Attachment 8.8

Capex business cases – South Australia

SA Final Plan July 2021 – June 2026

July 2020

Part 1: pages 1-102 (SA101, SA103, SA104 & SA105)

Contents

SA101 – Dig up and repair TP pipeline locations with multiple DCVG indications of <15% IR

1.1 Project approvals

Table 1.1: Business case SA101 – Project approvals

Prepared by	Nick Rubbo, Integrity 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 SA101 – Project overview

Description of the problem / opportunity	The South Australia (SA) distribution network includes approximately 200 km of metropolitan transmission pressure (TP) pipelines, which deliver gas to over 450,000 consumers. These steel TP pipelines are prone to corrosion, which if left untreated can lead to pipeline integrity failure and a major uncontrolled gas escape. The consequences of a major uncontrolled gas escape can be severe, as metropolitan TP pipelines are typically located in or near developed areas and major population centres. To help mitigate the corrosion risk, one of the methods we use to manage corrosion is to conduct direct current voltage gradient (DCVG) surveys, which detect faults in pipeline coatings. The DCVG surveys are followed by direct inspection excavations (or 'dig ups') of areas where DCVG indicates the pipeline coating has failed. All 200 km of TP pipeline is surveyed via DCVG every five years. These surveys are conducted in accordance with Australian Standard AS 2885, whereby IR readings[1] above 15% are excavated and treated immediately as part of business as usual process. Pipeline locations with IR readings less than 15% are traditionally deemed low priority and are either not excavated or are deferred until more urgent excavations have been completed. However, over the past five years we found that the size of the IR reading does not necessarily correlate to the amount of corrosion. Excavation of 79 locations originally deemed low priority revealed a very high instance of corrosion. This instance was particularly high (95%) where the location had previously recorded another indication below 15% (i.e. multiple indications). Recent DCVG surveys have identified [redacted] sites where there have been multiple indications over the past 10-15 years even though the IR readings are less than 15%. Traditionally, these sites would have been deemed low priority and not excavated. However, given the frequency of corrosion at prior multiple indication sites, we consider it prudent to excavate, examine (and repair where necessary) these [redacted] additional sites. Note that these [redacted] locations are not currently subject to in-line inspection. This business case proposes these 68 sites be dug up (and repaired as required) in addition to any high priority (>15% IR) identified through the DCVG process. This business case is for the capital costs associated with the 68 multiple indication sites only.
Untreated risk	As per risk matrix = **High**
Options considered	• **Option 1** – Do not conduct dig ups on TP pipelines at locations with an IR reading <15%. Conduct reactive repairs as leaks occur on TP pipelines (no additional upfront capital cost)

1 IR readings are the measure of current flowing from the pipe to the soil.

	• **Option 2** – Dig up and repair the [redacted] TP pipeline locations where multiple indications of IR <15% have been recorded. This work will be conducted over five years ($1.3 million) • **Option 3** – Dig up and repair the [redacted] TP pipeline locations where multiple indications of IR <15% have been recorded. This work will be conducted over ten years ($0.6 million[2])
Proposed solution	Option 2 is the proposed solution. This involves excavating the [redacted] locations where indications have been recorded multiple times. This activity will mitigate the high health and safety, operational and compliance risks associated with corrosion of the TP pipelines. It will also reduce the operational and financial risks of emergency repairs. Option 1 does not mitigate the high health and safety, operational and compliance risks associated with corrosion of the TP pipelines. Option 3 will result in mitigating only half of the found defects in the upcoming access arrangement (AA) period. While this does reduce the risk, residual risk is still considerably higher than Option 2. In addition, repairing only half of the known indications will result in a backlog of excavations. This will create problems in the when DCVG surveys inevitably find more defects as the pipelines age and deteriorate.
Estimated cost	The forecast direct capital cost (excluding overhead) during the next 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
[redacted] multiple indication dig ups	240.1	258.6	258.6	258.6	240.1	1,256.1

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 the Delivering for Customers aspect of our vision. It delivers for customers by mitigating the risk to public health & safety, as well as ensuring 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)(i) and (ii), as it is necessary to maintain the safety and integrity 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. 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.

2 The remaining $628,026 will be incurred in the subsequent five-year period.

	The proposed TP pipeline excavation program is a continuation of the asset safety and integrity program in place in the current AA period and is therefore consistent with the current practice customers have told us they value. Undertaking the proposed excavation 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 TP pipelines, which deliver gas to over 450,000 consumers. The map at Appendix A shows the full TP pipeline network.

The majority of the TP pipelines were constructed prior to 1987, with the two longest and most complex pipelines (M42 and M12) being over 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 biggest risk associated with steel pipelines is corrosion, which can weaken the pipe wall and cause an integrity failure. To mitigate the risk of a TP pipeline integrity failure, the pipelines are coated with corrosion-inhibiting products and subject to a cathodic protection (CP) system, which uses a low voltage electrical current to inhibit the onset of steel corrosion.

Some older sections of pipelines in our gas distribution networks are coated with coal tar enamel (CTE), while newer sections are coated with polyethylene (PE) and fusion bonded epoxy (FBE). Heat shrink sleeves (HSS) have been applied to pipelines of various ages.

AS 2885 requires the integrity of pipeline protective coatings to be assessed using a DCVG survey.[3] A DCVG involves taking surface measurements of the amount of electrical current that is escaping through coating faults into the surrounding soil. The coating fault 'indications' are denoted by an IR reading. The IR reading provides an indication of the size of the coating fault. Depending on the size of the IR reading, the location of the pipeline, CP performance and previous dig up history, the section of pipeline where coating indications have been identified will be excavated and directly examined.

DCVG and dig ups only provide an indication of the pipeline coating condition at a sample of locations where the pipeline steel condition has been assessed. Results must be extrapolated for the remaining sections of the pipeline.

Historically, only defects with IR readings greater than or equal to 15% were deemed high priority and subject to dig up and repair. Defects with readings less than 15% were deemed low priority and not subject to any remediation because it was expected that a small coating defect would be contained by the active corrosion protection system. However, excavations on low priority sites prior to the current AA period uncovered defects where the extent of corrosion was masked by the surrounding coating.

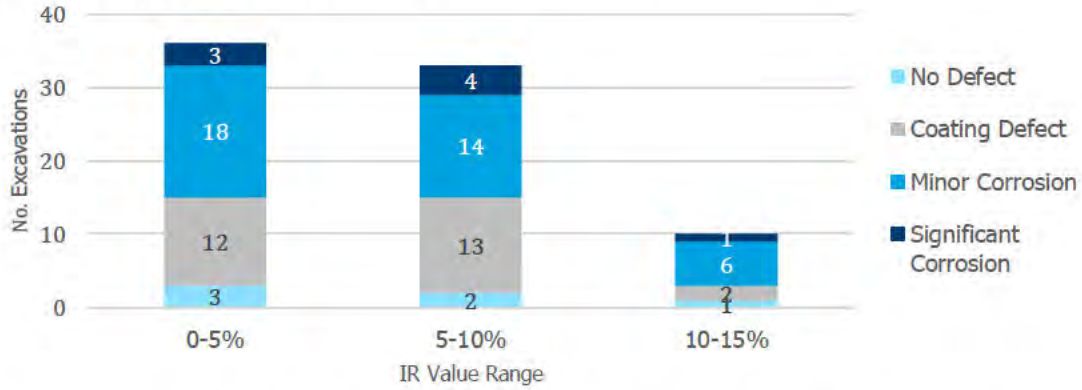
We concluded that the IR reading does not necessarily correlate to the amount of corrosion present. Therefore in 2014 we commenced excavation of locations where the IR reading was <15%.[4]

[3] The prevailing industry standard practice approach for detecting corrosion associated with coating disbonding is to use an inline inspection tool (also known as a pig). However, the TPs in the Adelaide distribution system are currently not piggable.

[4] [redacted] excavations for the current AA period were proposed and approved in business case SA36.

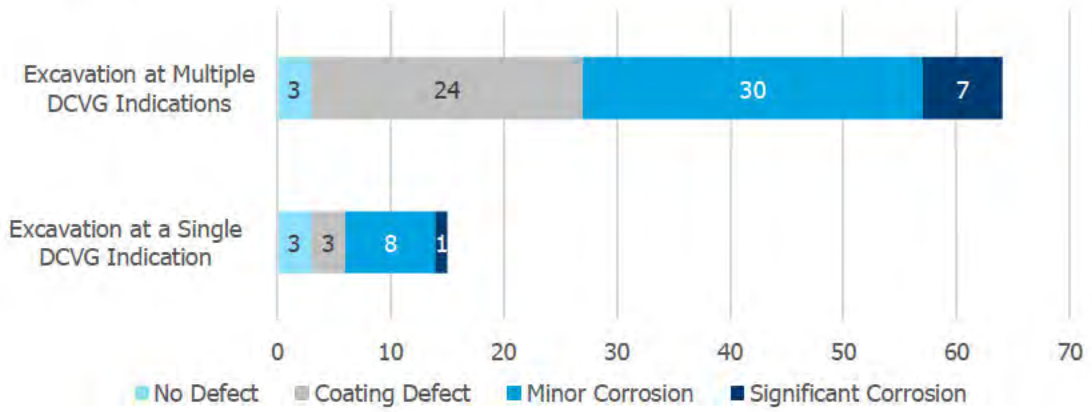
To date we have completed 79 excavations at these IR <15%, locations, including 63 in the current period and 14 in the prior AA period. As shown in Figure 1.1, the majority (92%) of these excavations revealed corrosion or coating defects.

Figure 1.1: TP pipeline DCVG IR value versus excavation result



Of the 79 excavations, the majority (64) of these were conducted at locations where there had been multiple DCVG IR readings below 15% at the same location. This resulted in a high fault detection rate, with 61 of the 64 excavations (95%) revealing a coating defect, as shown in Figure 1.2.

Figure 1.2: TP pipeline DCVG indication IR below 15% single versus multiple DCVG indications at an excavation



One DCVG excavation recently undertaken on [redacted] uncovered significant damage on the pipeline. We believe the damage was caused by an unreported third party asset strike with an auger (refer to Figure 1.3 below). The results of DCVG surveys completed in 2001 and 2012 both indicated IR readings less than 15% at this location. The excavation revealed minor corrosion on the pipeline, however it also identified gouges on the pipe resulting in reduced integrity. The damaged sections of the pipeline were temporarily repaired by the installation of Plidco bolted sleeves. Permanent steel sleeves are planned to be welded over the damaged pipe by the end of February 2020. If this defect was not detected and repaired, over time this could have resulted in a leak requiring isolation and emergency repair. Consequences of this would have included a high risk to the security of supply of around 100,000 consumers and an estimated repair cost of approximately $200,000.

Figure 1.3: Damage on [redacted] detected by DCVG survey and excavation

As per Australian Standard AS 2885, surveys of the whole 200 km of TP pipelines are performed every five years. The surveys performed over the last five years have identified a further [redacted] locations of multiple DCVG indications with IR reading <15%.

The results of DCVG excavations in the current period suggests it is likely that a high proportion of these [redacted] locations of multiple DCVG indications with IR reading <15% will have coating defects or corrosion. If left unchecked, corrosion will eventually cause leaks, posing a risk to the gas supply. The subsequent emergency repair could also result in large scale loss of gas supply and considerable disruption for customers.

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 1.4). 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 1.4: 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 associated with the identified [redacted] multiple DCVG indications is that one or more of these locations could be highly corroded, which if left untreated could 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.

The untreated risk[5] rating is presented in Table 1.3.

Table 1.3: Risk rating – 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	

Depending on the time and location it occurs, an integrity failure at one of these [redacted] locations can adversely affect supply to tens of thousands of customers. Additionally, in the event that an emergency repair is required, a pipeline section may need to be isolated, which can also affect supply to a significant number of customers.

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

In certain circumstances, an uncontrolled gas escape at one of these locations can have major health and safety consequences, leasing to fatality or life threatening injuries. As a result, the untreated risk associated with corrosion at these TP pipeline locations is rated high. The untreated risk also poses a moderate compliance risk, as having insufficient DCVG survey activity could result in non-compliance with our obligations under AS 2885.

1.5 Options considered

The following options have been identified to address the risk associated with potential corrosion where multiple IR readings less than 15% occurring multiple times at a single location:

- **Option 1** – Do not conduct dig ups on TP pipelines at locations with an IR reading <15%. Conduct reactive repairs as leaks occur on TP pipelines;
- **Option 2** – Dig up and repair the [redacted] TP pipeline locations where multiple indications of IR <15% have been recorded. This work will be conducted over five years; or
- **Option 3** – Dig up and repair the [redacted] TP pipeline locations where multiple indications of IR <15% have been recorded. This work will be conducted over ten years.

These options are discussed in the following sections.

We also considered the option of excavating all locations with 'low priority' defects that have only shown a single DCVG indication (i.e. where this is the first instance of an indication at the location). This option has been dismissed because a single DCVG indication has not been found to have the same very high correlation to coating defects and corrosion as multiple indications, and as such this would not be cost effective.

1.5.1 Option 1 – Do not conduct dig ups on TP pipelines at locations with an IR reading <15%.

Do not conduct DCVG excavations on TP pipelines at DCVG indications with an IR reading below 15%. Instead, reactive repairs will be conducted at these locations as leaks occur on TP pipelines. Only DCVG indications with a reading greater than or equal to 15% would be excavated and repaired.

1.5.1.1 Cost assessment

There would be no additional upfront capital costs with this option. However, once corrosion leaks begin to occur:

- extensive and high volume repair of TP pipelines will be required to re-establish network integrity, resulting in a risk to security of supply for thousands of customers; and
- there will be significant cost of leak repair on TP pipelines (approximately $200,000 per repair) as well as switching costs involving re-lights and temporary gas connection through emergency bottles or trailers for the affected customers.

1.5.1.2 Risk assessment

Option 1 results in a continued high overall risk level associated with coating and corrosion defects at the [redacted] multiple DCVG reading locations. Though there are some risk controls in place (the DCVG surveys and monitoring), they do not significantly decrease the risk to an acceptable level above beyond the untreated risk assessment (See Table 1.4)

Table 1.4: 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	High
Consequence	Major	Minor	Major	Minor	Significant	Minor	Minor	
Risk Level	High	Low	High	Low	Moderate	Low	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. In the absence of any effective risk treatment, this risk will continue to rise as the TP pipelines continue to age and deteriorate.

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
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

Option 1 would not align with our objectives of *Delivering for Customers*, as it would not address the safety risks associated with coating defects and corrosion on TP pipelines. Replacement of assets upon failure would also result in unplanned outages and disruption of supply for customers.

Allowing assets to fail and potentially giving rise to safety incidents would also place our employees in harm's way, and would also not be consistent with the actions of a socially responsible organisation. It is also likely that the long term costs of a 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*.

1.5.2 Option 2 – Dig up and repair the 68 TP pipeline locations where multiple indications of IR <15% have been recorded. This work will be conducted over five years.

Under this option, we would continue the practice established in the current AA period, whereby locations that have shown multiple IR readings of less than 15% will be dug up and then repaired (as necessary).

The high proportion of corrosion and coating defects found during the current AA period at locations of multiple DCVG survey indications provides substantial evidence that DCVG surveys are effective in detecting major coating defects.

It is therefore prudent to continue to excavate in locations of multiple DCVG survey indications, in order to mitigate the high risks associated with TP pipeline corrosion.

This option proposes excavation and repair of all of the [redacted] identified locations within the next AA period.

1.5.2.1 Cost assessment

The estimated direct capital cost of this option is $1.3 million. This estimate is based on current material and labour rates.

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

	2021/22	2022/23	2023/24	2024/25	2025/26	Total
No. excavations	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labour ($)	232.3	250.2	250.2	250.2	232.3	1,215.1
Materials ($)	7.8	8.4	8.4	8.4	7.8	41.0
Total	**240.1**	**258.6**	**258.6**	**258.6**	**240.1**	**1,256.1**

The key driver for this option is the early detection and repair of coating defects. This will maintain asset integrity and reduce the risk of corrosion leaks on these assets. The benefits of this option are:

- reducing the risks of safety incidents and of supply loss to up to 100,000 consumers due to a significant gas escape;
- minimise long term repair costs, by avoiding the high operational costs involved with an increased quantity of emergency repairs (approximately $200,000 per repair);
- avoid potential switching costs of $50-$100 per affected customer; and
- treatment of all likely coating and corrosion defects on TP pipelines as they occur, preventing the build-up of a backlog of these defects.

1.5.2.2 Risk assessment

This option reduces the risk from high to moderate. The residual risk outcomes are shown in Table 1.7.

Table 1.7: Residual risk – 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	Significant	Minor	Minor	
Risk Level	Moderate	Negligible	Moderate	Negligible	Low	Negligible	Negligible	

Undertaking dig ups at the 68 identified locations decreases the likelihood of the risk event occurring from unlikely (possible in certain circumstances) to remote (may occur if abnormal circumstances prevail). The risk consequence remains unchanged.

Reducing the overall risk to moderate is ALARP. The advantage with Option 2 compared with Option 3 is that it achieves the risk reduction associated with the [redacted] identified TP pipeline locations over a shorter period of time (five years compared with ten). We therefore consider this a more prudent course of action.

1.5.2.3 Alignment with vision objectives

Table 1.8 shows how Option 2 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	Y

Option 2 would align with the *Delivering for Customers* aspect of our vision, as TP pipeline excavations in locations that are likely to contain coating defects and corrosion will help maintain reliability of supply and mitigate the risk of public safety incidents.

The proposed solution is also *Sustainably Cost Efficient* as repair of pipeline coating defects is the lowest sustainable cost of managing the corrosion risk, being significantly less expensive than replacing whole sections of pipeline where the potential for corrosion exists. This ensures we can deliver the program within industry benchmarks.

1.5.3 Option 3 – Dig up and repair the 68 TP pipeline locations where multiple indications of IR <15% have been recorded. This work will be conducted over ten years.

Under this option, we would dig up and repair the [redacted] identified 'multiple indication' locations, however we would spread the work over ten years rather than five.

This has the effect of spreading the costs over two AA periods and therefore lessening the potential impact on regulated network reference tariffs. Half of the identified dig ups ([redacted] would be deferred into the subsequent AA period (July 2026 to June 31).

1.5.3.1 Cost assessment

The estimated direct capital cost of this option is $0.6 million. This estimate is based on current material and labour rates.

Table 1.9: Cost estimate – Option 3, $ real 2019/20

	2021/22	2022/23	2023/24	2024/25	2025/26	Total
No. excavations	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labour ($)	107.2	125.1	125.1	125.1	125.1	607.5
Materials ($)	3.6	4.2	4.2	4.2	4.2	20.5
Total	**110.8**	**129.3**	**129.3**	**129.3**	**129.3**	**628.0**

The benefits of Option 3 are similar to those of Option 2, however they would be achieved over a longer time frame. Option 3 also spreads the impact over two AA periods, therefore lessening the impact on regulated revenue (and therefore regulated tariffs within a single AA period).

However, the lower revenue impact would be at the expense of a smaller risk reduction and greater potential for failure of one of the identified assets within the next AA period. Asset integrity failure could give rise to substantial emergency repair costs.

Further, the five yearly DCVG program would likely continue to highlight additional locations with multiple indications <15% IR, creating a backlog if excavations and repairs of these locations are completed over ten years rather than five.

1.5.3.2 Risk assessment

As shown in Table 1.10, Option 3 reduces the risk from high to moderate.

Table 1.10: Risk assessment – Option 3

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

Although the overall risk rating of moderate for the risk treatment proposed under Option 3 is the same as for Option 2, this would be achieved over ten years instead of five. As a result, the residual risk over the next five years would be higher. This is because only half of the [redacted] identified at risk locations will have been addressed by the end of the AA period. We would, however, prioritise the locations with the greatest risk where practicable.

It could therefore be interpreted that Option 3 does not reduce the risk to ALARP as it treats the risk over a longer timeframe. Given the extended timeframe over which we are addressing the risk, the likelihood of us incurring a compliance breach is higher than for Option 2.

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	Y
Sustainably Cost Efficient – Delivering Profitable Growth	-
Sustainably Cost Efficient – Environmentally and Socially Responsible	Y

Option 3 would not align with our objectives of *Delivering for Customers* and being *A Good Employer*, as it would not address the safety and security of supply risks associated with coating defects and corrosion on TP pipelines in a timely manner.

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 alignment with our objectives

Table 1.12: Comparison of options

Option	Estimated cost ($ million)	Treated residual risk rating	Alignment with vision objectives
Option 1	0	High	Does not align with *Delivering for Customers or Sustainably Cost Efficient*
Option 2	1.3	Moderate - ALARP	Aligns with *Delivering for Customers and Sustainably Cost Efficient*
Option 3	0.6	Moderate – non ALARP	Aligns with *Sustainably Cost Efficient*, but does not reduce the risk to ALARP and therefore does not align with *Delivering for Customers*

1.7 Recommended option

Option 2 is the proposed solution. This solution involves excavating TP pressure pipelines at [redacted] locations where DCVG IR readings below 15% have been recorded multiple times.

This project will be delivered using an internal project manager to manage the schedule of works. The excavations will be conducted using a combination of external and internal resources. The results of excavations (the defects found and any repairs undertaken) will be reviewed by an internal engineer and added into the Geospatial Information System (GIS) system.

1.7.1 Why is the recommended option prudent?

Option 2 is the most prudent option because:

- excavating locations that have shown multiple IR indications locations has proven to detect TP pipeline corrosion defects;
- the proactive repair of coating and corrosion defects on TP pipelines will reduce the need for emergency repairs that have the potential to result in supply constraints and excessive repair and switching costs;
- it is the only option that reduces risks to an acceptable level:
  - Option 1 does not mitigate the high health and safety, operational and compliance risks associated with corrosion of the TP pipelines; and
  - Option 3 will mitigate only half the risk associated with coating defects and corrosion in the upcoming period, While Option 3 reduces Health & Safety and Operational risks to ALARP, the compliance risk is not reduced to low, as it would be under Option 2. In addition, repairing only half of the known indications will result in the build-up of a backlog of excavations. This will create a larger problem in future periods when DCVG surveys inevitably find more defects;
- it is consistent with customer and stakeholder expectations and our vision that we will maintain current high levels of safety and reliability; and

- it is deliverable, as evidenced by the delivery of a similar amount of excavations delivered in the current period.

1.7.2 Estimating efficient costs

The [redacted] excavations proposed is based on the number of locations in the most recent DCVG survey that show a second IR reading <15%. Consistent with a typical ongoing program, the work has been split evenly over the next five years.

The forecast cost breakdown is shown in the table below.

Table 1.13: Cost estimate – Option 2, $'000 2019/20

	2021/22	2022/23	2023/24	2024/25	2025/26	Total
No. excavations	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labour ($)	232.3	250.2	250.2	250.2	232.3	1,215.1
Materials ($)	7.8	8.4	8.4	8.4	7.8	41.0
Total	**240.1**	**258.6**	**258.6**	**258.6**	**240.1**	**1,256.1**

All expenditure related to this project is capex. This cost is based on:

- a labour cost unit rate of [redacted] per excavation. This is based on the historical cost of 63 excavations conducted on TP pipelines as part of the current period SA36 business case (between 2016 and 2019); and
- materials costs of [redacted] per repair for coating material, plus an assumed [redacted] for structural wrap for approximately 10% of the repairs. These assumptions are based on recent historical costs.

Please refer to Appendix B for a more detailed cost breakdown.

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

Table 1.14: Escalated TP pipelines ILI modification cost estimate ($'000)

	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Total unescalated ($ Dec 19)	240.1	258.6	258.6	258.6	240.1	1,256.1
Escalation	8.1	10.0	11.6	13.1	13.4	56.1
Total escalated ($ Jun 21)	**248.2**	**268.6**	**270.2**	**271.7**	**253.5**	**1,312.1**

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 that the ongoing integrity of the TP pipelines is maintained and to reduce the risk of major gas escapes that could impact public safety and reliability of supply, and is of a nature that a prudent service provider would incur.

- Efficient – The excavation and remediation work is the only practical and effective option. It is also the most cost effective option. Engineering assessments and design will be carried out by internal staff and field work will be carried out by external contractors based on competitively tendered rates. The expenditure is therefore of a nature that a prudent service provider acting efficiently would incur.

- Consistent with accepted and good industry practice – The ongoing effective management of the integrity of the TP pipelines is consistent with Australian Standard AS2885.3 Pipelines - Gas and Liquid Petroleum, Part 3: Pipeline Integrity Management. Reducing the risks posed by the corrosion of these pipelines to as low as reasonably practicable and in a manner that balances costs and risks is also consistent with this standard.

- To achieve the lowest sustainable cost of delivering pipeline services – The excavation and remediation works are necessary to maintain the long term integrity of the TP pipelines. Failure to do so would result in additional expenditure (reactive response to a major gas escape and bringing forward replacement) and shorten the life of the pipelines. 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 79(2)(c)(ii), as it is necessary to maintain the safety and integrity of services. Allowing TP pipelines to continue to corrode to the extent performance is compromised will lead to network integrity issues, disruption to customer supply and potential uncontrolled release of gas. Though Option 3 ultimately achieves the same level of operational risk reduction as Option 2, it does this over a longer time period and at no lesser cost. We therefore consider Option 2 better meets the requirements of NGR 79(2).

As outlined in the business case, current practice has proven successful in uncovering coating defects and corrosion and remediation of these issues will allow us to maintain a level of service consistent with customer and stakeholder expectations.

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 – Asset maps

SA metropolitan TP pipeline network

Appendix B – Cost estimates

Option 2

Category	Description	Item ea	Unit Cost $/ea	Total $'000
Materials				
Coating	Coating material	[redacted]	[redacted]	[redacted]
Snap Wrap	Structural wrap (approx.10% of joints)	[redacted]	[redacted]	[redacted]
Subtotal materials				41.0
Labour				
TP pipeline excavation	Excavation (based on historical rate)	[redacted]	[redacted]	[redacted]
Subtotal labour				1,215.1
Grand total				**1,256.1**

Note: The labour costs above include the cost of project management, engineering, crews, plant and equipment, traffic control and reinstatement.

Option 3

Category	Description	Item ea	Unit Cost $/ea	Total $'000
Materials				
Coating	Coating material	[redacted]	[redacted]	[redacted]
Snap Wrap	Structural wrap (10% of joints)	[redacted]	[redacted]	[redacted]
Subtotal Materials				20.5
Labour				
TP pipeline excavation	Excavation (based on historical rate)	[redacted]	[redacted]	[redacted]
Subtotal Labour				607.5
Grand Total				**628.0**

Note: The labour costs above include the cost of project management, engineering, crews, plant and equipment, traffic control and reinstatement.

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	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 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	Significant	Minor	Minor	
Risk Level	Moderate	Negligible	Moderate	Negligible	Low	Negligible	Negligible	

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

SA103 – Replacement of valves

1.1 Project approvals

Table 1.1: Business case SA103 – Project approvals

Prepared by	Nick Rubbo, Integrity Engineer, APA
Reviewed by	Robin Gray, SA Operations Manager, APA
Approved by	Craig Bonar, Head of Planning & Engineering, APA Mark Beech, General Manager Network Operations, AGN

1.2 Project overview

Table 1.2: Business case SA103 – 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. Australian Standards AS 2885 and AS/NZS 4645 require transmission pipeline and distribution network operators to install and maintain isolation valves to allow the pipeline or network to be isolated for emergency and maintenance purposes. Valves also allow for control flexibility to help ensure security of supply. There are 1,207 steel valves in the SA networks. Of these, 283 valves are located on TP pipelines, and 924 in the smaller distribution mains. Valves are typically located in medium and high density suburban areas. Most were installed in the 1970s and 1980s. We have identified [redacted] valves that are currently either inoperable or have had leaks repaired but are in a deteriorated state. Inoperable valves mean sections of the network cannot be isolated during emergency repairs or planned maintenance. This increases the number of customers that may be impacted during a supply outage. A valve that has leaked but since been repaired is usually a precursor to valve failure as the repaired valve will typically be weakened. A leaking valve can pose a health and safety risk if the leak is near a building. The current risk control for inoperable and leaking valves is to repair them where practicable, only replacing upon failure. However, due to the age and ongoing deterioration of valves, repair is a temporary measure and replacement is the only effective long term solution. This business case considers options to replace a number of valves that have been identified as inoperable, as well as commencing a proactive replacement program for replacing valves that have leaked previously.
Untreated risk	As per risk matrix = **High**
Options considered	• **Option 1** – Replace [redacted] valves. [redacted] inoperable valves ([redacted] transmission and [redacted] distribution). Proactive replacement of [redacted] previously leaking valves ([redacted] transmission and [redacted] distribution) ($5.0 million) • **Option 2** – Replace [redacted] inoperable valves only ([redacted] TP and [redacted] distribution). Do not replace previously leaking valves that do not represent a significant immediate safety hazard; ($2.8 million) • **Option 3** – Maintain status quo. Continue the scheduled maintenance program only. Do not commence a new proactive replacement program for inoperable valves. Do not replace leaking valves that do not represent a significant immediate safety hazard (no additional upfront capital cost)
Proposed solution	Option 1 is the proposed solution because: • it addresses security of supply risks associated with inoperable valves; • it addresses the potential security of supply risks associated with leaking valves that are deteriorating towards inoperability;

- it is the most efficient cost option, as a proactive replacement program costs significantly less than a reactive program. Option 1 will also help reduce emergency repair costs over the long term.

Estimated cost

The forecast direct capital cost (excluding overhead) during the next access arrangement (AA) period (July 2021 to June 26) is $5 million.

$'000 2019/20	21/22	22/23	23/24	24/25	25/26	Total
[redacted] valve replacements	624.2	1,013.2	1,514.5	909.8	909.8	4,971.5

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 our vision objective of Delivering for Customers. It delivers for customers by ensuring security and reliability of gas supply, particularly during emergency situations.

It also aligns with our Sustainably Cost Efficient vision objective. Replacing valves is the most cost-effective solution to this issue, with the long term costs of a reactive valve replacement being greater than proactive replacement.

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 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 valve replacement program represents a shift to proactive asset management, which results in lower long term costs than maintaining a reactive treatment program. Proactively replacing leaking valves helps address the public safety risk and is therefore consistent with the current safety practices customers have told us they value.

Undertaking the proposed valve replacement 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 TP pipelines and 8,000 km of distribution pipelines, which deliver gas to over 450,000 customers.

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.

Valves are strategically placed to allow critical assets such as district regulator stations and demand customer meter sets to be isolated without materially impacting the rest of the network. The quantity and location of valves depends on the asset design, pipe material and the consequences of any loss of containment (urban vs rural).

There are 1,207 steel valves in the SA networks. Of these, 283 valves are located on TP pipelines, and 924 in the smaller distribution mains. Valves are typically located in medium and high density suburban areas. Most were installed in the 1970s and 1980s.

All steel valves are susceptible to corrosion. Once corroded they can either seize and become inoperable, or they can leak. Leaking is usually a precursor to them becoming inoperable. The risk of corrosion depends on the valve location, environmental conditions, coating degradation, and whether the cathodic protection system is effective.

The highest risk family of valves are large diameter valves (>150mm) housed in underground concrete or brick chambers. These valves are accessed via manholes located in the roadway or footpaths. Valves in chambers are particularly susceptible to corrosion, as the chambers often collect water, which can create a humid environment conducive to corrosion. These valves are typically not protected by the pipeline cathodic protection system (impressed cathodic protection or anode) because they are not in contact with the soil to make the electrical connection.

Smaller valves that are not located in chambers can also be susceptible to corrosion. As valves age, components such as the valve key and shaft corrode, the valve plug can irreparably seize, and the flange gaskets deteriorate. Some valves cannot be visually inspected for damage or corrosion unless excavated.

1.3.1 Inoperable valves

An inoperable valve is one that does not isolate the network, either because it has seized and cannot be turned, or because it does not fully isolate supply when turned. Inoperable valves pose a high risk to security of supply. This is because if a valve cannot be closed (or opened) to isolate a section of network/pipeline, the number of customers at risk of supply interruption during an emergency or during maintenance increases.

Using an alternative valve upstream or downstream to conduct an emergency gas escape could result in significantly more customers being impacted than would otherwise be necessary. Flow-stopping high pressure mains when a valve is inoperable takes considerable time to excavate, prepare the main, and insert stopples to halt the flow of gas.

Generally, isolation of supply has the potential to affect gas supply of up to 51,600[6] customers for transmission valves and up to 5,000 customers for major gas distribution valves. We have identified [redacted] currently inoperable valves, of which [redacted] are on TP pipelines and [redacted] are in the distribution networks. A list of the inoperable valves is provided in Appendix A.

6 Note we have identified seven locations where up to 51,600 customers would be affected. Our proposal to address this risk is discussed in business case SA107.

1.3.2 Repaired valves (that have previously leaked)

Historically, when a valve leaks it is repaired (where safe to do so). A repaired valve can continue to operate adequately, however, experience shows that a repaired valve will typically be weaker than a new valve and is more prone to leak again or become inoperable in the future.

When a valve leaks it can pose a supply and reputational risk, particularly if the leaking valve is located near a road or a similarly built-up area. For example, in May 2018, the transmission steel valve number 1034 failed. The valve shaft cracked causing a leak during preventative maintenance. The valve had leaked previously and had been repaired. Inspection after the May 2018 leak indicated that the crack was due to weakness in the shaft, hidden by the gearbox used to operate the valve.

The valve was located near a main road in the Adelaide eastern suburbs. The leak meant an exclusion zone had to be set up along and around the road (as shown in Figure 1.1). In this instance, because the leak occurred through a small capillary within the valve shaft, a sheath was able to be placed over the leak to vent gas out of the chamber and keep the traffic operating on one lane of the road.[7] While the leaking gas in this instance posed a low health and safety risk (as it could be vented), the valve failure and subsequent repair activities caused considerable disruption to traffic and the public.

Figure 1.1: Isolation and replacement of TP valve 1034, March 2018

In addition to the integrity risk and public disruption caused by a leaking valve, a valve leak is often a lead indicator of condition and future failure. Leaking valves, if left untreated, eventually become inoperable.

We have identified [redacted] valves that have leaked previously (and been repaired), of which [redacted] are on TP pipelines and [redacted] are in the distribution networks. A list of these repaired valves is provided in Appendix A.

1.3.3 Valve replacement

Replacement of an inoperable or leaking valve is proposed when all other options for repair have been exhausted. We will attempt a repair where safe to do so, noting that a repaired valve will typically be weakened and is likely to leak in the future. However, if the valve is completely seized

[7] Note that this is not always possible, meaning in many cases the entire road may need to be closed.

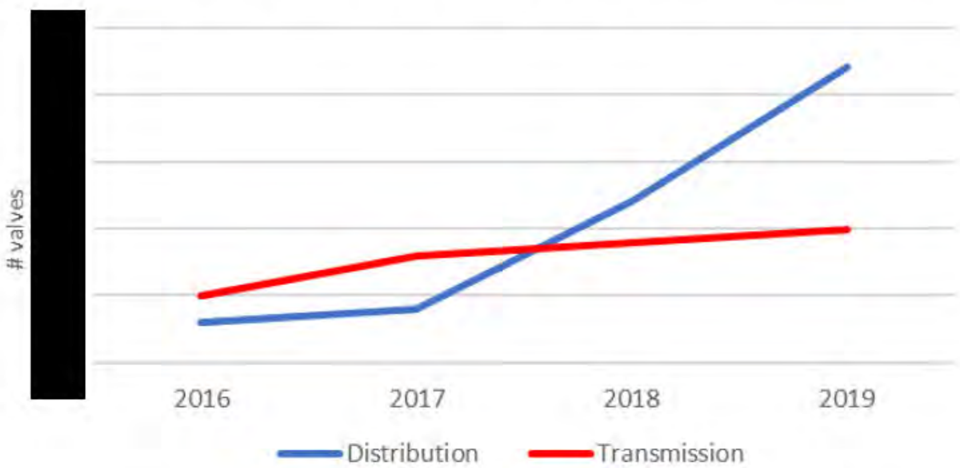
or the integrity of the valve has been compromised such that it is irreparable, we will replace that valve completely.

As a result of the high security of supply risk associated with inoperable valves, business Case SA70 was endorsed for the current AA period to replace [redacted] inoperable valves, placing particular focus on the highest risk large diameter valves in chambers. To date, [redacted] of these have been completed, with the other three scheduled to be completed by the end of the current AA period. While Business Case SA70 was not necessarily designed to be a precursor to an ongoing replacement program, it has set a useful precedent for the costs and ongoing valve management requirements. We therefore consider that a valve replacement program continues over the next AA period (July 2021 to June 2026).

Our investigation of valve condition shows that the number of inoperable and leaking valves is greater than initially estimated, and only replacing [redacted] valves in any one AA period would be insufficient to address the increasing risk associated with valve failure.

Over the current AA period there has been a gradual increase in the number of inoperable and leaking valves, as shown in Figure 1.2. Half of these valves ([redacted]) are already inoperable. The remaining [redacted] have leaked and subsequently been repaired, but are likely to become inoperable in the future.

Figure 1.2: Backlog of previously leaking (repaired) and inoperable major transmission and distribution valves[8]



The problem is expected to exacerbate over the coming years given the increasing age of the asset base. As such, we consider it prudent to continue the program to replace inoperable valves (albeit at a slightly higher replacement rate). We also consider it prudent to commence a program to proactively replace repaired valves that have previously leaked – before they become inoperable. Addressing repaired valves in a timely manner will allow us to keep on top of the growing valve seizure/failure issue, and ensure the risk is managed to as low as reasonably practicable (ALARP).

8 This excludes the three inoperable valves that are still to be replaced in the current period as part of Business Case SA70

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 1.3). 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 1.3: 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 (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 considered in this business case is that during an emergency (or planned maintenance) situation, we find that the valve necessary to isolate that section of pipeline is inoperable, meaning we need to isolate a greater number of customers and therefore impact gas supply to >10,000 customers or a demand customer >10 TJ p.a.

The risk consequence category most impacted by inoperable valves is operations (supply). There is also a moderate safety, compliance and reputational risk. An inoperable valve can have a significant impact on gas supply to tens of thousands of customers, while also exposing us to significant reputational risk due to public/traffic disruption when valves fail. The safety risk associated with inoperable valves is moderate, as a seized (inoperable) valve does not necessarily mean a leak is present.

The risk associated with inoperable steel valves on TP pipelines and distribution mains has been assessed as high (see Table 1.3). This is because there are a number of valves already identified as inoperable or that have leaked in the past, which means the likelihood of an emergency happening at a location where we cannot isolate that section is rated as occasional (potentially every two years). The consequences of our inability to isolate customers is rated major, as in some instances up to 51,600 customers could be impacted.[9]

The likelihood of this risk event occurring will increase with time if the condition of these valves is not addressed. The untreated risk[10] rating is presented in Table 1.3.

Table 1.3: Risk rating – untreated risk

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

1.5 Options considered

We have identified the following options to address the high operational and reputational risks associated with inoperable and previously leaking valves:

- **Option 1** – Replace [redacted] valves. Replace [redacted] inoperable valves ([redacted] TP and [redacted] distribution). Proactive replacement of [redacted] previously leaking valves ([redacted] TP and [redacted] distribution);
- **Option 2** – Replace [redacted] inoperable valves only ([redacted] TP and [redacted] distribution). Do not replace the previously leaking valves that do not represent a significant immediate safety hazard; or
- **Option 3** – Maintain status quo. Continue the scheduled maintenance program only. Do not commence a new proactive replacement program for inoperable valves. Do not replace the previously leaking valves that do not represent a significant immediate safety hazard.

These options are discussed in the following sections.

9 Note Business Case SA107 proposes a solution to reduce the number of customers impacted by TP pipeline isolation to fewer than 10,000 at any one TP isolation point.

10 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 [redacted] inoperable and previously leaking valves

Under Option 1 we would replace all currently inoperable steel valves, and commence a program to proactively replace valves that have leaked in the past. We have identified a total of [redacted] inoperable or previously leaking valves in our networks ([redacted] inoperable and [redacted] leaking) that require treatment during the next five years.

The proposed works program would comprise:

- immediately replacing all identified inoperable transmission valves ([redacted] TP valves and [redacted] distribution); and
- commencing a proactive replacement program for replacing identified valves that have leaked and subsequently been repaired in the past (currently [redacted] TP and [redacted] distribution).

We estimate that around 50% of the valves will require installation of a temporary bypass to maintain supply during replacement works. This assumption is based on a desktop exercise that assesses the location of these valves and whether there is a back feed available from other locations.

1.5.1.1 Cost assessment

The estimated direct capital cost of this option is $5 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	215.0	992.8	1,207.8	858.9	858.9	4,133.4
Materials	409.2	20.4	306.7	50.9	50.9	838.0
Total	**624.2**	**1,013.2**	**1,514.5**	**909.8**	**909.8**	**4,971.5**

The proposed works program would prioritise currently inoperable valves, so that all [redacted] identified inoperable TP and distribution valves are replaced within the first three years of the next AA period. The program to proactively replace previously leaking valves would commence in 2023/24.

The key driver for this option is to reduce the number of customers at risk of supply cut-off in an emergency isolation situation. Replacing all [redacted] identified valves will help maintain security of supply for the Adelaide metropolitan area during maintenance/repair, reducing the likelihood of costly supply outages that could affect up to 51,600 customers at any one time.

Commencing proactive replacement of previously leaking valves will also reduce long term repair costs, as replacing these valves before they become inoperable will allow us to avoid the high operational costs involved with emergency repairs.

1.5.1.2 Risk assessment

Option 1 reduces the risk from high to low. This is because replacing the currently inoperable and previously leaking valves decreases the potential number of customers that would be impacted during emergency repairs. This reduces the risk consequence for operations to significant. The fact that the previously leaking valves are also being addressed also means the likelihood of us finding that the isolation valve is inoperable during an emergency situation is reduced to remote.

The residual risk outcomes are 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	Minimal	Significant	Minor	Minor	
Risk Level	Negligible	Negligible	Low	Negligible	Low	Negligible	Negligible	

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	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	Y

Option 1 would align with the *Delivering for Customers* aspect of our vision, as replacement of inoperable and previously leaking valves will help maintain reliability of supply to more customers, particularly during emergency situations.

The proposed solution is also *Sustainably Cost Efficient* as replacing leaking valves is the most cost-effective solution to address this issue. The long term costs of a reactive valve replacement are significantly greater than proactive replacement.

1.5.2 Option 2 – Replace [redacted] inoperable valves only ([redacted] TP and [redacted] distribution). Do not replace previously leaking valves that do not represent a significant immediate safety hazard

Under Option 2 we would replace all [redacted] inoperable valves immediately (as per Option 1). We would not replace the [redacted] valves that have leaked previously (but have since been repaired). Instead, we would continue to monitor the previously leaking valves and then either replace them when they become inoperable or if the leak reoccurs and is irreparable and/or poses a public safety hazard.

1.5.2.1 Cost assessment

The estimated direct capital cost of this option is $2.8 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	215.0	992.8	1,100.3	-	-	2,308.1
Materials	409.2	20.4	40.7	-	-	470.3
Total	**624.2**	**1,013.2**	**1,141.0**	**-**	**-**	**2,778.3**

Under this option, all [redacted] inoperable valves will be replaced by 2023/24. No capital costs are included to proactively replace the other [redacted] valves that have leaked previously. Any capital costs associated with replacing these leaking valves upon failure will be incurred reactively.

If we wait until the [redacted] previously leaking valves become inoperable (or begin leaking again), in addition to exposing the public to safety risks, there is also a risk that the cost of reactive replacement will be significantly higher than expected. For example, costs may escalate quickly when considering such things as reactive purchase of materials, prioritised procurement costs, reactive traffic management and out of hours labour costs.

1.5.2.2 Risk assessment

This option reduces the risk from high to moderate. Replacing all currently inoperable valves significantly reduces the number of customers that may be impacted during emergency situations, reducing the risk consequence from major to significant. However, because the previously leaking valves remain in the network, there remains a greater likelihood that come of these valves may not allow sections of the network to be fully isolated or that they may become entirely inoperable in the near future. As a result, the likelihood of the risk event occurring under Option 2 is only reduced from occasional to unlikely (compared with a remote likelihood rating under Option 1).

The residual risk outcomes are 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	Remote	Unlikely	Remote	Remote	Remote	Remote	Moderate
Consequence	Significant	Minimal	Significant	Minimal	Significant	Minor	Minor	
Risk Level	Moderate	Negligible	Moderate	Negligible	Low	Negligible	Negligible	

While the immediate supply risk associated with inoperable valves is reduced, this option results in a growing backlog of valves that require treatment. These previously leaking valves will eventually become inoperable and have the potential to cause supply issues.

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	Y
Delivering for Customers – Customer Service	N

Vision objective	Alignment
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	Y

Option 2 would not align with the *Delivering for Customers* aspect of our vision. Although replacing the inoperable valves will help maintain reliability of supply, not addressing previously leaking valves has the potential to impact customer service during emergency/reactive works. Valves that have leaked in the past also have a higher potential for leaking in the future, which can result in a health and safety risk.

Option 2 would not align with our objectives of being *Sustainably Cost Efficient*, as the costs associated with replacing leaking valves will be higher where urgent reactive replacement is required.

1.5.3 Option 3 – Maintain status quo

Under Option 3 we would return to the periodic valve maintenance program. Once the current valve replacement program has been completed, we would return to the historical maintenance program and the 16 inoperable and previously leaking valves would be left in place.

Any seized or leaking valves would continue to be maintained to the extent possible, with valves only being replaced reactively once discovered to be inoperable.

1.5.3.1 Cost assessment

There would be no additional upfront capital costs associated with this option. Valve maintenance would be completed consistent with the historical operating expenditure program.

The valve maintenance program includes conducting valve inspection and leak repairs where possible. When a valve has a leaking gasket, this can sometimes be repaired either by tightening the flange connection or by injecting resin around the gasket. However, once a valve has leaked, the likelihood of the leak reoccurring is high and any repair would be temporary only. This short term risk treatment is cost effective compared to a valve replacement. However a leak on the valve is an indicator that the valve is nearing the end of its useful life. The leak repair is therefore considered a short term solution.

Further, as valves fail and/or pose a significant health and safety risk, they would need to be replaced reactively. A reactive replacement program would be at least 1.3 times more expensive than a proactive program.

1.5.3.2 Risk assessment

Option 3 does not reduce the untreated risk rating. While the likelihood of a major supply interruption is rated unlikely, the consequences of valve failure are not diminished.

Valves will only be replaced where they fail and/or pose a significant health and safety risk. As a result, many of the inoperable and previously leaking valves will remain in the networks. This is likely to cause significant disruption to large numbers of customers if emergency works are required and sections of pipeline cannot be isolated.

Further, the high cost and disruption caused by reactive valve repair (as per the Adelaide incident in March 2018) means the compliance and reputational risks remain moderate.

The residual risk rating under this option is shown in 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	Remote	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Significant	Minimal	Major	Minimal	Significant	Significant	Minor	
Risk Level	Moderate	Negligible	High	Negligible	Moderate	Moderate	Low	

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 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	N

Option 3 would not align with our objective of *Delivering for Customers*, as it would not address the increased number of customers at risk in an emergency situation due to inoperable valves.

Allowing valves to fail and potentially giving rise to safety incidents would also place our employees in harm's way, and would not be consistent with the actions of a socially responsible organisation. The costs of a reactive valve replacement are greater than proactive replacement. This option therefore does not align with our objective to be *Sustainably Cost Efficient*.

1.6 Summary of costs and benefits

Table 1.12: Comparison of options

Option	Estimated cost ($ million)	Treated residual risk rating	Alignment with vision objectives
Option 1	5.0	Low	Aligns with De*livering for Customers, A Good Employer* and *Sustainably Cost Efficient*
Option 2	2.8	Moderate	Does not align with *Delivering for Customers, A Good Employer* or *Sustainably Cost Efficient*
Option 3	No additional upfront capital cost	High	Does not align with *Delivering for Customers, A Good Employer* or *Sustainably Cost Efficient*

1.7 Recommended option

Option 1 is the proposed solution to the problem of inoperable and leaking steel valves. This involves:

- immediate replacement of all inoperable transmission valves ([redacted] transmission and [redacted] distribution); and
- implementation of a scheduled ongoing replacement program for leaking valves ([redacted] transmission and [redacted] distribution).

Replacement of the inoperable valves will be prioritised over those that are leaking but still operable.

This project will be delivered using an internal project manager to manage the schedule, resourcing and budget, with the work split between internal operations crews and external contractors. Contractors will be engaged based on a competitive tender process. Once a valve is replaced the relevant records will be updated in the Geospatial Information system

A risk to project delivery will be the availability of resources. However, current project delivery practices and controls such as advanced planning and scheduling of work are in place to effectively manage this risk. The risk of not completing this project is considered to be low.

1.7.1 Why is the recommended option prudent?

Option 1 is proposed because:

- it is consistent with AS 2885 and AS/NZS 4645, with strategically placed (operable) valves providing control flexibility to help ensure security of supply;
- it is the only solution that addresses the risks associated with inoperable and leaking isolation valves over the long term. Leak repair is a short term temporary solution; and
- it is the most cost-effective way of managing the risks associated with the seized valves.

To not replace the valves would expose us to much higher costs in the event of an emergency incident on the TP and distribution pipelines lines. An emergency incident would require the mobilisation of a specialist emergency repair contractor with a minimum mobilisation time of 24 hours and the closure of alternative isolation valves or timely and expensive live high pressure mains flow stopping techniques. Closure of alternative isolation valves would affect a greater number of customers, particularly in the Adelaide CBD. It could also lead to relatively high rectification costs, given the costs associated with relighting. We estimate reactive replacement costs around three times that of proactive replacement.

We consider the valve replacement program is deliverable within the next AA period.

1.7.2 Estimating efficient costs

The volume of work proposed is based on the currently identified number of TP and distribution inoperable and leaking valves. As shown in Table 1.13, these have been allocated evenly across the next access arrangement period, with inoperable valves prioritised for the first three years. TP valves have a long delivery lead time.

Table 1.13: Volumes – Option 1

	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Tx procure	[redacted]		[redacted]			[redacted]

	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Tx replace inoperable		[redacted]	[redacted]			[redacted]
Tx replace leaking				[redacted]	[redacted]	[redacted]
Dx procure & replace inoperable	[redacted]	[redacted]	[redacted]			[redacted]
Dx procure & replace leaking			[redacted]	[redacted]	[redacted]	[redacted]

Unit rates for valve replacements are provided in Table 1.14. These are based on the following assumptions:

- A portion of the TP and distribution valves requiring replacement will require a bypass installed to ensure continuity of gas supply downstream. The requirement for a bypass is based on numerous factors, including the number of customers impacted, the time of year and the network configuration. While each location will be individually assessed prior to the project starting, historical precedent from valve and other pipeline works suggests that bypasses will be required in around 50% of instances; and
- the estimated valve replacement costs are based on the actual costs of recently completed projects[11]:
  - Transmission valves including a bypass - [redacted]
  - Transmission valves without a bypass - [redacted]
  - Distribution valves including a bypass - [redacted]
  - Distribution valves without a bypass - [redacted]

These projects represent a reasonable basis for the forecast estimate because the proposed works are very similar in nature for both labour and materials requirements.

Table 1.14: Unit rates – Option 2, $ real 2019/20

	Transmission pressure (TP)	Distribution
Rate with bypass		
Labour	[redacted]	[redacted]
Materials	[redacted]	[redacted]
Total	[redacted]	[redacted]
Rate without bypass		
Labour	[redacted]	[redacted]
Materials	[redacted]	[redacted]
Total	[redacted]	[redacted]
% requiring bypass	50%	50%
Weighted average rate		
Labour	[redacted]	[redacted]
Materials	[redacted]	[redacted]

11 Presented in real 2019/20 dollars.

	Transmission pressure (TP)	Distribution
Total	[redacted]	[redacted]

The outcome from applying the weighted average cost to the forecast volumes is an estimated capital cost of replacing these [redacted] valves of $5 million as shown in Table 1.15.

Table 1.15: Cost estimate – Option 2, $'000 2019/20

Option 1	2021/22	2022/23	2023/24	2024/25	2025/26	Total
TP						
Labour	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Materials	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Distribution						
Labour	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Materials	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	**624.2**	**1,013.2**	**1,514.5**	**909.8**	**909.8**	**4,971.5**

For TP valves, bottom-up estimates have also been produced and these have generated a similar forecast amount to that shown in the above tables. This is provided in Appendix B.

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

Table 1.16: Escalated replacement of valves cost estimate ($'000)

	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Total unescalated ($ Dec 19)	624.2	1,013.2	1,514.5	909.8	909.8	**4,971.5**
Escalation	21.0	39.2	67.9	46.0	50.7	**224.8**
Total escalated ($ Jun 21)	**645.2**	**1,052.4**	**1,582.4**	**955.8**	**960.5**	**5,196.3**

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 that TP and distribution valves are operable for emergency isolation and pressure control. Failure to address the inoperable 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 – Replacement of these valves is the only practical and cost-effective option. Costs have been based on recent similar valve replacement 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 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 inoperable valves 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 – The valve replacement works are necessary to maintain the long term integrity of the pipelines. Failure to do so could result in additional expenditure (reactive response to a safety critical valve 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. Allowing the number of inoperable and leaking valves to continue to grow will lead to an increasing number of customers at risk of supply in an emergency isolation situation.

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 – List of inoperable and leaking steel valves to be replaced

List of inoperable steel valves

Valve #	Location	Size	Year of installation	Condition
Transmission pressure valves				
506	[redacted]	250SP	1968	Ageing valve seized and inoperable. Requires replacement.
1482	[redacted]	300SP	2002	Inoperable broken valve. Requires replacement.
29	[redacted]	300SP	1975	Ageing, inoperable seized valve. Requires replacement.
752	[redacted]	300SP	1979	Ageing, inoperable seized valve. Requires replacement.
858	[redacted]	300SP	1980	Ageing, inoperable broken valve. Requires replacement.
318	[redacted]	150SP	1975	Ageing valve seized and inoperable. Requires replacement.
Distribution networks valves				
618	[redacted]	50SP	1976	Broken inoperable valve. Requires replacement.
193	[redacted]	150SP	1975	Seized valve. Requires replacement.
73	[redacted]	150SP	1995	Seized valve. Requires replacement.
768	[redacted]	150SP	1979	Seized valve. Requires replacement.
511	[redacted]	80SP	1986	Broken inoperable valve. Requires replacement.
301	[redacted]	150SP	1975	Seized valve. Requires replacement.
301	[redacted]	150SP	1975	Seized valve. Requires replacement.
854	[redacted]	150SP	1986	Seized valve. Requires replacement.
5853806	[redacted]	100SP	1986	Broken inoperable valve. Requires replacement.
5846768	[redacted]	50SP	1986	Broken inoperable valve. Requires replacement.

List of steel valves that have leaked previously

Valve #	Location	Size	Year of installation	Condition
Transmission pressure valves				
285	[redacted]	200SP	1970	Ageing valve. 1 Leak already reported and repaired. Requires replacement.
570	[redacted]	200SP	1975	Ageing valve. 1 Leak already reported and repaired. Requires replacement.
1693	[redacted]	300SP	2011	Leak reported on this valve. Requires replacement as leak was on the valve cavity.
298	[redacted]	200ST	1968	Ageing valve. 1 Leak already reported and repaired. Requires replacement.
Distribution networks valves				
965	[redacted]	150SP	1984	Ageing valve at risk. Previous leak repaired. Requires replacement.
435	[redacted]	150SP	1975	Ageing valve at risk. Previous leak repaired. Requires replacement.
728	[redacted]	100SP	1979	Ageing valve at risk. Previous leak repaired. Requires replacement.
765	[redacted]	100SP	1979	Ageing valve at risk. Previous leak repaired. Requires replacement.
1033	[redacted]	150SP	1992	Ageing valve at risk. Previous leak repaired. Requires replacement.
612	[redacted]	80SP	1981	Ageing valve at risk. Previous leak repaired. Requires replacement.
5836424	[redacted]	50SP	1995	Previous leak repaired. Requires replacement.
5838269	[redacted]	40SP	1986	Ageing valve at risk. Previous leak repaired. Requires replacement.
168	[redacted]	50SP	1975	Ageing valve at risk. Previous leak repaired. Requires replacement.
5836706	[redacted]	100SP	1986	Ageing valve at risk. Previous leak repaired. Requires replacement.
5856017	[redacted]	50SP	1986	Ageing valve at risk. Previous leak repaired. Requires replacement.
743	[redacted]	80SP	1996	Ageing valve at risk. Previous leak repaired. Requires replacement.

Appendix B – Cost estimate validation (bottom-up)

B.1: Transmission with bypass

Category	Description	Units	Units QTY	Number of sites	Unit Cost $/ unit	Total $'000	Avg cost per valve $' 000
Materials							
Pipe	DN200 Line pipe consists of 20m bypass	meters	[redacted]	[redacted]	[redacted]	[redacted]	
	DN250 Line pipe consists of 20m bypass	meters	[redacted]	[redacted]	[redacted]	[redacted]	
	DN300 Line pipe consists of 20m bypass	meters	[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]	

Category	Description	Units	Units QTY	Number of sites	Unit Cost $/ unit	Total $'000	Avg cost per valve $' 000
	DN250 ShortStopps for stoppling and bypass	each	[redacted]	[redacted]	[redacted]	[redacted]	
	DN300 ShortStopps for stoppling and bypass	each	[redacted]	[redacted]	[redacted]	[redacted]	
							[redacted]
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	meters	[redacted]	[redacted]	[redacted]	[redacted]	
	Welder	hours	[redacted]	[redacted]	[redacted]	[redacted]	
	Welding supervisor	hours	[redacted]	[redacted]	[redacted]	[redacted]	

Category	Description	Units	Units QTY	Number of sites	Unit Cost $/ unit	Total $'000	Avg cost per valve $' 000
	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]	
	Reinstatement (assuming 30 sqm - 275mm asphalt and including backfill material and compaction)	Sqm	[redacted]	[redacted]	[redacted]	[redacted]	
Total labour						**1,869.0**	[redacted]
Total project						**2,194.9**	[redacted]

B.2: Transmission without bypass

Category	Description	Units	Units QTY	Number of sites	Unit Cost $/ unit	Total $'000	Avg cost per valve $'000
Materials							
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]	

Category	Description	Units	Units QTY	Number of sites	Unit Cost $/ unit	Total $'000	Avg cost per valve $'000
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]	
Total materials						**258.3**	[redacted]
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]	

Category	Description	Units	Units QTY	Number of sites	Unit Cost $/ unit	Total $'000	Avg cost per valve $'000
	Asphalt and concrete cutters	meters	[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]	
	Reinstatement (assuming 30 sqm - 275mm asphalt and including backfill material and compaction)	Sqm	[redacted]	[redacted]	[redacted]	[redacted]	
Total labour						**1,086.8**	[redacted]
Total project						**1,345.1**	[redacted]

Appendix C – Comparison of risk assessments for each option

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

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

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

SA104 – M53 offtake replacement

1.1 Project approvals

Table 1.1: Business case SA104 – Project approvals

Prepared by	Nick Rubbo, Integrity 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 SA104 – Project overview

Description of the problem / opportunity	The South Australia (SA) distribution network includes approximately 200 km of metropolitan transmission pressure (TP) pipelines, which deliver gas to over 450,000 consumers. The majority of these pipelines were constructed in the 1970s and 80s and are steel, and therefore susceptible to corrosion. We use a number of protective solutions to reduce the risk of corrosion for steel pipelines, including coatings, cathodic protection and sacrificial anodes. We also inspect steel pipelines for corrosion through inline inspection (pigging) where possible, and direct current voltage gradient (DCVG) surveys combined with direct inspection excavations (dig ups) where pigging is not possible. M53 was originally a 7.9 km pipeline commissioned in 1975. Through DCVG surveys and excavations we identified significant pitting corrosion beneath dis-bonded heat shrink sleeves. In 2013, 3.1 km of the M53 was replaced and renamed M131. A further 4.06 km DN200 section is being replaced during the current access arrangement (AA) period. These transmission pipelines are being replaced on a like-for-like basis to address corrosion, reduce the safety risk and ensure ongoing supply to the major residential growth area of the southern suburbs of metropolitan Adelaide. The third and final section of M53 replacement is a smaller diameter 800 m DN100 offtake that services 600 customers in the Hackham area. This business case considers a number of options to address the same corrosion and associated safety risks on the last section of pipeline M53.
Untreated risk	As per risk matrix = **High**
Options considered	• **Option 1** – Replace the M53 offtake with a new polyethylene (PE) HP distribution trunk main ($1.6 million) • **Option 2** – Like-for-like replacement of the M53 offtake with a new steel TP pipeline ($2.5 million) • **Option 3** – Repair the M53 offtake ($1.6 million) We also considered downgrading the maximum allowable operating pressure (MAOP) of the existing pipeline from transmission to distribution pressure, but dismissed it as imprudent as while it would reduce the consequence of a risk event from, it would not change the likelihood nor would it address the corrosion which triggers the risk event. Therefore, the risk would not be reduced to as low as reasonably practicable (ALARP), required under our risk management framework.
Proposed solution	Option 1 is the proposed solution. This involves installing a new TP to high pressure (HP) district regulator and polyethylene (PE) HP distribution trunk main along Main South Rd to tie into existing downstream HP network. This activity will mitigate the high health and safety, operational and compliance risks associated with corrosion of the TP pipelines. It will also reduce the operational and financial risks of emergency repairs. Option 2 achieves the same risk reduction but at a higher cost. We do not consider the growth in the area requires maintaining the current capacity of the steel TP offtake.

Option 3 achieves the same risk reduction in relation to the identified corrosion on the M53, but at a higher cost. Moreover, it only addresses the known corrosion identified through DCVG surveys and excavation. It is therefore possible that corrosion may remain on areas of the pipeline that have not been excavated.

Estimated cost

The forecast direct capital cost (excluding overhead) during the next access arrangement (AA) period (July 2021 to June 26) is $1.6 million.

$'000 2019/20	21/22	22/23	23/24	24/25	25/26	Total
M53 replace-ment	376.0	1,193.4	-	-	-	1,569.5

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 the Delivering for Customers aspect of our vision. It delivers for customers by mitigating the risk to public health & safety, as well as ensuring 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)(i) and (ii), as it is necessary to maintain the safety and integrity 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 latest 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 replacement of the 800 m offtake of the M53 pipeline TP pipeline will mitigate the risk of known corrosion, and reduce the risk of unidentified corrosion, mitigating public health & safety risks, as well as ensuring security and reliability of gas supply for the customers in Hackham.

The replacement of the pipeline with a new PE HP distribution trunk main is the lowest cost solution of addressing the corrosion, while maintaining the level of service to customers.

Other relevant documents

- Attachment 8.2 Strategic Asset Management Plan

1.3 Background

The SA gas distribution network includes approximately 200 km of metropolitan TP pipelines[12], which deliver gas to over 450,000 consumers. The majority of these TP pipelines are steel and were constructed in the 1970s and 1980s.

The primary risk associated with steel pipelines is corrosion, which can weaken the pipe wall and cause an integrity failure. To mitigate the risk of a TP pipeline integrity failure, the pipelines are coated with corrosion-inhibiting products such as coal tar enamel, fusion bonded epoxy and PE and subject to a cathodic protection (CP) system, which uses a low voltage electrical current to inhibit the onset of steel corrosion. Heat shrink sleeves (HSS) have been applied to pipelines of various ages.

We also routinely inspect steel pipelines for corrosion through direct current voltage gradient (DCVG) surveys combined with direct inspection excavations (dig ups) where inline inspection is not possible.

The original M53 pipeline was a 7.9 km TP pipeline between Lonsdale and Noarlunga commissioned in 1975. Since installation, some sections of the pipeline have been replaced and renamed. Table 1.3 shows the key features of the original M53 pipeline.

Table 1.3: M53 pipeline information

Pipeline	M53
Location	Lonsdale to Noarlunga
Total length	7.9 km
Age	45 years
Diameter	DN200, DN100
Pipe material	API 5L Gr B
Pipe wall thickness	6.35mm, 4.37mm
Line-pipe coating	Yellow jacket polyethylene
Field coating	Heat-shrink sleeve
Cathodic protection	Impressed current cathodic protection

Through DCVG surveys and excavations, we identified significant pitting corrosion beneath disbonded heat shrink sleeves along the length of the M53 pipeline. The M53 pipeline is being replaced over three phases and three AA periods.

The first phase was completed in 2013, with 3.1 km of the M53 replaced to address this corrosion, reduce the safety risk and ensure ongoing supply to the major residential growth area of the southern suburbs of metropolitan Adelaide. This 3.1 km of the original M53 pipeline was renamed M131.

The second phase is due for completion during the current AA period (July 2016 to June 21), with a further 4.06 km of DN 200 section of M53 being replaced.

This business case considers a number of options to address the corrosion and associated safety risk of the third and final phase of the M53 replacement, which is an 800 m section of DN100. This short section of TP pipeline is an offtake servicing 600 customers in the Hackham area, which we

[12] TP pipelines operate with a maximum allowable operating pressure (MAOP) above 1050 kPa, therefore their design, construction, operation and maintenance are governed by Australian Standard 2885.

are not expecting significant growth in, given the bounding of the area, and therefore restricted development opportunities (see Appendix A).

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 associated with the M53 offtake is pipeline failure due to corrosion causing an uncontrolled gas escape, resulting in major injury or fatality, or impacting supply to <1,000 customers. Untreated, this results in a safety risk rating of high. The reputational risk consequence of this risk event occurring is significant, therefore the reputation and customer risk is rated moderate.

The untreated risk[13] associated with this project is shown 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	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Major	Minor	Minor	Minor	Minor	Significant	Minor	
Risk Level	High	Low	Low	Low	Low	Moderate	Low	

1.5 Options considered

The following options have been identified to address the risk associated with corrosion on the M53 pipeline:

- **Option 1** – Replace the M53 offtake with new PE HP distribution trunk main;
- **Option 2** – Like-for-like replacement of the M53 offtake with new steel TP pipeline; or
- **Option 3** – Repair the M53 offtake.

These options are discussed in the following sections.

We also considered downgrading the maximum allowable operating pressure (MAOP) of the existing pipeline from transmission to distribution pressure. This option would cost around $1 million as it would require the replacement of the district regulator station (DRS). However, downgrading the pressure would only reduce the severity of the risk event. It would not address the likelihood of the risk event as downgrading pressure would not address the corrosion. The treated risk would not be considered ALARP and is therefore inconsistent with the risk management framework. Derating the pipeline was therefore considered imprudent and not considered further in this business case.

1.5.1 Option 1 – Replace the M53 offtake with a new PE HP distribution trunk main

This option would involve decommissioning the 800 m DN100 section of M53 pipeline and installing a new PE trunk main including by boring a 300 m section below the Main South Road overpass and tying the new pipe into the existing downstream HP network. This option would also require replacing the existing R405 district regulator station (DRS) with a new TP to HP DRS.

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

1.5.1.1 Cost assessment

The estimated direct capital cost of this option is $1.6 million. This estimate is based on current material and labour rates.

Table 1.5: Cost estimate – Option 1, $'000 2019/20

	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Scope	Plan and design	Install and commission/ decommission				
Labour ($)	196.8	1,148.6	-	-	-	**1,345.5**
Materials ($)	179.2	44.8	-	-	-	**224.0**
Total	**376.0**	**1,193.4**	-	-	-	**1,569.5**

The key driver for this option is removal of all identified and unidentified corrosion on the M53 offtake. Doing this will mitigate the safety risk associated with a failure of the M53, and maintain service to our customers. The benefits of this option are:

- renewing the asset life, reducing the risks of safety incidents and of supply loss to up to 600 consumers due to a significant gas escape;
- minimising long term repair costs, by avoiding the high operational costs involved with an increased quantity of emergency repairs (approximately $200,000 per repair);
- avoiding the cost of managing a gas outage, including potential switching costs of $50-$100 per affected customer; and
- maintaining current levels of service to customers.

Note that replacing the current TP steel pipeline with a PE HP main means there is less provision for load growth going forward than if a TP steel pipeline is retained. However, given the bounding of the area, and therefore restricted development opportunities (see Appendix A), a material increase is unlikely.

1.5.1.2 Risk assessment

Option 1 reduces the risk of pipeline failure due to corrosion from high to low. By replacing the corroded asset with a new asset that cannot corrode, the likelihood of a pipeline failure due to corrosion is reduced as low as possible to rare. The risk assessment is shown in Table 1.6.

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	Minor	Minor	Significant	Minor	
Risk Level	Low	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	

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

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	Y

Option 1 would align with the *Delivering for Customers* aspect of our vision, as addressing corrosion on the M53 by replacing the pipeline will help mitigate the risk of public safety incidents. Although the replacement is not like-for-like, the proposed solution will maintain current levels of service and reliability of supply to our customers in Hackham.

The proposed solution is also *Sustainably Cost Efficient* as replacing the M53 offtake with a new PE HP distribution trunk main is the lowest sustainable cost of managing the corrosion risk, and is less expensive than replacing it with a like-for-like solution. Using PE in these circumstances is consistent with prudent asset management and is within industry benchmarks.

1.5.2 Option 2 – Like-for-like replacement of the M53 offtake with new steel TP pipeline

Under this option, we would decommission the 800 m DN100 section of M53 pipeline and install a new steel TP pipeline capable of inline inspection.[14] This solution would also require boring a 300 m section below the Main South Road overpass and replacing the existing R405 DRS with a new TP to HP DRS.

1.5.2.1 Cost assessment

The estimated direct capital cost of this option is $2.5 million. This estimate is based on current material and labour rates.

A cost breakdown is provided in Table 1.8.

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

	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Scope	Plan and design	Install and commission /decommission				
Labour ($)	296.8	1,875.0	-	-	-	2,171.8
Materials ($)	224.0	56.0	-	-	-	280.0

[14] More information on inline inspections is available in APA Technical Policy – In-line Inspection Transmission Pressure Pipelines – 320-POL-AM-0022.

	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Total	520.8	1,931.0	-	-	-	2,451.8

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

The key driver for this option is removal of all identified and unidentified corrosion on the M53 offtake. Doing this will mitigate the safety risk associated with a failure of the M53, and maintain service to our customers. The benefits of this option are:

- renewing the asset life, reducing the risks of safety incidents and of supply loss to up to 600 consumers due to a significant gas escape;
- the new pipeline is capable of the more effective and efficient inline inspection method of detecting corrosion (although it will not be required for ten years);
- minimising long term repair costs, by avoiding the high operational costs involved with an increased quantity of emergency repairs (approximately $200,000 per repair);
- avoiding the cost of managing a gas outage, including potential switching costs of $50-$100 per affected customer; and
- allowing for significant future growth in the Hackham area.

Option 2 is inconsistent with our risk management framework as it does not reduce the risk below moderate and is consistent with some (but not all) of our vision objectives as discussed in the following sections.

1.5.2.2 Risk assessment

Option 2 reduces the risk of pipeline failure due to corrosion from high to moderate. By replacing the corroded asset with a new asset, the likelihood of a pipeline failure due to corrosion is reduced to remote. However, because there remains a risk of corrosion on the new steel pipeline, unlike the replacement with PE, the likelihood cannot be reduced to rare.

The risk assessment is shown in Table 1.9.

Table 1.9: 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	Minor	Minor	Minor	Significant	Minor	
Risk Level	Moderate	Negligible	Negligible	Negligible	Negligible	Low	Negligible	

1.5.2.3 Alignment with vision objectives

Table 1.10 shows how Option 2 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

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	N
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 addressing corrosion on the M53 by replacing the pipeline will help mitigate the risk of public safety incidents and maintain current levels of service and reliability of supply to our customers in Hackham. Keeping this 800 m section of main as TP steel means the pipeline retains greater capacity to support load growth in the future than a PE HP trunk main would (as per Option 1).

The like-for-like replacement of the M53 offtake with a steel TP pipeline results in a substantially higher cost and tariff impact than replacing it with a new PE HP distribution trunk main. Option 2 would therefore not be considered prudent and is not the most *Sustainably Cost Efficient* solution.

1.5.3 Option 3 – Repair the M53 offtake

Under this option, we would repair all identified areas of corrosion on the M53 offtake. This would involve excavating the pipeline at 12 m intervals and repair corrosion beneath the disbanded heat shrink sleeve field joint coating. As excavation cannot occur for the 300 m section below the Main South Road overpass, we would replace this section with new steel pipeline. The pipeline would remain incapable of facilitating inline inspection.

1.5.3.1 Cost assessment

The estimated direct capital cost of this option is $1.6 million. This estimate is based on current material and labour rates.

Table 1.11: Cost estimate – Option 3, $'000 2019/20

	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Scope	Plan	Dig up and Repair				
Labour ($)	196.8	1,340.0	-	-	-	1,536.8
Materials ($)	77.4	19.4	-	-	-	96.8
Total	**274.3**	**1,359.3**	**-**	**-**	**-**	**1,633.6**

This option addresses known risks associated with corrosion on the M53 offtake, but does not:

- reflect the actions of a prudent asset manager;
- significantly extend the asset life or renew the pipeline;
- reduce the risks of safety incidents and of supply loss to up to 600 consumers due to a significant gas escape caused by unidentified corrosion, the risk of which increases over time as the M53 continues to age and deteriorate;

- avoid the high operational costs involved with an increased quantity of emergency repairs (approximately $200,000 per repair) associated with unidentified corrosion; and
- avoid the cost of managing a gas outage, including potential switching costs of $50-$100 per affected customer.

Option 3 is inconsistent with our risk management framework and our vision objectives as discussed in the following sections.

1.5.3.2 Risk assessment

Option 3 reduces the risk of pipeline failure due to corrosion from high to moderate. By repairing known corrosion on the M53 offtake, the likelihood of a pipeline failure due to corrosion is reduced to remote.

Option 3 achieves the same risk rating as the replacement of the M53 with a new steel TP pipeline (Option 2). However, the likelihood of corrosion is significantly higher under this option as the pipeline itself is not renewed, and therefore:

- the remainder of the pipeline could have unidentified corrosion; and
- the likelihood of corrosion increases over time as the M53 continues to age and deteriorate.

This option is inconsistent with our risk management framework as it does not reduce the risk to low or ALARP. The risk assessment is shown in Table 1.12.

Table 1.12: Risk assessment – Option 3

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

1.5.3.3 Alignment with vision objectives

Table 1.13 shows how Option 3 aligns with our vision objectives.

Table 1.13: 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	-

Option 3 would not align with the *Delivering for Customers* aspect of our vision, it will help mitigate the risk of public safety incidents related to known corrosion and maintain current levels of service and reliability of supply to our customers in Hackham. However, it would not address corrosion risk on the remainder of the ageing pipeline.

The repair of the M53 offtake results in a similar cost and tariff impact as replacing it under either option 1 or 2, but would not deliver the same level of risk reduction. This option would therefore not be considered prudent and is not the most *Sustainably Cost Efficient* solution.

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 alignment with our vision objectives.

Table 1.14: Comparison of options

Option	Estimated cost ($ million)	Treated residual risk rating	Alignment with vision objectives
Option 1	1.6	Low	Aligns with *Delivering for Customers* and *Sustainably Cost Efficient*
Option 2	2.5	Moderate	Does not align with *Delivering for Customers* and *Sustainably Cost Efficient*
Option 3	1.6	Moderate	Is not ALARP and does not align with *Delivering for Customers* and *Sustainably Cost Efficient*

1.7 Recommended option

Option 1 is the proposed solution and involves:

- decommissioning the 800 m long DN100 section of M53 pipeline;
- installing a new PE trunk main including by boring a 60 m section below the Main South Road overpass and tying the new pipe into the existing downstream HP network; and
- replacing the existing R405 DRS with a new TP to HP DRS.

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 as it removes all identified and unidentified corrosion on the M53 offtake, thereby mitigating the safety risk associated with a failure of the M53;
- it maintains current levels of service to our customers including:
  - preventing the loss of supply to up to 600 consumers due to a significant gas escape;
  - avoiding the cost of managing a gas outage, including potential switching costs of $50-$100 per affected customer; and
  - allows for moderate growth in the Hackham area; and
- it minimises long term repair costs, by avoiding the high operational costs involved with an increased quantity of emergency repairs in particular those associated with leaks related to corrosion (approximately $200,000 per repair); and

- it is consistent with stakeholder requirements and our vision.

1.7.2 Estimating efficient costs

Key assumptions made in the cost estimation for the corrosion on the M53 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;
- 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 M53 project by cost category. Table 1.16 provides the costs escalated to June 2021 dollars.

Table 1.15: Corrosion on the M53 cost estimate ($'000 2019/20)

	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Labour ($)	196.8	1,148.6	-	-	-	1,345.5
Materials ($)	179.2	44.8	-	-	-	224.0
Total	**376.0**	**1,193.4**	-	-	-	**1,569.5**

Table 1.16: Corrosion on the M53 cost estimate ($'000)

	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Total unescalated ($ Dec 19)	376.0	1,193.4	-	-	-	1,569.5
Escalation	12.7	46.1	-	-	-	58.8
Total escalated ($ Jun 21)	**388.7**	**1,239.5**	-	-	-	**1,628.2**

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 that the ongoing integrity of the M53 offtake is maintained and to reduce the risk of major gas escapes that could impact public safety and reliability of supply, and is of a nature that a prudent service provider would incur.

- Efficient – The replacement of the M53 offtake with a new PE HP distribution trunk main aligns with good industry practice and is the most cost effective option. Engineering assessments and design will be carried out by internal staff and field work will be carried out by external contractors based on competitively tendered rates. The expenditure is therefore of a nature that a prudent service provider acting efficiently would incur.

- Consistent with accepted and good industry practice – The ongoing effective management of the integrity of the TP pipelines is consistent with Australian Standard AS2885.3 Pipelines - Gas and Liquid Petroleum, Part 3: Pipeline Integrity Management. Reducing the risks posed by the corrosion of these pipelines to as low as reasonably practicable and in a manner that balances costs and risks is also consistent with this standard.

- To achieve the lowest sustainable cost of delivering pipeline services – The excavation and remediation works are necessary to maintain the long term integrity of the TP pipelines. Failure to do so would result in additional expenditure (reactive response to a major gas escape and bringing forward replacement) and shorten the life of the pipelines. The project is therefore consistent with the objective of achieving the lowest sustainable cost of delivering services.

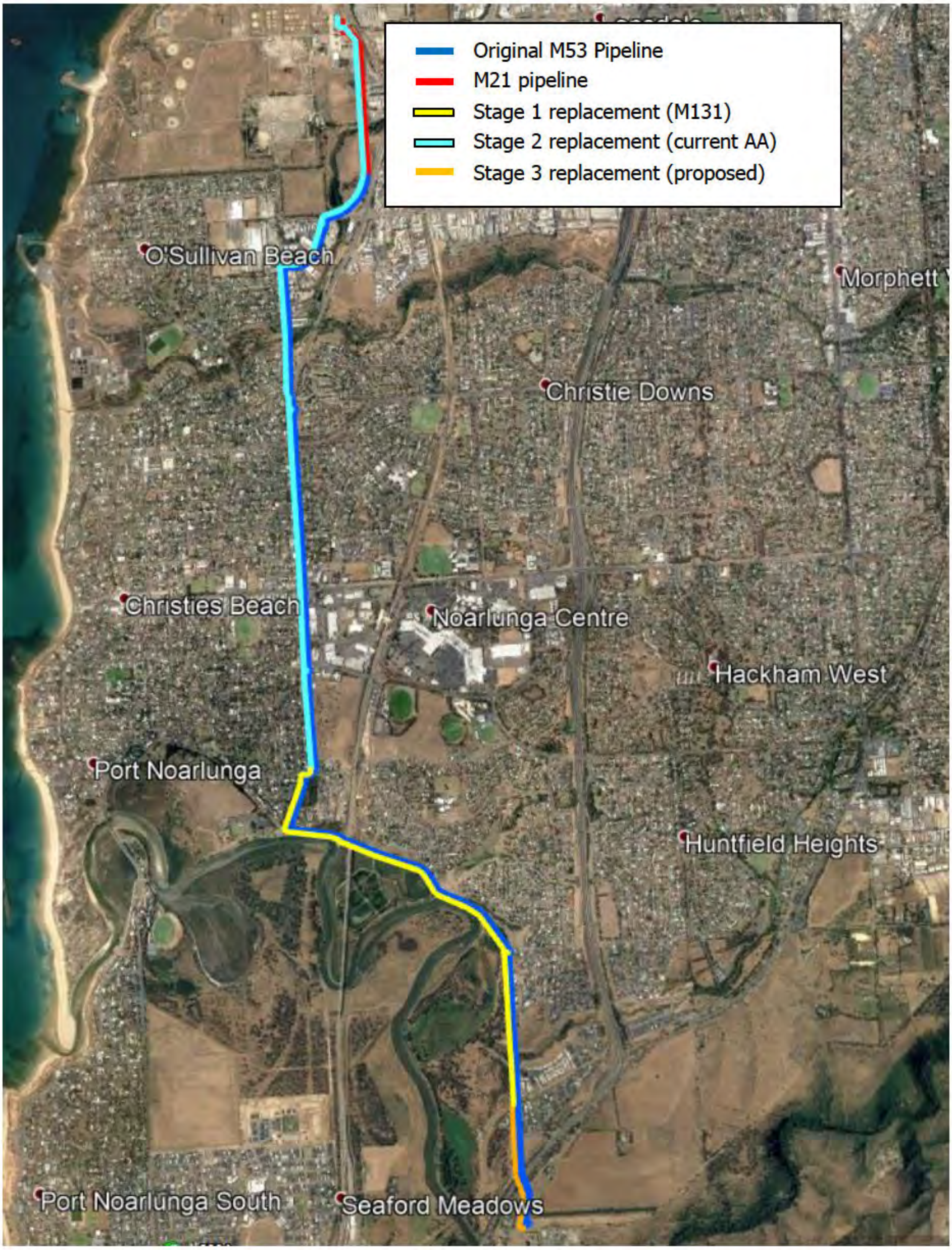
NGR 79(2)

The proposed capex is justifiable under NGR 79(2)(c)(i) and 79(2)(c)(ii), as it is necessary to maintain the safety and integrity of services. Allowing HP pipelines to continue to corrode to the extent performance is compromised will lead to network integrity issues, disruption to customer supply and potential uncontrolled release of gas.

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 – Map of the M53 pipeline



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	Minor	Minor	Minor	Significant	Minor	
Risk Level	High	Low	Low	Low	Low	Moderate	Low	

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	Minor	Minor	Significant	Minor	
Risk Level	Low	Negligible	Negligible	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	Minor	Minor	Minor	Significant	Minor	
Risk Level	Moderate	Negligible	Negligible	Negligible	Negligible	Low	Negligible	

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

Appendix C – Cost estimates

Option 1 - Replacement of the M53 offtake with a new PE HP distribution trunk main

Category	Description	Units	Units QTY	Number of sites	Unit Cost $/ unit	Total $'000
Materials						
Pipe, valves and fittings	DN280 polyethylene pipe, valves and fittings	meters	[redacted]	[redacted]	[redacted]	[redacted]
	TP- HP DRS materials	each	[redacted]	[redacted]	[redacted]	[redacted]
Other	Freight, storage, and handling	each	[redacted]	[redacted]	[redacted]	[redacted]
Total materials						**224.0**
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]
	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]
	Survey Alignment, land acquisition and third party permits	each	[redacted]	[redacted]	[redacted]	[redacted]
	Workshop fabrication and installation of TP-HP DRS	each	[redacted]	[redacted]	[redacted]	[redacted]
Project site labour and delivery	Contractor rate	meters	[redacted]	[redacted]	[redacted]	[redacted]
	Reinstatement	meters	[redacted]	[redacted]	[redacted]	[redacted]
	Reinstatement (DPTI Road Profiling)	meters	[redacted]	[redacted]	[redacted]	[redacted]
	Traffic control	meters	[redacted]	[redacted]	[redacted]	[redacted]

Category	Description	Units	Units QTY	Number of sites	Unit Cost $/ unit	Total $'000
	Pressure testing (Hydro test)	each	[redacted]	[redacted]	[redacted]	[redacted]
	Non-destructive testing	each	[redacted]	[redacted]	[redacted]	[redacted]
	Commissioning	each	[redacted]	[redacted]	[redacted]	[redacted]
Total Labour						**1,345.5**
Total Project						**1,569.5**

Option 2 – Like-for-like replacement of the M53 offtake with a new steel TP pipeline

Category	Description	Units	Units QTY	Number of sites	Unit Cost $/ unit	Total $'000
Materials						
Pipe, valves and fittings	DN150 Steel pipe, valves and fittings	meters	[redacted]	[redacted]	[redacted]	[redacted]
	TP- HP DRS materials	each	[redacted]	[redacted]	[redacted]	[redacted]
Other	Freight, storage, and handling	each	[redacted]	[redacted]	[redacted]	[redacted]
Total materials						**280.0**
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]
	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]
	Survey alignment, land acquisition and third party permits	each	[redacted]	[redacted]	[redacted]	[redacted]
	Workshop fabrication and installation of TP-HP DRS	each	[redacted]	[redacted]	[redacted]	[redacted]
Project site labour and delivery	Contractor rate	meters	[redacted]	[redacted]	[redacted]	[redacted]
	Reinstatement	meters	[redacted]	[redacted]	[redacted]	[redacted]
	Reinstatement (DPTI Road Profiling)	meters	[redacted]	[redacted]	[redacted]	[redacted]
	Traffic control	meters	[redacted]	[redacted]	[redacted]	[redacted]
	Pressure testing (Hydro test)	each	[redacted]	[redacted]	[redacted]	[redacted]

Category	Description	Units	Units QTY	Number of sites	Unit Cost $/ unit	Total $'000
	Non-destructive testing	each	[redacted]	[redacted]	[redacted]	[redacted]
	Commissioning	each	[redacted]	[redacted]	[redacted]	[redacted]
Total labour						**2,171.8**
Total project						**2,451.8**

Option 3 – Repairing the M53 offtake

Category	Description	Units	Units QTY	Number of sites	Unit cost $/ unit	Total $'000
Materials						
Pipe, valves and fittings	DN150 Steel pipe, valves and fittings	meters	[redacted]	[redacted]	[redacted]	[redacted]
	Coating UHBE	each	[redacted]	[redacted]	[redacted]	[redacted]
Other	Freight, storage and handling	each	[redacted]	[redacted]	[redacted]	[redacted]
Total materials						**96.8**
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]
	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]
	Survey alignment, land acquisition and third party permits	each	[redacted]	[redacted]	[redacted]	[redacted]
	Dig ups and repair	each	[redacted]	[redacted]	[redacted]	[redacted]
Project site labour and delivery	Contractor rate	meters	[redacted]	[redacted]	[redacted]	[redacted]
	Reinstatement	meters	[redacted]	[redacted]	[redacted]	[redacted]
	Traffic control	meters	[redacted]	[redacted]	[redacted]	[redacted]
	Pressure testing (Hydro test)	each	[redacted]	[redacted]	[redacted]	[redacted]
	Non-destructive testing	each	[redacted]	[redacted]	[redacted]	[redacted]

Category	Description	Units	Units QTY	Number of sites	Unit cost $/ unit	Total $'000
	Commissioning	each	[redacted]	[redacted]	[redacted]	[redacted]
Total labour						**1,536.8**
Total project						**1,633.6**

SA105 – Pipeline modification for in line inspection

1.1 Project approvals

Table 1.1: Business case SA105 – Project approvals

Prepared by	Nick Rubbo, Integrity 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 SA105 – Project overview

Description of the problem / opportunity	The South Australia (SA) distribution network includes approximately 200 km of metropolitan transmission pressure (TP) pipelines, which deliver gas to over 450,000 customers. Currently, the integrity of the SA metropolitan transmission pipelines is monitored by conducting direct current voltage gradient (DCVG) surveys combined with direct inspection excavations (or 'dig ups'). While DCVG and dig ups provide useful information on pipeline condition, they do not provide a complete picture of the amount of corrosion on a pipeline. This is because not every part of a pipeline is accessible (particularly in built-up metropolitan areas). This means DCVG and dig-up results have to be extrapolated across a pipeline and are therefore subject to considerable imprecision. The effectiveness of DCVG and dig ups alone as an integrity management tool is also limited by the fact many pipelines in the SA network have vintage coatings, or coatings that shield cathodic protection (e.g. heat shrink sleeves). These coatings are showing increasing signs of degradation, which makes it difficult to demonstrate structural integrity using the DCVG method alone. As a result, the potential for corrosion defects to go undetected is high, which can lead to pipeline failure. In line inspection (ILI) (also known as pigging) is a method of inspection whereby an ILI tool (pig) is pushed through the pipeline, measuring pipe wall thickness, internal pipe dimensions, and detecting defects. ILI is common practice on most other Australian gas transmission and high pressure pipelines, and is proven to be a highly effective and efficient method of managing pipeline integrity. We therefore propose to adopt ILI inspection for our SA TP pipelines. ILI will enable us to create an accurate data baseline for our pipelines, which we can use to assess ongoing structural integrity. We can use this information to inform investment decisions on asset management activities. From an economic perspective, ILI will enable us to pinpoint areas of corrosion, dents and gouges and apply targeted correction/maintenance, which will allow us to manage the ongoing integrity of the pipeline more efficiently. This in turn will allow us to safely operate the assets beyond for more than 40 years. The data provided by ILI will also provide important information to inform decisions on future asset management strategies. Most importantly, being able to perform ILI will improve our ability to detect and address issues on these high pressure pipelines before they escalate into uncontrolled gas escapes. Adopting ILI will reduce the safety and integrity risk associated with TP pipelines from high to moderate, by significantly reducing the likelihood of an integrity failure that could affect tens of thousands of customers and put the public in the vicinity of the gas escape at risk. The majority of SA metropolitan TP pipelines were constructed more than 30 years ago and are not configured to accommodate ILI. We therefore need to undertake a program of work to modify all of our TP pipelines over the next 20-30 years

	Our ultimate goal is to make all of our TP pipelines piggable, either by modifying existing pipelines to allow ILI tools to pass through them, or by ensuring any new TP pipelines are piggable. We recognise that the overall cost of modifying around 200 km of TP pipelines will be significant, and the time and resourcing effort to achieve this must be carefully managed. It is not practicable to modify all SA TP pipelines within the next five years. However, it is prudent to commence the pigging journey and conduct the necessary engineering studies to identify the costs, challenges and ongoing benefits of reconfiguring the pipelines. This includes identifying the order in which pipelines should be made piggable and the most prudent timeframe to achieve this. This business case therefore considers a number of options to commence studies and ILI modification activities over the next five years. It focuses on the program for modifying five TP pipelines that have been identified as the most suitable and/or highest priority candidates for ILI modification: M12, M42, M55, M84 and M101.
Untreated risk	As per risk matrix = **High**

Options considered	• **Option 1** – Maintain status quo - continue with current practice of DCVG and dig ups only, and then repair/replace the pipelines upon failure
	
	Zero upfront additional capital cost, however the cost of replacing the TP pipelines upon failure will be substantial
	
	• **Option 2** – Conduct physical FEED[15] study on the four highest priority TP pipelines and undertake one high priority ILI modification project that will be indicative of the costs and challenges of future works. This includes:
	  ◦ conducting potholing and using ground penetrating radar to determine scope of required modifications on pipelines M12, M84, M42 and M101;
	  ◦ modifying TP pipelines M12 and M84[16] for compatibility with ILI; and
	  ◦ conducting an ILI run on the M12 and M84 pipelines
	
	Estimated cost = $32 million
	
	• **Option 3** – Conduct physical FEED study on all five pipelines[17] and undertake a pilot program to modify a small, simple section of TP pipeline for ILI compatibility. This includes:
	  ◦ conducting potholing and using ground penetrating radar to determine scope of required modifications on TP pipelines M12, M42 M55, M84 and M101 pipelines;
	  ◦ modifying TP pipeline M55 for compatibility with ILI; and
	  ◦ conducting an ILI run on the M55 pipeline.
	
	Estimated cost = $22 million
	
	• **Option 4** – Conduct physical FEED study and then modify the four highest priority TP pipelines in order to achieve the greatest risk reduction quickly. This includes:
	  ◦ conducting potholing and using ground penetrating radar to determine scope of required modifications on TP pipelines M12, M42, M84 and M101;
	  ◦ modifying TP pipelines M12, M42, M84 and M101 for compatibility with ILI; and
	  ◦ conducting an ILI run on the M12, M42, M84 and M101 pipelines.
	
	Estimated cost = $72 million
	
	Note additional options were considered and rejected at the pre-business stage. These included re-coating the pipelines, de-rating the pipelines to a pressure below 1050 kPa, and increasing the frequency of DCVG and dig ups.
	
	The re-coating option was dismissed as the cost of re-coating the metropolitan TP pipelines would be upwards of $38 million and re-coating pipelines will not address corrosion that has already occurred.

15 Front End Engineering Design.

16 Note M84 is a relatively short pipeline connected to the much longer M12 pipeline, which can be pigged in the same run. Therefore for technical and economic efficiency reasons, these two would be modified for ILI at the same time.

17 The four highest priority pipelines, plus M55.

	Derating the pipelines would require additional costs to modify 93 district regulator stations, as well as modifying meter facilities for a number of demand customers. It may also lead to insufficient spare capacity to cater for future growth. The de-rating option was therefore not pursued further. Increasing the frequency of DCVG and dig ups was dismissed there will always be sections of pipeline that are inaccessible, meaning corrosion cannot be detected. Simply doing more DCVG and dig ups would therefore do little to address the risk associated with these pipelines.
Proposed solution	Option 2 is the proposed solution because it addresses a high priority and fairly complex pipeline (M12), while also providing an important practical example of the process, costs and challenges associated with making a pipeline piggable. This will allow us to establish a suite of unit rates and valuable data to inform the future ILI modification program. We consider this a prudent approach, which will ultimately allow us to deliver the long term program more efficiently. Option 2 also provides the best net present value (NPV) of the options considered. Option 2 is preferable to Option 3. This is because modifying the relatively short and simple M55 pipeline would not be as representative of the likely costs and practicalities of modifying many of the longer, more complex pipelines (such as M12). Given these more complex and higher risk pipelines will need to be modified at some point, we see less value in deferring these in favour of a simple project in the first instance. Option 4 would achieve the greatest risk reduction during the next access arrangement (AA) period. However, reconfiguring all four pipelines would be more resource-intensive and the program would be at greater risk of under-delivery if problems are encountered. It is also the highest short term cost option. Option 1 is the least efficient over the long term, as it would not allow us to safely extend the technical design life of some of our largest and most expensive assets. Option 1 would not represent the actions of a prudent asset manager, particularly when ILI is a proven solution. Option 1 would not reduce the risk associated with high pressure natural gas assets to as low as reasonably practicable (ALARP).
Estimated cost	The forecast direct capital cost (excluding overhead) during the next AA period (July 2021 to June 2026) is $32 million.

$'000 2019/20	21/22	22/23	23/24	24/25	25/26	Total
Pipeline ILI	4,250.7	6,776.8	7,075.7	7,065.0	6,821.4	31,989.6

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 investment aligns with Delivering for Customers, as enabling ILI will mitigate the risk of TP pipeline failure, which would cause significant disruption to up to 450,000 customers. The proposed Option 2 is also Sustainably Cost Efficient, as it represents an efficient balance between incurring costs now and gathering important data and experience that will allow the future program to be delivered efficiently. We are conscious of the short term impact large scale projects can have on network tariffs. We are therefore taking a measured and prudent approach to undertaking this critical pipeline integrity program. We consider the mix of study and practical completion under Option 2 is consistent with achieving the lowest sustainable cost of maintaining TP pipeline integrity over the long term.
Consistency with the National Gas Rules (NGR)	**NGR 79(1)** – the proposed solution is consistent with good industry practice, as ILI is a proven and efficient method of detecting corrosion and maintaining pipeline integrity. 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 current TP pipeline condition and priority as per the Strategic Asset Management Plan. NPV assessments have been conducted for each option. 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. Consistent with our customers' preferences, we have taken steps to ensure the ILI modification program does not significantly impact prices in the short term, and to enable the program to be delivered efficiently over the coming decades. Our aim is to take a pragmatic approach to this critical integrity program, spreading the costs over a reasonable time frame – balanced against other investments – to help keep network costs affordable. Customers have told us that they want and value the service provided by our natural gas network, and that they expect to be able to access natural gas over the long term. The ILI modification program is vital to ensuring the TP pipelines remain operable over the long term and allow us to continue to meet customers' expectations.
Other relevant documents	• Attachment 8.2 Strategic Asset Management Plan • Supporting Information 8.8.1 SA105 NPV & Options Analysis • APA Technical Policy – In-line Inspection Transmission Pressure Pipelines – 320-POL-AM-0022 • Cost Verification – Transmission Pipeline Modification for ILI – 19737-REP-001

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 are primarily located in suburban or industrial areas, which are typically heavily developed[18] and/or near to population centres. As a result, the consequences of a metropolitan TP pipeline failure are potentially more severe than failures in sparsely populated areas. Refer to Appendices A and C for a summary of the SA metropolitan TP pipeline details.

The majority of our TP pipelines were constructed prior to 1987, with the two longest and highest priority pipelines (M42 and M12) being over 50 years old. The greatest risk associated with these steel pipelines is corrosion, which can weaken the pipe wall and cause an integrity failure. To mitigate the risk of a TP pipeline integrity failure, the pipelines are coated with corrosion-inhibiting products and subject to a cathodic protection (CP) system, which uses a low voltage electrical current to inhibit the onset of steel corrosion.

Some older sections of pipelines in our gas distribution networks are coated with coal tar enamel (CTE), while newer sections are coated with polyethylene (PE). Heat shrink sleeves (HSS) have been applied to pipelines of various ages.

The CTE coatings are showing signs of deterioration, which means some of our oldest pipelines are becoming less well protected against corrosion. Though PE coatings and HSS have been applied to pipelines more recently, these too are showing signs of deterioration. HSS in particular have begun

[18] Developed areas typically have sealed ground surfaces and opportunity for significant volumes of gas to collect below ground or below a building in the event of an uncontrolled gas escape.

to pose problems[19], as they can disbond from the pipeline surface. Disbonded HSS impact the effectiveness of the CP system, as it prevents the electrical current reaching the steel surface.

Coatings and CP are the primary forms of preventing pipeline corrosion. It is therefore important to be able to continually measure and monitor the effectiveness of these systems and have sufficient information to be able to demonstrate the structural integrity of the steel pipelines.

Demonstrating structural integrity is a requirement of Australian Standard AS2885.3-2012 (clause 6.5). There are two principal methods currently used by natural gas network owners/operators to monitor (and ultimately demonstrate) the structural integrity of a pipeline:

1. Measure the pipeline coating for faults with a Direct Current Voltage Gradient (DCVG) survey and conduct direct examination (dig ups) at faults to inspect for pipeline steel deterioration; and
2. Measure the thickness and condition of the pipeline steel by in-line inspection (ILI) and verify the results by direct examination.

Both these methods are accepted industry practice and are used by gas distribution network businesses to maintain the structural integrity of TP pipelines in a prudent and efficient manner. These two pipeline integrity management methods are discussed further in the following sections.

1.3.1 DCVG

A DCVG survey is used to measure the condition of pipeline coatings. DCVG involves taking surface measurements of the amount of electrical current that is escaping through coating faults into the surrounding soil. The coating fault 'indications' are denoted by an IR reading. The IR reading provides an indication of the size of the coating fault. Depending on the size of the IR reading, the location of the pipeline, CP performance, and previous dig up history, the section of pipeline where the coating defect has been identified will be excavated and directly examined.

There is generally little correlation between the size of coating faults and defects in the steel pipeline wall (a large coating default does not necessarily mean there will be substantial corrosion at that location). However, because an uncoated section of pipeline is more likely to develop corrosion over time, DCVG is a useful lead indicator of pipeline integrity.

Though DCVG remains an important and well-accepted pipeline integrity management practice, there are limitations to its effectiveness. The accuracy of DCVG readings can be impacted by soil conditions and other ground infrastructure in proximity to the pipeline. Disbonded HSS can also shield CP, which leads to a lower probability that faults along that pipeline will be detected. Some TP pipeline sections cannot be directly examined by excavation simply because they are inaccessible (e.g. sections of pipeline that pass under rivers and rail crossings, or in some sections of road reserve).

DCVG and dig ups only provide an indication of the pipeline coating condition at a sample of locations where the pipeline steel condition has been assessed. Results must be extrapolated for the remaining sections of the pipeline.

1.3.2 ILI

ILI involves inserting an intelligent pigging tool into the pipeline, which takes measurements of the pipeline steel condition as it is propelled[20] through the pipeline. ILI has a high probability of

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[19] Note TP pipelines M53 and M21 recently had to be replaced due to an integrity failure. The failure was caused by excessive corrosion and pinholes beneath heat shrink sleeves.

[20] The pig is propelled through the pipeline by the pressure of the natural gas flow.

detecting steel defects as it measures an entire continuous length of pipeline (rather than relying on extrapolation of spot results). ILI also has a high degree of accuracy.

ILI provides detailed information on the structural integrity of pipelines. It identifies the precise location of corrosion or defects that could lead to corrosion. Most significantly, ILI allows inspection of sections of pipelines that cannot be accessed by DCVG and dig ups.

ILI requires the TP pipeline to be of sufficient diameter, configuration and bend radius to allow the 'pig' to pass through it without getting stuck. Older pipelines often have inconsistent diameters or tight bends, as they were constructed before ILI was a consideration. Many older pipelines therefore require modification (including installation of a pig launcher and a pig catcher) before ILI can be conducted.

1.3.3 Benefits of ILI

The benefit of the data provided by ILI is that it allows the asset owner/operator to make informed decisions about ongoing pipeline management, including whether it is safe to extend (or continue to extend) use of the pipeline beyond its technical design life. The SA network of TP pipelines has a technical design life of around 40 years. Where pipelines exceed their design life, they are subject to a 'remaining life review', which is an assessment of the safety and suitability of the pipeline for continued use.[21]

The actual condition of a pipeline does not always correlate to its age – a 40-year old pipeline may well have suffered less corrosion than a 20-year old pipeline. However, if a TP steel pipeline has been in situ for longer than its design life, and the entire length of the pipeline cannot be inspected (because ILI is not available), serious consideration must be given to replacing the pipeline as the potential for significant corrosion will be high.

The cost of replacing metropolitan TP pipelines can run into hundreds of millions of dollars, and can cause significant disruption to a large number of customers.[22] A prudent asset manager will therefore seek to repair and extend the life of a TP pipeline where practicable and safe to do so. However, due to the risk associated with a high pressure pipeline located in a heavily populated area, its technical design life should ideally only be extended if the structural integrity of the pipeline can be demonstrated and there is sufficient confidence that the risk of integrity failure is tolerable. Without ILI, the asset manager must rely on assumptions and an extrapolated view of pipeline condition.

ILI provides a full picture of asset condition. It therefore allows the asset manager to safely extend the life of the asset where the inspection shows the pipeline to be in good or serviceable condition. AS 2885 requires ILI be considered for steel TP pipelines. Typically, ILI is undertaken at ten-yearly intervals or more frequently unless engineering assessment determines a lesser frequency is appropriate.

The data provided by ILI also allows more efficient ongoing management of the pipeline. Being able to pinpoint the location of defects means dig ups, repairs and replacements can be targeted and scheduled in an economically efficient manner. It also means the environmental conditions and contributing factors to corrosion/defects at those locations can be analysed, and lessons learnt can be applied to other pipelines with similar characteristics.

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[21] Pipelines M101 and M42 were last reviewed in 2019, and M12, M42, M55 and M84 in 2018.

[22] For example, the estimated cost of replacing just the ~75 km of TP pipeline currently identified for ILI modification in the SA networks is $204 million. There is a total of 200km of metropolitan TP pipelines, which supply gas to around 450,000 consumers.

Put simply, if an ILI run on an aged pipeline shows substantial corrosion, it allows an asset manager to replace or repair only the corroded sections of a pipeline rather than having to replace the entire pipeline. This can result in a significant cost saving.

1.3.4 Suitability of the SA TP pipelines for ILI

ILI is considered good industry practice and has become a standard pipeline integrity management activity used by pipeline owners/operators. Section 6.6.1 of AS 2885.3-2012 states:

> *Where a pipeline (or section of a pipeline) is not capable of being inspected by an inline tool, the Licensee shall consider whether the pipeline needs to be modified to permit inspection by an inline inspection too. Any decision not to undertake modification for this purpose shall be consistent with the safety management study and PIMP, and shall be documented.*

Other gas distribution business, including Jemena in NSW and ATCO Gas in Western Australia have recently commenced modifying some of their high pressure pipelines for ILI as part of industry good practice. During 2016 to 2018 ATCO Gas modified pipeline to enable ILI on two high pressure pipelines (East Perth Lateral and Harrow Road).

The lessons and data from both the ILI modification project and the subsequent pigging run have since been integrated into ATCO's forward-looking maintenance and replacement schedule. This has enabled ATCO Gas to more confidently maximise the asset performance and technical life, while meeting its obligations in having informed Pipeline Integrity Management Plans.

Jemena NSW recently[23] put forward a proposal for reconfiguring parts of its Sydney Primary Main to enable ILI. This is to address concerns associated with corrosion and CP failure caused by disbonded HSS. Jemena's proposal was reviewed and subsequently endorsed by the Australian Energy Regulator (AER)[24] and the AER's technical consultant Zincara[25].

APA's ILI Policy requires all new transmission pipelines with a diameter greater than or equal to DN150 be designed to accommodate ILI tools. None of our metropolitan SA TP pipelines are currently capable of accepting an ILI tool.[26]

Table 1.3 shows the pipelines that are candidates to be made piggable and a priority ranking for modifying them. The priority ranking is based on pipeline age, coating defects, and the length of pipeline situated in high density or sensitive areas[27]. The pipelines shaded in blue are those that have been considered for ILI modification within the next AA period (June 2021 to July 2026).

Table 1.3: Summary of pipeline piggability

Priority to make piggable	Pipeline number	Pipeline name	Current piggability
1	M12	Waterloo Corner to Yatala Vale	Candidate to make piggable
2	M42	Brompton to Pt. Stanvac	Candidate to make piggable
3	M101	Eastern Ring Main	Candidate to make piggable

23 JGN, June 2019, *2020 Plan*.

24 AER, November 2019, Draft Decision, Jemena Gas Networks (NSW) Ltd Access Arrangement 2020 to 2025, Attachment 5 Capital expenditure, page 5-34.

25 Zincara, 2019, Access Arrangement 2019 JGN Capital Expenditure Review, prepared for the AER, page 75.

26 Although projects to replace M53 and M21 with piggable pipelines are currently under way.

27 Sensitive areas are locations where the consequences of an integrity failure could be most severe, for example near to schools, hospitals, prisons, shopping centres, or other areas where there is a high concentration of the general public.

Priority to make piggable	Pipeline number	Pipeline name	Current piggability
4	M90	Hendon to South Brighton	Candidate to make piggable
5	M63	Port Pirie	Candidate to make piggable
6	M79	Glanville to Pt. Adelaide	Candidate to make piggable
7	M37	Plympton to Edwardstown	Candidate to make piggable
8	M83	Pt Adelaide to Queenstown	Candidate to make piggable
9	M71	Birkenhead	Candidate to make piggable
10	M22	Le Fevre Peninsula	Candidate to make piggable
11	M55	Elizabeth	Candidate to make piggable
12	M94	Dry Creek to Ingle Farm	Candidate to make piggable
13	M82	Elizabeth to Smithfield Plains, Coventry Rd	Candidate to make piggable
14	M84	Para Hills to Ingle Farm	Candidate to make piggable
15	M80	Port Adelaide to Dry Creek	Candidate to make piggable
16	M68	Nuriootpa	Candidate to make piggable
17	M76	Blacks Rd, Flagstaff Hill	Candidate to make piggable
18	M38	GMH Elizabeth	Candidate to make piggable
19	M36	Seacombe Gardens to Flagstaff Hill	Candidate to make piggable
20	M6	Churchill Road	Candidate to make piggable
21	M7	Churchill Rd to Dry Creek	Candidate to make piggable
22	M5	Prospect to Brompton	Candidate to make piggable
23	M114	Southern Loop (O'Halloran Hill to Woodcroft)	Candidate to make piggable
24	M149	Seacombe Gardens	Candidate to make piggable
25	M143	Greenhill (Keswick to Linden Park)	Candidate to make piggable
26	M148	West Terrace	Candidate to make piggable
27	M117	Brompton to ACI (West Croydon)	Candidate to make piggable
28	M124	Cormack Rd to Cooper's Brewery	Candidate to make piggable
29	M126	SEA GAS Interconnection	Candidate to make piggable
30	M131	Pt Noarlunga to Noarlunga Downs	Candidate to make piggable
31	M172	Park Tce to Exeter Tce, Bowden	Candidate to make piggable
32	M183	Port Rd, Bowden	Candidate to make piggable
33	N/A	Snuggery	Candidate to make piggable
34	M150	Tanunda	Candidate to make piggable
35	M53	Lonsdale to Noarlunga	Recently replaced, compatible with ILI technology
36	M21	Grid System to Lonsdale	Recently replaced, compatible with ILI technology

Priority to make piggable	Pipeline number	Pipeline name	Current piggability
N/A	M60	Richmond to STA	Not feasible to safely conduct ILI on pipeline of this size with current technology
N/A	M120	Graves St, Newton	Not feasible to safely conduct ILI on pipeline of this size with current technology
N/A	N/A	Berri Township	Not feasible to safely conduct ILI on pipeline of this size with current technology
N/A	N/A	Murray Bridge Township	Not feasible to safely conduct ILI on pipeline of this size with current technology

TP Pipelines M12, M42 and M101 are the three highest priority pipelines for ILI. This is because they are among the oldest and longest in the network, supplying the highest number of customers (approximately 195,000). These pipelines also feature HSS, and have shown signs of deterioration following recent DCVG and dig ups.

We propose at least one or all of these three highest priority pipelines should be modified for ILI within the next five years. As part of any ILI modification to M12 (the highest priority pipeline) we would also modify M84. M84 is a relatively short TP pipeline, with common diameters, directly connected to M12. It would therefore be pigged in the same run. It therefore makes technical and economic sense to modify M84 at the same time as M12.

We have also identified M55 as a suitable candidate for ILI. M55 is a relatively short and simple pipeline, located in a highly accessible area. This means the cost of modifying this pipeline would be relatively low and the process of modification would be straightforward. M55 is also reasonably high priority (11th out of 36) and the project could be delivered quickly.

Modifying the SA TP pipelines to accept an ILI tool involves replacing main-line plug valves, as well as selective replacement of elbows, tees and hot-tap fittings. Unlike metropolitan transmission pipelines in Victoria, which have a comparatively straight alignment, the SA metropolitan TP pipelines form a looped network, with many pipelines including multiple changes in alignment, nominal diameter, and bore (due to changes of pipe wall thickness). The SA TP pipelines therefore require a greater quantity of proving and verification excavations to ensure elbows and bends will accommodate an ILI tool.

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 associated with the identified TP pipelines is that undetected corrosion, if left untreated, results in a significant uncontrolled gas escape in a densely populated area, resulting in fatality or permanent injury and/or loss of supply to >10,000 customers or a demand customer >1 TJ p.a.

The untreated risk[28] associated with the M12, M42, M55, M84 and M101 TP pipelines is assessed as high.

Table 1.4: TP pipelines integrity 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	

Given the proximity of these TP pipelines to developed and densely populated areas, there is the potential for a safety or supply incident with major consequences in certain circumstances. This also leads to the potential for significant compliance, reputational, and financial consequences.

1.5 Options considered

We have considered the following options to address the risk associated with undetected corrosion on the high priority TP pipelines and to commence the process of ILI modification:

- **Option 1** – Maintain status quo. Continue with current practice of DCVG and dig ups only, and repair/replace the pipelines upon failure.
- **Option 2** – Conduct physical FEED study on the four highest priority[29] TP pipelines and undertake one high priority ILI modification project that will be indicative of the costs and challenges of future works. This includes:
  - conducting potholing and using ground penetrating radar to determine scope of required modifications on pipelines M12, M84, M42 and M101;
  - modifying TP pipelines M12 and M84 for compatibility with ILI; and
  - conducting an ILI run on the M12 and M84 pipelines.
- **Option 3 –** Conduct physical FEED study on all five[30] TP pipelines and undertake a pilot program to modify a small, simple section of TP pipeline for ILI compatibility. This includes:
  - conducting potholing and using ground penetrating radar to determine scope of required modifications on TP pipelines M12, M42, M55, M84 and 101 pipelines;
  - modifying TP pipeline M55 for compatibility with ILI; and
  - conducting an ILI run on the M55 pipeline.

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

[29] M12, M42 and M101 are the highest priority, with M84 being modified as part of the M12 project.

[30] The four highest priority pipelines, plus M55.

- Option 4 – Conduct physical FEED study and then modify the four highest priority TP pipelines in order to achieve the greatest risk reduction quickly. This includes:
  - conducting potholing and using ground penetrating radar to determine scope of required modifications on TP pipelines M12, M42, M84 and M101;
  - modifying TP pipelines M12, M42, M84 and M101 for compatibility with ILI; and
  - conducting an ILI run on the M12, M42, M84 and M101 pipelines.

These options are discussed in the following sections.

1.5.1 Option 1 – Maintain status quo. Continue with current practice of DCVG and dig ups only

Under this option, we would continue to undertake DCVG and direct excavation examinations on all TP pipelines as per current practice. We would not conduct any FEED work or investigation into ILI, and the risk associated with undetected corrosion would be managed using current controls only.

All repairs and/or replacement would be conducted reactively as leaks occur or as dig ups reveal significant corrosion has occurred.

1.5.1.1 Cost assessment

There would be no additional upfront capital costs associated with this option. The forecast DCVG and dig ups program over the next five years would be similar to historical levels. However, there would likely be some increase in costs over the longer term with the frequency of dig ups increasing as the age of the pipelines increase and they near the end of their design lives.

If only the current risk controls are maintained, the condition of the pipelines can only be assessed indirectly by extrapolating the results of DCVG surveys and dig ups across the length of each pipeline. For longer metropolitan pipelines, which typically pass through sensitive areas and have many sections that cannot be accessed via dig ups, the integrity of the entire pipeline will remain unknown.

When the integrity of the entire pipeline cannot be demonstrated, the TP pipeline (or at least significant sections of it) will likely be replaced at the end of its technical design life. As an estimate, the cost of replacing the M12, M42, M84 and M101 pipelines would be approximately $204 million.

In addition to the end of life replacement costs, allowing undetected corrosion to persist on ageing pipes increases the likelihood of leaks. This in turn can result in costly emergency repairs. For example, a hot tap and bypass in an emergency response to a gas escape can cost approximately $200,000.

The cost of turning gas on and off to effect emergency repairs also costs between $50 to $100 per customer. Approximately 195,000 customers are supplied by the M12, M42, M84 and M101 TP pipelines.

1.5.1.2 Risk assessment

If we maintain the status quo, the current risk controls will continue. These controls are:

- additional pipe wall thickness when built (many pipelines are designed with a wall thickness greater than the minimum required to comply with AS2885);
- DCVG surveys;

- direct inspection excavations (dig ups); and
- CP monitoring.

While the current controls mitigate the untreated risk, they do not reduce the risk level associated with the identified TP pipelines to ALARP.

Table 1.5: TP pipelines integrity 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	High
Consequence	Major	Minor	Major	Minor	Significant	Significant	Significant	
Risk Level	High	Low	High	Low	Moderate	Moderate	Moderate	

Conducting DCVG and dig ups are useful controls, and we advocate that they continue in the future. However, because there are sections of these pipelines that simply cannot be excavated, the safety and supply risk associated with these pipelines is not diminished substantially below the untreated risk rating.

The risk associated with the longest and oldest TP pipelines in the network will increase as the pipelines age. Though the recent remaining life reviews on the pipelines[31] indicated it was safe to extend the use of these pipelines by ten years, this decision was based on the limited data provided by DCVG and dig ups. As the pipelines age and sections of the pipeline remain uninspected, the likelihood that the lives can be safely extended further decreases.

ILI is becoming standard practice for gas distribution networks[32], and is a widely accepted form of corrosion risk mitigation. Section 6.6.1 of AS 2885.3-2012 requires pipeline owners/operator to consider adopting ILI where practicable. The improved data from ILI allows remaining life reviews to be conducted with greater confidence, and reduces the likelihood that some or all of each pipeline will require replacement.

If we take no action to consider and adopt ILI on unpiggable pipelines, not only will we be foregoing the opportunity to make asset life decisions based on better data, we could also be found to be non-compliant with Section 6.6.1 of AS 2885.3-2012.

Taking all this into consideration, Option 1 does not adequately address the ongoing risk associated with these pipelines and is not consistent with our risk management framework.

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	N
Delivering for Customers – Reliability	N
Delivering for Customers – Customer Service	N
A Good Employer – Health and Safety	Y

31 Pipelines M101 and M42 were last reviewed in 2019, and M12, M42, M55 and M84 in 2018.

32 As discussed in section 1.3.2, ATCO Gas (WA) and Jemena (NSW) have recently commenced ILI modification and pigging on their high pressure distribution pipelines.

Vision objective	Alignment
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 1 would not align with our objective of *Delivering for Customers*, as it would not address the safety and reliability risks associated with undetected corrosion on TP pipelines. It may also result in considerable disruption to the 450,000 customers that are supplied by the 200 km of TP pipeline in our networks, particularly as the pipelines move further beyond the end of their design lives and become prone to failure.

Option 1 would also not align with our objective of remaining *Sustainably Cost Efficient*. By not pursuing ILI, we are decreasing the likelihood that the design life of our TP pipelines can be extended safely. If we are unable to demonstrate the integrity of pipelines and develop an economically efficient condition-based replacement program, the pipelines will need to be replaced at end of life.

This means a significant volume of these high cost assets will require end of life replacement at around the same time, as most of the pipelines are of a similar age. This will result in significant cost increases and price shock for customers in the future.

Not adopting ILI would also not be consistent with accepted asset management practice within the pipeline industry.

For these reasons, if ILI is not adopted, it may be increasingly difficult to demonstrate that increasing capital expenditure associated with TP pipeline corrosion management 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 providing services*[33].

1.5.2 Option 2 – Conduct physical FEED study on the four highest priority TP pipelines and undertake one high priority ILI modification project that will be indicative of the costs and challenges of future works.

Under this option, we would conduct physical FEEDs to understand the detailed costs and technical requirements of modifying the highest priority TP pipelines in our networks to enable ILI in the next AA period. The identified pipelines are:

- M12 (and M84);
- M42; and
- M101.

The physical characteristics of these pipelines are summarised in Appendix C. These pipelines have been selected as they are longest and oldest pipelines in the network and surveys have revealed significant numbers of coating defects. They also supply a large number (around 195,000) of

[33] NGR 79(1)(a)

customers and pass through several sensitive areas. While pipeline M84 is relatively short, it is connected to M12, has common diameters, and can be pigged in the same ILI run. It therefore makes technical and economic sense to modify these two pipelines at the same time.

We would then undertake the work to modify pipelines M12 and M84, and conduct an ILI run on each pipeline. Pipelines M42 and M101 would be scheduled for modification after 2025/26 (most likely within the following AA period).

Option 2 is designed to limit the price impact of commencing ILI modification within the next AA period, while enabling a reasonable level of risk reduction over the next five years. Most significantly, under Option 2 we will undertake an ILI modification project that will provide valuable information and insight on the costs and challenges associated with making the rest of our TP pipelines piggable.

The M12 pipeline is 20.7 km long, passes through seven sensitive areas, and has a combination of HSS and CTE coatings. It is 50 years old and supplies around 85,000 customers. We have selected M12 as the first pipeline to be modified because recent excavations have shown deterioration and long sections of the pipeline cannot be accessed by current corrosion detection practices (DCVG and dig ups). Of the three pipelines identified for treatment, it also supplies the most customers.

Modifying M12 is also a relatively complex project, which will provide valuable information for the remainder of the ILI modification program. By modifying M12 we expect to be able to establish a suite of unit rates that will be applicable to future ILI projects. We will also benefit from the practical experience and challenges that arise during the project. The data and lessons we learn from this initial indicative project will allow us to deliver future modification projects more efficiently than we would otherwise be able to.

In addition, the complexity of M12 will provide valuable insight on the cost of conducting an ILI run. The M12 pipeline is connected to two gate stations and has a T-junction. This means pigging is slightly more challenging than for some other pipelines, as it would have to be pigged from two points.

With regard to the FEED studies, the similar characteristics of the M12, M42 and M101 pipelines will enable some engineering activities to be conducted as a package of work. For example, ground sweeping and potholing investigations on M12, M101 and M42 can be delivered as a single project, which should be more efficient than if the FEEDs were treated as disparate projects.

1.5.2.1 Cost assessment

The estimated direct capital cost of Option 2 is $32 million. This estimate is based on current material and labour rates, and includes:

- the overall program of work costs (EPCM[34], pre-construction activities, etc.)
- the FEED costs for M12/M84, M42 and M101;
- modification costs of M12/M84; and
- ILI inspection costs for M12/M84.

[34] Engineering, procurement, construction management

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

	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Program of works	1,156.3	1,057.1	1,057.1	687.8	687.8	4,646.1
FEED costs						
M12/M84	641.6	1,295.4	-	-	-	1,937.1
M42	1,384.7	1,817.4	1,817.4	-	-	5,019.6
M101	1,068.0	1,012.4	1,012.4	-	-	3,092.9
ILI modification						
M12/M84	-	1,594.3	3,188.6	6,377.3	4,783.0	15,943.2
ILI run						
M12/84	-	-	-	-	1,205.7	1,205.7
MDR	-	-	-	-	145.0	145.0
Total	**4,250.7**	**6,776.8**	**7,075.7**	**7,065.0**	**6,821.4**	**31,989.6**

A more detailed breakdown of cost components is provided in Appendix B.

1.5.2.2 Risk assessment

Option 2 reduces the integrity risk associated with the identified TP pipelines from high to moderate.

Table 1.8: TP pipelines integrity 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	

Under Option 2 we are addressing the highest priority pipelines first, and modifying the individual pipeline that supplies the most customers (M12). While ILI inspection has no impact on the severity of the safety and supply risk consequences, the ability to detect corrosion on one of the longest and most critical TP pipelines in the Adelaide metropolitan area should reduce the likelihood of a major safety or supply incident to remote.

Option 2 also allows us to demonstrate pipeline integrity and comply with Section 6.6.1 of AS2885.3-2012. This is consistent with good industry practice and the actions of a prudent asset manager. As a result, the compliance, reputational, and financial risk consequences are reduced from significant to minor. Though the overall level of risk reduction under Option 2 is less than if we were to modify all four high priority pipelines within the next five years (see Option 4), we consider this option achieves a good balance between risk reduction and cost impact to customers.

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

Vision objective	Alignment
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	Y

Option 2 would align with our objective of *Delivering for Customers*, as it would address the safety and reliability risks associated with undetected corrosion on TP pipelines. The ability to conduct ILI on a major TP pipeline will enable us to manage the corrosion risk more effectively, promoting public safety, reliability of supply and minimising disruption to customers.

Option 2 also aligns with our objective of being *Sustainably Cost Efficient*, as it will enable us to make informed (and ultimately more efficient) decisions on the future capital program associated with the M12 and M84 pipelines. Having better data on the condition of the pipelines will allow us to pinpoint when and where maintenance activities should be conducted. More significantly, better integrity data may allow us to extend use of the pipelines beyond their technical design lives, deferring the need for costly end of life replacement.

Option 2 will also allow us to deliver the remainder of the ILI modification program more efficiently. Delivering the M12/M84 project will establish valuable precedents for ILI modification of our networks, and means we will be in a better position to deliver the ILI capex program at the lowest sustainable cost. This option is also the most economically efficient as it provides the best NPV of considered options.

1.5.3 Option 3 – Conduct physical FEED study on five TP pipelines and a pilot project to modify a small, simple section of TP pipeline for ILI compatibility

Under this option, we would conduct physical FEEDs to understand the detailed costs and technical requirements of modifying five TP pipelines to enable ILI in the next AA period. The identified pipelines are:

- M12 (and M84);
- M42;
- M55; and
- M101.

The M12/M84 and M42 pipelines are the highest priority for ILI modification. The M55, while relatively high priority (11th of 36), is a simple section of TP pipeline that can be accessed easily.

During the next AA period we would modify and conduct an ILI run on the M55 pipeline only. The concept is to treat M55 as a pilot program to allow us to test the ILI technology before commencing conversion of other, more complex pipelines in future AA periods.

Option 3 enables us to commence the ILI modification journey, while limiting the price impact in the next AA period. Undertaking a short, simple pipeline in the first instance will provide useful insight into the ILI technology, while the FEEDs for the other more complex pipelines will have been conducted.

The M55 pipeline is 4.7 km long, and is in a location that can be accessed with minimal disruption to traffic and customers. It has a one-way flow and can be pigged relatively easily. Though the M55 pipeline modification will not be as representative of future works as a more complex project (such as M12), it will enable us to establish the ILI technology and demonstrate compliance with AS 2885. Lessons learnt from the M55 project would be applied to the ongoing ILI modification program.

1.5.3.1 Cost assessment

The estimated direct capital cost of Option 3 is $22 million. This estimate is based on current material and labour rates, and includes:

- the overall program of work costs (EPCM, pre-construction activities, etc.)
- the FEED costs for M12/M84, M42, M55 and M101;
- modification costs of M55; and
- ILI inspection costs for M55.

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

	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Program of works	815.7	746.3	746.3	402.4	402.4	3,113.0
FEED costs						
M12/M84	641.6	1,295.4	-	-	-	1,937.1
M42	1,384.7	1,817.4	1,817.4	-	-	5,019.6
M55	200.5	627.3	-	-	-	827.9
M101	1,068.0	1,012.4	1,012.4	-	-	3,092.9
ILI modification						
M55	-	-	749.1	3,745.6	2,996.5	7,491.2
ILI run						
M55	-	-	-	-	602.9	602.9
MDR	-	-	-	-	136.0	136.0
Total	**4,110.6**	**5,498.9**	**4,325.3**	**4,148.0**	**4,137.8**	**22,220.6**

A more detailed breakdown of cost components is provided in Appendix B.

1.5.3.2 Risk assessment

While Option 3 carries a lower compliance, reputational and financial risk rating than the current controls (Option 1), it does not substantially reduce the safety or supply risk. As a result, the overall risk rating remains high.

Table 1.11: TP pipelines integrity 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	High
Consequence	Major	Minor	Major	Minor	Minor	Minor	Minor	
Risk Level	High	Low	High	Low	Low	Low	Low	

Under Option 3 we are commencing our ILI modification journey, and can demonstrate compliance with Section 6.6.1 of AS2885.3-2012. However, because the M55 pipeline is shorter and supports fewer customers than M12 and the other high priority pipelines, the overall safety and operations risk reduction associated with Option 3 is significantly less than Option 2 or 4.

For example, the ability to inspect between 20 km and 70 km of high priority pipeline (as we would under Option 2 or 4) would improve our risk management capabilities to a much greater extent than only being able to inspect the 4.05 km of lower priority pipeline under Option 3. While the risk over the long term as the ILI program is delivered would reduce, we consider that only having the ability to inspect the M55 pipeline would not reduce the likelihood of a safety or supply risk event to remote.

Notwithstanding this, Option 3 would mark the start of our longer term risk reduction program, and the data received from pigging the M55 pipeline will set useful risk management precedents for the future.

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	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	Y
Sustainably Cost Efficient – Delivering Profitable Growth	-
Sustainably Cost Efficient – Environmentally and Socially Responsible	N

Option 3 would not align with our objective of *Delivering for Customers*, as it would not materially address the safety and reliability risks associated with undetected corrosion on some TP pipelines. Conducting the FEED on our highest priority pipelines while undertaking a relatively simple ILI modification project, will improve our network integrity management capabilities. However, given the pipeline being modified and pigged during the next AA period is not the highest priority pipeline, and does not support a large number of customers, it could be argued that we are not meeting our reliability and customer service objectives fully.

Option 3 aligns with our objective of being *Sustainably Cost Efficient*, as it is has the lowest price impact in the short term. It will also provide some useful information to help us deliver future ILI modification works more efficiently in the future. However, it should be noted that because the M55 project would not be representative of other works in the future, it will provide less scope for establishing unit rates and ongoing cost efficiencies.

1.5.4 Option 4 – Conduct physical FEED and then modify the four highest priority TP pipelines in order to achieve the greatest risk reduction quickly

Under this option, we would modify the four highest priority TP pipelines for ILI compatibility in the next access arrangement period. This option would include conducting the necessary FEEDs, pipework reconfiguration and pigging runs. The four pipelines to be modified under Option 4 are:

- M12 (and M84);
- M42; and
- M101.

The combined length of these pipelines is approximately 71 km, and they supply gas to 195,000 people in the SA Metropolitan Area, passing through 26 sensitive areas.

Option 4 is designed to achieve the greatest risk reduction in the shortest time possible. Modifying the M12, M42, M84 and M101 represents the most ILI modification work we believe we can deliver within the next AA period. While the cost of undertaking this work is significantly greater than the other options, it will provide us detailed corrosion data on our most critical assets, while establishing important precedents for the forward-looking the ILI modification program.

Due to the length, complexity and resourcing effort required to engineer and modify these four pipelines, Option 4 will offer the most value in terms of lessons learnt and risk reduction over the next and subsequent AA periods. However, Option 4 would be at greater risk of under-delivery (within an AA period) than the other options considered, and would contribute the most to regulated distribution network costs.

1.5.4.1 Cost assessment

The estimated direct capital cost of Option 4 is $72 million. This estimate is based on current material and labour rates, and includes:

- the overall program of work costs (EPCM, pre-construction activities, etc.)
- the FEED costs for M12/M84, M42 and M101;
- modification costs of M12/M84, M42 and M101; and
- ILI inspection costs for M12/M84, M42 and M101.

Table 1.13: Cost estimate – Option 4, $'000 2019/20

	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Program of works	2,392.9	2,392.9	2,392.9	2,392.9	2,392.9	11,964.5
FEED costs						
M12/M84	1,937.1	-	-	-	-	1,937.1
M42	1,384.7	1,817.4	1,817.4	-	-	5,019.6

	2021/22	2022/23	2023/24	2024/25	2025/26	Total
M101	-	-	3,092.9	-	-	3,092.9
ILI modification						
M12/M84	6,180.2	6,508.6	3,254.3	-	-	15,943.2
M42	2,313.7	4,627.4	3,655.0	7,310.0	-	17,906.2
M101	-	-	-	4,635.8	7,323.2	11,959.0
ILI run						
M12/M84	-	-	-	-	1,205.7	1,205.7
M42	-	-	-	-	1,354.2	1,354.2
M101	-	-	-	-	904.4	904.4
MDR	-	-	-	-	500.0	500.0
Total	**14,208.6**	**15,346.4**	**14,212.6**	**14,338.7**	**13,680.5**	**71,786.8**

1.5.4.2 Risk assessment

Option 4 reduces the integrity risk associated with the identified TP pipelines from high to moderate.

Table 1.14: TP pipelines integrity risk assessment – Option 4

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

Under Option 4, the four highest priority TP pipelines will have been modified for ILI, and we will have detailed condition data on each. This will result in the greatest risk reduction of all the options considered.

Note that under the risk matrix, the likelihood of a major pipeline integrity failure event is unlikely to be assessed as rare[35], therefore the risk is the same as Option 2. However, because under Option 4 a larger volume of TP pipeline will have been inspected (71 km compared with 25 km), the likelihood of severe corrosion going undetected will be lower. Therefore, the risk of an integrity failure on the TP networks that leads to a major public safety or supply incident will be less.

Option 4 also allows us to demonstrate pipeline integrity, and comply with Section 6.6.1 of AS2885.3-2012.

1.5.4.3 Alignment with vision objectives

Table 1.15 shows how Option 4 aligns with our vision objectives.

Table 1.15: Alignment with vision – Option 4

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

[35] The definition of Rare is 'Conceivable but has not been known to arise previously. Less than once in 100 years'.

Vision objective	Alignment
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	Y
Sustainably Cost Efficient – Delivering Profitable Growth	-
Sustainably Cost Efficient – Environmentally and Socially Responsible	N

Option 4 would partially align with our objective of *Delivering for Customers*, as it would address the safety and reliability risks associated with undetected corrosion on TP pipelines. Modifying our highest priority pipelines to allow ILI will improve our public safety and network integrity management capabilities, minimising the likelihood of uncontrolled gas escapes and extended outages.

However, Option 4 comes at a substantial cost within a single AA period, which would place pressure on regulated distribution network tariffs. Though undertaking a more expensive works program now will likely help reduce costs in subsequent AA periods, the revenue impact may lead to some customers experiencing sharp short term price increases. This would not be consistent with feedback we have received from customers that they expect us to keep natural gas affordable.

The volume of works required within such a reasonably short timeframe may also lead to greater disruption (i.e. traffic management, switching supply, etc.) than some customers would be prepared to tolerate.

Option 4 would also be less well aligned with our objective to remain *Sustainably Cost Efficient*. While the precedents set by modifying all four high priority pipelines will allow us to deliver the ongoing ILI capex program at a lower cost, the greater in-period cost of Option 4 is less sustainable than Options 2 and 3. Under Option 4 we would be foregoing the opportunity to smooth costs over a longer period, but achieving a faster risk reduction.

1.5.5 Other options considered at pre-business case stage

Other options to address undetected corrosion on TP pipelines were considered and subsequently dismissed at the pre-business case stage. These were:

- Re-coating the pipelines;
- De-rating the pipelines;
- Increasing the frequency of DCVG and dig ups.

Re-coating the pipelines would include re-coating the M12, M42 and M101 pipelines with newer PE based coatings and removing the remaining[36] HSS. This requires the pipelines to be excavated, with consumers' supply re-directed (or potentially isolated) while the excavation work occurs. Undertaking this work would cost upwards of $38 million, but would not achieve the same level of risk reduction as replacement. Nor would it provide a full view of pipeline integrity. The prohibitive cost and potential for customer disruption means re-coating was not pursued as a viable option.

[36] We have already removed some HSS where there were corrosion issues under a separate opex package of work (refer to SA21a from the current AA period).

De-rating the pipeline would reduce the maximum allowable operating pipeline pressures to less than the current 1050 kPa. This would reduce the likelihood of a significant uncontrolled gas escape, and potentially allow the pipeline to operate beyond 40 years. However, we dismissed this option because:

- many demand customers that come off the TP pipelines operate at high pressures (~800 kPa). These customers would require their meter stations to be redesigned and rework in order for them to be able to continue to operate effectively;
- approximately 93 district regulator stations would require modification and possibly a rebuild in some cases;
- spare capacity for future growth will be limited, even if we duplicated some of the de-rated pipelines; and
- by derating the pipe we haven't really addressed the integrity risk (i.e. mitigated possible corrosion and other issues).

Increasing the frequency of DCVG and dig ups was dismissed as there will always be sections of pipeline that are inaccessible, meaning corrosion cannot be detected. Simply doing more DCVG and dig ups would do little to address the risk associated with large sections of the metropolitan TP pipelines.

1.6 Summary of costs and benefits

Table 1.16 presents a summary of how each option compares in terms of the estimated cost, the residual risk rating, and alignment with our objectives.

To assess which solution is likely to offer the most value over time, we have conducted a net present value (NPV) analysis of each option. To ensure the NPV analyses are comparable, within each NPV assessment we have considered the long term costs of treating all five TP pipelines considered in the four options: M12, M42, M55, M84 and M101.

Table 1.16: Comparison of options

Option	Estimated cost ($ million)	Treated residual risk rating	Alignment with vision objectives	25 yr NPV ($million)
Option 1 – current practice	0	High	Does not align with *Delivering for Customers* or *Sustainably Cost Efficient*	-165.8
Option 2 – FEED study and one high priority indicative project	32.0	Moderate	Aligns with *Delivering for Customers* and *Sustainably Cost Efficient*	-75.5
Option 3 – FEED study and small simple pipeline	22.2	High	Does not align with *Delivering for Customers.* Aligns with *Sustainably Cost Efficient*, however this option offers less scope for future efficiencies than Option 2	-75.7
Option 4 – FEED study and four high priority projects	71.8	Moderate	Aligns with *Delivering for Customers* but does not fully align with *Sustainably Cost Efficient*	-79.0

The assumptions of capital expenditure requirements for the next AA period and in the future are presented in the following table.

Table 1.17: NPV assumptions for the treatment of TP pipelines M12, M42, M55, M84, M101

Option	Capex assumptions for the next AA period (July 21 to June 26) - $'000	Future capex assumptions (for purpose of NPV assessment) - $'000
Option 1	Continue with current practice of DCVG and direct excavations only. Cost = zero additional capital cost	Replace M12, M84, M42, M55 and M101 at the end of their technical design lives. Cost = $203,541.4
Option 2	Conduct the FEED on four pipelines (M12, M42, M84 and M101) and undertake one high priority ILI modification project (M12 & M84, which are connected) that will be indicative of future works, and conduct an ILI run. Cost = $31,989.6	The FEED for M55 and ILI modification of the remaining three pipelines (M42, M55 and M101) will be undertaken in the subsequent AA period (July 26 to June 31). Cost = $51,968.2
Option 3	Conduct the FEED on four pipelines (M12, M42, M84 and M55) and undertake one small, simple ILI modification project (M55) and conduct an ILI run. Cost = $22,220.6	The FEED for M101 and ILI modification of the remaining four pipelines (M12, M42, M84, M101) will be undertaken in the subsequent AA period (July 26 to June 31). Cost = $61,737.2
Option 4	Conduct the FEED and modify four of the highest priority pipelines (M12, M42, M84, M101) and conduct ILI runs on each. Cost = $71,786.8	Conduct the FEED and modify M55 in the next AA period (26/27 to 30/31). Cost = $12,171.0

1.7 Recommended option

Option 2 is the proposed solution to reduce the risk posed by undetected corrosion and pipeline deterioration on transmission pipelines.

1.7.1 Why is the recommended option prudent?

Option 2 is the most prudent solution because it addresses a high priority and complex pipeline (M12), while also providing an important practical example of the process, costs and challenges associated with making a pipeline piggable.

M12 is 20.7 km long and passes through seven sensitive areas in the metropolitan area. The modification of M12 for ILI will require detailed planning and project execution as it requires excavation of several different types of ground cover, traffic management and working near hazards such as high voltage powerlines and other utilities.

The project to modify M12 will address many of the same challenges and characteristics as many future pipeline modification projects, including those to modify the M42 and M101 pipelines. This will allow us to establish a suite of unit rates, identify preferred vendors/contractors, and identify potential efficiencies for future works.

We therefore consider undertaking a challenging project (rather than a simple one) in the first instance is a prudent approach and will ultimately allow us to deliver the long term program more efficiently.

Option 2 delivers the best NPV of presented options. While the NPV for Option 3 is similar, Option 2 is preferable, as modifying the relatively short and simple M55 pipeline would not be as representative of the likely costs and practicalities of modifying many of the longer, more complex pipelines. We consider the experience and precedents set by undertaking this higher cost and more challenging project now will enable us to deliver future works more efficiently in the future. However, it is not possible to quantify these benefits ahead of actually delivering the M12 project.

Given pipelines M12, M42 and M101 will need to be modified at some point, we see less value in deferring these in favour of a simple project in the first instance. Option 2 also delivers a greater risk reduction than Option 3, and can be delivered within the AA period without the need for a significant ramp up in resources.

Option 2 is preferred to Option 4 because although Option 4 achieves the greatest risk reduction, Option 4 also has the greatest cost impact within the next AA period. We consider a staged approach of completing the FEEDs for M42 and M101 within the next AA period, and then modifying them for ILI in the following period, would help smooth the revenue impact and ultimately lessen the potential price shock.

Option 1 is not considered viable as it is the least efficient over the long term. It would not represent the actions of a prudent asset manager, nor would it reduce the risk associated with high pressure natural gas assets to as ALARP.

1.7.2 Estimating efficient costs

The forecast of work to be completed over the next AA period is based on the following:

- the volume of pipelines chosen for modification to facilitate ILI is based on current capacity to complete such a volume of work, as well as customer price impact considerations;
- a risk based approach has been taken to prioritise TP pipelines with highest risk, including consideration of the pipeline age, coating defects, and the length of pipeline which is situated in high density or sensitive location classes;
- the volume of proving investigative excavations, valve replacements, and elbow replacements required are based on a desktop review of the pipeline alignment drawings and verified by GPA engineering - refer to document 19737-REP-001;
- the cost estimate is based on costing the activities that comprise the work breakdown structure; and
- the rates utilised in costing these activities are based on current vendor and contractor rates in 2019 and historical costing.

This project will be delivered using a number of external resources. The design, proving excavations, construction, installation and ILI inspection will be completed by contractors with support from internal technicians and engineers. Contractors will be selected through a competitive tender process.

Project delivery practices and controls such as advanced planning and scheduling of work are in place to effectively manage risk in delivery. Proving excavations, construction and installation will be undertaken by multiple crews to ensure critical path activities are not reliant on a single contractor and therefore do not result in project delays

The forecast cost breakdown is shown in the table below.

Table 1.18: Forecast capital cost of materials and labour, $'000 2019/20

	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Scope	Ground sweep and potholing on M12/M84, M101 and M42 Conduct field integrity investigation on M12/M84	Field integrity investigation on M42 Pipe spool + bend fabrication and replacement on M12/M84	Field integrity investigation on M101 Pipe spool + bend fabrication and replacement on M12/M84	Pipe spool + bend fabrication and replacement on M12M84	Pipe spool + bend fabrication and replacement on M12/M84 Install launcher and receiver stations Conduct ILI	All scope
Materials	927.0	2,033.0	2,122.7	2,119.5	2,046.4	9,248.6
Labour	3,323.7	4,743.8	4,953.0	4,945.5	4,775.0	22,740.9
Total	**4,250.7**	**6,776.8**	**7,075.7**	**7,065.0**	**6,821.4**	**31,989.6**

The following table shows the TP pipelines ILI modification costs escalated to June 2021 dollars.

Table 1.19: Escalated TP pipelines ILI modification cost estimate ($'000)

	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Total unescalated ($ Dec 19)	4,250.7	6,776.8	7,075.7	7,065.0	6,821.4	31,989.6
Escalation	143.3	262.0	317.1	357.2	380.1	1,459.8
Total escalated ($ Jun 21)	**4,394.0**	**7,038.8**	**7,392.8**	**7,422.2**	**7,201.5**	**33,449.4**

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 proposal to conduct the necessary FEEDs and to undertake a relatively complex and indicative project in the first instance is consistent with the requirements of NGR 79(1). Specifically, we consider that the capital expenditure is:

- **Prudent** – the expenditure is necessary in order to detect corrosion on aged TP pipelines. The M12 pipeline is more than 50 years old, well over halfway into its technical design life. Recent excavations have shown deterioration and several long sections of the pipeline are inaccessible to current corrosion detection practices. Introducing ILI is therefore prudent if we are to maintain the integrity of the pipeline and make informed decisions on future maintenance/replacement requirements. M84 is a relatively short TP pipeline, with common diameters, directly connected to M12 and would be pigged in the same run. It therefore makes technical and economic sense to modify M84 at the same time as M12. The proposed risk treatment is consistent with accepted industry practice and current design standards, and is proven to address the risk associated with TP pipelines. 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 – the forecast expenditure is based on rates applied in similar projects and a detailed scope of work verified by an experienced third-party engineering consultant. Commencing the ILI modification program by undertaking FEED and an indicative project in the first instance will help us identify efficiencies for the future program, while lessening revenue impact in the next AA.

- Consistent with accepted and good industry practice – ILI is becoming standard industry practice for corrosion detection and is consistent with the requirements of AS2885.

- To achieve the lowest sustainable cost of delivering pipeline services – the proposed expenditure will enable us to extend the technical design life of some of its highest cost assets, and manage the future replacement/maintenance schedule more efficiently. Deferring replacement costs and being able to utilise fully-depreciated assets for as long as is safe and practicable will eventuate in the lowest sustainable cost of providing pipeline services.

NGR 79(2)

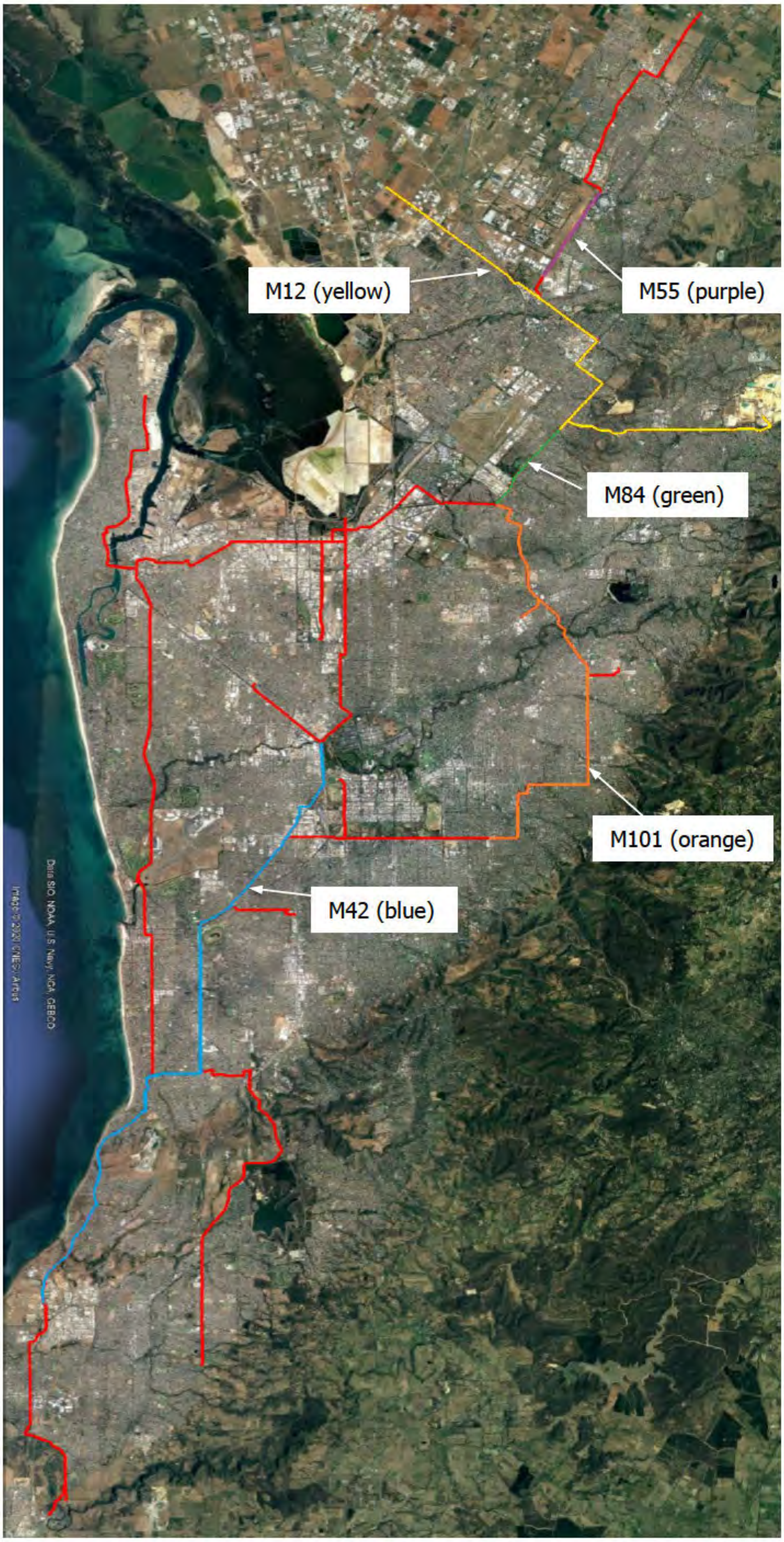
The proposed capex is justifiable under NGR 79(2)(c)(i), as it is necessary to maintain the integrity of the pipelines. Corrosion is one of the primary failure modes associated with steel TP pipelines, and any pipeline failure has the potential to interrupt supply to more than 1,000 customers at any one time. Early detection of corrosion is essential to maintain integrity of services, particularly with pipelines that are beyond their design life.

The current practice of DCVG surveys and dig-ups alone is insufficient to manage the integrity risk to an acceptable level, as there are too many sections of the TP pipelines that cannot be dug up or inspected without inserting an inline inspection tool. It is therefore prudent to reconfigure the pipelines to allow pigging and extend the life of the assets, negating the need to incur the high costs of pipeline replacement.

NGR 74

Cost estimates have been arrived at on a reasonable basis by following realistic assumptions of costs, informed by independent engineering advice and experience in other jurisdictions. Rates are comparable with the market and the volume of pipeline that is to be reconfigured is being limited for the next access arrangement period, with a view to informing more accurate forecasts in future periods. We therefore consider the costs estimates represent the best forecast possible in the circumstances.

Appendix A – Adelaide TP pipeline overview



Appendix B – Cost estimates

Cost estimate – Option 1

Category	Description	Total $'000
M12 replacement		
Engineering and procurement services		[redacted]
Permanent materials (line pipe, valves, etc)		[redacted]
Pre-construction activities		[redacted]
Facilities fabrication including materials		[redacted]
Early construction activities		
	Site survey layout	[redacted]
	Tree slashing	[redacted]
	Ground sweep and service locates	[redacted]
	Recruitment and mobilisation	[redacted]
	Onsite construction management	[redacted]
	Construction support services	[redacted]
	Construction direct supervision	[redacted]
HDD installation		
	Civil and earthworks	[redacted]
	Haul and string pipe	[redacted]
	String fabrication	[redacted]
	HDD installation support	[redacted]
	Tie- in and backfill	[redacted]
Thrust bore installation		
	Civil and earthworks	[redacted]
	Haul and string pipe	[redacted]
	String fabrication	[redacted]
	Thrust bore installation support	[redacted]
	Tie- in and backfill	[redacted]
Conventional installation		
	Clear and grade open cut section	[redacted]
	Open cut load out/ haul/ string pipe	[redacted]
	Section 1 (3,212m)	[redacted]
	Section 2 (962m)	[redacted]
	Section 3 (1,170m)	[redacted]
	Section 4 (1,190m)	[redacted]
	Section 5 (918m)	[redacted]
	Section 6 (1,031m)	[redacted]

Category	Description	Total $'000
	Section 7 (1,138m)	[redacted]
Hydrostatic testing		[redacted]
Reinstatement crew		[redacted]
Service line connection		[redacted]
Demobilisation		[redacted]
ILI baseline inspection run		[redacted]
Total		**48,127.1**

Category	Description	Total $'000
M42 replacement		
Engineering and procurement services		[redacted]
Permanent materials (line pipe, valves, etc)		[redacted]
Pre-construction activities		[redacted]
Facilities fabrication including materials		[redacted]
Early construction activities		
	Site survey layout	[redacted]
	Tree slashing	[redacted]
	Ground sweep and service locates	[redacted]
	Recruitment and mobilisation	[redacted]
	Onsite construction management	[redacted]
	Construction support services	[redacted]
	Construction direct supervision	[redacted]
HDD installation		
	Civil and earthworks	[redacted]
	Haul and string pipe	[redacted]
	String fabrication	[redacted]
	HDD installation support	[redacted]
	Tie- in and backfill	[redacted]
Thrust bore installation		
	Civil and earthworks	[redacted]
	Haul and string pipe	[redacted]
	String fabrication	[redacted]
	Thrust bore installation support	[redacted]
	Tie- in and backfill	[redacted]
Conventional installation		
	Clear and grade open cut section	[redacted]
	Open cut load out/ haul/ string pipe	[redacted]

Category	Description	Total $'000
	Section 1 (1,273m)	[redacted]
	Section 2 (3,992m)	[redacted]
	Section 3 (1,918m)	[redacted]
Hydrostatic testing		[redacted]
Reinstatement crew		[redacted]
Service line connection		[redacted]
Demobilisation		[redacted]
MDR		[redacted]
ILI baseline inspection run		[redacted]
Total		**73,485.1**

Category	Description	Total $'000
M55 replacement		
Engineering and procurement services		[redacted]
Permanent materials (line pipe, valves, etc)		[redacted]
Pre-construction activities		[redacted]
Facilities fabrication including materials		[redacted]
Early construction activities		
	Site survey layout	[redacted]
	Tree slashing	[redacted]
	Ground sweep and service locates	[redacted]
	Recruitment and mobilisation	[redacted]
	Onsite construction management	[redacted]
	Construction support services	[redacted]
	Construction direct supervision	[redacted]
HDD installation		
	Civil and earthworks	[redacted]
	Haul and string pipe	[redacted]
	String fabrication	[redacted]
	HDD installation support	[redacted]
	Tie- in and backfill	[redacted]
	Civil and earthworks	[redacted]
Conventional installation		
	Clear and grade open cut section	[redacted]
	Open cut load out/ haul/ string pipe	[redacted]
	Section 1 (185m)	[redacted]
	Section 2 (1,255m)	[redacted]
	Section 3 (417m)	[redacted]

Category	Description	Total $'000
	Section 4 (345m)	[redacted]
	Section 5 (380m)	[redacted]
	Section 6 (45m)	[redacted]
	Section 7 (455m)	[redacted]
Hydrostatic testing		[redacted]
Reinstatement crew		[redacted]
Service line connection		[redacted]
Demobilisation		[redacted]
MDR		[redacted]
ILI baseline inspection run		[redacted]
Total		**11,932.8**

Category	Description	Total $
M84 replacement		
Engineering and procurement services		[redacted]
Permanent materials (line pipe, valves, etc)		[redacted]
Pre-construction activities		[redacted]
Facilities fabrication including materials		[redacted]
Early construction activities		
	Site survey layout	[redacted]
	Tree slashing	[redacted]
	Ground sweep and service locates	[redacted]
	Recruitment and mobilisation	[redacted]
	Onsite construction management	[redacted]
	Construction support services	[redacted]
	Construction direct supervision	[redacted]
HDD installation		
	Civil and earthworks	[redacted]
	Haul and string pipe	[redacted]
	String fabrication	[redacted]
	HDD installation support	[redacted]
	Tie- in and backfill	[redacted]
Conventional installation		
	Clear and grade open cut section	[redacted]
	Open cut load out/ haul/ string pipe	[redacted]
	Section 1 (100m)	[redacted]
Hydrostatic testing		[redacted]

Category	Description	Total $
Reinstatement crew		[redacted]
Service line connection		[redacted]
Demobilisation		[redacted]
MDR		[redacted]
ILI baseline inspection run		[redacted]
Total		**15,950.4**

Category	Description	Total $'000
M101 replacement		
Engineering and procurement services		[redacted]
Permanent materials (line pipe, valves, etc)		[redacted]
Pre-construction activities		[redacted]
Facilities fabrication including materials		[redacted]
Early construction activities		
	Site survey layout	[redacted]
	Tree slashing	[redacted]
	Ground sweep and service locates	[redacted]
	Recruitment and mobilisation	[redacted]
	Onsite construction management	[redacted]
	Construction support services	[redacted]
	Construction direct supervision	[redacted]
HDD installation		
	Civil and earthworks	[redacted]
	Haul and string pipe	[redacted]
	String fabrication	[redacted]
	HDD installation support	[redacted]
	Tie- in and backfill	[redacted]
Thrust bore installation		
	Civil and earthworks	[redacted]
	Haul and string pipe	[redacted]
	String fabrication	[redacted]
	Thrust bore installation support	[redacted]
	Tie- in and backfill	[redacted]
Conventional installation		
	Clear and grade open cut section	[redacted]
	Open cut load out/ haul/ string pipe	[redacted]
	Section 1 (206m)	[redacted]

Category	Description	Total $'000
	Section 2 (233m)	[redacted]
	Section 3 (348m)	[redacted]
Hydrostatic testing		[redacted]
Reinstatement crew		[redacted]
Service line connection		[redacted]
Demobilisation		[redacted]
MDR		[redacted]
ILI baseline inspection run		[redacted]
Total		**54,045.9**

Cost estimate – Option 2

Category	Description	Total $'000
Program of works		
	EPCM	[redacted]
	Pre-construction activities	[redacted]
	Early construction activities	[redacted]
	Onsite construction management	[redacted]
M12/M84 pipeline		
	Ground sweep - GPR marking	[redacted]
	Potholing investigation	[redacted]
	Field integrity investigation	[redacted]
	Pipe spool / bend fabrication program	[redacted]
	Bend replacement program	[redacted]
	ILI inspection	[redacted]
M42 pipeline		
	Ground sweep - GPR marking	[redacted]
	Potholing investigation	[redacted]
	Field integrity investigation	[redacted]
	Pipe spool / bend fabrication program	[redacted]
	Bend replacement program	[redacted]
	ILI inspection	[redacted]
M101 pipeline		
	Ground sweep - GPR marking	[redacted]
	Potholing investigation	[redacted]
	Field integrity investigation	[redacted]
	Pipe spool / bend fabrication program	[redacted]

Category	Description	Total $'000
	Bend replacement program	[redacted]
	ILI inspection	[redacted]
MDR		[redacted]
Total		**31,989.6**

Cost estimate – Option 3

Category	Description	Total $'000
Program of works		
	EPCM	[redacted]
	Pre-construction activities	[redacted]
	Early construction activities	[redacted]
	Onsite construction management	[redacted]
M55 pipeline		
	Ground sweep - GPR marking	[redacted]
	Potholing investigation	[redacted]
	Field integrity investigation	[redacted]
	Pipe spool / bend fabrication program	[redacted]
	Bend replacement program	[redacted]
	ILI inspection	[redacted]
M12/M84 pipeline		
	Ground sweep - GPR marking	[redacted]
	Potholing investigation	[redacted]
	Field integrity investigation	[redacted]
	Pipe spool / bend fabrication program	[redacted]
	Bend replacement program	[redacted]
	ILI inspection	[redacted]
M42 pipeline		
	Ground sweep - GPR marking	[redacted]
	Potholing investigation	[redacted]
	Field integrity investigation	[redacted]
	Pipe spool / bend fabrication program	[redacted]
	Bend replacement program	[redacted]
	ILI inspection	[redacted]
M101 pipeline		
	Ground sweep - GPR marking	[redacted]
	Potholing investigation	[redacted]
	Field integrity investigation	[redacted]
	Pipe spool / bend fabrication program	[redacted]
	Bend replacement program	[redacted]

Category	Description	Total $'000
	ILI inspection	[redacted]
MDR		[redacted]
Total		**22,220.6**

Cost estimate – Option 4

Category	Description	Total $'000
Program of works		
	EPCM	[redacted]
	Pre-construction activities	[redacted]
	Early construction activities	[redacted]
	Onsite construction management	[redacted]
M12/M84 pipeline		
	Ground sweep - GPR marking	[redacted]
	Potholing investigation	[redacted]
	Field integrity investigation	[redacted]
	Pipe spool / bend fabrication program	[redacted]
	Bend replacement program	[redacted]
	ILI inspection	[redacted]
M42 pipeline		
	Ground sweep - GPR marking	[redacted]
	Potholing investigation	[redacted]
	Field integrity investigation	[redacted]
	Pipe spool / bend fabrication program	[redacted]
	Bend replacement program	[redacted]
	ILI inspection	[redacted]
M101 pipeline		
	Ground sweep - GPR marking	[redacted]
	Potholing investigation	[redacted]
	Field integrity investigation	[redacted]
	Pipe spool / bend fabrication program	[redacted]
	Bend replacement program	[redacted]
	ILI inspection	[redacted]
MDR		[redacted]
Total		**71,786.8**

Appendix C – Pipeline technical details

Pipeline number	Pipeline name	Nominal diameter (mm)	MAOP (kPa)	Length (km)	Date constructed	Wall thickness (mm)	Pipe grade	SMYS (MPa)	Pipeline coating	Measure-ment length (m)	% Length @ class T1	% Length @ class T2	QTY sensitive areas
M5	Prospect to Brompton	475 (470mm OD)	1,896	3.35	1969	6.35	ASA149	245	Tar Enamel	198	100%	0%	0
M6	Churchill Road	300	1,896	3.36	1969	5.56	5L Grade A	210	Tar Enamel	131	100%	0%	1
M7	Churchill Rd to Dry Creek	200 / 300 / 400	1,896	1.52	1969	4.8 / 6.35 / 7.1	5L Grade X42	290	Tar Enamel	82 / 131 / 172	100%	0%	0
M12	Waterloo Corner to Yatala Vale	200 / 250 / 300	1,896	20.745	1969	7 / 9.2 / 6.6	5L Grade X42 / B / X46	290 / 245 / 320	Tar Enamel / Polyethylene / HSS	82 / 107 / 131	100%	0%	7
M21	Grid System to Lonsdale (Dyson Rd.)	200	1,896	0.92	1970	6.35	5L Grade B	245	Tar Enamel / HSS	82	100%	0%	0
M22	Le Fevre Peninsula	150 / 200	1,896	5.01	1970	6.35 / 6	5L Grade B / X42	245 / 290	Polyethylene / HSS	60 / 82	100%	0%	1
M36	Seacombe Gardens to Flagstaff Hill	200 / 300	1,896	4.81	1970	4.78 / 5.3	5L Grade B	245	Tar Enamel / Polyethylene / Tape Wrap	82 / 131	100%	0%	1
M37	Plympton to Edwardstown	150	1,896	2.46	1972	4.78	5L Grade B	245	Polyethylene / HSS	60	100%	0%	2
M38	G.M.H. Elizabeth	150 / 200	1,896	1.05	1973	4.8 / 7.1	5L Grade B	245	Polyethylene	60 / 82	100%	0%	0
M42	Brompton to Pt. Stanvac	250 / 300	1,896	27.73	1964	6.35 / 6.35	5L Grade A / B	210 / 245	Tar Enamel	107 / 131	100%	0%	7
M53	Lonsdale to Noarlunga	100 / 200	1,896	4.8	1975	4.37 / 6.35	5L Grade B	245	Polyethylene / HSS	38 / 82	100%	0%	0
M55	Elizabeth	150	1,896	4.05	1975	4.75	5L Grade B	245	Polyethylene / HSS	60	100%	0%	1
M60	Richmond to STA	80 / 100	1,896	0.9	1975	5.5 / 4.37	5L Grade B	245	Polyethylene / HSS / Tape Wrap	28 / 38	100%	0%	0

Pipeline number	Pipeline name	Nominal diameter (mm)	MAOP (kPa)	Length (km)	Date constructed	Wall thickness (mm)	Pipe grade	SMYS (MPa)	Pipeline coating	Measure -ment length (m)	% Lengt h @ class T1	% Length @ class T2	QTY sensitive areas
M63	Port Pirie	80 / 150 /200	1,200	5.23	1976	3.96 / 4.37 / 6.35	5L Grade B	245	Polyethylene / HSS	22 / 48 / 65	100%	0%	5
M68	Nuriootpa	80 /100 / 150	1,896	0.54	1977	3.96 / 4.37 / 4.8	5L Grade B / X42	245 / 290	Polyethylene	28 / 38 / 60	100%	0%	0
M71	Birkenhead	200	1,896	1.39	1978	6.35	5L Grade B	245	Polyethylene / HSS	82	100%	0%	2
M76	Flagstaff Hill - Blacks Rd	200	1,896	1.44	1978	4.78	5L Grade B	245	Polyethylene HSS	82	100%	0%	0
M79	Glanville to Pt Adelaide	200 / 300	1,896	2.53	1979	4.78 / 5.56	5L Grade B	245	Polyethylene	82 / 131	76%	24%	2
M80	Port Adelaide to Dry Creek	300	1,896	8.68	1980	6.35	5L Grade B / X46	245 / 320	Polyethylene	131	100%	0%	0
M82	Elizabeth to Smithfield Plns, Coventry Rd	150	1,896	8.95	1985	4.8	5L Grade B / X42	245 / 290	Polyethylene / Tape Wrap	60	100%	0%	1
M83	Pt Adelaide to Queenstown	300	1,896	1.64	1981	6.35	5L Grade B	245	Polyethylene	131	100%	0%	2
M84	Para Hills to Ingle Farm	250 / 300	1,896	3.95	1981	5.56 / 6.35	5L Grade B	245	Polyethylene	107 / 131	100%	0%	1
M90	Hendon to South Brighton	300	1,896	18.4	1982	6.35 / 5.15	5L Grade B	245	Polyethylene / HSS	131	100%	0%	7
M94	Dry Creek to Ingle Farm	300	1,896	6.1	1982	6.35	5L Grade B	245	Polyethylene / HSS	131	100%	0%	1
M101	Eastern Ring Main	300	1,896	18.52	1986	6.4 / 4.8	5L Grade B / X42	245 / 290	Polyethylene / HSS / Tape Wrap	131	100%	0%	11
M114	Southern Loop (O'Halloran Hill to Woodcroft)	300	1,896	8.3	1996	6.4 / 4.8	5L Grade B / X42	245 / 290	Polyethylene / Tape Wrap	131	100%	0%	0
M117	Brompton to ACI (West Croydon)	150	1,953	3.09	2002	6.35	5L Grade X42	290	Polyethylene / Tape Wrap	61	100%	0%	0

Pipeline number	Pipeline name	Nominal diameter (mm)	MAOP (kPa)	Length (km)	Date constructed	Wall thickness (mm)	Pipe grade	SMYS (MPa)	Pipeline coating	Measure -ment length (m)	% Length @ class T1	% Length @ class T2	QTY sensitive areas
M120	Graves St., Newton (to bus depot)	100	1,960	1.34	2003	4.8	5L Grade X42	290	Polyethylene / Tape Wrap	38	100%	0%	1
M124	Cormack Rd to Cooper's Brewery	150	1,896	3.93	2003	7.1	5L Grade X42	290	Polyethylene / Tape Wrap	60	100%	0%	0
M126	SEAGAS Interconnection	400	1,960	0.54	2004	9.53	5L Grade X42	290	Polyethylene / Tape Wrap	175	100%	0%	0
M131	Pt Noarlunga to Noarlunga Downs	300	1,896	0.95	2009	6.35	5L Grade X42	290	Trilaminate / Protal UHBE	131	100%	0%	0
M143	Greenhill (Keswick to Linden Park)	300	1,960	7.19	2013	6.4	5L Grade X42 / X52	290 / 360	Trilaminate / Dual Layer FBE / Tape Wrap / Protal UHBE	133	100%	0%	1
M148	West Terrace	300	1,960	2.38	2015	6.4	5L Grade X52	360	Trilaminate / Protal UHBE	133	100%	0%	1
M149	Seacombe Gardens	200 / 300	1,960	0.785	2013	4.8 / 6.4	5L Grade X42	290	Trilaminate / Polyethylene / Tape Wrap	83 / 133	100%	0%	1
M150	Tanunda	150	1,600	0.685	2013	4.8	5L Grade X52 PSL2	360	Trilaminate / Protal UHBE	55	0%	0%	0
M172	Park Tce. to Exeter Tce., Bowden	300	1,960	2.23	2017	6.4 (9.52 HDD)	5L Grade X52 PSL2	360	Trilaminate / Dual Layer FBE / Protal UHBE	133	100%	0%	0
M183	Port Rd., Bowden	150	1,960	0.768	2017	7.11	5L Grade X42 PSL2	290	Trilaminate / Protal UHBE	61	100%	0%	0
BT	Berri Township	100	1,600	7.2	1995	4.8	5L Grade X42	290	Polyethylene	35	30%	0%	0
MBT	Murray Bridge Township	50	1,920	1.75	2003	3	5L Grade X42	290	Polyethylene / Tape Wrap	18	100%	0%	0
SNG	Snuggery Pipeline	150	1,960	0.816	1990	4.2	5L Grade X42	290	Polyethylene	61	0%	0%	0

Appendix D – 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	Significant	Significant	
Risk Level	High	Low	High	Low	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	Minor	Significant	Significant	Significant	
Risk Level	High	Low	High	Low	Moderate	Moderate	Moderate	

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 3	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	Minor	Minor	Minor	
Risk Level	High	Low	High	Low	Low	Low	Low	

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