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GGP

**December 15, 2023**

# Reliability and maintenance Program

# document control

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*Table 1.1: Revision Record*

| Version | Changes Made |
|---|---|
| *0.1* | *Initial draft* |
| *0.2* | *Feedback received from document review* |

*Table 1.2: Review and Distribution*

| Name | Role | Action | Sections |
|---|---|---|---|
| [redacted] | [redacted] | *Initial draft* | *All* |
| [redacted] | [redacted] | *Review and Input* | *All* |
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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] | [redacted] | *Approval* | *07 Dec 2023* |
| [redacted] | [redacted] | *Approval* | *15 Dec 2023* |

*Other project specific approvers can be added if required.*

Delegation Policy

# Contents

# 1. Executive Summary

## 1.1. Action Requested

This business case seeks to gain approval of $41.3 million (CY$2023)[1] to undertake a program to replace end of life equipment across the GGP over the remainder of AA4 as well as AA5 and AA6. Of this $20.6 million (CY$2023) is scheduled to be included in AA5 and $11.4 million (CY$2023) will be allocated to the covered pipeline.[2]

## 1.2. Options Considered

Four different programs of work have been considered:

1. Defer program to AA6.
2. Focus on control and cathodic protection systems.
3. Complete in AA5.
4. Complete over AA5 and AA6 (**preferred option**).

## 1.3. Project Overview

Commissioned in 1996, the GGP is approaching mid-life and will be 33 years old by 2029. While the pipeline itself has a long-life, facility equipment tends to have shorter useful lives ranging from about 10 to 20 years.

Most of the equipment across the GGP, including the cathodic protection units, valve actuators, power systems, gas chromatographs were originally installed when the GGP was commissioned. Similarly, several control systems components have reached their end of useful life.

We have been able to extend the life of these systems beyond their original design life and typical replacement timeframes applied by other infrastructure owners and operators across Australia.

However, the life of these systems cannot be extended indefinitely. Obsolescence risks, from a lack of spares and vendor support, together with an increasing likelihood of failure are increasing safety, financial and operational capability risks.

Given these risks and recent failures on the GGP and other assets with similar equipment, conceptual development work has commenced to identify optimal equipment strategies. This will allow further development and the more detailed scope of work for each system and site to be produced.

This business case considers the optimal timing and packaging of works to replace end-of-life equipment. This includes whether the program can be deferred, whether the program can be initially limited to higher risk components and whether to implement a program over 1 or 2 access arrangement periods.

The expected risk, cost and performance outcomes under each option has been evaluated. We identify that undertaking a replacement program over AA5 and AA6 is the preferred option as it incurs the second lowest cost, has no moderate risks, and is unlikely to lead to a material reduction in operational performance.

[1] This is equivalent to $34.6 million ($2023) in present value terms.
[2] The allocation of costs to covered and uncovered pipelines has been made on a site-by-site basis.

## 2. Context

The GGP's facilities[3] are essential for the efficient and safe transportation of natural gas. Facilities on the GGP include:

- Compressor Stations – To move gas through the pipeline. All compressor stations also function as Scraper Stations.
- Scraper Stations – Installed at approximately 170km intervals, these facilities have pipework for 'pigs' to be launched and received allowing the pipeline to be inspected and cleaned.
- Mainline Valves (MLVs) – Strategically placed along the pipeline to control the flow of gas, they are essential for isolating sections of the pipeline for maintenance or in case of an emergency. Mainline values are installed at each scraper station, mid-way between each scraper station and at other key locations to maintain operational security and minimise risk to the community. All mainline valves can be manually controlled while those at key locations can be controlled remotely.
- Offtakes – Where gas is diverted off the main line for delivery to end-users, or downstream pipelines. Each facility has a mainline value and a meter, while some also include a pressure regulator.

Electrical, instrumentation, control, cathodic protection and power systems are installed across the GGP's facilities.

Most of this equipment was installed when the pipeline was commissioned in 1996. These components have reached (or will soon reach) the end of their useful life.

Age itself does not drive replacement. We have been able to extend the life of these systems beyond their original design life. The average age of our systems is beyond typical replacement timeframes applied by other infrastructure owners and operators across Australia.

However, the life of these systems cannot be extended indefinitely. Factors such as wear and tear, performance degradation and obsolescence of key components lead to increased safety, reliability and integrity risks. These risks can be managed in the short to medium term; but not in the longer term due to increasing failure rates and spare component scarcity.

Given the range of issues identified with several critical components, we have commenced concept development work, including pre-FEED studies on key facility equipment. This includes the recent completion of Gas Quality Review (in August) and ongoing studies into the GGP's Solar Power Systems and Mainline Valves. Similar work is ongoing at the APA-group level into the optimal approach for control systems and CP units.

The purpose of these development reports is to review the equipment, identify future hardware plans and strategies (leveraging on APA's national expertise and knowledge), identify preferred equipment, undertake a feasibility review and confirm future directions.

[3] The list of GGP compressor stations, scraper stations and mainline valves, in order from the first inlet at Yarraloola through to last outlet at Kalgoorlie South is provided in Appendix 1.

It is intended that, consistent with good industry practice, a series of uniform standard approaches (rather than a site-by-site specific approaches) are developed to:

- Enhance operational reliability and safety through improved equipment performance and maintenance predictability.
- Simplify maintenance, as it allows technicians to uniformly apply their skills and knowledge across the entire pipeline, reducing the need for specialised training for different types of equipment.
- Streamline inventory management and improved procurement, as fewer unique parts and tools are needed, leading to cost savings and a more straightforward supply chain.

While concept development has not been completed, a summary of the current status of each key system and the issues we have identified is set out below as well as delivery considerations.

Lastly, we note that AS2885.3 requires that pipelines are operated within their designated process and mechanical design parameters to ensure the safe and efficient operation of the pipeline. This includes ensuring that all associated equipment is maintained in a state that is fit for purpose.

## 2.1. Control system

All remotely controlled GGP facilities are fitted with a series of interconnected control systems allowing seamless and safe operation. Key components include:

- Remote Terminal Units (RTUs) – the interface between local control systems and the broader SCADA system. They gather and process data from various sensors and controls across the facility providing vital information on operational parameters like pressure, temperature, and flow rates. This data is crucial for transmitting to the central SCADA system for monitoring the pipeline's status, making informed decisions about its operation and controlling each facility.
- Programmable Logic Controllers (PLCs) – responsible for the real-time control and automation of specific operations within the facility. Their functions include station control (including for valve actuators), managing the Gas Engine Alternator (GEA), and regulating compressor units. PLCs receive input from the both the RTU and directly from local sensors and devices, executing control commands and ensuring that the facility operates within set parameters.
- Emergency Shutdown (ESD) system – a critical safety feature designed to rapidly shut down operations in case of an emergency, such as a leak, extreme pressure variation, or other hazardous conditions. The ESD system is directly integrated with both the RTU and PLCs, allowing for a coordinated and swift response to any potential threats, thereby minimising risks to the facility and surrounding area.

The standard useful life for control systems, consistent with all computer-based technologies, is much shorter than other assets and is generally accepted to be around 15 years.[4]

The shorter expected life for these assets is due to the significant changes in hardware, software, and regulatory requirements, especially concerning cybersecurity, leading vendors to develop new replacement products and platforms. The development of newer products often results in

[4] This is a standard view across the utilities industry. For instance see Power and Water Corporation (see page 8 here), AusNet (see page 11 here), and GHD (see page 37 here).

manufacturers withdrawing support,[5] ceasing the production of spares, and creating challenges in maintaining compatibility with existing infrastructure. As a result, operating obsolete equipment not only leads to increased reliability risks but also poses challenges in regulatory compliance and can incur higher costs in the long run.

The obsolete Modicon Quantum RTUs at Yarraloola, Wyloo West, Wiluna, Kalgoorlie South and Leinster metering station have all been replaced or will be replaced by the end of AA4.[6] We will also remove all of the GE PLC's (e.g. at Kalgoorlie South) by the end of AA4.

Despite these recent replacements, as outlined in Table 3, our control systems are ageing (beyond their typical useful life), we are experiencing failures while spares are hard or not possible to obtain.

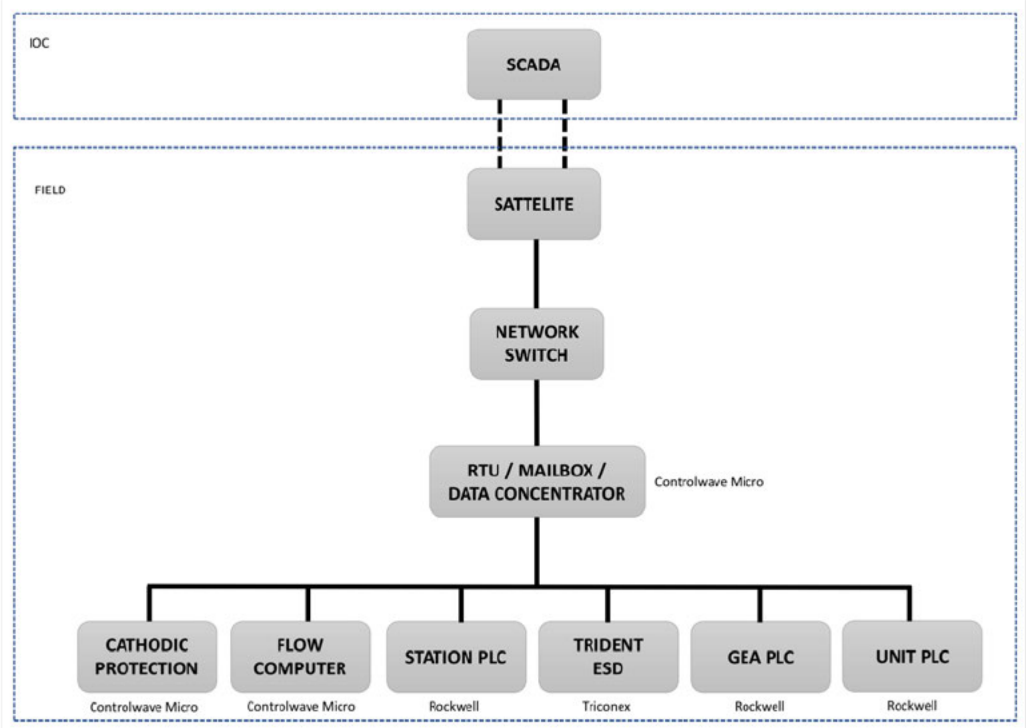
The obsolescence risk (and in turn risk to operational capability) is the highest with the existing Modicon PLCs, Control Wave Micro RTU's and Flow computers and Rockwell SCL05 PLCs.

**Table 3 Status of control system components**

| Control System Component | Knowledge score[7] | Spares availability | Recent failures? | Approx age | Obsolete? |
|---|---|---|---|---|---|
| CWM RTU / Flow computer | 20% | Long lead time item | 2 | 25 | Yes. Support ends 2028. |
| Rockwell PLC for compressors | 90% | Yes | 0 | 10 | No. |
| Rockwell PLC for GEA SLC05 | 90% | No. | 3 | 20 | Yes |
| Trident ESD | 75% | Yes | - | 25 | Expected in 2030. |
| Schneider PLC ESD | 90% | Yes | 0 | 10 | No |
| Modicon PLC | 90% | No | 1 | 30 | Yes |
| GE PLC | 90% | No | 1 | 30 | Yes |

[5] Typical product lifecycles include preferred (available, being promoted and updated by the vendor), available (for expansions but not new installations and no longer being enhanced), mature (withdrawn for sale but ongoing support and spares available from the vendor), obsolete (vendor no longer provides support or spares).
[6] Replacement program has been delayed to COVID related supply chain issues.
[7] Estimated proportion of electrical engineers familiar with the system.

**Figure 1 GGP facility control system network**




## 2.2. Cathodic protection units

Cathodic protection systems are a critical part of all high-pressure gas pipeline's integrity management plans. They function by applying a small electrical current, effectively turning the pipeline into the cathode of an electrochemical cell. This current counteracts the natural corrosion tendency of the pipeline's metal, thereby extending the pipeline's lifespan and maintaining the integrity of the pipeline.

Pipeline Licence 24 required the cathodic protection to be designed, constructed, tested and maintained in accordance with Australian Standard AS 2382.1.[8]

Pipeline coatings complement cathodic protection, serving as the primary defence against corrosion by providing a physical barrier between the pipeline metal and its environment. This barrier reduces exposure to moisture, salts, and other corrosive elements.

Although effective, coatings are not infallible. Over time, they can develop small defects or damages. In such cases, cathodic protection offers a secondary layer of protection by delivering a small electrical current to prevent corrosion in areas where the coating may be compromised. The significance of cathodic protection increases as pipelines age and their coatings deteriorate.

The GGP's cathodic protection system is designed to split the pipeline into electrically separated sections via insulating joints at scraper stations, offtakes and at selected mainline valves. Current is applied via cathodic protection units at the start and end of each section. There is one CP unit installed at the start and end of the pipeline while there are two units at each scraper station each providing protection to the upstream and downstream section of the pipeline.

[8] Clause III(4) and specifications C.

As CP units are electrical components with power, control and communication components, the design life, lifecycle and obsolescence risks are similar to other electronic equipment. The CP units on the GGP were installed and commissioned in 1996 (and are 25 old) and now considered obsolete. Spares cannot be purchased. The manufacturer (Bartronics) no longer produces CP units.

When a CP unit fails, an immediate like-for-like replacement cannot occur. Instead, a new unit needs to be procured, often with long lead times. Engineering design is also required to ensure compatibility and integration with the existing pipeline system. This design process must take into account not only the technical specifications of the new unit but also adapt to any updated industry standards and technological advancements to ensure both efficient functionality and compliance with regulatory requirements.

In August 2022, a CP unit at Wiluna failed. It took 8 months for a replacement unit to be installed. As the failed unit was at Wiluna (where there are two CP units) a temporary fix was put in place using the other CP unit to maintain cathodic protection on both pipeline sections.

CP unit failures of the same brand, model and age are not uncommon with three failures occurring all of APA's managed assets over the last year.

Together the age, obsolescence and lack of spares increases the risk of a cathodic protection system failure which in turn increase the likelihood of accelerated corrosion rate and potential risk the integrity of the pipeline, particularly given the age of the GGP and degradation of the pipeline coatings.

**Figure 2 CP Unit at Newman Scraper Station**

## 2.3. Actuators

Isolation valves are installed on all pipelines for maintenance purposes and to allow sections to be isolated in the event of a loss of containment. Isolation valves are required by AS2885.1 Section 4.8.1 as they are a standard item for pipeline safety.

All isolation valves can be operated manually. 28 critical isolation valves positioned at scraper stations and other key points can be operated remotely via SCADA. These remotely controlled isolation valves include a valve and a gas or air powered actuator operated by a solenoid pilot valve. These solenoids must be rated for installation in a Class 1, Zone 1 hazardous area.

Isolation valve actuators are original equipment and have reached the end of their useful life (typically around 20-30 years). As a result, we have experienced several issues recently which we expect to continue:

- Difficult to maintain and ensure functionality – the installed actuators (Ledeen hydraulic actuators) are now obsolete and spare parts can no longer be obtained. New components need to be retrofit to existing actuators delaying reactive replacement.
- Poor operational performance – due to wear and degradation of internal components (such as the spring and rubber diaphragm), particularly given remote WA's hot and dry conditions.
- Non-compliance with modern Australian Standards – some solenoid valves and limit switches attached to the actuators installed do not adhere to the current standard (AS/NZS

60079[9]). This standard mandates that electrical equipment operating in hazardous areas must be certified under the Australian National Ex Certification Scheme (ANZEx Scheme) or the International Electrotechnical Commission Ex Scheme (IECEx Scheme), as the components were installed prior to the establishment these Schemes (and compliant with the standards of the time). Although they hold certification under the European Union's ATEX scheme, this alone is insufficient for acceptance in Australia, unless it is it is justified and established to provide an equivalent level of safety. As a result, when these components fail they cannot be replaced like-with-like.

Across all of APA’s assets we have experienced two failures of this make and model and others are anticipated to fail. In one case the actuator failure led to an unplanned valve closure while in another incident the actuator failed to operate when required. Unplanned valve failures of this kind risks supply but can generally be resolved in less than a day (by sending a technician to manually operate the valve).

If a valve fails to operate in the case of an emergency, this will delay the isolation of a pipeline section. It will require the remote isolation of an additional section of the pipeline and technician to physically attend site and manually operate the closer isolation valve (which could take up to a day given the GGP’s remoteness).

This delay and the increased amount of gas lost could delay an incident response and pose additional safety risks to employees, contractors and the general public. It would also lead to lost gas and environmental consequences.

[9] The standard for the design construction, operation and maintenance of equipment in hazardous areas

**Figure 3 Kalgoorlie North Main Line Valve**

## 2.4. Solar Power Systems

Given the remote location of the GGP, solar power and battery systems provide power for communication, control systems and cathodic protection systems for all scraper stations and mainline valves (unless mains power is available). Power to compressor stations is also supplied by Gas Engine Alternators (GEAs).

The installed solar panels have a nominal design life of about 20 years while lead acid batteries have a typical design life between 5 and 10 years. However, the expected life of these systems in remote WA is lower given high average temperatures, dust etc.

Performance of these systems degrade over time. Condition of these assets has deteriorated such that we are now experiencing reliability issues. Without power, these stations cannot be remotely controlled or monitored. A lack of power would also result in the shutdown of the cathodic protection system which is critical to maintaining pipeline integrity and the measurement information on gas flows, pressure, quality etc.

Given that a reliable power supply is essential to ensuring that critical equipment can continue to operate, good industry practice is to proactively replace these power systems by the end of their useful life. This is the practice by APA across its assets and by the Dampier to Bunbury Pipeline (where solar panels and batteries are replaced at 10 year and 5 - 8-year timeframes reflecting their useful life and historical actual performance.[10]).

Since the 1990s, significant advancements have been made in both solar power and battery technology. Modern solar panels now boast longer lifespans and efficiency (due to cell designs and manufacturing process, antireflective coatings etc), with slower degradation rates, ensuring more consistent performance over time. In battery technology, the shift has been towards lithium-ion batteries, which offer higher energy density, longer life cycles and better efficiency. These developments have made newer solar power systems more reliable, efficient, and cost-effective.

**Figure 4 Newman Scraper Station Power system**


## 2.5. Measurement

Gas chromatographs (GCs) across the GGP measure the heating value, specific gravity and gas composition to enable accurate measurement of gas flow, metering and billing. The GGP was originally designed with a series of GCs – two at Yarraloola (where gas enters the pipeline), as well as at Newman, Leinster, Kalgoorlie South and Parkeston delivery points. These were initially installed when the pipeline was commissioned in 1996.

[10] Dampier to Bunbury Pipeline 2020, Capex Business Cases, January, pp 76-66. Available here.

GC's have a design life of 10 years.[11] The GC's at Yarraloola and Kalgoorlie South has been recently replaced and are in good condition. However, due to their age, the remaining GCs have experienced increasing reliability and servicing issues (due to long-lead times). GC failure creates operational issues (having to divert engineering, technician and billing system resources) and risk the integrity of billing data.

Since the GGP was commissioned, technological advancements have led to enhanced software and increased detector sensitivity of GCs and improved monitoring of gas composition and quality. Concurrently, advancements in computer modelling have enabled more precise predictions complementing the empirical data from GC. APA's experience on other pipelines has found that these predictions have good performance and reliability and can be used for billing in place of readings from an actual GC.

As a result, the use of modelling of gas quality, together with readings from GCs on the Northern Goldfields Interconnect can result in the decommissioning of the GC at Newman and Parkeston. GCs at the start (Yarraloola), end (Kalgoorlie south) and middle (Leinster) of the GGP will still be required.

### 2.6. GGP delivery considerations

The remote location of the GGP creates several challenges including:

- Extended response and repair times: Longer timeframes are needed to respond and undertake reactive repairs, due to the significant travel and coordination time required compared to urban settings.
- Increased mobilisation costs: Undertaking works in remote locations requires skilled technicians and engineers to travel to the site, which can take over a day. In many locations, it's necessary to set up camp, involving mobile accommodation and food provisions, as local services are often unavailable.

These factors have significant implications for the optimal works delivery model. Generally, the high mobilisation costs mean that delivering similar works as a single package on a site-by-site basis is more efficient than a component-by-component approach. This strategy also reduces rework associated with reprogramming and ensures better integration of the connected control equipment, compared to a staged upgrade approach.

However, there are limits to the ability to package work. For example, combining a turbine overhaul with a control system upgrade presents scheduling challenges and complicates the testing and commissioning of new systems.

[11] GCs tended to be included within measurement or gas quality regulatory asset lives in the order of 10 and 15 years. Examples include Jemena's NSW Gas Network (see here page 10), AGN's Victorian networks (see here, page 13) and APA's Victorian Transmission system (see here page 9).

# 3. Options assessment

Four options have been considered:

1. Defer program to AA6
2. Focus on control and cathodic protection systems
3. Complete in AA5
4. Complete over AA5 and AA6

## 3.1. Option 1 – Defer until AA6

In this option the replacement of end-of-life equipment is deferred until AA6.

The primary benefit of this program is the time value of money benefits from deferring the end-of-life equipment replacement program. However, this approach has two main drawbacks.

1. Reactive replacement costs. We expect that we will experience at least one failure per year at an average cost of $0.4m.[12] Costs are expected to be higher than a proactive replacement given the shorter timeframes, insufficient development work and additional engineering to identify an ad hoc solution (due to the absence of spare parts etc.)

2. Increased risk to supply, integrity of the pipeline and safety. Each component on the GGP is required to support the ongoing safe and reliable supply of gas. Given the obsolete nature of the equipment, failures are not only more likely to occur but will also result in a lack of functionality until a temporary engineering solution can be developed.

The overall cost of this program is $28.8 million ($2023) in present value terms. Notably the time value of money benefits exceeds the additional reactive replacement costs.

A summary of the key risks in this option is outlined in Table 3.1. These residual risks are outside of APA's risk tolerance and are not as low as reasonably practicable as required by AS2885.

**Table 3.1 Option 1 - Key risks**

| Risk | Likelihood | Impact | Residual risk |
|---|---|---|---|
| **Cathodic protection unit failure** leads to a 3-month absence of cathodic protection of a pipeline section leading to accelerated corrosion and integrity management costs up to $20 million (requiring additional ILI and defects rectification) | Unlikely | Significant | Moderate |
| **Control system failure with no spares** at a mainline valve or scraper station leads to a supply interruption of less than 1 day | Unlikely | Significant | Moderate |
| **Solar power system or actuator failure** leads to a supply interruption of less than 1 day | Unlikely | Significant | Moderate |
| **GEA control system** failure with no spares leads to the shutdown of a compressor station and supply interruption to multiple major customers forcing the shutdown of customer operations (with associated loss of revenue and flow on economic impacts) for up to a week. | Unlikely | Major | High |

[12] Reactive replacement costs calculated to be 1% of the overall program costs per year.

## 3.2. Option 2 – Focus on the control and cathodic protection systems

In this option we deliver a program focussed on only replacing control system and cathodic protection units. The replacement of actuators and the solar power systems are deferred until the AA6 period.

This approach reduces the scope of works and in turn costs in the short term. However, it will result in higher costs in later periods as we will need to remobilise and perform additional rework (reprogramming control systems etc.).[13] The overall cost is $35.1 million ($2023) in present value terms.

This option reduces the risks from cathodic protection and control system failures but the risks from failed power systems and actuators is unchanged.

**Table 3.2 Option 2 - Key risks**

| Risk | Likelihood | Impact | Residual risk |
|---|---|---|---|
| **Cathodic protection unit failure** leads to a 3-month absence of cathodic protection of a pipeline section leading to accelerated corrosion and integrity management costs up to $20 million (requiring additional ILI and defects rectification) | Rare | Significant | Negligible |
| **Control system failure with no spares** at a mainline valve or scraper station leads to a supply interruption of less than 1 day | Rare | Significant | Negligible |
| **Solar power system or actuator failure** leads to a supply interruption of less than 1 day | Unlikely | Significant | Moderate |
| **GEA control system** failure with no spares leads to the shutdown of a compressor station and supply interruption to multiple major customers forcing the shutdown of customer operations (with associated loss of revenue and flow on economic impacts) for up to a week. | Rare | Major | Low |

## 3.3. Option 3 – Complete over AA5

Under this option a 6-year program is undertaken to replace all obsolete equipment across all sites.

This option results in the greatest risk reduction by lowering the likelihood of all key risks to rare. However, this option also incurs the highest costs over the AA5 period and requires carries with it the highest delivery risks.

The cost of this option is $35.9 million ($2023) in present value terms.

[13] Accordingly, we assume that works delayed and delivered as a sperate project are 50% higher than it bundled with other electrical, instrumental and control system replacements.

**Table 3.3 Option 3 - Key risks**

| Risk | Likelihood | Impact | Residual risk |
|---|---|---|---|
| **Cathodic protection unit failure** leads to a 3-month absence of cathodic protection of a pipeline section leading to accelerated corrosion and integrity management costs up to $20 million (requiring additional ILI and defects rectification) | Rare | Significant | Negligible |
| **Control system failure with no spares** at a mainline valve or scraper station leads to a supply interruption of less than 1 day | Rare | Significant | Negligible |
| **Solar power system or actuator failure** leads to a supply interruption of less than 1 day | Rare | Significant | Negligible |
| **GEA control system** failure with no spares leads to the shutdown of a compressor station and supply interruption to multiple major customers forcing the shutdown of customer operations (with associated loss of revenue and flow on economic impacts) for up to a week. | Rare | Major | Low |

## 3.4. Option 4 – Complete over AA5 and AA6

Under this option equipment is replaced over a 11-year replacement program. This option reduces AA5 capex and results in a smaller program of work with lower deliverability risks (when considered in the context of the overall GGP program of work). Over the first 6-years the program will focus sites based on criticality and operational risk. These initial replacements will provide a source of spares which reducing the risk from failure at other facilities.

As a result, the risks in this program are marginally higher than in Option 3. The key risks in this option are negligible or low.

The cost of this option is $34.6 million ($2023) in present value terms.

**Table 3.4 Option 4 - Key risks**

| Risk | Likelihood | Impact | Residual risk |
|---|---|---|---|
| **Cathodic protection unit failure** leads to a 3-month absence of cathodic protection of a pipeline section leading to accelerated corrosion and integrity management costs up to $20 million (requiring additional ILI and defects rectification) | Rare | Significant | Negligible |
| **Control system failure with no spares** at a mainline valve or scraper station leads to a supply interruption of less than 1 day | Rare | Significant | Negligible |
| **Solar power system or actuator failure** leads to a supply interruption of less than 1 day | Rare | Significant | Negligible |
| **GEA control system** failure with no spares leads to the shutdown of a compressor station and supply interruption to multiple major customers forcing the shutdown of customer operations (with associated loss of revenue and flow on economic impacts) for up to a week. | Rare | Major | Low |

### 3.5. Preferred option

Option 4 (complete over AA5 and AA6) has been selected as it represents the best balance of cost, risk and performance. Specifically, option 4 is the lowest cost option with an acceptable level of risk.

Option 1 (Defer to AA6) was not selected, even though it has a lower cost,[14] due to the unacceptable financial and operational capability risks.

Option 3 (complete in AA5) was not selected primarily due to deliverability risks from a whole of GGP program perspective.

**Table 3.5 Cost comparison ($millions, $2023)**

| Option | Present Value | AA4 capex | AA5 capex | AA6 capex |
|---|---|---|---|---|
| Option 1 - Defer to AA6 | 28.8 | 0.2 | 4.6 | 38.6 |
| Option 2 - Focus on control and cathodic protection systems | 35.1 | 10.2 | 16.4 | 17.2 |
| Option 3 – Complete in AA5 | 35.9 | 10.8 | 30.6 | - |
| Option 4 – Complete over AA5 and AA6 | 34.6 | 10.8 | 20.6 | 10.0 |

**Table 3.6 Risk summary**

| Option | Cathodic protection Unit failure | Control system failure | Solar power system or actuator failure | GEA control system |
|---|---|---|---|---|
| Option 1 - Defer to AA6 | Moderate | Moderate | Moderate | High |
| Option 2 - Focus on control and cathodic protection systems | Negligible | Negligible | Moderate | Low |
| Option 3 – Complete in AA5 | Negligible | Negligible | Negligible | Low |
| Option 4 – Complete over AA5 and AA6 | Negligible | Negligible | Negligible | Low |

14 As the time value of money costs from deferring work outweigh the expected additional reactive repair costs incurred

### 3.6. Consistency with the National Gas Rules

The preferred option meets the requirements of Rule 79 and is conforming capital expenditure.[15]

**Prudent and good industry practice**

Capex incurred to replaced equipment reaching the end of its useful life would be incurred by a prudent service provider activity efficiency in accordance with accepted good industry practice, as evidenced by almost all other infrastructure providers implementing proactive replacement programs for similar components.[16]

Aged, obsolete and failing equipment threatens the ongoing safety, integrity and reliability of services. In turn, replacing this equipment to ensure ongoing functionality is required to maintain and improve the safety of services as well as to maintain the integrity of services.[17] Replacing this equipment is also required to ensure that we can continue to operate the GGP consistent with AS 2885 and is in turn required to comply with Pipeline Licence 24.[18]

**Efficient**

GGT/APA tenders the provision of work on a competitive basis and 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 consistent with the expenditure that a prudent service provider acting efficiently would incur.

**To achieve the lowest sustainable cost of delivering pipeline services**

The preferred option represents lowest sustainable cost of providing services and takes into account: the high-mobilisation costs incurred in performing work on the GGP, work packaging efficiencies and inefficiencies, and the optimal phasing of the program to manage deliverability and rework risks.

[15] The allocation of costs between the notional covered and uncovered GGP pipelines is addressed separately.
[16] Rule 79(1)(a)
[17] Rule 79(2)(c)(i)&(ii)
[18] Rule 79(2)(c)(iii)

# Appendix 1. GGP Facilities

**Table 7 GGP compressor stations, scraper station and mainline valves**

| Facility | Function |
|---|---|
| Yarraloola | Compressor Station |
| Red Hill | Mainline Valve |
| Wyloo West | Mainline Valve & Compressor Station |
| Wyloo East | Mainline Valve |
| Paraburdoo | Mainline Valve & Compressor Station |
| Boonamichi | Mainline Valve |
| Turee Creek | Mainline Valve & Compressor Station |
| Newman | Mainline Valve |
| Newman | Scraper Station |
| Beyondie | Mainline Valve |
| Ilgarari | Mainline Valve & Compressor Station |
| Karlawinda | Mainline Valve |
| Three Rivers | Mainline Valve |
| Ned's Creek | Mainline Valve & Compressor Station |
| Cunyu | Mainline Valve |
| Wiluna | Mainline Valve & Compressor Station |
| Mt Keith | Mainline Valve |
| Leinster | Mainline Valve |
| Leinster | Scraper Station |
| NGI | Connection |
| Stuart Meadows | Mainline Valve |
| Leonora | Mainline Valve |
| Jeedamya | Scraper Station |
| Mt Vetters | Mainline Valve |
| Kalgoorlie North | Mainline Valve |
| Kalgoorlie West | Mainline Valve |
| Kalgoorlie South | Mainline Valve & Receiver |

# Appendix 2. End of life equipment replacement program

**Table 8 Compressor Station - equipment replacement program**

| Facility | RTU | GEA PLC | Cathodic protection | Actuator |
|---|---|---|---|---|
| Yarraloola | | | ✓ | |
| Wyloo West | ✓ | ✓ | ✓ | ✓ |
| Paraburdoo | ✓ | ✓ | ✓ | ✓ |
| Turee Creek | | ✓ | ✓ | ✓ |
| Ilgarari | ✓ | ✓ | ✓ | ✓ |
| Ned's creek CS | ✓ | ✓ | ✓ | ✓ |
| Wiluna | | | | ✓ |

Note that Yarraloola and Wiluna RTU's, Wiluna CP unit and were replaced in the AA4 period while the GEA's are currently being replaced at Yarraloola.

**Table 9 Scraper Station - equipment replacement program**

| Facility | RTU | Cathodic protection | Solar Power | Actuator | Other |
|---|---|---|---|---|---|
| Newman | ✓ | ✓ | ✓ | ✓ | |
| Leinster | ✓ | ✓ | ✓ | ✓ | ✓ Metering |
| Jeedamya | ✓ | ✓ | ✓ | ✓ | |
| Kalgoorlie South (Receiver) | | ✓ | | ✓ | |

Note that the Kalgoorlie South RTU has been replaced this period. Kalgoorlie South also has access to mains power so does not have a solar power system.

**Table 10 MLV - equipment replacement program**

| Facility | RTU | Cathodic protection | Solar Power | Actuator | Other | Other |
|---|---|---|---|---|---|---|
| Red Hill | | | | | | |
| Wyloo East | | | | | | |
| Boonamichi | ✓ | | ✓ | | | |
| Newman | ✓ | | | | ✓ Metering | |
| Beyondie | | | | | | |
| Karlawinda | | | | | | |
| Three Rivers | ✓ | | ✓ | ✓ | | |
| Cunyu | | | | | | |
| Mt Keith | ✓ | | ✓ | ✓ | ✓ Metering | |
| Leinster | ✓ | | | | | |
| Stuart Meadows | | | | | | |
| Leonora | ✓ | ✓ | ✓ | ✓ | | |
| Mt Vetters | | | | | | |
| Kalgoorlie North | ✓ | | ✓ | ✓ | | |
| Kalgoorlie West | ✓ | | | ✓ | | |

**Table 11 Selected offtakes - equipment replacement program**

| Facility | RTU | Cathodic protection | Solar Power | Actuator | Other | Other |
|---|---|---|---|---|---|---|
| Cosmos | ✓ | | ✓ | | | |
| Jaguar | ✓ | | ✓ | | | |
| Marymia | | ✓ | | | | |
| Parkeston | ✓ | | | | | |
| Wiluna Gold | | | Not yet scoped | | | |
| Yarnima | | | Not yet scoped | | | |