Five year plan for the Dampier Bunbury Natural Gas Pipeline

Dampier Bunbury Pipeline

1 January 2026 - 31 December 2030

FINAL PLAN

January 2025

Contents

We are Australian Gas Infrastructure Group. We provide natural gas transportation and other pipeline services for customers in Western Australia via the Dampier to Bunbury Natural Gas Pipeline (DBNGP).

Our services play a critical role in the Western Australian economy. Through the DBNGP we transport gas to mining, industrial, commercial and power generation customers. We also transport gas to distribution networks in Perth and other towns to provide energy to homes and businesses.

We understand that the safety, reliability and security of the pipeline are important for our customers, and to support economic prosperity in Western Australia.

With this in mind, our future plans have considered and responded to the long-term interests of our customers and stakeholders.

CEO Foreword

At AGIG we deliver infrastructure for a sustainable future. Our Final Plan for the Dampier to Bunbury Natural Gas Pipeline (DBNGP) takes place during a time of rapid change in the energy sector. At the same time, a higher cost environment, including higher interest rates, will impact on the prices we offer our customers. We continue to prioritise efficient and effective operations and the needs of our customers as the energy transition gathers pace.

Our Final Plan sets out our plans for the DBNGP for the next Access Arrangement (AA) period from 1 January 2026 to 31 December 2030. It describes how we will continue to deliver safe and reliable services to our customers during a period of ongoing change in the energy sector.

Dampier Bunbury Pipeline (DBP) owns and operates the DBNGP and is part of the Australian Gas Infrastructure Group (AGIG), one of Australia's largest energy infrastructure businesses. The DBNGP is one of the most important pieces of energy infrastructure in not only Western Australia, but Australia as a whole. It transports natural gas over 1,600 km from the state's north-west to Bunbury, south of Perth, and the surrounding regions for use in power generation, minerals processing, alumina refining and in our homes.

It is our vision to be the leading gas infrastructure business in Australia. We aim to do this by achieving top quartile performance in delivering for customers, being a good employer and being sustainably cost efficient.

Performance during AA5

In the current AA period (AA5), from 1 January 2021 to 31 December 2025, we have performed well against our vision.

The energy transition is changing the way our customers use the DBNGP. They rely on natural gas as a reliable and flexible source of energy in support of the growing proportion of renewable electricity supply.

During the 2023/24 summer, the DBNGP saw record flows of natural gas, particularly to dispatchable gas-fired power generators. We maintained 100% reliability throughout this period, proving the capabilities of the DBNGP as a vital and sustainable source of energy.

Our strong operational performance has remained above target throughout the current AA period—with no curtailments and 100% system reliability throughout AA5 to date.

On the safety front, there have been no Tier 1 or Tier 2 process safety incidents (the most serious). The Total Recordable Injury Frequency Rate (TRIFR) is currently at 3.2 for 2024 YTD, below our threshold of 3.6. Safety remains a key focus area for improvement, consistent with our vision to achieve Zero Harm for our employees, contractors and the Western Australian public.

Our performance against AA5 expenditure benchmarks has been affected by challenging economic conditions. High inflation and tight labour market conditions have had an impact above and beyond expectations and will likely continue for some time.

This has resulted in our capital expenditure being above the benchmark set for the current period, notwithstanding prudent deferrals and re-scoping of projects where sensible to do so. It has also meant that we have needed to review the competitiveness of our wages and salaries and respond to a range of other recurrent cost pressures. Despite these challenges, our controllable operating expenditure is expected to only marginally exceed the benchmark allowance for the AA5 period, although we have seen a trend increase from Covid lows in the latter part of AA5.

Our customers will benefit from our adoption of an efficiency mechanism in AA5 which means that the full impact of the cost pressures we have are not carried over to customers in full in AA6.

Plans for AA6

Looking forward to the next AA period (AA6), challenging economic conditions centred on ongoing inflation and contract labour availability are likely to persist.

Most notably for AA6, our modelling shows that a significant increase in our forecast funding costs will have a material impact on prices for our services. While interest rates have recently stabilised, they remain well above the historic lows seen at the beginning of the AA5 period. Between now and the Economic Regulation Authority's (ERA's) Final Decision, expected towards the end of 2025, we can expect further volatility.

Adopting the regulatory approach to determine the rate of return, we have proposed an indicative rate of return of 6.93% reflecting more recent market conditions, nearly double the 3.54% applied in AA5.

Our operating expenditure forecast for the AA6 period reflects our most recent actual operating expenditure towards the end of AA5, when the labour market and other cost pressures impacted our expenditure. We have faced heightened market pressure related to wage levels in 2024 which has seen further growth in our expenses to ensure staff attraction and retention.

Our AA6 capital expenditure forecast is also higher than that in AA5 due to inflationary conditions in the WA economy. The forecast incorporates recurrent programs of work along with some new projects. For this Final Plan we have decided not to proceed with our compression reduction project due to uncertainty around the timing of new supplies from the Perth basin. However, we remain committed to finding means to reduce our ongoing costs for Shippers while meeting their gas transportation requirements.

Future of Gas

We have also undertaken further work on the future of gas, including more detailed modelling than was undertaken before AA5. Our focus for AA6 and beyond has been on achieving relative price stability as we steer our assets through the energy transition.

In AA5 the ERA agreed that there is long-term uncertainty around the future use of the DBNGP and supported bringing forward the economic life for the pipeline to 2063, meaning the DBNGP would be fully depreciated by that date.

Our modelling shows that this was a good decision for customers, resulting in prices lower for AA6 than they would otherwise have been in the absence of bringing forward the DBNGP's economic life.

For AA6, we are maintaining the economic life of the DBNGP at 2063. Although there are many different approaches we could take to depreciation, which we have tested, we consider the status quo is capable of dealing with evolving risks to ourselves and shippers during AA6, based on the information which is currently available to us.

We will continue to update and refine our future of gas modelling and it is possible that changes will be made to the depreciation profile of the DBNGP in future AA periods, as more information comes to hand about the energy transition.

Demand and Price

As with AA5, we have relied upon the contracted requirements of Shippers to set the demand for AA6. We have also tested our demand forecasts against the Gas Statement of Opportunities as an independent source of information about demand over AA6. This worked well in AA5 with actual Full Haul capacity largely consistent with the benchmark. The approach also enables full transparency with the ERA through the provision of the requisite contract schedules.

Our average Full Haul capacity forecast for AA6 of 549 TJ/day is around 51 TJ/day (or 9%) below AA5 capacity. This continues a trend observed since AA3 of shippers relinquishing Full Haul capacity over time.

Our Final Plan presents an indicative price for AA6 of $2.45/GJ FHE ($2024), an uplift of $0.88/GJ on the current price of $1.57/GJ. The single largest driver of the price increase is the increase to the rate of return, which contributes $0.60TJ/day of the increase.

Customer and Stakeholder Engagement

This Final Plan for the AA6 period has been developed following a significant program of customer and stakeholder engagement.

We published our Draft Plan in July 2024 and have incorporated feedback from our customers and stakeholders into our Final Plan.

Over the last 18 months our four-stage engagement approach has involved seven roundtable sessions and two additional online sessions, altogether with 25 of our Shippers. The ERA attended the meetings as observers, hearing about issues first-hand, but also participated in discussion as required. This process has facilitated an early awareness of key issues for our planning.

Our Final Plan encapsulates the feedback received from Shippers at the roundtable meetings and in individual discussions, as well as from written submissions on the Draft Plan. I would like to thank all of our stakeholders for their participation in this process.

The ERA will next consult directly on our Final Plan with stakeholders before issuing its Draft Decision in mid-2025.

We look forward to more engagement with our stakeholders in 2025 before the Final Plan is approved by the ERA.

Craig de Laine

Chief Executive Officer

Final Plan 2026 –2030
Delivering for Western Australia

Our plan will ensure we continue to deliver a safe and reliable source of energy for our customers during the energy transition.

In a higher cost environment, we remain committed to servicing our customers efficiently and playing a pivotal role in the Western Australian economy.

Delivering for customers

100%
reliability of the DBNGP

0
loss of containment of an energy source

>8 out of 10
customer satisfaction

Enhanced in line and station inspection activity to ensure the smooth operation of DBNGP

A good employer

> 99%
transmission training compliance

0
lost time injuries in 2024

Ageing Compressor Station accommodation upgraded for a more diverse workforce

Maintaining our strong safety performance with continued focus on achieving zero harm

Sustainably cost efficient

1%
spend above benchmark for controllable opex in AA5

6.93%
regulated rate of return (3.54% in AA5) driving higher prices

Cost challenges met with prudent revisions to project deliveries

More holistic approach to managing power assets at Compressor Stations and large facilities

Full Haul reference price of $2.45 impacted by rate of return almost doubling from current period to the next period

Glossary			
AA	Access Arrangement	GEA	Gas Engine Alternator
AA5	DBNGP Fifth Access Arrangement (for the period 2021-2025)	GC	Gas Chromatograph
AA6	DBNGP Sixth Access Arrangement (for the period 2026-2030)	GJ	Gigajoule/s
ABS	Australian Bureau of Statistics	LTIFR	Lost Time Injury Frequency Rate (the number of lost-time injuries per million hours worked)
AER	Australian Energy Regulator	MLV	Mainline Valve
AGIG	Australian Gas Infrastructure Group	MRP	Market Risk Premium
ALARP	As low as reasonably practicable	MS	Meter Station
AMP	Asset Management Plan	NGL	National Gas Law
capex	Capital Expenditure	NGR	National Gas Rules
CCVT	Closed Cycle Vapour Turbogenerator	opex	Operating Expenditure
CESS	Capital Expenditure Sharing Scheme	PJ	Petajoule/s
CMS	Contract Management Solution	PMM	Project Management Methodology
CPI	Consumer Price Index	PMO	Project Management Office
CRS	Customer Reporting System	PPI	Producer Price Index
CS	Compressor Station	PRC	Project Review Committee
DBNGP	Dampier to Bunbury Natural Gas Pipeline (used in reference to the pipeline)	SCADA	Supervisory Control and Data Acquisition
DBP	Dampier to Bunbury Pipeline (used in reference to the companies which own and operate the pipeline)	SP-2	Security Profile level 2
DRP	Debt Risk Premium	SSC	Standard Shipper Contract
EBSS	Efficiency Benefit Sharing Scheme	SUG	System Use Gas
ECI	Electrical Control and Instrumentation	SWIS	South West Interconnected System
ERA	Economic Regulation Authority	TAB	Tax Asset Base
ERP	Enterprise Resource Planning	TJ	Terajoule/s
FOG	Future of gas	TRIFR	Total Recordable Injury Frequency Rate (the number of total recordable injuries per million hours worked)
FFO	Funds from operations	WPI	Wage Price Index

1 Plan highlights

Our Final Plan outlines the activities and investments we propose to undertake for the 2026 to 2030 period and the resulting price change for our customers.

IN THIS CHAPTER:

- **We continue to deliver strong safety, reliability and cost performance in AA5**
- **Our investments in AA5 and AA6 will ensure we maintain our strong performance in the future**

Our Final Plan outlines our proposals for the AA6 period and has been informed by a robust customer and stakeholder engagement program.

The following sections highlight how we have developed our Final Plan, our achievements in AA5, and the key elements of our plans for AA6.

Our overarching objective is to submit a Final Plan (or AA Proposal) to the ERA that delivers for customers, is underpinned by effective stakeholder engagement and is capable of being accepted.

This Final Plan incorporates the feedback we received from stakeholders on our Draft Plan, the key activities and expenditure we intend to undertake and the prices we propose to charge over the AA6 period.

This section summarises what we have delivered over the current AA period (AA5) and what we propose to deliver over the next AA period (AA6).

1.1 What we have delivered

We have continued to deliver on the high expectations placed on us, including by meeting key safety and reliability standards set for our business. Our key achievements in the 2021 to 2025 period so far include:

Delivering for customers

- Consistently high reliability, with 100% system reliability, 99% compressor station availability and no curtailments;
- Zero tier 1 and tier 2 safety events, which means there have been no incidents of primary loss of containment of an energy source;
- Critical support provided to the SWIS by delivering gas for during the heat wave in the summer of 2024; and
- Delivering and implementing our customer satisfaction surveys, which provide the business with direct information to understand and improve our customer service.
- electricity generation

A good employer

- Strong safety performance where we have averaged less than two lost time injuries per annum in our workforce for the first three years of the AA period;
- Met the challenge presented by COVID-19 lockdowns by maintaining employee engagement at least in the top 50% for our industry through AA5; and

- Began our program to renovate/refurbish the original compressor station accommodation on the DBNGP to cater for a more diverse workforce.

Sustainably cost efficient

- Forecast to spend only marginally above our controllable operating expenditure benchmark for AA5, despite the higher cost environment.

1.2 What we will deliver

Our Final Plan for AA6 builds on our strong performance over AA5. The activities and expenditure we propose to undertake in the five year period include to:

Delivering for customers

- Maintain our strong performance on reliability and public safety;
- Deliver standalone communications infrastructure for the northern section of the DBNGP;
- Replace obsolete control systems; and
- Modernise the customer experience.

A good employer

- Maintain strong health and safety performance;
- Achieve top quartile employee engagement; and
- Redevelop our depot at Jandakot to provide fit-for-purpose office and training spaces, weatherproof warehousing for critical equipment and spares, and improve site ingress and egress.

Sustainably cost efficient

- Invest in our IT systems, data management and digital capabilities to ensure we address operational risks to the business and meet our customer needs.

1.3 Next steps

We encourage stakeholders to provide feedback on this Final plan to the ERA, as explained in section 2.10. Your feedback is a key part of assisting DBP to achieve its objective of ensuring our AA Proposal delivers for customers.

2 Our business

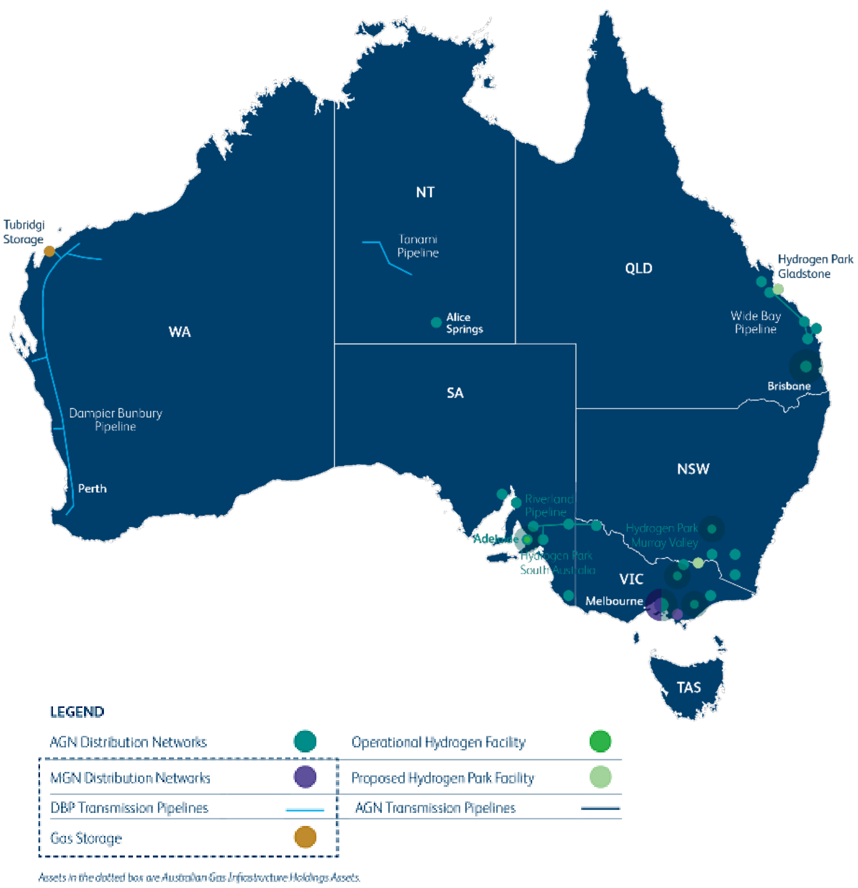
A significant majority of the gas used in Western Australia is transported in the DBNGP, making the pipeline one of the most important pieces of infrastructure in the state and Australia.

IN THIS CHAPTER:

- **AGIG is one of Australia's largest gas infrastructure businesses**
- **Our vision and values drive what we do and the way we do it**
- **Feedback is key in the development of our plans and we take a no surprises approach to stakeholder engagement**

Dampier Bunbury Pipeline (DBP), the owner and operator of the DBNGP, is part of Australian Gas Infrastructure Group (AGIG), one of the largest gas infrastructure businesses in Australia.

Figure 2.1: AGIG assets and operations



2.1 About AGIG

AGIG serves over 2 million customers across every mainland state and the Northern Territory. Our assets include over 35,000 km of distribution networks, over 4,300 km of transmission pipelines and 60PJ of gas storage capacity.

In Western Australia we own and operate critical assets that deliver and store gas the gas that supports the state's economy. This includes the DBNGP, Western Australia's single most important piece of energy infrastructure.

2.2 Our values

Our values of respect, trust, perform and one team drive our culture, how we behave and how we make decisions.

As owners of critical infrastructure, which provides essential services to Australians, we must ensure we act with integrity and do the right thing for current and future generations.

2.3 Zero Harm

In developing the DBNGP Final Plan, and in all our activities, maintaining the safety of our workforce and the public is always our priority. Our proposals do everything we think necessary to meet the requirements of our safety case, asset management plans and to work towards achieving zero harm.

Our Zero Harm principles are 'non-negotiable'; the rules we expect our staff and contractors to follow are aimed at ensuring the safety of our workforce and the public (Figure 2.2).

Figure 2.2: Zero Harm Principles

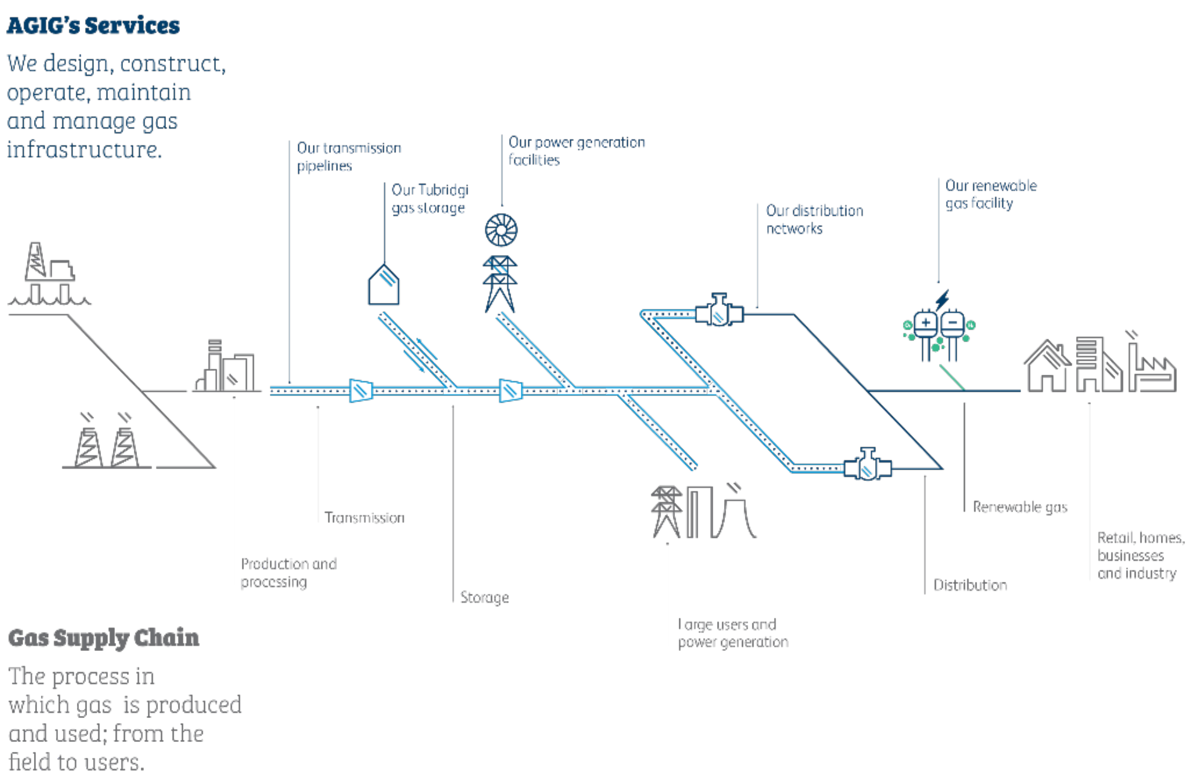
2.4 The gas supply chain

We own and operate gas infrastructure, including transmission pipelines, distribution networks and gas storage facilities across Australia. We play an important role in the safe and reliable supply of gas to customers at various parts of the gas supply chain. Key components of the gas supply chain are illustrated in Figure 2.3 and include upstream, transmission, distribution, storage and downstream.

The DBNGP is a transmission pipeline carrying gas for our customers (shippers) from production facilities in the northwest of Western Australia to the major load centres in the south and around Perth (Figure 2.4 on the next page).

Over 90% of gas transported through the DBNGP is delivered to large customers connected to the pipeline. The remainder is delivered to Perth's gas distribution network owned by ATCO Gas Australia, which in turn delivers the gas to homes and business. Their customers are billed by the retailer of their choice. For Perth small businesses and householders, only 3% of the total gas retail bill is attributable to our transmission costs.

Figure 2.3: The gas supply chain



2.5 Our role in Western Australia

Western Australia is the most energy and gas dependent economy in Australia with natural gas contributing over 50% of primary energy usage and approximately 61% of electricity generation in the state.[1]

The DBNGP is Western Australia's most critical piece of domestic energy infrastructure and is the backbone of the state's economy.

Our customers receive gas transportation and other services from us. It is our job to transport large quantities of gas safely and reliably, every day.

One of the largest capacity natural gas pipelines in Australia, the pipeline carries gas from production facilities to customers throughout the state. The pipeline stretches almost 1,600 km, linking the gas fields located in the state's north-west directly to mining, industrial, and commercial customers, and ultimately via distribution networks to residential customers in Perth. There are also emerging new supplies of gas in Western Australia from the Perth Basin, with the potential to enter the DBNGP around 350 km north of Perth. Beginning near the township of Dampier, the pipeline runs parallel to the west coast of Western Australia and ends near Bunbury.

Figure 2.4: DBNGP operation in WA

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[1] *Australian Energy statistics 2023*. Tables C and O.

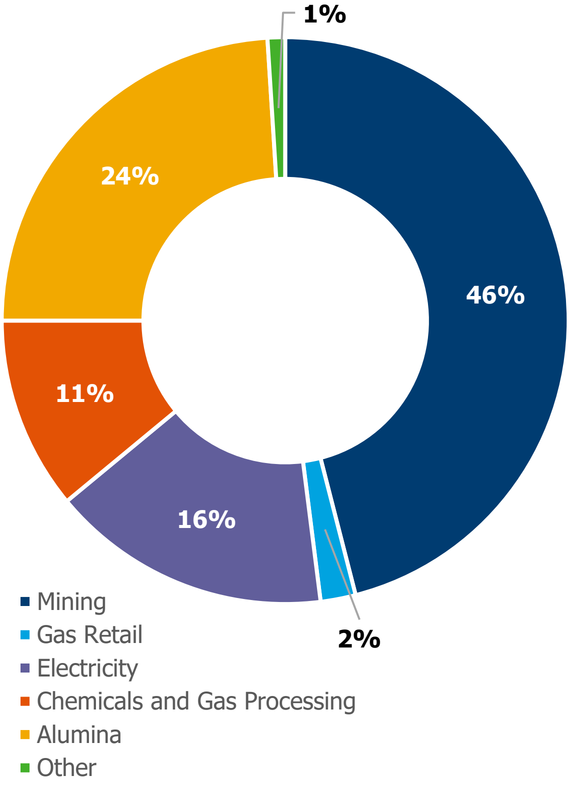
2.6 About the DBNGP

Since 1985, we have transported large quantities of gas safely and reliably along the DBNGP to provide energy for Western Australian industry, power generation, homes and businesses. Figure 2.5 shows gas received on the DBNGP by industry in 2022.

We deliver leading operational performance with 100% system reliability, 99% compressor station availability and no curtailments.

Figure 2.6 on the next page outlines the development of the DBNGP since its construction in 1984. From 2006 to 2010 the pipeline underwent significant expansion. Since 2011 a number of new sources of supply have come online and energy markets have begun a significant transition. We have seen further relinquishment of Full Haul capacity for AA6, as we did for the current AA5 period. We may see further changes in demand for natural gas and the way the DBNGP is used, as more wind, solar generation and battery storage enters the market, and gas from the Perth Basin may become available.

Figure 2.5: Gas receivers on DBNGP by industry (2022)



2.7 Regulatory Framework

The National Gas Law (NGL) and National Gas Rules (NGR) provide the framework for the independent regulation of certain gas pipelines in Australia.

In Western Australia, the Economic Regulation Authority (ERA) is responsible for regulation under the NGL and NGR framework, including the approval of Access Arrangement (AA) proposals and revisions every five years.

The AA contains the terms and conditions under which an independent third party can gain access to the DBNGP.

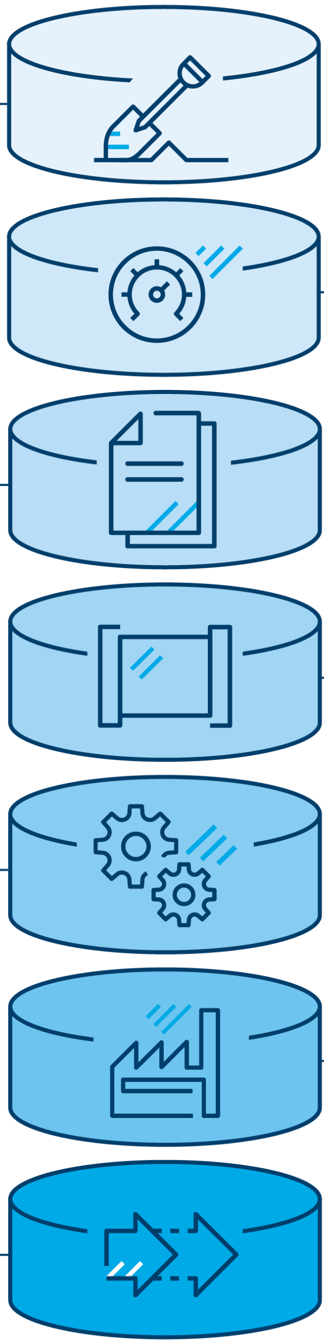
This includes:

- the price (or tariffs) paid for services; and
- the non-price terms under which access will be provided.

The NGL and NGR framework and the terms and conditions approved through an AA, set a framework around which pipeline operators like AGIG and users can negotiate access to meet customers' needs. We often work with our shippers to reach agreements that provide more tailored access and services on the pipeline outside the regulated process.

Figure 2.6: History of the DBNGP

History of the DBNGP



1984
Construction

The DBNGP was constructed in 1984 by SECWA. It delivered up to 200TJ per day of natural gas from the North West Shelf to industry south of Perth.

1986
Compressors

Compressors were added to the pipeline incrementally in 1986, 1991, 1997 and 2000, expanding capacity to 625TJ per day.

2001
Regulation

Independent economic regulation of the DBNGP was introduced in 2001. The regulated reference tariff continues to set a benchmark price for access to the DBNGP.

2006
Looping

In 2006, 2008 and 2010 the pipeline went through significant expansion to loop 85% of the pipeline, add further compressors and upgrade control systems. Total expanded capacity of 845TJ per day and capex investment of over $1.8b (dollars of the day).

2011
Changing Supply

Several new gas supplies have come online since 2011 and a large amount of supply has come into the DBNGP south of Compressor Station 1. The changing supply dynamics, whch follow two decades of relative stability, has seen a greater utlilisation of Part Haul and Back Haul transportation services in place of Full Haul.

2021
Changing Demand

Demand for natural gas in WA is changing as energy markets and technologies, such as wind and solar, evolve. The peakiness of gas demand to power gas-fired generation has increased and gas will be used as a transitional fuel as coal generation retires over the next decade.

2026
Transition Progresses

Our customers and the way they use the DBNGP continues to change as the energy transition progresses. While decarbonisation gathers pace, the reliability and flexibility of the DBNGP grow in importance. Alternative supply options, like the Perth Basin, are emerging and our service offerings need to continue to meet changing customer demands.

2.8 Our review objectives

This Final Plan sets out our plans for the DBNGP for the five-year period commencing on 1 January 2026.

It follows our Draft Plan published in July 2024 which formed an important part of our stakeholder engagement program and assisted us in refining our plans for AA6.

Our objective is to develop a plan that:

- ✓ **Delivers for current and future customers;**
- ✓ **Is underpinned by effective stakeholder engagement; and**
- ✓ **Is capable of being accepted by our customers and stakeholders.**

2.9 Stakeholder feedback

The Final Plan incorporates feedback received to date from our customers and stakeholders including on our Draft Plan and outlines our proposed approach for the next 2026 to 2030 AA period (AA6). It outlines our views on the activities and expenditure we propose to undertake during AA6. We also identify the proposed change in prices that we will charge our customers (shippers).

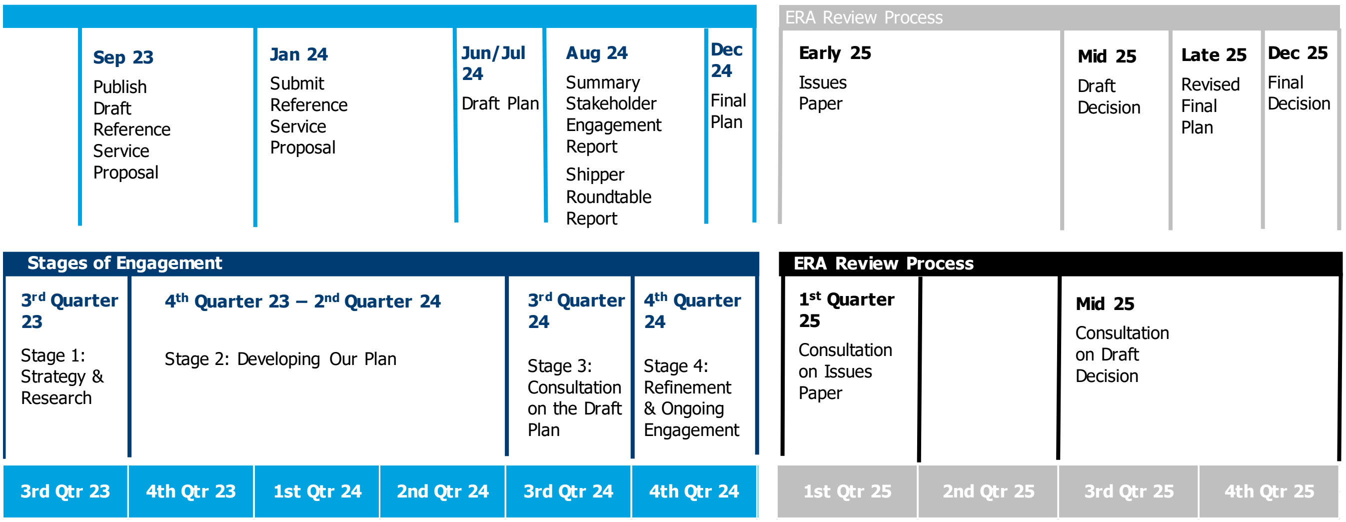
2.10 Next steps

Our customers and stakeholders will have the opportunity to comment on the Final Plan in 2025 through a formal process organised by the ERA (Figure 2.7).

We encourage stakeholders to provide feedback on this Final Plan through the ERA process. We will continue with our stakeholder engagement process in 2025 to complement this process.

Feedback is welcome on any topic relating to our tariffs and expenditure plans over AA6. Your feedback is important for our objective of finalising an AA Proposal which is supported by our customers and stakeholders for delivery from 1 January 2026.

Figure 2.7: Our AA6 timeline and stages of engagement



3 Our track record

During AA5 we have maintained the reliability of the DBNGP, and the safety of our assets and our workforce, while facing challenging new operational conditions.

IN THIS CHAPTER:

- **Safety – strong public and workforce safety performance, with a continued focus on our principle of Zero Harm**
- **Reliability – 98% service availability, 100% system reliability and no curtailments**
- **Efficiency – effectively in line with benchmark for our controllable opex which is not dependent on throughput and we have undertaken additional capex investment to ensure the integrity of our assets**

In AA5 we have continued to prudently and efficiently deliver for our customers, despite changing and challenging operating conditions for the DBNGP.

The following sections show how we are achieving our vision to:

- deliver for customers;
- be a good employer; and
- be sustainably cost efficient.

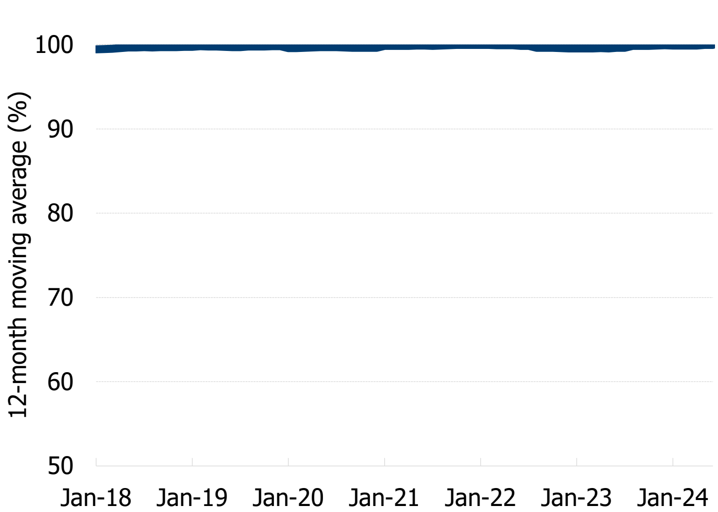
3.1 Delivering for customers

In the AA5 period we continue to deliver for our customers by maintaining the strong safety, reliability and service performance our customers value.

We have:

- delivered zero Tier 1 and Tier 2 safety incidents (incidents of primary loss of containment of an energy source);
- maintained 100% system reliability;
- maintained compressor station reliability at close to 100% (Figure 3.1); and
- will invest a total of $288 million in capex projects including:

Figure 3.1: Compressor Station Reliability



- implement a fit for purpose Transmission Billing System to ensure that our customers are billed in a timely and accurate manner;
- purchase spare meters to allow for their recalibration, improving billing accuracy;
- deliver SCADA hardware and software upgrades;
- replace obsolete compressor unit control systems which are over 15 years old and no longer supported by the manufacturer, in a program coordinated with GEA replacement;
- replace some of the original accommodation facilities at compressor stations and redevelop our Jandakot site to ensure that they are fit for purpose and properly accommodate all of our employees as our field workforce demographic changes;
- deliver the Northern Communications System more efficiently through and in-house model; and
- replace IT hardware including laptops and switches and consolidate existing Data Centres.

Figure 3.2: DBP Total Recordable Injury Frequency Rate (TRIFR) and Lost Time Injury Frequency Rate (LTIFR)

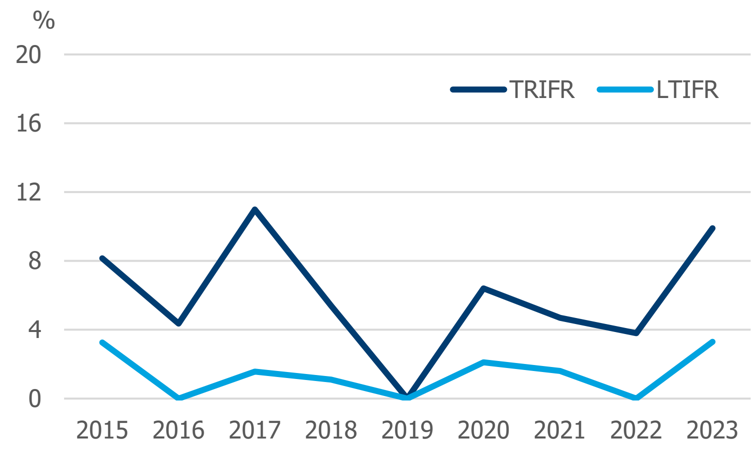
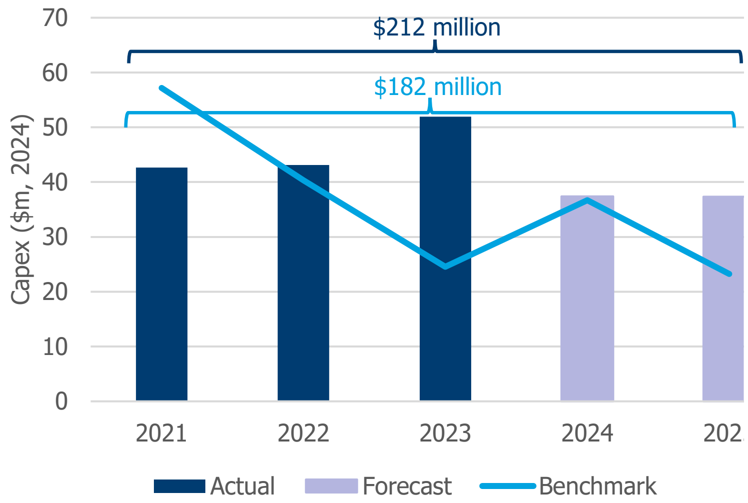


Figure 3.3: Total capex in AA5



3.2 A good employer

In the AA5 period we are continuing to be a good employer by:

- maintaining our strong safety performance with an average total recordable injury frequency rate (TRIFR) of 6.1 between 2021 and 2023 per annum and an average of 1.6 lost time injuries (LTI) per annum over the same period;
- working towards a target of zero, in line with our zero harm safety principles (Figure 3.2);
- achieving employee engagement results in the top half amongst our comparison group of organisations, and moving to a culture focussed approach; and
- investing $24.8 million on capex projects including replenishing our vehicle fleet and building fit for purpose accommodation at two of our compressor stations.

3.3 Sustainably cost efficient

During AA5, high inflation and tight labour market conditions and supply chain pressures have increasingly affected our performance beyond expectations at the time our Final Plan was approved.

Due to these pressures, we anticipate overspending the AA5 capex benchmark by $30.4 million (16.7%) (Figure 3.3).

Despite these pressures, we are on track to keep our controllable opex relatively aligned with the benchmark.

During AA5, DBP is forecast to incur $371 million in controllable opex (excluding SUG, GEA/turbine overhauls and inspections and other asset management items), which is 1% above our allowance of $367 million for this expenditure.

Excluding SUG only, our opex is still forecast to be relatively aligned with the benchmark – projected to be 2% higher (Figure 3.4). SUG is forecast to exceed the benchmark (by $20 million) due to higher throughput in AA5 than forecast (Figure 3.5).

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Figure 3.4: Total opex in AA5

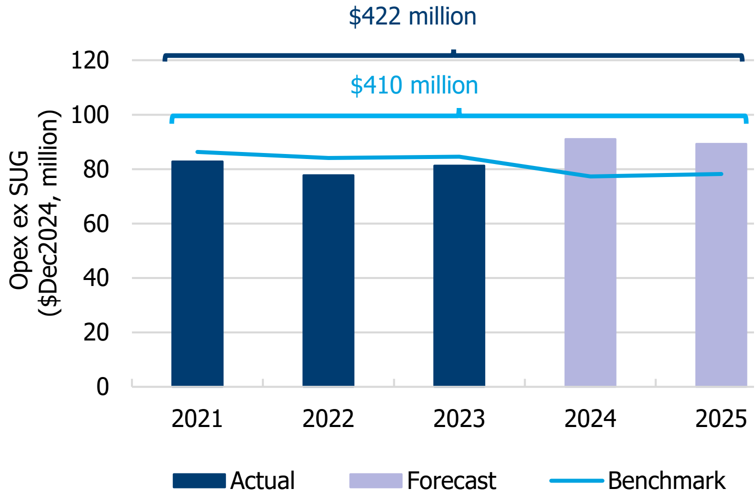
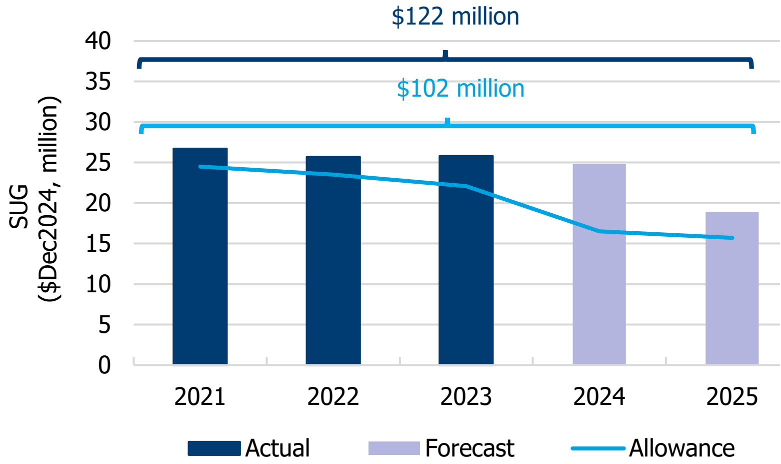


Figure 3.5: System use gas in AA5



4 What we will deliver

We will continue to deliver reliable energy for Western Australian industry, power generation and homes, as the DBNGP plays an important role in the energy transition

IN THIS CHAPTER:

- **In AA6, we propose to maintain the strong performance achieved to date in AA5 in terms of delivering for our customers, being a good employer and being sustainably cost efficient**
- **We propose a full haul reference price of $2.45 per GJ (before inflation), with the price increase primarily driven by financing costs**

Our Final Plan puts in place the investments necessary to meet the changing energy needs of Western Australia

The Final Plan for AA6 has been developed to meet our objectives to submit a plan which will:

- deliver for current and future customers;
- be underpinned by effective stakeholder engagement; and
- be capable of being accepted by our customers and stakeholders.

The following sections summarise what we will deliver in AA6.

4.1 Overview

Our Final Plan for AA6 proposes to maintain the strong performance achieved to date in AA5, despite continued challenging economic conditions including a significant uplift in our funding costs.

Our plans support our vision to be the leading gas infrastructure business in Australia by achieving top quartile performance against our targets.

In particular, this Final Plan supports our vision to:

- deliver for customers;
- be a good employer; and
- be sustainably cost efficient.

An overview of our plans against the elements of our vision is included in Figure 4.1.

4.2 Delivering for customers

Delivering for customers means maintaining our exceptional record of public safety, the reliability of our services and customer service.

Our Final Plan delivers for our customers by:

- delivering a full haul reference price of $2.45 per GJ (before inflation), which is an increase of $0.88 per GJ relative to AA5, primarily driven by financing costs;
- maintaining our strong safety performance with no loss of primary containment of an energy source;
- maintaining the reliability of the DBNGP at or near 100%;
- continuing to offer Full Haul, Part Haul and Back Haul reference services;
- investing $288 million in capex projects including to undertake:
  - preventative works and repairs to protect compressor stations from corrosion and safety hazards;
  - the installation of new gas chromatographs in

response to changing gas flow dynamics;

- the purchase of spare meters to allow the recalibration of meters to ensure customers are billed accurately; and
- field works, asset maintenance and customer service activities.

4.3 A good employer

To be a good employer we focus on the health and safety of our employees, employee engagement and the skills of our workforce.

In AA5 we have demonstrated strong safety performance, and our Final Plan provides the resources to continue this performance.

Through our Final Plan for AA6 we will be a good employer by:

- continuing ongoing health and safety initiatives such as undertaking audits, reporting and investigating incidents, and providing employee training; and
- investing $15 million in renovations to remote accommodation to ensure facilities are appropriate to accommodate our employees as our field workforce becomes more diverse.

4.4 Sustainably cost efficient

To be sustainably cost efficient, our Final Plan focuses on meeting industry benchmarks and improving productivity, delivering profitable growth, and being environmentally and socially responsible.

Figure 4.2 over the page summarises the regulatory building blocks in AA6 and Figure 4.3 on the next page shows the impact on price from each building block.

Our Final Plan reference price reflects a significant uplift in our funding costs that, based on current expectations, leads to a price of $2.45 per GJ.

We are responding to changes in the energy sector, by planning for the long-term use of our assets in a carbon-constrained economy.

Figure 4.2: Our performance targets in AA6

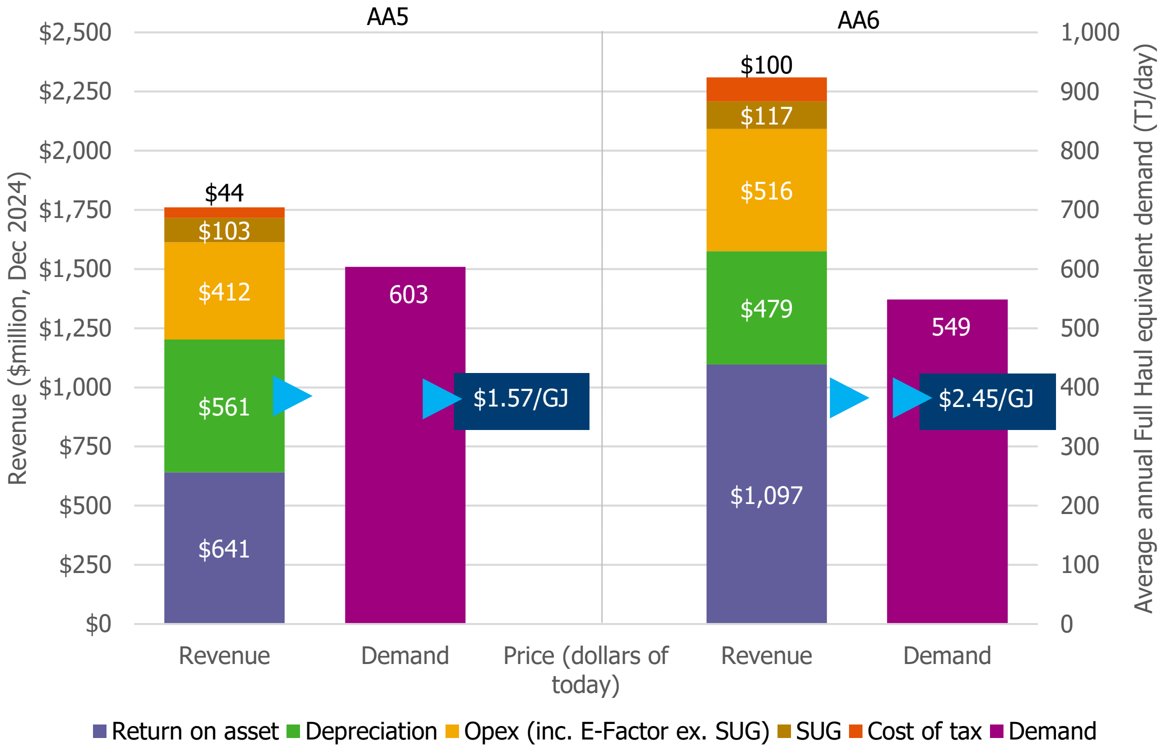
Our Final Plan is sustainably cost efficient as it:

- maintains an efficient operating program for our customers in a challenging higher cost environment, with our proposed opex 20% higher than our projected AA5 performance;
- incorporates efficient allocations from capex to opex for a share of our labour costs and to implement Software as a Service (SaaS) and Platform as a Service (PaaS) technologies to best equip our business to respond to operational risks moving forward;
- delivers a capex program which is prudent, efficient and in line with good industry practice
- invests $288 million in capex projects including increased investment in cyber security, data management, digital capabilities and modernising our IT systems;
- further develops our approach to the future of gas, with a focus on customer outcomes and price stability through time as substitutes for natural gas, decarbonisation policy settings and market conditions continue to evolve;
- calculates financing costs consistent with the ERA's Final Rate of Return Guidelines;
- is based on a robust analysis of the forecast demand for our reference services;
- strengthens our incentives to incur efficient opex by continuing the E Factor efficiency benefit sharing scheme introduced in AA5; and
- proposes to recover revenues from our full, part and back haul reference services consistent with the current approach.

4.5 Summary

Our Final Plan ensures we will maintain the exceptional reliability and safety of the DBNGP. We will have a safe, healthy, engaged and skilled workforce; and we will deliver value for our customers in challenging market conditions.

Figure 4.2: Summary of regulatory building block, demand and price in AA5 and AA6



5 Customer and stakeholder engagement

We actively engaged with our stakeholders to inform and shape our Final Plan.

IN THIS CHAPTER:

- **We directly engaged with our stakeholders to understand how they wanted to be involved in the development of our plans for the DBNGP**
- **We held a series of Shipper Roundtable meetings to help develop our plans, and offered ongoing opportunities for our stakeholders to contribute on the development of our plans**

We have engaged with our stakeholders throughout the planning for the AA6 period to develop a plan that delivers during ongoing change in the energy sector.

We held a series of in-person Shipper Roundtables, one-on-one meetings and on-line information sessions, to help inform and receive feedback from our stakeholders on the key elements of our plans.

Effective stakeholder engagement continued as key to developing a plan for the AA6 period that delivers for our current and future customers, one that is capable of acceptance, and continued delivery of safe and reliable services.

This section explains our approach to stakeholder engagement and outlines how the program has influenced the development of our plans for AA6.

5.1 Overview

Our commitment to best practice stakeholder engagement with a 'no surprises' approach, was embedded throughout the planning process, providing our customers and stakeholders with the opportunity to be actively involved in helping us shape our plans.

We began in June 2023 by publishing our Draft Engagement Plan for Consultation, *Developing our Future Plans for the Dampier Bunbury Natural Gas Pipeline* (Attachment 5.1), which outlined our proposed engagement approach with customers and stakeholders in the development of our plans. In this document we also sought feedback on the most important aspects of our services, and for any issues we should be considering in our future planning for the DBNGP.

Shippers told us they continue to place high value on reliability and price, with price certainty, and fair and reasonable tariffs.

Shippers raised interest in decarbonisation, including our future plans for the DBNGP, the potential for carbon capture storage, and our innovation plans to meet their changing needs.

Other topics of interest included the future planning of the use of the DBNGP as we transition into a low carbon future as well as

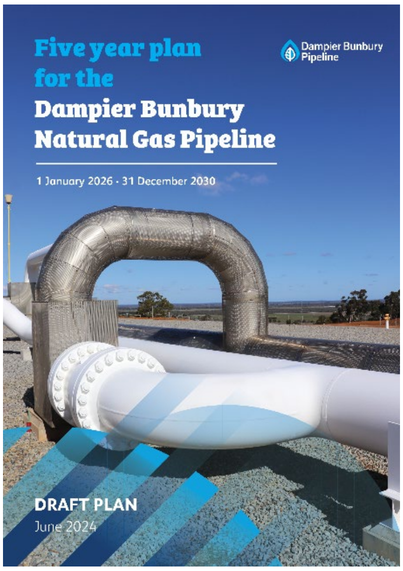
revalidating future of gas modelling applied in AA5.

The key insights from our early engagement enabled us to identify the topics of interest to customers and focus on in subsequent engagement activities.

Feedback from these sessions was used to inform our final engagement strategy, ensuring our activities were appropriate and allowed for meaningful engagement, and in August 2023 we published our Final Engagement Plan, summarising key insights from our early engagement (Attachment 5.2).

The initial one-on-one meetings not only provided an opportunity to help guide our proposed engagement approach and activities, but also offered stakeholders to provide feedback on the most important aspects of our services and the key issues we should consider in the future planning for our pipeline.

In August 2023 we commenced the next phase of our engagement program, with the first of a series of Shipper Roundtable meetings. The Shipper Roundtable was established to consider and advise on key topics and issues of



- our Reference Service Proposal;
- reliability of service;
- price and services;
- rate of return;
- capital and operating expenditure proposals;
- decarbonisation and the Safeguard Mechanism;
- the future of gas and accelerated depreciation;
- demand and the changing demand profile on the pipeline; and
- understanding of the key regulatory building blocks.

Feedback from the Shipper Roundtables has been captured and used to inform and refine this Final Plan.

In July 2024 we published a Draft Plan for consultation for a period of six weeks (Attachment 1.2). The Draft Plan was distributed to key stakeholders, and feedback encouraged through formal submissions.

5.1.1 Engagement informing our plans

We are committed to delivering a plan underpinned by effective and transparent engagement, and capable of acceptance.

We have sought ongoing feedback throughout the development of our plans.

"AGIG adopted a "no surprises" approach, which was a guiding theme throughout all seven Shipper Roundtables. With a structured approach to key areas impacting future plans, AGIG worked methodically to gather feedback at each session. This engagement was essential to gain clear insights into the long-term needs and interests of customers, ensuring these are well-considered in the planning process." KPMG (Attachment 5.4).

We commenced engagement with our customers and stakeholders in June 2023, ensuring involvement from the outset through to the development of our Final Plan.

Our engagement activities have informed this Plan, and we have:

- clearly documented feedback and how we have responded in each chapter;
- clearly demonstrated where there has been support for our plans; and
- been transparent where there hasn't been support from all stakeholders on issues or proposals.

We have documented our engagement process and how we have used feedback throughout the four stages of our engagement plan.

A summary of all feedback and how it has informed our Final Plan is included in

Table 5.6.

5.2 Our stakeholders

Given the important role the DBNGP plays in Western Australia, many stakeholders have an interest in our transmission business.

Our key stakeholder groups are illustrated in Figure 5.1.

These key stakeholder groups represent our direct and indirect customers, and other businesses in the gas supply chain. They remain the same as with the AA5 engagement program, and include regulators, shippers and gas marketers and producers.

Stakeholders also include government departments and agencies recognising that the DBNGP is part of broader energy policy, land management, safety and environmental protection considerations.

5.3 Our approach to stakeholder engagement

We adopted a series of engagement principles to guide our engagement, which were reviewed and endorsed by Shippers, as illustrated in Table 5.1. We continued with the four stage approach adopted in AA5 to engage and involve stakeholders throughout our planning process, as illustrated in Figure 5.2.

Stage 1: Strategy & Research

Stage 1 was a research stage to better understand customer and stakeholder needs and expectations. This included consultation on our proposed engagement strategy, ensuring we engaged meaningfully and effectively to meet stakeholder expectations.

During this stage we tested our assumptions about what was important to our stakeholders and identify topics they wanted to be engaged on. This concluded with our Final Engagement Plan, summarising stakeholder feedback

Figure 5.1: Our Stakeholders

Table 5.1: Our Stakeholder Engagement Principles

Principle	Our Commitment
Genuine and committed	We listen and respond to the needs of our stakeholders, driving a culture of delivering value for our customers.
Clear, accurate and timely communication	We provide information that is clear, accurate, relevant and timely.
Accessible and inclusive	We involve stakeholders on an ongoing basis in a meaningful way to ensure plans deliver for our customers.
Transparent	We clearly identify and explain the role of stakeholders in the engagement process, and consult with stakeholders on information and feedback processes.
Measurable	We measure success, or otherwise, of our engagement practices.

Figure 5.2: Our Four-stage Engagement Approach

Stage 1	Stage 2	Stage 3	Stage 4
Strategy and research	Developing our Draft Plan	Consultation on our Draft Plan	Refinement and engagement
Jun - Sep 2023	**Oct 2023 - Mar 2024**	**Apr - Jun 2024**	**Jul - Dec 2024**

and our final engagement strategy.

Stage 2: Developing our Draft Plan

In Stage 2 we used the insights from Stage 1 to inform the drafting of our plans. Stage 2 included targeted engagement activities on our investment proposals and regulatory modelling. During this stage we ran a series of Shipper Roundtable activities, including one-on-one and roundtable meetings, consulting on key topics to guide the development of our plans, as well as an online deep dive information session refamiliarising Shippers on the fundamentals of the regulatory process.

Stage 3: Consultation on our Draft Plan

In Stage 3 we consulted on our Draft Plan which we published in July 2024. We actively engaged with stakeholders through Roundtable meetings to ensure this plan delivers for our customers today and into the future.

Stage 4: Refinement and Ongoing Engagement

Consultation feedback from Shippers on our Draft Plan and ongoing Roundtables in Stage 3 informed this Final Plan. We will continue engagement after we submit to the ERA, ensuring our customers and stakeholders are kept informed prior to the ERA's Final Decision expected late 2025.

5.3.1 Activities

In June 2023 we published and made available our Draft Stakeholder Engagement Plan for Consultation, *Developing Our Future Plans for the Dampier Bunbury Natural Gas Pipeline*, seeking feedback through to end of July 2023.

We engaged with twenty-six Shippers, producers and gas trading agents, including holding twelve one-on-one dedicated shipper meetings.

A list of engagement questions from Stage 1 is captured in Table 5.2.

During June and July 2023, we met with a number of key stakeholders to discuss our proposed engagement approach and explore key issues. All meetings were documented, summarised and used to shape our final engagement strategy, including topics for engagement.

Upon completion of Stage 1 engagement, we documented all feedback from our stakeholders in our Final Engagement Plan.

5.3.2 Capturing key insights

During Stage 1 we asked our stakeholders for feedback on:

- key issues of importance and topics of interest for engagement; and
- our proposed engagement strategy.

A summary of stakeholder feedback received during Stage 1 is captured in Table 5.3.

During stakeholder meetings we facilitated discussion around eight consultation questions.

- Are our engagement principles appropriate to develop plans that deliver for our stakeholders?
- Have we identified all relevant stakeholder groups?
- What are the most important aspects of our services?
- What issues should we consider in our future planning for the DBNGP?
- What aspects of our future plans would you like to engage on?
- How would you like to participate in our engagement process?
- Is our proposed approach open and transparent?
- Are there ways we could improve our proposed approach?

Table 5.2: Stage 1 Consultation Questions

Topic	Consultation Question
Engagement principles	• *Are our engagement principles appropriate to develop plans that deliver for our stakeholders and customers?*
Our stakeholders	• *Have we identified all relevant stakeholder groups?*
Our future plans	• *What are the most important aspects of our services?* • *What issues should we be considering in our future planning for the DBNGP?* • *What aspects of our future plans would you like to engage on?*
Engagement activities	• *How would you like to participate in our process?*
Engagement approach	• *Is our proposed approach open and transparent?* • *Are there ways we could improve our proposed approach?*

Table 5.3: Stage 1 Stakeholder Feedback

	Stakeholder Feedback	Our Response
Key Insights	• Stakeholders placed a strong focus on decarbonisation, including future plans for the DBNGP, hydrogen and carbon capture and storage, and the impact of renewable energy on gas flows, pipeline operations, the location of supply and/or demand centres, capacity, and the implications of policy changes. • Stakeholders continued to place a high value on the reliability and safety of the DBNGP. • Reliability and price were two important considerations for stakeholders. Price and price certainty, with fair and reasonable tariffs that meet industry and customer expectations, were also important. • Innovation plans for the DBNGP to meet the changing environment and stakeholders' needs was a key area of focus. • Some stakeholders wanted us to consider a flexible approach in the development of our future plans acknowledging the dynamic nature of the energy industry. • Revalidating future of gas modelling, future use of infrastructure, with gas being a transition fuel and potential use of renewable electricity generation for compressor stations were also important issues for future planning for the DBNGP. • Consideration of stakeholders' future needs being modelled where possible and balanced with current costs was identified by some stakeholders. • Some stakeholders wanted the inclusion of their future needs in the overarching objective when planning for reliability, products and services, terms and conditions, and future price paths.	• We explored key insights identified with our stakeholders as we developed our Draft and Final Plans through a series of Roundtables and on-line information sessions.
Our Engagement Approach and Principles	• Stakeholders appreciated the opportunity to provide feedback on our proposed engagement process and to participate in future stakeholder consultation as planning develops. • Stakeholders valued our transparent, inclusive and collaborative approach to stakeholder engagement. • Stakeholders noted early and transparent consultation was important to support our 'no surprises' approach and assist with our future planning, particularly as we transition towards a low carbon future.	• We confirmed our commitment to our engagement principles, a 'no surprises' approach and our objective of submitting a plan capable of being accepted. • We confirmed our four-stage engagement approach.
Our Stakeholders	• Stakeholders were comfortable with the stakeholder representative groups identified. • Whilst some stakeholders did not want to be directly involved in our engagement activities they were still interested in being kept informed through our engagement program.	• We focussed our engagement with stakeholders directly connected to the DBNGP (and their representatives) through both Shipper Roundtable activities and one-on-one engagement as needed. • All stakeholders had access to documentation and engagement materials which were housed on our on-line engagement portal, Gas Matters.

Our Engagement Activities	• Stakeholders were keen to be involved in our engagement program. • Stakeholders supported the establishment of a Shipper Roundtable, noting it is a transparent forum providing time to discuss and understand issues throughout the regulatory process. • Stakeholders welcomed regular contact and transparency but requested fewer Shipper Roundtables than the previous AA period, with the addition of deep dive sessions throughout the process if required. • Stakeholders preferred to maintain one-on-one meetings to engage in matters from a commercial perspective. • Stakeholders were generally supportive of the ERA being present at Shipper Roundtables in the capacity of an observer.	• We engaged with Shippers with fewer Shipper Roundtables compared to the previous AA period. • We engaged with individual Shippers on commercial aspects directly with one-on-one meetings. • We provided deep dive information sessions as required. • We provided regulatory stakeholder engagement updates throughout the process.
Our Timeline	• Stakeholders supported our timeline.	• We confirmed the timeline for developing our plans.

5.4 Stage 2 Engagement – Developing our Draft Plan

In Stage 2 of our engagement we delivered activities based on preferences received from stakeholders during Stage 1.

During Stage 2 we delivered three face to face Roundtable meetings – a summary of meetings and topics is included in Table 5.4.

In Stage 2 our engagement included:

- an overview of our engagement plan and approach to delivering plans capable of acceptance by our customers and stakeholders;
- consulting with Shippers on our Reference Service Proposal;
- providing key price drivers and impacts, and our proposed approach to rate of return and inflation impacts;
- proposed operational and capital expenditure forecasts and comparisons; and
- an update on the future of gas and accelerated depreciation.

A summary of feedback captured during the Shipper Roundtables in Stage 2 (together with feedback captured during Stages 3 and 4) is shown in Table 5.6.

Shippers were offered the opportunity to provide feedback during the meetings, and KPMG also offered one-on-one stakeholder feedback sessions at any time. We also encouraged Shippers to request additional information that may assist in supporting meaningful engagement.

All Roundtable meetings were documented by KPMG, and minutes circulated to stakeholders and posted on our online engagement portal, Gas Matters.

During Stage 2 we held an additional online information session for those who were interested in a refreshing regulatory fundamentals, including building block revenue, demand and price, and capital and operational expenditure.

Shipper Roundtables

In June 2023 we invited all direct customers and gas trading agents to be involved in a series of Shipper Roundtables.

The Shipper Roundtables were established as a forum for AGIG to actively engage Shippers in the development of its plans for 2026 to 2030.

A total of seven meetings were held between August 2023 and December 2024.

Shipper Roundtable meetings were a critical input and valuable way to work together with customers to shape our plans.

- ✓ 81% of Shippers attended one or more Roundtable meetings.
- ✓ We significantly strengthened our approach to transparency and engagement with Shippers compared to the previous period.
- ✓ We shared our Draft Plan six months early to capture feedback and allow for meaningful engagement.
- ✓ We publicly reported all agendas, minutes and presentation materials online (gasmatters.agig.com.au).

Meetings were facilitated by a third party (KPMG) to ensure independence in the documentation of feedback. Shippers were offered the opportunity to provide feedback during or after meetings.

KPMG offered one-one-one stakeholder feedback sessions at any time. We encouraged Shippers to request any additional information that may assist in understanding our plans.

KPMG independently surveyed Shipper Roundtable members after Meeting No. 5 to assess how AGIG had performed against its engagement principles and found that:

- ➢ 100% of Shippers agreed that the Shipper Roundtables had provided a useful format to engage with AGIG as part of its AA6 submission.
- ➢ 78% of Shippers agreed that AGIG had adopted a 'no surprises' approach.
- ➢ 100% of Shippers agree that the topics presented at the Shipper Roundtables were relevant and appropriate for the AA6 submission.

Full survey results are included in KPMG's Customer Engagement Report (Attachment 5.4).

Table 5.4: Shipper Roundtable Meeting Topics

	Meeting	Key Topics	Summary of information presented
Stage 2: Developing our Draft Plan	Meeting 1	• Our Engagement Approach • AA5 Performance to Date • Reference Service Proposal	• Role of the Shipper Roundtable • Our Stakeholder Engagement Approach – including principles, fit-for-purpose activities, key topics and timeline • Key Insights from Stage 1 Engagement • Reference Service Proposal – factors, background and our proposed approach
	Meeting 2	• Reference Service Proposal • Rate of Return • Operating Expenditure Performance and Plans • Future of Gas / Accelerated Depreciation Update	• Reference Service Proposal status and timing, proposed and excluded services • Key price drivers and impacts • Rate of return and inflation impacts, return on asset • Operational expenditure factor forecasts, AA5 performance • Future of gas and accelerated depreciation - price stability
	Meeting 3	• Demand • Capital Expenditure Proposal	• Demand approach and forecast for AA6 • Proposed Capital Expenditure including development background, stay in business and forecast comparisons between AA5 and AA6, and compression reduction project
Stage 3: Consultation on the Draft Plan	Meeting 4	• Draft Plan	• Draft Plan overview • Highlighted key issues and how we responded to feedback • Consultation process
Stage 4: Refining and Ongoing Engagement	Meeting 5	• Draft Plan Feedback	• Draft Plan feedback and AGIG's response • Refining our plans
	Meeting 6	• Commercial Updates	• Off-specification gas • Transmission billing system
	Meeting 7	• Refining our Plans	• Our Final Plan (2026–2030) • KPMG Reporting

5.5 Stage 3 Consultation on our Draft Plan

Our Draft Plan was published July 2024 during Stage 3 of our engagement program.

The Draft Plan was shared directly with stakeholders and made available via our online engagement portal, Gas Matters, and open for consultation for a six week period.

We held an online information session where we provided a general overview of our Draft Plan. In addition we held a Roundtable meeting in August 2024 providing an in depth overview of our Draft Plan and key highlights, initiating the consultation process for feedback to help refine our plan. We also offered Shippers additional one-on-one meetings if required.

The Draft Plan:

- highlighted key issues of importance that had been identified by our customers and stakeholders;
- showed how we have responded to feedback throughout the development of our plans;
- identified how we plan to deliver into the future for our customers and stakeholders; and
- asked a series of questions to facilitate engagement on key topics as shown in Table 5.5.

As part of our consultation on the Draft Plan we received feedback from Shippers (Attachment 5.3) regarding our engagement activities, in particular that:

"*been valuable in providing transparency and understanding of the building blocks that form the regulated tariff*";

Table 5.5: Stage 3 Consultation Questions

Topic	Consultation Question
What we will deliver	• *Do you have any feedback on our overall plans and performance targets for AA6?*
Future of Gas	• *Do you agree that we need to consider accelerating depreciation to address future risks?* • *Is achieving stability in prices through the long term important?* • *Do you have any other feedback on our accelerated depreciation approach for AA6?*
Operating Expenditure	• *Do you support our approach for forecasting opex? Is there sufficient information to understand our proposals and the basis of costs included?* • *Do you support our proposed input cost assumptions? If not, why?* • *Do you think the forecast level of opex is prudent and efficient, particularly given the current cost environment?* • *Do you have any other feedback on our opex forecast for AA6?*
Capital Expenditure	• *Do you support our approach to forecasting capex? Have we provided sufficient information to understand our proposals and the basis of the costs included?* • *Do you think the forecast level of capex in AA5 and AA6 is justified?* • *Do you have any other feedback on our capex forecast for AA6?*
Capital Base	• *Is our approach to adjusting the capital base, including to account for the impacts of accelerated depreciation, appropriate?*
Financing Costs	• *Do you have any comments on our approach to setting the financing and tax costs in the Draft Plan?*
Incentive Scheme	• *Do you support our proposed calculation of the Efficiency Carryover Mechanism (ECM) for AA5?* • *Do you support our proposed continuation of the ECM in AA6 and the proposed exclusion of 'inspections and asset management' items?*
Demand	• *Do you support our proposed approach to forecasting demand?* • *Are there any other factors, including any of your own plans, you think we should consider?*
Revenue and Prices	• *Have we provided enough information to understand the basis of our proposed price, including how it is split between the capacity and commodity components?* • *Do you support the proposed cost pass through for the Safeguard Mechanism costs?*

and

"*allowed for the opportunity to comment on the Draft Plan inputs with greater understanding*".

Key areas of feedback identified from Stage 3 engagement in relation to our Draft Plan included:

- understanding how demand for the AA5 period was used in current plans;
- seeking information on our approach to NPV revenue smoothing including alternative profiles considered;
- interest in completed accelerated depreciation modelling ahead of our Final Plan to review underlaying modelling assumptions and outputs;
- an update on capital expenditure projects, including compression reduction, gas chromatography improvement and off-specification gas liability, and forecast; and
- more information for proposed operational expenditure increase, including labour costs and the impact of assumptions for modelling SUG and overhaul costs.

All feedback received during Stage 3 is included in Table 5.6.

5.6 Stage 4 Refining and Ongoing Engagement

In Stage 4 we addressed and informed Shippers through Roundtable meetings on how we had responded to their feedback on our Draft Plan and refined our Final Plan for submission to the ERA.

In addition we held a Roundtable to update stakeholders on commercial focus areas regarding off-speculation gas and the transmission billing system.

5.6.1 Key topics for further exploration

Shippers were particularly interested in demand forecasting, the future of gas and depreciation, and our proposed capital and operational expenditure for the AA6 period.

5.7 Summary

We have actively engaged with our customers and stakeholders to inform this Final Plan.

All feedback received throughout our engagement and how it has been reflected in this Final Plan is provided in Table 5.6. This table summarises how we have acted on what we heard from our stakeholders, and includes outcomes on how our engagement has shaped our plans, as illustrated below:

✓	Positive/Green – we have responded to all feedback and have customer/stakeholder support for our proposal
⊖	Neutral/Orange – we have responded to customer and stakeholder feedback, but we do not have full support of all customers/ stakeholders
⊗	Negative/Red – we have not responded to customer feedback and we do not have customer/ stakeholder support for our proposal

Table 5.6: Customer and Stakeholder Feedback Summary

Topic	Customer and Stakeholder Feedback	Our Response
Pipeline and Reference Services	**Stage 1 & 2 Engagement: Developing our Plans**	

	• Shippers generally supported the Draft Reference Service Proposal (RSP) and agreed to the three proposed reference services.
	• We received one written submission which suggested to:
	  ◦ consolidate all firm and interruptible services into just two service offerings;
	  ◦ reclassify our interruptible services as reference services;
	  ◦ extend the Pilbara Service to include the Perth Basin; and
	  ◦ reinstate pipeline storage services and data services that were no longer proposed to be offered.
	• At the Roundtables, Shippers asked:
	  ◦ if tariffs would be fixed for the entire AA6 period and the impact of rebates on annual tariffs; and
	  ◦ about the pipeline's capability to accept alternate gases to natural gas.
		• We published information summarising proposed services on our online engagement portal, Gas Matters.
		• We responded directly to questions regarding our services in roundtables and explained that:
		  ◦ it was likely that tariffs would continue to be adjusted for 70% of the 'rebateable service' revenue received and that demand for the services remained unpredictable.
		  ◦ other gases could be injected into the pipeline subject to meeting gas specifications, noting that there are currently no such plans for this to occur.
		• We met directly with the individual Shipper that made a submission about our RSP.
		• Our Final RSP incorporated our responses to issues raised regarding our services, including:
		  ◦ the distinction between each of the reference services is applied as a practical way to define the specific extent and direction of services contracted for, whether they are full or part haul and forward or back haul.
		  ◦ non-reference services, including interruptible services, do not meet the reference service factors (RSF) because they are tailored to meet specific Shipper needs.
		  ◦ extending the Pilbara Service to include the Perth Basin would increase its cost and there was limited additional support for this option from Shippers.
		  ◦ data services were in low demand and that changing operational pipeline dynamics meant that we can no longer offer storage as a firm service.
		• We submitted our RSP to the ERA in December 2023.

	Stage 3 Engagement: Draft Plan Consultation	
	• The ERA published a notice on 9 February 2024, establishing its own consultation on the Draft RSP. It posed various questions, including about the removal of the Data and Storage Services and non-reference service classifications.	• We made a submission to the ERA's notice and maintained that the non-reference services do not meet the RSFs, and that changing operational dynamics on the pipeline would make the demand for them even less predictable. • We noted that we could continue to offer the Data Service and the Storage Service but that the latter would be on an interruptible basis only. • Our Draft Plan reflected the ERA's decision on our RSP dated 1 July 2024.
	Stage 4 Engagement: Refining our Plans	
	• Shippers were keen to know which services would be rebateable and the associated impact on tariffs.	• We propose in our Final Plan that the same non-reference services be rebateable as in AA5 (Spot Capacity, Peaker, Other Reserved and Backflow Services) with the addition of the Pilbara Service, and that the rebate portion of revenue applied to reduce the reference tariff continues to be 70%.
	Final Plan Outcome	

	• Our proposal for Full Haul, Part Haul and Back Haul Reference Services is consistent with the current Reference Services and has been agreed by the ERA. • Our other pipeline services reflect feedback we received on our service offerings and have also been agreed by the ERA, with the revenue for all haulage non-reference services planned to be 'rebateable'.	
Topic	**Customer and Stakeholder Feedback**	**Our Response**
Future of Gas	**Stage 1 & 2 Engagement: Developing our Plans**	
	• Clarification was sought on the economic life of the DBNGP and our approach to depreciation.	• We presented our focus for the next period concerning depreciation was on customer outcomes, including demand and price stability, lower risk in the face of decarbonisation challenges and the energy transition. • We discussed our consideration of a tilted profile for economic recovery rather than or in addition to changing the economic life of the pipeline.
	Stage 3 Engagement: Draft Plan Consultation • **Do you agree that we need to consider accelerating depreciation to address future risks?** • **Is achieving stability in prices through the long term important?** • **Do you have any other feedback on our accelerated depreciation approach for AA6?**	
	• Shippers sought clarification on when we expect to have the model, analysis and outcome concluded, and which analytical methods we use. • Shippers asked if the proposed amount represented a significant shift from the current period and if the placeholder was consistent with expectations based on the updated model. • A question was asked if there was an opportunity to apply less depreciation, and if Shippers have the flexibility to select the depreciation. • Shippers expressed interest in accessing final depreciation modelling in advance of the Final Plan to review modelling assumptions and model outputs.	• We provided an overview of the different smoothing profiles using the tilt mechanism with our approach to NPV. • We indicated that there should not be a substantial difference between AA5 and AA6 calculations, and noted expect the final value submitted to the ERA would be likely to be lower than the $113 million included in the Draft Plan. • We confirmed this plan will likely maintain the asset end life of 2063, as per the current AA5 period. We added the additional $113 million in depreciation included in the Draft Plan was a placeholder, and noted the possibility this could be reduced following the model update. • We clarified that Shippers do not have the flexibility to choose the depreciation amounts, noting their crucial role in the engagement process informing decisions. • We explained that work was currently being finalised in preparation for discussion with stakeholders in the Shippers and the next stage of engagement.

	• A Shipper agreed accelerating depreciation is applicable to address the DBNGP's future risk and should be earlier than the original 2090 estimate. • A Shipper noted that the right balance between price stability, predictability and costs to Shippers was important as cost increases directly impact Shippers' short to medium term views on domestic gas and may deter future investment into gas as a viable fuel source. • It was suggested, due to the current anticipated economic life to 2063 being set early in the current period, this date be reviewed on a regular basis due to the energy transition and different solutions emerge.	
	Stage 4 Engagement: Refining our Plans	
	• Shippers asked at Roundtable No. 5 whether depreciation could be flattened, whether the costs were in real terms or inflation, and the difference between straight-line and regulatory depreciation.	• At Roundtable No. 5 we updated the depreciation calculation method, noting that the 2063 asset end date from the current period remained valid, resulting in no additional depreciation being included in this Final Plan. • We directly responded to Shippers' queries on depreciation in Roundtable No. 5.
	Final Plan Outcome	
	• We have presented a "no-change" outcome whereby we have kept the depreciation profile from AA5 out to 2063. We have also presented evidence showing that this is likely sufficient to cover risk sufficiently and avoid price shocks for our shippers in coming decades.	

<table>
<tr><th>Topic</th><th>Customer and Stakeholder Feedback</th><th>Our Response</th></tr>
<tr><td rowspan="6">Operating Expenditure</td><td colspan="2">Stage 1 & 2 Engagement: Developing our Plans</td></tr>
<tr><td>Shippers were supportive of our proposed opex approach and initial draft forecast for our AA6 opex needs.
Shippers requested further details on our specific plans in our Draft Plan.</td><td>We provided our preliminary AA5 performance and AA6 expenditure forecasts, noting the base year was based on budget estimates for 2024 only.</td></tr>
<tr><td colspan="2">Stage 3 Engagement: Draft Plan Consultation
Do you support our approach to forecasting opex? Is there sufficient information to understand our proposals and the basis of costs included?
Do you support our proposed input cost assumptions? If not, why?
Do you think the forecast level of opex is prudent and efficient, particularly given the current cost environment?
Do you have any other feedback on our opex forecast for AA6?</td></tr>
<tr><td>In response to our Draft Plan, one Shipper recommended consideration of the impact on opex and particularly our turbines from an increased reliance from firming on gas.
Shippers sought further information generally on the proposed spending increases in AA6.
In Roundtables, Shippers also sought further information on:
our insurance for assets.
SUG modelling for AA6 including higher gas contract costs and the impact from the Waitsia project and the potential Compression Reduction Project.</td><td>Our Draft Plan AA6 opex forecast of $606 million was based on 2024 budget estimates for the base year only.
We emphasised that estimates would be revised once nine months of actuals were available, closer to submission of the Final Plan.
We reviewed our SUG forecasts to account for the impact from the increasing need for firming and adjusted some model inputs accordingly (including related to transient behaviour and the use of CS10 units).
We advised that expected insurance premium costs would feed into our base year forecast for 2026 but that estimates would need to be reviewed further because the insurance policy is renegotiated annually and renewed in September, and we were awaiting a final report on expected premium costs from our insurer.
We clarified that the impact of the Backflow throughput on compression needs had been considered in the SUG forecasts and that the potential SUG savings from the Compression Reduction Project had not been factored into the Draft Plan because it was not yet approved for progression.</td></tr>
<tr><td colspan="2">Stage 4 Engagement: Refining our Plans</td></tr>
<tr><td>In response to further revised opex forecasts, Shippers acknowledged the higher cost environment but sought further information about the proposed increase in labour and other costs in AA6.
In a Roundtable it was also asked whether information on staffing levels would be provided with the Final Plan.</td><td>We provided an update at Shipper Roundtable No. 5 on opex forecasts which were revised up to $633 million from the Draft Plan for three quarters of actual expenses then available for 2024 and other further revisions to estimates.
In addition, we noted that our costs have been rising due to labour market pressure but also due to the impact of the reclassification of labour expenses from capital projects (as was noted in the Draft Plan) and the market pressure on our field, utility, insurance and other expenses.</td></tr>
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<tr><td rowspan="3"></td><td></td><td>We also advised that further information on labour cost increases (including staffing levels) would be provided in the Final Plan and/or made available to the ERA, as required.
For the proposed increase in our Inspections and Other Asset Management category of expenses, we outlined the need for the program of inspections and other works to maintain the safety and reliability of the pipeline.</td></tr>
<tr><td colspan="2">Final Plan Outcome</td></tr>
<tr><td colspan="2">Our opex proposal continues to be responsive to customer needs for a strong focus on operational issues which is important for safety, reliability and emergency management.
Our forecasts in AA6 reflect the higher cost environment that we have begun to experience at the end of AA5, but we have sought to incorporate efficiencies where feasible.
Customers are broadly comfortable with our forecasting methodology which has been endorsed by the ERA in the past.
We have supported our forecasts with business cases and other sources of evidence.</td></tr>
</table>

Topic	Customer and Stakeholder Feedback	Our Response
	Stage 1 & 2 Engagement: Developing our Plans	
	• Shippers were generally supportive of our proposed capital expenditure approach, initial draft forecast or our AA5 performance update, and requested further details on our specific plans in our Draft Plan. • There was interest in the value of a small number of deferred capital projects, including how any interest earned would be used. • Shippers sought information on the Compression Reduction Project including the reduction of gas speed and any emissions reduction. • Shippers requested an update on the Pluto Expansion Project. • Some Shippers indicated concern regarding gas specifications and the risk of gas flow and quality. It was proposed that we recommend changes so the ERA could address this issue.	• We provided detailed information on capital expenditure, including AA5 forecasts and proposed revised AA6 expenditure. • We presented an update on deferred projects, in particular the Northern Communications Project including higher than expected initial tender responses, ultimately resulting in us seeking alternative delivery solutions. We advised that only capex incurred is added to the Regulatory Asset Base. • We also provided an update on the Compression Reduction Project and noted our aim to reduce costs and the carbon footprint without affecting capacity. • We updated the status of the Pluto Expansion project, and its progression in line with the schedule. • In response to gas specifications concerns, we referenced our contractual relationship with Shippers rather than Producers and advised that given our obligations around gas specifications we would propose improving our ability to measure gas purity in the DBNGP. • We noted our intention to engage directly with Shippers regarding flow and quality of gas with a view to consider potential actions.
Capital Expenditure	**Stage 3 Engagement: Draft Plan Consultation** • **Do you support our approach to forecasting capex? Have we provided sufficient information to understand our proposals and the basis of the costs included?** • **Do you think the forecast level of capex in AA5 and AA6 is justified?** • **Do you have any other feedback on our capex forecast for AA6?**	
	• At the Roundtable it was asked if we could clarify the reconciliation of actual outcomes relative to benchmarks set for AA5, in particular whether the entirety of the capital allocation had been expended, or is there a transfer of capital to the AA6 period and what implications would this have.	• At Shipper Roundtable No. 5 we presented our proposed capex of $413 million, including $123 million for the Compression Reduction Project. • We presented to Shippers on the compressor stations upgrade, the Jandakot redevelopment, new gas chromatographs and enhanced pipeline requirements. • We confirmed that the actual capital expenditure incurred for AA5 would exceed the allowance set. We noted the Draft Plan contained further information and confirmed we would look to include more detailed information in this Final Plan.

	• Shippers asked if gas chromatography improvements and off-specification gas liability responsibility should be shifted to the responsibility of the Producers and also potentially DBP if it knowingly accepts an operator's indicated off-specification gas into their asset. • Shippers asked if it should be expected for Producers to provide specific information, adding the current provision of data seemed inadequate. • At the Roundtable Shippers asked if it was feasible to obtain two readings and ensure that the issue could be addressed within six minutes. • Shippers sought further information on the Compression Reduction Project, in particular whether what cost benefit analyses and Net Present Value (NPV) calculations were conducted, timing of next benefits to Shippers and the potential to delay for lower interest rates. Sharing of the business case prior to the Final Plan would be ideal. • Shippers asked whether assets with values not fully realised should be excluded from consideration, and only assets with actual value in use be counted.	• We commented that we have shifted to new methods with the aim to improve redundancy and transparency, and allowing for timely issue validation and response. We noted that whilst this approach involves some duplication, it enables us to effectively monitor hydrogen sulphide levels, assess issues and respond promptly with detailed insights on legacy inlets. • We acknowledged Shippers' concerns and confirmed the installation of additional monitoring equipment to ensure faster response times and added that this enhanced visibility and minimised risk for Shippers Producers were not required to provide the same level of information. • We confirmed that it is possible to obtain multiple readings with newer equipment and acknowledged the shortcomings in our current measurement assets which lack transparency, which would benefit Shippers. • We updated Shippers regarding the Compression Reduction Project advising it was in the FEED phase and subject to continued analysis. • We confirmed that a comprehensive review of their Regulatory Asset Base (RAB) was carried out in AA5 to ensure accurate asset valuation and usage.

Stage 4 Engagement: Refining our Plans	
• Shippers sought clarification regarding gas chromatography, and impact on nameplate capacity.	• We presented at Roundtable No. 5 details regarding the $123 million reduction to capital expenditure proposals, and provided updates on the Jandakot redevelopment, IT infrastructure budget and compressor station upgrades. • We explained the merits of compression reduction on the pipeline, noting the uncertainties of Perth Basin developments means further work must be conducted to fully understand the need, risks, costs and benefits of decommissioning compressor stations and looping the DBNGP. This means we are unlikely to include this project in our Final Plan. • We also addressed Shippers queries regarding gas chromatography improvement and off-specification liability, adding we have included $7.8 million in the forecast for new GCs at KGP, Macedon, Wheatstone and Gorgon, replacement GCs at VI and Pluto, and new analysers for moisture, H2S and total sulphur (Waitsia – H2S and total sulphur only). • We discussed the overall quantum of the capex forecast and that is higher than in previous periods due to a number of assets on long-term replacement cycles coming due for replacement in AA6 and that the cost environment changed in AA5 which led to higher costs in the AA6 forecast.

Final Plan Outcome

- Our stay in business capex forecast proposal includes continuation of existing programs of work on our compressor stations, meter stations and pipeline, investments in pipeline accommodation and gradual integration of renewable generation solutions.
- Our proposal delivers against customer expectations that current levels of reliability are maintained.
- This Final Plan provides supporting information on capex and evidence of our governance arrangements that support costs being efficient.
- Customers are comfortable with our approach and level of capex.

Topic	Customer and Stakeholder Feedback	Our Response
Financing Costs	**Stage 1 & 2 Engagement: Developing our Plans**	
	• Stakeholders acknowledged our intentions to adopt the ERA's Rate of Return Guidelines in formulating our plans, consistent with the approach taken for our other assets. • A Shipper asked what the actual financial performance compared to the projected performance for AA5 was due to the significant expected increase in the WACC, and how has this impacted the formulation of AA6 pricing. • Shippers requested we provide an overview of the WACC calculations and our current gearing level.	• We responded that the Rate of Return Instrument (RoRI) served as a binding instrument that determined the methodology for estimating our WACC and our rate of return in AA6. We note the RoRI is published on the ERA website. • We explained to Shippers how the annual adjustment of the debt-risk premium is determined by the ERA. • We explained the WACC to be used for the AA6 Final Decision would be determined later in the process and that we will maintain transparency by clearly displaying the components of the calculation. • We presented our current rate of return and financing calculations for AA6 in the Draft Plan.
	Stage 3 Engagement: Draft Plan Consultation • **Do you have any comments on our approach to setting the financing and tax costs in the Draft Plan?**	
	• In the Roundtable it was asked what analytical methods we use to evaluate the rate of return for making business decisions, and if assume any risk related to interest rates.	• We responded to a Shipper query that the Rate of Return fluctuates in line with the market movement affecting the cost of debt and risk-free rate, and clarified that unspent capex cannot be carried over to future periods. Interest rate fluctuations drive price increases, and we mitigate some of this risk through hedging. The cost of debt is based on actual data, and we only recover what the ERA approves, noting not benefit to AGIG or customers from higher interest rates. • We commented our goal is to maintain price stability; however, this does not guarantee that prices will remain unchanged, because of the way the WACC operates.
	Stage 4 Engagement: Refining our Plans	
	• No further information was requested in relation to financing costs.	• We presented the WACC approach, following the ERA's RoRI, and provided a summary of where rate of return had moved since the Draft Plan.
	Final Plan Outcome	
	• We have applied the ERA's Rate of Return Instrument, based on data on interest rates from September 2024, giving a WACC of 6.93%. This will be finalised in the ERA's Final Decision.	

<table>
<tr><th>Topic</th><th>Customer and Stakeholder Feedback</th><th>Our Response</th></tr>
<tr><td rowspan="8">Incentive Scheme</td><td colspan="2">Stage 1 & 2 Engagement: Developing our Plans</td></tr>
<tr><td>• Our customers told us that they were broadly comfortable that the current framework regarding the Efficiency factor (E Factor) mechanism appropriately incentivises us to incur only efficient opex.</td><td>• During Stage 2 of our stakeholder engagement program, we held Shipper Roundtables to engage on key areas of our plan, including our proposed continuation of the E Factor incentive scheme for AA6.</td></tr>
<tr><td colspan="2">Stage 3 Engagement: Draft Plan Consultation
• Do you support our proposed calculation of the Efficiency Carryover Mechanism (ECM) for AA5?
• Do you support our proposed continuation of the ECM in AA6 and the proposed exclusion of ‘inspections and asset management’ items?</td></tr>
<tr><td>• Stakeholders continued to indicate broad agreement for the proposed E factor calculation to apply in AA6 with no concerns identified.
• One Shipper requested that we indicate the estimated benefit in AA6 by way of a tariff reduction ($/GJ) from the impact of the negative E factor carryover.</td><td>• We presented at Shipper Roundtable No. 4 the key opex drivers for AA5 and AA6, noting implications from the current high-cost environment.
• We shared our preliminary E Factor forecast for AA5 and proposed that the labour cost rate update be excluded from the calculation. We also proposed that ‘Inspections and other asset management’ items be excluded in AA6 on the basis that expenditure has been driven by inspection outcomes and pipeline safety and reliability objectives rather than efficiency.
• We have included the equivalent tariff benefit from the E Factor negative carryover in Chapter 12 of this Plan.</td></tr>
<tr><td colspan="2">Stage 4 Engagement: Refining our Plans</td></tr>
<tr><td>• No further feedback was received.</td><td>• We presented at Roundtable No. 5 the current E Factor carryover forecast of negative $48 million, based on forecast AA5 opex performance at that stage, noting it would be subject to further revisions ahead of the Final Plan.</td></tr>
<tr><td colspan="2">Final Plan Outcome</td></tr>
<tr><td colspan="2">• We have proposed continuation of the E Factor incentive scheme to apply to our opex in AA6 with the additional exclusion of ‘Inspections and other asset management’ non-recurrent cost items. We have recalculated the E Factor carryover in AA5 (based on our final AA5 opex forecasts) to be negative $21 million with this exclusion, as well as adjusting for the impact from the update to labour cost rates. This results in a 2c/GJ benefit to our Shippers in AA6.</td></tr>
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<table>
<tr><th>Topic</th><th>Customer and Stakeholder Feedback</th><th>Our Response</th></tr>
<tr><td rowspan="8">Demand</td><td colspan="2">Stage 1 & 2 Engagement: Developing our Plans</td></tr>
<tr><td>Shippers asked about our plans to increase the capacity of the DBNGP, including an increase in demand resulting from AA5.
It was asked if the peakiness on the asset held any inherent value when considering overall demand.
Shippers were generally interested in how decarbonisation impacted our future needs.</td><td>We provided our demand approach for the Draft Plan in AA6 noting it will be the same as for AA5.
We also acknowledged the current variability on the asset and its potential value concerning overall demand.
Separate to the Roundtables in Stage 2 we engaged directly with Shippers to assist with demand forecasts to ensure a reasonable degree of certainty.</td></tr>
<tr><td colspan="2">Stage 3 Engagement: Draft Plan Consultation
Do you support our proposed approach to forecasting demand?
Are there any other factors, including any of your own plans, you think we should consider?</td></tr>
<tr><td>It was asked whether the demand for AA5 was equivalent to that projected for AA6.
A Shipper asked if the loads were assumed to be contracted on a long-term basis, or if they pertained to retail loads with contracts of up to three years.
It was asked if the increase in gas-powered generation (GPG) was primarily driven by capacity considerations.
A Shipper asked whether AGIG had considered that there is the potential for contracted full haul equivalent capacity will increase significantly to several WA energy market factors such as an increase in Perth Basin supply and coal power closures.</td><td>At the Shipper Roundtable we confirmed the finalisation of the AA6 forecast on best available information. Demand will be updated as further information becomes available.
We informed Shippers of a 48 TJ reduction from the previous update which is included in this plan.
We confirmed that demand for AA5 was used in our planning for our plans, noting demand remains level for 90% of Shippers.
We confirmed that the demand projections for AA6 in the Draft Plan are quite similar to the current levels in AA5, with many Shippers experiencing stable capacity and utilisation. We have however updated for customer plant closures.
We stated that the contracting period depends on the Shipper and the service in question, and acknowledged that the situation varies by case, with some contracts extending long-term and others being limited to shorter agreements.
While market averages are considered, a segment of the market is still outstanding, but it is not expected to differ significantly from AA5.</td></tr>
<tr><td colspan="2">Stage 4 Engagement: Refining our Plans</td></tr>
<tr><td>Shippers asked if any new facilities were expected to be added in the future.</td><td>We presented our planned closures for the 5-year plan, leading to a 48TJ reduction from our previous update and to be included in this Final Plan.</td></tr>
<tr><td colspan="2">Final Plan Outcome</td></tr>
<tr><td colspan="2">Our demand forecast is based on the most recent information predominately set in contracts and recent utilisation of their reserved capacity. It has also been checked against the AEMO's Gas Statement of Opportunities (GSOO) forecasts. Some Shippers are still finalising their position, and we expect some updates to the forecast during 2025.</td></tr>
</table>

Topic	Customer and Stakeholder Feedback	Our Response
Revenue and Prices	**Stage 1 & 2 Engagement: Developing our Plans**	
	• Shippers asked if it was advisable for them to account and plan for rebates in the annual tariff submission given it is recalculated annually. • Shippers sought clarification on the tariff calculation bottom-up process.	• We suggested Shippers plan for rebates in their annual submissions due to the annual recalculation taking into account any potential rebates associated with the annual tariff. However, we made it clear that forecast tariffs do not include any forecast of likely rebates. • We clarified the bottom-up approach accurately reflected the methodology used in the calculation of the tariffs.
	Stage 3 Engagement: Draft Plan Consultation • **Have we provided enough information to understand the basis of our proposed price, including how it is split between the capacity and commodity components?** • **Do you support the proposed cost pass through for the Safeguard Mechanism costs?**	
	• Shippers supported the cost pass through for the Safeguard Mechanism, noting it fair.	• We will propose the cost pass through for the Safeguard Mechanism. • We presented an overview of key price drivers, noting the implications with increased tariff of $2.41 compared to the previous $2.35.
	Stage 4 Engagement: Refining our Plans	
	• Shippers wanted to be updated on our proposed pricing.	• We continued to provide building block and price updates at Shipper Roundtable meeting as we refined our Final Plan.
	Final Plan Outcome • The Future of Gas depreciation applied in AA5 has relieved price pressure in AA6 reducing tariffs by around 10 cents. • Our Final Plan outlines further information on cost allocation and adopts an approach consistent with the approach accepted in AA5.	

<table>
<tr><th>Topic</th><th>Customer and Stakeholder Feedback</th><th>Our Response</th></tr>
<tr><td rowspan="4">Pipeline Access</td><td colspan="2">Stage 1 & 2 Engagement: Developing our Plans</td></tr>
<tr><td>At the initial roundtables, Shippers expressed concern about the issue of off-specification gas (“off-spec gas”), including:
why they were liable if specifications aren’t met (and not producers or the DBNGP);
why they could not take action themselves and “shut in” producers (i.e. stop flow); and
how the ERA might enforce an amendment to SSCs to shift the risk back to producers, thereby preventing the passing of Gas Chromatograph (GC) costs to Shippers, which was seen as particularly important with changing flow dynamics in the pipeline.
Shippers requested further engagement on off-spec gas to address these concerns.</td><td>The off-spec issue is covered in the current Reference Service Contract (clauses 6 and 7) but we noted that it remained an ongoing issue (given that legacy infrastructure now allows only a few minutes for notifications and there are other challenges with providing timely warnings to Shippers). We indicated that we were exploring ways to improve the notification system.
We also explained how:
the framework governing gas specifications is under legislation and beyond our control;
our contractual relationship was solely with Shippers, not the producers of gas; and
we would be installing GCs to monitor gas specifications at inlet points.
In the lead up to our Draft Plan we further indicated that we sought feedback from Shippers on our review of our reference service terms and conditions and any other specific issues they sought to be addressed.</td></tr>
<tr><td colspan="2">Stage 3 Engagement: Draft Plan Consultation
Do you have any feedback on the terms and conditions for our reference services?
Are there any specific issues that you would like to see addressed through this terms and conditions review?</td></tr>
<tr><td>Submissions to our Draft Plan asked:
how the review of off-specification provisions in the Reference Service Contracts would interact with a Shipper’s SSC, and whether any revisions would be mirrored into existing SSCs; and
whether our review would consider all capacity contracts (existing and new).</td><td>We explained how any changes to Reference Service Contracts could also be included in the SSCs but individual non-reference contracts could only be updated as they are negotiated or renegotiated.
Given the interest from Shippers on the topic of off-spec gas, we decided to hold a dedicated Shipper Roundtable on this topic and to introduce the new transmission billing system (which might also help with notifications).</td></tr>
</table>

Stage 4 Engagement: Refining our Plans

- At the dedicated Roundtable on off-spec gas, Shippers:
  - sought an understanding of the management of off-specification gas;
  - requested more information on the details of the new process and the scope for receiving automated reports; and
  - wanted to understand the impact on the imbalance charging framework.
- Shippers agreed to our proposal to remove the requirement in T&Cs to send notices by fax.

- We advised Shippers of our Final Plan position, acknowledging that Shippers would not see the desired resolution to the off-spec gas issue that they were seeking as our contractual relationship is with Shippers and not the producers of gas, although Shippers could exercise any rights against producers which supply off-specification gas.
- We also responded to questions and explained:
  - the new process, noting it was possible to receive notices in .CSV format;
  - how we use third-party GCs to constantly monitor for Hydrogen Sulphide and Mercury and that we would add GC to legacy inlet points where the process was manual; and
  - advised that there were no changes to the imbalance framework.
- Lastly, we provided an overview of the proposed changes to reference service contracts in AA6 and encouraged Shippers to submit any further queries and feedback to us.

Final Plan Outcome

- Our T&Cs in AA6 have been updated.

6 Future of gas

The future of gas transmission infrastructure in a decarbonised energy environment is uncertain and our plans for the DBNGP must be adaptable to the needs of shippers as they decarbonise in different ways.

IN THIS CHAPTER:

- **We outline how we analyse long-run future demand**
- **We show how we consider depreciation profiles in the context of how they will influence price across different simulations of the future**
- **We explain how this has led us to propose no change to our depreciation profile for AA6**

Decarbonisation by our shippers and of the DBNGP itself will change long-term demand for pipeline services. Our aim, in the face of this uncertainty, is to avoid price shocks for shippers into the long term.

Depreciation is an important tool used by pipelines and regulators to deal with evolving risk. Changing the depreciation profile to match a changing demand profile helps maintain price stability for shippers and to maintain the risk balance between the pipeline and its shippers.

For AA6 we have built on the approach taken in AA5. This chapter explains our approach to depreciation, the risks we are seeking to mitigate and our modelling approach to determine the appropriate amount of depreciation.

6.1 Regulatory framework

Regulatory depreciation is governed by Section 89 of the National Gas Rules, which sets out how invested capital is to be recovered over the economic life of assets, and how changes in economic lives are to be reflected in changes to depreciation.

Prior to AA5, economic lives had not changed in roughly 20 years. We recognised as we planned for AA5 that the transformation of Australia's energy market meant consideration of changes to economic lives was necessary. We therefore proposed changes to depreciation in our AA5 proposal.

A need to reflect energy market developments in depreciation was recognised by the ERA in the Final Decision for AA5, and has been recognised by the AER in its *Regulating Gas Pipelines under Uncertainty* information paper (available here). It has also been recognised in regulatory decisions, with each decision on gas networks around Australia since our AA5 decision reflecting some changes to depreciation schedules.

6.2 Overview

Our modelling approach for AA6 takes a more granular perspective than was the case in AA5, looking very carefully at the options each of our largest shippers could actually use to reduce their gas demand and the conditions under which they might take a particular option. We then look at what this would mean for prices for remaining shippers at the point in time when a particular shipper reduces gas demand. Finally, we examine possible depreciation pathways within that framework to ascertain whether changes in the profile could avoid price shocks for remaining shippers if and when a given shipper reduced gas demand.

After examining many different approaches to depreciation, we concluded that our approach from AA5, is sufficient to avoid price shocks over the longer term and maintain the risk balance between DBP and our shippers. Our Final Plan therefore does not propose any changes from what is an accepted approach.

6.3 Stakeholder Engagement

We discussed our approach to depreciation with shippers at several of the stakeholder forums. We have also discussed the modelling approach, and operation of the model with the ERA. Detail on stakeholder views is contained in Table 6.1.

Table 6.1: Summary of customer and stakeholder engagement on Future of Gas

Topic	Customer and Stakeholder Feedback	Our Response
Future of Gas	**Stage 1 & 2 Engagement: Developing our Plans**	
	• Clarification was sought on the economic life of the DBNGP and our approach to depreciation.	• We presented our focus for the next period concerning depreciation was on customer outcomes, including demand and price stability, lower risk in the face of decarbonisation challenges and the energy transition. • We discussed our consideration of a tilted profile for economic recovery rather than or in addition to changing the economic life of the pipeline.
	Stage 3 Engagement: Draft Plan Consultation • **Do you agree that we need to consider accelerating depreciation to address future risks?** • **Is achieving stability in prices through the long term important?** • **Do you have any other feedback on our accelerated depreciation approach for AA6?**	
	• Shippers sought clarification on when we expect to have the model, analysis and outcome concluded, and which analytical methods we use. • Shippers asked if the proposed amount represented a significant shift from the current period and if the placeholder was consistent with expectations based on the updated model. • A question was asked if there was an opportunity to apply less depreciation, and if Shippers have the flexibility to select the depreciation. • Shippers expressed interest in accessing final depreciation modelling in advance of the Final Plan to review modelling assumptions and model outputs.	• We provided an overview of the different smoothing profiles using the tilt mechanism with our approach to NPV. • We indicated that there should not be a substantial difference between AA5 and AA6 calculations, and noted expect the final value submitted to the ERA would be likely to be lower than the $113 million included in the Draft Plan. • We confirmed this plan will likely maintain the asset end life of 2063, as per the current AA5 period. We added the additional $113 million in depreciation included in the Draft Plan was a placeholder, and noted the possibility this could be reduced following the model update. • We clarified that Shippers do not have the flexibility to choose the depreciation amounts, noting their crucial role in the engagement process informing decisions. • We explained that work was currently being finalised in preparation for discussion with stakeholders in the Shippers and the next stage of engagement.

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A Shipper agreed accelerating depreciation is applicable to address the DBNGP’s future risk and should be earlier than the original 2090 estimate.
A Shipper noted that the right balance between price stability, predictability and costs to Shippers was important as cost increases directly impact Shippers’ short to medium term views on domestic gas and may deter future investment into gas as a viable fuel source.
It was suggested, due to the current anticipated economic life to 2063 being set early in the current period, this date be reviewed on a regular basis due to the energy transition and different solutions emerge.

</td><td></td></tr>
<tr><td></td><td colspan="2">Stage 4 Engagement: Refining our Plans</td></tr>
<tr><td></td><td>

Shippers asked at Roundtable No. 5 whether depreciation could be flattened, whether the costs were in real terms or inflation, and the difference between straight-line and regulatory depreciation.

</td><td>

At Roundtable No. 5 we updated the depreciation calculation method, noting that the 2063 asset end date from the current period remained valid, resulting in no additional depreciation being included in this Final Plan.
We directly responded to Shippers’ queries on depreciation in Roundtable No. 5.

</td></tr>
<tr><td></td><td colspan="2">Final Plan Outcome</td></tr>
<tr><td>✓</td><td colspan="2">

We have presented a “no-change” outcome whereby we have kept the depreciation profile from AA5 out to 2063. We have also presented evidence showing that this is likely sufficient to cover risk sufficiently and avoid price shocks for our shippers in coming decades.

</td></tr>
</table>

6.4 Risks to price from changes in demand

To understand the risks that affect both DBP and shippers, it is important to understand how our tariffs work. At present, tariffs have a 94% capacity charge and a 6% commodity charge. The capacity charge is for the right to take a certain amount of pipeline capacity and is paid whether the pipeline is used on a given day or not. The commodity charge is paid only on gas actually transported.

Risk is *realised* when a shipper replaces some or all of its demand for gas with a substitute for gas. If this happens during an AA period, our revenues will fall. Then, at the start of the next AA period, when prices are reset, prices will increase to spread our costs over the remaining customers as per the regulatory building block model. This may, in turn, cause another shipper to replace some or all of its gas demand with a substitute, perpetuating price rises for remaining shippers.

However, risk can build, *unrealised*, for some time before this happens. Consider a gas-fired generator which needs to provide firm power to back-up renewable power when it is unavailable and cannot predict when this need might eventuate.

Such a shipper might choose to contract for their full required load on the days when they are needed to make sure they have the gas available to run when they need to, and they do not know when that will be. This means that the effective price per GJ actually used is much higher than the tariff. Moreover, if the share of renewables is rising, the effective tariff will also rise.

The risk remains unrealised (to us) because our annual revenues remain the same; we cannot see the effective price of the gas for the shipper. Eventually the effective price of gas used may rise to such a point that a substitute for the task for which the shipper is using the gas becomes viable and the shipper may reduce some or all of its demand for gas; at which point the risk is realised for us, and for remaining shippers who will then pay higher prices.

Unless we plan for this risk we, and the shippers who remain, will face a revenue and price shock as the formerly unrealised risk is crystalised into an actual consequence for us and for remaining shippers.

For this reason, we have focussed our modelling on the impacts on the effective price of gas used, rather than, say, our annual revenues based on the current tariff structure, and sought to avoid shocks to this effective price of gas used.

6.5 Context for long-term demand

We expect to be revisiting the depreciation schedule in every future access arrangement as the energy market changes through time. This is because depreciation is a flexible tool which can be used to address these changes. We have done so in AA6, updating information from AA5 to re-look at issues surrounding depreciation. We provide detail on this assessment in Attachment 6.1.

Much has changed since AA5. Within WA, the uptake of renewable power has increased significantly, with rooftop solar now being so prevalent that there are times when it endangers the grid requiring policymakers to develop responses to this issue. Batteries, which can extend the range of renewable power into the evenings are starting to expand rapidly with some 1400 MW of grid-scale batteries to come online during AA6 compared with none at the start of AA5.

Globally, too, the prices of renewables have fallen to the point where they no longer require subsidies. However, this does not mean they are not subsidised, with both supply side and demand side policies by governments around the world distorting the marketplace, and making predictions very challenging.

Forecasts decades into the future, such as the series of GenCost reports by the CSIRO remain roughly similar in terms of price predictions circa 2050 from their perspective at the start of AA5. This suggests that, to the extent that price (and cost of technology) is a driver, the longer-term picture has not changed significantly.

One key focus for us in AA6 has been the particular options our shippers may take to move away from gas and the conditions under which they might choose to do so. These choices are not just a consequence of different energy prices, but also factor in other things, like reliability of alternatives. The intermittency of renewable power can mean that, for a production process requiring steady 24/7 power, it is not economical even as a MWh of renewable power is cheaper than a MWh of gas-fired power.

On the flipside, many of our shippers are subject to domestic carbon restrictions such as the Safeguard Mechanism, or similar pressure internationally, and these pressures are set to rise through time. This may mean that gas-fired power, even if it is cheaper and more reliable than renewables, may not be feasible because of policy-led restrictions.

Finally there are questions of risk. Even where energy costs are not a large part of the overall cost stack for a shipper, it is a crucial input, without which production simply cannot happen. Alternatives to gas in the provision of energy for a particular process may be untested, and considered very risky. Conversely, gas is subject to various policy restrictions which might endanger its future availability (see, for example, gas exploration bans in Victoria or New Zealand) and shippers may move away from gas before it is cost-effective to do so to mitigate future risk.

All of these factors make forecasts challenging; much more challenging than just predicting when a given form of energy will be the least costly. We have endeavoured to factor all of these challenges into our modelling approach. Attachments 6.1 and 6.2 provide much more detail underlining how we have done this.

6.6 Our modelling approach

Our modelling approach builds upon our work from AA5, as well as subsequent work undertaken for some of our distribution assets on the East Coast. We have made three key conceptual changes to the way we model:

- Our approach is much more granular. Rather than looking at prices for gas and substitutes (as in AA5) and assuming replacement when the substitute price was lower than gas without considering what new equipment could be used, we have looked in far more detail at what our shippers can do to move part or all of their production processes away from gas.
- We have examined changes in the shape of the depreciation profile through time rather than just changes in asset lives. This picks up an innovation we developed for our other networks since our AA5 proposal, which has subsequently been used by other networks and accepted by regulators.
- We have focussed more on shipper prices through time than we did for our AA5 proposal.

Owing to the granular nature of the modelling, rather than focus on demand from all sectors, we focus on the three key sectors of gas for power generation, alumina and chemicals and gas processing. These comprise roughly 80 percent of our revenues, which we believe represents sufficient information to plan an appropriate depreciation schedule.

In our modelling framework, there are a number of key drivers of future demand by our shippers, including "contextual factors" which cover things like policy shifts, and price drivers. They combine in simulations to give views of the future.

These drivers feed through into a (separate; but linked) model of the SWIS and of key industrial shippers so we can ascertain whether realisations of the driver variables are sufficient to cause a shipper to embrace a technology which allows it to move some or all of its demand away from gas. Decisions made by shippers in a given future AA period then feed back into price determination in the following AA periods.

We run the model, then test different depreciation profiles to ascertain whether changing depreciation has a significant impact on the price per GJ of gas used by the shippers who remain on gas in each AA period, and we focus in particular on avoiding shocks to the effective price per GJ of gas used t capture emerging risks as they arise for the shipper.

It is important to note that we are not looking for an optimal depreciation profile; that would be a spurious degree of precision given the scale of future uncertainty we are dealing with. Instead, we are looking for depreciation profiles which improve the position for us and our shippers, to an appreciable degree, from the status quo where we make no change.

Significantly more detail on how the model works is contained in Attachment 6.1, which is itself backed up by expert advice on how to parameterise key drivers in the model, contained in the expert report from CarbonTP at Attachment 6.2.

6.7 Modelling results

We ran a number of different trials of different depreciation profiles using our tilt function approach which brings forward depreciation compared to the straight line model currently used. However, none of the tilt function approaches produced what we were looking for, creating too much risk reduction in future and prices which were too high today, or leaving too much risk on the table for future shippers. In particular, even where the tilt function gave similar results to the current AA5 approach for a decade or so, it would apportion too much risk to the late 2050s compared to our AA5 approach which, by virtue of the original 2001 RAB coming to the end of its economic life in the mid-2050s, gives a distinct drop in risk in the latter half of that decade.

As a general proposition, we realised through our work that the simple function form of the tilt function produced smooth curves which, whilst they are appropriate for distribution networks where there are a large number of homogeneous customers, are less well-suited to the small number of large, idiosyncratic customers of a gas transmission pipeline.

A more complex tilt function might better suit transmission pipeline shippers, but runs the risk of overfitting the function to the data we do have in the model and creating a result which performs poorly when it meets the reality we cannot see. For this reason, before attempting more complex tilt functions, we looked at how well our existing depreciation profile performs. The results of this analysis are shown in Figure 6.1 in the context of the effective price per GJ of gas used.

This is, we believe, a reasonably good result; in two of the three major cases we examine, prices decline through time and in the third, they rise during the 2040s (this is due to the expansion of offshore wind in this scenario) before falling with expanding energy demand. Moreover, the AA5 approach has been broadly accepted by stakeholders. Rather than trying to create a more complex tilt function for marginal gain, we consider it more prudent to keep the AA5 approach as being good enough, and then revisit the question again in AA7.

A key lesson which came out of the modelling is the importance of gas as a provider of firming power and the importance of that to the DBNGP in an environment of an increasing share of renewables in energy supply. If a user of gas for, say, process heat electrifies their load, then the energy they require is supplied by the SWIS, not the DBNGP. However, with the increase in electricity load, the SWIS will need more gas for firming power.

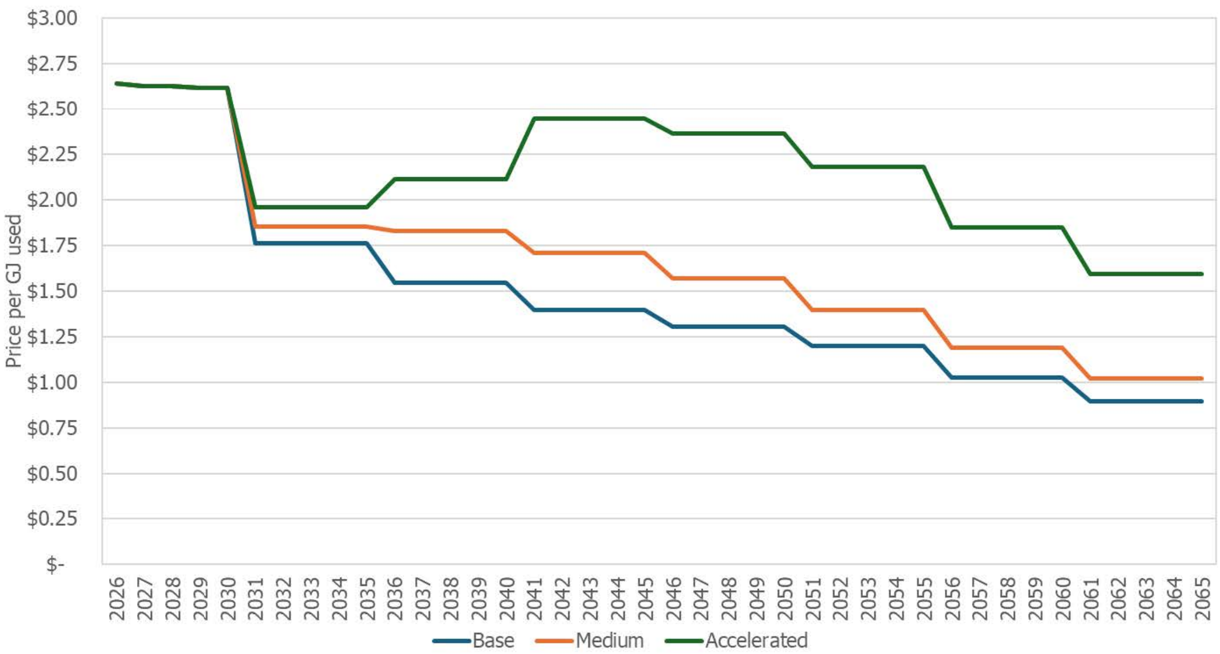
Even in the unlikely event that all current uses of gas were electrified, provided gas remained the most economical way to provide firming power, the DBNGP retains a role; albeit one with a much narrower focus than it plays today.

Based on expert advice on the economics of substitutes from CarbonTP, our modelling assumes that gas does remain the most economical way to provide firming power, and this is a key driver of our results.[2] However, this does not mean that substitutes will never emerge; there are several which are technically viable right now, but are just too expensive.

Any approach which was predicated on gas retaining its role in providing firming power

forever (or indeed, any assumption that any aspect of any regulated infrastructure service lasted forever; this is not simply a

Figure 6.1 Price per GJ under assumed pathways using AA5 depreciation method



[2] The continued operation of major shippers is another, though we do test scenarios where a major shipper fails. In reality, for shippers who remain at a point in time, the presence or absence of other shippers and the effective price per GJ of gas being used for firming power interact in ways which can be complex. This is an issue we discuss in more detail in Attachment 6.1

DBNGP issue) must produce the wrong results. The further into the future one assumes that the firming power role of gas will continue with no economic substitutes emerging, the more likely the resulting analysis will be in error.

We have kept the AA5 approach because it provides an adequate degree of insurance, for both us and for our shippers who remain through time, against the "unknown unknown" of gas for firming power being supplanted by a cheaper substitute. We have not brought forward depreciation because our modelling suggests that we do not need to do so in order to prevent price shocks and because information not in our modelling suggests we do not need any more insurance than we already have. This is an issue which we will pick up again for AA7, when more information about the future is available.

6.8 Summary

Our more detailed and granular assessment of future demand suggests that, although many different options for depreciation might be implemented, the approach the ERA approved in AA5 meets our goals in terms of avoiding price shocks and apportioning risk between ourselves and shippers appropriately in a changing world. It is not perfect forever, but it does give a reasonable result until we can re-examine the issue with new information in AA7.

Our work also highlighted that a key issue in the context is the emergence, or not, of an economic substitute for gas as a provider of firm power. Whilst this substitute remains elusive (it is not in our model), the AA5 approach appears adequate to manage risk. However, the importance of this role for the DBNGP means we will be giving it renewed focus in AA7, when we expect to be better informed by the future after seeing several years of history from currently planned deployments of grid-scale batteries and the impacts of the retirement of coal.

7 Pipeline and Reference Services

The proposed pipeline and reference services for AA6 are generally consistent with those currently provided on the DBNGP.

IN THIS CHAPTER:

- **We have proposed pipeline and reference services generally consistent with those provided in AA5**
- **Full haul, part haul and back haul services will continue to be complemented by a suite of non-reference services**
- **A portion of non-reference service revenue will also be rebated to our customers through reference tariff reductions each year, as in AA5**

We offer various pipeline services to meet the needs of our shippers. The regulatory framework requires that at least one pipeline service be categorised as a reference service.

On 8 December 2023 we submitted our Reference Service Proposal (RSP) to the ERA. The RSP set out all the pipeline services we could offer in AA6, and nominated which of those services should be reference services, with the remainder classified as non-reference services.

Reference services are determined based on 'reference service factors' including demand, substitutability and the usefulness of the service in supporting access negotiations. The ERA made its Final Decision on the RSP in July 2024. The reference services we propose for AA6 are as per the Final Decision, which is consistent with those applied in previous AA periods: full haul, part haul and back haul services. The reference services form the basis for this Final Plan.

As well as the reference services, the following sections also outline non-reference services.

We are required to propose whether a non-reference service is rebateable or not. The proposal must include the proportion of the rebate, how the rebate mechanism operates, and show how much of our costs should be allocated to reference services.

We are proposing a continuation of the approach taken in AA5, with the Pilbara Service to be also made rebateable in AA6.

Finally, we have undertaken a review of the terms and conditions of our reference services, the outcome of which is included in Chapter 15 of this Final Plan. Further details are provided in the attachments to that chapter.

7.1 Regulatory framework

Under changes to the *National Gas Rules* (NGR), published 21 March 2019, we are required to include a list of all pipeline services we can reasonably offer in a RSP at the start of the AA process, and specify which are reference services. Based on the RSP, the ERA decides on reference services prior to our Access Arrangement proposal (this Final Plan).

In considering which services should be specified as reference services, the ERA has regard to reference service factors and the feedback of stakeholders.

The reference service factors (RSFs) (in accordance with NGR 47A(15)) are:

- actual and forecast demand for the pipeline service and the number of prospective users of the service;
- the extent to which the pipeline service is substitutable with another pipeline service specified as a reference service;
- the feasibility of allocating costs to the pipeline service;
- the usefulness of specifying the pipeline service as a reference service in supporting access negotiations and dispute resolution for other pipeline services; and
- the likely regulatory cost for all parties.

The National Gas Rules allow the ERA to allocate costs from non-reference services to reference services. The revenue from the service (once it is sold) is then rebated to reduce the reference tariff (NGR 93 (3)). These services are termed 'rebateable services'.

The rules also state that a service is 'rebateable' if substantial uncertainty exists concerning the extent of demand for the service or the revenue to be generated from it (NGR 93 (4)(b)).

7.2 Stakeholder engagement

We have engaged extensively with stakeholders on our proposed reference and non-reference pipeline services.

In December 2023, we published our Reference Service Proposal (RSP), which we submitted to the ERA incorporating the feedback we received through our engagement on a draft version.

Shippers generally agreed that it was appropriate to continue with the current three reference services in AA5. This was on the basis that the reference services continue to reflect the key services demanded on the DBNGP, noting other pipeline services reflect the bespoke requirements of certain shippers (which also have largely unpredictable demand, costs and revenue).

The ERA undertook its own consultation process which culminated in its decision on our RSP on 1 July 2024. It approved the same reference services and other haulage non-reference services as we had proposed and required that Data services and Storage services continue to be provided in AA6.

A summary of all customer and stakeholder feedback regarding pipeline services, and how we have responded, is summarised in Table 7.1

7.3 Pipeline services

Consistent with the ERA's decision on our RSP, we are proposing to offer three reference services and nine non-reference services in the AA6 period. These are shown in Table 7.2.

Table 7.1: Customer and stakeholder engagement on pipeline and reference services

Topic	Customer and Stakeholder Feedback	Our Response
Pipeline and Reference Services	**Stage 1 & 2 Engagement: Developing our Plans**	

	• Shippers generally supported the Draft Reference Service Proposal (RSP) and agreed to the three proposed reference services.
	• We received one written submission which suggested to:
	  • consolidate all firm and interruptible services into just two service offerings;
	  • reclassify our interruptible services as reference services;
	  • extend the Pilbara Service to include the Perth Basin; and
	  • reinstate pipeline storage services and data services that were no longer proposed to be offered.
	• At the Roundtables, Shippers asked:
	  • if tariffs would be fixed for the entire AA6 period and the impact of rebates on annual tariffs; and
	  • About the pipeline's capability to accept alternate gases to natural gas.
		• We published information summarising proposed services on our online engagement portal, Gas Matters.
		• We responded directly to questions regarding our services in roundtables and explained that:
		  • it was likely that tariffs would continue to be adjusted for 70% of the 'rebateable service' revenue received and that demand for the services remained unpredictable;
		  • other gases could be injected into the pipeline subject to meeting gas specifications, noting that there are currently no such plans for this to occur.
		• We met directly with the individual Shipper that made a submission about our RSP.
		• Our Final RSP incorporated our responses to issues raised regarding our services, including that:
		  • the distinction between each of the reference services is applied as a practical way to define the specific extent and direction of services contracted for, whether they are full or part haul and forward or back haul;
		  • non-reference services, including interruptible services, do not meet the reference service factors (RSFs) because they are tailored to meet specific Shipper needs;
		  • extending the Pilbara Service to include the Perth Basin would increase its cost and there was limited additional support for this option from Shippers;
		  • data services were in low demand and that changing operational pipeline dynamics meant that we can longer offer storage as a firm service.
		• We submitted our final RSP to the ERA in December 2023.

	Stage 3 Engagement: Draft Plan Consultation	
	• The ERA published a notice on 9 February 2024, establishing its own consultation on the Draft RSP. It posed various questions, including about the removal of the Data and Storage Services and non-reference service classifications.	• We made a submission to the ERA's notice and maintained that the non-reference services do not meet the RSFs, and that the changing operational dynamics on the pipeline would make the demand for them more predictable rather than less predictable. • We noted that we could continue to offer the Data Service and the Storage Service but that the latter would be on an interruptible basis only. • Our Draft Plan reflected the decision by the ERA on our RSP, dated 1 July 2024.
	Stage 4 Engagement: Refining our Plans	
	• Shippers wanted to know which services would be rebateable and the associated impact on tariffs.	• We propose in our Final Plan that the same non-reference services be rebateable as in AA5 (Spot Capacity, Peaking, Other Reserved and Backflow Services) with the addition of the Pilbara Service, and that the rebate portion of revenue applied to reduce the reference tariff continues to be 70%.
	Final Plan Outcome	
	• Our proposal for Full Haul, Part Haul and Back Haul Reference Services is consistent with the current Reference Services and has been agreed by the ERA. • Our other pipeline services reflect feedback we received on our service offerings and have also been agreed by the ERA, with the revenue for all haulage non-reference services planned to be 'rebateable'.	

Table 7.2: Pipeline services

Pipeline services	Service description
Reference Services (descriptions applicable to Reference and Negotiated Shipper Contracts)	
Full Haul T1 Service	Forward Full Haul (subject to available capacity) with outlet point downstream of CS9, regardless of the location of inlet point upstream of MLV31
Part Haul P1 Service	Forward Part Haul (subject to available capacity) with the inlet point upstream of the outlet point, regardless of the location of the outlet point, and is not a Full Haul Service
Back Haul B1 Service	Back Haul (subject to available capacity) service where the inlet point is downstream of the outlet point
Non-reference Services	
Spot capacity service	Allows access to gas transmission capacity on a day ahead basis where available via auction (subject to available capacity)
Pipeline impact agreement (PIA)	An agreement specified under the Gas Supply (Gas Quality Specifications) Act 2009 developed to allow gas producers to supply broader quality gas in Western Australia
Data service	A service developed to assist gas marketers in providing gas allocations on Shippers' behalf on the DBNGP (subject to operational availability)
Inlet sales agreement	A pipeline service that facilitates the trading of gas between Shippers at a single inlet point on the DBNGP (subject to operational availability)
Other reserved service	A suite of interruptible services offered on a bespoke basis to Shippers with new projects and/or uncertain demand, often ahead of a firm service. The services have a reservation charge but exclude T1, P1, B1 and spot capacity.
Pilbara service	The Pilbara Service is an interruptible transportation service on the DBNGP where deliveries are within the Pilbara Zone (between I1-01 and MLV31 includes I1-01 and MLV31)
Peaking service	A pipeline service where a Shipper can obtain additional peaking limits to those set in standard terms
Storage service	A Park and Loan service, permitting limited gas storage in the DBNGP, and/or taking additional gas from the DBNGP when required (subject to operational availability)
Backflow service (Ullage)	A bespoke capacity service where gas is required to be delivered to the Karratha Gas Plant

7.4 Rebatable non-reference services

For non-reference services, the ERA must determine whether revenue earned from these services is either kept by the pipeline in its entirety, or whether some revenue is 'rebated' to shippers, or where demand is more certain, take account of the service in its cost allocation approach.

The rebate compensates reference service customers for pipeline service costs that are attributable to rebateable services, but which have not been directly allocated to customers through the determination of our revenue allowance in the building block model.

Consistent with the ERA's Final Decision for AA5, we have rebated a share of the annual revenue earned from four of our non-reference services: the Spot Capacity Service, the Peaking Service, the Backflow Service (Ullage) and the Other Reserved Service.

The ERA determined for AA5 that demand and revenue was sufficiently uncertain for these services to be rebateable.[3] The same decision applied in AA4 for Spot Capacity and Other Reserved services (noting Peaking and Backflow Services were not yet available at that time).

Park and Loan, Pipeline Impact Agreements, Data Services, Inlet Sales and the Pilbara Service were deemed to be non-rebateable (see Final Decision Table 8 pp 70-71).[4]

In the AA5 Final Decision for rebateable non-reference services, the ERA determined that:

- The Spot Capacity Service is limited by available capacity on a given day, it is sufficiently uncertain that it meets the requirements of NGR 93(4) (see Final Decision [277] to [279]).
- The Peaking Service, given that it is a new service, is subject to substantial uncertainty and that AGIG could have little understanding of how the service will actually be used (see Final Decision [289]). It noted that uncertainty should reduce over AA5 as shippers actually make use of the service (Final Decision [290]).
- The Backflow Service, given its nature in respect of its unique circumstances and availability, is sufficiently uncertain to be deemed rebateable (see Final Decision [233]).
- The Other Reserved Services represent a suite of services designed for shippers with new projects or some other form of uncertain demand which allow them to obtain an interruptible service ahead of moving to a firm service, which makes demand inherently uncertain (Final Decision [247]).

We consider that the demand and revenue outlook for these services continues to be uncertain in AA6.

- Spot and Other Reserve Services are inherently uncertain, as they relate to available capacity or the bespoke needs of new projects.
- Demand for the Peaking and Backflow Services, which were first introduced in this AA5 period, are also highly unpredictable. We provide further evidence of the variation in demand for these services in confidential Attachment 7.1.

In addition, we consider that there is enough evidence in AA5 to suggest that demand for the Pilbara Service is also sufficiently uncertain to compromise accurate forecasting. For this reason, we propose that the Pilbara Service is also a rebateable service in AA6. The significant variation in demand for this service is also shown in Attachment 7.1.

7.4.1 Rebate portion

We are proposing no change to the portion of rebateable services revenue to be rebated back to shippers in AA6 from that applied in AA5.

The AA5 rebate portion is 70%. This means tariffs in each year are adjusted to return 70% of the revenues earned from the provision of rebateable non-reference services to shippers via lower tariffs. The ERA's reasoning in approving this rebate amount is set out in the AA5 Final Decision as follows (see [1962] to [1964]):

> *The ERA considers that the AER's final decision considerations of the Roma to Brisbane Pipeline access arrangement are applicable to the DBNGP access arrangement. That is, like the service provider of the Roma to Brisbane Gas Pipeline, DBP will incur incremental costs when*

[3] ERA, *Final Decision on proposed revisions to the Dampier to Bunbury Natural Gas Pipeline access arrangement 2021 to 2025*, 1 April 2021 (ERA Final Decision AA5) [1854-1863].

[4] Note that Seasonal Services, Metering and Temperature Services and Odorisation Servies were deemed as ancillary services and are not considered further in AA6.

providing the rebateable services and should therefore be able to keep some of the revenue earned from these services.

The ERA considers that the amount of revenue to be kept by DBP should be such to:

- Allow DBP a reasonable opportunity to recover at least the efficient costs associated with providing the rebateable services.
- Incentivise DBP to maintain the provision of rebateable and other pipeline services and to respond to customer needs and charge efficient tariffs.

As indicated in the draft decision, the ERA considers that the AER's final decision for the Roma to Brisbane Gas Pipeline and the ERA's approval of DBP's proposed E Factor incentive mechanism support DBP's proposal to retain 30 per cent of the revenue generated from the sale of rebateable services and to return 70 per cent back to customers (that is, 70 per cent being the "rebateable amount").

Very little has changed in the four years since this decision was made. We therefore propose to continue the rebate portion of 70% to Shippers in AA6 because:

- it appropriately balances the allocation of efficient costs between rebateable and other services;
- our E-Factor (operating expenditure efficiency sharing scheme) rebate proportion remains at 70%;
- consistent with established regulatory practice where the AER applies a 70% rebate portion to the Roma to Brisbane Pipeline; and
- provides a reasonable incentive for us to continue to provide the services.

7.4.2 Reference service cost apportioning

For remaining non-reference services which are not rebated, we propose to apportion a share of costs to them which is deducted from our revenue allowance. This is consistent with the approach applied by the ERA in AA5.

The ERA outlined its determination of how to allocate costs between reference and non-reference services in [1832] and [1863] of its AA5 Final Decision, and summarised this approach in [292]:

> *There is no need to allocate costs to rebateable non-reference services. The NGR require DBP to rebate a portion of the revenue earned from the sale of rebateable services. The rebate compensates reference service customers (via a reduced reference tariff) for costs that are attributable to rebateable services, but which have not been directly allocated to customers using the services. As such, no allowance for demand for rebateable non-reference services needs to be made in the building blocks used to determine the total revenue requirement, and hence the reference tariffs, for AA5.*
>
> *The allocation of efficient costs between reference and non-reference services for the purpose of determining reference tariffs should be based on a revised allocation ratio of 99:1. That is, 99 per cent of revenue is expected to be derived from reference services and rebateable non-reference services, with the remaining one per cent derived from the provision of other non-reference services (that are not rebateable).*

For the first three years of AA5, the revenue earned from these non-reference services (excluding the Pilbara Service which we are proposing as a rebateable non-reference service in AA6) was $5 million[5] out of a total reference and non-reference service revenue of around $1,000 million[6]. Therefore, the share of non-reference services in total revenue (reference plus rebateable non-reference plus non-reference, as per the ERA approach) is roughly 0.5 percent of the total.[7] This means that,

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[5] Revenue taken from DBP Regulatory Information Notice submitted to ERA 31 May 2024

[6] Ibid

[7] The ERA nets out the attribution of fuel gas to the non-reference services by multiplying the percentage of non-reference services by the cost of fuel gas. In this instance, the proportion is, to two decimal places, 0.47 percent, so the ERA could simply use 99.6:0.4 and make no fuel gas adjustment in the tariff model if it wished to simplify its calculations. The figure of 99.5:0.5 in the main text is before any fuel gas adjustment and rounded up to one decimal place.

rather than a ratio of 99:1 as in AA5, the allocation of efficient costs between reference and non-reference serves should be at a rate of 99.5:0.5.

7.5 Summary

We propose that the reference services for the DBNGP in the AA6 period remain consistent with those applied in the AA5 period. The ERA accepted the reference services in July 2024 and most of our customers have also supported this approach.

In AA6 we shall offer three reference and nine non-reference services, as listed in Table 7.2.

In respect of the nine non-reference services, we propose that Spot Capacity, Pilbara, Backflow, Peaking and Other Reserved Services be rebateable.

Continuing the approach approved in AA5, we propose that the rebateable services be rebated through a reduction in tariffs during the subsequent year (as required by the National Gas Rules) in the proportion of 70:30 in favour of Shippers.

The non-rebateable non-reference services represent around 0.5 percent of our revenues, and we are therefore planning for a 99.5:0.5 allocation of costs between reference and other non-reference services.


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8 Operating expenditure

We are maintaining an efficient operating program for our customers in a challenging higher cost environment

IN THIS CHAPTER:

- **Our 'controllable' operating expenditure performance in AA5 is estimated to be just 1% higher than the benchmark allowance despite significant labour and other cost pressures in the latter years of AA5**
- **Our total opex forecast in AA6 is an increase of 20% on our AA5 performance, reflecting a continuation of higher costs in recent years**
- **Despite higher costs, we are committed to maintaining the safe, reliable and high-quality service our customers value and demand in a prudent and efficient manner**

We incur operating expenditure (opex) to undertake activities that allow us to safely, reliably and efficiently operate and maintain the DBNGP. Opex also underpins our customer experience and our healthy, safe, engaged and skilled workforce.

Our hybrid top-down and bottom-up approach to forecasting opex for AA6 is consistent with the ERA-endorsed approach applied in AA4 and AA5.

The following sections outline this approach, key drivers of expenditure and our performance relative to benchmark in AA5. In addition, the sections outline how we ensure the opex we incur is efficient. All figures quoted are dollars of December 2024, unless otherwise labelled.

8.1 Regulatory framework

Our forecast opex must reflect that incurred by a prudent gas pipeline business, acting efficiently and in accordance with good industry practice to achieve the lowest sustainable cost of providing Reference Services to our customers.

Any forecast or estimate must be reasonable and the best forecast or estimate possible in the circumstance.

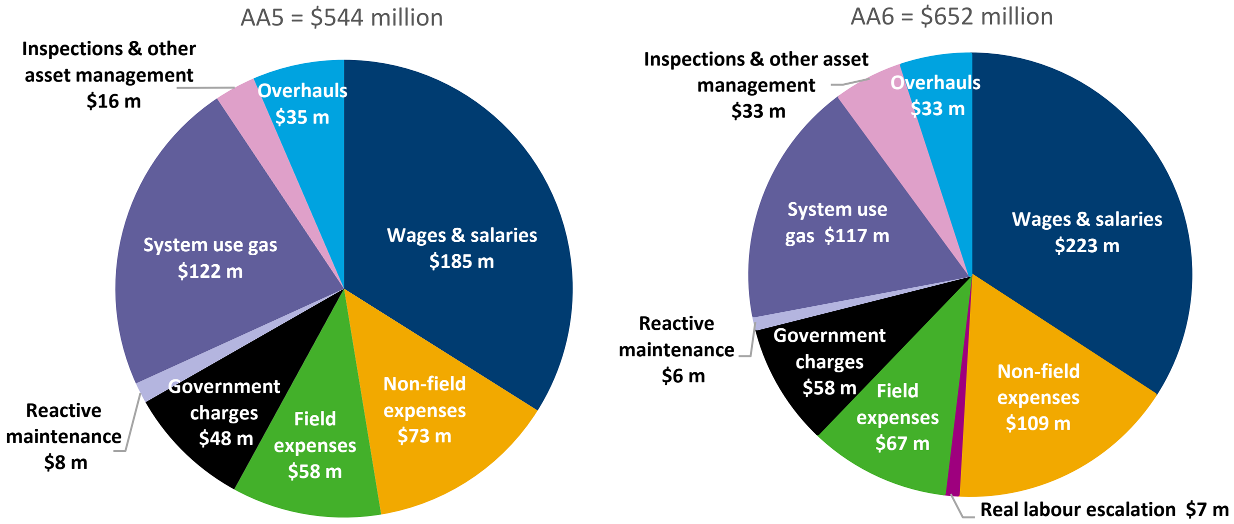
8.2 Overview

Our forecast opex for AA6 is $652 million over the five years. This is an increase of around $109 million (or 20%) compared to our actual performance over the current AA5 (2021–25) period.

A tight labour market and other wages and salary expense pressures (such as the legislated requirement for higher superannuation contributions), as well as unavoidable increases in insurance, utility, field, rental and other costs, have contributed to a large share of the cost increases (accounting for $45 million and $27 million respectively).

The increase is also driven by higher 'inspection and other asset management' item costs (for

Figure 8.1: Total forecast AA5 and AA6 opex by category ($Dec 2024)



critical inspection, safety and other asset management related activities). Expenditure for inspections can vary significantly from one AA to the next to align with Australian standard requirements.

Altogether this expenditure category accounts for $17 million of the increase in opex.

We also have an uplift in our IT capability (accounting for $22 million of the projected increase) to ensure we can continue to sufficiently address operational risks in IT and operational technology (OT) to our business and meet customer and stakeholder technology-related needs. Of this uplift, we are proposing $10 million in additional opex for our Software as a Service (SaaS) and Platform as a Service (PaaS) cloud-based needs, which is consistent with the AER's guidance on the appropriate classification for this type of expenditure.

The forecast increases in insurance and IT expenses are evident in higher non-field expenses shown in Figure 8.1.

8.3 Stakeholder engagement

Our Final Plan is informed by feedback from our stakeholders on our Draft Plan and other engagement activities. Chapter 5 summarises our engagement program and how we have used feedback to inform our plans.

Respondents to our Draft Plan raised two key issues related to our opex forecasts. First, they sought more information on the reasons for the cost increases in our opex forecasts.

Second, we were asked whether we had considered the impact of an increased reliance for firming on gas with units running harder for shorter periods of time and more volatility of demand presented by renewable output swings.

In general, our engagement activities to date have reinforced how stakeholders highly value the current levels of reliability and would be concerned if these were to change, including due to challenges associated with changing operational dynamics on the pipeline.

There also appears to be acknowledgement that the economy post COVID has presented difficult cost pressures.

In our roundtable meetings, Shippers were broadly comfortable with our opex estimation approach for AA6, plus the reasons for higher opex in some categories. They had questions regarding labour costs and some category costs, such as for system use gas (SUG), which we have further considered.

Table 8.1 summarises our engagement on our opex forecasts and responses to the issues raised by stakeholders.

Table 8.1: Summary of customer and stakeholder engagement on our opex forecasts

Topic	Customer and Stakeholder Feedback	Our Response
	Stage 1 & 2 Engagement: Developing our Plans	
	• Shippers were supportive of our proposed opex approach and initial draft forecast for our AA6 opex needs. • Shippers requested further details on our specific plans in our Draft Plan.	• We provided preliminary AA5 performance and AA6 expenditure forecasts, noting the base year was based on budget estimates for 2024 only.
	Stage 3 Engagement: Draft Plan Consultation • **Do you support our approach to forecasting opex? Is there sufficient information to understand our proposals and the basis of costs included?** • **Do you support our proposed input cost assumptions? If not, why?** • **Do you think the forecast level of opex is prudent and efficient, particularly given the current cost environment?** • **Do you have any other feedback on our opex forecast for AA6?**	

Operating Expenditure	• In response to our Draft Plan, one Shipper recommended consideration of the impact on opex and particularly our turbines from an increased reliance from firming on gas.
	• Shippers sought further information generally on the proposed spending increases in AA6.
	• In Roundtables, Shippers also sought further information on:
	  ◦ our insurance for assets.
	  ◦ SUG modelling for AA6 including higher gas contract costs and the impact from the Waitsia project and the potential Compression Reduction Project.
		• Our Draft Plan AA6 opex forecast of $606 million was based on 2024 budget estimates for the base year only.
		• We indicated that estimates would be revised once nine months of actuals were available, closer to submission of the Final Plan.
		• We reviewed our SUG forecasts to account for the impact from the increasing need for firming and adjusted some model inputs accordingly (including related to transient behaviour and the use of CS10 units).
		• We advised that expected insurance premium costs would feed into our base year forecast for 2026 but that estimates would need to be reviewed further because the insurance policy is renegotiated annually and renewed in September, and we were awaiting a final report on expected premium costs from our insurer.
		• We clarified that the impact of the Backflow throughput on compression needs had been considered in the SUG forecasts and that the potential SUG savings from the Compression Reduction Project had not been factored into the Draft Plan because it was not yet approved for progression.

	Stage 4 Engagement: Refining our Plans	
	• In response to further revised opex forecasts, Shippers acknowledged the higher cost environment but sought further information about the proposed increase in labour and other costs in AA6. • In a Roundtable it was also asked whether information on staffing levels would be provided with the Final Plan.	• We provided an update at Shipper Roundtable No. 5 on opex forecasts which were revised up to $633 million from the Draft Plan for three quarters of actual expenses then available for 2024 and other further revisions to estimates. • In addition, we noted that our costs have been rising due to labour market pressure but also due to the impact of the reclassification of labour expenses from capital projects (as was noted in the Draft Plan) and the market pressures on our field, utility, insurance and other expenses.

	• We also advised that further information on labour cost increases (including staffing levels) would be provided in the Final Plan and/or made available to the ERA, as required. • For the proposed increase in our Inspections and Other Asset Management category of expenses, we outlined the need for the program of inspections and other works to maintain the safety and reliability of the pipeline.
	Final Plan Outcome
	• Our opex proposal continues to be responsive to customer needs for a strong focus on operational issues which is important for safety, reliability and emergency management. • Our forecasts in AA6 reflect the higher cost environment that we have begun to experience at the end of AA5, but we have sought to incorporate efficiencies where feasible. • Customers are broadly comfortable with our forecasting methodology which has been endorsed by the ERA in the past. • We have supported our forecasts with business cases and other sources of evidence.

8.4 How we develop our opex forecast

There are two different methods we use to forecast our opex over AA6. For most opex categories, we have applied a 'base year roll-forward' approach.

For three other opex categories: SUG, turbine and gas engine alternator (GEA) overhauls, and inspections and other asset management works, we use a bottom-up approach. This approach considers the quantity and cost of activities required over the five years.

The hybrid approach is consistent with the ERA's preferred forecasting method applied in AA4 and AA5.

Under the top-down component of our approach, the latest revealed cost is used as a base for future costs. The latest revealed costs by the time prices are set for AA6, and therefore our 'base year', is 2024.

We also make adjustment to the base year costs for some opex categories where it is prudent to do so.

The next step in the base year roll-forward approach is to consider any cost increases or decreases that are applicable in AA6 due to changes in legislation, regulatory obligations or new activities. These are referred to as 'step changes'.

We are proposing four step changes from 2026 for insurance and IT.

Finally, real cost escalation is applied to those cost categories which grow at a faster rate than inflation. Consistent with the approach in AA5, we apply real cost escalation to labour costs.

We then add our separate forecasts of:

- SUG, which is a function of quantity required and forecast gas price;
- turbine and GEA overhauls, which is a function of unit run hours and costs per unit; and
- the value of pipeline, mainline valve and station inspections, other minor pipeline works plus a small amount for decommissioning activities and health and safety initiatives, which are generally all non-recurrent and a function of the number of activities/initiatives required and cost per activity/initiative.

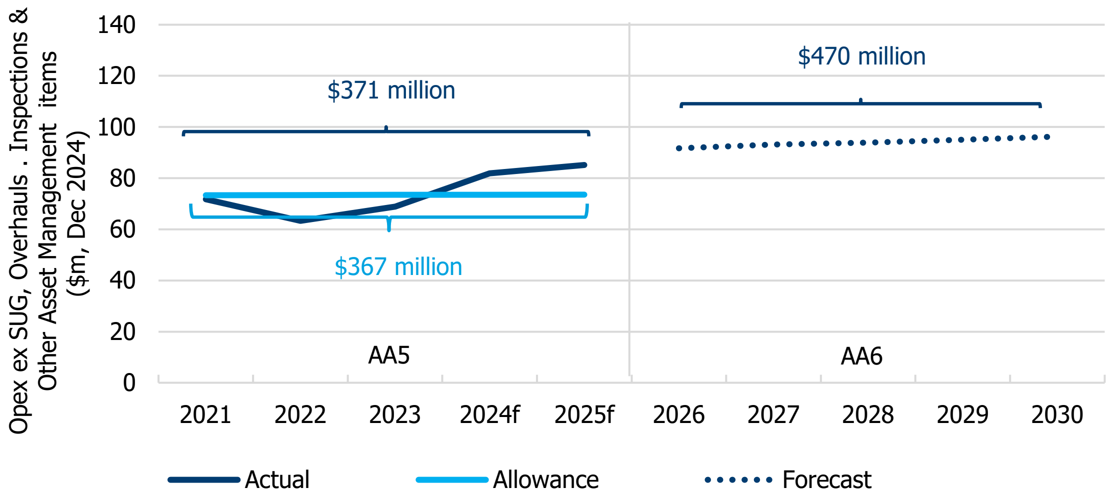
8.5 Key drivers in AA6

We will maintain our strong safety, reliability and customer service, within our opex forecasts in AA6.

8.5.1 Delivering for customers

Our opex proposal delivers for customers by ensuring we are funded to undertake asset maintenance as required by Australian Standards and our asset management plans. Our other proposed initiatives, such as the uplift in our IT capability (including related to the new Transmission Billing System) will directly benefit our customers and ultimately, help to ensure our

Figure 8.2: AA5 and AA6 forecast 'controllable' opex performance ($million, Dec 2024)



strong safety, reliability and customer service performance.

Our customer interactions will continue to be guided by the customer experience aspirations we have agreed to.

8.5.2 A good employer

Our opex proposal will help us provide a healthy, safe, engaged and skilled workforce. We have included an uplift to our human capital management needs in IT which helps us to maintain compliance and security for our staffing needs.

Our asset management initiatives include workplace health and safety program, and our field expenses include employee and contractor training and development initiatives.

8.5.3 Sustainably cost efficient

Our opex proposal shows we are sustainably cost efficient as we have kept:

- real opex in AA5 virtually on par with the benchmark allowance (higher by one percent), excluding SUG, overhauls and 'inspections and other asset management' items ('controllable' opex); and
- our 'controllable' opex in AA6 at similar levels to that incurred towards the end of AA5 (see Figure 8.2), when significant cost pressures have arisen in the market.

8.6 Our AA6 opex forecast

The following sections outline each of the elements of our AA6 opex forecast. Towards the end of the section, we present our opex forecasts by category in Table 8.4.

8.6.1 2024 base year

We are proposing calendar year 2024 as our base year for forecasting much of our AA6 opex. This is the penultimate year of the current AA5 period. This is consistent with regulatory practice across Australia.

At this stage, our forecast in our Final Plan comprises nine months of actual opex and three months of budget opex for 2024. Before our plan is finalised for implementation in 2026, we will adjust the 2024 estimate to reflect the actual opex for 2024.

We are proposing the same controllable opex categories as AA5 for our base year. These are:

- wages and salaries;
- non-field expenses;
- field expenses;
- government charges; and
- reactive maintenance.

We are confident our 2024 base year opex is prudent and efficient because it has been forecast with reference to verified records of actual operating expenditure over 2021-24;

Any variances compared with 2024 have been tested through our budget processes, including for 2025.

8.6.2 Adjustments to base year opex

As mentioned in Section 8.4, we adjust our base year opex where it is not reflective of efficient costs likely to be incurred in a typical year.

The base year costs that we have adjusted are for:

- Wages and salaries (+$3.0 million)
- Consulting (+$0.9 million)
- IT (+$1.7 million)
- Insurance (+$0.7 million), and
- Government charges (+$1.0 million.

The number of required adjustments we are proposing reflect the extent of rising costs that we are experiencing at the end of AA5.

Wages and salaries expenses

Our wages and salaries costs are projected to be higher than in 2024 due to the adjustment for the legislated increase in the Superannuation Guarantee contribution (a further 0.5% by 2026), the cost of the field staff remuneration increase from the second half of 2024 being extrapolated to a full year, and a provision for further filling of vacancies post-Covid. The box over the page explains these adjustments to wages and salaries expenses and explains how they remain efficient under tight labour market conditions and the impact of the update to our internal charge out rates for DBP staff.

Consulting costs

We take a five-year average of our consulting costs, rather than the 2024 base year, due to the volatility that is often experienced in this cost category. This is consistent with the approach approved by the ERA in AA5.

IT costs

Our adjustment to IT base year costs reflects the actual costs of our current IT opex without the adjustments for savings sought in AA5. It is no longer sustainable to absorb these costs in the current economic climate for the business.

Insurance costs

We have directly estimated insurance costs in 2026 given the significant projected increase in real terms since 2024. Our final quarter forecast in 2024

Efficiency considerations for Wages and Salaries expenses in AA6

- **Impact of labour cost rate update**: Wages and salary expenses for the DBNGP have increased by an estimated $8.5 million per year from 2024 because of the reduction to labour charge out rates for DBP staff (which in turn increases the allocation to opex e.g. from capex projects). Attachment 8.3 provides external advice on the prudency and efficiency of the increase and the implications to the business.

- **Comparison of expense levels:** Excluding the impact of this rate adjustment, wages and salaries expenses in 2024 are still forecast to be $4.1 million lower than 2021 levels ($Dec2024). Forecasts in AA6 are also just 10% higher than projected AA5 performance (which includes the impacts of Covid) without the change.

- **Continued need to fill staff vacancies**: there were 302 staff and 24 (8%) vacancies to operate the DBNGP at the end of November 2024, demonstrating the need to continue to fill vacancies to maintain the safety and integrity of the pipeline post-Covid.

- **Field staff remuneration increase:** Wages and salaries expenses have also increased from 2024 by $1.6 million per year with the increase in remuneration for field staff. This change aligns DBP salary rates with market rates in order to promote staff retention and to fill vacancies faster. Confidential Attachment 8.5 provides more information on the market assessment underpinning this renumeration increase.

- **Superannuation contributions:** the legislated requirement for employer Superannuation Guarantee contributions increased by 0.5% per annum from 1 July 2021 to 30 June 2026. This has added another $0.21 million to the base year estimate in 2026.

- **Exclusion of industry-based wages price premium:** We have excluded an industry-based premium from our estimate for real labour cost escalation, despite forecast labour supply in the utilities industry continuing to be very low.

incorporates the higher premiums that were reset from September by our insurer (but not otherwise reflected in the 2024 actuals). This approach is different to the rolling six-year average of our insurance costs which we used to estimate these costs for AA5, because we instead have a direct estimate from our insurer for total premium costs, which are rising consistently above CPI from 2025 (Confidential Attachment 8.4).

The higher premium costs are due to the combined effect of an insurance claim by DBP, asset revaluations and increased risks in the market more generally. We also have a new cybersecurity insurance policy in place.

Government charges

The adjustment to the base year forecast for government charges is for higher utility charges, higher telecommunication charges (such as for the new datacentre) and higher rental expenses for certain facilities, which will occur from 2025. There are no corresponding reductions in government charges expected to maintain the 2024 level or an historical cost average.

8.6.3 Opex step changes

We adjust our AA6 opex for any ‘step changes’ in our costs resulting from changes in legislation, regulatory obligations or new activities.

We have included three step changes in AA6, as follows:

- Further projected above-CPI increases in insurance premium costs from 2027 ($4.9 million in total over AA6),
- New recurrent costs for ‘IT sustaining applications’, including SaaS and PaaS applications ($8.3 million),

- New recurrent costs for 'IT sustaining infrastructure' ($1.8 million), and
- New recurrent costs for various cybersecurity initiatives ($2.3 million).

We have discussed the drivers of our higher projected insurance premium costs over the AA period in Section 8.6.2.

The step changes in IT reflect the most cost-effective options to maintain infrastructure and address outdated applications in a changing risk environment.

In particular, we are leveraging the industry trend of moving to cloud-based infrastructure hosting and application software to ensure it is fit for purpose in the long run.

The additional expenditure for IT sustaining applications is associated with licensing costs for our replacement applications for human capital management and billing, as well as to improve our business processes. We will also incur additional opex related to the provision of Maximo, as it is most prudent to continue it as SaaS, and similarly, for SAP RISE (PaaS), which replaces the existing on-premises SAP licence.

The associated uplift in IT sustaining infrastructure is for the recurrent costs attached to the additional data centre platform.

Finally, our new cybersecurity initiatives seek to address gaps in our IT and OT security, and include recurrent costs for:

- data privacy and security;
- access control – particularly with respect to remote access and consistent control of access to both internal applications and cloud-based applications; and
- maintaining currency of cyber security platforms and services.

These initiatives will expand on capabilities achieved during the AA5 period, continue the ongoing program to manage the cyber security risks to which DBP is exposed, and ensure compliance with the *Security of Critical Infrastructure Act* (SOCI Act).

Our capital expenditure business cases for IT (Attachment 9.5) and our IT Investment Plan (Attachment 9.4) provide more information about the need for each of the uplifts in IT opex.

8.6.4 Input cost escalation

We make further adjustments to our AA6 opex to account for costs that are increasing at a faster rate than inflation (real cost escalation).

We have applied real cost escalation of 0.67% per year to our labour costs.

Consistent with the approach previously approved by the ERA, the appropriate labour cost escalation is calculated by:

- taking the Western Australian Treasury Wage Price Index (WPI) forecasts for the upcoming period (2024–25 to 2027–28 given forecasts currently available), less
- the benchmark inflation estimates for the upcoming period (2024–25 to 2027–28), based on the WA Treasury's Perth CPI forecasts.

Table 8.2 provides the values used in this calculation.

In our Draft Plan we also proposed that an industry-based wage price premium be applied to our labour cost escalation estimate. Although there is evidence to suggest that real wages growth in the utilities industry could exceed that in the broader market over the forecast period,[1] we have decided to exclude a premium, consistent with the ERA's recent regulatory decisions.[2]

Table 8.2: Annual labour cost escalation estimate for AA6

Measure	Value
WA Treasury WPI Forecast	3.31%
Inflation	2.63%
Annual labour cost escalation	**0.67%**

8.6.5 Output growth

We are not proposing to apply an output growth factor to our base year roll-forward opex. Two of our key costs, SUG and overhauls, vary with throughput and are already forecast using a unit cost and volume methodology. Therefore, these costs are already linked to the level of forecast throughput.

8 KPMG, *Wage Price Index Forecasts*, AER, 8 April 2024. See Table 2 (National All Industry WPI and National Utilities WPI) and page 17 (which states "Jobs and Skills Australia forecasts only 11,600 new employees will enter the (utilities) industry (nationally) by 2028, the lowest of all industries."

9 See: ERA, *Final decision on access arrangement for the Mid-West and South-West Gas Distribution Systems (2025 to 2029) – Attachment 5: Operating expenditure*, 8 November 2024, pp 40.42.

8.6.6 Productivity growth

We have considered whether there should be an adjustment to capture the benefits of any potential future productivity gains made by the business during the next AA period.

The necessary dataset for measuring historic industry productivity performance through econometric modelling is not available for gas transmission. Therefore, we have relied upon indicators such as output and capex growth to guide our assessment of the potential for productivity gains over the period.

We consider that the growth and scale forecasts over AA6 in aggregate are weak and as such, are unlikely to materially drive improvements in our productivity.

As discussed in Chapter 13, there is lower throughput forecast compared with the estimates for AA5.

In addition, as outlined in Chapter 9, our forecast capex program is focused on pipeline-sustaining activities, rather than growth activities that could create increasing returns to scale.

A tight labour market and skills shortages will continue to characterise our industry, as identified by KPMG (see footnote 8), and labour market conditions, rather than productivity improvements, will drive real wages growth.

Further, in formulating our opex forecasts, we have already sought to ensure that they are efficient as possible, essentially crystalising future efficiency improvements at the outset of the AA.

For these reasons, we have not incorporated a factor for productivity improvements in our opex forecasts.

8.6.7 System use gas

We are forecasting $116.6 million in SUG costs in AA6. As shown in Figure 8.3, this is similar overall to our projected SUG costs in AA5 of $122 million ($Dec2024).

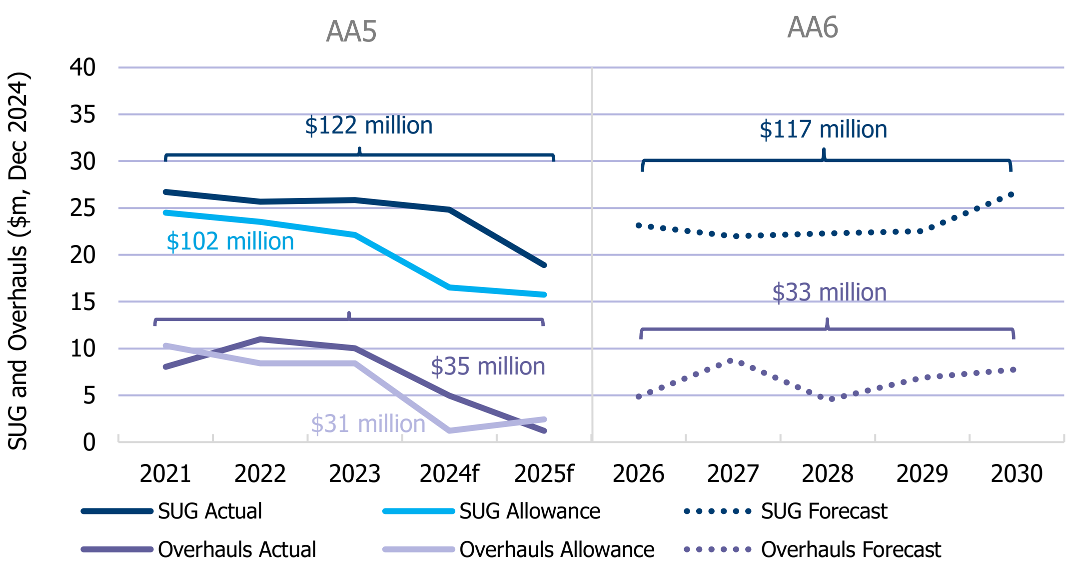
As mentioned above at section 8.4, our SUG costs are a function of forecast quantity and the forecast gas price. For AA6, our lower throughput forecasts, as discussed in Chapter 13, are likely to be partially offset by higher gas prices since we last tendered for our SUG requirements in 2019.

We have forecast lower throughput than in AA5 and our average projected fuel efficiency of 1.2% over AA6 (compared with 1.5% over AA5) reflects that we will be operating on the lower part of the fuel curve.

The forecast quantity of SUG is linked directly to our projected full-haul throughput, and is driven by expected gas quality, the quantity required as compressor fuel to transport forecast throughput and the quantity required for all other operational activities including in GEAs and heaters and vented during normal operation and maintenance activities. The main hydraulic modelling inputs are the same as assumed in AA5 for our SUG forecasts.

The Waitsia project has been further delayed until the end of AA5 and we consider that enough uncertainty remains about the impact on SUG needs on the

Figure 8.3: AA5 and AA6 forecast SUG and overhauls performance ($million, Dec 2024)



DBNGP over AA6 to retain the current modelling assumptions.

We have also revised two provisions in our SUG forecasts for the likely impacts on compressor operation from changing operational dynamics. We have increased the assumption for CS10 use (from 0.3 to 0.5) and we have revised our assumption for transient behaviour from 10 to 15%, reflecting more volatile demand.

Our forecast price is now reduced to around $10/GJ ($Dec2024) based on current market indications for securing gas to meet our forecast SUG quantity requirements in AA6.

8.6.8 Turbine and GEA overhauls

We are forecasting $32.8 million in turbine and GEA overhauls in AA6 (as was also shown in Figure 8.3).

Our turbine and GEA overhaul costs are a function of unit run hours and estimated cost per unit.

In AA6, we will continue to include turbine and GEA overhauls as opex for regulatory purposes. This is consistent with the ERA's preferred treatment of these costs.

Turbine overhauls

Our replacement strategy for our turbine units is to overhaul them after 30,000 run hours in line with manufacturer specifications. After 30,000 run hours, the likelihood and cost of failure of turbine units increases significantly (by around 1.5 times). As our turbines are integral to the safe and reliable delivery of our services, and because there can be long lead times in ordering parts, our turbine overhauls must be carefully planned. In considering overhaul requirements we look closely at the current and projected utilisation of our compressors on the pipeline.

Based on current run hours and utilisation rates for turbine units, we are forecasting to overhaul five units in AA6 with one in each of the five years. We have also allowed for two additional overhauls for premature failure of our turbine units in AA6, as such failures have occurred in both AA4 and AA5, including again, most recently, in late 2024.

Attachment 8.2 includes the business case for our turbine overhaul needs and forecasts in more detail.

GEA overhauls

GEAs are the primary power source at many of our remote facilities, including all compressor stations north of Perth.

Our GEAs are serviced regularly, with major services (overhauls) required at 12,000, 24,000, 48,000 and 52,000 hours.

Based on current run hours and utilisation we are forecasting 10 GEA overhauls in AA6, averaging $0.7 million per annum. This is lower than the average cost of GEA overhauls in AA5 ($1.1 million). Our GEA Engine Replacement capex program (see Attachment 9.5 for the Business Case for this project) has reduced the need for GEA overhauls in AA6.

Our cost estimates for overhauls are otherwise consistent with historical average cost estimates.

8.6.9 Inspections and other asset management

In AA6, we have forecast altogether $33.0 million in asset inspections, decommissioning activities, health and safety initiatives and other asset management needs as part of opex.

Most of the forecast expenditure (almost 80%) is for station and pipeline and MLV inspections (representing allocations of $8.7 million and $17.0 million respectively).

Both inspection programs align with our requirements regarding Australian standards (AS 3788 and AS 2885).

We have a well-established inspection routine for pressure vessel and relief valve inspections and propose to continue this throughout the AA6 period along with the inspection and re-preservation of stored compressor bundles.

We have expanded the station inspection program to cover additional mechanical/rotational routine pressure valve and relief valve inspections. The expanded inspection regime is already yielding results in terms of identifying and addressing previously undetected risks. For example, during AA5 we detected the issue of corrosion under pipework insulation, which has subsequently driven a program of work that has allowed us to address this corrosion issue before it escalates to a point of asset failure.

The pipeline and MLV inspections planned expenditure continues our ongoing inspection program and accounts for the inline inspections (ILI) of piggable pipeline assets which are now due. Our plan includes bringing forward the ILI of the section of Mainline South between Kwinana Junction and Wagerup West to improve our knowledge on the large number of identified defects in this area.

Overall, spending requirements for our inspection programs can vary significantly from AA to AA (depending on when inspections fall due) but are integral to maintaining the safety and integrity of the pipeline.

We have planned eight assets for decommissioning activities at a cost of $0.6 million which avoids unnecessary running costs and mitigates the risks of leaving these unused assets live.

We propose almost $1.0 million for health, safety and environment (HSE) initiatives which continues our health and safety spending on a range of programs (in ergonomics, noise management, leadership in safety and work training permits) at historical average levels plus allows for one new project to monitor VOC (Volatile Organic Compounds) and BTEX (Benzene, Toluene, Ethyl-Benzene Xylene). This new project is consistent with the emerging compliance requirements in this area and is essential for the safety of our staff and the public.

Lastly, we propose altogether $5.6 million on a range of projects aligned with our asset management program to further ensure safety and reliability of our pipeline, with a key focus on:

1) Engineering and Operational Projects (EOP), including GIS mapping and control software updates and the review of critical spares;

2) Management of Change (MoC) projects to address defects or unsafe situations such as corrosion repairs; and

3) Asset preservation including emergency line pipe, equipment and spares that are in storage.

Business cases at Attachment 8.2 provide the context and reasons for the proposed expenditure for our full suite of Inspection and Other Asset Management activities, including the assessment of alternative options to ensure prudency and efficiency in our approach.

8.7 How we will ensure the opex we incur is prudent and efficient

We operate within a framework of external and internal controls which govern the way we fund the day-to-day operations in our business. This framework ensures we are making sound decisions for our customers, our stakeholders and our business.

8.7.1 Our Asset Management Plan, maintenance regime and Safety Case

Our overarching Asset Management Plan (AMP) considers the relationships between asset life/performance, economic returns, operating costs, safety and reliability all within the context of our short, medium and long-term business strategy. For operations, it sets out the asset maintenance regime applied to the DBNGP which supports our vision to deliver for customers, be a good employer and be sustainably cost efficient.

The maintenance regime has been developed over time incorporating regulatory requirements, risk assessment outcomes, substantial operating experience, good industry practice and lessons learned from others.

More specifically, the maintenance regime for identified maintenance tasks outlines the purpose, failure impact, priority, frequency or condition, required tools, spares and consumables, estimated duration and required labour hours by skill, as well as any preconditions such as isolation or availability of alternate equipment. These factors drive planning for the execution of maintenance tasks to minimise the impact of maintenance activities on the safe, efficient and reliable delivery of gas.

We periodically review and update our Asset Management Plan to ensure our maintenance strategies evolve or are amended in response to investigations of equipment failures.

Work instructions for each maintenance activity and asset type ensure the required work is carried out in line with our AMP requirements and safe work practices.

We also have several procedures, guidelines, plans and performance targets which govern the way we operate the DBNGP day to day. These ensure we undertake all operating activities in a prudent and efficient manner, consistent with good industry practice and in line with our vision of being the leading gas infrastructure business in Australia.

The *Work Health and Safety Act 2020* and associated *Work Health and Safety (Petroleum and Geothermal Energy Operations) Regulations 2022* (WA) require us to submit our Safety Case to the Department of Energy, Mines, Industry Regulation and Safety every five years. Our Safety Case is the primary document outlining how we operate the DBNGP in compliance with our obligations under the Act, Regulations and our operating licences. It demonstrates the adequacy of the systems, processes and procedures in place to support us in safely operating the DBNGP.

It also describes the hazards associated with operation, and controls in place to minimise the risk so far as is reasonably practicable. The maintenance requirements set out in our AMP ensures these controls remain available, reliable and effective. Therefore, our AMP is a key part in the Safety Case for demonstrating our ability to adequately control the risks of our operations

Table 8.2: Minimum purchasing requirements

Value	Minimum Requirement
<$100k	One written quote
$100k-$500k	Three written quotes
>$500k	Tender from four vendors

Table 8.3: Delegation of Financial Authority

Role	Budgeted	Un-budgeted
CEO	$5m	$5m (if it fits within overall approved budget)
GM	$500k	Nil
Manager E&OP	$100k	Nil
Project Manager	Nil	Nil

8.7.2 Financial governance

We regularly report our forecast and actual opex through our internal budgeting processes and financial performance reporting. Our performance against internal budgets, prior year spend and approved regulatory allowances is heavily scrutinised, particularly where there are variances or costs are increasing.

Furthermore, our corporate KPIs track our safety, reliability, customer service and financial performance. These performance measures incentivise us to continually seek out ways to outperform our targets, without favouring one area over another (i.e. reporting against all of these measures means we cannot make financial savings to the detriment of safety, reliability or customer service).

8.7.3 Procurement

All procurement activities are subject to our Contracts and Procurement Policy, which superseded our previous Purchasing Policy in December 2023. This policy ensures we continue to carry out these activities in an efficient, cost effective, confidential and ethical manner by:

- ensuring our procurement meets the highest standards of business ethics and integrity; and
- that our contracts and purchases represent value for money.

The Procurement group is the owner of the Contracts and Procurement Policy and is responsible for ensuring it is up to date and appropriately applied in the business.

Table 8.2 outlines the minimum information requirements which must be met, dependent upon the value being procured. All procurement activities exceeding a value of $100,000 generally must be competitively tendered to at least three vendors, over $500,000 requires at least four vendors.

Our Delegation of Financial Authority covers all financial transactions within our organisation. It outlines the financial authority at each level within our organisation, depicted in Table 8.3.

Only the CEO has financial delegation to approve funds for unbudgeted initiatives, and then only if it aligns within the overall approved budget. This approach provides strong financial controls and governance in the delivery of prudent and efficient opex.

8.8 Our performance in AA5

We are forecasting $543.9 million in opex in AA5. Our "controllable" opex i.e., opex excluding those expenses dependent on throughput - SUG and GEA/turbine overhauls - as well as the inspections and other asset management items, is $370.9 million, which is just $3.7 million or 1% higher than our approved allowance for these expenses in AA5. This reflects continued efficiency by DBP under challenging operating and economic circumstances.

Our total SUG costs are forecast to be $19.6 million (19%) above our allowance of $102.4 million. The main driver for higher SUG costs in AA5 has been higher throughput than forecast (which increases the quantity of SUG required).

Our Turbine and GEA overhauls are estimated to be $4.4 million (14%) above our allowance of $30.8 million in AA5. This outcome reflects

- two premature failures of turbines occurring in the period (although our costs are reduced because they were both under warranty);
- higher full haul throughput than forecast (which increases the run hours required across our fleet of turbines and gas engines, and therefore accelerates the time taken to reach the defined run hour parameters for overhauls);
- air freight costs for transportation of turbines to avoid penalties in returning them, if needed;
- air filtration system costs not budgeted for; and
- higher unit prices in the market.

Our Wages & Salaries expenses are estimated to be $16.1 million (10%) higher than the allowance. As was discussed in section 8.6.2, the increase in largely due to the update to our labour cost rates in late 2023 following an internal review of appropriate salary on-costs, and a subsequent lower allocation away from opex.

The COVID pandemic impacted our Field expenses in 2021 and 2022. These have been below the allowance in AA5 over the five years by $9.4 million (14%). The Government charges and Reactive maintenance costs we have incurred have also been lower than the benchmark – by $2.7 million (5%) and $2.5m (24%) respectively – the latter due to the improved reliability of the pipeline services though our planned asset maintenance program.

Non-field expenses are $2.4 million (3%) higher than our allowance due to an uplift in our IT capability following implementation of the 'One ERP' project. In addition, we are facing higher insurance and other supplier costs across the network.

We have also incurred higher 'inspection and other asset management' costs (by $3.5 million (29%) with new projects for the replacement of critical spares and the development of essential training modules for process safety, as well as additional costs associated with water bath heater inspections at three metre stations.

8.9 Summary

Our forecasts for opex in AA6 are summarised by category in Table 8.4.

The key aspects of our opex forecasting methodology are outlined below.

- We have adopted the same opex categories as used in AA5.
- We have applied a base year roll-forward approach for most categories of opex.
- Our 2024 estimate is based on three quarters of actuals and one quarter of budget forecasts and will be updated for full year actuals when available.
- We have adjusted our base year for average consulting costs given the potential for volatility in these costs year to year, consistent with the approved approach in AA4 and AA5.
- We have adjusted the 2024 estimate for insurance costs and included a step change for insurance across remaining years in AA6 given increasing premiums (above CPI), which is supported by information direct from our

insurer (Confidential Attachment 8.4).

- We have also adjusted our base year for further increases in telecommunication charges, utility prices, vendor prices and rental expenses.
- We have included three other step changes for IT initiatives to address cybersecurity risk and embrace cloud-based application and infrastructure solutions which best address other operational risks to the business in the most cost-effective manner. (Attachments 9.4 and 9.5 provide more information on our IT expenditure plans.)
- Real cost escalation of 0.67% per annum has been applied to labour costs using the real cost escalation methodology approved by the ERA in AA5.
- We have not applied any additional productivity growth in AA6 because we do not consider that we can deliver the pipeline services to essential reliability and safety standards without incurring the input costs we have forecast.
- We forecast lower SUG costs in AA6 than in AA5 with lower forecast throughput partially offset by the higher weighted average gas price that we expect to achieve across our SUG supply contracts.
- Turbine and GEA overhauls are based on unit run hours and estimated unit costs per overhaul (expensed for regulatory purposes as per the ERA's preferred approach). Attachment 8.2 includes the turbine overhauls business case.
- The projected revenue need for inspections and other asset management activities is based on a similar costing approach (to overhauls), and is supported by business cases, which explore the most efficient and prudent inspection and asset management approaches (Attachment 8.2).

Table 8.4: AA6 opex forecasts by category ($m, Dec2024)

Category	2026	2027	2028	2029	2030	AA6 Total
Wages & salaries	45.2	45.5	45.8	46.1	46.4	229.1
Field expenses	13.4	13.4	13.4	13.4	13.4	67.1
Non-field expenses	20.2	21.4	21.9	22.7	23.6	109.7
Government charges	11.6	11.6	11.6	11.6	11.6	57.9
System use gas	23.1	22.0	22.3	22.5	26.7	116.6
Reactive maintenance	1.3	1.3	1.3	1.3	1.3	6.3
GEA & turbine overhauls	4.9	8.8	4.5	6.9	7.8	32.8
Inspections & other asset management	4.8	10.4	10.4	3.6	3.7	33.0
Total	**124.5**	**134.4**	**131.1**	**128.0**	**134.4**	**652.5**
Controllable opex total (excludes SUG, overhauls, inspections & other asset management items)	**91.7**	**93.1**	**93.9**	**95.1**	**96.3**	**470.1**

9 Capital expenditure

Our proposed capital expenditure will enable continued strong safety, reliability and service performance into AA6.

IN THIS CHAPTER:

- **An update on the delivery of our AA5 capex program**
- **Our stay in business capex forecast for AA6 including:**
    - **Continuation of existing programs of work on our compressor stations, meter stations and pipeline**
    - **Investments in accommodation along the pipeline to align with the industry standard and reflect our changing workforce**
    - **Gradual integration of renewable generation solutions at our sites**

We incur capital expenditure (capex) to ensure the ongoing safe and reliable supply of natural gas to Western Australian homes and business every day.

The bottom-up approach to forecasting capex for AA6 is consistent with our approach in previous periods, with a strong emphasis on meeting the requirements of our Safety Case, Asset Management Plans (AMP) and Risk Management Framework.

The following sections outline the projects we will deliver in AA6, the key drivers of the forecast and our forecasting approach. We will show how we are performing in AA5 and the measures we have taken to deliver the program of work prudently and efficiently, despite very challenging economic conditions.

Our capex plans are supported by detailed business cases, which have been provided in Attachment 9.5. These business cases describe how the capital programs delivered in AA5 and planned for AA6 are prudent and efficient.

Our forecast capex over 2026–30 is $288 million which is 76 million (36%) higher than the capex forecast for AA5.

All values quoted are dollars of December 2024, unless otherwise labelled.

9.1 Regulatory framework

Our forecast capex must reflect that required by a prudent transmission pipeline business, acting efficiently and in accordance with good industry practice to achieve the lowest sustainable cost of providing Reference Services to our customers.

Forecast capex must also satisfy at least one of several criteria under Rule 79 of the NGR, which includes expenditure to maintain or improve safety, ensure integrity, comply with our regulatory obligations, meet demand on the pipeline or that generates additional revenue that exceeds associated costs.

Figure 9.1: How we develop our regulatory business cases and DBP's risk matrix

RISK MATRIX

Frequency	Impact: Catastrophic	Major	Severe	Minor	Trivial
Frequent	Extreme	Extreme	High	Intermediate	Low
Occasional	Extreme	High	Intermediate	Low	Low
Unlikely	High	High	Intermediate	Low	Negligible
Remote	High	Intermediate	Low	Negligible	Negligible
Hypothetical	Intermediate	Low	Negligible	Negligible	Negligible

People
Environment
Loss of Supply
AGIG Loss
Reputation/Outrage

Recently, a further criterion for expenditure assessment has been introduced to cover expenditure that can assist with meeting WA's emissions reduction targets.

9.2 Overview

We categorise our capex as either:

- stay-in-business capex, which maintains or improves our ability to continue to deliver the services our customers demand; or
- expansion capex, which is required to increase the quantity of services we can deliver to our customers.

In previous periods many compressor station and pipeline assets were refurbished rather than replaced and will reach the end of their technical life in AA6. This necessitates replacement in the next AA period to maintain the safety and integrity of the Dampier Bunbury Natural Gas Pipeline (DBNGP).

9.2.1 Our AA6 Forecast

Our forecast capex over 2026–30 is $288 million driven by the need to:

- undertake preventative works and repairs to protect compressor stations from corrosion and conduct hazardous area rectifications (Compressor Stations Business Case, $10 million);
- replace metering assets, recalibrate/recertify meters and purchase spares to ensure billing accuracy (Meter Stations Business Case, $7 million);
- SCADA hardware and software upgrades (Operational Technology Business Case, $8 million);
- replace ageing and out of date accommodation at two of our compressor stations, install two dongas and build a northern hub in Karratha to ensure that the accommodation we provide to our field staff is fit for purpose, enables attraction and retention of staff, particularly as our workforce demographic changes (Structures and Operational Sites Business Case, $15 million);
- replace obsolete GEA (gas engine alternators) control systems which are over 15 years old and no longer supported by the manufacturer in a program coordinated with GEA Engine replacement with smaller units (Power Generation and

Management Business Case, $18 million);

- install new gas chromatographs and analysers that detect gas composition, moisture and sulphur in response to changing gas flow dynamics driven by new sources of gas (Meter Stations Business Case, $11 million);
- maintain our OneERP and Maximo software with major and minor upgrades (IT Sustaining Applications Business Case, $11 million);
- replace IT hardware including laptops and switches, and transition our data centre to cloud (IT Sustaining Infrastructure Business Case, $6 million); and
- undertake ongoing replacement of vehicles and civil equipment (Fleet and Civil Equipment Business Case, $13 million).

9.2.2 Our AA5 Estimate

In AA5 we estimate a $212 million investment in capex, which is $30 million (17%) above our approved allowance, primarily driven by the need to:

- replace, repair and undertake corrosion prevention works on our compressor stations ($40 million);
- replace a large number of end-of-life metering assets ($19 million);
- replace our northern communications system ($36 million);
- replace and refurbish pipeline and main line valve assets ($15 million);
- replace compressor unit control systems along the pipeline ($18 million);
- maintain a stable set of Information Technology applications that is current and fit for purpose ($38 million);
- refurbish/renovate original compressor station accommodation ($2 million); and
- invest in IT security ($2 million).

Our AA5 capex program was adversely impacted by the pandemic, which disrupted global supply chains. The mismatch between supply and demand has driven both materials and contractor labour costs up significantly across the Australian economy in recent years.

Higher costs are demonstrated by the performance of producer price indexes (PPIs) in Australia since March 2020 (with many industry categories exceeding consumer price inflation over this period) and various public reports on current cost pressures in the economy.[10]

These increases have been particularly felt in Western Australia which closed its borders for almost two years during the pandemic. Constrained supply of contractor labour and materials led to rising costs during AA5, particularly in energy infrastructure, mining and oil and gas sectors. In response to these pressures, we have prudently deferred some projects and insourced where possible to mitigate overspend against benchmark. We explain these measures in more detail in Section 9.9.

9.2.3 Our Capex investment over time

In 2024, the DBNGP marked 40 years of operation and 20 years since its expansion. As shown in Figure 9.2, the capex required to maintain the safety and the reliability of the pipeline has increased over time.

Further, the nature of capital expenditure can be lumpy in nature as particular classes of assets reach end of life at the same time over time.

In the mid-2000s we undertook a large expansion capex program at a cost of $2.6 billion to loop 85% of the pipeline and provide associated compression.

Jandakot facilities and most of the accommodation at compressor station sites were constructed during the first 10 years of DBNGP operations. They are now in poor condition, have fallen below what competing employers offer and pose health and safety risks if not addressed. Inadequate accommodation affects staff morale which leads to high staff turnover, in turn increasing wages costs.

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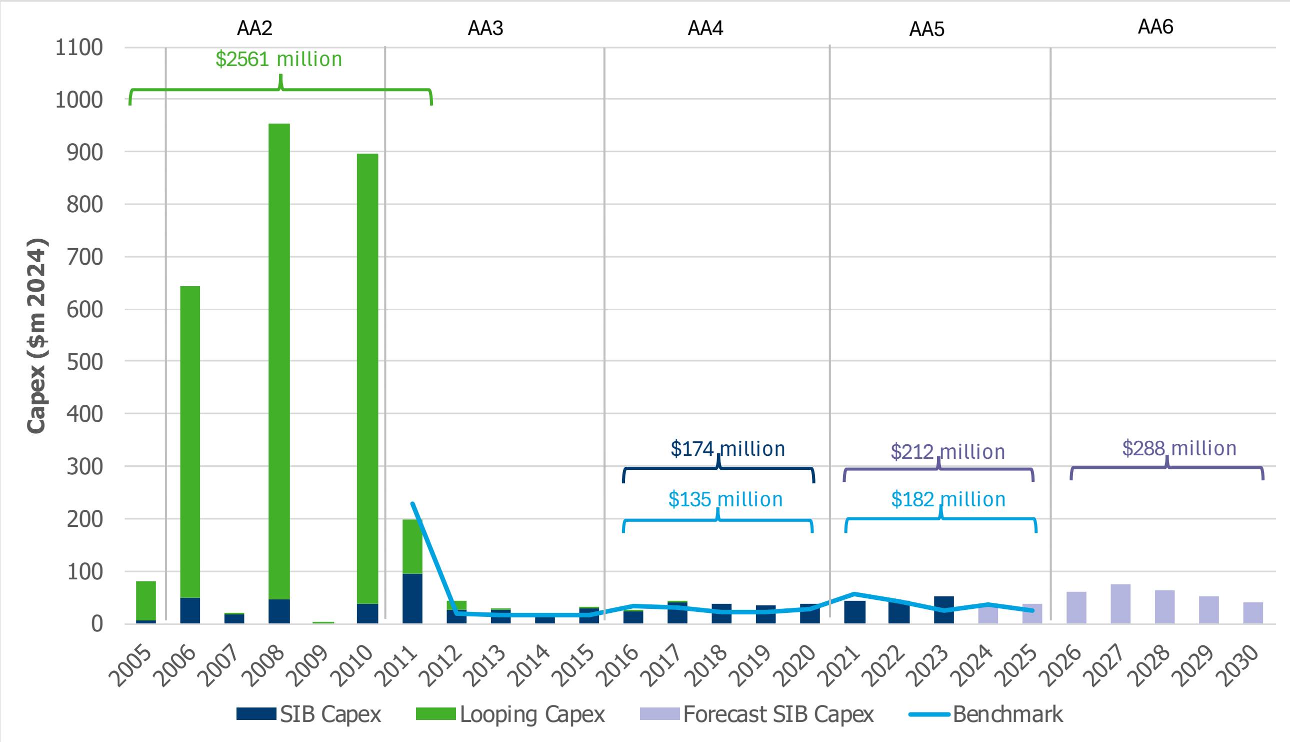
[10] Growth in the ABS PPI (Original) for the Oil and Gas Extraction industrial subgroup was 70% above the CPI from September 2020 to September 2024 (ABS, 6427.0 Producer Price Indexes, Australia, Sept 2024, Table 13), Chamber of Commerce and Industry WA (CCIWA) Business Confidence report (https://cciwa.com/business-pulse/1-in-5-businesses-at-risk-of-closing-downsizing-cciwa-report) and AI Group (https://aigroup.com.au/news/media-centre/2024/untamed-inflation-puts-interest-rate-rises-back-on-the-agenda/).

Figure 9.2: DBP Capex over time (AA2 to AA4 actuals and AA5 and AA6 forecast)



As Figure 9.2 shows, capex in AA6 will be determined by stay-in-business requirements which focus on maintaining or improving our ability to deliver current Reference Services.

Continued investment in the DBNGP is critical to ensure we continue to safely and reliably transport gas to our customers in the future.

9.3 Stakeholder engagement

At the Shipper Roundtables we engaged on key areas of our planning, including our proposed capex.

Our shippers were broadly comfortable with our approach and high-level program in AA6 and asked various questions throughout the engagement stages, including in relation to:

- providing more details on our capex plans and capex forecasting approach;
- whether the compression reduction project would affect the capacity of the DBNGP and how it would potentially affect other business cases;
- whether the compression reduction project would reduce DBNGP emissions;
- deferral of projects such as the Northern Communications Project which we explained had been delayed due to higher than expected tendered costs, which led us to insource the project; and
- the issue of gas specifications and risks of gas flow and quality.

Stakeholders also told us they highly value current levels of reliability and would be concerned if these were to change.

We responded that we intend on continuing the current levels of reliability through the continuation of our capex program into AA6.

In relation to the the compression reduction project (included in our Draft Plan) we advised shippers that we would most likely not proceed in AA6 due to uncertainty around the timing of new supply coming online from the Perth Basin.

We responded that we will propose to install Gas Chromatographs (GC) to satisfy our contractual obligations and in response to stakeholder concerns in relation to gas specification.

The feedback and insights gathered through our Shipper Roundtables are reflected throughout our forecast capex, particularly in the information we have provided on key areas of increased spend, project governance and procurement, and our performance in AA5.

Further information on the feedback we have received from stakeholders can be found in Chapter 5.

Topic	Customer and Stakeholder Feedback	Our Response
	Stage 1 & 2 Engagement: Developing our Plans	
Capital Expenditure	• Shippers were generally supportive of our proposed capital expenditure approach, initial draft forecast or our AA5 performance update, and requested further details on our specific plans in our Draft Plan. • There was interest in the value of a small number of deferred capital projects, including how any interest earned would be used. • Shippers sought information on the Compression Reduction Project including the reduction of gas speed and any emissions reduction. • Shippers requested an update on the Pluto Expansion Project. • Some Shippers indicated concern regarding gas specifications and the risk of gas flow and quality. It was proposed that we recommend changes so the ERA could address this issue.	• We provided detailed information on capital expenditure, including AA5 forecasts and proposed revised AA6 expenditure. • We presented an update on deferred projects, in particular the Northern Communications Project including higher than expected initial tender responses, ultimately resulting in us seeking alternative delivery solutions. We advised that only capex incurred is added to the Regulatory Asset Base. • We also provided an update on the Compression Reduction Project and noted our aim to reduce costs and the carbon footprint without affecting capacity. • We updated the status of the Pluto Expansion project, and its progression in line with the schedule. • In response to gas specifications concerns, we referenced our contractual relationship with Shippers rather than Producers and advised that given our obligations around gas specifications we would propose improving our ability to measure gas purity in the DBNGP. • We noted our intention to engage directly with Shippers regarding flow and quality of gas with a view to consider potential actions.

	Stage 3 Engagement: Draft Plan Consultation • **Do you support our approach to forecasting capex? Have we provided sufficient information to understand our proposals and the basis of the costs included?** • **Do you think the forecast level of capex in AA5 and AA6 is justified?** • **Do you have any other feedback on our capex forecast for AA6?**	
	• At the Roundtable it was asked if we could clarify the reconciliation of actual outcomes relative to benchmarks set for AA5, in particular whether the entirety of the capital allocation had been expended, or is there a transfer of capital to the AA6 period and what implications would this have. • Shippers asked if gas chromatography improvements and off-specification gas liability responsibility should be shifted to the responsibility of the Producers and also potentially DBP if it knowingly accepts an operator's indicated off-specification gas into their asset. • Shippers asked if it should be expected for Producers to provide specific information, adding the current provision of data seemed inadequate. • At the Roundtable Shippers asked if it was feasible to obtain two readings and ensure that the issue could be addressed within six minutes. • Shippers sought further information on the Compression Reduction Project, in particular whether what cost benefit analyses and Net Present Value (NPV) calculations were conducted, timing of next benefits to Shippers and the potential to delay for lower interest rates. Sharing of the business case prior to the Final Plan would be ideal. • Shippers asked whether assets with values not fully realised should be excluded from consideration, and only assets with actual value in use be counted.	• At Shipper Roundtable No. 5 we presented our proposed capex of $413 million, including $123 million for the Compression Reduction Project. • We presented to Shippers on the compressor stations upgrade, the Jandakot redevelopment, new gas chromographs and enhanced pipeline requirements. • We confirmed that the actual capital expenditure incurred for AA5 would exceed the allowance set. We noted the Draft Plan contained further information and confirmed we would look to include more detailed information in this Final Plan. • We commented that we have shifted to new methods with the aim to improve redundancy and transparency, and allowing for timely issue validation and response. We noted that whilst this approach involves some duplication, it enables us to effectively monitor hydrogen sulphide levels, assess issues and respond promptly with detailed insights on legacy inlets. • We acknowledged Shippers' concerns and confirmed the installation of additional monitoring equipment to ensure faster response times and added that this enhanced visibility and minimised risk for Shippers. Producers were not required to provide the same level of information. • We confirmed that it is possible to obtain multiple readings with newer equipment and acknowledged the shortcomings in our current measurement assets which lack transparency, which would benefit Shippers. • We updated Shippers regarding the Compression Reduction Project advising it was in the FEED phase and subject to continued analysis. • We confirmed that a comprehensive review of their Regulatory Asset Base (RAB) was carried out in AA5 to ensure accurate asset valuation and usage.

	Stage 4 Engagement: Refining our Plans	
	• Shippers sought clarification regarding gas chromatography, and impact on nameplate capacity.	• We presented at Roundtable No. 5 details regarding the $123 million reduction to capital expenditure proposals, and provided updates on the Jandakot redevelopment, IT infrastructure budget and compressor station upgrades. • We explained the merits of compression reduction on the pipeline, noting the uncertainties of Perth Basin developments means further work must be conducted to fully understand the need, risks, costs and benefits of decommissioning compressor stations and looping the DBNGP. This means we are unlikely to include this project in our Final Plan. • We also addressed Shippers queries regarding gas chromatography improvement and off-specification liability, adding we have included $7.8 million in the forecast for new GCs at KGP, Macedon, Wheatstone and Gorgon, replacement GCs at VI and Pluto, and new analysers for moisture, H2S and total sulphur (Waitsia – H2S and total sulphur only). • We discussed the overall quantum of the capex forecast and that is higher than in previous periods due to a number of assets on long-term replacement cycles coming due for replacement in AA6 and that the cost environment changed in AA5 which led to higher costs in the AA6 forecast.
	Final Plan Outcome	
	• Our stay in business capex forecast proposal includes continuation of existing programs of work on our compressor stations, meter stations and pipeline, investments in pipeline accommodation and gradual integration of renewable generation solutions. • Our proposal delivers against customer expectations that current levels of reliability are maintained. • This Final Plan provides supporting information on capex and evidence of our governance arrangements that support costs being efficient. • Customers are comfortable with our approach and level of capex.	

9.4 How we develop our capex plans

This section describes how we develop the key elements of our capex forecast, being the proposed activities and forecast costs.

9.4.1 Determining our investment priorities

The programs and projects in our capex plan are built up from our AMPs and our Safety Case. Some of these are continuing programs of work, such as dry gas seal and valve replacements, hardware and software upgrades and cathodic protection. Others are periodic projects, including the replacement of turbine exhaust units, gas engines alternators (GEA) and GEA control systems, as well as a major SCADA system upgrade.

Additionally, we will undertake discrete projects, such as installing GCs and analysers and the redevelopment of our Jandakot facilities.

Projects and programs are proposed by our asset managers for consideration of inclusion in AA6, including the drivers of proposed projects and determination of optimal phasing based on risk (to the business, people, environment, reputation, asset damage, loss of supply and financial losses).

Phasing is critical to the successful delivery of the capex program, i.e. it should not contemplate the majority of the work being performed in the final years of the AA period due to the risk of capex program slippage.

Highly ranked projects and programs are summarised into regulatory Business Case categories for consideration, comparison to prior spend and full options analysis. Lower ranked projects are deferred.

More information about our project governance is provided below in Section 9.7. Importantly, Shippers and stakeholders can provide feedback on our capex plans in response to this Final Plan in writing or in future Shipper Roundtables.

9.4.2 Forecasting efficient costs

Since we released our Draft Plan in July 2024, we have continued work on confirming and refining our cost estimates.

There are three specific methods we have used to forecast capex, depending on the nature of the work. These methods consider actual historic costs along with specialised engineering advice and market testing through vendor quotes and expressions of interest.

For ongoing activities that are volume driven we estimate costs by identifying the volume of work to be undertaken and applying a historical average unit rate (typically for the last three full calendar years).

Where the program of work is delivered externally, consideration is also given to the specific projects and locations where historical work has been delivered, particularly given the geographical isolation of much of the DBNGP.

For periodic programs of work (those that may not be required in every regulatory period) cost estimates have been developed with regard to historical costs (over a longer time period) for the same, or similar programs of work. Where the program of work has not been delivered for some time (for example, replacing assets at the end of their useful life) we may also have regard to updated vendor and contractor quotes.

For one-off, new or discrete projects which have not been required in the past, efficient costs are determined through a competitive tender process. Where a competitive tender process has not yet been undertaken, an expression of interest is undertaken or a bottom-up cost estimate is produced.

A bottom-up cost estimate will be based on recent works where the project is sufficiently comparable, using the most recent unit rates or actual costs. Where the work is unique or greater than $5 million, an efficient cost estimate is developed using internal estimates from different engineering disciplines or using external engineering or building specialists.

Further detail on each of our forecast capex cost estimates is outlined in Attachment 9.7, Cost estimation methodology 2026-30.

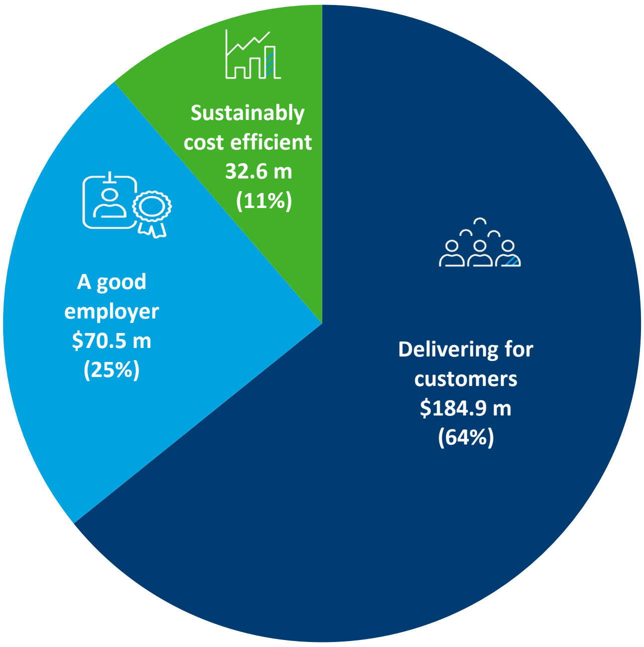
9.5 Key drivers

Our capex in AA6, depicted in Figure 9.3 (next page), aligns with our vision of:

- delivering for customers;
- being a good employer; and
- being sustainably cost efficient.

64% of our total capex in AA6 is aligned to our vision of delivering for customers, 25% on being a good employer and 11% is focused on being sustainably cost efficient.

Figure 9.3: Total AA6 capex by driver ($Dec 2024)



9.5.1 Delivering for customers

We will invest $185 million in projects and programs that will deliver for customers. We will maintain our strong safety and reliability performance and provide a modernised customer experience. This is $9 million more than the $176 million we proposed in our Draft Plan in July 2024 as a result of refining our cost estimates for the projects and programs we will deliver in AA6.

9.5.2 A good employer

We will invest $71 million in projects and programs in accordance with our vision to be a good employer. We will maintain strong health and safety performance, continue our upgrades of original compressor station accommodation to reflect our changing workforce and redevelop our Jandakot facility.

This is $14 million higher than the $57 million we proposed in our Draft Plan in July 2024 as a result of refining our cost estimates for the projects and programs we will deliver in AA6.

9.5.3 Sustainably cost efficient

We will invest $33 million in projects and programs that will ensure we are sustainably cost efficient into the future. We will invest in our IT systems, data management and digital capabilities. This is $147 million less than the $180 million we proposed in our Draft Plan in July 2024 as a result of removing the Compression Reduction Project ($123 million) and IT projects cost refinement in AA6.

9.6 Key projects and programs in AA6

The following sections provide some further detail on some of the key projects and programs we will deliver in AA6.

Together these key projects and programs represent around 95% of our total capex requirements in AA6.

The remaining 5% of capex in AA6 is made up of ongoing programs of work required to ensure the safe and reliable operation of the DBNGP.

Each of the capex projects and programs is supported by a business case that evaluates options, risks, alignment with our objectives, and compliance with the capex criteria outlined in rule 79 of the NGR.

9.6.1 Compressor stations

Compressor stations are integral to the safe and reliable delivery of natural gas along the DBNGP. There are a total of ten compressor stations along the DBNGP, each with multiple compressor units. Compressor units are run based on the requirements of our customers and their operation must be ramped up or down quickly to meet these needs.

The key driver of the compressor stations program is delivering for customers, particularly in terms of public safety and reliability.

Over AA6 we are forecasting to spend $34 million on compressor stations. The proposed program covers the following areas:

- a continuation of end-of-life replacements for rotating equipment and compression assets, such as dry gas seal ($2 million), compressor air packages ($3 million), passing recycle and isolation valves ($1 million), rotor bundles ($2 million), mainline flow meters ($1 million) and the upgrade of water bath heaters to electric heaters ($4 million);

- corrosion prevention and risk mitigation activities to preserve the DBNGP's integrity totalling $12 million, including refurbishment of below ground pipework ($4m), painting of facilities above ground and rectification of corrosion under insulation;
- mandatory inspection and rectification of non-conformances in hazardous areas ($2 million); and
- electrical protection integrity testing ($1 million) and the installation of a fire and gas detection and suppression system ($1 million).

9.6.2 Compressor unit control systems

Compressor unit control systems provide critical safety and control functions by monitoring the turbine compressors along the DBNGP, optimising system efficiency by enhancing compressor function. When compressors are not operating optimally, pipeline integrity can be impacted, as can our ability to fulfil our contractual obligations to customers.

The compressor units are operated remotely from our Perth control room. It is important to have a reliable control system that can control processes accurately as well as protect equipment in case of abnormal conditions such as fire, vibration and over-pressurisation.

The control systems have reached the end of their technical life and are no longer supported by the manufacturer. We have implemented a staged replacement approach for compressor unit control systems to ensure obsolete hardware is replaced in a timely manner without affecting the safe operation of compressor units.

During AA6, we will deliver the majority of the program, with one unit deferred until AA7 due to resourcing constraints.

In AA6 we will replace five units at a total cost of $16 million. The key driver for this work is delivering for customers in terms of public safety and reliability. The new control system will also allow us to utilise the new control optimisation package that has been developed by our key supplier of compressor units.

9.6.3 Meter stations

This ongoing capital works program ensures metering facilities continue to operate safely, reliably and within acceptable risk tolerances. Ongoing investment is also necessary to meet the gas delivery, quality and remote operability requirements as specified by our commercial agreements and relevant legislation such as *Petroleum Pipelines Act 1969, Work Health and Safety Act 2020* and *Gas Supply (Gas Quality Specifications) Regulations 2010*).

Operating meter stations is an ongoing project which combines refurbishment and replacement of metering assets along the DBNGP depending on their age and performance.

Routine inspections are required to determine asset performance and when these assets reach the end of their technical life they must be replaced. There is a cyclical peak in the age of these assets which must be addressed in AA6, along with some other key projects:

- Installation of gas chromatographs (GC) at six inlet stations ($6.0 million) and installation of moisture, H2S and total sulphur analysers at six inlet sites to monitor gas quality ($4.7 million). The GCs are required at strategic locations to meet regulatory obligations regarding gas quality. We are proposing the installation of new GCs at KGP, Varanus Island, Pluto, Macedon, Wheatstone and Gorgon meter stations. In addition, we plan to install new GCs at CS1 and CS2 for comingled gas ($1.5 million) to enable accurate billing, due to the changing flow dynamics of the pipeline. We also plan to replace aging components and software of existing GCs at CS1, CS2, CS6, CS8 and Kwinana Junction. This will ensure we can meet the gas delivery requirements as specified by standard shipper contracts, reference service contracts, relevant legislation, regulatory instruments and Australian Standards.
- Meter replacement and refurbishment ($3.3 million) will enable working meters to be swapped out, calibrated and recertified so that meters are accurately recording flow usage. This is compliance driven as there is an increasing focus on measurement, with more accurate measurement in turn leading to more accurate billing.
- Continuation of our 35-year replacement program for fuel gas heater trains ($3.9 million), and odorant facilities. This is another example of an asset that requires replacement during AA6 because of a replacement cycle that does not fall due every AA period. Fuel gas heater trains ensure safe and efficient fuel supply by regulating gas pressure and flow. We replaced two fuel gas heater trains in AA5 and we propose to replace seven in AA6 as they are beyond their useful and useful and technical lives.

9.6.4 Pipeline and MLV

This work program ensures that our Pipeline and Main Line Valve (MLV) assets are operating safely and reliably, and falls into three categories:

- preventative works to protect pipeline and MLV assets from corrosion ($7.4 million), including the annual dig up program, fit for purpose transformer rectification units replacement and cathodic protection;
- replacement of end-of-life electrical control and instrumentation (ECI) equipment ($1.7 million), including solar panels, radio, communication equipment and monitoring devices; and
- replacement of end-of-life mechanical equipment such as isolation valves to facilitate in line inspections ($2.3 million).

This program maintains the design life of the DBNGP by ensuring all ECI and mechanical assets are in good working order.

The pipeline and MLVs have been in operation for more than 40 years. As assets age, they deteriorate, which increases the likelihood of underperformance and failure. As such, the ongoing levels of planned, preventative and proactive capex activity typically increases over time.

The ongoing program of capex works can be lumpy, particularly as installed ECI, mechanical or cathodic protection assets of a similar age reach end of life at the same time. To smooth the capex profile, our approach is to extend the life of assets where safe and prudent to do so. Where this is not possible, we will replace assets at the end of their technical life.

The program is predominantly a continuation of ongoing works and maintenance techniques based on asset performance, age and inspection data. Corrosion inspection in recent years has identified a significant amount of unexpected corrosion under pipeline and asset insulation.

9.6.5 Compression reduction project

The scope of this project includes additional looping and removal of a small amount of compression without impacting DBNGP nameplate capacity.

The project was expected to add economic value by:

- reducing compression by mothballing or decommissioning one or more compressor stations to reduce operational and capital costs in a sustainable way;
- reducing or avoiding potential future Safeguard Mechanism costs; and
- reducing DBNGP emissions.

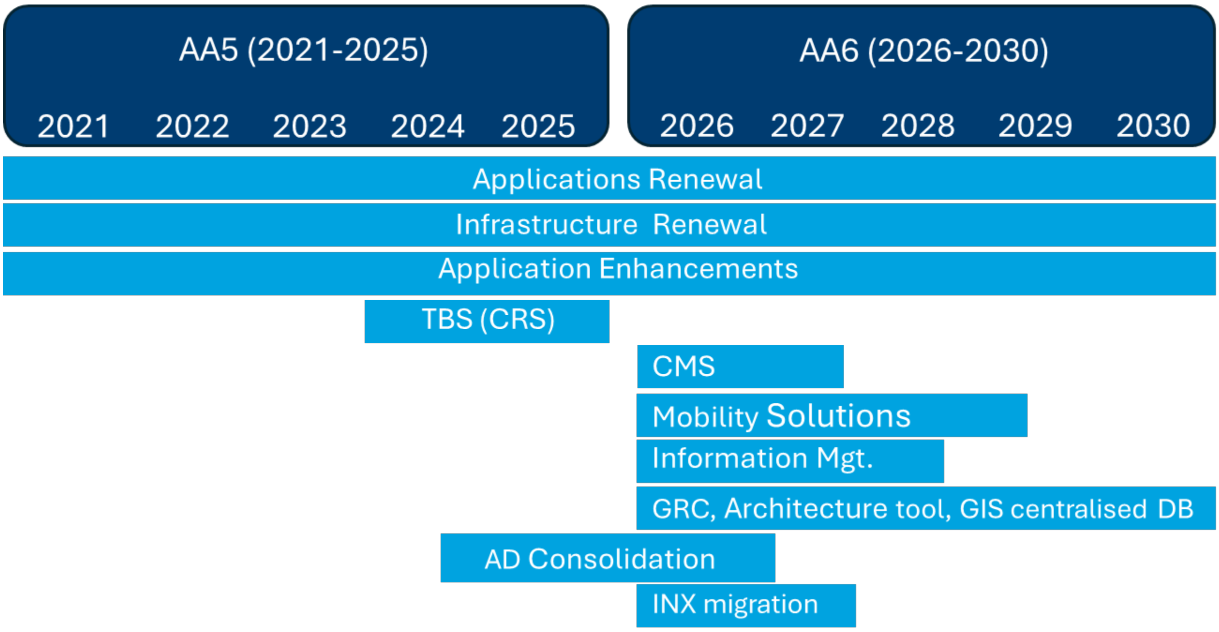
Due to uncertainties about the impact and timing of Perth Basin developments we have decided not to move forward with the Compression Reduction project in our Final Plan. Further work must be conducted to fully understand the need, risks, costs and benefits of decommissioning compressor stations and looping the DBNGP. Should the fundamentals of this project improve we may propose it in the future.

9.6.6 Information Technology

Our information and technology systems are integral to delivering safe, reliable and efficient services. We have delivered IT infrastructure based on our overarching IT strategy which is to implement a fit-for-purpose digital environment. We discuss what has been achieved in AA5 in Section 9.9.7 and DBP’s IT timeline is shown in Figure 9.4.

The digital strategy and roadmap of initiatives for AA6 are driven by our vision to be sustainably cost efficient. The digital strategy also delivers for customers by securing against threats, modernising systems and increasing digital capabilities. This enables us to be a good employer by modernising systems and investing in data management and business intelligence.

Figure 9.4: Timeline of the implementation of DBP's IT program



9.6.7 IT Sustaining Applications

The IT Sustaining Applications business case encompasses several projects to maintain the current levels of IT services and mitigate risks associated with our core business systems through a prudent cycle of system upgrades and replacements.

In AA6, the total forecast spend is around $21 million, which is $8 million lower than our Draft Plan proposal as a result of more refined cost estimates for the work within this program. Our forecast for this program comprises:

- periodic major and minor upgrades and patches to applications, which comprises the majority of our recurrent sustaining apps, such as OneERP SAP S/4 HANA ($3.3 million), Maximo Suite 9 ($3.0 million), the Transmission billing system ($1.7 million) and the GIS database ($1.3 million);
- the Draft Plan included a Field Mobility business case ($7 million) which aimed to modernise our outdated field maintenance process which involves printing hundreds of pages of work instructions which are then physically transported along the pipeline. We identified that Maximo version 9 contains a mobility module that can deliver this functionality for a far lower investment. Hence, the Field mobility business case has been removed;
- application enhancements to enable additional functionality and improve user experience. This includes enhancing SAP S/4 Hana and Maximo ($4.3 million) to incorporate mobility, analytics, artificial intelligence capabilities and strengthened integration. We have considered each functionality enhancement on a case-by-case basis and plan to invest only in enhancements that will offer value to customers; and
- undertaking in-depth analysis to inform the design and implementation of a new Contract Management Solution (CMS), aimed at streamlining the end-to-end procurement process, centralising contract administration, and optimising integration with SAP S/4Hana ($0.3 million).

9.6.8 Cybersecurity

The Cybersecurity business case includes expenditure on data security and meeting cyber security obligations. As an operator of critical infrastructure, we take our obligation to operate the DBNGP safely and securely very seriously. We are also subject to regulatory obligations as an operator of critical infrastructure (i.e. the *Security Of Critical Infrastructure Act 2018 (Australia)* (SOCI), which drives expenditure in this area.

Directors are accountable for ensuring cyber controls are commensurate with the organisation's cyber risk. Responding to this regulatory obligation, we are aiming to reach the appropriate security profile in the current AA period.

The key aspects of the Cybersecurity program are:

- cyber resilience;
- technology governance and architecture;
- data protection and privacy; and
- consistent access control for both internal and cloud-based applications

9.6.9 IT sustaining Infrastructure

Our IT infrastructure underpins the delivery of all DBP services. It enables our staff to connect to our systems, data and communication networks. It also allows us to securely store, search and process the large volumes of data we need to service our customers and to meet a range of legal and regulatory obligations.

The scope of this business case encompasses three workstreams:

- End user devices ($4 million), which covers the ongoing refresh or replacement of DBP's end user devices, including laptops and mobile phones, office equipment, work from home equipment and field devices to allow for hybrid working arrangements and increased staff mobility;
- Network and currency ($7 million) which reflects the interconnected nature of the assets and shared support arrangements provided by AGIG. DBP, as part of the broader AGIG group, take part in the roadmap initiatives, to enable economies of scale and adequate risk mitigation; and
- Data centres ($1.0 million capex and $1.8 million opex): following the consolidation and rationalisation of our data centres during the AA5 period, we will migrate our data to the cloud in line with most other energy infrastructure businesses.

9.6.10 Operating Technology

Operational Technology (OT) is recognised as critical to the functioning of the DBNGP, communicating all operational and billing data from remotely located assets to the Transportation Services Control Centre in Perth.

The OT network is interconnected by a wide area network spanning 1,600 kilometres and consists of processing equipment (servers, Remote Terminal Units and operator stations) as well as network infrastructure and security (routers, switches, firewalls, terminal servers and protocol converters).

Communication between the main control site and disaster recovery site at Jandakot is via a fibre ring, established to achieve security and resilience of service in the event of an emergency requiring the control room to move to Jandakot.

Over the next five years, we propose to continue the ongoing program of works and replace critical OT assets that will reach the end of the technical life. These include:

- two software systems, Ansible and Solarwinds, due for their five-yearly replacement;
- a hardware replacement program encompassing replacing Uninterruptable power supply (UPS), 19 SCADA servers, 4 switches, and 2 communication systems and 6 communication switches;
- replacement of obsolete Remote Terminal Units (RTU). Over the AA6 period, we will have 114 obsolete RTUs at MLVs and meter stations along the network that need replacing to ensure we have visibility and control of assets at these sites;
- replacement of our obsolete SCADA system which has reached the end of its technical life in 2024 and is no longer supported by the original equipment manufacturer. In the AA5 proposal we had forecast a major upgrade (i.e. not replacement) would occur in 2024 in line with the SCADA Master Station AMP and Operational Risk Framework. Foundational work and a front-end engineering design study to perform needs analysis and planning will be undertaken in AA5 as planned. However, the scope of work has been extended from a major upgrade to a full replacement. As part of the project, we will implement a contemporary version of our existing SCADA software, 'Enterprise SCADA 2023', undertake a SCADA alarm criticality upgrade and replace critical control room fixtures and fittings.

9.6.11 Power Generation and Management

This business case evaluates the various power generation and management assets essential for ensuring reliable electricity supply to operate the DBNGP.

We will take a more holistic approach that centres on the strategic and sustainable management of these assets in AA6, involving optimising the replacement of end-of-life assets and integrating renewable generation solutions to reduce carbon emissions.

In the AA6 period we propose to replace our obsolete power generation and management assets including:

- Gas Engine Alternators (GEA) which are critical to provide reliable power for compressors and all equipment and buildings at compressor stations and maintain pipeline pressure. Considering cost effectiveness, we propose to replace certain GEAs, a majority of which are due for a major overhaul, with smaller and more efficient units;
- GEA control systems are a supervisory system that we use to control multiple GEAs. We have considered the GEA control system replacement schedule and aligned it to the GEA replacement program to avoid any unnecessary reconfiguration works that would arise from a new unit being installed. This will help streamline delivery and minimise cost;
- Closed Cycle Vapor Turbogenerators (CCVT) - 19 of our repeater sites along the pipeline are powered by CCVTs which were selected to allow for minimal maintenance and no overhaul required during their technical life. As these units become obsolete with no manufacturer's support, consistent with our focus on reducing emissions, we will move to power these sites with renewable energy;
- renewable power supply - we use renewable energy (solar photovoltaic (PV) panels coupled with a charger (rectifier) and battery) where it is possible and economically viable to do so. For smaller sites such as repeater sites and spur sites we use this as a primary energy source and/or UPS. The technical life of solar panels used on the DBNGP is 15 years and their components 7 years, but we extend their usage beyond technical life where prudent to do so. We need to replace 5 solar PV arrays, 65 batteries and 32 rectifiers in AA6;
- Loadbank control panels are used at compressor stations for testing, maintenance and validation of our power generation systems. We have identified an issue with the loadbank control panels installed as part of the Stage 5A expansion. The design of some of the cabling and components has been causing electrical overheating and tripping. We commenced a program to replace these loadbanks in AA5 and will continue it in AA6 at a rate of two per year, a rate which is aligned with the GEA control system replacement program; and
- Our electrical systems at MLVs and meter stations were installed during the pipeline's construction. Key elements of the electrical systems such as wiring and circuits need to be upgraded to current standards to provide us with the opportunity to install renewable power generation and increase our uptake of low emissions technology at strategic locations along the pipeline.

9.6.12 Structures & Operational Sites

Our structures and operational sites enable us to safely maintain DBNGP's critical assets that support the transportation of natural gas to all customers. This does not include the corporate and operational headquarters in Perth or Jandakot.

The DBNGP pipeline is 40 years old, and a significant majority of our operational sites were constructed along the length of the pipeline in the first 10-15 years of operation and now present a number of emerging risks. These risks include safety related issues of noise, heat and snake exposure for our staff while working on site at compressor stations. Figure 9.5 shows the location of our accommodation is close to the operational assets that create heat and noise issues.

Following a strategic and consolidated review of our structures and operational sites, we have developed a series of solutions that address health, safety, environmental and security requirements, as well as proposals that enable our facilities to cater for a diverse workforce.

The identified projects fall under two key categories:

- Health, safety, environment (HSE) and security compliance: including programs to upgrade working at height facilities ($2 million), installation of remote site toilets ($1.7 million), replacement of water reverse osmosis units ($1.5 million), refurbishment of helicopter landing pads ($0.6 million) and underground oil sump tanks ($0.6 million), investments driven by SOCI requirements ($2 million) which includes the installation of CCTV, boom gates, fencing and swipe card systems; and
- Operational facility structures and accommodation: we will replace the accommodation at two of our compressor stations where they have been heavily used and are most dilapidated. We initially

Figure 9.5: Operational site with accommodation near live assets and noisy operations.

planned to complete four accommodation replacements along the DBNGP but have scaled back our plans to only two in AA6 due to the high cost ($6 million per site). This decision balances the wellbeing of our workforce with the pricing impact on our customers. We will be addressing the remaining accommodation sites which are also in a very poor condition over the course of the next two AA periods.

The new accommodation will offer a safe and comfortable living environment, promoting better mental health and physical well-being for workers. This, in turn, will enhance job satisfaction and performance, which is especially important in remote areas.

It will also support a more inclusive and diverse workforce, attract and retain skilled professionals, and help reduce the employee conditions gap between those provided by DBP's facilities and its competitors.

The proposal to relocate accommodation further from high-pressure gas facilities will enhance safety by reducing noise and exposure to potential gas release hazards. This strategy allows current facilities to remain operational whilst the new facilities are constructed, minimising disruption.

9.6.13 Fleet & civil equipment

We own a fleet of vehicles and civil equipment which is used to inspect, maintain and repair equipment installed on the DBNGP. There are three categories of fleet which we need to maintain: our vehicles, civil equipment and Manitou units.

- Vehicle replacement - travelling by road is categorised as an 'extreme' risk activity in the AMP Significant Risk register. Our vehicles are maintained regularly and replaced on an age, distance travelled and/or condition basis to ensure the safety and reliability of the fleet, minimise potential risk to employees and minimise whole of life costs. We have identified a target of greater than 150,000 km or five years as a trigger for fleet vehicle replacement, which is based on an assessment of escalating maintenance costs and increased risk profile after these milestones.

The lingering impact of COVID on the supply chain has resulted in significant vehicle shortages, leading to a backlog in required replacements of multiple vehicles which have travelled more than 250,000 km, compromising the safety of one of our primary activities as a remotely operating business, i.e. driving.

This has been compounded by the escalating cost of vehicles in Western Australia. Over the past five years, the average transaction price for new vehicles, including 4WDs, has risen by approximately 25%, which is attributed to several factors, such as higher production and shipping costs, along with stock shortages during the pandemic. As a result, we have fallen behind in our replacement schedule during AA5 period, with 57% of our fleet now operating above 150,000kms. We modify our utility vehicles with specialised fit outs to enable them to be fit for purpose and fully equipped for remote operations. Over the AA6 period we propose replacing 60 of the 106 light vehicles, which represents a total investment of $9 million.

- Civil equipment replacement - our civil equipment includes trucks, trailers, plant, heavy vehicles and other equipment including graders, front end loaders, forklifts, generators and more. This equipment is utilised across the entire DBNGP as required for both scheduled works and when necessary, for reactive and emergency works. Heavy vehicles have a typical useful life of 8 years. This is based on escalating maintenance costs and increased risk profile after this time. During the upcoming period we are forecasting $2 million for replacements of civil equipment.
- We also have eight versatile Manitous, with the oldest introduced in 2006, used for material handling and working at heights. These units are reaching their end of life, and major overhauls can no longer effectively extend their life span. Due to their age, they are consistently failing or requiring further ongoing maintenance following both major and minor repairs and we propose to replace them at a total cost of $1 million.

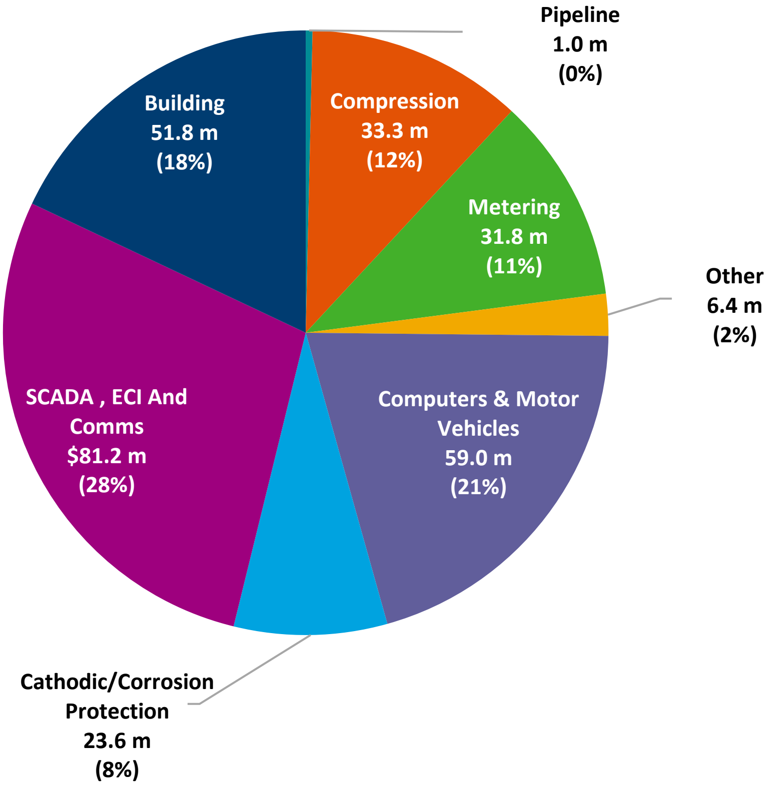
9.6.14 Jandakot Facility Redevelopment

The Jandakot redevelopment project was accepted as part of the AA5 determination and was due for construction during 2024 and 2025. The global pandemic and subsequent business disruptions resulted in a 2-year deferral of the project.

The project is now entering the detailed design and planning phases throughout 2024 and 2025, with the majority of construction works to be conducted throughout AA6. The need for redevelopment has not changed during the current period and the requirement to replace the existing 35-year-old facilities remains. Figure 9.6 displays the concept design to redevelop Jandakot.

Figure 9.6: Concept planning and designs for Jandakot redevelopment

Figure 9.7: Total AA6 capex by asset class ($Dec 2024)



Construction of a purpose-built facility in Jandakot will also provide a backup control room, server and communications facilities as well as accommodation for the Transmission Operations division.

Over the past five years, commercial building costs in Western Australia have increased significantly. Factors such as global supply chain disruptions, increased demand for materials, and rising labour costs have all contributed to this rise. The average annual increase in commercial construction costs has resulted in a revised cost estimate of $34 million.

9.6.15 Summary of our AA6 capex by asset category

Figure 9.7 shows our AA6 capex by asset category. As already described above, our expenditure in AA6 is largely driven by the replacement of obsolete and end-of-life compression, pipeline and metering assets, OT systems, an uplift in corrosion prevention as well as the redevelopment of Jandakot facilities and replacement of accommodation at two most dilapidated compressor sites to ensure we can continue to deliver gas safely and reliably into the future. Table 9.1 below provides a summary of the major business cases for AA6 relative to AA5 forecast.

Table 9.1: Summary of major AA6 projects ($m 2024)

Business Case	AA5	AA6	Description
Compressor Stations	39.9	34.8	Continuation of ongoing programs including cyclical asset replacements for dry gas seal, water bath heaters, air package and valves, corrosion prevention activities and rectification for safety hazards
Pipeline and MLV	14.9	12.1	Corrosion management and cathodic protection for pipeline and MLV assets, end of life ECI equipment upgrades and isolation valve replacement
Meter Stations	18.7	32.6	Installing gas chromatographs (GC) at producer inlet points and installing moisture and sulphur analysers to monitor gas quality issues, meter replacement and recalibration, heater fuel gas train and odorant systems replacement
Operational Technology (OT)	2.4	24.8	Hardware replacement and software upgrades to SCADA
Structures and Operational Sites	2.4	27.3	Health, safety, environment and security compliance and replacement of original accommodation facilities at compressor stations
Compressor Unit Control Systems	18.3	15.7	Replacing obsolete compressor unit control systems which are over 15 years old and no longer supported by the manufacturer
Jandakot Facility Redevelopment	3.2	34.6	Continuation of the upgrade and redevelopment of the Jandakot site and facilities
Power Generation and Management	5.9	35.0	GEA replacement, GEA Control System Replacement, CCVT Replacement, Renewable Power Supply, Loadbank control panel replacement
IT security	2.0	7.6	Responding to regulatory obligations to maintain a secure IT environment
IT Sustaining Applications	37.8	21.4	Ongoing upgrades and patches to sustaining applications, including OneERP, Maximo, Transmission Billing System (TBS) Geographic Information Systems (GIS) database and other core systems and enhancement in app functionalities for our Contract Management System
IT Sustaining Infrastructure	5.8	14.5	Replacement of IT hardware, refresh of network connectivity and moving our managing data to the cloud

9.7 How we will deliver our capex plan efficiently

We operate within a framework of internal and external controls that govern the way we plan, assess, procure and deliver capital works. This framework ensures we are making sound investment decisions for our customers, our stakeholders and our business.

9.7.1 Our Safety Case and Asset Management Plans

Our Safety Case is the primary document outlining how we operate the DBNGP in compliance with our obligations under the *Petroleum Pipelines Act 1969* (WA), *Work Health and Safety Act 2020*, regulations and our operating licences.

The Safety Case provides assurance that the systems, processes and procedures we have in place will support us in systematically and continually identifying and assessing threats to asset integrity and therefore, the safe and reliable operations of the DBNGP.

Our AMPs guide the way we invest in our assets and help to ensure that the capex activities we undertake are clearly aligned with our vision. An overarching AMP sets the framework, while specific AMPs outline key risks and controls for each asset type. These AMPs demonstrate the logical development of asset improvement and replacement plans and complete the feedback loop by monitoring asset performance.

The AMPs also outline how we continually monitor, evaluate, plan and undertake asset integrity assessments to extend the remaining life of assets, improve, replace, or where necessary, retire assets. This ensures that efficient, reliable and safe operations of the DBNGP are maintained.

Similarly, our IT Investment Plan outlines how we invest in IT projects to ensure that we deliver safe, reliable and efficient services to our customers.

9.7.2 Project governance

Our business planning doesn't stop with each AA period. We continually update our capex plans to respond to changing business needs.

In the annual planning process, all proposed capex projects with more accurate budgets and scopes are risk ranked, and the list is approved for inclusion in the annual capex program and budget approved by the Board each year. The delivery of the program is reported in the monthly business reports and at the Project Review Committee where the Traffic Light Dashboard is reported, and performance is assessed.

Risk ranking is refreshed annually to ensure project assumptions remain valid and are assessed against emerging risks that have been identified. This ensures the prudent deployment of capital, based on risks, business needs and significant unplanned events.

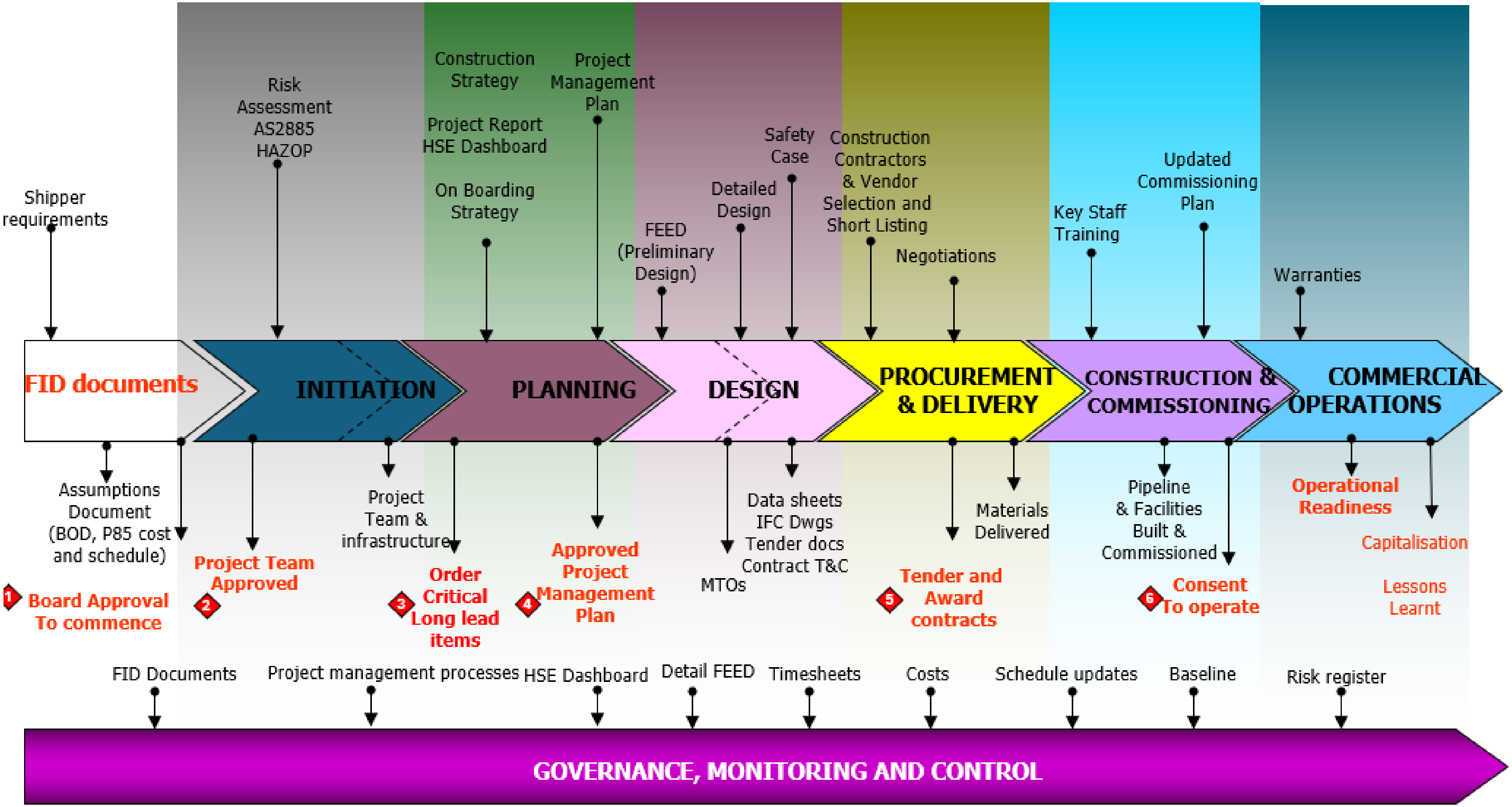
The approved capex projects are presented for approval in accordance with our Delegation of Financial Authority policy, for example to the Board, Executive Leadership Team, depending on its value. Once approved, projects are then managed and monitored in line with our Project Management Methodology (PMM). We regularly report our expenditure performance against prior year spend and approved regulatory allowances.

As the owner of the PMM, the Project Management Office (PMO) is responsible for the quality and fitness for purpose of the PMM as well as ensuring the PMM is appropriately applied in the business.

The PMM outlines the approval process and major project milestones at each stage of the project lifecycle. Our project delivery process and governance is depicted in Figure 9.8 and our project governance structure in Figure 9.9.

Any material changes that occur during project execution are strictly managed through the Project Change Request process. This process ensures there is proper governance around changes in scope and cost at all stages of the project lifecycle, including execution.

Figure 9.8: Project Delivery Process and Governance



9.7.3 Procurement

As outlined in Chapter 8, all procurement activities are subject to our Contracts and Procurement Policy. This ensures we carry out these activities in an efficient, cost effective, confidential and ethical manner to:

- maximise cost savings;
- mitigate risks associated with the provision of goods and services; and
- achieve excellence in both operational and financial performance.

Table 9.2 outlines the minimum information requirements that must be met, depending on the value being procured. Procurement activities exceeding a value of $100,000, must be competitively tendered to at least three vendors, and exceeding $500,000 to at least four vendors.

Contractual or pricing agreements for ongoing supply of goods or services are reviewed annually.

Our Delegation of Financial Authority policy covers all financial transactions within our organisation. It outlines the level of financial authority at each level within our organisation. Only the CEO has financial delegation to approve funds for unbudgeted initiatives, and only where it fits within the overall approved budget. This provides strong financial controls and governance in the delivery of capex.

Figure 9.9: Our project governance structure

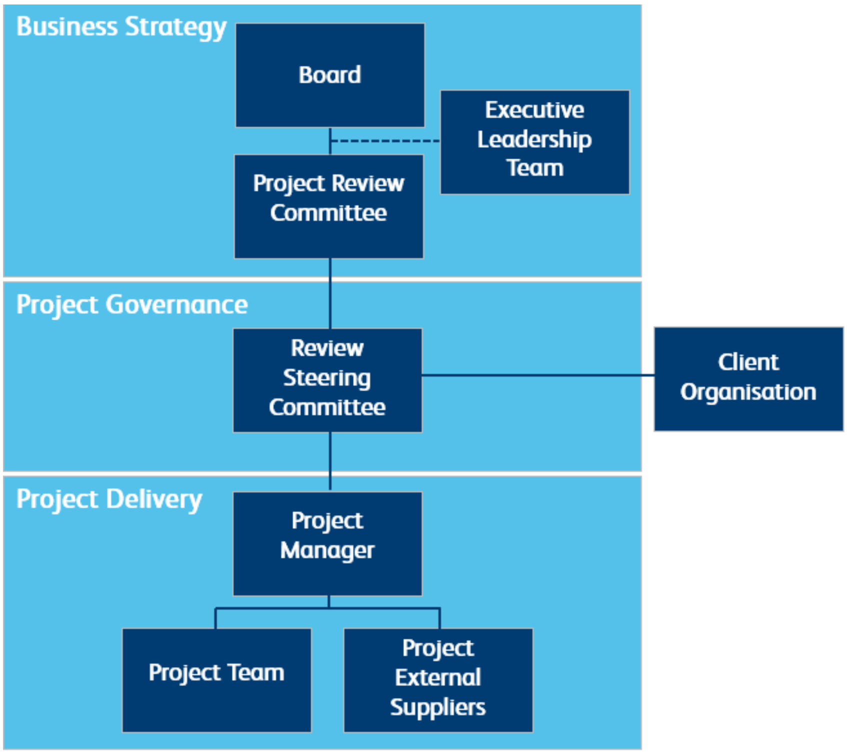


Table 9.2: Minimum purchasing requirements

	< $1K	< $20K	$20K - $100K	$100K - $250K	$250K – $500K	$500K+
Via existing Supply Agreements in place	1 written quote (min.) required from available Supply Agreements conducted by the business then validated by C&P			3 written quotes (min.) required from available Supply Agreements conducted by the business then validated by C&P		Tender process min. 4 bidders conducted by C&P
NO existing Supply Agreements in place	Credit card (if-available) for non-inventory items or Purchase Order	1 written Quote (min.) conducted by the business then validated by C&P	3 written quotes (min.) conducted by the business then validated by C&P	3 written quotes (min.) conducted by the business then validated by C&P	3 written quotes (min.) conducted by C&P	

9.8 Our performance in AA5

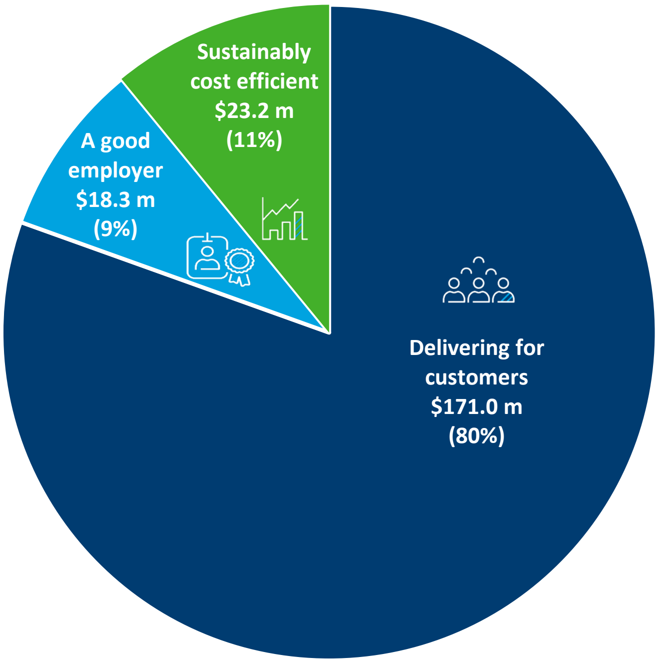
We have invested $175 million of capex so far in AA5 and are forecasting to invest a further $37 million, totalling $212 million by the end of the period. This is $30 million (17%) higher than the allowance for AA5 of $182 million, with the delivery of projects impacted by the COVID-19 pandemic and associated delays, supply chain constraints and higher priced inputs.

Our AA5 capex program is designed to achieve our vision of:

- delivering for customers;
- being a good employer; and
- being sustainably cost efficient.

In AA5, 80% of our capex will be invested to help deliver for our customers (Figure 9.10).

Figure 9.10: Total AA5 capex by driver ($Dec 2024)



9.8.1 Delivering for customers

We have invested $145 million to date ($171 million by the end of the period) on various projects and programs that enable us to provide the services our customers require and value. So far in AA5, we have continued to achieve 100% system reliability and zero curtailments.

We have been investing in AA5 to ensure the ongoing safety and reliability of our pipeline, including the rectification of corrosion occurring under compressor insulation, the replacement of end-of-life Fuel Gas trains and Turbine Exhausts and the refurbishment of ageing pipework below the ground.

The key project which is scheduled to commence in 2025 is the Enterprise SCADA software upgrade. We are also in the process of delivering a new Transmission Billing System for our customers, replacing obsolete control systems at Compressor Stations and continuing the dry gas seal and valve replacement programs.

9.8.2 A good employer

We are on track to invest $18 million in projects and programs aligned with our vision objective to be a good employer. In the current AA period, we have delivered a strong safety performance through our investments in the replacement of obsolete isolation valves and the upgrade of fire and gas control systems and working at heights equipment.

We are committed to providing reasonable working conditions for our employees so in the current period we refurbished compressor station accommodation and advanced the planning and approval phase for the Jandakot redevelopment, which will replace the current dilapidated warehousing and office facilities on the site, whilst also housing our back up Control room. We also invested in core Enterprise Resource Planning software provides the digital foundation for many of our core business functions, servicing both our employees and our customers. We continued to refine and update our Safety Case, replenished our inventory of tools and purchased fleet vehicles to ensure that our employees' safety is our number one priority.

9.8.3 Sustainably cost efficient

We have invested $23 million into projects and programs to ensure we are sustainably cost efficient. We have invested in our IT assets to ensure market currency, compatibility of our services and further cyber resilience through new data centre infrastructure, and various IT hardware and software upgrades.

We are also developing a Decarbonisation Strategy for the

DBNGP. These initiatives will help drive efficiencies going forward.

9.9 Key projects and programs we are delivering in AA5

The following sections provide further detail on some of the key projects and programs we are delivering in AA5. Together, these projects and programs represent more than 80% of the total capex invested in AA5.

9.9.1 Communications infrastructure

In AA5 we will spend around $35.9 million to deliver independent communications infrastructure for the northern section of the DBNGP. Once completed in 2026, we expect to deliver the project around $4m over the benchmark of $36.6m.

The project was prudently deferred from the original proposed start date of 2021 as initial quotes for the work came in significantly higher than expected. Our internal governance process led us to refine the project scope, to ensure that we could deliver the project efficiently. We have adopted an in-house delivery approach which has resulted in significant savings compared with the alternative contracting option.

The work includes replacement of original towers and dishes, obsolete analogue radio equipment, power systems and cabling at compressor stations and rectifiers. We will also increase point-to-point capabilities.

The project was prudently deferred from the original proposed start date of 2021 as initial quotes for the work came in significantly higher than expected. Our internal governance process led us to refine the project scope, to ensure that we could deliver the project efficiently. We have adopted an in-house delivery approach which has resulted in significant savings compared with the alternative contracting option.

The project will be completed in AA6, with $5 million allocated to year one, i.e. 2026.

9.9.2 Compressor stations

Expenditure on Compressor Stations in the AA5 period is forecasted to be $39.9 million, closely aligned with the $40.3 million allowance. The compressor station program has been largely driven by delivering for customers, particularly by ensuring public safety and reliability. The major projects in AA5 were:

- the renewal of end-of-life rotating plant, including dry gas seals, fire suppression systems, vibration monitoring systems and air inlet filters totalling $6 million;
- the upgrade of ECI ($5 million) and mechanical equipment ($8 million);
- repair, rectification and preventative works that provide corrosion protection ($18 million) such as below ground pipework refurbishment and rectification of corrosion under insulation; and
- addressing safety hazards ($3 million).

Asset corrosion has been more prevalent than expected due to harsh weather conditions along the pipeline, necessitating additional works not accounted for in the allowance. In particular, we have to carry out works to rectify corrosion under insulation ($6 million).

9.9.3 Meter stations

By the end of AA5 we will have invested $18.7 million in our meter stations, exceeding the allowance of $9.4 million. The increased costs were primarily driven by unforeseen and urgent projects to address safety, compliance and operational challenges, including valve replacements and pipeline modifications ($3.6 million), odourant facility upgrades ($1.4 million), corrosion under insulation

Figure 9.11: Compressor Station 10 in Kwinana

inspections and repairs ($1.4 million), turbine meter replacements ($1.1 million) and the installation of an ultrasonic meters ($0.7 million). Sites are now being targeted on a priority basis to control costs.

9.9.4 Pipeline and MLV

By the end of AA5 we will have spent $14.9 million to undertake pipeline and MLV works. This is $4.3 million above the allowance approved ($10.6 million) for AA5.

The variance in AA5 is primarily due to an increase in activities to address unforeseen corrosion under insulation, the additional investigations and dig ups for the southern pipeline prompted by Runcom results (enabling prudent deferral of further dig ups to AA6). Delays were also due to the Wheatstone Ashburton West Pipeline (WAWP) project, which involved constructing a 1.8 kilometre pipeline loop to maintain pipeline integrity and ensure continued bidirectional gas flow. The WAWP project safeguarded industrial and metropolitan gas supply during potential constraints or interruptions between the Karratha Gas Plant and CS3.

We have also needed to replace valves following issues with pig receivers and launcher isolation valves leaking in preparation for our next pigging program in AA6.

9.9.5 Compressor unit control systems

We have implemented a staged replacement approach for compressor unit control systems to ensure obsolete hardware is changed in a timely manner without affecting the safe operation of compressor units.

In AA5 we will replace six units at a total cost of $16 million. This is $4 million below the $20 million benchmark approved for eight units. The variance is primarily due to the replacement of the CS9/2 compressor unit which was originally scheduled for 2025 being deferred to AA6.

The key driver for this work is delivering for customers in terms of public safety and reliability. The new control system will also allow us to utilise the new control optimisation package that has been developed by our key supplier of compressor units.

9.9.6 Information technology

During the current AA period, we have completed a data centre consolidation, rationalisation of our IT managed service providers, Phase 1 of our OneERP program and the uplift of our cyber security capabilities.

In AA5 we forecast an investment of $51 million in IT. Our AA5 IT expenditure is summarised below:

- Replacement of the Customer Reporting System (CRS) with Transmission Billing System (TBS) ($8 million): this project will upgrade the CRS user interface so it is compatible with use on mobile devices while continuing to support upgrades to the system as business requirements and customer needs change;
- IT Enabling ($1 million): uplift to the delivery of DBP IT services, enabling the provision of effective and efficient services to the customer and ensuring compliance with regulatory obligations;
- IT Sustaining applications ($34 million): this project maintains the current levels of IT services and mitigates risks associated with our core business systems through a prudent cycle of system upgrades and replacements;
- IT Sustaining infrastructure ($6 million): ensures existing IT infrastructure continues to support our business systems; and
- IT Security ($2 million): ensures all IT services are delivered safely and securely, are resilient to external threats and comply with our security obligations.

Our projected IT capex for AA5 is around $51.4 million, which is above our approved allowance of $25.8 million. The higher than forecast expenditure is mainly due to:

- a change in approach to the managed IT infrastructure services and consolidating data centres as part of transition to the shared AGIG infrastructure, enabling us to leverage economies of scale for long-term benefits (+$2 million);
- additional requirements of the Maximo Business Process Redesign and Asset Data Integrity Improvement Program (+$2 million); and
- higher than forecast costs to deliver our OneERP program to replace the obsolete Dynamics AX system with SAP S/4HANA (+$17 million).

The Dynamics AX system is obsolete and not supported, which therefore necessitated the OneERP project. Once commenced, the project proved to be more complex than expected. This, coupled with deliverability issues, resulted in delays and increased costs of the project.

Implementation of the selected OneERP system (SAP S/4HANA) is also integral to achieving harmonisation across the three businesses that make up AGIG being, DBP, Australian Gas

Networks and Multinet Gas Networks. also enabled a one AGIG.

Though delivery of some IT projects were delayed across the period, by the end of AA5 we will have:

- completed major upgrades to our asset management system and minor updates to several other critical applications;
- transitioned our IT managed service providers and uplifted our IT operating model;
- completed the implementation of the OneERP program establishing a functional, fully supported, industry-standard system; and
- completed the replacement of our Transmission Billing System.

9.9.7 Summary of our AA5 capex by asset category

Figure 9.12 shows our AA5 capex by asset category. Our expenditure in AA5 has been driven by renewal of compressor station and metering equipment, the replacement of obsolete and end-of-life communications, the implementation of the OneERP, cathodic protection (including intelligent pigging and in line inspection of the entire DBNGP) and other ongoing activities to ensure the ongoing safety and reliability of the DBNGP.

Figure 9.12: Total AA5 capex by asset category ($Dec 2024)

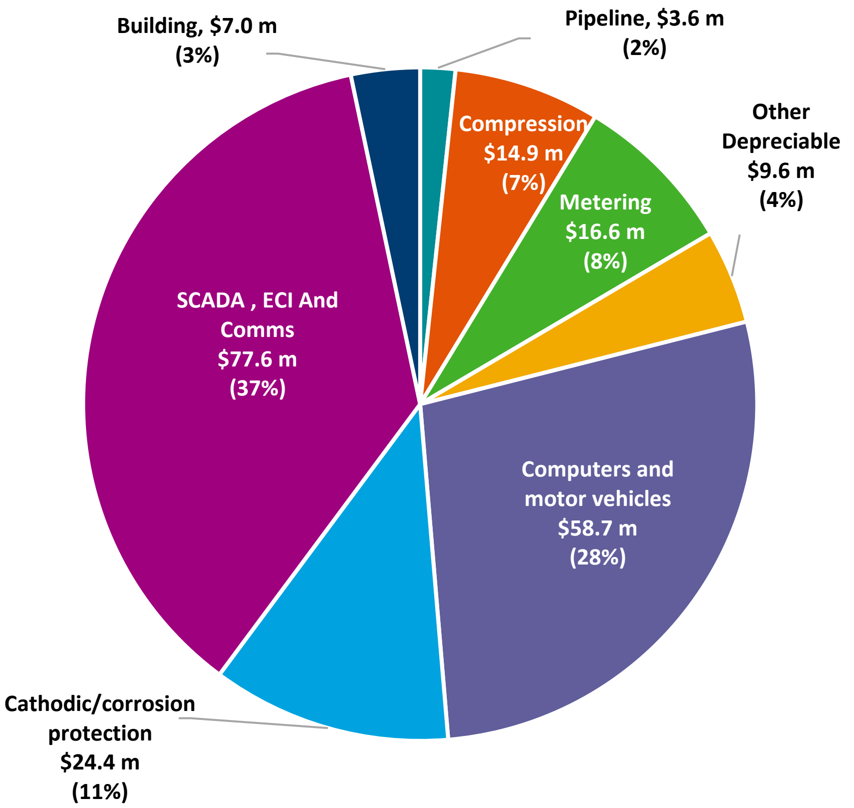


Table 9.3: Summary of AA6 Capex ($million, Dec 2024)

Business Case ($2024)	2026	2027	2028	2029	2030	Total AA6
Compressor stations	8.2	5.5	8.6	5.9	6.7	34.8
Pipeline and MLV	2.8	2.6	1.9	1.9	2.9	12.1
Meter stations	9.1	9.2	5.8	4.2	4.2	32.6
Operating Technology (OT)	5.6	5.0	5.1	4.8	4.3	24.8
Compressor unit control systems	3.1	3.1	3.1	3.1	3.1	15.7
Jandakot	1.1	16.7	16.9	0.0	0.0	34.6
Power Generation & Mgt.	5.9	8.9	7.5	8.7	4.0	35.0
Structures & Operational Sites	3.1	9.0	2.7	8.4	4.1	27.3
Fleet & civil equipment	3.2	2.6	2.3	2.2	2.3	12.7
IT Sustaining Apps	4.8	3.3	2.9	7.7	2.6	21.4
IT Sustaining Infrastructure	4.8	3.7	1.8	1.5	2.7	14.5
All other	9.3	4.3	3.6	3.2	2.2	22.5
Total	**61.1**	**73.9**	**62.3**	**51.6**	**39.2**	**288.0**

9.10 Summary

Our capex in AA6 will ensure we:

- maintain the strong safety, reliability and service performance we are delivering in AA5;
- have a healthy, engaged and skilled workforce; and
- are sustainably cost efficient into the future.

As outlined in the Table 9.3, key projects and programs we will deliver in AA6 are:

- ongoing replacement of end-of-life assets, corrosion prevention, mandatory safety inspection and rectification at compressor stations, meter stations and pipeline and MLV sites;

- replacing critical OT assets that will reach the end of the technical life including SCADA systems and RTU;
- redeveloping and constructing Jandakot facilities;
- replacing outdated power assets, optimising efficiency and integrating renewable energy solutions including GEA and GEA control systems;
- replacing two compressor station accommodation huts in most need of renewal;
- replacing aging vehicles and civil equipment; and
- investing in our IT systems, data management, digital capacities and cyber resilience.

Together with the rest of our AA5 capex program, these projects will continue to deliver the strong safety and reliability valued by our customers.

As demonstrated in the current period, in AA6 we will deliver our capex program in a prudent and efficient manner, whilst operating in a challenging external environment, by applying our established project governance and procurement frameworks and reassessing our plans where our business needs change.

10 Capital base

We estimate the value of our capital base at the end of AA6 will decline to $3.38 billion in nominal terms, or $2.92 billion in real $December 2024 terms.

IN THIS CHAPTER:

- **Our capital base reflects the value of past investments that we have made in the network, but not yet recovered from our customers**
- **We have re-examined the rate at which we recover our capital base through depreciation as described in Chapter 6, Future of Gas**

We adjust our capital base for capex, depreciation and inflation

Our adjusted capital base uses actual information over the current AA period and forecast information over the next AA period.

10.1 Regulatory framework

We are required to adjust our capital base to reflect the actual capital expenditure incurred (net of any amounts contributed by our customers), inflation and depreciation to arrive at our closing AA5 capital base.

We are also required to remove the value of any assets that we have sold and reflect the reuse of redundant assets in the current AA period.

Our capital base for AA6 is determined from the closing value of the capital base for AA5 and then adjusted for forecast capex, depreciation and inflation during AA6.

Our forecast of depreciation is required to be set:

- so that our prices vary over time in a way that promotes the efficient growth in the market for reference services provided by our business;
- so that our assets are depreciated once over their economic life;
- to allow for changes in the expected economic life of particular assets; and
- to allow for our reasonable needs for cash flow to meet our costs.

The value of our forecast of regulatory depreciation for AA6 is consistent with the approach that we took, and which the ERA approved, for AA5. We retained this approach after undertaking significant work examining other approaches in the light of potential long run demand for the DBNGP. The means by which we assessed an appropriate amount for depreciation is explained in Chapter 6 (Future of Gas).

Depreciation is also influenced by the outcome of the asset recategorisation process undertaken as part of the ERA's Final Decision in AA5. This process gave rise to an amount of unrecovered asset from previous AAs which the ERA spread over several AA periods (see Final Decision [1435] to [1443]. This has been incorporated into our tariff model over AA6 and AA7.

10.2 Stakeholder engagement

We engaged extensively with our shippers in respect of depreciation (covered in Chapter 6), capital expenditure (Chapter 9) and the ERA’s approach to inflation (Chapter 11). A summary of the outcomes of those engagement processes is contained in each chapter. We did not engage explicitly on the capital base itself, as it is an outcome of all of these processes.

- However, in response to our Draft Plan, stakeholders did ask us to:
- Present the 2021-25 capital base roll-forward in nominal dollar terms to show the individual drivers of the roll-forward and the basis of the opening capital base value for the AA6 period, and
- ensure that only assets with carrying value are included in the roll-forward.

In respect of the nominal roll-forward, we present the RAB in dollars of December 2024 to make them relatable to the reference tariff. We have explained the effects of indexing to the shipper concerned in separate communication to address their specific issue.

In respect of the second point, both we and the ERA ensure through a series of checks that only asset values with a positive carrying value are included in the roll-forward.

10.3 Capital base at 1 January 2026

We have adjusted (or rolled forward) our capital base as at 1 January 2026 for actual capex and inflation, and for forecast depreciation over the remainder of the current AA5 period. Table 10.1 shows the adjustments we have made to our capital base over AA5, however, as it is shown in dollars of December 2024, it does not show the impact of inflation.

10.4 Capital base at 31 December 2030

This section discusses the forecast adjustments made to the capital base over the next AA period.

Table 10.1: Roll forward of the capital base 2021 to 2025 ($million, Dec 2024)

	2021	2022	2023	2024	2025
Capital base at 1 January	4,003.6	3,833.4	3,741.3	3,655.6	3,555.2
Plus Conforming Capex	45.0	44.9	53.5	39.2	39.0
Less					
Disposals and redundant assets	-	-	-	-	-
Depreciation	-215.2	-137.0	-139.2	-139.6	-141.1
Capital base at 31 December	**3,833.4**	**3,741.3**	**3,655.6**	**3,555.2**	**3,453.1**

Table 10.2: Forecast capex by regulatory asset category in AA6 ($million, Dec 2024)

	2026	2027	2028	2029	2030
Pipeline	0.2	0.2	0.2	0.3	0.2
Compression	7.8	6.7	8.1	5.3	5.3
Metering	8.8	8.8	5.9	4.2	4.1
BEP Lease	1.4	1.6	1.1	1.3	1.1
Computers & Motor Vehicles	17.8	11.9	8.6	12.3	8.3
SCADA/ECI/Comms	5.5	4.9	4.5	4.4	4.3
Cathodic/Corrosion protection	18.2	16.4	16.1	17.3	13.3
Other	1.4	23.4	17.8	6.6	2.6
Total capex	**61.1**	**73.9**	**62.3**	**51.6**	**39.2**

Table 10.3: Proposed asset categories and lives

Proposed AA6 asset categories and lives	Asset life (years)
Pipeline	Capped at 2063
Compression	30
Metering	30
BEP Lease	57
Computers & Motor Vehicles	5
SCADA/ECI/Comms	10
Cathodic/Corrosion protection	15
Other	10

10.4.1 Capital expenditure

Our forecast capex was discussed in Chapter 9 of this Final Plan and is reproduced in Table 10.2. The asset categories are consistent with those applied in AA5.

10.4.2 Forecast depreciation

The value of our forecast of straight-line depreciation for AA6 is $822 million, which reflects the:

- approach we took to depreciation reflecting the future of demand for gas (described in Chapter 6);
- results of the asset recategorisation approach approved in the ERA's Final Decision for AA5 (described briefly above); and
- the standard economic lives of asset classes outlined in Table 10.3.

Table 10.4 shows our forecast straight-line depreciation for the AA6 period.

Table 10.4: Forecast straight line depreciation for AA6 ($million, Dec 2024)

	2026	2027	2028	2029	2030
Pipeline	84.9	84.9	84.9	84.9	84.9
Compression	24.9	25.1	25.4	25.6	25.8
Metering	2.4	2.7	3.0	3.1	3.3
BEP Lease	28.1	3.2	2.7	2.6	2.4
Computers & Motor Vehicles	21.1	15.1	14.9	10.8	12.0
SCADA/ECI/Comms	16.1	4.5	4.3	4.4	4.6
Cathodic/Corrosion protection	49.5	11.5	12.4	13.6	14.6
Other	0.1	0.3	0.8	1.1	1.3
Cost of Raising Equity	0.2	0.3	0.3	0.4	0.4
BEP Lease	0.5	0.5	0.5	0.5	0.5
Total straight-line depreciation	**227.8**	**148.1**	**149.2**	**147.3**	**149.8**

Table 10.5: Forecast regulatory depreciation over AA6 ($million, nominal)

	2026	2027	2028	2029	2030
Straight line depreciation	241.4	160.3	165.1	166.5	173.1
Less inflation	78.2	76.1	76.0	75.6	74.9
Regulatory depreciation	**163.2**	**84.2**	**89.1**	**90.9**	**98.2**

10.4.3 Inflation

Forecast inflation is a critical element in determining our total revenue and pricing. As explained earlier, forecast inflation is used to adjust the capital base over AA6. This forecast is later updated for actual inflation as AA6 progresses.

Forecast inflation is also used in determining the total revenue that we can recover (and hence the prices we can charge). This is reflected in the methodology that the ERA uses to determine our total revenue, which relies on inflation to determine the following two costs:

- Return on capital—which is calculated by multiplying a nominal rate of return (see Chapter 11) by the nominal capital base determined in this section (where a nominal value includes the impact of inflation); and
- Regulatory depreciation—which is calculated by deducting from forecast straight-line depreciation (see Table 10.5) the forecast inflation adjustment applied to the capital base.

The ERA removes inflation when calculating regulatory depreciation to remove the additional compensation for inflation in determining the return on capital, which arises from multiplying a nominal rate of return by a nominal capital base (referred to as a double count of inflation).

The ERA requires the application of the break-even approach to forecast inflation for an AA period, which is detailed in its Rate of Return Guidelines. This approach uses the difference between nominal and inflation-indexed Commonwealth Government bonds to derive a forecast of inflation. The forecast is made before the Final Decision.

Applying the ERA's approach to forecast inflation for the Final Plan provides an estimate of 2.18% per annum over AA6.

10.4.4 Forecast closing capital base

The forecast roll forward of our capital base over AA6, taking into account forecast depreciation, capex and inflation, is set out in nominal terms in Table 10.6: Forecast capital base over AA6 ($million, nominal), while Table 10.7 presents the same information but in $December 2024. In nominal terms, or capital base declines over the period from $3,581 million as at 1 January 2026 to $3,379 million as at 31 December 2030.

10.5 Summary

We have adjusted our capital base over AA5 and AA6 to reflect actual and forecast capex, depreciation, including an assessment of future demand and how that changes prudent depreciation profiles, and inflation.

The lower value of the asset base to start AA6 has already delivered lower prices to shippers; we shared an impact of roughly 10 cents per GJ with shippers compared to what they would have paid if we had not taken the steps in respect of depreciation that we took in AA5.

Based on current information and assuming no significant shocks to the various building blocks, we believe our approach to depreciation, through a falling capital base, will continue to deliver price reductions through time.

Table 10.6: Forecast capital base over AA6 ($million, nominal)

	2026	2027	2028	2029	2030
Capital base at 1 Jan	3,580.8	3,484.2	3,481.5	3,462.7	3,431.1
Plus Inflation	78.2	76.1	76.0	75.6	74.9
Plus Conforming Capex	66.6	81.5	70.3	59.3	46.1
Less Disposals and redundant assets	-	-	-	-	-
Less Depreciation	-241.4	-160.3	-165.1	-166.5	-173.1
Capital base at 31 December	**3,484.2**	**3,481.5**	**3,462.7**	**3,431.1**	**3,379.1**

Table 10.7: Forecast capital base over AA6 ($million, Dec 2024)

	2026	2027	2028	2029	2030
Capital base at 1 Jan	3,453.1	3,288.1	3,215.3	3,129.6	3,034.8
Plus Conforming Capex	62.9	75.3	63.6	52.4	39.9
Less Disposals and redundant assets	-	-	-	-	-
Less Depreciation	-227.8	-148.1	-149.2	-147.3	-149.8
Capital base at 31 December	**3,288.1**	**3,215.3**	**3,129.6**	**3,034.8**	**2,924.9**

11 Financing costs

We have set our financing costs in line with the regulatory Rate of Return Instrument (RoRI) resulting in a rate of return of 6.93% and total financing costs of $749 million in AA6.

IN THIS CHAPTER:

- **We have followed the ERA's Rate of Return Instrument**
- **The rate of return for AA6 is estimated to be 6.93%, compared to 3.54% in AA5**
- **The significant increase to the rate of return reflects much higher recent government bond rates**
- **As a result, financing costs have increased to $749 million in AA6, up from $430 million in AA5**
- **The tax allowance for AA6 is $100 million, up from $45 million in AA5**

Financing the $3.45 billion investment in the DBNGP is our largest cost.

Achieving a reasonable rate of return is essential to attract the necessary funding from shareholders and debt providers, and to continue to invest in our pipeline. We also estimate a regulatory tax allowance to cover the cost of tax over AA6.

The following sections outline our approach to calculating financing costs in AA6. All numbers quoted are dollars of December 2024, unless otherwise labelled.

11.1 Regulatory framework

We have applied the ERA's Rate of Return Instrument (RoRI), published in December 2022 and amended in September 2023, to calculate our allowed financing costs. Pipelines and the ERA are required by the NGL and NGR to use the RoRI to determine financing costs.

In addition, we also must estimate the cost of tax using a specified methodology accepted by regulators. This methodology considers our forecast taxable income, the applicable corporate tax rate and the value of imputation credits (gamma) to equity holders.

11.2 Overview

Our real financing costs account for 47% of our required revenue. Financing costs represent the cost of financing our capital base and meeting our tax obligations. Our forecast of total financing costs for AA6 is:

- $749 million return on asset; and
- $100 million in cost of tax.

Both have been calculated in accordance with the RoRI.

Note that the return on asset for AA6 ($749 million) is significantly larger than was the case in AA5 ($430 million) and is the largest single driver of the price increase in AA6. Although there are some changes in the ERA's approach in estimating the return on asset from its 2018 Rate of Return Guideline (which was used for AA5) and the 2022 RoRI, the increase is due primarily to changes in government bond rates, which have risen from 0.29% to 3.96%.

11.3 Stakeholder engagement

As outlined in Chapter 5 of this Final Plan, stakeholder engagement is a key aspect of our approach to developing our plans for 2026–30. We held several Shipper Roundtables to engage on key areas of our planning, including our financing costs.

Our Shippers understand that we must apply the 2022 RoRI in determining our financing costs, that financing costs are driven primarily by government bond rates at the time the ERA makes its Final Decision for AA6, and, therefore, that financing costs in this Final Plan are indicative only.

A summary of stakeholder feedback regarding our financing costs and how we have responded is summarised in Table 11.1.

Table 11.1: Summary of customer and stakeholder engagement on our financing costs

Topic	Customer and Stakeholder Feedback	Our Response
Financing Costs	**Stage 1 & 2 Engagement: Developing our Plans**	
	• Stakeholders acknowledged our intentions to adopt the ERA's Rate of Return Guidelines in formulating our plans, consistent with the approach taken for our other assets. • A Shipper asked what the actual financial performance compared to the projected performance for AA5 was due to the significant expected increase in the WACC, and how has this impacted the formulation of AA6 pricing. • Shippers requested we provide an overview of the WACC calculations and our current gearing level.	• We responded that the Rate of Return Instrument (RoRI) served as a binding instrument that determined the methodology for estimating our WACC and our rate of return in AA6. We note the RoRI is published on the ERA website. • We explained to Shippers how the annual adjustment of the debt-risk premium is determined by the ERA. • We explained the WACC to be used for the AA6 Final Decision would be determined later in the process and that we will maintain transparency by clearly displaying the components of the calculation. • We presented our current rate of return and financing calculations for AA6 in the Draft Plan.
	Stage 3 Engagement: Draft Plan Consultation • **Do you have any comments on our approach to setting the financing and tax costs in the Draft Plan?**	
	• In the Roundtable it was asked what analytical methods we use to evaluate the rate of return for making business decisions, and if assume any risk related to interest rates.	• We responded to a Shipper query that the Rate of Return fluctuates in line with the market movement affecting the cost of debt and risk-free rate, and clarified that unspent CAPEX cannot be carried over to future periods. Interest rate fluctuations drive price increases, and we mitigate some of this risk through hedging. The cost of debt is based on actual data, and we only recover what the ERA approves, noting not benefit to AGIG or customers from higher interest rates. • We commented our goal is to maintain price stability; however, this does not guarantee that prices will remain unchanged, because of the way the WACC operates.
	Stage 4 Engagement: Refining our Plans	
	• No further information was requested in relation to financing costs.	• We presented the WACC approach, following the ERA's RoRI, and provided a summary of where rate of return had moved since the Draft Plan.
	Final Plan Outcome	
	• We have applied the regulatory Rate of Return Instrument, based on data on interest rates from September 2024, giving a WACC of 6.93%. This will be finalised in the ERA's Final Decision.	

11.4 Return on asset

Our return on asset is determined based on an estimate of the return on equity and the return on debt to be incurred over AA6.

11.4.1 Return on equity

The return on equity reflects the return required by shareholders to invest in the pipeline. Unlike the return on debt, it is not possible to observe the return on equity required by shareholders in the market. This means that we are required to use financial models and other market evidence to inform the estimate of the return on equity required by shareholders.

The ERA estimates the return on equity using the Capital Asset Pricing Model, which requires the following three parameters to be estimated:

- the risk-free rate—which measures the return an investor would expect from an asset with no risk. It is estimated based on the interest rate on Australian Commonwealth government bonds with a ten-year term;
- the market risk premium—which reflects the expected return over the risk-free rate that investors require to invest in a well-diversified portfolio of risky assets; and
- equity beta—which measures the sensitivity of an asset's returns relative to movements in the overall market returns.

In the RoRI, the market risk premium and equity beta are fixed. The risk-free rate is estimated based on a 20-day window close to the time of the ERA's Final Decision. The return on equity is fixed during AA6.

For the purposes of this Final Plan, we have chosen an estimate based on data for September 2024. The indicative return on equity is 8.23%, shown at Table 11.2.

Table 11.2: Indicative return on equity

Parameters	Value
Equity risk-free rate	3.96%
Beta	0.7
Market Risk Premium	6.1%
Return on equity	**8.23%**

11.4.2 Cost of debt

The cost of debt reflects the interest rate required by debt holders. Much like the return on equity, the cost of debt can be thought to comprise a base interest rate and a risk premium, in this case referred to as the debt risk premium. The approach for estimating the return on debt is prescribed in the RoRI.

The cost of debt is observable in the marketplace and the ERA makes use of market data by summing:

- the five-year swap rate chosen just prior to the Final Decision;
- an allowance for swapping and hedging (fixed at 0.288%); and
- an estimate for the premium above the ten-year swap rate of ten-year, BBB+ corporate debt, formed as a ten-year trailing average and estimated using the ERA's bespoke index methodology.

The return on debt will be updated annually for the trailing average debt risk premium during AA6.

Based upon data for September 2024, the indicative cost of debt for this Final Plan is 5.87%, as shown at Table 11.3.

Table 11.3: Indicative cost of debt

Parameters	Value
Debt risk-free rate	3.76%
Debt Risk Premium	1.82%
Debt raising costs	0.165%
Hedging costs	0.123%
Cost of debt	**5.87%**

11.4.3 Rate of return

The ERA assumes gearing of 55%. This means it is assumed 55% of our total financing costs relate to debt, with the remaining 45% relating to equity. Applying these percentages to the return on equity (8.23%) and cost of debt (5.87%) results in an overall rate of return of 6.93% over AA6, as shown in Table 11.4.

Table 11.4: Indicative rate of return

Parameters	Value
Return on equity	8.23%
Cost of debt	5.87%
Gearing	55%
Rate of return	**6.93%**

11.5 Cost of tax

Our tax costs are based on an assessment of our taxable income, the applicable corporate tax rate and the value of imputation credits (gamma) to equity holders.

11.5.1 Calculating the tax allowance

The taxable profit is total revenue (excluding the cost of tax) less opex, tax depreciation and interest expense, where:

- Total revenue—is the sum of all of our costs except the cost of tax (see Chapter 14);
- Opex—is a specific building block that is used to determine total revenue (see Chapter 8);
- Tax depreciation—is based on the calculation of the tax asset base in any particular year
- Interest expense—is determined by multiplying the cost of debt (of 5.87%) by 55% of our capital base in each year, reflecting the debt funded proportion of the total capital base (see Chapter 10).

The corporate income tax rate is set at 30% consistent with the prevailing corporate tax rate applying in Australia, as per the ERA's requirements. This is then applied to taxable income to obtain a cost of tax.

This cost of tax is then multiplied by 'gamma' which represents the value of imputation credits. This gives the value of the tax allowance which we are able to recover.

In the RoRI, gamma is set at 0.5. This means our effective tax rate is half of the corporate tax rate.

Table 11.5: Roll forward of the tax asset base ($million, nominal)

	2026	2027	2028	2029	2030
Opening tax asset base	549.7	487.4	451.9	402.8	373.2
Plus Gross Capex	66.6	81.5	70.3	59.3	46.1
Less Tax depreciation	128.9	117.0	119.4	88.9	90.7
Closing tax asset base	**487.4**	**451.9**	**402.8**	**373.2**	**328.6**

Table 11.6: Total tax allowance ($million, December 2024)

	2026	2027	2028	2029	2030
Gross estimated tax cost	55.6	31.4	31.4	40.6	41.1
Less Imputation credits	27.8	15.7	15.7	20.3	20.5
Tax Allowance	**27.8**	**15.7**	**15.7**	**20.3**	**20.5**

11.5.2 Tax depreciation

Tax depreciation is used to determine the estimate of taxable income and to update the value of our Tax Asset Base (TAB). Our approach to determining tax depreciation is consistent with that applied in previous AAs and the ERA's requirements.

11.5.3 Tax asset base

The opening TAB of $550 million as at 1 Jan 2026 has been adjusted for the same forecast of capex used to determine the capital base (see Chapter 10) plus capital contributions received, and a forecast of tax depreciation over AA6 shown in Table 11.5.

11.5.4 Tax Allowance

Using the above information, the tax allowance to be recovered in AA6 is summarised in Table 11.6. The gross tax allowance is the corporate tax rate multiplied by taxable profits, and taxable profits are formed as revenues minus operating costs, tax depreciation and interest costs.

11.6 Summary

A summary of our key financing cost parameters, developed in accordance with the RoRI, is provided in Table 11.7.

Table 11.7: Summary of financing cost parameters

Parameters	Value
Return on equity	8.23%
Return on debt	5.87%
Overall rate of return	**6.93%**

12 Incentive scheme

The opex incentive arrangement was introduced for the first time in AA5 to further incentivise efficient opex. Amidst significant cost pressures, we have maintained relative opex efficiency in AA5.

IN THIS CHAPTER:

- **While our controllable opex performance is relatively aligned with the benchmark in AA5, we are forecasting a negative efficiency carryover of $21.4 million in AA6. This outcome reflects the higher cost environment we have experienced towards the end of AA5.**
- **We have adjusted our performance against the benchmark on account of a change in our labour cost rate in 2024 and expenditure to address an unforeseen level of defects and other safety-related needs, both of which do not reflect opex efficiency performance.**
- **We propose continuation of the scheme as the only incentive scheme to apply on the DBNGP in AA6.**

We support the E Factor mechanism as an effective, outcome-based incentive scheme that promotes the long-term interests of our customers.

12.1 Overview

From AA5, an operating cost efficiency incentive mechanism has applied to the operating expenditure we incur for delivery of our transmission pipeline services. The operating cost efficiency incentive mechanism is called the E Factor.

Based on our performance in AA5, we estimate that the E Factor efficiency carryover is negative $21.4 million in AA6.

We propose that application of the E Factor continues from AA6. However, we propose an additional exclusion from the calculation of the E Factor: 'Inspections and other asset management' items.

12.2 Regulatory Framework

Under the NGR, an access arrangement may include one or more incentive mechanisms to encourage the efficient provision of services.

Incentive mechanisms provide additional rewards and penalties which can be financial, reputational or administrative (i.e. fast-tracked reviews).

Incentive schemes are often used by regulators to:

- strengthen a service provider's incentive to continuously seek out efficiency and performance improvements and share the benefits with customers;
- balance incentives between opex and capex for the most efficient expenditure mix;
- pursue efficiencies while improving or maintaining service quality; and
- encourage investment in innovation in areas that can provide longer-term benefits to our customers.

12.3 Stakeholder engagement

During Stage 2 of our stakeholder engagement program for AA6, we have held Shipper Roundtables to engage on key areas of our plan. This has included the calculation of the E Factor carryover from AA5 and our intention to continue the scheme into AA6. In Stage 3 of our engagement program, we also engaged further on our proposal for the Scheme in our Draft Plan.

There was no feedback to suggest that our customers are not broadly comfortable with the current framework to incentivise us to incur only efficient operating costs, nor our proposed exclusions in calculating the E Factor benchmark and our performance.

A summary of customer and stakeholder feedback regarding our opex incentive scheme and how we have responded is summarised in Table 12.1.

12.4 How the E Factor works

Similar to the Gain Sharing Mechanism (GSM), applied by the ERA to Western Power, and the Efficiency Benefit Sharing Scheme (EBSS) applied by the AER, the E Factor provides a continuous incentive to achieve efficiency gains.

The E Factor establishes an annual opex benchmark, which is the sum of all forecast opex that is reasonably within our control and has been calculated using the top-down, roll-forward method.

Any forecast opex that is uncontrollable or that has been forecasted by another method (bottom-up build, for example) is not included in the annual benchmark. This is because opex forecast using a bottom-up build (or similar):

- is typically not predictable enough to prevent windfall gains or losses under an incentive scheme; or
- is built up using forecast demand, including both System Use Gas (SUG) and turbine use, and therefore its inclusion in the scheme would counteract the incentive for demand effects.

Each year, if we outperform the benchmark (spend less than the target), we will then be allowed to retain approximately 30% of the saving (referred to as an efficiency gain), with the other estimated 70% returned to customers via a tariff revenue adjustment in AA6.

To ensure the incentive to outperform the opex benchmark is even in each year of an access arrangement period (and spans between periods), the incremental efficiency gains or losses are carried forward for five years.

The E Factor complements the base year approach we apply to forecasting opex by balancing incentives to make efficiencies in all years of the regulatory period.

The E Factor operating alone might incentivise cost reductions to the detriment of service levels or higher capex. However, there are strict conditions in our shipper contracts and operating licences that require us to deliver on public safety, reliability and customer service.

12.4.1 Allowed exclusions

The annual E Factor benchmark in AA5 is the total annual operating expenditure forecast approved by the ERA, including any relevant cost pass through event, less the following E Factor exclusions:

1. movement in provisions (such as related to employee provisions);
2. any operating expenditure sub-category not forecast using a top-down, revealed cost approach. These costs:
   i. may include, but are not limited to, operating costs relating to system use gas (SUG), gas engine alternator (GEA) and turbine overhauls and non-recurrent operating expenditure.
   ii. must not include operating expenditure previously classified as capital expenditure that was forecast on a bottom-up basis.
3. any operating expenditure amount not included in the ERA approved operating expenditure forecast, but that meets the requirements of Rule 91(1) and was incurred for the purpose of reducing capital expenditure; and
4. any other operating expenditure amount that the ERA agrees or requires us to exclude from the E Factor benchmark.

Therefore, under clause 15.11(e) of the AA, we have the option to propose to exclude further costs than those already excluded from the opex base from the calculation of the E Factor where we consider that the exclusion of those costs would be consistent with the revenue and pricing principles and the National Gas Objective.

Table 12.1: Summary of customer and stakeholder engagement on our opex incentive scheme

Topic	Customer and Stakeholder Feedback	Our Response
Incentive Scheme	**Stage 1 & 2 Engagement: Developing our Plans**	
	• Our customers told us that they were broadly comfortable that the current framework regarding the Efficiency factor (E Factor) mechanism appropriately incentivises us to incur only efficient opex.	• During Stage 2 of our stakeholder engagement program, we held Shipper Roundtables to engage on key areas of our plan, including our proposed continuation of the E Factor incentive scheme for AA6.
	Stage 3 Engagement: Draft Plan Consultation • **Do you support our proposed calculation of the Efficiency Carryover Mechanism (ECM) for AA5?** • **Do you support our proposed continuation of the ECM in AA6 and the proposed exclusion of 'inspections and asset management' items?**	
	• Stakeholders continued to indicate broad agreement for the proposed E Factor calculation to apply in AA6 with no concerns identified. • One Shipper requested that we indicate the estimated benefit in AA6 by way of a tariff reduction ($/GJ) from the impact of the negative E Factor carryover.	• We presented at Shipper Roundtable No. 4 the key opex drivers for AA5 and AA6, noting implications from the current high-cost environment. • We shared our preliminary E Factor forecast for AA5 and proposed that the labour cost rate update be excluded from the calculation. We also proposed that 'Inspections and other asset management' items be excluded in AA6 on the basis that expenditure has been driven by inspection outcomes and pipeline safety and reliability objectives rather than efficiency. • We have included the equivalent tariff benefit from the E Factor negative carryover in Chapter 12 of this Plan.
	Stage 4 Engagement: Refining our Plans	
	• No further feedback was received.	• We presented at Roundtable No. 5 the current E Factor carryover forecast of negative $48 million, based on forecast AA5 opex performance at that stage, noting it would be subject to further revisions ahead of the Final Plan.
	Final Plan Outcome	
	• We have proposed continuation of the E Factor incentive scheme to apply to our opex in AA6 with the additional exclusion of 'Inspections and other asset management' non-recurrent cost items. We have recalculated the E Factor carryover in AA5 (based on our final AA5 opex forecasts) to be negative $21 million with this exclusion, as well as adjusting for the impact from the update to labour cost rates. This results in a 2c/GJ benefit to our Shippers in AA6.	

12.5 AA5 opex performance

We are forecasting an efficiency carryover of negative $21.4 million in the next AA period from the operation of this scheme in AA5 (see Table 12.2).

Our opex performance in the current period is discussed in more detail in Chapter 8. Our opex forecasting approach relies on actual incurred opex in the penultimate year of an AA period being efficient (currently forecast to be $72.8 million, with proposed exclusions (SUG, GEA/turbine overhauls, movement in provisions and the labour cost rate update).

12.5.1 Our proposed AA5 exclusions

Our total opex performance from 2021 to 2024 is estimated to be $435.8 million ($Dec2024). For the purpose of the E Factor, we have excluded $103.0 million in SUG and $34.0 million in overhauls from our AA5 opex performance estimate. We have further excluded $8.4 million for the movement in employee provisions in 2021 to 2024. These types of omissions were explicitly agreed by the ERA in the benchmark allowance.

In addition, we have excluded $8.5 million in employee expenses in 2024 associated with our update to our labour cost rates for DBNGP staff, which has seen a lower allocation to capex. The effect of the change should be excluded from the calculation of our opex performance because it helps to reduce capital expenditure for the business, it does not reflect our opex efficiency performance, and the original benchmarks were set under the old labour charge out rate.

We also excluded $12.9 million in expenditure on 'Inspections and other asset management' since the higher expenditure was driven by the need for additional inspections, including related to investigations for defects, asset corrosion, as well as new projects for the replacement of critical spares and the development of essential training modules for process safety. These activities were beyond our control since maintaining the safety and reliability of the pipeline is most critical. Accordingly, we also removed these items from the benchmark.

12.5.2 Our proposed AA6 exclusions

In addition to the list of exclusions which have applied in AA5, we also propose that our 'Inspections and other asset management' expenditure be excluded from the calculation of the AA6 E Factor benchmark. Chapter 8 provides more detail on the nature of this expenditure which is generally non recurrent and can be dependent on factors outside our control of efficiency (such as asset condition, throughput and climatic factors). In addition, when unforeseen events occur (such as more defects being identified in pipe), the need for more expenditure might be necessary to ensure the integrity of the pipeline. For these reasons, the proposed exclusion of Inspections and other asset management expenditure is consistent with other approved exclusions from the E Factor benchmark.

12.6 Summary

We forecast a negative efficiency carryover of $21.4 million as the outcome of the opex efficiency carryover scheme in AA5 (see Table 12.2).

We propose that the E Factor scheme continues to apply in AA6 as it has in AA5 but that 'Inspections and other asset management' items be excluded from the calculation of the benchmark.

Table 12.2: Efficiency carryover mechanism

$million (Dec2024)			**AA5 period**					**AA6 period**			
Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**Total**
Opex benchmark (A)	73.3	73.4	73.5	73.5	73.6						
Opex actual (B)	65.3	62.8	68.0	72.8	72.9						
Cumulative saving (C = A - B)	8.0	10.6	5.5	0.7	0.7						
Incremental saving (C_n - C_{n-1})	8.0	2.6	-5.1	-4.8	0.0						
Carryover of incremental gain/loss made in year:											
Year 1		8.0	8.0	8.0	8.0	8.0					
Year 2			2.6	2.6	2.6	2.6	2.6				
Year 3				-5.1	-5.1	-5.1	-5.1	-5.1			
Year 4					-4.8	-4.8	-4.8	-4.8	-4.8		
Year 5						-0.0	-0.0	-0.0	-0.0	-0.0	
Total Carryover:						0.7	-7.4	-9.9	-4.8	0.0	**-21.4**
Benefits to business (30% based on sum in NPV terms)											
(Cumulative saving + carryover)	8.0	10.6	5.5	0.7	0.7	0.7	-7.4	-9.9	-4.8	0.0	+0 p.a. to year 30
Benefits to customers (70% based on sum in NPV terms)											
(Cumulative saving + carryover 6 years deferred)						0.0	8.0	10.6	5.5	0.7	+0.7 p.a. to year 30

13 Demand

Our forecast of demand for reference services has two components: contracted capacity and throughput. Our forecast has been reconciled to AEMO's December 2024 Gas Statement of Opportunities.

IN THIS CHAPTER:

- **We discuss demand for reference services on the DBNGP which requires a forecast of both contracted capacity (reserved capacity) and throughput (utilisation of reserved capacity) for the AA6 period, and we outline how our forecasts have been determined**

Demand for our services drives our operations and is also a key determinant in calculating reference tariffs.

Western Australia's energy sector continues to undergo a transition toward a net zero emissions economy. Chapter 6, Future of Gas, describes many of the changes occurring as part of the energy transition including the growth of renewable electricity and the state government's policy to retire coal fired electricity generators. These changes have had (and will have in the case of coal retirements) a significant effect on gas demand and the use of the DBNGP.

These forces make forecasting demand on the DBNGP challenging, which is why we rely on the contracted capacity of our shippers to forecast demand for AA6, as we did for AA5.

Our Final Plan forecast for contracted capacity is 548.6 TJ per day average Full Haul Equivalent (FHE) and 481.1 TJ per day average for throughput FHE. This continues a trend observed since AA3 of Shippers relinquishing Full Haul capacity.

Our contracted capacity forecast for each reference service for AA6 relies on the capacity that our Shippers have contracted with us. Our throughput forecast utilises the contract capacity with a utilisation factor applied. This is the same approach as applied and accepted by the ERA for AA5.

The following sections outline our demand outcome in AA5, our approach to forecasting demand for AA6 and the verification processes we have undertaken.

There are also two confidential attachments in support of our demand forecast:

- Attachment 13.1 - which contains confidential information about demand from AA5, and reconciles our AA6 throughput forecasts with the GSOO
- Attachment 13.2 capacity schedules from contracts with our major shippers.

13.1 Regulatory Framework

Our AA proposal should include a forecast of pipeline capacity and utilisation for reference services over the AA6 period that must:

- be arrived at on a reasonable basis; and
- represent the best forecast or estimate possible in the circumstances.

13.2 Stakeholder engagement

We have discussed our demand forecasts with shippers as part of the Roundtable process and individually summarised in Table 13.1. Given the commercially sensitive nature of each shipper's demand profile, one-on-one sessions have comprised the bulk of our consultation on demand.

Table 13.1: Summary of customer and stakeholder engagement on demand

Topic	Customer and Stakeholder Feedback	Our Response
Demand	**Stage 1 & 2 Engagement: Developing our Plans**	
	• Shippers asked about our plans to increase the capacity of the DBNGP, including an increase in demand resulting from AA5. • It was asked if the peakiness on the asset held any inherent value when considering overall demand. • Shippers were generally interested in how decarbonisation impacted our future needs.	• We provided our demand approach for the Draft Plan in AA6 noting it will be the same as for AA5. • We also acknowledged the current variability on the asset and its potential value concerning overall demand. • Separate to the Roundtables in Stage 2 we engaged directly with Shippers to assist with demand forecasts to ensure a reasonable degree of certainty.
	Stage 3 Engagement: Draft Plan Consultation • **Do you support our proposed approach to forecasting demand?** • **Are there any other factors, including any of your own plans, you think we should consider?**	
	• It was asked whether the demand for AA5 was equivalent to that projected for AA6. • A Shipper asked if the loads were assumed to be contracted on a long-term basis, or if they pertained to retail loads with contracts of up to three years. • It was asked if the increase in gas-powered generation (GPG) was primarily driven by capacity considerations. • A Shipper asked whether AGIG had considered that there is the potential for contracted full haul equivalent capacity will increase significantly to several WA energy market factors such as an increase in Perth Basin supply and coal power closures.	• At the Shipper Roundtable we confirmed the finalisation of the AA6 forecast on best available information. Demand will be updated as further information becomes available. • We informed Shippers of a 48 TJ reduction from the previous update which is included in this plan. • We confirmed that demand for AA5 was used in our planning for our plans, noting demand remains level for 90% of Shippers. • We confirmed that the demand projections for AA6 in the Draft Plan are quite similar to the current levels in AA5, with many Shippers experiencing stable capacity and utilisation. We have however updated for customer plant closures. • We stated that the contracting period depends on the Shipper and the service in question, and acknowledged that the situation varies by case, with some contracts extending long-term and others being limited to shorter agreements. • While market averages are considered, a segment of the market is still outstanding, but it is not expected to differ significantly from AA5.
	Stage 4 Engagement: Refining our Plans	
	• Shippers asked if any new facilities were expected to be added in the future.	• We presented planned closures for the 5-year plan, leading to a 48TJ reduction from our previous update and to be included in this Final Plan.
	Final Plan Outcome	
	• Our demand forecast is based on the most recent information predominately set in contracts and recent utilisation of their reserved capacity. It has also been checked against the AEMO's Gas Statement of Opportunities (GSOO) forecasts. Some Shippers are still finalising their position, and we expect some updates to the forecast during 2025.	

13.3 Demand during AA5

In this section, we provide an overview of demand during AA5, utilising RIN data provided to the ERA.

13.3.1 Reference service demand

Reference service capacity demand data is shown in Table 13.2 while reference services throughput demand is shown in Table 13.3.

In respect of contracted capacity for Full Haul shippers, the only significant difference from the AA5 forecast occurred in 2023, when one new contract was signed. Part and back-haul contracts do differ from forecast through the period, as shippers change between their part and back-haul contracts when their needs change. The different distance factors in different contracts explain the majority of the variances observed against forecast.

Throughput is similar to capacity when it comes to a comparison between forecast and actual, in particular in respect of the throughput of part and back-haul.

Finally, we report the number of shippers at inlet and outlet points in Table 13.4. The results are largely similar to AA5.

Table 13.2: Capacity demand 2021-23(TJ/d)

	2021	2022	2023
Full Haul T1			
Benchmark	606.1	591.1	570.3
Actual	609.2	602.9	611.3
Part Haul P1 (FHE)			
Benchmark	26.0	25.4	26.9
Actual	24.6	22.9	33.7
Back Haul B1 (FHE)			
Benchmark	18.1	17.3	17.3
Actual	23.4	24.5	27.4
Total (FHE)			
Benchmark	**650.1**	**633.7**	**614.5**
Actual	**657.2**	**650.4**	**672.4**

Table 13.3: Throughput demand 2021-25 (TJ/d)

	2021	2022	2023	2024	2025
Full Haul T1					
Maximum	610.1	600.6	601.4	488.7*	454.2*
Average	562.8	550.2	536.8	488.7	454.2
Minimum	494.6	480.8	459.2	488.7*	454.2*
Benchmark	555.3	540.8	521.6	465.9	459.6
Part Haul P1					
Maximum	204.7	173.5	210.2	123.3*	129.7*
Average	107.8	124.8	140.8	123.3	129.7
Average (FHE)	18.4	17.4	26.0	n/a	n/a
Minimum	64.3	77.9	81.4	123.3*	129.7*
Benchmark	133.0	133.2	139.6	196.0	182.4
Benchmark (FHE)	17.7	17.9	19.6	34.0	36.3
Back Haul B1					
Maximum	313.5	316.3	363.0	276.5*	268.7*
Average	268.0	271.9	282.0	276.5	268.7
Average (FHE)	19.5	20.2	20.4	n/a	n/a
Minimum	161.2	165.1	172.0	276.5*	268.7*
Benchmark	175.9	165.7	165.7	165.7	165.7
Benchmark (FHE)	13.9	13.3	13.3	13.3	13.3

*2024 and 2025 values are forecasts of average. We do not forecast maximum and minimum.

13.4 Non-reference service demand

Demand for non-reference services is summarised in Table 13.5, comparing forecast with actual. Note that not all actual results are available due to confidentiality constraints.

There is little correlation between forecast and actual demand for non-reference services. This is expected as these services are classified as non-reference services because they are not predictable.

This is exemplified by the Pilbara Service. This is a service which producers in the Pilbara use to facilitate transfers between each other in the region. The service is often used as insurance for when a supplier may need to use an alternate facility.

During 2023, demand for this service increased rapidly when incidents at three separate production facilities (Varanus Island, Devil Creek and Wheatstone) removed around 60 percent of daily gas production from the WA gas market. As a result, line-pack on the pipeline approached critical levels and the State Government activated its emergency management plan for energy supply disruptions to ensure supply to critical gas users, such as electricity generators.[11] Producer issues continued for nearly three months, restricting the supply of gas and increasing the secondary gas supply market.

Events such as this, which are unpredictable, make the Pilbara Service unpredictable. This is why

Table 13.4: Inlet and outlet points (current as at November 2024)

Inlet point	Number of shippers	Outlet point	Number of shippers
DDR	24	Full Haul	14
Pluto	19	Part Haul	20
MLV7 Interconnect	6	Back Haul	21
Devil Creek	22		
Gorgon	26		
Macedon	24		
Wheatstone	23		
Varanus Island	25		
Waitsia	7		
Mondarra	9		

Table 13.5: Non-reference service demand – forecast and actual (TJ/day)

	2021	2022	2023	2024	2025
Forecast					
Rebateable non-reference services					
Spot Capacity Service	4.2	4.2	4.2	4.2	4.2
Other Reserved Services	39.0	39.0	39.0	39.0	39.0
Peaker Service	n/a	n/a	n/a	n/a	n/a
Ullage (Backflow) Service	n/a	n/a	n/a	n/a	n/a
Other non-reference services					
Storage Service	1.4	0.68	-	-	-
Pilbara Service	30.0	30.0	30.0	30.0	30.0
Actual					
Rebateable non-reference services					
Spot Capacity Service	24.6	34.2	22.7		
Other Reserved Services	42.6	25.8	22.2		
Peaker Service	n/a	n/a	n/a		
Ullage (Backflow) Service	n/a	n/a	n/a		
Other non-reference services					
Storage Service	-	-	-		
Pilbara Service	32.8	34.1	46.7		

[11] *See Economics and Industry Standing Committee, Report 7 – Domestic Gas Security in a Changing World - Inquiry into the WA Domestic Gas Policy: Interim Report, February 2024, p 20 available here, for details.*

we have proposed the Pilbara Service as a rebateable non-reference service in section 7.4 of Chapter 7.

The main drivers of demand for rebateable non-reference services have been:

- Spot – was driven by gas powered generation demand, particularly in 2022 due to unforeseen coal and wind outages in combination with colder than expected weather. Recently, it has been driven primarily by the Wholesale Electricity Market (WEM) reform process which opened electricity support services (previously provided by Synergy) to competition in October 2023. Spot Services are used by gas generators to facilitate additional electricity generation in response to these changes as they compete for the new market.
- Other Reserve Services – have been driven by some small-scale gas trading agreements and some bespoke services for particular shippers. As the ERA is aware, this service is intended to facilitate new product offerings by shippers, and hence its use is always sporadic.

13.5 Demand forecasts for AA6

In this section, we provide an overview of our contracted capacity and throughput forecasts for AA6, and an overview of the process of independent verification of these forecasts that we have undertaken.

The contracted capacity forecasts are provided in Table 13.6 and the throughput forecasts are provided in Table 13.7.

Table 13.5: Contracted capacity forecasts AA6 (TJ/d)

	2026	2027	2028	2029	2030
Full Haul	481.3	494.3	489.3	469.5	472.5
Part Haul	265.1	262.0	245.0	244.0	244.0
Part Haul (FHE)	30.6	34.9	34.2	37.2	37.2
Back Haul	332.6	332.6	332.6	332.6	332.6
Back Haul (FHE)	32.4	32.4	2.4	32.4	32.4
Total (FHE)	**544.3**	**561.6**	**555.9**	**539.0**	**542.0**

Table 13.7: Throughput forecasts AA6 (TJ/d)

	2026	2027	2028	2029	2030
Full Haul	458.9	443.7	434.9	424.1	429.0
Part Haul	144.9	144.4	131.9	131.2	131.2
Part Haul (FHE)	22.3	26.7	25.9	28.9	28.9
Back Haul	174.8	174.8	174.8	174.8	174.8
Back Haul (FHE)	16.4	16.4	16.4	16.4	16.4
Total (FHE)	**497.7**	**486.8**	**477.3**	**469.4**	**474.4**

As in previous AA proposals, our contracted capacity forecasts are based upon actual contracted capacity for AA6 where available. A small number of shippers will be finalised next year and therefore we have relied on the information they have provided to us at this time. Our throughput forecasts are based on the contracted capacity forecast and historic capacity utilisation rates.

We have not included any uncontracted demand for AA6 as we have had no firm indications of intent to require additional capacity during AA6. We note that we followed the same approach during AA5 and, as discussed above, only one additional contract emerged during the five-year period. Moreover, our reconciliation of our AA6 forecast against the GSOO suggests our approach is sound.

We have included a small amount of relinquishment of capacity consistent with the requirements of a shipper.

13.5.1 Independent verification of forecasts

We have followed two approaches to verify our demand forecasts for AA6 as being reasonable.

The first approach to verification is to provide the ERA with the cover page, nomination and term for all of our Full Haul T1 shippers who have completed the process of contracting for capacity in AA6. For the T1 shippers who have not completed this process, we provide letters of commitment and notes from the shippers (Attachment 13.2).

Our T1 shippers comprise 90 percent of our contracted capacity on a full-haul equivalent basis, meaning these contracts cover the vast majority of our capacity for AA6. We note that we have also gone through a process of mapping all of our haulage contracts into our regulatory model consistently and giving each contract a unique identifying number. This has been provided to the ERA in Attachment 13.1. We are also happy to provide other contractual information on a confidential basis to the ERA as required.

The second approach is a reconciliation of our full-haul throughput against the "South-West and Metro" demand component of the most recent GSOO from AEMO (Attachment 13.1). This covers roughly 90 percent of our demand on a full-haul equivalent basis and is the only part of the GSOO forecasts which can be sensibly mapped against our services as the other regional forecasts, and the state total, take in throughput through other pipeline systems. Having said that, however we show in Attachment 13.1 that, taking into consideration flows in other pipelines and the major expansion of Perdaman's Karratha Urea Plant which, despite using a significant amount of gas will utilise very little gas transport on the DBNGP, that our forecast and those in the GSOO for other regions are effectively equivalent.

In respect of the South West, once we take account of gas delivered via non-Full Haul T1 contracts (i.e. gas in Part Haul P1 contracts, gas from non-reference services and gas which flows to the South West via the Parmelia Pipeline), the differences between our forecasts and those of the GSOO relate to:

- the restarting of curtailed plant; and
- fuel switching by industrial producers.

The differences relate to the expected timing of some projects, gas transportation services required during the early stages of those projects and then ultimately the source of the gas, which would dictate if a the Full Haul (T1) or Part Haul (P1) transportation services would be required We show in Attachment 13.1 how, once these issues are considered, our forecasts line up well with the GSOO; particularly considering the gas supply shortages the GSOO predicts may happen during AA6.

13.6 Summary

Our average daily contracted capacity in AA6 is 548.6 TJs on a full haul equivalent basis and throughput of 481.1 TJ/day, around 9% below our AA5 capacity. This continues a trend observed since AA3 of Shippers relinquishing Full Haul capacity.

As with AA5, we have relied on our shippers' contracted capacity when setting the forecast for AA6. We have tested the throughput forecast for AA6 against independent forecasts from the GSOO, which show minimal variance.

In the event that our shippers share new demand information with us during 2025, by either increasing or decreasing nominated capacity in contracts (existing or new), we will share all the required information with the ERA, as it becomes available.

14 Revenue and Prices

Increases to interest rates in AA6 when compared to the historic lows of AA5 has resulted in a higher rate of retunr for AA6, and therefore higher proposed revenues in AA6 than current AA5.

IN THIS CHAPTER:

- **Real revenue increases to $2,309 million in AA6, up from $1,761 million in AA5**
- **Price increases to $2.45/GJ Full Haul Equivalent (FHE) in AA6 compared to $1.57/GJ FHE in AA5.**
- **Key drivers are the return to more normal interest rates in AA6 following historic lows in AA5 and a higher inflationary environment**

Our Final Plan for AA6 reflects a departure from the AA5 period which was marked by unprecedented financial market intervention and low inflation. Revenues for AA6 reflect a return to historically 'normal' financial market conditions.

This Final Plan has described the reference services we will provide (Chapter 7) and the cost of providing those services (Chapters 6 and 8 to 12).

Our costs are referred to as 'building blocks' and are summed to determine total revenue in each year of the AA period (referred to as building block total revenue). We recover this revenue through the prices (or tariffs) that we charge shippers for providing services.

This section sets out the total revenue we require over AA6 and how we will recover this through our reference service prices.

14.1 Regulatory framework

We are required to determine total revenue for each year of the next AA period as the sum of our forecast opex (Chapter 8), return on our capital base (Chapter 11), depreciation of the capital base (Chapter 10) and a forecast of the tax allowance (Chapter 11).

Our prices are required to reflect the efficient cost of providing reference services to our shippers, and this underpins the ERA's assessment of all aspects of our proposal.

14.2 Stakeholder engagement

Through our stakeholder engagement program, Shippers indicated price as a topic they wanted to engage on early in the process.

Stakeholder feedback in respect to overall revenue and prices, and our responses to this feedback, are contained in Table 14.1.

Table 14.1: Summary of customer and stakeholder engagement on our revenue and prices

<table>
<tr><th>Topic</th><th>Customer and Stakeholder Feedback</th><th>Our Response</th></tr>
<tr><td rowspan="6">Revenue and Prices</td><td colspan="2">Stage 1 & 2 Engagement: Developing our Plans</td></tr>
<tr><td>Shippers asked if it was advisable for them to account and plan for rebates in the annual tariff submission given it is recalculated annually.
Shippers sought clarification on the tariff calculation bottom-up process.</td><td>We suggested Shippers plan for rebates in their annual submissions due to the annual recalculation taking into account any potential rebates associated with the annual tariff. However, we made it clear that forecast tariffs do not include any forecast of likely rebates.
We clarified the bottom-up approach accurately reflected the methodology used in the calculation of the tariffs.</td></tr>
<tr><td colspan="2">Stage 3 Engagement: Draft Plan Consultation
Have we provided enough information to understand the basis of our proposed price, including how it is split between the capacity and commodity components?
Do you support the proposed cost pass through for the Safeguard Mechanism costs?</td></tr>
<tr><td>Shippers supported the cost pass through for the Safeguard Mechanism, noting it fair.</td><td>We will propose the cost pass through for the Safeguard Mechanism.
We presented an overview of key price drivers, noting the implications with increased tariff of $2.41 compared to the previous $2.35.</td></tr>
<tr><td colspan="2">Stage 4 Engagement: Refining our Plans</td></tr>
<tr><td>Shippers wanted to be updated on our proposed pricing.</td><td>We continued to provide building block and price updates at Shipper Roundtable meeting as we refined our Final Plan.</td></tr>
<tr><td></td><td colspan="2">Final Plan Outcome
The Future of Gas depreciation applied in AA5 has relieved price pressure in AA6 reducing tariffs by around 10 cents.
Our Final Plan outlines further information on cost allocation and adopts an approach consistent with the approach accepted in AA5.</td></tr>
</table>

Table 14.2: Building block and Smoothed Tariff revenue 2026-2030 ($mil Dec 2024)

	2026	2027	2028	2029	2030
Return on capital	160.4	152.7	149.4	145.4	141.0
Return of capital (depreciation)	227.8	148.1	149.2	147.3	149.8
Estimated cost of tax	27.8	15.7	15.7	20.3	20.5
Operating costs	125.2	127.0	121.2	123.2	134.4
Building Block Revenue	**538.7**	**441.3**	**433.4**	**434.1**	**443.7**
Smoothed Tariff Revenue	**459.5**	**472.4**	**468.7**	**453.6**	**456.2**
0.5% non-reference service allocation**	-2.6	-2.1	-2.1	-2.1	-2.1
Total Smoothed Tariff Revenue	**456.9**	**470.3**	**466.6**	**451.5**	**454.1**

*Total doesn't necessarily equal cost of service due to revenue smoothing and discounting.
** See Chapter 7 for derivation of 0.5% allocation

14.3 Revenue

This Final Plan has set out the derivation of all the relevant building blocks that are used to determine building block total revenue.

We recover the building block revenue through our prices. We are required to set our prices such that the total revenue we recover through prices is the same as the building block total revenue.

The building block total revenue is set out in Table 14.2.

14.4 Prices

As already noted, we recover our revenue through the prices that we charge shippers for providing reference services. This section outlines our proposed prices.

There are two components to our prices:

- a capacity (or reservation) component; and
- a commodity (or throughput) component.

The capacity (or reservation) price is set to cover the fixed costs of delivering reference services and is determined by dividing the sum of the fixed cost elements of our building blocks total revenue by the forecast capacity demand.

The commodity (or throughput) price is set to cover the variable costs, i.e. System Use Gas (SUG), of delivering reference services and is determined by dividing the variable cost components of our building block total revenue by the forecast capacity demand.

As a result of non-SUG costs increasing at a faster rate than SUG costs, the proportion of fixed and variable costs has shifted in comparison to AA5. To reflect this, we have proposed a ratio of the capacity and commodity components of our reference prices in AA6 of 95:5 (compared to 94:6 in AA5).

Table 14.3: Final Plan proposed tariffs

	T1 service ($/GJ)	P1 & B1 services ($/GJ/km)
Capacity reservation charge	2.323912	0.001661
Commodity charge	0.123728	0.000088
Total tariff	**2.447640**	**0.001750**

In line with stakeholder feedback, we have not proposed any changes to the way our costs are allocated between Full Haul (T1), Part Haul (P1) and Back Haul (B1) prices.

In order to calculate T1, P1 and B1 prices, all demand is converted into T1 'full-haul equivalent' demand. For example, a 10 TJ load halfway down the pipeline would have a full-haul equivalent of 5 TJ. The sum of all full-haul and full-haul equivalent loads is used to determine the T1 tariff, which is then converted to a per kilometre price for P1 and B1 services. This is consistent with the approach adopted by the ERA in previous AAs.

Our proposed prices for AA5 are shown in Table 14.3.

14.5 Adjustments to Tariff Variation Mechanism

14.5.1 Safeguard Mechanism

We are proposing an additional factor to be included in the reference tariff variation formulae in relation to the Commonwealth

Government's Safeguard Mechanism.[12]

The Safeguard Mechanism is legislated as part of the National Greenhouse and Energy Reporting Act 2007 and Safeguard Mechanism Rules. It requires facilities in Australia which are responsible for more than 100,000 tonnes of carbon dioxide equivalent per annum to keep their net emissions below an emissions limit (a 'calculated emissions baseline' or simply 'baseline'). Reforms which commenced on 1 July 2023 apply a declining rate to facilities' baselines so that they are reduced predictably and gradually over time on a trajectory consistent with achieving Australia's emission reduction targets of 43% below 2005 levels by 2030 and net zero by 2050.

The DBNGP is a Safeguard facility that is subject to a designated baseline declining over time.

DBNGP can therefore incur costs in complying with the Safeguard Mechanism; either to reduce emissions or to purchase and surrender emissions credits to ensure that net emissions from the network remain within the baseline.

DBP's covered emissions for 2022–23 exceeded the baseline emissions number for the first financial year of the proposed Multi Year Monitoring Plan (MYMP) to 2026–27 that DBNGP had opted to be a part of under the Safeguard Mechanism.

We have committed to a range of activities in the MYMP for the DBNGP to reduce the emissions intensity of the DBP's production variables for natural gas throughput and electricity generation by the end of the monitoring period.

- Pipeline reconfiguration to allow for multi-directional flow of natural gas whilst meeting increased throughput demands, thereby reducing the need for multiple compressors to be running consistently along the pipeline;
- Replacement of seven Gas Engine Alternators (GEAs) with accurately sized and more efficient GEAs at six compressor stations. Note that only one engine will be replaced inside the MYMP timeline; the remainder will be replaced in subsequent years; and
- Replacement of closed-circuit vapour turbines at 19 repeater sites along the pipeline with solar and batteries. Note that six of these turbines will be replaced within the MYMP period. The remainder will be replaced in subsequent years.

These planned decarbonisation activities are reasonably likely to reduce DBP's net emissions number for the MYMP below DBP's facility baseline emission number for the MYMP, to prevent an excess emissions situation which would be unacceptable for the business.

Therefore, we have not proposed any new compliance costs with the Safeguard Mechanism in our AA6 proposal for opex.

Instead, we have proposed amendments to the Reference Tariff Variation Mechanism in Clause 18 of the Access Arrangement to capture the potential unforeseen costs in our reference prices for the Safeguard Mechanism.

This approach is consistent with that applied by the Australian Energy Regulator to recover Safeguard Mechanism costs through the tariff variation mechanism for the three Victorian gas distribution businesses (AusNet Gas Services, Australian Gas Networks and Multinet Gas Networks) for the 2023/24 to 207/28 Access Arrangement periods.[13]

The approach also accommodates the potential variability in the Safeguard Mechanism Amount from year to year.

14.6 Summary

Our Final Plan delivers revenue of $2,309 million over AA6, a real increase of $549 million (31%) compared to current AA5 building blocks with return on asset being the key driver.

Our proposed 1 January 2026 reference price of $2.45 is a 79% price increase for many of our customers from the start of AA5, and a 56% increase on current reference prices, also reflecting marked changes in the inflationary environment since 2021.

The capacity and commodity ratio in AA6 is 95:5, compared to 94:6 in AA5, reflecting forecast non-SUG costs increasing at a faster rate than SUG costs.

Our Part and Back Haul prices will continue to reflect a distance factor of the Full Haul price.

[12] Safeguard-mechanism-reforms-factsheet.pdf (dcceew.gov.au).

[13] Australian Energy Regulator, *Final Decision AusNet Gas Services Attachment 10 – Reference tariff variation mechanism, June 2023, Section 10.1.6.1 p 6.*

15 Pipeline Access

Following our review, we propose amendments to the reference services terms and conditions and the Access Arrangement.

IN THIS CHAPTER:

- **We have undertaken a review of our reference service terms and conditions**
- **Our proposed changes update our reference service contracts**

Our reference service terms and conditions set out the contractual arrangements between DBP and reference service customers and provide a framework for negotiated services.

We provide three reference services - full haul, part haul and back haul services – for which reference service terms and conditions are available and are proposed to be revised as set out below.

We also continue to offer other pipeline services, with specific terms and conditions. For many of these services, our reference service terms and conditions form an appropriate framework for negotiated terms and conditions. We invite any current and prospective shipper to discuss their specific requirements with our commercial team.

15.1 Regulatory framework

Our proposed reference service terms and conditions are set out in the Proposed Revisions to the Access Arrangement (AA Document) as explained at Attachment 15.5 and as required by the NGR.[14]

15.2 Stakeholder engagement

We have engaged extensively with customers and other stakeholders on specific areas of our reference service contracts.

A summary of customer and stakeholder feedback on our terms and conditions for pipeline access and how we have responded are summarised in Table 15.1.

[14] NGR 48(1)(d)(ii).

Table 15.1: Summary of customer and stakeholder engagement on our terms and conditions for pipeline access

Topic	Customer and Stakeholder Feedback	Our Response
Pipeline Access	**Stage 1 & 2 Engagement: Developing our Plans**	

	• At the initial roundtables, Shippers expressed concern about the issue of off-specification gas ("off-spec gas"), including:
	  • why they were liable if specifications aren't met (and not producers or the DBNGP);
	  • why they could not take action themselves and "shut in" producers (i.e. stop flow); and
	  • how the ERA might enforce an amendment to SSCs to shift the risk back to producers, thereby preventing the passing of Gas Chromatograph (GC) costs to Shippers, which was seen as particularly important with changing flow dynamics in the pipeline.
	• Shippers requested further engagement on off-spec gas to address these concerns.
		• The off-spec issue is covered in the current Reference Service Contract (clauses 6 and 7) but we noted that it remained an ongoing issue (given that legacy infrastructure now allows only a few minutes for notifications and there are other challenges with providing timely warnings to Shippers). We indicated that we were exploring ways to improve the notification system.
		• We also explained how:
		  • the framework governing gas specifications is under legislation and beyond our control,
		  • our contractual relationship was solely with Shippers, not the producers of gas, and
		  • we would be installing GCs to monitor gas specifications at inlet points.
		• In the lead up to our Draft Plan we further indicated that we sought feedback from Shippers on our review of our reference service terms and conditions and any other specific issues they sought to be addressed.

	Stage 3 Engagement: Draft Plan Consultation • **Do you have any feedback on the terms and conditions for our reference services?** • **Are there any specific issues that you would like to see addressed through this terms and conditions review?**	

	• Submissions to our Draft Plan asked:
	  • how the review of off-specification provisions in the Reference Service Contracts would interact with a Shipper's SSC, and whether any revisions would be mirrored into existing SSCs; and
	  • whether our review would consider all capacity contracts (existing and new).
		• We explained how any changes to Reference Service Contracts could also be included in the SSCs but individual non-reference contracts could only be updated as they are negotiated or renegotiated.
		• Given the interest from Shippers on the topic of off-spec gas, we decided to hold a dedicated Shipper Roundtable on this topic. We also noted that a new transmission billing system is being introduced (which might also help with notifications).

Stage 4 Engagement: Refining our Plans

- At the dedicated roundtable on off-spec gas, Shippers:
  - sought an understanding of the management of off-specification gas,
  - requested more information on the details of the new process and the scope for receiving automated reports,
  - wanted to understand the impact on the imbalance charging framework.
- Shippers agreed to our proposal to remove the requirement in T&Cs to send notices by fax.
- We advised Shippers of our Final Plan position, acknowledging that Shippers would not see the desired resolution to the off-spec gas issue that they were seeking as our contractual relationship is with Shippers and not the producers of gas, although Shippers could exercise any rights against producers which supply off-specification gas.
- We also responded to questions and explained:
  - the new process, noting it was possible to receive notices in .CSV format;
  - how we use third-party GCs to constantly monitor for Hydrogen Sulphide and Mercury and that we would add GC to legacy inlet points where the process was manual; and
  - advised that there were no changes to the imbalance framework.
- Lastly, we provided an overview of the proposed changes to reference service contracts in AA6 and encouraged Shippers to submit any further queries and feedback to us.

Final Plan Outcome

- Our T&Cs in AA6 have been updated.

15.3 Terms and conditions review

In developing our proposed changes to the terms and conditions in our reference service contracts for AA6, we have reviewed three key issues:

- Off-Specification Gas provisions although no amendments are proposed (refer to the explanation in Attachment 15.1).
- Modifying the restriction on confidential information concerning the generation and sale of electricity so that related body corporates of the Operator would be permitted to generate or sell electricity so long as there is no connection to gas flows on the DBNGP. The rationale is that the existing restriction should not apply in this instance where Shipper gas flows have no relevance to such activities (refer to the explanation in Attachment 15.1).
- The need to clarify that terms of existing reference contracts are deemed to be modified to align with applicable terms under a subsequent Access Arrangement approved by the ERA.

15.4 Summary

Clean and marked-up versions of our proposed terms and conditions for each of our reference services, full haul (T1), part haul (P1) and back haul (B1) are at Attachments 15.2, 15.3 and 15.4 to the Access Arrangement Document.

Our proposed revisions to the DBP Access Arrangement document include:

- an update to the description of the pipeline;
- an update to the provisions relating to signing of access requests; and
- clarification that terms of existing reference contracts are deemed to be modified to align with applicable terms under a subsequent Access Arrangement approved by the ERA.

Submissions supporting the proposed changes and a review of the T1, P1 and B1 reference service terms and conditions (Attachment 15.1) and the Access Arrangement terms (Attachment 15.5) are provided.

Other standard updates relate to our proposals regarding depreciation for establishing the Opening Capital Base, the application of fixed principles, the annual tariff variation mechanism and other definitional changes or corrections.

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