Economic Regulation Authority

Final decision on revisions to the access arrangement for the Dampier to Bunbury Natural Gas Pipeline (2026 to 2030)

Overview

18 December 2025

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We acknowledge their continuing connection to culture and community, their traditions and stories. We commit to listening, continuously improving our performance and building a brighter future together.

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1. Overview

This final decision is the Economic Regulation Authority's response to Dampier Bunbury Pipeline's proposed five-year access arrangement for the Dampier to Bunbury Natural Gas Pipeline. It covers the period from 1 January 2026 to 31 December 2030 (the sixth access arrangement period, referred to as AA6).

To make this decision, the ERA has undertaken a detailed assessment of Dampier Bunbury Pipeline's (DBP) proposal to ensure that all intended expenditure is efficient and prudent, and the reference tariffs and terms and conditions are reasonable.

The Dampier to Bunbury Natural Gas Pipeline (DBNGP) is one of the largest natural gas transmission pipelines in Australia, spanning 1,600 kilometres from Dampier in the north-west, running down the coast to Bunbury, south of Perth. The pipeline links the gas fields located in the Carnarvon and Perth basins to mining, industrial and commercial customers, as well as customers on the Mid-West and South-West Gas Distribution Network.

This access arrangement review has been conducted during a period of considerable uncertainty for the future of natural gas use. Long-term, gas use is expected to decline as both state and federal governments plan for a net-zero emissions future. However, the timing and pace of this decline is unclear. Current gas demand remains strong, and there is the possibility for growth through the development of onshore gas fields in Western Australia.

We have increased DBP's proposed demand forecast for AA6, taking into account information on expected pipeline use from DBP's customers. However, we do acknowledge that it is becoming harder to accurately forecast gas use, and therefore pipeline use. For this reason, we have included a new tariff variation mechanism in this final decision, allowing for haulage reference tariffs to be adjusted should there be a significant variance between actual and forecast demand.

Changing economic and financial conditions are important factors in determining DBP's cost of capital and the regulatory value of its capital base. A higher rate of return accounts for 29.8 per cent of the total increase in revenue between what we approved for AA5 and this AA6 final decision. Higher rates of inflation account for 20 per cent of the total increase in revenue between AA5 and AA6.

These higher costs flow through to higher tariffs, but the ERA has mitigated this wherever possible by ensuring that DBP's proposed expenditure for the pipeline is prudent and efficient. The ERA has made reductions to capital and operating expenditure allowances where this is not the case.

To reach its final decision the ERA has considered expert opinions and analysis from external independent consultants and stakeholder submissions. We have also taken account of the revised national gas objective, which now requires us to consider expenditure to reduce carbon emissions in line with government targets.

This Overview sets out the ERA's high-level reasoning for our final decision, the components of which are set out in more detail in separate attachments that together comprise the full final decision. The ERA's final decision is to not accept DBP's revised proposal and as a result, the ERA has published its own approved access arrangement and access arrangement information for the AA6 period.

Final decision

The ERA has approved total revenue of $2,464.2 million (nominal) in this final decision, $27.3 million lower than DBP's revised proposal ($2,491.5 million), but $73.3 million higher than our draft decision ($2,390.9 million).

Our final decision differs from the draft decision published in July 2025 in the following key ways:

- We have increased DBP's forecast capacity for the pipeline to include intended capacity demand from existing shippers that is not yet contracted, as well as prospective capacity demand associated with new projects from these existing shippers that are highly likely to become operational during AA6.
- Our AA6 operating expenditure of $607.4 million is 13.5 per cent higher than our draft decision amount of $535.0 million (in real terms). The $72.5 million increase is mainly driven by an increase in system use gas expenditure ($46.9 million more), which is related to our forecast increase in demand throughput; and increases to salaries expenditure ($17 million more) after considering additional information from DBP to justify the costs.
- After receiving more detailed information from DBP, we approved higher amounts of capital expenditure (in real terms) for Information Technology ($9.4 million more) and DBP's Jandakot redevelopment project ($1 million more).
- We changed the rebateable portion of rebateable services from 90 per cent in the draft decision to 80 per cent. This is the amount of revenue from the sale of rebateable services that DBP must return to reference service users via a reduction to the haulage reference tariff. We have changed this after considering further information from DBP on the incremental costs incurred for the provision of rebateable services.
- We also made changes to the reference tariff structure to account for revenue derived from overrun gas charges, which has been increasing. The reference tariff will now comprise three tariff components: the existing capacity reservation and commodity tariffs, and a new overrun tariff (as discussed below).

Tariffs

There are three regulated tariffs for the DBNGP: T1, P1 and B1 Tariffs, which apply to the haulage reference services: full haul T1, part haul P1 and back haul B1 Services.

In setting the haulage reference tariffs to apply in AA6, the ERA has made an adjustment to rebate 70 per cent of rebateable services revenue earned by DBP during the period 1 October 2024 to 30 September 2025. This adjustment is made in accordance with the tariff variation mechanism that was approved for the AA5 period (1 January 2021 to 31 December 2025).

The ERA's final decision rebated T1 Tariff to apply from 1 January 2026 is $1.82 per gigajoule per day (nominal). This is approximately 33 per cent higher than the current 2025 tariff of $1.37 per gigajoule per day.

As proposed in our draft decision, we have elected to implement this tariff change in a single step, instead of smoothing it across the five years of the access arrangement. This results in a more stable price path during AA6, as well as lower actual tariffs in the out-years than under tariff smoothing.

The rebated P1 Tariff and B1 Tariff to apply from 1 January 2026 is $0.001300 per gigajoule per day per kilometre (nominal); determined using the full haul tariff but on a per kilometre basis. That is, part haul and back haul service users are charged based on the number of kilometres from their inlet point to their outlet point.

Tariffs for the remaining years of the AA6 period (2027 to 2030) will be determined in accordance with the tariff variation mechanism that applies for AA6, which includes an annual schedule variation to adjust tariffs for inflation; the cost of debt; rebateable services; Safeguard Mechanism costs or benefits; net overrun revenue; and significant variations in demand.

DBP's haulage reference tariffs are paid by its customers, which are large producers and purchasers of gas. The State Government sets the maximum amount that households can be charged for their gas.

Overrun gas

For AA6, the ERA has made changes to the reference tariff structure to account for the revenue derived from overrun gas charges, which increased significantly over AA5 and is expected to remain material during AA6. The reference tariff will now include three distinct tariff components: a capacity reservation tariff, a commodity tariff and an overrun tariff.

Overrun gas refers to gas received by a shipper on a gas day in excess of the shipper's contractual entitlement. The rights and obligations relating to overrun gas is dealt with in contractual provisions that are attached to each of the reference services; hence, the ERA has determined that the net revenue from overrun gas charges should be accounted for in the revenue equalisation process under rule 92 of the National Gas Rules. Revenue equalisation requires that forecast tariff revenues are set to equal forecast total revenue that is determined from the building block components. The omission of overrun gas revenue in this equalisation process conflicts with the national gas objective and revenue and pricing principles because the tariffs set would be higher than necessary for DBP to recover its efficient costs of providing reference services. That is, had overrun gas revenue been accounted for in the revenue equalisation process, the tariffs set would have been lower and more reflective of the tariffs needed to recover the efficient costs required to operate the pipeline.

The ERA acknowledges that for previous access arrangements, overrun gas revenue has not been accounted for as part of the revenue equalisation process. Through the issuance of the Regulatory Information Notices in AA5, the ERA has become aware of the increasing materiality of overrun gas usage. For this and the other reasons set out in this decision, the ERA has decided to address the revenue derived from overrun gas charges via changes to the reference tariff to ensure the haulage reference tariffs that are payable by shippers are cost reflective and promote economic efficiency.

2. Final decision

The ERA's final decision is to not approve DBP's revised access arrangement proposal for its gas transmission pipeline, which was submitted on 19 August 2025.

A summary of the ERA's final decision considerations is provided in section 3 of this document. The process the ERA followed to make its final decision is set out in section 4.

Detailed reasons for the final decision are set out in the following (separate) attachments, which together form the ERA's final decision.[1]

Attachment 1: Access arrangement and services

Attachment 2: Demand

Attachment 3: Revenue and tariffs

Attachment 4: Regulatory capital base

Attachment 5: Operating expenditure

Attachment 6: Depreciation

Attachment 7: Return on capital, taxation, incentives

Attachment 8: Other access arrangement provisions

Attachment 9: Service terms and conditions

The amendments that the ERA requires to DBP's revised access arrangement are set out in the final decision attachments. A summary of these required amendments is provided in Appendix 2.

Pursuant to the regulatory framework, the ERA must now itself propose revisions to the access arrangement for the DBNGP and make a decision to give effect to its proposal, within two months of this final decision.[2]

This final decision constitutes the decision that gives effect to the ERA's proposed access arrangement revisions.

As required, the ERA has determined its proposed revisions to the access arrangement having regard to the regulatory requirements, DBP's revised proposal and the ERA's reasons for not approving it. The ERA has made the necessary revisions to DBP's revised access arrangement proposal, consistent with the required amendments in this final decision.[3]

The ERA has also drafted its own access arrangement information that contains the information required to understand the basis and derivation of the various elements of the approved access arrangement.

1 This document and its attachments are available from the ERA website.

2 NGR, rules 64(1) and 64(4).

3 NGR, rule 64(2). The ERA has also made minor administrative amendments (for example, typographical and formatting amendments) to the Access Arrangement and deleted the provision for 'interval of delay' (clause 14.2) given this Access Arrangement has commenced without delay.

The ERA has published on its website this final decision and approved access arrangement and access arrangement information.[4]

The ERA's approved access arrangement will take effect on 1 January 2026.[5]

4 NGR, 64(5).

5 NGR, rule 64(6).

3. Final decision considerations

A summary of the key matters addressed in, and reasons for, the ERA's final decision is provided here. This summary is not intended to be a comprehensive statement of the ERA's considerations. The ERA's detailed reasons are set out in the attachments to this document, which together comprise the ERA's final decision.

3.1 Access arrangement and services

In its access arrangement proposal, DBP:

- Identified the pipeline to which the access arrangement relates as the DBNGP, with a detailed description of the pipeline and additional information about the pipeline provided on DBP's website.
- Specified the access arrangement review submission date and revision commencement date as 1 January 2030 and 1 January 2031, respectively.
- Specified a total of three haulage reference services to be offered under the access arrangement (Full Haul T1 Service, Part Haul P1 Service, and Back Haul B1 Service), which are consistent with the reference services approved in DBP's reference service proposal.

The ERA approved the abovementioned elements of DBP's access arrangement proposal in the draft decision, subject to DBP amending the specification of the Pilbara Service to be a non-reference service only (rather than a non-reference rebateable service).

DBP's revised proposal amended the Pilbara Service to be a non-reference (non-rebateable) service and made several consequential administrative amendments to cross-reference this amendment.

Noting the above, the ERA approves DBP's pipeline description, access arrangement dates and reference services for inclusion in the access arrangement for AA6.

3.2 Demand

Demand forecasts directly influence the levels of capital and operating expenditure required by the service provider over the access arrangement period. These forecasts serve as a primary input into the revenue model, used to determine the network tariffs the service provider is permitted to charge.

Under the access arrangement, DBP offers three reference services. Demand for these reference services is measured using two metrics: unweighted volume (gas demand) and distance-weighted Full Haul Equivalent (FHE) volume, known as "FHE demand". Gas demand comprises capacity and throughput, while FHE demand is derived from the underlying gas demand and is used to calculate the applicable reference tariff.[6]

6 The full haul distance is 1,399 kilometres. The FHE factor of part haul (P1) and back haul (B1) services is the contracted distance proportionate to the full haul distance, with a maximum factor of 1.0 for the full haul (T1) service. The FHE demand is calculated as gas demand multiplied by the FHE factor.

"Capacity" is the volume of gas reserved during the contracted period; whereas "throughput" is the actual volume of gas transported.

DBP's revised demand proposal in response to the draft decision incorporated known contractual changes and some of the ERA's adjustments set out in the draft decision.

DBP did not include capacity forecasts for planned projects that it considered unlikely to be commissioned during AA6. It also did not include increases in capacity demand from shippers in gas-powered generation arising from potential delays of new renewable and storage projects, or from intermittency associated with renewable power generation. DBP also did not adopt the ERA's draft decision approach of assessing historical load factors at both contract and shipper levels for determining forecast throughput.[7]

For AA6, DBP's revised proposal for reference services forecast an average FHE capacity of 549.3 TJ/d and gas throughput of 486.6 TJ/d.

In this final decision, the ERA has assessed DBP's revised demand forecast for reference services, using information submitted by DBP, actual gas demand during AA5, stakeholder submissions and feedback, as well as information from the Australian Energy Market Operator (AEMO).

The ERA has adjusted DBP's revised capacity forecast to include intended capacity demand from existing shippers on the DBNGP in AA6 that is not yet contracted, as well as from prospective capacity demand associated with new projects from these existing shippers that are highly likely to become operational during AA6.

The ERA maintains its draft decision that historical load factors should be assessed at both contract and shipper levels, recognising that shippers may vary throughput across their portfolios using multiple contracts and service types.

Recognising the uncertainties surrounding gas demand during the energy transition, the ERA has decided to introduce a tariff variation and fixed principle to allow tariff adjustments in circumstances where actual demand for reference services differ by more than +/- 5 per cent from the demand forecast during AA6. Details of this tariff variation and fixed principle for demand uncertainty are provided in section 3.8.

For AA6, the ERA has forecast an average FHE capacity of 626.9 TJ/d and gas throughput of 560.2 TJ/d.

Table 1 compares the ERA's and DBP's demand forecast, while Table 2 compares the demand forecast on a FHE basis.

7 Some shippers have multiple contracts and/or contracting in multiple reference service types.

Table 1: Reference service gas demand forecast comparison between DBP revised proposal and ERA final decision (average TJ/d)

	DBP revised proposal	ERA final decision	Variance	Variance %
Capacity				
Full haul	479.3	548.5	69.2	14.4
Part haul	377.1	395.3	18.2	4.8
Back haul	333.0	345.4	12.4	3.7
Total	**1,189.4**	**1,289.2**	**99.8**	**8.4**
Throughput				
Full haul	435.7	501.0	65.3	15.0
Part haul	245.5	254.6	9.1	3.7
Back haul	221.0	243.8	22.8	10.3
Total	**902.2**	**999.4**	**97.2**	**10.8**

Source: Final Decision Attachment 2, Table 2.1.

Table 2: Reference service FHE demand forecast comparison between DBP revised proposal and ERA final decision (average TJ/d)

	DBP revised proposal	ERA final decision	Variance	Variance %
Capacity (FHE)				
Full haul	479.3	548.5	69.2	14.4
Part haul	37.6	45.5	7.9	21.3
Back haul	32.4	32.9	0.5	1.5
Total	**549.3**	**626.9**	**77.6**	**14.1**
Throughput (FHE)				
Full haul	435.7	501.0	65.3	15.0
Part haul	29.3	35.7	6.4	21.8
Back haul	21.6	23.5	1.9	8.8
Total	**486.6**	**560.2**	**73.6**	**15.1**

Source: Final Decision Attachment 2, Table 2.2.

3.3 Revenue and tariffs

The regulatory framework provides for an amount of revenue to be determined for each year of the access arrangement period to provide DBP with the ability to recover its efficient costs to operate the DBNGP for the long-term interest of natural gas users. DBP's revenue includes the following "building blocks":

- A return on the projected capital base (see section 3.7).
- Depreciation on the projected capital base (see section 3.6).
- The estimated cost of corporate income tax (see section 3.7).
- A forecast of operating expenditure (see section 3.5).
- Adjustments to reflect the operation of the "E Factor" incentive mechanism (see section 3.7).

Once the efficient amount of revenue (the "total revenue" amount) is determined, reference tariffs are calculated by allocating the portion of total revenue relevant to the provision of reference services (see section 3.1) and dividing by the forecast demand (see section 3.2) for those services.

3.3.1 Total revenue

The ERA has approved a total revenue amount of $2,464.2 million in this final decision for AA6 based on the decisions for the components of total revenue (Table 3). This is $73.3 million more than the ERA's draft decision of $2,390.9 million.

The main difference between the draft and final decisions are the increases in operating and capital expenditure allowances for AA6, following the ERA's consideration of additional information provided by DBP.

The ERA's final decision total revenue amount is still $27.3 million less than DBP's revised total revenue proposal of $2,491.5 (Table 4).

Table 3: ERA final decision total revenue requirement for AA6 ($ million, nominal)

Building block	2026	2027	2028	2029	2030	Total
Return on capital base	250.1	247.9	246.0	243.2	239.6	**1,226.8**
Regulatory depreciation						
Depreciation	164.5	172.7	177.6	180.2	187.0	**881.9**
Inflationary gain	(77.7)	(77.0)	(76.4)	(75.5)	(74.4)	**(380.9)**
Operating expenditure	115.3	133.7	136.2	135.7	143.0	**663.9**
Regulatory corporate income tax						
Corporate income tax	33.5	40.9	42.0	53.6	55.1	**225.1**
Imputation credits	(16.7)	(20.5)	(21.0)	(26.8)	(27.6)	**(112.6)**

Building block	2026	2027	2028	2029	2030	Total
Incentive mechanism adjustment (E factor)	(3.7)	(11.9)	(14.1)	(10.3)	-	**(40.0)**
Total revenue (unsmoothed)	**465.2**	**485.9**	**490.3**	**500.0**	**522.9**	**2,464.2**

Source: Final Decision Attachment 3, Table 3.4.

Table 4: ERA final decision total revenue requirement for AA6 compared to DBP revised proposal ($ million, nominal)

Building block	DBP revised proposal (A)	ERA final decision (B)	Difference (B – A)
Return on capital base	1,230.8	1,226.8	(4.0)
Regulatory depreciation			
Depreciation	884.7	881.9	(2.8)
Inflationary gain	(354.3)	(380.9)	(26.6)
Operating expenditure	675.6	663.9	(11.7)
Regulatory corporate income tax			
Corporate income tax	222.1	225.1	3.0
Imputation credits	(111.0)	(112.6)	(1.6)
Incentive mechanism adjustment (E factor)	(56.4)	(40.0)	16.4
Total revenue (unsmoothed)	**2,491.5**	**2,464.2**	**(27.3)**

Source: Final Decision Attachment 3.

3.3.2 Allocation of total revenue

The ERA's final decision allocation ratio of efficient costs between reference and non-reference services is 98:2. That is, this decision has allocated 98 per cent of the total revenue requirement to reference services, and 2 per cent to non-reference services (Table 5).

DBP rejected the ERA's draft decision to include revenue from overrun gas charges in the allocation of total revenue, on the basis that overrun gas is neither a reference service nor a non-reference service. Subsequently, DBP revised the allocation ratio between reference and non-reference services to be 98:2 in its revised proposal (compared to the ERA's draft decision allocation ratio of 95:5).

Consistent with the ERA's final decision not to treat revenue derived from overrun gas charges as non-reference service revenue, and to retain the Pilbara Service as a non-reference (non-rebateable) service, the ERA's final decision sets the allocation of costs between reference and non-reference services at 98:2.

Table 5: ERA allocation of total revenue between reference and other (non-reference) services for AA6 ($ million, nominal)

	2026	2027	2028	2029	2030	Total
Total revenue	**465.2**	**485.9**	**490.3**	**500.0**	**522.9**	**2,464.2**
Allocation to reference services	456.3	476.8	481.1	490.7	513.2	2,418.1
Allocation to other (non-reference) services	8.9	9.1	9.1	9.3	9.7	46.1

Source: Final Decision Attachment 3.

3.3.3 Reference tariffs

In setting the reference tariffs to apply from 1 January 2026 to 31 December 2026, the ERA must make an adjustment to rebate 70 per cent of the rebateable services revenue earned by DBP during the period 1 October 2024 to 30 September 2025.

Applying the 70 per cent rebate reduces the full haul T1 Tariff by $0.24 or 12.3 per cent (in real terms) as set out in Table 6. A proportional reduction occurs for both the part haul P1 and back haul B1 Tariffs, which are determined using the T1 Tariff but on a per kilometre basis.

Table 6: Comparison of ERA final decision non-rebated and rebated haulage reference tariffs for 2026 ($, real 31 December 2024)

Tariff component	2026 tariff without rebate adjustment (Non-rebated tariff)	2026 tariff with rebate adjustment (Rebated tariff)	Change (%)
Full haul T1 Service			
Capacity (reservation) charge ($/GJ/day)	1.798191	1.580753	(12.1)
Commodity (throughput) charge ($/GJ/day)	0.155091	0.132948	(14.3)
T1 Tariff	**1.953282**	**1.713701**	**(12.3)**
Part haul P1 Service			
Capacity (reservation) charge ($/GJ/km/day)	0.001285	0.001130	(12.1)
Commodity (throughput) charge ($/GJ/km/day)	0.000111	0.000095	(14.4)
P1 Tariff	**0.001396**	**0.001225**	**(12.2)**
Back haul B1 Service			
Capacity (reservation) charge ($/GJ/km/day)	0.001285	0.001130	(12.1)
Commodity (throughput) charge ($/GJ/km/day)	0.000111	0.000095	(14.4)
B1 Tariff	**0.001396**	**0.001225**	**(12.2)**

Source: Final Decision Attachment 3, Table 3.12.

The rebated tariffs set out in Table 6 are shown in real dollars ($2024). To convert these rebated tariffs into nominal dollars for 2026, the ERA has used the latest available inflation up to September 2025 from the weighted average of all capital cities from the ABS.

The nominal rebated T1 Tariff for 1 January 2026 is $1.818828, and the nominal rebated P1/B1 Tariff is $0.001300 (Table 7).

Table 7: ERA final decision rebated haulage reference tariffs to apply from 1 January 2026 ($, nominal)

Tariff component	1 January 2026 rebated tariff
Full haul T1 Service	
Capacity (reservation) charge ($/GJ/day)	1.677725
Commodity (throughput) charge ($/GJ/day)	0.141103
T1 Tariff	**1.818828**
Part haul P1 Service	
Capacity (reservation) charge ($/GJ/km/day)	0.001199
Commodity (throughput) charge ($/GJ/km/day)	0.000101
P1 Tariff	**0.001300**
Back haul B1 Service	
Capacity (reservation) charge ($/GJ/km/day)	0.001199
Commodity (throughput) charge ($/GJ/km/day)	0.000101
B1 Tariff	**0.001300**

Source: Final Decision Attachment 3, Table 3.13.

3.3.4 Tariff variation mechanism

The tariff variation mechanism is set out in Annexure A of the access arrangement. For AA5 it included an annual schedule variation (to adjust tariffs for inflation, the cost of debt and rebateable services), and variations for tax changes and cost pass through events.

The T1/P1/B1 Tariffs for 2027 to 2030 will be determined in accordance with the tariff variation mechanism approved for AA6, which was amended by DBP to include adjustments for Safeguard Mechanism costs imposed or any benefits paid by the Federal Government in the annual scheduled variation.

The ERA has further amended the annual scheduled variation to include two new mechanisms to adjust the haulage reference tariffs to account for the revenue derived from overrun gas charges and significant variances in demand.

Overrun gas refers to gas received by a shipper on a gas day in excess of the shipper's contractual entitlement. The rights and obligations relating to overrun gas is dealt with in contractual provisions that are attached to each of the reference services; hence, the ERA has determined that the net revenue from overrun gas charges should be accounted for in the revenue equalisation process under rule 92 of the National Gas Rules. Revenue equalisation requires that forecast tariff revenues are set to equal forecast total revenue that is determined from the building block components. The omission of overrun gas revenue in this equalisation process conflicts with the national gas objective and revenue and pricing principles because the tariffs set would be higher than necessary for DBP to recover its efficient costs of providing reference services. That is, had overrun gas revenue been accounted for in the revenue equalisation process, the tariffs set would have been lower and more reflective of the tariffs needed to recover the efficient costs required to operate the pipeline.

The ERA acknowledges that for previous access arrangements, overrun gas revenue has not been accounted for as part of the revenue equalisation process. Through the issuance of the Regulatory Information Notices in AA5, the ERA has become aware of the increasing materiality of overrun gas usage. For this and the other reasons set out in this decision, the ERA has decided to address the revenue derived from overrun gas charges via changes to the reference tariff to ensure the haulage reference tariffs that are payable by shippers are cost reflective and promote economic efficiency.

While the ERA is satisfied that its final decision demand forecast for AA6 has been arrived at on a reasonable basis and represents the best possible forecast in the circumstances, there is a higher than normal forecasting risk given the uncertainty associated with the energy transition away from coal.[8] The ERA considers that potential future demand for gas-powered generation poses significant forecasting risks. For this reason, and in response to submissions received since the draft decision, the ERA has decided to introduce a tariff variation mechanism for AA6 to adjust the haulage reference tariff for significant variances between actual and forecast demand. Demand is a critical element in the tariff setting process as it directly impacts the tariff payable – higher demand will result in a lower tariff and lower demand will result in a higher tariff.

Further to these changes, the ERA has also increased the rebateable portion for rebateable services from 70 to 80 per cent. That is, for AA6, DBP will return 80 per cent of the revenue generated from the sale of rebateable services to reference service users via a reduction to the haulage reference tariff. This differs from the draft decision, where the rebateable portion was increased from 70 to 90 per cent. The ERA's change results from further information provided by DBP on its incremental costs. While not agreeing with the methodology used by DBP to calculate incremental costs for the provision of rebateable non-reference services, the ERA considers that providing DBP 20 per cent of rebateable services revenue to cover the incremental costs of providing these services is reasonable.

3.4 Regulatory capital base

The regulatory framework requires the roll forward of the capital base from AA5 to AA6. Actual capital expenditure incurred during AA5 is reviewed by the ERA and once approved can be added to the capital base going forward and used in setting the opening capital base for AA6. As the actual capital expenditure for the last year of AA5 (2025) will not be known before the publication of the ERA's final decision, there will be an adjustment for any under or over forecast of expenditure when the assessment for the next access arrangement period (AA7) is carried out. The projected capital base for AA6 must be reviewed in AA7 before it can be approved for addition to the capital base.

The projected capital base for AA6 is important for setting the tariffs during AA6, so must reflect the best possible forecast of prudent and efficient investment and allow an appropriate amount of depreciation. The ERA considered information provided by DBP, public

8 The ERA's consideration of demand is set out in Final Decision Attachment 2.

submissions and findings from the ERA's technical consultant (EMCa) to determine the amount of capital expenditure that meets the requirements of the NGR.

The ERA assessed DBP's proposed actual and forecast capital expenditure for AA5 and AA6 in accordance with the NGR using a three-step framework:

- Consider whether the expenditure is justifiable under the various capital expenditure criteria (economic, incremental revenue, safety, integrity).
- Evaluate whether the expenditure would be undertaken by a prudent service provider acting efficiently, in accordance with accepted good industry practice to achieve the lowest sustainable cost of providing services consistent with the national gas objective.
- Assess whether forecasts or estimates have been arrived at on a reasonable basis and do they represent the best forecast or estimate possible in the circumstances.

3.4.1 Opening capital base

The opening capital base for the start of AA6 (1 January 2025) is $3,438.0 million (real $2024). This reflects the ERA's final decision on the amount of conforming capital expenditure for AA5 and the inclusion of approved AA5 depreciation.

The ERA has determined that $205.3 million in AA5 is conforming capital expenditure.

DBP's revised proposal rejected the ERA's draft decision and proposed AA5 capital expenditure of $211.8 million; $1.0 million less than its initial proposal and $18.7 million more than the draft decision. DBP updated its 2025 forecast expenditure for the Jandakot redevelopment, resulting in the revised proposal being $1.0 million less than its initial proposal.

The ERA's approved final decision on capital expenditure increased by $12.3 million from the draft decision, mainly driven by:

- **Buildings (+ $1.0 million):** DBP has provided significant additional information to justify the increase cost of the Jandakot redevelopment project it is undertaking in AA6 that justifies the planning expenditure in AA5.
- **Information Technology (IT) (+ $9.4 million):** Additional information regarding the OneERP project accounts for the increase in approved IT expenditure in AA5.
- **Metering (+ $3.5 million):** The ERA has reconsidered applying a different treatment to metering cost recovery for certain assets and will now apply this from AA6 onwards instead of retrospectively during AA5.

3.4.2 Projected capital base

The projected capital base for the end of AA6 (31 December 2029) is $2,888.9 million (real $2024). This reflects the ERA's final decision on the amount of conforming forecast capital expenditure and depreciation for AA6.

The ERA's final decision is to approve forecast capital expenditure of $250.8 million for AA6. This is 4 per cent lower than DBP's revised proposal of $262.0 million.

DBP's revised proposed AA6 capital expenditure was $26.1 million less than its initial proposal but $42.1 million more than the ERA's draft decision for AA6. DBP's revised expenditure reflected updated cost information for specific projects and its differing assessment of the prudency of projects disallowed by the ERA.

The increase in the ERA's approved final decision capital expenditure of $30.9 million from the draft decision is mainly driven by:

- **Buildings (+ $18.0 million):** DBP has provided significant additional information to justify the increased cost of the Jandakot redevelopment project in AA6, with the majority of the expenditure now meeting the conforming capital expenditure criteria. The ERA has made a reduction to this project to account of use of the site by non-regulated DBNGP entities and DBP's parent company, the Australia Gas Infrastructure Group (AGIG).

- **IT (+ $9.2 million):** The ERA initially reduced expenditure for a number of IT projects based on a lack of information and justification of the benefits of the projects. DBP has provided greater information in its revised proposal, resulting in the acceptance of most IT related expenditure in the final decision.

- **Compression (+ $3.5 million):** DBP provided additional information and more detailed unit rates in its revised proposal removing the need for a business case wide unit cost percentage reduction which was applied in the draft decision.

3.5 Operating expenditure

The ERA has decided that a prudent and reasonable forecast of operating expenditure for AA6 is $607.4 million (real $2024). This is 2.4 per cent lower than DBP's revised proposal ($622.3 million) but 13.5 per cent higher than our draft decision ($535.0 million).

While the ERA accepted DBP's revised forecast expenditure for items such as gas engine alternators (GEA) and turbine overhauls, insurance and the update to 2024 actuals, we found that other expenditure items, such as wages, salaries and information technology (IT) were not reasonable. We have also recalculated the System Use Gas (SUG) expenditure based on our demand forecast, resulting in an increase in the SUG expenditure. These differences are summarised below:

- **Wages and salaries base year expenditure:** The ERA has approved a base year wages and salary expenditure of $35.1 million instead of DBP's revised proposal expenditure of $44.9 million.

  - In line with the draft decision, the ERA did not consider the expenditure associated with the charge out rate change as reasonable. The lower charge out rate imposed a significant additional burden on the regulated operating expenditure of DBP.

  - The ERA also approved a base year adjustment of $2.5 million instead of the $4.7 million adjustment sought by DBP. The ERA did not find that the head count increase sought by DBP was reasonable.

- **IT step expenditure:** We approved the base year IT expenditure. However, we did not approve DBP's proposed IT step change expenditure for IT sustaining applications and infrastructure.

  - For the sustaining application step expenditure, the ERA approved $2.2 million instead of the $5.3 million sought by DBP, considering the savings that will be made because of DBP's investments.

- For the sustaining infrastructure step expenditure, the ERA considered that $1.8 million expenditure sought by DBP was not reasonable. Given the efficiencies that should be evident from its infrastructure capital investments, DBP did not provide evidence of additional IT infrastructure costs that would warrant a step change.

- **SUG expenditure:** The ERA has replaced DBP's revised demand forecast with its own for the final decision, which results in a higher full haul throughput forecast used to calculate SUG. The AA6 final decision SUG expenditure is $144.5 million, which is $50.0 million higher than DBP's revised proposal.

3.6 Depreciation

Depreciation of the capital base is one revenue component of the total revenue building block and allows for the recovery of approved capital expenditure over time.

DBP's revised proposed approach to calculating depreciation for AA6 includes two parts:

- **Base depreciation allowance:** DBP proposed maintaining the current depreciation approach used in AA5. This approach continued the straight-line depreciation of assets, where the pipeline asset classes were subject to an economic asset life cap of 2063. This revised proposed base allowance was a total of $733.9 million (real 2024) over the AA6 period.

- **Deferred depreciation allowance:** DBP accepted the ERA's draft decision that $81.0 million (real 2024) be included over the AA6 period due to the restructure of the regulated asset base in AA5.

The ERA has considered and accepted DBP's approach to calculate base depreciation. DBP has analysed a range of credible scenarios that indicate that the 2063 economic life date is still capable of balancing the risks between DBP and shippers given current information.

Accordingly, the ERA has allowed for a total of $726.1 million (real $2024) for base depreciation over AA6, which varies from DBP's revised proposal due to the ERA's approved capital expenditure levels in this final decision.

The ERA has accepted DBP's revised proposed deferred depreciation approach which simplifies its modelling implementation and spreads the deferred depreciation over the five years of the access arrangement period it applies to. The approach is consistent with the amounts of deferred depreciation resulting from the AA5 final decision and smooths tariff increases. This results in $81.0 million (real $2024) of deferred depreciation being provided over AA6.

The ERA's forecast total regulatory depreciation allowance for AA6 is $807.1 million (real $2024) as shown in Table 8.

Table 8: ERA final decision regulatory depreciation ($ million, real 31 December 2024)

	2026	2027	2028	2029	2030	Total
Straight-line depreciation	141.1	145.5	146.4	145.4	147.7	726.1
Add: Deferred depreciation	16.2	16.2	16.2	16.2	16.2	81.0
Total regulatory depreciation	**157.3**	**161.7**	**162.6**	**161.6**	**163.9**	**807.1**

Source: Final Decision Attachment 6, Tables 6.6 and 6.7.

3.7 Return on capital, taxation and incentives

3.7.1 Return on the regulatory capital base

The rate of return provides service providers with the funding to pay interest on loans and give a return on equity to investors. The rate of return is expressed as a weighted average cost of capital (WACC).

A gas rate of return instrument is required under the NGL.[9] The gas instrument sets out the methods the ERA and service providers must use to estimate the allowed rate of return and the value of imputation credits for gas transmission and distribution service providers.

The rate of return DBP used in its access arrangement proposal for AA6 is consistent with the application of the gas rate of return instrument.

Changing economic and financial conditions are important factors in determining DBP's cost of capital and the regulatory value of its capital base. The rate of return in this final decision (7.12 per cent, nominal after-tax) was updated for current market conditions, with a 20-trading day averaging period to 19 September 2025. Higher rates of inflation account for 20 per cent of the total increase in revenue between the AA5 final decision and the AA6 final decision. Updated rates of return also account for 29.8 per cent of the total increase in revenue between the AA5 final decision and the AA6 final decision.

3.7.2 Taxation

A tax building block is included in the annual revenue requirement estimate for each year. The taxation cost is calculated by multiplying the estimated taxable income by the statutory income tax rate of 30 per cent. The estimated taxation payable is calculated by deducting the value of imputation credits.

DBP's method of calculating AA6 taxation was consistent with its approach in AA5. The ERA has updated the AA6 taxation calculation based on approved capital expenditure and taxable revenue calculations in this final decision.

3.7.3 Incentive mechanisms

The regulatory framework provides that a full access arrangement may include incentive mechanisms to encourage efficiency in the provision of services by the service provider. An

[9] NGL, section 30D, 30E.

incentive mechanism may provide for the carrying over of increments for efficiency gains and decrements for efficiency losses from one access arrangement period to the next.

The current AA5 access arrangement contains the Efficiency Factor (E Factor) scheme, which DBP proposed to continue in the access arrangement for AA6, with some minor amendments to the wording of the scheme.

DBP's revised proposal addressed the requirements of the ERA's draft decision, and the ERA has therefore approved the operation of the E Factor scheme in AA6 in accordance with section 15 of the access arrangement. The E Factor benchmarks for AA6 have been calculated based on the ERA's final decision on the efficient forecast of operating expenditure for AA6.

In applying the E Factor for AA5, DBP calculated a revised negative efficiency carryover of $52.3 million (real $2024).

The ERA rejected DBP's revised operating expenditure proposal relating to the labour cost rate update and has therefore maintained its draft decision to accept an amount of $7.7 million for the change in capitalisation policy.

The ERA also rejected DBP's proposed exclusion of $1.6 million for inspections and other asset management expenditure. The ERA has not received any information that conclusively demonstrates this cost was not already included in the base-year operating expenditure approved for AA5. In addition, the amount is not materially significant and is expected to be managed within the approved operating expenditure allowance.

Based on the above positions, the ERA has calculated a negative efficiency carryover of $36.9 million (real $2024) to apply in AA6.

3.8 Other access arrangement provisions

DBP must include requirements for queuing, extensions and expansions, and capacity trading in the access arrangement for DBNGP. DBP must also include principles for changing inlet and outlet points.

The requirements for queuing, extension and expansion and capacity trading, and the principles for changing inlet/outlet points remain unchanged from the current (AA5) provisions. Given these provisions remain consistent with the requirements of the NGR, and that there were no submissions raising any concerns with them, the ERA maintains its draft decision position that there is no reason to require any amendments to these provisions for AA6.

3.8.1 Access request requirements

For AA6, DBP proposed some amendments to the requirements for access requests to clarify the terms of existing reference contracts and to update the requirements for executing access requests.

The ERA approved DBP's amended access request requirements, noting they did not materially change the provisions, but required minor clarifications on contract term updates in the queueing process and that "mail" includes email.

DBP's revised proposal addresses the intent of the required amendments, and while the ERA considers the revised drafting of clauses 5.3(d) and 4.3 relating to automatic contract modifications reasonable, the ERA requires clause 5.3(d) to be reformatted for greater clarity.

3.8.2 *Fixed principles*

An access arrangement may include optional fixed principles to ensure certain elements remain unchanged for a set period, and DBP has elected to carry over the fixed principles from AA5 to AA6 with only minor date amendments.

DBP's revised proposal accepted the ERA's required amendments to clarify the operation of the fixed principle for the rebate mechanism and has incorporated these changes into the fixed principles for AA6.

Consistent with the ERA's final decision on the treatment of overrun gas charges, the ERA requires a new fixed principle to provide certainty on the treatment of net overrun revenue and its use in adjusting the reference tariff.

3.8.3 *Mechanism for demand uncertainty*

In the draft decision, the ERA considered and decided against a trigger event mechanism and tariff variation mechanism for demand uncertainty. The ERA's draft decision position was that the focus should remain on assessing DBP's forecasting and estimating methods to ensure the methods produce demand forecasts that are arrived at on a reasonable basis and represent the best forecast possible, as required under the regulatory framework.[10]

For this final decision, the ERA has reconsidered and decided to introduce a mechanism to address demand forecasting uncertainty in response to a submission on the draft decision.

Although the ERA is satisfied that its AA6 demand forecast is reasonable and represents the best possible estimate, a higher-than-normal level of forecasting risk remains. Due to the uncertainty of the energy transition away from coal, future demand for gas-powered generation continues to present significant forecasting risks.

For this reason, the ERA has introduced a fixed principle and a new provision in the tariff variation mechanism to adjust demand when there is a variance greater than +/- 5 per cent between actual and forecast demand, and for this adjustment to flow through to reference tariffs.

3.9 Service terms and conditions

The regulatory framework requires the access arrangement to specify, for each reference service, a reference tariff and the other terms and conditions on which the service will be provided. The terms and conditions approved under an access arrangement establish standard terms and conditions that users can either accept or use as a point of reference to negotiate their own terms and conditions to meet specific operational needs. In the event terms and conditions cannot be agreed, the access arrangement can be used to guide an arbitrator in an access dispute.

DBP's proposed terms and conditions for the T1, P1 and B1 Services for AA6 (Attachments 2, 3, and 4 of the access arrangement, respectively) included general administrative amendments, additional wording to some clauses and changes to the Access Request Form.

The ERA's draft decision was to conditionally approve DBP's proposed amendments to the terms and conditions, subject to DBP amending:

10 NGR, rule 74.

- Clause 7.9 to create a new sub-heading to better highlight the operator's liability for out of specification gas.
- The pipeline description document with the correct date references used in the terms and conditions.
- The drafting of proposed clause 38(c) so that changes to the contract are applied automatically subject to the parties acknowledging that the changed provisions are applicable and appropriate to the circumstances.

DBP's revised terms and conditions addressed all the ERA's required amendments. The revised terms and conditions also included other minor (administrative) amendments, which the ERA considers do not materially change the terms and conditions. For this reason, the ERA has accepted these other minor amendments.

Additionally, in response to the ERA's draft decision to incorporate the revenue derived from overrun gas charges into the cost allocation process for total revenue, DBP proposed to materially increase the *overrun rate* and the *unavailable overrun charge* in clause 11.1(b)(i) and Schedule 2 of the reference service terms and conditions, respectively.[11]

The ERA considers that DBP did not provided sufficient justification for the proposed increase in the overrun rate (from 115 per cent to 200 per cent of the respective T1, P1 and B1 Tariff) and unavailable overrun charge (from 250 per cent to 300 per cent of the T1 Tariff) and in particular, has not demonstrated that the proposed increases reflect the "genuine pre-estimates of the unavoidable additional costs, losses and damages that DBP will incur" as a result of shippers taking overrun gas. For this reason, the ERA has rejected DBP's proposal to increase the overrun rate/charge.

11 "Overrun" refers to the gas on a particular gas day that a shipper receives across all outlet points that exceeds the aggregate of the quantities of contracted capacity (including the T1, P1 and B1 capacity and any capacity under spot services).

4. Review process

4.1 Regulatory framework

The NGL and NGR, as enacted by the *National Gas (South Australia) Act 2008*, establish the legislative framework for the independent regulation of certain gas pipelines in Australia. The *National Gas Access (WA) Act 2009* implements a modified version of the NGL and NGR in Western Australia.[12] The rules referenced in this decision are those that apply in Western Australia.[13]

The legislative framework for the regulation of gas pipelines includes a central objective, being the national gas objective, which is:

> … to promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to—
>
> (a) price, quality, safety, reliability and security of supply of natural gas; and
>
> (b) the achievement of targets set by a participating jurisdiction—
>
> (i) for reducing Australia's greenhouse gas emissions; or
>
> (ii) that are likely to contribute to reducing Australia's greenhouse gas emissions.
>
> **Note—**
>
> The AEMC must publish targets in a targets statement: see section 72A.[14]

Under the legislative framework, the ERA is responsible for regulating third-party access to gas pipelines in Western Australia. DBP's gas transmission pipeline is one of three regulated pipelines that require an access arrangement to be approved by the ERA under the legislative framework.[15]

An access arrangement provides details of the terms and conditions, including prices, for the provision of pipeline services to a third party to transport and/or receive gas. Once approved, the access arrangement may serve as a benchmark for negotiating access to pipeline services that are offered by means of the regulated pipeline.

As the service provider, DBP is responsible for developing and proposing a relevant access arrangement for its transmission pipeline. As the regulator, the ERA is responsible for assessing the proposed access arrangement against the legislative requirements set out in the NGL and NGR and approving a compliant access arrangement.

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12 The NGL as implemented in Western Australia is set out as a note in the *National Gas Access (WA) Act 2009*. This note does not form part of the Act but shows the text that applies as the *National Gas Access (Western Australia) Law*. In this paper, references to the "NGL" are references to the Western Australian National Gas Access Law text, unless otherwise specified.

13 The current rules that apply in Western Australia are available from the Australian Energy Market Commission: AEMC, 'National Gas Rules (Western Australia)' (online) (accessed December 2025). At the time of this decision, National Gas Rules – Western Australia version 12 (1 February 2024) was in effect.

14 NGL, section 23.

The national gas objective has changed since the last review of DBP's access arrangement. The amended objective came into effect in Western Australia on 25 January 2024. See: *Western Australian Government Gazette 24 January 2024 No.8* (online) (accessed December 2025).

15 The other pipelines which require an approved access arrangement in Western Australia are the Goldfields Gas Pipeline (a transmission pipeline) and the Mid-West and South-West Gas Distribution Systems (a distribution pipeline).

4.2 Access arrangement requirements

Rule 48 of the NGR sets out the required content of an access arrangement. These requirements are summarised in Table 9. In addition, rules 90 and 92 set out further requirements relating to the calculation of depreciation and revenue equalisation.

Table 9: Required content of an access arrangement proposal

Legislative requirement	Legislative reference
Proposal identifies the pipeline to which the access arrangement relates and includes a reference to a website where a description of the pipeline can be inspected.	NGR 48(1)(a)
Proposal describes all the pipeline services that the service provider can reasonably provide (and is consistent with the ERA's reference service proposal decision, unless there has been a material change in circumstances).	NGR 48(1)(b)
Proposal specifies the reference services (and is consistent with the ERA's reference service proposal decision, unless there has been a material change in circumstances).	NGR 48(1)(c)
If the pipeline services and reference services information is different to the ERA's reference service proposal decision, proposal describes the material change in circumstances that necessitated the change having regard to the reference service factors.	NGR 48(1)(c1)
For each reference service, proposal specifies the reference tariff and the other terms and conditions on which each reference service will be provided.	NGR 48(1)(d)
If the access arrangement is to contain queuing requirements, proposal sets out the queuing requirements.	NGR 48(1)(e)
Proposal sets out the capacity trading requirements.	NGR 48(1)(f)
Proposal sets out the extension and expansion requirements.	NGR 48(1)(g)
Proposal states the terms and conditions for changing receipt and delivery points	NGR 48(1)(h)
If there is to be a review submission date, proposal states the review submission date and the revision commencement date.	NGR 48(1)(i)
If there is to be an expiry date, proposal states the expiry date.	NGR 48(1)(j)

In addition to its access arrangement proposal, the service provider must submit Access Arrangement Information (AAI).[16] AAI is information that is reasonably necessary for users (including prospective users) to understand the background to the access arrangement; and the basis and derivation of the various elements of the access arrangement.[17] AAI must include any information that is specifically required by the NGL and NGR. Specifically, rule 72 sets out requirements for AAI relevant to price and revenue regulation. These requirements are summarised in Table 10.

The NGR also provide for the following general requirements for all financial information:

16 NGR, rule 43.

17 NGR, rule 42.

- All financial information must be provided on a nominal or real basis, or some other recognised basis for dealing with the effects of inflation (rule 73).
- All information in the nature of a forecast or estimate must be supported with a statement explaining it. A forecast or estimate must be arrived at on a reasonable basis and must represent the best forecast or estimate possible (rule 74).
- Information that is of the nature of an extrapolation or inference must be supported by the primary information on which the extrapolation or inference is based (rule 75).

Table 10: Requirements for AAI relevant to price and revenue regulation

Legislative requirement	Legislative reference
If the access arrangement period commences at the end of an earlier access arrangement period, AAI includes: • Capital expenditure (by asset class) over the earlier access arrangement period. • Operating expenditure (by category) over the earlier access arrangement period. • Pipeline use over the earlier access arrangement period showing: – for a distribution pipeline: minimum, maximum and average demand; and for a transmission pipeline: minimum, maximum and average demand for each receipt or delivery point. – for a distribution pipeline: customer numbers in total and by tariff class; and for a transmission pipeline: user numbers for each receipt or delivery point.	NGR 72(1)(a)
AAI includes information on how the capital base is arrived at and, if the access arrangement period commences at the end of an earlier access arrangement period, a demonstration of how the capital base increased or diminished over the previous access arrangement period.	NGR 72(1)(b)
AAI includes the projected capital base over the access arrangement period, including: • A forecast of conforming capital expenditure for the period and the basis for the forecast. • A forecast of depreciation for the period including a demonstration of how the forecast is derived on the basis of the proposed depreciation method.	NGR 72(1)(c)
AAI includes, to the extent it is practicable to forecast pipeline capacity and utilisation of pipeline capacity over the access arrangement period, a forecast of pipeline capacity and utilisation of pipeline capacity over that period and the basis on which the forecast has been derived.	NGR 72(1)(d)
AAI includes a forecast of operating expenditure over the access arrangement period and the basis on which the forecast has been derived.	NGR 72(1)(e)
AAI includes the allowed rate of return for each regulatory year of the access arrangement period.	NGR 72(1)(g)
AAI includes the estimated cost of corporate income tax calculated in accordance with rule 87A, including the allowed imputation credits referred to in that rule.	NGR 72(1)(h)

Legislative requirement	Legislative reference
If an incentive mechanism operated for the previous access arrangement period, AAI includes the proposed carry-over of increments for efficiency gains, or decrements for efficiency losses, in the previous access arrangement period and a demonstration of how allowance is to be made for any such increment or decrements.	NGR 72(1)(i)
AAI includes the proposed approach to the setting of tariffs, including the suggested basis of reference tariffs including the method used to allocate costs and a description of any pricing principles employed.	NGR 72(1)(j)
AAI includes the service provider's rationale for any proposed reference tariff variation mechanism.	NGR 72(1)(k)
AAI includes the service provider's rationale for any proposed incentive mechanism.	NGR 72(1)(l)
AAI includes the total revenue to be derived from pipeline services for each regulatory year of the access arrangement period	NGR 72(1)(m)

4.3 Processes and timeframes

The process for gas access arrangement reviews has changed since the ERA's last review of DBP's access arrangement for its transmission pipeline in 2020. There are now two key stages involved in the assessment process for an access arrangement:

- Stage A: Reference service proposal submission and assessment.
- Stage B: Access arrangement proposal submission and assessment.

Stage A: Reference service proposal

The reference service proposal is focused on identifying the full range of pipeline services that can be offered by means of the pipeline and determining which of these services should be specified as a reference service under the access arrangement.[18] The proposal must be submitted at least 12 months prior to the access arrangement proposal.

DBP submitted a reference service proposal for its transmission pipeline on 8 December 2023. After a period of consultation, the ERA decided to not approve DBP's reference service proposal. The ERA disagreed with DBP's decision to remove data services and storage services from its list of pipeline services due to low or no forecast demand for these services.[19] Consequently, the ERA revised DBP's reference service proposal and published its own reference service proposal, listing these services as pipeline services that can be offered by means of the DBNGP, as required under the NGR.[20] The ERA did, however, agree with DBP's

18 A "reference service" is a pipeline service that has a reference tariff that is set (approved) by the regulator under the access arrangement framework, with the reference tariff being the price that a pipeline operator can charge its customers.

19 ERA, *Reference service proposal decision: Proposed reference services for the Dampier to Bunbury Natural Gas Pipeline submitted by DBNGP (WA) Transmission Pty Ltd*, 1 July 2024 (online) (accessed December 2025).

20 ERA, *Reference service proposal for the Dampier to Bunbury Natural Gas Pipeline: 1 January 2026 – 31 December 2030,* 1 July 2024 (online) (accessed December 2025).

proposed reference services for AA6 (being the full haul T1 Service, part haul P1 Service and back haul B1 Service).

The ERA's approved reference service proposal determined which pipeline services are to be specified as reference services in the access arrangement for DBP's transmission pipeline.[21] DBP must set out its proposed terms, conditions and prices for the approved reference services, along with proposed revisions to other access arrangement provisions, in its access arrangement proposal.

Stage B: Access arrangement proposal

Scheduled revisions to DBP's access arrangement for its transmission pipeline were last approved by the ERA in April 2021 for the period 1 January 2021 and finish 31 December 2025, being the fifth access arrangement period (AA5).[22] The review submission date in the AA6 access arrangement is 1 January 2025.

DBP submitted its access arrangement proposal for the next (AA6) access arrangement period, 1 January 2026 to 31 December 2030, in accordance with the AA6 review submission date. The ERA is to assess the proposal in accordance with the provisions of the regulatory framework. The procedure for dealing with an access arrangement proposal is set out in rules 58 to 62 of the NGR.

4.3.1 Timeframes

In most cases, individual review processes are subject to legislated timeframes. These timeframes may change over the course of the review, to the extent the legislation allows, depending on the circumstances at the time.[23] A timeframe for the review of DBP's access arrangement proposal is set out in Table 11.

[21] Rules 48(1)(c) and (c1) of the NGR allow DBP to specify different reference services in its access arrangement proposal if there has been a material change in circumstances since the ERA's reference service proposal decision.

[22] ERA, *Final Decision on Proposed Revisions to the Dampier to Bunbury Natural Gas Pipeline Access Arrangement for 2021 to 2025: Submitted by DBNGP (WA) Transmission Pty Ltd*, 1 April 2021.

[23] Further to setting timeframes for specific processes, the NGR allows certain time periods ('stop-the-clock' periods) to be disregarded when calculating the time elapsed for a process. For example, under rule 11(1)(c), any period allowed for public submissions on an access arrangement proposal or on the ERA's draft decision can be disregarded when calculating the time elapsed for the publication of the ERA's final decision.

Table 11: Timeframe for the review of DBP's access arrangement proposal

Review process stage	Legislated timeframe	Actual date
Stage A: Reference service proposal (completed)		
DBP reference service proposal submitted to ERA	12 months prior to the review submission date for the access arrangement	8 December 2023
Public consultation on DBP's proposal	A period of at least 15 business days	9 February 2024 to 11 March 2024
ERA reference service proposal decision published	No later than 6 months prior to the review submission date for the access arrangement	1 July 2024
Stage B: Access arrangement proposal (in progress)		
DBP access arrangement proposal submitted to ERA	By the review submission date in the current access arrangement	2 January 2025
Initiating notice published by ERA to notify of DBP's proposal	As soon as practicable after receipt of proposal (a delay of up to 30 business days is allowed if the ERA finds the proposal to be deficient and requires DBP to correct the deficiency)	23 January 2025
Public consultation (1st round) on DBP's proposal	A period of least 20 business days after publication of initiating notice	23 January 2025 to 1 April 2025
ERA issues paper published	[not applicable]	4 March 2025
ERA draft decision published	**No legislated timeframe**	**7 July 2025**
Hearing about the ERA draft decision (if, requested by a person and/or provided by ERA)	If a hearing is to be requested by a person, the request must be made within 10 business days after the publication of the draft decision	[not scheduled]
Revision period for DBP to submit a revised proposal in response to the ERA draft decision	A period of at least 30 business days after publication of the draft decision	8 July 2025 to 19 August 2025
Public consultation (2nd round) on ERA draft decision and DBP's revised proposal	A period of at least 20 business days from the end of DBP's s revision period	20 August 2025 to 17 September 2025
Additional public consultation on treatment of overrun revenue and mechanism for demand uncertainty	No legislated timeframe.	10 November 2025 to 17 November 2025
ERA final decision published	Within 8 months from the receipt of DBP's access arrangement proposal, with an extension of up to an additional 2 months (i.e. 10 months in total)	18 December 2025
Access arrangement start date	Date specified in the final decision (or otherwise 10 business days after the date of the final decision)	1 January 2026

Appendix 1 List of Tables

Appendix 2 List of Required Amendments

In making its final decision, the ERA identified the following required amendments that need to be made. These required amendments appear in the attachments to the final decision, along with the ERA's detailed considerations and reasoning for them.

Attachment 1: Access arrangement and services

No required amendments.

Attachment 2: Demand

Required amendment 2.1

The capacity and throughput forecasts for AA6 must be amended to reflect the values in Table 2.8 and Table 2.9 of Final Decision Attachment 2. The amended forecasts must be set out in the access arrangement information.

Attachment 3: Revenue and tariffs

Required amendment 3.1

The values for total revenue (in real terms) must be amended to reflect the values set out in Table 3.8 of Final Decision Attachment 3. The total revenue values must be set out in the access arrangement information.

Required amendment 3.2

The access arrangement must apply a cost allocation ratio of 98:2 to allocate total revenue (and costs) between reference and non-reference services.

Required amendment 3.3

The haulage component of reference tariffs (T1 Tariff, P1 Tariff, B1 Tariff) set out in clauses 3.3, 3.4 and 3.5 of access arrangement for AA6 must be amended to reflect the rebated haulage component of reference tariffs set out in Table 3.13 of Final Decision Attachment 3. These tariffs will apply for the period 1 January 2026 to 31 December 2026.

Required amendment 3.4

The access arrangement must be amended to incorporate a new overrun tariff component. The required amendments are summarised in paragraph 80 and set out in Appendix 2 of Final Decision Attachment 3.

Required amendment 3.5

The administrative drafting amendments set out in Table 3.14 of Final Decision Attachment 3 must be made to Annexure A of the access arrangement.

Required amendment 3.6

Annexure A of the access arrangement must be amended to include new part "A7 Adjustments for Net Overrun Revenue". The required wording for Annexure A7 is set out in Appendix 2 of Final Decision Attachment 3.

Required amendment 3.7

Annexure A5 of the access arrangement must be amended to:

- Reference "80%" as the rebateable portion in clauses 18.19 and 18.20.
- Insert a new clause 18.20(d) to clarify the rebateable portion that applies in the previous access arrangement period and the services to which this rebateable portion applies. The wording for new clause 18.20(d) is set out in paragraph 128 of Final Decision Attachment 3.
- Correct an error in clause 18.20(a); the table in this clause must be amended to correct the end date in Column A for the Period "AA6, 6" from 31 December 2031 to 31 December 2030 to reflect the end date of the access arrangement period.

Required amendment 3.8

Clause 11.3 and Annexure A1 of the access arrangement must be amended to refer to the provisions in Annexure A6 (Adjustments for Safeguard Mechanism) of the access arrangement. The required amended wording is set out in paragraph 133 of Final Decision Attachment 3 and includes some further administrative amendments to clarify that existing Annexures A3 and A4 are both relevant to the trailing average approach used to estimate the debt risk premium used to determine the reference tariff.

Attachment 4: Regulatory capital base

Required amendment 4.1

The opening capital base for AA6 (closing capital base for AA5) must be amended in the access arrangement information to reflect the values in Table 4.8 of Final Decision Attachment 4.

Required amendment 4.2

The projected capital base for AA6 (closing capital base for AA6) must be amended in the access arrangement information to reflect the values in Table 4.16 of Final Decision Attachment 4.

Attachment 5: Operating expenditure

Required amendment 5.1

The access arrangement information must be amended to reflect the operating expenditure forecast of $607.4 million (real 31 December 2024) and the values in Table 5.14 of Final Decision Attachment 5.

Attachment 6: Depreciation

Required amendment 6.1

The forecast regulatory total depreciation allowance for AA6 must be amended to reflect the amounts for 2026 to 2030 as set out in Table 6.8 of Final Decision Attachment 6. The depreciation allowance must be set out in the access arrangement information.

Clause 9.4(a) of the access arrangement must also be amended to reflect the 11 asset categories/groups provided for in Table 6.8.

Attachment 7: Return on capital, taxation and incentives

Required amendment 7.1

The return on capital base must reflect the weighted average cost of capital parameters in Table 7.8 of Final Decision Attachment 7.

Required amendment 7.2

The estimated cost of corporate income tax must be amended in accordance with the values set out in Table 7.11 of Final Decision Attachment 7.

Required amendment 7.3

In accordance with the calculations set out in Table 7.14 and Table 7.15 of Final Decision Attachment 7, a negative efficiency carryover of $36.9 million (real 31 December 2024) must be applied in AA6.

Required amendment 7.4

The E Factor benchmarks to apply for AA6, as set out in section 15 of the access arrangement, must be updated to reflect the benchmarks set out in Table 7.16 of Final Decision Attachment 7.

Attachment 8: Other access arrangement provision

Required amendment 8.1

The access request and queuing requirements in clause 5.3(d) of the access arrangement must be amended to reflect the formatting set out in paragraph 24 of Final Decision Attachment 8.

Required amendment 8.2

Section 13 (Fixed Principles) of the access arrangement must be amended to include a new fixed principle to fix the method used to adjust the reference tariff for actual overrun gas charges collected by DBP. The required drafting amendments are set out in paragraph 33 of Final Decision Attachment 8.

Required amendment 8.3

Section 13 (Fixed Principles) of the access arrangement must be amended to include a new fixed principle for demand to adjust the reference tariff when there is a variance of more than +/- 5 per cent between actual and forecast demand.

Annexure A of the access arrangement must be amended to include a new “demand true-up mechanism”, which details the method used to adjust the reference tariff for variances between forecast and actual demand.

The required drafting for the new fixed principle and tariff variation mechanism for demand is set out in paragraph 52 of Final Decision Attachment 8.

Attachment 9: Service terms and conditions

Required amendment 9.1

The overrun rate set out in clause 11.1(b) of the reference service terms and conditions must be amended to be “115%”, and the unavailable overrun charge set out in Schedule 2 (Row 4) of the reference service terms and conditions must be amended to be “250%”.

Appendix 3 Submissions

Submissions on DBP proposal and/or ERA issues paper
Alinta Energy
Gas Trading Australia
Horizon Power
NewGen Power Kwinana
Wesfarmers Chemicals, Energy and Fertilisers

Submissions on ERA draft decision and/or DBP revised proposal
Mark Chatfield
NewGen Power Kwinana
Wesfarmers Chemicals, Energy and Fertilisers

Submissions in response to further consultation on specific matters (treatment of overrun revenue and mechanism for demand uncertainty)
CITIC Pacific Mining
Dampier Bunbury Pipeline
Mark Chatfield
NewGen Power Kwinana
South32
Wesfarmers Chemicals, Energy and Fertilisers

Appendix 4 Abbreviations

AA5	fifth access arrangement period (1 January 2021 to 31 December 2025)
AA6	sixth access arrangement period (1 January 2026 to 31 December 2030)
AA7	seventh access arrangement period
AAI	Access Arrangement Information
ACCUs	Australian Carbon Credit Units
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CAPM	Sharpe-Lintner Capital Asset Pricing Model
CMP	CITIC Pacific Mining
CPI	Consumer Price Index
DBNGP	Dampier to Bunbury Natural Gas Pipeline
DBP	Dampier Bunbury Pipeline
ERA	Economic Regulation Authority
FHE	full haul equivalent
GCs	gas chromatographs
GSOO	Gas Statement of Opportunities
NewGen	NewGen Power Kwinana
NGL	National Gas Law
NGR	National Gas Rules
NPV	net present value
OffGAR	Office of Gas Access Regulation
off-spec gas	out of specification gas
PJ	petajoule
RBA	Reserve Bank of Australia
SMCs	Safeguard Mechanism Credits
SUG	system use gas
SWIS	South West Interconnected System
TJ	terajoule
WACC	weighted average cost of capital
WesCEF	Wesfarmers Chemicals Energy and Fertilisers