steel—where there is no polyethylene coating on the steel mains and service lines. Bare steel mains and service lines are prone to corrosion.

AusNet Gas and Multinet Gas are the only gas distribution NSPs with over 50km of unprotected steel in their networks in the 2020 regulatory year. However, in the period of 2011 to 2020, the amount of unprotected steel has been steadily reducing. These are being replaced to reduce the risk of gas leakage, as part of AusNet Gas and Multinet Gas's mains replacement programs.

These replacement programs and resulting materials mix have influenced forecast regulated expenditure requirements. In particular, replacing old and substantially depreciated steel and cast iron mains with polyethylene and polyamide piping mains materially extends the potential economic lives of the assets, noting polyethylene and polyamide mains may have standard lives typically ranging from 60 to 80 years.[21] We discuss this expenditure in greater detail in section 5.

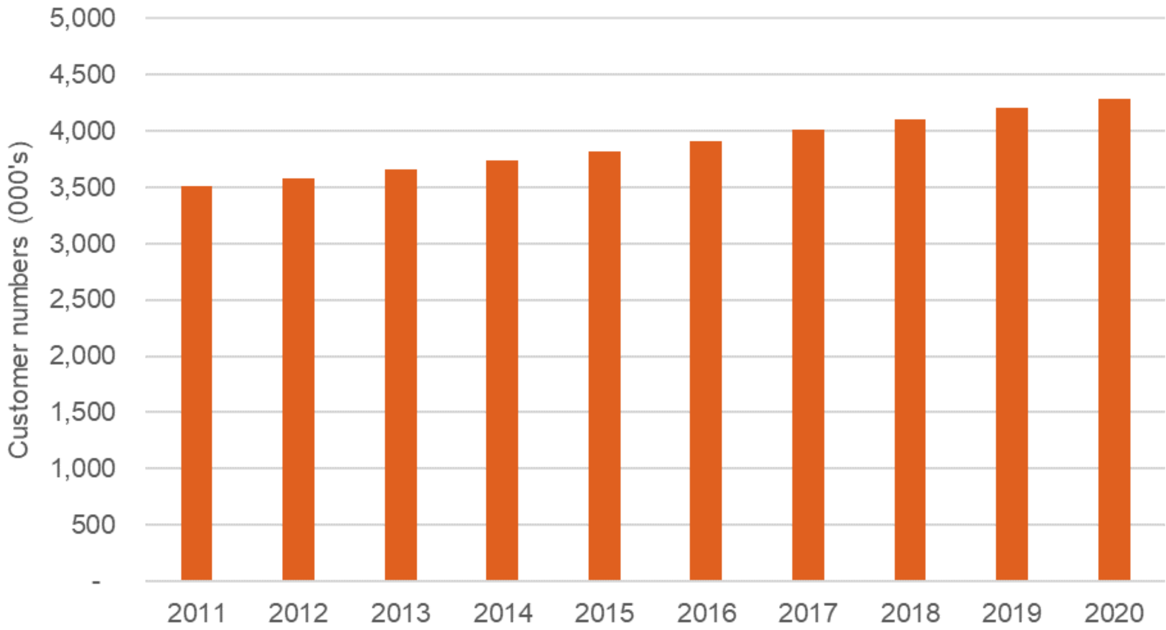
3.3 The number and type of customers connected to gas distribution networks

Reflecting their different operating environments, different gas distribution NSPs have materially different customer bases.

> Over 2011 to 2020, we observe that:
>
> - Customer numbers connected to the gas distribution networks have increased by 22%.
> - Increasing customer numbers is mainly driven by increasing residential connections in NSW and Victoria.

21 ENA, *The role of gas networks in Australia's long term energy security*, 2016, p. 2.

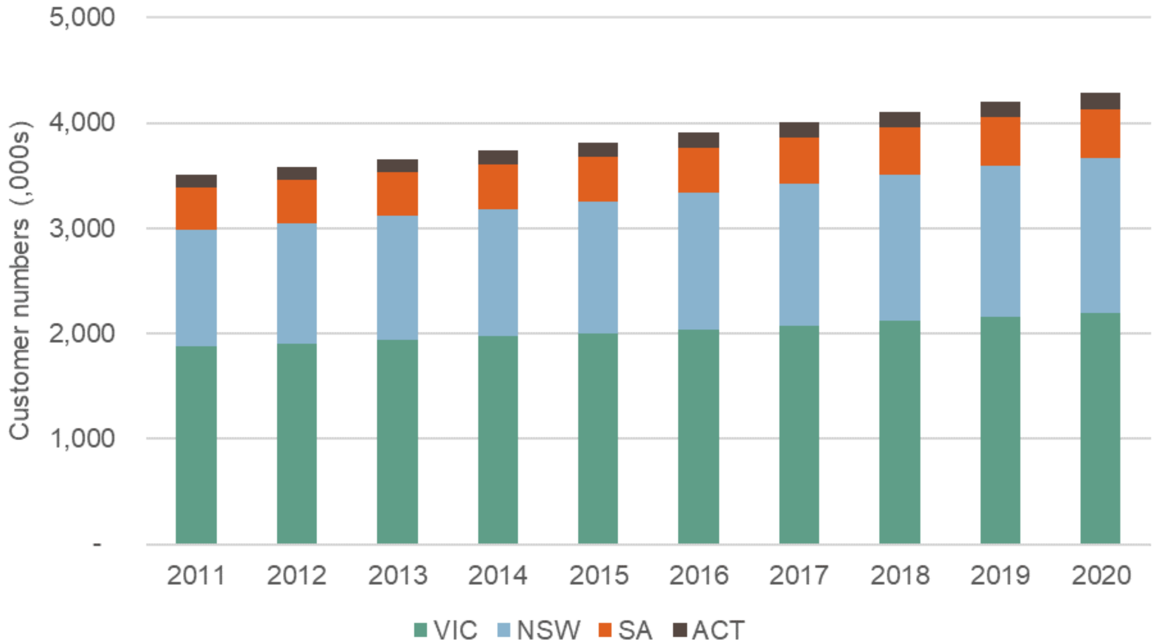
Figure 3-9 Customer numbers – Gas distribution NSPs



Source: Operational performance data, AER analysis

As illustrated in Figure 3-10, the majority of gas distribution customers are in Victoria and NSW.

Figure 3-10 Customer numbers by state/jurisdiction – Gas distribution NSPs



Source: Operational performance data, AER analysis

Customer types

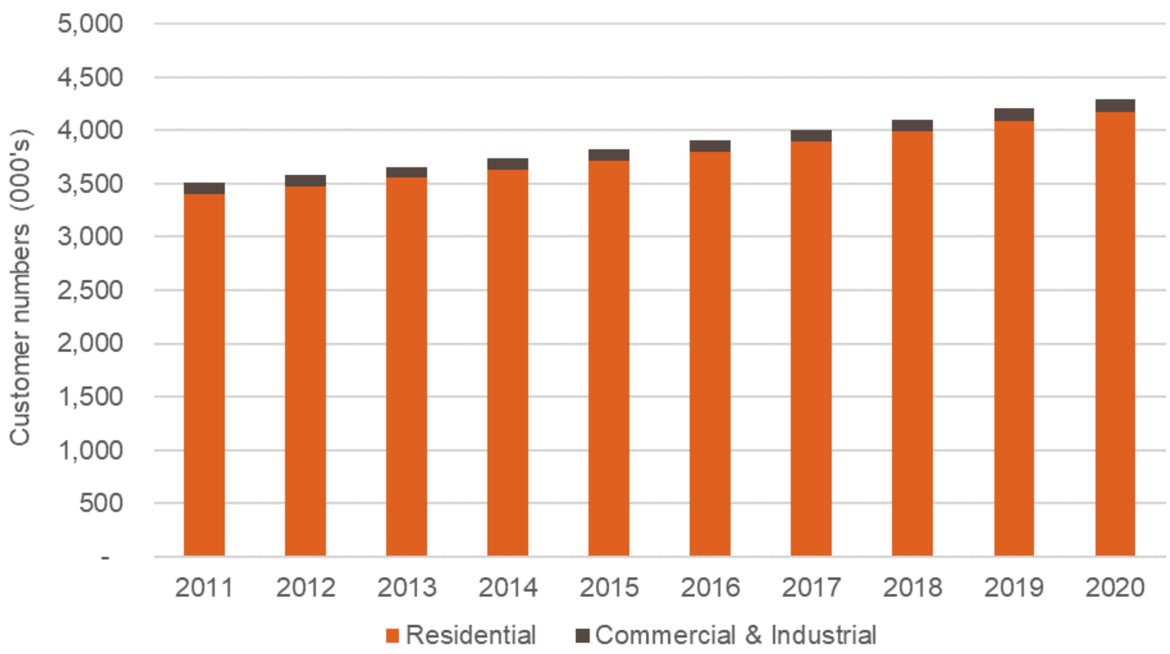
Gas distribution NSPs report customer numbers grouped into three categories, being:

- Residential customers – Customers who purchase gas principally for personal, household or domestic use.
- Commercial customers – Customers who purchase gas principally for use in commercial premises.
- Industrial customers – Customers who purchase gas for use in large scale production of goods and services.

Many industrial customers directly connect to transmission pipelines and therefore do not use gas distribution NSPs to transport gas. As such, the outcomes observed in this data do not necessarily represent broader changes in industrial use of natural gas.

As set out in Figure 3-11, residential customers account for a significant majority of individual connections to the gas distribution NSPs' networks. The high proportion of residential customers is consistent across all gas distribution NSPs in the 2020 regulatory year, with non-residential customers ranging from 2% to 3.4% of their customer bases.

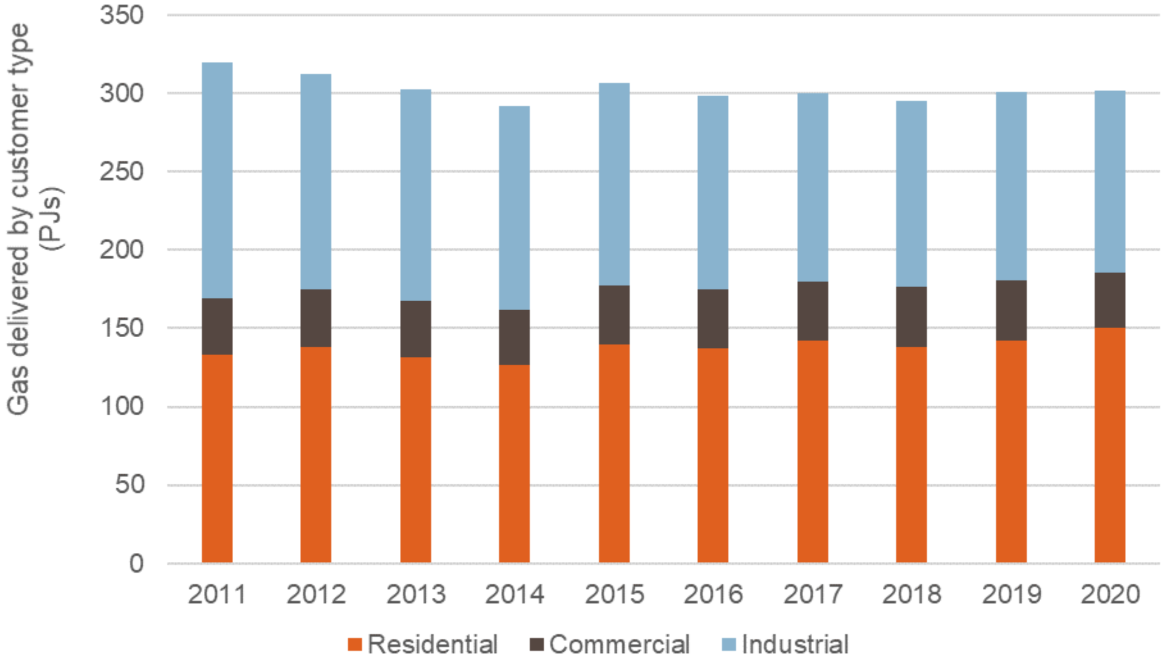
Figure 3-11 Residential and non-residential customer numbers – Gas distribution NSPs



Source: Operational performance data, AER analysis

Although commercial and industrial customers make up a very small proportion of connections, they typically consume at least 50% of total gas delivered, as set out in Figure 3-12. For example, in the 2020 regulatory year, commercial and industrial customers represented 2.6% and 0.03% of total customer numbers, respectively. However, the 1,415 industrial customers connected to gas distribution NSPs accounted for 38.5% of total consumption. This is important as the amount of gas delivered is a key driver of the costs faced by each customer type after they are connected to the gas distribution NSP's network.[22]

Figure 3-12 GJ delivered by customer type – Gas distribution NSPs



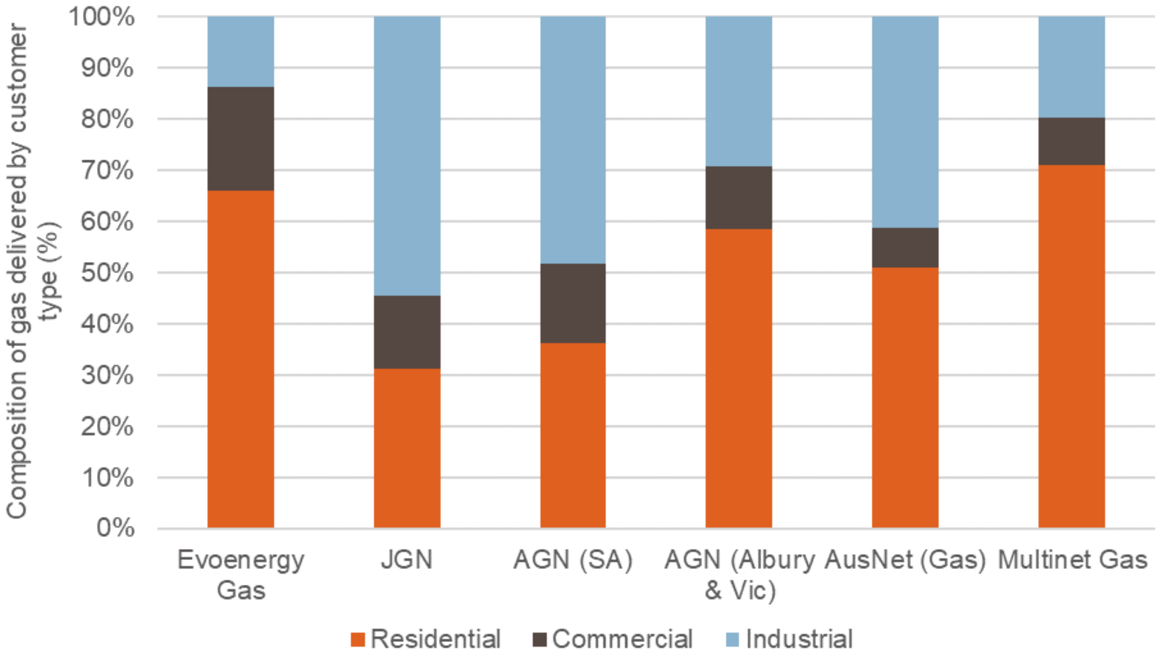
Source: Operational performance data, AER analysis

We also observe that the composition of gas delivered by customer type varies materially between gas distribution NSPs (see Figure 3-13). For example, JGN and AGN (SA) deliver the majority of gas to commercial and industrial customers within their network, whereas networks in Victoria and the ACT deliver the majority of gas to residential customers.

These different compositions are important for understanding the potentially different demand drivers for gas distribution reference services, or the elasticity of demand for pipeline services to changes in the cost of natural gas. More generally, understanding these different customer bases is important for interpreting network revenue, demand, expenditure and profit outcomes since the different customer types will use the networks differently and face different proportional costs.

22 It should be noted that some commercial and large industrial customers may pay large up-front customer contribution costs to connect to the gas distribution network and face relatively low reference service costs for the amount of gas delivered.

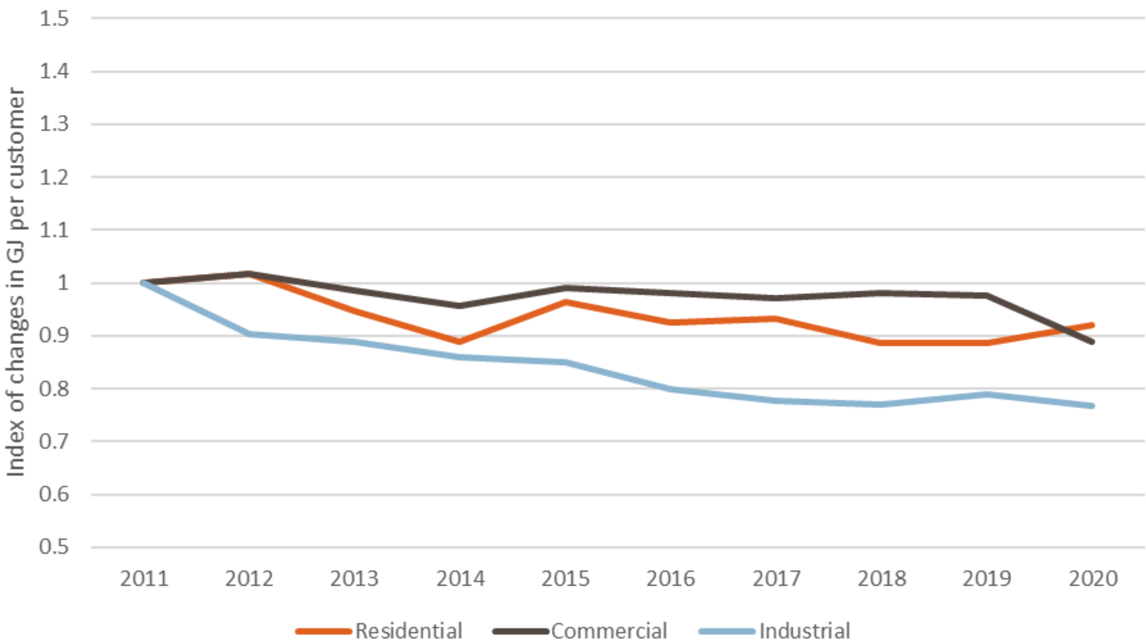
Figure 3-13 Composition of gas delivered by customer type in 2020 – Gas distribution NSPs



Source: Operational performance data, AER analysis

Figure 3-14 illustrates that GJ per customer has decreased for each customer type since 2011, with the greatest decrease coming from industrial customers.

Figure 3-14 GJ per customer for different customer types since 2011 – Gas distribution NSPs



Source: Operational performance data, AER analysis

These movements reflect the impacts of a 22% increase in customer numbers since 2011, combined with a decrease in gas delivered, as set out in Figure 3-12. Several factors may explain these changes. We will continue to monitor these movements in future reporting years and may investigate the drivers in more detail.

4 Revenue collected from customers

All fully regulated gas distribution NSPs' reference services are regulated under a price cap form of control.

This begins with a process where we establish a building block revenue forecast.[23] Then, having regard to forecast demand over the access arrangement period, we convert this building block revenue forecast into:

- A set of initial year tariffs
- A series of 'X-factors',[24] which along with actual inflation, changes in demand and other factors, constrain annual price increases for those tariffs during the access arrangement period. X-factors govern real annual price changes arising as a result of forecast revenue requirements.

Under price caps, gas distribution NSPs can earn above or below forecast revenue over time due to changes in demand. If actual demand exceeds forecast demand, gas distribution NSPs keep the higher resulting revenue. Similarly, if actual demand is less than forecast revenue, gas distribution NSPs are exposed to the shortfalls. This differs from revenue caps where revenue overspends and underspends ('overs and unders') in any year are carried forward and accounted for to provide revenue certainty.

The tariffs we determine (including the means of varying the tariffs from year-to-year), along with X-factors and changes in real inflation are used to determine the NSP's proposed reference service revenue each regulatory year during access arrangement periods, rather than the total revenue requirement set in our decisions. However, changes in forecast building blocks remain a key determinant of the costs that customers face.

In this section, we analyse:

- The total revenue gas distribution NSPs have collected from customers through reference services.
- The major drivers of this revenue through time, being building block revenue forecasts and demand.

23 The process for establishing a building block forecast also applies to revenue caps. Revenue caps are the form of control that applies to electricity distribution and transmission NSPs. Details on revenue caps are provided on the AEMC's network regulation webpage.

24 The X-factor is used with CPI to smooth the revenue an NSP will collect from customer each regulatory year. This X-factor is an input in the control formula applied to revenues or prices in annual pricing and is the change in real revenue/price from year-to-year. The X-factor is updated annually for changes in the cost of debt.

4.1 What revenue have the gas distribution NSPs recovered through reference services?

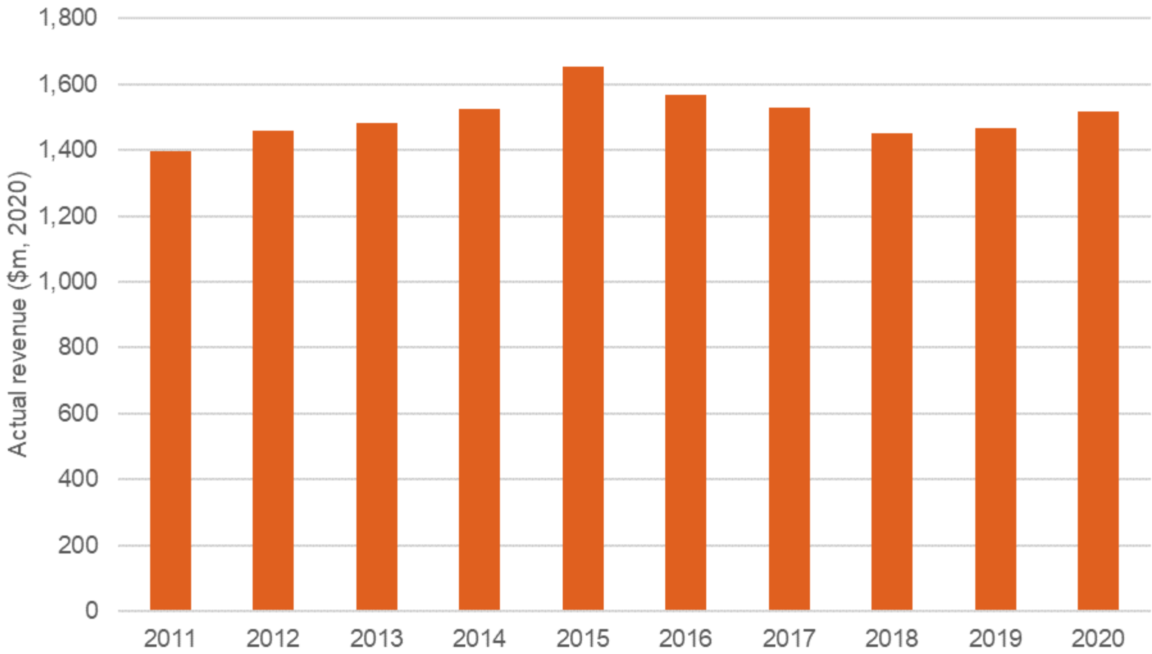
For customers connected to a gas distribution network, bills will depend on several factors, including their own consumption of gas. This means that analysis of overall revenue collection is not a perfect measure of the network costs of gas usage for specific customers. However, in our view, it is a useful measure of broad trends in the costs of haulage services to customers.

4.1.1 Actual network revenue

In 2020:

- Reference service revenue increased in 2020. Revenue is higher than it was in 2011, but remains below a peak in 2015.
- In contrast, revenue per customer is materially below 2011 levels due to growth in residential customer numbers.
- This pattern varies between jurisdictions. In recent years, revenue per customer has grown in Victoria and South Australia and declined in NSW and the ACT.

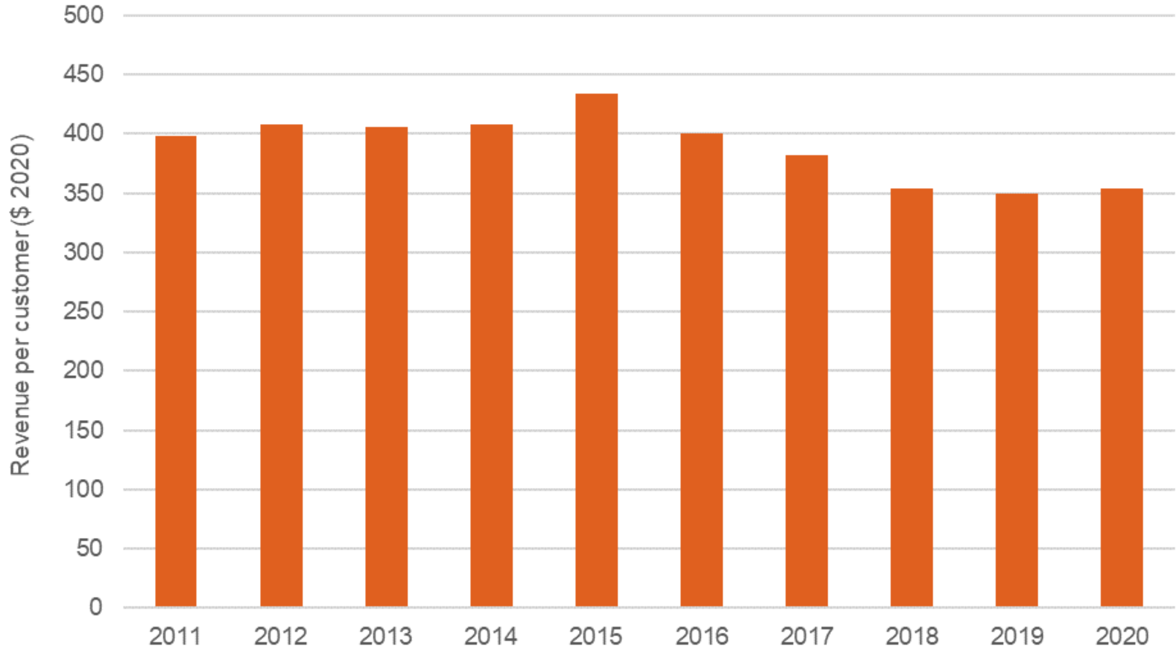
Figure 4-1 Total reference service revenue recovered from customers – Gas distribution NSPs



Source: Operational performance data, AER analysis.

Reference service revenue has been increasing since 2018, however it is still lower than peak levels between 2015 to 2017. At the same time, gas distribution NSPs are distributing gas to a growing number of customers. The result is that the moderate recent declines in revenue in the 2018 to 2020 regulatory years have led to more substantial declines in revenue recovered per customer, as noted in Figure 4-2.

Figure 4-2 Total reference service revenue per customer – Gas distribution NSPs

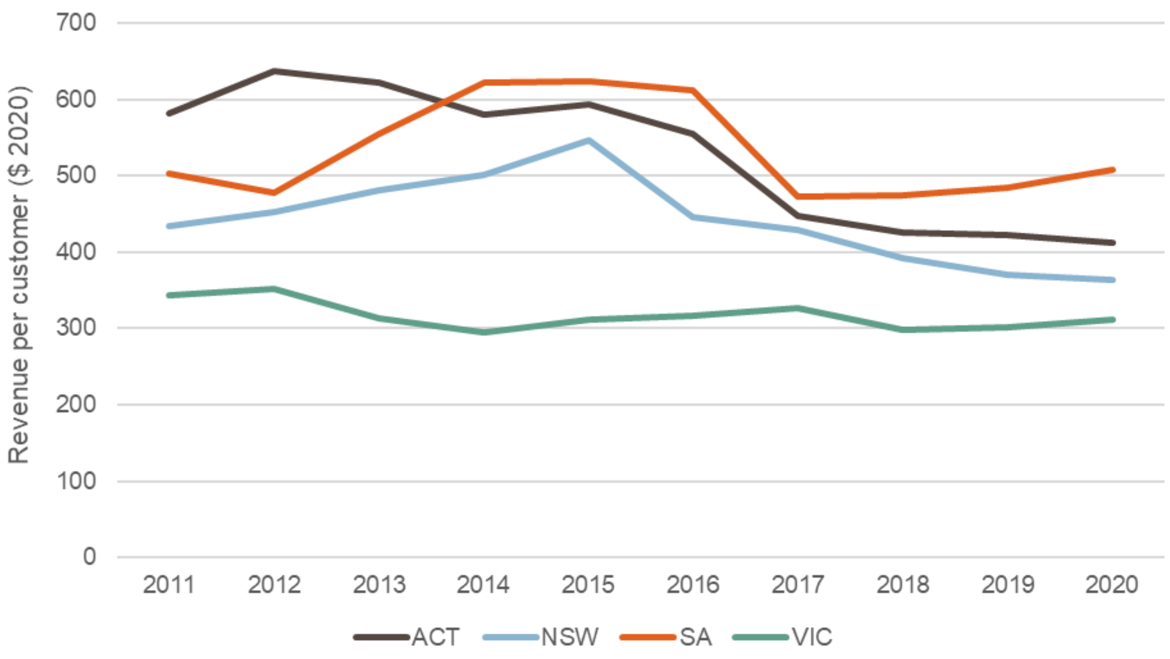


Source: Operational performance data, AER analysis.

In our view, revenue per customer is a broadly useful indicator of customer billing impacts arising from reference services. However, in practice, revenue is not collected evenly from across customers. Customers who consume large amounts of gas, despite being a small proportion of total customer numbers, provide a relatively high proportion of revenue to distribution NSPs, reflecting their higher usage of reference services. Under a price cap, declining revenue at an aggregate level could also reflect changing usage within a particular customer class. If so, these aggregate impacts will not be consistent across customer classes.

Also, the costs of providing reference services, customer demographics and the usage of gas by each customer type are not uniform between each state/jurisdiction.

Figure 4-3 Total reference service revenue per customer by state/jurisdiction – Gas distribution NSPs



Source: Operational performance data, AER analysis.

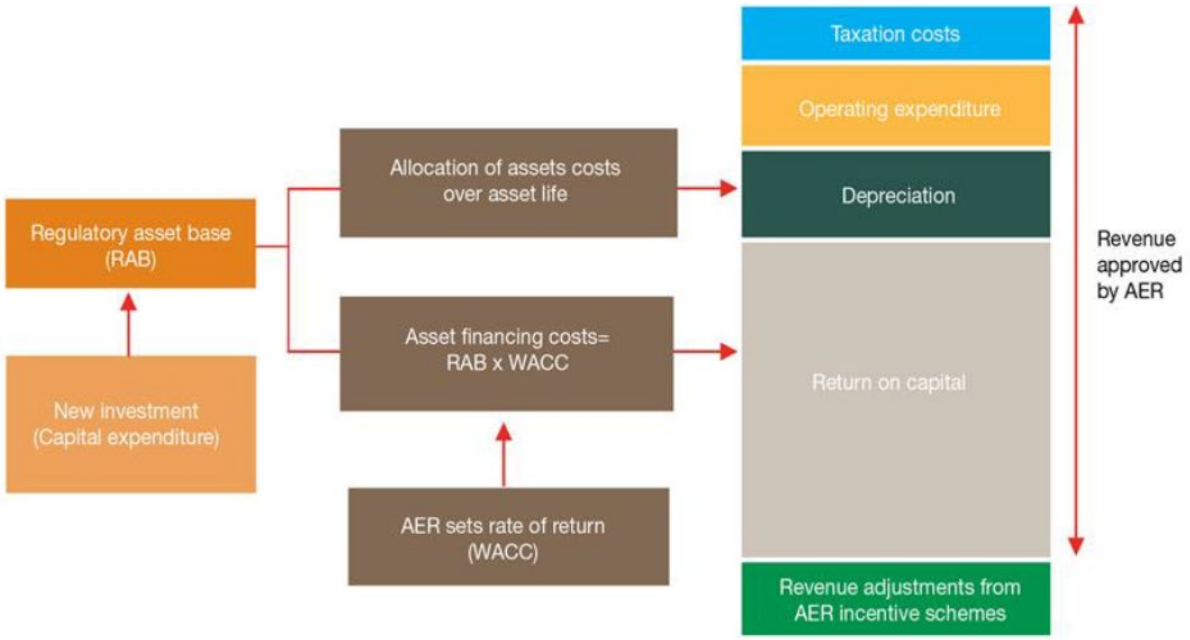
4.2 Building block revenue forecasts

All fully regulated gas distribution NSPs are regulated under price caps. Initial year prices and 'X-factors' governing annual tariff variations are set using a forecast of revenue 'building blocks' that an efficient gas distribution NSP would require to provide core regulated services. These include:

- A return on the capital base (or return on capital, to compensate investors for the opportunity cost of funds invested in the fully regulated gas distribution NSP).
- Depreciation of the capital base (or return of capital, to return the initial investment to investors over time).
- Forecast capital expenditure — the capital expenditure incurred in the provision of network services. This mostly relates to expenditure on assets with long lives, the costs of which are recovered over several access arrangement periods. The forecast capital expenditure approved in our decisions directly affects the projected size of the regulated asset base (RAB) and therefore the revenue generated from the return on capital and depreciation building blocks.
- Forecast operating expenditure — the operating, maintenance and other non-capital expenses incurred in the provision of network services.
- The estimated cost of corporate income tax.
- Revenue adjustments, including revenue increments or decrements resulting from the application of various incentive schemes. Incentive schemes are regulatory tools designed to encourage desirable behaviours by NSPs. In the case of gas distribution NSPs, these

relate principally to making efficiency improvements in operating and capital expenditure. These desirable behaviours should deliver better outcomes for consumers and promote achievement in the NGO.

Figure 4-4 The building block model to forecast network revenue



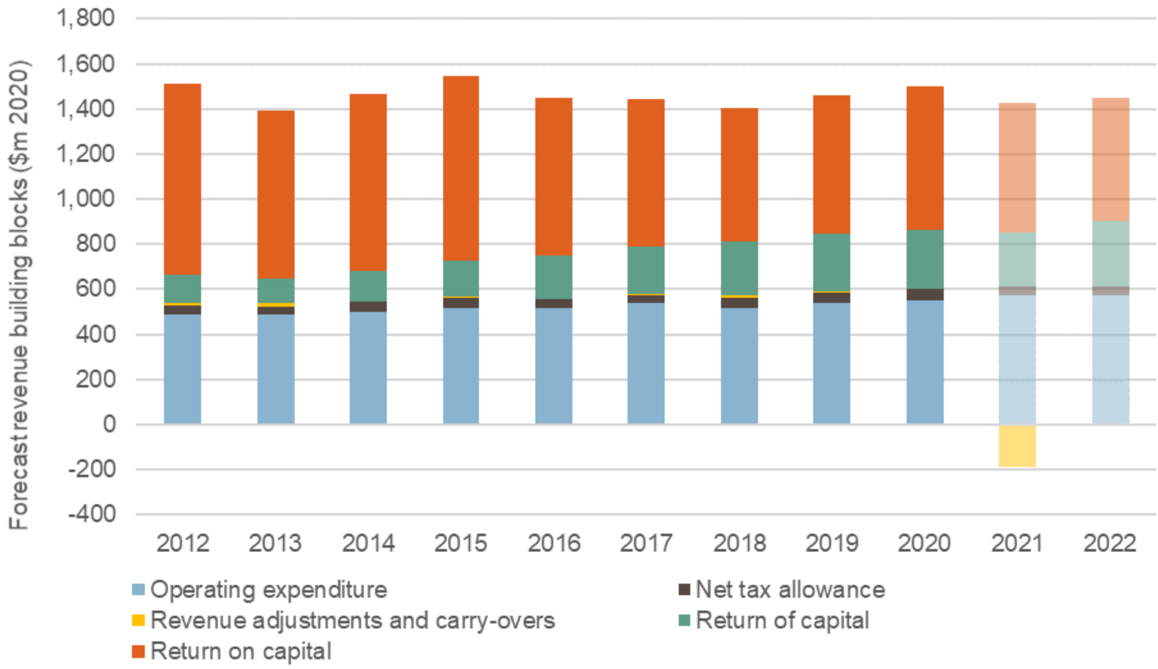
Source: AER, State of the Energy Market, December 2018, p.138.

Note: In Figure 4-4 we use 'RAB' interchangeably with the term 'capital base', meaning the total economic value of the service provider's regulated assets.

We observe that:

- Total forecast revenue shows some variability year-to-year, but the aggregate level has remained relatively steady.
- Underneath this aggregate outcome, there have been material changes in specific building blocks.
- Returns on capital have declined, driven by lower forecast rates of return somewhat offset by growing capital bases.
- Returns of capital (depreciation) have increased rapidly, driven by growing capital bases from connections and mains replacement programs in South Australia and Victoria and some material investments in assets with shorter economic lives.

Figure 4-5 Forecast revenue building blocks – Gas distribution NSPs



Source: Operational performance data, AER analysis.

The major drivers of changes in forecast revenue are:

- Returns on capital decreasing, driven by lower rates of return. These are offset somewhat by growing capital bases, particularly in Victoria and South Australia.
- Depreciation growing rapidly, driven in large part by material expenditure from JGN on information and control technology (ICT). ICT has a short economic life, meaning that expenditure translates more acutely to increased revenue.
- Gradual increases in forecast operating expenditure.

In the remainder of this section, we expand on these specific drivers.

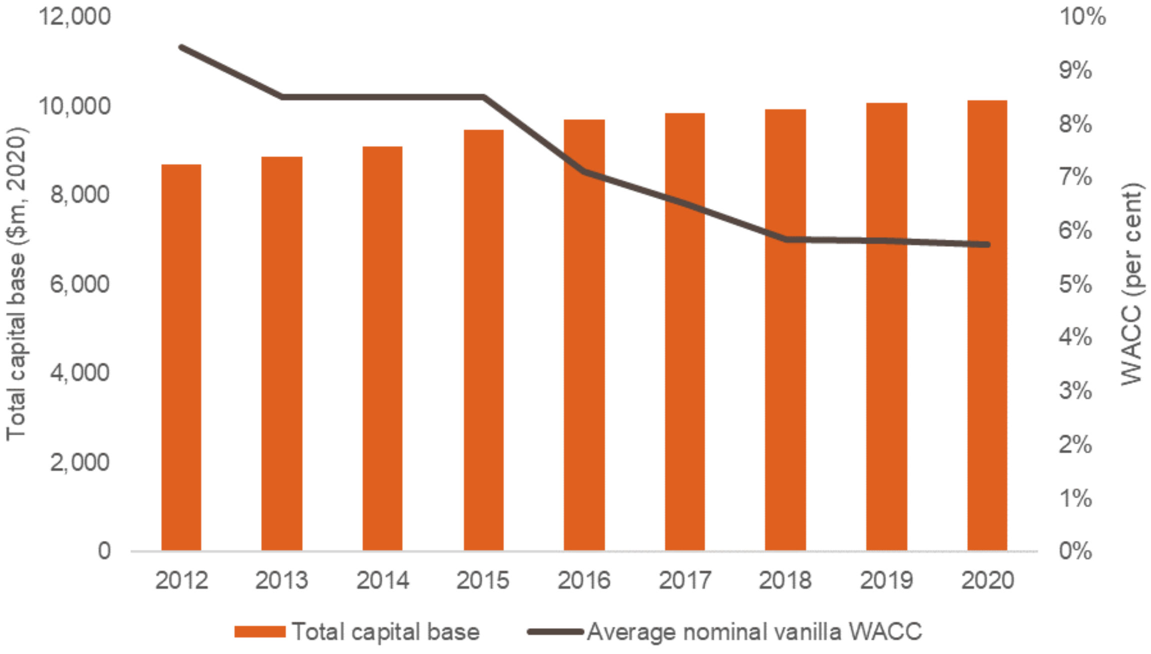
4.2.1 Declining returns on capital

Gas distribution NSPs are capital intensive businesses. The return on capital is one of two building blocks through which NSPs recover the costs of raising this capital. It is the product of:

- The capital base—the remaining economic value of assets used to deliver the regulated services; and
- The rate of return on capital—the costs of raising each dollar of capital, typically expressed as a percentage.

In recent years, we have observed and forecast declining required returns on capital in our regulatory decisions. Holding other factors constant, this would contribute materially to declining overall revenue requirements. However, this has been offset by material growth in capital bases (investment in network assets), which require gas distribution NSPs to finance through issuing debt or raising equity. These two effects are set out in Figure 4-6.

Figure 4-6 Declining costs of capital compared to growing capital bases – Gas distribution NSPs



Source: Operational performance data, AER analysis.

This growth in capital bases also contributes to higher forecast depreciation, which we discuss in the next section. Gas distribution NSP expenditure and network investment are analysed further in section 5.

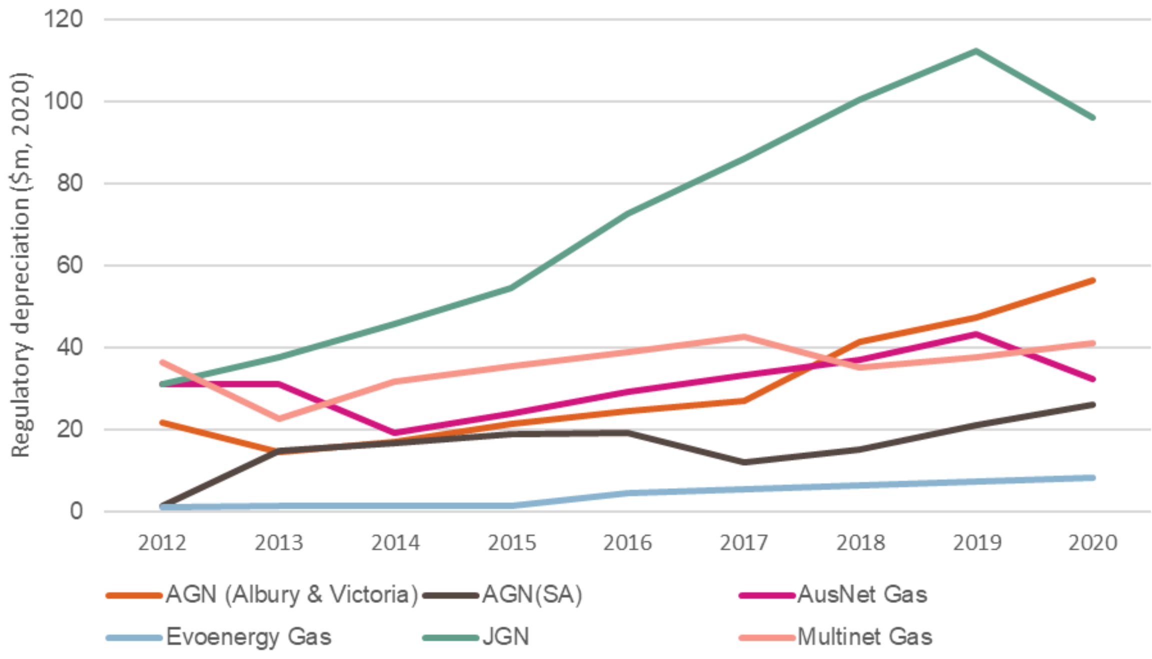
4.2.2 Growth in forecast depreciation

When network investments are added to the capital base, they begin to gradually depreciate over their economic lives. Pursuant to the regulatory framework, we approve forecast regulatory depreciation for our access arrangement decisions. This ensures that over the full economic lives of the assets, gas distribution NSPs recover revenue equal to the value of the investments.

However, the type of assets being invested in (and the economic life of the assets) affects the rate at which this depreciation occurs, and the resulting impact on revenue in any given access arrangement period. For example, mains replacements or new pipeline mains typically provide services over a long time (at least 50 years) and therefore typically have long economic lives. In contrast, expenditure on ICT is depreciated or amortised over a shorter period as ICT investments are more prone to being technologically superseded or determined obsolete.

Figure 4-7 illustrates forecast depreciation by gas distribution NSP over 2011 to 2020.

Figure 4-7 Growth in the forecast depreciation building block – Gas distribution NSPs



Source: Operational performance data, AER analysis.

Due to growing capital bases, forecast regulatory depreciation has increased across all gas distribution NSPs. Forecast depreciation typically changes gradually because regulated NSPs are comprised largely of long-lived assets. However, JGN's forecast depreciation increased by 260 per cent over 2012 to 2019 despite only a 12 per cent increase in its capital base. The key driver of this outcome was a material program of expenditure on ICT software (approximately $135m in 2020 dollars). ICT software has an economic life of only five years, so this investment rapidly increased forecast depreciation.

Regulating gas pipelines under uncertainty

The forecast depreciation building block provided above reflects the economic lives of the gas distribution NSPs' network assets. The market is transitioning to low-carbon fuels driven by carbon emissions reduction commitments. Coupled with the opportunities hydrogen presents, this is driving uncertainty in the future demand for gas pipelines. Should demand for gas decline, there could be a stranded asset risk for fully regulated gas NSPs in the long-term.

Our *Regulating Gas Pipelines Under Uncertainty* information paper identifies accelerated depreciation for network assets as an option to address the implications of falling gas demand. As noted in the information paper, an adjustment to shorten the asset life or speed up the depreciation rate of gas distribution NSP's network assets may increase the costs for consumers in the short term, but it mitigates the potential price increases in the long term.[25]

25 AER, *AER Information paper – Regulating gas pipelines under uncertainty*, 2021, pp 29-32.

This information paper has been released to stakeholders to discuss the factors that are likely to change local demand for natural gas in the medium to long term, including decarbonisation, increased competitiveness of electricity as a substitute for natural gas, improvements in energy efficiency, and growing investment in renewable energy. In addition, the information paper also introduces options that may address the pricing risks for consumers and stranded asset risks for fully regulated gas NSPs. The paper therefore opens the door for industry discussions on ideas such as adjusting depreciation, revaluing assets, sharing costs, as well as other options that were previously suggested by stakeholders.

We acknowledge in section 8 that the options provided in the information paper may become more prominent in regulatory proposals and our access arrangement reviews for regulated gas NSPs. We expect that future gas network performance reports will analyse the extent to which these issues end up impacting network performance outcomes and decisions.

4.3 Demand for reference services

The other key driver of actual revenue collected from gas distribution customers is the level of demand for reference services.

What we mean by demand

In this section, 'demand' refers broadly to the various charging parameters that make up gas tariffs, including but not limited to:

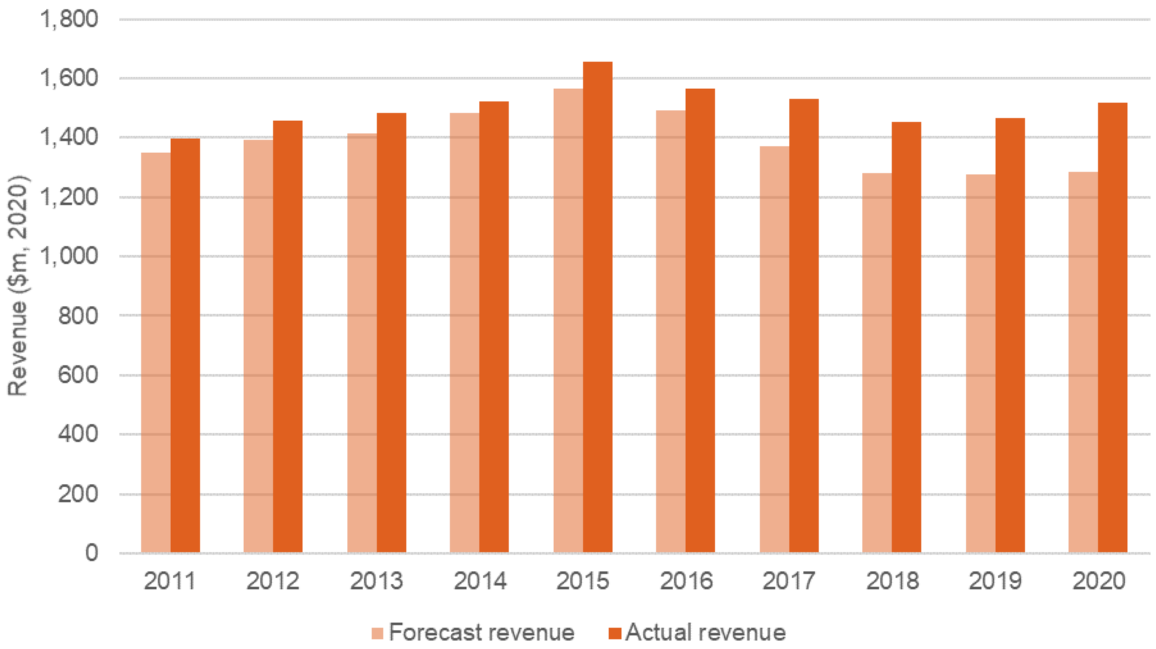
- Customer numbers—more customers connected to a gas distribution network typically increase revenue collected through fixed charges.
- Gas delivered—the amount of gas transported through the gas distribution network.

Under price caps, gas distribution NSPs are exposed to what we call 'volume-risk'. This means that if actual demand exceeds forecast demand, gas distribution NSPs keep the higher resulting revenue. Similarly, if actual demand is less than forecast revenue, gas distribution NSPs are exposed to the shortfalls. This provides gas distribution NSPs with the incentive to develop tariff structures and undertake other activities that encourage utilisation of the network. However, it also means that errors in demand forecasts can contribute to customers paying more revenue than is necessary, or gas distribution NSPs recovering less revenue than is necessary to efficiently provide gas haulage services. As a result, demand forecasts are an important contributor to overall revenue outcomes.

We observe that:

- Since 2011, gas distribution NSPs in aggregate have recovered revenue above forecast revenue requirements.
- These differences have grown larger in recent years as customer numbers have grown faster than forecast, leading to increased demand.

Figure 4-8 Reference service revenue compared to forecast revenue – Gas distribution NSPs



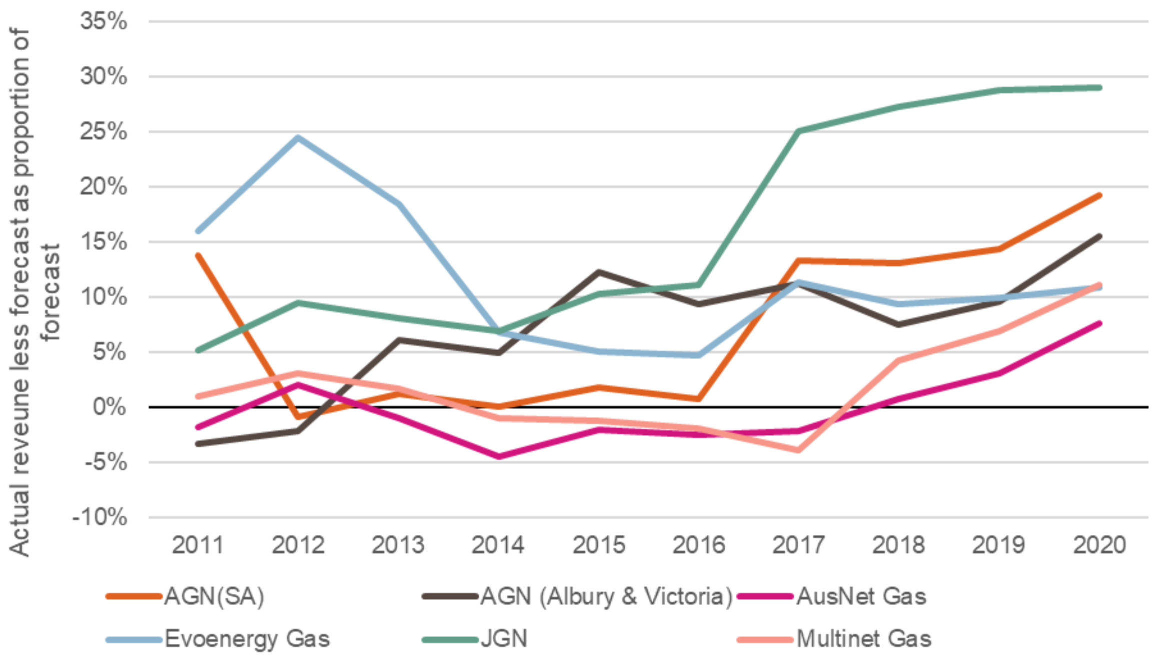
Source: Operational performance data, AER analysis.

Figure 4-9 shows the difference between actual and post-tax revenue model (PTRM) forecast revenue as a proportion of the forecast. These outcomes are expressed as a percentage, where percentages above zero mean that actual revenue exceeded forecast revenue by that proportion. For most gas distribution NSPs, because this is a comparison of actual and forecast revenue, these impacts should ordinarily reflect:

- The impacts of demand for reference services
- The forecasts of that demand
- How tariffs are changed through the access arrangement period subject to approved tariff variation mechanisms.

In the following section, we set out an example of how these factors interact.

Figure 4-9 Reference service revenue compared to forecast revenue – Gas distribution NSPs



Source: Operational performance data, AER analysis.

Note: JGN's revenue outperformance from 2015-16 is influenced by a number of factors discussed below. One major influence was the application of enforceable undertakings pending the outcome of limited merits review appeal process.

In practice, it is complex to analyse the impacts of actual demand compared to forecast demand because the dynamics vary between NSPs and tariffs. Actual and forecast demand may differ because of unforeseen market changes. In this scenario, the demand forecasts may still reflect the best forecasts possible with the information available at the time. Alternatively, differences between actual and forecast demand might reflect shortcomings in demand forecasting. In addition, gas distribution NSPs have some scope to re-balance or vary tariffs each year within 'side-constraints' and this re-balancing can impact overall revenue recovery relative to forecast. Understanding the interaction of these effects is important in evaluating the effectiveness of our regulatory decisions and approaches.

In our view, the comparison of actual revenue against forecast revenue is a useful overall indicator of the impacts of unexpected changes in demand. It is worth noting that while unexpected demand increases provide opportunities for revenue outperformance, these are also likely to be associated with unexpected increases in costs. This is because higher than forecast customer numbers and throughput demand will likely lead to higher connections, capital expenditure and operating expenditure than forecast by the gas distribution NSP.

Nonetheless, given the significance of demand to revenue impacts, we plan to expand our analysis of actual and forecast demand in future network performance reports.

4.3.1 JGN's revenue growth

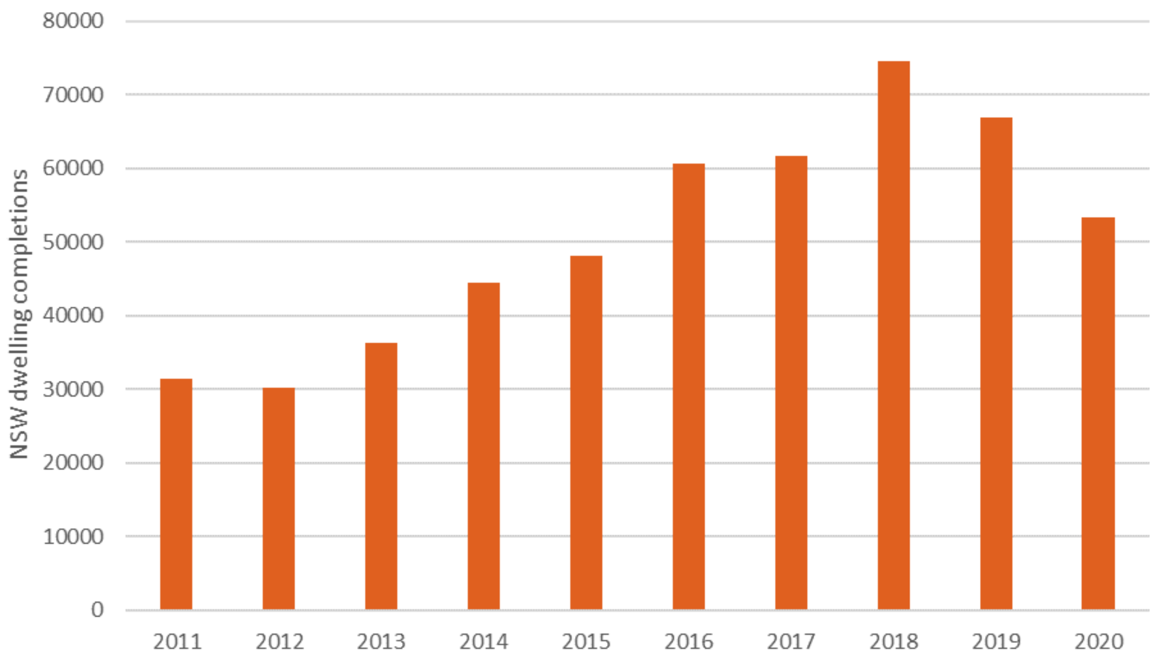
Most gas distribution NSPs have consistently recovered revenue above forecast. Over 2015 to 2020, this pattern was most pronounced on JGN's gas distribution network. In this section, we expand on some of the factors contributing to this pattern. In our view, this example illustrates the complex range of factors weighing upon comparison of forecast and actual revenue under price caps. In JGN's case, these include impacts from:

- Actual demand varying from forecast demand
- Annual tariff variation adjustments for other factors affecting annual price caps
- A limited merits review process and application of interim enforceable undertakings to set how JGN's revenues and tariffs were determined for the period from 2015 to 2020

Changes in demand

Much of the difference between actual revenue and our PTRM forecast revenue appears to be driven by demand growth over the period of analysis. As set out in Figure 4-10, NSW dwelling completions grew rapidly over 2013 to 2018.

Figure 4-10 NSW dwelling completions



Source: ABS

Note: this series is calculated as the sum of annual NSW dwelling completions for all building types across all sectors. Raw data is from ABS series A83801953A

This translated into JGN's customer numbers increasing by approximately 300,000 customers (32 per cent) over 2011 to 2020.

Other factors impacting annually on the price cap

JGN's price cap includes an 'annual adjustment factor' to account for movements in a series of underlying costs outside the control of JGN (e.g. UAFG and jurisdictional licence fees) price drivers.[26] Ordinarily this would be updated each year, but because of the remittal process, the adjustment factors from price changes for each year from 2015 to 2020 were applied in 2020. This resulted in an approximately $26m increase to JGN's target revenue for 2020, which is not captured in our PTRM forecast. In effect, this would further reduce the difference between forecast and actual revenue by roughly 10 per cent in the 2020 regulatory year.

Limited merits review

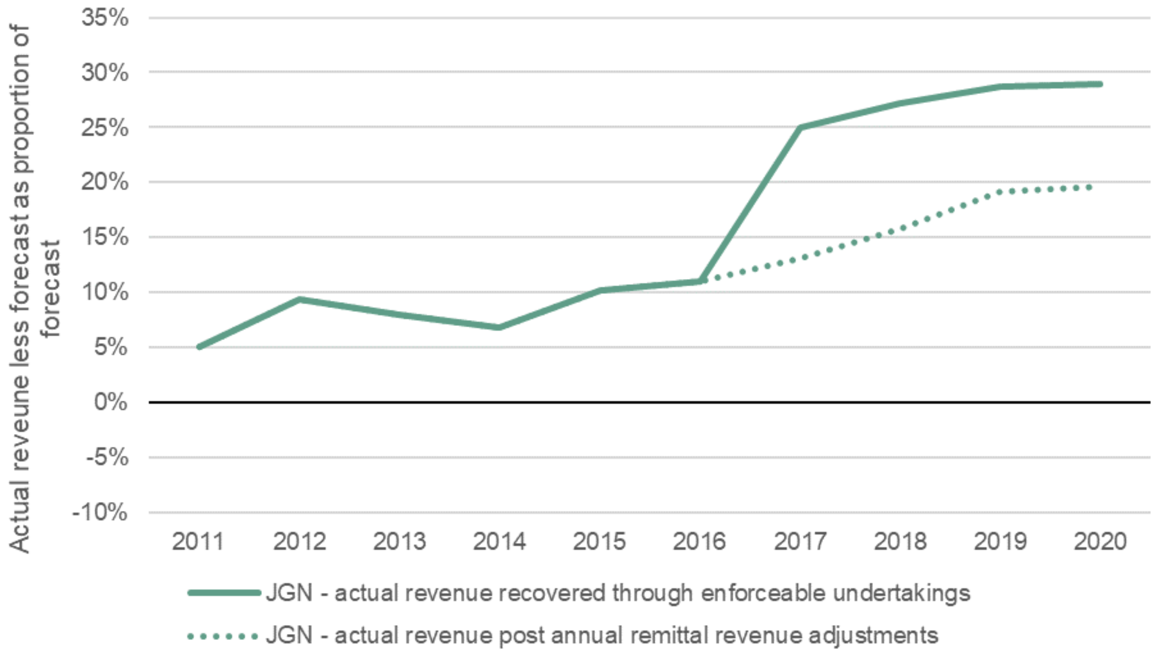
In addition, JGN's actual revenue path is impacted by its limited merits review process. The remittal process[27] included reviews of the AER's determinations sought by the JGN under the limited merits review framework. Pending the outcome of appeals the AER and JGN developed enforceable undertakings that set out how JGN's revenues and network tariffs would be determined for each year from 2015 to 2019. The application of enforceable undertakings led JGN to materially over-recover revenue when compared to the remittal final decision. Following the completion of the remittal process, JGN's forecast revenue for its 2020 to 2025 access arrangement period includes a downward adjustment of $169m ($ Jun 2020), or roughly 25 per cent of revenue above forecast since 2016.

Figure 4-11 presents how the proportion of over recovery of revenue (actual less forecast) differs for the two revenue paths, being the difference between actual revenue reported under the enforceable undertakings and what the actual revenue would have been from 2017 to 2020 with the annual remittal revenue adjustments.

26 JGN, *Access arrangement 2015 to 2020, AER final decision revisions – schedule 3*, February 2019, pp. 59-65

27 A remittal was a process undertaken by the AER and an NSP to remake parts of an access arrangement final decision pursuant to a determination made by the Australian Competition Tribunal.

Figure 4-11 Reference service revenue compared to forecast revenue – JGN



Source: AER analysis.

Giving effect to the remittal adjustments demonstrates how the actual level of revenue would have been lower reducing the average annual percentage difference between actual and forecast revenue from 24 per cent to 17 per cent from 2015 to 2020.

The NSW/ACT remittals

In April and June 2015, the AER published final decisions on the 2014 to 2019 distribution determinations for NSW and ACT electricity distributors (Ausgrid, Endeavour Energy, Essential Energy and Evoenergy —then ActewAGL Distribution), and on the 2015 to 2020 access arrangement for the NSW gas distribution NSP, JGN.

All five businesses sought merits review of the AER’s final decisions. The Public Interest Advocacy Centre (PIAC) also applied for review of the AER’s NSW final decisions. The Commonwealth minister intervened.

The Australian Competition Tribunal handed down its decisions in February 2016 (and March 2016 for JGN). It remitted the decisions to the AER to be remade, in particular in accordance with its orders regarding: the return on debt; the value of imputation credits (gamma); the four electricity distributors’ operating expenditure; and aspects of JGN’s capital expenditure.

In March 2016, the AER sought judicial review of the Tribunal’s decisions on gamma, return on debt and operating expenditure in the Full Federal Court. The Court upheld the AER's appeal in respect of the Tribunal's construction of the rules regarding gamma, but dismissed the appeal in relation to the return on debt and operating expenditures of the electricity businesses.

As a result, the AER was tasked with revisiting its decisions regarding the return on debt, the four electricity distributors’ operating expenditure and aspects of JGN’s capital expenditure.

5 Network expenditure

In this section, we report on capital and operating expenditure trends. In particular, we focus on capital expenditure drivers to ascertain trends across the regulated gas distribution NSPs operating in different states or jurisdictions

Over 2011 to 2020, we observe that:

- Total gas distribution NSP expenditure has grown gradually, with a peak in 2015 driven by high capital expenditure.
- The cumulative capital base of fully regulated gas distribution NSPs has grown approximately 21 per cent, driven in large part by expenditure on connections and mains replacement programs.
- Despite this, the capital intensiveness of most gas distribution NSPs has remained relatively stable due to growth in customer numbers.

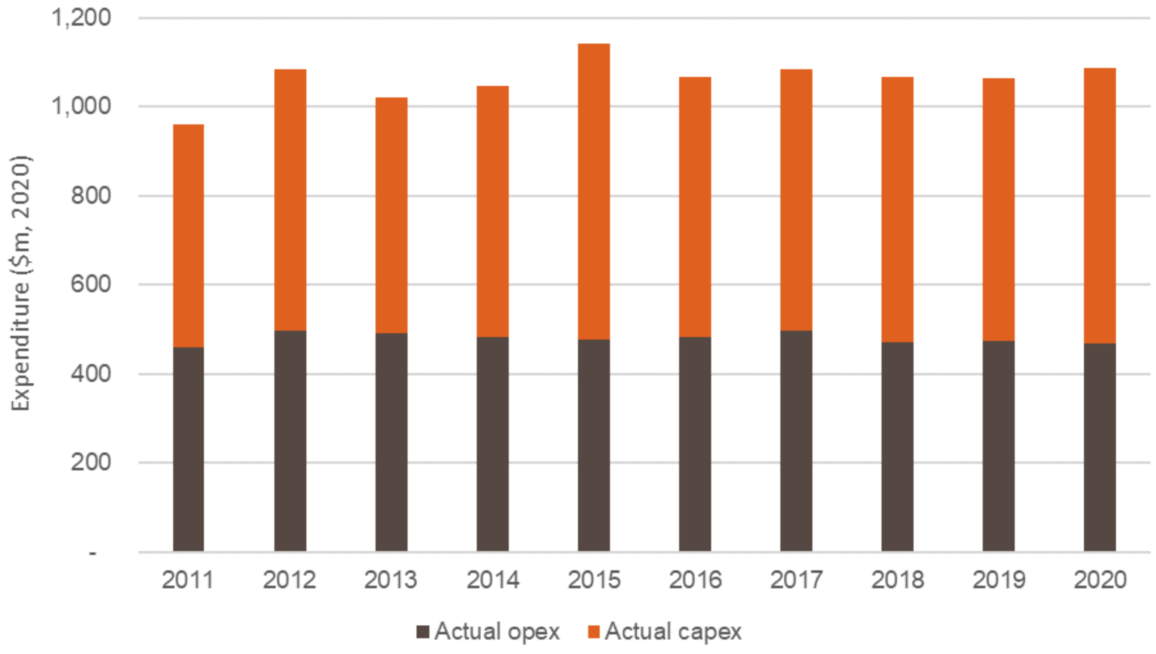
5.1.1 Expenditure

With the revenue collected from consumers, gas distribution NSPs undertake operating and capital expenditure in whichever way they determine to be most efficient in providing a safe and reliable supply of natural gas.

In our view, reporting on total levels of expenditure presents an overall view of expenditure that is not impacted by changes to the gas distribution NSP's capitalisation policies over time. It also illustrates the potential trade-offs between operating expenditure and capital expenditure.

Figure 5-1 shows gas distributions NSPs' total expenditure over 2011 to 2020.

Figure 5-1 Expenditure – Gas distribution NSPs



Source: Operational performance data, AER analysis.

Over 2011 to 2020, we observe that:

- Total expenditure has grown gradually, with a peak in 2015 driven by capital expenditure.
- Operating expenditure has remained relatively steady, with most year-to-year variation driven by capital expenditure.

Operating and capital expenditure

The short-term impacts of capital expenditure and operating expenditure on revenue requirements, and therefore the costs faced by customers, are different:

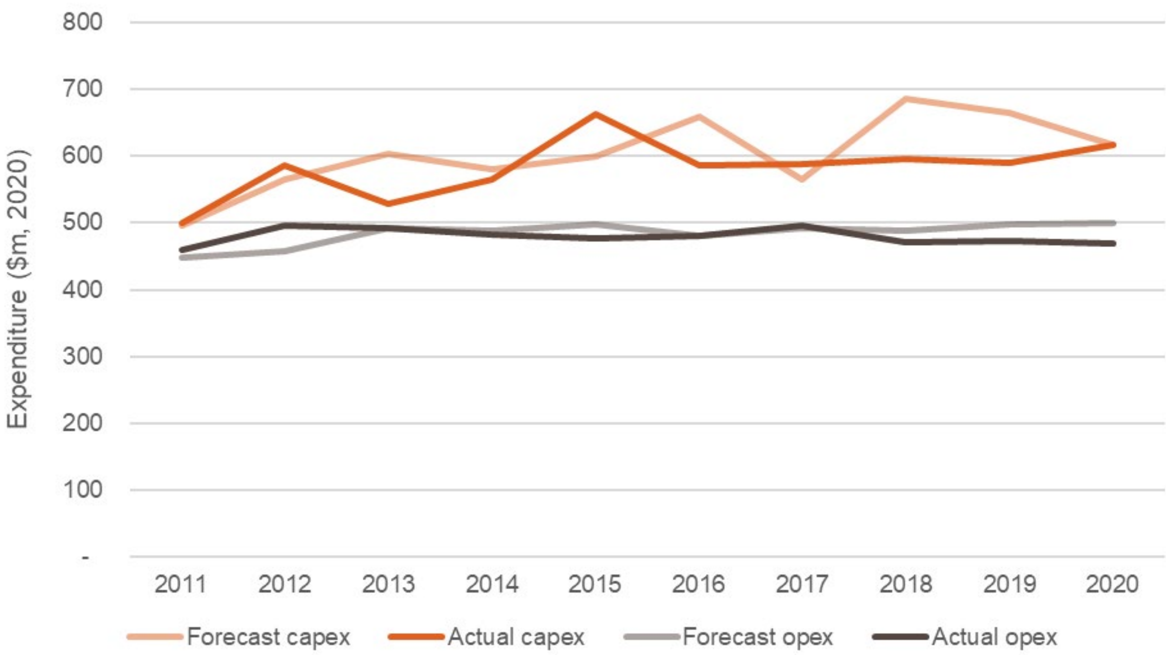
- Forecast operating expenditure requirements translate directly into overall revenue allowances in the years we expect the expenditure will be incurred.
- In contrast, capital expenditure is added to the capital base. NSPs fund this capital expenditure through debt and equity capital raising. They recover the costs associated with this capital raising (return on capital and depreciation) gradually over the economic lives of the assets. Asset lives can range from depreciating within a single regulatory period to upwards of 50 years, depending on the asset category.

In Figure 5-2 we compare total operating and capital expenditure outcomes against our forecasts determined in access arrangement reviews.

Over 2011 to 2020, we observe that:

- In total, gas distribution NSPs have typically incurred operating expenditure at or slightly below our forecast. This relatively consistent outcome likely reflects the recurrent, and therefore predictable, nature of operating expenditure.
- Capital expenditure has been more variable, with a mixture of aggregate overspends and underspends compared to forecast. However, in recent years we have observed more and more material cumulative underspends.
- These outcomes may in part reflect the operation of incentive schemes. We have applied operating expenditure efficiency schemes to gas distribution NSPs since we assumed responsibility for gas distribution regulation in 2010, but have only begun to apply capital expenditure sharing schemes (CESS) in decisions since 2018.

Figure 5-2 Comparison of actual and forecast expenditure – Gas distribution NSPs



Source: Operational performance data, AER analysis.

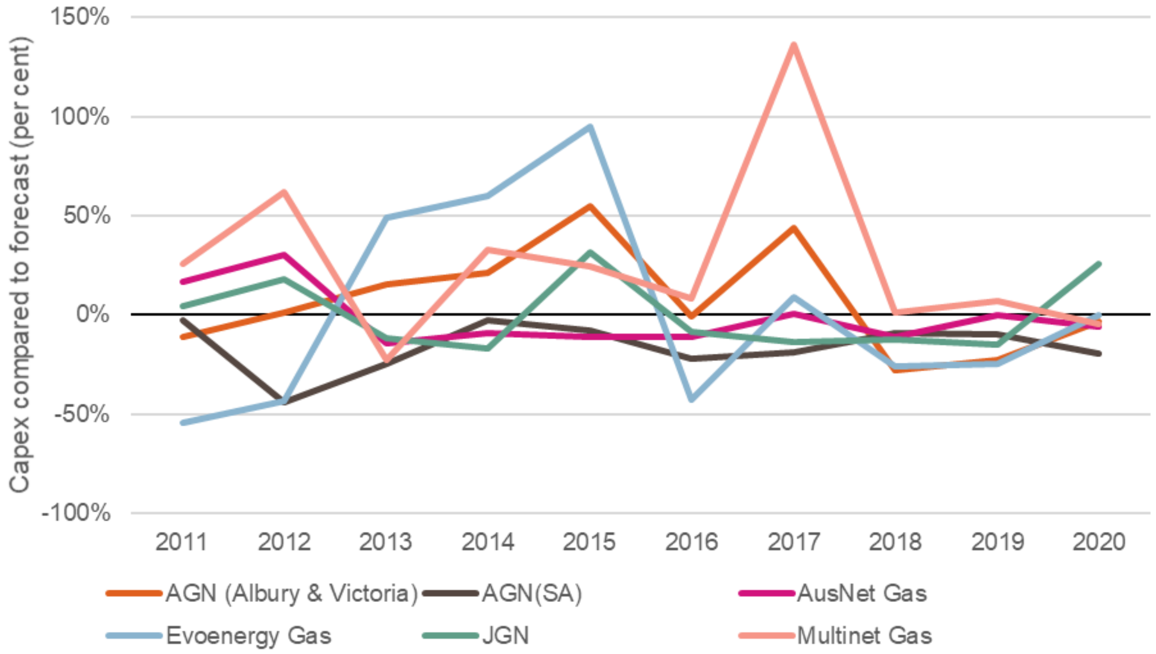
When viewed at an individual gas distribution NSP level, there is material year to year variability in the difference of actual capex compared to forecast capex amongst gas distribution NSPs, as shown in Figure 5-3. These outcomes may be indicative of the lumpiness of capital expenditure on long lived assets and how gas distribution NSPs plan and execute their capital expenditure projects in each access arrangement period.

In December 2016, we produced a Capital Expenditure Sharing Scheme (CESS) information paper to assess whether an incentive scheme was needed to incentivise gas distribution NSPs to undertake efficient capital expenditure during an access arrangement period.[28]

Following this information paper and after consultation between gas distribution NSPs and stakeholders, we decided to implement a CESS for gas distribution NSPs. The CESS was applied to the Victorian gas distribution networks from 2018, JGN from 2020, and Evoenergy and AGN (SA) from 2021. We noted in the Victorian 2018 to 2022 access arrangement decisions that the CESS would provide the benefits of efficient capital expenditure by:[29]

- Smoothing capex incentives throughout the access arrangement period
- Placing downward pressure on capital base growth
- Addressing the imbalance in the incentives applicable to decision whether to undertake capex or opex, particularly toward the end of the access arrangement period.

Figure 5-3 Capital expenditure compared to forecast – Gas distribution NSPs



Source: Operational performance data, AER analysis

28 AER, *Capital expenditure sharing scheme for gas distribution network service providers – Information paper*, 2016, p 5.

29 AER. *Draft decision – AGN Victoria and Albury gas access arrangement decision 2018 to 2022 – Attachment 14 Other incentive schemes*, 2017, p 10; AER. *Draft decision – AusNet Gas gas access arrangement decision 2018 to 2022 – Attachment 14 Other incentive schemes*, 2017, p 10; AER. *Final decision – Multinet Gas gas access arrangement decision 2018 to 2022 – Attachment 14 Other incentive schemes*, 2017, p 6.

5.1.2 Capital bases

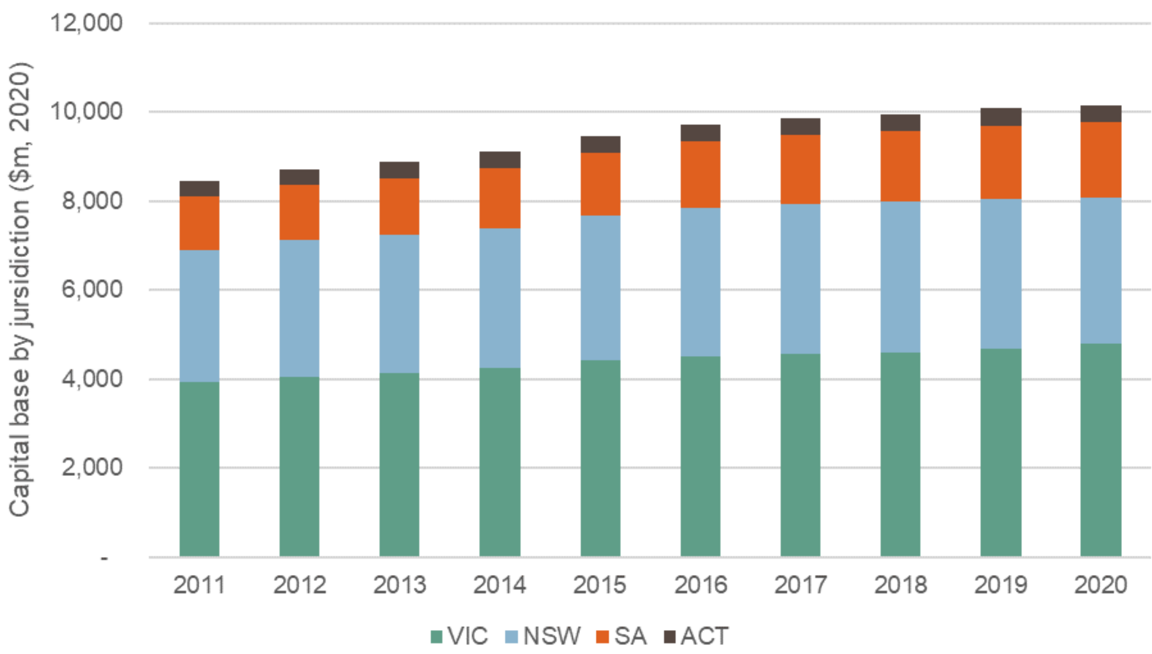
The NSPs' capital bases capture the total economic value of assets that are providing reference services to customers. These assets have been accumulated over time and will be at various stages of their economic lives. Individual gas distribution NSPs' assets may be relatively old or new compared to other NSPs' assets, depending on the NSP's growth and where they are in the replacement cycle.

The value of the capital base substantially impacts NSPs' revenue requirements, and the total haulage costs consumers ultimately pay. Figure 5-4 sets out the combined capital bases of the six gas distribution NSPs.

Over 2011 to 2020, we observe that:

- The total value of regulated network assets has grown by approximately 21 per cent.
- Capital bases have grown across all jurisdictions, but have done so to the greatest extent in Victoria and South Australia.
- Capital base growth compared against measures of network usage—such as customer numbers and volumes of gas delivered—emphasises that AGN (SA) is the most capital intensive network and that this margin is widening with its mains replacement program.

Figure 5-4 Capital base by state/jurisdiction – Gas distribution NSPs

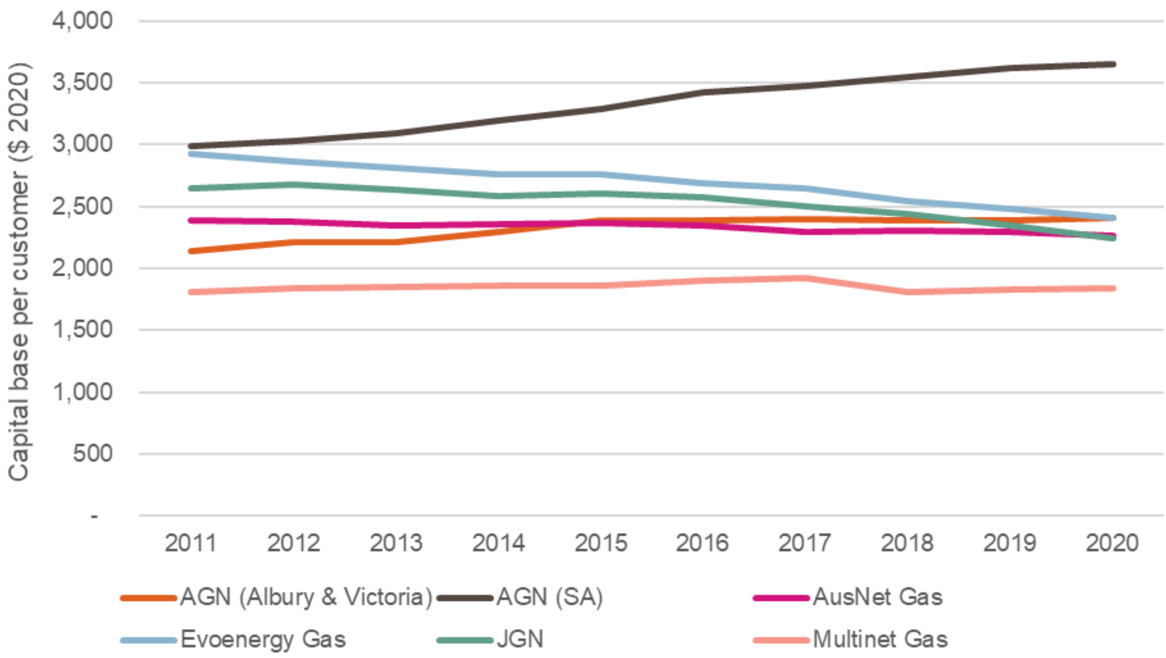


Source: Operational performance data, AER analysis.

It is important to note that a stable capital asset base may allow declining real capital costs per customer if the customer base is growing. This effect is amplified where required rates of return are declining, as observed in Figure 4-6.

Reflecting the growth in customers connected to gas distribution networks, we generally observe steady to declining capital base per customer, apart from AGN (SA). This is an outcome of AGN (SA)'s significant mains replacement program, as forecast and included in its recent access arrangement. The capital expenditure investments of each gas distribution NSP and how they differ is discussed in section 5.1.3 below.

Figure 5-5 Capital base per customer – Gas distribution NSPs



Source: Operational performance data, AER analysis.

While capital base per customer is a useful indicator of the average value of capital employed per customer, it is sensitive to the composition of the NSP's customer base. For example, a distribution network such as AGN (SA) with a relatively higher proportion of industrial gas delivered to its industrial customer base might—holding other things constant—be expected to have a more capital invested per customer.

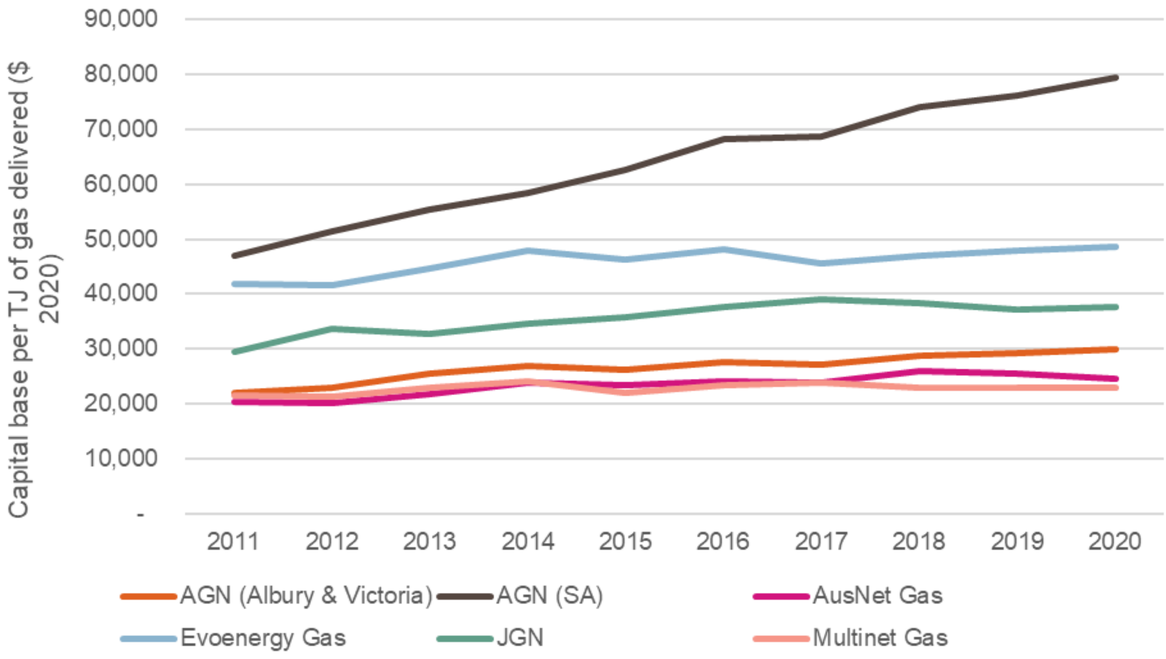
For this reason, we have set out in Figure 5-6 the capital base per volume of gas delivered. In our view, this measure is less sensitive to the composition of customers, since it accounts for the different patterns of usage by different customer types.

Over 2011 to 2020, we observe gradual increases in capital base per volume of gas delivered, except for in South Australia where the growth is more rapid.

When normalising using customers or volumes of gas delivered, these measures are likely to be indicative of the underlying asset age profile driving trends in replacement, and/or relative changes in customer numbers and gas demand. For example, earlier we presented Figure 3-11 and Figure

3-14, which showed that despite increases in the number of customers aggregate level of gas delivered has declined since 2011. In addition, AGN (SA)'s average annual proportion of mains replacement capex of total capex was 44.6 per cent from 2011 to 2020. In comparison, the average annual proportion of mains replacement across all gas distribution networks was 24.3 per cent.

Figure 5-6 Capital base per TJ of gas delivered – Gas distribution NSPs



Source: Operational performance data, AER analysis.

5.1.3 Network investment (capital expenditure)

As highlighted in previous sections, we have observed materially different recent investment programs between the gas distribution NSPs, reflecting their different operating circumstances and stage of their assets' lives. In this section, we set out further analysis on the drivers of recent gas distribution network capital expenditure.

We collect data on NSPs capital expenditure by purpose which includes the purposes detailed in Table 5-1.

Table 5-1 Capital expenditure purpose and definition

Capital Expenditure Purpose	Definition
Connections	Capital expenditure related to connecting new customers to the gas distribution network.
Mains replacement	Capital expenditure related to replacing the existing mains and services in the gas distribution network due to the condition of those mains and services. This does not include mains and services replaced due to a change in capacity requirements, which is included in mains augmentation.
Mains augmentation	Capital expenditure related to a change in the capacity requirements of mains and services in the gas distribution network to meet the demands of existing and future customers

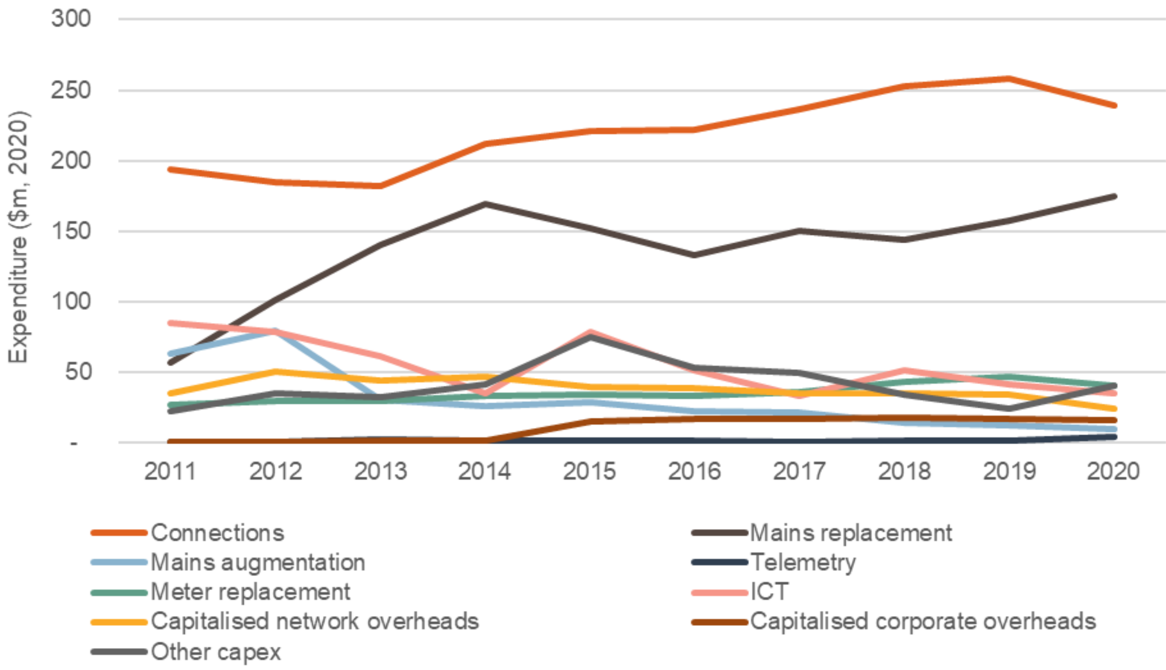
Telemetry	Capital expenditure related to a replacement of SCADA operating in the network due to the condition of the assets.
Meter replacement	Capital expenditure related to replacing installed meters with new or refurbished meters.
ICT	Capital expenditure related to ICT assets but excluding all costs associated with SCADA expenditure that exist beyond gateway devices (routers, bridges etc.) at corporate offices
Capitalised Overheads	Corporate or Network overheads which are capitalised as part of the network asset.
Other	Capital expenditure which is not related to any other capital expenditure purpose. This is associated with but not restricted to vehicles and non-operational buildings.

Figure 5-7 sets out capital expenditure by purpose combined across all the gas distribution NSPs.

Over 2011 to 2020, we observe that:

- Connections expenditure, driven by customer demand and mains replacement expenditure make up a significant portion of the investments by the gas distribution NSPs.

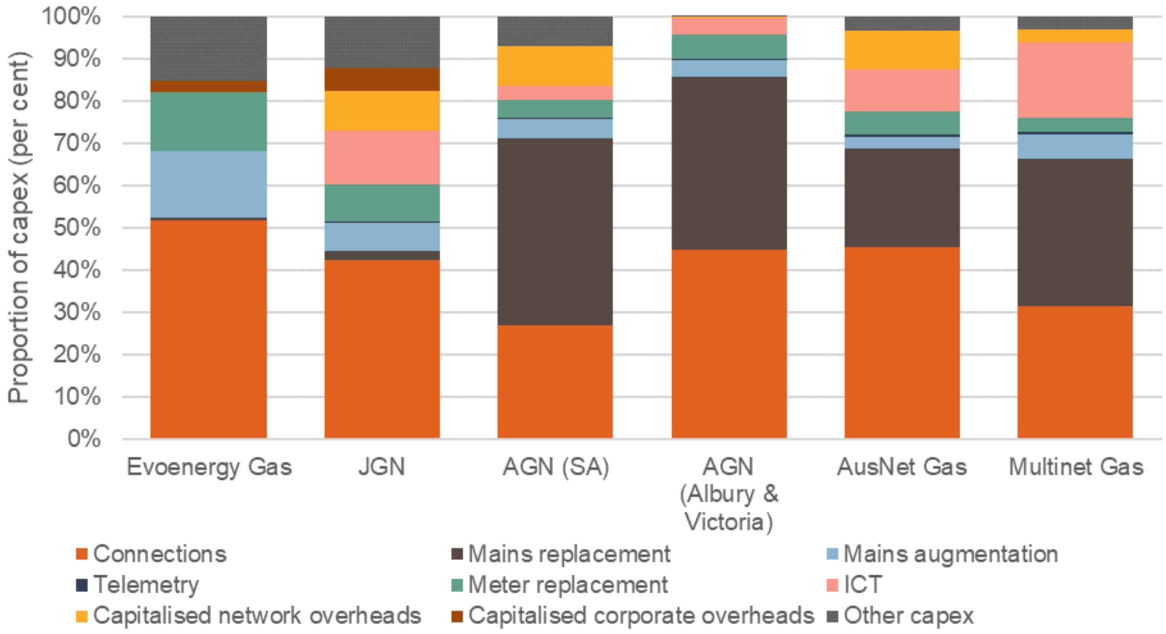
Figure 5-7 Capital expenditure by purpose – Gas distribution NSPs



Source: Annual Regulatory Information Notices (RIN), AER analysis.

However, as highlighted in previous sections, we observe significant variation across networks in the average proportion of actual capital expenditure incurred for each of the categories for the period from 2011 to 2020.

Figure 5-8 Capital expenditure by purpose as proportion of total capital expenditure – Gas distribution NSPs



Source: Annual RINs, AER Analysis.

Figure 5-6 and Figure 5-7 identify that the capital expenditure categories of connections and mains replacement are significant drivers of expenditures adding new long-lived assets to the capital base.

Over 2011 to 2020, we observe that:

- The Victorian and South Australian gas distribution NSPs are all undertaking material mains replacement programs.
- Capital bases have grown across all jurisdictions, but have done so to the greatest extent in Victoria and South Australia.
- Capital base growth compared against measures of network usage—such as customer numbers and volumes of gas delivered—emphasises that AGN (SA) has the most capital intensive network and that this margin is widening alongside its mains replacement program.

Mains replacement programs

These programs commenced for the Victorian gas distribution NSPs in their 2003 to 2007 access arrangement period.[30] The programs were designed to progressively replace the ageing cast iron pipelines in the network,[31] on the basis that this was necessary to maintain the gas distribution NSPs' safety and reliability.[32] Similarly, AGN (SA)'s cast iron replacement program also sought to reduce the risk of losses from gas leaks and increase both the capacity and reliability of the gas networks. Alongside these benefits, the replacement programs were also expected to improve the UAFG for these gas distribution NSPs,[133] reducing the gas loss caused by the deteriorating cast iron pipes.

JGN and Evoenergy Gas have not recently undertaken mains replacement programs targeting low pressure cast iron pipes. JGN's cast iron replacement program in the 1990s reduced the amount of cast iron in their network to less than 1%,[34] and Evoenergy Gas has not had any cast iron mains since at least 2011.

The low pressure replacement programs for the other gas distribution NSPs are still ongoing. This was noted by AGN (SA) in its recent access arrangement proposal for its 2022 to 2026 access arrangement period.[35] In Victoria, AGN (Albury and Victoria) expected to complete their program in the 2018 to 2022 access arrangement period,[36] AusNet Gas stated their program would continue until 2025,[37] and Multinet Gas indicated their 30 year program was expected to conclude in 2033.[38] These programs have influenced the capital expenditure allowances forecast for these gas distribution NSPs in their current access arrangements.

Figure 5-9 shows the estimated weighted-average remaining life of each gas distribution NSP at the commencement of its most recent access arrangement determination.[39]

30 AER, *Multinet Gas – Draft Decision – 2013 to 2017 access arrangement*, 2012, p 36.

31 ESCV, *Review of Gas access arrangements final decision,* 2002, p 117.

32 ESCV, *Review of Gas access arrangements final decision,* 2002, p 117.

33 ESCV, *Review of unaccounted for gas benchmarks: final decision – calculation*, 2017, p.5.

34 JGN, *JGN – 2021 to 2026 access arrangement revised proposal – Attachment 8.5*, p i.

35 AGN (SA), *AGN (SA) – 2021 to 2026 access arrangement proposal*, p 3.

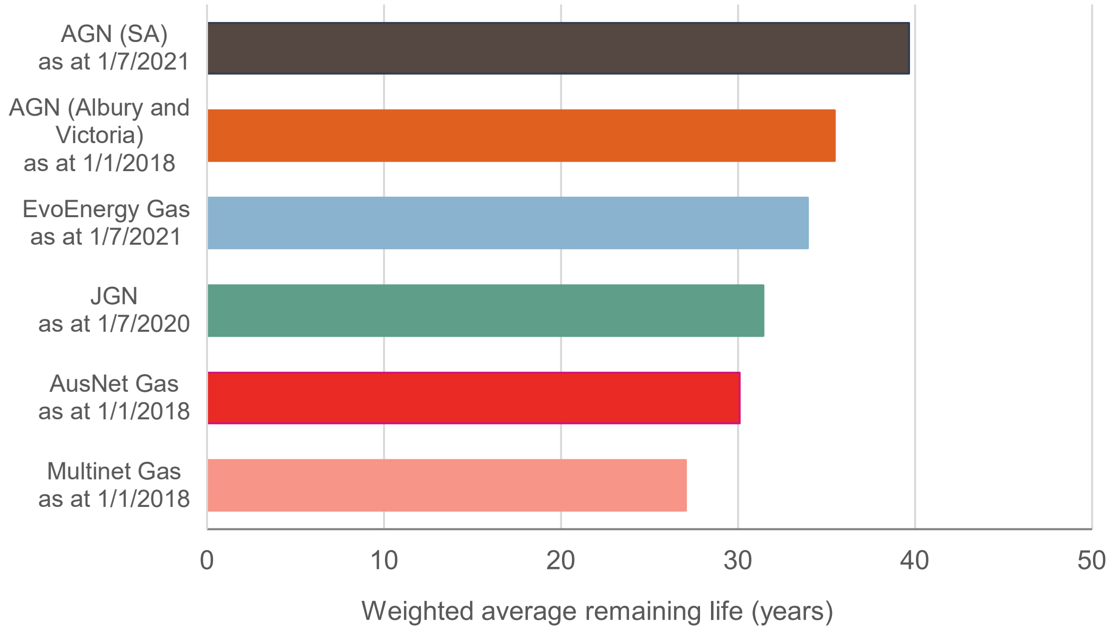
36 AGN (Albury & Victoria), *AGN (Albury & Victoria) – 2021 to 2026 access arrangement proposal*, p 83.

37 AusNet Gas, *Ausnet Gas – 2018 to 2022 access arrangement information*, 2016, p 106.

38 Multinet Gas, *Multinet Gas – 2018 to 2022 access arrangement information*, 2016, p 56.

39 The weighted average remaining (economic) life presents a snapshot of the combined age of assets in a distribution network weighted by the value of each asset class.

Figure 5-9 Capital base weighted average remaining life (years) – Gas distribution NSPs



Source: Post-tax revenue models, AER analysis.

Note: We collated data from each gas distribution NSP's most recent determination PTRMs on the value of the opening capital base value and depreciation by asset class. We used this data to calculate a weighted average remaining life to provide a snapshot of the relative age of each network. This provides additional insight on the effect of the timing of capital expenditure programs on asset age as identified by the capital expenditure category purpose analysis.

Gas distribution NSPs with a high proportion of connections or mains replacement capital expenditure also have relatively younger networks (or longer remaining lives). The size and composition of a gas distribution NSP's capital expenditure program impacts the value-weighted average remaining (economic) life of the capital base over which it can provide services.

At the start of the most recent access arrangement period, mains pipelines and services across the various NSPs accounted for between 78 to 90 per cent of the distributors' capital bases. The standard asset life of these mains pipelines and services can range from 50 to 80 years.[40] Figure 5-6 and Figure 5-7 identify that the capital expenditure categories of connections and mains replacement are significant drivers of expenditures adding new long-lived assets to the capital base. As new assets are added to the capital base each regulatory year, the weighted average remaining asset life in years calculated in Figure 5-9 for each gas distribution NSP will change accordingly.

Depreciation schedules and asset lives

A gas distribution NSP's depreciation schedule sets out the basis on which the capital asset base (used to provide regulated reference services) are to be depreciated for the purposes of determining a reference tariff.[41]

40 Multinet Gas's approved standard life for mains pipelines and services is 50 years which is the lowest for all gas distribution NSPs.

41 NGR, r.88

Key inputs into the depreciation schedule are the economic life of assets or a group of assets (known as an asset class). Our assessments of the standard (economic) life and remaining life of assets are compliant with the depreciation criteria under the NGR. This assessment also considers the revenue and pricing principles (RPP) and seeks to promote the NGO.[42]

In general, we consider that consistency in the standard asset life for each asset class across access arrangement periods will allow reference tariffs to vary over time in a manner which would promote efficient growth in the reference service. Our assessment on the standard asset life of an asset class also considers the technical life (or the engineering designed life) of the assets associated with the asset class. The economic life need not match the technical life of the asset, but if an asset is technically available for use, then it usually is able to serve an economic purpose.

Our final decision for Evoenergy Gas's 2021 to 2026 access arrangement accepted Evoenergy Gas's proposal to apply shorter standard asset life to pipeline assets in both the ACT and NSW regions.[43] Evoenergy Gas proposed to reduce the standard asset lives of its pipeline assets. This involved the standard asset lives for high pressure mains reducing from 80 years to 50 years and medium pressure mains and services reducing from 50 years to 30 years.[44]

Evoenergy Gas's submission sighted ACT Government's Climate Change Strategy 2019 to 2025 with a focus to reduce emission from transport and gas after 2020.[45] The ACT government strategy included the:

- Removal of a mandated requirement that new suburbs be connected to gas
- Support of gas to electric appliance upgrades
- Encouraging all new (housing) builds to be all-electric.

We accepted Evoenergy Gas's proposal to reduce the standard asset life of pipeline assets in the both ACT and NSW regions, because the ACT Government's policy for existing gas consumers to progressively switch over to electricity could lead to a decline in the future usage of the Evoenergy Gas's network.[46]

The changes to the standard life of the pipeline assets and depreciation schedule will apply from the start of the 2022 regulatory year. Therefore, they are not reflected in Evoenergy's capital asset base weighted average remaining life in Figure 5-9.

42 NGL, s 28; NGR r.100(1).

43 AER, *Final decision – Evoenergy Gas access arrangement 2021 to 2026, Attachment 4 – Regulatory depreciation*, 2021, pp. 11-12.

44 Evoenergy Gas, *Regulatory proposal – Attachment 4 – Capital base and depreciation*, June 2020, pp. 4-10.

45 ` Evoenergy Gas, *Evoenergy Gas access arrangement information 2021 to 2026*, June 2020, pp. 7-9.

46 AER, *Final decision – Evoenergy Gas access arrangement 2021 to 2026, Attachment 4 – Regulatory depreciation*, 2021, pp. 5-6.

6 Network service outcomes for customers

In this section, we consider the network service outputs customers receive for their expenditure on gas network services.

For our first report, we have focused our analysis of network service outputs on network outages and UAFG. These measures of service quality are readily quantifiable and the gas distribution NSPs report data annually on both measures.

Over 2011 to 2020, we observe that:

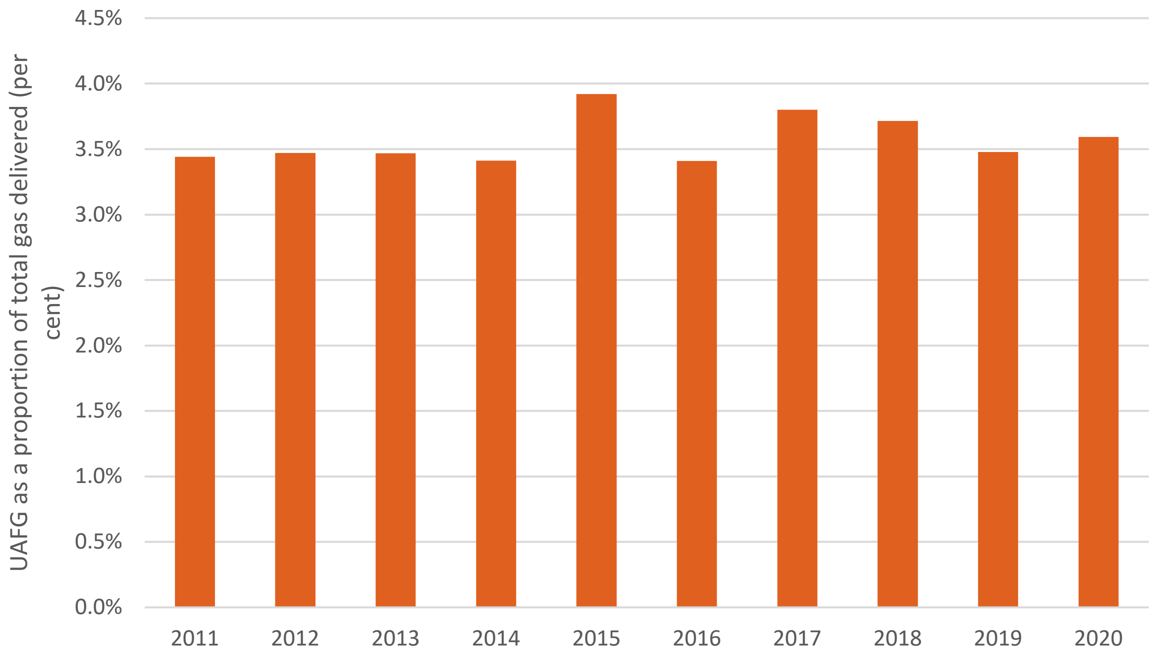
- UAFG levels have declined overall from their peak in 2015, but have increased 3.6 per cent over 2020.
- Total UAFG across the gas distribution NSPs varies annually but has remained relatively stable overall.
- However, we also observe divergent trends between gas distribution NSPs. This is a combined product of increasing levels of UAFG across most NSPs and material declines in UAFG on AGN's South Australian gas distribution network.
- Network outages increased consistently over a period of years but have recently stabilised and shown some signs of decreasing.

We intend to continue our strategy of pre engagement with stakeholders to inform areas of interest for future network performance reports, particularly to refine measures of service performance. In particular, we recognise that gas distribution NSPs are inherently reliable, for reasons discussed further in this section. Over time, we will investigate whether other service outcomes are important to gas distribution NSP customers and which can be included in our reporting.

6.1 Unaccounted for gas

UAFG is the difference between the measured quantity of gas entering the network (gas receipts) and metered gas deliveries (gas withdrawals). UAFG can result from gas leakage, inaccuracies in gas measurement, gas heating values or theft. It is an important measurement for customers as they ultimately face its cost.

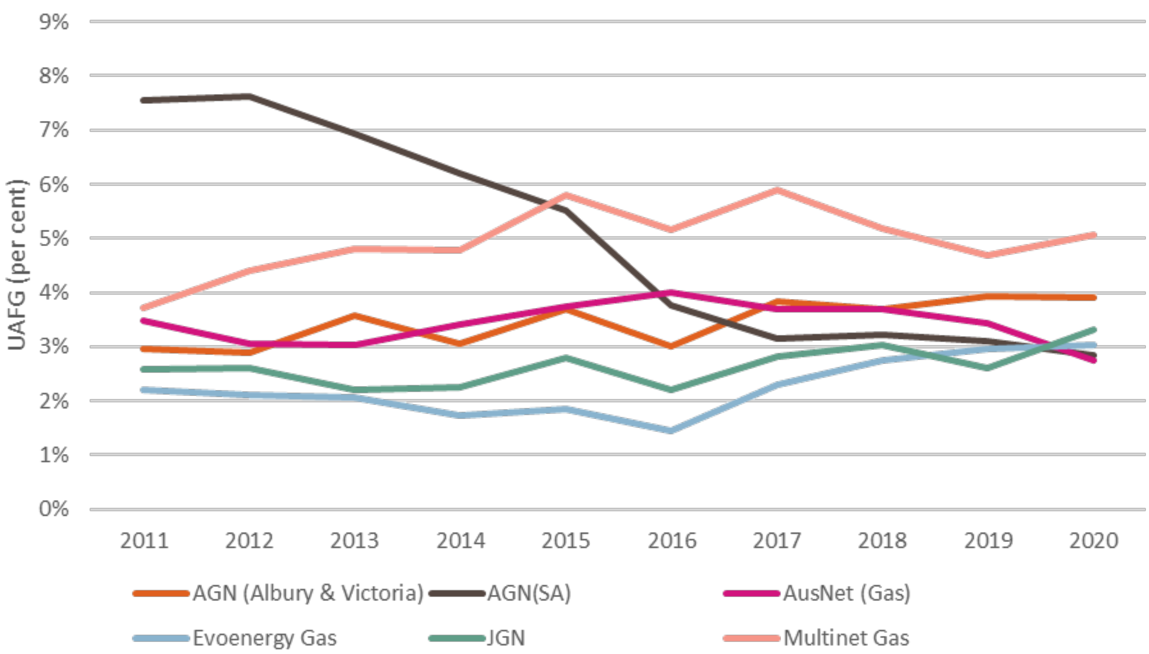
Figure 6-1 UAFG compared to gas delivered – Gas Distribution NSPs



Source: Operational performance data, AER analysis.

UAFG has remained stable on average, for the most part varying from just below 3.5% to 4% of delivered gas volumes. However, at a gas distribution NSP level, we observe clearer evidence of trends. Figure 6-2 illustrates the changes from 2011 to 2020 in reported volumes of UAFG as a proportion of total gas delivered for each gas distribution NSP.

Figure 6-2 UAFG as a proportion of gas delivered – Gas distribution NSPs



Source: AER analysis

We observe that:

- Levels of UAFG have increased for all but two gas distribution NSPs over 2011 to 2020.
- AGN (SA) has experienced significant reductions in its levels of UAFG. While the drivers of change in UAFG are too complex to attribute precisely, we expect this is partly an outcome of its ongoing mains replacement program, identified in section 5.
- As at 2020, there is a narrower range of UAFG levels between gas distribution NSPs.

How UAFG costs impact the cost of reference services

Networks in the ACT, NSW and South Australia are required to directly contract UAFG volumes. As a result, UAFG is included in an NSP's allowed operating expenditure under our access arrangement determinations and recovered via network charges. NSPs are incentivised to reduce operating expenditure through base step trend operating expenditure forecasts and the efficiency carry over mechanism. If actual UAFG rates are below (above) forecast rates, an NSP will over (under) recover its actual UAFG costs. This will flow through to customers via a lower (higher) operating expenditure forecast in the next regulatory determination.

Victorian NSPs operate under a slightly different framework. The Victorian Essential Service Commission (ESCV) sets a benchmark rate of UAFG for each NSP[1], measured as UAFG divided by total gas delivered. Gas retailers are required to contract sufficient gas to cover customer consumption and the actual UAFG. If actual UAFG is greater than the benchmark, the NSP is required to compensate retailers for the UAFG in excess of the benchmark. Where actual UAFG is lower than the benchmark, retailers make reconciliation payments to the NSP.

Benchmark levels of UAFG for 2018 to 2022 can be found in ESCV's 2017 UAFG benchmark review. Because UAFG is considered via the ESCV benchmark process it is not considered in our access arrangement determinations, nor included in Victorian operating expenditure forecasts.

Under both frameworks, NSPs are only rewarded or penalised for changes in the relative UAFG volumes, or the benchmark rate. NSPs are not rewarded or penalised for changes in the absolute levels of UAFG or changes in gas price. For those NSPs that directly contract UAFG, any volatility from the price of purchasing gas differing from approved forecasts, or the total demand differing from forecasts they are trued-up through the tariff variation mechanism.

6.1.1 Causes of UAFG

Through our reporting, we intend to explore what evidence is available on the causes of UAFG and its sensitivity to those causes.

The ESCV periodically sets UAFG benchmarks for the Victorian gas distribution NSPs. In determining its methodology during its 2017 UAFG benchmarks review, the ESCV observed that:[47]

- Information it received from the gas distribution NSPs suggested five key categories of UAFG drivers, being:
  - Fugitive emissions—gas lost into the atmosphere due to leakage from the gas distribution networks
  - Metering errors
  - Heating value—the relationship between the volume of UAFG and the quantity of energy lost to customers. This is related to the quality of gas injected into the gas distribution network.
  - Data quality
  - Theft
- There is uncertainty about the extent to which different factors cause changes in UAFG levels.
- Gas distribution NSPs have different degrees of control over these causes. For example, networks have a relatively high degree of control over fugitive emissions, but the impact of heating value depends on the quality of gas injected into the gas distribution network, which is largely outside of their control.

As a first step in this analysis, we have undertaken a preliminary investigation into relationships between reported mains leaks and UAFG since gas distribution NSPs have significant control over this driver. This allows us to test the new datasets reported to us through Annual RINs. As we collect a longer time series and have greater opportunity to interrogate it, we intend to expand on this analysis.

6.1.2 Relationship between leaks and UAFG

As an initial step in analysing the drivers of UAFG, we have examined the relationship between reported mains leaks and UAFG levels. We focussed on mains leaks in particular because:

- Networks have indicated in access arrangement proposals that mains replacement programs should have a noticeable impact on the level of UAFG.[48]
- While there is uncertainty around the direct impact of mains leaks on UAFG, research has found that mains leaks may contribute from between 20% to 40% of UAFG.[49]

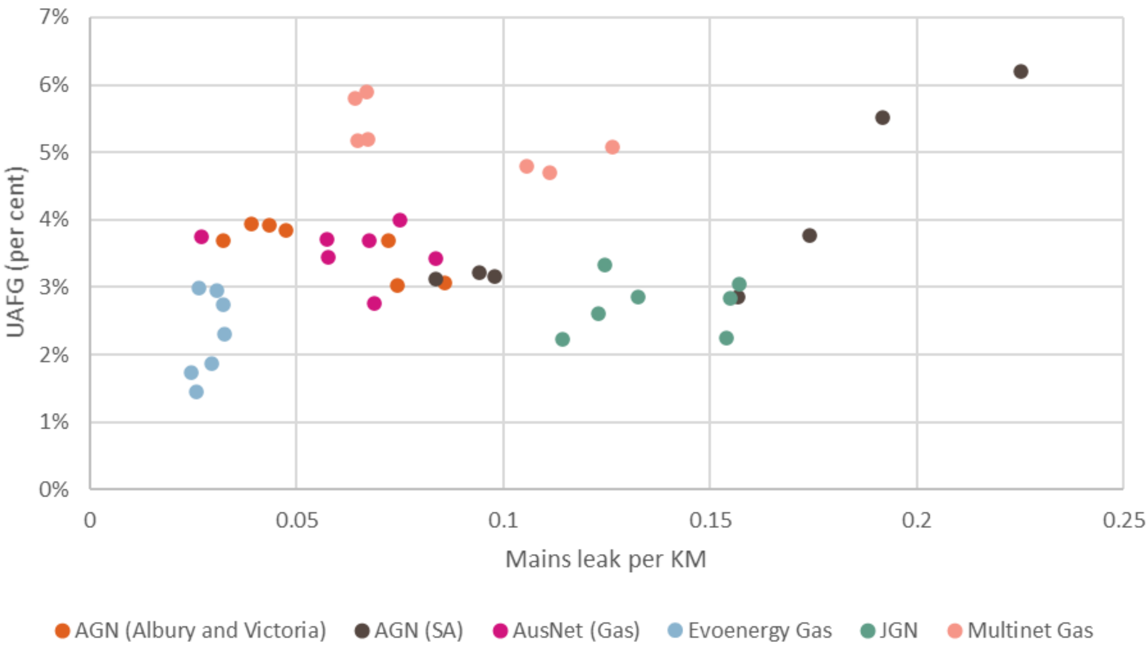
47 Essential Services Commission, *Review of unaccounted for gas benchmarks: final decision – methodology*, July 2017, pp. 5-9.

48 Australian Gas Network, *Access arrangement information,* July 2015, pp. 37-38; Multinet Gas, *Establishing the 2018 to 2022 unaccounted for gas class B benchmarks*, pp. 7-10.

49 AIA, *Review of Multinet gas' unaccounted for gas*, April 2017, pp. 14-16; Zincara, *Review of unaccounted for gas benchmarks – methodology prepared for Essential Services Commission*, pp. 9-10.

To test for this relationship amongst the fully regulated gas distribution NSPs, Figure 6-5 plots UAFG against reported mains leaks per kilometre between 2014 and 2020. We report from 2014 to avoid impacts of the material changes in JGN and Evoenergy Gas's reporting approaches from 2014 onwards.

Figure 6-3 UAFG and mains leaks per kilometre – Gas distribution NSPs (2014 to 2020)

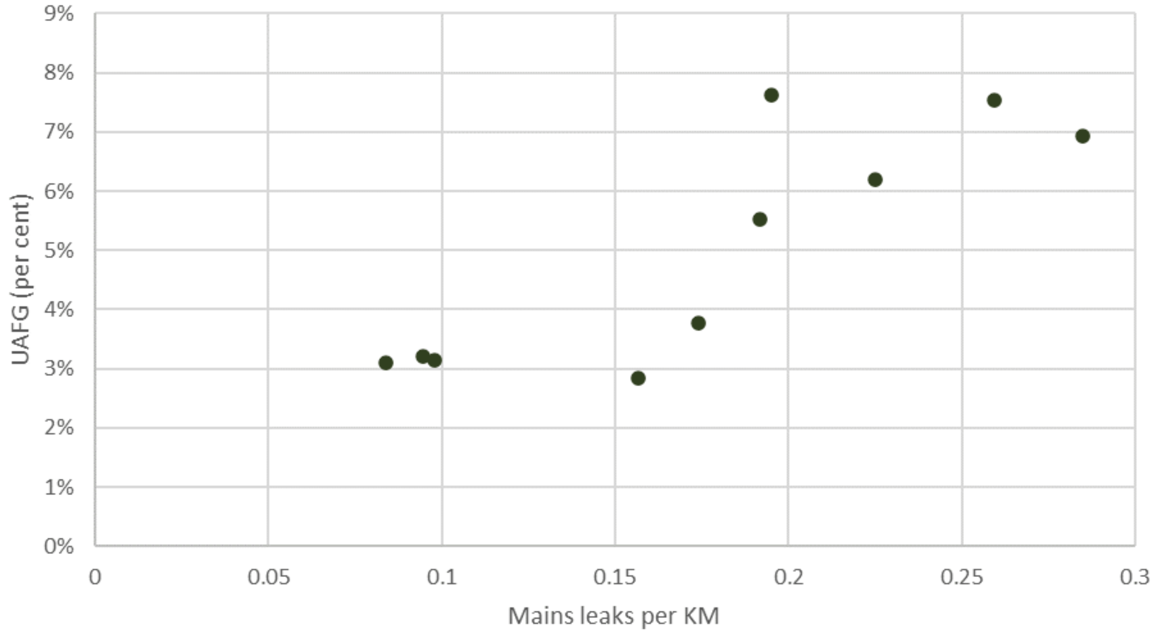


Source: Annual RINs, AER analysis.

When these observations are pooled across all NSPs, we do not observe clear evidence of a systematic relationship between mains leaks and UAFG. Similarly, outcomes for many of the individual NSPs are clustered, suggesting some level of random annual variation.

Nonetheless, some evidence suggests such a relationship may exist in specific circumstances. For example, Figure 6-4 sets out the relationship only for AGN (SA), over a period in which it commenced a substantial mains replacement program.

Figure 6-4 UAFG and mains leaks per km – AGN (SA) (2011 to 2020)



Source: AR RINs, AER analysis.

We expect the strength of this relationship might vary in response to factors, such as:

- As set out in section 5, gas distribution NSPs are at different points in their capital expenditure replacement programs. This means that:
  - The age of networks vary.
  - Networks have materially different operating pressures and asset material makeup.
- Gas distribution NSPs survey different proportions of their networks each year. This means that in any given year, the reported leaks on network mains reflect the segment of network that has been surveyed. As a result, reported leaks in any given year may not be representative of changes in total network leaks.
- Our data series does not measure the total fugitive emissions caused by each leak.

While these factors create material difficulties in understanding the extent to which mains leaks drive UAFG, we consider this an important issue to examine in more detail. UAFG is an important driver of costs for networks, both in terms of the fuel cost and through increasing the need for significant capital investment in mains replacement programs. In future reports, we will look to deepen our analysis of this relationship and other potential drivers of UAFG.

6.2 Network outages

Gas distribution NSPs are inherently reliable. This is in part because:

- The pipelines are predominately underground so are less exposed to adverse environmental conditions than, for example, electricity networks.

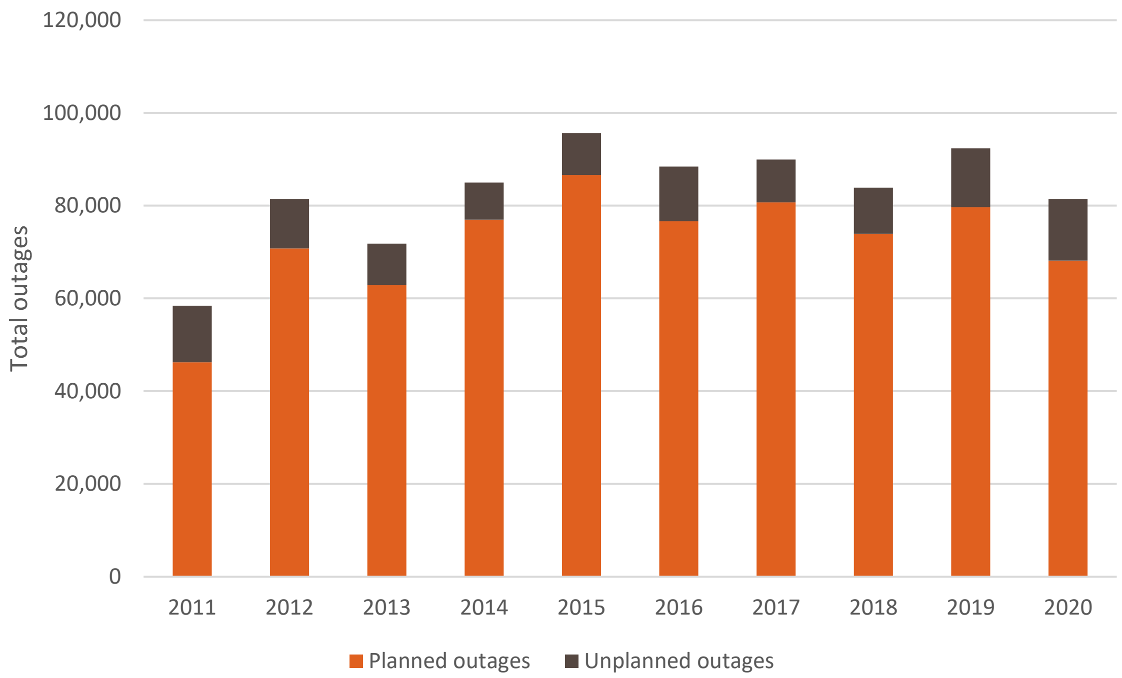
- Gas NSPs can carry out works without causing supply outages to customers.

Due to these factors, customers experience network outages infrequently. For example:

- in 2020 there were on average 0.019 outages per customer.[50]
- alongside the infrequent nature of network outages, they also impact relatively few customers at once. For example, only 0.9% of unplanned outages and 0.5% of total outages between 2011 and 2020 affected more than 5 customers.

Nonetheless, since the consequences of outages can be material for those customers they do affect, we consider it important to monitor aggregate changes in outages over time. Figure 6-5 sets out total outages across the gas distribution NSPs, divided into planned and unplanned outages.

Figure 6-5 Network outages – Gas distribution NSPs



Source: Operational performance data, AER analysis.

Figure 6-5 shows that:

- Network outages in total are at the lowest level since 2013.
- This has been driven by a trend in the reduction of planned outages. Planned outages have reduced by 21% from a peak in 2015.

50 Note, this is distinct from the SAIFI measure we report in electricity as it is not weighted by the number of customers impacted per outage, recognising than an outage can affect more than one customer at once.

- Conversely, unplanned outages have increased by 67% from a low in 2014. Directionally, this is not what we would expect with many gas distribution NSPs having undertaken significant mains replacements over the same period. However, we recognise that even at their highest levels, these unplanned outages remain rare for consumers. We will continue to monitor these outcomes and investigate what is driving outages in future reports.

When engaging on this data, we observed that gas distribution NSPs have adopted materially different approaches to reporting outages. As such, our view is that while Figure 6-7 and the underlying outage data is useful to monitor trends through time, it is less informative about the comparative reliability of individual gas distribution NSPs.

7 Profitability

In this section, we consider the levels of profitability that the fully regulated gas distribution NSPs have generated from the revenue allowances paid by customers.

The regulatory framework is designed to compensate NSPs in expectation for efficiently incurred costs (such as operating expenditure, depreciation, interest on debt, and tax) and to provide them with a forecast return in line with the required return in the market for an investment of similar risk.

The forecast return, if set at an appropriate level and supported by appropriate incentives, should attract efficient investment. As a feature of the incentive-based regulatory framework, we expect NSPs' actual outcomes to differ from the forecasts and benchmarks we set. These actual outcomes then provide us with a historical benchmark for setting revised efficient allowances for NSPs in future access arrangements.

The revenue requirement is not a guaranteed return, as NSPs' actual returns are determined in part by whether they spend more or less than the forecasts and benchmarks used to determine their revenue in our access arrangement decisions. Nonetheless, to the extent that profitability results are systematically and materially higher or lower than forecast, this would prompt us to investigate the causes in more detail.

As such, reporting on profitability measures should contribute to achievement of the NGO by making the gas distribution NSPs' returns and their drivers transparent. This reporting should also assist us and stakeholders as an additional source of information with which to review the overall effectiveness of the regulatory regime.

Our key findings are that:

- Both forecast and actual NSP returns have declined over time. However, over 2014 to 2020, actual profits have typically exceeded forecast returns.
- The largest driver of this outperformance appears to be revenue over recovery due to higher demand for reference services than forecast.
- Unlike electricity NSPs regulated under revenue caps, gas NSPs under price caps retain these additional returns arising from higher demand.
- Based on recent trading and transaction RAB multiples, investors appear to view the expected returns from investing in regulated NSPs as being at least sufficient to attract investment.

In this first gas network performance report, we report on three of our four profitability measures, being:

- Return on assets
- Earnings before interest and tax (EBIT) per customer
- RAB multiples

All analysis in this section is presented:

- As real returns, excluding annual returns from RAB indexation
- Including rewards and penalties arising from incentive schemes
- Over 2014 to 2020, for consistency with our electricity profitability analysis.

Other permutations of these measures are available in our financial performance dataset, released alongside this report. We will expand on this reporting to include the return on regulated equity measure in our 2022 gas network performance report.

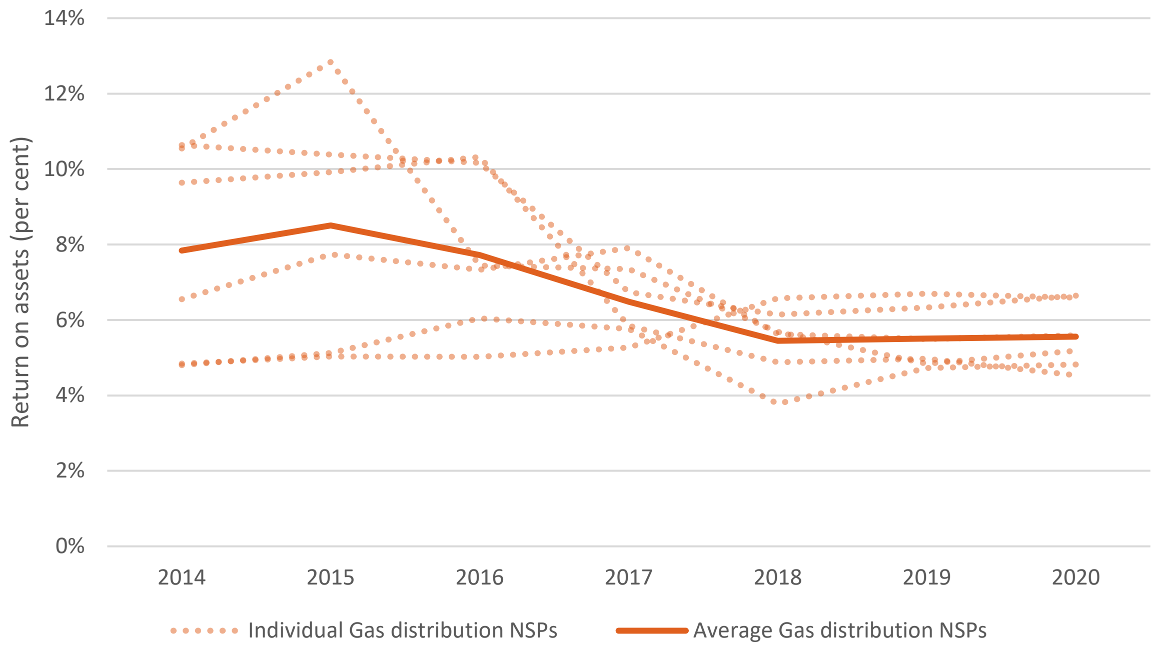
7.1 Return on Assets

The return on assets is a simple, partial profitability measure allowing us to compare network profits against our allowed rates of return. It does not capture all potential drivers of network profits. In particular, it does not capture network performance against our allowances for the costs of debt (interest expense) or tax expense. However, it does capture the impact of incentive scheme rewards and penalties, as well as network performance against operating expenditure allowances, as well as capital expenditure forecasts.

Over 2014 to 2020, we observe that:

- Average returns on assets have declined materially across the gas distribution NSPs.
- This is driven in large part by lower forecast returns on capital.

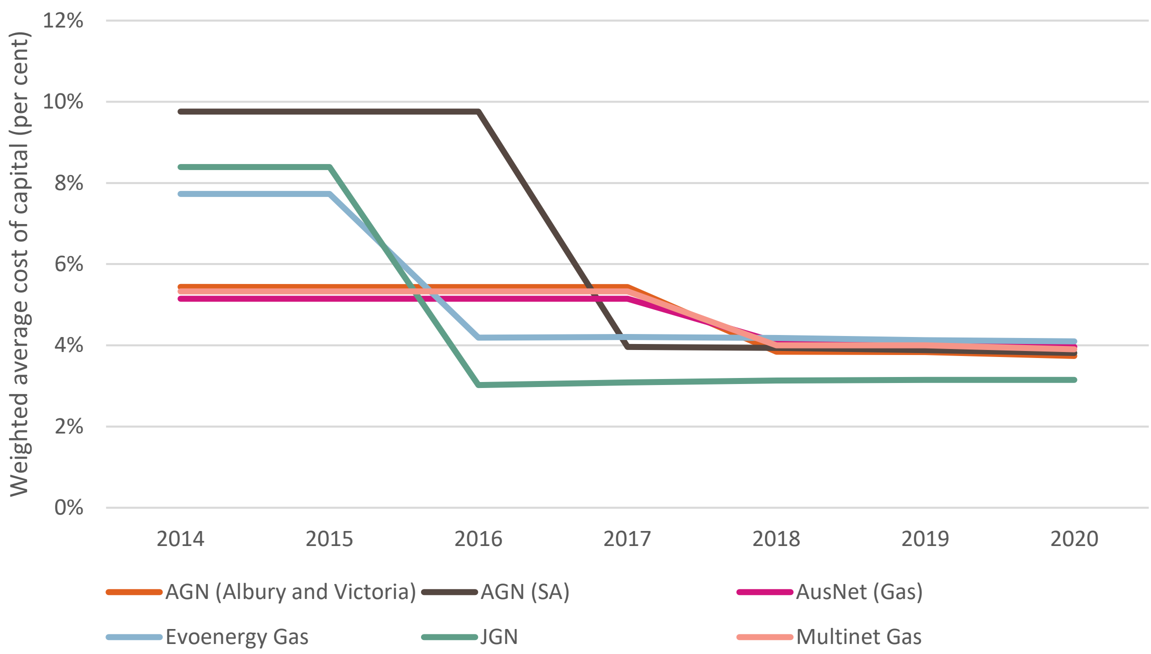
Figure 7-1 Regulatory returns on assets – Gas distribution NSPs



Source: Financial performance data, AER analysis

In addition to declining average returns, we observe that the range of outcomes between the gas distribution NSPs has narrowed since 2018. This appears driven by a range of factors in combination. The most material factor appears to be the decline and convergence of forecast costs of capital, which are a major driver of building block revenue.

Figure 7-2 Forecast real weighted average costs of capital – Gas distribution NSPs



Source: PTRM, AER analysis

Forecast returns on capital

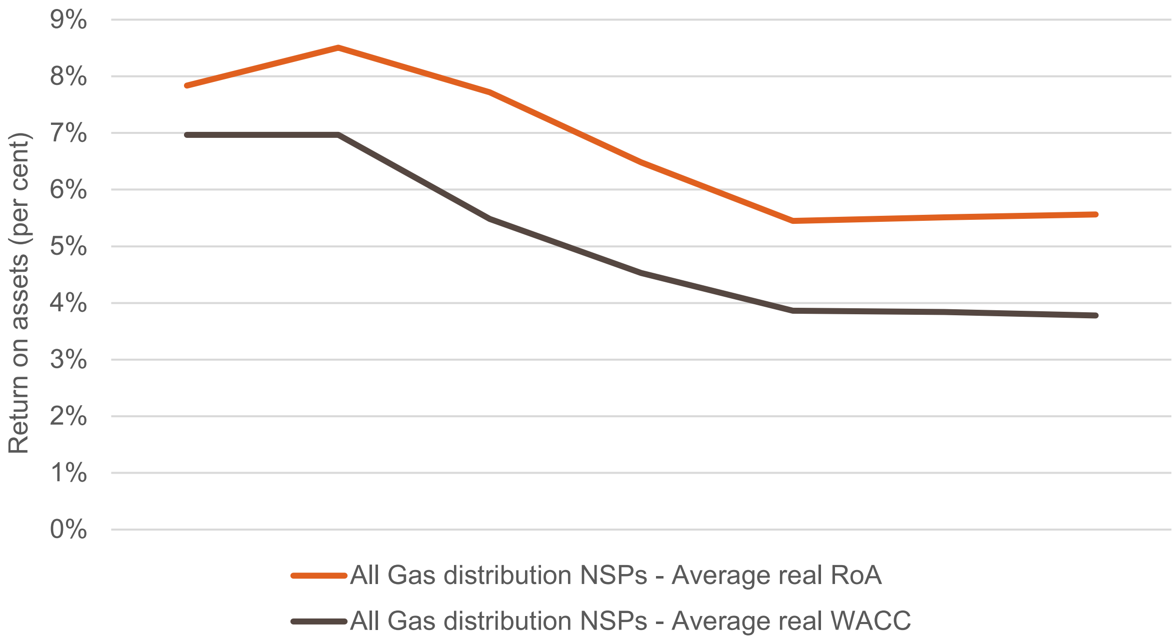
The return on capital building block included in our access arrangement determinations is made up of a return on debt component and a return on equity component. The return on debt, for example, is made up of the amount of debt we forecast (RAB multiplied by gearing) multiplied by the rate of return on debt. Equity is similar. We refer to the rates of return on debt and equity (in combination, the weighted average cost of capital or WACC) as 'forecast' returns.

This observed convergence in the forecast rates of return arises because:

- In decisions from 2015, returns on both equity and debt were reset under our 2013 rate of return guideline. In addition to changes to equity parameters, prevailing interest rates were materially lower than in the previous cycle of decisions.
- As the gas distribution NSPs gradually had their building block revenues set under that guideline, real forecast returns converged between 3% to 4%.
- Under the trailing average portfolio return on debt approach, introduced in the 2013 guideline, the return on debt component of these forecast returns is updated annually. This reduces divergence relative to when each NSP's allowed return on debt for an access arrangement period (which differed between NSPs) was based on the benchmark cost of debt near the start of that period
- In 2018 we made our first binding rate of return instrument. In the instrument, we made changes to both equity and debt parameters, contributing to further reductions in forecast rates of return. These will apply in 2021 for the Victorian gas distribution NSPs, and in subsequent years to the other gas distribution NSPs.

Nonetheless, while actual and forecast returns have both declined, gas distribution NSPs have continued to generate returns consistently and materially above forecast returns.

Figure 7-3 Actual and forecast returns on assets – Gas distribution NSPs

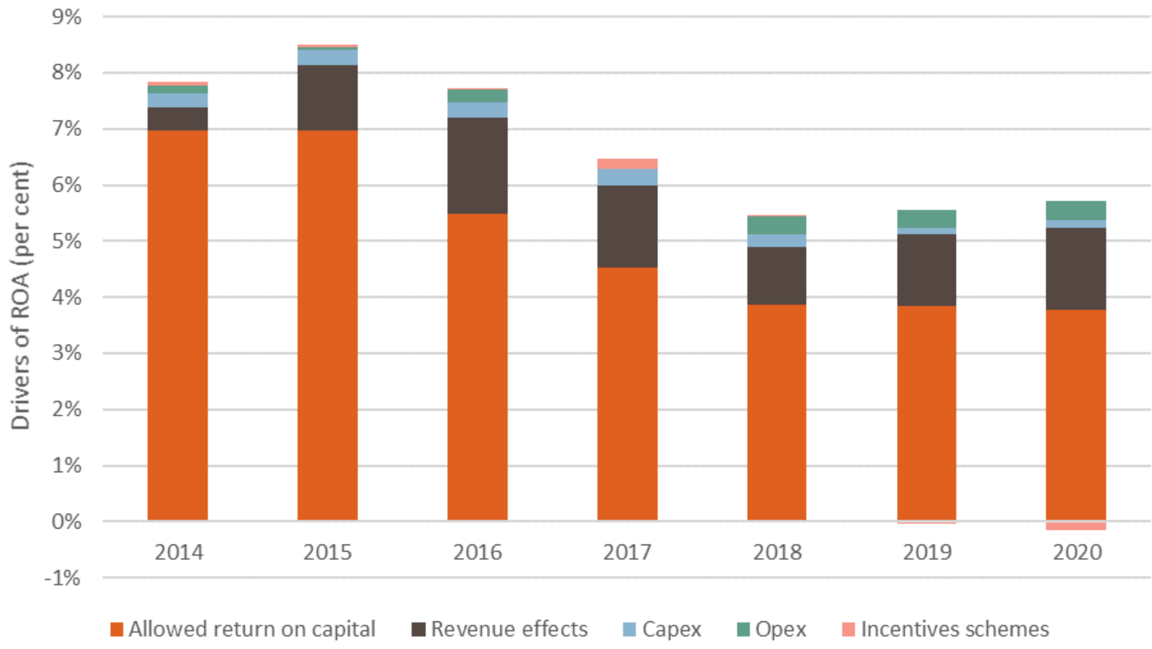


Source: Financial performance data, AER analysis

Our analysis suggests that this margin reflects a number of factors. As set out in Figure 7-4, the most material driver of differences appears to be what we collectively term 'revenue effects', which includes:

- Changes in usage of the gas distribution network, such as growth in demand or customer numbers
- Impacts of revenue smoothing, which in any given year can result in material differences between unsmoothed revenue (that is, forecast expenditure) and smoothed revenue—holding forecast demand constant.

Figure 7-4 Factors contributing to the margin between forecast and actual returns on assets – Gas distribution NSPs



Source: Financial performance data, AER analysis

Note: We have calculated the above by substituting our forecast of each factor, with the actuals that each NSP reported. So, for example, we have substituted in forecast operating expenditure from our PTRM with actual operating expenditure used in calculating the real return on assets. We calculate the incremental change in returns with each new factor for each network in every year of the time series.

'Revenue effects' are calculated as the remaining impact after accounting for the impacts of incentive schemes, operating expenditure and capital expenditure. This can include revenue outperformance under the weighted average price cap, differences between estimated and outturn inflation and other factors.

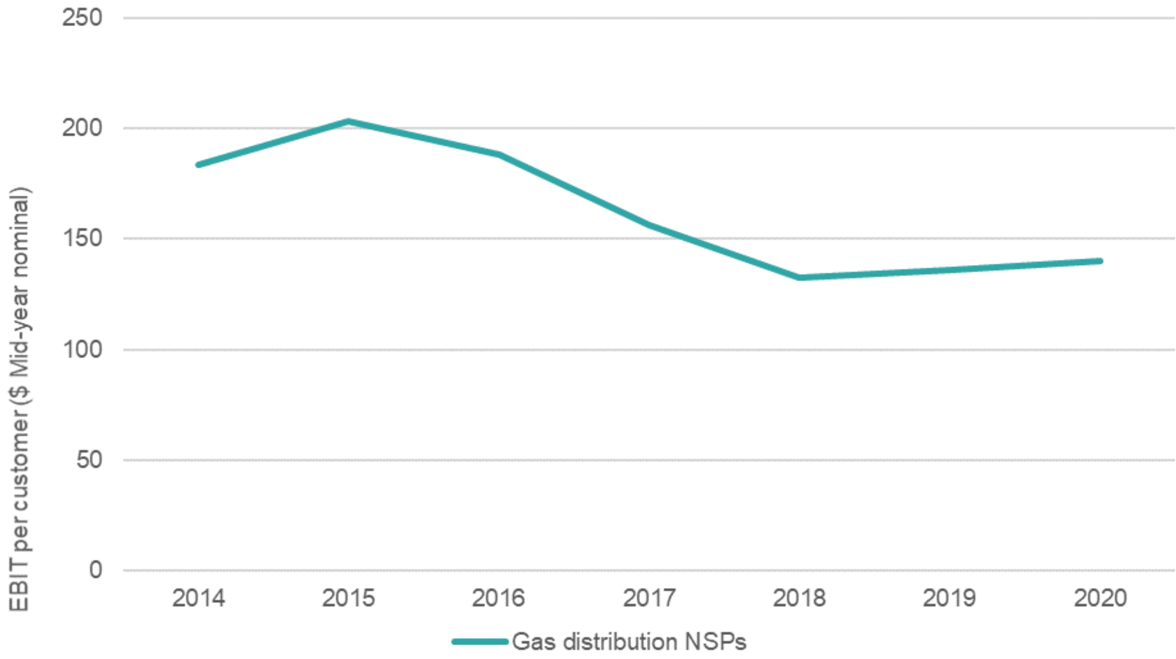
7.2 EBIT per customer

EBIT per customer is a measure of an NSP's operating profit over its consumer base. It is a complementary measure to the return on assets, capturing the same measure of profit (earnings before interest and tax, or EBIT) over a different cost-driver.

Importantly, EBIT per customer is *not* a measure of the profit that individual residential consumers contribute to the network. It is an average of all consumers, including commercial and industrial customers, who may contribute a substantially greater proportion of network revenue per customer despite their smaller numbers.

Figure 7-5 sets out the average real EBIT per customer, including incentive scheme payments and excluding the impacts of RAB indexation. In our view, this is the most informative single version of the EBIT per customer measure. It uses an estimate of EBIT that is computationally consistent with how real returns on assets are calculated.

Figure 7-5 Average EBIT per customer – Gas distribution NSPs



Source: Financial performance data, AER analysis

Over 2014 to 2020, we observe that:

- Like return on assets, EBIT per customer has declined driven by lower forecast rates of return.
- The proportional decline is larger in EBIT per customer due to the growth in customer numbers over the same period.

7.3 RAB multiples

RAB multiples are a measure of investor expectations about a network's future returns and are widely used by market analysts in connection with regulated utilities. They are calculated as an entity's enterprise value divided by its RAB.[51] Importantly, they are forward-looking, where the other profitability measures are based on historical outcomes. However, given most of our regulatory approaches are predictable and set out in guidelines, if returns had been systematically insufficient, we expect this might be evident in RAB multiples.

In practice, several factors affect RAB multiples and not all of those factors are direct outcomes of the regulatory regime or the networks' core regulated services. In advice given during development of the 2018 rate of return instrument, Biggar observed that:[52]

51 The RAB of fully regulated gas NSPs is known as the capital base. We have referred to capital base as RAB in this section for simplicity.

52 Darryl Biggar, *Understanding the role of RAB multiples in the regulatory process*, 2018.

Based on the data above and the analysis in this paper, is it possible to suggest a "normal" or "typical" range for RAB multiples?

This is difficult to assess and there is no fully objective perspective. In my view, due to each firm's ability to earn rewards for taking desirable actions, an Enterprise Value (EV)/RAB ratio of slightly above one should be considered normal. This is consistent with the theoretical observation that the regulated firm must be left some "information rents" in an optimal regulatory contract. I therefore suggest that, as a starting point, an EV/RAB in the vicinity of 1.1 should be considered unobjectionable. In addition, due to uncertainties and complexities in the regulatory process, and in the process of estimating the EV and the RAB, I suggest an error margin of plus or minus twenty per cent on this figure could be considered a "normal range".

For these reasons, we do not expect RAB multiples to be precisely at one under a well-functioning regulatory regime and consider that RAB multiples somewhat above one would not necessarily indicate a problem.

This is consistent with the approach followed by a range of other regulators that use RAB multiples as a reasonableness check or input into allowed rates of return.

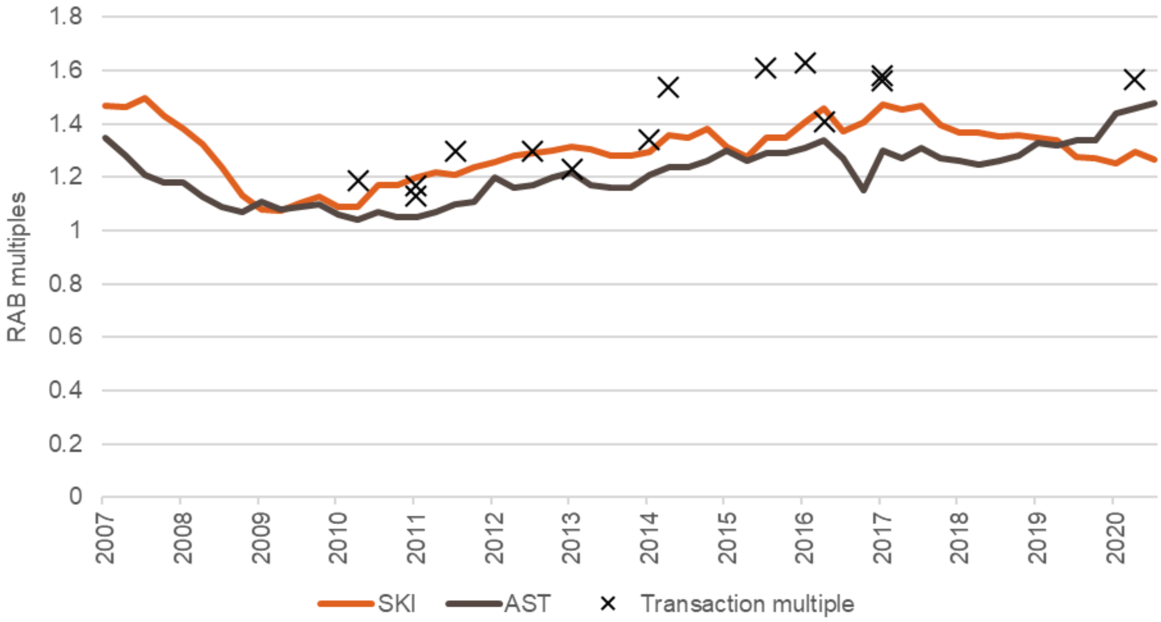
To draw on the largest possible body of market evidence, we have reported on two types of RAB multiples, sourced from Morgan Stanley:

- Transaction multiples – RAB multiples arising from the transaction of a discrete component of an ownership group including regulated networks.
- Trading multiples – RAB multiples generated using market value data on the enterprise value of publicly listed entities.

Further details of RAB multiples, including the implications of the measure are provided in the explanatory note for RAB multiples, which is published with this report.

Figure 7-6 combines our time series of both trading and transaction RAB multiples.

Figure 7-6 AER regulated NSPs – transaction and trading multiples



Source: Morgan Stanley Research, AER analysis.

Note: SKI is Spark Infrastructure, which holds ownership stakes in SA Power Networks (49%), Victoria Power Networks (49%) and TransGrid (15%). AST is AusNet Services, which owns a Victorian electricity distribution network, electricity transmission network and gas distribution network.

The set of transaction multiples in Figure 7-6 captures a balanced mix of both electricity and gas networks held by the entities. The trading multiples mainly reflect ownership interest in electricity networks, with gas ownership limited to AusNet's ownership of its gas distribution network. We consider RAB multiples associated with both electricity and gas network ownership informative for understanding outcomes of regulation more broadly. This position reflects the overlap in our approaches to expenditure forecasting and determining rates of return when regulating gas and electricity networks.

While there are some differences between the regulation of gas and electricity networks, including differences in the form of control applied (that is, price caps versus revenue caps), there are many similarities. We have previously considered these similarities when determining that gas and electricity networks face similar levels of market risk. In our view, RAB multiples are part of a broader set of information assisting us to form insights about the sufficiency of returns achieved under both the gas and electricity regulatory framework. We consider in this context they are similarly applicable to both the fully regulated electricity and gas NSPs.

While the drivers of RAB multiples are difficult to quantify precisely, the evidence they provide is consistent with the other profitability measures in this report, which supports a view that investors view regulated returns as being at least sufficient to attract investment. Put conversely, it would be difficult to explain the persistence of premiums in both trading and transaction multiples if investors perceived systematic deficiencies in returns generated through the economic regulatory framework.

The most recent transaction multiple that involved a fully regulated gas distribution NSP was the purchase of the DUET Group in 2017, which owned Multinet Gas, for a transaction multiple of

1.56. This followed the purchase of Envestra in 2014 for a transaction multiple of 1.54, which owned the gas distribution NSPs now known as AGN (Albury & Victoria) and AGN (SA).

From data released over the last year, we note that:

- In July 2020, OMERS acquired a 19.99% stake in TransGrid at a RAB multiple of 1.57. This is approximately the same RAB multiple at which the privatisation of TransGrid took place at in 2014.
- The average of trading multiples is slightly up on 2019.

In the absence of more recent transaction multiples involving gas distribution NSPs, we believe TransGrid's purchase can provide insight as to current transaction multiples for fully regulated NSPs. As with all transaction multiples, we expect the premium on the TransGrid transaction may to some extent reflect sector, asset or buyer specific factors. However, in our view the stable premium for the specific asset suggests projected returns under the regulatory framework are at least sufficient to attract investment, noting:

- Forecast rates of return have declined since the initial privatisation of TransGrid.
- Trading multiples have varied through time but, since 2014, have been relatively steady despite material declines in allowed returns on capital over the same period.

Similarly, we observe variation in trading multiples over time between AST (AusNet Services Ltd) and SKI (Spark Infrastructure Group). This variation suggests that there are some company-specific factors which impact trading multiples.

However, it remains the case that even the lower of the two multiples over time has traded at a price that reflects an enterprise value that is a premium to the RAB. We also note that both AST and SKI are currently subject to takeover bids. Given this market activity is occurring after the 2020 regulatory year, we have not sought to analyse it in this report. However, we will analyse any relevant market developments over this period in our 2022 electricity and gas network performance reports.

8 Looking ahead to 2022

Each year, we aim to identify issues to be investigated in detail as our focus areas for future gas network performance reports.

Over coming years, we will revisit the focus and scope of this report in the context of any changes to the regulatory framework for how we regulate gas network assets. In May 2021, the Energy Ministers agreed on a Decision Regulation Impact Statement (DRIS) identifying an agreed package of reforms to improve gas pipeline regulation.[53] The recommended reform option includes a number of monitoring requirements that may interact with the scope of this network performance report.

In addition, as noted in our Regulating gas pipelines under uncertainty information paper, we and stakeholders are grappling across many different forums with the ongoing energy transition and decarbonisation objectives committed by Australian governments. Decarbonisation of the economy and more specifically the energy supply chain will have implications for pipeline services. These impacts may vary between states and jurisdictions depending on policy settings and the makeup of customer bases. Increasingly, these issues are prominent in regulatory proposals and are issues of note in our access arrangement reviews for regulated gas networks. As our decisions progress and our reporting develops, we aim to identify these emerging impacts and undertake deeper analysis of the extent to which they are impacting network performance outcomes and our decisions.

Besides those broader strategic considerations, our work this year has identified a number of potential focus areas for 2022 and beyond, including:

- Extending reporting to cover fully regulated gas transmission NSPs
- Introducing the return on regulated equity measure
- Analysing the impact of COVID-19 on fully regulated gas NSPs and the gas sector
- Undertaking deeper analysis of changing asset age profiles

As we did in 2021, we will engage with stakeholders to identify whether we should investigate these and/or other focus areas in our 2022 report.

53 National Cabinet – Energy Ministers Meeting, *Gas pipeline regulation – Regulation impact statement*, National Cabinet – Energy Ministers Meeting, 2021, accessed 3 December 2021.

Appendix A: Objectives of network performance reporting

Through this report and the accompanying data, we intend to advance the network performance reporting objectives, determined with the input of stakeholders.[54] These are set out in Table A-1.

Table A-1 How we are advancing our objectives for network performance reporting

Objective	What we are doing
Provide an accessible information resource	We have drafted this report with the intent of making it both informative and accessible for stakeholders. Alongside this report, we have published two data models covering: • Our operational performance data. • Our financial performance data. These cover much of the data captured in this report at a greater level of detail. We aim to present the data in a form that enables stakeholders to use it in their own analysis.
Improve transparency	Through the report and our published data, we are trying to illustrate the impacts and interactions of network performance under different regulatory tools or settings. The regulatory regime can be complex. Our objective through this reporting is to make network regulation and its outcomes more transparent for stakeholders. For example, in this report we have provided key performance measures which we hope will assist stakeholders in gaining preliminary views on the regulatory framework.
Improve accountability	The focus of this report is on the effectiveness of network regulation holistically, increasing our accountability for regulatory decisions, and for the networks and their performance under those decisions. Further, our published data allows for comparisons of individual networks and, in our published data and analysis, we highlight particular areas where particular networks depart from broader trends.
Encourage improved performance	By improving accountability and transparency, we expect these reports over time will contribute to improved performance by: • Informing ourselves and stakeholders about emerging trends that may require a regulatory response. • Contributing to the incentives on NSPs to improve performance.
Inform consideration of the effectiveness of the regulatory regime	Our analysis in this report is intended to support consideration of how the regulatory regime contributes to network performance and outcomes. We aim to explore where actual outcomes depart from forecasts or trends, whether this is widespread and what implications that has for our regulatory approaches.
Improve network data resources	Through our analysis of the data, we have sought to: • Investigate and make use of a wide range of our network data sources. • Identify and manage differences in reporting that impede comparability of data provided by different NSPs. • Identify important questions on which we would like to form views but are limited by data availability or consistency. Over time, we expect this approach will also assist us to form a view on any data we currently collect that may be excessive or not useful.

Source: AER analysis

In setting out these objectives, we recognise this is our first gas network performance report. Due to this, we encourage stakeholder feedback on the report and our accompanying data resources so that we can improve its usefulness over time. Following release of the report, we encourage input from stakeholders by emailing networkperformancereporting@aer.gov.au.

54 AER, *Objectives and priorities for reporting on regulated electricity and gas network performance—Final*, June 2020.

Appendix B: Figures source data

The source data for figures included in this report are found in our operational and financial performance datasets, gas annual RINs (ARs) and the access arrangement roll forward models (RFMs) and PTRMs. Table B-1 provides the specific data source for each figure and any calculations made to the data.

Data on actuals for the capital base and capital expenditure is sourced from the gas distribution NSP's final decision RFM where available, then from their AR if no RFM is available. All other data on actuals is sourced from the gas distribution NSP's AR. Data on forecasts is sourced from the gas distribution NSP's final decision PTRM.

Table B-1 Data source for Figures included in Gas Network Performance Report

Figure	Data	Data Source	Calculation
Figure 2-1	Access arrangement periods	No AER data used	N/A
Figure 3-1	Map of fully regulated gas distribution NSPs	No AER data used	N/A
Figure 3-2	Network length	Network length – AR – N2.1 Network length by pressure and asset type	N/A
Figure 3-3	Network length by pressure type	Network length – AR – N2.1 Network length by pressure and asset type	N/A
Figure 3-4	Network length by pressure type for Evoenergy Gas	Network length – AR – N2.1 Network length by pressure and asset type	N/A
Figure 3-5	Network length by pressure type for JGN	Network length – AR – N2.1 Network length by pressure and asset type	N/A
Figure 3-6	Network length by pressure type for Victorian gas distribution NSPs	Network length – AR – N2.1 Network length by pressure and asset type	N/A
Figure 3-7	Network length by pressure type for AGN (SA)	Network length – AR – N2.1 Network length by pressure and asset type	N/A
Figure 3-8	Network length by asset type	Network length – AR – N2.1 Network length by pressure and asset type	N/A
Figure 3-9	Customer numbers	Customers numbers – AR – S1.1 Customer numbers by customer type	N/A
Figure 3-10	Customer numbers by state/jurisdiction	Customers numbers – AR – S1.1 Customer numbers by customer type	N/A
Figure 3-11	Customer numbers by type	Customers numbers – AR – S1.1 Customer numbers by customer type	N/A
Figure 3-12	Gas delivered by customer type	Gas delivered – AR – N1.1 Demand by customer type	N/A
Figure 3-13	Gas delivered by customer type for each gas distribution NSP	Gas delivered – AR – N1.1 Demand by customer type	Composition of gas delivered by each gas distribution NSP into customer types.
Figure 3-14	GJ per customer for different customer types	Gas delivered – AR – N1.1 Demand by customer type Customers numbers – AR – S1.1 Customer numbers by customer type	Index of gas delivered for each customer type using 2011 as a base.

			Gas delivered for each customer calculated in method noted in Figure 3-12
Figure 4-1	Reference service revenue	Reference services revenue – AR – S3.1 Reference services	Reference services revenue converted into $ Jun 2020 terms
Figure 4-2	Reference service revenue per customer	Reference Services Revenue – AR – S3.1 Reference services Customers Numbers – AR – S1.1 Customer numbers by customer type	Reference service revenue divided by number of customers.
Figure 4-3	Reference service per customer by state/jurisdiction	Reference Services Revenue – AR – S3.1 Reference services Customers Numbers – AR – S1.1 Customer numbers by customer type	Reference services revenue converted into $ Jun 2020 terms Reference service revenue for each state/jurisdiction divided by number of customers for each state/jurisdiction.
Figure 4-4	AER building block model to forecast revenue	No AER data used	N/A
Figure 4-5	Forecast revenue building blocks	Forecast revenue – PTRM – Revenue summary – Building block components	Forecast revenue converted into $ Jun 2020 terms
Figure 4-6	Cost of capital compared to capital base	Capital Base – RFM – Total capital base roll forward – Interim closing capital base. Where not available – AR – F10.1 Capital base values Nominal vanilla weighted average cost of capital (WACC) – PTRM – WACC	Capital base converted $ Jun 2020 terms
Figure 4-7	Forecast depreciation revenue building block	Forecast depreciation revenue – PTRM – Revenue summary – Building block components	Forecast depreciation revenue converted into $ Jun 2020 terms
Figure 4-8	Reference service revenue compared to forecast revenue	Reference Services Revenue – AR – F3.1 Reference services Forecast revenue – PTRM – Revenue summary – Building block components	Reference service revenue and forecast revenue converted into $ Jun 2020 terms
Figure 4-9	Reference service revenue compared to forecast revenue	Reference Services Revenue – AR – F3.1 Reference services Forecast revenue – PTRM – Revenue summary – Building block components	Reference service revenue and forecast revenue converted into $ Jun 2020 terms Reference service revenue less forecast revenue. Difference divided by forecast revenue.
Figure 4-10	NSW dwelling completions	No AER data used. Date sourced from Australian Bureau of Statistics – series A83801953A	N/A
Figure 4-11	Reference service revenue compared to forecast revenue – JGN	Reference Services Revenue – AR – F3.1 Reference services Forecast revenue – PTRM – Revenue summary – Building block components. JGN Annual remittal revenue adjustments – JGN and AER Analysis	Reference service revenue and forecast revenue converted into $ Jun 2020 terms JGN Annual remittal revenue adjustments calculated as difference between enforceable undertakings and access arrangement information.
Figure 5-1	Capital and operating expenditure	Capital expenditure – RFM – RFM input – Actual capital expenditure, Actual asset disposal, Actual capital contributions. Where not available AR – F2.4 Capex by asset class, F2.5 Capital contributions by asset class, F2.6 Disposals by asset class Operating Expenditure – AR – F4.1 Opex by purpose	Capital expenditure and operating expenditure converted into $ Jun 2020 terms Net capital expenditure is gross capex, less capital contributions and less disposals.
Figure 5-2	Capital and operating expenditure compared to forecast capital and operating expenditure	Capital expenditure – RFM – RFM input – Actual capital expenditure, Actual asset disposal, Actual capital contributions. Where not available AR – F2.4 Capex by	Capital and operating expenditure, and forecast capital expenditure and operating expenditure converted into $ Jun 2020 terms

		asset class, F2.5 Capital contributions by asset class, F2.6 Disposals by asset class Operating expenditure – AR – F4.1 Opex by purpose Forecast capital expenditure – PTRM – PTRM Input – Forecast net capital expenditure Forecast operating expenditure – PTRM – PTRM Input – Forecast operating and maintenance expenditure	Net capital expenditure is gross capex, less capital contributions and less disposals.
Figure 5-3	Capital expenditure compared to forecast capital expenditure	Capital expenditure – RFM – RFM input – Actual capital expenditure, Actual asset disposal, Actual capital contributions. Where not available AR – F2.4 Capex by asset class, F2.5 Capital contributions by asset class, F2.6 Disposals by asset class Forecast capital expenditure – PTRM Input – Forecast net capital expenditure	Capital expenditure, and forecast capital expenditure converted into $ Jun 2020 terms Capital expenditure less forecast capital expenditure. Difference divided by forecast capital expenditure. Net capital expenditure is gross capex, less capital contributions and less disposals.
Figure 5-4	Capital base by state/jurisdiction	Capital Base – RFM – Total capital base roll forward – Interim closing capital base. Where not available – AR – F10.1 Capital base values	Capital base converted into $ Jun 2020 terms
Figure 5-5	Capital base per customer	Capital Base – RFM – Total capital base roll forward – Interim closing capital base. Where not available – Annual RIN – F10.1 Capital base values Customers Numbers – AR – S1.1 Customer numbers by customer type	Capital base converted into $ Jun 2020 terms Capital base for each gas distribution NSP divided by number of customers for each gas distribution NSP
Figure 5-6	Capital base per TJ of gas delivered	Capital Base – RFM – Total capital base roll forward – Interim closing capital base. Where not available – AR – F10.1 Capital base values Gas delivered – AR – N1.1 Demand by customer type	Capital base converted into $ Jun 2020 terms Capital base for each gas distribution NSP divided by gas delivered by each gas distribution NSP
Figure 5-7	Capital expenditure by purpose	Capital expenditure by purpose – AR – E1.1.1 Reference Services	Capital expenditure by purpose converted into $ Jun 2020 terms
Figure 5-8	Capital expenditure by purpose	Capital expenditure by purpose – AR – E1.1.1 Reference Services	Capital expenditure by purpose converted into $ Jun 2020 terms Each capital expenditure purpose as a proportion of total capital expenditure
Figure 5-9	Capital base remaining years	Capital base remaining life – PTRM – Assets – Asset values	Calculation of weighted average remaining life for each gas distribution NSP
Figure 6-1	UAFG compared to gas delivered	UAFG – AR – S11.3 UAFG – Transmission and Distribution Gas delivered – AR – N1.1 Demand by customer type	UAFG as a percentage of total gas delivered
Figure 6-2	UAFG compared to gas delivered	UAFG – AR – S11.3 UAFG – Transmission and Distribution Gas delivered – AR – N1.1 Demand by customer type	UAFG as a percentage of total gas delivered for each gas distribution NSP
Figure 6-3	UAFG and mains leaks per kilometre	UAFG – AR – S11.3 UAFG – Transmission and Distribution Gas delivered – AR – N1.1 Demand by customer type Mains leak – AR – S14.1 Loss of containment	UAFG as a percentage of total gas delivered for each gas distribution NSP Mains leak per kilometre of network length for each gas distribution NSP

		Network length – AR – N2.1 Network length by pressure and asset type	
Figure 6-4	UAFG and mains leaks per kilometre	UAFG – AR – S11.3 UAFG – Transmission and Distribution Gas delivered – AR – N1.1 Demand by customer type Mains leak – AR – S14.1 Loss of containment Network length – AR – N2.1 Network length by pressure and asset type	UAFG as a percentage of total gas delivered for each gas distribution NSP Mains leak per kilometre of network length for each gas distribution NSP
Figure 6-5	Network outages	Planned and Unplanned Outages – AR – S11.1 Network outages	N/A
Figure 7-1	Return on assets	Return on Assets – Financial Performance data	Calculation of return on assets specified in financial performance data. Additional detail provided in return on assets explanatory note.
Figure 7-2	Forecast real WACC	Real WACC – PTRM – WACC	N/A
Figure 7-3	Actual and forecast return on assets	Return on Assets – Financial Performance data Real WACC – PTRM – WACC	N/A
Figure 7-4	Real actual and forecast return on assets	Return on Assets – Real – Financial Performance data Real WACC – PTRM – WACC	Calculation of return on assets specified in financial performance data. Calculation of differences between actual returns and forecast returns. This calculation involves substituting for each factor, one at a time, our forecast of that factor for a network in place of the actuals that the networks have reported. Factors which contribute to differences between actual and forecast returns are also explained in return on assets explanatory note.
Figure 7-5	EBIT per customer (Real)	EBIT per customer – Real – Financial Performance data	Calculation of EBIT per customer specified in financial performance data.
Figure 7-6	Transaction and trading multiples of regulated NSPs	No AER data used. Data sourced from Morgan Stanley Research	N/A