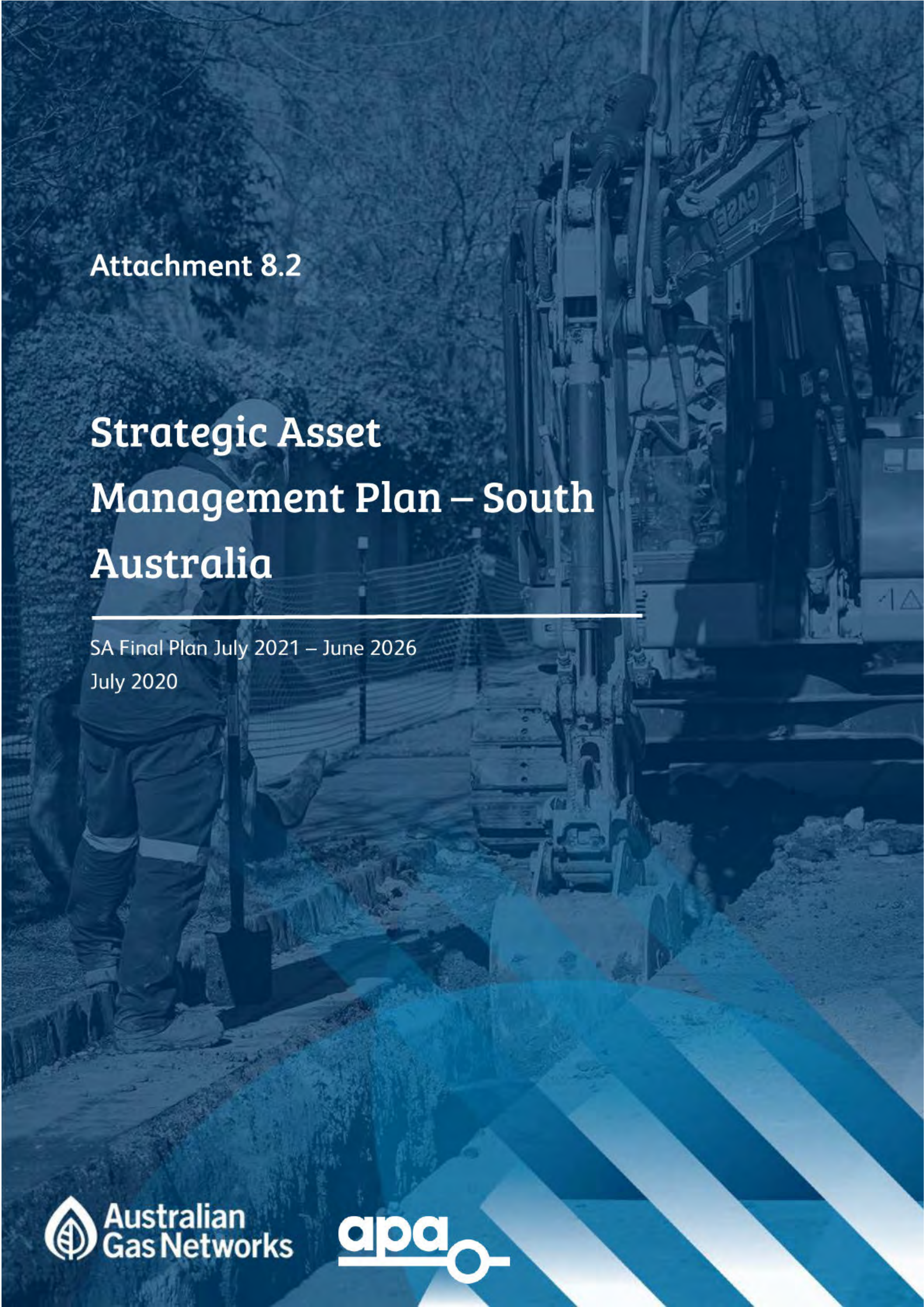


Attachment 8.2

Strategic Asset Management Plan – South Australia

SA Final Plan July 2021 – June 2026

July 2020

Australian Gas Networks

apa

Preparation Record:

Position	Organisation	Name
Prepared		
Project Manager SA Access Arrangement	APA	Ashraf Salha
Reviewed		
Manager Asset Strategy & Planning	APA	Martijn Vlugt
Head of Network Strategy & Planning	AGN	Troy Praag
Senior Regulatory Advisor	AGN	Brooke Palmer
Head of Compliance	AGN	Vicky Knighton
Approved		
Head of Planning and Engineering	APA	Craig Bonar
General Manager Network Operations	AGN	Mark Beech

Revision	Date	Reason / Changes Made
1	June 2020	Issued for use

Executive Summary

As part of the Australian Gas Infrastructure Group (AGIG), Australian Gas Networks (AGN) distributes gas to over 1.3 million residential, commercial and industrial customers across South Australian, Victoria and Queensland (mostly Brisbane), as well as smaller towns in New South Wales (Albury, Wagga Wagga) and the Northern Territory (Alice Springs). The combined networks include over 1,300 km of transmission pipelines and 24,000 km of distribution mains.

In South Australia, our Network supplies gas to more than 450,000 end users through a network of approximately 8,000 km of distribution mains, and 200 km of transmission pipelines. Our South Australian operations also manages our smaller non-regulated networks in the Northern Territory and Mildura (Victoria).

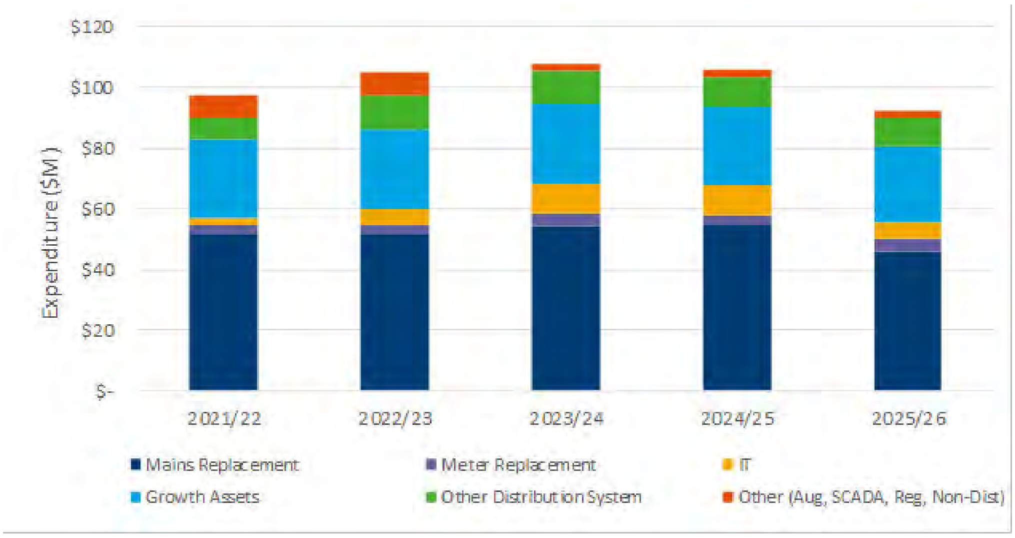
Our vision is to be the leading gas infrastructure business in Australia. By doing so, we aim to always deliver for the customer, be a good employer and be sustainably cost efficient.

This Strategic Asset Management Plan (SAMP) provides a consolidated view of the strategies adopted by us (and our network operator – APA Group) to manage the assets contained in our South Australian, Northern Territory and Mildura (Vic) networks. The SAMP is derived from a number of key operational and technical plans and is a key input into the development of business plans and capital expenditure forecasts.

Our approach to Asset Management is consistent with our Vision and is outlined in Section 3 of this document. The regulatory environment in which we operate is summarised in Section 4. An overview of our networks, including key characteristics, is contained in Section 5, followed by a summary of network and asset performance in Section 6. Finally, Sections 7 (regulated networks) and Section 8 (non-regulated networks) provide an overview of our capital requirements for the next Access Arrangement (AA) period (1 July 2021 to 30 June 2026).

In total, we are forecasting to incur $508.0 million of capital expenditure in our regulated SA network during the next AA period. This is summarised by asset type in Figure 0.1 below.

Figure 0.1: Capital Expenditure Summary (Regulated Networks) - direct, unescalated ($million 2019/20)



We are forecasting to incur $15.9 million of capital expenditure for the same period on our smaller unregulated gas networks in the NT and Mildura.

Contents

1. Document Overview

1.1. Purpose

This SAMP provides a consolidated view of strategies for and asset lifecycle issues of Australian Gas Networks (AGN) assets in South Australia, Northern Territory and Mildura in Victoria that are managed by the South Australian networks business of APT O&M Services Pty Ltd (APA). The SAMP is derived from a number of key operational and technical plans and is a key input into the development of business plans and capital expenditure requirements.

This plan provides a high-level view and medium-term strategy for the safe and efficient operation, management and development of the gas network assets. It defines our Asset Management vision and objectives and explains our Asset Management Framework, drivers and processes. An overview of our gas distribution network assets and a summary of the strategies for, and the main issues pertaining to, these assets is provided in section 5.

Section 7 of this plan is central to the delivery of network services to our customers. It outlines our planned capital expenditure profile for the forecast period (1 July 2021 to 30 June 2026) and links the overarching strategies defined in Sections 3 to 6 to the underpinning asset specific projects and programs. It covers network expenditure for our gas distribution and transmission assets.

This plan should be read in conjunction with the following documents:

- Safety, Reliability, Maintenance and Technical Management Plan (SRMTMP);
- Distribution Mains & Services Integrity Plan (DIMSIP);
- Meter Replacement Plan;
- Procurement Policy & Procedure;
- IT Investment Plan; and
- Risk Management Framework.

1.2. Coverage

This SAMP covers our natural gas assets in South Australia (metropolitan and regional areas), Northern Territory and Mildura in Victoria. Refer to Section 4 for the regulatory environment that applies to these assets, and Section 5 for a description of these assets.

1.3. Time Period

This SAMP provides strategic view of the management of the assets, relevant issues, and a forward work plan for the period 2020/21 to 2025/26.

The SAMP refers to the previous, current and next AA period. The dates for each period are:

- Previous Period – July 2011 to June 2016;
- Current Period – July 2016 to June 2021; and
- Next Period – July 2021 to June 2026.

1.4. Phasing and Financial Disclosure

All programs defined within the SAMP are presented in financial years (July to June) consistent with the reporting requirements of the Australian Energy Regulator (AER) and where applicable the *Gas Distribution Code SA* (Issue No. GDC/06[1]).

Where required for conversion to calendar year (January to December), dollars and volumes can be estimated using a 50:50 expenditure split.

All financial figures quoted within this document (unless otherwise stated) are direct unescalated (excluding overheads) dollars of December 2019.

Total values shown in tables and referred to in the text of this document may not reconcile due to rounding.

1.5. Document Review

The SAMP is reviewed and approved at a minimum every five years or when changes are required. The review integrates risk management activities and the budgeting process with external influencing factors such as demand and networks growth, technology and regulatory requirements.

[1] As at 1 July 2020 Gas Distribution Code SA (Issue No. GDC/07)

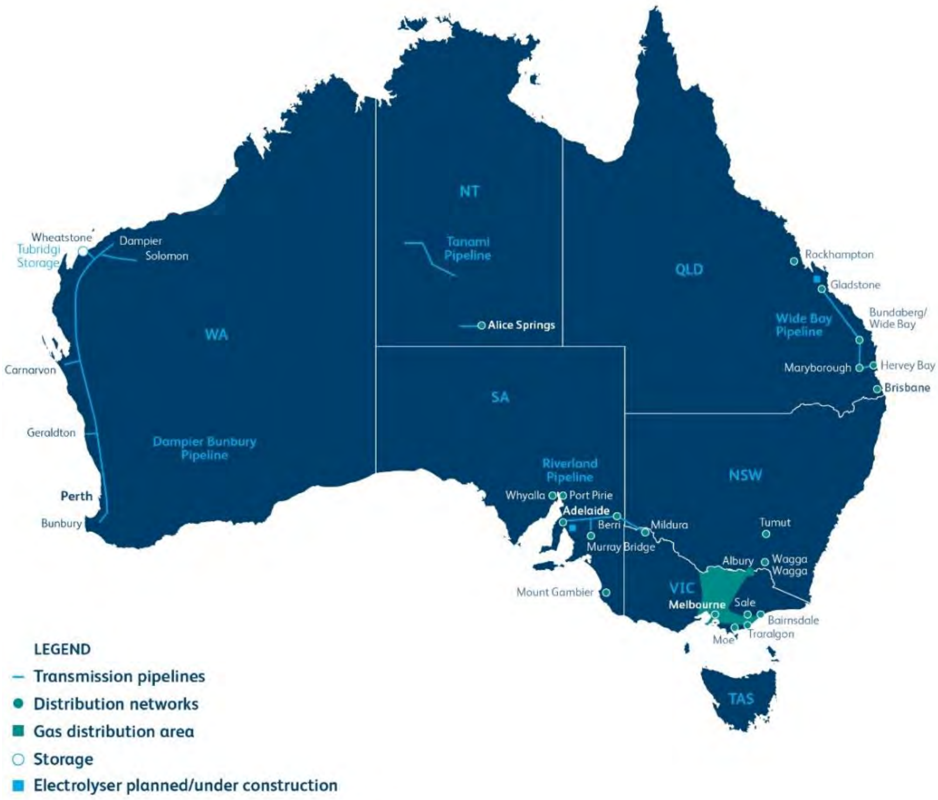
2. Australian Gas Networks

2.1. About AGN

AGN is a gas distributor who supplies gas to over 1.3 million residential, commercial and industrial customers across South Australian, Victoria, Queensland (mostly Brisbane) as well as smaller towns in New South Wales (Albury, Wagga Wagga) and the Northern Territory (Alice Springs). The network includes over 1,300 km of transmission pipelines and 24,000 km of distribution mains.

AGN forms part of Australian Gas Infrastructure Group (AGIG)[2] which is one of the largest gas infrastructure businesses in Australia.

Figure 2.1: AGIG Operations



In South Australia, our network supplies gas to more than 450,000 end users through a network of more than 8,000 km of distribution mains, and 200 km of transmission pipelines. Our South Australian operations also manages our smaller non-regulated networks in the Northern Territory and Mildura (Victoria).

[2] AGIG also includes Dampier Bunbury Pipeline (DBP), WA's key gas transmission pipeline which transports gas to mining, industrial, commercial and residential customers across Western Australia as well as Multinet Gas Networks, a gas distributor delivering gas to over 710,000 customers throughout Melbourne's inner and outer east, the Yarra ranges and South Gippsland in Victoria

2.1.1. Vision

Our vision to be the leading gas infrastructure business in Australia, outlined in Figure 2.2, is shared by all of our networks.

Figure 2.2: AGIG Vision

2.1.2. Values

Our corporate values drive the culture at AGIG (including AGN) by determining how employees should behave and make decisions. Our corporate values of "Respect", "Trust", "Perform" and "One Team" are highlighted in Figure 2.3.

Figure 2.3: AGIG Values

2.2. Key Stakeholders

This SAMP is required to address the requirements of key stakeholders that have an interest in the management of AGN's assets in SA.

Table 2.1: Key Stakeholders

Organisation	Role
AGN	Network Owner
APA	Network Operator
Australian Energy Market Operator (AEMO)	Market operator of gas network in SA and Victoria.
Office of the Technical Regulator (OTR) Energy Safe Victoria (ESV)	Technical Regulator of the SA (OTR) and Mildura (ESV) network assets
Australian Energy Regulator (AER)	Economic Regulator of the SA regulated network
Gas retailers and end users	Users of services provided by the assets
Department of Mines and Energy (DEM) (SA) Department of Environment Land Water and Planning (DELWP) (Vic) Department of Primary Industries and Resources (DPIR) (NT)	Provision, administration of Transmission pipeline licenses in SA, Mildura and NT.
Essential Services Commission of South Australia (ESCOSA) Essential Services Commission of Victoria (ESCV)	Provision, administration and enforcement of energy distribution licenses and oversight of the security and reliability of the SA and Mildura networks
Energy and Water Ombudsman Victoria (EWOV) Energy and Water Ombudsman SA (EWOSA)	Customer complaint resolution management in Vic and SA.

The key asset management requirements of each stakeholder are summarised as follows:

- AGN - as asset owner, requires that APA adopts appropriate asset management practices based on regulatory obligations, accepted industry codes and standards, and that are consistent with those of a prudent and efficient network operator. AGN undertakes to manage the network assets in a safe, efficient and economic manner in partnership with its network operator;
- APA - as day-to-day operator and manager of the network assets, is expected to ensure that AGN's requirements as described above are fulfilled. APA is responsible for all aspects of the operation and management of the networks in accordance with the licenses, regulatory requirements and applicable industry standards;
- AEMO – as the market operator, they require the timely and accurate provision of metering data and heating values required for market settlement.
- OTR / ESV – as the technical regulators, they require compliance with legislative and industry standards as they apply to the safe operation of the networks;
- AER - requires economically efficient operating costs and provides oversight such that network charges are reflective of prudent capital investment and comply with the National Gas Rules (NGR) and National Energy Retail Rules (NERR);

- Gas retailers and customers – require provision of a safe, secure and reliable supply of gas at a reasonable cost. Cost of supply should include a high level of service delivery and quick response to gas supply problems and associated issues; and
- DEM / DELWP / DPIR – provide provision and administration of our transmission pipeline licenses in SA, Mildura and NT. Requires alignment and compliance with AS 2885.
- EWOV / EWOSA – requires prompt response and resolution to end customer complaints.
- ESCOSA / ESCV - regulate AGN's gas distribution operations in SA and Mildura through the provision, administration and enforcement of a licensing regime, which is supported by industry codes that contain SA or Victorian (as applicable) specific requirements that are in addition to the national regulatory framework.

2.3. Key Corporate Policies

Table 2.2 shows the corporate policies of AGN and APA that provide context and inform the asset management vision, objectives, processes and performance requirements of our assets.

Table 2.2: Guiding Corporate Policies and Plans

	Policy / Plan	Document Number
AGN	Compliance Policy	AGIG-POL-Compliance
	Zero HARM Principles	AGIG-POL-HSE-0005
	Health and Safety Policy	AGIG-POL-HSE-0001
	Environment Policy	AGIG-POL-HSE-0002
	Statement of Commitment	AGIG-POL-HSE-0004
	Risk Management Policy	AGIG-POL-Risk Management Policy
APA	Asset Management Policy	APA POL Asset Management
	Economic Regulation Compliance Policy	APA POL Economic Regulation Compliance
	Health Safety and Environment Policy	APA HSE POL 001
	HSE Non-Negotiables Policy	APA HSE POL 005
	Information and Records Management Policy	APA POL Information and Records Management
	Procurement Policy	APA POL Procurement
	Risk Management Policy	APA POL Risk Management
	Risk Management System	132-FW-R-0001
	Engineering and technical policies, procedures and standards	-

2.4. Operating Licenses

2.4.1. Gas Distribution License - SA

Our South Australian distribution system is as defined in its Gas Distribution Licence, issued by the ESCOSA under section 19 of the *Gas Act 1997*. Our gas distribution licence was originally issued on 16 September 1998 and is amended from time to time.

The license has several key compliance conditions including the obligations to:

- Comply with the requirements under the *Gas Act 1997* and the *National Gas (South* Australia) Act 2008;
- Comply with applicable codes or rules made under the *Essential Services Commission Act 2002*;
- Prepare, revise and maintain a Safety, reliability, maintenance and technical management plans (SRMTMP), and have this approved by the OTR;
- Comply with customer-related standards and procedures; and
- Comply with other applicable codes, standards, rules and guidelines specified by the Commission.

2.4.2. Gas Distribution License - Mildura

Our Mildura network is as defined in its Gas Distribution Licence, issued by the ESCV under section 48E of the *Gas Industry Act 1994*. AGN's gas distribution license was originally issued on 28 October 1999 and is amended from time to time.

The license has several key compliance conditions including the obligations to:

- Comply with the requirements under the *Gas Industry Act 1994*;
- Prepare, revise and maintain a Safety Case and have this approved by the ESV;
- Comply with customer-related standards and procedures; and
- Comply with other applicable codes, standards, rules and guidelines specified by the Commission.

2.4.3. Transmission Pipeline Licenses

Our transmission pipelines, as defined in Section 5.3, are licensed in accordance with the requirements of the:

- *Petroleum and Geothermal Energy Act 2002* in South Australia, administered by Department of Energy and Mining (DEM);
- *Pipelines Act 2005* in Victoria administered by Department of Environment, Land, Water and Planning (DELWP); and
- *Energy Pipelines Act 2015* in the Northern Territory, administered by Department of Primary Industries and Resources (DPIR).

The individual licenses contain details of pipe location and route, length, diameter, maximum allowable operating pressure (MAOP) and material specifications.

2.5. Network Operations

AGN is the holder of the gas transmission and distribution licences for the natural gas assets. We have contracted APT Operation & Maintenance Services (referred to in this document as "APA") to install, operate and maintain our gas infrastructure assets. In doing so APA must comply with all applicable laws and authorisations. APA is responsible for all aspects of the operation and management of our networks in accordance with prudent and accepted industry standards.

APA's operational activities are underpinned by its Health, Safety and Environment (HSE) Policy[3] and Safety Management System "Safeguard", which has been developed to deliver on its HSE commitments, including providing a zero harm work environment.

[3] Refer to APA Health Safety and Environment Policy – APA HSE POL001 and APA HSE Non Negotiables Policy – APA HSE POL 005

3. Asset Management at AGN

Asset Management occurs within the context of our Asset Management Framework (AMF), which delivers a consistent, collaborative and integrated approach to the management of the asset lifecycle to achieve optimum outcomes and ensure efficiency across the network.

This SAMP has been developed as part of the AMF, and provides a summary of the strategies for, and the main issues pertaining to our gas distribution network assets.

3.1. Asset Management Definition

Asset management is an evolving area of business practice which focusses on the assets (broadly defined) held by an organisation.

The Asset Management Council (Australia)[4] defines asset management as, "*The life cycle management of physical assets to achieve the stated outputs of the enterprise*". This definition specifies a focus upon the delivery of a stated capability in which assets play a key role, and in which the business must manage its physical assets commensurate with the business need for that capability. Thus, the definition is concerned with short, medium and long-term considerations from the conception of the asset's need, through its complete operating life, until its disposal phase.

In the AGN context, this means the recognition of the whole lifecycle of all its gas distribution and transmission assets, together with the internal and external factors which influence that lifecycle, and implementation of processes and procedures to:

- Influence and manage asset lifecycles;
- Intervene to prudently and efficiently correct deficiencies; and/or
- Extend asset lives; or
- Replace assets at the end of their lives.

3.2. Asset Management Approach

Our asset management approach is to ensure an optimal balancing of capital and recurrent expenditure, so that maintenance, replacement and augmentation of the gas distribution network, delivers the required level of services at the lowest possible life cycle cost. Gas distribution is capital intensive and so except in the case where outputs are mandated, cost benefit analysis needs to be undertaken in order to assess whether the overall economic value of capital expenditure is positive.

As per rule 79 (3) of the National Gas Rules (NGR), in deciding whether the overall "economic value of capital expenditure is positive", consideration is to be given only to economic value directly accruing to the service provider, gas producers, users and end users". Consistent with this, in assessing the incremental costs we have regard to:

- Direct costs; PLUS
- Allocation of capitalised overheads; PLUS

[4] Asset Management Council website: http://www.amcouncil.com.au/

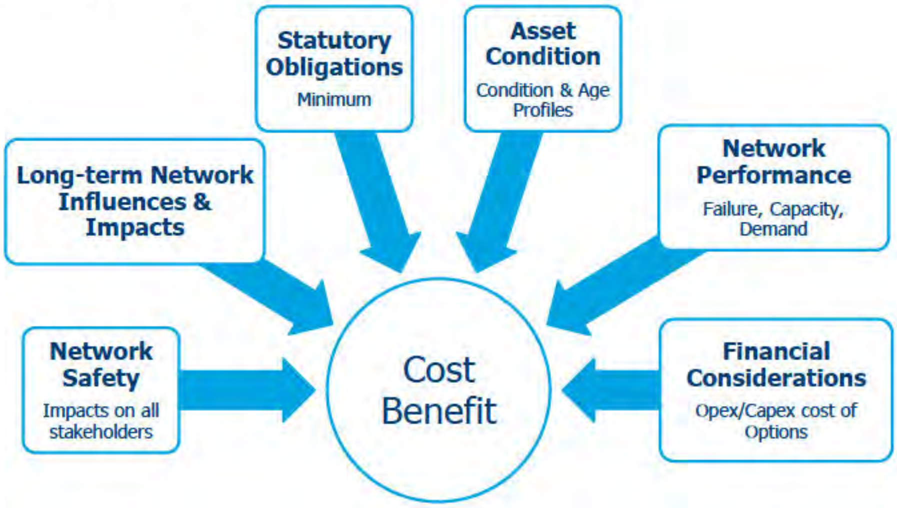
- Imposed costs stemming from the program, which accrue to network users and end customers.

The latter – incremental benefits – has regard to the full societal benefits, which includes:

- Direct benefits to our customers; PLUS
- Additional benefits stemming from the program, which accrue to network users and end customers.

Where the delivery of certain outputs is a function of the external obligations placed upon the business (e.g. legislation stipulating network safety requirements), a different approach is undertaken. Often (but not in every case), we adopt a cost effectiveness (least cost) analysis to ensure that where options exist, the output is delivered at least cost. Delivered benefits are a function of the explicit customer value proposition, or proxy via the adoption of minimum performance standards which are stipulated in legislation or other statutory or regulatory instruments.

Figure 3.1: Cost Benefit Analysis Drivers



In our asset management approach, 'Delivered Benefits' are dependent upon efficient works execution through:

- Efficient construction, maintenance and operation of network assets in accordance with the asset strategies, asset management plan and budget;
- Ensure effective management of programs (inspections, etc.); and
- Effective capturing, management and diagnosis of asset condition and performance data.

3.3. Asset Management Framework

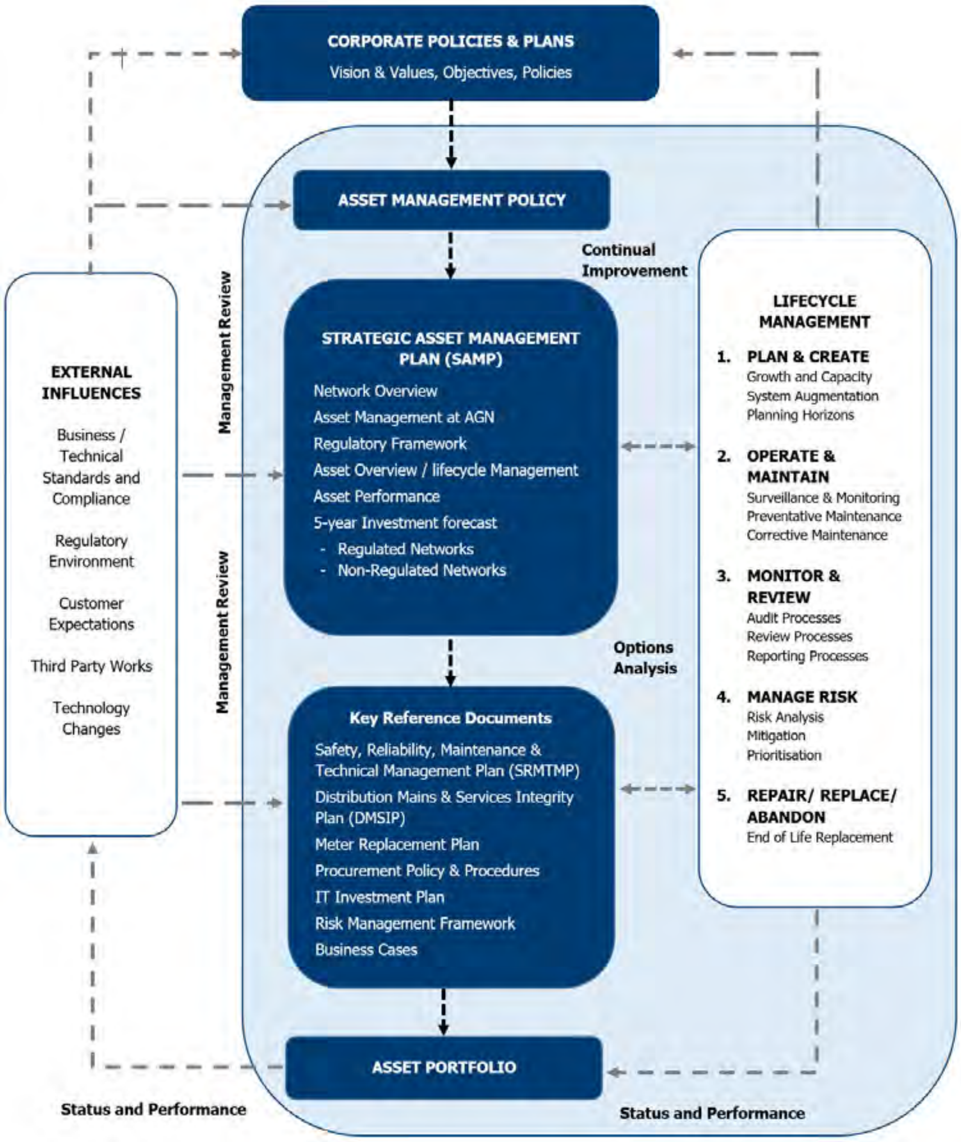
We have adopted an AMF that delivers a consistent, collaborative and integrated approach to the management of the asset lifecycle to achieve optimum outcomes in an efficient way across AGN and APA.

Asset management is a year-round process with two parallel streams:

- Monitoring asset performance and condition, and implementation of the previous year's asset projects and programs of work; and
- Review of asset issues, quantifying risks, development of technical solutions, budgeting, and securing approvals for proposed programs of work.

The SAMP is a key asset management document within this framework. As indicated in Figure 3.2 below, the SAMP is informed by the five (5) asset lifecycle processes. From these processes, the required capital programs needed to achieve the long-term objectives of the various asset classes are derived.

Figure 3.2: Asset Management Framework



3.4. Asset Management Policy

The Asset Management Policy supports the efficient and effective delivery of value underpinned by the implementation of the AMF which is utilised to develop strategic initiatives aligned to our vision and values, enabling effective Asset Management of our network assets.

APA, as the asset operator, establishes strategic initiatives that collectively enable Asset Management of our assets to balance risk, cost and performance to deliver maximum long term value.

As part of the Asset Management Policy, we adhere to the following:

- We maintain appropriate safety protocols at our assets to ensure our people remain safe and our assets operate safely;
- We take a long term focus on our assets - we will not compromise short term gain for long term detriment of an asset;
- We balance risk, cost and performance when allocating resourcing;
- We meet the commitments we make to regulators, employees and stakeholders; and
- We will not compromise our reputation in making asset decisions.

This Policy and associated AMF are based on ISO 55000 – Asset Management Fundamentals, which are:

- *Value*: Assets exist to provide value to the organisation and its stakeholders;
- *Alignment*: Asset management translates the organisational objectives into technical and financial decisions, plans and activities;
- *Leadership*: Leadership and workplace culture are determinants of realisation of value; and
- *Assurance*: Asset management assures that assets will fulfil their required purpose.

3.5. Asset Objectives

We align to six (6) asset objectives which are link to our vision and underpin our asset management practices. By achieving these objectives, we deliver for our customers, remain a good employer and are sustainably cost efficient.

Operate and invest in our assets to keep the public and our employees safe

We will achieve this by:

- Investing in and operating our network in line with our Gas Safety Case, zero harm principle and all laws and relevant industry standards;
- Managing known risks to as low as reasonably practicable (ALARP); and
- Meeting emergency response Key Performance Indicators (KPIs) (call centre, high priority leaks).

Maintain continuity of supply to our customers

We will achieve this by:

- Meeting network availability KPIs;
- Maintaining operating pressures through monitoring and augmenting our network; and
- Addressing leaks in line with our leak management plan.

***Improve our customers' service** experience in line with their expectations*

We will do this by:

- Maintaining accuracy of metering assets within relevant industry standards;
- Delivering valued services to customers at the lowest sustainable price; and
- Meeting customer KPIs (reliability/outages, safety, complaints, and overall customer satisfaction).

Balance network performance and costs to deliver affordable services

We will do this by:

- Optimising overall asset lifecycle management costs;
- Maintaining operating efficiency without compromising safety and reliability;
- Developing investment plans that consider stakeholder expectations; and
- Leveraging people, data and technology to deliver continuous improvement.

Promote gas usage to ensure the networks remain sustainable

We will achieve this by:

- Connecting new greenfield expansion projects in a timely manner;
- Enabling new urban infill connections;
- Engaging with key stakeholders to develop adequate network solutions for future supply options;
- Increasing long term competitiveness of networks through higher asset utilisation; and
- Promoting use of gas.

Embrace innovation and work towards net-zero emissions

We will achieve this by:

- Considering alternative innovative, sustainable and/or lower long-term cost solutions in our investment decisions;
- Pursuing research and development opportunities where they facilitate us to meet our vision and objectives; and
- Supporting the decarbonisation of our gas supplies and the move to smarter gas networks.

3.6. Asset Management Drivers

The following influence the Asset Management approaches and processes employed:

- Corporate Policies and Plans: The corporate policies listed in Section 2.3 provide direction and guidance for the AMF and processes;
- Safety: Ensuring the safety of the workforce and the community is a primary driver for our asset management activities. Our gas distribution network carries the inherent safety risks associated with transporting natural gas. Any leak can pose a safety risk; however, the greatest risk occurs where mains break or crack, releasing gas into (or beneath) a building where it may collect, be ignited and cause an explosion.

  Asset management activities are designed to increase the likelihood of leaks being detected and repair before they can pose a threat to public safety. A key indicator of asset condition can be age. However, asset condition is also heavily dependent on the material, location, and conditions under which the pipe was laid.

  We prepare a SRMTMP as part of our regulatory framework, applied to our SA gas networks. The SRMTMP includes work, health and safety (WHS) issues and issues relating to technical standards, operation, maintenance and emergency procedures and management practices with continuing review and improvement.

  The SRMTMP describes how we will comply with the requirements of legislation as well as relevant standards and codes. These standards and codes form the technical framework for ensuring high levels of safety and reliability in the operation of our gas distribution network. It provides a mechanism to compare safety and reliability expectations with actual performance. It also provides an auditable quality approach to safety

  Like the SRMTMP, we prepare a Safety Case for our Victorian networks, inclusive of the Mildura Network. The Safety Case is required under the Gas Safety Act 1997, prepared in line with the Gas Safety Regulations 2018 and is accepted by Energy Safe Victoria (ESV).
- Network Growth: On-going growth drives expansion of the network into new areas and includes additional mains and pressure control facilities to augment network capacity. New connections are made to the network every year giving rise to additional network mains, services and meters. Drivers for new residential connections include population and associated housing growth, interest rates, and building codes for homes. The primary driver for new industrial and commercial connections is delivered energy cost compared to the nearest alternative;
- Customer Consumption: Residential consumption drivers include weather, retail gas price, microeconomic factors, appliance efficiency and alternative energy appliances. Drivers for commercial and industrial consumption include the retail gas price, micro- and macro-economic factors, and appliance efficiency;
- Asset Useful Life: The useful service life of an asset is the period during which it is expected to be usable for the purpose it was acquired/designed. The term applies to:
  - Actual physical life, where beyond this it is not possible to continue operations, or
  - Economic life, where the cost of repair and maintenance becomes greater than the cost of replacement.

  Within gas networks, assets such as distribution mains and services have very long useful lives (50-60 years), whereas SCADA assets have shorter lives (5-10 years) due to technology improvements and obsolescence;

- Asset Condition: The overall condition of the asset has a bearing on risks that might be apparent as it ages and degrades over time. For example, a major cost component for us relates to locating and repairing leaks associated with old Cast Iron (CI) and unprotected Steel (UPS) mains. As these mains age, increasing expenditure is necessary to repair an increasing frequency of leaks. There is a point where it is more economically viable to replace a main than it is to continue repairing it. Our CI/UPS mains replacement program enables us to mitigate the risk associated with CI/UPS leaks in a sustainably cost-efficient manner;
- Security of Supply: Gas networks are typically a complex series of interconnected pipes that generally provide more than one gas supply path to any customer within the network. Network design for extensions, alterations, augmentation and replacement considers scenarios where a single point of failure could result in significant number of customers losing supply. These scenarios are evaluated based on cost and risk, with additional mains, regulators and surveillance equipment installed where considered appropriate;
- Economic Regulatory Frameworks: The economic regulatory requirements of the NGL and NGR impose obligations on us to incur the expenditure in a prudent and efficient manner as well as in accordance with good industry practice; it also requires that the expenditure must be justifiable;[5]
- Technical Regulatory Frameworks:
  - Require compliance with the governing Australian Standards, AS 4645 for distribution networks and AS 2885 for transmission pipelines, and
  - influence items such as periodic replacement of gas meters, in line with the requirements of the SA Gas Metering Code[6] and AS/NZS 4944:2006 Gas meters - In-service Compliance Testing, which in turn gives rise to an ongoing meter replacement program;
- Third Party Works: Capital works programs by other utilities, local government, road and rail authorities require that from time to time, gas mains be moved, modified and/or replaced. The cost of such works is recovered from the requesting authority.
- Changing Technology: New technology often brings with it significant improvements in functionality and reduced maintenance costs. However, asset management strategies must also consider the implications for older equipment that may become unsupported and therefore obsolete before the end of their intended service lives.

  An example is the evolution of AS 2885 to require a more definitive knowledge of the condition of transmission pipelines. The safety requirements of AS 2885 are now such that pipeline owners are requiring all pipelines to have In-Line Inspections (ILI also referred to as "pigging") to definitively determine corrosion and wall thickness loss rather than previously accepted methods of DCVG[7] surveys and other external inspections. This includes pipelines (generally older in age) that were not designed to be piggable. We are planning to commence an ILI program in the next AA period.

  Changes in technology also influence gas demand, where energy efficient technologies and other energy sources such as renewables become more competitive, which often results in a slowing of demand growth.

[5] National Gas Rules, Version 48, Clause 79 (1) & (2)

[6] Essential Services Commission of South Australian Gas Metering Code, GMC/04 February 2013, GMC/05 from 1 July 2020

[7] Direct Current Voltage Gradient

- Decarbonisation of Networks: One very significant change being faced by AGN and all gas distribution businesses in Australia is climate change. Australia is part to global imperatives, strategies and agreements which seek to limit the effect of climate change by moving away from fossil fuels, of which natural gas is one, to renewable and less emission intense energy sources. The long-term view is that the use of natural gas may be supplanted by renewable energy sources such as wind and solar and related technologies such as battery storage.

  AGN is knowledgeable and understanding of these major global and local trends, but is also aware that gas distribution systems carry more end-use energy than the electricity distribution networks. To completely supplant natural gas with renewable based electricity will require prohibitively large investments (doubling or more) in the electricity distribution networks.

  As part of AGIG, we participant in the gas industry's Gas Vision 2050, which in part seeks to "decarbonise" gas distribution networks away from carbon based fuels to more environmentally sustainable energy sources. We have a long term strategy to convert our gas distribution networks to a more renewal basis, actively considering fuels such as hydrogen and bio-gas.[8] We believe we are at the forefront of this strategic shift in the industry with our HyP SA project, which will inject a blend of natural gas and hydrogen into the distribution network in the suburb of Mitchell Park[9].

  Conversion of the distribution systems to these types of fuels will have implications for the management of network assets. We are commencing programs to assess the impact of renewable fuels on the various gas distribution network assets. Longer term there may be work programs and capital expenditure implications for asset management programs to prepare networks for these fuels of the future. An example is the replacement of CI and UPS mains with Polyethylene material, while undertaken for other reasons, will render the networks suitable for future hydrogen conversion.

3.7. Lifecycle Management of Assets

We deploy our AMF through five (5) major processes, which reflect the lifecycle of an asset from creation to disposal/abandonment:

1. Plan and Create;
2. Operate and Maintain;
3. Monitor and Review;
4. Manage Risk; and
5. Repair / Replace / Abandon.

[8] The future of natural gas | Australian Gas Networks

[9] Hydrogen Park SA | AGIG

3.7.1. Plan and Create

Planning and creation considers current and future customer growth and load demands, asset performance and service needs, and secures the necessary approvals for expenditure. It includes the creation of new assets to:

- Extend the mains network (either small extensions to connect new domestic customers or large extensions to service new step-out developments such as new estates or extension to unserviced areas);
- Provide new network, metering and SCADA facilities; and
- Augment the existing assets as capacity limitations are reached due to demand growth.

Planning Horizons

We use a rolling 10-year plan for assets. Year one (1) of the plan represents firm requirements for the next budget year, while subsequent year forecasts are indicative reflecting forecast connections, growth and utilisation rates, network performance and condition.

- Mains replacement planning is based on an assessment of risk, performance and condition/integrity;
- Mains extension analyses, including extending mains to new estates or major industrial customers, is based on cost-benefit modelling using a planning horizon applicable to each case; and
- Major network augmentation projects are evaluated using a horizon consistent with the reliability of forecast information.

As an example, our risk-based approach has improved efficiency through prioritising the criticality and urgency of the mains replacement program. In addition we implemented a method of inline camera inspection on HDPE 575 DN50 pipe to find squeeze offs and install reinforcements on them.

Key Financial Controls

Network asset creation is subject to the following financial controls, which ensure that creation of assets only occurs in accordance within established prudent approval processes:

1. All domestic mains extensions, Industrial & Commercial (I&C) connections are evaluated using a Net Present Value (NPV) model, while mains replacement projects are evaluated on a risk-based approach;
2. All capital expenditure projects are subject to a formal business case/justification requiring management approval, and in the case of growth projects, a standard financial model;
3. A defined delegation of authority is in place to determine the approval requirements (by either APA or AGN) for all projects; and
4. APA reports to us monthly on progress against capital budget and schedule for major capital projects.

3.7.2. Operate and Maintain (O&M)

Our approach to network operation and maintenance is detailed in the SRMTMP. Operation and Maintenance involves three principal sub-processes:

1. Surveillance & Monitoring.
2. Preventative Maintenance; and
3. Corrective Maintenance.

Maintenance of assets is undertaken to ensure that they continue to fulfil their intended functions (performance levels) within their expected lifetime. Maintenance processes and frequencies take into account:

- Asset type, age, history and risk of failure;
- Location and operating environment;
- Manufacturer's recommendations;
- Condition monitoring;
- Australian Standards requirements; and
- Good industry practice.

Operating Manuals, Procedures, Plans and Technical Instructions describe minimum requirements for the maintenance and condition monitoring of network assets. They detail the frequency and scope of work to be carried out and are used in conjunction with relevant codes of practice and equipment manufacturers' instructions.

Operation & Maintenance practices are audited from time to time by external auditors and the OTR. Regional licensed pipelines and networks are regularly audited APA, the OTR or ourselves for compliance with the licence conditions and AS2885.3 and AS4564 requirements.

Surveillance and Monitoring

The aim of surveillance is for early detection of an issue or failure, to allow for timely dissemination of information for corrective actions to be taken. Monitoring involves the intermittent analysis of routine measurements (e.g., monitoring cathodic protection readings) and observations to detect changes in the environment or status of an asset.

Table 3.1 outlines activities undertaken for surveillance and monitoring.

Table 3.1: Activities Undertaken for Surveillance and Monitoring

Process	Activities
Surveillance and Monitoring	Telemetry pressure point and demand customer monitoring
	Cathodic protection Monitoring
	Coating survey, Leak survey
	Odorant and gas quality monitoring
	Pipeline patrol and inspection
	Special crossing inspections
	Camera Inspection
	Inline Inspection (ILI)

An example of the effectiveness of these activities is the identification of third party damage on our transmission pipeline on Exeter Terrace by the DCVG coating survey. The pipe has been repaired by installing a sleeve at each damaged location.

Preventative Maintenance

Preventative Maintenance is planned maintenance that prolongs the lifespan of our assets, and equipment. PM is a systemic approach of maintenance activities that are performed routinely and aimed at reducing and preventing failures. Surveillance and condition monitoring play a key role in identifying the PM activities and frequencies.

Table 3.2 outlines activities undertaken for Preventative Maintenance.

Table 3.2: Activities Undertaken for Preventative Maintenance

Process	Activities
Preventative Maintenance	Cathodic protection maintenance
	Meter maintenance (I&C)
	Network Facility Installations
	Telemetry System maintenance
	Regulators and Valves maintenance
	Reinforcement at squeeze off points

Corrective Maintenance

Corrective Maintenance (CM) are maintenance activities are performed in order to rectify and repair issues/ failures on our assets. Unlike Preventative Maintenance, CM activities can be planned and/or unplanned and aim at repairing failures.

Table 3.3 outlines activities undertaken for Corrective Maintenance.

Table 3.3: Activities Undertaken for Corrective Maintenance

Process	Activities
Corrective Maintenance	Repairing leaks and third party damage
	Repairing cathodic protection system faults
	Repairing pipe coating failures/faults
	Clearing water ingress and other blockages
	Telemetry system faults
	Fault finding on network facility installations
	Resolving meter problems / failures
	Reinforcement at leaking squeeze off points
	Resolving supply issues

3.7.3. Monitor and Review

All gas distribution assets are continually monitored to review their performance and maintain integrity in line with accepted standards of operation.

Performance aspects include the ability to provide the required capacity to meet customer demands for gas, delivered at required flow rates and pressures.

Assets are monitored to highlight existing and emerging issues related to normal aging over time, accelerated aging or new risk issues.

Operational data is collected on a continuous basis, with programs in place to monitor trends and identify emerging issues. Following risk analysis, new or changed operational procedures are implemented, or capital projects/programs generated.

Audit Processes

Auditing ensures that all activities and processes comply with required industry standards. The results of both internal and external auditing are reported to management.

Key internal audits include:

- Supervisor monitoring audits - To ensure field activities are performed in accordance with internal requirements and relevant legislation;
- Verification audits - Conducted by trained quality and safety auditors, under a certified ISO 9001 management system, independent to the operating function. The purpose of these audits is to verify that audits of task related activities provide credible and consistent results;
- Technical facility audits - Performed by trained quality and safety auditors under an ISO 9001 management system, since the level of exposure of the business tends to be greater with critical gas facilities. Findings from these audits are reported to management through detailed reports; and
- HSE Management system audits - provide evidence that the APA HSE system is effective. These audits are conducted by trained safety auditors and reported to management through reports.

Key external audits include:

- AGN audits - Performed on an "as required" basis to provide confidence that APA is conducting their operational function with due diligence and in compliance with our requirements. The results of these audits are communicated to the APA management team.
- Regulatory audits - Conducted by regulators as a means of ensuring that activities performed conform to legislative requirements. Audit results form an important input to management improvement processes.
- Safety Plan audits – external auditors may be engaged to conduct audits on particular aspects of safety or operating plans.

Review Processes

Formal and informal reviews undertaken throughout the organisation form a vital input into the planning and management processes. The following outline key areas used to assist in planning and management decision making:

- Asset Condition and KPIs - Asset KPIs detailed in Section 6.2 are the primary measures of asset performance, condition and integrity. These are reviewed on a monthly basis in the APA monthly operating and management report and annually through the Distribution System Performance Review (DSPR).
- Skills and Competencies - Skills and competencies of staff and contractors are viewed as critical in the effective management of the assets. Activities in the business have been assessed for risk, and where ranked as critical, are managed through a robust method of individual certification. Critical activities may only be performed by operators who can demonstrate their competence to nationally registered assessors and have been issued with an 'authorisation to operate'. These critical skills are reassessed every two years to ensure competence is maintained and to provide an opportunity to assess the effectiveness of training.

Reporting Processes

Business reporting is largely hierarchical in nature with the key principal of ensuring that the business is meeting its goals and objectives. Reports may be categorised as compliance reports, operational reports, exception reports and financial reports. In general, the vertical reporting structure has the following levels:

- Corporate governance compliance report is a high level acknowledgement that activities and functions provided by the business conform to all legislative and industry expectations. The report is produced six-monthly for AGN's Board and Risk and Compliance Committee;
- The AGN operational report is produced monthly and draws together key operating criteria, system performance, HSE performance, financial measures, internal and external audits, and other predictive measures into a single, extensive document;
- Departmental reports are produced monthly for the General Manager, APA and provide key operational performance information and HSE performance;
- Section reports are also produced monthly and keep departmental managers informed of the activities under their control;
- HSE committee reports are produced by each operating unit to keep all staff informed of the issues that affect their area of operation and control;
- In some situations, the vertical reporting structure is augmented by horizontal reporting methods. Examples of such reporting include hazard alerts, technical bulletins, management presentations, emails and notice boards;
- Budget planning and monitoring is undertaken to ensure planned work is delivered efficiently and within economic constraints. Detailed budgets are prepared annually and monitored on a monthly basis; and

- Regulatory Reporting – Annual reports covering the financial year are submitted to the OTR and the ESCOSA in accordance with the Gas Regulatory Information Requirements – Distribution System Gas Industry Guideline No.1 and the Gas Distribution Code. The guideline and Code prescribes various operational reports:
  - Major Interruptions;
  - Statistical Information;
  - Technical Information;
  - Key performance indicators;
  - Unaccounted for Gas (UAFG); and
  - Mains replacement progress.

  The Mildura networks is included in quarterly and annual regulatory reporting requirements to ESV as required by the *Information Specification – Performance Indicators: Requirements for Reporting by Victorian Gas Distribution Companies (January 2009)*

3.7.4. Manage Risk

We recognise risk management as an integral part of our operations and strategic planning. Risk management, including risk identification, evaluation, treatment and documentation, is undertaken in a systematic manner to comply with ISO 31000.

There is an inherent risk associated with gas mains and services. Whenever a gas main leaks, cracks, or breaks there is the potential for the community and employees to be seriously injured, or for supply to be disrupted. The risk can vary depending on the location, material type, pressure and age of each gas main or service inlet. We review the performance indicators of mains to assess the potential risk associated with deterioration in condition.

We have an ongoing process for systematic identification, analysis, assessment, treatment, monitoring and communication of all credible risks associated with conveyance of gas across the network as well as regulatory compliance and construction and maintenance activities. Risk assessments are regularly updated to reflect new information on asset condition, and the consequent risk rating guides the actions and activities that ensure network safety and compliance is maintained as efficiently and effectively as possible.

The risk management process undertaken is in accordance with the APA Risk Management Policy and Risk Management System. All network assets are regularly assessed for a range of identified risks. Following identification mitigations are implemented to reduce the risks in accordance with the risk management policy. This results in projects which are proposed, approved and regularly tracked to completion, or operational activities which are placed into operational and maintenance work management systems.

The change in treatment of Multiuser sites (MUS) is an example of how we have improved controls over replacement activities. We have found continuing the replacement of all MUS in the current AA period is not prudent as a number of these MUS are of lower risk category. We have further categorised MUS in priority groups based on their associated risk rating of High, Intermediate or Low. Following re-assessment of the risk and associated prioritisation of these assets. We will replace the priority group 1 MUS first in the current and next AA period. This has decreased the total number of MUS for replacement to 457. Additional leak surveys and education campaigns will support the management of priority group 2 MUS to ALARP.

3.7.5. Repair / Replace / Abandon

Repair

Repairs to assets are necessary when they fail to perform the function for which they were created. This can be due to either part failures, third party intervention or age. Typically, parts failures occur on network facilities and SCADA assets, while repairs are necessary on mains and services as a result of third party interventions (damage from excavations by others etc) or asset deterioration.

Repair of leaks on mains and services is one of APA's primary work activities. AGN, APA and the technical regulators in each state closely monitor leak occurrence and repair data, including time to respond to leak reports and repair time for leaks.

Replacement

Assets that are approaching the end of their useful service life, or those that experience accelerated deterioration, are identified for replacement. Where feasible (and safe to do so), refurbishment is considered as an option to extend the asset's useful life. The option to replace or refurbish is typically considered as part of the business case process.

The asset replacement decision is driven by the prudent balance between avoiding future costs of maintenance, current replacement cost, risk, regulatory compliance and levels of service. Where replacement is identified as the prudent option, the asset replacement program takes into account the efficient allocation of resources.

In general, useful service lives vary from:

- 5 to 10 years for SCADA assets, which are particularly sensitive to technical obsolescence;
- 10 to 20 years for domestic and I&C meters; and
- 50 to 60 years for distribution mains and services.

Abandonment

Where an asset has reached the end of its useful life (and cannot be refurbished), it is decommissioned. Like the commissioning process, our decommissioning process is guided by AS/NZS 4645 (for distribution assets) and AS/NZS 2885 (for transmission assets).

3.8. Capacity Management

Network capacity is managed by:

- monitoring network performance;
- assessing forecast demand; and
- assessing threats to supply.

Network capacity issues are addressed according to the risk they present, and undertaken subject to qualitative and quantitative analysis of costs and benefits. The network requires augmentation when:

- the minimum pressure in a network falls, or is forecast to fall, below the recommended minimum end of main pressure during design load conditions; or
- there is insufficient redundancy within the network, which adversely affects the security of supply to a large number of customers.

The capacity management process involves the following activities:

- Maintaining baseline capacity models – Network configurations within the Geospatial Information System (GIS) are exported into capacity modelling software (Synergi). Network models are validated against actual field conditions using gate station inputs, large volume customer hourly demand, system pressures and derived domestic, commercial and industrial loads. Computer models are iteratively balanced so that modelled pressures match those from the field;
- Design load assessment – Domestic, commercial and small industrial design loads are derived from the validated baseline network load, corrected to allow for additional consumption consistent with a one-in-two probability winter's day. Tariff D[10] customer load is normalized based on variation in consumption during the daily peak hour period throughout winter. In each case the design load is based on a peak hourly load as this is the important parameter for maintaining supply to the network;

  As an example, duplication of the main exiting the Virginia gate station was planned during the current AA period. A much slower I&C growth rate in the Virginia area and a reassessment of the Virginia Gate Station capacity by Epic Energy has deferred the need for a previously planned augmentation of this gate station and duplication of the main into the subsequent AA period.
- Forecasting load growth – a range of sources, including Planning Authority publications, precinct structure plans, publicly available documentation from "forecast.id" and HIA statistics, as well as internal marketing data, are used to forecast the number and location of new residential connections. Market trend analysis is used to determine the rate of new connections for industrial and commercial, and demand market sectors.

  The additional connections are converted to an expected hourly demand within the network to develop an annual load growth profile that is superimposed on the network model to identify future capacity constraints;
- Network scenario modelling – Synergi is used to evaluate various load scenarios and augmentation options. Capacity shortfalls are identified, and solutions modelled to confirm augmentation requirements;
- Mains replacement planning – the output of the mains replacement planning process is combined with capacity and security of supply issues to optimise the location and size of principal supply mains within the network;
- Project initiation – the various capacity, replacement and security of supply issues are reviewed and options considered. These projects are reviewed annually to confirm their timing and scope.

3.9. Related Documents and Data Sources

The following documents and processes in Table 3.4 provide information to, or draw information from, this SAMP.

[10] Tariff D is reserved for the largest connections on the network. Tariff D applies to customers using greater than 10,000 GJ a year or more than 10 GJ MHQ.

Table 3.4: Document/ Processes providing information to or from the SAMP

Document / Process	Document Number
Annual Distribution System Performance Report (SA) (DSPR)	420-RP-AM-0019
Distribution Mains and Services Integrity Plan (SA) (DMSIP)	AGN SA Final Plan - Attachment 8.3
Five yearly Meter Replacement Plan (SA)	AGN SA Final Plan - Attachment 8.4
Annual capital planning and budgeting cycle, and related processes	-
Annual Capital and Operational Work Programs	-
Asset risk capture, assessment and reduction processes	-
Safety Reliability Maintenance and Technical Management Plan (SRMTMP)	420-PL-AM-0001 AGN SA Final Plan – Attachment 8.1
Pipeline Integrity Management Plan (PIMP)	420-PL-L-0001
Pipeline Safety Management Studies (SMS)	Various
Formal Safety Assessment (FSA)	420-PR-AM-0014
Pipeline Remaining Life Reviews (RLR's)	Various

4. Regulatory Frameworks

4.1. Legislation

The key legislation with which we are required to comply is shown in Table 4.1.

The primary legislation of gas distribution networks in South Australia is the *Gas Act 1997*, while the *Petroleum and Geothermal Energy Act 2000* applies to transmission pipelines. The *Essential Services Commission Act 2002* established the ESCOSA, which is responsible for distribution licensing participants in the South Australian gas industry.

We must also comply with relevant legislation in NT and Victoria for our assets in these states.

Table 4.1: Key Legislation

State	Legislation	Description
Federal	National Gas Law (NGL) National Gas Rules (NGR) National Energy Retail Rules (NERR)[11]	Regulation of Wholesale and Retail Gas Markets Access Arrangement Decisions Govern the sale and supply of energy from retailers and distributors to customers
	National Measurement ACT 1960	Legislation for Australia's measurement system that applies to utility meters
	General Laws	E.g. *Corporations Act 2001*
South Australian	*Gas Act 1997*	Industry Specific Regulatory Framework, SA
	Gas Regulations 2012	Industry Specific Regulatory Framework, SA
	Petroleum and Geothermal Act 2000	Regulatory Framework that applies to transmission pipelines in SA
	Petroleum and Geothermal Energy Regulations 2013	Regulatory Framework that applies to transmission pipelines in SA
	Essential Services Commission Act 2002	General framework for regulated industries in SA
Victorian	*Gas Safety Act 1997*	Industry Specific Regulatory Framework Vic
	Gas Safety Regulations 2018	Industry Specific Regulatory Framework Vic
	Gas Industry Act 2001	This Act regulates the Victorian gas industry
	Pipelines Act 2005	Regulatory Framework that applies to transmission pipelines in Victoria
	Pipeline Regulations 2017	Regulatory Framework that applies to transmission pipelines in Victoria
	Essential Service Commission Act 2001	Provides generally for the ESCV's functions and powers

[11] Only applicable in New South Wales, Queensland, South Australia, Tasmania and the Australian Capital Territory

State	Legislation	Description
Northern Territory	*Energy Pipelines Act 1981*	Regulatory Framework that applies to transmission pipelines in NT
	Energy Pipelines Regulations 2001	Regulatory Framework that applies to transmission pipelines in NT
	Dangerous Goods Act 1998	Legislation that sets out the requirements and allowances for licensing, packaging, storage, transportation and use of fuel gas.
	Dangerous Goods Regulations 1985	Legislation that sets out the requirements and allowances for licensing, packaging, storage, transportation and use of fuel gas.

4.2. Regulatory Authorities

The applicable state and national regulator which we work closely with to monitor and discharge our obligations are summarised in Table 4.2.

Table 4.2: Gas Distribution and Transmission Regulators

Regulator	Responsibilities
AER	Regulation of tariffs for reference services
	Governing Third Party Access
	Monitors, investigates and enforces compliance with national energy legislation and rules
AEMO	Market and Transmission Systems operator
ESCOSA	Industry Licencing requirements (Distribution) Gas Distribution Code and Gas Measurement Code in South Australia
OTR	Responsible for monitoring gas safety and other technical matters in South Australia
DEM	Administer transmission pipelines legislation in SA
DELWP	Administer transmission pipelines legislation in Vic
DPIR	Administer transmission pipelines legislation in NT
EWOSA	Responsible for customer complaints and related issues
ESV	Responsible for monitoring gas safety and other technical matters in Victoria
ESCV	Industry Licencing requirements (Distribution) Gas Distribution System Code
EWOV	Responsible for customer complaints and related issues
WorkSafe NT	Responsible for monitoring gas safety and other technical matters in Northern Territory

5. Assets Overview

5.1. Overall Description of Networks

Our gas transmission and distribution assets in South Australia, Northern Territory and Mildura (VIC) are operated by APA.

They comprise assets that are subject to economic regulation under the NGL and thus are subject to an AA administered by the AER (regulated assets), and assets that are not subject to economic regulation under the NGL (unregulated assets).

Table 5.1 provides a high-level summary of these assets, and Appendix A shows an overall map of locations.

Table 5.1: AGN Asset Summary – SA, NT and VIC (Mildura)

Assets	State	Network
Regulated Assets	SA	SA Distribution network – Adelaide metropolitan area and regional towns
Unregulated Assets	SA	Riverland Pipeline System: • Riverland Pipeline • Berri Mildura Pipeline (SA section) • Murray Bridge lateral Angaston Compressor Station
	Vic	Berri Mildura Pipeline (Victorian section), Mildura distribution network
	NT	Palm Valley Pipeline (PVP), Alice Springs distribution network

This SAMP covers the description, high level operational issues of and medium term forecasts for all these assets managed by APA, and is structured between regulated assets and unregulated assets, such that issues and work programs for regulated assets can be readily identified.

5.2. Source of Supply

Natural gas is supplied to our distribution networks in South Australia, Northern Territory and Victoria from the following sources:

South Australian Networks

- From the Moomba via the Moomba to Adelaide Pipeline System (MAPS), owned by Epic Energy, and from 'Queensland to South Australia/New South Wales (QSN) Link' owned by APA;
- From Bass Strait (via Longford and Bassgas), Port Campbell and New South Wales (via the Victorian Northern Interconnect (VNIE)), all transported to Adelaide via the SEA Gas Pipeline, owned by SEA Gas; and
- From South East South Australia (SESA) pipeline owned by APA.

Northern Territory Network

- From the Blacktip gas field, offshore from the Northern Territory via the Amadeus Gas Pipeline (owned by APA), and via the Palm Valley Interconnect (owned by Power and Water Corporation (NT)).

Mildura Network (Victoria)

- From Cooper Basin via the MAPS and Riverland Pipeline System (owned by AGN).

5.3. Asset Groups

The following section provides an overview of the key asset groups and sub-groups that make up our gas distribution networks.

Table 5.2: Assets Groups Overview

Primary Asset Group	Secondary Asset Group	Function Description
Transmission Pipelines	None	Primary supply to HP distribution networks
Distribution Mains and Services	HP Network	MAOP of 420kPa Operating pressures of 250 to 350 kPa Reticulation to domestic, commercial and industrial customers[12]
	MP Network	MAOP up to 140 kPa Operating pressures of 90 to 100 kPa Reticulation to domestic, commercial and industrial customers[13]
	LP Network	MAOP up to 7 kPa Operating pressures of 1.7 to 7 kPa Reticulation to domestic, commercial and industrial customers
	Services	Connection of mains to customer metering facilities
Network Facilities	Gate Regulating Station	Pressure reduction from the upstream TP network (owned by others) into AGN's TP mains network
	Gate Heating Facilities	Control of gas temperature ex gate station pressure regulating facilities
	District Regulator Stations	Pressure reduction from AGN TP network to HP, MP, LP networks
	Emergency Isolation Valves	Mainline and branch valves used to isolate sections of the network
	Cathodic Protection	Corrosion protection for coated steel pipes
	Odorant Facilities	Network odorant injection – maintaining network odorant levels

[12] There are a small number of high pressure trunk mains in regional areas that operate at higher than 350 kPa, including a 600 kPa trunk mains system in Mt Gambier.

[13] There is a small number of medium pressure networks in regional areas that operate at higher than 140 kPa, includes a 200 kPa medium pressure network in Mt Gambier.

Primary Asset Group	Secondary Asset Group	Function Description
Metering Facilities	Custody Transfer Meter	Metering of gas delivered into AGN's network from the upstream pipeline facilities operator
	Domestic Meter	Basic residential customer metering - capacity up to 10 m3/hr
	I&C Meter	Industrial and Commercial metering - less than 10 TJ p.a
	Demand Meter	Industrial and Commercial metering - greater than 10 TJ p.a
SCADA Facilities	Pressure Monitoring & Control	Telemetry monitoring network pressure regulating facilities
	Network Fringe Point Monitoring	Telemetry fringe point pressure monitoring
	Demand Customer Monitoring	Interval (hourly) metering data acquisition at demand metering sites
Compressor Facilities	Compressor Mechanical Compressor Electrical and Instrumentation	Provides increase in pressure at specific locations along transmission pipelines to enable gas demand requirements to be met

5.4. Transmission Pipelines

Transmission pipelines in the gas industry are those which have a maximum allowable operating pressure (MAOP) greater than 1,050 kPa, and which are covered by Australian Standard AS/NZS 2885.

Typically, the bottom end of this range applies to pipelines embedded within metropolitan area or regional township distribution systems (e.g. MAOPs of 1,750 to 2,500 kPa), while MAOPs above this apply to longer distance cross country pipelines at pressures above approximately 2,500 kPa.

Our transmission pipelines are the primary supply to the gas distribution networks and as such are critical to the safe and reliable supply of gas to customers. The consequences of a pipeline failure include potential for serious injuries to the public (gas jet fires) and or loss of supply to tens of thousands of customers.

Our transmission pipelines are designed, constructed, operated and maintained in accordance with AS/NZS 2885. These pipelines are steel, externally coated and cathodically protected with impressed current or galvanic sacrificial anode systems. They have maximum allowable operating pressure ratings ranging from 1,650 kPa up to 9,100 kPa.

Table 5.3 provides details of transmission pipeline lengths within discrete networks and their age profiles.

Table 5.3: Transmission Pipelines as at August 2019

Network / Pipeline		Licence No	Total km	Age Profile years					
				0-10	10-20	20-30	30-40	40-50	50-60
Regulated	Adelaide Metro	NA	193	17	15	10	82	3	65
	Port Pirie	NA	5	-	-	-	5	-	-
	Murray Bridge	NA	4	2			2	-	-
	Berri	NA	10				10	-	-
	Nuriootpa	NA	1			1		-	-
	Tanunda	NA	1	1				-	-
	Total Regulated		215	20	15	11	99	3	65
Unregulated	Riverland	PL 6	224	-	-	224	-	-	-
	Berri to Mildura Pipeline (BMP)	PL 11	148	-	-	148	-	-	-
	Palm Valley Pipeline (PVP)	PL 1(NT)	161	-	-	-	161	-	-
	Total Unregulated		*533*	*0*	*0*	*372*	*161*	*0*	*0*
Total (km)			**748**	**20**	**15**	**383**	**260**	**3**	**65**

5.5. Distribution Mains and Services

Our SA distribution networks (including Mildura and Alice Springs) consist of over 8,400 km of mains and approximately 470,000 services of materials operating at pressures from 1.7 kPa to 350 kPa. These mains and services form the reticulation network that delivers gas to residential, commercial and industrial customers.

Distribution trunk mains operating at high and medium pressure form the backbones of the distribution network, feeding smaller mains and more local areas. The consequences of a failure of these trunk mains include potential for serious injuries to the public and/or loss of supply to several hundreds to several thousands of customers.

Table 5.4 summarises the installed mains as at 30 June 2019.

Table 5.4: Installed Mains 1 July 2019 (km)

Network Pressure	CI	UPS	HDPE 250	HDPE 575	HDPE 100	PE80	PS and copper	Total
Low	373	36	155	48	12	58	15	697
Medium	17	4	125	491	396	1,387	481	2,901
High	-	-	-	765	711	1,926	1,140	4,542
Total regulated (SA)	**390**	**40**	**279**	**1,304**	**1,118**	**3,372**	**1,636**	**8,140**
Mildura and NT - High	-	-	-	-	22	249	44	315
Total unregulated	**-**	**-**	**-**	**-**	**22**	**249**	**44**	**315**

Services comprise the service pipe and fittings with transition from the buried service to the aboveground meter via a metallic service upstand, on which an isolation valve is installed so that supply can be shut off in an emergency. There are around 470,000 services in our South Australian Distribution Network.

Services generally consist of material of the same vintage of the gas main to which they are connected, as they generally were laid together as one project. That is, when cast iron mains were laid, galvanised steel services would have been laid at the same time (and when such mains were replaced with Polyethylene (PE), the associated services were renewed with PE). It is generally assumed that services have the same age of the main to which they are connected.

Multi user sites (MUS) are a combination of services connected to a sub main feeding a number of units/houses within the same property. These are typically located at located at subdivided properties, aged care homes and government housing.

5.6. Network Facilities

The asset subgroups of Network Facilities are shown in Table 5.2 (above) and include gate regulating stations, district regulating stations, heater facilities, isolation valves and ordorisation facilities.

Several of these secondary asset groups have significant effects on gas supply:

- Gate regulator stations, which are the primary supply points for the networks where failure could result in reduced or total loss of supply to tens of thousands of customers;
- Gas heating facilities (usually located at GRS facilities), where failure would have similar effects to failure of GRSs; and
- District regulator stations, which deliver gas into lower pressure networks, where failure could result in reduced or total loss of supply to between hundreds and thousands of customers.

5.6.1. Gate Regulator Stations

These facilities (also known as City Gate Stations) are typically located at the custody transfer points reducing and controlling pressure from the upstream transmission supply pipeline (owned by others) to a level consistent with the MAOP of our downstream pipelines.

Facilities consist of filters, isolation, bypass and pressure control valves and are located in fenced compounds. In some instances they contain gas heating facilities, owned by the upstream gas transmission pipeline business or by AGN (refer Network Facilities below).

The 18 gate stations feeding our distribution networks range in capacity and pressure regulation, based on their location and the size of the downstream distribution network. The consequences of a failure of these gate stations include potential for serious injuries to the public and/or loss of supply to several hundred to several tens of thousands of customers, depending on the network they supply.

Gate stations are typically upgraded or replaced when the growth in demand from the downstream network exceeds their capacity or when components are no longer available to adequately maintain the facility. Table 5.5 summarises gate station locations and the networks they supply.

Table 5.5: Gate Regulator Stations

<table>
<tr><th>Regulatory Status</th><th>Network</th><th>CTM Group</th><th>Location</th><th>Asset Owner</th></tr>
<tr><td rowspan="13">Regulated</td><td rowspan="4">Adelaide Metro</td><td>MAP</td><td>Dry Creek</td><td rowspan="3">Epic Energy</td></tr>
<tr><td>MAP</td><td>Elizabeth</td></tr>
<tr><td>MAP</td><td>Taperoo</td></tr>
<tr><td>SEAGAS</td><td>Dry Creek</td><td>SEAGAS</td></tr>
<tr><td>Angaston</td><td>MAP</td><td>Angaston</td><td rowspan="9">Epic Energy</td></tr>
<tr><td>Freeling</td><td>MAP</td><td>Freeling</td></tr>
<tr><td>Nuriootpa</td><td>MAP</td><td>Nuriootpa</td></tr>
<tr><td>Port Pirie</td><td>MAP</td><td>Port Pirie</td></tr>
<tr><td>Whyalla</td><td>MAP</td><td>Whyalla</td></tr>
<tr><td>Virginia</td><td>MAP</td><td>Virginia</td></tr>
<tr><td>Peterborough</td><td>MAP</td><td>Peterborough</td></tr>
<tr><td>Mount Gambier</td><td>Katnook</td><td>Mount Gambier</td></tr>
<tr><td>Tantanoola</td><td>Katnook</td><td>Tantanoola</td></tr>
<tr><td rowspan="5">Unregulated</td><td>Berri</td><td>Riverland</td><td>Berri</td><td rowspan="5">AGN</td></tr>
<tr><td>Mildura</td><td>Riverland</td><td>Mildura</td></tr>
<tr><td>Murray Bridge</td><td>Riverland</td><td>Murray Bridge</td></tr>
<tr><td rowspan="2">Alice Springs</td><td>Palm Valley</td><td>Alice Springs</td></tr>
<tr><td>Palm Valley</td><td>Norris Belle</td></tr>
</table>

5.6.2. Gas Heating Stations

Gas heaters are often required at GRSs, where large pressure reductions occur. The Joule-Thompson effect of this loss of pressure reduces the temperature of the gas to below acceptable levels, requiring the application of heat to raise it again.

There are five (5) heating facilities within our distribution network as shown in Table 5.6.

Table 5.6: Gas Heating Facilities

Regulatory Status	Location	Gas Heater Type
Regulated	Virginia	Water bath
	Berri	Water bath
Unregulated	Alice Springs	Catalytic
	Mildura	Water bath
	Murray Bridge	Water bath

Water bath heaters use usually gas fired "fire tubes" which are immersed in and heat up a tank of water. The flowing gas stream also passes through this "water bath" in a separate set of tubes, and absorbs heat from the water.

Catalytic heaters use chemical reactions to generate radiant (infrared) energy which is directed at the flowing gas stream, which then absorbs the energy to raise its temperature.

5.6.3. District Regulator Stations

District Regulation Stations (DRSs) control the delivery of gas into the HP, MP, LP distribution networks within the allowable operating pressure of the downstream network. These facilities consist of filters, isolation, bypass and pressure control valves that are located in either below ground vaults (TP) or above ground kiosks (HP, MP).

Various configurations are used with past designs predominately consisting of single stream active-monitor arrangements. A new standard implemented in 2012 has a twin stream design that now provides additional security of supply.

DRSs are typically upgraded or replaced when the growth in demand from the downstream networks exceeds their capacity or when components are no longer available to adequately maintain the facility. Table 5.7 summarises our DRS installations as of August 2019.

Table 5.7: District Regulators

	Outlet Pressure			
Inlet Pressure	**High**	**Medium**	**Low**	**Total**
Transmission	64	27	0	91
High	5	50	44	99
Medium	0	0	65	65
Total	**69**	**77**	**109**	**255**

Of these regulators, there are four in the Mildura unregulated network.

5.6.4. Emergency Isolation Valves

There are about 9,200 emergency isolation valves installed throughout the SA, NT and Mildura networks. These provide emergency isolation and control during normal operation, maintenance and emergency response situations. Table 5.8 summarises the various types of network isolation valves. Of these valves, 111 are contained in unregulated networks.

Table 5.8: Network Isolation Valves

Valve Category	Total
City Isolation	11
Inlet to Pressure Regulator	187
Major Control	2,059
Secondary Isolation	6,932
Total	**9,189**

5.6.5. Cathodic Protection

A network corrosion protection system is used to protect over 1,700 km of steel mains and pipelines. There are 21 impressed current cathodic protection (ICCP) units (13 installed in the SA regulated network) consisting of a transformer rectifier and ground bed and approximately 4,500 sacrificial anodes in the system (circa 2,400 in the SA network).

Many ICCP units are monitored continuously via our SCADA system. ICCP units provide more effective and reliable corrosion protection, particularly in soils with high resistivity, and where high corrosion protection currents are required (e.g. at coating defects). These units can be adjusted to provide the right level of protection (current), compensating for coating defects.

5.7. Metering Facilities

The asset subgroups of Metering Facilities are shown in Table 5.2 (above). Four types of meters are used for domestic, I&C and demand customer metering:

- Diaphragm meters – domestic consumer and smaller I&C customer installations;
- Rotary meters - medium to large I&C customer installations;
- Turbine meters - very large I&C customer installations; and
- Coriolis meters – very large I&C customer installations.

Clause 2.6 of the South Australian Gas Metering Code requires that:

- The net volume of gas delivered to each delivery point is measured to an accuracy of ±2%; and
- There is no systemic bias in metering facilities within the allowable margin of accuracy.

The manufacturer tests all new meters to an accuracy of ±1.0% prior to delivery and installation into our distribution networks.

In accordance with AS/NZS 4944 all diaphragm meters with a capacity up to 25 m^3/hr, installed prior to 2006, are deemed to have an initial field life of 15 years. New meter types (or variants thereof) installed after 2006 are required to undergo compliance testing of a meter family sample within a period of three to five years from installation.

The OTR has agreed to accept this standard on the basis that:

- All new domestic meters must be within ±2.0% accuracy and are deemed to have an initial service life of 10 years; and
- Compliance testing showing accuracy ±1.5% or better may extend the service life to 18 years.

Compliance testing of diaphragm meters also complies with Clause 6.2.2 under AS/NZS 4944 which requires that the maximum number of meters in a meter population that may be installed without further testing is five times the size of the initial population tested.

Historical practice in SA is that all meters with a capacity greater than 10m^3/hr, typically I&C meters, are deemed to have an initial service life of 10 years. This practice is being reviewed for new meters greater than 10m^3/hr and up to 25m^3/hr to determine if an initial service life of 15 years is more applicable.

Figure 5.1 charts the year of installation for our domestic meter fleet. Domestic meters have a technical life of 10 to 18 years.

Figure 5.1: Year of installation – Domestic meters as at May 2019

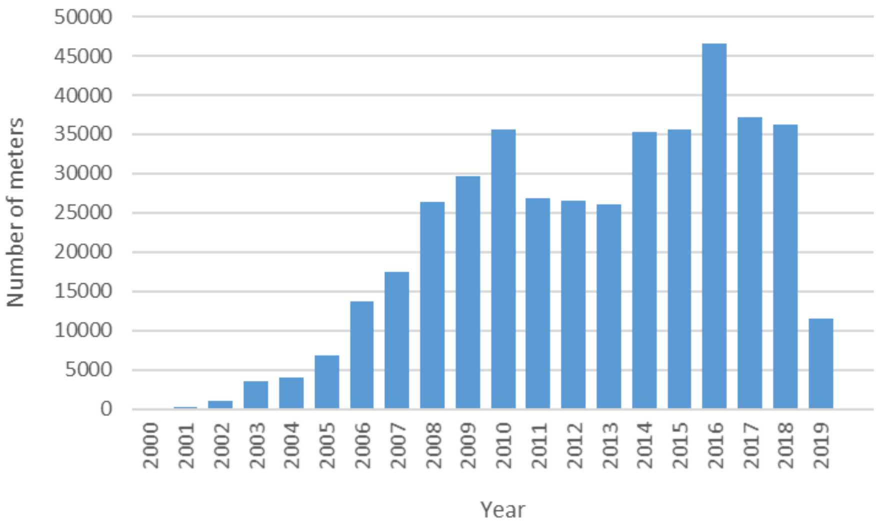
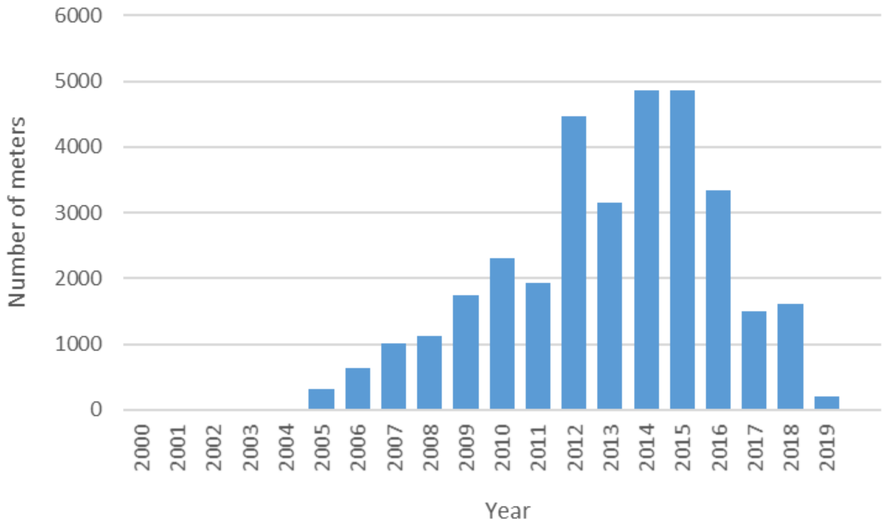


Figure 5.2 charts the year of installation for our I&C meter fleet. I&C meters have a technical life of 10 or 15 years.

Figure 5.2: Year of installation – I&C meters as at May 2019



Approximately 98% of the total meter population is installed in regulated networks.

5.8. SCADA Facilities

Our SCADA system monitors a total of 299 pressure and/or flow sites, which include both regulated and unregulated sites, including:

Regulated sites

- 4 x metropolitan gate stations (Epic Energy & SEA Gas), monitoring pressures and flows;
- 86 x TP to HP DRS monitoring inlet and /or outlet pressures;
- 8 x regional gate stations, monitoring pressures and flows;
- 13 x other critical HP-MP or HP-HP regulators monitoring pressures;
- 35 network fringe point sites that monitor system pressures; and
- 123 x demand customers monitoring pressures and/or flows.

Unregulated sites

- 6 x regional gate stations, monitoring pressures and flows or odorisation levels;
- 8 x other critical TP or HP regulators monitoring pressures;
- 3 network fringe point sites that monitor system pressures;
- 7 x demand customers monitoring pressures and/or flows;
- 5 x offtakes off PVP monitoring pressures and/or flows; and
- 1 x compressor station at Angaston.

Failure of SCADA monitoring to critical facilities such as gate stations and major DRS would result in the inability to detect (and thus respond to) alarms, although the station would continue to operate as designed. This may put at risk gas supply to several hundreds to tens of thousands of customers, depending on the site if a simultaneous fault at the station was undetected.

SCADA failures at fringe point monitoring sites would result in low network pressures not being detected, potentially resulting in poor or no supply to tens through to thousands of customers.

5.9. Compressor Facilities

We own a single gas compressor facility, at Angaston in the Barossa Valley, which is located on the Riverland Pipeline and provides a compression service to the Riverland and Berri-Mildura pipelines. It is a critical asset in maintaining required pressure at the Mildura city gate stations, and thus adequate supply into the reticulation networks in the Mildura area.

A summary of the installed facilities is shown in Table 5.9.

Table 5.9: Angaston Compressor Summary

Item	Value
Inlet Pressure min/max	1,700 / 7,322 kPa
Outlet Pressure – maximum operating	9,525 kPa
MAOP – new compressor unit	10,977 kPa
MAOP – old compressor unit	8,620 kPa
Design life, depending on components	10-30 years
Maximum average flow capacity	13,000 m3/hr

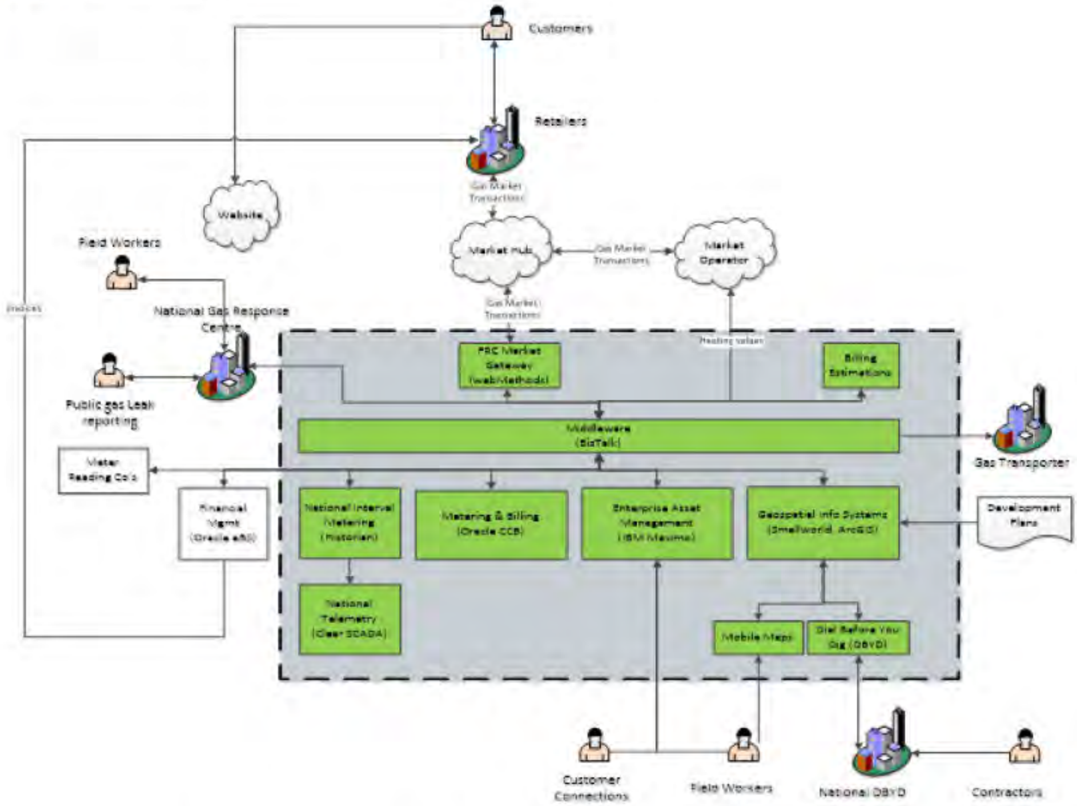
5.10. Information Technology

Our IT systems provide the following functionality to allow us to deliver a safe and reliable supply gas to our customers:

- managing market transactions;
- issuing and controlling field work;
- monitoring and recording gas deliveries to customer sites;
- facilitating emergency response services;
- monitoring network condition;
- analysing network capacity;
- recording the configuration and location of assets;
- providing information to our customers and the community; and
- interacting with our customers.

We operate and maintain a highly integrated IT architecture as shown in Figure 5.3.

Figure 5.3: AGN IT infrastructure



Our key business systems are outlined in Table 5.10.

Table 5.10: Overview of key IT and OT business systems

System	Functionality
Geospatial Information System (GE Smallworld, ARCGis)	Provides management of map-based (Cadastre), delivery point lifecycles, network configuration and connectivity, emergency response and mains extension and replacement planning
Networks Interval Metering Data System (Historian OsiPi)	Provides storage of SCADA data and billing information
Billing estimation model (APA custom)	Provides delivery point forward estimates, interval consumer management service and base load and TSF calculations
Dial Before You Dig (Mipela)	Provides management of national Dial Before You Dig enquiries and asset location notifications
Mobile maps (GE Smallworld)	Provides the capability to view GIS maps on mobile devices, enabling a geospatial understanding of asset locations in the field
Metering & billing system (Oracle CC&B)	Provides transaction workflows, meter readings and delivery point billing
Enterprise asset management (IBM Maximo)	Provides planning, dispatching work, job completion details, delivery point status management, preventative maintenance, contractor payment and meter management services
FRC market gateway (Web Methods)	Sends and receives order requests, meter fixes and customer transfer requests
Telemetry system (Clear SCADA)	Provides real time data and alarms to enable effective remote monitoring of critical assets

System	Functionality
Business intelligence platform	Provide the technology platform to combine multiple disparate sources of data to facilitate analysis and inform business management decisions
Middleware (BizTalk)	Enables tightly controlled data integration between multiple enterprise applications
Field data/mobility systems	Provides capability for real time data capture in the field to drive business efficiency and provision of mobility applications improving safety, compliance and customer service outcomes
Website/web	Portal system
Enterprise resource planning (SAP)	Provides the platform for all accounting, budgeting and planning and tax functionality

6. Assets Performance Summary

6.1. Asset Class Performance Requirements

The following sections describe the general performance requirements for each asset class.

Transmission & Distribution Mains

1. Transmission capacity sufficient to maintain supply under 1 in 20 year conditions;
2. Distribution capacity sufficient to maintain supply under 1 in 2 year conditions;
3. Gas pressure maintained above recommended minimum values at network extremities.
4. No harm to persons or property due to network failure;
5. Total mains and service leaks reported per km of main reduce over time;
6. The moving annual 12-month UAFG is at a level that is considered acceptable for the characteristics of the network; and
7. The number of third party damages per km of main is consistent with that of a prudent operator.

Network Facilities

1. Networks do not exceed their MAOP;
2. Supply pressures are reliably controlled to maintain adequate end of mains pressures, above recommended minimums, with no loss of supply; and
3. Cathodic protection systems are operated and maintained in accordance with Procedure 9019 Cathodic Protection System Maintenance and Testing, and pipe to soil potentials maintained within the values required by this procedure and associated Work Instructions.

Metering

1. Metering accuracies are maintained within tolerances specified in the South Australian Gas Metering Code and the Gas Distribution System Code for Mildura;
2. Timeframes for installation, upgrading and maintenance are in accordance with the South Australian Gas Metering Code and the Gas Distribution Code for Mildura;
3. Metering data is supplied within the timeframes specified by the Retail Market Procedures and in accordance with the South Australian Gas Metering Code and GDC; and
4. In the absence of a specific Gas Metering Code in the Northern Territory, AGN applies the relevant requirements of the South Australian Gas Metering Code and the Australian Standards listed herein to the Alice Springs distribution network.

SCADA Facilities

1. Sufficient monitoring and control is in place to enable efficient planning, monitoring and emergency response; and
2. Demand customer data is accurate, validated (estimated/substituted) and supplied in accordance to the Retail Market Procedures and the applicable gas metering codes.

Compressor Facilities

1. The compressor starts when called on to start, 100% of the time;
2. Inlet pressure at Mildura City Gate is maintained above the nominated minimum pressure;
3. The compressor station control system operates as designed; and
4. Operating costs remain within budget.

6.2. Performance Indicators

Table 6.1 summarises a range of Performance Indicators (PIs) used for the various asset groups. Performance Indicators are used by the relevant operating departments with Key Performance Indicators (KPIs) reported to senior management, while various KPIs and data are also provided to the technical regulators in each state as required.

Table 6.1: Performance Indicators

Primary Asset Group	Performance Indicators (PIs)	KPI
Transmission Pipelines	No. of 3rd party damages	Y
	No. of 3rd party near misses	Y
	% of pipeline patrolled	
	No. of coating faults/km	
	No. leaks reported & repaired	
	Intelligent Pigging Survey Results	
	CP Survey Readings	
	Coating Survey Results	
	Emergency exercises completed	
Distribution Mains & Services	Leaks/km main surveyed	Y
	No. 3rd Party Damage.	Y
	Supply Outages to 5 or more consumers	Y
	No. of gas in building incidents	Y
	No. of fires as result of gas leak	Y
	Onsite response to emergency within prescribed time	Y
	UAFG levels	Y
	No. leaks reported & repaired	
	No. of outstanding leaks	
	No. of services replaced	
	Poor supply incidents/outages	
	No. of over pressurisations	
	No of 3rd party locations	
	CP Survey Readings	
	Km of mains laid	
	Km of mains replaced	
	No of services Laid	
	No of services replaced	
Network Facilities - PRS	No. of PM jobs scheduled but more than 1 month overdue	Y
	% PM Schedule Complete	
Network Facilities - CP	% of CP test points checked	Y
	% of test points outside tolerance	Y
	% TP Protected by CP	
	% HP/MP/LP Network protected by CP	
Network Facilities - ODOR	% of regulatory odorant surveys conducted	Y
	Odorosity detectable < 20% LEL	Y
Metering Facilities	No. of PM jobs scheduled but more than 1 month overdue	Y
	No. of inaccurate meters detected	
	No. of meter failures	

Primary Asset Group	Performance Indicators (PIs)	KPI
	No. of time-expired meters replaced No. of meter leaks % of PM Schedule complete No. of meters replaced per annum Other KPIs as set out in the GMMP	
SCADA Facilities	Availability of telemetry systems	
Compressor	Number of successful starts / mth	Y
	Number of unsuccessful starts / mth	Y
	Number of times Mildura inlet pressure less than minimum/mth	Y
	Run hours / mth	
	Operating costs vs budget	
	Electricity costs vs GJ throughput / mth	

6.3. Transmission Pipelines

6.3.1. Plan and Create

Growth of the TP pipeline system is driven by extensions and augmentation to supply residential, industrial and commercial development. Table 6.2 shows the projects that will be required to augment capacity of the transmission pipelines network over the planning horizon.

The extension of natural gas to the greater Mt Barker area has been approved by the AER.[14] The project will see a new 40 km DN150 TP pipeline (and further reticulation) feeding new developments (approximately 8,000m^3/h additional load over the next 30 years) in Mt Barker.

Table 6.2: TP Pipeline Capacity Forecast Requirements

Location		Status
Regulated	Mt Barker	Plans for residential development within the area for 7,000 additional homes, will increase the population in the area to 35,000 over the next 20 years. The supply to Mt Baker will come from the Riverland Pipeline (RLP) Murray Bridge lateral via a 40 km TP extension.
	Adelaide South	Following the extension of the River Road TP in 2018 no further augmentation of the TP network is envisaged over the current regulatory period. Future analysis is underway which will determine the timing of any further TP augmentations in the southern area.
	Adelaide West (Le Fevre Peninsula)	Adequate capacity for at least the next 5 years.
	Port Pirie	An existing Tariff D customer at Port Pirie has increased its demand, Augmentation may be required upstream of the Port Pirie distribution network, in the Epic Energy supply pipeline.

[14] AER Final Decision - AGN - Mount Barker gas network extension - 18 December 2018, https://www.aer.gov.au/system/files/AER%20-%20Final%20Decision%20-%20AGN%20-%20Mount%20Barker%20gas%20network%20extension%20-%2018%20December%202018_0.pdf .

Location		Status
Unregulated	Riverland – Berri Mildura	Additional Tariff D customers at Murray Bridge and Mildura and the potential supply to Mt Barker may require augmentation of the Riverland Pipeline in the next 2-7 years. Analysis and modelling is underway post the 2019 peak winter period to determine options and timing.

6.3.2. Operate and Maintain

Transmission pipelines are maintained through a program of inspections and condition monitoring activities as summarised in Table 6.3.

Table 6.3: Transmission Pipelines Inspection and Monitoring Regimes

Maintenance Activity	Frequency
Pipeline patrols	Daily/Weekly/Monthly
Above ground mains inspections	Annually
Cathodic protection potential checks	Monthly (detailed survey every six months)
DVCG coating survey	Every five years
Integrity excavations	Condition based
Leak survey (full right of way (ROW))	Every five years Annually for assessed higher risk locations
Vegetation management	As required

Refer to the SA Networks Pipeline Integrity Management Plan (PIMP) for further details.

6.3.3. Monitor and Review

The integrity of our transmission pipelines is assessed and managed through a system of five yearly location class and safety management studies (SMS), five yearly DCVG coating surveys, and 10 year remaining life reviews (RLR). The key integrity issues and proposed actions have been summarised below.

Pipe Wall Integrity

- [redacted]. The corrosion beneath HSS is unable to be detected by DCVG survey because the disbonded HSS interferes with this process. Replacement of this pipeline is currently underway, to be completed in the current AA period. Replacement of a separate 800m long DN100 section of M53 is planned for the next AA period (Refer to Section 7.8.1, Business Case SA104)
- External pipeline corrosion identified during DCVG surveys remains a prevalent issue. Continuation of a program to dig up and repair DCVG indications with a %IR drop less than 15%, will provide greater detail regarding the extent of pipeline corrosion outside of HSS dig ups. In order to improve safety, this program exceeds the requirements of AS2885 to dig up DCVG indications with a %IR drop greater than 15%. (Refer to Section 7.8.1, Business Case SA101)

- A direct assessment program is planned to assess the extent of corrosion beneath HSS across a number of other 'vintage' transmission mains within the Adelaide metropolitan area. This is part of our Opex program.
- A manufacturing defect on the [redacted] was discovered during excavation, as part of a major mains alteration. The pipe section was removed as part of the scope of the mains alteration. It is proposed to conduct physical excavations on short radius bends in the next AA period to determine whether this pipeline can be made piggable so it can be inspected to determine if there are any similar issues along the rest of the pipeline.

Third Party Damage

- Old, unreported third party damage (gouges and crack) was identified by DCVG survey on the TP main at [redacted] The pipe has been repaired by installing a sleeve at each damaged location.
- There are a number of locations in the network where TP pipelines are located under verges in close proximity to public facilities such as schools and community centres. These pose a high risk to public safety in the event of third party damage, and a program of installing protective slabbing is proposed for the next AA period. (Refer to Section 7.8.1, Business Case SA131)

Alternating Current (AC) Interference

- AC interference issues have been found in a number of locations within the Adelaide metropolitan TP network, with the maximum effect [redacted]. ICCP units to mitigate these effects are proposed to be installed.

Coating Systems

- A DCVG survey of the Berri to Mildura Pipeline (BMP) was completed in 2018 with [redacted] defects to be investigated;

Cathodic Protection

- Some test points on the BMP have inadequate levels of cathodic protection (CP) with two additional impressed current system (ICS) units being considered;
- Not all points on the [redacted] have the required levels of CP, and an additional [redacted] ICCP units are planned to be installed. Land acquisition issues for one of these units are currently being progressed.

6.3.4. Manage Risk

Risk and issues for transmission pipelines are detailed below. The normal process of assessing and prioritising these risks will result in projects and work programs proposed as part of the annual capital budgeting and five-yearly AA processes.

- Railway sleeve crossing remediation;
- Corrosion beneath heat shrink sleeves;
- Corrosion dig-ups and repairs;
- Repair of creek crossing washouts;
- Cathodic Protection management;
- Proposed In-line Inspection (pigging) programs (Refer to Section 7.8.1, Business Case SA105);
- Telemetry on DRS; and
- Unregulated bypasses on DRS (Refer to Section 7.8.1, Business Case SA106).

6.3.5. Repair/ Replace/ Abandon

Refurbishment works include valve corrosion protection, TP regulator station recoating and soil to air interface recoating.

We have repaired old, unreported third-party damage (gouges and crack) identified by DCVG survey on the TP main at [redacted] We have also repaired [redacted] transmission valves that have leaked and identified [redacted] valves that are inoperable requiring replacement. Table 6.4 provides a list of these inoperable transmission valves.

Table 6.4: Inoperable Transmission Valves

Valve #	Location	Size	Year of installation
506	[redacted]	250SP	1968
1482	[redacted]	300SP	2002
29	[redacted]	300SP	1975
752	[redacted]	300SP	1979
858	[redacted]	300SP	1980
318	[redacted]	150SP	1975

[redacted] has [redacted] pitting (up to [redacted] wall loss) beneath HSS. Replacement of this pipeline is currently underway, to be completed in the current AA period. Replacement of a separate 800m long DN100 section of M53 is planned for the next AA period.

Replacement works over the next five years include:

- Replacement of aging and inoperable Transmission valves (Refer to Section 7.8.3, Business Case SA103); and
- Replacement of an 800m section of M53 pipeline [redacted] (Refer to Section 7.8.1, Business Case SA104).

6.4. Distribution Mains and Services

6.4.1. Plan and Create

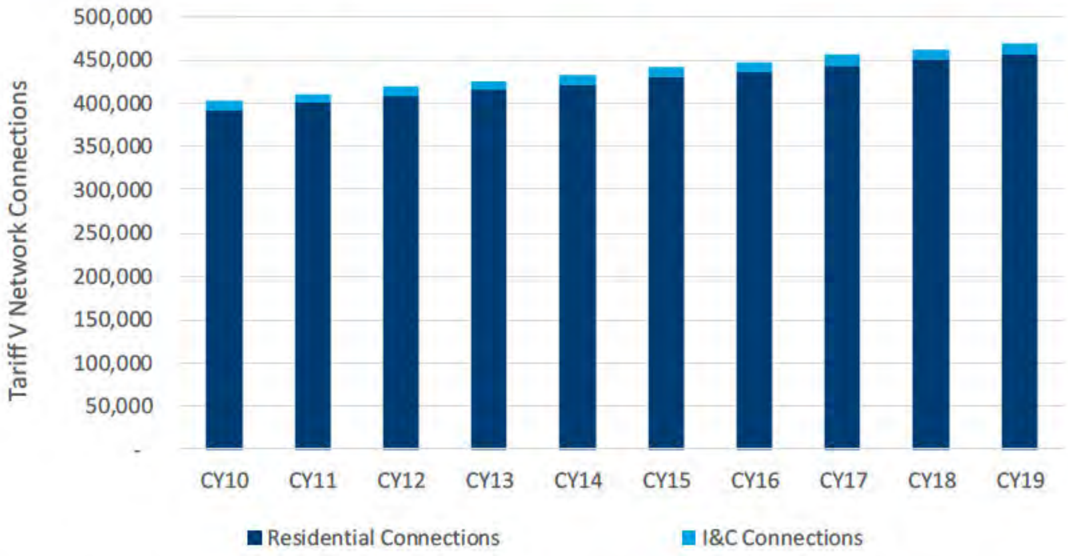
Distribution Mains and Services performance is driven by growth and augmentation.

Organic Growth

Organic growth relates to general growth within networks of a small to medium nature, typically small mains extensions within the network, urban renewal and infill projects.

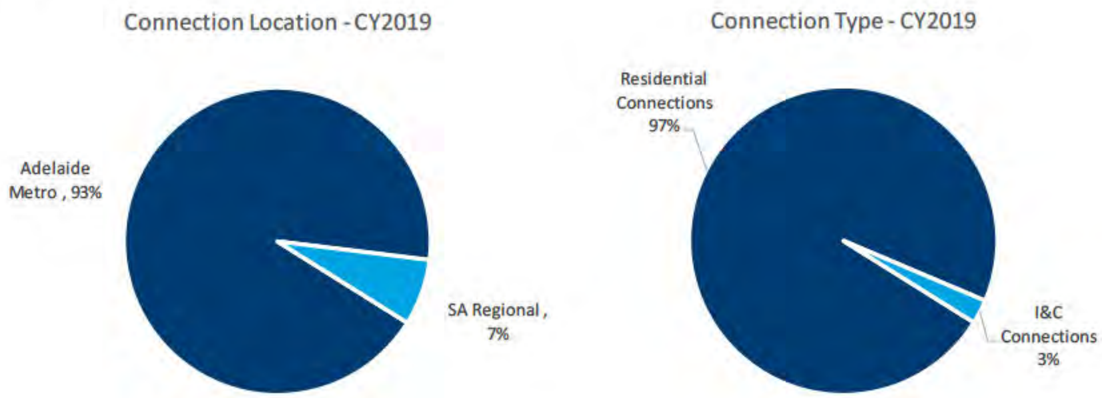
Figure 6.1 below shows the historical growth residential and I&C customers (<10TJ).

Figure 6.1: SA Networks Residential and I&C Customers



Over 97% of our network connections are of the residential type. Residential net connections have grown by about 1.7% per year over the last 10 years, slowing to 1.5% per year since 2016. I&C connections make up less than 3% of total connections, growing on average by 1.5% per year over the past 10 years, slowing to 1.2% per year since 2016.

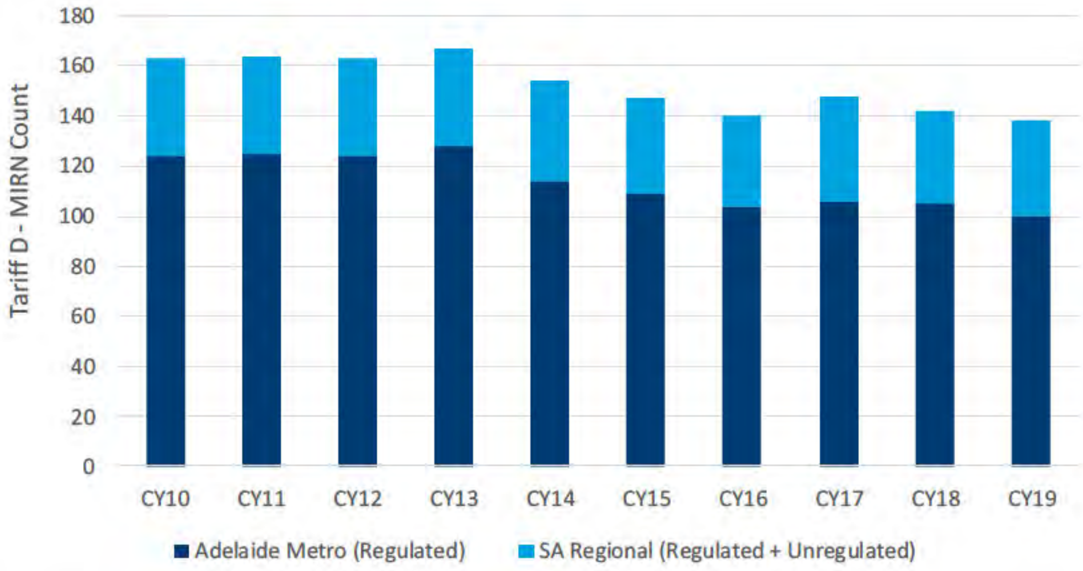
Figure 6.2: Tariff V connection breakdown



Our Adelaide metro network contains more than 93% of all network connections. Our regional networks have grown by average of 2.9% per year over the past 10 years, which is greater than our metro networks which have grown by an average of 1.6% over the same period. Both regions are experience declines in growth rates in more recent years. Growth in the regional areas is principally associated with our Mildura network.

Figure 6.3 below shows the historical growth of Tariff D customers.

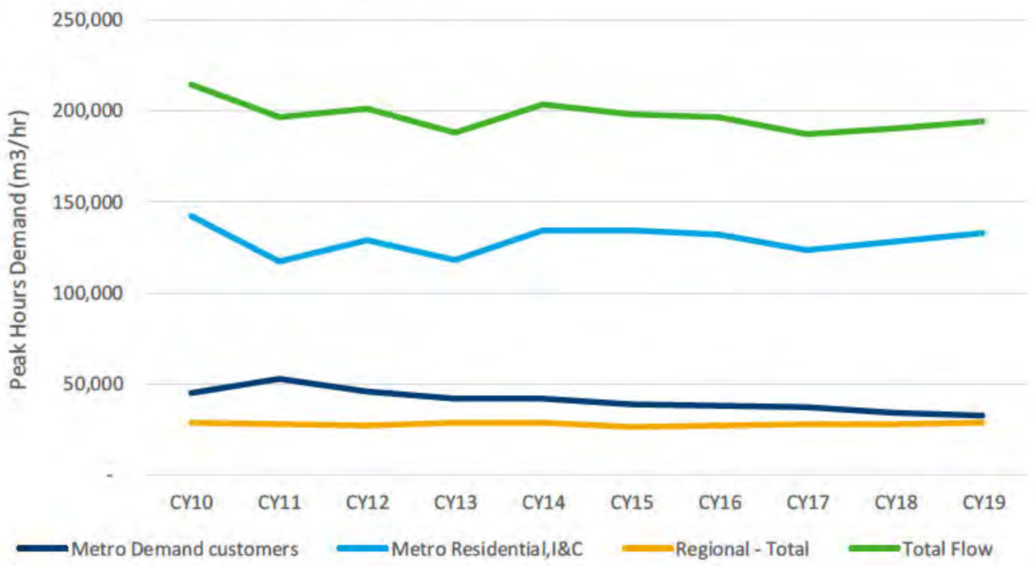
Figure 6.3: SA Networks Tariff D Customers



Tariff D customer numbers have been declining in the Adelaide metropolitan area over the last ten years, consistent with the downturn in the manufacturing industries, but this appears to have stabilised since 2016.

Figure 6.4 below shows the SA Networks peak hour demand over the last 10 years.

Figure 6.4: SA Networks Peak Hour Demand (last 10 years)



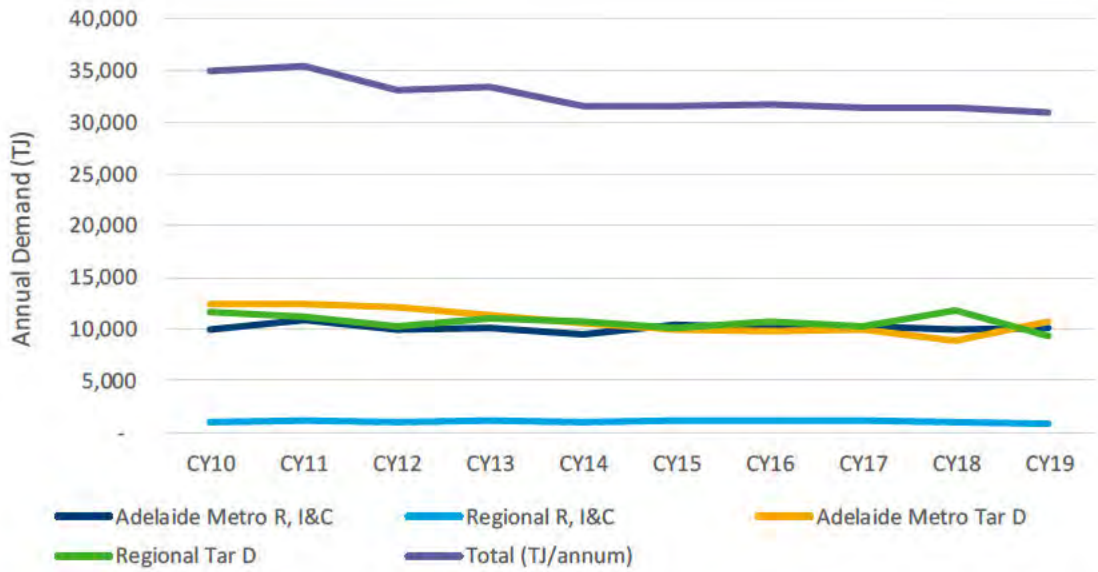
The Adelaide metropolitan total peak hour consumption in 2019 was 2% (3,000 m^3/hr) higher that recorded in 2018. This was driven by a 3.7% (4,800 m^3/hr) increase Residential, and I&C consumption.

The Adelaide metropolitan 10-year peak hour demand continues to trend down driven largely by a reduction in Tariff D loads.

Total regional network demand has increased by 8% over the last 10 years. Significant increases have been seen in Virginia (26%), Mildura (19%), Alice Springs (20%) and in Port Pirie (27%) where a Demand customer has significantly increased production in the last 12 months.

Table 6.3 below shows the SA Networks annual demand over the last 10 years.

Figure 6.5: SA Networks Annual Network Demand (last 10 years)



Total SA Networks (including Mildura and Alice Springs) annual demand has remained flat over the last five years.

Adelaide metropolitan Residential, Industrial and Commercial annual demand has remained relatively flat over the last 10 years, with a slight reduction in the last 12 months, despite annual growth of about 1.6 % in customer connections.

The declining trend in Adelaide metropolitan Tariff D demand is driven by the decline in the manufacturing industry. As mentioned further above, Tariff D demand in regional areas has shown a significant increase in the last 12 months due to a Demand customer at Port Pirie recommencing production, which has offset the decline in the Adelaide area.

Step Out Developments

Step out developments are those of a more significant nature such as major development areas of a residential, industrial or mixed use nature on network fringes, and major extensions of natural gas to new areas.

The SA Government has confirmed that the Roseworthy Residential Development will provide housing for about 10,000 people over 30 years. The township of Roseworthy will be expanded by rezoning approximately 550 hectares of land for residential development, shopping centres, social infrastructure, employment and industry purposes. Major developers have plans to develop approximately 4,000 lots in the area, with the first lots being ready in late 2019. There are also areas zoned for light and large commercial developments.

Concordia Residential Development is approximately 920 hectares and is identified as a 'long term urban growth area' in the '30 Year Plan for Greater Adelaide'. There are progressive development plans of 9,500 dwellings plus supporting physical, social and commercial infrastructure over the same 20-year development period. The first lots are expected to be ready in 2025. Refer to business case SA122.

Kingsford Regional Industrial Estate is a 170 hectare site located between Gawler and Roseworthy, 46 km north of Adelaide. The Kingsford Estate has been identified by State Government as a key area for major industrial development, which has rezoned the area to encourage development of manufacturing and other industrial facilities.

The Kingsford Estate is not currently connected to the natural gas network. Regional Development Australia and the local council have expressed a desire for gas supply in the area, and local businesses have indicated support for an extension of the natural gas network to the region.

Kingsford is already home to a number of medium-to-large businesses. Expansion of the gas network to the industrial estate is expected to commence during 2021/22. We estimate the Kingsford development will result in around 15 new industrial and commercial (I&C) customer connections to the natural gas distribution network over 20 years. Refer to business case SA124.

Springwood is a new housing development in Gawler East which will include 2,000 homes, 6,000 people, supermarket and speciality shops, retirement living, a major new sporting oval and a primary school. Currently over 200 lots are developed and connected to natural gas.

Capacity studies have concluded that a new gate station near Gawler will be required in the next 2-5 years to service these developments. Refer to business cases SA122 and SA115.

Mildura has been experiencing an average growth rate of about 5% per year or about 400 residential connections per year. This is expected to continue over the foreseeable future. This ongoing growth is expected to drive augmentation of the Riverland Pipeline in about 5 years.

The extension of natural gas to the greater Mt Barker area has been approved by the AER and is currently being delivered. The project will see a new 40 km DN150 TP pipeline (and further reticulation) feeding new developments (approximately 8,000m^3/h additional load over the next 30 years) in Mt Barker.

Table 6.5 summarises the likely growth due to large step-out developments over the planning horizon.

Table 6.5: Anticipated Major Growth Areas

Development	Regulated / Unregulated	Growth Type	Anticipated Commencement	Approx No of lots pa to be serviced over the planning horizon
Roseworthy Residential Development	Regulated	Step-out	2020	50
Concordia Development	Regulated	Step-out	2022	240
Springwood – Gawler East	Regulated	Organic	In progress	50
Kingsford Regional Industrial Estate	Regulated	Step-out	2022	10
Mildura	Unregulated	Organic	2020	700

Augmentation

Table 6.6 shows the status and the capacity forecast requirements of distribution mains.

Table 6.6: Distribution Mains Capacity Forecast Requirements

Location		Asset Class	Status
Regulated	Adelaide Northern (Gawler Gate Station)	HP Mains	HP trunk main augmentation utilising a new gate station in the vicinity of the Springwood development in Gawler East will be required. The timing of this augmentation is subject to the timing of residential developments in Roseworthy, Springwood and Concordia, and growth in the Gawler/Evanston area and is planned for the next AA period Additional industrial developments west of Gawler will also require HP mains extensions.
	Seaford / Aldinga	HP Mains	An extension of the transmission main from River Road to Main South Road and a new TP-HP regulator, and a 280mm P8 trunk main to tie into the HP network along Commercial Rd (commissioned in May 2018) will significantly improve end of main pressures at Aldinga from the 2018 winter period. Augmentation of the Seaford to Aldinga HP trunk main will be required in the next AA period to support residential growth in the southern area of the SA metropolitan network.
	Virginia	HP Mains	Duplication of the main exiting the gate station was planned during this AA period. A much slower I&C growth rate in the Virginia area and a reassessment of the Virginia Gate Station capacity by Epic Energy has deferred the need for a previously planned augmentation of this gate station into the subsequent AA period.
	Adelaide East/NE (Modbury, Rostrevor, Myrtle Bank)	MP/HP mains	These networks were approaching their capacity, however this has been resolved in conjunction with mains replacement works undertaken in 2018.
	Adelaide West and North of the city	LP Mains	The LP cast iron networks are nearing capacity. LP network is expected to be replaced in the next AA period.

6.4.2. Operate and Maintain

The majority of maintenance is associated with reactive response and repair of public reported leaks. Key mains and services operation and maintenance activities are detailed in the Table 6.7.

Table 6.7: Distribution Mains Maintenance Activities

Maintenance Activity	Frequency/Target
Phone response for public leak reports	Target of 90% of calls to be answered within 10 seconds
Response to public reported leaks	All public reported leaks to be attended on site within 2 hours
Planned Leak Survey	A rolling 5-year survey of all mains with 6 month and 12-month special surveys of 'high' risk areas. Target is to undertake 100% of planned surveys each year.
Cathodic protection potential checks	Every six months
Winter Pressure Surveys	Annually

Inline camera inspection and reinforcement of squeeze off locations where required is undertaken for some HP HDPE 575 mains as a risk mitigation measure for suitable mains not identified for replacement over the current or next AA period.

SCADA is used to provide surveillance of network pressures with additional monitoring provided through fixed and mobile data loggers and chart recorders. Data collected from these is reviewed and analysed to diagnose pressure control equipment faults and network capacity problems. Chart recorders are being superseded by electronic data loggers, which are more reliable, and require less maintenance.

Mains Alterations

Mains alterations due to third party works are an ongoing activity across all networks and regions. The major projects completed in this AA period are:

- Adelaide Airport;
- Tramline extension;
- South Rd – Torrens to Torrens project;
- South Road – Darlington project; and
- South Road – Regency to Pym project.

6.4.3. Monitor and Review

Reliability of supply is a good indicator of asset performance. Reliability of supply is related to gas incidents and interruptions to supply. We look at the outcomes of asset management policies, processes and plans in terms of:

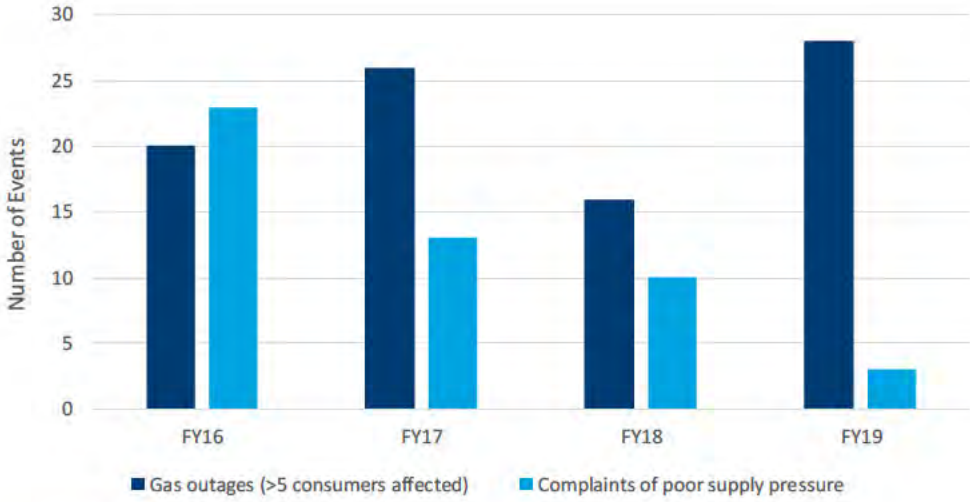
- Reliability (gas interruptions);
- Condition/integrity (leaks, gas in building, third party damage UAFG);
- Emergency leak response; and
- Gas quality.

Reliability

Our network is inherently reliable with customer on our network, on average, experiencing an unplanned outages every 40 years or more.

Figure 6.6 outlines the number of outages per annum where greater than five end users were impacted, and the number of complains we received per annum due to poor supply pressures since 2016/17.

Figure 6.6: Network Reliability



Condition and Integrity

A detailed assessment of the risk and integrity of mains and services and associated management strategies (including replacement) have been included in the South Australian Networks Distribution Mains and Services Integrity Plan (DMSIP).

Key condition and integrity observations and issues include:

- The completion of the CBD replacement by the end of the current AA period will remove all extreme risk mains from our Network, with the last 8 kilometres of CBD mains due to be removed in 2020/21. This is a significant safety milestone for our business and delivers against our commitments made to the OTR and in our AA submission in 2016 to remove the highest risk rated assets in the Network, as a priority;
- By June 2026, we will complete the replacement of all remaining high risk cast iron (CI), unprotected steel (UPS) and other low pressure mains in our South Australian distribution network. This is a significant safety milestone for our business, modernising our Network to consist of steel and plastic mains;
- The mains replacement program will continue in the next AA period, with 870 km of the highest risk mains scheduled for replacement;
- We will continue to prioritise inline camera inspection and reinforcement (where it is technically feasible and an effective alternative to replacement) for our HDPE 575 DN50 mains;
- Badly corroded UPS inlet services to multi-user sites are being progressively replaced to align system integrity with that of the inserted and pressure upgraded mains to which these assets are connected. This program will continue into the next AA period, with all priority group 1 MUS (457 sites) forecast to be replaced.

Refer to Section 7.1 for additional details on our investment strategies for the next AA period.

Mains and Service Leaks

Leaks are inherent in natural gas distribution networks. Leaks typically occur at joints between assets, particularly gas mains, inlet services and meters. Most leaks develop slowly and release minimal quantities of natural gas, which dissipates harmlessly into the atmosphere. However, in specific circumstances (relating to location, material type, and pressure), leaks can pose a potential safety risk.

Though leaks cannot be eliminated from the network, we have a rigorous inspection and leak detection program to help identify and prevent leaks. We invest in technology and training to help improve our leak detection capability, which in turn improves the quality and accuracy of data and risk assessment.

Figure 6.7 shows the mains and services leak rate over calendar years 2014 to 2019.

Figure 6.7: Mains and Services Leak Rate

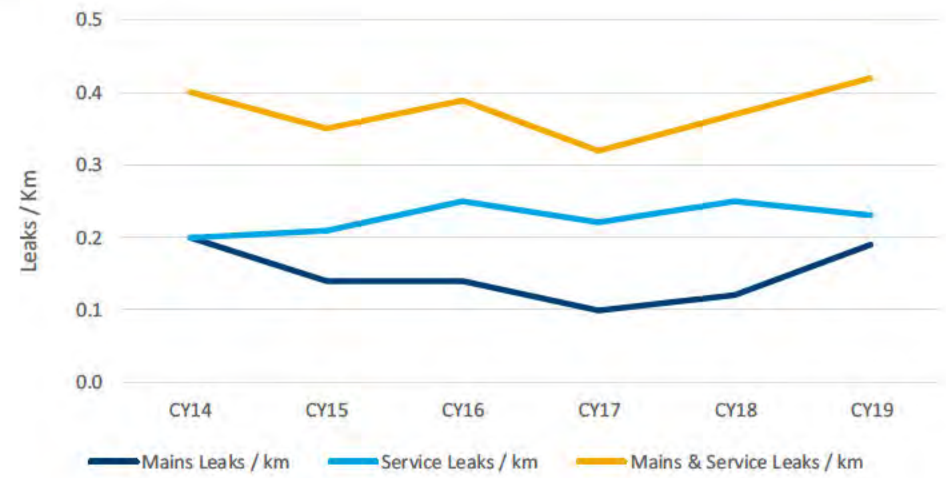
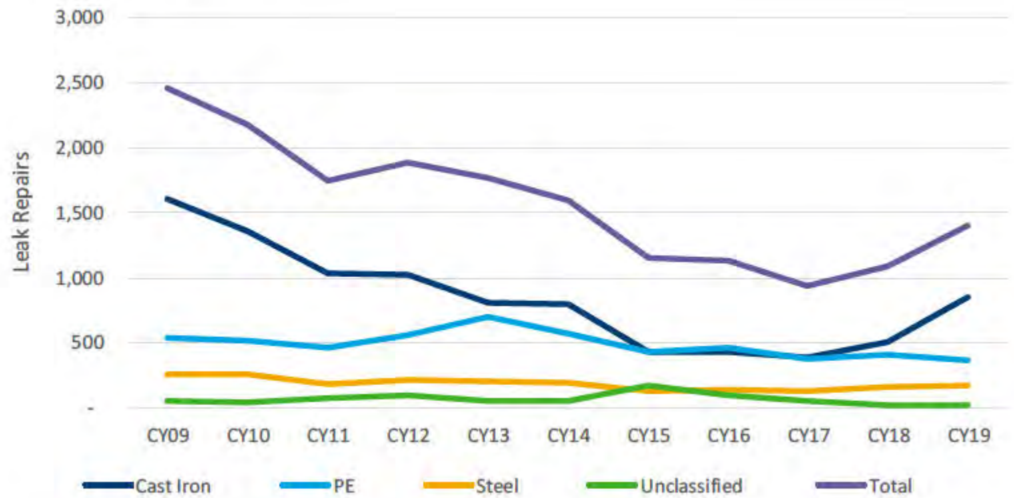


Figure 6.8 shows the mains leak repairs by material types over calendar years 2009 to 2019.

Figure 6.8: Mains leaks by material type



Mains leaks rates have historically shown a declining trend, consistent with the replacement of several hundred kilometres of CI and UPS over that time. In more recent years, the rise in CI leaks, and therefore total leaks, is attributed to increased leak survey activities undertaken on yet to be replaced cast iron mains and ongoing deterioration of this asset class.

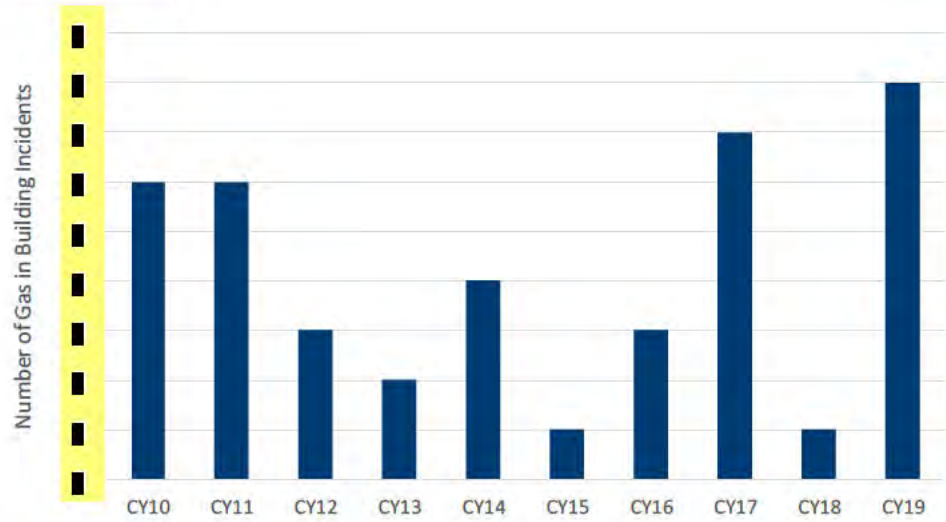
PE leaks within Figure 6.8 are inclusive of both early generation (HDPE 250 & 575) and modern PE mains types. A breakdown of leak repairs in CY2019 indicates early generation PE mains are overrepresented in terms of PE leak repairs (69%) relative to their contribution to total PE length (26%).

Leak rates are anticipated to reduce further with the ongoing completion of the replacement of CI and UPS and a significant replacement program of HDPE in the next AA period.

Gas in Buildings

[redacted] shows the performance of Gas in Buildings (GIB) incidents over the last 11 years.

[redacted]



Following just one GIB in 2018, there were eight GIB incidents in 2019, as detailed below:

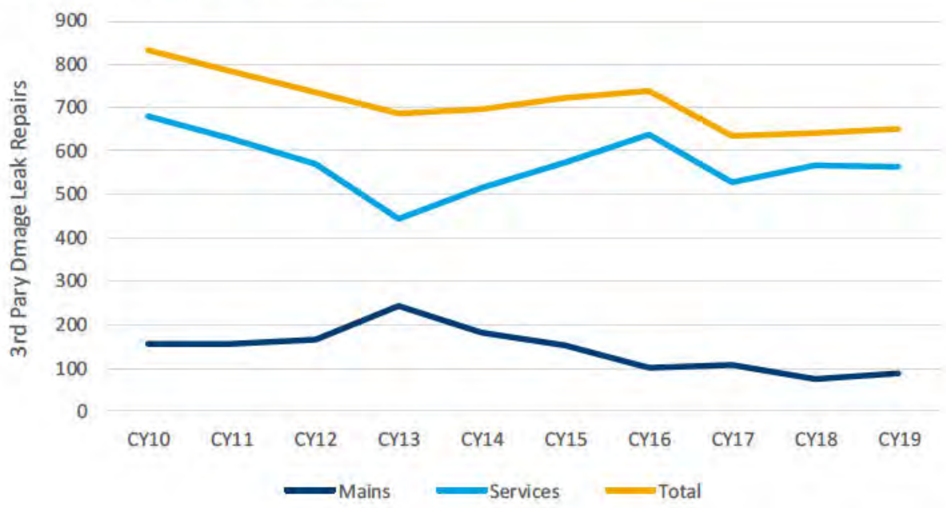
- [redacted] (March 2019) – Gas was detected from a drain trap in the internal laundry. The cause was identified as third party damage to the inlet service with a drain machine;
- [redacted] (May 2019) – Gas was detected at a school. The source of the leak was downstream of the inlet service, within the wall cavity. Supply was isolated, the service was replaced, and the gas meter relocated;
- [redacted] (July 2019) – Gas was detected inside a building, with the source identified as a leaking joint on a 250 mm LP CI main. The main was isolated and site made safe. This area is scheduled for mains replacement in CY 2020/ CY 2021;
- [redacted] (July 2019) – Low level gas readings were detected inside a building, and the source identified as the valve pit on the main road. The leak was confined to a section of medium pressure CI mains. The gas reading inside the building was associated with the prevailing wind direction. The section of CI main involved in this incident has been decommissioned;
- [redacted] (July 2019) – In response to gas readings from a service to 8 residential units, supply was turned off at the site's boundary regulator. This service feeding the communal hot water system was repaired and supply reinstated;

- [redacted] (July 2019) – The smell of gas (and confirmed gas readings) inside of a building prompted the isolation of supply. The leak was identified on the MP service. A service renewal for permanent repair was completed;
- [redacted] (July 2019) – Technicians responded to the smell of gas with the leak identified downstream of the meter within a wall cavity of a unit complex. Supply was isolated via the boundary regulator, and the repair actioned; and
- [redacted] (November 2019) – Gas detected in the wall cavity of the building was traced to a leak downstream of the meter. The meter was turned off, the property vented, and repairs actioned.

Third Party Incidents

Figure 6.10 shows the leak repair performance due to third party damage.

Figure 6.10: Mains and Services by Third Party Damage



Unaccounted for Gas

Unaccounted for Gas (UAFG) is the difference between metered gas injected into our network and the metered / allocated gas at delivery points (i.e. end customers). The contributory elements to UAFG are classified as either Measurement UAFG or Fugitive Emission UAFG.

Fugitive Emission UAFG elements include:

- Losses from the LP, MP, HP and Transmission pipelines – varies with material and pressure;
- Losses from service lines – varies with material and pressure;
- Regulator leakage – control system bleeds to atmosphere;
- Third Party Damage – losses to atmosphere; and
- Meter Losses – joint leakage.

Measurement UAFG elements include:

- Pressure measurement – gas delivered at variation to Standard Conditions;
- Temperature measurement – gas delivered at variation to Standard Conditions;
- Higher heating value (HHV) measurement – gas delivered at variation to declared HHV;

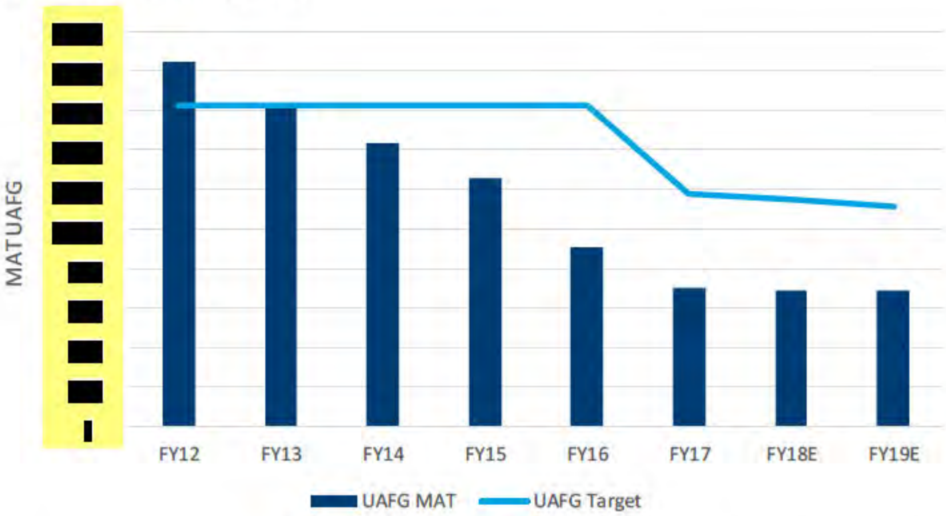
- CTM measurement – uncertainty in metered volumes;
- Meter Accuracy - uncertainty in metered volumes;
- Linepack Changes – Linepack volume varies each year end date;
- Administrative errors – incorrect records;
- Own Use Gas – gas used for operational reasons; and
- Theft.

UAFG is inherently difficult to break into component parts due to the uncertainty of metering a compressible fluid and the lack of data associated with determining physical unmetered losses

A benchmark representing efficient levels of UAFG is set by the AER for each regulatory period. We are provided an allowance (set at the UAFG benchmark) to purchase gas to offset actual UAFG performance.

Figure 6.11 shows our UAFG performance over last 8 years, with respect to the benchmark. We have achieved a decline of UAFG which looks to be stabilising in recent years.

Figure 6.11: South Australia Networks UAFG - MAT



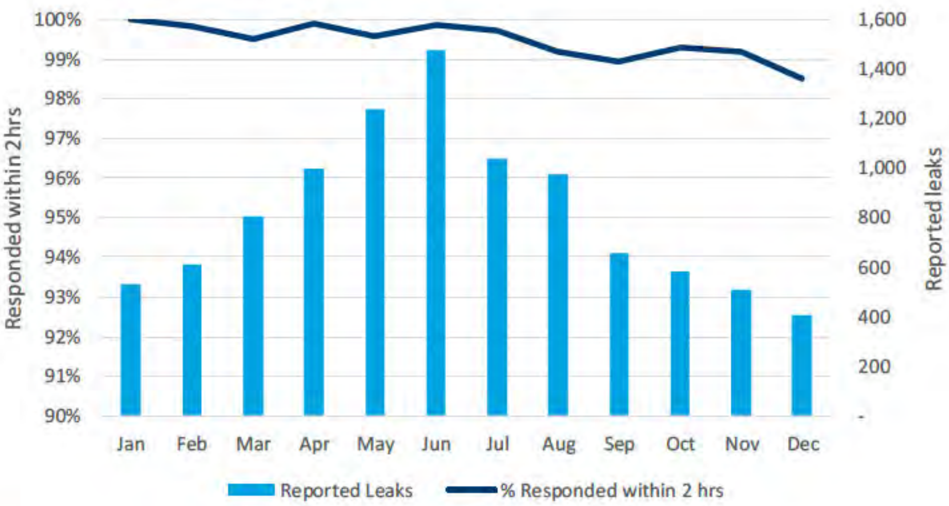
It is noted that the raw data used to generate UAFG values is subject to review and amendment for up to 425 days after the end of the financial year. In Figure 6.11, UAFG performance for 2018/19 and 2019/20 are still subject to change.

Emergency Response

Response to network incidents / emergencies remains the highest priority for our network operations teams. In South Australia, we are to respond to publicly reported leaks within two hours.

Figure 6.12 shows our leaks response performance for 2019. In 2019, we responded to 99.5% of leaks within two hours. This compares to 99.1% in 2018.

Figure 6.12: Emergency Leak Response - CY2019



Gas Quality

Odourosity and heating value testing are detailed in the Bureau Veritas Gas Chemistry – Odourising Annual Report, Financial Year 2019. In summary:

- Network odorant concentrations were reported within acceptable levels in the Calendar Year 2019 reporting period. However, it is noted that an increased focus on the sampling schedule in regional areas is required for the 2020 reporting period; and
- Average heating values for Moomba and SEA Gas natural gas were within heating value specifications.

Existing odorant and heating value monitoring processes will continue in the next AA period.

6.4.4. Manage Risk

Risk issues for distribution mains and services are:

- Various network augmentation projects (refer to Section 7.3);
- HDPE risk mitigation, including squeeze off damage sites that are not included in the current regulatory period work program; and
- Continuing the planned replacement of CI and UPS mains, in line with risk assessment prioritisation.

The outcome of the mains replacement planning outlined in the DMSIP has resulted in a 'planned' baseline to reduce risk within the distribution mains network for the next AA period of 870 km, which includes a nominal provision for 10 km of reactive (ad hoc) replacement based on condition. The annual target is based on an average of the proposed five-year target.

Table 6.8 summarises the regulatory mains risk reduction benchmark targets for 'planned mains' over the next AA period. Refer to our DMSIP for further information.

Table 6.8: Distribution Mains Risk Reduction Targets

Asset Category	Inventory at July 2021	Risk at July 2021	Inventory at July 2026	Risk at July 2026
1 CI/UPS - block	558[15]	High	0	Low
2 HDPE 250 – remaining	14	High	0	Low
3 HDPE 575 DN50 - HP	57	High	0	Intermediate (ALARP)
4 HDPE 575 DN50 - MP	259	Intermediate	0	Intermediate (ALARP)
5 HDPE 575 DN40	447	Intermediate	0	Low
6 HDPE 575 DN50 inspected	310	Intermediate (ALARP)	626[16]	Intermediate (ALARP)
7 MUS – Priority group 1	457	High	0	Low
8 MUS – Priority group 2	1,653	Intermediate (ALARP)	1,653	Intermediate (ALARP)
Residual risk in 2026				Intermediate (ALARP)

6.4.5. Repair/ Replace/ Abandon

Details of the mains and service replacement program have been included in the SA Networks DMSIP. Section 7.1 in this SAMP shows the planned work program to reduce risk by replacing cast iron and unprotected steel within the distribution mains and services over the next 5 years. In summary, 870 km mains are planned for replacement, 316 km of mains are planned for inspection and reinforcement where required and all priority group 1 MUS are planned for replacement over the 5 years.

A study was completed in 2018/19 to assess options to improve the security of supply to customers during emergency response on the Adelaide metropolitan transmission network resulted in the proposal to install additional inline valves in the next AA period to minimise the number of customers impacted by the closure of mainline valves in event of an emergency (Refer to Section 7.8.3, Business Case SA107).

[15] The term 'CI/UPS – block' refers to all remaining mains in the LP network (to the specific exclusion of the new CBD LP mains) which includes mains of material other than CI/UPS

[16] Note that HDPE 575 DN50 HP (57 km) and MP (259 km) are included in the 'inspected' category in 2026

6.5. Network Facilities

6.5.1. Plan and Create

Gate Regulator Stations

A new gate station injection point in the vicinity of Gawler East will be required in the next two to five years due to residential development planned for Roseworthy (4,000 homes), Concordia (9,500 homes) and Springwood (2,000 homes). The timing of this gate station is subject to the timing of residential developments in Roseworthy, Springwood and Concordia, and is proposed for the next AA period (Refer to Section 7.3, Business Case SA115).

A much slower I&C growth rate in the Virginia area and a reassessment of the Virginia Gate Station capacity by Epic Energy has deferred the need for a previously planned augmentation of this gate station into the subsequent AA period.

The reticulation of residential developments in Mt Barker requires a new gate station located in the Mt Barker area. This station was approved by the AER as part of the scope for the Mt Barker extension project.

District Regulator Stations

The additional TP-HP DRS in the Seaford – Aldinga area has addressed capacity issues in this network, which will ensure adequate capacity to this network is maintained over the next few years.

6.5.2. Operate and Maintain

Preventative maintenance (PM) and operational checks are undertaken on all network facilities in accordance with predefined job plans and frequencies.

Gate and District Regulator Stations

- Maintenance is carried out on a three-month, annual and five-yearly basis. The three-monthly and annual checks include inspection, set point and operational checks. The five-yearly maintenance activities include a major overhaul of the regulators, control valves and pilots and all soft seal components are replaced.
- DRS preventative maintenance will reduce progressively with the replacement of LP mains. The 109 LP DRSs feeding these networks will become redundant over the next AA period as the LP CI and UPS mains replacement program is completed.
- A program to provide real time SCADA pressure surveillance on TP regulators will be continued over the next AA period (Refer to Section 7.4, Business Case SA111). Real time monitoring of regulator supply pressures provides a 'health' check of these facilities allowing timely diagnosis and rectification of equipment performance before problems arise.

Emergency Isolation Valves

- Valve maintenance comprises annual inspection and maintenance of transmission and critical emergency isolation valves, and three-yearly inspection and maintenance of other valves.

- Preventative valve maintenance volumes will not materially change over the next AA period. There will be small 'organic' growth as the network expands to serve new customers, however this is will be covered by existing resources.
- A program to replace inoperable distribution valves is proposed for the next AA period (Refer to Section 7.8.3, Business Case SA107).

Cathodic Protection

- ICCP units are monitored continuously via the SCADA system while the operational status of galvanic anodes is gathered every six months from control area surveys.

6.5.3. Monitor and Review

Performance

- The performance of the gate and district regulator stations is assessed annually with the latest assessment showing that previously forecast upgrades to the Virginia and Mildura Gate stations are now, following further analysis, not required.
- A program to install real time, remote monitoring of cathodic protection (CP) systems on TP pipelines will be undertaken in the next five years with [redacted] sites targeted over the next AA period. Real time monitoring of TP pipeline CP systems will allow for earlier detection of CP equipment failure or transient loss of protection therefore reducing possibility of undetected corrosion leading to a reduction in asset life (Refer to Section 7.8.2, Business Case SA126).

Condition and Integrity

- Degradation of brick-constructed below ground vaults is contributing to water ingress leading to corrosion of pipe valves and fittings within the chamber. The wet and congested environment within these chambers has been identified as a maintenance risk. A replacement program commenced in the previous AA period to mitigate the risk associated with water ingress into below ground vaults.
- The sacrificial anodes in some locations on the Adelaide metropolitan, Riverland-Berri-Mildura, and Palm Valley transmission pipelines have reached the end of their useful service lives and are not providing adequate cathodic protection. A program to upgrade cathodic protection to more reliable and efficient impressed current units is underway and is planned to continue over the next seven years, with the Adelaide Metropolitan scope being proposed in the next AA period (Refer to Section 7.8.2, Business Case SA112)
- The program to replace the Grove pressure regulating and OPSO valves at TP district regulator stations is expected to be complete in the current AA period. However further risks have been identified at some TP DRSs, with the bypass at these sites not having a regulator installed, and relying on manual control during maintenance. A new program to install pressure regulation on DRS bypasses is proposed for the next AA period. (Refer to Section 7.4, Business Case SA106)

6.5.4. Manage Risk

Risk issues for network facilities are:

- DRS failures potentially leading to overpressure of downstream networks;
- Leakage and HSE issues in old brick underground regulator vaults;
- Significant corrosion in critical TP and HP underground isolation valves, with some being inoperable;
- End of life replacement of fully enclosed concrete DRS lids with manhole access, with properly designed butterfly style lids to allow easy access and egress, and provide enhanced venting capacity in the event of a gas leak (Refer to Section 7.5, Business Case SA109);
- Minimisation of number of customers who lose supply in an emergency – to address this risk [redacted] new transmission EIVs are proposed to be installed in the next AA period (Refer to Section 7.8.3, Business Case SA107);
- Inoperable critical underground isolation valves;
- Non-compliant cathodic protection of transmission pipelines and distribution mains;
- Isolated sections of unprotected steel mains, where installation of anodes or replacement with PE is proposed for the next AA period (Refer to Section 7.8.2, Business Case SA127); and
- End of life replacement of anodes at ICCP units and within the network in general (Refer to Section 7.8.2, Business Case SA112).

6.5.5. Repair/ Replace/ Abandon

- The replacement program of below ground transmission system regulators that are subject to water ingress will continue over the current AA period. The new designs will significantly improve the safety and maintainability of these facilities.
- Maintainability issues at a number of TP DRS have been identified, with spare parts no longer available for old Grove regulators and some older types of OPSO valves. A program to replace the Grove pressure regulating and OPSO valves at these stations is expected to be completed in the current AA period.

6.6. Metering Facilities

6.6.1. Plan and Create

Ongoing residential, commercial and industrial customer growth is expected to continue at rates similar to historic growth.

6.6.2. Operate and Maintain

Maintenance activities for specific types of meter installation are described below.

- Low pressure installations – low pressure sites are sites that operate at less than 7 kPa. These sites all have smaller diaphragm meters and no routine maintenance is carried out unless the consumer, retailer or APA personnel report a problem;
- Elevated pressure installations with remote telemetry and correcting instruments – the sites are visited every six months to check the pressure and temperature transducers for accuracy; uncorrected flow; and general condition and integrity of the facility;
- Elevated pressure installations with correcting instruments and no remote telemetry – these installations are visited annually to check: pressure and temperature transducers for accuracy; corrected and uncorrected flow; and general condition and integrity of the facility;
- Elevated pressure installations with no correcting instruments and no remote telemetry – these installations are visited either annually if they have a pressure relief valve or every three years if they do not. The visits consist of checking the site and meter integrity, checking the set pressure on the regulator, checking meter site for leaks and functionality, painting if appropriate and ensuring all signage is appropriate. There are no plans to change the current maintenance regimes.

6.6.3. Monitor and Review

Performance

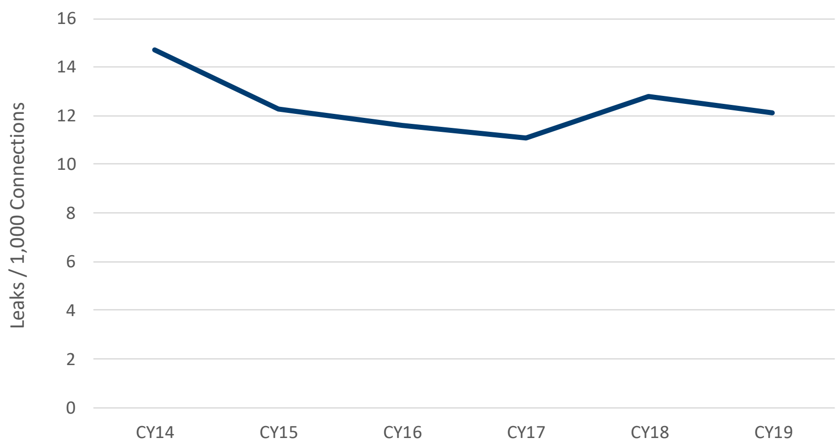
All new residential meters are accuracy tested and pressure tested prior to delivery. We procure only two types of meters for residential use - the AMPY 750 and EDMI U8.

The purchase requirement is for the accuracy of all new meters to be ±1%, and new meters have consistently met this accuracy.

Condition and Integrity

Figure 6.13 details leak repairs associated with metering facilities (meter isolation valve, pipe and fittings, pressure regulator and the meter).

Figure 6.13: Meter Leak Rate



We completed approximately [redacted] leak repairs per 1,000 connections for calendar year 2019 associated with metering facilities (meter isolation valve, pipe and fittings, pressure regulator and the meter).

The metering facility includes the meter isolation valve, pipe and fittings, pressure regulator and the meter. The downward trend in the meter leak rate since 2014 has reversed, with an increase of 9% in the last 24 months, the vast majority of which relates to a continued increase in venting failures. Further investigation is required to confirm the reasons for this trend.

Some meters inside buildings do not comply with current standards. Some of these have risers inside wall cavities, making rectification difficult. A program to relocate non-compliant meters is planned for the current AA period.

The pipework and valves at a number of I&C metering facilities has corroded, especially at the ground to air interface of the pipe riser, to the extent a program of in situ grit blasting and painting is being progressed in the current and next AA period (Refer to Section 7.8.4, Business Case SA108).

Additionally, some I&C metering facilities have been found to have unregulated bypasses, leading to the potential overpressure of the downstream customer piping. A program to install regulators on these is proposed for the next AA period (Refer to Section 7.8.4, Business Case SA129)

6.6.4. Manage Risk

Risk and issues for metering facilities are:

- Grit blast and repaint the corroded paintwork on elevated pressure I&C meter sets (refer to business case SA108);
- Survey and replace non-compliant meters within buildings and carports; and
- Install regulators on unregulated bypasses of some I&C customers (refer to business case SA129)

6.6.5. Repair/ Replace/ Abandon

Meters are replaced once they have reached their 'deemed' life, as per the South Australian Gas Metering Code. This gives rise to between 15,000 to 30,000 periodic meter changes (PMC) per year.

In addition to the PMC program, meters are replaced on a 'reactive' basis in response to leakage and meter accuracy complaints, with average of 2,500 meters per annum being replaced over the last three years.

The Meter Replacement Plan (SA) details the regulatory obligations pertaining to metering, processes by which meters are selected for replacement, and the forecast number of meter replacements over the next AA period. This Plan only applies to the forecast PMCs for the regulated networks, which comprise approximately 98% of our South Australian Networks meters.

6.7. SCADA Facilities

6.7.1. Plan and Create

SCADA technology has advanced significantly in recent years and can now provide enhanced solutions in terms of both cost effectiveness and technical capability. Installation of additional SCADA sites is part of a strategic approach to increase use of technology for remote monitoring and real time data capability.

New SCADA facilities are added in response to growth in other asset classes, Stay in Business (SIB) projects that address various identified risks, and increases in the overall network. Examples include:

- New Tariff D customers;
- New fringe point monitoring sites for organic growth or step out developments; and
- Addition of monitoring to sites with no existing installed SCADA.

6.7.2. Monitor and Review

The maintenance for SCADA and telemetry systems comprises an annual visit to each site to:

- Test and calibrate all instruments, pressure and temperature transmitters, and verify flow computer calculations;
- Test batteries conditions and earthing systems;
- Clean solar systems and verify functionality; and
- Inspect hazardous area installations.

Typical issues currently being found are:

- Batteries requiring replacement – a program of installing solar panel to provide recharge facilities for batteries is underway;
- Slam shut switches sticking; and
- Drift of pressure transmitter calibration.

6.7.3. Manage Risk

Risk issues for SCADA facilities are:

- Inadequate real time monitoring of critical facilities – a program is underway to install telemeters at transmission pressure regulator locations;
- Inefficient and unreliable network pressure data capture – telemeters are being installed at network fringe points to replace chart recorders;
- End of life replacement of flow correctors and modem equipment at demand customer sites;
- End of life replacement of a variety of obsolete SCADA equipment;
- Ensure adequate CP protection levels are provided. A program is planned to install SCADA at critical CP rectifier units; and

- Adequate real time pressure monitoring of network fringe points. (Refer to Section 7.4, Business Case SA111).

6.7.4. Replace/ Repair/ Abandon

Generally, SCADA facilities are replaced as result of technical obsolescence. SCADA facilities have a technical life of about ten years. Over the last five years the move to standard communication protocols (GSM/GPRS) has driven changes to field devices using telecommunications.

Following the upgrade of the central SCADA facility to the national APA Clear SCADA server platform in 2013, field sites are now being upgraded with new hardware and software. This will ensure that the regulatory initiative to harmonization of the Gas Day to a national basis across eastern Australia can be accommodated.

In-Line flow correctors have become obsolete and require replacement as a priority. They are planned to be replaced with more modern units in the next AA period. (Refer to Section 7.4, Business Case SA110).

7. Capital Expenditure – Regulated Networks

This section provides an overview of our network investment (i.e. capital expenditure) forecast for the next AA period (1 July 2021 to 30 June 2026).

For regulated assets (i.e. our SA distribution network), our investment forecast is grouped in the following categories, as defined by the AER:

- Mains Replacement - Capital expenditure incurred for the replacement of existing mains and services in the network due to the condition of those mains and services;
- Meter Replacement - Capital expenditure incurred for the replacement of installed meters with new or refurbished meters;
- Augmentation - Capital expenditure incurred to change the capacity requirements of mains and services in the gas distribution network to meet the demands of existing and future customers;
- Telemetry - Capital expenditure incurred in the replacement of SCADA operating in the network due to the condition of the assets;
- Regulators - Capital expenditure incurred in the replacement or upgrade of our gate and district regulator stations due to the condition of the assets;
- Growth (Connections) - Capital expenditure incurred when connecting new customers to the gas distribution network;
- ICT - Capital expenditure associated with ICT assets but excluding all costs associated with SCADA expenditure that exist beyond gateway devices (routers, bridges etc.) at corporate offices;
- Other – Capital expenditure which is not captured by other capital expenditure categories (as defined above). Other expenditure is split between capital incurred on asset directly relating to the distribution network (Other – Distribution System) and assets not directly related to the network (e.g. vehicles and non-operational buildings).

Our forecast excludes capitalised network or corporate overheads.

An overview of our capital program is contained in Table 7.1 and summaised in Figure 7.1. In total, we are forecasting to spend $508 million of the five-year AA period.

Figure 7.1: Capital Expenditure Summary by asset type (Regulated Networks)

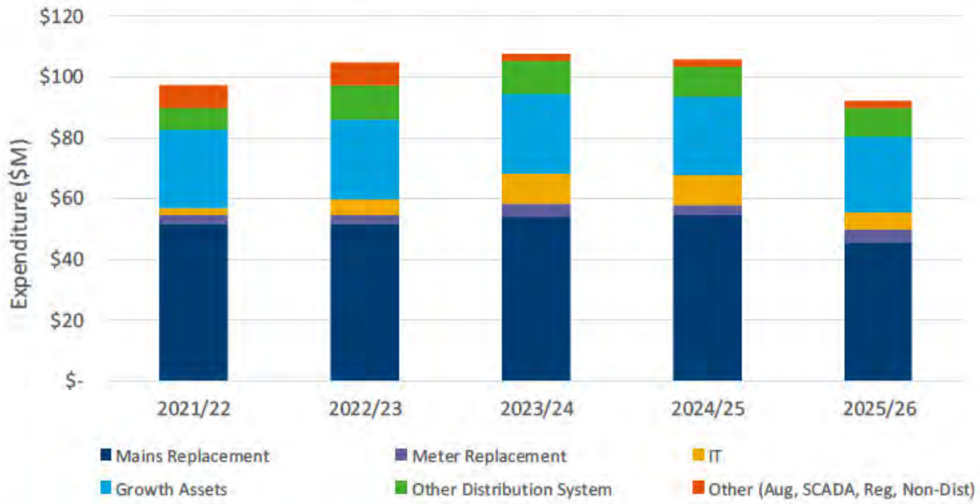
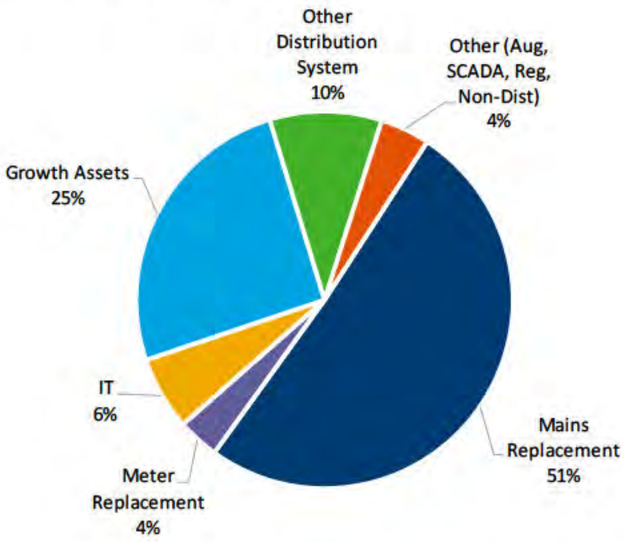


Table 7.1: Capital Expenditure Summary (Regulated Networks)

Ref	Capex Category	2021/22	2022/23	2023/24	2024/25	2025/26	Total
7.1	Mains Replacement	51.71	51.71	54.09	54.57	45.93	258.01
7.2	Meter Replacement	3.08	2.99	4.31	3.58	4.20	18.15
7.3	Augmentation	4.91	5.29	0.00	0.00	0.00	10.21
7.4	Telemetry & SCADA	0.50	0.34	0.34	0.31	0.25	1.76
7.5	Regulators	0.71	0.79	1.19	1.19	1.19	5.07
7.6	ICT	2.10	4.92	9.88	9.87	5.24	32.00
7.7	Growth Assets	25.89	26.59	26.46	25.44	24.99	129.37
7.8	Other Distribution System	1.08	1.08	0.75	0.75	0.87	48.92
7.9	Other Non-Distribution System	51.71	51.71	54.09	54.57	45.93	4.52
	Total Expenditure ($M)	**97.28**	**104.92**	**107.68**	**105.75**	**92.37**	**507.99**

Cumulatively, 76% of our forecast capital expenditure for the next AA period is related to our Mains Replacement and Growth programs; as shown in Figure 7.2.

Figure 7.2: Capital Expenditure Summary – Breakdown by Capex Category



Each expenditure category is further explained in the following sections.

7.1. Mains Replacement

Our distribution network dates back to the late 1880's and consequently consists of a variety of materials which at the time of installation were deemed fit for purpose. Cast iron (CI) and unprotected steel were predominantly used until the introduction of polyethylene pipe mains in the 1970's.

The type of material has a major bearing on the maximum operating pressure of the network. Since CI can only be operated at medium and low pressures compared to polyethylene, the replacement of CI mains with polyethylene pipe over time means that the capacity, integrity safety of the network is maintained.

Our mains replacement program remains a key focus in the next AA period. It is the single most important activity we undertake to ensure public safety.

As part of our mains replacement program we will:

- Complete the replacement of all remaining low-pressure CI, UPS and other mains. All low and medium pressure CI and UPS mains will be removed from the network by the end of the next AA period which represents a significant safety milestone;
- Complete the replacement of all remaining high-risk early generation plastic piping (HDPE 250);
- Undertake inline camera inspections and reinforcement of HDPE 575 DN50, and replace a prioritised portion of the more narrow high-risk early generation HDPE 575 DN40 mains, where inline camera inspection and reinforcement cannot be undertaken;
- Replace 457 multi user services at high risk;
- Continue to replace mains reactively as a means of overcoming urgent leakage problems or localised cases of water ingress or shallow mains; and

- Continue to replace services when leaks or damage occur on the service and inspection reveals that the service is heavily corroded or in such poor condition that repairs are not viable.

This follows a significant program of mains replacement undertaken in the current AA period, which will see the replacement of all mains with Adelaide CBD and all medium pressure truck mains replaced by the end of the current AA period.

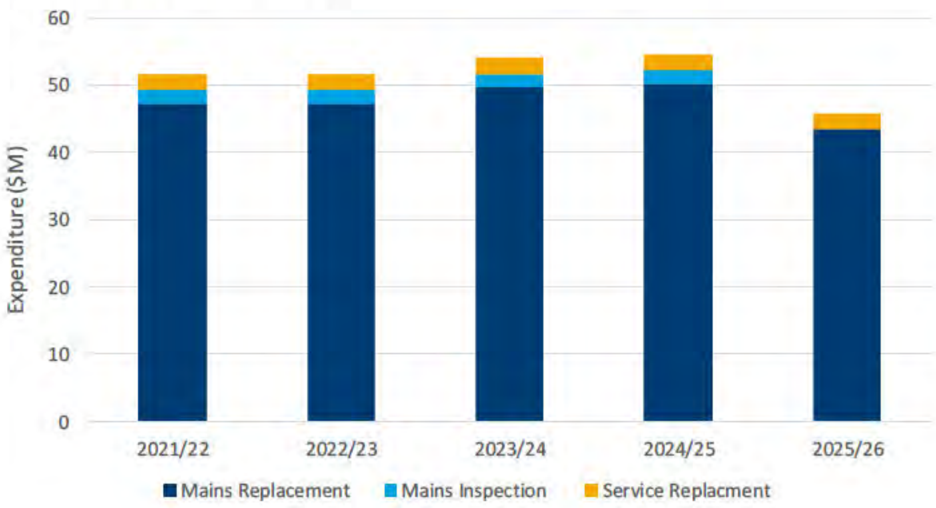
Table 7.2 shows our forecast capital expenditure relating to "Mains Replacement", split into the core activities of mains replacement, mains inspection and service replacement, for the next AA period. Note that the table does not include $1.2 million per annum ($6.02 million over the AA period) of piecemeal replacement of mains as this program forms part of our cost base (i.e. Opex).

Table 7.2: Mains Replacement – Expenditure Summary

Program	2021/22	2022/23	2023/24	2024/25	2025/26	Total
CI & UPS Block Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
HDPE Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Mains Replacement	*47.29*	*47.29*	*49.69*	*50.27*	*43.59*	**238.11**
Inline Camera Inspection	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Mains Inspection	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
MUS Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non MRP service replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Service Replacement	***2.36***	***2.36***	***2.34***	***2.34***	***2.34***	***11.74***
Total Expenditure ($M)	**51.71**	**51.71**	**54.09**	**54.57**	**45.93**	**258.01**

The expenditure profile for Mains Replacement activates is shown in Figure 7.3.

Figure 7.3: Mains Replacement – Expenditure Summary



7.1.1. Mains Replacement Programs

Block Replacement Program – CI/UPS

We have an established history of replacing / renewing our low pressure mains and services to high pressure standard. This program is our largest, contributing over 50% of mains replacement capital expenditure over the current AA period. The focus of the renewal program is heavily deteriorated Cast Iron mains which have exceeded their service life. Polyethylene mains, installed through insertion methods are predominantly used to upgrade the low pressure networks to high pressure.

The inherent risk of CI and UPS mains has been understood for a period of time, so we have prioritised a widespread replacement program to remove them from our Network. The highest risk mains in the CBD, as well as the medium pressure trunk mains will have been removed in full in the current AA period. All remaining CI and UPS mains will have been replaced by the end of the next AA period.

Table 7.3 shows the direct capital expenditure forecast for our block replacement programs for the AA period. For forecasting purposes, the program is segmented into two; General Block Replacement and North Adelaide Block Replacement, to acknowledge the increased difficulty of replacement of mains in the North Adelaide area.

Table 7.3: Block Replacement Summary

Program		2021/22	2022/23	2023/24	2024/25	2025/26	Total
General Block Replacement	Length (Km)	104	104	106	106	100	520
	Unit Rate ($/m)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Subtotal ($M)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Nth Adelaide Replacement	Length (Km)	10	10	10	8	-	38
	Unit Rate ($/m)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Subtotal ($M)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Expenditure ($M)		**32.58**	**32.58**	**33.09**	**31.93**	**25.73**	**155.91**

HDPE Mains Replacement

The High Density Polyethylene (HDPE) Replacement Program specifically targets early or first generation HDPE introduced onto our network. These first generation polyethylene mains were classified as Class 250 and Class 575 for operation at medium and high pressure. The main difference between the class ratings is the variation in wall thickness with Class 250 having a thinner wall thickness than that of the Class 575 of the same nominal bore size. It is typically these early or first generation polyethylene mains that offer limited resistance against Slow Crack Growth (SCG) induced through severe environmental and operating conditions, as they have substandard material properties relative to newer polyethylene mains.

HDPE 250 mains were mostly laid in the 1970s and is our oldest class of polyethylene. These mains are becoming increasingly brittle with age, which reduces their ability to withstand SCG induced at damaged sections of the main caused by previous squeeze-offs. They are considered unmaintainable, therefore their replacement is considered a priority activity for the business.

HDPE 575 was laid from the late 1970s to the mid-1990s. They operate at high or medium pressure and, like HDPE 250, they are susceptible to SCG resulting from damage inflicted by previous squeeze offs or other stress concentrators. Many of these mains are located in populated areas near buildings where escaped gas has the potential to collect. The pipes installed in the late 1970s are additionally showing early signs of non-squeeze-off SCG failures such as rock impingement and fusion joint failures.

All HDPE 575 mains with a history of squeeze off failure will have been replaced by the end of the current AA period.

The HDPE 575 mains are separated in two sub categories, with the smaller diameter mains (DN40 or below) requiring replacement while bigger diameter mains (DN50 or above) are suitable for inline camera inspection and associated reinforcement Through experience gained in the current AA period, inline camera inspection and reinforcement is a considered a practical alternative to replacement for these mains and is now adopted as our primary management policy for mains where there is no history of squeeze off failure, and the technology can be effectively employed (refer to Section 7.1.2 below).

For the next AA period, we are forecasting the continued replacement of HDPE 575 mains where inline camera inspection is not possible. Table 7.4 shows the direct capital expenditure forecast for our HDPE Replacement program.

Table 7.4: HDPE Mains Replacement Program

Program		2021/22	2022/23	2023/24	2024/25	2025/26	Total
HDPE 575 DN40 MP	Length (Km)	10	10	20	25	25	90
	Unit Rate ($/m)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Subtotal ($M)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
HDPE 575 DN40 HP	Length (Km)	40	40	40	40	38	198
	Unit Rate ($/m)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Subtotal ($M)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
HDPE 250 Replacement	Length (Km)	7	7	-	-	-	14
	Unit Rate ($/m)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Subtotal ($M)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Expenditure ($M)		**14.71**	**14.71**	**16.59**	**18.34**	**17.86**	**82.20**

7.1.2. Inline Camera Inspections

As part of our response to a network incident that occurred in 2014, we introduced live camera inspection technology for the inspection of our early generation HDPE mains. The camera system is a useful element to mitigate PE risks, specifically the risk associated with SCG induced by mains squeeze-offs on early generation PE mains.

The inline camera is used to inspect the inside of the pipe and identify squeeze off points, i.e. points on the main susceptible to sudden failure. Once identified, the pipe is clamped and reinforced with a stainless-steel clip. This provides protection to the weakened parts of the pipe wall caused by squeeze off and reduces/removes the event of squeeze off failures that would release gas. By reducing the likelihood of squeeze off as a source of failure, the overall risk of these pipes is significantly reduced. This inspection and reinforcement option is only available for mains with a diameter of at least 50mm, as that is the size required to allow the camera access.

Inline camera inspection and reinforcement is a practical alternative to replacement for these mains and is now adopted as our primary management policy for mains where there is no history of squeeze off failure, and the technology can be effectively employed.

In the next AA period, we are forecasting to inspection all remaining HDPE 575 mains of at least 50mm diameter. The total cost of this is program is $8.16 million which is significantly less than an alternate replacement program.

Table 7.5: HDPE Inline Camera Inspection program

Program		2021/22	2022/23	2023/24	2024/25	2025/26	Total
Inline Camera Inspection	Length (Km)	80	80	80	76	-	316
	Unit Rate ($/m)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Expenditure ($M)		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

7.1.3. Service Replacement Program

Multi User Sites Replacement

Prior to 2012, replacement of internal services within MUS sites was not included in the scope of the Mains Replacement Program (MRP). During installation of new/replacement High Pressure mains, MUS sites were fitted with a boundary regulator and the existing internal service within each MUS site remained operating at low pressure. From 2012, MUS replacements have been packaged with MRP.

A boundary regulator is located on the front boundary of property reducing pressure from high pressure to medium or low pressure. A sub-main is connected to the boundary regulator and runs through the MUS property. Individual inlets branch off the sub-main to reach inlet risers and gas meters for each unit. The majority of the MUS sub-mains and inlets are aging unprotected steel and galvanized pipe.

Badly corroded UPS inlet services to multi-user sites are being progressively replaced to align system integrity with that of the inserted and pressure upgraded mains to which these assets are connected. In the next AA period, we are replacing 457 MUS sites that are at high risk meaning the meters are located in non-compliant locations and the services are aging unprotected steel and galvanized pipe.

Table 7.6 shows the direct capital expenditure forecast for MUS replacement program.

Table 7.6: MUS Replacement

Program		2021/22	2022/23	2023/24	2024/25	2025/26	Total
Service Renewal - MUS	Sites	92	92	91	91	91	457
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Reactive Service Replacement

Reactive services replacement provides for an allocation of capital expenditure to allow for the piecemeal renewal of services outside the planned mains replacement program. The need for such service replacements arise when leaks or damage occur on the service and inspection reveals that the service is heavily corroded or in such poor condition that repairs are not viable, or that the service is at a non-compliant depth.

Table 7.7 shows the expenditure forecast for the reactive services replacement program.

Table 7.7: Reactive Service Replacement

Program		2021/22	2022/23	2023/24	2024/25	2025/26	Total
Reactive Service Replacement	Services	490	490	490	490	490	2,450
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

7.2. Meter Replacement

Capital expenditure associated with the replacement of meters (with new or refurbished meters) on the distribution network is captured in the "Meter Replacement" expenditure category.

Our meter replacement programs are founded by the South Australian Gas Metering Code and aligned with the requirements of AS/NZS 4944:2006 Gas meters—In-service compliance testing.

The Meter Replacement Plan (Attachment 8.3) outlines the program of work we undertake to manage the accuracy and integrity of our customer gas meters on a rolling five-year basis. Within the Plan there are broadly three key activities of work:

- Periodic Meter Changes (PMC) where meters are replaced at the end of their deemed useful life or compliance period.
- Meter Testing – inclusive of initial in-service compliance testing and field-life extension testing; and
- Reactive replacement of defective meters.

Our Meter Replacement work program for the next AA period will replace over 93,000 meters at cost of $18.15 million and includes:

- Over 81,500 forecast end of life meters
- Over 400 initial in-service compliance testing of new meter families;
- Continued focus on extending the life of meters by conducting field-life extension (FLE) testing on more asset families. We estimate approximately 1,500 meters will be removed from the field and subject to FLE testing over the next five years; and
- Reactive replacement of approximately 10,000 defective meters.

This follows on from a similar work program which will be delivered in the current AA period that replaced over 140,000 meters at a total forecast cost of $22 million.

The Meter Replacement work program is guided by strict standards for metering installations and the obligations we have to test and replace these meters. The volume of work required under this Plan for each AA period is heavily influenced by the age of the current stock of domestic and commercial meters in our network at that time.

The Meter Replacement Plan further sets out our metering related regulatory obligations, the current stock and performance of domestic and commercial meters in our network, our meter replacement policy, our performance in the current AA period and our forecast meter replacement program for the next AA period (including our step by step approach to coming up with this forecast).

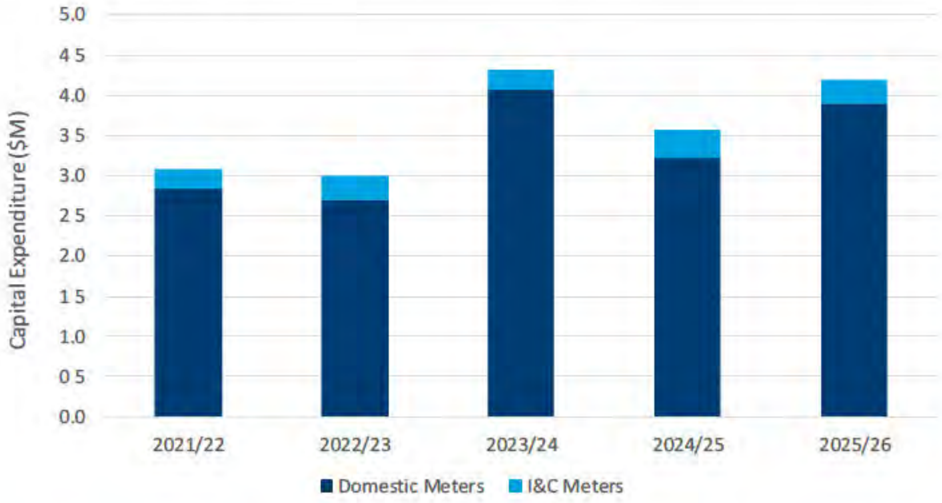
Table 7.8 shows the expenditure relating to "Meter Replacement" for the next AA period.

Table 7.8: Meter Replacement – Expenditure Summary

Program	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Domestic Meter Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
I&C Meter Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Expenditure ($M)	**3.08**	**2.99**	**4.31**	**3.58**	**4.20**	**18.15**

The expenditure profile for Meter Replacement is shown in Figure 7.4. Were possible, we aim to flatten the replacement profile to ensure deliverability of the replacement program.

Figure 7.4: Meter Replacement – Expenditure Summary



Domestic Meter Replacement

Over 90% of our meter replacement program (by cost) relates to the testing and replacement of domestic meter types. Domestic meters are subjected to the testing requirements as defined in AS/NZS 4944:2006 Gas meters—In-service compliance testing.

In total, we will replace over 90,000 meters in the next AA period. A breakdown of domestic meter replacement volumes and costs are contained in Table 7.9.

Table 7.9: Domestic Meter Replacement

Program	2021/22	2022/23	2023/24	2024/25	2025/26	Total
End-of-life Meters	12,726	11,844	19,622	15,424	19,328	**78,944**
Meter Testing	139	488	363	270	270	**1,530**
Reactive Replacement	2,500	2,250	2,000	1,750	1,500	**10,000**
Total Meters	**15,365**	**14,582**	**21,985**	**17,444**	**21,098**	**90,474**
Unit Rate ($/Meter)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Expenditure ($M)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

I&C Meter Replacement

A smaller component of the program is the periodic replacement of I&C meters. A breakdown of the I&C meter replacement program is provided in Table 7.10.

Table 7.10: I&C Meter Replacement

Program	2021/22	2022/23	2023/24	2024/25	2025/26	Total
End-of-life Meters	395	534	456	660	539	2,584
Meter Testing	106	83	60	81	81	411
Total Meters	501	617	516	741	620	2,995
Unit Rate ($/Meter)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Expenditure ($M)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

7.3. Augmentation

Network augmentation is the addition of gas network infrastructure (mains, gate station, and pressure facilities), aimed at providing adequate capacity to maintain a safe and reliable supply of gas to customers.

Networks are augmented to:

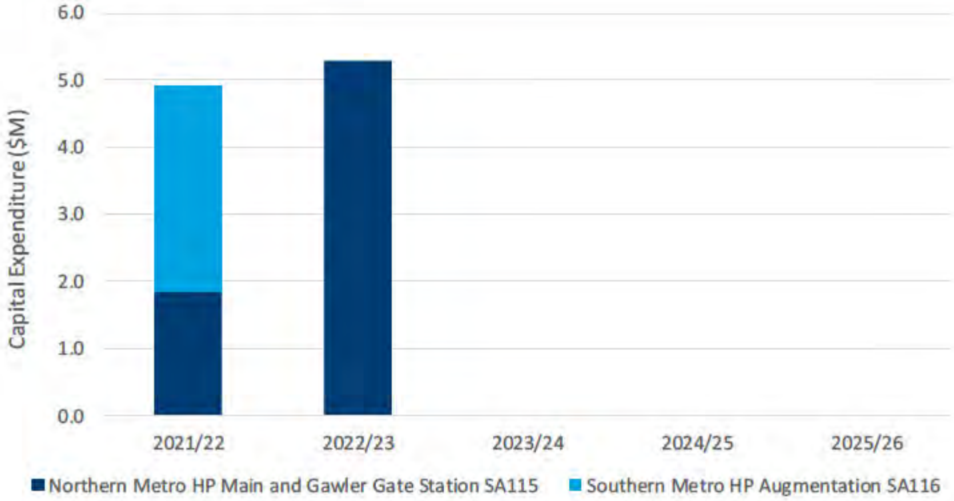
- maintain a safe supply of gas to customers – poor network pressures could lead to a momentary loss of supply to an appliance. Should a 'flame out' occur and remain unnoticed, this could lead to a gas in building incident, which in turn could result in serious injuries and/or fatality through a gas explosion or asphyxiation. While the likelihood of this is low the consequences could be major;
- maintain supply reliability to existing customers – growth within and at the extremity of networks can decrease network capacity to the extent that supply reliability may be compromised resulting in a gas outage. Supply interruption to customers can pose significant operational, compliance and reputational issues. We are obligated under the Gas Distribution Code to maintain system delivery pressures above nominated minimums that are deemed to maintain a safe and reliable supply of gas; and
- avoid a major gas outage caused by a single point failure – a single point of failure (third party damage, major mains leak, pressure regulating facility failure) could give rise to significant operational, compliance and reputational issues. There are several controls (dial before you dig, pipeline route surveys, SCADA monitoring, preventative maintenance programs, and design redundancy) that aim to mitigate this risk. However, there are still situations that could give rise to an unacceptable risk. In these circumstances, additional network infrastructure may be considered to reduce the risk.

An overview of network capacity (for key regions) is summarised in Section 6.3.1 (Transmission Pipelines) and Section 6.4.1 (Distribution Mains & Services) of this SAMP. A number of augmentation programs are forecast for completion in the next AA period; as shown in Table 7.11.

Table 7.11: Augmentation - Expenditure Summary

Program	Business Case	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Gawler Gate Station	SA115	1.84	5.29	-	-	-	7.13
Seaford Aldinga HP Augmentation	SA116	3.07	-	-	-	-	3.07
Total Expenditure ($M)		4.91	5.29	-	-	-	10.21

Figure 7.5: Augmentation - Expenditure Summary



Northern Metro HP Main and Gawler Gate Station – Business Case SA115

The northern suburbs of metropolitan Adelaide, and in and around Gawler, continue to be one of the major residential growth (greenfield and infill) areas in South Australia. Three large residential and commercial developments near the Gawler region (Springwood, Roseworthy and Concordia) are expected to connect to the SA natural gas distribution networks within the next five years. These new developments will significantly increase load in the region and exhaust network capacity.

This load increase will have the greatest impact on the northern extremity of the Gawler area network, particularly in and around Willaston. Willaston is located 11 km from the nearest transmission pressure/high pressure (TP/HP) regulator at Munno Para, which serves around 3,200 customers. The pressure drop over the 11 km trunk main means the Willaston area is sensitive to load growth. A relatively minor increase in load can rapidly draw down spare capacity within the network, leading to substandard pressures and potential loss of supply.

Network augmentation is therefore required to ensure pressures do not drop below minimum acceptable levels in the Willaston area when the new residential and commercial developments are completed. Without augmentation, we expect extremity pressures to fall below the minimum acceptable pressure of 90 kPa in 2023.

The Gawler Gate Station project is forecast to cost $7.13 million and be completed by winter 2023.

Seaford Aldinga HP Augmentation – Business Case SA116

The southern suburbs of metropolitan Adelaide, from Noarlunga down to Sellicks Beach, is a major residential growth area. Over the past five years, the number of customer connections in the region has grown by an average of 498 new residential connections per year. We expect growth to continue at this rate (as a minimum) over the next AA period.

This historical growth in residential connections has decreased the amount of spare capacity in the Seaford Aldinga HP network, and we are reaching the point where augmentation is required in order to maintain customer supply pressures.

Several infrastructure projects such the Main South Road duplication, and construction of a new school in Aldinga, combined with forecast residential growth in the City of Onkaparinga[17], indicates that residential growth will continue to be strong and natural gas demand in the region will continue to increase.

Continued load growth in the region increases the risk of pressures dropping below 90 kPa, which is the minimum level necessary to maintain a safe and reliable customer supply. Based on the historical growth rates alone, we estimate that unless action is taken to augment the southern network, pressures will fall below 90 kPa before 2023.

The load increase will have the greatest impact on the southern extremity of the Seaford Aldinga HP network, particularly in and around Aldinga itself, which is home to around 2,400 customers.

Network augmentation is therefore required before 2023 to ensure customers' supply is not affected. This business case considers options to augment the Seaford Aldinga HP network during 2021/22

The proposed Seaford Aldinga HP Augmentation project will result in the duplication of a [redacted] km of DN280 trunk main from McLaren Vale to Aldinga, forecast to cost $3.07 million and be completed before winter 2023.

7.4. Telemetry

Capital expenditure incurred in the replacement or upgrade of our SCADA and Telemetry systems are contained within this expenditure category. SCADA facilities includes:

- Pressure monitoring and control equipment;
- Network fringe point control; and
- Demand customer monitoring (including telemetry).

We are forecasting $1.76 million of capital expenditure, across two programs of work, during the next AA period. The larger of the programs (SA110) is aimed to replace obsolete equipment in our existing SCADA network.

Table 7.12 shows the expenditure related to "Telemetry" projects for the next AA period.

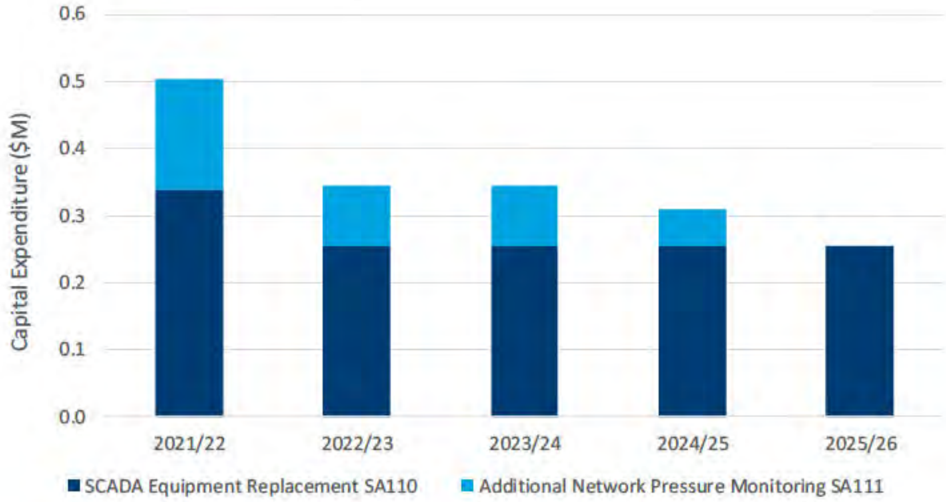
[17] Projections from .id, see: https://forecast.id.com.au/onkaparinga/residential-development?WebID=10

Table 7.12: Telemetry & SCADA – Expenditure Summary

Program	Business Case	2021/22	2022/23	2023/24	2024/25	2025/26	Total
SCADA Equipment Replacement	SA110	0.34	0.25	0.25	0.25	0.25	1.36
Additional Network Pressure Monitoring	SA111	0.17	0.09	0.09	0.05	-	0.40
Total Expenditure ($M)		0.50	0.34	0.34	0.31	0.25	1.76

The expenditure profile is shown in Figure 7.6. A summary of each project within the "Telemetry" capital category is provided below.

Figure 7.6: Telemetry & SCADA – Expenditure Summary



SCADA Equipment Replacement – Business Case SA110

We use SCADA systems to monitor and report on the flow of gas at each of the 325 critical facilities, 170 contestable meter sites (>10TJ/year), 15 gate stations and a further 73 strategic sites across the network including district regulator stations (DRS), network fringe points and demand customers.

We have a program to proactively replace SCADA equipment when it is technically obsolete (around 10 years, in line with original equipment manufacturer's recommendations) to reduce the risk of a significant failure of our system. Over the next five years, the following equipment requires replacement:

- 50 remote telemetry units (RTU) used to collect and code data into a format that is transmittable and transmit the data back to a central station.
- 67 data loggers used to remotely measure and record flow and pressure at strategic facilities in the network.
- 11 electronic flow correctors used to measure and record pressure and calculate a correction factor to convert actual volumes recorded by the meter to the standard billing volume.

In addition to this ongoing replacement program, within the forthcoming AA period, we will replace 3G modems embedded in the network. The 3G mobile telecommunication network (which is operated by third-party providers) is used to transmit data to a central system. The 3G network is expected to be phased out by all providers by 2024. We have assessed our SCADA system and have determined that modems at 60 of our sites are incompatible with the new 4G protocols and will need to be replaced before the 3G network ceases.

Additional Network Pressure Monitoring – Business Case SA111

Installing SCADA pressure monitoring equipment across our network is critical to:

- ensure early detection of network issues such as over/under pressurisation which is increasingly important in our aging network and allows lower cost proactive repairs to occur;
- allow the effective and efficient response to asset failures and the associated potential emergency events;
- provide a view of network performance during high demand seasons;
- facilitate efficient and prudent network modelling that helps with the safe and reliable operation of the network; and
- inform investment decisions, in particular, in relation to expansion and augmentation projects.

When expanding and augmenting our network, we consider the criticality of our assets and the value derived from installing SCADA on them.

In 2012, we commenced a program to install telemetering on all District Regulator Stations (DRS). By the end of the current AA period, pressure monitoring will have been installed on [redacted] of our 91 DRSs. This business case addresses the five remaining sites.

As the network continues to grow, the need for pressure monitoring at sites across the network are periodically assessed. A recent review identified [redacted] sites across the network where remote pressure monitoring is required to ensure effective network monitoring. These locations are:

- in expanding areas of the network likely to see reasonable growth in demand over the next 1-5 years (new developments and estates); and
- where there is considerable distance between the area and district regulator station supplying the network, sometimes in combination with small trunks between supply regulators and area, where a small increase in demand in the area can lead to a significant pressure drop.

Over the next AA period, we plan to install pressure monitoring at these [redacted] strategic sites to ensure capacity and supply requirements continue to be met.

7.5. Regulators

Capital expenditure incurred in the replacement or upgrade of our gate and district regulator stations is contained within this expenditure category.

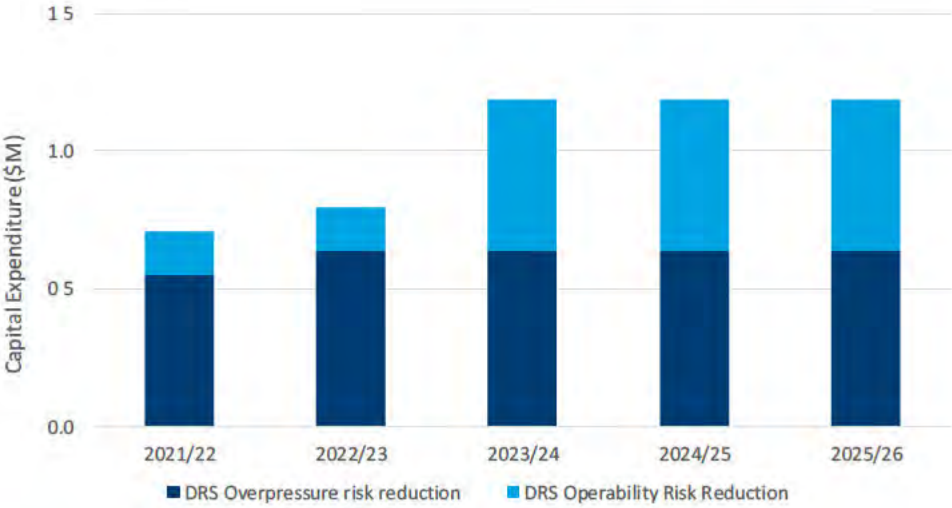
We are forecasting $5.07 million of capital expenditure, across two risk reduction programs during the next AA period. Table 7.13 shows the expenditure related to "Regulator" projects for the next AA period.

Table 7.13: Regulators – Expenditure Summary

Program	Business Case	2021/22	2022/23	2023/24	2024/25	2025/26	Total
DRS Overpressure risk reduction	SA106	0.55	0.64	0.64	0.64	0.64	3.10
DRS Operability Risk Reduction	SA109	0.16	0.16	0.55	0.55	0.55	1.97
Total Expenditure ($M)		0.71	0.79	1.19	1.19	1.19	5.07

The expenditure profile is shown in Figure 7.7. A summary of each project within the "Regulators" capital category is provided below.

Figure 7.7: Regulators – Expenditure Summary



DRS Over Pressure Risk Reduction – Business Case SA106

Each District Regulator Station (DRS) facility has a service bypass line. The bypass line allows us to maintain supply to the downstream network while we shut down the DRS and conduct maintenance. Approximately 30 years ago the standard design for DRS facilities was modified to include a secondary isolation valve on the bypass line to reduce the likelihood of an overpressure event. In 1998 the standard was modified again to include regulators on bypass lines. These design changes allow DRS maintenance to be conducted with minimum disruption to the downstream network and its customers.

Since 1998, all new DRS facilities installed on the network have been designed to the contemporary standard. At 1 July 2020, [redacted] TP DRS facilities with unregulated bypass lines remain in the SA network.

We plan to install isolation valves and regulators on [redacted] bypasses over the next AA period, at a forecast cost of $3.10 million, to manage the overpressure risk. The remaining [redacted] DRS shall be addressed during the following access arrangement period.

DRS Operability Risk Reduction – Business Case SA109

[redacted] existing underground District Regulator Stations (DRS) in the South Australian natural gas distribution networks have fully enclosed concrete Gatic manhole lids. These manhole lids present a health and safety risk to technicians. The lids make it difficult to access and egress the pits, particularly in the event of an emergency evacuation. The enclosed nature of this style of pit lid also poses a risk to operations technicians where the technicians could become asphyxiated in an event of a gas leak in the pit.

Replacing fully enclosed lids with butterfly style lids will allow for easy access and egress, and provide significant capability to vent any potential gas leaks at the DRS. It will also demonstrate compliance with Regulation 64 and Regulations 34-38 of the Work Health and Safety (Confined Spaces) Code of Practice 2015.

Over the next AA period we plan to replace the existing manhole concrete lids on [redacted] with butterfly style lids, at a total forecast cost of $1.97 million.

7.6. Information Technology (IT)

Capital expenditure relating to our IT platforms is contained within the "IT" capital expenditure category.

Our IT systems provides a suite of functionality to allow us to deliver a safe and reliable supply gas to our customers. Refer to Section 5.10 for additional information.

In recent years we have introduced a national program to coordinate development and maintenance of our IT systems across all jurisdictions in which we operate. We've done this to achieve economies of scale through streamlined implementation and business processes, standardised data models and data migration techniques, and by utilising existing hardware platforms.

Considerable progress has been made. Major projects initiated during the current AA period include upgrading our geospatial information systems (GIS) and metering & billing applications, mobility integration and developing a business intelligence platform. These core systems will allow us to leverage efficiencies in business operations through better data consolidation, standardisation of national processes and task automation.

We have also begun coordinating software application upgrades and updates across the AGN business. Our application renewal program seeks to bring our existing suite of IT applications up to an acceptable industry standard, and schedule subsequent updates so that the ongoing IT renewal program is delivered in an efficient and seamless manner.

Given this centralised approach, the majority of IT capex required to deliver the program of work for South Australia over the next AA period has been estimated in total (across all distribution networks) and then allocated to the South Australian gas distribution business on the most appropriate basis. This is consistent with methods adopted in previous regulatory submissions, and has previously been endorsed by the AER[18]. Successful and efficient delivery of the national applications renewal program requires approval of this approach in all jurisdictions.

Our forecast for "IT" capital expenditure for the next AA period is shown in Table 7.14.

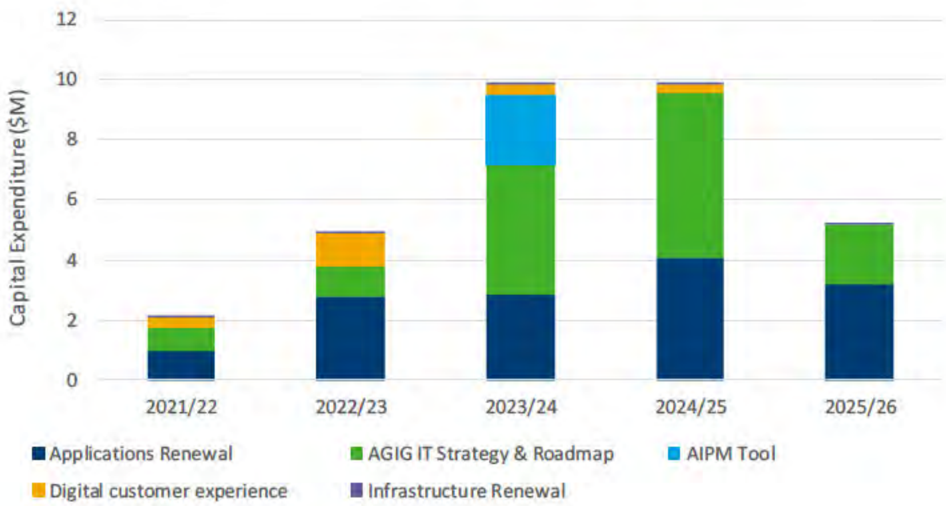
[18] For example in approving the GIS upgrade as part of our previous AA submission, the AER acknowledged that these projects formed part of a national program, with an "appropriate division of costs" between jurisdictions, "*Draft Decision: Australian Gas Networks Access Arrangement 2016 to 2021, Attachment 6 – Capital expenditure*", November 2015, pg. 6-42.

Table 7.14: IT Expenditure Summary

Program	Business Case	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Applications Renewal	SA117	0.98	2.78	2.83	4.04	3.20	13.82
AIPM Tool	SA121	0.00	0.00	2.36	0.00	0.00	2.36
Digital customer experience	SA137	0.36	1.15	0.35	0.29	0.00	2.16
AGIG IT Strategy & Roadmap	SA138	0.73	0.98	4.30	5.50	1.99	13.51
Infrastructure Renewal	SA139	0.02	0.01	0.03	0.02	0.05	0.15
Total Expenditure ($M)		**2.10**	**4.92**	**9.88**	**9.87**	**5.24**	**32.00**

The phasing of IT capital expenditure is shown in Figure 7.8. Each project within the program is further articulated below.

Figure 7.8: IT Expenditure Summary



Applications Renewal - Business Case SA117

There are number of critical Information Technology (IT) systems that are integral to the efficient and effective management of the SA natural gas distribution networks. The systems include:

- Dial Before You Dig system;
- metering & billing system;
- enterprise asset management;
- geospatial information system;
- enterprise historian including national interval metering system;
- FRC market gateway;
- middleware; and
- field data / mobility applications.

IT systems are updated on a continual basis. This includes applying software patches that upgrade applications to the latest version as per the vendors' recommendations. Renewing and upgrading applications ensures the continued provision of ongoing support and maintenance of our key IT systems, and that any known issues, including security vulnerabilities, can be addressed.

Prior to the current AA period, the majority of our core IT applications had not been updated for many years. Over the past five years we moved to the standard industry practice of applying version upgrades to business systems every three years.

Our IT upgrade strategy is being delivered via a nationwide program that crosses all of the jurisdictions in which AGN operates. The program was approved by the AER in the prior South Australia determination and in the most recent AGN Victoria & Albury determination.

The work proposed in this business case forms part of the AGN Applications Renewal roadmap across all jurisdictions we operate. It involves the systematic upgrading of software and applications used to manage our SA network, ensuring that these critical applications are kept up-to-date over the forthcoming AA period.

Our application renewal program is the highest cost activity within the ICT expenditure category, forecast to cost $15.69 million over the coming AA period.

AIPM Tool - Business Case SA121

This project involves improving our asset investment planning and optimisation processes and systems, while removing the amount of manual intervention currently required. The Asset Investment Planning & Management (AIPM) tool will allow us to leverage the large volume of data that has now become available following completion of key projects in the current period such as the GIS updates and the new mobility system. By allowing greater consolidation and analysis of data, the AIPM tool will help us improve decision making in areas such as:

- asset replacement and asset design;
  - for example, improved access to data would assist capacity modelling ensure that asset design and timing of construction is optimised;
- asset maintenance versus asset replacement;
  - for example, improved access to the additional asset data made available through the AIPM will allow maintenance frequencies to be optimised and scheduled maintenance activities to target specific asset components that are identified as showing signs of deteriorating reliability; and
- prioritisation and prudent deferral of investments.

The AIPM tool will cost approximately $2.4 million and will be fully delivered in the next AA period. The tool should result in positive economic benefits to customers, with substantial amounts of capex being avoided and deferred, mostly to the following regulatory period.

Digital Customer Experience - Business Case SA137

This project involves continuing work started during the current period to enhance the scope of digital communication with our customers. We will develop a flexible customer relationship management (CRM) solution with self-service capability. In particular, this includes:

- catering for tailored responsive support, confidentiality and proactive reporting for life support and vulnerable customer segments. This is driven by increased customer needs as well as an increasing regulatory expectation of communication with vulnerable customers (accelerated in more recent times due to COVID-19); and

- updating customer communications and notification from the predominantly one-way, highly manual and paper-based processes, to digital communication. This is consistent with regulatory needs, customer expectations that of other energy players. This includes ensuring customers are aware of information relating to works at their premises or in their local community, enabling our customers to engage with us as and when they want, and ensuring contemporary data security and privacy standards are met.

This CRM solution will cost approximately $2.16 million and will be fully delivered in the next AA period.

AGIG IT Strategy & Roadmap - Business Case SA138

In 2019, AGIG developed the AGIG IT Strategy and Roadmap to stabilise and align our IT management processes, IT architectures, acquisition methods and certain core technology platforms across the Group. The objectives of this program were to:

- better deliver the AGIG corporate strategy and individual business unit operating strategies and plans;
- support feedback from our stakeholders, regulators and customers that they value reliable and safe delivery of energy to our customers backed up by timely support when they need help;
- address specific issues and risks common to all AGIG businesses, including cyber security, likelihood of errors and avoid poor management decisions based on the incorrect or untimely information, and employee frustration due to lack of access to data and ability to collaborate effectively; and
- achieve economies of scale in purchasing and support costs.

To facilitate this, a two-stage program was developed.

- Stage 1, which started in 2020, involved delivering a foundational program to ensure effective use collaboration, appropriate management of cyber risks and leveraging economies of scale. This also included initial components of a larger program to improve reporting capabilities, empowering management with more accurate and timely information.
- Stage 2 plans to build on and leverage the foundational program via several transformational initiatives. In particular, this includes the 'OneERP' project – development of a standardised enterprise resource planning (ERP) system across the AGIG group. Having a standard ERP system will allow us to remove the heavy customisation, and therefore the substantial risks, associated with local finance systems.

We will also continue the Stage 1 program to improve reporting capabilities by adopting standardised reporting tools and data structures, which will provide access to the 'right' information quickly, reliably and dynamically.

The majority of Stage 1 work is being completed in the current AA period. The remainder of Stage 1, along with Stage 2, is planned for the next AA period. This requires approximately $13.5 million investment in the next AA period and is expected to be completed by 2025/26

Infrastructure Renewal - Business Case SA139

The infrastructure renewal program is a 'stay in business' program that involves periodic renewal of network and end-user devices such as laptops, audio/visual equipment, telephony, internet links and servers that support critical business functions. The updates ensure we continue to maintain reliable, resilient, compliant and efficient network and end-user devices, and preserve the ongoing integrity of our services. It includes ensuring that any known issues, including security vulnerabilities, can be addressed.

The forecast cost of infrastructure renewal over the next AA period is $0.16M. This investment provides for retention of the current managed services agreement that supports the 50 current AGN IT users, allowing for hardware upgrades according to our lifecycle management plan.

The program also includes undertaking a number of general improvements around cyber security and the Intelligent Information Management System (IIMS). This includes annual penetration testing, enhancing controls in live with the ASD Essential Eight, improved backup/restore capabilities, improved mobile device management and enhanced wireless security. These improvements will mitigate cyber and productivity impact risks. It will also improve operational efficiency, delivering timely support for customers, improved working conditions for employees, and the lowest long-term cost for us and our customers.

7.7. Growth

Capital expenditure relating to the connection of new customers or users of our distribution network is contained within the "Growth" capital expenditure category.

Growth expenditure is broken down into two categories:

- Organic Growth involves incremental growth of the networks, typically involving small mains extensions to service new subdivisions and properties, urban renewal and infill projects within or adjacent to our existing network.
- New Growth Areas are step changes in the scope of the distribution network which involves larger main extensions to service new regions of network growth.

The expenditure profile is shown in Table 7.15. A summary of each project within the "Growth" capital category is provided below.

Table 7.15: Growth – Expenditure Summary

Program	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Organic Growth	15.75	19.12	20.46	21.81	21.54	98.68
New Growth Areas	10.14	7.48	6.00	3.64	3.45	30.69
Total Expenditure ($M)	25.89	26.59	26.46	25.44	24.99	129.37

The expenditure profile is shown in Figure 7.9. Additional information on the forecasting approach for Organic Growth, and the projects underpinning New Growth Areas is provided below.

Figure 7.9: Growth – Expenditure Summary

7.7.1. Organic Growth

Organic growth involves incremental growth of the networks, typically involving small mains extensions to service new subdivisions and properties, urban renewal and infill projects within or adjacent to our existing distribution network to services new customers. New connections can be classified as either:

- Greenfield – Reticulation of newly developed areas (e.g. new estates) which dwellings are newly constructed.
- Brownfield – Reticulation of established areas not serviced by natural gas. This may include new dwellings (e.g. demolition, urban infill and rebuilds) or existing homes not connected to gas.

Our strategy to capture new residential growth opportunities is to install new mains and services in greenfield developments rather than brownfield existing housing areas. Greenfield developments can be reticulated at significantly lower costs due to utilisation of common service trenching provided by the developer, and reduced reinstatement and traffic management costs.

Reticulating brownfield areas is more technically challenging due to congestion of other third party services, increased reinstatement costs associated with remediating established roads and footpaths and increased traffic management costs to manage disruption to traffic and pedestrians.

In addition to lower costs and fewer operational issues, reticulating greenfield developments generates much higher penetration rates as customer install multiple new gas appliances at time of building. Typical gas penetration rates in new greenfield developments in SA are greater than 95%.

When reticulating brownfield areas, gas connection requests and penetration rates are primarily driven by appliance changeover decisions, so growth is much slower as customers are generally reluctant to switch appliances until they are no longer working, or where incentivised, to do so. Typical gas penetration rates in brownfield areas grow at 2 to 5% per year and average 74% across our SA network.

There are two general types of customers which connection to the distribution network:

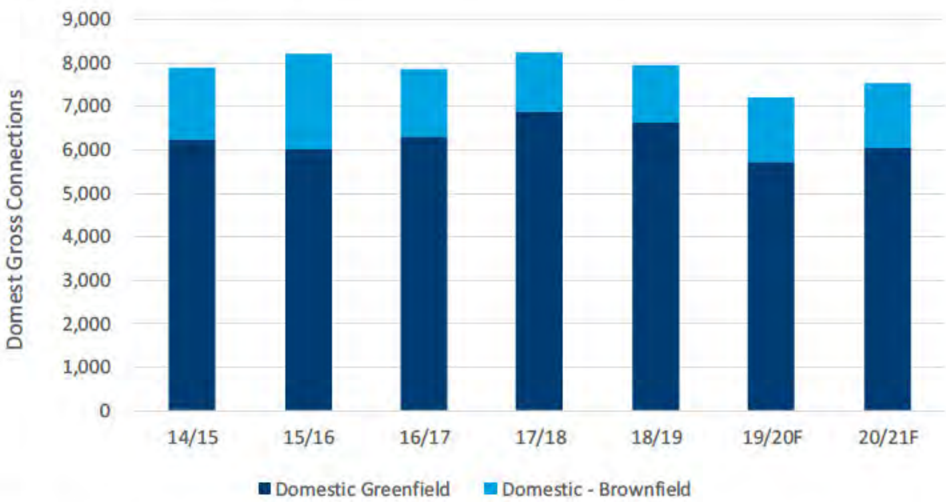
- Domestic Connections – customers who use gas for domestic purposes.
- I&C Connections – customers who use less than 10 TJ per annum and use gas for non-domestic purposes.

Adelaide metropolitan residential net connections have been growing by about 1.6% per year over the last 10 years. This includes pockets of higher growth including:

- Northern Metropolitan – Blakeview, Direk, Elizabeth Park, Evanston Gardens, Evanston South, Gawler East, Munno Para, Munno Para West and Reid
- Central Metropolitan – Bowden, Plympton Park and St Clair
- Southern Metropolitan – Craigburn Farm and Seaford Meadows
- Ongoing residential, commercial and industrial customer growth is expected to continue at rates similar to historic growth.

Regional networks residential net connections have been growing by 2.9% per year over the last 10 years, although it has reduced to 2% in the last 3 years. This growth is principally associated with the Mildura network (Victoria).

Figure 7.10: Domestic Gross Network Connections



Tariff D customer numbers have been declining in the Adelaide metropolitan area over the last five years, consistent with the downturn in the manufacturing industries, but this appears to have stabilised since 2016.

Refer to Section 6.4.1, specifically Figure 6.3 for additional details on historic network growth.

Forecast of Gross Network Connections

We are forecasting to connect over 36,000 new customers to the network during the next AA period, the majority (>97%) of which will be domestic end users. On average we will connect 7,035 domestic and 215 I&C end users p.a. over the next AA period.

Gross connection rates are taken from our demand forecast developed by Core Energy.

Table 7.16 provides our forecast for domestic and I&C connections.

Table 7.16: Growth - Gross Network Connections

Connection Type	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Domestic Connections	6,078	6,637	7,198	7,760	7,653	35,327
I&C Connections	93	260	260	259	258	1,130
Total Gross Connections	6,171	6,898	7,458	8,019	7,912	36,457

Figure 7.11: Growth - Gross Network Connections

Expenditure Breakdown by Connection Type

Our organic growth expenditure forecasts are calculated with reference to our forecast of gross connection volumes (outlined above) and forecast unit rates incurred for the installation of mains, services and meters required to connect new customers.

At the aggregated level, the average cost per connection is around [redacted] per domestic connection and around [redacted] per I&C connection for the next AA period.

Our total expenditure forecast for organic growth (by connection type) for the coming AA period is contained in Table 7.17.

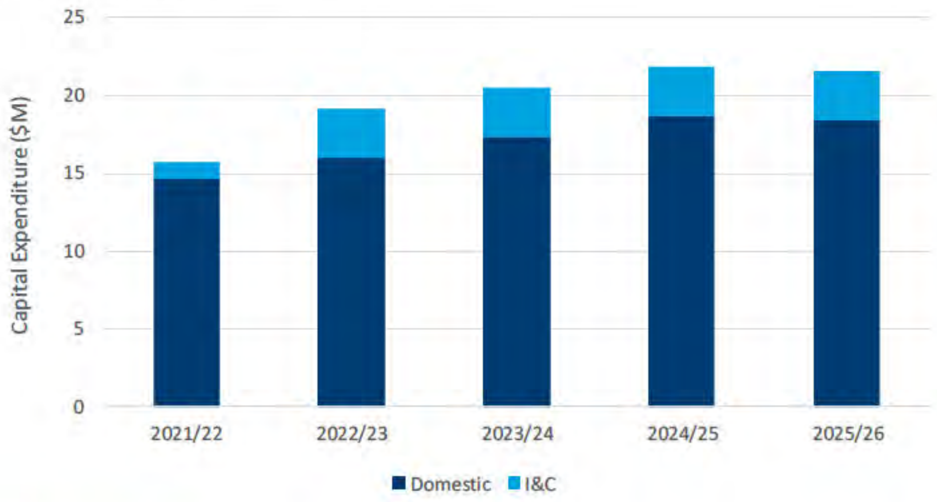
Table 7.17: Organic Growth – Expenditure breakdown by Connection Type

Program	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Domestic Connections	14.64	15.99	17.34	18.69	18.43	85.09
I&C Connections	1.11	3.13	3.13	3.11	3.11	13.59
Total Expenditure ($M)	15.75	19.12	20.46	21.81	21.54	98.68

Due to the cost disparity between domestic and I&C connections, domestic connections contribute 86% of forecast expenditure, but 97% by total volume.

Total expenditure by connection type is shown in Figure 7.12.

Figure 7.12: Growth – Expenditure breakdown by Connection Type



Breakdown by Asset Type

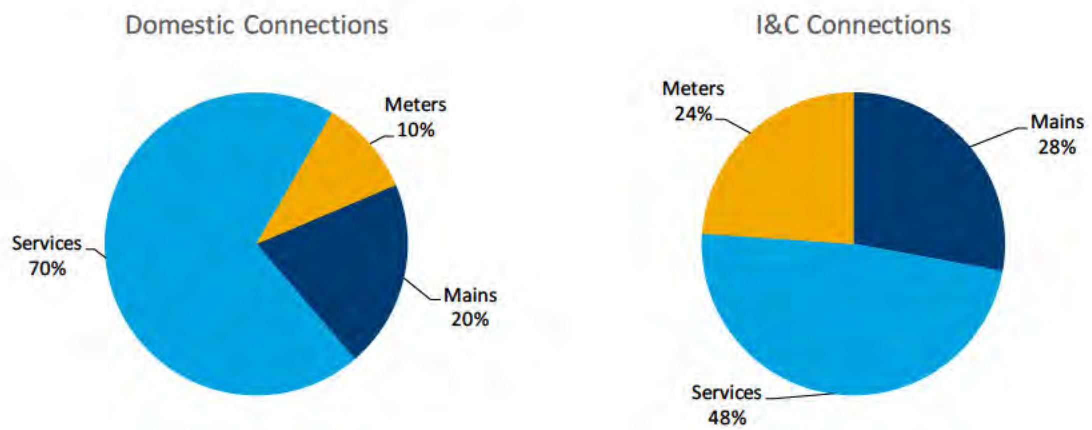
The bottom-up build for connections allows for the disaggregation of expenditure by asset class required to connection domestic and I&C customers. A breakdown of expenditure on mains, services and meters is shown in Table 7.18.

Table 7.18: Organic Growth – Expenditure by Asset Type

Program	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Mains	3.26	4.09	4.36	4.63	4.58	20.92
Services	10.73	12.64	13.57	14.51	14.33	65.77
Meters	1.77	2.39	2.53	2.66	2.63	11.98
Total Expenditure ($M)	**15.75**	**19.12**	**20.46**	**21.81**	**21.54**	**98.68**

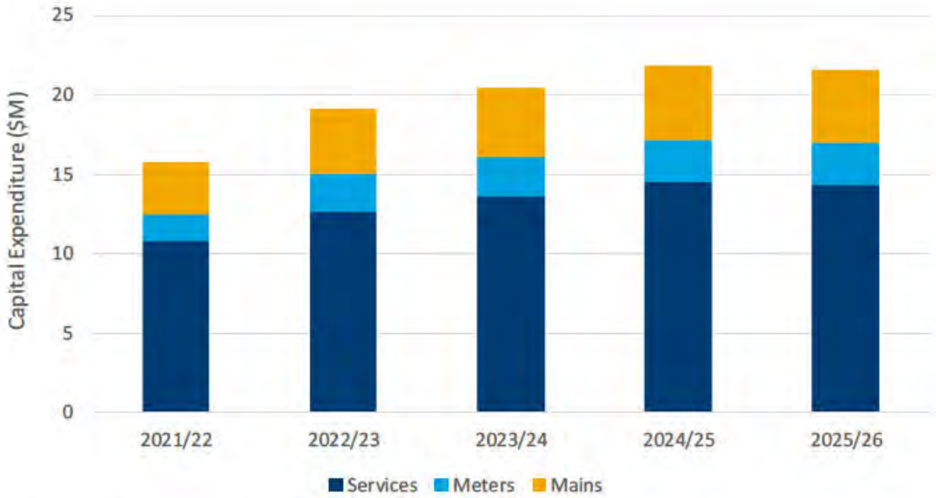
A breakdown of connect type (domestic and I&C) by asset class (mains, service & meters) is shown in Figure 7.13. Service costs contributes the greatest component of connection costs for both domestic (70%) and I&C (48%) connection types. For domestic connections, the meter cost contributes 10%, while mains contribute 20% of total connection costs. Meter and Mains costs are roughly equal for I&C connections.

Figure 7.13: Growth - Connection cost breakdown by Asset Type.



Total forecast expenditure by asset type is shown in Figure 7.14.

Figure 7.14: Growth – Expenditure breakdown by Asset Type



Expenditure by Asset Class (as shown above) is an amalgamation of expenditure subcategories with individual unit rates and volume forecasts. This is shown below.

Mains

Mains expenditure is broken down into three (3) expenditure sub-categories; the installation of mains at greenfield sites (i.e. new estates – assumed domestic connections) and brownfields sites (split into domestic and I&C connections types).

The required mains length (by category) is forecasted with referenced to the average mains length required per connection over the past 3 years. Refer to our Unit Rates paper for the build-up of unit rates per category.

A breakdown of mains by works program is provided in Table 7.19. Approximately 70% of new mains are forecast to be laid in New Estates.

Table 7.19: Organic Growth – New Mains

Program		2021/22	2022/23	2023/24	2024/25	2025/26	Total
New Residential Connections (New Estate)	Length (Km)	20.6	22.4	24.3	26.2	25.9	119.5
	Unit Rate ($/m)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	subtotal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
New Residential Connections (Existing Areas)	Length (Km)	7.8	8.5	9.2	9.9	9.8	45.2
	Unit Rate ($/m)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	subtotal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
New Commercial Connections (I&C <10TJ)	Length (Km)	0.5	1.5	1.5	1.5	1.4	6.3
	Unit Rate ($/m)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	subtotal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Expenditure ($M)		**3.26**	**4.09**	**4.36**	**4.63**	**4.58**	**20.9**

Services

Services expenditure is broken in to four sub-categories; new homes, existing homes, Multi User Sites (MUS) and I&C connections.

The volumes of services required is related to the forecasted volume of new connections during the AA period. Approximately 77% of service connections are forecast to occur at new homes, followed by 14% in existing areas. 5% of service connections will occur at Multi-user sites, with four (4) end connections (meters) forecasted for each site. I&C connections contributes the remainder of service connections.

Refer to our Unit Rates paper for the build-up of unit rates per service type.

A breakdown of mains by works program is provided in Table 7.20.

Table 7.20: Organic Growth – New Service

Program		2021/22	2022/23	2023/24	2024/25	2025/26	Total
New Estate Connections	Services	4,173	4,557	4,941	5,327	5,254	24,253
	Unit Rate ($/Service)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	subtotal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Existing Home	Services	787	859	931	1,004	990	4,572
	Unit Rate ($/Service)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	subtotal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Multi User	Services	280	305	331	357	352	1,626
	Unit Rate ($/Service)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	subtotal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
I&C <10Tj	Services	93	260	260	259	258	1,130
	Unit Rate ($/Service)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	subtotal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Expenditure ($M)	**10.73**	**12.64**	**13.57**	**14.51**	**14.33**	**64.77**

Meters

A meter is required at every connection off the distribution network. The volume of meters forecast for the next AA period directly relates to the volume of expected connections, by connection type.

Refer to our Unit Rates paper for the build-up of unit rates per meter type.

A breakdown of meters by connection type is provided in Table 7.21.

Table 7.21: Organic Growth – New Meters

Program		2021/22	2022/23	2023/24	2024/25	2025/26	Total
New Meter – Domestic	Meters	6,078	6,637	7,198	7,760	7,653	35,327
	Unit Rate ($/Meter)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	subtotal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
New Meter – I&C	Meters	93	260	260	259	258	1,130
	Unit Rate ($/Meter)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	subtotal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Expenditure ($M)		**1.77**	**2.39**	**2.53**	**2.66**	**2.63**	**2.63**

7.7.2. New Growth Areas

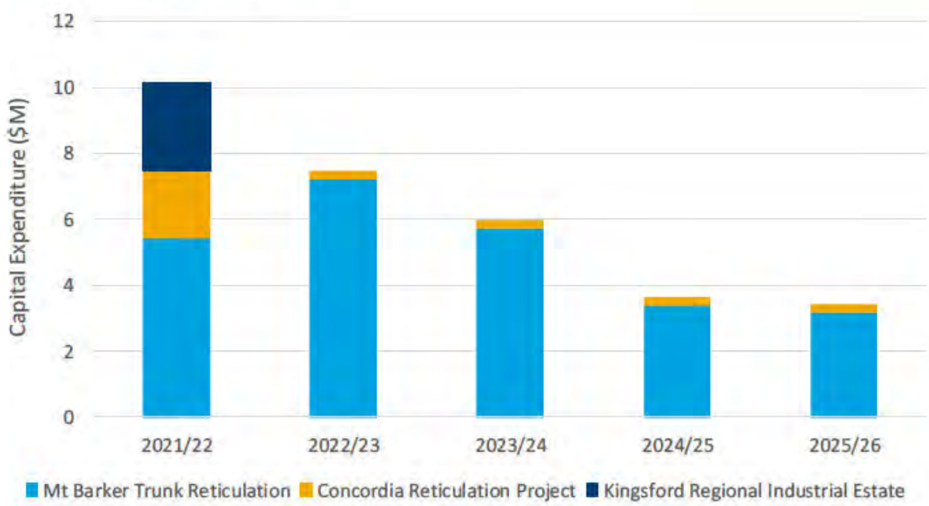
New Growth Areas are step changes in the scope of our distribution network, involving larger mains extensions to service new regions of network growth. Each project is individually assessed as to ensure their commercial viability.

Our forecast for New Growth Area projects for the next AA period is contained in Table 7.22 and shown in Figure 7.15.

Table 7.22: New Growth Areas - Expenditure Summary

Project	Business Case	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Concordia Reticulation Project	SA122	2.04	0.26	0.26	0.26	0.25	3.06
Kingsford Regional Industrial Estate	SA124	2.66	-	-	-	-	2.66
Mt Barker Trunk & Reticulation	-	5.43	7.22	5.74	3.38	3.19	24.97
Total Expenditure ($M)		**10.14**	**7.48**	**6.00**	**3.64**	**3.45**	**30.69**

Figure 7.15: New Growth Areas – Expenditure Summary



Concordia Reticulation Project – Business Case SA122

Greenfield growth in Concordia, north of Adelaide, is forecast to commence in 2021/22. The Concordia Growth Area is a master planned community that will form a natural extension of the existing Gawler Township and is expected to result in an additional 10,000 connections to the SA gas distribution network over 25 years.

To provide gas supply to the region and allow new customers to connect, we plan to expand the network to the new Concordia development and conduct reticulation works within the next AA period. Connecting to the existing Gawler network and reticulating the site as a greenfield project will enable new homes and businesses to connect immediately and at a lower overall cost than if the Concordia development were to be constructed as a brownfield project.

Developers and potential customers have expressed a desire for gas in the area, and there is sufficient evidence that the forecasted number of connections will arise if the necessary gas infrastructure is installed.

Connecting Concordia to the existing Gawler network has been deemed the most efficient means of supplying gas to the region as it takes advantage of the new SEAGas connection proposed for Gawler (refer to business case SA115), which is necessary to address existing pressure issues in the Gawler and Willaston networks.

The forecast cost of the Concordia reticulation project in the next AA period is $3.06 million.

Kingsford Regional Industrial Estate – Business Case SA124

Kingsford Regional Industrial Estate is a 170 hectare site located between Gawler and Roseworthy, 46 km north of Adelaide. The Kingsford Estate has been identified by State Government as a key area for major industrial development, which has rezoned the area to encourage development of manufacturing and other industrial facilities.

The Kingsford Estate is not currently connected to the natural gas network. Regional Development Australia and the local council have expressed a desire for gas supply in the area, and local businesses have indicated support for an extension of the natural gas network to the region.

Kingsford is already home to a number of medium-to-large businesses. Expansion of the gas network to the industrial estate is expected to commence during 2021/22. We estimate the Kingsford development will result in around 15 new industrial and commercial (I&C) customer connections to the natural gas distribution network over 20 years.

The forecast cost of the Kingsford Regional Industrial Estate project in the next AA period is $2.66 million.

Mt Barker Trunk & Reticulation

Mount Barker is 36 kilometres south-east of Adelaide and is one of the fastest growing regions in SA. The Mount Barker region includes Littlehampton, Nairne and Kanmantoo, which are also home to manufacturing, food processing, logistics and mining businesses. The region is predicted to grow from 33,000 now to 55,000 by 2036.

Extension of natural gas to the greater Mt Barker area was approved by the AER during the current AA period.[19] We are currently delivering this project, including a 40km DN150 TP pipeline extension, which is forecasted for completion in the current AA period.

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Our growth forecast for organic growth (constrained in Section 7.7.1) does not include connection and capital forecasts for network reticulation and connections in Mt Baker. These costs have been forecast separately (as part of this project) and reflects the AER's Final Decision on the Mount Barker extension.

The forecast cost of the Mt Barker trunk reticulation in the next AA period is $24.97 million.

7.8. Other Distribution

This category captures distribution system capex that does not fall into the capex categories we discussed in Section 7. Other distribution capex includes programs of works in relation to our metropolitan transmission pipelines operating at 1,750 kPa, cathodic protection (CP) systems, valves and I&C meter sets (<10TJ p.a).

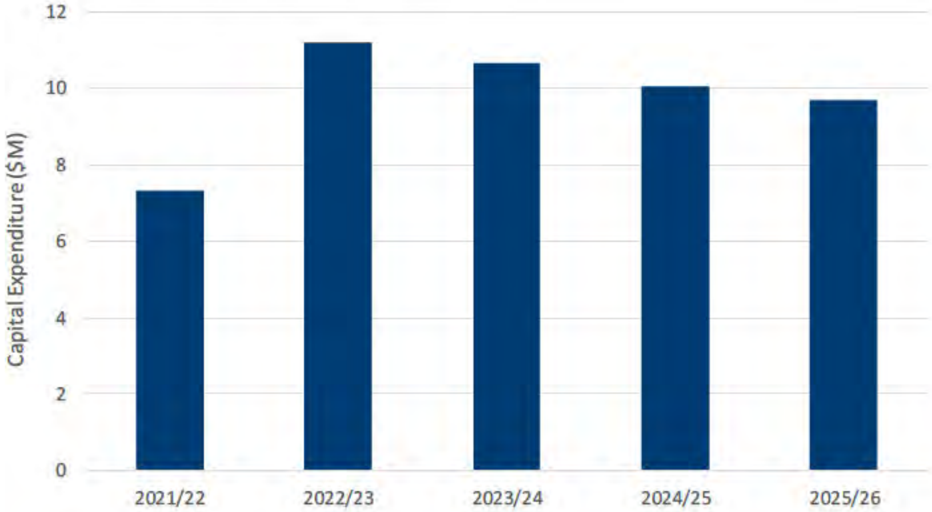
Table 7.23 shows the expenditure forecast for our "Other – Distribution" program.

Table 7.23: Other Distribution – Expenditure Summary

Program	Business Case	2021/22	2022/23	2023/24	2024/25	2025/26	Total
DCVG Dig ups	SA101	0.24	0.26	0.26	0.26	0.24	1.26
M53 Replacement	SA104	0.38	1.19	-	-	-	1.57
Modifications for ILI	SA105	4.25	6.78	7.08	7.07	6.82	31.99
Slabbing near sensitive areas	SA131	0.27	-	-	-	-	0.27
CP assets - end of life rep	SA112	0.33	0.33	0.33	0.33	0.33	1.65
Isolated steel sections from CP	SA127	0.11	0.28	0.27	0.27	0.25	1.17
CP remote Monitoring	SA126	0.30	0.18	-	-	-	0.48
Valves Replacement	SA103	0.62	1.01	1.51	0.91	0.91	4.97
Additional Valves	SA107	0.07	0.44	0.44	0.44	0.37	1.77
I&C Overpressure risk reduction	SA129	0.47	0.47	0.51	0.51	0.51	2.46
I&C meter set refurbishment	SA108	0.27	0.27	0.27	0.27	0.27	1.34
Total Expenditure ($M)		**7.30**	**11.20**	**10.66**	**10.05**	**9.71**	**48.92**

The expenditure profile is shown in Figure 7.16. A summary of each project within the "Other – Distribution" capital category is provided below.

Figure 7.16: Other Distribution System – Expenditure Summary



7.8.1. Transmission Pipelines

DCVG Dig-ups - Business Case SA101

Our Metropolitan transmission pipelines are prone to corrosion, which if left untreated, can lead to pipeline integrity failure and a major uncontrolled gas escape. The consequences of a major uncontrolled gas escape can be severe, as metropolitan TP pipelines are typically located in or near to developed areas and major population centres.

To help mitigate the corrosion risk, one of the methods we use to detect and treat corrosion is to conduct DCVG surveys, which detect faults in pipeline coatings. The DCVG surveys are followed by direct inspection excavations (or 'dig ups') of areas where DCVG indicates the pipeline coating has failed.

These surveys are conducted in accordance with Australian Standard AS 2885, whereby IR readings above 15% are excavated and treated immediately as part of business as usual processes.

Pipeline locations with IR readings less than 15% are traditionally deemed low priority and are either not excavated or are deferred until more urgent excavations have been completed. However, over the past five years we found that the size of the IR reading does not necessarily correlate to the amount of corrosion. Excavation of [redacted] locations originally deemed low priority revealed a very high instance of corrosion. This instance was particularly high (95%) where the location had previously recorded another indication below 15% (i.e. multiple indications).

Recent DCVG surveys have identified [redacted] sites where the IR readings are less than 15%, but there have been multiple indications at that site over the past 10-15 years. Given the frequency of corrosion at prior multiple indication sites, we consider it prudent to excavate, examine (and repair where necessary) these [redacted] additional sites. Note that these [redacted] locations are on pipelines not currently subjected to in-line inspection.

The total cost of this program for the next AA period is forecasted to be $1.26 million.

M53 Replacement – Business Case SA104

Pipeline M53 was originally a 7.9 km pipeline commissioned in 1975. Through DCVG surveys and excavations we identified significant pitting corrosion beneath dis bonded heat shrink sleeves. In

2013, 3.1 km of the M53 was replaced and renamed M131. A further 4.06 km section of DN200 is being replaced during the current AA period. This transmission pipeline is being replaced on a like-for-like basis to address corrosion, reduce the safety risk and ensure ongoing supply to the major residential growth area of the southern suburbs of metropolitan Adelaide.

The third and final section of M53 replacement is a smaller diameter 800 m DN100 offtake that services [redacted] customers in the [redacted] and is planned to be replaced in the next AA period, at a cost of $1.57 million.

Modifications for Inline Inspection (ILI) – Business Case SA105

Currently, the integrity of the SA metropolitan transmission pipelines is monitored by conducting DCVG surveys combined with direct inspection excavations (or 'dig ups'). While DCVG and dig ups provide useful information on pipeline condition, they do not provide a complete picture of the amount of corrosion on a pipeline. This is because not every part of a pipeline is accessible (particularly in built-up metropolitan areas). This means DCVG and dig-up results are extrapolated across a pipeline to give an indication of asset health and are therefore subject to considerable imprecision.

The effectiveness of DCVG and dig ups alone as an integrity management tool is also limited by the fact many pipelines in the SA network have vintage coatings, or coatings that shield cathodic protection (e.g. heat shrink sleeves). These coatings are showing increasing signs of degradation, which makes it difficult to demonstrate structural integrity using the DCVG method alone. As a result, the potential for corrosion defects to go undetected is high, which can lead to pipeline failure.

In line inspection (ILI) (also known as pigging) is a method of inspection whereby an ILI tool (pig) is pushed through the pipeline, measuring pipe wall thickness, internal pipe dimensions, and detecting defects. ILI is common practice on most other Australian gas transmission and high pressure pipelines, and is proven to be a highly effective and efficient method of managing pipeline integrity. We therefore propose to adopt ILI inspection for our SA TP pipelines.

ILI will enable us to create an accurate data baseline for our pipelines, which we can use to assess ongoing structural integrity. We can use this information to inform investment decisions on asset management activities. From an economic perspective, ILI will enable us to pinpoint areas of corrosion, dents and gouges and apply targeted correction/maintenance, which will allow us to manage the ongoing integrity of the pipeline more efficiently. This in turn will allow us to safely extend the useful life of the assets beyond their technical design lives (40 years). The data provided by ILI will also provide important information to inform decisions on future asset management strategies.

Most importantly, being able to perform ILI will improve our ability to detect and address issues on these transmission pressure pipelines before they escalate into uncontrolled gas escapes. Adopting ILI will reduce the safety and integrity risk associated with TP pipelines from high to moderate, by significantly reducing the likelihood of an integrity failure that could affect tens of thousands of customers and put the public in the vicinity of the gas escape at risk.

The majority of SA metropolitan TP pipelines were constructed more than 30 years ago and are not configured to accommodate ILI. We therefore need to undertake a program of work to modify all of our TP pipelines over the next 20-30 years.

Our ultimate goal is to make all of our TP pipelines piggable, either by modifying existing pipelines to allow ILI tools to pass through them, or by ensuring any new TP pipelines are piggable. We recognise that the overall cost of modifying around 200 km of TP pipelines will be significant, and the time and resourcing effort to achieve this must be carefully managed.

It is not practicable to modify all SA TP pipelines within the next five years. However, it is prudent to commence the pigging journey and conduct the necessary engineering studies to identify the costs, challenges and ongoing benefits of reconfiguring the pipelines. This includes identifying the order in which pipelines should be made piggable and the most prudent timeframe to achieve this.

Over the next AA period we plan to commence studies on M42, M55 and M101 and perform ILI modification activities on M12 and M84. This will be done at a total forecast cost of $31.99 million over the AA period.

Slabbing Near Sensitive Areas – Business Case SA131

A review of our transmission pressure network in the Adelaide metropolitan area has identified four sections of transmission pressure pipeline, totalling [redacted] metres, which are in high consequence, sensitive use areas, are susceptible to strike by an auger or excavator, and require additional measures to mitigate the threat of pipeline damage resulting in rupture.

These four short sections of TP pipelines are:

- located near a high consequence, sensitive use area (as defined in Australian Standard 2885 as areas where vulnerable members of the community congregate including childcare centres, schools, hospitals, aged care homes and prisons); and
- have no additional protection measures; and
- are not located beneath a roadway.

We plan install slabbing above these sections of TP pipelines there by increasing protection for the most vulnerable members of the community. The total cost of this program in the next AA period is $0.27 million, to be completed in the 2021/22 year.

7.8.2. Network Facilities - Cathodic Protection

CP Asset Replacement – Business Case SA112

With our ageing pipeline infrastructure (30-45 years old), corrosion prevention and asset life maximisation measures such as cathodic protection (CP) are essential.

CP assets include sacrificial anodes and impressed current cathodic protection (ICCP) units. Anodes and ICCP units are used to protect steel pipelines from corrosion. They do this by creating an electrical circuit with the steel pipeline and anodic material, which means the anode corrodes in favour of the pipeline.

696 sacrificial anodes have reached or will reach their end of life within the next five years. Three ICCP units will also reach end of life. These assets require replacement in order to keep the CP system effective and help protect our steel pipelines from corrosion.

Over the next AA period we will replace end of life assets with an optimised ICCP and anode combination ($1.65 million). This comprises:

- Replacing 250 existing depleted anodes with 250 new anodes;
- Replacing 446 existing depleted anodes by installing 7 ICCP units; and
- Replacing the three existing end of life ICCP units with three new ICCP units

Isolated steel sections from CP – Business Case SA127

There are [redacted] short isolated sections of steel distribution pipe located in various areas of the Adelaide metropolitan and regional network that have no form of cathodic protection (CP). These sections are largely at creek crossings, large storm water crossings, road intersections and bridge crossings. They range in length from 5m to 200m and are typically 30 to 40 years old.

Corrosion prevention measures are required to mitigate public safety or loss of supply risks, whilst also ensuring we maximise steel pipe asset lives. Unfortunately, however, these short sections cannot be connected to nearby CP control areas as they are located within the polyethylene (PE) distribution systems, typically operating at medium pressure (100 kPa).

We strive for a fully fused PE distribution network where reasonable to do so, as this is the ideal solution from an asset management perspective, however, we are mindful that this may not always be practical or cost effective.

We plan to protect [redacted] sections of CP isolated steel pipe with anodes, at a forecast cost of $1.17 million and replace the remaining [redacted] sections with PE pipe over the next AA period.

CP remote Monitoring – Business Case SA126

With our ageing transmission pipeline infrastructure (30-45 years) and with an increasing number of other assets underground that can interfere with cathodic protection measures, it is prudent to install proactive cathodic protection monitoring.

The installation of CP monitoring units on transmission pipelines is considered good industry practice and in recent years the cost of monitoring equipment has reduced significantly. It is now considered a very reasonable investment for the additional asset management benefits.

Benefits include the ongoing asset integrity measurement of our key high value and high risk assets, identifying faults earlier, avoiding short term expensive reactive costs and better informing asset management plans to maximise asset life.

Over the next AA period, we will install [redacted] remote monitoring units on CP test points on our transmission pipelines that are capable of sending data to our SCADA system. This will result in a remotely monitored solution for early detection of CP defects, which will help reduce the risk of accelerated corrosion. The total cost of this program is $0.48 million.

7.8.3. Network Facilities - Valves

Valves Replacement – Business Case SA103

Australian Standards AS 2885 and AS/NZS 4645 require transmission pipeline and distribution network operators to install and maintain isolation valves to allow the pipeline or network to be isolated for emergency and maintenance purposes. Valves also allow for control flexibility to help ensure security of supply.

There are 1,207 steel valves in the SA networks. Of these, 283 valves are located on TP pipelines, and 924 in the smaller distribution mains. Valves are typically located in medium and high density suburban areas. Most were installed in the 1970s and 1980s. We have identified [redacted] valves that are currently either inoperable or have had leaks repaired but are in a deteriorated state.

Inoperable valves mean sections of the network cannot be isolated during emergency repairs or planned maintenance. This increases the number of customers that may be impacted during a supply outage.

A valve that has leaked but since been repaired is usually a precursor to valve failure as the repaired valve will typically be weakened. A leaking valve can pose a health and safety risk if the leak is near a building.

The current risk control for inoperable and leaking valves is to repair them where practicable, only replacing upon failure. However, due to the age and ongoing deterioration of valves, further repair is not a viable option on these valves and replacement is the only effective long term solution.

Over the next AA period AGN will replace [redacted] steel valves; [redacted] inoperable valves ([redacted] transmission and [redacted] distribution), and the proactive replacement of [redacted] previously leaking valves ([redacted] transmission and [redacted] distribution) at a total cost of $4.97 million.

Additional Valves – Business Case SA107

We have conducted a review of the metropolitan TP pipeline system, focusing on the number of customers supplied by each isolated section of the pipeline, and how many would be affected by an emergency shutdown of each section.

Under our risk matrix management framework, our aim is to reduce the overall risk associated with isolating customers to as low as reasonably practicable. To achieve this, we must ideally reduce the number of customers potentially impacted by ensuring we can isolate each section of the network to fewer than 10,000 customers. This would result in a risk consequence rating of Significant or Medium (depending on the section being isolated).

Our review has identified [redacted] locations where it is possible to significantly reduce the number of customers that would be impacted during network/pipeline isolation. Of these, there are [redacted] locations where the current number of impacted customers is greater than 10,000, including one area where up to 51,600 customers would be impacted in the event of an emergency shutdown on the TP system. We therefore consider it prudent to install additional valves so that no more than 10,000 customers would be impacted by isolation of a single network/pipeline section. This will also allow for strategic segregation of the interconnected transmission pipeline network, providing for better isolation during planned maintenance and emergency situations.

Over the next AA period we plan to install [redacted] new inline valves to reduce supply outage risk in Adelaide's TP system. Procurement and installation activities are offset for this work to enable efficient delivery. The total cost of this program is $1.77 million.

7.8.4. Metering Facilities - I&C Meter Sets (<10 TJ p.a)

I&C Meter Set Over pressure risk reduction – Business Case SA129

The South Australian gas distribution network has more than 33,000 industrial and commercial (I&C) customer metering facilities. I&C metering facilities are used to supply and measure the high volumes of gas supplied to our I&C customers and as such are a critical network asset.

Metering facilities are made up of the meter unit itself and the meter set. The meter set comprises valves, pipework, regulators, fittings and other minor components.

[redacted] I&C customers are supplied with large meter sets that have a service bypass line. The purpose of the bypass line is to allow us to maintain the customer's supply while we shut down and conduct maintenance on the primary service line.

In 2016 the standard design for large I&C meter sets was modified to include a regulator on the bypass line. This new design reduces the risk the customer's equipment could become overpressurised when the bypass line is in use.

This change was made in line with good industry practice and design standards, and allows I&C maintenance to be conducted with minimum disruption to the customer. Work to commence installation of regulators on bypass lines of new large I&C meter sets commenced in 2016.

As at 1 July 2020, [redacted] large I&C meter sets with unregulated bypass lines remain in the SA network. We plan to install regulators on [redacted] of these outstanding bypasses over the next AA period at a total cost of $2.46 million.

The remaining [redacted] DRS shall be addressed during the following AA period.

I&C Meter Set Refurbishment Program – Business Case SA108

There are approximately 2,000 elevated pressure meter sets with large regulators, filters, pilots and over pressure shut off (OPSO) valves fitted. I&C metering facilities are critical to accurately measure high volumes of gas from the network to AGN's large customers. Metering facilities are made up of the meter unit itself, and the meter set which includes the valves, pipework, regulators, fittings and other minor components.

These meter sets deteriorate over time. If left untreated, deterioration could lead to corrosion. This presents a risk of leaking and/or component failure and may in turn result in the interruption of supply to customers, and risk the health and safety of the public.

Through periodic condition assessments we have identified [redacted] I&C meter sets that need refurbishment to address corrosion and inhibit further deterioration. This is in line with our historical refurbishment volumes of around [redacted] per annum.

We refurbish meter sets by grit blasting and applying a coat of protective paint. This helps extend the life of the meter sets (noting that the meter unit itself is replaced on a ten-year cycle as per the Meter Replacement Plan) and is a critical ongoing program necessary to manage the integrity of the I&C gas supply points on the AGN network.

Over the next AA period we plan to continue our meter set refurbishment program.

7.9. Other Non - Distribution

A standard suite of plant and equipment is required on an ongoing basis to enable our workforce to conduct repair and alteration work on the pipelines and other gas asset infrastructure. This equipment is used for activities such as flow stopping, underground asset detection, gas detection, welding and fusion, and pressure testing.

As existing plant and equipment age, they must be replaced before they become unfit for purpose (either due to wear or obsolescence). Technological advancements or changes in standards can also drive the need for new types of equipment.

There are three key categories of plant and equipment (P&E) expenditure:

- Small P&E – general (small value) replacement and new plant and equipment items that require ongoing purchase each year;
- Vehicles – trucks and other vehicles, which are replaced as and when they become unsafe or it becomes inefficient to continue to use and maintain them; and
- High pressure flow stopping – stopple equipment, which used to flow stop high pressure steel pipelines, enabling the safe isolation of the gas supply and controlled gas release.

Ongoing proactive investment in new and replacement plant and equipment helps create a safe working environment for all employees and contractors by providing plant, tools and equipment that are in good working order, fit for purpose and tested/calibrated (as required) to the required standard.

Over the next AA period we will continue our proactive replacement of plant and equipment. Table 7.24 shows expenditure related to "Other Non-Distribution" capital for the next AA period.

Table 7.24: Other Non-Distribution - Expenditure Summary

Program	Business Case	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Proactive replacement of plant and equipment	SA113	1.08	1.08	0.75	0.75	0.87	4.52
	Total Expenditure ($M)	1.08	1.08	0.75	0.75	0.87	4.52

8. Capital Expenditure - Unregulated Networks

This section provides an overview of network investment (Capex) forecast for our unregulated networks for the forecasting period (1 July 2021 to 30 June 2026).

In total, we are forecasting to incur $15.9 million of investment over the period; substantially less than our regulated networks. Key programs include:

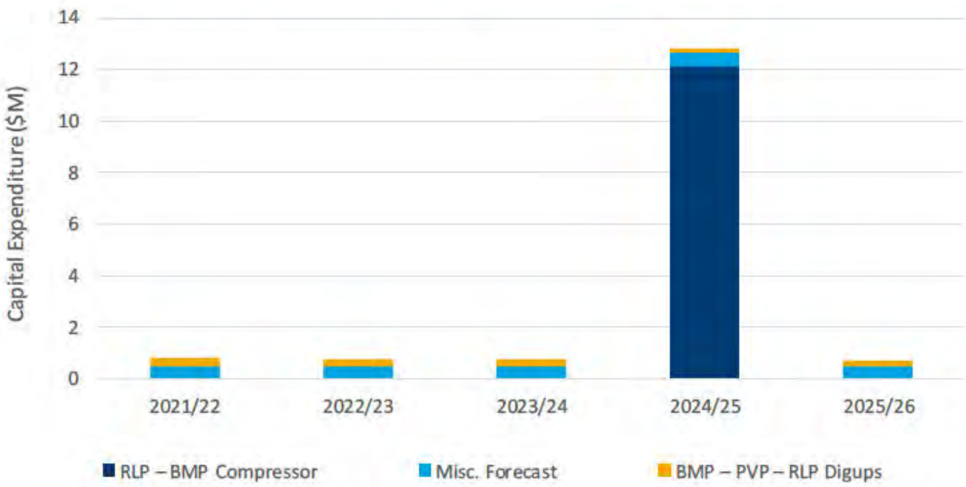
- Upgrades to the Riverland Pipeline (RLP) / Berri Mildura Pipeline (BMP) Compressor Station required to service additional growth (including Tariff D customers) in Murray Bridge and Mildura, and the growing demand of Mt Barker.
- Pipeline integrity dig-ups on the BMP, RLP and Palm Valley Pipelines (PVP); and
- An allowance for miscellaneous works. Previous examples including the pigging of the PVP, installation of telemetry units on the RLP and CP unit installations. .

Table 8.1 shows Capex expenditure related to unregulated assets over the forecasting period.

Table 8.1: Unregulated Assets - Expenditure Summary

Program	Business Case	2021/22	2022/23	2023/24	2024/25	2025/26	Total
RLP – BMP Compressor	-	-	-	-	12.15	-	12.15
Misc. Forecast	-	0.47	0.48	0.49	0.50	0.51	2.44
BMP – PVP – RLP Digups	-	0.35	0.25	0.25	0.20	0.20	1.25
Total Expenditure ($M)		0.82	0.73	0.74	12.84	0.71	15.85

Figure 8.1: Capital Expenditure Summary – Unregulated Networks



9. Abbreviations

TERM	DEFINITION
AA	Access Arrangement
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGIG	Australian Gas Infrastructure Group
AGN	Australian Gas Networks Ltd
AMP	Asset Management Plan
APA	APT O&M Service Pty Ltd
AS	Australian Standard
BMP	Berri – Mildura Pipeline
Capex	Capital expenditure
CBD	Central business district
CI	Cast Iron
clearSCADA	National SCADA IT platform
CP	Cathodic Protection
CTM	Custody Transfer Meter
CY	Calendar Year
DBP	Dampier to Brumby Pipeline
DCVG	Direct Current Voltage Gradient
DEM	Department of Energy and Mining (SA)
DMSIP	Distribution Mains and Services Integrity Plan
DM&S	Distribution Mains & Services
DN	Nominal Diameter
DRS	District Regulator Station
DSPR	Distribution System Performance Report
EIV	Emergency Isolation Valve

TERM	DEFINITION
ESCOSA	Essential Services Commission of Sth Australia
EWOSA	Energy and Water Ombudsman SA
EWOV	Energy and Water Ombudsman Victoria
GDC	Gas Distribution Code
GHF	Gas Heating Facility
GIB	Gas In Building
GIS	Geospatial Information System
HDPE	High Density Polyethylene
HP	High Pressure (MAOP = 420 kPa)
HSE	Health Safety and Environment
HSS	Heat Shrink Sleeve
I&C	Industrial and Commercial (customer)
ICCP	Impressed Current Corrosion Protection
Km	Kilometre
kPa	Kilopascal
KPI	Key Performance Indicator
LEL	Lower Explosive Limit
LP	Low Pressure (MAOP=1.7 kPa)
m^3/hr	Cubic metres per hour
MAOP	Maximum Allowable Operating Pressure
MAPS	Moomba Adelaide Pipeline System
MP	Medium Pressure (up to 140 kPa)
MPT	Magnetic Particle Testing
NERR	National Energy Retail Rules
NGL	National Gas Law
NGR	National Gas Rules
NT	Northern Territory

TERM	DEFINITION
O&M	Operations & Maintenance
ODOR	Odorisation Facility
Opex	Operational expenditure
OPSO	Overpressure Shut Off
OTR	Office of the Technical Regulator
PE	Polyethylene
PI	Performance Indicator
PIMP	Pipeline Integrity Management Plan
PM	Preventative Maintenance
PMC	Periodic Meter Change
PVP	Palm Valley Pipeline
RLP	Riverland Pipeline
SA	South Australia
SAMP	Strategic Asset Management Plan
SCADA	Supervisory Control and Data Acquisition
SCC	Stress Corrosion Cracking
SIB	Stay in Business
SRMTMP	Safety Reliability Maintenance and Technical Management Plan
Tariff D	Haulage tariff applied to customers using greater than 10 TJ / annum
Tariff V	Volume based haulage tariff applied to customers using < 10 TJ/annum
TJ	Terajoule
TP	Transmission Pipeline / Transmission Pressure
UAFG	Unaccounted For Gas
UPS	Unprotected Steel
VIC	Victoria
VNIE	Victorian Northern Interconnect

10. List of Tables

11. List of Figures

Appendix A – Network Location Map