Attachment 8.8

Capex business cases – South Australia

SA Final Plan July 2021 – June 2026

July 2020

Part 2: Pages 103-212 (SA106, SA107, SA108, SA109, SA110, SA111 & SA112)

Australian Gas Networks

apa

Contents

SA106 – District regulator station overpressure risk reduction

1.1 Project approvals

Table 1.1: Business case SA106 – Project approvals

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1.2 Project overview

Table 1.2: Business case SA106 – Project overview

Description of the problem / opportunity	The South Australian (SA) gas distribution network has 91 transmission pressure (TP) district regulator stations (DRS). These DRS facilities regulate pressure from a higher pressure network to a lower pressure network, and are critical for maintaining a safe and reliable natural gas supply. Each 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. This business case considers the costs and benefits of installing isolation valves regulators on [redacted] bypasses over the next five years, as well as other options to manage the overpressure risk. The remaining [redacted] DRS shall be addressed during the following access arrangement (AA) period.
Untreated risk	As per risk matrix = **High**
Options considered	• **Option 1** – Continue with current practice of manually throttling supply for the [redacted] outstanding TP DRS facilities during maintenance (zero upfront capex, however there is potential for ongoing costs/compensation charges associated with supply interruption) • **Option 2** – Install a pressure regulator and secondary isolation valve on the bypass line of [redacted] TP DRS facilities ($3.1 million) • **Option 3** – Install a secondary isolation valve on the bypass line of [redacted] TP DRS ($2.7 million) • **Option 4** – Isolate supply for the [redacted] outstanding TP DRS facilities during maintenance (zero upfront capex, however there is potential for ongoing costs/compensation charges associated with supply interruption)
Proposed solution	This business case recommends Option 2 as it achieves the required risk reduction associated with overpressurisation of the network at the lowest sustainable cost with the minimum disruption to supply. The recommended option is in line with current industry good practice and design standards, and consistent with the Strategic Asset Management Plan. It removes the risk of human error contributing to the likelihood of high consequence safety outcomes without interrupting supply.

Estimated cost	The forecast direct capital cost (excluding overhead) during the next AA period (July 2021 to 2026) is $3.1 million.

$'000 2019/20	2021/22	2022/23	2023/24	2024/25	2025/26	Total
DRS risk reduction	551.1	637.2	637.2	637.2	637.2	3,099.8

Basis of costs	All costs in this business case are expressed in real unescalated dollars at December 2019 unless otherwise stated. Some tables may not add due to rounding.
Alignment to our vision	Addressing the risk of I&C overpressure events by installing pressure regulators and secondary isolation valves on the bypass line at TP DRS facilities aligns with AGN's vision in relation to: • *Delivering for Customers*, as avoiding overpressurisation events in networks downstream of DRS will help maintain reliability of supply and mitigate the risk of asset failure, personnel errors and/or unplanned outages. • *Sustainably Cost Efficient*, as proactively augmenting existing assets rather than installing new DRS, using a blend of internal and external resources in a phased project, is the lowest sustainable cost of managing the overpressure risk.
Consistency with the National Gas Rules (NGR)	**NGR 79(1)** – the proposed solution is consistent with good industry practice, several practicable options have been considered, and market rates have been tested to achieve the lowest sustainable cost of providing this service. **NGR 79(2)** – proposed capex is justifiable under NGR 79(2)(c)(i), as it is necessary to maintain the safety of services. **NGR 74** – the forecast costs are based on the latest market rate testing and project options consider the asset management requirements as per the Strategic Asset Management Plan. This business case considers the costs and the benefits of each options. The estimate has been arrived at on a reasonable basis and represents the best estimate possible in the circumstances.
Treated risk	As per risk matrix = **Low**
Stakeholder engagement	We are committed to operating our networks in a manner that is consistent with the long-term interests of our customers. To facilitate this, we conduct regular stakeholder engagement to understand and respond to the priorities of our customers and stakeholders. Feedback from stakeholders is built into our asset management considerations and is an important input when developing and reviewing our expenditure programs. Our customers have told us their top three priorities are price/affordability, reliability of supply, and maintaining public safety. They also told us they expect us to deliver a high level of public safety and are satisfied that this is current practice. The proposed DRS overpressure risk reduction capital expenditure is designed to ensure the network operates in line with good industry practice, safety standards and compliance requirements, thereby helping maintain a safe and reliable service to customers. These activities are consistent with stakeholder expectations of our network and the level of service our customers value.
Other relevant documents	• Attachment 8.2 Strategic Asset Management Plan

1.3 Background

The SA natural gas distribution network is supplied by 91 transmission pressure (TP) district regulator stations (DRS). These DRS facilities are used to provide supply and regulate pressure from the higher pressure networks to the lower pressure networks.

Like all network assets, DRS facilities require periodic maintenance. To allow us to conduct maintenance without disrupting supply, each DRS facility has a service bypass line that allows us to maintain supply to the downstream network while we shut down the DRS.

Isolation valves are used to divert flow to the bypass line. Isolation valves are manually throttled by a technician to allow continued supply through the bypass line during maintenance activities. If there is no pressure regulator on the bypass line, the throttling is monitored intermittently and the throttling adjusted manually while the technician is working on the DRS facility.

Approximately 30 years ago the standard design for DRS facilities was modified to include a secondary isolation valve on the bypass line. This provides a second control and reduces the likelihood of an overpressure event during maintenance. In 1998 the standard design for DRS facilities was modified again to include a regulator on the bypass line (as well as a secondary isolation valve). Using a regulator eliminates the need for manual throttling and monitoring, and therefore removes the risk associated with human error leading to an overpressure event.

A secondary isolation valve and a regulator is the current industry design standard for a DRS bypass line.

All DRS facilities installed in our network have been designed to the standard in place at the time of installation. At 1 July 2020, of our 91 TP DRS facilities:

- [redacted] have only one isolation valve on the bypass line;
- [redacted] have a primary and secondary isolation valve on the bypass line; and
- [redacted] either have a regulator and a secondary isolation valve on the bypass line or are twin-stream (without the need for a bypass line).

Where a DRS has only one isolation valve and no regulator, there is a high risk of an overpressure event. Overpressure incidents can have major risk consequences. For example, in 2018 an incident occurred at a regulator station in Boston[37], USA, which resulted in the overpressurisation of a section of the distribution network. The incident caused a gas escape at numerous domestic meter sets and resulted in significant damage to property, many injuries and a fatality.

While the Boston incident was not directly related to manually throttling isolation valves, it highlighted the serious risk associated with overpressure and led us to review the overpressure risk within the SA network. Our review concluded that the single isolation valve on the bypass line of TP DRS facilities - which separates two pressure regimes - presents a high risk of over pressurisation.

An overpressure incident also occurred in the Queensland gas distribution network. In June 2019, an isolation valve on a bypass line at a meter set was accidently opened by the technician for an extended period. The customer's installation became overpressurised, damaging the appliance pressure regulators and other equipment.

A review of the Queensland incident showed the issue could easily have resulted in more severe consequences, including a major gas-in-building scenario with the potential for ignition. The overpressure incident could have been prevented if there had been a regulator installed on the bypass.

In light of these two incidents, we are taking steps to mitigate the overpressure risk and help prevent similar incidents occurring in the SA network. We have developed a business case (SA129 – I&C customer overpressure risk reduction) to install regulators on all bypass lines for individual I&C customers. This eliminates the risk of human error when conducting maintenance at the customer's meter set.

Similarly, we consider it prudent to install regulators on TP DRS bypasses, as this mitigates the risk of an overpressure incident when conducting maintenance at the DRS. Note that an overpressure

[37] National Transport Safety Board (NTSB) reference NTSB/PSR 18-02

incident at a TP DRS can impact many customers, whereas overpressure at the I&C meter set will only impact one customer.

Managing the overpressure risk is a high priority for AGN. This business case considers the costs and benefits of installing secondary isolation valves and regulators on DRS bypasses over the next five years, as well as other options to manage the overpressure risk.

1.4 Risk assessment

Risk management is a constant cycle of identification, analysis, treatment, monitoring, reporting and then back to identification (as illustrated in Figure 1.1). When considering risk and determining the appropriate mitigation activities, we seek to balance the risk outcome with our delivery capabilities and cost implications. Consistent with stakeholder expectations, safety and reliability of supply are our highest priorities.

Figure 1.1: Risk management principles

Our risk assessment approach focuses on understanding the potential severity of failure events associated with each asset and the likelihood that the event will occur. Based on these two key inputs, the risk assessment and derived risk rating then guides the actions required to reduce or manage the risk to an acceptable level.

AGN's risk management framework is based on:

- AS/NZS ISO 31000 Risk Management – Principles and Guidelines;
- AS 2885 Pipelines-Gas and Liquid Petroleum; and
- AS/NZS 4645 Gas Distribution Network Management.

The Gas Act 1997 and Gas Regulations 2012, through their incorporation of AS/NZS 4645 and the Work Health and Safety Act 2012, place a regulatory obligation and requirement on AGN to reduce risks rated high or extreme to low or negligible as soon as possible (immediately if extreme). If it is not possible to reduce the risk to low or negligible, then we must reduce the risk to as low as reasonably practicable (ALARP).

When assessing risk for the purpose of investment decisions, rather than analysing all conceivable risks associated with an asset, we look at a credible, primary risk event to test the level of investment required. Where that credible risk event has an overall risk rating of moderate or higher, we will undertake investment to reduce the risk.

Seven consequence categories are considered for each type of risk:

1. **Health & safety** – injuries or illness of a temporary or permanent nature, or death, to employees and contractors or members of the public
2. **Environment** (including heritage) – impact on the surroundings in which the asset operates, including natural, built and Aboriginal cultural heritage, soil, water, vegetation, fauna, air and their interrelationships
3. **Operational capability** – disruption in the daily operations and/or the provision of services/supply, impacting customers
4. **People** – impact on engagement, capability or size of our workforce

5 **Compliance** – the impact from non-compliance with operating licences, legal, regulatory, contractual obligations, debt financing covenants or reporting / disclosure requirements

6 **Reputation & customer** – impact on stakeholders' opinion of AGN, including personnel, customers, investors, security holders, regulators and the community

7 **Financial** – financial impact on AGN, measured on a cumulative basis

A summary of our risk management framework, including definitions, has been provided in Attachment 8.10.

The primary risk identified for TP DRS facilities with a single isolation valve and no regulator on the bypass line is the downstream network becoming overpressurised during maintenance of the duty line. The overpressurisation event is the result of failure or malfunction of the bypass valve, or due to the valve being left open for an extended period. Overpressurisation at the TP DRS can lead to a major gas escape affecting supply to >10,000 customers or damage to equipment and/or serious harm (fatality).

The overall untreated risk rating is high, as an overpressure safety or supply incident with major consequences, though unlikely, has the potential to happen in certain circumstances. As shown by the Boston and Queensland incidents, major overpressure risk events have been known to occur elsewhere. Any major overpressure event also has potential to cause a significant people, compliance, reputational and financial risk, due to the harm or supply interruption caused. As a result, the overall risk rating for these risk categories is moderate.

The untreated risk[38] rating is presented in Table 1.3.

Table 1.3: DRS overpressure risk assessment – Untreated risk

Untreated risk	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Major	Minor	Major	Significant	Significant	Significant	Significant	
Risk Level	High	Low	High	Moderate	Moderate	Moderate	Moderate	

1.5 Options considered

Different options have been considered to address the risks associated with the overpressurisation of the downstream network resulting from TP DRS facilities with a single isolation valve on the bypass. The options are:

- **Option 1** – Continue with current practice of manually throttling supply for the [redacted] outstanding TP DRS facilities during maintenance;
- **Option 2** – Install a pressure regulator and secondary isolation valve on the bypass line of [redacted] outstanding TP DRS facilities;
- **Option 3** – Install a secondary isolation valve on the bypass line of [redacted] outstanding TP DRS facilities; or
- **Option 4** – Isolate supply for the [redacted] outstanding TP DRS facilities during maintenance.

These options are discussed in the following sections.

38 Untreated risk is the risk level assuming there are no risk controls currently in place. Also known as the 'absolute risk'.

1.5.1 Option 1 – Continue with current practice of manually throttling supply for the [redacted] outstanding TP DRS facilities during maintenance

Under this option, we would continue the current practice of an operator manually throttling the single isolation valve to allow continued supply through the bypass line during planned and reactive maintenance activities. The manual throttling is then monitored intermittently while the technician is working on the DRS facility.

1.5.1.1 Cost assessment

There are no upfront capital costs associated with this this option. The capital cost of replacing the DRS facilities would only be incurred upon failure, or as part of the future end of life replacement plan and therefore incurred over several regulatory periods. [39]

However, the current design with existing controls in place risks asset failure and/or operator error of the manually operated isolation valves. This could result in the overpressurisation of the downstream network and a significant uncontrolled gas escape, damage to the downstream network and subsequent customer outages. Where there is fault on AGN, outages can result in substantial penalties and customer compensation. Outages can also lead to foregone revenue for customers and AGN.

1.5.1.2 Risk assessment

Option 1 does not adequately address the health and safety risk associated with DRS overpressure events. Table 1.4 shows the residual risk associated with DRS overpressure events if Option 1 is undertaken.

Table 1.4: DRS overpressure risk assessment – Option 1

Option 1	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	
Consequence	Major	Minor	Major	Significant	Significant	Significant	Significant	High
Risk Level	High	Low	High	Moderate	Moderate	Moderate	Moderate	

Though there are a number of current risk controls in place, such as procedural controls and telemetered pressure alarms, these controls do not significantly reduce the likelihood of the primary risk event occurring. The current controls also do little to reduce the potential consequence of the risk event. As a result, Option 1 fails to reduce the overall risk rating to low or ALARP as required by our risk management framework.[40]

1.5.1.3 Alignment with vision objectives

Table 1.5 shows how Option 1 aligns with our vision objectives.

Table 1.5: Alignment with vision – Option 1

Vision objective	Alignment
Delivering for Customers – Public Safety	N
Delivering for Customers – Reliability	N

[39] These DRS have an estimated remaining life of 20 to 30 years.

[40] Note that while Option 1 logically carries lower risk than an untreated risk, the limited granularity under the AS 4645-based risk matrix do not allow the current controls are not sufficient to reduce the likelihood or consequence rating.

Vision objective	Alignment
Delivering for Customers – Customer Service	N
A Good Employer – Health and Safety	N
A Good Employer – Employee Engagement	-
A Good Employer – Skills Development	-
Sustainably Cost Efficient – Working within Industry Benchmarks	N
Sustainably Cost Efficient – Delivering Profitable Growth	-
Sustainably Cost Efficient – Environmentally and Socially Responsible	-

Option 1 does not align with our objectives of *Delivering for Customers* or *A Good Employer*, as it would not address the safety and reliability risks associated with overpressurisation of downstream network assets.

Option 1 is also not *Sustainably Cost Efficient* as addressing the overpressure events retrospectively is not the most sustainable cost option. Having TP DRS with no secondary valve or regulator on the bypass line is also not consistent with current design standards. It is therefore prudent to move to the new standard within a reasonable timeframe rather than maintain the overpressure risk for longer than necessary.

1.5.2 Option 2 – Install a pressure regulator and secondary isolation valve on the bypass line of [redacted] outstanding TP DRS facilities

Under this option we would augment the existing bypass line at [redacted] of the [redacted] outstanding TP DRS facilities to include a new pipe spool, secondary isolation valve and pressure regulator (see Appendix A). This is consistent with good industry practice and current design standards.

The complexity of the project and competing resource constraints means it may not be practicable to install pressure regulator and secondary isolation valves on all [redacted] TP DRS during the next AA period. We have considered the risk associated with the [redacted] DRS facilities and consider it is prudent to spread the program and resulting tariff impact over ten years. We therefore propose to address half the outstanding DRS in the next AA period, and the remainder in the following period.

Installing a secondary isolation valve will reduce the risk of asset failure leading to overpressurisation of the downstream network such as the 2018 incident in Boston. Installing a pressure regulator will mitigate the risk of human error leading to overpressurisation of the downstream network such as the 2019 incident in Queensland.

The new equipment will be maintained as part of the normal routine preventative maintenance activities on DRS facilities. The additional time required for checking functionality of the new equipment while completing normal scheduled preventative maintenance is not material.

1.5.2.1 Cost assessment

The estimated capital cost of installing a secondary isolation valve and pressure regulators on bypass lines at [redacted] outstanding TP DRS facilities is $3.1 million. This estimate is based on current material and labour rates for new installations and assumes [redacted] DRS facilities will be addressed over the next five years (see Table 1.6). A further [redacted] DRS would be addressed during the following AA period.

Table 1.6: Cost assessment – Option 2, $'000 2019/20

Option 2	2020/21	2021/22	2022/23	2023/24	2024/25	Total
Scope	Procure materials Modify [redacted] DRS	Modify [redacted] DRS	Modify [redacted] DRS	Modify [redacted] DRS	Modify [redacted] DRS	Modify [redacted] DRS
Labour	285.4	570.7	570.7	570.7	570.7	2,568.4
Materials	265.7	66.4	66.4	66.4	66.4	531.4
Total	**551.1**	**637.2**	**637.2**	**637.2**	**637.2**	**3,099.8**

1.5.2.2 Risk assessment

Option 2 reduces the risk rating associated with overpressurisation of the downstream network from high to low. Table 1.7 shows the residual risk associated with the completed 18 DRS facilities if Option 2 is undertaken.

Table 1.7: Risk assessment – Option 2

Option 2	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Remote	Remote	Remote	Remote	Remote	Remote	Remote	
Consequence	Significant	Minor	Significant	Minor	Minor	Minor	Minor	Low
Risk Level	Low	Negligible	Low	Negligible	Negligible	Negligible	Negligible	

Having both the second isolation valve and the regulator installed on the bypass line reduces the risk consequences from major to significant, as these controls result in less gas being released and fewer customers being impacted if there is an overpressure event. These two controls combined should also decrease the likelihood of an overpressure event from unlikely to remote, as they eliminate the need for manual intervention.

Of the options considered, Option 2 achieves the greatest risk reduction (low) and is therefore consistent with our risk management framework, as well as current industry practice and design standards.

1.5.2.3 Alignment with vision objectives

Table 1.8 shows how this option aligns with our vision objectives.

Table 1.8: Alignment with vision – Option 2

Vision objective	Alignment
Delivering for Customers – Public Safety	Y
Delivering for Customers – Reliability	Y
Delivering for Customers – Customer Service	Y
A Good Employer – Health and Safety	Y
A Good Employer – Employee Engagement	-
A Good Employer – Skills Development	-
Sustainably Cost Efficient – Working within Industry Benchmarks	Y
Sustainably Cost Efficient – Delivering Profitable Growth	-
Sustainably Cost Efficient – Environmentally and Socially Responsible	-

Option 2 would align with the *Delivering for Customers* aspect of our vision, as proactive augmentation of existing facilities will help maintain reliability of supply and mitigate the risk of public safety incidents. Customers (and staff working) in the downstream network will be safe from elevated operating pressures.

Option 2 is also *Sustainably Cost Efficient,* as augmenting the outstanding TP DRS to be consistent with the current design standard means we are operating these critical assets in line with accepted industry practice. We are also undertaking this work over ten years, helping reduce the network tariff impact on customers during the next AA period.

1.5.3 Option 3 – Install a secondary isolation valve on the bypass line of [redacted] TP DRS facilities

Under this option we would augment the existing bypass line at [redacted] of the [redacted] outstanding TP DRS facilities to include a new pipe spool and secondary isolation valve. We would not install a regulator.

The complexity of the project and competing resource constraints means it may not be practicable to install secondary isolation valves on all [redacted] TP DRS during the next AA period. We have considered the risk associated with the [redacted] DRS facilities and consider it is prudent to spread the program and resulting tariff impact over ten years. We therefore propose to address half the outstanding DRS in the next AA period, and the remainder in the following period.

Installing a secondary isolation valve will reduce the risk of asset failure leading to overpressurisation of the downstream network such as the 2018 event in Boston. However, the absence of a regulator means we will rely on manual operation of the isolation valves. Option 3 will therefore not mitigate the risk of human error leading to overpressurisation of the downstream network during maintenance (such as the 2019 Queensland incident).

The new equipment will be maintained as part of the normal routine preventative maintenance activities on DRS facilities. The additional time required for checking functionality of the new equipment while completing normal scheduled preventative maintenance is not material.

1.5.3.1 Cost assessment

The estimated capital cost of installing a secondary isolation valve and pressure regulator on bypass lines at [redacted] TP DRS facilities is $2.7 million. This estimate is based on current material and labour rates for new installations and assumes all identified DRS facilities will be addressed over the next five years (see Table 1.9). A further [redacted] DRS would be addressed during the following AA period.

Table 1.9: Cost assessment - Option 3, $'000 real 2019/20

Option 3	2020/21	2021/22	2022/23	2023/24	2024/25	Total
Scope	Procure materials Modify [redacted] DRS	Modify [redacted] DRS	Modify [redacted] DRS	Modify [redacted] DRS	Modify [redacted] DRS	Modify [redacted] DRS
Labour	266.4	532.8	532.8	532.8	532.8	2,397.8
Materials	157.7	39.4	39.4	39.4	39.4	315.4
Total	**424.1**	**572.3**	**572.3**	**572.3**	**572.3**	**2,713.2**

1.5.3.2 Risk assessment

Option 3 reduces risk associated with overpressurisation of the downstream network from high to moderate for the completed [redacted] DRS facilities (Table 1.10).

Table 1.10: Risk assessment – Option 3

Option 3	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Moderate
Consequence	Significant	Minor	Significant	Minor	Minor	Minor	Minor	
Risk Level	Moderate	Low	Moderate	Low	Low	Low	Low	

Though installing the isolation valve on the bypass line reduces the overall risk to moderate, because a pressure regulator is not installed the risk of overpressure due to human error is not eliminated. Installing the secondary valve means the consequences of an overpressure event occurring are lower than the untreated risk, however the requirement for manual intervention means human error remains a significant factor. The likelihood of an overpressure event therefore remains rated unlikely (rather than remote as in Option 2).

Option 3 is therefore not consistent with our risk management framework, which requires the risk to be reduced to low or ALARP. It is also inconsistent with current industry practice and design standards.

1.5.3.3 Alignment with vision objectives

Table 1.11 shows how Option 3 aligns with our vision objectives.

Table 1.11: Alignment with vision – Option 3

Vision objective	Alignment
Delivering for Customers – Public Safety	N
Delivering for Customers – Reliability	N
Delivering for Customers – Customer Service	N
A Good Employer – Health and Safety	N
A Good Employer – Employee Engagement	-
A Good Employer – Skills Development	-
Sustainably Cost Efficient – Working within Industry Benchmarks	N
Sustainably Cost Efficient – Delivering Profitable Growth	-
Sustainably Cost Efficient – Environmentally and Socially Responsible	-

This option does not align with our objectives of *Delivering for Customers* or *A Good Employer*, as it would not address the safety and reliability risks associated with human error causing overpressurisation of the downstream network.

Option 3 is also not *Sustainably Cost Efficient* as further work would be required at the site to mitigate the outstanding risk associated with a lack of pressure control equipment. It also means the DRS design would remain inconsistent with the current design standard. The relatively minor difference in cost between Option 3 and Option 2 (~$400k) also indicates that Option 3 is not the most efficient solution, given it does not reduce the overpressure risk to the same extent.

1.5.4 Option 4 – Isolate supply for the [redacted] outstanding TP DRS facilities during maintenance

Under this option, we would isolate the TP regulator set when performing maintenance on each of the [redacted] DRS facilities with single isolation valves on the bypass line. This option may involve the installation of temporary bypasses where practical to facilitate maintenance.

We would only replace these legacy DRS facilities with new-specification equipment (which feature regulators and secondary isolation valves on bypass as standard) upon failure or as part of end of life replacement.[41]

We would endeavour to undertake planned preventive maintenance activities in line with the Strategic Asset Management Plan. However, the practicality of isolating supply is expected to cause delays and deferrals of maintenance due to network hydraulics and/or customer demand restrictions. This will increase the cost of coordinating and undertaking maintenance in the short term, and increase the likelihood of asset failure over the longer term.

1.5.4.1 Cost assessment

There would be no upfront capital cost associated with this option. The capital cost of replacing the DRS facilities would only be incurred upon failure, or as part of the future end of life replacement plan and therefore incurred over several regulatory periods.

However, upfront operating costs are higher due to the need for coordinating and undertaking maintenance including for example if temporary bypasses were to be installed, or additional resources were used to balance network pressures from other locations prior to or during maintenance work.

This solution reduces the overpressurisation risk to an acceptable level to customers in affected areas, reducing the risk of both valve failure and operator error. However, in reducing the overpressurisation risk by isolation it introduces an unacceptable loss of supply risk.

Outages for major customers can result in penalties and payment of compensation to customers, in addition to foregone revenue for customers and AGN. Therefore, as a prudent asset manager, isolating the DRS (and those customers connected to it) is not recommended.

1.5.4.2 Risk assessment

Option 4 reduces the safety risk associated with overpressurisation from high to negligible, however it does not reduce the operational risk to supply (see Table 1.12).

Table 1.12: Risk assessment – Option 4

Option 4	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Remote	Remote	Occasional	Remote	Occasional	Occasional	Unlikely	High
Consequence	Minor	Minimal	Major	Minor	Minor	Significant	Minor	
Risk Level	Negligible	Negligible	High	Negligible	Low	Moderate	Low	

Under this option, because the gas supply from the DRS is being isolated it eliminates the downstream overpressure risk (as no gas will be present downstream). As a result, the safety risk is almost entirely mitigated. However, Option 4 give rise to a different risk.

Because Option 4 requires supply from the DRS to be isolated during maintenance, a large number of customers will have their supply interrupted. The frequency of this is rated as 'occasional', as DRS maintenance is an ongoing work activity. As a result, the operational risk (interruption to supply) remains high. In addition, the frequency of supply interruptions is likely to give rise to a moderate reputational risk due to the volume of dissatisfied customers. Option 4 does therefore not align with our risk management framework and does not reflect the actions of a prudent asset manager.

41 These DRS have an estimated remaining life of 20 to 30 years.

1.5.4.3 Alignment with vision objectives

Table 1.13 shows how Option 4 aligns with our vision objectives.

Table 1.13: Alignment with vision – Option 4

Vision objective	Alignment
Delivering for Customers – Public Safety	Y
Delivering for Customers – Reliability	N
Delivering for Customers – Customer Service	N
A Good Employer – Health and Safety	Y
A Good Employer – Employee Engagement	-
A Good Employer – Skills Development	-
Sustainably Cost Efficient – Working within Industry Benchmarks	N
Sustainably Cost Efficient – Delivering Profitable Growth	-
Sustainably Cost Efficient –Environmentally and Socially Responsible	-

Option 4 does not align with our objective of *Delivering for Customers*. Even though this solution mitigates the safety risks associated with overpressurisation of the downstream network, it introduces unacceptable risks of loss of supply to the same customers.

Isolating supply each time maintenance is required is not in line with customer expectations. In many instances it is not possible to find suitable times to shut down operations for example due to network hydraulics or customer requirements. An inability to undertake maintenance may also result in non-compliance with regulatory requirements. For example, AS 60079 specifies electrical equipment in hazardous areas must be inspected every three years and any defects found must be rectified.

Upfront operating costs would also be higher due to the need to coordinate maintenance or use additional resources to balance network pressures from other locations prior to or during maintenance work. This does not align to our objective to be *Sustainably Cost Efficient*.

1.6 Summary of costs and benefits

Table 1.14 presents a summary of how each option compares in terms of the estimated cost, the residual risk rating, and aligning with our objectives.

Table 1.14: Summary of costs and benefits

Option	Estimated cost ($ million)	Treated residual risk rating	Alignment with vision objectives
Option 1	0	High	This would fail to achieve safety and reliability objectives or meet current design standards.
Option 2	3.1	Low	This would align with all relevant vision objectives.
Option 3	2.7	Moderate	This option reduces one area of identified risk but does not address all risks. It is also inconsistent with current design standards.
Option 4	0	High	This would fail to achieve safety and reliability objectives or meet current design standards.

1.7 Recommended option

Option 2 is the recommended option as it is the most cost-effective solution to reduce the risk of overpressurisation posed by TP DRS facilities.

1.7.1 Why is the recommended option prudent?

Option 2 reduces the risk of DRS facilities resulting in overpressurisation of the downstream network without compromising supply. Option 2 provides a level of risk reduction that is already addressed in current industry design standards and mitigates the risks identified in the Boston and Queensland overpressure events. Option 2 reduces the risk to ALARP and therefore aligns with our Asset Management Plan and risk management framework. It also aligns with the:

- *Delivering for Customers* aspect of our vision, as proactive augmentation of existing DRS facilities will help maintain reliability of supply and mitigate the risk of public safety incidents; and
- *Sustainably Cost Efficient* aspect of our vision, as installing a regulator and secondary valve at DRS facilities is consistent with industry design standards and can be delivered at a cost that is commensurate with the risk reduction.

A risk-based approach to deliver this program will be adopted, whereby works will be prioritised on those DRS facilities with highest risk to the network and feeding high consequence areas.

1.7.2 Estimating efficient costs

Key assumptions made in the cost estimation for the DRS overpressure risk reduction project include:

- all [redacted] DRS shall be completed during a 10 year period, with [redacted] completed during the next 5 year period;
- costs are based on historical expenditure noting that these works are not new, with labour rates based on work breakdown structure of activities, and material rates based on historical costs for similar materials;
- estimates derived from contractual rates of vendors to be utilised;
- resource cost based on other similar projects ongoing at present or in previous AA periods; and
- original equipment manufacturer contractual rates for spares and labour that are part of our services agreements.

Table 1.15 presents a breakdown of the DRS overpressure risk reduction project by cost category. Table 1.16 provides the costs escalated to June 2021 dollars.

Table 1.15: Project cost estimate, by cost category, $'000 2019/20

	2020/21	2021/22	2022/23	2023/24	2024/25	Total
Scope	Procure materials Modify [redacted] DRS	Modify [redacted] DRS	Modify [redacted] DRS	Modify [redacted] DRS	Modify [redacted] DRS	Modify [redacted] DRS
Labour	285.4	570.7	570.7	570.7	570.7	2,568.4
Materials	265.7	66.4	66.4	66.4	66.4	531.4
Total	**551.1**	**637.2**	**637.2**	**637.2**	**637.2**	**3,099.8**

Table 1.16: Escalated project cost estimate ($'000)

	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Total unescalated ($ Dec 19)	551.1	637.2	637.2	637.2	637.2	3,099.8
Escalation	18.6	24.6	28.6	32.2	35.5	139.5
Total escalated ($ Jun 21)	**569.7**	**661.8**	**665.8**	**669.4**	**672.7**	**3,239.4**

1.7.3 Consistency with the National Gas Rules

In developing these forecasts, we have had regard to Rule 79 and Rule 74 of the NGR. With regard to all projects, and as a prudent asset manager, we give careful consideration to whether capex is conforming from a number of perspectives before committing to capital investment.

Rule 79(2)

The proposed capex is justifiable under NGR 79(2)(c)(i), as it is necessary to maintain the safety of services. Continuing with current practice results in an unacceptable safety risk for customers and our staff, network integrity issues, disruption to customer supply and potential uncontrolled release of gas.

Consistent with the Strategic Asset Management Plan, and as outlined in this business case, current industry practice, to include an additional control and regulator on all TP DRS facility bypass lines will allow us to provide a level of service consistent with industry and design standards, consistent with customer expectations.

Rule 79(1)

The augmentation of TP DRS facilities to install a second isolation valve and pressure regulator on each bypass line is consistent with the requirements of NGR 79(1)(a), Specifically, we consider the capital expenditure is:

- **Prudent** – the expenditure is necessary in order to deliver gas safely and reliably to the downstream network. The proposed risk treatment is consistent with accepted industry practice and current design standards and is proven to address the risk associated with TP DRS facilities. Several practicable options have been considered to address the risk. The proposed expenditure is of a nature that would be incurred by a prudent service provider.

- **Efficient** – the forecast expenditure is based on historical average actuals and tender contract values. The proposed expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur. The project is being delivered at an achievable rate of installation.

- **Consistent with accepted and good industry practice** – the proposed expenditure follows good industry practice by ensuring existing safety risks are addressed to ALARP and in line with current industry practice and design standards. The proposed capital expenditure is therefore such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice.

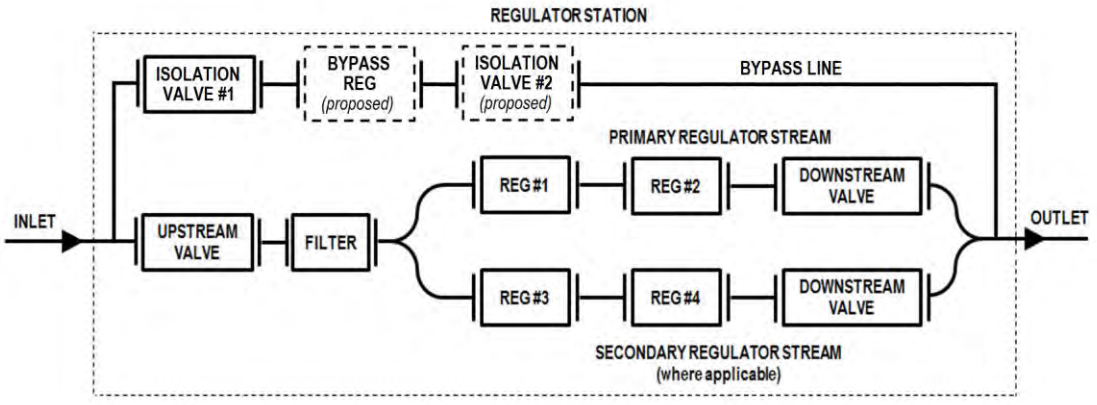
- To achieve the lowest sustainable cost of delivering pipeline services – the sustainable delivery of services includes reducing risks to as low as reasonably practicable while maintaining reliability of supply. The proposed solution allows us to undertake critical maintenance without disrupting customer supply, while at the same time reducing the overpressure risk to ALARP. Further, we have spread the works over a reasonable timeframe that balances risk reduction with network tariff impact.

Rule 74

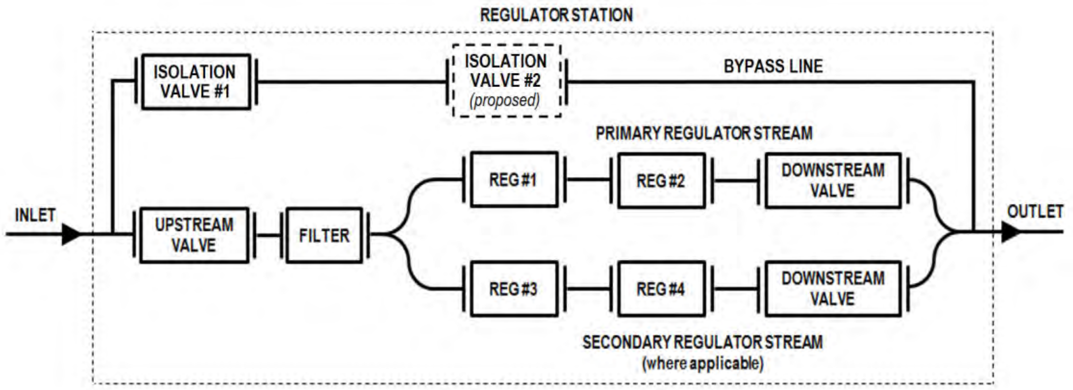
The forecast costs are based on the latest market rate testing and project options consider the asset management requirements as per the Strategic Asset Management Plan. The estimate has therefore been arrived at on a reasonable basis and represents the best estimate possible in the circumstances.

Appendix A – DRS proposed modification diagram

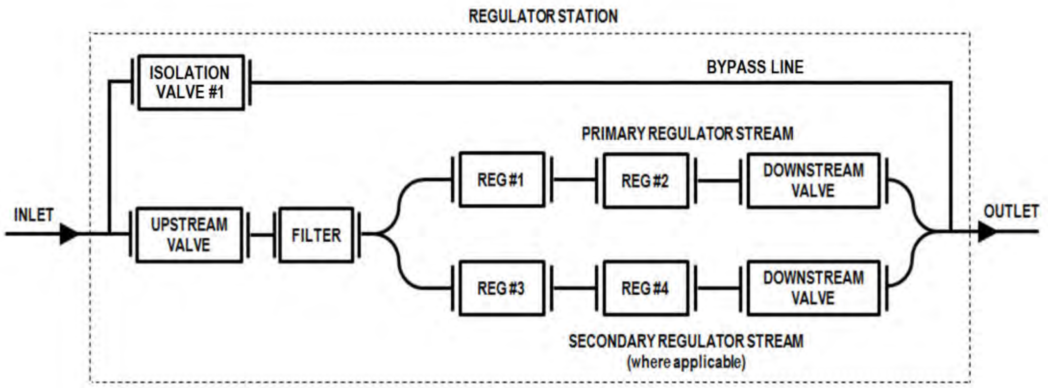
Regulator and secondary isolation valve on bypass



Secondary isolation valve on bypass



Current set up



Appendix B – Comparison of risk assessments for each option

Untreated risk	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Major	Minor	Major	Significant	Significant	Significant	Significant	
Risk Level	High	Low	High	Moderate	Moderate	Moderate	Moderate	

Option 1	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Major	Minor	Major	Significant	Significant	Significant	Significant	
Risk Level	High	Low	High	Moderate	Moderate	Moderate	Moderate	

Option 2	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Remote	Remote	Remote	Remote	Remote	Remote	Remote	Low
Consequence	Significant	Minor	Significant	Minor	Minor	Minor	Minor	
Risk Level	Low	Negligible	Low	Negligible	Negligible	Negligible	Negligible	

Option 3	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Moderate
Consequence	Significant	Minor	Significant	Minor	Minor	Minor	Minor	
Risk Level	Moderate	Low	Moderate	Low	Low	Low	Low	

Option 4	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Remote	Remote	Occasional	Remote	Occasional	Occasional	Unlikely	High
Consequence	Minor	Minimal	Major	Minor	Minor	Significant	Minor	
Risk Level	Negligible	Negligible	High	Negligible	Low	Moderate	Low	

SA107 – Isolation valves

1.1 Project approvals

Table 1.1: Business case SA107 – Project approvals

Prepared by	Peiman Vakili, Gas Networks and Pipeline Engineer, APA
Reviewed by	Jason Morony, Manager Capital Delivery, APA
Approved by	Martijn Vlugt, Asset Planning Manager SA, APA Mark Beech, General Manager Network Operations, AGN

1.2 Project overview

Table 1.2: Business case SA107 – Project approvals

Description of the problem / opportunity	The South Australia (SA) natural gas distribution networks include approximately 200 km of metropolitan steel transmission pressure (TP) pipelines, and 200 km of steel distribution pipelines, which deliver gas to over 450,000 customers. The current TP system in the Adelaide metro area consists of a series of interconnected pipelines. This interconnectivity facilitates the security of gas supply in the networks. In an emergency situation, and in other situations where there is a need to shut down a TP pipeline, the interconnectivity assists by securing supply. However, it also means that an incident on one pipeline could result in isolation of other pipelines, affecting supply to a significant number of customers (depending on the incident location). 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. The SA networks continue to grow, with more customers connecting to the network and system hydraulics changing over time. As a result, the number and location of valves necessary to appropriately manage customer supply will change over time. 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 management framework[42], 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. This business case considers options on how many additional valves should be installed within the next five years.
Untreated risk	As per risk matrix = **High**

[42] Our risk management framework is based on the guidance of AS/NZS 4645.

Options considered	• **Option 1** – Maintain status quo. Do not install additional inline valves in Adelaide's TP system (no additional upfront capital cost) • **Option 2** – Install [redacted] new inline valves to reduce supply outage risk in Adelaide's TP system ($3.1 million) • **Option 3** – Install [redacted] new inline valves that will reduce the potential number of customers impacted by supply outage risk in Adelaide's transmission pipeline system to fewer than 10,000 at any location ($1.8 million)
Proposed solution	Option 3 is the proposed solution as it supports a consistent approach to supply integrity across the entire network, by maintaining a risk consequence impact of 'significant' or lower (fewer than 10,000 customers) at all locations, for a reasonable level of investment. This involves installing [redacted] new inline valves strategically located to increase the segmentation of the pipelines and minimise the number of customers impacted in an emergency shutdown situation. Option 1 does not mitigate the high operational risk associated with the potential for service shutdown to a significant number of customers in an emergency situation. Option 2 will mitigate the operational risk, but this will be at a significantly higher cost per customer mitigated than Option 3.
Estimated cost	The forecast direct capital cost (excluding overhead) during the next access arrangement (AA) period (July 2021 to June 2026) is $1.8 million.

$'000 2019/20	21/22	22/23	23/24	24/25	25/26	Total
4 new valve installations	68.1	441.5	441.5	441.5	373.4	1,765.8

Basis of costs	All costs in this business case are expressed in real unescalated dollars at December 2019 unless otherwise stated. Some tables may not add due to rounding.
Alignment to our vision	This project links to the Delivering for Customers aspect of our vision. It delivers for customers by ensuring acceptable levels of security and reliability of gas supply.
Consistency with the National Gas Rules (NGR)	This project complies with the following National Gas Rules (NGR): **NGR 79(1)** – the proposed solution is consistent with good industry practice, several practicable options have been considered, and market rates have been tested to achieve the lowest sustainable cost of providing this service. **NGR 79(2)** – proposed capex is justifiable under NGR 79(2)(c)(ii), as it is necessary to maintain the integrity of services. **NGR 74** – the forecast costs and are based on the latest market rate testing and project options consider the asset management requirements as per the Strategic Asset Management Plan. The estimate has therefore been arrived at on a reasonable basis and represents the best estimate possible in the circumstances.
Treated risk	As per risk matrix = **Moderate**
Stakeholder engagement	We are committed to operating our networks in a manner that is consistent with the long term interests of our customers. To facilitate this, we conduct regular stakeholder engagement to understand and respond to the priorities of our customers and stakeholders. Feedback from stakeholders is built into our asset management considerations and is an important input when developing and reviewing our expenditure programs. Our customers have told us their top three priorities are price/affordability, reliability of supply, and maintaining public safety. They also told us they expect us to deliver a high level of public safety and are satisfied that this is current practice. The proposed installation of additional valves at strategic locations on the transmission pipeline system will assist us to maintain the reliability of supply, and is therefore consistent with the current practice customers have told us they value.
Other relevant documents	• Attachment 8.2 Strategic Asset Management Plan

1.3 Background

The SA natural gas distribution networks include approximately 200 km of metropolitan steel TP pipelines, which deliver gas to over 450,000 customers.

The metropolitan TP pipelines form the backbone of the SA gas distribution network. Gas enters the network via upstream gate stations which feed directly into the transmission pipelines. These transmission pipelines form a network across metropolitan South Australia and supply downstream district regulator stations. The majority of the TP pipelines were constructed prior to 1987, with the two longest and most complex pipelines (M42 and M12) being more than 50 years old. TP pipelines operate with a maximum allowable operating pressure above 1050 kPa, therefore their design, construction, operation and maintenance are governed by Australian Standard AS 2885.

The current TP system in the Adelaide metro area consists of a series of interconnected pipelines. In an emergency situation, and in other situations where there is a need to shut down a transmission pipeline, the interconnectivity assists by allowing sections of the network to be supplied from another pipeline/direction. However, it also means that an incident on one pipeline could result in isolation of other pipelines, affecting supply to a significant number of customers (depending on the incident location).

Australian Standards AS 2885.1 (Pipelines - Gas and Liquid petroleum) and AS/NZ 4645.1 (Gas distribution network management) require TP pipeline and network operators to install and maintain isolation valves to allow for expedient isolation of the pipeline or network for emergency and maintenance purposes. The quantity and location of these valves depends on the design of the asset (pipe diameter), the valve location (urban vs rural), the pipe material used (material grade) and the consequences of any loss of containment.

The SA network continues to grow, with more customers connecting to the network and system hydraulics changing over time. We have therefore conducted review of the metropolitan TP network to understand how many customers would be impacted if each section of the TP network were to be isolated during an emergency situation.

We have identified [redacted] long sections of pipeline that supply district regulator stations (DRS) between existing valves. If these sections of pipeline have to be isolated, it could cut off supply to up to 51,600 customers. This supply risk could be mitigated if we install additional inline valves along the transmission mains.

Installing valves at these [redacted] locations would lead to fewer DRS being affected during emergency isolation, and reduce the number of customers impacted. Table 1.3 summarises the number of customers impacted when isolating each of the [redacted] TP pipelines with and without the installation of additional valves.

Table 1.3: Customer supply impacts at identified isolation locations

Pipe diameter (mm)	Suburb	Location of emergency incident	Proposed location of new valve	Customers affected (without proposed valve)	Customers affected (with proposed valve)
250mm	Salisbury Plains	Between regulators R146 & R162	1km north from regulator R146 inlet main	51,600	0
200mm	Wynn Vale	Between regulators R110 & R161	1.4km east from regulator R110 inlet main	43,900	9,199

Pipe diameter (mm)	Suburb	Location of emergency incident	Proposed location of new valve	Customers affected (without proposed valve)	Customers affected (with proposed valve)
300mm	Kensington	Between regulators R138 & R139	1.4km north from regulator R138 inlet main	15,800	7,700
250mm	North Plympton	Between regulators R413 & R404	0.2km north from regulator R413 inlet main	10,073	1,986
250mm	South Brighton	Between regulators R335 & R308	0.9km north from regulator R335 inlet main	2,300	1,600
300mm	West Beach	Between regulators R329 & R145	1.2km south from regulator R145 inlet main	3,000	850
200mm	Largs Bay	Between regulators R224& R150	1km north from regulator R224 inlet main	2,800	2,500

This business case considers different options for addressing this supply risk during the next AA period.

1.4 Risk assessment

Risk management is a constant cycle of identification, analysis, treatment, monitoring, reporting and then back to identification (as illustrated in Figure 1.1). When considering risk and determining the appropriate mitigation activities, we seek to balance the risk outcome with our delivery capabilities and cost implications. Consistent with stakeholder expectations, safety and reliability of supply are our highest priorities.

Figure 1.1: Risk management principles

Our risk assessment approach focuses on understanding the potential severity of failure events associated with each asset and the likelihood that the event will occur. Based on these two key inputs, the risk assessment and derived risk rating then guides the actions required to reduce or manage the risk to an acceptable level.

Our risk management framework is based on:

- AS/NZS ISO 31000 Risk Management – Principles and Guidelines;
- AS 2885 Pipelines-Gas and Liquid Petroleum; and
- AS/NZS 4645 Gas Distribution Network Management.

The Gas Act 1997 and Gas Regulations 2012, through their incorporation of AS/NZS 4645 and the Work Health and Safety Act 2012, place a regulatory obligation and requirement on AGN to reduce risks rated high or extreme to low or negligible as soon as possible (immediately if extreme). If it is not possible to reduce the risk to low or negligible, then we must reduce the risk to as low as reasonably practicable (ALARP).

When assessing risk for the purpose of investment decisions, rather than analysing all conceivable risks associated with an asset, we look at a credible, primary risk event to test the level of investment required. Where that credible risk event has an overall risk rating of moderate or higher, we will undertake investment to reduce the risk.

Seven consequence categories are considered for each type of risk:

1 **Health & safety** – injuries or illness of a temporary or permanent nature, or death, to employees and contractors or members of the public

2 **Environment** (including heritage) – impact on the surroundings in which the asset operates, including natural, built and Aboriginal cultural heritage, soil, water, vegetation, fauna, air and their interrelationships

3 **Operational capability** – disruption in the daily operations and/or the provision of services/supply, impacting customers

4 **People** – impact on engagement, capability or size of our workforce

5 **Compliance** – the impact from non-compliance with operating licences, legal, regulatory, contractual obligations, debt financing covenants or reporting / disclosure requirements

6 **Reputation & customer** – impact on stakeholders' opinion of AGN, including personnel, customers, investors, security holders, regulators and the community

7 **Financial** – financial impact on AGN, measured on a cumulative basis

A summary of our risk management framework, including definitions, has been provided in Attachment 8.10.

The risk event being assessed is that an emergency (or planned maintenance) situation occurs at a location where isolating that section of the network results in loss of supply to more than 10,000 customers or a demand customer >10 TJ p.a.

Currently, when an emergency situation such as a gas leak arises on a section of the TP system, depending on the location, this could adversely affect supply to between 2,300 and 51,600 customers. Though a major supply incident is rated unlikely (possible in certain circumstances), the number of customers at risk of supply interruption means the consequence is rated major, leading to an overall risk rating of high.

The untreated risk[43] rating is presented in Table 1.4.

Table 1.4: Risk rating – untreated risk

Untreated risk	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Remote	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Minor	Minimal	Major	Minimal	Significant	Significant	Minor	
Risk Level	Low	Negligible	High	Negligible	Moderate	Moderate	Low	

[43] Untreated risk is the risk level assuming there are no risk controls currently in place. Also known as the 'absolute risk'.

1.5 Options considered

We have identified the following options:

- **Option 1** – Maintain status quo. Do not install any additional inline valves in Adelaide's transmission pipeline system;
- **Option 2** – Install [redacted] new inline valves to reduce supply outage risk in Adelaide's transmission pipeline system; or
- **Option 3** – Install [redacted] new inline valves that will reduce the potential number of customers impacted by supply outage risk in Adelaide's transmission pipeline system to fewer than 10,000 (from 'major' to 'significant' consequence rating). This is the recommended option.

These options re discussed in the following sections.

1.5.1 Option 1 – Maintain status quo. Do not install additional inline valves in Adelaide's transmission pipeline system

Under Option 1 we would not install any additional inline valves in the TP system. We would continue to use the existing valves to isolate sections of the network.

1.5.1.1 Cost assessment

There would be no additional upfront capital costs with this option. The current number of TP valves would be maintained, and any capital costs associated with inline valves would be for replacement or repair of existing assets (see business case SA103).

1.5.1.2 Risk assessment

Option 1 results in a high overall risk level associated with emergency isolation valves. Risk controls such as existing transmission isolation valves and pipeline patrols are in place. However, even with the current controls, the risk remains high as the potential number of customers that can be impacted if any of [redacted] identified pipeline locations are isolated will be between 2,300 and 51,600. Allowing an outage affecting up to 51,600 customers to occur (when it would be preventable at a relatively low cost) would also give rise to a moderate compliance and reputational risk.

Table 1.5: Risk assessment – Option 1

Option 1	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Remote	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Minor	Minimal	Major	Minimal	Significant	Significant	Minor	
Risk Level	Low	Negligible	High	Negligible	Moderate	Moderate	Low	

Failing to address a high risk rating where there is a practicable treatment available is not consistent with the requirements of our risk management framework, and does not reflect the actions of a prudent asset manager.

1.5.1.3 Alignment with vision objectives

Table 1.6 shows how Option 1 aligns with our vision objectives.

Table 1.6: Alignment with vision – Option 1

Vision objective	Alignment
Delivering for Customers – Public Safety	-
Delivering for Customers – Reliability	N
Delivering for Customers – Customer Service	N
A Good Employer – Health and Safety	-
A Good Employer – Employee Engagement	-
A Good Employer – Skills Development	-
Sustainably Cost Efficient – Working within Industry Benchmarks	N
Sustainably Cost Efficient – Delivering Profitable Growth	-
Sustainably Cost Efficient – Environmentally and Socially Responsible	-

Option 1 would not align with our objectives of *Delivering for Customers*, as it would not address the current risk of loss of supply to a significant number of customers in an emergency situation.

This option also does not align with our objectives of *Working within Industry Benchmarks*, as prevailing industry standards support mitigation of supply loss risk by installation of valves.

1.5.2 Option 2 – Install [redacted] additional transmission inline valves

Under Option 2 we will install new inline valves at all seven locations listed in Table 1.3 above. This will reduce the potential number of customers that may be impacted by isolation at these locations to between 850 and 9,199.

1.5.2.1 Cost assessment

The estimated direct capital cost of this option is $3.1 million.

Table 1.7: Cost estimate – Option 2, $'000 2019/20

	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Total	746.8	882.9	509.5	509.5	441.5	3,090.2

The key driver for this option is the maximum reduction in the number of customers at risk of supply cut-off in an emergency isolation situation. The benefits of this option are:

- it allows for strategic segregation of the interconnected transmission pipeline network, providing greater flexibility for isolation during planned maintenance and emergency situations; and
- it will reduce the number of affected customers during an emergency event on the transmission pipeline to as low as reasonably practical at all locations.

1.5.2.2 Risk assessment

This option reduces the risk from high to moderate. The potential number of customers impacted in an emergency event situation that requires shutdown of a section of transmission pipeline is reduced by between 300 and 51,600 customers.

Table 1.8: Risk assessment – Option 2

Option 2	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Remote	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Moderate
Consequence	Minor	Minimal	Significant	Minimal	Minor	Minor	Minor	
Risk Level	Low	Negligible	Moderate	Negligible	Low	Low	Low	

By installing [redacted] new valves we are reducing the risk consequence from major to significant, as no more than 10,000 customers would be impacted by any single isolation. At locations where the number of impacted customers becomes fewer than 1,000, the risk consequence would be rated even lower (minor). However, under the risk matrix, we apply the highest residual risk, therefore the risk consequence remains significant.

1.5.2.3 Alignment with vision objectives

Table 1.9 shows how Option 2 aligns with our vision objectives.

Table 1.9: Alignment with vision – Option 2

Vision objective	Alignment
Delivering for Customers – Public Safety	-
Delivering for Customers – Reliability	Y
Delivering for Customers – Customer Service	Y
A Good Employer – Health and Safety	-
A Good Employer – Employee Engagement	-
A Good Employer – Skills Development	-
Sustainably Cost Efficient – Working within Industry Benchmarks	N
Sustainably Cost Efficient – Delivering Profitable Growth	-
Sustainably Cost Efficient – Environmentally and Socially Responsible	-

Option 2 aligns with our objectives of *Delivering for Customers*, as it addresses the security of supply risks associated with isolation requirements on transmission pipelines in an emergency situation.

However, it could be argued that Option 2 is not the most *Sustainably Cost Efficient*, as the additional risk reduction beyond addressing the [redacted] locations where the current number of customers affected is greater than 10,000 is not commensurate with the additional cost.

As discussed in the following sections, Option 3 achieves a similar level of risk reduction, but does so at a considerably lower cost.

1.5.3 Option 3 – Install [redacted] additional transmission inline valves

Under Option 3 we would only install additional valves at the locations where the current number of impacted customers is greater than 10,000 (Salisbury Plains, Wynn Vale, Kensington and North Plympton).

The other three locations where the current number of affected customers is fewer than 10,000 will not be treated, and will remain subject to current controls.

1.5.3.1 Cost assessment

The estimated direct capital cost of this option is $1.8 million.

Table 1.10: Cost estimate – Option 3, $'000 2019/20

	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Total	68.1	441.5	441.5	441.5	373.4	1,765.8

The key driver for this option is maintaining a consistent approach to supply integrity across the entire network. The benefits of this option are that it:

- allows for strategic segregation of the interconnected transmission pipeline network, providing for better isolation during planned maintenance and emergency situations
- results in a risk consequence impact of 'significant' or lower (<10,000 customers) at all locations;
- costs more than a million dollars less than Option 2, while achieving a similar level of risk reduction.

1.5.3.2 Risk assessment

As shown in Table 1.11, this option reduces the risk from high to moderate. This is primarily driven by a reduction in the operational risk. Even though fewer valves are being installed under this option compared to Option 2, the locations where the number of customers at risk is >10,000 are being addressed. Therefore, the risk consequence is still reduced to significant.

However, there is no change in the number of customers impacted by the risk event at three locations, with a maximum of 3,000 potential customers still impacted at the West Beach location. As a result, even though the overall risk for Option 3 is the same of Option 2, there is a slightly higher residual risk.

Table 1.11: Risk assessment – Option 3

Option 3	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Remote	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Moderate
Consequence	Minor	Minimal	Significant	Minimal	Minor	Minor	Minor	
Risk Level	Low	Negligible	Moderate	Negligible	Low	Low	Low	

Option 3 represents the greatest value in terms of risk reduction. As per Option 2, the overall risk consequence is reduced from major to significant (noting that Option 2 reduces the consequence to minor at some locations), however the cost is around $1.2 million lower.

1.5.3.3 Alignment with vision objectives

Table 1.12 shows how Option 3 aligns with our vision objectives.

Table 1.12: Alignment with vision – Option 3

Vision objective	Alignment
Delivering for Customers – Public Safety	-
Delivering for Customers – Reliability	Y
Delivering for Customers – Customer Service	Y
A Good Employer – Health and Safety	-
A Good Employer – Employee Engagement	-
A Good Employer – Skills Development	-

Vision objective	Alignment
Sustainably Cost Efficient – Working within Industry Benchmarks	Y
Sustainably Cost Efficient – Delivering Profitable Growth	-
Sustainably Cost Efficient – Environmentally and Socially Responsible	-

Option 3 aligns with our objectives of *Delivering for Customers*, as it addresses the majority of security of supply risks associated with isolation requirements on transmission pipelines in an emergency situation.

This option also aligns with *Sustainably Cost Efficient*, as it is the lowest cost option for achieving an acceptable level of risk reduction.

1.6 Summary of costs and benefits

Table 1.13: Summary of costs and benefits

Option	Estimated cost ($ million)	Treated residual risk rating	Alignment with vision objectives
Option 1	0	High	Does not align with *Delivering for Customers* and is not *Sustainably Cost Efficient*
Option 2	3.1	Moderate	Aligns with *Delivering for Customers* but is arguably not as *Sustainably Cost Efficient* as Option 2.
Option 3	1.8	Moderate	Aligns with *Delivering for Customers* and *is Sustainably Cost Efficient*

1.7 Recommended option

Option 3 is the proposed solution. This solution involves the installation of [redacted] additional transmission inline valves to allow for strategic isolation of transmission pipelines in the event of an emergency.

This project will be delivered using a combination of internal and external resources. The project will be initiated internally by the asset manager. Design and installation will be completed by contractors. Contractors will be selected through a competitive tender process. Quality assurance and project closure will be handled by internal resources.

1.7.1 Why is the recommended option prudent?

Option 3 is proposed because:

- it supports a consistent approach to supply integrity across the entire network, and reduces the risk consequence from major to significant at the highest risk locations;
- it represents a standard engineering practice, as supported by AS/NZS 4645.1 and AS 2885.1;
- it reduces this risk to an acceptable level for a reasonable investment level:
  - Option 1 does not mitigate the risk of losing gas supply to a significant number of customers during an emergency event on the transmission pipelines and this is not considered an appropriate long term outcome.

   - While Option 2 reduces the risk even further than Option 3 (to ALARP), the much lower number of customers impacted by the additional three valves, along with a similar cost of installation for each valve, means that the marginal additional risk reduction of Option 3 is at a significantly higher cost;

- it is consistent with customer and stakeholder requirements and our vision, by delivering for customers and being sustainably cost efficient; and

- the delivery of the scope of works is achievable in the time frame envisaged.

1.7.2 Estimating efficient costs

The volume of the work proposed is based on ensuring fewer than 10,000 customers would be impacted by isolation at each location. This requires the installation of valves at Salisbury Plains, Wynn Vale, Kensington and North Plympton. To mitigate delivery risk, this has been spread across the forthcoming AA period (see Table 1.14), with valves prioritised based on the highest number of affected customers. Transmission valves have a long lead time for delivery.

Table 1.14: Volumes – Option 2

	2020/21	2021/22	2022/23	2023/24	2024/25	Total
Procure	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Replace		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

These valve installations are all expected to require a bypass. Given this, the unit rates for these installations are based on the historical costs of the recent [redacted] (2016/17) project of $[redacted] This project represents a reasonable basis for the forecast estimate because the proposed works are very similar in nature for both labour and materials requirements.

Table 1.15: Unit costs from [redacted] valve replacement project (2016/17), $real 2019/20

	[redacted]
Labour	[redacted]
Materials	[redacted]
Total	[redacted]

The outcome from using the [redacted] project as a basis for the estimate is a forecast capital cost of installing these [redacted] valves of $1.77 million, as shown in Table 1.16 below.

Table 1.16: Cost estimate – Option 2, $'000 2019/20

	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Labour	-	373.4	373.4	373.4	373.4	1,493.6
Materials	68.1	68.1	68.1	68.1	-	272.2
Total	**68.1**	**441.5**	**441.5**	**441.5**	**373.4**	**1,765.8**

This historical project expenditure forecast is also supported by a bottom-up estimate that has generated a similar forecast amount. This is provided in Appendix A.

Table 1.17 shows the costs escalated to June 2021 dollars.

[44] Real 2019/20 $

Table 1.17: Escalated TP inline valve installation cost estimate ($'000)

	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Total unescalated ($ Dec 19)	68.1	441.5	441.5	441.5	373.4	1,765.8
Escalation	2.3	17.1	19.8	22.3	20.8	82.3
Total escalated ($ Jun 21)	**70.4**	**458.6**	**461.3**	**463.8**	**394.2**	**1,848.3**

1.7.3 Consistency with the National Gas Rules

In developing these forecasts, we have had regard to Rule 79 and Rule 74 of the NGR. With regard to all projects, and as a prudent asset manager, we give careful consideration to whether capex is conforming from a number of perspectives before committing to capital investment.

NGR 79(1)

The proposed solution is prudent, efficient, consistent with accepted and good industry practice and will achieve the lowest sustainable cost of delivering pipeline services:

- **Prudent** – The expenditure is necessary in order to ensure there are sufficient transmission and distribution valves available for emergency isolation and pressure control. Failure to have an adequate number of operable valves could result in isolation of a larger than necessary section of pipeline in an emergency situation, therefore increasing the number of customers cut off from supply. The proposed expenditure is therefore consistent with that which would be incurred by a prudent service provider.
- **Efficient** – Installation of these valves is the most practical and cost-effective option. Costs have been based on recent similar valve installation projects. Where contractors are engaged, this will be based on a competitive tender process. The expenditure is therefore consistent with what a prudent service provider acting efficiently would incur.
- **Consistent with accepted and good industry practice** – Maintaining critical isolation valves for emergency control is consistent with *AS 2885.3 Pipelines - Gas and Liquid Petroleum, Part 3: Pipeline Integrity Management* and *AS/NZ 4645 Distribution*. We consider reducing the number of impacted customers to fewer than 10,000 per location, and therefore reducing the risk to as low as reasonably practicable, is consistent with good industry practice.
- To **achieve the lowest sustainable cost of delivering pipeline services** – We have selected the lowest sustainable cost option, balancing costs against the level of risk reduction that can be achieved. We therefore consider Option 3 represents the lowest sustainable cost of delivering pipeline services during an emergency/maintenance situation.

NGR 79(2)

The proposed capex is justifiable under 79(2)(c)(ii), as it is necessary to maintain the integrity of services. The proposed option will allow us to maintain a consistent approach to supply integrity across the entire network, by maintaining a risk consequence impact of significant or lower at all locations.

NGR 74

The forecast costs are based on the latest market rate testing and project options consider asset management requirements as per the Strategic Asset Management Plan. The estimate has therefore been arrived at on a reasonable basis and represents the best estimate possible in the circumstances.

Appendix A – Cost estimate validation (bottom-up)

Category	Description	Units	Units QTY	Number of sites	Unit cost $/ unit	Total $	Avg cost per valve $
Materials							
Pipe	DN200 Line pipe consists of 20m bypass	metres	[redacted]	[redacted]	[redacted]	[redacted]	
	DN250 Line pipe consists of 20m bypass	metres	[redacted]	[redacted]	[redacted]	[redacted]	
	DN300 Line pipe consists of 20m bypass	metres	[redacted]	[redacted]	[redacted]	[redacted]	
	Freight, storage and delivery for Pipe	each	[redacted]	[redacted]	[redacted]	[redacted]	
Valves	DN200 Sferova Full Bore Ball Valve	each	[redacted]	[redacted]	[redacted]	[redacted]	
	DN250 Sferova Full Bore Ball Valve	each	[redacted]	[redacted]	[redacted]	[redacted]	
	DN300 Sferova Full Bore Ball Valve	each	[redacted]	[redacted]	[redacted]	[redacted]	
Valve chambers	Road Ring 3 Pin	each	[redacted]	[redacted]	[redacted]	[redacted]	
	Base StormPro	each	[redacted]	[redacted]	[redacted]	[redacted]	
	Valve Cover StormPro	each	[redacted]	[redacted]	[redacted]	[redacted]	
	StormPro Chamber 750mm	each	[redacted]	[redacted]	[redacted]	[redacted]	
Pipe fittings	DN200 90DEG Elbows	each	[redacted]	[redacted]	[redacted]	[redacted]	
	DN250 90DEG Elbows	each	[redacted]	[redacted]	[redacted]	[redacted]	
	DN250 90DEG Elbows	each	[redacted]	[redacted]	[redacted]	[redacted]	
	DN200 Flanges (W/N and blind)	each	[redacted]	[redacted]	[redacted]	[redacted]	
	DN250 Flanges (W/N and blind)	each	[redacted]	[redacted]	[redacted]	[redacted]	
	DN300 Flanges (W/N and blind)	each	[redacted]	[redacted]	[redacted]	[redacted]	
Inservice fittings	DN50 Thread Orings for venting	each	[redacted]	[redacted]	[redacted]	[redacted]	
	DN150 ShortStopps for bags	each	[redacted]	[redacted]	[redacted]	[redacted]	
	DN200 ShortStopps for stoppling and bypass	each	[redacted]	[redacted]	[redacted]	[redacted]	
	DN250 ShortStopps for stoppling and bypass	each	[redacted]	[redacted]	[redacted]	[redacted]	
	DN300 ShortStopps for stoppling and bypass	each	[redacted]	[redacted]	[redacted]	[redacted]	
Total materials						**264.0**	[redacted]

Category	Description	Units	Units QTY	Number of sites	Unit cost $/ unit	Total $	Avg cost per valve $
Labour							
Project management, design and initiation	Project manager	hours	[redacted]	[redacted]	[redacted]	[redacted]	
	Project engineer	hours	[redacted]	[redacted]	[redacted]	[redacted]	
	Planning engineer	hours	[redacted]	[redacted]	[redacted]	[redacted]	
	Welding engineer	hours	[redacted]	[redacted]	[redacted]	[redacted]	
	GIS technician	hours	[redacted]	[redacted]	[redacted]	[redacted]	
	Draftsperson	hours	[redacted]	[redacted]	[redacted]	[redacted]	
	Site Supervisor	hours	[redacted]	[redacted]	[redacted]	[redacted]	
	Compliance and communication officer	hours	[redacted]	[redacted]	[redacted]	[redacted]	
	HSE representative	hours	[redacted]	[redacted]	[redacted]	[redacted]	
Project site labour and delivery	Crew (3 ppl incl. team leader)	hours	[redacted]	[redacted]	[redacted]	[redacted]	
	Excavator (8T)	hours	[redacted]	[redacted]	[redacted]	[redacted]	
	Tipper Truck (8T)	hours	[redacted]	[redacted]	[redacted]	[redacted]	
	Vac Truck	hours	[redacted]	[redacted]	[redacted]	[redacted]	
	Traffic setup (high fencing, water barriers, VMS board)	each	[redacted]	[redacted]	[redacted]	[redacted]	
	Traffic Control (2 ppl including ute)	hours	[redacted]	[redacted]	[redacted]	[redacted]	
	Asphalt and concrete cutters	metres	[redacted]	[redacted]	[redacted]	[redacted]	
	Welder	hours	[redacted]	[redacted]	[redacted]	[redacted]	
	Welding supervisor	hours	[redacted]	[redacted]	[redacted]	[redacted]	
	Non Destructive Testing (incl reports)	hours	[redacted]	[redacted]	[redacted]	[redacted]	
	Hot tapping, stoppling, and commissioning (2 ppl incl equipment)	hours	[redacted]	[redacted]	[redacted]	[redacted]	
	Grit blasting and coating (2ppl)	hours	[redacted]	[redacted]	[redacted]	[redacted]	
	Cranage (1 rigger including 25T crane)	hours	[redacted]	[redacted]	[redacted]	[redacted]	
	Asbestos removal of tar enamel coating	hours	[redacted]	[redacted]	[redacted]	[redacted]	

Category	Description	Units	Units QTY	Number of sites	Unit cost $/ unit	Total $	Avg cost per valve $
	Reinstatement (assuming 30 sqm - 275mm asphalt and including backfill material and compaction)	Sqm	[redacted]	[redacted]	[redacted]	[redacted]	
Total labour						**1,495.1**	[redacted]
Total project						**1,759.2**	[redacted]

Appendix B - Comparison of risk assessments for each option

Untreated risk	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Remote	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Minor	Minimal	Major	Minimal	Significant	Significant	Minor	
Risk Level	Low	Negligible	High	Negligible	Moderate	Moderate	Low	

Option 1	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Remote	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Minor	Minimal	Major	Minimal	Significant	Significant	Minor	
Risk Level	Low	Negligible	High	Negligible	Moderate	Moderate	Low	

Option 2	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Remote	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Moderate
Consequence	Minor	Minimal	Significant	Minimal	Minor	Minor	Minor	
Risk Level	Low	Negligible	Moderate	Negligible	Low	Low	Low	

Option 3	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Remote	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Moderate
Consequence	Minor	Minimal	Significant	Minimal	Minor	Minor	Minor	
Risk Level	Low	Negligible	Moderate	Negligible	Low	Low	Low	

SA108 – Refurbishment of industrial and commercial meter sets

1.1 Project approvals

Table 1.1: Business case SA108 – Project approvals

Prepared by	Peiman Vakili, Gas Networks and Pipeline Engineer, APA
Reviewed by	Robin Gray, SA Operations Manager, APA
Approved by	Craig Bonar, Head of Engineering and Planning, APA Mark Beech, General Manager Network Operations, AGN

1.2 Project overview

Table 1.2: Business case SA108 – Project overview

Description of the problem / opportunity	The South Australian natural gas distribution network has 33,030 industrial and commercial (I&C) metering facilities. 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 our 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 our network. This business case considers the various options to continue the refurbishment program or move to a replacement only approach.
Untreated risk	As per risk matrix = **High**
Options considered	• **Option 1** – Continue with current practice and refurbish [redacted] I&C meter sets ($1.3 million) • **Option 2** – Cease the ongoing refurbishment program and move to reactive replacement only (zero upfront capex, with higher cost reactive replacement of ~$4 million) • **Option 3** – Replace [redacted] I&C meter sets proactively ($2.4 million)
Proposed solution	This business case recommends Option 1, as it reduces the risks associated with the corrosion of I&C meter sets at the lowest sustainable cost. Option 1 also continues to apply standard industry asset management practices, which are proven to be effective in the past.
Estimated cost	The forecast direct capital cost (excluding overhead) during the next access arrangement (AA) period (July 2021 to June 2026) is $1.3 million.

$'000 2019/20	21/22	22/23	23/24	24/25	25/26	Total
Refurbish 250 meter sets	267.9	267.9	267.9	267.9	267.9	1,339.3

	The costs over the next AA period are consistent with the historical costs of the ongoing I&C meter set refurbishment program. In the current AA period we will spend $1 million to refurbish [redacted] meter sets.
Basis of costs	All costs in this business case are expressed in real unescalated dollars at December 2019 unless otherwise stated. Some tables may not add due to rounding.
Alignment to our vision	The refurbishment of our I&C meter sets aligns with our vision in relation to: • *Delivering for Customers* as proactive treatment of I&C meter sets will help maintain reliability of supply and mitigate the risk of asset failure and/or unplanned outages; and • *Sustainably Cost Efficient* as coating the I&C meter sets is the lowest sustainable cost of managing the corrosion risk.
Consistency with the National Gas Rules (NGR)	**NGR 79(1)** – the proposed solution is consistent with good industry practice, several practicable options have been considered, the completion of the works remains at the current sustainable level and market rates have been tested to achieve the lowest sustainable cost of providing this service. **NGR 79(2)** – proposed capex is justifiable under NGR 79(2)(c)(ii), as it is necessary to maintain the integrity of services. **NGR 74** – the forecast costs and are based on the latest market rate testing and project options consider the asset management requirements as per the Strategic Asset Management Plan. The estimate has been arrived at on a reasonable basis and represents the best estimate possible in the circumstances.
Treated risk	As per risk matrix = **Low**
Stakeholder engagement	We are committed to operating our networks in a manner that is consistent with the long-term interests of our customers. To facilitate this, we conduct regular stakeholder engagement to understand and respond to the priorities of our customers and stakeholders. Feedback from stakeholders is built into our asset management considerations and is an important input when developing and reviewing our expenditure programs. Our customers have told us their top three priorities are price/affordability, reliability of supply, and maintaining public safety. They also told us they expect us to deliver a high level of public safety and are satisfied that this is current practice. Our current practice of refurbishing I&C meter sets where practicable has delivered a level of public safety to date that our customers have told us they value and are satisfied with. We therefore consider it prudent and in line with customers' expectations that we continue our I&C refurbishment program. Continuing the refurbishment program in line with historical rates will also help maintain reliability of supply at the lowest sustainable cost, minimising the impact on customers' gas bills.
Other relevant documents	• Attachment 8.2 Strategic Asset Management Plan

1.3 Background

I&C metering facilities are made up of the meter unit itself and the meter set assembly, which includes the valves, pipework, regulators, fittings and other minor components. Note the meter units are not within scope of this business case. This business case is for capital works on the **meter sets only**. Replacement of meter units is covered by the Meter Replacement Plan.

There are 33,030 I&C meter sets in our South Australian natural gas distribution network. Of these, around 2,000 are high pressure sets fitted with large regulators, filters, pilots and OPSO valves. It is important these I&C meter sets function properly so that the large volumes of gas consumed by our I&C customers is measured correctly and customers' bills are accurate.

Corrosion is a significant ongoing risk for meter sets. Protective coatings deteriorate over time due to environmental factors, which leads to corrosion and damage of the meter assembly pipework, valves and fittings. The corrosion risk for each meter set varies by location, environmental conditions, age, pressure and component/configuration type.

If corrosion is left untreated, it can result in the entire meter set, pipework and components having to be replaced. Replacing components typically requires the I&C customer’s gas supply to be isolated, which in many cases is not practicable and would cause significant disruption to the customer’s commercial operations.

Corroded meter sets and pipework can also fail and cause an uncontrolled gas release. The proximity of meter sets to customer sites means an uncontrolled gas release can cause major public safety consequences, as well as impacting that customer’s supply.

Our aim is to refurbish meter sets and their associated pipework and components before they become unsafe or inoperable. We refurbish meter sets by grit blasting and re-applying protective paint to the meter set components (valves, pipework, regulators, fittings and other minor components). This helps extend the life of the assets and is a critical ongoing program necessary to manage the integrity of I&C gas supply points on our network.

As part of our ongoing meter set management program, we conduct periodic inspections, testing and maintenance of all metering sets, and prioritise subsequent treatment by risk. This inspection and maintenance program involves mechanical and instrumentation checks, replacement of small parts, and minor painting (‘touch ups’). Where the level of corrosion on a meter set is at a level where touching up the paintwork is no longer sufficient, or where the protective paint has deteriorated to an extent that the likelihood of corrosion is significant, that meter set is flagged for refurbishment.[45]

Examples of how corrosion can affect meter sets are shown in Figure 1.1 to Figure 1.3.

Figure 1.1: I&C meter set – corrosion of valve and regulator

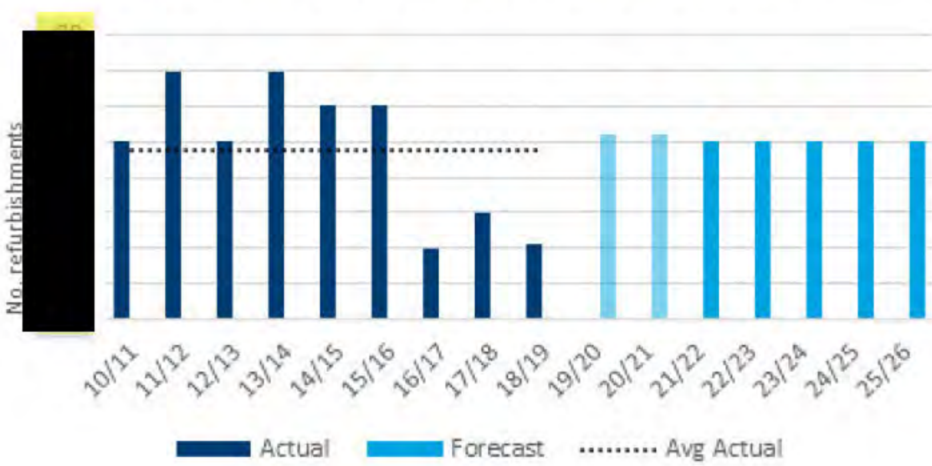
[45] Note the meter units themselves are replaced on a ten-year cycle as part of a separate meter replacement cycle with consideration to field life extension in some cases. Meter units are not coated, or grit blasted as part of the meter set management program.

Figure 1.2: I&C meter set – general corrosion

Figure 1.3: I&C meter set corrosion – soil/air interface

Through the meter set management program we have identified [redacted] I&C meter sets that need refurbishment to address corrosion and inhibit further deterioration. This is in line with the program's average historical refurbishment volumes of around [redacted] per annum (see Figure 1.4).

Figure 1.4: I&C meter set historical and forecast refurbishment rates since 2010 to 2025



The lower delivered volumes during 2016 to 2019 were due to a reduction in the number of external contractors with the capacity and capability to undertake works. The external contractor issues have since been resolved and we have returned to historical refurbishment rates in 2019/20.

1.4 Risk assessment

Risk management is a constant cycle of identification, analysis, treatment, monitoring, reporting and then back to identification (as illustrated in Figure 1.5). When considering risk and determining the appropriate mitigation activities, we seek to balance the risk outcome with our delivery capabilities and cost implications. Consistent with stakeholder expectations, safety and reliability of supply are our highest priorities.

Figure 1.5: Risk management principles

Our risk assessment approach focuses on understanding the potential severity of failure events associated with each asset and the likelihood that the event will occur. Based on these two key inputs, the risk assessment and derived risk rating then guides the actions required to reduce or manage the risk to an acceptable level.

Our risk management framework is based on:

- AS/NZS ISO 31000 Risk Management – Principles and Guidelines;
- AS 2885 Pipelines-Gas and Liquid Petroleum; and
- AS/NZS 4645 Gas Distribution Network Management.

The Gas Act 1997 and Gas Regulations 2012, through their incorporation of AS/NZS 4645 and the Work Health and Safety Act 2012, place a regulatory obligation and requirement on us to reduce risks rated high or extreme to low or negligible as soon as possible (immediately if extreme). If it is not possible to reduce the risk to low or negligible, then we must reduce the risk to as low as reasonably practicable (ALARP).

When assessing risk for the purpose of investment decisions, rather than analysing all conceivable risks associated with an asset, we look at a credible, primary risk event to test the level of investment required. Where that credible risk event has an overall risk rating of moderate or higher, we will undertake investment to reduce the risk.

Seven consequence categories are considered for each type of risk:

1. Health & safety – injuries or illness of a temporary or permanent nature, or death, to employees and contractors or members of the public
2. Environment (including heritage) – impact on the surroundings in which the asset operates, including natural, built and Aboriginal cultural heritage, soil, water, vegetation, fauna, air and their interrelationships
3. Operational capability – disruption in the daily operations and/or the provision of services/supply, impacting customers
4. People – impact on engagement, capability or size of our workforce
5. Compliance – the impact from non-compliance with operating licences, legal, regulatory, contractual obligations, debt financing covenants or reporting / disclosure requirements

6 **Reputation & customer** – impact on stakeholders' opinion of AGN, including personnel, customers, investors, security holders, regulators and the community

7 **Financial** – financial impact on AGN, measured on a cumulative basis

A summary of our risk management framework, including definitions, has been provided in Attachment 8.10.

The risk event identified for I&C meter sets is corrosion of the pipework and/or components, leading to loss of wall thickness or damage to a level where the asset can no longer maintain the pressure of the supplied gas, resulting in an uncontrolled gas release causing damage to equipment and/or serious harm (fatality).

The risk associated with the corrosion of meter sets has been assessed as high (see Table 1.3). The likelihood of this risk event occurring will increase with time if the condition of these meter sets is not addressed in a timely manner.

Table 1.3: I&C meter sets risk assessment – Untreated risk

Untreated risk	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Major	Minor	Minor	Minimal	Minor	Minor	Minimal	
Risk Level	High	Low	Low	Negligible	Low	Low	Negligible	

1.5 Options considered

Different options have been considered to address the risks associated with corroded I&C meter sets. The options are:

- **Option 1** – Continue with current practice and refurbish [redacted] I&C meter sets;
- **Option 2** – Cease the ongoing refurbishment program and only replace meter sets upon failure; or
- **Option 3** – Replace [redacted] I&C meter sets proactively.

These options are discussed in the following sections.

1.5.1 Option 1 – Continue with current practice and refurbish [redacted] I&C meter sets

With this option, we would continue the meter set management program established in 2010. This involves addressing corrosion and inhibiting further deterioration by continuing to refurbish I&C meter sets.

The continuation of the program would see [redacted] I&C meter sets refurbished over the next five years, in line with the program's average historical refurbishment volumes of [redacted] per annum. As part of project design and scheduling we will consider the environmental factors that contributed to the deterioration of the meter set, as well as the asset life.

1.5.1.1 Cost assessment

The estimated capital cost of continuing with current practice and refurbishing [redacted] I&C meter sets over the next five years is $1.3 million. This estimate is based on current material and labour rates. A breakdown is provided in Table 1.4.

Table 1.4: Cost assessment - Option 1, $'000 real 2019/20

	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Refurbishment volumes (#)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Materials	30.0	30.0	30.0	30.0	30.0	150.0
Labour	237.9	237.9	237.9	237.9	237.9	1,189.3
Total	**267.9**	**267.9**	**267.9**	**267.9**	**267.9**	**1,339.3**

As shown in Table 1.5, the forecast for the next AA period is consistent with the costs incurred on the ongoing meter set refurbishment over the current AA period.

Table 1.5: Historical I&C meter set refurbishment capital expenditure, $'000 real 2019/20

	2016/17	2017/18	2018/19	2019/20*	2020/21*	Total
Refurbishment volumes (#)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Materials	11.9	19.8	20.3	30.0	30.0	117.0
Labour	93.2	156.3	202.4	237.9	237.9	927.6
Total	**105.1**	**176.1**	**227.7**	**267.9**	**267.9**	**1,044.7**

*forecast.

Continuing our established asset management program at historical levels will provide certainty of:

- risk reduction outcomes, due to the effectiveness of the technical solution and prudent timing of volumes;
- unit costs, due to the costs data captured over the ten year program, and ability to efficiently contract resources (including to achieve economies of scale and to avoid ramping costs etc); and
- delivery capability.

This option will ensure the meter set corrosion risk is managed in a timely manner, helping maintain asset integrity and prudently minimising long-term repair costs. Option 1 is therefore the lowest sustainable cost of addressing the risks associated with corrosion of I&C meter sets.

Option 1 is consistent with our risk management framework and vision objectives (see following sections).

1.5.1.2 Risk assessment

Option 1 reduces the risk associated with corrosion of I&C meter sets from high to low. Table 1.6 shows the residual risk associated with I&C meter sets if Option 1 is progressed.

Table 1.6: Risk assessment – Option 1

Option 1	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Rare	Rare	Rare	Rare	Rare	Rare	Rare	Low
Consequence	Major	Minor	Minor	Minimal	Minor	Minor	Minimal	
Risk Level	Low	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	

This option represents the lowest treated risk and is consistent with our risk management framework. While both Option 1 and Option 3 deliver the same risk reduction under the AS 4646 risk assessment, Option 1 does so at a lower cost.

1.5.1.3 Alignment with vision objectives

Table 1.7 shows how Option 1 aligns with our vision objectives.

Table 1.7: Alignment with vision – Option 1

Vision objective	Alignment
Delivering for Customers – Public Safety	Y
Delivering for Customers – Reliability	Y
Delivering for Customers – Customer Service	Y
A Good Employer – Health and Safety	Y
A Good Employer – Employee Engagement	-
A Good Employer – Skills Development	-
Sustainably Cost Efficient – Working within Industry Benchmarks	Y
Sustainably Cost Efficient – Delivering Profitable Growth	-
Sustainably Cost Efficient – Environmentally and Socially Responsible	-

Option 1 would align with the *Delivering for Customers* aspect of our vision, as proactive treatment of I&C meter sets will help maintain reliability of supply and mitigate the risk of public safety incidents. Refurbishing the meter sets rather than replacing the various components also means we will not have to isolate the customer's gas supply, minimising disruption to them.

This option is also *Sustainably Cost Efficient* as coating the meter sets is the lowest sustainable cost of managing the corrosion risk. This ensures we can deliver the program within industry benchmarks.

1.5.2 Option 2 – Cease the ongoing refurbishment program

Under this option, we would cease the current meter set refurbishment program and stop conducting proactive remedial works on I&C meter sets. Instead, we would move to an entirely reactive approach, replacing metering facility assets only after they have failed.

1.5.2.1 Cost assessment

There would be no upfront capital cost associated with this option. In the short term, this would put downward pressure on gas distribution tariffs and allow resources to be deployed elsewhere. However, over the longer term a reactive asset management approach would increase both tariffs and the overall resource requirement.

Once leaks occur on the corroded assets there will be increasing operational costs, culminating in the capital costs associated with replacing the failed I&C meter sets on a reactive basis. It is not possible to forecast how many of the identified [redacted] I&C meter sets will fail in the next five years. However, if all [redacted] meter sets were to fail, the capital cost of reactively replacing them would be around $4 million.

This estimate is based on the assumption that an unplanned, reactive replacement program would cost around three times more than addressing these assets in a planned and proactive manner.

This assumption is consistent with the commonly accepted asset management principle that reactive asset maintenance can be around two to five times higher than proactive planned maintenance.[46]

The higher cost of reactive replacement compared with proactive asset management is due to penalty charges, potentially larger scope of works and additional charges for expediting delivery of materials and meter set fabrication. Reactive replacement can also driver higher labour costs due to the need to conduct work out of hours as well as delivering customers support throughout an unplanned interruption.

Option 2 would also lead to costs associated with the disruption of supply to I&C customers, as well as the public safety risk associated with asset failure and an uncontrolled release of gas. This would not align with our vision objectives or risk management principles.

Significant disruption to supply or occurrence of a major safety incident can also result in significant reputational damage.

1.5.2.2 Risk assessment

Table 1.8 shows the residual risk associated with I&C meter sets if Option 2 is undertaken.

Table 1.8: Risk assessment – Option 2

Option 2	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Major	Minor	Minor	Minimal	Minor	Minor	Minimal	
Risk Level	High	Low	Low	Negligible	Low	Low	Negligible	

Option 2 is inconsistent with our Strategic Asset Management Plan and does not reduce the risk associated with corrosion of I&C meter sets to low or ALARP. As such, it is inconsistent with the risk management framework.

1.5.2.3 Alignment with vision objectives

Table 1.9 shows how Option 2 aligns with our vision objectives.

Table 1.9: Alignment with vision – Option 2

Vision objective	Alignment
Delivering for Customers – Public Safety	N
Delivering for Customers – Reliability	N
Delivering for Customers – Customer Service	N
A Good Employer – Health and Safety	N
A Good Employer – Employee Engagement	-
A Good Employer – Skills Development	-
Sustainably Cost Efficient – Working within Industry Benchmarks	N
Sustainably Cost Efficient – Delivering Profitable Growth	-
Sustainably Cost Efficient – Environmentally and Socially Responsible	N

46 Marshall Institute, Omega engineering, ARMS reliability.

This option does not align with our objective of *Delivering for Customers*, as it does not address the safety risks associated with the corrosion of I&C meter sets. Replacement of assets after failure would also result in unplanned outages and disruption of supply for customers.

Allowing assets to fail increases the likelihood of safety incidents, which does not align with our *Public Safety* and *Health and Safety* objectives.

The long term costs of reactive asset replacement would be considerably greater than a proactive refurbishment (or proactive replacement) program. This option therefore does not align with our objective to be *Sustainably Cost Efficient*.

1.5.3 Option 3 – Replace [redacted] I&C meter sets

Under this option we would address the corrosion risk by replacing the [redacted] I&C meter sets identified as in poor condition. These meter sets would be replaced with newly-designed and fabricated components, at a rate of around [redacted] per year.

1.5.3.1 Cost assessment

The estimated capital cost of replacing [redacted] I&C meter sets over the next five years is $2.4 million. This estimate is based on current material and labour rates for new I&C installations and assumes all [redacted] identified I&C meter sets will be replaced over the next five years. A cost breakdown is provided in Table 1.10.

Table 1.10: Cost assessment - Option 3, $'000 real 2019/20

	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Refurbishment volumes (#)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Materials	174.6	174.6	174.6	174.6	174.6	873.0
Labour	299.8	299.8	299.8	299.8	299.8	1,499.0
Total	**474.4**	**474.4**	**474.4**	**474.4**	**474.4**	**2,372.0**

This option would also require the scheduled isolation of some I&C customers' gas supply while assets are being replaced. This would require rigorous planning and may be undesirable and/or cause significant disruption and cost to some customers. This cost to customers cannot be quantified, but it could be significant.

This option would deliver the same level of risk reduction as Option 1 but at a higher cost to us and our customers.

The benefits of this option are summarised below:

- this option will ensure the corrosion risk is managed in a timely manner, helping maintain asset integrity and long-term supply;
- no reactive maintenance work, such as minor painting, would be required for an extended period of time;
- new installations will be aligned with the current industry standards and best practices, with the maximum forecast asset life; and
- replacement of meter set assets could be scheduled to coincide with the replacement of some metering units, where those metering units are reaching their replacement cycle within the next five years.

Option 3 consistent with our risk management framework and some (but not all) of our vision objectives as discussed in the following sections.

1.5.3.2 Risk assessment

Table 1.11 shows the residual risk associated with I&C meter sets if Option 3 is undertaken.

Table 1.11: Risk assessment – Option 3

Option 3	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Rare	Rare	Rare	Rare	Rare	Rare	Rare	Low
Consequence	Major	Minor	Minor	Minimal	Minor	Minor	Minimal	
Risk Level	Low	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	

Option 3 represents the lowest treated risk and is consistent with the Strategic Asset Management Plan. It reduces the risk to low and is therefore consistent with our risk management framework.

While both Option 3 and Option 1 deliver the same risk reduction, Option 3 does not address the corrosion risk associated with I&C meter sets for the lowest sustainable cost.

1.5.3.3 Alignment with vision objectives

Option 3 would align with the *Delivering for Customers* and *Health and Safety* objectives, as proactive treatment of I&C meter sets will help maintain reliability of supply and mitigate the risk of public safety incidents. However, replacing the meter sets rather than refurbishing them may mean in some instances we have to isolate customers' gas supply, causing significant disruption and potential costs to them.

A proactive meter set replacement program, while more cost efficient than a reactive replacement program, results in a substantially higher short term cost and tariff impact than simply refurbishing the meter sets (as per Option 1). Option 3 is therefore not the most *Sustainably Cost Efficient* solution.

Table 1.12 shows how Option 3 aligns with our vision objectives.

Table 1.12: Alignment with vision – Option 3

Vision objective	Alignment
Delivering for Customers – Public Safety	Y
Delivering for Customers – Reliability	Y
Delivering for Customers – Customer Service	N
A Good Employer – Health and Safety	Y
A Good Employer – Employee Engagement	-
A Good Employer – Skills Development	-
Sustainably Cost Efficient – Working within Industry Benchmarks	N
Sustainably Cost Efficient – Delivering Profitable Growth	-
Sustainably Cost Efficient – Environmentally and Socially Responsible	-

1.6 Summary of costs and benefits

Table 1.13 presents a summary of how each option compares in terms of the estimated cost, the residual risk rating, and aligning with our objectives.

Table 1.13: Summary of cost/benefit analysis

Option	Estimated cost ($ million)	Treated residual risk rating	Alignment with vision objectives
Option 1	1.3	Low	This would align with all relevant vision objectives.
Option 2	4.0	High	This would fail to achieve safety and reliability objectives or meet industry standards.
Option 3	2.4	Low	This option sufficiently reduces risk in the short term, but is not the lowest cost. It may also result in unnecessary disruption to customers' gas supply.

1.7 Recommended option

Option 1 is the recommended option as it is the most cost-effective solution to reduce the risk posed by corrosion of I&C meter sets.

1.7.1 Why is the recommended option prudent?

Option 1 reduces the risk of corrosion leaks on these assets to ALARP and therefore aligns with our Strategic Asset Management Plan and risk management framework. Moreover, the scheduled refurbishment prevents disproportional increases in operational costs involved with an increased quantity of emergency repairs.

It supports our vision and values in relation to *Delivering for Customers* as it will help maintain reliability of supply and mitigate the risk of public safety incidents. It is also *Sustainably Cost Efficient* as coating the meter sets is the lowest sustainable cost of managing the corrosion risk.

1.7.2 Estimating efficient costs

Key assumptions made in the cost estimation for the I&C meter set refurbishment program include:

- cost based on historical expenditure noting that these works are not new;
- estimates derived from contractual rates of vendors to be utilised;
- resource cost based on other similar projects ongoing at present or in previous AA periods; and
- original equipment manufacturer contractual rates for spares and labour that are part of our services agreements.

Table 1.14 presents a breakdown of the I&C meter set refurbishment program by cost category. Table 1.15 provides the costs escalated to June 2021 dollars.

Table 1.14: Project cost estimate by cost category, real $'000 2019/20

	2020/21	2021/22	2022/23	2023/24	2024/25	Total
Materials	30.0	30.0	30.0	30.0	30.0	150.0
Labour	237.9	237.9	237.9	237.9	237.9	1,189.3
Total	**267.9**	**267.9**	**267.9**	**267.9**	**267.9**	**1,339.3**

Table 1.15: Escalated project cost estimate ($'000)

	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Total unescalated ($ Dec 19)	267.9	267.9	267.9	267.9	267.9	1,339.3
Escalation	9.0	10.4	12.0	13.5	14.9	59.9
Total escalated ($ Jun 21)	**276.9**	**278.3**	**279.9**	**281.4**	**282.8**	**1,399.4**

1.7.3 Consistency with the National Gas Rules

In developing these forecasts, we have had regard to Rule 79 and Rule 74 of the NGR. With regard to all projects, and as a prudent asset manager, we give careful consideration to whether capex is conforming from a number of perspectives before committing to capital investment.

Rule 79(1)

The proactive refurbishment of I&C meter sets is consistent with the requirements of NGR 79(1)(a). Specifically, we consider that the capital expenditure is:

- **Prudent** – the expenditure is necessary in order to deliver gas safely and reliably to customer outlet points, as well as to ensure accurate measurement and billing of services occurs. The proposed risk treatment is consistent with accepted industry practice and current design standards and is proven to address the risk associated with I&C meter sets. Several practicable options have been considered to address the risk. The proposed expenditure can therefore be seen to be of a nature that would be incurred by a prudent service provider.

- **Efficient** – the forecast expenditure is based on historical average actuals and tender contract values. The proposed expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur.

- **Consistent with accepted and good industry practice** – the proposed expenditure follows good industry practice by ensuring that critical infrastructure is maintained within its useful life and to current technological standards, therefore the proposed capital expenditure is such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice.

- To achieve **the lowest sustainable cost of delivering pipeline services** – The sustainable delivery of services includes reducing risks to as low as reasonably practicable and maintaining reliability of supply, whilst achieving the lowest sustainable costs by undertaking the works in line with the relevant useful life and adopting proven new and emerging technologies and techniques that reduce long-term costs.

Rule 79(2)

The proposed capex is justifiable under NGR 79(2)(c)(ii), as it is necessary to maintain the integrity of services. Allowing I&C meter sets to fail or corrode to the extent performance is compromised will lead to network integrity issues, disruption to customer supply and potential uncontrolled release of gas.

Consistent with the Strategic Asset Management Plan, and as outlined in this business case, current practice has proven to mitigate network integrity issues and will allow us to maintain a level of service consistent with customer expectations.

Rule 74

The forecast costs are based on the latest market rate testing and project options consider the asset management requirements as per the Strategic Asset Management Plan. The estimate has therefore been arrived at on a reasonable basis and represents the best estimate possible in the circumstances.

Appendix A – Comparison of risk assessments for each option

Untreated risk	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Major	Minor	Minor	Minimal	Minor	Minor	Minimal	
Risk Level	High	Low	Low	Negligible	Low	Low	Negligible	

Option 1	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Rare	Rare	Rare	Rare	Rare	Rare	Rare	Low
Consequence	Major	Minor	Minor	Minimal	Minor	Minor	Minimal	
Risk Level	Low	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	

Option 2	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Major	Minor	Minor	Minimal	Minor	Minor	Minimal	
Risk Level	High	Low	Low	Negligible	Low	Low	Negligible	

Option 3	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Rare	Rare	Rare	Rare	Rare	Rare	Rare	Low
Consequence	Major	Minor	Minor	Minimal	Minor	Minor	Minimal	
Risk Level	Low	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	

SA109 – DRS operability risk reduction

1.1 Project approvals

Table 1.1: Business case SA109 – Project approvals

Prepared by	Peiman Vakili, Gas Networks and Pipeline Engineer, APA
Reviewed by	Nick Rubbo, Integrity Engineer, APA
Approved by	Jarrod Dunn, Manager Planning and Integrity, APA Mark Beech, General Manager Network Operations, AGN

1.2 Project overview

Table 1.2: Business case SA109 – Project overview

Description of the problem / opportunity	[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. This business case considers the costs and benefits of installing butterfly lids, as well as other options.
Untreated risk	As per risk matrix = **High**
Options considered	• **Option 1** – Replace the existing manhole concrete lids on [redacted] DRS with butterfly style lids ($2 million) • **Option 2** – Replace [redacted] underground DRS completely with half pits ($5 million) • **Option 3** – Maintain the status quo (No additional upfront capex required)
Proposed solution	Option 1 is the proposed solution because it reduces the risks associated with the health and safety of the operations personnel when working in the pit. It achieves the required risk reduction at a lower cost than replacing the entire pit (Option 2). Option 3 (status quo) is not recommended as it does not address the health and safety risk.
Estimated cost	The forecast direct capital cost (excluding overhead) during the next access arrangement (AA) period (July 2021 to June 2026) is $2.0 million.
Basis of costs	All costs in this business case are expressed in real unescalated dollars at December 2019 unless otherwise stated. Some tables may not add due to rounding.
Alignment to our vision	This project links to the A Good Employer aspect of our vision, which includes keeping our employees safe from harm.

$'000 2019/20	21/22	22/23	23/24	24/25	25/26	Total
DRS operability risk reduction	157.2	157.2	550.3	550.3	550.3	1,965.3

Consistency with the National Gas Rules (NGR)	**NGR 79(1)** – the proposed solution is consistent with good industry practice, several practicable options have been considered, and market rates have been tested to achieve the lowest sustainable cost of providing this service. **NGR 79(2)** – proposed capex is justifiable under NGR 79(2)(c)(i), as it is necessary to maintain the safety of services. **NGR 74** – the forecast costs and are based on the latest market rate testing and project options consider the asset management requirements as per the Strategic Asset Management Plan. The estimate has been arrived at on a reasonable basis and represents the best estimate possible in the circumstances.
Treated risk	As per risk matrix = **Moderate**
Stakeholder engagement	We are committed to operating our networks in a manner that is consistent with the long-term interests of our customers. To facilitate this, we conduct regular stakeholder engagement to understand and respond to the priorities of our customers and stakeholders. Feedback from stakeholders is built into our asset management considerations and is an important input when developing and reviewing our expenditure programs. Our customers have told us their top three priorities are price/affordability, reliability of supply, and maintaining public safety. They also told us they expect AGN to deliver a high level of public safety. Specific engagement with stakeholders on this project has not been conducted. However, addressing the safety risk to personnel is consistent with feedback from customers that safety is a priority. We consider our stakeholders' safety expectations include keeping our personnel safe. Undertaking this DRS operability risk reduction project to help protect our workforce when working around natural gas assets is therefore consistent with our safety obligations.
Other relevant documents	• Attachment 8.2 Strategic Asset Management Plan

1.3 Background

The South Australian (SA) natural gas distribution network is supplied by 91 transmission pressure (TP) District Regulator Stations (DRS), which feed from the upstream metropolitan TP pipelines and supply the downstream distribution network. The TP DRS regulate the pressure between these higher and lower pressure sections of our networks, and are critical in ensuring a safe and reliable natural gas supply to more than 450,000 consumers.

Many of the TP DRS were constructed in the 1970s and 1980s, when it was common practice to place these stations in pits. When maintenance activities are required, the DRS pits are accessed through a covered manhole. DRS pits meet the definition of a confined space under Regulation 5 of the *Work Health and Safety (Confined Spaces) Code of Practice 2015*.

[redacted] of our DRS pits have covered manholes with fully enclosed Gatic concrete lids. Gatic manhole lids typically comprise a large section of immovable concrete, with a small opening in one corner to allow technicians to enter and exit the chamber (see Figure 1.1).

Figure 1.1: Example of a Gatic concrete DRS lid

This type of concrete manhole lid presents a health and safety risk to technicians because it makes access to and from the pit difficult, especially in the event of an emergency evacuation. The manhole lid design makes it difficult to use safety lines and rescue apparatus. The limited access provided by the manhole also means personnel have to unclip from a rescue line to move from one end of the pit to the other.

This pit access design is not consistent with the requirements of the *Work Health and Safety (Confined Space) Code of Practice 2015* (WHS Code of Practice), which recommends that:

- *Access points (including those within the confined space, through divisions, partitions or obstructions) should be large enough to allow people wearing the necessary protective clothing and equipment to pass through, and to permit the rescue of all people who may enter the confined space.*
- *A safe means of access to and within the confined space, such as fixed ladders, platforms and walkways should be provided. Further guidance is available in AS 1657 Fixed platforms, walkways, stairways and ladders – Design, construction and installation.*
- *Access points should be unobstructed by fittings or equipment that could impede rescue and should also be kept free of any obstructions during work in the confined space. If equipment such as electrical cables, leads, hoses and ventilation ducts are required to pass through an access hole, a second access point may be needed.*
- *There should be enough access points to provide safe entry to and exit from the confined space. For example, the spacing of access holes on sewers (or in the case of large gas mains, the absence of such access holes over considerable lengths) may affect*[47]

More significantly, the enclosed nature of the lids does not allow gas to vent through them easily. This means operations personnel are at risk of asphyxiation if a leak occurs while preventative maintenance work is being conducted inside the pit.

We therefore propose to address the risk associated with these concrete manhole lids, as per the requirements of Regulation 64 of the WHS Code of Practice*:*

> *Regulation 64: A designer, manufacturer, importer or supplier of a plant or structure, and a person who installs or constructs a plant or structure must eliminate the need to enter a confined space and eliminate the risk of inadvertent entry. If this is not reasonably practicable, then:*
>
> – *the need for any person [to] enter the space must be minimised so far as is reasonably practicable*
> – *the space must be designed with a safe means of entry and exit, and*

[47] Work Health and Safety (Confined Space) Code of Practice 2015, Section 2.2 Entry and Exit

- *the risk to the health and safety of any person who enters the space must be eliminated or minimised as far as is reasonably practicable.*

This business case discusses practicable options to replace the lids with a safer solution.

1.4 Risk assessment

Risk management is a constant cycle of identification, analysis, treatment, monitoring, reporting and then back to identification (as illustrated in Figure 1.2). When considering risk and determining the appropriate mitigation activities, we seek to balance the risk outcome with our delivery capabilities and cost implications. Consistent with stakeholder expectations, safety and reliability of supply are our highest priorities.

Figure 1.2: Risk management principles

Our risk assessment approach focuses on understanding the potential severity of failure events associated with each asset and the likelihood that the event will occur. Based on these two key inputs, the risk assessment and derived risk rating then guides the actions required to reduce or manage the risk to an acceptable level.

Our risk management framework is based on:

- AS/NZS ISO 31000 Risk Management – Principles and Guidelines;
- AS 2885 Pipelines-Gas and Liquid Petroleum; and
- AS/NZS 4645 Gas Distribution Network Management.

The Gas Act 1997 and Gas Regulations 2012, through their incorporation of AS/NZS 4645 and the Work Health and Safety Act 2012, place a regulatory obligation and requirement on AGN to reduce risks rated high or extreme to low or negligible as soon as possible (immediately if extreme). If it is not possible to reduce the risk to low or negligible, then we must reduce the risk to as low as reasonably practicable (ALARP).

When assessing risk for the purpose of investment decisions, rather than analysing all conceivable risks associated with an asset, we look at a credible, primary risk event to test the level of investment required. Where that credible risk event has an overall risk rating of moderate or higher, we will undertake investment to reduce the risk.

Seven consequence categories are considered for each type of risk:

1. Health & safety – injuries or illness of a temporary or permanent nature, or death, to employees and contractors or members of the public
2. Environment (including heritage) – impact on the surroundings in which the asset operates, including natural, built and Aboriginal cultural heritage, soil, water, vegetation, fauna, air and their interrelationships
3. Operational capability – disruption in the daily operations and/or the provision of services/supply, impacting customers
4. People – impact on engagement, capability or size of our workforce

5 **Compliance** – the impact from non-compliance with operating licences, legal, regulatory, contractual obligations, debt financing covenants or reporting / disclosure requirements

6 **Reputation & customer** – impact on stakeholders' opinion of AGN, including personnel, customers, investors, security holders, regulators and the community

7 **Financial** – financial impact on AGN, measured on a cumulative basis

A summary of our risk management framework, including definitions, has been provided in Attachment 8.10.

The risk event identified for DRS pits with concrete manhole lids is the inability for technicians to exit the pit in an emergency, which can lead to slips and strains, or in extreme circumstances result in the technician becoming overcome by gas in the confined space resulting in serious harm or fatality.

The untreated risk[48] rating is shown in Table 1.3.

Table 1.3: DRS operability risk assessment – Untreated risk

Untreated risk	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Remote	Remote	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Major	Minimal	Minimal	Significant	Significant	Significant	Minor	
Risk Level	High	Negligible	Negligible	Moderate	Moderate	Moderate	Low	

Though a major safety incident is only likely to occur in certain circumstances, the absence of effective risk controls means the overall risk remains high. In addition, failure to provide employees with a safe working environment and effective emergency evacuation equipment also carries a significant people, compliance and reputational risk.

1.5 Options considered

We have identified the following options to address the health and safety risk associated with concrete manhole lids on DRS pits:

- **Option 1** – Replace the concrete lids on the [redacted] underground DRS with steel butterfly style lids;
- **Option 2** – Replace [redacted] underground DRS completely with half pits, which eliminates the confined space risk; or
- **Option 3** – Maintain the status quo – do not replace the lids or pits, and maintain the current controls only.

These options are discussed in the following sections.

[48] Untreated risk is the risk level assuming there are no risk controls currently in place. Also known as the 'absolute risk'.

1.5.1 Option 1 – Replace concrete lids with steel butterfly style lids

Under Option 1 we propose to replace the concrete manhole lids on the [redacted] underground DRS with steel butterfly lids.

Figure 1.3: Example of proposed steel butterfly lid

Steel butterfly lids allow escaped gas to vent through them, which reduces the risk of asphyxiation. The proposed lids are lighter than the concrete Gatic lids, and have spring loaded opening systems that allow a much larger chamber opening to be uncovered, with minimal manual handling (see Figure 1.3). These lids are used in other networks and are becoming standard practice for pits.

The lid design improves accessibility to and from the undergrounds pit, and makes rescue easier in the event of an emergency. Because the lids are lighter, the size of the DRS pit opening can be larger, which means the tripods for the emergency line can be positioned more easily. This means technicians can move more freely around the DRS pit chamber without obstruction to the rescue line.

The new lids feature a locking mechanism that secures the lid in the open position when maintenance is being undertaken. This minimises the risk that the lids could close while a technician is working in the chamber. The steel lids are also designed in accordance with AS 3990 to make sure they are strong enough to withstand private/non-commercial vehicles driving over them. We will also install bollards around the lid to prevent vehicles from parking on the lid. This will help negate the cost of having to reinforce the lids further or install more expensive heavier-duty lids.

The steel butterfly lids we propose to install are consistent with current design standards and are commonly used by other distribution networks to access similar underground pits.

Replacing the existing concrete lids with the butterfly lids is consistent with the requirements of WHS Code of Practice in that *the risk to the health and safety of any person who enters the space must be eliminated or minimised as far as is reasonably practicable.*[49]

The list of DRS requiring new lids is provided in Appendix B.

1.5.1.1 Cost assessment

The cost associated with Option 1 is $2.0 million. This estimate is based on recent current material and labour rates. Refer to section 1.7.2 for the more detailed cost breakdown.

Under this option, all [redacted] DRS pits would be addressed during the next AA period (July 2021 to June 2026).

[49] Regulation 64.

Table 1.4: Cost assessment – Option 1, $'000 2019/20

	2020/21	2021/22	2022/23	2023/24	2024/25	Total
Scope	Replace [redacted] concrete DRS lids with butterfly lids	Replace [redacted] concrete DRS lids with butterfly lids	Replace [redacted] concrete DRS lids with butterfly lids	Replace [redacted] concrete DRS lids with butterfly lids	Replace [redacted] concrete DRS lids with butterfly lids	Replace [redacted] concrete DRS lids with butterfly lids
Materials	84.4	84.4	295.4	295.4	295.4	1,055.0
Labour	72.8	72.8	254.9	254.9	254.9	910.3
Total	**157.2**	**157.2**	**550.3**	**550.3**	**550.3**	**1,965.3**

1.5.1.2 Risk assessment

Option 1 reduces the risk associated with the DRS pits from high to low. Table 1.5 shows the treated risk rating under Option 1.

Table 1.5: DRS operability risk assessment – Option 1

Option 1	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Remote	Remote	Remote	Remote	Remote	Remote	Remote	Low
Consequence	Significant	Minimal	Minimal	Minor	Minor	Minor	Minor	
Risk Level	Low	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	

Installing steel butterfly manhole lids reduces the likelihood of a serious health and safety incident from unlikely to remote. The severity of a safety incident is also diminished, as the butterfly lids will enable swifter evacuation of the pit if an uncontrolled gas escape occurs. Though there is always a safety risk when working with live natural gas assets, having a larger and more accessible pit opening will help mitigate the risk of fatality or serious/permanent injury.

This option also satisfies the requirements of the Regulation 64 of the WHS Code of Practice, as *the risk to the health and safety of any person who enters the* [confined] *space* is *eliminated or minimised as far as is reasonably practicable*. As a result, the people, compliance and reputational risk is reduced.

1.5.1.3 Alignment with vision objectives

Table 1.6 shows how Option 1 aligns with our vision objectives.

Table 1.6: Alignment with vision – Option 1

Vision objective	Alignment
Delivering for Customers – Public Safety	-
Delivering for Customers – Reliability	-
Delivering for Customers – Customer Service	-
A Good Employer – Health and Safety	Y
A Good Employer – Employee Engagement	-
A Good Employer – Skills Development	-
Sustainably Cost Efficient – Working within Industry Benchmarks	Y
Sustainably Cost Efficient – Delivering Profitable Growth	-
Sustainably Cost Efficient – Environmentally and Socially Responsible	Y

Option 1 aligns with the *A Good Employer* aspect of our vision, as it helps us achieve our aim of keeping our employees and contractors safe from harm.

It also aligns with being *Sustainably Cost Efficient*, as Option 1 is the lowest cost option to address the safety risk, and the proposed manhole lid design is consistent with industry standards.

1.5.2 Option 2 – Replace [redacted] underground DRS pits completely with half pits

This option is to replace the existing fully-enclosed DRS pits with steel half-pits. The half pits allow access to DRS components from ground level, and do not require the technician to enter a confined space. This eliminates the confined space risk and significantly reduces the likelihood of injury, or in extreme cases, asphyxiation.

However, due to the size and complexity of replacing an entire pit, it is not feasible to replace all [redacted] pits within one five-year period. We estimate [redacted] pits can be replaced during the next AA period ([redacted] per year), with the remainder monitored and then replaced over the course of the following five to ten years.

The list of DRS requiring complete replacement is presented in Appendix B.

1.5.2.1 Cost assessment

The cost associated with Option 2 is $5.0 million. This estimate is based on recent current material and labour rates, and the assumption that only [redacted] of the [redacted] pits will be replaced within the next five years. Based on historical actuals from similar projects, the total labour and material costs of replacing DRS pits is around [redacted] per pit[50].

Table 1.7: Cost assessment – Option 1, $'000 2019/20

	2020/21	2021/22	2022/23	2023/24	2024/25	Total
Scope	Replace [redacted] underground DRS pits with steel half pits	Replace [redacted] underground DRS pits with steel half pits	Replace [redacted] underground DRS pits with steel half pits	Replace [redacted] underground DRS pits with steel half pits	Replace [redacted] underground DRS pits with steel half pits	Replace [redacted] underground DRS pits with steel half pits
Materials	200.0	200.0	200.0	200.0	200.0	1,000.0
Labour	800.0	800.0	800.0	800.0	800.0	4,000.0
Total	**1,000.0**	**1,000.0**	**1,000.0**	**1,000.0**	**1,000.0**	**5,000.0**

Under Option 2 we would deliver the balance of the [redacted] pit replacements over the following five to ten years. The totals cost of replacing all [redacted] pits would be around $12.5 million.

1.5.2.2 Risk assessment

Option 2 reduces the risk associated with concrete manhole lids on DRS pits from high to negligible. However, it should be noted that Option 2 only addresses ten of the [redacted] pits within the next five years. The full risk reduction will therefore not be achieved as quickly as with Option 1. Table 1.8 shows the risk rating under Option 2.

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50 Reference Project No. 38059 REG CL17 Replace Reg Richmond = $[redacted] and Project No. 40203 SA22 Below Grn Reg = $[redacted]

Table 1.8: DRS operability risk assessment – Option 2

Option 2	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Rare	Rare	Rare	Rare	Rare	Rare	Rare	Negligible
Consequence	Minor	Minimal	Minimal	Minimal	Minimal	Minimal	Minimal	
Risk Level	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	

Option 2 completely eliminates the confined space risk. With the half-pits, the technician can access components from ground level, and does not have to enter a confined space. As a result, the likelihood of a risk event occurring is reduced to rate. In addition, the risk of asphyxiation and/or serious injury is eliminated, reducing the safety consequence to minor.

Therefore, this option best meets the requirements of Regulation 64 of the WHS Code of Practice:

***Regulation 64**: A designer, manufacturer, importer or supplier of a plant or structure, and a person who installs or constructs a plant or structure must eliminate the need to enter a confined space and eliminate the risk of inadvertent entry.*

1.5.2.3 Alignment with vision objectives

Option 2 aligns with the *A Good Employer* aspect of our vision, as it helps us achieve our aim of keeping our employees and contractors safe from harm.

However, it does not align with being *Sustainably Cost Efficient*, as Option 2 is significantly more expensive than Option 1, and also addresses the DRS pit risk over a longer time frame.

Table 1.9 shows how this option aligns with our vision objectives.

Table 1.9: Alignment with vision – Option 2

Vision objective	Alignment
Delivering for Customers – Public Safety	-
Delivering for Customers – Reliability	-
Delivering for Customers – Customer Service	-
A Good Employer – Health and Safety	Y
A Good Employer – Employee Engagement	-
A Good Employer – Skills Development	-
Sustainably Cost Efficient – Working within Industry Benchmarks	N
Sustainably Cost Efficient – Delivering Profitable Growth	-
Sustainably Cost Efficient – Environmentally and Socially Responsible	N

1.5.3 Option 3 – Maintain the status quo

Under Option 3, we would not replace the manhole lids, and would continue to operate in and around DRS pits with concrete lids.

1.5.3.1 Cost assessment

This option would require no upfront capital costs, however, it does not address the health and safety risk to our employees. We would still incur reactive costs and risks associated with leaks and repairs. This cost would be eliminated under Options 1 and 2.

1.5.3.2 Risk assessment

The current controls to address the risk associated with DRS pits are:

- use of breathing apparatus as required;
- complete removal of the concrete lids during leak repair; and
- use of harness gear tethered to a winch and tripod used by personnel as part of a procedural control.

Despite these current controls the risk associated with DRS with concrete lids remains rated high. This is because the current controls are insufficient to allow rapid evacuation and safe working around the assets in the pit, and can lead to serious harm in certain circumstances. Table 1.10 shows the risk associated with Option 3 (status quo).

Table 1.10: DRS operability risk assessment – Option 3

Option 3	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Remote	Remote	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Major	Minimal	Minimal	Minor	Minor	Minor	Minor	
Risk Level	High	Negligible	Negligible	Low	Low	Low	Low	

Though the people, compliance and reputational risks are lower than the untreated risk (because at least some controls are in place), the safety risk is not diminished. Though in some instances the entire concrete Gatic lid can be removed to allow safer access, this is not always possible and requires strenuous manual handling.

Under Option 3 we would not be able to demonstrate compliance with the relevant WHS Confined Spaces Code of Practice regulations. As a result, maintaining the status quo is not recommended as it does not reduce the risk to low or ALARP and is therefore inconsistent with our risk management framework.

1.5.3.3 Alignment with vision objectives

Table 1.11 shows how this option aligns with our vision objectives.

Table 1.11: Alignment with vision – Option 3

Vision objective	Alignment
Delivering for Customers – Public Safety	-
Delivering for Customers – Reliability	-
Delivering for Customers – Customer Service	-
A Good Employer – Health and Safety	N
A Good Employer – Employee Engagement	-
A Good Employer – Skills Development	-
Sustainably Cost Efficient – Working within Industry Benchmarks	N
Sustainably Cost Efficient – Delivering Profitable Growth	-
Sustainably Cost Efficient – Environmentally and Socially Responsible	N

Option 3 does not align with the *A Good Employer* aspect of our vision, as it does not reduce the potential for serious harm to our employees and contractors.

It is also not *Sustainably Cost Efficient*, as although Option 3 results in no additional costs, it is not consistent with the actions of a socially responsible organisation, nor is it consistent with industry practice.

1.6 Summary of costs and benefits

Table 1.12 presents a summary of how each option compares in terms of the estimated cost, the residual risk rating, and aligning with objectives.

Table 1.12: Summary of costs and benefits

Option	Estimated cost ($ million)	Treated residual risk rating	Alignment with vision objectives
Option 1	2.0	Low	This option would achieve safety objectives, and aligns with our vison to remain sustainably cost efficient
Option 2	5.0	Negligible	This option would exceed safety objectives, albeit over a longer time frame than Option 1. However, Option 2 is not sustainably cost efficient.
Option 3	0	High	This option does not achieve safety objectives, and does not reflect the actions of a socially responsible organisation.

1.7 Recommended solution

Option 1 is the recommended solution.

1.7.1 Why is the recommended option prudent?

Replacing the concrete lids with lighter, more manageable steel lids that provide a safe working environment, vent gas and allow easier and compliant access/egress for technicians is the most cost effective to option to address the safety risk. Though replacing the entire pit (Option 2) would eliminate the confined space risk completely, Option 1 reduces the risk to ALARP within a much shorter time frame and at considerably lower cost.

Option 1 also best aligns with our vision objectives.

1.7.2 Estimating efficient costs

Key assumptions made in the cost estimation for this project include:

- cost based on historical expenditure, with labour rates based on work breakdown structure of activities, and material rates based on historical costs for similar materials;
- estimates derived from contractual rates of vendors to be utilised;
- the work activities will extend over a period of two days per each site;
- [redacted] TP DRS have been identified as having manhole concrete lids, which will all be replaced within the next AA period;
- the first year will be taken up by fabrication costs with the actual change over commencing in the second year and progressively completing all pits by the end of the AA period; and

- original equipment manufacturer contractual rates for spares and labour that are part of our services agreements; and
- the design is compliant with Health and Safety requirements, confined space working and AS3990 Mechanical equipment – Steelwork.

The costliest aspect of the design relates to the weight the pit lids have to be able to withstand, such as a vehicle driving over the steel DRS pit lid or worse; parking on it. However, we have been able to reduce these costs by installing bollards around the new pit, which will prevent vehicles from parking on the lid. This means we do not have to use a higher grade of reinforced steel for the lids, which would significantly increase the materials and installation costs beyond the current estimate.

We consider the unit cost is proportional to the risk reduction. More detail on the forecast cost breakdown is provided in Appendix C.

Table 1.13 presents a breakdown of the DRS Operability Risk Reduction Project by cost category. Table 1.14 provides the costs escalated to June 2021 dollars.

Table 1.13: Project cost estimate by cost category, real $'000 2019/20

	2020/21	2021/22	2022/23	2023/24	2024/25	Total
Scope	Replace [redacted] DRS manhole concrete lids with butterfly style steel lids	Replace [redacted] DRS manhole concrete lids with butterfly style steel lids	Replace [redacted] DRS manhole concrete lids with butterfly style steel lids	Replace [redacted] DRS manhole concrete lids with butterfly style steel lids	Replace [redacted] DRS manhole concrete lids with butterfly style steel lids	Replace [redacted] DRS manhole concrete lids with butterfly style steel lids
Materials	84.4	84.4	295.4	295.4	295.4	1,055.0
Labour	72.8	72.8	254.9	254.9	254.9	910.3
Total	**157.2**	**157.2**	**550.3**	**550.3**	**550.3**	**1,965.3**

Table 1.14: Escalated project cost estimate ($'000)

	21/22	22/23	23/24	23/25	25/26	Total
Total unescalated ($ Dec 19)	157.2	157.2	550.3	550.3	550.3	1,965.3
Escalation	5.3	6.1	24.7	27.8	30.7	94.5
Total escalated ($ Jun 21)	**162.5**	**163.3**	**575.0**	**578.1**	**581.0**	**2,059.8**

1.7.3 Consistency with the National Gas Rules

In developing these forecasts, we have had regard to Rule 79 and Rule 74 of the NGR. With regard to all projects, and as a prudent asset manager, we give careful consideration to whether capex is conforming from a number of perspectives before committing to capital investment.

Rule 79(1)

Replacing the concrete lids with steel butterfly lids is consistent with the requirements of NGR 79(1)(a), Specifically, we consider that the capital expenditure is:

- Prudent – the expenditure is necessary in order to enable our employees and contractors to carry out maintenance work safely. The proposed risk treatment is consistent with accepted industry practice and current design standards, and alternative practicable options have been considered to address the risk. The proposed expenditure can therefore be seen to be of a nature that would be incurred by a prudent service provider.

- Efficient – the forecast expenditure is based on historical precedent and tender contract values. The solution to replace the lids and reduce the risk to ALARP rather than replace the entire pit and completely eliminate the confined space risk (noting there will always be some risk associated with performing maintenance on natural gas assets), is the lowest cost option. The proposed expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur.

- Consistent with accepted and good industry practice – the proposed expenditure follows good industry practice by ensuring that existing safety risks are addressed to ALARP.

- To achieve the lowest sustainable cost of delivering pipeline services – the proposed solution achieves the necessary risk reduction in the shortest time frame possible, at the lowest overall cost.

Rule 79(2)

The proposed capex is justifiable under NGR 79(2)(c)(i), as it is necessary to maintain the safety of services, specifically with a view to keeping our employees safe from harm. Continuing with current practice results in an unacceptable safety risk for customers and AGN is seeking to maintain a level of service consistent with industry and design standards.

Rule 74

The forecast costs are based on the latest market rate testing and project options consider the asset management requirements as per the Strategic Asset Management Plan. The estimate has therefore been arrived at on a reasonable basis and represents the best estimate possible in the circumstances.

Appendix A – Comparison of risk assessments for each option

Untreated risk	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Remote	Remote	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Major	Minimal	Minimal	Significant	Significant	Significant	Minor	
Risk Level	High	Negligible	Negligible	Moderate	Moderate	Moderate	Low	

Option 1	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Remote	Remote	Remote	Remote	Remote	Remote	Remote	Low
Consequence	Significant	Minimal	Minimal	Minor	Minor	Minor	Minor	
Risk Level	Low	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	

Option 2	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Rare	Rare	Rare	Rare	Rare	Rare	Rare	Negligible
Consequence	Minor	Minimal	Minimal	Minimal	Minimal	Minimal	Minimal	
Risk Level	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	

Option 3	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Remote	Remote	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Major	Minimal	Minimal	Minor	Minor	Minor	Minor	
Risk Level	High	Negligible	Negligible	Low	Low	Low	Low	

Appendix B – List of DRS lids to be replaced

	DRS ID	Pressure Configuration	Location
1	R127	TP to HP	Womma Rd, EDINBURGH NORTH 5113
2	R912	TP to HP	Albert Tce, PORT PIRIE 5540
3	R414	TP to HP	Frank St, MARINO 5049
4	R413	TP to HP	Kingston Ave, RICHMOND 5033
5	R411	TP to HP	Mooringe Ave, NORTH PLYMPTON 5037
6	R338	TP to HP	Finian Rd / Dyson Rd, CHRISTIE DOWNS 5164
7	R321	TP to MP	Clark Ave, GLANDORE 5037
8	R315	TP to HP	South Ave, HALLETT COVE 5158
9	R310	TP to HP	Grand Central Ave, HALLETT COVE 5158
10	R216	TP to HP	Eastern Parade, OTTOWAY 5013
11	R215	TP to HP	Cormack Rd, WINGFIELD 5013
12	R213	TP to HP	Diment Rd, BURTON 5110
13	R210	TP to HP	Purling Ave, EDINBURGH 5111
14	R130	TP to MP	Old Port Rd, ROYAL PARK 5014 SA
15	R119	TP to HP	Bolivar Rd, BURTON 5110
16	R303	TP to MP	Folkestone Rd, DOVER GARDENS 5048 SA
17	R135	TP to MP	Tapleys Hill Rd, SEATON 5023 SA
18	R220	TP to HP	Cormack Rd & South Rd. WINGFIELD 5013
19	R308	TP to MP	Stephenson Ave, SOUTH BRIGHTON 5048
20	R318	TP to HP	Black Rd, HAPPY VALLEY 5159
21	R324	TP to MP	Rose St, GLENELG 5045
22	R402	TP to MP	Churchill Ave, GLANDORE 5037
23	R404	TP to MP	London Rd, MILE END SOUTH 5031
24	R910	TP to HP	Grey Tce, PORT PIRIE SOUTH 5540
25	R408	TP to HP	Port Rd, THEBARTON 5031 SA

Appendix C – Cost estimates based on work breakdown

Category	Description	Units	Units QTY	Number of sites	Unit Cost $/ unit	Total $'000
Materials						
Lids	New Butterfly Lids	each	[redacted]	[redacted]	[redacted]	[redacted]
	Bollards	each	[redacted]	[redacted]	[redacted]	[redacted]
Other	Freight, storage, and handling (excl. pipe)	each	[redacted]	[redacted]	[redacted]	[redacted]
Total materials						1,055.0
Labour						
Project management, design and initiation	Project manager	hours	[redacted]	[redacted]	[redacted]	[redacted]
	Project engineer	hours	[redacted]	[redacted]	[redacted]	[redacted]
	Draft person	hours	[redacted]	[redacted]	[redacted]	[redacted]
	Site supervisor	hours	[redacted]	[redacted]	[redacted]	[redacted]
	HSE representative	hours	[redacted]	[redacted]	[redacted]	[redacted]
Project site labour and delivery	Crew (3 ppl incl. team leader)	hours	[redacted]	[redacted]	[redacted]	[redacted]
	Excavator (8T)	hours	[redacted]	[redacted]	[redacted]	[redacted]
	Tipper truck (8T)	hours	[redacted]	[redacted]	[redacted]	[redacted]
	Traffic setup (high fencing, water barriers, VMS board)	each	[redacted]	[redacted]	[redacted]	[redacted]
	Traffic control (2 ppl including ute)	hours	[redacted]	[redacted]	[redacted]	[redacted]
	Cranage (1 rigger including 25T crane)	hours	[redacted]	[redacted]	[redacted]	[redacted]
	Reinstatement - concrete 150mm	SQM	[redacted]	[redacted]	[redacted]	[redacted]
	Third party permits (DPTI, SAPN)	each	[redacted]	[redacted]	[redacted]	[redacted]
Total labour						910.3
Total project						**1,965.3**

SA110 – SCADA equipment replacement

1.1 Project approvals

Table 1.1: Business case SA110 – Project approvals

Prepared by	Allan Gabriel, E&I Engineer, APA
Reviewed by	Robin Gray, Manager Operations SA, APA
Approved by	Craig Bonar, Head of Engineering and Planning, APA Mark Beech, General Manager Network Operations, AGN

1.2 Project overview

Table 1.2: Business case SA110 – Project overview

Description of the problem / opportunity	We use a supervisory control and data acquisition (SCADA) system to monitor and report on the flow of gas at 292 critical sites across the network including gate stations, district regulator stations (DRS), critical transmission and high pressure regulators, compressor stations, cathodic protection units, 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 next access arrangement (AA) period (July 2021 to June 2026) we also need to replace our 3G modems. The 3G mobile telecommunication network (which is operated by third-party providers) is used to transmit data to our 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 is switched off.
Untreated risk	As per risk matrix: • Obsolete SCADA equipment = **High** • 4G incompatible modems = **High**
Options considered	• **Option 1** – Replace all modems incompatible with the 4G network and reactively repair and replace on failure all other obsolete SCADA equipment ($1.9 million) • **Option 2** – Continue the proactive replacement program for SCADA equipment, including replacing the 4G incompatible modems ($1.4 million)
Proposed solution	This business case recommends Option 2. Proactive replacement of all technically obsolete SCADA equipment in the network is the lowest sustainable cost of continuing to comply with the pressure monitoring and metering requirements under the Gas Distribution Code, Australian Standard 60079 and the National Gas Market Rules. The recommended option is in line with current industry good practice and design standards, and consistent with the Strategic Asset Management Plan.
Estimated cost	The forecast direct capital cost (excluding overhead) during the next AA period (July 2021 to June 2026) is $1.4 million.

$'000 2019/20	21/22	22/23	23/24	24/25	25/26	Total
4G incompatible modems	[redacted]					[redacted]
Obsolete SCADA equipment	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	**337.8**	**254.6**	**254.6**	**254.6**	**254.6**	**1,356.3**

Basis of costs	All costs in this business case are expressed in real unescalated dollars at December 2019 unless otherwise stated. Some tables may not add due to rounding.
Alignment to our vision	Replacing SCADA equipment proactively in line with the end of its technical design life and reducing the risk of SCADA system failure aligns with the following aspects of our vision: • *Delivering for Customers* as the end of life replacement of SCADA equipment across our network will ensure the continued reliability of supply and mitigate the risk of pressure related events, and ensure accurate data is captured and used for customer billing purposes; and • *Sustainably Cost Efficient* as the cost of replacing assets at the end of their technical design lives as part of a proactive planned program is the lowest sustainable cost of managing the risk of a significant failure of the SCADA system as it is lower cost than a reactive replace on failure program.
Consistency with the National Gas Rules (NGR)	**NGR 79(1)** – the proposed solution is consistent with good industry practice, several practicable options have been considered, and market rates have been tested to achieve the lowest sustainable cost of providing this service. **NGR 79(2)** – proposed capex is justifiable under NGR 79(2)(c)(i), (ii) and (iii), as it is necessary to maintain and improve the safety of services, maintain the integrity of services and comply with regulatory obligations. **NGR 74** – the forecast costs and are based on the latest market rate testing and project options consider the asset management requirements as per the Strategic Asset Management Plan. The estimate has therefore been arrived at on a reasonable basis and represents the best estimate possible in the circumstances.
Treated risk	As per risk matrix: • Obsolete SCADA equipment = **Low** • 4G incompatible modems = **Low**
Stakeholder engagement	Our customers have told us their top three priorities are price/affordability, reliability of supply, and maintaining public safety. They also told us they expect us to deliver a high level of public safety and are satisfied that this is current practice. This proposed SCADA replacement program is designed to ensure the network operates in line with good industry practice, safety standards and compliance requirements, thereby helping maintain a safe and reliable service to our customers. The proposed solution to replace these assets at the end of their technical lives will also help to maintain the reliability of gas supply at the lowest sustainable cost, minimising the impact on customers' gas bills.
Other relevant documents	• Attachment 8.2 Strategic Asset Management Plan

1.3 Background

We use a SCADA system to monitor and report on the flow of gas across the South Australian (SA) gas distribution network. SCADA equipment is installed at each of the 18 gate stations, 63 DRSs, 21 critical regulators, 130 demand customer sites and a further 60 strategic sites[51] across the network.

The SCADA system is used to:

- manage safe asset control and facilitate emergency crew dispatch to maintain safe and efficient network operations in accordance with AS 4645;
- validate the quality and quantities of gas delivered to customers;
- determine current operations and future investment plans for the network;
- reconcile market delivery; and
- capture and transmit data to:
  - facilitate performance reporting requirements and customer experience evaluations; and
  - facilitate demonstration of meeting legislative requirements.

SCADA equipment in our network is generally in good condition. Given the critical nature of accurately monitoring network pressure and reporting consumption for billing purposes, our asset management approach is to replace SCADA equipment when it is technically obsolete to reduce the risk of a significant failure of our system. The average technical design life of our SCADA equipment is 10 years, in line with original equipment manufacturer's recommendations.

Over the next five years, we propose to continue the SCADA replacement program and replace the following equipment that will reach the end of its life:

- 50 remote telemetry units 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 actual; and
- 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.

Mobile telecommunications networks, including the 3G network, are used to transmit data to our central system. The 3G mobile network is likely to be phased out by all providers by 2024. We have assessed our SCADA system and determined that modems at 60 of our sites are incompatible with the new 4G protocols and will need to be replaced prior to the 3G network being decommissioned.

[51] Strategic sites are locations critical to short term reactive operational network performance, and also for longer term capital investment planning based on accurate network hydraulics. This business case covers the replacement of equipment at existing strategic sites. The business case SA111 – Additional Network Pressure Monitoring recommends introducing pressure monitoring at the remaining 5 DRSs and 13 new locations in the network. These assets will become part of the SCADA equipment replacement program once installed.

1.4 Risk assessment

Risk management is a constant cycle of identification, analysis, treatment, monitoring, reporting and then back to identification (as illustrated in Figure 1.1). When considering risk and determining the appropriate mitigation activities, we seek to balance the risk outcome with our delivery capabilities and cost implications. Consistent with stakeholder expectations, safety and reliability of supply are our highest priorities.

Figure 1.1: Risk management principles

Our risk assessment approach focuses on understanding the potential severity of failure events associated with each asset and the likelihood that the event will occur. Based on these two key inputs, the risk assessment and derived risk rating then guides the actions required to reduce or manage the risk to an acceptable level.

Our risk management framework is based on:

- AS/NZS ISO 31000 Risk Management – Principles and Guidelines;
- AS 2885 Pipelines-Gas and Liquid Petroleum; and
- AS/NZS 4645 Gas Distribution Network Management.

The Gas Act 1997 and Gas Regulations 2012, through their incorporation of AS/NZS 4645 and the Work Health and Safety Act 2012, place a regulatory obligation and requirement on us to reduce risks rated high or extreme to low or negligible as soon as possible (immediately if extreme). If it is not possible to reduce the risk to low or negligible, then we must reduce the risk to as low as reasonably practicable (ALARP).

When assessing risk for the purpose of investment decisions, rather than analysing all conceivable risks associated with an asset, we look at a credible, primary risk event to test the level of investment required. Where that credible risk event has an overall risk rating of moderate or higher, we will undertake investment to reduce the risk.

Seven consequence categories are considered for each type of risk:

1. **Health & safety** – injuries or illness of a temporary or permanent nature, or death, to employees and contractors or members of the public
2. **Environment** (including heritage) – impact on the surroundings in which the asset operates, including natural, built and Aboriginal cultural heritage, soil, water, vegetation, fauna, air and their interrelationships
3. **Operational capability** – disruption in the daily operations and/or the provision of services/supply, impacting customers
4. **People** – impact on engagement, capability or size of our workforce
5. **Compliance** – the impact from non-compliance with operating licences, legal, regulatory, contractual obligations, debt financing covenants or reporting / disclosure requirements
6. **Reputation & customer** – impact on stakeholders' opinion of AGN, including personnel, customers, investors, security holders, regulators and the community
7. **Financial** – financial impact on AGN, measured on a cumulative basis

A summary of our risk management framework, including definitions, has been provided in Attachment 8.10.

The primary risk event identified for technically obsolete SCADA equipment and the decommissioning of the 3G network is equipment failure, coinciding with a failure in the facility, which would go undetected as a result. The undiagnosed failure of a primary supply regulator facility or other strategic asset, or pressure excursion can lead to interruption of supply to more than 10,000 customers, or in severe cases, can lead to an overpressure incident, which has the potential to cause serious injury. This means risk to health and safety and operations is rated high.

SCADA equipment failure also poses moderate compliance, reputational and financial risks. This is because SCADA failure can result in incorrect billing information, leading to financial penalties for non-compliance with the National Gas Market Rules. Section 6.3 of AS 4645 requires us to manage and monitor the pressure of the network, which means SCADA failure poses a further compliance risk.

The untreated risk[52] associated with technically obsolete SCADA equipment is presented in Table 1.3.

Table 1.3: Technically obsolete SCADA equipment risk assessment – untreated risk

Untreated risk	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Major	Minor	Major	Minor	Significant	Significant	Significant	
Risk Level	High	Low	High	Low	Moderate	Moderate	Moderate	

The untreated risk associated with the decommissioning of the 3G network is presented in Table 1.4. Note that the likelihood of the risk event is rated higher than for the SCADA equipment failure, as we know the 3G network will be decommissioned in the near future.

Table 1.4: Decommissioning of the 3G network risk assessment – untreated risk

Untreated risk	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Occasional	Unlikely	Occasional	Unlikely	Occasional	Occasional	Occasional	High
Consequence	Major	Minor	Major	Minor	Significant	Significant	Significant	
Risk Level	High	Low	High	Low	Moderate	Moderate	Moderate	

1.5 Options considered

We have considered the following options to address the risks associated with technically obsolete SCADA equipment and the decommissioning of the 3G network. These options are:

- **Option 1** – Replace all modems incompatible with the 4G network and reactively repair and replace on failure all other technically obsolete SCADA equipment; or
- **Option 2** – Continue the proactive replacement program for SCADA equipment, Continue the proactive replacement program for SCADA equipment, including replacing the 4G incompatible modems.

These options are discussed in the following sections.

52 Untreated risk is the risk level assuming there are no risk controls currently in place. Also known as the 'absolute risk'.

1.5.1 Option 1 – Replace modems incompatible with the 4G network

Under this option, we would replace modems at 60 of our SCADA sites that are incompatible with the new 4G protocols. We would do this before 2024, which is when the 3G network is expected to be decommissioned. Note this is the equivalent of a replace on failure approach, except we know the timing of the failure.

Other SCADA equipment would be maintained[53] on a three-monthly basis for equipment at district regulator sites and gate stations, or otherwise annually. Equipment would then be reactively repaired or replaced when it fails.

With this option, the volume of SCADA equipment replacements undertaken in the next five years would be directly driven by the number of breakages/outages experienced on these assets. While it is not possible to predict with accuracy the number of failures that will occur over the next five years, given many assets are approaching their 10-year replacement cycles, the likelihood of failure is expected to be higher than during the current AA period if not treated proactively. Given the higher cost of reactive replacement compared with proactive replacement (potentially two to five times higher per asset depending on asset type and location), the potential cost of works during the next five years is significantly greater than the proposed works program if widespread asset failure arises.

Should asset failure be lower than expected, the overall cost of reactive SCADA equipment replacements may be less than forecast. However, the residual risk associated with this assets will not be addressed, as a number of aged and/or obsolete SCADA assets will remain in the network. Our Strategic Asset Management Plan and risk management framework requires us to address all risks rated as high, and reduce them to low or ALARP. A reactive approach would not achieve this.

These potentially higher costs and unaddressed residual risk are not tolerable for the network or our customers. An entirely reactive 'replace on failure' approach to managing SCADA equipment is not consistent with good asset management practice, and therefore not consistent with NGR 79(1)(a).

1.5.1.1 Cost assessment

With Option 1, the unit costs incurred would almost certainly be higher. Corrective activities are likely to incur higher costs compared to planned activities due to:

- additional travel costs (planned activities allow us to share travel costs across different activities at the same location);
- increased likelihood of overtime and shift penalties (planned activities allow us to optimise staff rostering);
- additional costs for expediated freight; and
- additional costs for removing crews from other planned work to address a corrective maintenance requirement and then remobilising to complete the previous planned work.

We may also incur unplanned operating expenditure, as failures could lead to interruption to supply requiring additional customer liaison, temporary gas supply (such as CNG bottles) for critical customers and customer relights. Interruption to supply could also cost us and our customers in foregone revenues.

[53] The maintenance program includes inspecting, testing, calibrating, cleaning and verifying functionality and calculations for all equipment. Maintenance is not part of this business case. It is part of the operating expenditure forecast.

While it is not possible to estimate precisely how many asset failures will occur during the next five years, broad cost estimates can be developed based by escalating the cost of the proposed works program if delivered reactively. It is a generally accepted asset management principle that delivery of works reactively is significantly more expensive than undertaking proactive or preventative works. Various sources cite the increase in reactive costs compared with proactive can be between two and five times[54] more than undertaking the same works proactively.

For the South Australian gas distribution network the cost escalation for reactive vs proactive works varies depending on the type (and scarcity) of the asset being replaced, as well as the remoteness of the asset from the Metropolitan area.

Taking a conservative approach, if we assume a weighted average increase of only 1.5 times the material and labour/contractor costs if the SCADA equipment replacement program were to be undertaken reactively[55], it would cost approximately $1.9 million to deliver.

The replacement of 4G incompatible modems by the end of 2024 would be planned and delivered at the same historical cost, adding around $83,000 to the cost of the replacement program.

In any event, costs associated with a predominantly replace on failure works program would not *be such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services.*[56]

1.5.1.2 Risk assessment

If we replace 3G incompatible modems, but only repair and replace all other SCADA equipment on failure (rather than proactive replacement), the risk is reduced to low for modems, but remains high for other SCADA equipment.

Moving to a replacement on failure approach for SCADA equipment (Option 1), the risk associated with technically obsolete SCADA equipment will not be addressed and the risk will increase as the assets age. This is inconsistent with our risk management framework, which requires risk to be reduced to low or ALARP.

Table 1.5 and Table 1.6 show the residual risk associated with technically obsolete SCADA equipment if Option 1 is pursued.

Option 1	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	
Consequence	Major	Minor	Major	Minor	Significant	Significant	Significant	High
Risk Level	High	Low	High	Low	Moderate	Moderate	Moderate	

Table 1.6

Table 1.5: Option 1 – Reactive replacement of technically obsolete SCADA equipment risk assessment

Option 1	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	
Consequence	Major	Minor	Major	Minor	Significant	Significant	Significant	High
Risk Level	High	Low	High	Low	Moderate	Moderate	Moderate	

54 Marshall Institute, Omega engineering, ARMS reliability.

55 This is a rule of thumb estimate, noting that some aspects of the compressor program would be undertaken reactively anyway, and assuming that in this scenario 'proactive' maintenance works are all undertaken as assets/components fail.

56 NGR 79(1)(a).

Table 1.6: Option 1 – Replacing the 3G modems risk assessment

Option 1	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Remote	Remote	Remote	Remote	Remote	Remote	Remote	Low
Consequence	Significant	Minor	Significant	Minimal	Minor	Minor	Minimal	
Risk Level	Low	Negligible	Low	Negligible	Negligible	Negligible	Negligible	

1.5.1.3 Alignment with vision objectives

Table 1.7 shows how this option aligns with our vision objectives.

Table 1.7: Alignment with vision – Option 1

Vision objective	Alignment
Delivering for Customers – Public Safety	N
Delivering for Customers – Reliability	N
Delivering for Customers – Customer Service	N
A Good Employer – Health and Safety	N
A Good Employer – Employee Engagement	-
A Good Employer – Skills Development	-
Sustainably Cost Efficient – Working within Industry Benchmarks	N
Sustainably Cost Efficient – Delivering Profitable Growth	-
Sustainably Cost Efficient – Environmentally and Socially Responsible	-

Option 1 would not align with our objective of *Delivering for Customers*, as it would not address the public safety or reliability risks associated with a significant failure of the SCADA system. The failure of the SCADA system could lead to the undiagnosed failure of a primary supply regulator facility with potential for network pressure event or the extended response to containment of emergency situations.

Option 1 would also not align with our objective of remaining *Sustainably Cost Efficient* as it is not the least cost option of addressing the risks associated with technically obsolete SCADA equipment. It is also not consistent with industry standards as it is inconsistent with the original equipment manufacturer's recommendations and does not conform to the requirements of the National Gas Market Code, or the Gas Distribution Code. It is therefore inconsistent with our objective of working within industry benchmarks.

1.5.2 Option 2 – Continue the proactive replacement program for SCADA equipment, including replacing the 4G incompatible modems

Under this option we would continue with the ongoing proactive replacement of our SCADA equipment that has reached the end of its technical design life (around 10 years) and obsolete. This includes replacing the modems that are not compatible with the 4G network. This includes:

- 50 remote telemetry units 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 actual gas consumption for small customer sites;

- 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; and
- 60 modems that are incompatible with the new 4G protocols and will need to be replaced prior to the decommissioning of the 3G network.

The replacement assets will then be maintained[57] under the existing maintenance program which is on a three-monthly basis for equipment at district regulator sites and gate stations, or otherwise annually.

1.5.2.1 Cost assessment

The estimated capital cost of proactively replacing all SCADA equipment that has reached the end of its technical design life over the next five years is $1.4 million. This estimate is based on current material and labour rates for new installations (see Table 1.8).

Table 1.8: Cost estimate – Option 2, $'000 2019/20

	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Labour	123.4	85.2	85.2	85.2	85.2	464.0
Materials	214.4	169.5	169.5	169.5	169.5	892.2
Total	**337.8**	**254.6**	**254.6**	**254.6**	**254.6**	**1,356.3**

1.5.2.2 Risk assessment

Option 2 reduces the risk associated with all SCADA equipment identified in the Strategic Asset Management Plan as technically obsolete is reduced from high to low.

Table 1.9 shows the residual risk associated with proactively replacing all technically obsolete SCADA equipment (Option 2).

Table 1.9: Option 2 – Proactive replacement of all technically obsolete SCADA equipment including 3G modems risk assessment

Option 2	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Remote	Remote	Remote	Remote	Remote	Remote	Remote	Low
Consequence	Significant	Minor	Significant	Minimal	Minor	Minor	Minimal	
Risk Level	Low	Negligible	Low	Negligible	Negligible	Negligible	Negligible	

Proactively replacing all technically obsolete SCADA equipment in the network including all modems incompatible with the new 4G mobile network reduces the likelihood and the potential consequence of a significant system failure, which could in turn lead to:

- the undiagnosed failure of a primary supply regulator facility with potential for network over/under pressure; and
- extended response to containment of emergency situations (e.g. major gas release as result of third-party damage).

Of the options considered, Option 2 is consistent with original equipment manufacturer's recommendations, achieves the greatest risk reduction, reducing the risk to low, and is therefore

57 The maintenance program includes inspecting, testing, calibrating, cleaning and verifying functionality and calculations for all equipment. Maintenance is not part of this business case. It is part of the operating expenditure forecast.

consistent with our risk management framework, as well as current industry practice and design standards.

1.5.2.3 Alignment with vision objectives

Table 1.10 shows how this option aligns with our vision objectives.

Table 1.10: Alignment with vision – Option 2

Vision objective	Alignment
Delivering for Customers – Public Safety	Y
Delivering for Customers – Reliability	Y
Delivering for Customers – Customer Service	Y
A Good Employer – Health and Safety	Y
A Good Employer – Employee Engagement	-
A Good Employer – Skills Development	-
Sustainably Cost Efficient – Working within Industry Benchmarks	Y
Sustainably Cost Efficient – Delivering Profitable Growth	-
Sustainably Cost Efficient – Environmentally and Socially Responsible	-

Option 2 would align with our objective of *Delivering for Customers*, as it would address the public safety or reliability risks associated with a significant failure of the SCADA system. It will reduce the risk of failure of the SCADA system leading to an undiagnosed failure of a primary supply regulator facility with potential for network pressure event or the extended response to containment of emergency situations.

Option 2 would also align with our objective of remaining *Sustainably Cost Efficient* as it is the least cost option of addressing the risks associated with technically obsolete SCADA equipment. It is also consistent with industry standards and conforms to the requirements of the National Gas Market Code, and the Gas Distribution Code and is therefore consistent with our objective of working within industry benchmarks.

1.6 Summary of costs and benefits

Table 1.11 presents a summary of how each option compares in terms of the estimated cost, the residual risk rating, and aligning with our vision objectives.

Table 1.11: Comparison of options

Option	Estimated cost ($ million)	Treated residual risk rating	Alignment with vision objectives
Option 1	1.9	High	This would fail to achieve safety and reliability objectives or meet industry standards.
Option 2	1.4	Low	This would align with all relevant vision objectives.

1.7 Recommended option

Option 2 is the proposed solution to reduce the risk posed by technically obsolete SCADA equipment.

1.7.1 Why is the recommended option prudent?

Option 2 delivers a solution that reduces the risk associated with all SCADA equipment identified in the Strategic Asset Management Plan as technically obsolete is reduced from high to low at the lowest cost. It is therefore consistent with good industry practice, our Strategic Asset Management Plan and the risk management framework.

It supports the vision and values in relation to:

- *Delivering for Customers*, as it would address the public safety or reliability risks associated with a significant failure of the SCADA system. It will reduce the risk of failure of the SCADA system leading to an undiagnosed failure of a primary supply regulator facility with potential for network pressure event or the extended response to containment of emergency situations.
- *Sustainably Cost Efficient*, as it is the least cost option of addressing the risks associated with technically obsolete SCADA equipment. It is also consistent with industry standards and conforms to the requirements of the National Gas Market Code, and the Gas Distribution Code and is therefore consistent with our objective of working within industry benchmarks.

A risk-based approach to deliver this program will be adopted, whereby works will be prioritised for SCADA equipment with highest risk to the network.

1.7.2 Estimating efficient costs

Key assumptions made in the cost estimation for the SCADA equipment replacement program include:

- costs based on historical expenditure noting that these works are standard practice;
- estimates derived from contractual rates of vendors to be utilised;
- resource cost based on other similar projects ongoing at present or in previous AA periods; and
- original equipment manufacturer contractual rates for spares and labour that are part of our services agreements.

Table 1.12 presents a breakdown of the SCADA equipment replacement program by cost category.

Table 1.13 provides the costs escalated to June 2021 dollars.

Table 1.12: Project cost estimate by cost category, $'000 2019/20

	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Labour	123.4	85.2	85.2	85.2	85.2	464.0
Materials	214.4	169.5	169.5	169.5	169.5	892.2
Total	**337.8**	**254.6**	**254.6**	**254.6**	**254.6**	**1,356.3**

Table 1.13: Escalated project cost estimate ($'000)

	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Total unescalated ($ Dec 19)	337.8	254.6	254.6	254.6	254.6	1,356.3
Escalation	11.4	9.8	11.4	12.9	14.2	59.7
Total escalated ($ Jun 21)	**349.2**	**264.4**	**266.0**	**267.5**	**268.8**	**1,415.9**

1.7.3 Consistency with the National Gas Rules

In developing these forecasts, we have had regard to Rule 79 and Rule 74 of the NGR. With regard to all projects, and as a prudent asset manager, we give careful consideration to whether capex is conforming from a number of perspectives before committing to capital investment.

Rule 79(1)

The continued proactive replacement of our SCADA equipment is consistent with the requirements of NGR 79(1)(a). Specifically, we consider that the capital expenditure is:

- Prudent – the expenditure is necessary in order to deliver gas safely and reliably to the downstream network and ensure accurate billing information for our customers. Proactive replacement of technically obsolete SCADA equipment is therefore prudent and necessary to continue to supply services. The proposed risk treatment is consistent with accepted industry practice and current design standards, and is proven to address the risk of a significant failure of our SCADA system. Several practicable options have been considered to address the risk. The proposed expenditure is therefore consistent with that which would be incurred by a prudent service provider.

- Efficient – historical average actuals and tender contract values have been used to inform cost estimates. The proposed expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur.

- Consistent with accepted and good industry practice – the proposed expenditure follows good industry practice by ensuring that existing safety risks are addressed to low or ALARP and in line with current industry practice and design standards. The proposed capital expenditure is therefore such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice.

- To achieve the lowest sustainable cost of delivering pipeline services – the sustainable delivery of services includes reducing risks to as low as reasonably practicable and maintaining reliability of supply, whilst achieving the lowest sustainable costs by undertaking the works in line with the relevant useful life and adopting proven new and emerging technologies and techniques that reduce long-term costs.

Rule 79(2)

The proposed capex is justifiable under NGR 79(2)(c)(i) as it is necessary to maintain the safety of services. Not addressing the risk of obsolete SCADA equipment results in an unacceptable safety risk for customers and our staff, network integrity issues, disruption to customer supply and potential uncontrolled release of gas.

The continued proactive replacement of our SCADA equipment has proven to reduce the risk of a significant SCADA system failure and will allow us to maintain a level of service consistent with customer expectations. Moreover, this is the most cost efficient solution to reduce the identified risk and is therefore consistent with good industry practice.

Rule 74

The forecast costs are based on the latest market rate testing and project options consider the asset management requirements as per the Strategic Asset Management Plan. The estimate has therefore been arrived at on a reasonable basis and represents the best estimate possible in the circumstances.

Appendix A – Comparison of risk assessments for each option

Untreated - Technically obsolete SCADA equipment risk assessment

Untreated risk	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	
Consequence	Major	Minor	Major	Minor	Significant	Significant	Significant	High
Risk Level	High	Low	High	Low	Moderate	Moderate	Moderate	

Untreated - Decommissioning of the 3G network risk assessment

Untreated risk	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Occasional	Unlikely	Occasional	Unlikely	Occasional	Occasional	Occasional	
Consequence	Major	Minor	Major	Minor	Significant	Significant	Significant	High
Risk Level	High	Low	High	Low	Moderate	Moderate	Moderate	

Option 1 – Reactive replacement of technically obsolete SCADA equipment risk assessment

Option 1	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	
Consequence	Major	Minor	Major	Minor	Significant	Significant	Significant	High
Risk Level	High	Low	High	Low	Moderate	Moderate	Moderate	

Option 1 – Replacing the 3G modems risk assessment

Option 1	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Remote	Remote	Remote	Remote	Remote	Remote	Remote	
Consequence	Significant	Minor	Significant	Minimal	Minor	Minor	Minimal	Low
Risk Level	Low	Negligible	Low	Negligible	Negligible	Negligible	Negligible	

Option 2 – Proactive replacement of all technically obsolete SCADA equipment including 3G modems risk assessment

Option 2	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Remote	Remote	Remote	Remote	Remote	Remote	Remote	
Consequence	Significant	Minor	Significant	Minimal	Minor	Minor	Minimal	Low
Risk Level	Low	Negligible	Low	Negligible	Negligible	Negligible	Negligible	

SA111 – Additional network pressure monitoring

1.1 Project approvals

Table 1.1: Business case SA111 – Project approvals

Prepared by	Peiman Vakili, Gas Networks and Pipeline Engineer, APA
Reviewed by	Robin Gray, SA Operations Manager, APA
Approved by	Craig Bonar, Head of Planning and Engineering, APA Mark Beech, General Manager Network Operations, AGN

1.2 Project overview

Table 1.2: Business case SA111 – Project overview

Description of the problem / opportunity	The South Australia (SA) natural gas distribution networks include approximately 200 km of metropolitan steel transmission pressure (TP) pipelines and 200 km of steel distribution pipelines, which deliver gas to over 450,000 customers.
	Installing supervisory control and data acquisition (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 ageing 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; and
	• facilitate efficient and prudent network modelling that:
	    • helps us safely and reliably operate the network in real time; 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 we may derive from installing SCADA on them.
	In 2012, we commenced a program to install telemetering on all of our District Regulator Stations (DRS). By the end of the current access arrangement (AA) period, we will have pressure monitoring on 86 of our 91 TP DRSs. This business case addresses the five remaining sites.
	As the network continues to grow, we periodically reassess the need for pressure monitoring at sites across the network. A recent review identified 13 sites across the network where remote pressure monitoring is required to ensure effective network monitoring as required by AS 4645. 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 DRS supplying the network, sometimes in combination with small trunks between supply regulators and area, a small increase in demand in the area can lead to a significant pressure drop.
	This business case considers the case for installing pressure monitoring at 13 strategic sites at the fringes of the network to provide adequate pressure monitoring of the network, thereby ensuring capacity and supply requirements can continue to be met for our customers.

Untreated risk	As per risk matrix = **High**
Options considered	• **Option 1** – Continue the current DRS telemetering program and install new pressure monitoring points. This includes: • installing pressure monitoring on the remaining five DRSs; and

	- installing SCADA equipment on assets at 13 strategic sites in high demand areas at the fringes of our networks ($0.4 million) - **Option 2** – Continue the current DRS telemetering program and monitor pressure at the fringes of our networks using temporary solutions ($0.2 million)
Proposed solution	Option 1 is the proposed solution because: - it significantly reduces the safety and supply risks associated with inadequate remote pressure monitoring at the lowest sustainable cost; - the solution aligns with AS 4645 and good industry practice for network monitoring; and - it provides information for use in network modelling to inform investment decisions in relation to potential augmentation and expansion projects.
Estimated cost	The forecast direct capital cost (excluding overhead) for the next AA period (July 2021 to June 2026) is $0.4 million.
Basis of costs	All costs in this business case are expressed in real unescalated dollars at December 2019 unless otherwise stated. Some tables may not add due to rounding.
Alignment to our vision	This project aligns with to the Delivering for Customers aspect of our vision. It delivers for customers by mitigating the risk to public health and safety, as well as promoting security and reliability of gas supply. It also links to the Sustainably Cost Efficient aspect of our vision. Installing pressure monitoring telemetry equipment at the remaining 5 DRSs and in high demand areas at the fringes of our networks is consistent with good industry practice and is the most cost-effective solution to address the safety and supply risks that result from having insufficient real time information about the operation and performance of our network assets.
Consistency with the National Gas Rules (NGR)	This project complies with the following National Gas Rules (NGR): **NGR 79(1)** – the proposed solution is consistent with good industry practice, several practicable options have been considered, and market rates have been tested to achieve the lowest sustainable cost of providing this service. **NGR 79(2)** – proposed capex is justifiable under NGR 79(2)(c)(i) and(ii), as it is necessary to maintain the safety and integrity of network services. **NGR 74** – the forecast costs are based on the latest market rate testing and project options consider the asset management requirements as per the Strategic Asset Management Plan. The estimate has therefore been arrived at on a reasonable basis and represents the best estimate possible in the circumstances.
Treated risk	As per risk matrix = **Low**
Stakeholder engagement	We are committed to operating our networks in a manner that is consistent with the long-term interests of our customers. To facilitate this, we conduct regular stakeholder engagement to understand and respond to the priorities of our customers and stakeholders. Feedback from stakeholders is built into our asset management considerations and is an important input when developing and reviewing our expenditure programs. Our customers have told us their top three priorities are price/affordability, reliability of supply, and maintaining public safety. They also told us they expect us to deliver a high level of public safety and are satisfied that this is current practice. The proposed completion of our DRS telemetering program and installation of telemetry equipment on assets at 13 strategic sites in high demand areas at the fringes of our networks will ensure we can monitor pressure on those assets in real time to maintain reliability of supply at the lowest sustainable cost, minimising the impact on customers' gas bills.

$'000 2019/20	21/22	22/23	23/24	24/25	25/26	Total
Additional pressure monitoring	166.9	90.2	90.2	54.1	-	401.4

Other relevant documents	• Attachment 8.2 Strategic Asset Management Plan

1.3 Background

The South Australia (SA) natural gas distribution networks include approximately 200 km of metropolitan steel transmission pressure (TP) pipelines and 8,000 km of distribution pipelines, which deliver gas to over 450,000 customers.

Section 6.3 of AS 4645 requires us to effectively monitor network pressure to ensure minimum supply arrangements are maintained and the maximum allowable operating pressure (MAOP) of the network is not exceeded. We fulfil this by monitoring pressure in our network in real time via our SCADA system. This is a key part of our management and operation of the network, monitoring of network performance, and thereby manage a variety of costs and risks.

Installing SCADA equipment across our network is critical to:

- provide real time monitoring of pressure to provide a "health" check of assets allowing timely diagnosis and rectification of equipment performance issues before problems arise;
- provide real time monitoring of the network to identify network issues early, such as over/under pressurisation which is increasingly important in our ageing network and allows lower cost proactive repairs to occur;
- allow the effective and efficient response to asset failures and the associated potential emergency events from early warning (alarms) of potential loss of supply in the event of equipment malfunction or third party damage;
- improve safety for operational staff by reducing the need for operators to work in a confined space environment for assets located in underground pits;
- provide for real time and optimum network pressure control, which will assist in minimising unaccounted for gas losses and optimising network pressures depending on season and demand conditions;
- facilitate efficient and prudent network modelling that:
  - helps us safely and reliably operate the network in real time; and
  - inform investment decisions, in particular, assist in producing optimum network augmentation designs including pressure control facilities; and
- provide for a more cost effective and responsive monitoring solution by eliminating the need to undertake periodic data logging at fringe points and manual processing of this data.

We have reviewed the operation of pressure monitoring across the network and consider there is an opportunity to:

- **Complete the proactive installation of SCADA equipment on all DRSs** - In 2012, we commenced a program to install telemetering on all of our District Regulator Stations (DRS). By the end of the current AA period, we will have pressure monitoring on 86 of our 91 DRSs. This will leave five DRSs without SCADA equipment.

- Install SCADA equipment at 13 strategic sites at the fringes of our networks - As the network continues to grow, we periodically reassess the need for pressure monitoring at sites across the network. A recent review identified 13 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 (e.g. areas of significant infill, and new developments and estates);
  - in areas of the network where augmentation has been undertaken as part of the mains replacement program in the current AA period, and is likely to be required in the near future (including for example reconfiguration of the network);
  - in significant areas of the network or at network supply points where there is no remote monitoring capability (e.g. large country towns); and
  - where there is considerable distance between the area and DRS 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.

1.4 Risk assessment

Figure 1.1: Risk management principles

Risk management is a constant cycle of identification, analysis, treatment, monitoring, reporting and then back to identification (as illustrated in Figure 1.1). When considering risk and determining the appropriate mitigation activities, we seek to balance the risk outcome with our delivery capabilities and cost implications. Consistent with stakeholder expectations, safety and reliability of supply are our highest priorities.

Our risk assessment approach focuses on understanding the potential severity of failure events associated with each asset and the likelihood that the event will occur. Based on these two key inputs, the risk assessment and derived risk rating then guides the actions required to reduce or manage the risk to an acceptable level.

When assessing risk for the purpose of investment decisions, rather than analysing all conceivable risks associated with an asset, we look at a credible, primary risk event to test the level of investment required. Where that credible risk event results in a risk event rated moderate or higher, we will consider investment to reduce the risk.

Our risk management framework is based on:

- AS/NZS ISO 31000 Risk Management – Principles and Guidelines;
- AS 2885 Pipelines-Gas and Liquid Petroleum; and
- AS/NZS 4645 Gas Distribution Network Management.

The Gas Act 1997 and Gas Regulations 2012, through their incorporation of AS/NZS 4645 and the Work Health and Safety Act 2012, place a regulatory obligation and requirement on us to reduce risks rated high or extreme to low or negligible as soon as possible (immediately if extreme). If it is not possible to reduce the risk to low or negligible, then we must reduce the risk to as low as reasonably practicable (ALARP).

When assessing risk for the purpose of investment decisions, rather than analysing all conceivable risks associated with an asset, we look at a credible, primary risk event to test the level of investment required. Where that credible risk event has an overall risk rating of moderate or higher, we will undertake investment to reduce the risk.

Seven consequence categories are considered for each type of risk:

1. **Health & safety** – injuries or illness of a temporary or permanent nature, or death, to employees and contractors or members of the public
2. **Environment** (including heritage) – impact on the surroundings in which the asset operates, including natural, built and Aboriginal cultural heritage, soil, water, vegetation, fauna, air and their interrelationships
3. **Operational capability** – disruption in the daily operations and/or the provision of services/supply, impacting customers
4. **People** – impact on engagement, capability or size of our workforce
5. **Compliance** – the impact from non-compliance with operating licences, legal, regulatory, contractual obligations, debt financing covenants or reporting / disclosure requirements
6. **Reputation & customer** – impact on stakeholders' opinion of AGN, including personnel, customers, investors, security holders, regulators and the community
7. **Financial** – financial impact on AGN, measured on a cumulative basis

A summary of our risk management framework, including definitions, has been provided in Attachment 8.10.

The primary risk associated with insufficient remote telemetry on our network is the extended response times resulting in an undetected asset failure which has the potential to result in a significant uncontrolled gas escape, resulting in fatality or permanent injury and/or loss of supply to >10,000 customers.

The untreated risk[58] rating is presented in Table 1.3.

Table 1.3: Risk assessment – untreated risk

Untreated risk	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Major	Minimal	Major	Minor	Minor	Minor	Minor	
Risk Level	High	Negligible	High	Low	Low	Low	Low	

1.5 Options considered

We have identified the following options to address the risks associated with insufficient remote telemetry on our network:

- **Option 1** – Continue the current DRS telemetering program and install new pressure monitoring points. This includes:
  - installing pressure monitoring on the remaining five DRSs; and

[58] Untreated risk is the risk level assuming there are no risk controls currently in place. Also known as the 'absolute risk'.

  - installing new pressure monitoring points on assets at 13 strategic sites in high demand areas at the fringes of our networks; or

- **Option 2** – Continue the current DRS telemetering program and monitor pressure at the fringes of our networks using temporary solutions.

These options are discussed in the following sections.

1.5.1 Option 1 – Continue the current DRS telemetering program and install new pressure monitoring points

Under Option 2, we would continue the current DRS telemetering program and install new pressure monitoring points at strategic sites at the fringes of our networks.

The continuation of our proactive installation of SCADA on our DRSs will involve installing pressure monitoring on the remaining five DRSs in West Beach, Edinburgh, Bedford Park, Glandore and Mile End South.

We will install new SCADA equipment on assets at the fringe of our network in 13 strategic sites. Of these, 11 are on the high pressure network, and the other two are medium pressure. More information on the proposed pressure monitoring sites considered is provided at Appendix A.

1.5.1.1 Cost assessment

The estimated capital cost of this option is $0.4 million. This estimate is based on current material and labour rates.

We will prioritise the five remaining DRSs in 2021/22 to complete the current DRS telemetering program, then move the resources to deliver the 13 strategic sites over the remainder of the next AA period.

Table 1.4 provides a breakdown of costs.

Table 1.4: Cost estimate – Option 1 $'000 2019/20

	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Labour	84.9	52.3	52.3	31.4	-	220.9
Materials	82.0	37.9	37.9	22.7	-	180.5
Total	**166.9**	**90.2**	**90.2**	**54.1**	**-**	**401.4**

Further information on the cost estimate is provided at Appendix C.

This option is consistent with our risk management framework and our vision objectives as discussed in the following sections.

1.5.1.2 Risk assessment

Option 1 reduces the risk from high to low. This is because having remote SCADA pressure monitoring equipment at all DRSs and the 13 key sites identified as the highest risk reduces the likelihood and consequence of a:

- supply risk event from unlikely and major to remote and significant; and
- safety risk from unlikely and major to remote and minor.

This is because the additional remote monitoring SCADA equipment will provide adequate real-time pressure monitoring across the network ensuring no delays in addressing issues as they arise.

This option is consistent with our Strategic Asset Management Plan and risk management framework.

The risk assessment is shown in Table 1.5.

Table 1.5: Risk assessment – Option 1

Option 1	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Remote	Remote	Remote	Remote	Remote	Remote	Remote	Low
Consequence	Minor	Minimal	Significant	Minor	Minor	Minor	Minor	
Risk Level	Negligible	Negligible	Low	Negligible	Negligible	Negligible	Negligible	

1.5.1.3 Alignment with vision objectives

Table 1.6 shows how this option aligns with our vision objectives.

Table 1.6: Alignment with vision – Option 1

Vision objective	Alignment
Delivering for Customers – Public Safety	Y
Delivering for Customers – Reliability	Y
Delivering for Customers – Customer Service	-
A Good Employer – Health and Safety	Y
A Good Employer – Employee Engagement	-
A Good Employer – Skills Development	-
Sustainably Cost Efficient – Working within Industry Benchmarks	Y
Sustainably Cost Efficient – Delivering Profitable Growth	-
Sustainably Cost Efficient – Environmentally and Socially Responsible	Y

Option 1 would align with the *Delivering for Customers* aspect of our vision, as installing additional pressure monitoring equipment helps prevent, identify and address network issues that may result in a loss of containment or loss of customer supply.

The proposed solution is also *Sustainably Cost Efficient,* as the benefits for long term asset management and the avoidance of short term reactive work significantly outweigh the investment.

1.5.2 Option 2 – Continue the current DRS telemetering program and monitor pressure at the fringes of our networks using temporary solutions

Under Option 2, we would continue the current DRS telemetering program and monitor the pressure at the fringe of our networks using temporary data loggers.

The continuation of our proactive installation of SCADA on our DRSs will involve installing pressure monitoring on the remaining five DRSs in West Beach, Edinburgh, Bedford Park, Glandore and Mile End South.

We will continue the current program of installing temporary data loggers at network fringe points when a poor pressure problem is identified. This approach is a reactive program that does not provide real time notification of when pressures fall below minimum levels.

1.5.2.1 Cost assessment

The estimated capital cost of this option is $0.2 million. This estimate is based on current material and labour rates. We will prioritise the five remaining DRSs in 2021/22 to complete the current DRS telemetering program.

Table 1.7 provides a breakdown of costs.

Table 1.7: Cost estimate – Option 2 $'000 2019/20

	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Labour	84.9	-	-	-	-	84.9
Materials	82.0	-	-	-	-	82.0
Total	**166.9**	**-**	**-**	**-**	**-**	**166.9**

There is no upfront capital expenditure related to pressure monitoring of the identified strategic, fringe of network sites included in this business case. However, we will continue to incur the following costs:

- Ongoing operational costs by means of a reactive program of installing temporary data loggers at network fringe points when customer complaints are received or to investigate network performance during peak times.
- Processing of data logger data into electronic systems, and reactive augmentation planning to provide quick-fix solutions.
- Supply outages or restrictions to groups of consumers resulting from unidentified areas where pressures are below the minimum.
- Operational costs associated with less efficiently planning and completing augmentation projects.

This option is inconsistent with our risk management framework and our vision objectives as discussed in the following sections.

1.5.2.2 Risk assessment

Option 2 reduces the risk from high to moderate. Installing pressure monitoring on all remaining DRSs reduces the consequence of safety and supply risk events from major to significant.

The installation of SCADA equipment at each of our DRSs will provide some visibility in real time of pressure in the network, meaning that any asset failure or pressure event will be downstream of the DRS, minimising the potential consequence of a safety or supply event.

It does not, however, reduce the likelihood of pressure events downstream of the DRS in fringe of network areas. It is therefore not consistent with our Strategic Asset Management Plan or risk management framework which requires risk to be reduced to low or ALARP.

The risk assessment is shown in Table 1.8.

Table 1.8: Risk assessment – Option 2

Option 2	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Moderate
Consequence	Significant	Minimal	Significant	Minor	Minor	Minor	Minor	
Risk Level	Moderate	Negligible	Moderate	Low	Low	Low	Low	

1.5.2.3 Alignment with vision objectives

Table 1.9 shows how Option 2 aligns with our vision objectives.

Table 1.9: Alignment with vision – Option 2

Vision objective	Alignment
Delivering for Customers – Public Safety	N
Delivering for Customers – Reliability	N
Delivering for Customers – Customer Service	-
A Good Employer – Health and Safety	N
A Good Employer – Employee Engagement	-
A Good Employer – Skills Development	-
Sustainably Cost Efficient – Working within Industry Benchmarks	N
Sustainably Cost Efficient – Delivering Profitable Growth	-
Sustainably Cost Efficient – Environmentally and Socially Responsible	-

Option 2 would not align with our objective of *Delivering for Customers*, as it would not address the risks of extended response times due to lack of sufficient remote telemetry resulting in an undetected asset failure, which could lead to a significant uncontrolled gas escape, resulting in a safety event and/or loss of supply.

Option 2 would not align with our objective of *Sustainably Cost Efficient*. We would not mitigate shorter term reactive costs that will cost more than a planned proactive approach.

1.6 Summary of costs and benefits

Table 1.10 presents a summary of how each option compares in terms of the estimated cost, the residual risk rating, and alignment with our objectives.

Table 1.10: Comparison of options

Option	Estimated cost ($ million)	Treated residual risk rating	Alignment with vision objectives
Option 1	0.4	Negligible	Aligns with *Delivering for Customers* and *Sustainably Cost Efficient*
Option 2	0.2	Moderate	Does not align with Delivering for Customers, or *Sustainably Cost Efficient* Not ALARP

1.7 Recommended option

Option 1 is the recommended solution. We consider completing the current DRS telemetry program and installing remote pressure monitoring at 13 strategic, fringe of network sites is a cost efficient and prudent risk treatment.

1.7.1 Why is the recommended option prudent?

Option 1 is the most prudent option because it is the most cost efficient option of reducing risks to an acceptable level, consistent with stakeholder requirements and our vision, as it provides real time monitoring of pressure to:

- allow the effective and efficient response to asset failures and the associated potential emergency events from early warning (alarms) of potential loss of supply in the event of equipment malfunction or third party damage;
- provide a "health" check of assets allowing timely diagnosis and rectification of equipment performance issues before problems arise;
- identify network issues early, such as over/under pressurisation which is increasingly important in our ageing network and allows lower cost proactive repairs to occur;
- improve safety for operational staff by reducing the need for operators to work in a confined space environment for assets located in underground pits;
- provide for real time and optimum network pressure control, which will assist in minimising unaccounted for gas losses and optimising network pressures depending on season and demand conditions;
- facilitate efficient and prudent network modelling that:
  - helps us safely and reliably operate the network in real time; and
  - inform investment decisions, in particular, assist in producing optimum network augmentation designs including pressure control facilities; and
- provide for a more cost effective and responsive monitoring solution by eliminating the need to undertake periodic data logging at fringe points and manual processing of this data.

1.7.2 Estimating efficient costs

Key assumptions made in the cost estimation for this project include:

- cost based on historical expenditure noting that these works are not new, with labour rates based on work breakdown structure of activities, and material rates based on historical costs for similar materials;
- estimates derived from contractual rates of vendors to be utilised;
- resource cost based on other similar projects ongoing at present or in previous AA periods; and
- original equipment manufacturer contractual rates for spares and labour that are part of our services agreements.

Table 1.11 presents a breakdown of the program by cost category. Table 1.12 provides the costs escalated to June 2021 dollars.

Table 1.11: Project cost estimate by cost category, real $'000 2019/20

	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Scope	Install SCADA at [redacted] DRS	Install SCADA at [redacted]	Install SCADA at [redacted]	Install SCADA at [redacted]		Install SCADA at [redacted] DRSs and [redacted] strategic sites

	2021/22	2022/23	2023/24	2024/25	2025/26	Total
		strategic sites	strategic sites	strategic sites		
Labour	84.9	52.3	52.3	31.4	-	220.9
Materials	82.0	37.9	37.9	22.7	-	180.5
Total	**166.9**	**90.2**	**90.2**	**54.1**	**-**	**401.4**

Table 1.12: Escalated project cost estimate ($'000)

	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Total unescalated ($ Dec 19)	166.9	90.2	90.2	54.1	-	401.4
Escalation	5.6	3.5	4.0	2.7	-	15.9
Total escalated ($ Jun 21)	**172.5**	**93.7**	**94.2**	**56.8**	**-**	**417.3**

More detail on the cost breakdown is provided in Appendix C.

1.7.3 Consistency with the National Gas Rules

In developing these forecasts, we have had regard to Rule 79 and Rule 74 of the NGR. With regard to all projects, and as a prudent asset manager, we give careful consideration to whether capex is conforming from a number of perspectives before committing to capital investment.

NGR 79(1)

The proposed solution is prudent, efficient, consistent with accepted and good industry practice and will achieve the lowest sustainable cost of delivering network services:

- **Prudent** – The expenditure is necessary in order to allow the effective and efficient response to asset failures and the associated potential emergency events from early warning (alarms) of potential loss of supply in the event of equipment malfunction or third party damage. Failure to address provide effective real-time telemetry at DRSs and fringe of network sites could result in leakage or isolation of a larger than necessary section of network in an emergency situation, therefore increasing the number of customers cut off from supply. The proposed expenditure is therefore consistent with that which would be incurred by a prudent service provider.

- **Efficient** – Installation of SCADA equipment at the identified locations is the most cost effective option. Costs have been based on market rates and where contractors are engaged, this will be based on a competitive process. The expenditure is therefore consistent with what a prudent service provider acting efficiently would incur.

- **Consistent with accepted and good industry practice** – Proactive telemetering is consistent with good industry practice. Reducing the risks posed by asset failures and the associated potential emergency events in a manner that balances costs and risks is also consistent with these standards.

- To **achieve the lowest sustainable cost of delivering pipeline services** –Proactive telemetering is necessary to maintain the long term integrity of the network. Failure to do so could result in additional expenditure (reactive response to pipeline or network failure). The project is therefore consistent with the objective of achieving the lowest sustainable cost of delivering services.

NGR 79(2)

The proposed capex is justifiable under NGR 79(2)(c)(i) and(ii), as it is necessary to maintain the safety and integrity of network services. A more reactive approach will inevitably lead to disruption of service and gas supply to customers.

NGR 74

The forecast costs are based on the latest market rate testing and project options consider asset management requirements as per the Strategic Asset Management Plan. The estimate has therefore been arrived at on a reasonable basis and represents the best estimate possible in the circumstances.

Appendix A – Summary of proposed pressure monitoring sites

Location	Site type	Pressure regime	Suburb
Frank St	New site	Medium pressure	Brooklyn Park
Curtis Rd	New site	High pressure	Andrews Farm
Elizabeth Way	New site	High pressure	Elizabeth
Lower North East Rd	New site	Medium pressure	Highbury
Washington Drive	New site	High pressure	Mildura
Pelham near corner of Senate Rd	New site	High pressure	Pt Pirie
Hanson St near corner of Daly Ave	New site	High pressure	Freeling
Roper Rd	New site	High pressure	Murray Bridge
Alfred Rd	New site	High pressure	Virginia
Torrens Ave	New site	High pressure	Lockleys
MacInerney Ave	New site	High pressure	Mitchell Park
Semaphore Rd	New site	High pressure	Semaphore
Gawler Rd	New site	High pressure	Two Wells
Tapleys Hill Rd	DRS R145	Transmission / High pressure	West Beach
Purling Ave	DRS R210	Transmission / High pressure	Edinburgh
Marion Rd	DRS R332	Transmission / High pressure	Bedford Park
Churchill Ave	DRS 402	Transmission / Medium pressure	Glandore
London Rd	DRS R404	Transmission / Medium pressure	Mile End South

Appendix B – Comparison of risk assessments for each option

Untreated	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Major	Minimal	Major	Minor	Minor	Minor	Minor	
Risk Level	High	Negligible	High	Low	Low	Low	Low	

Option 1	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Remote	Remote	Remote	Remote	Remote	Remote	Remote	Low
Consequence	Minor	Minimal	Significant	Minor	Minor	Minor	Minor	
Risk Level	Negligible	Negligible	Low	Negligible	Negligible	Negligible	Negligible	

Option 2	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Moderate
Consequence	Significant	Minimal	Significant	Minor	Minor	Minor	Minor	
Risk Level	Moderate	Negligible	Moderate	Low	Low	Low	Low	

Appendix C – Cost estimates

Installing new telemetry on DRS						
Category	**Description**	**Units**	**QTY**	**Number of Sites**	**Unit Cost ($ea)**	**Total $'000**
Materials						
	Telemetry equipment	each	[redacted]	[redacted]	[redacted]	[redacted]
	Solar panels	each	[redacted]	[redacted]	[redacted]	[redacted]
	Freight, storage and handling	each	[redacted]	[redacted]	[redacted]	[redacted]
Total materials					[redacted]	**82.0**
Labour						
	Project manager	hours	[redacted]	[redacted]	[redacted]	[redacted]
	Electrical and Instrumentation Engineer	hours	[redacted]	[redacted]	[redacted]	[redacted]
	Draftsperson	hours	[redacted]	[redacted]	[redacted]	[redacted]
	2 x Electrical and Instrumentation technician (incl. vehicle)	hours	[redacted]	[redacted]	[redacted]	[redacted]
	Vac Truck - Contractor	hours	[redacted]	[redacted]	[redacted]	[redacted]
	Reinstatement (150mm concrete)	sqm	[redacted]	[redacted]	[redacted]	[redacted]
Total labour					[redacted]	**84.9**
Total project					[redacted]	**166.9**

Installing New Pressure Monitoring Point						
Category	**Description**	**Units**	**QTY**	**Number of Sites**	**Unit Cost ($ea)**	**Total $'000**
Materials						
	Telemetry equipment	each	[redacted]	[redacted]	[redacted]	[redacted]
	Solar panels	each	[redacted]	[redacted]	[redacted]	[redacted]
	Freight, storage and handling	each	[redacted]	[redacted]	[redacted]	[redacted]
Total materials					[redacted]	**98.5**
	Project manager	hours	[redacted]	[redacted]	[redacted]	[redacted]
	Electrical and Instrumentation Engineer	hours	[redacted]	[redacted]	[redacted]	[redacted]
	Draftsperson	hours	[redacted]	[redacted]	[redacted]	[redacted]
	2 x Electrical and Instrumentation technician (incl. vehicle)	hours	[redacted]	[redacted]	[redacted]	[redacted]
	Vac Truck - Contractor	hours	[redacted]	[redacted]	[redacted]	[redacted]
	Reinstatement (150mm concrete)	sqm	[redacted]	[redacted]	[redacted]	[redacted]
Total labour					[redacted]	**136.0**
Total project					[redacted]	**234.5**

SA112 – Cathodic protection asset replacement

1.1 Project approvals

Table 1.1: Business case SA112 – Project approvals

Prepared by	Peiman Vakili, Gas Networks and Pipeline Engineer, APA
Reviewed by	Robin Gray, SA Operations Manager, APA
Approved by	Craig Bonar, Head of Engineering and Planning, APA Mark Beech, General Manager Network Operations, AGN

1.2 Project overview

Table 1.2: Business case SA112 – Project overview

Description of the problem / opportunity	The South Australia (SA) natural gas distribution networks include approximately 200 km of metropolitan steel transmission pressure (TP) pipelines and 200 km of steel distribution pipelines, which deliver gas to over 450,000 customers. 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. This business case considers options for replacing these CP assets.
Untreated risk	As per risk matrix = **High**
Options considered	**Option 1** – Replace end of life assets with an optimised ICCP and anode combination ($1.7 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 3 existing end of life ICCP units with 3 new ICCP units. **Option 2** – Replace end of life assets on a like for like basis ($2.7 million). This comprises: • replacing the 696 existing depleted anodes with 696 new anodes; • replacing the 3 existing end of life ICCP units with 3 x new ICCP units; and • A third option of not replacing depleted anodes or end of life ICCP units was considered. However, this approach is not prudent nor credible due to the high safety risks associated with pipeline corrosion and non-compliance to governing Australian Standards AS 2885 and AS/NZS 4645.
Proposed solution	**Option 1** is the proposed solution because: • it reduces the risks associated with corrosion of steel mains at the lowest sustainable cost; • the solution aligns with industry practice for pipelines; and • it significantly reduces the risk of accelerated corrosion and incidents on assets that are already 30 to 40 years old.

Estimated cost	The forecast direct capital cost (excluding overhead) during the next access arrangement (AA) period (July 2021 to June 2026) is $1.7 million. **$'000 2019/20** | **21/22** | **22/23** | **23/24** | **24/25** | **25/26** | **Total** CP asset replacement | 330.5 | 330.5 | 330.5 | 330.5 | 330.5 | 1,652.3
Basis of costs	All costs in this business case are expressed in real unescalated dollars at December 2019 unless otherwise stated. Some tables may not add due to rounding.
Alignment to our vision	This project aligns with to the *Delivering for Customers* aspect of our vision. It delivers for customers by mitigating the risk to public health & safety, as well as promoting security and reliability of gas supply. It also links to the *Sustainably Cost Efficient* aspect of our vision. Installing ICCP units in place of sacrificial anodes (where practicable) is the most cost-effective solution to this issue.
Consistency with the National Gas Rules (NGR)	**NGR 79(1)** – the proposed solution is consistent with good industry practice, several practicable options have been considered, and market rates have been tested to achieve the lowest sustainable cost of providing this service. **NGR 79(2)** – proposed capex is justifiable under NGR 79(2)(c)(i) and (ii), as it is necessary to maintain the safety and integrity of pipeline services. **NGR 74** – the forecast costs are based on the latest market rate testing and project options consider the asset management requirements as per the Strategic Asset Management Plan. The estimate has therefore been arrived at on a reasonable basis and represents the best estimate possible in the circumstances.
Treated risk	As per risk matrix = **Moderate**
Stakeholder engagement	We are committed to operating our networks in a manner that is consistent with the long-term interests of our customers. To facilitate this, we conduct regular stakeholder engagement to understand and respond to the priorities of our customers and stakeholders. Feedback from stakeholders is built into our asset management considerations and is an important input when developing and reviewing our expenditure programs. Our customers have told us their top three priorities are price/affordability, reliability of supply, and maintaining public safety. They also told us they expect us to deliver a high level of public safety and are satisfied that this is current practice. The proposed ICCP and anode bag installation solution results in lower short-term capital investment as well as longer term cost savings compared to a like for like replacement project. Proactively installing cathodic protection helps address the public safety risk and is therefore consistent with the current safety practices customers have told us they value. Undertaking the proposed program will also help maintain reliability of supply at the lowest sustainable cost, minimising the impact on customers' gas bills.
Other relevant documents	• Attachment 8.2 Strategic Asset Management Plan

1.3 Background

The SA natural gas distribution networks include approximately 200 km of metropolitan steel transmission pipelines and 8,000 km of distribution pipelines, which deliver gas to over 450,000 customers.

AS 2885.1:2018 specifies that where corrosion could affect the integrity of the pipeline system during its life, the pipeline system shall have appropriate corrosion mitigation methods implemented. Corrosion mitigation methods on buried pipelines shall be by two independent methods, pipeline coatings and cathodic protection (CP). It is critical the transmission pipeline system is protected by appropriate CP assets that are still functional and have not exceeded their operational life.

Similarly for the distribution steel mains AS 4645.2:2018 clause 3.10 specifies that where steel pipelines are buried, a CP system should be designed, documented and implemented to mitigate corrosion risk on the steel pipelines. A lack of functional anodes and ICCP units may increase the risk of corrosion, leading to integrity in the distribution network. It is critical that CP on distribution steel mains remains functional and compliant with Australian standards

CP is installed on the majority of our transmission and distribution steel pipelines. CP uses the electrical properties of the steel pipes to provide a system for the protection of the buried pipes against corrosion and extending their operational life. The CP system creates an electrical circuit with a steel pipeline and an anodic material whereby the anode corrodes in favour to the pipeline. The anode is then replaced upon depletion.

Two types of CP are used in the Adelaide metropolitan gas network; galvanic sacrificial anodes and ICCP. The metropolitan gas distribution network contains 2,405 sacrificial anodes and 13 ICCP units. Refer to Appendix A for a list of CP assets.

1.3.1 Impressed current cathodic protection (ICCP)

ICCP units provide the most cost-effective long term means of corrosion protection. However, there are limitations on where ICCP units can be installed.

The key difference between ICCP units and sacrificial anodes is that an ICCP system uses an external power source with inert anodes, whereas sacrificial anodes use the naturally occurring electrochemical potential difference between the anode and the steel pipeline to provide protection. The dependence on an external power supply, combined with the need for anodes to be relatively close to each other to form a circuit, means ICCP systems can only be installed on certain pipeline configurations and locations.

An ICCP system typically provides anodes of a much longer life span than a galvanic sacrificial system. ICCP units include a rectifier that converts the alternating current power source to a direct current that is calibrated to provide the required protection. Since the power source is delivered to the anode and is not generated by anode degradation, the power supply may be recalibrated to provide additional power, provided the electrodes are still functional. Therefore, our preference is to install ICCP units in favour of sacrificial anodes where practicable.

Of the 13 ICCP units currently installed in the network, three ICCP units are expected to reach the end of operational life in the next five years and require complete replacement. In addition to these three depleted ICCP units, we have identified seven other areas of the network where it may be more cost effective to install ICCP units instead of sacrificial anodes.

1.3.2 Sacrificial anodes

Sacrificial anodes are installed on the pipe using a welded coupon and are connected to an inspection station (test post) installed near the surface of the ground. Galvanic anode systems have a limited life span during which the sacrificial anode will continue to degrade and protect the pipe. When the sacrificial anode is depleted it will no longer protect the pipe and corrosion can occur at an accelerated rate. The life of a sacrificial anode is typically 10 to 15 years.

Recent CP surveys have highlighted areas of distribution mains where pipelines are no longer subject to CP due to depleted sacrificial anodes. These survey results, combined with the age and remaining useful lives of anodes installed in the network, means approximately 696 sacrificial anodes require replacement within the next five years.

Based on the location, pipeline length and spread of the depleted anodes, we estimate 446 of these anodes could be replaced with ICCP units. The remaining 250 can only be replaced with like-for-like anodes.

1.4 Risk assessment

Risk management is a constant cycle of identification, analysis, treatment, monitoring, reporting and then back to identification (as illustrated in Figure 1.1). When considering risk and determining the appropriate mitigation activities, we seek to balance the risk outcome with our delivery capabilities and cost implications. Consistent with stakeholder expectations, safety and reliability of supply are our highest priorities.

Figure 1.1: Risk management principles

Our risk assessment approach focuses on understanding the potential severity of failure events associated with each asset and the likelihood that the event will occur. Based on these two key inputs, the risk assessment and derived risk rating then guides the actions required to reduce or manage the risk to an acceptable level.

AGN's risk management framework is based on:

- AS/NZS ISO 31000 Risk Management – Principles and Guidelines;
- AS 2885 Pipelines-Gas and Liquid Petroleum; and
- AS/NZS 4645 Gas Distribution Network Management.

The Gas Act 1997 and Gas Regulations 2012, through their incorporation of AS/NZS 4645 and the Work Health and Safety Act 2012, place a regulatory obligation and requirement on AGN to reduce risks rated high or extreme to low or negligible as soon as possible (immediately if extreme). If it is not possible to reduce the risk to low or negligible, then we must reduce the risk to as low as reasonably practicable (ALARP).

When assessing risk for the purpose of investment decisions, rather than analysing all conceivable risks associated with an asset, we look at a credible, primary risk event to test the level of investment required. Where that credible risk event has an overall risk rating of moderate or higher, we will undertake investment to reduce the risk.

Seven consequence categories are considered for each type of risk:

1. Health & safety – injuries or illness of a temporary or permanent nature, or death, to employees and contractors or members of the public
2. Environment (including heritage) – impact on the surroundings in which the asset operates, including natural, built and Aboriginal cultural heritage, soil, water, vegetation, fauna, air and their interrelationships
3. Operational capability – disruption in the daily operations and/or the provision of services/supply, impacting customers
4. People – impact on engagement, capability or size of our workforce
5. Compliance – the impact from non-compliance with operating licences, legal, regulatory, contractual obligations, debt financing covenants or reporting / disclosure requirements
6. Reputation & customer – impact on stakeholders' opinion of AGN, including personnel, customers, investors, security holders, regulators and the community
7. Financial – financial impact on AGN, measured on a cumulative basis

A summary of our risk management framework, including definitions, has been provided in Attachment 8.10.

The primary risk associated with depleted sacrificial anodes and ICCP units is that it can lead to accelerated and undetected corrosion, which has the potential to result in a significant uncontrolled gas escape, resulting in fatality or permanent injury and/or loss of supply to >10,000 customers or a demand customer >1 TJ p.a. Untreated, the risk consequence of this event is rated high.

Further, if the CP system is underperforming, we are at risk of non-compliance with the Australian Standards. The reputational risk is therefore rated moderate.

The untreated risk[59] rating is presented in Table 1.3.

Table 1.3: Risk assessment – untreated risk

Untreated risk	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Major	Minor	Major	Minor	Significant	Minor	Minor	
Risk Level	High	Low	High	Low	Moderate	Low	Low	

1.5 Options considered

We have identified the following options to address the risks associated with corrosion detection:

- **Option 1** – Replace end of life assets with an optimised ICCP and anode combination:
  - replace 250 existing depleted anodes by installing 250 new anodes;
  - replace 446 existing depleted anodes by installing 7 x ICCP units; and
  - replace 3 x existing end of life ICCP units with 3 x new ICCP units; or
- **Option 2** – Replace end of life asset on a like-for-like basis:
  - replace 696 existing depleted anodes by installing 696 new anodes; and
  - replace 3 x existing end of life ICCP units with 3 x new ICCP units.

These options are discussed in the following sections.

A third option of not replacing depleted anodes or end of life ICCP units was considered. However this approach was not considered a viable nor credible option due to the extreme safety risks and non-compliance with governing Australian Standards.

1.5.1 Option 1 – Replace end of life assets with an optimised ICCP and anode combination

Under Option 1, we would replace approximately 446 of the depleted galvanic sacrificial anodes with seven ICCP units. ICCP is the preferred method of cathodic protection where it can be deployed, with galvanic sacrificial anodes being a secondary solution where it is not practical to use ICCP. A list of the seven areas where ICCP units would be used in place of sacrificial anodes is provided in Appendix B.

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59 Untreated risk is the risk level assuming there are no risk controls currently in place. Also known as the 'absolute risk'.

For the 250 sacrificial anodes that cannot be replaced with ICCP at this time, the proposal is to replace them with new anodes on a like for like basis.

The 3 x ICCP units that have reached end of life will be replaced with 3 x new ICCP units.

1.5.1.1 Cost assessment

The unit costs are $[redacted] per ICCP unit and $[redacted] per anode. Where possible, if more than 22 anodes exist in one area of the network that can be cathodically connected, it is more cost effective, on an upfront capital basis, to install ICCP[60].

The proposal is to install 250 anode bags and 10 ICCP units, with the estimated direct capital cost of this option being $1.7 million as shown in Table 1.4.

Table 1.4: Cost estimate – Option 1 $'000 2019/20

	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Labour	228.5	228.5	228.5	228.5	228.5	1,142.3
Materials	102.0	102.0	102.0	102.0	102.0	510.0
Total	**330.5**	**330.5**	**330.5**	**330.5**	**330.5**	**1,652.3**

1.5.1.2 Risk assessment

Option 1 reduces the risk from high to moderate. This is because having a functioning CP system reduces the likelihood of a major safety or supply risk evert from unlikely to remote.

Table 1.5: Risk assessment – Option 1

Option 1	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Remote	Remote	Remote	Remote	Remote	Remote	Remote	Moderate
Consequence	Major	Minor	Major	Minor	Minor	Minor	Minor	
Risk Level	Moderate	Negligible	Moderate	Negligible	Negligible	Negligible	Negligible	

The residual risk of moderate is ALARP, as the potential consequences of a safety or operations event on a transmission pipeline would remain major. Having a functioning CP system in place will only reduce the likelihood of the risk event, not the consequence.

Option 1 achieves the same level of risk reduction as Option 2, however it does so at a lower overall cost.

1.5.1.3 Alignment with vision objectives

Table 1.6 shows how Option 1 aligns with our vision objectives.

Table 1.6: Alignment with vision – Option 1

Vision objective	Alignment
Delivering for Customers – Public Safety	Y
Delivering for Customers – Reliability	Y
Delivering for Customers – Customer Service	-

60 [redacted] anode bags x $[redacted] being $[redacted] which is greater than [redacted] x ICCP unit.

Vision objective	Alignment
A Good Employer – Health and Safety	Y
A Good Employer – Employee Engagement	-
A Good Employer – Skills Development	-
Sustainably Cost Efficient – Working within Industry Benchmarks	Y
Sustainably Cost Efficient – Delivering Profitable Growth	-
Sustainably Cost Efficient – Environmentally and Socially Responsible	-

Option 1 would align with the *Delivering for Customers* aspect of our vision, as replacing CP assets helps prevent undetected corrosion that may result in a loss of containment or loss of customer supply.

The proposed solution is also *Sustainably Cost Efficient*, as the benefits for long term asset management and the avoidance of short term reactive work significantly outweigh the investment.

1.5.2 Option 2 – Replace end of life asset on a like for like basis

Under Option 2 we would replace all 696 sacrificial anodes on a like-for-like basis. We would also replace the three end of life ICCP units with new like-for-like units.

1.5.2.1 Cost assessment

The unit costs are $[redacted] per ICCP unit and $[redacted] per anode. The estimated direct capital cost of installing 696 anode bags and three ICCP units is $2.7 million as shown in Table 1.7.

Table 1.7: Cost estimate – Option 2 $'000 2019/20

	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Labour	445.5	442.6	442.6	400.4	400.4	2,131.3
Materials	120.0	120.0	119.4	83.4	84.0	526.2
Total	**565.5**	**562.0**	**562.0**	**483.8**	**484.4**	**2,657.5**

1.5.2.2 Risk assessment

Option 2 reduces the risk from high to moderate. This is because having a functioning CP system reduces the likelihood of a major safety or supply risk evert from unlikely to remote.

Table 1.8: Risk assessment – Option 2

Option 2	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Remote	Remote	Remote	Remote	Remote	Remote	Remote	Moderate
Consequence	Major	Minor	Major	Minor	Minor	Minor	Minor	
Risk Level	Moderate	Negligible	Moderate	Negligible	Negligible	Negligible	Negligible	

Option 2 achieves the same level of risk reduction as Option 1, however it does so at a higher overall cost.

1.5.2.3 Alignment with vision objectives

Table 1.9 shows how Option 2 aligns with our vision objectives.

Table 1.9: Alignment with vision – Option 2

Vision objective	Alignment
Delivering for Customers – Public Safety	Y
Delivering for Customers – Reliability	Y
Delivering for Customers – Customer Service	-
A Good Employer – Health and Safety	Y
A Good Employer – Employee Engagement	-
A Good Employer – Skills Development	-
Sustainably Cost Efficient – Working within Industry Benchmarks	N
Sustainably Cost Efficient – Delivering Profitable Growth	-
Sustainably Cost Efficient – Environmentally and Socially Responsible	-

Similar to Option 1, Option 2 aligns with regards to *Delivering for Customers* aspect of our vision, as the installation of CP systems prevents undetected corrosion that may result in a loss of containment or loss of customer supply.

However, Option 2 does not align with *Sustainably Cost Efficient,* as the upfront capital cost of this solution is significantly more than Option 1. The higher lifecycle cost of anode bags vs ICCP units means this option is also less cost effective on a long term basis.

1.6 Summary of costs and benefits

Table 1.10 presents a summary of how each option compares in terms of the estimated cost, the residual risk rating, and alignment with our objectives.

Table 1.10: Comparison of options

Option	Estimated cost ($ million)	Treated residual risk rating	Alignment with vision objectives
Option 1	1.7	Moderate (ALARP)	Aligns with *Delivering for Customers* and *Sustainably Cost Efficient*
Option 2	2.7	Moderate (ALARP)	Aligns with *Delivering for Customers*, but not Sustainably Cost Efficient

The third option of not replacing depleted anodes or end of life ICCP units was considered. However, this approach was not considered prudent nor credible due to the high safety risks associated with transmission pipeline failure and non-compliance to governing Australian Standards AS 2885 and AS/NZS 4645.

1.7 Recommended option

Option 1 is the recommended solution. We consider installing ICCP units in place of galvanic sacrificial anodes where practicable is a more cost efficient and prudent risk treatment.

1.7.1 Why is the recommended option prudent?

Option 1 provides an acceptable level of risk reduction (ALARP) for the lowest sustainable cost. This solution reduces the risk of corrosion on steel pipelines, which in turn reduces the likelihood of emergency repairs and rising costs associated with having to excavate sections of pipeline where CP is not present.

While Option 2 will achieve the same risk outcome, as Option 1, it does so at a higher overall cost. Our ongoing strategy for CP is to replace sacrificial anodes with ICCP units wherever possible.

This project will be delivered using a combination of internal and external resources. External contractor/s will be engaged through a competitive tender process to perform dig ups of existing anodes and reinstatements. Internal resources will install the anodes and ICCP units and disconnect the existing depleted anodes, as well as manage work initiation, coordination, field supervision and customer liaison.

1.7.2 Estimating efficient costs

The forecast cost breakdown is based on the following assumptions:

- 6 new anodes can be installed to replace existing anodes in one day shift (8 hours);
- material rates for anodes and ICCP units are based on current vendor material rates; and
- labour rates are calculated based on a work breakdown structure approach as there are no historical costs available for reference.

Other considerations include:

- working out of hours on major roads to disconnect obsolete anodes;
- third party permits;
- rewiring;
- larger reinstatements;
- surveyor works; and
- capturing as constructed data for new assets.

Table 1.11 below shows the phasing of the preferred option.

Table 1.11: Cost estimate – Option 1, $'000 2019/20

	2022/23	2023/24	2024/25	2025/26	2026/27	Total
Scope	Install 2 x ICCP Replace 50 anodes	Install 2 x ICCP Replace 50 anodes	Install 2 x ICCP Replace 50 anodes	Install 2 x ICCP Replace 50 anodes	Install 2 x ICCP Replace 50 anodes	Install 10 ICCP units Replace 250 anodes by anodes
Labour	228.5	228.5	228.5	228.5	228.5	1,142.3
Materials	102.0	102.0	102.0	102.0	102.0	510.0
Total	**330.5**	**330.5**	**330.5**	**330.5**	**330.5**	**1,652.3**

Refer to Appendix D for cost breakdown details.

The following table shows the costs escalated to June 2021 dollars.

Table 1.12: Escalated replacement of valves cost estimate ($'000 real 2020/21)

	2022/23	2023/24	2024/25	2025/26	2026/27	Total
Total unescalated ($ Dec 19)	330.5	330.5	330.5	330.5	330.5	1,652.3
Escalation	11.1	12.8	14.8	16.7	18.4	73.9
Total escalated ($ Jun 21)	**341.6**	**343.3**	**345.3**	**347.2**	**348.9**	**1,726.4**

1.7.3 Consistency with the National Gas Rules

In developing these forecasts, we have had regard to Rule 79 and Rule 74 of the NGR. With regard to all projects, and as a prudent asset manager, we give careful consideration to whether capex is conforming from a number of perspectives before committing to capital investment.

NGR 79(1)

The proposed solution is prudent, efficient, consistent with accepted and good industry practice and will achieve the lowest sustainable cost of delivering pipeline services:

- **Prudent** – The expenditure is necessary in order to ensure sufficient corrosion protection of high value high risk assets. Failure to address corrosion risks could result in leakage or isolation of a larger than necessary section of pipeline in an emergency situation, therefore increasing the number of customers cut off from supply. The proposed expenditure is therefore consistent with that which would be incurred by a prudent service provider.

- **Efficient** – Installation of ICCP where possible and the direct replacement of anode bags where ICCP is not practical is the most cost effective option. Costs have been based on market rates and where contractors are engaged, this will be based on a competitive process. The expenditure is therefore consistent with what a prudent service provider acting efficiently would incur.

- **Consistent with accepted and good industry practice** – Proactive corrosion prevention in maintaining transmission pipelines is consistent with Australian Standard AS 2885.3 Pipelines - Gas and Liquid Petroleum, Part 3: Pipeline Integrity Management and AS/NZS 4645 distribution. Reducing the risks posed by corroding transmission pipelines in a manner that balances costs and risks is also consistent with these standards. We therefore consider the proposed capital expenditure is in accordance with accepted good industry practice.

- To **achieve the lowest sustainable cost of delivering pipeline services** –Proactive corrosion prevention measures are necessary to maintain the long term integrity of the pipelines. Failure to do so could result in additional expenditure (reactive response to pipeline failure). The project is therefore consistent with the objective of achieving the lowest sustainable cost of delivering services.

NGR 79(2)

The proposed capex is justifiable under 79(2)(c)(ii), as it is necessary to maintain the integrity of services. A more reactive approach will inevitably lead to disruption of service and gas supply to customers.

NGR 74

The forecast costs are based on the latest market rate testing and project options consider asset management requirements as per the Strategic Asset Management Plan. The estimate has therefore been arrived at on a reasonable basis and represents the best estimate possible in the circumstances.

Appendix A – Summary of existing CP assets

Area	Frequency of CP surveys	No of test points	No of anodes	No of control areas
Minor	12 months	499	511	504
North	6 months	559	738	193
Priority	6 months	290	158	35
Regional	6 months	206	182	56
South	6 months	670	816	211
Total	**N/A**	**2,224**	**2,405**	**999**

ICCP Unit No	Frequency of inspection	Description
TR Unit 10765	6 months	Corner of Greenhill Rd. and Portrush Rd. Linden Park
TR Unit 10177	6 months	Corner of Commercial Rd and John Rice Avenue
TR Unit 30007	6 months	Morrow Rd. O'Sullivans Beach
TR Unit West beach	6 months	10113 Corner Fawnbrake Crescent and Tapleyshill Rd.
TR Unit 30006	6 months	Corner of Duval Drive and States Rd. Morphett Vale
TR Unit 30005	6 months	Tiller Drive, Seaford
TR Unit 30002	6 months	Corner of Flagstaff Rd. and Black Rd. Flagstaff Hill
TR Unit	6 months	Cromwell Road Kilburn
TR Unit 30001	6 months	Corner of Regan Avenue and Morphett Rd. Morphettville
TR Unit 18452	6 months	Corner of Essington Lewis Ave and Hambridge Tce. Whyalla
TR Unit 18451	6 months	Lane between Fisk and Kinnane Ave. Whyalla
TR Unit 18450	6 months	Corner of Wittwer st and Ramsey St. Whyalla
TR Unit 18449	6 months	Corner of Kloeden St. and McDouall Stuart Ave. Whyalla

Appendix B – ICCP units proposed areas

No.	Primary street location	Secondary street location	Suburb
1	Main North Rd	Northside Court	Evanston Gardens
2	Halsey Rd	Blamey Rd	Elizabeth
3	Grenfell Rd	Chardonnay Crescent	Wynn Vale
4	Patapinda Rd	Main South Rd	Noarlunga
5	Burton Rd	Whites Rd	Paralowie
6	Main Rd	Rosella Ave	Glenalta
7	Daws Rd	Goodwood Rd	Pasadena

Appendix C – Comparison of risk assessments for each option

Untreated risk	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Major	Minor	Major	Minor	Significant	Minor	Minor	
Risk Level	High	Low	High	Low	Moderate	Low	Low	

Option 1	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Remote	Remote	Remote	Remote	Remote	Remote	Remote	Moderate
Consequence	Major	Minor	Major	Minor	Minor	Minor	Minor	
Risk Level	Moderate	Negligible	Moderate	Negligible	Negligible	Negligible	Negligible	

Option 2	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Remote	Remote	Remote	Remote	Remote	Remote	Remote	Moderate
Consequence	Major	Minor	Major	Minor	Minor	Minor	Minor	
Risk Level	Moderate	Negligible	Moderate	Negligible	Negligible	Negligible	Negligible	

Appendix D - Cost estimate

Option 1: Replace 250 depleted anodes like-for-like

Category	Description	Units	Units QTY	Number of sites	Unit Cost $/ unit	Total $'000
Materials						
	Anode 10kg zinc / magnesium	each	[redacted]	[redacted]	[redacted]	[redacted]
Total materials						[redacted]
Labour						
It is assumed 4 anodes can be replaced per 1 day shift (8 hrs)						
	Corrosion Engineer	hours	[redacted]	[redacted]	[redacted]	[redacted]
	CP Technician	hours	[redacted]	[redacted]	[redacted]	[redacted]
	Crew (3 ppl incl. team leader)	hours	[redacted]	[redacted]	[redacted]	[redacted]
	Excavator (8T)	hours	[redacted]	[redacted]	[redacted]	[redacted]
	Tipper Truck (8T)	hours	[redacted]	[redacted]	[redacted]	[redacted]
	Vac Truck	hours	[redacted]	[redacted]	[redacted]	[redacted]
	Traffic Control (2 ppl including ute)	hours	[redacted]	[redacted]	[redacted]	[redacted]
	Reinstatement (assuming 5 sqm - footpath and including backfill material and compaction)	Sqm	[redacted]	[redacted]	[redacted]	[redacted]
Total labour						[redacted]
Total cost						[redacted]

Option 2: Install 10 ICCPs (replacing 446 sacrificial anodes and 3 depleted ICCPs)

Category	Description	Units	Units QTY	Number of sites	Unit Cost $/ unit	Total $'000
Materials						
	ICCP Unit (Brodribb 20amp)	each	[redacted]	[redacted]	[redacted]	[redacted]
	RTU and Solar Panel	each	[redacted]	[redacted]	[redacted]	[redacted]
	Material beds (coke breeze)	each	[redacted]	[redacted]	[redacted]	[redacted]
Total materials						[redacted]
Labour						
	Corrosion Engineer	hours	[redacted]	[redacted]	[redacted]	[redacted]
	CP Technician	hours	[redacted]	[redacted]	[redacted]	[redacted]
	Crew (3 ppl incl. team leader)	hours	[redacted]	[redacted]	[redacted]	[redacted]
	Electrical and Instrumentation Engineer	hours	[redacted]	[redacted]	[redacted]	[redacted]
	Excavator (8T)	hours	[redacted]	[redacted]	[redacted]	[redacted]
	Tipper Truck (8T)	hours	[redacted]	[redacted]	[redacted]	[redacted]
	Vac Truck	hours	[redacted]	[redacted]	[redacted]	[redacted]
	Traffic Control (2 ppl including ute)	hours	[redacted]	[redacted]	[redacted]	[redacted]
	SAPN electricity supply	each	[redacted]	[redacted]	[redacted]	[redacted]
	Reinstatement (assuming 10 sqm - 100mm concrete including backfill material and compaction)	sqm	[redacted]	[redacted]	[redacted]	[redacted]
	Rewiring of anodes and work on major roads after hours	each	[redacted]	[redacted]	[redacted]	[redacted]
	Third party permits and after hours on major roads		[redacted]	[redacted]	[redacted]	[redacted]
Total labour						[redacted]
Total costs			[redacted]			[redacted]