APA
Australia's energy infrastructure partner

Pipeline Integrity Business Case

Roma to Brisbane Gas Pipeline Access Arrangement 2028–32

18 June 2026

Contents

Document control

Printed versions of this document are only valid on the date of print. For the latest version, please refer to the electronic version stored on the AP&L SharePoint site.

Table 1-1: Revision Record

Version	Changes Made
0.1	*Initial draft*
0.2	*Feedback received from document review*
0.3	*Additional detail requested*

Table 1-2: Review and Distribution

Name	Role	Action	Sections
[redacted]	*Specialist – Asset Lifecycle*	*Initial draft*	*All*
[redacted]	*Engineer - Pipeline*	*Review and Input*	*3-6*
[redacted]	*Lead Process Engineer - Emissions & Strategy*	*Review and Input*	*8*
[redacted]	*Manager Capacity & Long Term Planning*	*Review and Input*	*All*
[redacted]	*Team Lead Asset Engineering - Qld*	*Review and Input*	*All*
[redacted]	*Head of Emissions & LT Optimisation*	*Review and Input*	*8*

This document requires the following approvals. Approvals are inserted as an object in the table below (preferred) or stored with the approved document in electronic version on the Project Site in Project Server.

Table 1.3: Approvals

Name	Role	Approval	Date Approved
[redacted]	*Head of Asset Operations Qld*	*Approval*	
[redacted]	*General Manager – Gas Operations East*	*Approval*	

Other project specific approvers can be added if required.

Delegation Policy

1. Overview

Number/ identifier	A-1_Pipeline Integrity
Description of Issue/ Project	The RBP includes over 800km of buried pipelines, in sizes between DN200 and DN400, the oldest of which was constructed in 1968-1969 and has been in service ever since. All buried pipelines are subject to coating deterioration and corrosion from the soil environment and require integrity management to comply with standards and legislation. The RBP has particular characteristics such as is over-the-ditch tape coating system and its age that mean it requires significantly greater effort and expense in corrosion and integrity management than most other pipelines in Australia. If insufficiently managed the corrosion and integrity issues could lead to pipeline failures affecting both public safety (given the pipeline traverses many populated areas) and security of supply to customers. The successful solution will ensure an effective pipeline integrity management system is continued and that the risk of pipeline failure is managed to an acceptable level considering health and safety and security of supply.
Options considered	The following options have been considered: 1. Option 1: Do Nothing (Carry out only basic pipeline integrity activity; allow pipelines to deteriorate) **2. Option 2: Carry out pipeline integrity management activities** 3. Option 3: Replace pipelines
Proposed Solution	The scope of Option 2: Carry out pipeline integrity management activities comprises a number of different aspects: • Inline Inspection (ILI) • Excavation, integrity works and new coating upgrades and repair • Cathodic Protection Replacement and Upgrades • Other associated equipment upgrades to support the above activities
Estimated Cost	$39.3 million
Relevant standards	• AS 2885.3 Pipelines: Gas and Liquid Petroleum Operations and Maintenance. • AS 2832.1 Metal Pipeline Protection • AS 4853 2012 Electrical Hazards on Metallic Pipelines • RBP Pipeline Licence
Stakeholder Engagement	• Scope discussed during RBP Access Arrangement Stakeholder Meetings #3 (25/11/2025); #4 (10/02/2026); and #5 (31/03/2026)
Consistency with National Gas Rules (NGR)	The pipeline integrity management work complies with the capital expenditure criteria in Section 79 of the NGR because it: • is necessary to maintain and improve the safety and integrity of services (79(2)(c)(i) and (ii)); and • 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 (79(1)(a)).

2. Program details

2.1. Background

The RBP system includes over 800 km of buried pipelines, in sizes between DN200 and DN400, the oldest of which was constructed in 1968-69 and has been in service ever since. The pipelines transport natural gas between Wallumbilla, near Roma, and the Brisbane metropolitan region in south-east Queensland. The RBP is the sole supply route for natural gas to homes and businesses in south-east Queensland, including Dalby, Oakey, Toowoomba, Ipswich, greater Brisbane, the Gold Coast and far northern New South Wales.

All buried pipelines constructed of steel pipe are subject to coating deterioration and corrosion from the soil environment and require integrity management to comply with standards and legislation. Part of this integrity management is protection from corrosion that is applied to the pipeline. Primarily this protection comes in two ways. The first is a coating protection that is applied to the pipeline at the time of construction. The second is cathodic protection (CP) which uses current and an anode to protect the pipeline. As pipelines age the level of effort required to maintain their integrity increases.

The to the technologies available at the time of construction for the original RBP has particular characteristics, such as its over-the-ditch-applied polyethylene tape coating system (on the original DN250, DN300 and DN200 pipelines). Along with the age of the original pipelines means it requires significantly greater effort and expense in corrosion and integrity management than most other pipelines in Australia. This includes risks associated with deterioration of the tape coating, corrosion of the pipe wall and other mechanisms such as stress corrosion cracking.

2.2. DN250 and DN300 and DN200 Pipelines (1969 Vintage)

Globally in the pipeline industry there is an accepted differentiation between 'modern' and 'vintage' pipelines. The 'vintage' category generally includes pipelines constructed prior to the mid-1970s, which have relatively low toughness steel, over-the-ditch-applied coatings and a lower level of inspection and quality assurance compared to modern pipelines. The original 1960s RBP segments are clearly considered 'vintage' pipelines.

If insufficiently managed the corrosion and integrity issues could lead to pipeline failures affecting both

- public safety, given significant portions of the RBP are located within residential areas in Brisbane and surrounding areas, and
- security of supply to customers.

There have been significant improvements in pipeline coating technology such that modern pipe coatings such as fusion-bonded epoxy can be expected to last 50-60 years or longer, compared to less than 30-40 years seen on some sections of the RBP with the original over-the-ditch polyethylene tape coating system. One aspect of this is the thorough abrasive blast cleaning of the steel surface prior to coating, which was not done in the 1960s construction.

No design life for the pipeline was specified at original construction in 1968-69. In 2008-2009 a design life review was conducted (at 40 years age) which concluded that the pipeline could continue to operate subject to appropriate integrity management. A number of specific actions were recommended in the design life review including an increased focus on coating refurbishment. In 2015 a Remaining Life Review (as per AS 2885.3-2012) was conducted for the Metro section and in 2016 for the DN250 section. Since this time a major repair and CP program has been undertaken where it has been evident that pipeline coating integrity continues to decline and the expenditure required to maintain safe operation continues to increase.

2.3. DN400 Pipeline System

The RBP DN400 first looping stages were constructed in 1988 and are approaching 30 years in service. This pipeline has a different risk profile from the DN250 and its factory extruded HDPE coating ("yellowjacket") has generally performed well. However, In APA's experience, pipelines from the 1980s such as the RBP DN400 also have some of the characteristics of 'vintage' pipelines. In recent years evidence of longitudinal splitting of heat shrink sleeves has been observed which have led to corrosion of the pipeline.

Design lives for the DN400 looping stages are likely to have been nominated as between 40 and 60 years in accordance with normal industry practice, at the time of design and construction of each looping stage. The next Remaining Life Review on the DN400 system will be completed in 2032 (10 years from its MOP Upgrade) in accordance with AS 2885.3-2012, or earlier if required based on ILI and engineering assessment.

2.4. Main Integrity Issues

The main integrity issues faced by the RBP include the following:

- Deterioration and disbondment of the external coatings leading to high load on CP system and external corrosion where the CP system cannot sustain complete protection of the pipe wall
- Shielding of CP by disbonded coating leading to inadequate protection of pipe wall in shielded areas, including the entire DN250 pipeline and field joints with heat shrink sleeves and tape wrap coating on the DN400
- Deterioration of dents and gouges by a combination of the above factors with increased risk of fatigue cracking or stress corrosion cracking (SCC)
- 1960s Electric Resistance Welded pipes seams (DN250 Brassall to Bellbird Park) with occasional lack of fusion or other defects in the seam welds, which although passed a hydrotest at commissioning, are at risk of growth through SCC or fatigue
- Bending strain on pipeline caused by ground movement or external loads leading to excessive longitudinal stresses, coating degradation and potential circumferential SCC

2.5. Assessment of options

A number of methods have been considered with regard to maintaining pipeline integrity for the RBP Asset. These include:

- Inline Inspection (ILI)
- Excavation, integrity works and new coating upgrades and repairs
- Cathodic Protection Replacement and Upgrades
- Other associated equipment upgrades to support the above activities

2.5.1. Inherent Risk assessment

The inherent business case risk is shown below, as well as the residual risk rating of the preferred options. The risk assessment is based on APA's Enterprise Risk Matrix – Projects.

For a worst-case scenario, we need to consider the potential ramifications of a failure of Pipeline Integrity if these activities are not undertaken.

With a pipeline partially unprotected from corrosion, it could be assumed that corrosion occurs at a coating defect and the pipe wall thins to the extent where it fails by leak or rupture. A linear length could rupture where there is severe damage to the coating, such as a mechanical gouge removing the coating, or a large crack developing due to degradation of the polyethylene coating or seasonal ground movement.

A rupture is dramatic, causing severe asset damage and the potential for fatalities if people are present. Depending on the location, the pipeline might be out of service for days, weeks or even months, and recommencement may be subject to successful hydro-testing or only offered at a lower operating pressure.

Table 2-1: Inherent risk rating of the Pipeline Integrity business case

Risk Area	Option 1		Option 2:	
	Likelihood / Impact	Inherent risk rating	Likelihood / Impact	Risk rating
Health & Safety	Remote / Catastrophic	High	Rare / Catastrophic	Moderate
Environment	Remote / Significant	Low	Rare / Significant	Negligible
Operational	Remote / Significant	Low	Rare / Significant	Negligible
People	Remote / Significant	Low	Rare / Significant	Negligible
Compliance	Remote / Significant	Low	Rare / Significant	Negligible
Reputation & Customer	Remote / Major	Moderate	Rare / Major	Low
Financial	Remote / Significant	Low	Rare / Significant	Negligible
Untreated risk		**High**		**Moderate**

The risk assessment indicates that there is the potential for High risk, resulting from the failure to maintain effective Integrity of the pipeline. The impact is largely based upon the outcomes from failing to maintain a safe pipeline system and the associated disruption to normal business.

The preferred options presented in sections 3 to 6 lower the inherent risk from High to a Moderate residual risk.

Financial assessment

A consideration of the pros and cons of the expected financial outlays for all options is shown below. Net Present Value calculations have not been undertaken as a realistic expenditure profile is unable to be ascertained for option 1. Given end-of-life replacement and rectification costs are inevitable, this business case demonstrates that the proposed expenditure is efficient and appropriate to manage the associated risks.

Table 2-2: Financial assessment of the Integrity business case for ILI, CP & associated integrity activities.

	Commentary
Option 1: Do Nothing (Carry out only basic pipeline integrity activity; allow pipelines to deteriorate)	• No proactive management of the CP for the pipeline will lead to pipeline corrosion. • Corrosion will reduce the capacity of the pipeline through gas leakage, potentially causing damage to the environment and people, as well as a loss of revenue. • To repair extensive levels of corrosion entails digging and replacing entire sections of pipeline. This is more expensive than maintaining on-going CP of the pipeline and will also require lengthy interruptions to gas supply. • Interruptions to customer supply and gas leakage reduces income as will any pipeline failure that leads to a fatality or injury, due to litigation costs and payments for damages.

	• Regulatory and licence breaches would lead to fines and potentially a loss of the pipeline licence. • These outcomes would severely impact share price and the longevity of the business. • Avoided capex cost in the earlier years will be more than offset by the potential financial and reputational cost of regulatory fines, penalties arising from reputational damage, legal action and the loss of the RBP operating licence. • If a scheduled ILI cannot be completed to meet the date specified in the PIMP, one of the options available to the operator is to set a restricted operating pressure.
Option 2: Carry out pipeline integrity management activities	• Conduct ILI and associated dig & repair in accordance with AS 2885 Pipeline Integrity Management, ensuring defects are identified, validated, and remediated before they threaten pipeline integrity. • Cathodic protection system replacements are identified from detailed CP survey data and field assessments. • Replacements and upgrades will improve the standardisation of field equipment, reduce obsolescence risk and the financial costs of carrying multiple spare parts. • Steady replacement rate over the coming years gives predictability in expenditure. • Strengthening leak detection capabilities, including enhanced methane survey activities and other monitoring technologies, to enable more accurate and quantified leak detectionor emissions and support rapid response before safety or environmental impacts occur. • Other associated equipment upgrades to support the above activities
Option 3: Replace Pipelines	• Cost prohibitive, not prudent

Based on the risk and financial assessments above, RBP's preferred option to appropriately balance costs and risks is Option 2 across all components of the CP business case.

2.6. Consistency with the National Gas Rules and other regulations

The RBP is a major national pipeline, and good practice requires it to be appropriately equipped to eliminate the risk of corrosion events. Licence conditions and Australian Standards require management to actively manage corrosion.

The planned capital expenditure on the RBP is designed to meet the capital expenditure objectives set out in in section 79(2)(c)(ii) of the National Gas Rules (NGR) as the work is necessary to maintain the integrity of service.

Consistent with Rule 79 of the National Gas Rules, APA considers that the capital expenditure is:

Prudent – The expenditure is necessary in order to maintain and improve the safety of services and maintain the integrity of services to customers and is of a nature that a prudent service provider would incur. The program aligns with Australian Standard (AS) 2832.1 Cathodic Protection of Metals: Pipes and Cables, AS 2885.3 Pipelines: Gas and Liquid Petroleum Operations and Maintenance; and AS3000: Electrical Installations;

Efficient – The works will be subject to APA's procurement policy. The field work will be carried out by the external contractors that has been used to date, who has demonstrated specific expertise in completing the installation of the facilities in a safe and cost-effective manner. The expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur; and

Consistent with accepted and good industry practice – Addressing the risks associated with the cathodic protection system failure and replacing assets that have reached the end of their useful life is accepted as good industry practice. In addition, the reduction of risk to as low as reasonably practicable while balancing cost is consistent with Australian Standard AS2885.Proposed costs for FY28-FY32

The total forecast capital expenditure for the Roma to Brisbane Pipeline (RBP) Integrity Program over the FY28–FY32 access arrangement period is set out in Table 2-2.

This forecast represents the aggregated cost of the individual integrity activities described in Sections 3 to 8, including In Line Inspection, Validation Digs, Safety Critical Digs, Cathodic Protection, Pigging Enablement Upgrades, and Enhanced Methane Survey initiatives. The expenditure has been developed on a **prudent, efficient, and evidence based basis**, drawing on historical delivery volumes, asset condition data, and current market tested contractor rates under APA's national vendor arrangements. The timing and scale of the forecast reflect the requirements of the Pipeline Integrity Management Plan (PIMP), AS 2885.3, and licence obligations, ensuring that investment is targeted to known and foreseeable integrity risks. The proposed expenditure avoids inefficient deferral or reactive intervention and represents the **lowest sustainable cost** of maintaining the safety, reliability, and integrity of services, consistent with the capital expenditure criteria in **NGR Rule 79**.

Table 2-2: Total cost for Integrity business case ($000's Real 2026-27)

Category	FY28	FY29	FY30	FY31	FY32	Category Total
ILI	2,321	1,496	2185	0	0	6,002
Validation dig	2,768	1,964	3,013	1,978	525	10,248
CP	2,652	2,657	2,665	2,676	2,683	13,334
Safety Digs	721	2,686	1,246	2,182	729	7,563
ILI upgrade	-	2,114	-	-	-	2,114
Enhanced Methane Survey	-	-	2,897	-	-	2,897
FY Total	8,243	10,693	9,914	8,494	4,814	42,158

3. In Line Inspection (ILI)

3.1. Project objective and scope

As with all significant hydrocarbon transmission pipelines, the RBP requires regular inspections. In-line inspection (ILI) using intelligent pigs is one of the most important and conclusive activities in the spectrum of pipeline integrity management processes, as it allows pipeline deterioration and damage to be identified and rectified prior to failure.

ILI results are used to reassess dig numbers taking corrosion growth rates and adverse tool tolerance into account, as required by Australian Standard AS 2885.3-2012. Corrosion growth modelling based on data from previous ILI and validation excavations has indicated the appropriate re-inspection interval for metal loss as per the table below.

APA's experience is that reinspection generally results in a decrease in the number of features requiring repair, as actual corrosion growth rates can be established for features rather than assuming a uniform and conservative growth rate.

The required ILI technologies are as follows:

- High-resolution magnetic flux leakage (MFL) inspection – detects corrosion, gouges, grooves, mill defects, girth weld anomalies and other metal loss features. This is the standard ILI for which the corrosion growth modelling determines reinspection intervals.
- Geometry or calliper inspection – detects dents, ovality (out of roundness) and similar – can indicate 3rd party mechanical damage, rock dents from flooding or landslides, or dents remaining in the pipeline since construction. This is generally done in conjunction with the MFL inspection. It is noted by APA that dents are high risk of cracking or gouging and are the most likely defects to lead to pipeline failure. The ILI detection of dents has been a key part of the RBP integrity program and has enabled APA to find and repair dents with gouges, corrosion and cracking that would have had significant consequences if left to fail.
- Inertial Mapping (IMU) – Maps the geographical position of the pipeline centreline and records any movement or change in shape since previous inspection. IMU pigging enables curvature and strain analysis which is a key factor in mitigation of circumferential stress corrosion cracking. This is also done in conjunction with the MFL inspection as required.
- Electro-Magnetic Acoustic Transducer (EMAT) inspection –detects cracking and crack-like features. EMAT is used in the RBP to detect and manage stress corrosion cracking and longitudinal weld anomalies. This is a more specialised inspection technique with tighter operational requirements on pipeline velocity and may be scheduled separately or together with standard MFL ILI. EMAT is of particular importance to the original build pipeline segments as they are the most susceptible to stress corrosion cracking.

The table below illustrates the ILIs completed in the current access arrangement period and planned for the remaining years of the current period and next access arrangement period.

Table 3-1: ILI Length, Inspection Type and Next due dates

Pipeline Section	Approx. Length (km)	Inspection Type	Planned Timing
DN200 Lytton Lateral	~6 km	MFL + Geometry + IMU	FY28
DN250 Peat Lateral (Scotia-Woodroyd / Woodroyd-Arubial)	~45 km	MFL + Geometry + IMU	FY29

DN400 Mainline Campaign (5 sections)*	~160.9 km (Sections C-E)	MFL-A, Geometry, IMU	FY28
DN400 Mainline Campaign (3 sections)	~200 km (Sections F-G and Metro Loop)	MFL-A, Geometry, IMU	FY30
RBP400 Metro (CEP + MLP)	15.3 km Loop1: Preston Rd - Paringa Rd	MFL + EMAT + Geometry + IMU	FY31-FY32

**Note: For DN400 Mainline (Sections A-E) - sections A & B will be conducted in FY27 and sections C,D & E will be conducted in FY28 – Total length of Sections A-E is 279 km.*

3.2. Background

APA has a national policy and schedule for ILI. The policy sets out the frequency and schedule for ILI across the company's pipelines. This policy sets the standard duration between ILI at 10 Years, unless an engineering assessment determines otherwise. Further, the RBP is designated in the Queensland Petroleum and Gas (Production and Safety) Act 2004 as a 'Strategic Pipeline'. Under this legislation, all sections of pipeline under the RBP licence (#2) are required to be inspected by ILI within the first 7 years of operation, and at least once within every 10-year period after that. However, for the RBP, due to its age and complexity of integrity threats, many sections require more frequent inspections.

An ILI run will involve planning, set up, launching the sensor, monitoring the sensor and pipeline while the sensor operate and extraction of the sensor. This may involve multiple cleaning runs and potentially multiple runs to collect the data accurately.

3.3. Assessment of options

The options considered for the access arrangement period are:

— Option 1: Do nothing

— Option 2: Mandatory In Line inspection as per integrity management plan & AS2885

3.3.1. Risk assessment

Failing to conduct mandatory In Line Inspections can result in corrosion and cracking remaining undetected and contribute to a loss of containment.

Table 3-2: Risk assessment – ILI Inspections

Risk Area	Option 1		Option 2:	
	Likelihood / Impact	Inherent risk rating	Likelihood / Impact	Risk rating
Health & Safety	Remote / Catastrophic	High	Rare / Catastrophic	Moderate
Environment	Remote / Significant	Low	Rare / Significant	Negligible
Operational	Remote / Significant	Low	Rare / Significant	Negligible
People	Remote / Significant	Low	Rare / Significant	Negligible
Compliance	Remote / Significant	Low	Rare / Significant	Negligible
Reputation & Customer	Remote / Major	Moderate	Rare / Major	Low

Financial	Remote / Significant	Low	Rare / Significant	Negligible
Untreated risk		**High**		**Moderate**

Option 1

The 'Do Nothing' option carries a high risk that the condition of the pipeline will be unknown. This will result in any defects or anomalies remaining unidentified and subsequently not being treated.

Although this option defers any capital expenditure, it increases the risk of corrosion and the expenditure to rectify corrosion (once it occurs) will cost significantly more than conducting In line inspections (option 2) to ensure pipeline integrity.

If a scheduled ILI cannot be completed within the timeframe specified in the Pipeline Integrity Management Plan (PIMP), the operator may be required to apply a Restricted Operating Pressure (ROP) in accordance with AS 2885.3. Under this framework, the initial ROP is set to the P98 value of one year of pressure history (with at least 730 data points). From the second year onward, the ROP decreases annually by 2% where the design factor (DF) is less than or equal to 0.33, or by a percentage equal to 6 × DF where the DF exceeds 0.33.

Option 1 is not technically acceptable, nor aligned with the requirements of the RBP Pipeline Licence. It is not prudent nor consistent with good practice.

Option 2

Using ILI to maintain the integrity of pipelines is accepted good industry practice and achieves the lowest sustainable cost of providing services relative to other techniques. ILI is a proven technology used worldwide for monitoring pipeline integrity.

ILI is an essential part of the RBP's Pipeline Integrity Management Plan (PIMP) and is in turn necessary to maintain the safety and integrity of services by reducing the risk of a catastrophic failure. The program is necessary to maintain and improve the safety of services and maintain the integrity of services to RBP customers and is of a nature that a prudent service provider would incur.

ILI is also necessary to comply with regulatory obligations (regulatory requirement) and to maintain capacity to meet current levels of demand (by avoiding a requirement to de-rate the pipeline or the weeks/months it would take to restore service following a catastrophic failure).

APA tenders the provision of ILI services on a competitive basis. The works will be subject to APA procurement policies. The works will be carried out by external contractors who demonstrate specific expertise in completing the installation of the facilities in a safe and cost-effective manner. The expenditure can therefore be considered complaint with the expenditure that a prudent service provider acting efficiently would incur.

ILI is the most cost-effective solution and has been approved by the regulators for many other pipeline assets.

Financial assessment

Table 3–3: Option assessment – Conduct In-Line Inspections ($ Real 30 June 2026)

Option	Estimated cost	Treated residual risk rating	Benefit / Disbenefit
Option 1	N/A	High	Does not mitigate Health & Safety or Reputation & Customer Risk. Does not meet standard for pipeline integrity.
Option 2	$6.02M	Mod	Efficiently mitigates Operational, Compliance and Financial risk and complies with regulatory requirements.

Table 3–4: Financial assessment – Conduct In-Line Inspections ($ Real 30 June 2026)

	Description
Option 1: Do Nothing	• Interruptions to customer supply and gas leakage reduces income as will any pipeline failure that leads to a fatality or injury, due to litigation costs and payments for damages. • Regulatory and licence breaches would lead to fines and potentially a loss of the pipeline licence. • These outcomes would severely impact share price and the longevity of the business. • Avoided capex cost in the earlier years will be more than offset by the potential financial and reputational cost of regulatory fines, penalties arising from reputational damage, legal action and the loss of the RBP operating licence. • If a scheduled ILI cannot be completed to meet the date specified in the PIMP, one of the options available to the operator is to set a restricted operating pressure.
Option 2: Conduct In Line Inspections	• Conduct ILI and associated dig & repair in accordance with AS 2885 Pipeline Integrity Management, ensuring defects are identified, validated, and remediated before they threaten pipeline integrity.

APA's preferred option that it believes appropriately balances costs and risks is to conduct ILI on the RBP asset.

3.4. Proposed costs for FY28-FY32

The annual expenditure profile reflects the planned inspection schedule across RBP pipeline segments and accommodates the varying scope and inspection technologies required for each segment.

The costs are based on the ILI costs contained in the existing agreements. While these agreement s will expire prior to the end of the forecast Access Arrangement Period the existing agreements represent the best available information.

The proposed costs are summarised in **Table 3–3**, which sets out the estimated annual expenditure by pipeline section and inspection campaign.

Overall, the forecast represents an efficient and proportionate investment to maintain pipeline integrity, comply with regulatory obligations, and support the ongoing safe and reliable operation of the RBP, consistent with the capital expenditure criteria in **NGR Rule 79**.

Table 3–3: Estimated annual cost ILI Program sites ($000's Real 2026-27)

Description	FY28	FY29	FY30	FY31	FY32	Total
DN200 Lytton Lateral - ILI - MFL	**708**	-	-	-	-	708
DN250 Peat Lateral - ILI	-	**1,496**	-	-	-	1,495
DN400 - MFL Campaign (3 sections) FY28-30			2,185	-	-	2,185
DN400 - MFL Campaign (5 sections) FY26-28	1,613	-	-	-	-	1,613
FY Total	2,321	1,496	2185	0	0	6,002

Table 3–4: ILI Program unit rates ($000's Real 2026-27)

Inspection Program	Approx. Length (km)	Forecast Cost ($M)	$/km
DN200 Lytton Lateral	6	0.843	140,500[1]
DN250 Peat Lateral	45	1.496	33,200
DN400 Mainline (Sections A-E)*	161	1,613	10,018
DN400 Mainline (Sections F-G)	185	2.186	11,800
DN400 CEP	9.5	Included in DN400 Campaign	Included
DN400 MLP	5.8	Included in DN400 Campaign	Included
Total Program	**412**	**6.002**	

[1] Due to the shorter length of the ILI the $/km is more heavily influenced by set up and collection costs.

**Note: For DN400 Mainline (Sections A-E) - sections A & B will be conducted in FY27 and sections C,D & E will be conducted in FY28*

Table 3–5: ILI Program cost breakdown ($000's Real 2026-27)

Description	FY28	FY29	FY30	FY31	FY32	Total
Technican Costs	484	292	-	381	202	1359
Design Costs	210	127	93	166	88	684
Installation Costs	273	165		216	114	768
Internal Labour PE,PM. A&A, HSEH	189	114		149	79	532
ILI Vendor Costs	862	521	-	680	360	2422
Minor Sub contractor costs	84	51		66	35	236
FY Total	**2,103**	**1,271**	**93**	**1,658**	**877**	**6,002**

4. Validation Digs

4.1. Project objective and scope

To ensure that any features exceeding acceptance criteria are correctly remediated, and to verify the accuracy of the ILI tool results, validation digs are required following the completion of an ILI and review of the results.

Anomaly assessment and defect repair is a mandatory requirement of AS 2885.3. This requires APA to maintain the RBP's safety and integrity and ability to withstand the internal pressure and other loads.

Following the completion of an Inline Inspection, excavations are routinely undertaken to validate the data obtained from the ILI. These excavations verify the anomaly sizing accuracy and probability of the detection/identification if anomalies are within the statistical specifications of the ILI tool used. For older pipelines, it is common that the number of validation excavations required is less than the total number of anomalies identified by the ILI that require further investigation. These additional excavations are referred to as repair excavations and form the integrity upgrade programme.

For corrosion features, repair requirements have been developed and prioritised based on anomaly assessment of the ILI data using ASME B31G, Modified B31G, and Effective Area calculation methodologies.

A typical integrity upgrade excavation includes:

— Excavating and exposing the pipeline at the location of the anomaly

— Removing the pipeline coating from the pipeline exterior surface

— Inspection and assessment of the anomaly and determination of a repair process

— Repair of the anomaly and refurbishment of the pipeline coating

— Reinstatement of the earth fill around the pipeline and soil surface

4.2. Background

Validation digs are a critical component of the RBP's integrity management program, undertaken to confirm the accuracy and reliability of data obtained from In-Line Inspection (ILI) tools. Following each ILI, physical excavations are required to expose the pipeline, allowing engineers to directly inspect identified anomalies and verify that defect sizing and detection fall within the statistical performance specifications of the inspection technology used.

This process is essential for ensuring compliance with AS 2885.3, which mandates the assessment and remediation of features that could threaten pipeline integrity. Over time, particularly on older pipeline sections, validation digs have proven vital for accurately characterising corrosion, dents, cracking, and other forms of degradation that cannot be fully validated through remote inspection alone.

In addition to confirming ILI performance, validation digs support informed decision-making by improving the accuracy of corrosion growth models, strengthening confidence in reinspection intervals, and ensuring that required repairs are completed to maintain the safety and reliability of the RBP.

4.3. Assessment of options

The options considered for the access arrangement period are:

— Option 1: Do nothing (leave features unmitigated)

— Option 2: Perform Validation Digs Following ILI

4.3.1. Risk assessment

Failing to undertake validation digs after an ILI can result in anomalies being inaccurately sized or incorrectly characterised, leaving potential defects such as corrosion, cracking, dents, or gouges unverified.

Table 4–1: Risk assessment – conduct validation digs

Risk Area	Option 1		Option 2:	
	Likelihood / Impact	Inherent risk rating	Likelihood / Impact	Risk rating
Health & Safety	Remote / Catastrophic	High	Rare / Major	Low
Environment	Remote / Significant	Low	Rare / Significant	Negligible
Operational	Remote / Major	Moderate	Rare / Major	Low
People	Remote / Significant	Low	Rare / Significant	Negligible
Compliance	Remote / Minor	Low	Rare / Significant	Negligible
Reputation & Customer	Remote / Major	Moderate	Rare / Major	Low
Financial	Remote / Significant	Low	Rare / Significant	Negligible
Untreated risk		**High**		**Low**

4.3.2. Option 1

Under this option, no validation digs would be conducted following each In-Line Inspection (ILI). This would significantly increase the risk that detected anomalies are inaccurately sized or incorrectly characterised. Without physical verification, critical defects such as corrosion, cracking, dents, and gouges may remain unvalidated, potentially allowing threats to pipeline integrity to go unaddressed.

This approach is not compliant with AS 2885.3, which requires operators to confirm and remediate features that could compromise pipeline safety. As a result, Option 1 presents a high safety and compliance risk and is not considered prudent nor aligned with good industry practice.

4.3.3. Option 2

This option involves undertaking validation digs after each ILI to verify tool performance, confirm anomaly sizing, and ensure repairs are carried out where required. Validation digs support compliance with AS 2885.3 and provide essential calibration data to improve the accuracy of corrosion growth modelling and future reinspection intervals.

This option reduces uncertainty, increases confidence in the ILI results, and ensures that any features posing potential safety or operational risks are appropriately assessed and remediated. Although it requires ongoing investment, Option 2 represents prudent asset management, reduces lifecycle risk, and supports the safe and reliable operation of the RBP pipeline.

Financial assessment

Table 4-2: Option assessment – Conduct Validation Digs ($ Real 30 June 2026)

Option	Estimated cost	Treated residual risk rating	Benefit / Disbenefit
Option 1	N/A	High	Does not mitigate Health & Safety, Operational or Reputation & Customer Risk
Option 2	$10.25M	Low	Efficiently mitigates Health & Safety, Operational and Reputation & Customer Risk and complies with regulatory requirements.

4.4. Validation Dig estimation methodology

The forecast number of validation digs was developed using APA's "Estimating ILI-Guided Dig-up Packages" guideline.

The methodology uses:

- Pipeline age.
- Pipeline length.
- ILI technology type.
- Time since previous inspection.
- Location class and residential exposure.
- Historical inspection outcomes.

For MFL inspections, the planning estimate is:

Number of dig-ups = Length × Age^2 ÷ 25,000 (rounded up)

with adjustments for:

- Residential and Higher Consequence Areas.
- Historical corrosion performance.
- Mechanical damage exposure.
- Inspection interval.
- Anticipated validation requirements.

The resulting forecast dig program includes:

Program	Complex	Non-Complex
DN200 Lytton Validation Program	2	
DN300 Metro Validation Program	4	2
DN400 Validation Program (5 section)	6	6
DN250 Peat Validation Program	2	2
DN400 Validation Program (3 section)	3	3

Total forecast validation digs: 30 excavations over the Access Arrangement period.

The forecast was then translated into expenditure using complex & non-complex dig unit rates supported by historical project delivery costs and current contractor rates. The resulting cost build-up forms the basis of the Validation Dig forecast included within the Access Arrangement submission.

Table 4–3: Financial assessment – Validation Digs

	Commentary
Option 1: Do Nothing (Carry out only basic pipeline integrity activity; allow pipelines to deteriorate)	• Interruptions to customer supply and gas leakage reduces income as will any pipeline failure that leads to a fatality or injury, due to litigation costs and payments for damages. • Regulatory and licence breaches would lead to fines and potentially a loss of the pipeline licence. • These outcomes would severely impact share price and the longevity of the business. • Avoided capex cost in the earlier years will be more than offset by the potential financial and reputational cost of regulatory fines, penalties arising from reputational damage, legal action and the loss of the RBP operating licence.
Option 2: Carry out pipeline Validation Digs	• Conduct ILI and associated dig & repair in accordance with AS 2885 Pipeline Integrity Management, ensuring defects are identified, validated, and remediated before they threaten pipeline integrity. • Excavation, integrity works and new coating upgrades and repair

The preferred option that appropriately balances costs and risks is to conduct Validation Digs

4.5. Proposed costs for FY28-FY32

The total forecast capital expenditure for Validation Digs over FY28–FY32 is aligned with the planned ILI inspection program. This reflects the expected number, complexity, and location of excavations required to validate inspection results across the RBP. The expenditure profile varies year-to-year in line with inspection campaigns and avoids inefficient front-loading or duplication of works.

The proposed costs are summarised in **Table 4–3**, which sets out the estimated annual expenditure by pipeline segment and inspection campaign. The forecast represents a **reasonable, cost-reflective, and efficient investment** to maintain asset integrity, comply with regulatory obligations, and support the continued safe and reliable operation of the RBP, consistent with the capital expenditure criteria in **NGR Rule 79**.

Table 4-4: Estimated annual Validation Digs ($000's Real 2026-27)

Description	FY28	FY29	FY30	FY31	FY32	Total
DN250 Peat Lateral - Validation Dig ILI	-	-	1,043	-	-	1,043
DN300 Metro - Validation dig ILI	1,845	-	-	-	-	1,845
DN400 - Validation Dig ILI (3 sections)	-	982	985	989	262	3,219

DN400 - Validation Dig ILI (5 sections)	-	982	985	989	262	3,219
DN200 Lytton Lateral - Validation Dig ILI	923	-	-	-	-	923
FY Total	2,768	1,964	3,013	1,978	525	10,248

Table 4-5: Estimated yearly breakdown of complex & non-complex digs

Description	FY28	FY29	FY30	FY31	FY32	Total
Validation Digs (Complex)	6	2	2	2	0	12
Validation Digs (Non-complex)	0	4	8	4	2	18
FY Total	6	6	10	6	2	30

Table 4-6 Validation Dig Program cost breakdown ($000's Real 2026-27)

Description	FY28	FY29	FY30	FY31	FY32	Total
Civil Contractor Cost	1999	1418	2175	1428	379	7399
Internal Labour – Site Supervision	526	373	572	376	100	1947
Internal Labour - PE,PM. A&A, HSEH, CH	244	173	265	174	46	902
FY Total	2,768	1,964	3,013	1,978	525	10,248

Table 4-7 Validation Dig Unit Rates ($000's Real 2026-27)

Dig Classification	Unit Rate ($M per Dig)
Non-Complex Dig	0.185
Complex Dig	0.461

5. Safety Critical Digs

5.1. Project objective and scope

The Safety Critical Digs program addresses defects that present an immediate threat to the safety and integrity of the RBP. These excavations are undertaken when anomalies identified through ILI, CP assessments, or field observations exceed the acceptance limits defined in AS 2885.3 and therefore cannot be deferred.

5.2. Background

The DN250 pipeline—constructed in 1968–69 with over-the-ditch-applied polyethylene tape coating—is classified as a "vintage" asset and requires a significantly higher level of integrity management due to advanced coating deterioration and elevated corrosion risk. Disbondment of the original tape coating results in isolated shielding of cathodic protection, enabling external corrosion to progress unchecked across substantial lengths of the DN250 asset.

Sections A–F of the DN250 pipeline are currently suspended with suspension taking place between June 2019 and April 2025 inline with the current Access Arrangement business case. As these sections are currently suspended, safety dig-ups and further direct assessments are largely deferred unless that section is returned from suspension. Each suspended section is maintained a very low but positive pressure to prevent oxygen ingress and internal corrosion. These pressures are monitored by telemetry. Should a loss of pressure be detected integrity management actions are still required.

5.3. Assessment of options

The options considered for the access arrangement period are:

— Option 1: Do nothing

— Option 2: Undertake Safety Critical Digs

5.3.1. Risk assessment

Table 5–1: Risk assessment – Safety Critical Digs

Risk Area	Option 1		Option 2:	
	Likelihood / Impact	Inherent risk rating	Likelihood / Impact	Risk rating
Health & Safety	Remote / Catastrophic	High	Rare / Major	Low
Environment	Remote / Significant	Low	Rare / Significant	Negligible
Operational	Remote / Major	Moderate	Rare / Major	Low
People	Remote / Significant	Low	Rare / Significant	Negligible
Compliance	Remote / Minor	Low	Rare / Significant	Negligible
Reputation & Customer	Remote / Major	Moderate	Rare / Major	Low
Financial	Remote / Significant	Low	Rare / Significant	Negligible
Untreated risk		**High**		**Low**

Option 1

Under this option, no Safety Critical Digs would be undertaken, and defects identified through ILI, CP assessments, or field observations would remain unaddressed. For the DN250 pipeline—particularly the remaining in-service Brassall to Bellbird Park segment, this would leave known corrosion, coating disbondment, and potential ERW seam weld defects unmanaged. The risk of loss of containment would remain high, and the approach would be non-compliant with AS 2885.3, which requires immediate remediation of anomalies exceeding acceptance criteria. This option is therefore not technically acceptable nor prudent.

Option 2

Undertaking Safety Critical Digs ensures that any defects identified through ILI, CP assessments or field observations that exceed AS 2885.3 acceptance criteria are immediately excavated and remediated. This is critical for the DN250 pipeline, particularly the remaining in-service Brassall to Bellbird Park segment, which continues to exhibit corrosion-driven degradation, coating disbondment, and potential ERW seam-weld abnormalities. Completing Safety Critical Digs maintains compliance with AS 2885.3, reduces the likelihood of loss-of-containment events, and represents prudent and accepted good industry practice for managing high-risk legacy pipeline assets.

Financial assessment

Table 5-2: Option assessment – Safety Critical Digs ($ Real 30 June 2026)

Option	Estimated cost	Treated residual risk rating	Benefit / Disbenefit
Option 1	N/A	High	Does not mitigate Health & Safety, Operational or Reputation & Customer Risk
Option 2	$7.56M	Low	Efficiently mitigates Health & Safety, Operational and Reputation & Customer Risk and complies with regulatory requirements.

5.4. Safety Critical Dig estimate methodology

In addition to validation digs, APA has forecast 22 Safety Critical Digs over the 2027-32 Access Arrangement period.

The forecast has been informed by Sections 3.2 and 3.3.1 of the Dig-up Estimation Guideline, and calibrated against historical excavation performance, which provide planning allowances for:

- Time-critical defects identified following ILI;
- Defects requiring remediation before remaining wall thickness or failure pressure criteria are exceeded;
- Additional excavations associated with residential and higher consequence areas where the likelihood of mechanical damage is greater.

Section 3.2 of the methodology provides allowances for time-critical excavations following an ILI campaign based on pipeline age and inspection interval, while Section 3.3.1 provides additional allowances for excavations associated with third-party interference threats in residential and urban locations. These factors are particularly relevant to the DN300 Metro, DN200 Lytton Lateral and eastern sections of the DN400 pipeline where the pipeline traverses higher consequence areas.

The resulting forecast of 22 Safety Critical Digs represents approximately 4 to 5 digs per year across the Access Arrangement period and has been incorporated into the forecast expenditure

APA reviewed historical Safety Critical Dig activity undertaken across the RBP system between FY2011 and FY2025. During this period, a total of 538 Safety Critical Digs were completed, comprising 417 coating repairs and 121 structural repairs. This equates to a long-term average of approximately 36 digs per year.

Period	Total Safety Critical Digs	Average per Year
FY2011-FY2025	538	35.9
Forecast FY2028-FY2032	22	4.4

The forecast of 22 Safety Critical Digs is therefore materially below the long-term historical average.

APA considers this reduction reasonable because a significant proportion of historical excavation activity was associated with the original DN250 system, which has experienced the highest rates of coating degradation and corrosion-related defects due to its vintage construction characteristics and polyethylene tape coating system. As described in the business case, the DN250 pipeline has been a major contributor to historical integrity management activity and is now progressively being suspended from service. As a result, future excavation volumes are expected to be substantially lower than historic levels while continuing to maintain compliance with AS 2885.3 and pipeline licence requirements.

The forecast of 22 Safety Critical Digs therefore represents a prudent and efficient estimate based on documented engineering methodology, known pipeline condition, planned inspection activities and historical operating experience. It is also considered conservative when compared with the long-term excavation history of the RBP system.

Table 5–3: Financial assessment – Safety Critical Digs ($ Real 30 June 2026)

	Commentary
Option 1: Do Nothing (Carry out only basic pipeline integrity activity; allow pipelines to deteriorate)	• Interruptions to customer supply and gas leakage reduces income (RBP revenue per day) • litigation costs and payments for damages as will any pipeline failure that leads to a fatality or injury • Regulatory and licence breaches would lead to fines and potentially a loss of the pipeline licence. (max possible fine for safety breach under HSE and Qld Resource legislation) • These outcomes would severely impact share price and the longevity of the business.
Option 2: Carry out pipeline Safety Critical Digs	• Conduct ILI and associated dig & repair in accordance with AS 2885 Pipeline Integrity Management, ensuring defects are identified, validated, and remediated before they threaten pipeline integrity. • Excavation, integrity works and new coating upgrades and repair

The preferred option that appropriately balances costs and risks is Option 2, Carry out Safety Critical Digs.

5.5. Proposed cost for FY28-FY32

The forecast expenditure reflects the expected volume of non-deferrable excavations required to remediate defects that exceed acceptance criteria under **AS 2885.3** and therefore present an immediate risk to pipeline safety or integrity. Safety Critical Digs are inherently driven by inspection outcomes and field observations and cannot be precisely forecast in advance. The estimate has therefore been developed using a structured and evidence-based approach that integrates both historical performance and forward-looking inspection activity.

Historical delivery on the RBP indicates an average of approximately eight safety critical digs per annum, based on observed defect rates and past repair volumes. While this provides a relevant baseline, reliance on historical averages alone is not considered sufficiently robust for forecasting purposes, as it does not reflect the timing and scope of planned inspection activities or changes in asset condition.

To address this, APA has applied an internal estimation methodology that links forecast dig volumes (as described above) to the planned pigging and In-Line Inspection (ILI) program over the Access Arrangement period. This approach recognises that safety critical defects are predominantly identified through inspection and are therefore correlated with ILI campaign timing, rather than occurring uniformly year-on-year.

Under this approach:

- Forecast dig volumes are aligned to known ILI activities, reflecting when defect identification is most likely to occur
- Estimates consider relevant asset characteristics, including pipeline age, condition, and historical defect behaviour
- Allowances are made for time-critical defects and inspection variability, consistent with integrity management requirements under AS 2885.3
- The resulting profile reflects a non-linear distribution of works, rather than a simple steady-state annual assumption

Application of this methodology results in a forecast that is more targeted and responsive to the underlying risk drivers than a simple extrapolation of historical averages. In particular, it avoids systematic over-estimation in years without significant inspection activity, while still maintaining sufficient provision for emergent defects.

The estimate also differentiates between complex and non-complex dig-ups, recognising that cost is materially influenced by location and access constraints (e.g. urban areas, road and rail crossings). The proportion of complex digs has been developed based on the spatial characteristics of the RBP and recent delivery experience.

The resulting expenditure profile and expected mix of dig types are summarised in Tables 5-3 and 5-4.

Table 5–4: Estimated yearly cost of Safety Critical Digs ($'000s Real 2026-27)

Description	FY28	FY29	FY30	FY31	FY32	Total
Safety Critical Digs (Complex)	461	1387	464	1396	467	4,174
Safety Critical Digs (Non-complex)	259	1300	782	785	262	3,389
FY Total	721	2,686	1,246	2,182	729	7,563

Table 5–5: Estimated yearly breakdown of complex & non-complex digs

Description	FY28	FY29	FY30	FY31	FY32	Total
Safety Critical Digs (Complex)	1	3	1	3	1	9
Safety Critical Digs (Non-complex)	1	5	3	3	1	13
FY Total	2	8	4	6	2	22

Table 5-6: Safety Critical Dig Program cost breakdown ($000's Real 2026-27)

Description	FY28	FY29	FY30	FY31	FY32	Total
Civil Contractor Cost	519	1934	897	1571	525	5446
Internal Labour – Site Supervision	137	510	237	415	139	1437
Internal Labour - PE,PM. A&A, HSEH, CH	65	242	112	196	66	681
FY Total	721	2,686	1,246	2,182	729	7,564

Table 5-7: Safety Critical Dig Unit Rates ($000's Real 2026-27)

Dig Type	Quantity	Unit Rate ($M)	Forecast Cost ($M)
Complex	9	0.46	4.17
Non-Complex	13	0.26	3.39
Total Safety Critical Digs	22		7.56

6. Cathodic Protection

6.1. Project objective and scope

Cathodic protection (CP) is a critical integrity control for the Roma to Brisbane Pipeline (RBP), providing protection against external corrosion for all buried steel pipeline assets. The proposed CP capital program for the FY28–FY32 access arrangement period is required to maintain compliance with applicable Australian Standards, pipeline licence conditions, and APA's Pipeline Integrity Management Plan (PIMP).

The scope of the proposed program includes:

— replacement of depleted anode beds;

— replacement of ageing transformer–rectifier (TR) units that have reached end of service life;

— installation of new CP systems where surveys identify inadequate protection coverage, particularly on DN300 sections; and

— ongoing management of AC interference and CP performance monitoring.

Although segments of the DN250 pipeline are suspended or progressively being retired from service, these sections remain electrically bonded to the broader CP system and therefore require continued protection to prevent further corrosion until full decommissioning is completed.

The proposed expenditure is targeted, risk-based, and limited to the works necessary to maintain effective corrosion protection across the RBP.

6.2. Background

Cathodic protection (CP) is a mandatory integrity control for buried steel pipelines and is required under AS 2832.1, AS 2885.3, and the RBP pipeline licence. Although large sections of the DN250 pipeline are no longer operating, the asset has not been decommissioned and remains physically in the ground, electrically bonded, and registered. As such, APA is required to continue demonstrating that corrosion risks are being effectively managed.

At the current time, sections of the DN250 remain partially in use, while other sections are in a suspended state. Where suspension has occurred, operating pressure has already been reduced, materially lowering rupture risk. As customers are progressively removed and pressure is further reduced, corrosion risk and the required level of CP intervention also decline. This creates opportunities over time to optimise CP delivery, including:

- applying alternative CP performance criteria appropriate for suspended pipelines (e.g. polarisation-based criteria);
- reducing CP current outputs; and
- rationalising the number of CP installations and test points.

These optimisation opportunities are already being progressed. The Wallumbilla-to-Brassall section has accepted revised criteria, and a formal study is underway on the Brassall-to-Kogan section to further reduce CP requirements and cost. In addition, as anode beds progressively deplete, the need for replacement is assessed on a case-by-case basis with the objective of minimising capital expenditure while maintaining compliance.

Complete removal of CP on the DN250 is not viable. Doing so would result in uncontrolled corrosion of a large legacy asset, increase safety and environmental risk, compromise compliance, and potentially impact adjacent assets, including third-party pipelines electrically coupled to the RBP CP system. Ongoing CP is also required to maintain CP registration and support leak survey obligations until full decommissioning is achieved.

The forecast CP expenditure reflects uncertainty during this transition period and represents APA's best estimate of the lowest sustainable cost required to maintain the integrity of the DN250 while it remains suspended rather than decommissioned. While alternative criteria and optimisation measures are expected to reduce costs over time, maintaining CP on the DN250 remains the lowest-cost and lowest-risk option when compared to cessation of CP, premature decommissioning, or reactive integrity intervention.

6.3. Assessment of options

The options considered for the access arrangement period are:

— Option 1: Do nothing

— Option 2: Repair and upgrade existing CP systems (preferred option)

— Option 3: Full replacement of CP systems

6.3.1. Risk assessment

Table 6-1: Risk assessment – CP

Risk Area	Option 1		Option 2:	
	Likelihood / Impact	Inherent risk rating	Likelihood / Impact	Risk rating
Health & Safety	Remote / Minor	Negligible	Rare / Minor	Negligible
Environment	Unlikely / Minor	Low	Remote / Minor	Negligible
Operational	n/a		n/a	
People	n/a		n/a	
Compliance	Unlikely / Major	High	Remote / Significant	Low
Reputation & Customer	Unlikely / Significant	Moderate	Remote / Significant	Low
Financial	Unlikely / Minor	Low	Remote / Minor	Negligible
Untreated risk		**High**		**Low**

6.3.2. Financial assessment

Table 6-2: Option assessment – CP ($ Real 30 June 2026)

Option	Estimated cost	Treated residual risk rating	Benefit / Disbenefit
Option 1	N/A	High	Does not mitigate Compliance or Reputation & Customer Risk
Option 2	$13.334M	Low	Efficiently mitigates Compliance and Reputation & Customer Risk and complies with regulatory requirements.
Option 3	>$13.334M	Low	Mitigates Compliance and Reputation & Customer Risk and complies with regulatory requirement but at a much higher cost.

Table 6-3: Financial assessment – CP ($ Real 30 June 2026)

	Commentary
Option 1: Do Nothing	• Defers near-term CP capital expenditure. • Does not address ageing and end-of-life CP assets. • Increased risk of non-compliance with AS 2832.1. • Higher likelihood of corrosion escalation, unplanned repairs, and integrity incidents. • Short-term savings likely outweighed by higher long-term remediation and compliance costs.
Option 2: Repair and upgrade existing CP systems (preferred option)	• Targeted replacement of depleted anodes and ageing TR units. • Installation of new CP systems where protection is inadequate. • Maintains compliance with AS 2832.1 and AS 2885.3. • Reduces corrosion risk and avoids costly reactive interventions. • Represents prudent, efficient and risk-based expenditure consistent with NGR requirements.

Option 1

This option would retain existing CP assets without renewal or upgrade. While basic monitoring could continue, this option would not address depleted anode beds, failing TR units, or known CP deficiencies. Over time, corrosion risk would increase and compliance with AS 2832.1 would not be assured. This option is not prudent and does not meet legislative, licence, or safety obligations.

Option 2

This option involves targeted replacement of end-of-life CP assets, installation of new CP systems where surveys demonstrate inadequate protection, and continued CP monitoring and optimisation. Works are prioritised based on risk, asset condition, and exposure, and are limited to what is required to maintain effective corrosion protection.

Option 3

Wholesale replacement of all CP assets would exceed what is required to achieve compliance and safety outcomes and would not represent efficient expenditure. This option was not progressed further.

6.4. Proposed cost for FY28-FY32

Total forecast cathodic protection expenditure for the FY28–FY32 access arrangement period is set out in Table 6-1. This includes:

— ongoing CP program works on DN400 and DN300 pipelines; and

— continued CP management and interference mitigation associated with DN250 assets until full decommissioning is completed.

The expenditure profile reflects steady, predictable investment aligned with asset needs and avoids cost volatility associated with reactive or failure-driven interventions.

Costs averaged from recently completed CP Projects; Wallumbilla CP Anode replacement & MIM CP Upgrade Project. Both are on adjacent non-regulated asset.

Table 6-4: Annual estimated cost of CP Program ($'000s Real 2026-27)

Description	FY28	FY29	FY30	FY31	FY32	Total
CP Program	1,730	1,733	1,738	1,746	1,750	8,697
CP Interference (DN250) and Registration	923	924	927	931	933	4,638
FY Total	2,653	2,657	2,666	2,676	2,683	13,335

Table 6-5: Cost breakdown for CP Program ($'000s Real 30 June 2026)

Description	FY28	FY29	FY30	FY31	FY32	Total
Internal Labour - PE,PM. A&A, HSEH, CH	1,585	1,588	1,593	1,599	1,603	7,968
Procurement - Materials	245	246	247	248	248	1,234
Construction & Commissioning	822	824	826	829	832	4,133
FY Total	2,653	2,657	2,666	2,676	2,683	13,335

7. Pigging Enablement Upgrades

7.1. Project objective and scope

Pigging enablement upgrades are required to ensure the Roma to Brisbane Pipeline (RBP) retains the capability to undertake in-line inspection (ILI) and other pigging activities necessary to manage pipeline integrity in accordance with the Pipeline Integrity Management Plan (PIMP) and AS 2885.3.

Historically, pigging of the DN300 pipeline was undertaken from Bellbird Park using facilities associated with the DN250 pipeline. With the planned suspension of the remaining sections of the DN250, pigging capability must be established at Ellengrove to ensure the DN300 can continue to be pigged safely and in accordance with integrity requirements.

The scope of works for the FY28–FY32 access arrangement period includes targeted upgrades at specific RBP locations where existing facilities do not support safe or reliable pigging operations. The key elements of the program are:

— installation of pig launching and receiving facilities on the DN300 pipeline at Ellengrove to enable routine pigging and ILI; and

— safety-driven replacement of age degraded equipment at the DN300 pig receiver located at the South-East Area (SEA) compound to address known operational and safety deficiencies.

These upgrades are limited to locations where pigging capability is currently constrained and are necessary to maintain the ongoing integrity of the pipeline system.

7.2. Background

In-line inspection is a critical integrity tool for detecting corrosion, cracking, dents and other defects that cannot be reliably identified through external inspection alone. Without pigging capability, APA would be unable to:

— perform mandatory ILI on affected pipeline sections;

— maintain confidence in pipeline condition between inspection cycles; or

— comply with integrity management requirements under AS 2885.3 and the RBP pipeline licence.

At Ellengrove, the DN300 pipeline currently lacks pigging capability. If no enablement works are undertaken at this location, future inspections of this pipeline section would not be practicable, increasing integrity risk and restricting APA's ability to proactively manage degradation.

At the SEA compound, the existing pig receiver is suffering for age related degradation of it's critical safety isolation valves, nor does the design accommodate current standards for isolation capability and liquids handling. Operational workarounds are currently required, exposing personnel, the public and the environment to avoidable safety and environmental risks. Design changes are most efficiently applied at the point where the existing equipment is at end of life and needing replacement.

Given the age of the DN300 asset and its role within the RBP system, maintaining pigging capability is necessary to support continued safe and reliable operation.

7.3. Assessment of options

The options considered for the access arrangement period are:

— Option 1: Do Nothing

– Option 2: Implement the Pigging enablement upgrades (preferred)

7.3.1. Risk assessment

The primary risk addressed by the Pigging Enablement Upgrades is the inability to reliably inspect and monitor the condition of affected sections of the DN300 pipeline using in-line inspection (ILI). Without pigging capability, integrity threats such as internal corrosion, cracking, metal loss or deformation may remain undetected between inspection cycles, increasing the likelihood of loss-of-containment events.

While the planned suspension of the DN250 pipeline necessitates this upgrade, the need has been managed to date as the next DN300 pigging run is not scheduled until 2030, allowing the change to be accommodated within the current program.

The absence of pigging capability also limits APA's ability to comply with the inspection requirements set out in the Pipeline Integrity Management Plan (PIMP), AS 2885.3, and the RBP pipeline licence. In such circumstances, APA may be required to rely on conservative operational controls, including cascading pressure restrictions due to the DN300 route through densely housed suburbs.

At the SEA compound, deficiencies in the existing pig receiver configuration introduce avoidable safety and environmental risks during pigging operations, including inadequate isolation capability and uncontrolled release of gas or liquids. Continued reliance on procedural workarounds elevates personnel safety risk and is not consistent with accepted good industry practice.

Implementation of the Pigging Enablement Upgrades materially reduces these risks by restoring full pigging capability, enabling mandatory ILI, and eliminating identified safety hazards at existing facilities. With the upgrades in place, residual risk is assessed as low and consistent with prudent and accepted industry practice for gas transmission pipeline operations.

The program is non-recurring in nature and avoids future escalation in integrity management costs.

Table 7-1: Risk assessment – Pigging Enablement upgrades

Risk Area	Option 1		Option 2:	
	Likelihood / Impact	Inherent risk rating	Likelihood / Impact	Risk rating
Health & Safety	Remote / Catastrophic	High	Rare / Catastrophic	Moderate
Environment	Remote / Significant	Low	Rare / Significant	Negligible
Operational	Remote / Significant	Low	Rare / Significant	Negligible
People	Remote / Significant	Low	Rare / Significant	Negligible
Compliance	Remote / Significant	Low	Rare / Significant	Negligible
Reputation & Customer	Remote / Major	Moderate	Rare / Major	Low
Financial	Remote / Significant	Low	Rare / Significant	Negligible
Untreated risk		**High**		**Moderate**

7.3.2. Financial assessment

Table 7-2: Pigging Enablement upgrades ($ Real 30 June 2026)

Option	Estimated cost	Treated residual risk rating	Benefit / Disbenefit
Option 1	N/A	High	Does not mitigate Health & Safety or Reputation & Customer Risk
Option 2	$2.114	Low	Efficiently mitigates Health & Safety and Reputation & Customer Risk and complies with regulatory requirements.

Table 7–2: Financial assessment – Pigging enablement upgrades ($ Real 30 June 2026)

	Commentary
Option 1: Do Nothing	• Avoids near-term capital expenditure on pigging infrastructure. • Inability to undertake mandatory pigging and in-line inspection on affected DN300 sections. • Increased likelihood of undetected integrity defects leading to higher future remediation costs. • Potential for pipeline pressure restrictions or operational limitations to manage integrity risk. • Higher long-term costs driven by reactive repairs, safety incidents, or premature asset replacement.
Option 2: Implement the Pigging enablement project (preferred)	• Enables mandatory pigging and ILI in accordance with the PIMP and AS 2885.3. • Reduces lifecycle costs by supporting early detection and remediation of integrity threats. • Eliminates reliance on operational workarounds that increase safety and environmental risk. • Avoids inefficient costs associated with pipeline de-rating, service interruptions, or emergency repairs. • Represents prudent, efficient and safety-driven expenditure consistent with NGR requirements.

Option 1

Under this option, no pigging enablement or safety upgrades would be undertaken. Pigging and ILI would remain unavailable on affected sections of the DN300 pipeline, and existing operational risks at the SEA compound would persist. This option would materially increase integrity, safety and compliance risk and is not consistent with good industry practice.

Option 2

This option involves installing the minimum infrastructure required to enable pigging and addressing identified safety deficiencies at existing facilities. The scope is targeted and proportionate, addressing only those locations where pigging capability or safety outcomes cannot be achieved through operational controls alone.

Option 2 ensures APA can continue to meet integrity obligations, manage risk proactively, and safely operate pigging facilities.

7.4. Proposed cost for FY28-FY32

This expenditure relates primarily to safety and capability upgrades at identified DN300 facilities and is consistent with recent project delivery costs for comparable works.

The program is non-recurring in nature and avoids future escalation in integrity management costs.

Table 7–3: Annual estimated cost of ILI Upgrades ($'000s Real 2026-27)

Description	FY28	FY29	FY30	FY31	FY32	Total
DN300 Pig Receiver Safety Upgrades (SEA Compound)	-	2,114	-	-	-	**2,114**

Table 7–4: Cost breakdown for Pig Receiver Upgrades ($'000s Real 30 June 2026)

Cost Component	Cost ($000)
Project Management	326
Design	427
Procurement (Valves, Fabrication, Materials)	503
Construction	829
Commissioning & Handover	27
Total	**2,114**

8. Enhanced Methane Survey

8.1. Project objective and scope

The objective of the Enhanced Methane Survey program is to strengthen leak detection capability **across the Roma to Brisbane Pipeline (RBP)** by supplementing established integrity management activities with **direct, high-sensitivity methane measurement technologies**.

While the RBP integrity framework is primarily designed to identify and manage structural threats through in-line inspection (ILI), cathodic protection (CP) monitoring, and targeted excavations, methane surveys provide an additional and complementary control by focusing on **direct detection of loss-of-containment events**. This enhances APA's ability to identify, locate, and respond to methane emissions across the pipeline system before they escalate into safety, environmental, or service impacts.

The scope of the program includes:

- deployment of advanced methane detection technologies (including ground-based and, where appropriate, mobile or aerial surveys);
- collection of georeferenced and time-stamped methane measurement data across defined sections of the RBP;
- classification and prioritisation of detected emissions in accordance with established leak management protocols; and
- integration of survey outcomes into the Pipeline Integrity Management Plan (PIMP) to inform investigation, repair, and longer-term integrity planning.

The program is applied on a **risk-informed and targeted basis across the RBP**, rather than as a continuous or blanket monitoring regime, ensuring that the proposed expenditure remains proportionate and efficient.

8.2. Background

APA manages the RBP using a mature integrity management framework aligned with AS 2885 and licence requirements. This framework incorporates a range of preventative and monitoring controls, including:

- periodic in-line inspection using multiple technologies;
- cathodic protection systems supported by routine surveys;
- validation and safety-critical excavations; and
- routine patrols and operational surveillance.

These controls are effective in identifying structural defects and corrosion-related threats; however, they do not always provide early visibility of **small, emergent methane leaks**, particularly those arising between inspection cycles or associated with fittings, joints, or ageing infrastructure components.

In response to this gap, APA has developed and implemented enhanced methane measurement programs across other major transmission assets within its portfolio. These programs have demonstrated that:

- direct methane measurement provides a more accurate and asset-specific understanding of emissions than emissions-factor-based estimation methods;
- modern methane detection technologies are capable of identifying low-rate emissions with high confidence and precise location data; and
- targeted surveys can be efficiently integrated into existing asset management and integrity processes without duplication or unnecessary cost.

The proposed enhanced methane survey for the RBP applies these learnings in a **measured and proportionate manner**, supporting continuous improvement in integrity assurance, environmental performance, and transparency.

8.3. Assessment of options

The options considered for the access arrangement period are:

- Option 1: Do Nothing
- Option 2: Implement Enhanced Methane Survey (Preferred)

8.3.1. Risk assessment

The primary risk addressed by the Enhanced Methane Survey relates to the potential for methane leaks to remain undetected between scheduled integrity inspections or routine patrols. While the RBP benefits from a mature integrity management framework, existing controls are predominantly focused on identifying structural defects rather than directly detecting small or emerging loss-of-containment events. Undetected methane emissions present safety, environmental, compliance, and reputational risks, particularly given the length, age profile, and geographic reach of the RBP. Introducing enhanced methane detection provides an additional, independent control that materially reduces the likelihood and duration of undetected emissions, improves the timeliness of intervention, and lowers the residual risk across the pipeline system to an acceptable and manageable level. The residual risk with the enhanced survey in place is assessed as low and consistent with prudent and accepted good industry practice for major gas transmission assets.

Table 8–1: Risk assessment – Enhanced Methane Survey

Risk Area	Potential Impact	Option 1	Option 2	
		Inherent risk rating	Likelihood / Impact	Risk rating
Health & Safety	Fatality or injury	Moderate	Rare / Significant	Negligible
Environment	n/a	n/a	n/a	n/a
Operational	Disruption 1-3 months	Low	Rare / Minor	Negligible
Compliance	Regulatory breach	Moderate	Rare / Minor	Negligible
Reputation & Customers	Adverse media, negative feedback	Moderate	Rare / Significant	Negligible
Financial	Repair costs	Moderate	Rare / Significant	Negligible
Untreated risk		**Moderate**		**Negligible**

8.3.2. Financial assessment

Table 8-2: Enhanced Methane Survey ($ Real 30 June 2026)

Option	Estimated cost	Treated residual risk rating	Benefit / Disbenefit
Option 1	N/A	Moderate	Does not mitigate Health & Safety, Compliance, Reputation & Customer or Financial Risk
Option 2	$2.897	Negligible	Efficiently mitigates Health & Safety, Compliance, Reputation & Customer and Financial Risk

Table 8–3: Financial assessment – Enhanced Methane Survey ($ Real 30 June 2026)

	Commentary
Option 1: Do Nothing	• Avoids short-term expenditure on enhanced methane detection. • Relies on patrols, CP data, and indirect indicators with limited leak-detection sensitivity. • Increased risk of undetected low-rate emissions persisting over time. • Potential for higher downstream repair costs due to delayed detection. • Greater exposure to environmental, regulatory and reputational risk.
Option 2: Implement Enhanced Methane Survey (Preferred)	• Enables early detection and precise location of methane emissions. • Reduces lifecycle costs by preventing escalation of minor leaks. • Improves efficiency by targeting investigation and repair activities. • Complements existing integrity programs without duplication. • Represents prudent, risk-based and industry-accepted expenditure.

Option 1

Under this option, methane leak identification would continue to rely on existing integrity controls, periodic patrols, and indirect indicators such as CP performance and operational data. While these measures provide baseline assurance, they have limited sensitivity for detecting small or developing methane leaks across a complex, geographically extensive pipeline system.

This option increases the likelihood that minor emissions remain undetected for extended periods, potentially leading to higher cumulative emissions, delayed intervention, and heightened regulatory or reputational risk.

Option 2

This option introduces targeted enhanced methane surveys across the RBP to strengthen leak detection capability and improve the timeliness and accuracy of emissions identification.

Consistent with demonstrated outcomes from APA's broader methane measurement programs, this approach:

— materially improves sensitivity compared to conventional patrol-based detection;

— enables accurate localisation and prioritisation of emission sources using GPS-referenced data;

— supports efficient deployment of investigation and repair resources; and

— integrates seamlessly with existing integrity and maintenance workflows.

Importantly, the enhanced methane survey is not intended to replace established integrity activities, but to complement them, addressing residual risks that are not fully mitigated through existing controls. Application of the technology is informed by asset risk profile and operational context, ensuring the program remains efficient and proportionate.

Option 2 delivers improved safety, environmental, compliance, and reputational outcomes relative to Option 1 and represents accepted good industry practice for modern transmission pipeline operations.

8.4. Proposed cost for FY28-FY32

The proposed expenditure reflects the efficient cost of undertaking a targeted enhanced methane survey across the RBP during the Access Arrangement period. Cost estimates are based on current market pricing and informed by APA's recent experience implementing similar programs on other major transmission assets.

The scope has been deliberately designed to:

- avoid duplication with existing integrity activities;
- focus surveys where they provide incremental value; and
- limit the frequency of campaigns to those necessary to achieve assurance objectives.

APA expects that continued technological development will place downward pressure on unit costs over time. The survey will take place in FY27 and then again during the Access Arrangement period. The intended frequency is initially estimated to be every 3 years.

The proposed expenditure is consistent with the National Gas Rules as it:

- is necessary to maintain and improve the safety and integrity of pipeline services;
- supports proactive identification and management of loss-of-containment risks across the RBP;
- aligns with demonstrated industry practice and APA's experience on comparable sized assets (SWQP (Qld), MSP (NSW)); and
- represents prudent and efficient expenditure that a service provider acting efficiently and responsibly would incur.

Table 8–4: Annual estimated cost of Enhanced Methane Survey ($'000s Real 30 June 2026)

Description	FY28	FY29	FY30	FY31	FY32	Total
Enhanced Methane Survey	-	-	2,897	-	-	2,897

Table 8-5: Cost breakdown for Enhanced Methane Survey ($'000s Real 30 June 2026)

Item	Number	Unit Rate	Cost
Project Management	1	$130,365	$130,365
RBP aerial survey cost $438/km	438	$413	$180,894
RBP Ground Level Survey	1	$79,000	$79,000
Helicopter mobilisation cost	1	$38,280	$38,280
High Complexity Leak Repairs - Materials	19	$90,000	$1,710,000
High Complexity Leak Repairs - Labour	19	$25,000	$475,000
Low Complexity Leak Repairs	421	$675	$284,175
Leaks not viable to repair	62	$0	$0
Total			**$2,897,714**

Note: Leak identification rate and repair costs obtained from Enhanced Methane Survey and repair work previously carried out on non-regulated APA asset.